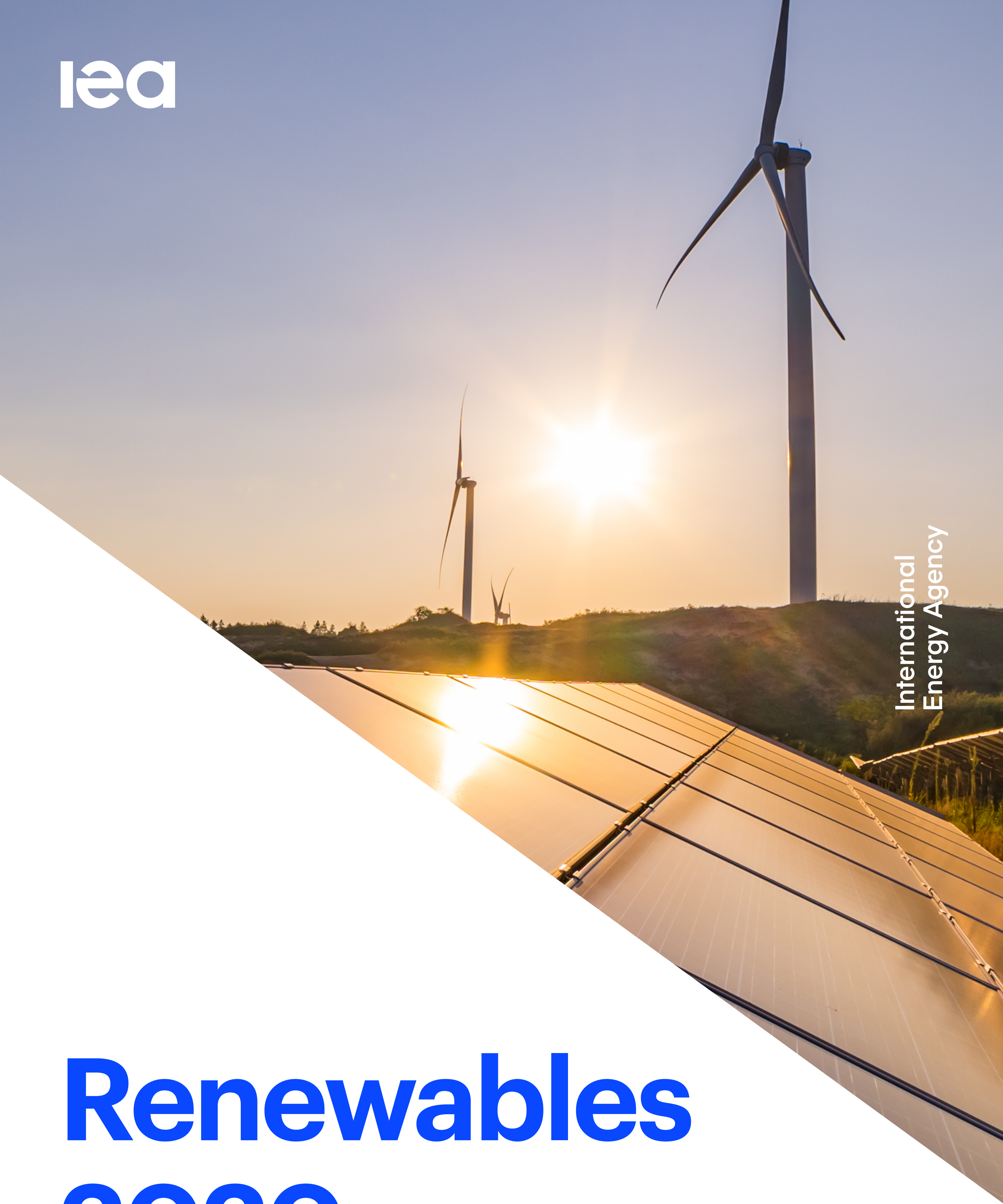


# Renewables 2020

Analysis and forecast to 2025

# Abstract

In May 2020, the IEA market update on renewable energy provided an analysis that looked at the impact of Covid-19 on renewable energy deployment in 2020 and 2021. This early assessment showed that the Covid-19 crisis is hurting – but not halting – global renewable energy growth. Half a year later, the pandemic continues to affect the global economy and daily life. However, renewable markets, especially electricity-generating technologies, have already shown their resilience to the crisis. Renewables 2020 provides detailed analysis and forecasts through 2025 of the impact of Covid-19 on renewables in the electricity, heat and transport sectors.

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# Executive summary

## Renewables' resilience is driven by the electricity sector

**In sharp contrast to all other fuels, renewables used for generating electricity will grow by almost 7% in 2020.** Global energy demand is set to decline 5% – but long-term contracts, priority access to the grid and continuous installation of new plants are all underpinning strong growth in renewable electricity. This more than compensates for declines in bioenergy for industry and biofuels for transport – mostly the result of lower economic activity. The net result is an overall increase of 1% in renewable energy demand in 2020.

**Despite looming economic uncertainties, investor appetite for renewables remains strong.** From January to October 2020, auctioned renewable capacity was 15% higher than for the same period last year, a new record. At the same time, the shares of publicly listed renewable equipment manufacturers and project developers have been outperforming most major stock market indices and the overall energy sector. This is thanks to expectations of healthy business growth and finances over the medium term. In October 2020, shares of solar companies worldwide had more than doubled in value from December 2019.

## Renewable power additions defy Covid to set new record

Driven by China and the United States, net installed renewable capacity will grow by nearly 4% globally in 2020, reaching almost 200 GW. Higher additions of wind and hydropower are taking global renewable capacity additions to a new record this year, accounting for almost 90% of the increase in total power capacity worldwide. Solar PV growth is expected to remain stable as a faster expansion of utility-scale projects compensates for the decline in rooftop additions resulting from individuals and companies reprioritising investments. Wind and solar PV additions are set to jump by 30% in both the People's Republic of China ("China") and the United States as developers rush to complete projects before changes in policy take effect.

**The renewables industry has adapted quickly to the challenges of the Covid crisis.** We have revised the IEA forecast for global renewable capacity additions in 2020 upwards by 18% from our previous update in May. Supply chain disruptions and construction delays slowed the progress of renewable energy projects in the first six months of 2020. However, construction of plants and manufacturing activity ramped up again quickly, and logistical challenges have been mostly resolved with the easing of cross-border restrictions since mid-May. Our new database for monthly capacity additions shows that they have exceeded previous expectations through September, pointing to a faster recovery in Europe, the United States and China.

## Europe and India will lead a renewables surge in 2021

**Renewable capacity additions are on track for a record expansion of nearly 10% in 2021.** Two factors should drive the acceleration, leading to the fastest growth since 2015. First, the commissioning of delayed projects in markets where construction and supply chains were disrupted. Prompt government measures in key markets – the United States, India and some European countries – have authorised developers to complete projects several months after policy or auction deadlines that originally fell at the end of 2020. Second, growth is set to continue in 2021 in some markets – such as the United States, the Middle East and Latin America – where the pre-Covid project pipeline was robust thanks to continued cost declines and uninterrupted policy support.

India is expected to be the largest contributor to the renewables upswing in 2021, with the country's annual additions almost doubling from 2020. A large number of auctioned wind and solar PV projects are expected to become operational following delays due not only to Covid-19 but also to contract negotiations and land acquisition challenges.

**In the European Union, capacity additions are forecast to jump in 2021.** This is mainly the result of previously auctioned utility-scale solar PV and wind projects in France and Germany coming online. Growth is supported by member states' policies to meet the bloc's 2030 renewable energy target and by the EU recovery fund providing low-cost financing and grants. In the Middle East and North Africa region and Latin America, renewable energy additions recover in 2021, led by the commissioning of projects awarded previously in competitive auctions.

## Increasing policy certainty in key markets could significantly boost renewables deployment

**Renewables are resilient to the Covid-19 crisis but not to policy uncertainties.** The expiry of incentives in key markets and the resulting policy uncertainties lead to a small decline in renewables capacity additions in 2022 in our main forecast. In China, onshore wind and solar PV subsidies expire this year, while offshore wind support ends in 2021. The policy framework for 2021-25 will be announced at the end of next year, leaving uncertainty over the pace of renewables expansion in China in 2022 and beyond. Renewable additions are also set to be held back in 2022 by the expiry of production tax credits for onshore wind in the United States, the ongoing financial struggles of distribution companies in India, and delayed auctions in Latin America. In particular, onshore wind additions are expected to decline by 15% globally, while offshore wind expansion continues to accelerate around the world.

If countries address policy uncertainties, as in our Accelerated Case, global solar PV and wind additions could each increase by a further 25% in 2022. This would push renewable capacity additions to a record 271 GW. China alone would account for 30% of the increase. The solar PV annual market could reach about 150 GW – an increase of almost 40% in just three years. In the United States, if additional policies for clean electricity are implemented, solar PV and wind may see much more rapid deployment, contributing to a faster decarbonisation of the US power sector.

## Renewables are set to lead the global electricity sector

**Cost reductions and sustained policy support are expected to drive strong renewables growth beyond 2022.** Despite the challenges emerging from the Covid crisis, the fundamentals of renewable energy expansion have not changed. Solar PV and onshore wind are already the cheapest ways of adding new electricity-generating plants in most countries today. In countries where good resources and cheap financing are available, wind and solar PV plants will challenge existing fossil fuel plants. Solar projects now offer some of the lowest-cost electricity in history. Overall, renewables are set to account for 95% of the net increase in global power capacity through 2025.

**Total installed wind and solar PV capacity is on course to surpass natural gas in 2023 and coal in 2024.** Solar PV alone accounts for 60% of all renewable capacity additions through 2025, and wind provides another 30%. Driven by further cost declines, annual offshore wind additions are set to surge, accounting for one-fifth of the total wind annual market in 2025. Offshore's growth moves beyond Europe to new markets such as China and the United States where ample potential remains. The rapid growth of variable renewables around the world calls for increased policy attention to ensure they are securely and cost-effectively integrated into electricity systems.

**Renewables will overtake coal to become the largest source of electricity generation worldwide in 2025**. By that time, they are expected to supply one-third of the world's electricity. Hydropower will continue to supply almost half of global renewable electricity. It is by far the largest source of renewable electricity worldwide, followed by wind and solar PV.

**Renewables' continued cost declines are changing the investor landscape and the role of policies**. The share of renewables' growth coming from purely market-based settings – outside of policy programmes like auctions and feed-in tariffs – triples from less than 5% today to more than 15% through 2025. This includes corporate power purchase agreements, plants with higher exposure to wholesale power prices or other contracts. While policies and regulatory frameworks remain critically important to provide long-term revenue stability, competition will continue to drive contract prices down. Auctions and green certificate schemes are forecast to cover 60% of renewable capacity expansion globally over the next five years. Major oil and gas companies' investments in new renewable electricity capacity are expected to increase tenfold from 2020 to 2025

## Covid causes biofuels' first contraction in two decades

**The biofuels industry has been strongly impacted by the Covid crisis.** Global transport biofuel production in 2020 is anticipated to decline by 12% from 2019's record. This is the first reduction in annual production in two decades, driven by both lower transport fuel demand and lower fossil fuel prices diminishing the economic attractiveness of biofuels. The biggest year-on-year drops in output are for US and Brazilian ethanol and European biodiesel.

A recovery in fuel demand and stronger policies in key markets can spur a rebound in production in 2021 and sustained growth through 2025. The greatest production increases in this case would be for ethanol in China and Brazil, and for biodiesel and hydrotreated vegetable oil in the United States and Southeast Asia.

## The demand shock hurts renewable heat consumption

**The drop in economic activity due to the pandemic is forecast to impact heat consumption in industry more than in buildings.** This affects demand for renewables, especially bioenergy use in industry. Elsewhere, Covid-19 has had a limited direct impact on short-term renewable heat consumption. Even though global electricity demand for heat is falling in industry and buildings, heat-related renewable electricity consumption is set to rise in both sectors in 2020 owing to higher shares of renewables in electricity generation.

**The share of renewable heat is expected to remain broadly constant over the next five years.** Global renewable heat consumption is projected to be 20% higher in 2025 than it was in 2019, with a stronger increase in the buildings sector than in industry. Despite this rise, renewables are on course to represent only 12% of global heat consumption by 2025, as the overall market is expected to expand, driven by industrial activity. Without a significant change in non-renewable heat consumption, total heat-related $CO_2$ emissions in 2025 are expected to be only 2% lower than in 2019.

## Recent policy momentum has the potential to give renewable energy use an extra boost

**Economic stimulus measures focused on clean energy can directly or indirectly support renewables.** While the majority of the USD 470 billion in energy-related stimulus packages announced by individual countries so far is primarily aimed at providing short-term economic relief, we estimate around USD 108 billion targets economic growth with a focus on clean energy. These measures can support renewables by providing additional financial support either directly – or indirectly through areas such as buildings, grids, electric vehicles and low-carbon hydrogen. This is also the case for the forthcoming EU economic recovery plan, which is expected to contain an estimated USD 310 billion of climate-related spending.

**Renewable fuels for transport are an area of particular potential support, as the sector has been severely hit by the crisis.** More can and should be done, however. For example, only two out of the 30 airlines worldwide that have received government support in response to the crisis were bound to environmental conditions, and only two have been required to commit to a sustainable aviation fuel blending level of 2%.

**Net-zero emission targets in key markets are expected to accelerate the deployment of renewables**. Following the European Union and several European countries, three major Asian economies recently announced targets for reaching net-zero emissions: Japan and South Korea by 2050, and China by 2060. While it is too early to assess their precise impacts, these stated ambitions are very likely to further accelerate the deployment of renewables across all sectors, with potentially significant effects on global markets.

# Covid-19 and the resilience of renewables

This section assesses how resilient renewable energy development and deployment have been during the pandemic crisis, with analysis based on various indicators from recent monthly and quarterly data (up to end-September 2020). Overall, renewable electricity has shown strong resistance according to data on monthly installations, awarded auctions, financing of new projects and equity performance.

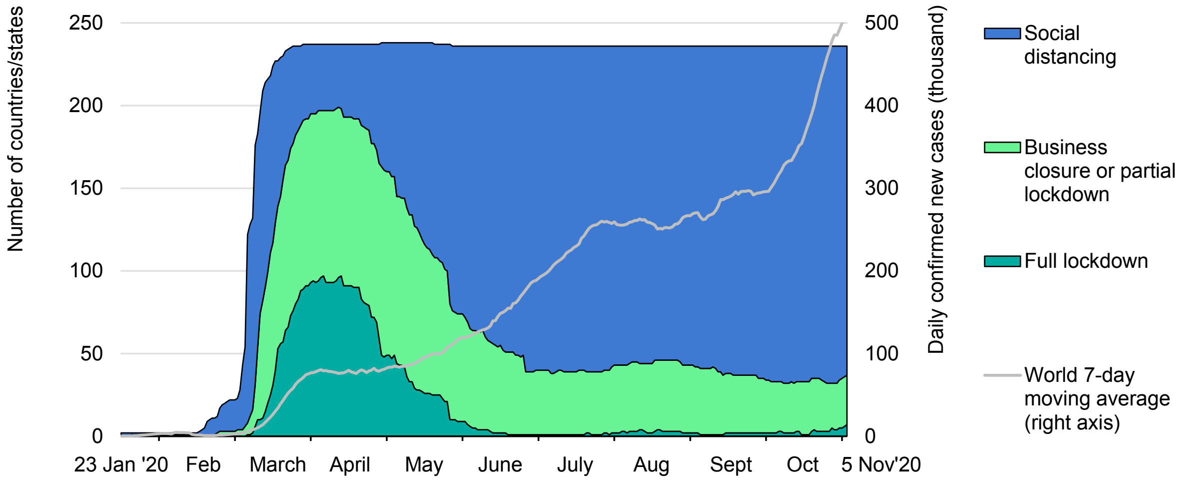
## The world after strict lockdowns

### Renewable capacity expansion adapted to the “new normal” after severe movement restrictions were lifted, but new uncertainties are looming

From February through mid-May 2020, roughly 100 countries, states and provinces – mainly in Europe, Asia and North America – implemented full lockdown measures to contain the pandemic while partial lockdowns were introduced in another 100 jurisdictions. Lockdowns generally lasted from four to ten weeks and were gradually lifted starting in the second half of April. Thanks to these containment measures, the spread of new infections slowed and plateaued globally in April and May.

However, these safety regulations and mobility restrictions also disrupted supply chains and temporarily delayed construction of renewable energy installations – especially onshore wind and solar PV – in key markets. Since mid-May, renewables-based construction projects, equipment supplies, policy implementation (permitting, licensing, auctions) and financing have returned to near normal levels in many countries because project developers and manufacturers have modified their operations to adapt to ongoing social-distancing rules.

**Figure 1.1 Global Covid-19 containment measures and daily new cases**






Sources: Based on Lejeune (2020), Coronavirus Counter Measures; Our World in Data (2020), ECDC Data.

Following the first peak, the number of Covid-19 cases reported globally began to increase rapidly again in June as more countries in Africa, Asia, Latin America and the Middle East became severely affected and testing capacity expanded in North America, Europe and the Russian Federation ("Russia"). By the end of summer, almost all European countries were recording a strong surge in cases.

Despite this, most countries and states (except Israel) had not (re)introduced full or partial lockdowns as of September because of the economic implications. Social distancing measures, however, remained in place in almost all countries and were being tightened in some to contain the second wave.

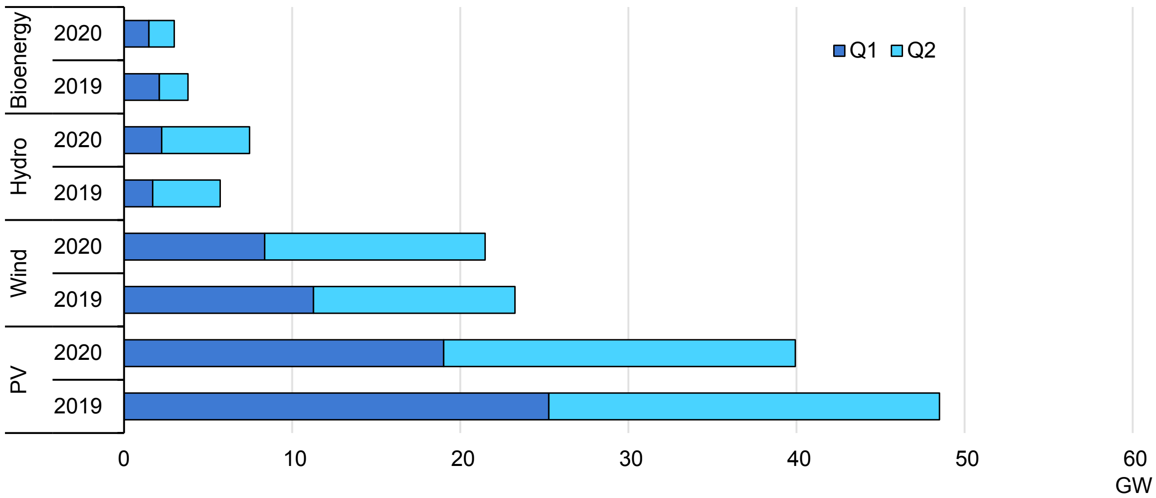
Internal movement restrictions, business closures and local lockdowns in some jurisdictions since the beginning of October have concerned mainly large and medium-sized cities. Although enhanced quarantine rules may apply to some workers in these areas, implications for renewable equipment manufacturing and renewable electricity construction activities are expected to be minimal, as facilities and sites are located mostly outside of heavily populated areas. Nevertheless, the renewed tightening of measures and the reintroduction of full and partial lockdowns in some European countries at the end of October cast additional uncertainty over the expansion of renewable energy in the last quarter of 2020 and 2021.

# January to June renewable electricity capacity additions

## The pace of solar PV and onshore wind additions slowed in the first half of 2020

Global renewable electricity capacity additions were over 11% lower in the first half of 2020 than in the first six months of 2019: developers connected an estimated 40 GW of solar PV, 17% less than last year, while wind expansion was down nearly 8%. Conversely, hydropower capacity additions increased in the first half of 2020, mostly owing to the commissioning of large-scale projects in the People's Republic of China ("China"). The impact of lockdowns and movement restrictions varied by country and technology, and initial IEA data shows that in most countries not only did renewable energy developers not halt construction, but they accelerated their installation activities once restrictions were eased to make up for delays.

**Figure 1.2 Renewable capacity additions by technology, Q1 and Q2 of 2019 and 2020**

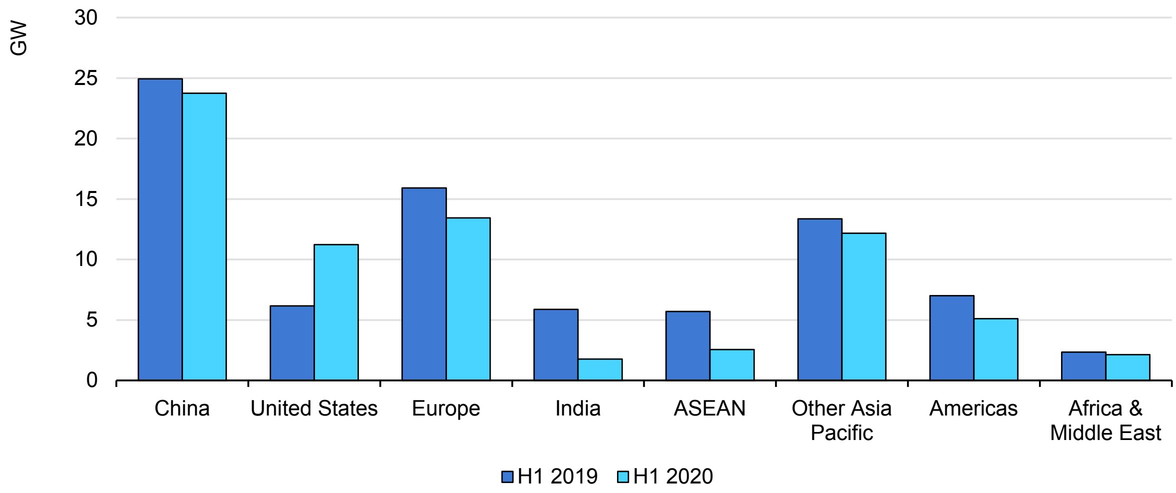





Note: Actual data collected from governments and industry associations cover Argentina, Australia, Brazil, Chile, China, France, Germany, India, Italy, Japan, Korea, the Netherlands, Poland, South Africa, Spain, Sweden, Chinese Taipei, Turkey, the United Kingdom and the United States. These sources represent 75% of total global capacity additions in 2019, with remaining additions estimated based on actual annual data and forecasts.

Compared with 2019, first quarter (Q1) capacity additions in 2020 were lower for all technologies except hydro, with solar PV and wind each contracting 25%. China was the primary driver of this trend, as provincial Covid-19 movement restrictions and related labour shortages reduced construction activity throughout the country. As a result, new wind installations in China declined by 50% and solar PV by 25% in the first three months of 2020. As the pandemic began to recede and lockdown measures were eased, China's growth regained momentum with utility-scale PV, wind and large hydropower plants being installed at a faster pace.

**Figure 1.3 Renewable electricity capacity additions, H1 2019 and H1 2020 by region**






Note: Actual data collected from governments and industry associations cover Argentina, Australia, Brazil, Chile, China, France, Germany, India, Italy, Japan, Korea, the Netherlands, Poland, South Africa, Spain, Sweden, Chinese Taipei, Turkey, the United Kingdom and the United States. These sources represent 75% of total global capacity additions in 2019, with remaining additions estimated based on actual annual data and forecasts.

In the United States, policy deadlines dictate wind and solar PV expansion, as renewable deployment remains largely sheltered from Covid-19 restrictions. US renewable capacity additions almost doubled in the first half of 2020 compared with last year, mainly driven by wind developers' rush to commission projects to meet federal tax incentive deadlines. At the same time, growth in renewable capacity in India slowed significantly – but this started happening prior to the nationwide lockdown imposed at the end of March and resulted largely from the persistent challenges of utilities' poor financial health and projects delays.

In Europe, although new renewable energy capacity additions were lower in the first half of 2020 than in 2019, the installation pace accelerated in the second quarter with the easing of lockdowns and movement restrictions. Germany registered a slowdown in installations (particularly of ground-mounted PV) when the pandemic first arrived in the country, but the recovery in May and June was strong, outpacing 2019 installations during the same time period. Recoveries were also recorded in Italy as additions rebounded to pre-pandemic levels in May after a 90% decline from February to April, and in the Netherlands the pace of combined wind and solar installations slowed during March and April, but recovered again in June.

The ASEAN region installed nearly 60% less capacity from January to June this year than during the same period in 2019. This decline is mostly due to the booming growth last year in Viet Nam as developers rushed to complete PV projects before policy deadlines. Elsewhere in the region, lockdown measures curbed construction activity in Thailand and Indonesia.

# Pre-crisis policies will have at least as much impact as Covid-19 on the future of renewable technologies

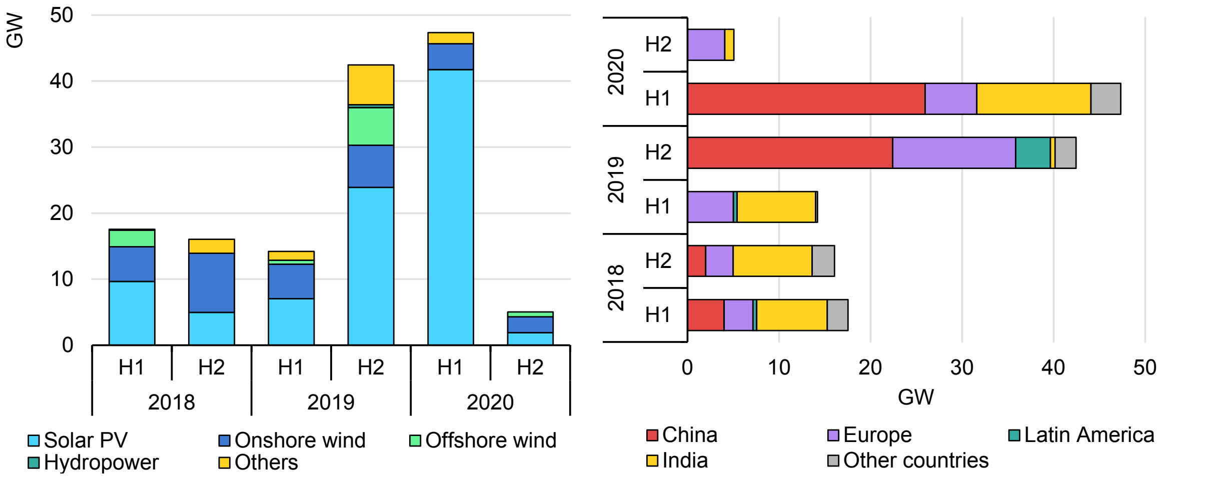
## Despite some delays due to Covid-19, renewable auction volumes are breaking records

In the first half of 2020, 13 countries awarded almost 50 GW of new renewable capacity to become operational during 2021-24, the highest amount ever. China’s national solar PV auction awarded 25 GW in June 2020, marking the global trend. Despite a sharp slowdown in construction activity, India awarded 11.3 GW of solar and almost 1 GW of wind capacity in central and state auctions, reversing the downward trend that had begun in the second half of 2019.

In Europe, Germany, France, Italy and Portugal each completed wind and solar PV auctions from January to June, but overall capacity awarded in the region was significantly lower than last year. Greece, the Netherlands and Ireland also held auctions, with some delays due to Covid-19.

In Latin America, a record 4 GW of capacity was awarded in 2019, mainly through tenders in Colombia, Brazil and Argentina. In 2020, however, the pandemic prompted countries such as Brazil, Argentina and Chile to postpone scheduled auctions, so the region awarded no new renewable capacity in the first half of 2020 as a result.

**Figure 1.4 Renewable electricity auction results by technology and country/region, 2018-20**





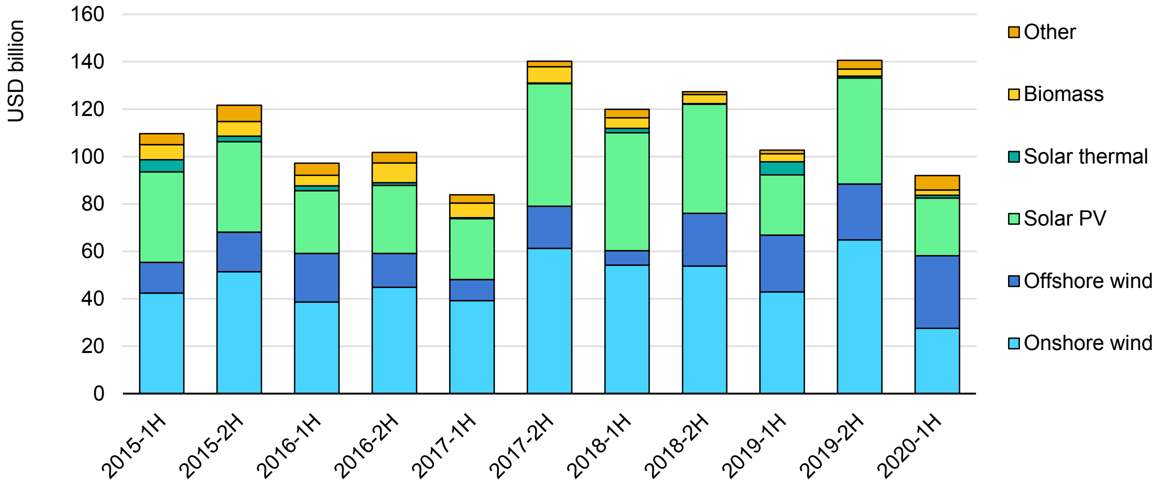

Note: 2020 H2 values only include auctions awarded until October.

## Although policy deadlines in key markets and the Covid-19 crisis reduced financing activity in the first half of 2020, expectations are high for the second half of the year

As the final investment decision (FID) is the last step before a renewable plant (or any other infrastructure project) can start construction, FID data can provide insights into how interested the financing community and investors are in realising renewable electricity projects. Solar PV and onshore wind projects usually start operating 6-12 months after reaching financial close, while longer lead times have been observed for offshore, hydropower and bioenergy projects.

Data show that there were 10% fewer FIDs for total utility-scale renewable projects (excluding large hydropower) in the first half of 2020 than in the same period last year. While support qualification deadlines in 2020 in key markets are the main reason for the decline, risk aversion concerning the economic uncertainty created by Covid-19 is also a factor. The initial shock of the pandemic in February/March led to the lowest quarterly FID since 2017.

**Figure 1.5 FIDs for new utility-scale renewable electricity plants, 2015-20**






Source: Calculations based on IJGlobal (2020), Transaction Data (database).

The largest downturn in the first half of 2020 was for onshore wind, with a year-on-year reduction of 36% marking the global FID trend. Financing activity for onshore wind in China and the United States had surged in 2018 and 2019 to meet policy deadlines for project deliveries this year, followed by an expected slowdown in 2020.

In contrast, offshore wind had the most FIDs of all renewable technologies, as the Covid-19 crisis did not delay major deals in Europe, the largest market. Developers in the Netherlands, the United Kingdom and France closed financing for almost 5 GW of new offshore wind capacity, while in China, several large-scale offshore projects reached financial close to meet the 2021 deadline for feed-in tariff (FiT) phaseout.

Although FIDs for utility-scale solar PV projects in the first half of this year were below USD 25 billion, they remained relatively stable at just 4% lower than in the same period last year. However, investment activity remains significantly below the historical averages of USD 35-45 billion over 2017 and 2018.

This decline is underpinned by developments in two key markets: first, the deadline to qualify for subsidies in China, the world's largest annual PV market, contributed to a flurry of financing activity in 2H 2019. To qualify, projects have to be commissioned by the end of 2020, thus most of them closed financing in the second half of 2019. Although this trend was expected to persist into the first quarter of 2020, the pandemic curbed financing activity significantly.

Second, in India, project delays and cancellations resulting from regulatory issues, combined with emerging financing challenges caused by Covid-19, kept the pace of financing activity slow in the first half of 2020.

Five reasons why financing activity for utility-scale renewables is expected to increase in the second half of 2020 (and beyond) are:

1) Monetary policies announced in most key renewables growth markets in the first half of the year support low interest rates in the foreseeable future, offering favourable conditions for wind and PV projects, which require high upfront investments.

2) Renewable energy projects provide a "safe haven" for certain institutional investors confronting the emerging economic slowdown because they often come with long-term fixed-price contracts.

3) Countries worldwide have awarded a record 100 GW of renewable electricity projects since June 2019, with the majority expected to close financing in 2020.

4) So far, the Covid-19 crisis has not prompted governments in major markets to abandon or cancel already-announced policies ensuring investors that policy support will continue despite the economic turbulence. In addition, long-term net-zero goals in the European Union and China, the two largest renewable energy markets, provide investors with long-range visibility.

5) Stimulus packages have maintained the solvency of major utilities and, to some extent, small businesses investing in renewable projects (i.e. independent power producers [IPPs]) in both emerging markets and advanced economies. These relief measures have been crucial to improve their cash flow and allow them to finance planned projects in the second half of this year.

# Renewable industry equity performance

## Publicly listed renewable equipment manufacturers and project developers remain attractive investment options despite dire economic outlook

Robust financial performance is important for renewable manufacturers and project developers to be granted a lower cost of capital to fund capital-intensive expansions. One measure of performance is the stock market, which can indicate rates of return and financial health because listed companies are required to provide a transparent method of assessing their financial performance (IEA, 2020).[1]

Prior to the pandemic, the renewable energy industry (including wind turbine and solar manufacturers as well as independent renewable power producers) had been achieving higher gains than most major stock market indices since 2018 and performing better

[1] Despite all their flaws, stock markets remain a key indicator of the financial attractiveness of renewable power companies.

than the overall energy sector. For instance, the shares of wind turbine manufacturers, solar equipment producers, and renewable independence power producers increased 30% to 70%. This is far higher than the -20% to +20% changes in major stock market indices and utilities in Europe and North America.

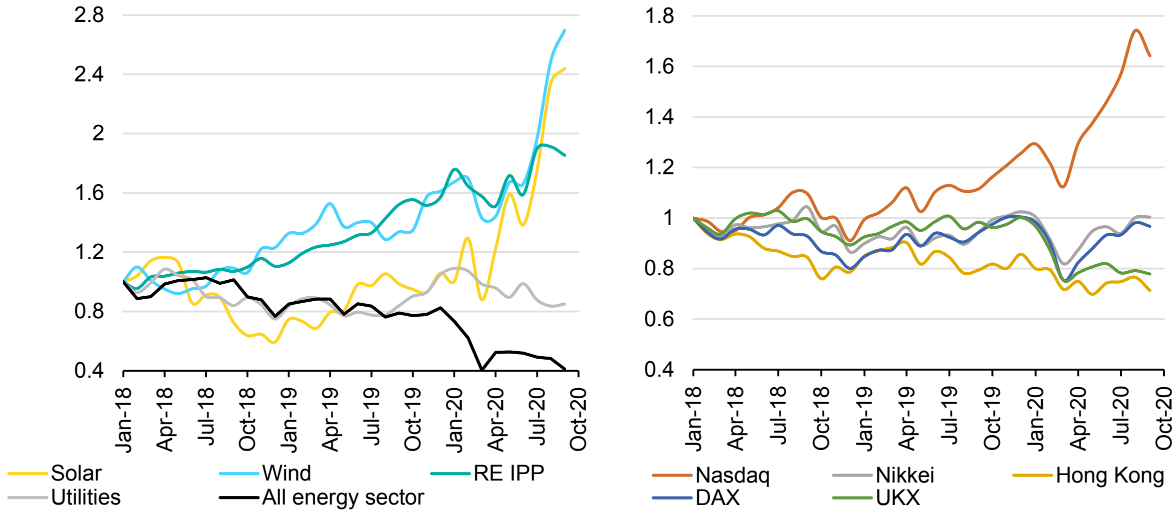
The equity performance of the renewable energy industry has remained resilient since the beginning of the pandemic. In March 2020, stock markets all around the world experienced major sell-offs due to concerns over the Covid-19 impact on the global economy. Wind turbine and solar manufacturers recorded significant declines, with many companies recording negative EBITDAs in the first half of the year as revenues temporarily fell.

However, the stock prices of major wind and solar companies have rebounded, reaching all-time highs owing to strong order backlogs indicating growing demand and healthy business over the medium to long term. Despite the Covid-19 crisis, major solar module manufacturers in China announced plans to double their panel manufacturing capacity in the medium term.

Renewable power producers have been mostly sheltered from the impact of the pandemic. Declining electricity demand and lower prices due to the Covid-19 crisis resulted in sharp revenue drops for major utilities all around the world, especially those deriving revenues from wholesale electricity markets. Due to revenue losses and slow demand recovery prospects, the market values of utilities remain below pre-Covid-19 levels.

In contrast, stock market prices for large renewable energy IPPs have recovered the losses of March and had reached new records by October. The solid performance of renewable IPPs compared with utilities results from the stable revenue stream they receive from existing projects with long-term (10-25 years), fixed-price contracts, which has mostly sheltered them from lower electricity prices.

**Figure 1.6 Indexed stock market prices for traded energy companies and major indices, 2018-20**






Note: Companies covered for each sector are:

**Solar: 19** (Jinko Solar Holding Co Ltd, SunPower, First Solar Inc, Canadian Solar Inc, Xinyi Solar, Trina Solar, JA Solar, LONGi Green Energy technology, GCLSI, Risen Energy, Yingli Green Energy, Enphase Energy, Scatec Solar, Solaria Energia y Medio Ambiente, Daqo New Energy Corp, SolarEdge Technologies, Sunrun Inc, Vivint Solar, SMA Solar Technology).

**Wind: 10** (Siemens Gamesa Renewable Energy, Acciona, Vestas Wind Systems, Xinjiang Goldwind Science & Technology Co Ltd, Suzlon Energy Ltd, China Longyuan Power Group Corp Ltd, Boralex, Northland Power Inc, TransAlta Renewables Inc, Nordex SE).

**RE IPPs: 17** (NextEra Energy Inc, Orsted, MVV Energie, Innergex Renewable Energy, Brookfield Renewable Energy Partners LP, Adani Green Energy Ltd, Encavis AG, Northland Power Inc, Neoen SA, CPFL Energia, Algonquin Power & Utilities Corp, ERG SpA, Falck Renewables, Terna Energy SA, BCPG PCL, Infigen Energy, Enlight Renewable Energy Ltd).

**Utilities: 16** ( Enel SpA, Iberdrola SA, Electricite de France SA, E.ON SE, EDP, Engie, SSE PLC, Drax Group PLC, ACS Actividades de Construccion y Servicios, Tata Power, RWE AG, AES Corporation, Duke Energy Corporation, Sempra Energy, National Grid PLC, Xcel Energy Inc).

Source: Based on Bloomberg (2020), Markets: Stocks (database).

# Impact of Covid-19 crisis on renewable electricity penetration and prices

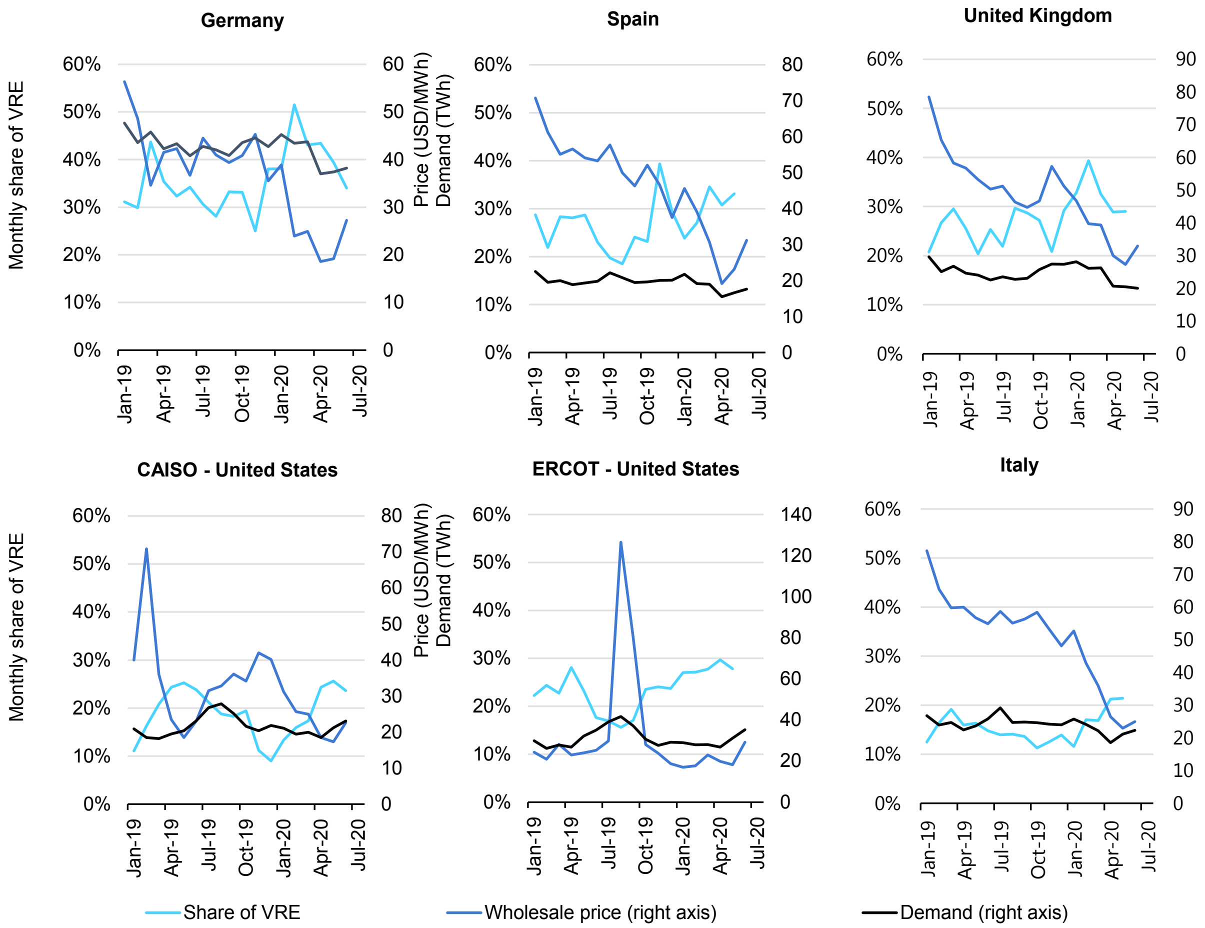
## VRE shares in electricity generation reached record levels during the Covid-19 demand shock, providing a glimpse into future high-VRE power markets

Movement restrictions, lockdowns and the economic slowdown caused by the Covid-19 crisis significantly reduced electricity demand around the world. In April 2020 relative to April 2019, power consumption had fallen 5% in the United States, 12% in Germany, 18% in Spain and 23% in India. Shares of wind and solar PV in electricity generation increased as a result, owing to their low variable costs, priority dispatch rules and long-term contracts – mostly through support policies such as FiTs, FIPs, CfDs and corporate PPAs, as well as continuous capacity deployment.

The combination of the demand shock, increased VRE penetration and low fuel prices pushed wholesale electricity prices down in Europe and the United States. In Germany, Italy, California, Spain and the United Kingdom, average spot market prices declined 30-50% from February to April.

Prior to the Covid-19 demand shock, historical data show that wholesale electricity prices have been supressed in times of high VRE penetration when a smaller conventional generation stack was required. In Germany, California, Texas and Spain, electricity prices have already dropped due to higher VRE shares in their electricity mixes in the last five years.

**Figure 1.7 Average monthly share of VRE-based generation and baseload wholesale electricity prices**






Source: Based on data from BNEF, EIA, and IEA Monthly Electricity Generation Database.

The unprecedented demand shock may be temporary, but it has offered a glimpse of what future electricity markets with high VRE shares could look like. The rapid expansion of wind and solar PV will continue in the medium and long term, spurred by government decarbonisation targets, continuous technology cost reductions and increasing deployment outside of government policy schemes (such as through corporate PPAs and bilateral contracts).

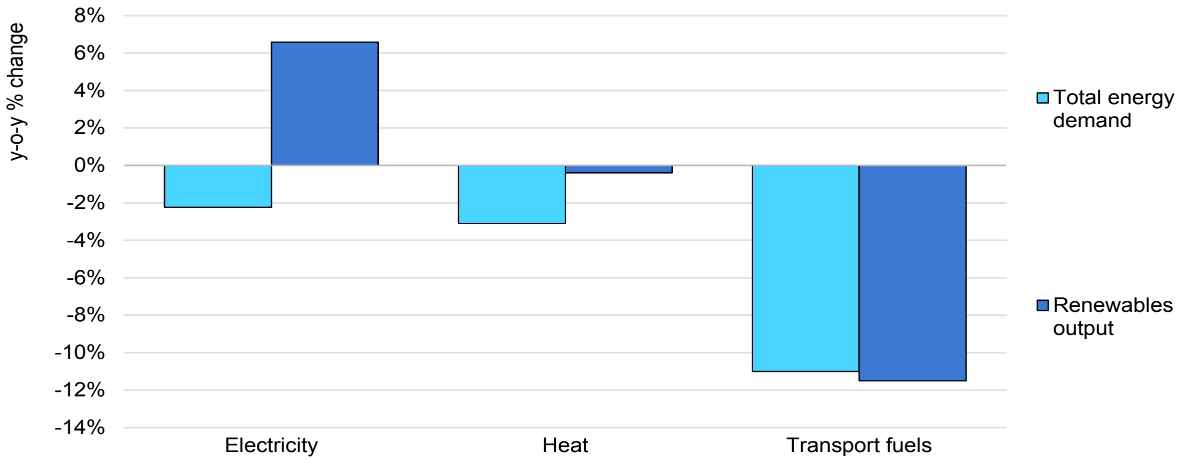
In the medium term, electricity prices in markets with rising VRE penetration could very well remain at the April and May levels. Low prices do not provide the price signals necessary for investment in either conventional or wind and solar PV capacity without long-term contracts. Consequently, electricity market reforms may be required in the short term to attract investment in flexible generation and grids to cost-effectively integrate higher VRE shares.

## Renewable energy in heat and transport is less resilient

Global electricity demand is expected to be more than 2% lower in 2020 than in 2019, while renewables-based generation increases by almost 7%. Despite the pandemic, renewable capacity additions are expected to reach another record – proving their resilience. Policy-driven fixed-price long-term contracts have protected renewables from both lower demand and wholesale electricity prices.

Global heat consumption in homes and for industrial processes is forecast to decline more than 3%, mostly due to curtailment of economic activity. Renewable heat consumption also decreases, but by only less than 1%, demonstrating a certain degree of resistance to the crisis. While reduced commercial, industrial and construction activity has translated into lower bioenergy and waste use in several energy-intensive industries such as paper and pulp and cement, the use of renewables in the residential sector has been less impacted by the demand shock. In addition, renewable electricity use for residential heating is forecast to increase this year, prompted by greater renewables-based generation.

**Figure 1.8 Renewables-based output and total demand change in the electricity, heat and transport sectors, 2019-20**






Biofuels use drops the most of all renewable energy sources as a result of the crisis, due to a combination of lower transport activity and downward pressure on oil prices. Global gasoline demand falls 9% and diesel consumption 7%, while jet fuel demand plummets almost 40%. Biofuel production is expected to decline a record 11.5% in 2020 compared with last year. In spite of blending mandates, demand for biofuels declines much more sharply than for either gasoline or biodiesel because falling crude oil prices since the start of the pandemic have made biofuels less competitive with fossil transport fuels.

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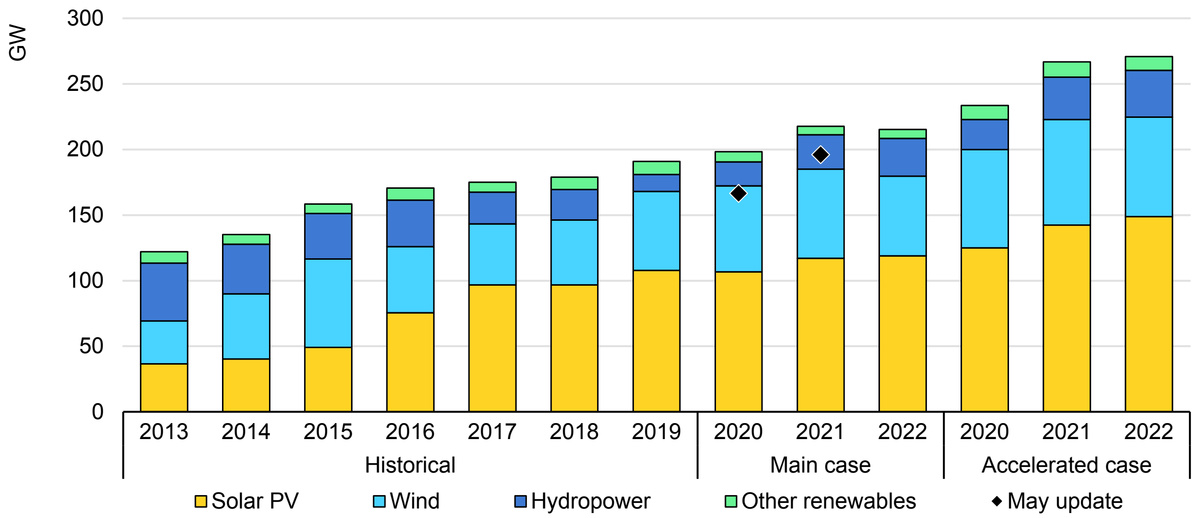
# Renewable electricity

## Forecast summary

### Renewable power markets are more resilient than previously thought

The IEA main case scenario forecasts that the increase in net renewable electricity capacity additions will be almost 4% higher in 2020 than in 2019. This means the world is expected to install over 198 GW of renewable capacity this year, breaking another record. accounting for almost 90% of the increase in total power capacity. Higher additions of wind (+8%) and hydropower (+43 %) are expected in 2020, while solar PV growth remains stable. More utility-scale PV plants will be installed, while growth in distributed PV systems decreases almost 8% as individuals and companies reprioritise investments in light of the economic crisis.

**Figure 2.1 Renewable electricity net capacity additions by technology 2013-22, main and accelerated case**






Supply chain disruptions and construction delays slowed the progress of renewable energy projects in the first six months of 2020. However, construction activity did not halt in many countries even during full/partial lockdowns, manufacturing activity has ramped up quickly, and logistical challenges have been mostly resolved with the easing of cross-border restrictions since mid-May. Monthly capacity additions through

September have exceeded previous expectations, pointing to a faster recovery in Europe, the United States and China. As a result, the forecast for 2020 has been revised upwards by over 18% from our previous update in May.

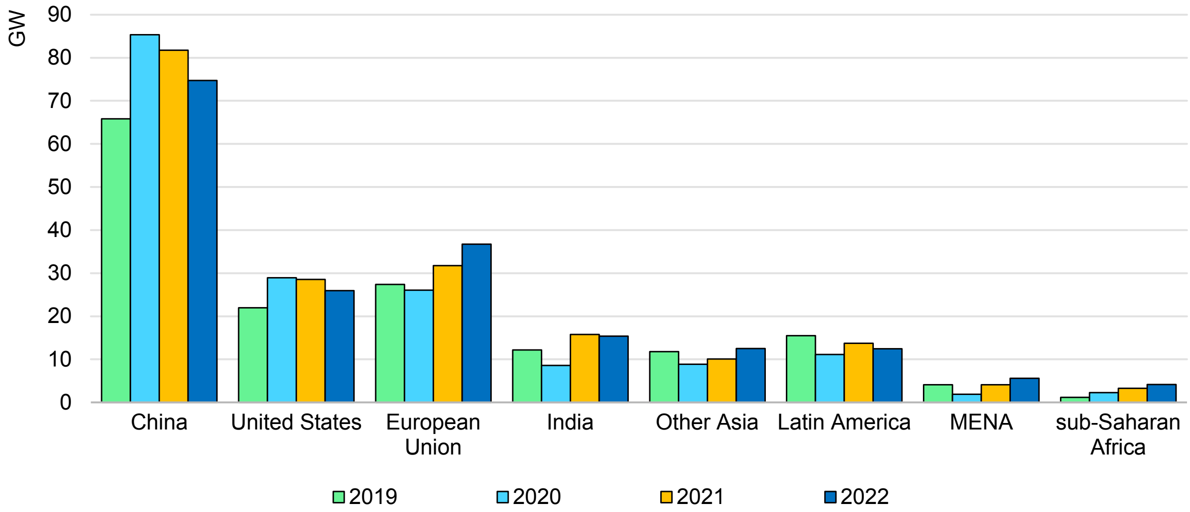
Depending on ongoing uncertainties created by the Covid-19 crisis, renewable capacity additions could reach almost 234 GW according to the accelerated case. China presents the largest forecast uncertainty, as most of its wind and PV projects usually become operational in December, and developers are rushing to make up for delays due to Covid-19, and complete projects before subsidies are phased out at the end of the year. Historically, similar policy-related rushes have led to combined wind and PV additions of 10 GW to almost 25 GW in the month of December. In the United States as well, the highest levels of wind and PV deployments usually happen in the last quarter of the year. For the rest of the world, however, realisation of the accelerated case depends mostly on faster commissioning of utility-scale wind, solar and hydropower projects, and stronger uptake of distributed PV installations.

## Renewable capacity additions rebound to break another record in 2021

Renewables will achieve record expansion in 2021, with almost 218 GW becoming operational – a 10% increase from 2020. The rebound is driven by two factors: first, the commissioning of delayed projects in markets where construction and supply chains were disrupted. Immediate government measures in key markets (the United States, India and several countries in Europe) have enabled developers to complete projects several months after policy or auction deadlines, shifting the forecast for some capacity from 2020 to 2021. Second, growth has been continuous in some markets where the pre-pandemic project pipeline was robust as a result of economic attractiveness and uninterrupted policy support.

India is the largest contributor to the renewables rebound in 2021, with the country's annual additions doubling from 2020. A large number of auctioned wind and PV projects are expected to become operational following delays due not only to Covid-19 but also to contract negotiation and land acquisition challenges. In the European Union, capacity additions jump in 2021, mainly as previously auctioned utility-scale PV and wind projects in France and Germany become operational. In the Middle East and North Africa (MENA) region, renewable capacity additions recover in 2021, led by the commissioning of major IPP projects awarded in competitive auctions in the United Arab Emirates, Qatar and Oman. A similar increase will happen in Latin America as Brazil's delayed wind projects from previous auctions become operational.

**Figure 2.2 Renewable electricity net capacity additions by country/region 2019-22, main case**






## The resilience of renewables will be retested in 2022

The expiration of incentives and consequent policy uncertainties in key markets, combined with upcoming financing challenges and limited stimulus targeting renewable electricity, will lead to a small decline in capacity additions in 2022 relative to 2021. In China, onshore wind and PV subsidies expire this year, while offshore wind support ends in 2021. The policy framework covering 2021-25 will be announced at the end of next year, while financing challenges remain for unsubsidised projects.

In the United States, the onshore wind production tax credit expires at the end of 2020, which will hamper wind capacity growth. In Latin America, delayed auctions in Chile, Brazil and Argentina, and policy uncertainty concerning electricity market reforms in Mexico, remain key variables for 2022.

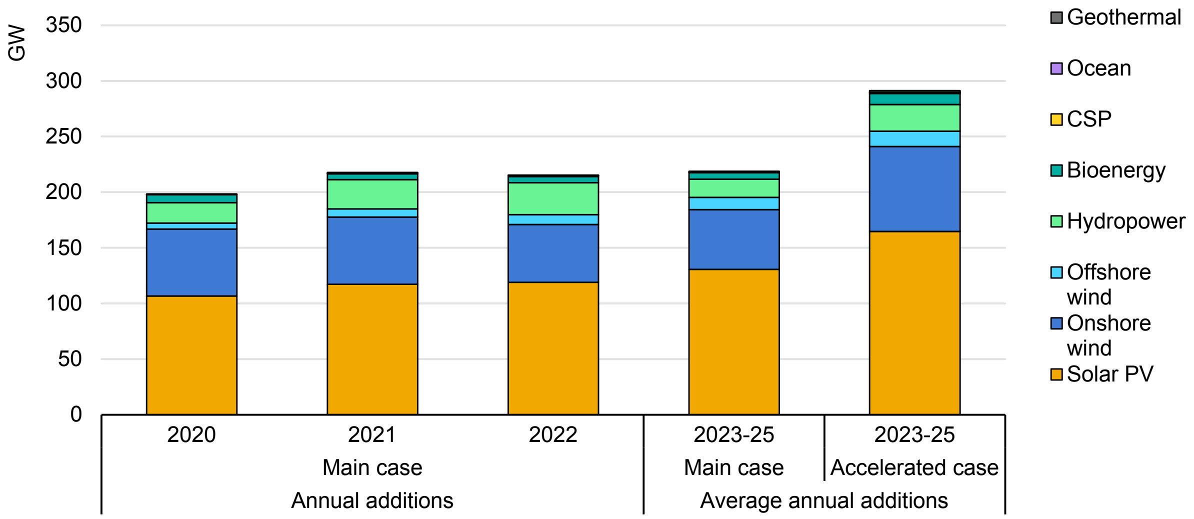
In Asia and Oceania, federal policy uncertainty and grid connection delays in Australia, and the precarious financial health of Indian distribution companies (DISCOMs), prevent renewable additions from further accelerating in 2022. Conversely, renewable capacity additions in Europe, the Middle East and Africa are forecast to continue expanding in 2022. Prior to the Covid-19 crisis, all EU countries had submitted plans to achieve a 32% share of renewables in energy by 2030. In July 2020, the European Union agreed on a EUR 750 billion (USD 840 billion) recovery fund, with at least 30% dedicated to climate change adaptation and mitigation. This financial stimulus is expected to raise the liquidity of renewable energy projects already planned under member country policies in the short-term. Capacity additions in the Middle East and Africa in 2022 double from 2019 because competitive auctions for utility-scale PV make the technology more economically attractive to meet growing electricity demand.

# Total installed wind and PV capacity surpasses coal by 2024

The Covid-19 crisis has introduced additional challenges for renewable energy, such as constraints on financing availability, the reprioritisation of government budgets, and electricity demand uncertainty. At the same time, however, the fundamentals of renewable energy expansion have not changed. Cost reductions and sustained policy support are expected to drive strong growth beyond 2022.

Average annual solar PV capacity additions during 2023-25 are expected to range from 130 GW in the main case to 165 GW in the accelerated case, accounting for almost 60% of total renewable energy expansion. In the next five years, the generation costs of utility-scale solar PV are expected to decline another 36%, making PV the least costly way to add new electricity capacity in most countries. Despite the cost of onshore wind improving 15% from 2020 to 2025, faster expansion is constrained by non-economic barriers such as permitting difficulties and social acceptance in the main case. Meanwhile, annual offshore wind additions during 2023-25 are forecast to be double the 2020 level.

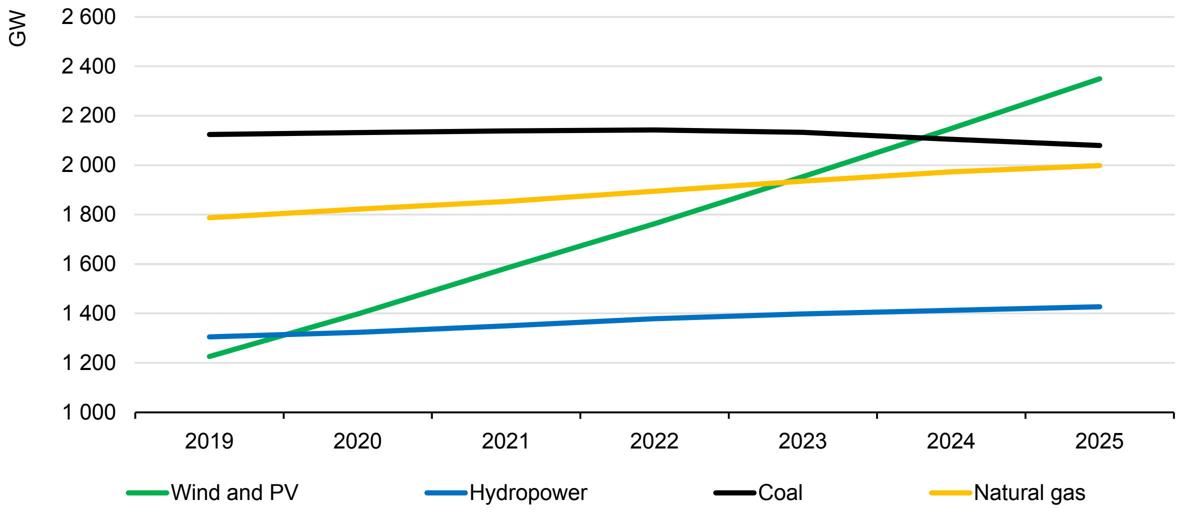
**Figure 2.3 Renewable capacity additions by technology 2020-25, main and accelerated cases**






In the main case, total wind and solar capacity doubles, expanding 1 123 GW between 2020 and 2025. With this growth, wind and PV achieve two important milestones during the forecast period: their total installed capacity surpasses that of natural gas in 2023 and that of coal in 2024. Overall, renewables account for 95% of the increase in total power capacity through 2025.

**Figure 2.4 Total installed power capacity by fuel and technology 2019-25, main case**





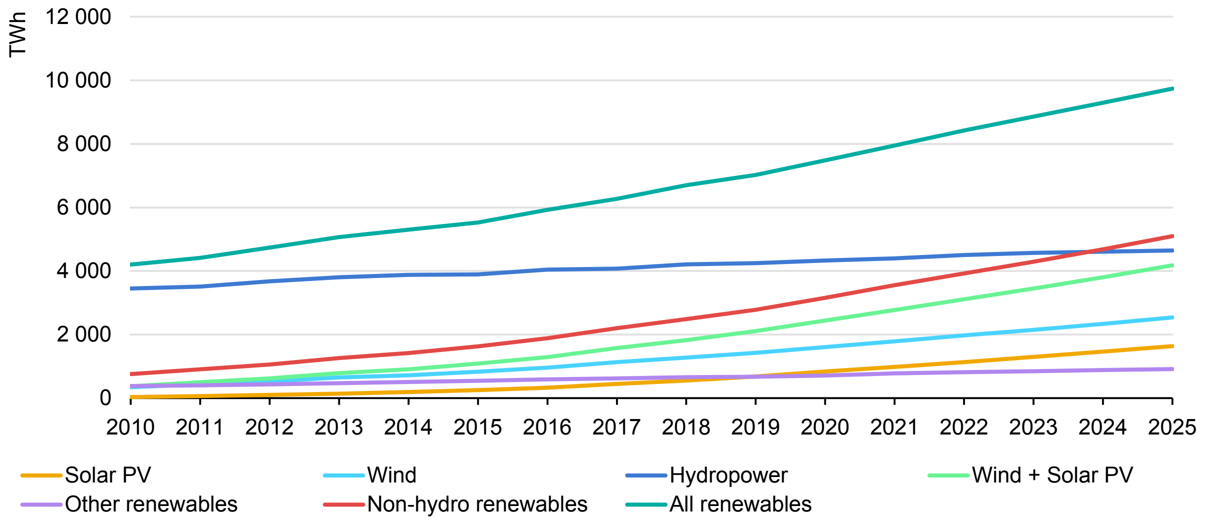

Source: IEA (2020), World Energy Outlook 2020.

## Renewables will become the largest source of electricity generation to surpass coal in 2025

With global electricity demand expected to contract this year, the share of renewables in electricity generation is forecast to increase a record 2.3 percentage points from 2019, to reach 27% in 2020. Electricity generation from renewables will expand almost 50% in the next five years to almost 9 745 TWh – equivalent to the combined demand of China and the European Union. By 2025, the share of renewables in total electricity generation is expected to be 33%, surpassing the coal-fired generation.

Hydropower remains the largest source of renewable electricity generation, but its share will drop below 50% for the first time in 2024. Combined wind and solar PV generation almost doubles to slightly above 4 000 TWh over the forecast period.

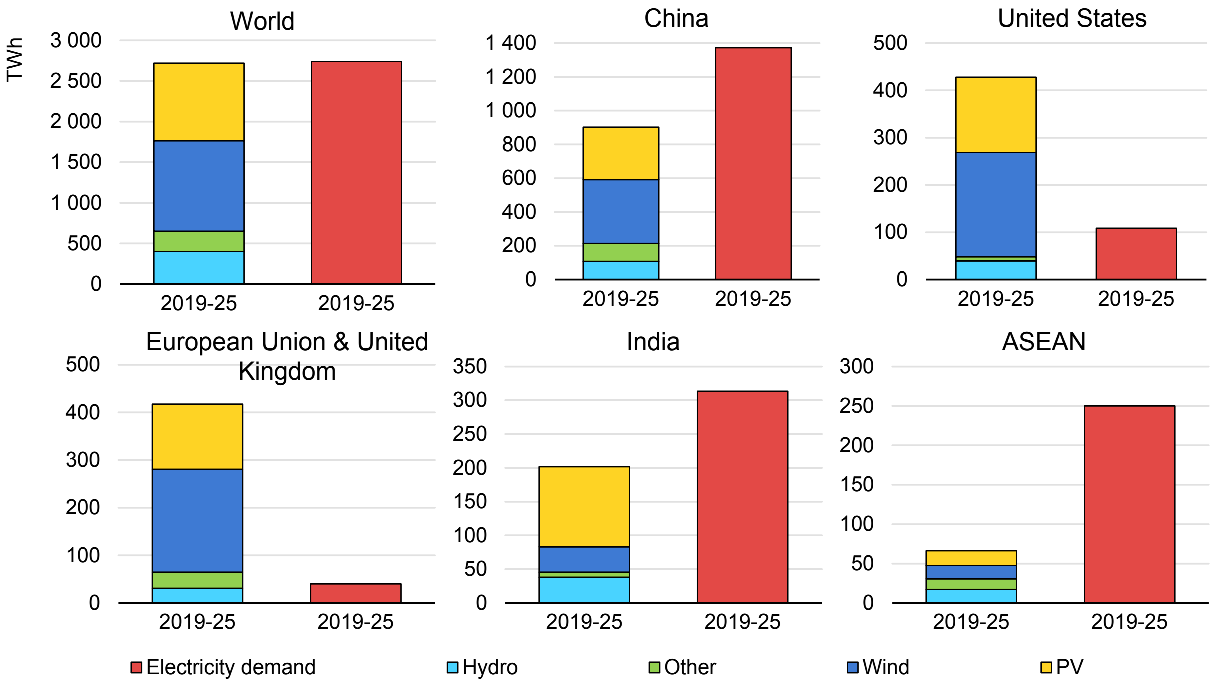
**Figure 2.5 Renewable electricity generation by technology, 2010-25**






Renewables are expected to meet 99% of the global electricity demand increase during 2020-25. In the European Union and the United Kingdom, the increase in renewables-based generation is expected to be more than nine times the rise in electricity demand, and close to three times the increase in US demand. In most advanced economies, renewables replace coal generation as aging fleets retire. In China and India, renewables are forecast to cover almost 65% of demand growth, while in ASEAN countries, fossil fuels dominate generation increases, preventing a rise in the renewables share.

**Figure 2.6 Electricity demand increases and renewable energy generation growth, 2019-25**






Source: IEA (2020), World Energy Outlook 2020.

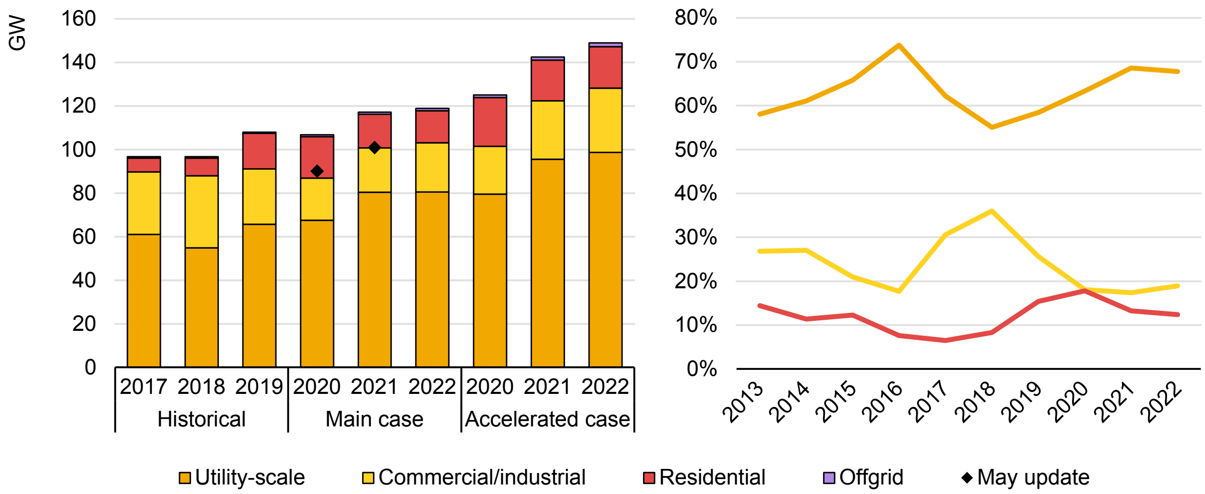
# Solar PV

## Forecast overview

Global solar PV capacity additions are expected to reach nearly 107 GW in 2020 in the main case, representing stable growth from 2019 (this forecast has been revised up by 18% from the market report update published in May). IEA monthly deployment data indicate that construction activity for utility-scale projects slowed from March through April, but rapidly regained speed in mid-May.

Deployment of distributed PV applications remains sluggish in large markets such as China and the United States, although activity in most European markets, Australia and Brazil has not been hampered significantly. Still, the share of distributed applications in total PV deployment is expected to decline to 37% this year, the lowest since 2017.

**Figure 3.1 Solar PV net capacity additions (left) and shares by application segment (right)**






In 2020, utility-scale additions will increase nearly 3% owing to record additions in the United States. China is expected to construct over 33% more PV capacity than in 2019, as developers rush to complete projects before the phaseout of subsidies. Additions in India decline for the second straight year as DISCOMs' financial health challenges persist and Covid-19 measures inhibit construction activity.

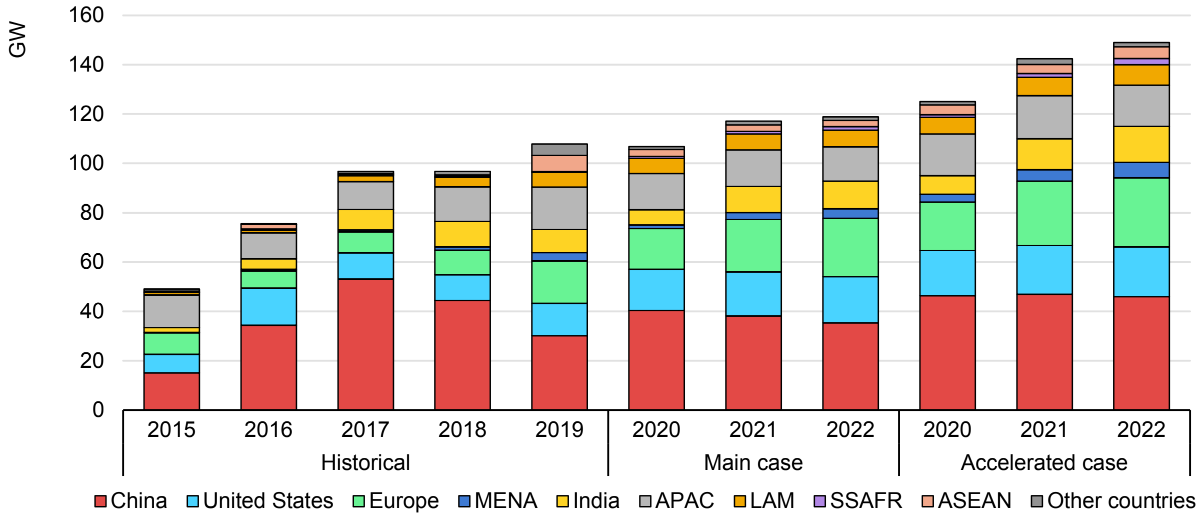
Global distributed PV additions are forecast to be 8% lower in 2020 than in 2019 as the current economic uncertainty shifts the financial priorities of both individuals and small/medium-sized enterprises in some countries. Fewer distributed PV additions in key markets such as the United States, the European Union, India and Japan mark the global trend. Conversely, generous policy incentives drive a residential market boom in China and spur commercial market activity in Brazil despite the pandemic.

In the accelerated case, global solar PV additions could be more than 120 GW in 2020, 16% higher than in the main case. China and the United States account for the largest portion of extra accelerated-case capacity because developers in both countries usually commission projects in the last quarter of the year, due to policy schedules. China’s historical last-quarter deployment (which ranges from 7 GW to 15 GW) does, however, introduce a major portion of 2020 PV forecast uncertainty.

Another record for global solar PV additions is anticipated for 2021, with nearly 117 GW installed – a nearly 10% rise from 2020. The increase results from a strong rebound in utility-scale plants outside of China, where the phaseout of subsidies curbs PV expansion. Utility-scale project development rebounds in India and key EU markets (France and Germany) to meet auction-commissioning deadlines.

With Chinese developers shifting investments from distributed to larger utility-scale projects as subsidies end, distributed PV growth does not fully return to the 2019 level. In 2022, global PV additions continue to expand to almost 120 GW. Although there is uncertainty concerning the new post-subsidy support scheme in China, PV deployment will gain speed in Europe and the United States thanks to increasing competitiveness and continuous policy support.

**Figure 3.2 Solar PV net capacity additions by country/region**





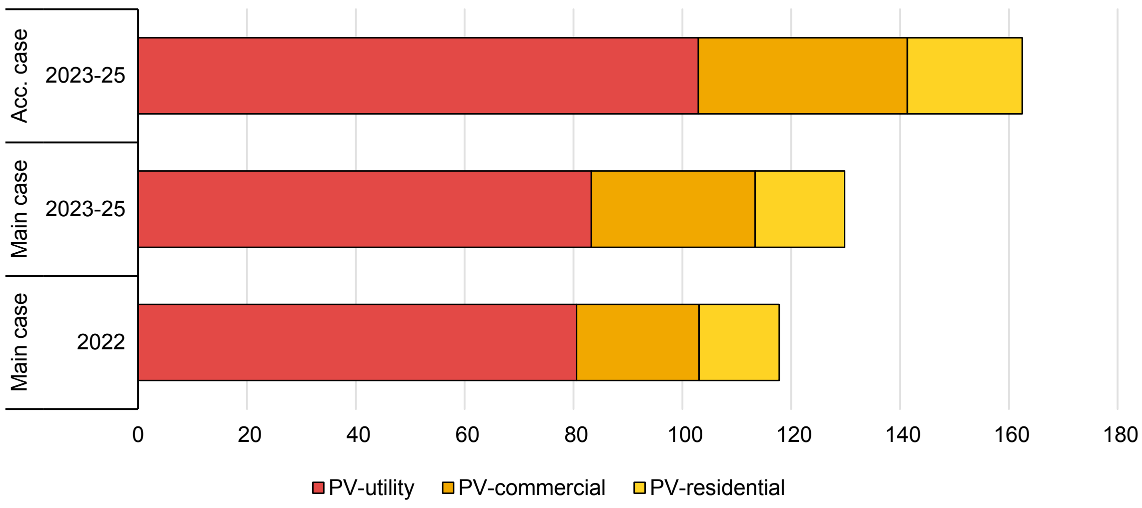

Notes: MENA = Middle East and North Africa. APAC = Asia and Pacific (not including China). LAM = Latin America. SSAFR = sub-Saharan Africa. ASEAN = Association of Southeast Asian Nations.

In the accelerated case, annual additions could reach over 142 GW in 2021 and 149 GW in 2022 with:

- A smooth policy transition to ensure investor confidence in China.
- Faster distributed PV recovery in the United States and Europe.
- Rapid implementation of auctions and grid connections in India and Latin America.
- Timely commissioning of auctioned capacities in the Middle East and Africa.
- Elimination of policy uncertainties and administrative challenges in ASEAN countries.

Global annual solar PV additions are expected to accelerate during 2023-25, owing to faster recovery of distributed PV applications as the global economy improves. Outside of government support schemes, market drivers such as corporate PPAs and bilateral contracts are forecast to support PV expansion globally. Potential in the ASEAN region remains largely untapped due to administrative and regulatory challenges, while the lack of policy certainty and infrastructure is hampering regional growth.

**Figure 3.3 Average global annual capacity additions in main and accelerated cases, 2023-25**






Global PV expansion after 2022 is expected to accelerate even more quickly, owing to continuous policy support and cost reductions. The distributed PV segment resumes growth during 2023-25 as global economic recovery supports faster adoption of commercial and residential systems. The higher potential for total PV in the accelerated case compared with the main case is significant, with the possibility of annual capacity additions averaging almost 165 GW during 2023-25.

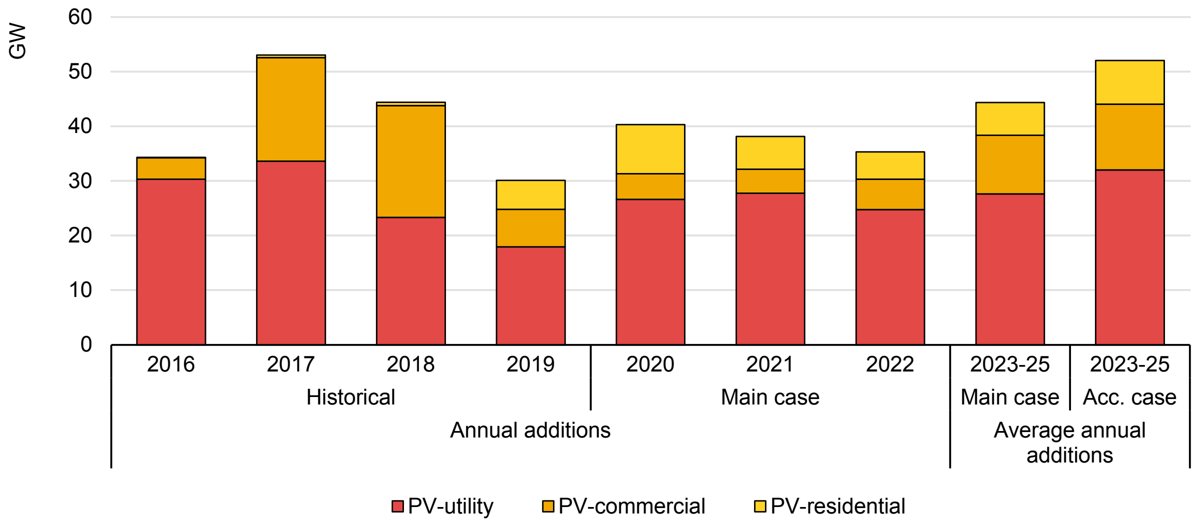
# China

## PV developers rush to meet subsidy deadlines in 2020

Solar PV capacity additions are expected to increase 33% in 2020 from 2019. China's PV growth slowed in 2018 and 2019 because the government temporarily froze PV subsidy allocations and announced the transition to competitive auctions in 2018. Growth resumed this year, however, with the commissioning of projects awarded in the country's competitive auctions held in June 2019 and June 2020 – before all PV subsidies are phased out at the end of 2020 (except for residential applications).

Overall, the policy transition to auctions has reduced the appetite for commercial PV applications, which accounted for almost half of PV growth in 2018. Conversely, the popularity of residential PV installations is booming thanks to continuous financial support through the end of 2021.

**Figure 3.4 China annual PV capacity additions 2016-22, and average annual additions 2023-25**





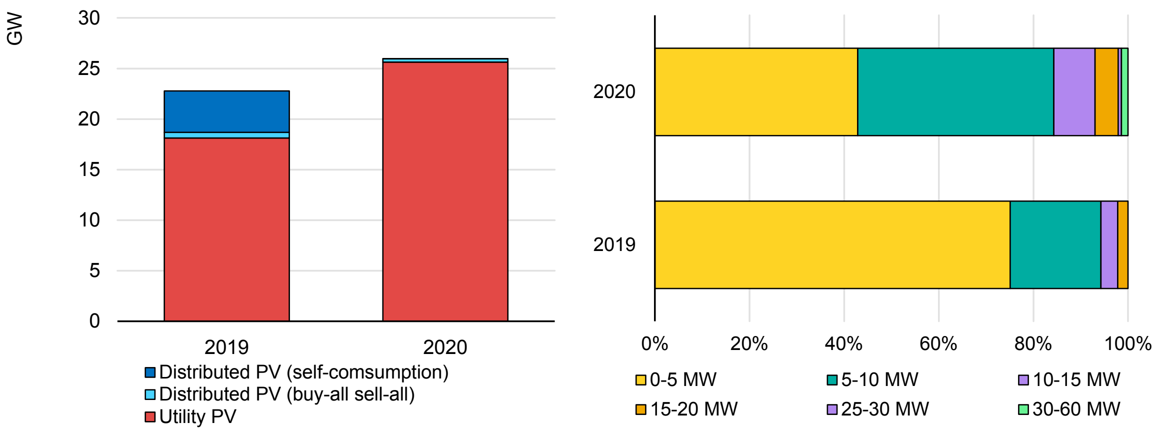

## China's PV auction in July 2020 showed clear shift to larger utility-scale projects while prices declined 18% on average

In its second auction in July 2020, China awarded almost 26 GW of solar PV projects – more than in the first one – as the average contract price drop of 18% spurred greater contracted capacity even though the subsidy budget had been cut by half.

Two key trends that have emerged from the auction will shape China's future solar PV market. First, commercial solar PV developers showed limited interest in the auction because the investment priorities of small and medium-sized enterprises have shifted with the Covid-19 crisis. Second, the competitive process has pushed developers to focus on larger projects in order to benefit from economies of scale and achieve lower bids.

In the 2019 auction, projects with a capacity of 1-5 MW accounted for a significant majority of awarded capacity, while the average project size was almost three times higher in the 2020 auction. Projects with winning bids are forecast to come online in 2020 and 2021 while residential solar PV additions are expected to range from 9 GW to 10 GW, almost double the 2019 level, as developers rush to benefit from the generous FiT scheme that will end in 2021.

**Figure 3.5 China competitive PV auction volumes (left) and project size (right), 2019 and 2020**






## Uncertainty over the new policy scheme for PV beyond 2021 persists

After subsidies are phased out in 2020/21 and the 13th Five-Year Plan on Renewables expires, capacity additions in 2022 are expected to decline due to uncertainties over the new policy scheme and targets in the upcoming 14th Five-Year Plan. An emerging development schedule shows plans for a pipeline of “grid parity” projects under 20-year contracts at administratively set provincial power prices. Although the government approved 29 GW of these projects in July 2020, many are expected to be cancelled or postponed due to increasing financing challenges caused by the Covid-19 crisis and a lack of penalties for non-completion.

Beyond 2022, growth in annual additions is projected to resume, averaging 40-50 GW through 2025. In the absence of subsidies, continuous PV cost declines will remain the key driver for expansion. The large difference between the main and accelerated cases reflects uncertainty over the new policy scheme after the phaseout of subsidies.

Although implementation of state-level renewable portfolio standards began this year, the current design provides only limited incentives for solar PV projects, especially rooftop distributed PV. The smooth interaction between newly introduced provincial spot electricity and green certificate markets, along with the implementation of the RPS scheme, will be key for faster solar PV project expansion.

# United States

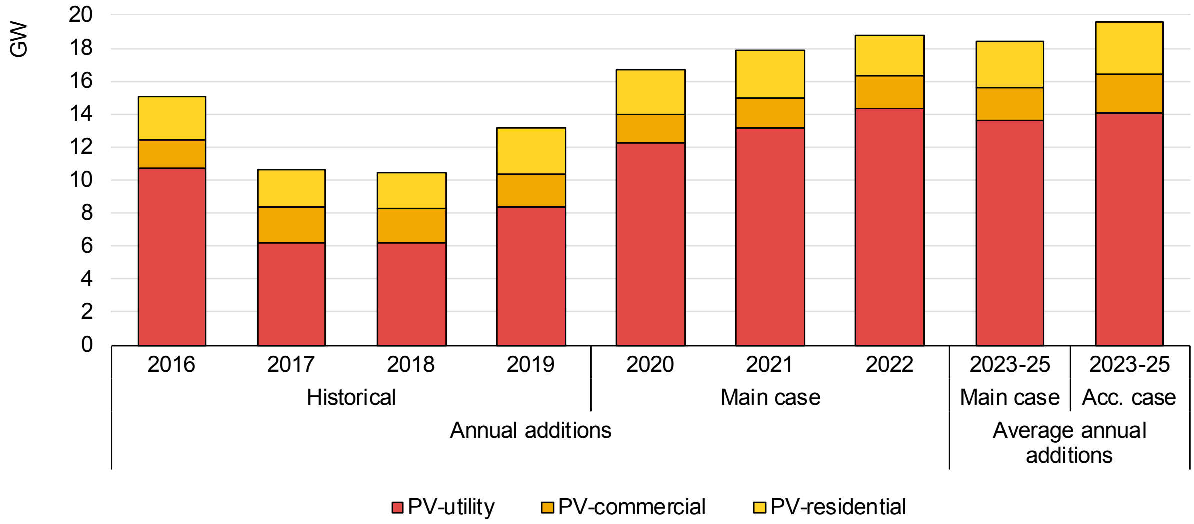
## Utility-scale capacity continues to increase in the face of the pandemic

Unprecedented US solar PV expansion of almost 17 GW is forecast for 2020, the highest annual increase to date. Growth is mostly in utility-scale projects, with 3.9 GW more additions than in 2019, which will more than offset the decline forecast for the distributed segment.

Numerous utility-scale projects were already under development at the beginning of 2020, and construction has continued relatively unaffected by shelter-in-place orders because many states deem construction an essential service. While some developers have reported delays or pauses in construction, newly installed capacity increased 30% from the first to the second quarter of 2020. Growth is expected to remain strong in the second half of the year, as remaining social-distancing measures are assumed to have very little effect on the considerable 13.6 GW under construction.

Meanwhile, distributed PV growth is expected to contract in 2020 because permitting and interconnection approval delays have been holding up development of some commercial systems. A slight contraction is also expected in the residential segment as shelter-in-place orders have limited the number of in-person sales. As a result, the number of new distributed PV installations dropped 23% from Q1 to Q2 (SEIA, 2020). The annual decline is expected to be less, however (8% down from 2019), as the transition to online processes for sales, consultation, and permitting indicates increased development activity during the second half of the year.

**Figure 3.6 US annual PV capacity additions 2016-22, and average annual additions 2023-25**






## Renewable portfolio standards remain a key driver, but PV capacity expansion increasingly comes from states without them, owing to lower costs and tax incentives

Annual additions are expected to rise in 2021 and continue to increase in 2022 owing to a large portfolio of contracted projects established on the basis of two main drivers. The first impetus remains renewable portfolio standards (RPSs), regulations that obligate retailers to supply a percentage of electricity from renewable energy. These have historically been a key driver for growth, and about half of the country's planned projects are in the 30 states that have them. The largest project slates are in states that have raised their targets in recent years (e.g. California, Nevada and New York), but more projects have also sprung up in Virginia, the most recent state to introduce an RPS in April 2020 that mandates 100% renewable electricity by 2050.

The second growth stimulus is economic attractiveness. An increasing share of expansion will be in states where RPSs have already been met or are non-existent, such as in the Southeast and Southwest. For instance, falling costs, investment tax credits, and excellent resource potential have launched numerous large utility projects in Texas, Florida and Georgia, where land availability is not a constraint. In addition, the economic attractiveness of solar-plus-storage is making utility-scale installations more appealing in some western states.

This forecast assumes these projects have already secured financing and, as such, are not at risk of cancellation during a weaker economic climate. Nevertheless, tighter financing conditions for new projects do pose a risk. Tax equity, the main source of financing for utility PV projects, is reported to have shrunk since March 2020 as a result of the lockdown, and project financing is being delayed until 2021 due to economic uncertainty (BNEF, 2020a).

If fewer projects secure financing in 2020/21, capacity expansion in 2021/22 will be lower. The more cautious lending environment will also impact the riskiest projects, especially those with a merchant tail (a period in which energy is being sold directly into the market).

After 2022, utility installation growth is expected to slow slightly due to a step-down in the Investment Tax Credit (ITC) to 10% in 2022. In addition, uncertainty over the business case in a weaker economic environment with potentially lower power prices and less demand may reduce corporate PPA demand.

Nonetheless, average annual growth during 2023-25 is still expected to be higher than in the years preceding the Covid-19 pandemic, owing to both ambitious state-level RPSs and utilities' self-mandated targets in states lacking an RPS, particularly in the Southeast. In the past year, several large state utilities announced emissions reduction targets for 2030 and 2050, and released integrated resource plans in which solar PV plays a key role (SACE, 2020).

For distributed PV, annual additions are forecast to increase in 2021 in anticipation of the phaseout of the residential ITC, and to subsequently decline in 2022. Also contributing to the expected contraction in 2022 is uncertainty over how attractive self-consumption will be for the commercial segment in a weaker economic climate. Less energy demand, company budget reprioritisations and tighter financing conditions could discourage new investments.

Yet, a rebound in average annual growth is expected between 2023 and 2025 as improved consumer confidence supported by favourable net-metering rules stimulates the residential sector, and new community solar initiatives help encourage the commercial segment.

Average annual growth could be 7% higher in the accelerated case. An increase in corporate buying and utility procurement would support this for utility scale. For distributed PV, these would require faster declines in soft costs, one of the largest costs for residential PV, and more rapid permitting and grid connection in areas where there are backlogs for commercial PV.

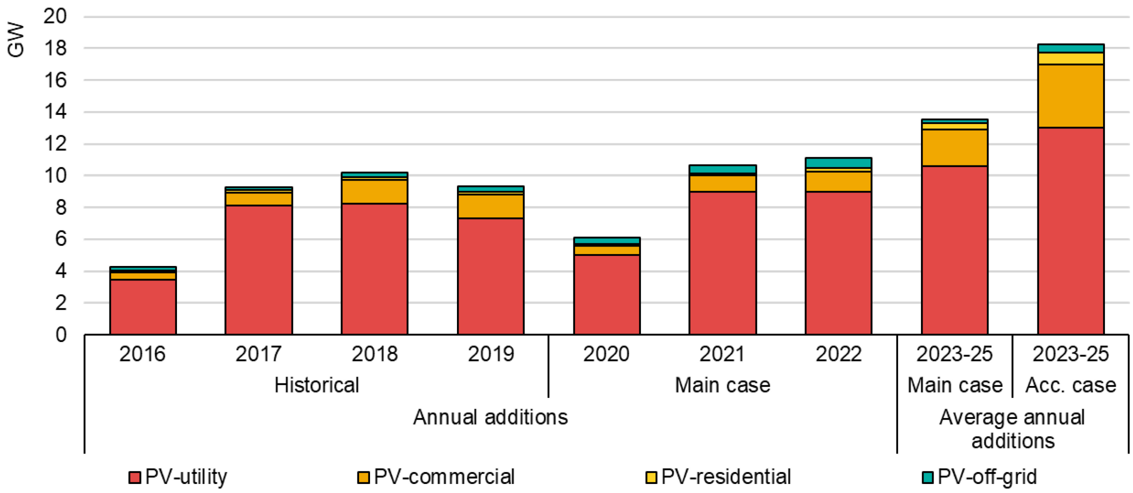
# India

## Covid-19 disruptions cause a significant slowdown in 2020 PV deployment, but a strong rebound is expected in 2021 and 2022

India's solar PV capacity additions are forecast to be one-third lower in 2020 than in 2019. In the first half of 2020, new PV capacity installations were 70% below average first-half growth of the previous three years. This drop resulted from a combination of Covid-19-related supply chain disruptions and construction slow-downs, as well as increased macroeconomic risks.

Consequently, compared with our previous update in May, this forecast anticipates 19% fewer additions in 2020. A rebound in PV deployment is expected for 2021 and 2022, with capacity additions exceeding the 2019 level as delayed and new projects become operational.

Figure 3.7 India PV capacity additions 2016-22, and average annual additions 2023-25






## Poor financial health of distribution companies remains the main challenge to greater solar PV deployment

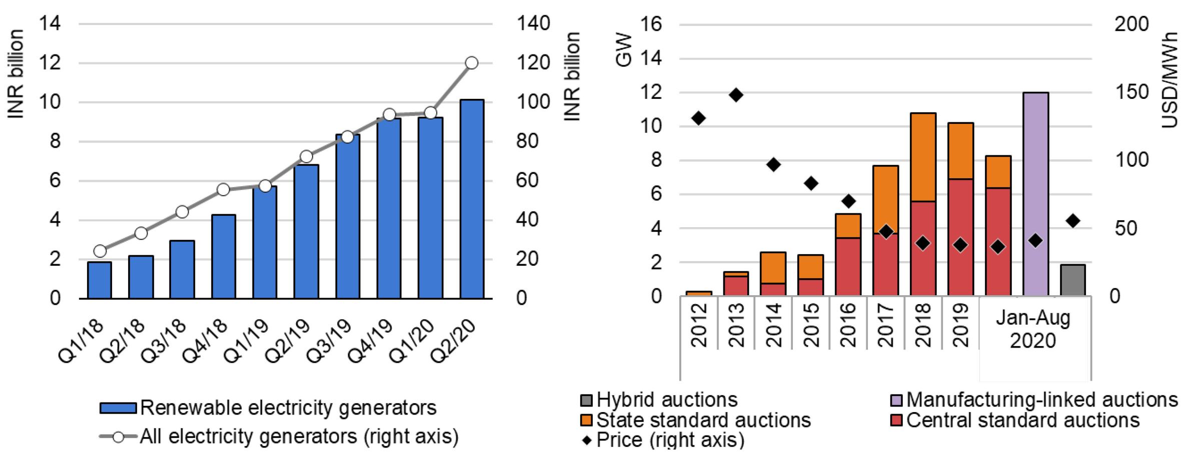
The Covid-19 crisis has compromised the financial viability of distribution companies (DISCOMs). The financial instability of many DISCOMs leads to delayed payments to generators, decreasing the profitability of existing projects and raising the level of risk perceived by potential developers and financial institutions.

According to the Ministry of Power's annual financial performance ratings, one-third of electricity sales in 2018 came from DISCOMs rated below B+ on a six-grade scale ranging from C to A+. New PV installations in networks managed by utilities with low grades will likely face greater obstacles than those overseen by healthier DISCOMs. In addition, distressed DISCOMs view the development of rooftop PV as an additional challenge, as higher self-consumption reduces revenues from their most profitable commercial customers.

Policies to improve DISCOMs' financial health through the UDAY scheme introduced in 2015 have been only partially successful, and overdue payments to generators began increasing again in 2018. In fact, from January to June 2020, total overdue payments owed by DISCOMs rose 28% for all electricity generators and 10% for renewable electricity plants.

In May 2020, India's government announced an extensive loan programme to reduce overdue amounts owed to generators. Although it is expected to provide important relief to renewable energy developers, a structural solution is needed to ensure the sustainability of DISCOMs to achieve faster PV growth.

**Figure 3.8 India DISCOMs' cumulative overdue payments to generators Q1/2018-Q2/2020 (left), and PV auction results (right)**






Sources: Left: PRAAPTI (2020), www.praapti.in. Right: based on BNEF (2020b), 3Q 2020 Global Auction and Tender Calendar and Results (database); Bridge to India (2020), India RE Navigator – Utility-scale solar, www.india-re-navigator.com/utility.

## Competitive auctions will continue to drive utility-scale PV growth, but challenges concerning project implementation remain

The main catalyst for utility-scale PV deployment is reverse-bid auctions. The switch from state-level to central auctions continued in 2020, as the latter provides more payment security and attracts greater competition. Despite Covid-19 disruptions, India had auctioned 8.2 GW of new PV capacity by the end of September 2020 – more than in the same period last year. Tariffs awarded in 2020 were 4% lower on average than in 2019, registering among the lowest in the world. In addition, the government awarded a record 12 GW of PV capacity linked with 3 GW of PV module manufacturing. New types of wind-solar-storage hybrid auctions were also held this year, making these systems competitive with existing coal-fired generators in many states.

Low bid ceilings, however, have been one of the main causes of undersubscription in many past auctions. Therefore, in March 2020 the government announced that future auctions will not contain ceilings, allowing developers to fully reflect changes in the economic environment in their bids and secure sustainable revenues.

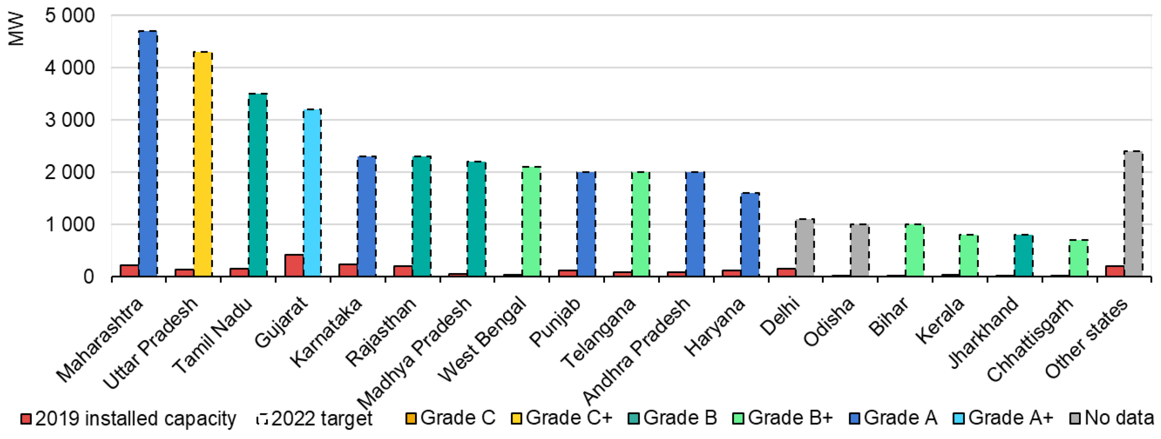
Despite auction design improvements, transmission grid bottlenecks and land acquisition challenges persist. The Indian government is taking action to overcome these obstacles, mainly through the Green Energy Corridor and Solar Parks projects, but faster development is needed to reach ambitious national capacity targets by 2022.

Distributed PV deployment in the commercial and residential sectors is also expected to fall due to Covid-19 disruptions. In our forecast, distributed PV capacity additions are 58% lower in 2020 than in 2019, and are not expected to exceed the 2019 level before 2022, as demand for installations likely remains subdued due to uncertainty regarding the macroeconomic environment and employment.

Because DISCOMs in better financial health usually support rooftop PV project deployment more eagerly, states with higher-graded utilities are more likely to meet their rooftop PV targets. Faster rooftop PV expansion requires that DISCOMs financial challenges be resolved to ensure their active co-operation in implementing state net-metering policies, and that affordable financing be made available.

A positive development is that new business models have emerged for DISCOMs to benefit from distributed PV deployment. In addition, demand aggregation models to streamline borrowing are being developed, but the reach of such programmes remains limited.

**Figure 3.9 India rooftop PV installed capacity by state in 2019, targets for 2022, and average grade of utilities**






Note: The A+ to C grading scale indicates DISCOM operational and financial health according to a framework approved by the Ministry of Power. State grade assignment is based on the weighted average of grades given to DISCOMs in the State Distribution Utilities Seventh Annual Integrated Rating.

Sources: Based on Ministry of Power (2019), State Distribution Utilities Seventh Annual Integrated Rating.

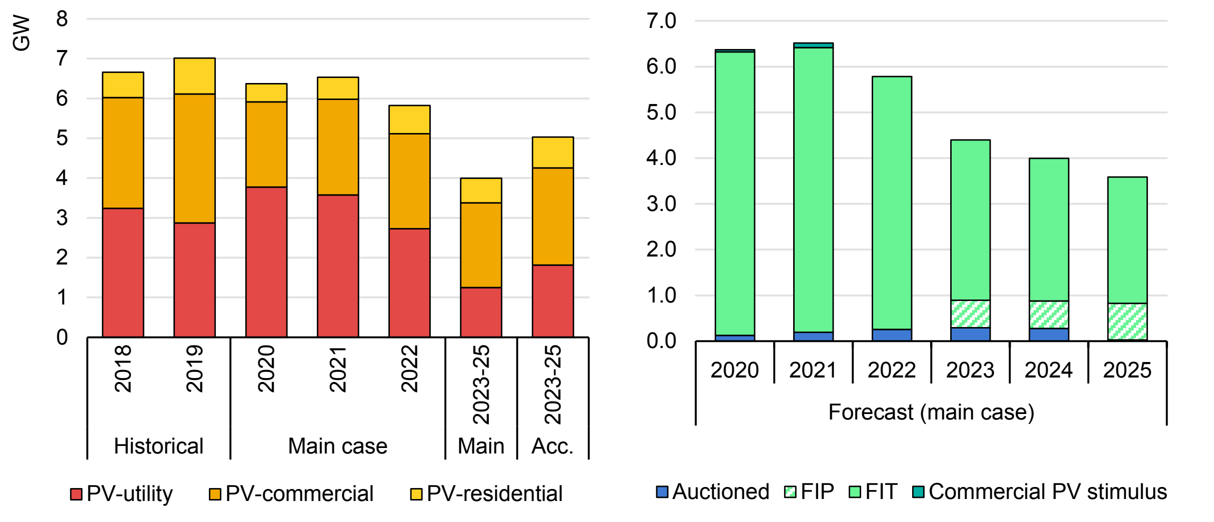
The forecast predicts stable annual capacity addition growth after 2022, resulting from declining PV installation costs, the continuation of auction programmes and gradually improving conditions for distributed PV development. Annual capacity increases during 2023-25 could average 13 GW to 18 GW between the main and accelerated cases. Achieving higher deployment will require that DISCOMs financial stability improves, the full potential of distributed PV is unlocked, transmission grid constraints are eliminated and land acquisition becomes simpler.

# Japan

## Solar PV growth slows, driven by the phaseout of FiTs for large-scale projects and undersubscribed auctions

Japan's solar PV market is expected to contract slightly (by 9%) in 2020 compared with 2019. Capacity additions are mostly driven by different commissioning deadlines for FiT-approved PV projects in each of the segments, while the impact of the Covid-19 crisis on solar PV construction activity has been minimal.

**Figure 3.10 Japan solar PV net annual capacity additions 2018-22 and average annual additions 2023-25 (left), and capacity additions forecast by policy, 2020-25 (right)**






Notes: All values shown in GW (DC). Auctions were held during 2017-21. The initial participation threshold of 2 MW was lowered to 500 kW in 2019 and 250 kW in 2020.
Sources: Right: based on FiT-Portal Japan (2020), FIT portal; GIO (2020), GIO website.

Utility-scale installations are most affected by commissioning deadlines because many FiT-approved projects need to be commissioned in 2020 and 2021 to maintain the previously agreed prices and support periods, resulting in strong growth in these years. Fewer FiT-based projects in 2022, however, is expected to reduce utility-scale PV additions, with only a minimal contribution from auctions.

Auction-based capacity is low relative to new FiT approvals, with previous auction rounds undersubscribed. For commercial solar PV, a rush to complete FiT-approved projects by 2022 due to commissioning deadlines, and additional investment subsidies for PV and storage as part of Covid-19 stimulus are expected to boost growth over 2020-22.

Japanese PV additions are expected to contract starting in 2022, mainly due to phaseout of the generous FiT scheme for large-scale projects and undersubscribed capacity in previous auctions. The government has approved introduction of a FIP scheme for large solar PV projects. The new policy aims to reduce financial burden, encouraging PV plants to participate in electricity markets to facilitate their system integration and providing a stable long-term revenue stream for developers. However, details regarding the maximum size of eligible projects, ceiling price and the competitive selection process have not yet been decided and remain a forecast uncertainty beyond 2022.

Smaller commercial installations will continue to be eligible for FiT-based remuneration, but they are likely to face stricter rules such as a self-consumption requirement of at least 30%.

Solar PV growth during 2023-25 could be one-fourth higher in the accelerated case, with more attractive FIP remuneration and further cost declines, unlocking of the potential of other revenue streams such as PPAs, and continuation of the FiT scheme for medium-sized commercial installations.

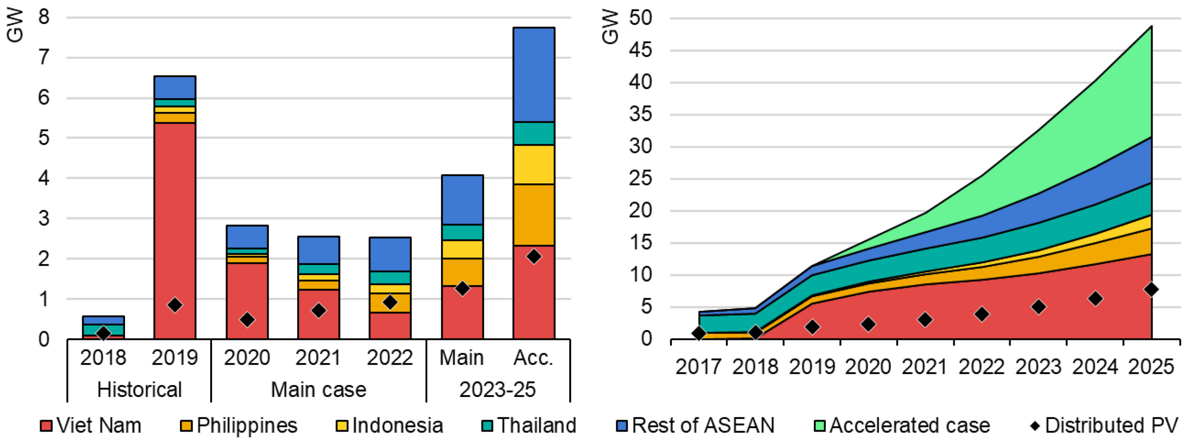
# ASEAN

## Viet Nam's boom-and-bust solar PV cycle reduces ASEAN capacity additions significantly in 2020

Solar PV capacity additions in the ASEAN region are forecast to reach 2.8 GW in 2020, 57% lower than last year when developers in **Viet Nam** rushed to complete projects before the announced FiT phase-out. In other ASEAN countries, PV development remains slow in 2020 due to limited policy support.

From 2021 onwards, however, a decrease in new installations in **Viet Nam** following its FiT phase-out should be mostly offset by faster growth in other ASEAN countries. Utility-scale projects account for the majority of new additions in the region due to limited support for distributed applications. However, the share of commercial and residential installations in total investments is likely to increase over 2023-25 thanks to an improved regulatory environment and rising economic attractiveness.

**Figure 3.11 ASEAN PV capacity additions 2018-22, average annual additions 2023-25 (left) and total installed capacity 2017-25 (right)**






In **Viet Nam,** PV capacity additions are expected to decline 65% to 1.9 GW in 2020 due to phase-out of the generous FiT in June 2019. Although a government decision to extend the commissioning deadline for previously approved projects to the end of 2020 will keep annual additions relatively strong, workforce shortages and supply chain disruptions due to the Covid-19 crisis – combined with grid connection challenges – could delay the completion of many approved projects to 2021.

In addition, transition from the FiT to an auction scheme is expected to further slow annual growth in 2022. Distributed PV deployment should accelerate during the forecast period, stimulated by decreasing costs and new business models, including on-site private PPAs and roof-space renting introduced in 2020.

During 2023-25, auctions and distributed PV are expected to boost capacity additions in **Viet Nam**. In the accelerated case, annual additions beyond 2022 could reach 2.5 GW assuming faster grid expansion, a smooth transition to the new auction scheme and further facilitation of private PPAs through standard contracts and more risk-sharing between developers and off-takers.

## PV expansion in Indonesia, the Philippines and Thailand will gain momentum, but regulatory and administrative challenges hamper faster growth

**Indonesia**'s PV growth is expected to remain limited in the 2020-22 period. Regulatory challenges persist, hampering the acceleration of renewable energy deployment. The main barrier remains a low tariff for renewable energy generators, set below the average purchase price of electricity. This low tariff and relatively high installation costs reduce the economic attractiveness of PV projects.

However, more supportive regulations are being introduced that could accelerate growth beyond 2022. In February 2020, the requirement to build all projects under the Build, Own, Operate, and Transfer scheme was lifted, increasing bankability. Plus, priority dispatch for renewable generators was introduced and the process of signing PPAs with the central off-taker was simplified. In addition, a new regulation that includes a FiT for smaller installations and auctions for larger systems is under government consideration.

The 2020 forecast for the **Philippines** assumes 0.2 GW of new PV installations, similar to the 2019 level. Since the beginning of 2020, an RPS with auctions has been introduced to increase the share of renewables in total electricity consumption from 21% in 2019 to 35% in 2030. The RPS is expected to drive PV growth, with annual deployment reaching almost 0.5 GW through 2022 and a further increase to 0.8 GW during 2023-25.

In **Thailand**, PV capacity additions are expected to remain between 0.1 GW and 0.3 GW per year over 2020-22 in the absence of new policies. Current support policies include annual contracting of 0.1 GW of residential rooftop PV for net-metering, but interest remains limited due to insufficient remuneration for excess generation.

The government is also encouraging floating PV deployment, with the first auction for 45 MW already awarded and more capacity planned. Without additional policy support, however, revenues for renewable energy generators in most cases remain too low to ensure significant acceleration.

# Australia

## With the Large-Scale Renewable Energy Target met, utility-scale PV additions slow in 2020 while distributed PV market expansion continues

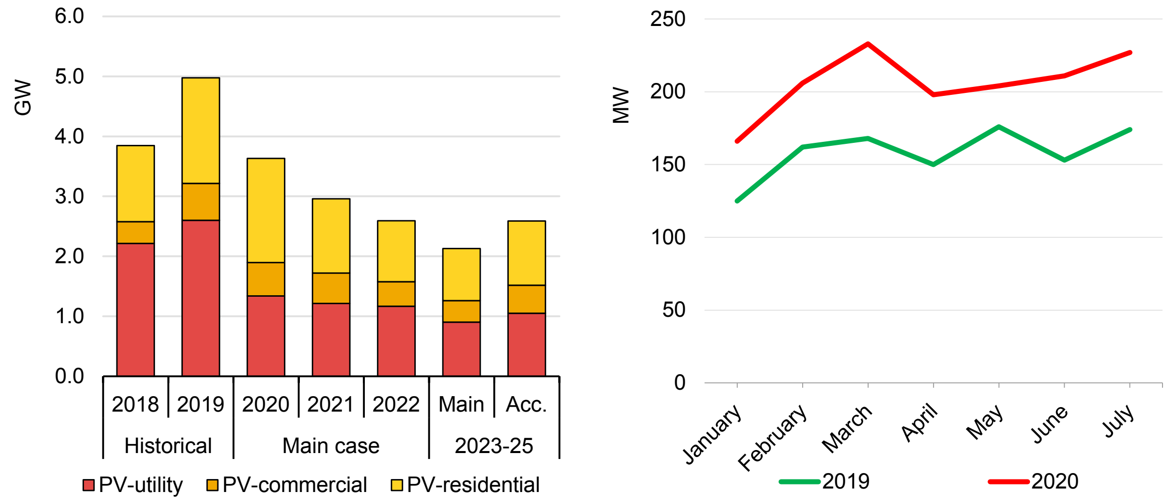
PV additions of just over 3.5 GW are expected in 2020 – over 30% less than in 2019. This decline results mostly from 50% lower utility-scale PV additions, as delays in grid connection approvals and new operational requirements have lowered project outputs, making the business case for multiple PV projects less attractive and reducing investor confidence.

In addition, Australia has already met its 2020 Renewable Energy Target, resulting in an oversupply of generation certificates, which reduces revenues and undermines the business case for new developments. Consequently, utility-scale additions are expected to shrink further in 2021 and 2022.

For distributed PV applications, installations continue to be encouraged by both the small-scale certificate programme and state-level FiT schemes (buy-back tariffs for distributed PV exports) offered by both utilities and retailors. The impact of the Covid-19 crisis remains limited, as monthly installations in 2020 already outpaced those of 2019, with additions expected to reach over 2 GW this year.

However, declining wholesale prices (which guide benchmark FiT rates in many states), market saturation in some states (e.g. New South Wales and Victoria), and lower values of small-scale certificates all challenge faster growth in 2021 and 2022.

**Figure 3.12 Australia solar PV capacity additions 2018-22, average annual additions 2023-25 (left) and monthly distributed PV additions 2019 and 2020 (right)**






Source: Australia Clean Energy Regulator (2020), [Postcode data for small-scale installations](#).

Moderate gains in utility-scale and distributed PV installations will begin in 2023 as both the small- and large-scale certificate programmes continue through 2030, and as improving grid conditions from planned new investments help reduce connection and curtailment challenges. However, with the projected generation target of the LRET programme having been met already, PV projects will have to rely on merchant installations, corporate PPAs or state-level incentives, such as the New South Wales Renewable Energy Zones.

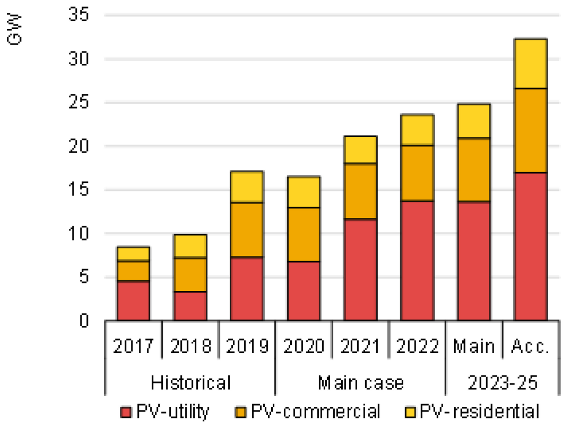
# Europe

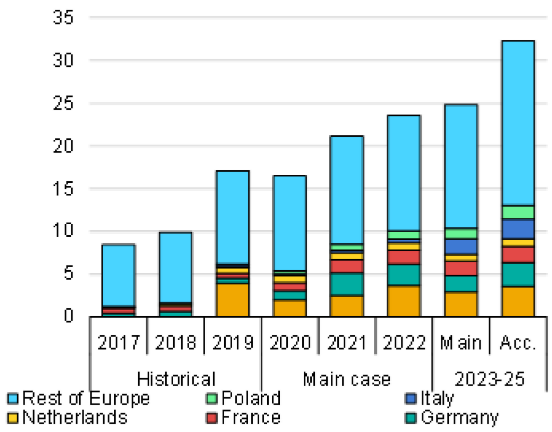
## Increased support to meet EU 2030 targets are a key driver of growth beyond 2020, but smooth policy transitions are needed to maintain the pace

Net PV additions are expected to reach 16.5 GW in 2020, a 4% decline relative to 2019, which had been an exceptional year as Spain added 4 GW of utility-scale PV to meet support deadlines. Excluding Spain, where additions in 2020 have halved, Europe's annual additions are set to grow by 13% in 2020 and reach their highest level since 2012 despite lockdowns and social distancing measures. Most of the increase is driven by utility-scale deployment from auctions in Germany, France and Poland. Higher growth also stems from the increasing attractiveness of net-metering in Turkey, Poland and the Netherlands.

After 2020, net additions in Europe are forecast to increase steadily from 21 GW in 2021 to an average of 25 GW per year between 2023 and 2025. This trend is largely underpinned by an increase in policy support to meet the European Union's 2030 renewable energy target of 32% under the Renewable Energy Directive. EU member states were required to submit their final 2030 renewable energy targets by the end of 2019, accompanied by plans to reach them, and several countries have already introduced or drafted national legislation to implement them.

**Figure 3.13 Europe annual PV capacity additions 2017-22 and average annual additions 2023-25 by segment (left) and by region (right)**






Utility-scale growth plays an increasingly important role over the forecast period, with its share rising from 41% in 2021 to an average of 55% annually by 2023-25, owing to an increase in competitive auctions. Over the past year, legislation to expand and extend support has either been passed or introduced to reach new 2030 targets in major markets. Italy introduced auction schemes in 2019 and Poland continued to raise auction volumes while in 2020 Spain announced plans to resume tenders and Germany proposed to increase and extend annual auction volumes.

Distributed PV continues to increase gradually in Europe during 2021-25, driven by steady growth in the commercial segment from self-consumption, net metering and, in some cases, auctions. However, the impact of support-scheme changes on large commercial systems in large markets is a forecast uncertainty. In an effort to stimulate growth while balancing support costs, several countries are modifying their policy designs by changing size eligibility and mechanism to determine remuneration levels. Germany, the largest commercial market, proposes changing support for large commercial rooftop systems from FIPs to competitive auctions, while in France, which has decided to move support for self-consumption in the segment back to administratively set tariffs, auctions were under subscribed.

Commercial PV is also remunerated by auctions in the Netherlands, but new auction design rules under the SDE++ scheme raise concerns about its competitiveness, as now commercial PV systems must compete with non-electricity technologies. Residential PV in Europe maintains steady growth, led by self-consumption in Germany and net metering in the Netherlands and Poland.

A number of factors could accelerate PV growth in Europe. Utility-scale capacity increases could be 25% higher on average during 2023-25 with clarity over auction design proposals, streamlined permitting and licensing to minimise under-subscription in auctions, and more attractive economics for corporate PPAs. Maintaining self-consumption support for distributed systems could boost annual growth by 37%.

# Germany

## Higher 2030 targets and extended support drive growth, but potential for distributed PV remains constrained

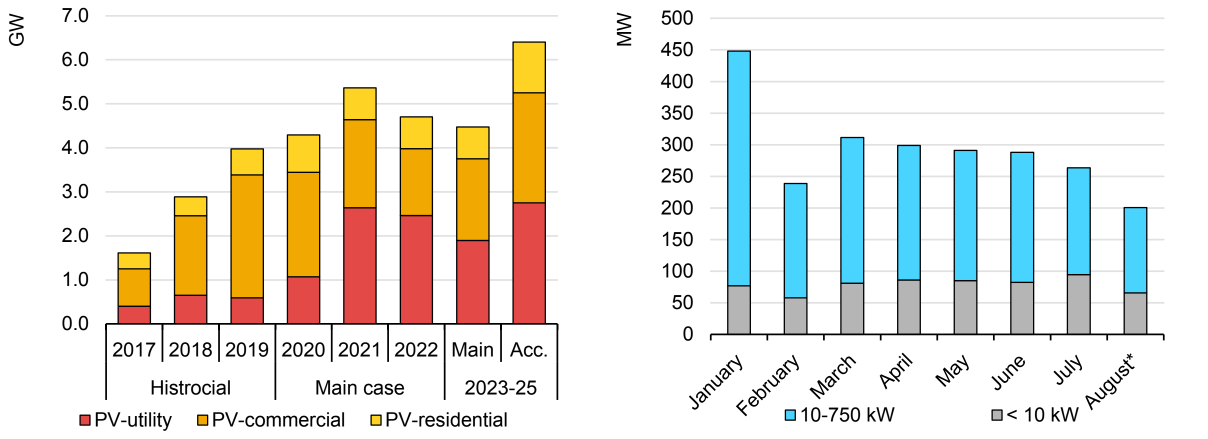
Solar PV additions in 2020 are forecast to increase 8% (to 4.3 GW) compared with 2019 as the result of a robust development slate of projects from competitive auctions and the continued attractiveness of self-consumption.

Despite lockdown measures, utility-scale additions more than doubled in the first half of 2020 compared with 2019, and additions in the residential segment expanded by 90% (Bundesnetzagentur, 2020). The utility-scale increase results from the commissioning of capacity from special auctions held in 2019 (an amendment to the Renewable Energy Act in 2018 introduced an additional 4 GW of auctions during 2019-21 to accelerate progress towards climate goals). The residential increase in installations is driven by falling system costs and high electricity prices.

However, two main uncertainties affect growth potential for the last quarter of 2020. The first is the risk of delays in utility-scale project development due to social-distancing measures related to Covid-19. The second is the impact of extension of support for distributed PV, a major motivator for the commercial segment.

Remuneration for excess generation was set to expire once cumulative PV capacity reached 52 GW, a threshold expected to be attained by mid-2020. The installation pace therefore increased in the months leading up to the looming expiration; however, the government removed the cap in May 2020 and extended support, and installations have since declined. Total installed distributed PV capacity had reached an estimated 2.4 GW by August 2020, and it remains to be seen how much the increased visibility over support will affect fourth-quarter deployment.

**Figure 3.14 Germany annual PV capacity additions 2016-22 and average annual additions for 2023-25 (left), and monthly distributed PV additions in 2020 (right)**






Notes: Monthly additions reflect installed (not registered) capacity that receive support under the EEG (Renewable Energy Act). They do not include systems that do not receive support payments. August data estimated based on the ratio trend between installed and registered capacity for the last two monthly data publications.
Source: Right: Bundesnetzagentur (2020), EEG-Zubau- und Summenwerte.

Additions are forecast to expand in 2021 owing to a strong increase in utility-scale projects from the additional 4 GW of auctions. Also supporting the sharp increase is additional capacity from the joint PV-wind auctions and the commissioning of unsubsidised projects (corporate PPAs and bilateral contracts with utilities). Five joint solar-PV auctions totalling 1 GW have been held since 2018, and all was awarded to solar PV with average prices ranging from EUR 47/MWh to EUR 57/MWh.

PV additions are expected to decline in 2022, largely due to a contraction in distributed PV stemming from a proposed reform to the Renewable Energy Act (the EEG 2021). The draft, released in September 2020, proposes that rooftop systems greater than 500 kW compete in competitive auctions capped at 200-400 MW per year starting in 2021, which is substantially lower than the 1 GW deployed in 2019 under the self-consumption scheme.

Utility-scale growth during 2023-25 is largely driven by the proposed EEG 2021. In June 2020, the government raised the 2030 target for the share of renewable electricity from 50% to 65%, and to meet this goal, in September 2020 the government proposed to increase the 2030 PV capacity target to 100 GW. This proposal raises annual utility-scale auction volumes from 600 MW to 1.9-2.8 GW.

For distributed PV, annual additions average 2.6 GW during 2023-25, significantly below growth in 2019 and 2020 due to limits on the amount of rooftop systems over 500 kW eligible for support. However, attractive economics for self-consumption with excess remuneration continue to drive medium- and small-scale commercial growth. For residential installations, the main case expects a steady increase, supported by higher demand from electric cars and heat pumps.

The main case reflects the draft EEG 2021 proposal, which still had to be passed by Germany's parliament at the time of writing. Total average annual growth could be 43% higher between 2023 and 2025 with stronger distributed PV deployment. This would require the final EEG 2021 Act to maintain self-consumption for the commercial segment or to hasten cost declines to make small commercial and residential systems more attractive. Additional accelerated deployment depends on faster economic recovery, higher electricity demand and increased corporate and utility PPAs outside of the auction scheme.

# Spain

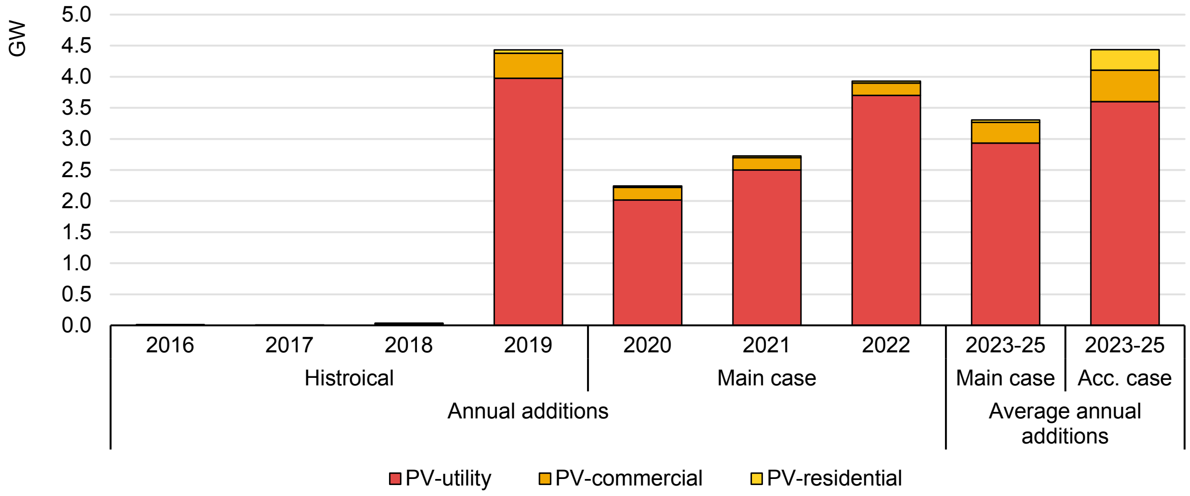
## Solar PV revival is driven by corporate PPAs and new auctions

Annual solar PV additions are expected to slow in 2020 after a record-breaking 2019 caused by a commissioning deadline for projects awarded in 2017 auctions. Still, utility-scale additions in 2020 are expected to demonstrate the second-highest growth, and further increases are forecast for 2021-22.

Expansion is mainly in unsubsidised projects supported by corporate PPAs, bilateral contracts with utilities, or by combining either with a merchant tail. Strong resource potential, falling investment costs and high wholesale electricity prices have created over 7 GW under construction, with commissioning affected only minimally by delays induced by Covid-19.

Improved regulatory conditions to shorten lead times also support the forecast. In Q2 2020, a series of legislation was passed establishing project deadlines to maintain permitting eligibility. These regulations are intended to speed up licensing approvals and minimise the reselling of permits for windfall profits.

**Figure 3.15 Spain annual PV capacity additions 2016-22 and average annual additions 2023-25**






Average annual growth is forecast to decelerate during 2023-25 due to uncertainty over future power demand, potentially challenging the financing for new unsubsidised projects. More than half of the growth in this period will result from the resumption of competitive auctions after a three-year break to meet newly raised 2030 targets and facilitate Covid-19 economic recovery. The new auction regime was approved in October 2020, but the tender design and timeline have yet to be announced at the time of writing. The main case assumes that 2 GW will be awarded auctioned every year, but higher volumes and strong corporate PPA demand could result in 23% higher average annual growth for utility systems in the accelerated case between 2023 and 2025.

Distributed PV growth is forecast to decline in 2020, based on the expectation that lockdown measures will have slowed installation rates relative to 2019. However, pre-pandemic regulatory reforms offering remuneration for grid exports and reducing the fixed part of retail tariffs have improved the economics of self-consumption. These reforms are expected to remain the main driver for distributed PV growth through 2025, although a potentially weaker economic climate remains a key uncertainty. Growth could more than triple if the Covid-19 crisis has a minimal impact on business demand for self-consumption and if economic recovery is strong.

# The Netherlands

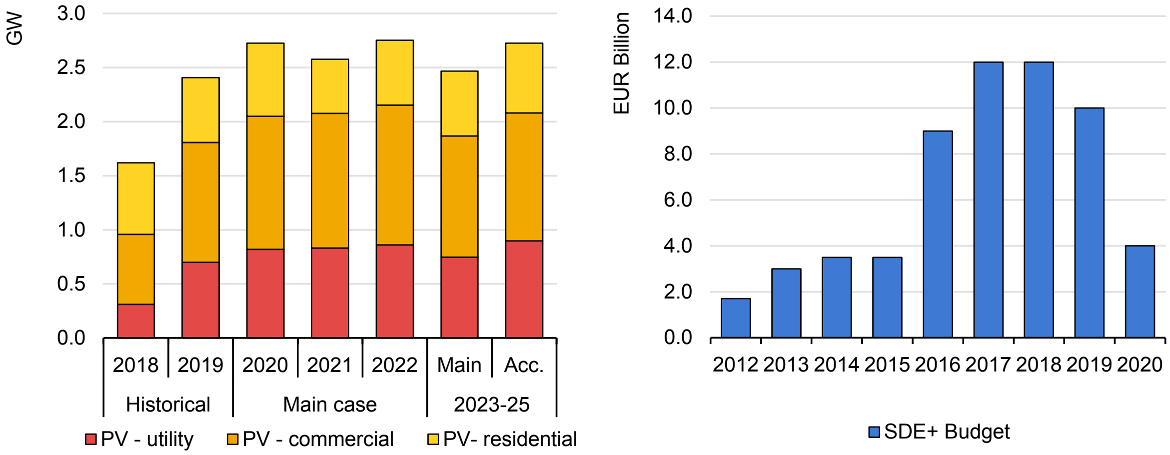
## The SDE+ policy and net metering deadlines propel solar capacity additions in 2020, but the transition to a new policy is a major forecast uncertainty

The Netherlands is forecast to add over 2.7 GW of solar PV across all sectors in 2020, 13% more than 2019. Driven by SDE+ auction rounds and net metering, there were over 500 MW of additions in first half of 2020. While the installation rate slowed during the first wave of the Covid-19 pandemic, capacity additions accelerated from May through July.

PV additions are expected to be in line with the 2020 level in 2021 and 2022 owing to commercial applications. In 2019, the government introduced the requirement to verify network availability before competing in an SDE+ auction, which challenged expansion in some areas. High electricity prices and a generous net-metering scheme support residential expansion.

Beyond 2022, policy deadlines drive PV capacity additions: the strongest growth is forecast for 2023, as remaining SDE+ and new SDE++ projects commission before subsidies are phased out; increased technology competition in the SDE++ support scheme is a forecast uncertainty, leading to declining additions in 2024 and 2025. In addition, net metering credit rates will be reduced 9% annually starting in 2024, reducing the profitability of residential PV projects. At the same time, declining equipment costs could raise demand for commercial and residential solar PV, resulting in higher growth in the accelerated case.

**Figure 3.16 Netherlands solar PV capacity additions 2018-22 (left), average annual additions 2023-25, and SDE+ budget 2012-20 (right)**



# France

## Strong capacity targets and the new auction schedule accelerate PV expansion

France's PV capacity additions are expected to amount to 1.3 GW in 2020, the highest level since 2012. This 50% growth compared with 2019 results from the commissioning of projects from auctions held during 2017-18 for large buildings and ground-mounted installations.

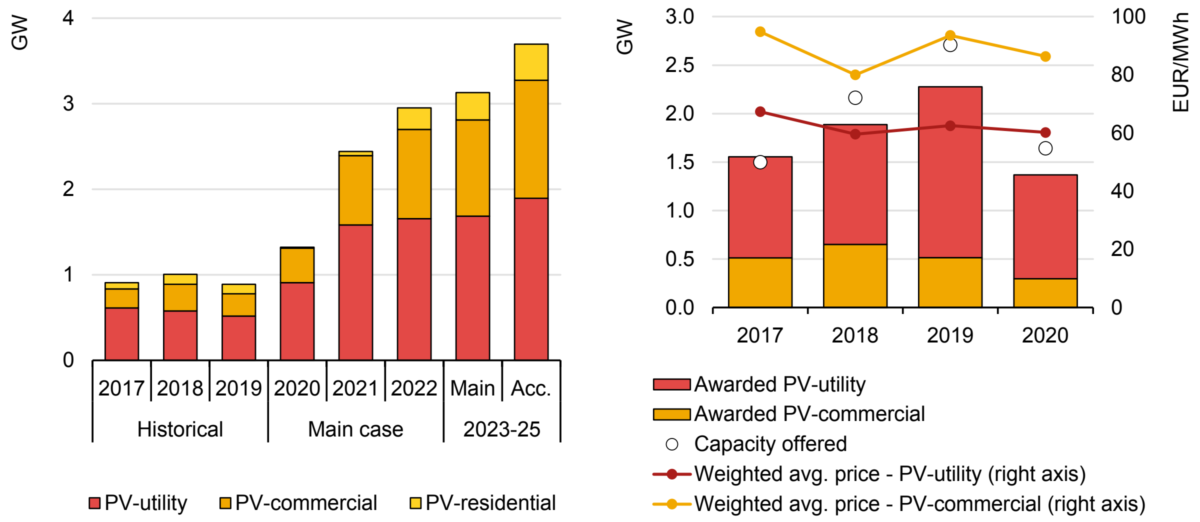
Annual additions accelerate in 2021 and 2022 owing to almost 7 GW of capacity awarded in previous auctions, with utility-scale projects accounting for almost two-thirds of the expansion. Residential systems under the FiT scheme are also expected to make a small additional contribution to the forecast.

In April 2020, the government published its new multiannual energy plan (the PPE), which confirms its commitment to 20 GW of PV capacity by 2023, as well as annual auctions for 2 GW of ground-mounted projects and 0.9 GW of large rooftop installations up to 2024.

Recent policy developments, such as PV installation obligations for new warehouses, supermarkets and parking canopies, extension of FiT eligibility to larger rooftop projects, tax cuts for large PV installations, and general tax reductions for enterprises as part of recovery measures, are also expected to accelerate deployment, especially for the commercial segment. However, the capacity of commercial PV developers to scale up deployment in the short term remains uncertain: the current rooftop auction scheme suffered undersubscription in 2018 and 2019, leading to a downward revision of auctioned capacity in 2020. Assuming sustained auction subscriptions and project completion rates for future rounds, capacity additions during 2023-25 are expected to remain over 2.5 GW/year, allowing France to meet its 2023 target.

With more streamlined permitting, higher participation in auctions for rooftop installations, a higher completion rate for awarded projects and stronger uptake of PV in the residential sector, annual capacity could average near 3.6 GW over 2023-25. The allocation and modality of support from the European stimulus package could be instrumental in this regard.

**Figure 3.17 France solar PV capacity additions 2017-22 and average annual additions 2023-25 (left), and solar PV auction results 2017-20 (right)**






Note: Right-hand figure covers auctions until September 2020.

# Italy

## After stalling since 2012, PV growth accelerates thanks to ambitious government targets and "green" recovery policies

Italy is forecast to add 0.8 GW of PV capacity in 2020, similar to 2019. Despite the Covid-19 crisis, PV capacity additions in the first half of 2020 were higher than in the same period last year.

Distributed PV applications are expected to lead Italy's PV growth in 2021 and 2022, encouraged by tax incentives, a real-time self-consumption scheme ("*Scambio sul posto*") for installations up to 0.5 MW and a FIP for systems over 0.5 MW. In addition, a new 110% tax rebate for residential PV systems installed together with building energy efficiency modernisations was introduced in May 2020 as part of the Covid-19 economic relief package, which is expected to further support PV deployment.

Beyond 2022, Italy's PV additions are expected to expand substantially. In its National Energy and Climate Plan, Italy set a target of 52 GW of PV capacity by 2030 – almost 2.5 times the 20.9 GW installed by 2019. The auction scheme introduced in 2019 is expected to propel PV expansion towards this target.

However, only 25 MW out of 1 000 MW was awarded to PV developers. This lack of interest results partly from rules prohibiting the use of agricultural land, which has prompted many investors to seek PPA contracts and developer merchant projects. Given the uncertainty over future electricity demand and prices, the forecast expects that PV developers will win more capacity in upcoming auctions.

Streamlining the permitting process, resolving land use challenges and implementing additional policies to stimulate deployment of distributed PV could boost average annual capacity additions to 4.6 GW during 2023-25 in the accelerated case.

# Poland

## PV installations are booming owing to new auctions and distributed PV expansion

Poland's PV capacity growth is expected to reach a record 1.4 GW in 2020, 44% higher than in 2019. A generous net-metering scheme and declining investment costs have created an investment boom in distributed PV, especially in the residential sector.

Furthermore, a new subsidy scheme was introduced in August 2019 enabling residential PV investors to receive government grants, with the programme budget allowing deployment of up to 1 GW of capacity. Since March 2020, another government programme supporting thermal renovation of houses has also provided preferential loans for the installation of PV systems.

Deployment in the distributed PV sector is expected to slow in 2021 due to phase-out of the subsidy programme in the second half of 2020. Meanwhile, the number of utility-scale PV projects is forecast to increase, driven by the 2019 auction.

With Poland's National Energy and Climate Plan aiming to double the country's share of renewables in electricity generation to 32% by 2030, the government is expected to implement additional auctions and continue to support the net-metering scheme and other incentives for distributed PV. As a result, the forecast expects an acceleration in PV additions during 2023-25.

# Belgium

## After a slight decline in 2020, residential PV recovers thanks to reintroduction of support in Flanders

PV deployment in Belgium is forecast to decline in 2020, as policy transitions and lockdown-related shortages in module deliveries postpone and delay rooftop installations. Following the Flemish government's announcement in June 2020 reintroducing support for residential and commercial rooftop PV starting in 2021, installation activity is anticipated to pick up again to reach over 0.5 GW.

Belgium's PV growth trend is expected to be sustained after 2022, with around 1.5 GW coming online in the three years leading up to 2025. Growth is primarily in the residential segment, spurred by high retail electricity prices and the reinstated investment subsidies in Flanders.

In the accelerated case, average 2023-25 additions could be up to 54% higher assuming greater profitability of residential applications under existing schemes as well as continued support for solar PV in Flanders beyond 2024.

# Latin America

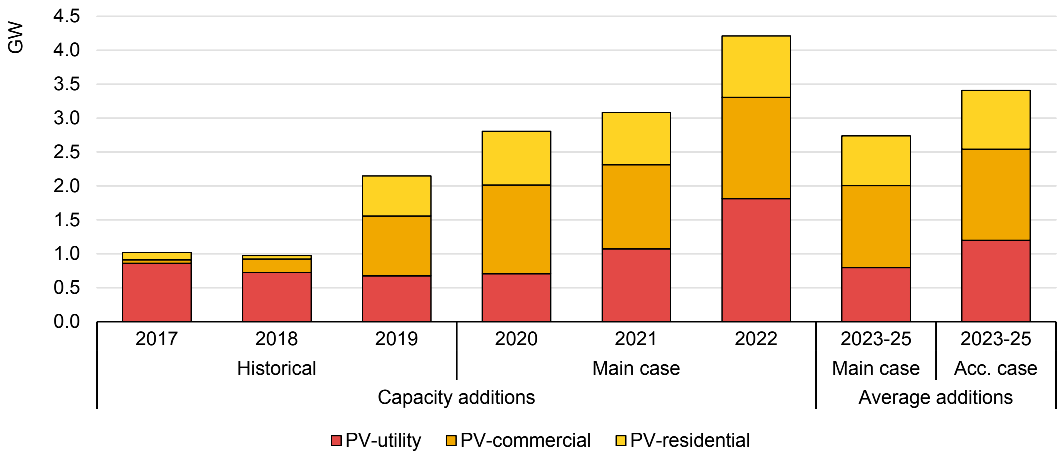
# Brazil

## Net-metering scheme makes distributed PV the primary source of near-term growth

Brazilian solar PV additions in 2020 will increase by over 30% from 2019, with distributed installations expanding the most – by over 2 GW, a record – thanks to continuation of the generous net metering programme. Mineas Gerais (the largest distributed PV market), Sao Paulo and Rio Grande do Sul are responsible for half of Brazil's distributed PV additions, owing in part to high retail tariffs (ANEEL, 2020).

In addition, over 700 MW of utility-scale additions are forecast to become operational as some plants under the central auction scheme connect prior to commissioning deadlines to take advantage of additional revenues from the unregulated market. The average spot market price in 2020 exceeds awarded contract prices in government auctions over the last three years (CCEE 2020).

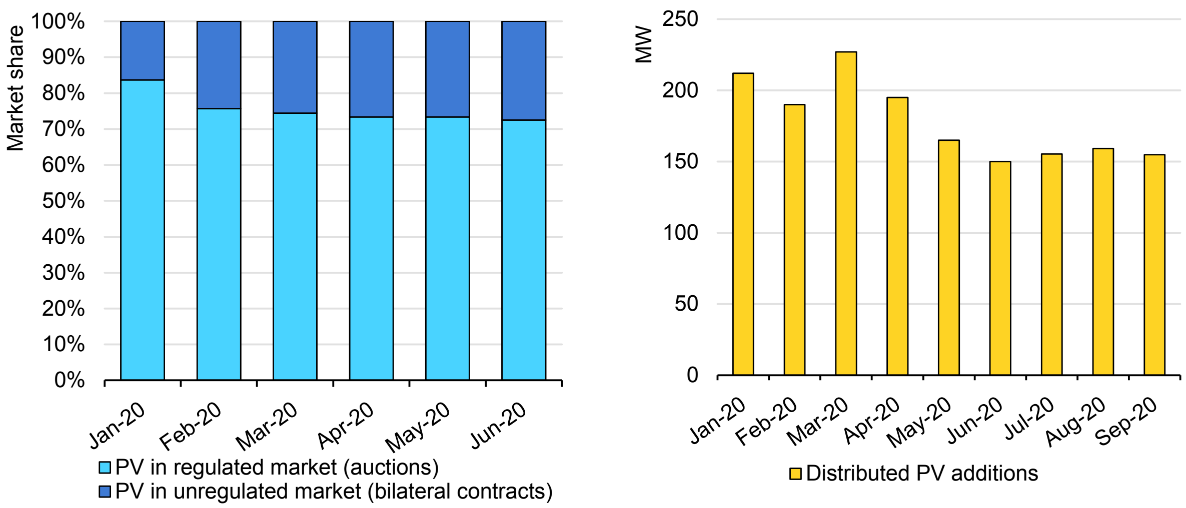
**Figure 3.18 Brazil solar PV capacity additions 2017-22 and average annual additions 2023-25**



PV additions are forecast to rise further in 2021 and 2022, as utility-scale projects begin to ramp up and distributed PV applications remain strong. Nearly 30% of total PV capacity was operating in the unregulated market in 2020, and the forecast expects that nearly half of the utility-scale growth in the next two years will be outside the auctions scheme considering the relatively high prices. In addition, the Brazilian government recently reduced import duties on PV equipment to zero, improving the competitiveness of solar projects.

With net metering and attractive financing options available for consumers, distributed PV additions surpass the 2-GW barrier in 2021. The forecast assumes that consumers and SMEs will rush to complete projects in 2022, anticipating a possible change in the net metering policy.

**Figure 3.19 Brazil shares of solar PV operating in the unregulated market (left) and monthly distributed solar PV additions, 2019-20 (right)**






Sources: CCEE (2020), InfoMercado Dados Gerais 2020,; ANEEL(2020), Geracao Distribuida.

The number of PV projects operating outside of the regulated environment continues to increase during 2023-25, with 75% of the expected growth facilitated through a combination of bilateral contracts with state utilities and corporate PPAs. Net metering will ensure stable distributed PV growth, assuming that low interest rates persist. However, a change in the net-metering scheme and the availability of affordable financing remain forecast uncertainties, as Brazil's economy is expected to enter a deep recession (OECD, 2020).

Under the accelerated case, increased electricity demand leads to higher auction capacity and additional PPAs, boosting utility-scale installations. Better financial conditions and higher demand, coupled with falling equipment costs, drive faster adoption of distributed PV as more consumers take advantage of net metering.

# Mexico

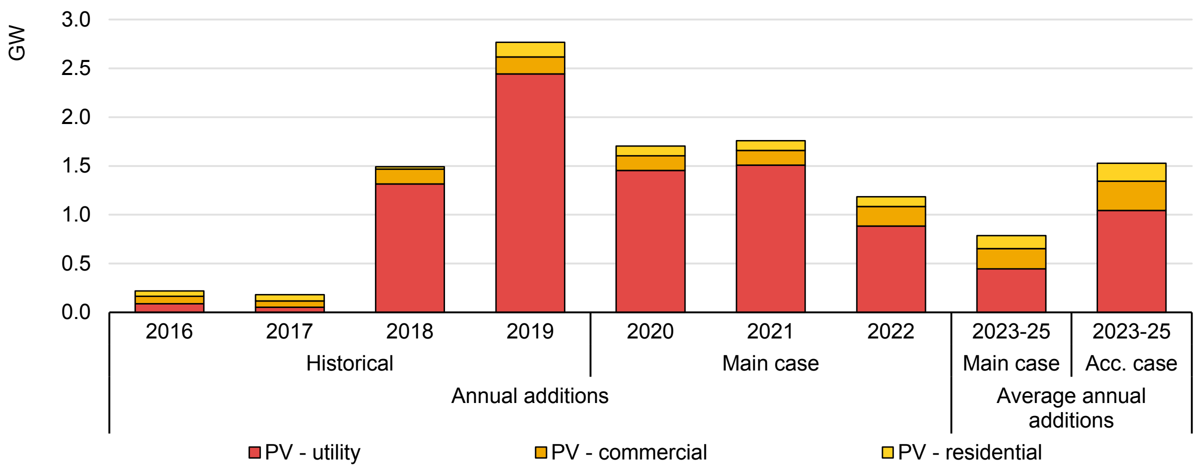
## Regulatory uncertainty hinders previously forecasted private investment increase in all PV segments

Compared with 2019, Mexico's PV capacity growth is set to drop almost 40% in 2020. Utility-scale projects dominate with almost 1.5 GW expected to come online, mostly from clean energy certificate (CEL) auctions held during 2015-17. The contraction in growth results partly from grid connection restrictions, imposed by the regulator and the system operator in response to reliability concerns caused by demand pattern changes during the Covid-19 crisis.

Annual auctions were paused in 2018 to review their objectives and scope. Still, Mexico has strong slate of projects under development (over 3.5 GW) from previous auctions and corporate PPAs, expected to come online during 2020-22.

The regulation restricting the connection of renewable energy projects has been challenged by developers, and courts have granted connections to some projects. In August 2020, the Supreme Court decided to suspend the regulation, so this forecast anticipates a faster connection rate than in our May update, with 2.4 GW of utility-scale PV projects being commissioned in 2021 and 2022.

**Figure 3.20 Mexico annual PV capacity additions 2016-22 and average annual additions 2023-25**






Despite the cancellation of CEL auctions, the government's 2024 target of 35% of electricity from clean energy sources remains in place and retailers and large consumers are still required to procure certificates to meet their obligations. As large consumers account for over 40% of electricity sales in Mexico, private renewable energy auctions and corporate PPAs are expected to drive annual additions of utility-scale PV during 2023-25.

The share of distributed applications in overall PV growth is forecast to increase owing to net metering and net billing policies, while higher unsubsidised residential and commercial retail electricity prices improve their economic attractiveness.

Nonetheless, the current political environment and the possibility of further regulatory changes create uncertainty for developers, reducing expectations for average annual additions to below the levels of preceding years. In the accelerated case, 3 GW more solar capacity could be online by 2025, contingent upon more regulatory certainty for developers and rapid economic recovery for the distributed segment.

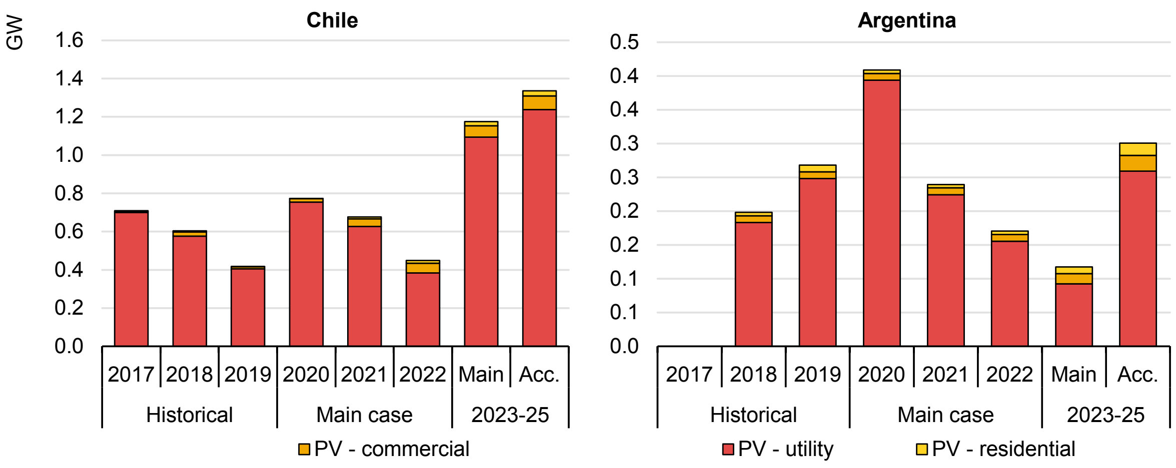
# Chile, Argentina and Colombia

## In Chile, auction schemes drive strong utility-scale PV expansion

**Chile's** solar capacity additions are forecast to reach more than 750 MW in 2020, almost double last year's amount. Capacity expansion is prompted mostly by early completion of some projects from the last auction held in 2017, with a commissioning deadline in 2024.

Additions are expected to slow in 2021 and 2022 as a result of the gap in auctions while corporate PPA activity gains traction and merchant plants suffer from declining spot prices.

**Figure 3.21 Chile and Argentina annual PV capacity additions 2017-22 and average annual additions 2023-25**



Chile's PV growth is expected to accelerate after 2022. As part of Covid-19 economic recovery efforts, the government has fast-tracked the environmental approvals of 55 solar projects. However, the electricity auction for regulated distributors was postponed from this year to the first half of 2021 and the government reduced the auction capacity due to uncertainty over future electricity demand.

In addition, land auctions awarding 2.6 GW of wind and solar PV capacity in Q3 of 2020 indicate further solar PV deployment in Chile. Furthermore, Chile's recently launched Casa Solar programme supports the development of distributed PV projects by allowing community groups to obtain solar panels at lower prices and receive state co-financing. This recent development helps propel distributed capacity expansion.

Thanks to constant annual additions, Chile is well on track to meet its 2025 target of 20% electricity from non-conventional renewable sources. The even greater expansion demonstrated in the accelerated case depends on higher auction capacity and increasing solar development under corporate PPAs.

## Argentina's PV expansion is expected to contract due to macroeconomic challenges and uncertainty over future auctions

**Argentina's** utility-scale PV capacity is forecast to double to over 800 MW of installed capacity this year thanks to the commissioning of previously auctioned projects. Despite this expected growth, however, many projects have suffered delays related to Covid-19, postponing pre-commissioning tests or halting construction. Delayed projects are expected to come online in 2021 and 2022.

PV expansion is expected to contract during 2023-25, as Argentina awarded only 100 MW of PV in the 2019 auction and timing of the auction round that was expected for this year remains uncertain. Outside of auctions, renewable energy projects can sign bilateral agreements with large consumers that need to comply with the country's goal of renewable energy covering 20% of electricity demand by 2025.

However, economic slowdown due to the Covid-19 crisis is expected to further exacerbate already existing macroeconomic challenges, affecting not only solar PV projects but also the grid expansion needed to connect renewables. The accelerated case demonstrates that Argentina's renewable growth beyond 2022 could be much higher if projects obtain affordable financing sooner and the number of corporate PPAs climbs quickly.

## Colombia could reach renewable energy target earlier than anticipated upon continuation of energy auctions

Colombia's utility-scale solar PV capacity additions are expected to increase more over the 2020-22 period than they did in 2019. Two auctions (for energy and reliability) combined will bring online almost 500 MW of utility-scale PV. The reliability charge auction is held for the purpose of ensuring the reliability of power generation capacity even during times of drought. Additionally, Colombia is expected to hold its first private renewable auction where 140 MW (20 GWh per month) of non-conventional renewable energy sources will be tendered this year.

For 2023 and beyond, the forecast assumes 1.2 GW of additional PV capacity, spurred by continuation of the auction scheme. Considering its contracted projects and government plans, Colombia could reach its 2030 target of 4 GW of non-conventional renewable energy sources five year earlier.

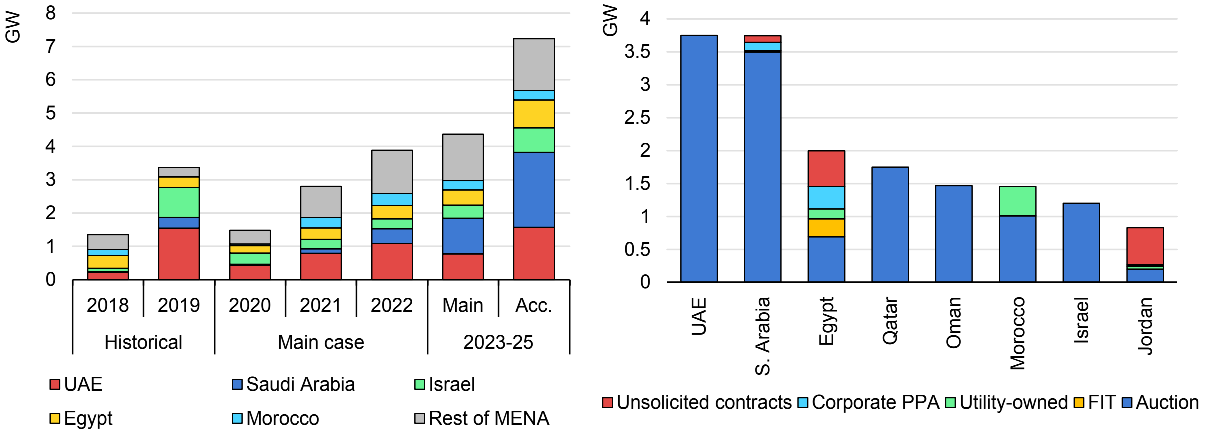
# Middle East and North Africa

## Net fossil fuel exporting countries account for almost half of PV capacity growth during 2020-25 owing to its increasing cost-effectiveness

The Middle East and North Africa (MENA) region is forecast to add 1.5 GW of solar PV in 2020. This growth is half of the region's expansion last year, but it is important to note that 2019 was a record year thanks to the commissioning of major projects under some of the first renewable support schemes for solar PV in the region.

For instance, the United Arab Emirates added 1.5 GW from two utility-scale projects awarded in some of the country's first competitive auctions held in 2016 and 2017. Egypt commissioned almost 1 GW of projects under its FiT programme and Saudi Arabia inaugurated 300 MW with the country's largest utility-scale PV plant, awarded in the first competitive solar IPP auction in 2017.

**Figure 3.22 MENA annual PV additions 2018-22 and average annual additions 2023-25 (left), and incremental growth by procurement type for selected countries 2020-25 (right)**






Note: The statistical data for Israel are supplied by and under the responsibility of the relevant Israeli authorities. The use of such data by the OECD is without prejudice to the status of the Golan Heights, East Jerusalem and Israeli settlements in the West Bank under the terms of international law.

Policy transitions and irregular procurement processes are expected to result in lower additions in 2020 due to gaps in the utility-scale project pipeline. A sharp decrease is forecast for Egypt, where a switch from FiTs to competitive auctions has been slow. FiT expiration, stop-and-go tender schedules, and caps on the size of projects eligible for corporate PPAs using the net-metering scheme have driven developers to approach the state utility independently, outside of a policy scheme, to negotiate bilateral PPAs.

In the United Arab Emirates and Saudi Arabia, additions are also lower this year because new projects from both countries' competitive auction schemes are still under construction.

Annual growth is expected to rebound in 2021, almost doubling owing to the commissioning of major IPP projects awarded in competitive auctions in the United Arab Emirates, Qatar and Oman. Annual growth increases further by 2022, reaching 4 GW per year, and averages just slightly higher during 2023-25 as capacity from other markets (Saudi Arabia, Jordan and Tunisia) begins to expand more quickly.

More than 20 GW of solar PV is expected to be added during 2020-25, led by the United Arab Emirates and followed by Saudi Arabia, Egypt, Qatar and Oman. Net fossil fuel exporter countries are expected to account for almost half of the region's PV expansion, compared with just one-third in the previous five-year period. Growth results mainly from the increasing economic attractiveness of utility-scale solar PV, as deployment is spreading rapidly to countries where PV previously had to compete with electricity generation from domestically produced low-cost hydrocarbons.

The main policy driver for this trend is the use of competitive auctions, which account for over three-quarters of the region's growth and have produced record-breaking tariffs awarded to solar PV. In the past year, bids at the lower end of the spectrum ranged from USD 13.5/MWh to USD 16.9/MWh thanks to good resource potential, economies of scale, and access to low-cost financing and land. These prices are very market-specific, however, reflecting favourable financing conditions and land affordability that may not be replicable in other markets.

**Table 3.1 MENA region selected utility-scale solar PV tender prices in 2019 and 2020**

| Date | Country | Capacity (MW) | Price (USD/MWh) | Status |
|---|---|---|---|---|
| October 2019 | United Arab Emirates (Dubai) | 900 | 16.9 | Awarded |
| January 2020 | Qatar | 800 | 15.7 | PPA signed |
| April 2020 | Saudi Arabia | 300 | 16.2 | Bids received |
| April 2020 | United Arab Emirates (Abu Dhabi) | 1 500 | 13.5 | Awarded |

Two key uncertainties cloud the forecast for the MENA region: first, the pace at which contractual agreements under the various policy procurement processes occur. For competitive auctions, PV expansion depends largely upon how quickly governments announce and move through the various processes, which is often unpredictable because many governments do not publish auction timelines in advance. In some countries, project development through this procurement method tends to be slower than when IPPs directly approach large consumers or utilities to formulate corporate PPAs or unsolicited bilateral contracts – which are the second-largest source of capacity growth in Egypt, Morocco and Jordan.

Second, the possible impact of the Covid-19 crisis on near-term project development is uncertain. In Tunisia, projects have been delayed by supply disruptions and postponed grid connections (MEES, 2020), while Abu Dhabi delayed announcing the winner of a 1.2-GW auction to adhere to social distancing measures.

In some hydrocarbon-exporting countries, minimising the pandemic's impact of low oil prices on state budgets has temporarily diverted attention away from renewable energy plans. Almost 2 GW of solar capacity is waiting to sign PPAs with Saudi Arabia's state utility, and Kuwait cancelled the 1.5-GW Al-Dabdaba tender when low oil prices induced a priority shift.

These developments are expected to be temporary, however, only shifting capacity forward and not affecting long-term growth. Tendering processes have resumed in the United Arab Emirates and were extended in Saudi Arabia while large projects in Qatar (800 MW) and Oman (500 MW) reached financial close during the height of the crisis.

Average annual growth could be two-thirds higher during 2023-25 if governments accelerate auction procedures and higher power demand increases the uptake of corporate PPAs in markets that permit them. The completion of planned grid upgrades in Tunisia and Jordan, which are essential for renewable energy expansion, would also accelerate growth in the region.

While most growth in the five-year period will be in utility-scale capacity (90%), distributed PV is expected to expand 2.5 GW during 2020-25. The commercial segment accounts for 77% of the increase, owing to FiTs in Israel and net-metering in the United Arab Emirates, Egypt and Jordan.

However, recent modifications to net-metering regulations in these markets threaten the forecast. Jordan suspended network access to projects of more than 1 MW under the net-metering scheme in early 2019 due to limited grid capacity, while both Dubai and Egypt placed limits on the amount of capacity eligible for remuneration.

# Sub-Saharan Africa

## South Africa boosts Africa's solar growth in 2020 as auction projects come online, but future additions depend on consistent tenders and mitigation of project risks

PV capacity additions in sub-Saharan Africa are forecast to more than double in 2020 from 2019 thanks to growth in **South Africa**. Even as lockdowns and border restrictions increased labour and cross-border-trade challenges in the region, the forecast shows stable annual additions, mostly from utility-scale applications awarded in previous auctions, and through PPAs and projects funded by international development groups. Policy uncertainty, off-taker risks and land rights issues are all barriers to increased additions and can stall development of not only an individual project but a large project pipeline.

**South Africa** will add over 400 MW of utility-scale PV in 2020 from previous tenders, the largest capacity addition since 2017. After stalled growth due to a three-year delay in PPA signing, three projects were commissioned in February and March. Although South Africa's Covid-19 lockdown caused construction of all renewable energy projects to stop completely in April before resuming again in late May (Pinsent Masons, 2020), another 190 MW is expected to be commissioned by the end of 2020.

PV projects from the 2015 tender, for which construction was delayed by the Covid-19 crisis, will not face any penalties for commissioning delays and are expected to come online during 2021-22 (ReNews, 2020). In addition, small PV capacity may be awarded in the emergency government auction announced in August 2020, but given the stringent operating requirements, the capacity is not expected to be significant.

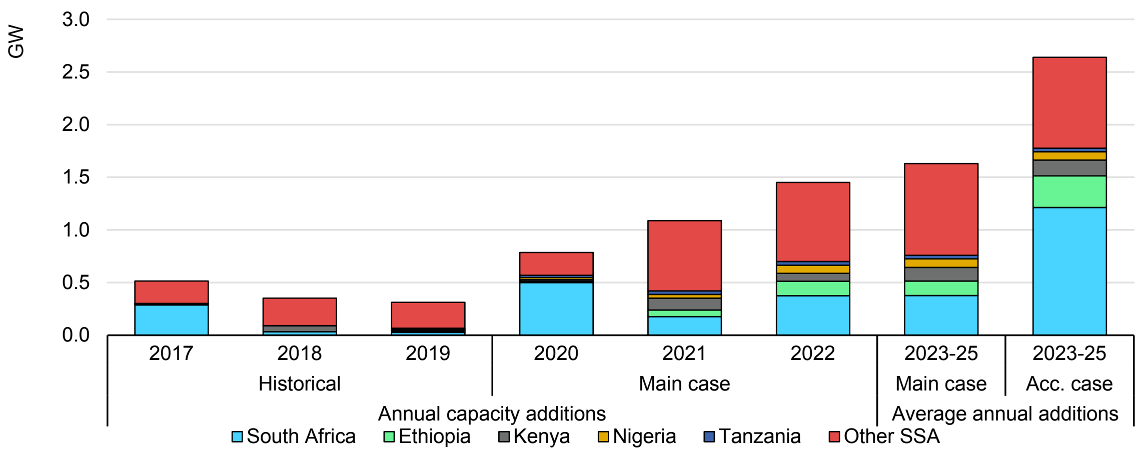
Outside of auctions, corporate PPAs represent a growing market, improving reliability for customers facing power cuts, reducing bills through self-consumption and helping corporations meet their carbon reduction goals. Two recently announced tenders are expected to increase commercial solar PV capacity by at least 80 MW during 2021 and 2022.

From 2023 to 2025, PV growth will be driven by new tenders with a total potential capacity of 8.8 GW. The first 2-GW technology-neutral tender was launched in August 2020, while additional tenders for 6.8 GW of renewables have only been announced. Ongoing financial difficulties and grid constraints remain critical challenges to further utility-scale development. Projects awarded in previous tenders experienced lengthy delays from the award date to PPA signature, while operational projects face curtailment concerns.

Planned commercial solar PV tenders should also contribute to future growth, with over 250 MW becoming operational over 2023-25 as companies continue to expand solar PV use to improve reliability, reduce costs and shrink their carbon footprint.

As South Africa endeavours to diversify its energy supply, the accelerated case forecasts additional capacity from the Integrated Resource Plan (IRP) and capacity from municipalities contracting directly with IPPs, a measure announced this year. Commercial PV capacity also increases as more organisations put out tenders for solar PV.

**Figure 3.23 Sub-Saharan Africa solar PV capacity additions 2017-22 and average annual additions 2023-25**






Elsewhere in Africa, Covid-19 challenges and an already-small pipeline indicate minor gains across the region this year. However, additions in 2021 and 2022 are poised to increase owing to a combination of FiTs, tenders and development agency-backed projects.

**Figure 1** **Selected Africa utility-scale solar PV additions by country and policy, 2021-22**

| Country | Main policy driver | Capacity (MW) |
|---|---|---|
| Ethiopia | Tender | 170 |
| Kenya | FiT | 120 |
| Nigeria | PPA | 113 |
| Tanzania | Grant | 30 |

Utility-scale solar PV project development in **Ethiopia**, **Kenya**, **Nigeria** and **Tanzania** requires bilateral agreements with the governments and state-owned utilities through tenders, FiTs or PPAs. However, off-taker risks and administrative challenges have delayed financial close for many projects since 2016.

In **Ethiopia**, land rights issues deter development, and some PV projects have been delayed by up to one year. The latest tenders in 2019 sought to alleviate this risk, with the government providing the land for installations as part of the tender (IJ Global, 2019). Even with the improved tender process, however, current projects are forecast to connect slowly, with just over 170 MW of utility-scale PV added from 2021 to 2022 and only 360 MW added during 2023-25. Further growth is dependent upon timely project implementation and additional tenders.

Land rights issues also pose a challenge in **Kenya**. Even after the signature of PPAs under the FiT scheme, local governments need to approve project development, which increases project risk. Despite developers having announced a large number of projects in Kenya, the long timelines from actual tendering to commissioning means that the country is forecast to only add 120 MW of utility-scale PV from 2021 to 2022 and 280 MW from 2023 to 2025. While the Energy Act of 2019 reaffirmed the FiT policy, uncertainty over its implementation persists.

In **Nigeria**, PPA renegotiations have hindered previously awarded PV projects, raising project risks significantly (PV Magazine, 2019). In addition, financing challenges in Nigeria's electricity sector hamper the necessary grid expansion required to connect large-scale renewable projects.

Given its solar PV potential, sub-Saharan Africa's renewable capacity expansion could be twice as high, as demonstrated in the accelerated case. This would, however, require countries to implement policies addressing off-taker and land acquisition risks. Timely implementation of announced auctions and faster grid expansion are also needed.

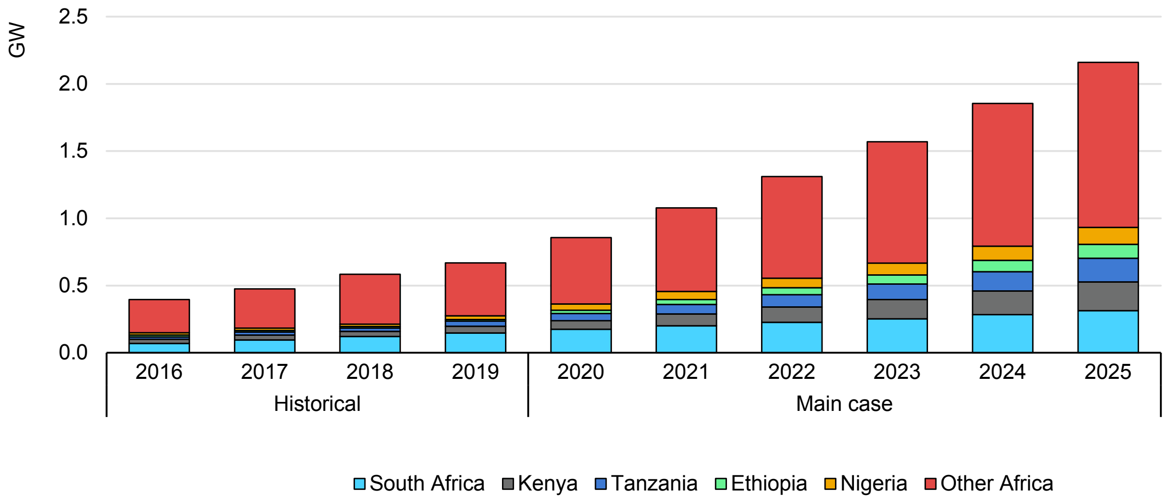
## Off-grid solar PV capacity has expanded with government-led rural electrification programmes and the help of development agencies and private firms, while the Covid-19 crisis has called attention to the urgent need for solutions and capital

Half of the people living in sub-Saharan Africa do not have access to electricity, so off-grid solar PV is expected to improve electricity access throughout the region. The forecast expects over 1 GW of new off-grid PV capacity to come online in the next five years, representing 20% of all PV additions in the region.

Capacity expansion is in the form of mini-grids and solar home systems. Prior to the pandemic, government funding and development agency grants financed numerous state-sponsored RFPs for mini-grid solutions to bring power to under-served populations and create critical infrastructure. In addition, decreasing PV system costs have enabled individual consumers to acquire solar home systems to power their homes.

The Covid-19 crisis has served to heightened interest in developing mini-grids, as relief packages have emphasised investing in renewable energy systems and programmes to power health and sanitation infrastructure and to support off-grid electrification for under-served populations.

**Figure 3.24 Sub-Saharan Africa off-grid PV installed capacity 2018-25**

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# Wind

## Forecast overview

### Wind capacity additions increase in 2020 despite Covid-19

Annual net wind capacity additions are expected to reach 65 GW in 2020, 8% more than in 2019. Covid-19 measures led to onshore construction activity slowing down from February to April due to supply chain disruptions and logistical challenges in many countries, but the offshore wind sector has been only mildly affected by delays caused by the Covid-19 crisis due to long project lead times. For 2021, the forecast assumes a further acceleration of wind additions to 68 GW (7.3 GW offshore), driven by delayed onshore projects becoming operational as key countries in Europe and the United States have passed regulations providing flexibility for commissioning deadlines.

In 2022, global annual installations return to the 2019 level due to the phase-out of incentives in major markets in the People's Republic of China ("China") and United States, which is partly offset by faster expansion in Europe. The share of offshore capacity in total wind additions reaches almost 15% in 2022 – 50% higher than in 2019 – thanks to acceleration in key European markets and large capacity becoming operational in nascent markets such as France, Korea and Viet Nam while the Chinese market slows. The United States is expected to join the ranks of the largest offshore markets after 2022.

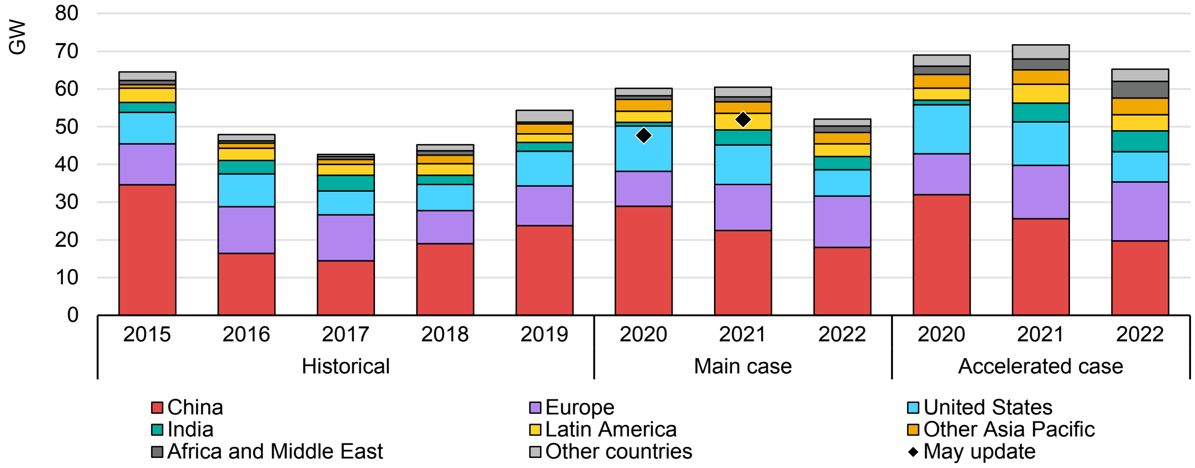
Annual global wind additions in 2023-25 could range from 65 GW in the main case and 100 GW in the accelerated case. Accelerating deployment will require the enhancement of policy support schemes, more investment in grids, eradication of social acceptance and permitting challenges, faster expansion of corporate PPAs and alleviation of regulatory uncertainties and off-taker risks in emerging markets. The share of offshore wind in total wind additions is expected to have increased further by 2025, reaching 20% as deployment in new markets gains momentum.

### Onshore wind market is proving to be more resilient than expected

Onshore wind capacity additions are expected to reach 60 GW in 2020, 11% more than in 2019. Onshore wind developers and equipment manufacturers adopted to the "new normal" under Covid-19 measures and accelerated construction activity in May after a slowdown in the first quarter of this year. As a result, the forecast has been revised upwards 26% from the May update.

China is most responsible for the revision, accounting for almost half of global onshore wind capacity growth this year (the highest since 2015) because developers are rushing to complete projects before the phase-out of subsidies. Additions in the United States also jump by over 30% this year, almost making up for the slowdown in Europe, whose contribution to global growth is at an historic low.

**Figure 4.1 Onshore wind net capacity additions by country/region**





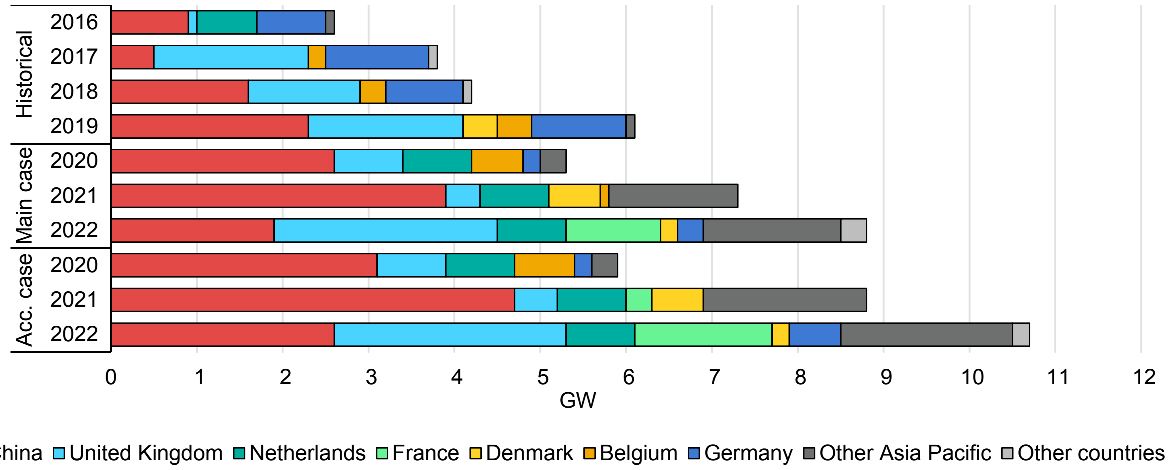

Onshore wind capacity additions are expected to further accelerate in 2021 thanks to the commissioning of delayed projects in Europe (mostly in France, Germany, Sweden and the Netherlands), and to faster growth in India and Latin America. For 2022 additions, the forecast assumes a slowdown in global deployment, mainly due to lower additions in China and the United States caused by planned changes in support policies, which will be only partly offset by growing expansion in Europe. Delayed auctions in Brazil, Chile and Argentina this year – due to lower-than-expected demand and macroeconomic uncertainties – also negatively impact 2022 additions.

## Offshore wind installations remain mostly unaffected by Covid-19 crisis

Offshore wind capacity additions are forecast to reach 5.3 GW in 2020, 13% less than 2019 growth. The forecast remains unchanged from the May update, as the offshore wind industry has been largely shielded from the Covid-19 crisis. For the first time, China accounts for over half of global offshore wind expansion, while European countries provide the remainder.

Additions are expected to reach a record 7.3 GW in 2021, led by China as developers meet the FiT commissioning deadline, while the first large-scale commercial offshore wind project becomes operational in Chinese Taipei. In 2022, despite slowdown in China, offshore capacity is expected to increase further thanks to higher deployment in the United Kingdom and France, and in other markets in Asia. With an extensive slate of projects supported by auctions, the United States is anticipated to become one of the largest offshore markets in 2024.

**Figure 4.2 Offshore wind net capacity additions by country/region**





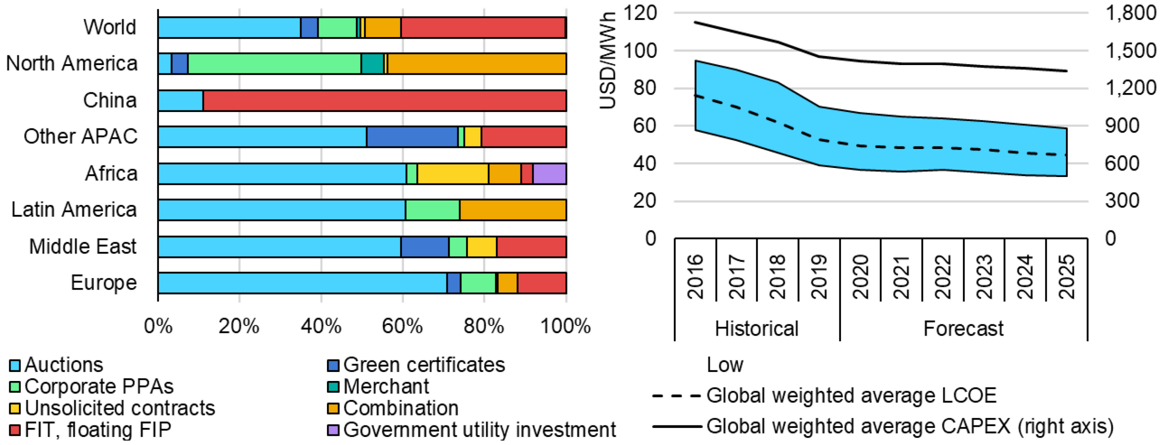

Note: Acc. = accelerated.

## Competitive auctions remain the main policy scheme globally, with the exceptions of China (which relies on FiTs) and the United States (where corporate PPAs predominate)

Support policies and continuous cost reductions are expected to be the main drivers of wind deployment in the next five years. Globally, 40% of all wind capacity forecast to come online during 2020-25 is supported by administratively set tariffs (FiTs or a floating FIP), followed by 35% supported by auctions scheme. Competitive auctions dominate growth in all regions except China and the United States.

In the United States, the main stimulants are corporate PPAs, tax credits and renewable portfolio standards (RPSs), and other revenue sources (wholesale prices, green certificates, etc.). In China, administratively set tariffs are expected to support almost all wind additions until 2025, and after 2020, tariffs for new onshore wind are set at provincial power benchmark prices. Globally, the transition from administratively set to competitively set remuneration policies is expected to accelerate in the next five years as costs continue to decline and the wind industry expands.

**Figure 4.3 Main remuneration schemes supporting forecast wind capacity additions 2020-25 (left) and actual and forecast onshore wind costs (right)**






Note: Other APAC = other Asia Pacific countries.
Sources: Left: IEA (2020), Renewables 2020; Right: based on IRENA (2020), Renewable Cost Database (dataset provided to the IEA).

## Despite cost declines and continuous policy support, faster wind growth hinges on resolving social acceptance, permitting and grid integration problems

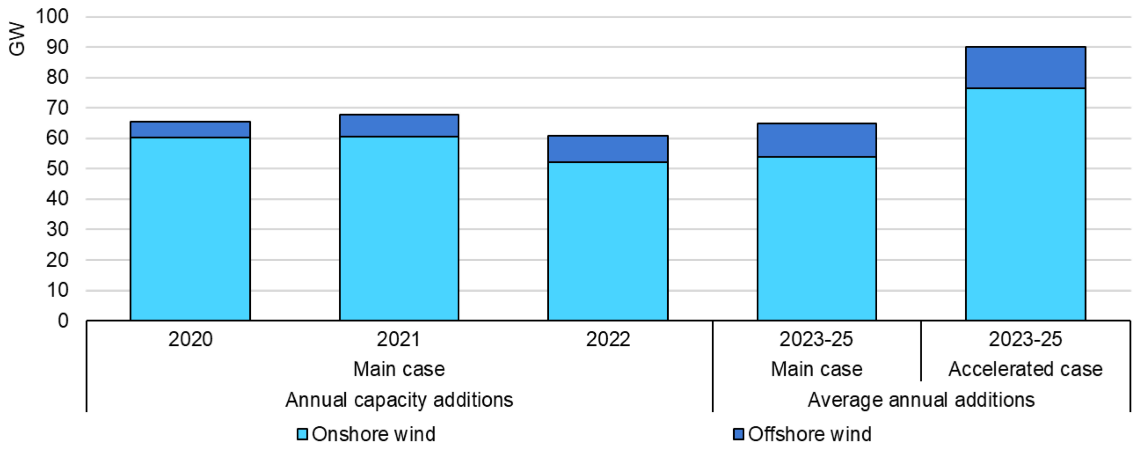
The cost of electricity generated from onshore wind continues to decrease, with the global average falling to USD 53/MWh in 2019. Thanks to advancements in turbine design, capacity factors are rising, making projects bankable even in areas with low wind speeds. The average LCOE for new onshore wind is expected to decline 15% during 2020-25 – a slower pace than in previous years – because larger shares of investment are going to more expensive markets in Europe instead of China. In addition, wind farms are increasingly been built at lower-wind-speed sites.

Over 2023-25, average annual wind additions could range from 65 GW in the main case to 90 GW in the accelerated case. Although they are becoming more cost-competitive, wind projects increasingly face permitting and social acceptance challenges in addition to policy uncertainties. Faster wind capacity growth in the accelerated case would be possible with:

- Higher targets and a robust policy framework under China's new 14th Five-Year Plan and the continuation of provincial auctions.
- Rapid expansion of competitive auctions and elimination of social acceptance and permitting challenges in Europe.
- Extension of tax incentives, faster expansion of corporate PPAs, and timely implementation of RPSs and of offshore wind auctions and procurements in the United States.

- Resolution of grid connection, land acquisition and DISCOMs financial health problems in India.
- Additional auction capacity and bilateral contracts in Latin America thanks to faster demand recovery.
- Policies to address regulatory uncertainties, off-taker risks and grid connection challenges in the ASEAN region and Africa.
- Faster development of electrical grids to reduce bottlenecks when integrating wind capacity into power systems.

**Figure 4.4 Global wind annual net capacity additions 2020-25**






Faster net capacity growth of onshore wind also hinges on policies for repowering and refurbishment, especially in Europe and the United States. By 2025, over 180 GW of global wind capacity is expected to be at least 15 years old: 86 GW in Europe, 39 GW in the United States and 30 GW in China. Repowering old turbines with new technology usually results in higher capacity and generation from fewer turbines, while taking advantage of existing grid infrastructure and land. If supporting policies are introduced in a timely manner, repowering may provide an additional boost to onshore wind additions and mitigate the adverse effects of first-generation wind turbine retirement.

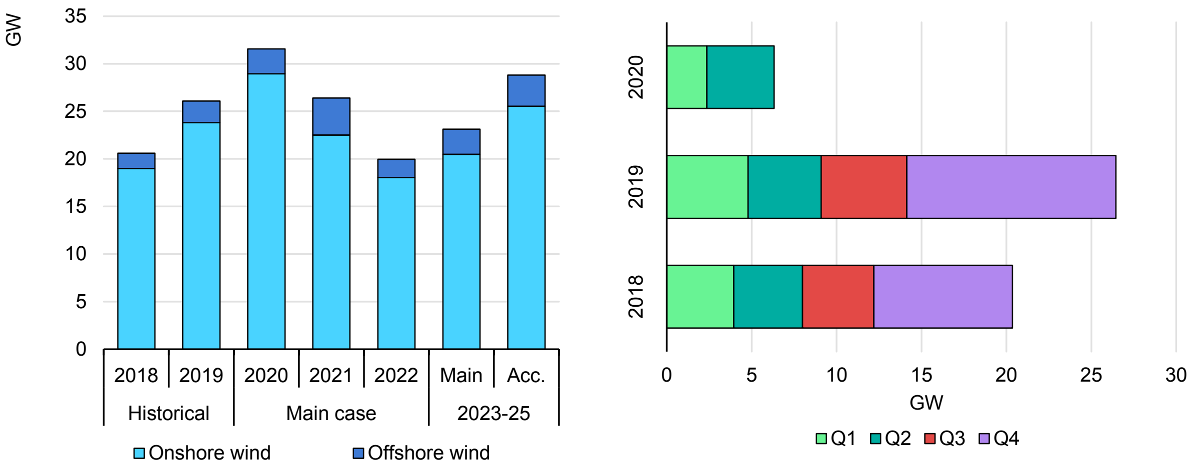
# China

## Policy deadlines propel onshore deployment in 2020, but post-subsidy uncertainties remain

China's wind capacity additions are expected to increase over 20% in 2020, consistent with last year, as onshore projects that qualified for FiTs before 2019 need to be commissioned by the end of this year. China installed 30% less onshore wind capacity in the first half of this year than in 2019 due to construction and supply chain delays related to Covid-19, but construction activity has regained momentum since June.

Although remuneration will be reduced for projects that miss the 2020 deadline, they can still come online next year. A deployment rush is therefore expected in the last quarter of 2020, but some onshore projects are forecast to miss the deadline and become operational in 2021. For offshore wind, record capacity is expected to come online next year, in line with phaseout of the generous FiT.

**Figure 4.5 China annual wind capacity additions 2018-22, average annual additions 2023-25 and quarterly wind deployment 2018-20**






In 2021 and 2022, wind capacity additions are expected to decline with the phaseout of subsidies. Deployment will be stimulated by wind auctions in some provinces and by projects accepting 20-year contracts at provincial power prices set administratively for all power generating technologies. The economic attractiveness of these projects is lower, however, especially in provinces closer to demand centres where generation costs are higher due to limited wind resource availability and relatively expensive land.

In addition, grid integration remains a challenge despite recent measures to reduce curtailment. In the absence of subsidies, the return on investment for wind projects is expected to decrease, and higher curtailment risks could reduce their bankability further.

In the accelerated case, wind additions average over 29 GW per year after 2022, assuming that provincial auctions continue and the 14th Five-Year Plan proposes a new policy framework to support further wind development. In addition, faster drops in turbine costs for low/medium-speed turbines could accelerate deployment, especially in the Eastern provinces.

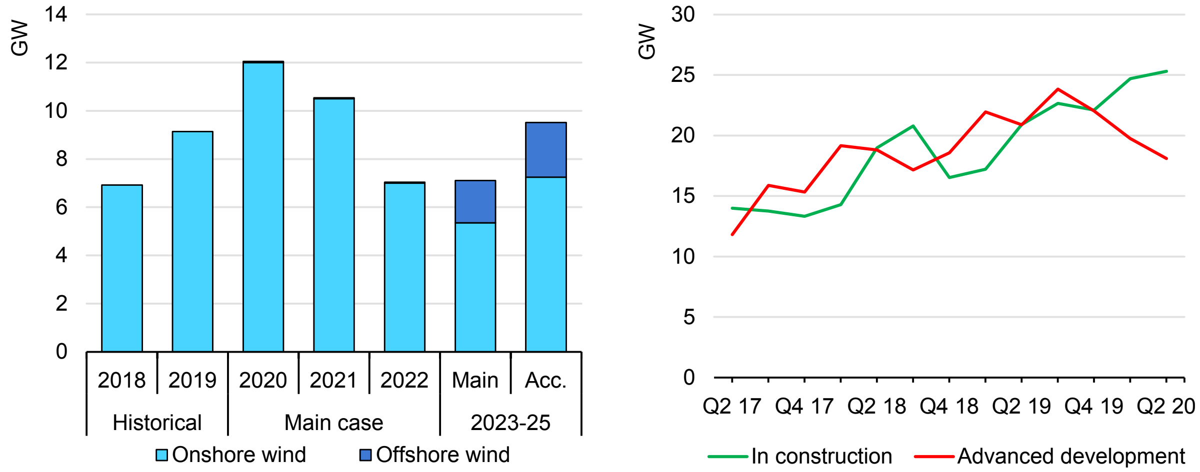
# United States

## PTC deadlines drive annual onshore wind additions, while state-level incentives also promote onshore expansion and boost offshore development

2020 will be the strongest year of onshore wind deployment in the United States since 2012 as projects qualifying for the full PTC add 12 GW, an over 30% increase from 2019. The Covid-19 crisis caused little to no market slowdown, with a record 4.3 GW of new capacity added in the first two quarters of this year. The US Treasury's extension of PTC Safe Harbour provisions will mitigate any lingering construction challenges and delays related to Covid-19.

The pace of additions is expected to decrease in 2021 and 2022 due to the PTC phase-down and a possible decline in the availability of tax equity, with both factors making projects less profitable. Project sponsors' revenues have fallen significantly with the economic slowdown, making it more difficult for them to monetise tax credits for developers (AWEA, 2020). Lower revenues and scarcity of capital have produced fewer projects in advanced development, the longest consecutive decline since 2016, and will result in a more than 40% decrease in additions from 2021 to 2023.

**Figure 4.6 US wind capacity additions 2018-22, average annual additions 2023-25 (left) and project development status 2017-22 (right)**






Source: AWEA (2020), Wind Powers America: Second Quarter 2020 Report.

The PTC phaseout schedule also affects additions beyond 2022, although a small peak is forecast for 2024, driven by the final PTC commissioning deadline for projects that qualified in 2020. Beyond tax incentives, state-level incentives such as RPSs and corporate power purchase agreements are expected to encourage onshore wind growth.

State RPSs represent a growth opportunity but also present challenges. The largest markets (Texas, Iowa and Oklahoma) have met their state-mandated targets and can still export across state lines, but segmented regional grids and RPS requirements to procure power from a regional power pool necessitate faster development of nascent and new markets. States with low installed wind capacity have ample potential but could encounter barriers, including public opposition and land constraints. Smaller plant sizes and relatively low capacity factors (compared with mature wind markets) result in higher generation costs, even as the price of wind power continues to decline.

In the accelerated case, additional capacity expansion results from lower prices and greater corporate PPA and RPS demand, especially in states where wind capacity is currently limited. IEA forecasts have excluded an additional extension of the PTC, which could lead to higher deployment than in the accelerated case.

The US offshore wind market is expected to emerge during 2023-25, with over 5 GW becoming operational as projects in New Jersey, New York, Massachusetts and Rhode Island are commissioned. The US Bureau of Ocean Energy Management is scheduled to announce its decision regarding the 800-MW Vineyard Wind farm by the end of 2020, a last major step for the project to advance.

Along with federal permitting approvals, challenges to offshore wind projects in the United States include a lack of local policy clarity, insufficient transmission and harbour infrastructure, relatively high costs and social disapproval. Still, with a large amount of capacity already awarded, the United States is forecast to install more offshore wind capacity in 2024 than any other country in the world.

**Table 4.1 US offshore wind tenders by state**

| State | Tenders | Tendered capacity (MW) | Awarded capacity (MW) | Award year | Awarded (levelised) |
|---|---|---|---|---|---|
| New York | 2* | 4 200 | 1 700 | 2019 | USD 83.6/MWh |
| New Jersey | 2* | 3 600 | 1 100 | 2019 | USD 98.1/MWh w/ 2% escalator (USD 116.82/MWh) |
| Massachusetts | 2 | 1 604 | 1 604 | 2018/19 | Tender 1: USD 65-74/MWh w/ 2.5% escalator (USD 89/MWh) Tender 2: USD 58.47/MWh |

| State | Tender s | Tendered capacity (MW) | Awarded capacity (MW) | Award year | Awarded (levelised) |
|---|---|---|---|---|---|
| Connecticut | 1 | 804 | 804 | 2019 | TBA** |
| Rhode Island | 1 | 400 | 400 | 2018 | USD 98.4/MWh |

*Includes open 2020 tender.

**PPA pricing currently under review.

Sources: NYSERDA (2019), Launching New York's Offshore Wind Industry: Phase 1 Report; State of New Jersey (2019), "In the Matter of the Board of Public Utilities Offshore Wind Solicitation for 1,100 MW – Evaluation of the Offshore Wind Applications"; Commonwealth of Massachusetts (2020), "Petition of NSTAR Electric Company, d/b/a Eversource Energy for approval by the Department of Public Utilities of two long-term contracts for procurement of Offshore Wind Energy Generation"; Yankee Institute for Public Policy (2020), Connecticut's offshore wind deals may drive up electricity costs for consumers; ecoRI News (2019), Revolution Wind offshore power contract approved.

Five states are attempting to mitigate the risks by including offshore wind in their comprehensive energy plans: they organised eight offshore wind tenders totalling over 10 GW through 2020, and awarded prices are beginning to match those of European offshore wind auctions over the same period. The success of these tenders has led to the planning of tenders for an additional over 10 GW of capacity, impacting growth beyond the forecast period.

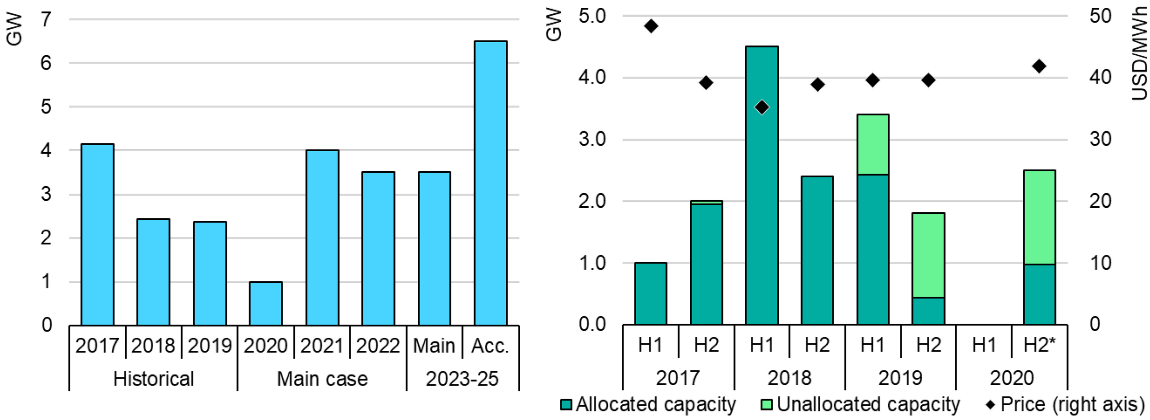
# India

## Auction undersubscription and poor DISCOM financial health hinder acceleration of wind deployment

India's wind capacity additions are expected to drop almost 60% from the 2019 level in 2020, falling to only 1 GW – the smallest increase since 2009. In the first half of 2020, India added only 0.3 GW of wind capacity (one-quarter the capacity added in the first half of 2019), as supply chain disruptions and lockdowns halted construction and delayed project commissioning.

Historically, the majority of annual construction activity in India has taken place in the first half of the year, before the monsoon season starts. Although this forecast expects construction activity to accelerate in the second half of 2020, some projects will finish construction in 2021, leading to a strong rebound.

**Figure 4.7 India annual wind capacity additions 2017-22, average annual additions 2023-25 (left) and wind auctions results (right)**






*Auctions conducted in July and August 2020.
Source: Based on BNEF (2020b), 3Q 2020 Global Auction and Tender Calendar and Results; Bridge to India (2020), India RE Navigator – Wind

Expansion is expected to remain below the 2021 level in 2022, as challenges faced by India's wind sector persist. In 2020, the financial condition of DISCOMs deteriorated further and wind auctions continued to be undersubscribed. After having been postponed several times, only one wind auction took place during the first eight months of 2020, with only 40% of the announced 2.5 GW successfully allocated with average contract prices 6% higher than last year.

Wind auction undersubscriptions result from relatively high project risks due to revenue uncertainty, land acquisition challenges, weak grid infrastructure and low tariff ceilings in the auctions. The removal of tariff ceilings, announced in March, may increase participation, enabling developers to fully incorporate perceived project risks into their bids. Plus, the recent introduction of hybrid auctions could raise competition and spur higher participation, as developers can distribute project risks among various technologies.

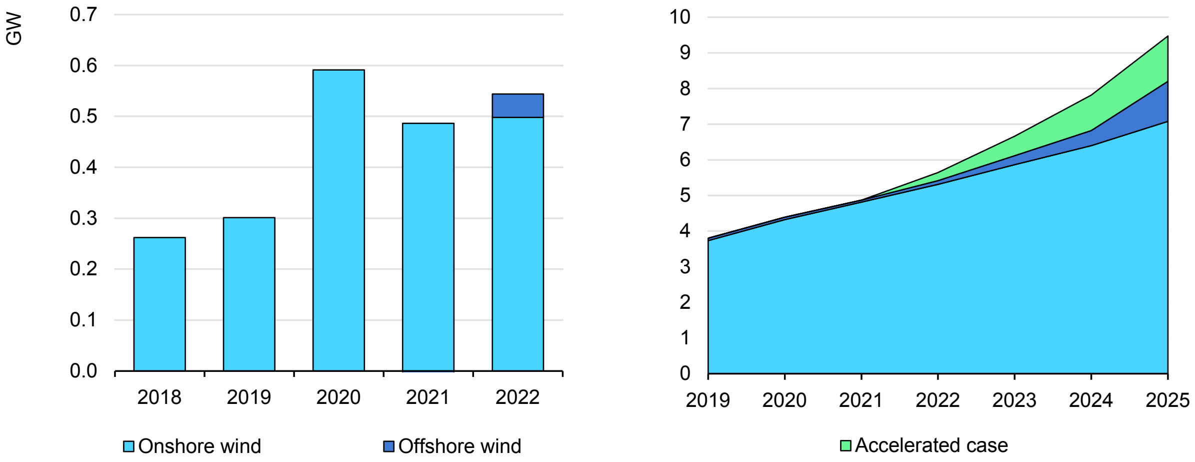
Given the various challenges, annual wind capacity additions are expected to remain at the 2022 level (3.5 GW) during 2023-25. In the accelerated case, however, average annual additions could double with higher allocations in wind auctions accompanied by accelerated grid expansion and policies facilitating land acquisition. Providing DISCOMs a sustainable solution to their financial challenges would also reduce off-taker risks, and the introduction of comprehensive, transparent and investor-friendly rules for signing private PPAs and enabling open grid access could spur higher investment independent from the auction system.

# Japan

## Wind deployment gains speed driven by large FiT pipeline

The Japanese wind market has started to expand significantly over the past few years and is set to accelerate further in 2020. The country's generous FiT has prompted development of a large collection of onshore wind projects slated for completion by 2025. While Japan's offshore wind market is still at an early stage of development, several FiT-supported projects will start construction in 2020 and the first offshore turbines are expected to become operational at the end of 2022.

**Figure 4.8 Japan annual wind capacity additions 2018-22 (left) and cumulative capacity 2019-25 (right)**






The growth trend is expected to continue beyond 2022 as more FiT projects reach completion, causing Japan's total wind capacity to double by 2025. Given longer development timelines and the large FiT project pipeline, the impact of Japan's transition to a FIP in 2022 will be limited during the forecast period.

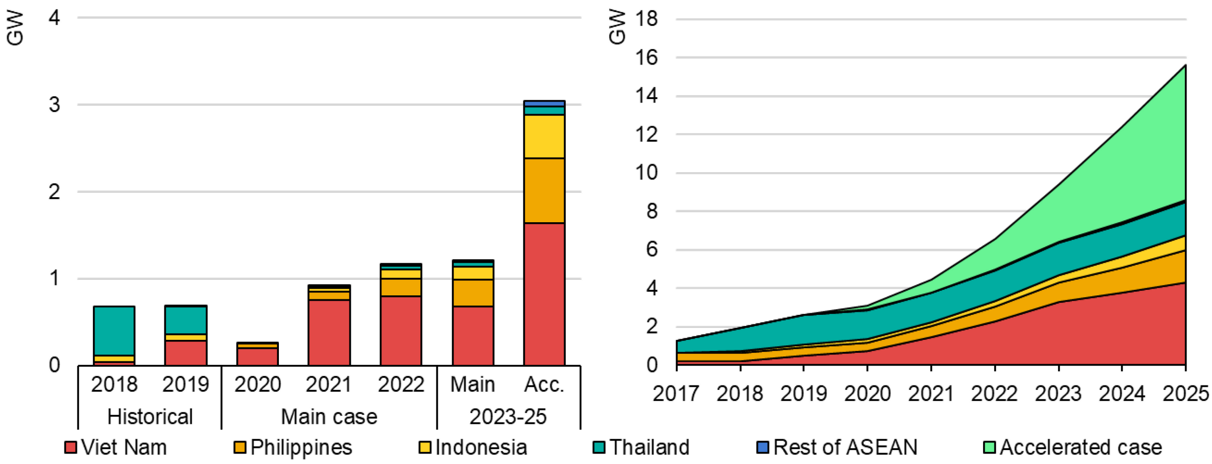
In addition, the government is expected to award 1.5 GW through an offshore wind tender next year, supporting capacity growth beyond 2022. Additional growth in the accelerated case is highly dependent on faster construction of FiT projects and offshore tender implementation, given Japan's limited experience in the wind industry.

# ASEAN

## Viet Nam leads ASEAN wind additions, but policy uncertainties and low remuneration hamper wind growth in the ASEAN region overall

ASEAN countries are expected to install 0.3 GW of wind capacity in 2020, 57% less than in 2019. Supply chain issues and construction delays due to the Covid-19 crisis and discontinuation of the FiT scheme in **Thailand** in 2018 are the main reasons for this decline**. Viet Nam** is expected to lead capacity growth from 2020 to 2022 (1.7 GW in total) as the FiT for onshore and offshore wind installations is planned to be extended to 2023.

**Figure 4.9 ASEAN annual wind capacity additions 2018-22, average annual additions 2023-25 (left) and total installed wind capacity 2017-25 (right)**






Additions are expected to decrease after 2023 due to a planned policy transition from FiTs to auctions in **Viet Nam**. In **Thailand** and **Indonesia,** wind deployment remains stalled by the limited availability of suitable land and a lack of supporting policies. In the **Philippines**, capacity addition increases are anticipated from 2022 owing to the RPS scheme introduced this year. However, implementation of the scheme remains a forecast uncertainty.

Although ASEAN offshore wind potential is vast, relatively high costs still prevent regional governments from supporting this technology. ASEAN annual capacity additions over 2023-25 range from 1.1 GW in the main case to 3.2 GW in the accelerated case, with almost half the growth happening in **Viet Nam**. Introducing support policies to provide stable, long-term remuneration for wind generators and reduce risks could significantly raise investment in the region in the accelerated case, boosting total wind capacity to 16 GW by 2025 – a more than sixfold increase.

# Australia

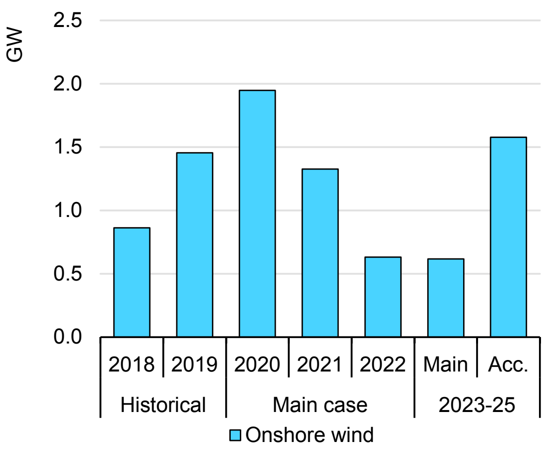
## 2020 is a record year for Australian wind capacity, but lower remuneration and curtailment concerns result in declining investment

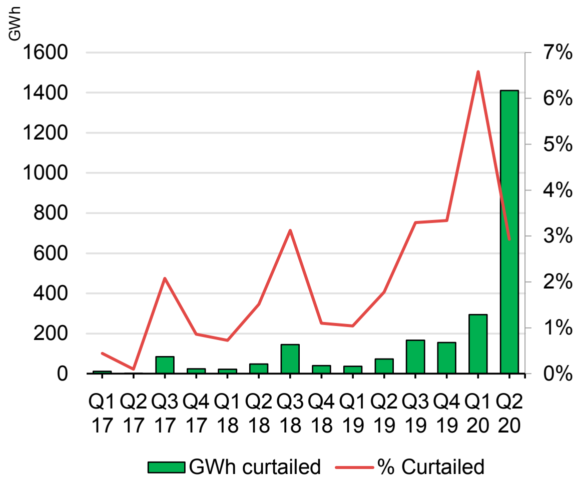
Australia's wind capacity additions are expected to increase 35% to 2 GW in 2020, driven in part by the country's Large-scale Renewable Energy Target (LRET) that has given wind projects revenue from the large-scale generation certificate (LGC) market. However, certificate prices in the spot market fell from over AUD 80/MWh in January 2018 to AUD 50/MWh in August 2019 because the number of accredited wind and PV projects will exceed the LRET this year (AEMC, 2019).

The forecast therefore expects wind additions to decline in both 2021 and 2022 as a result of lower returns. Furthermore, potential connection delays and curtailment issues are raising project risks significantly, an element in the fact that no projects reached financial close in Q2 2020.

Beyond 2022, corporate PPAs and merchant projects are expected to promote wind expansion in the absence of a new LRET and declining certificate prices. However, lower corporate electricity demand due to the Covid-19 crisis remains a forecast uncertainty for 2023-25. Given Australia's ample resources, average annual wind additions could return to 1.5 GW during 2023-25 in the accelerated case, aided by planned grid upgrades and commissioning of the New South Wales Central-West Orana Renewable Energy Zone, a renewable infrastructure project forecast to deliver up to 3 GW of additional renewable capacity.

**Figure 4.10 Australia wind capacity additions 2018-22, average additions 2023-25 (left) and AEMO wind curtailment data 2017-20 (right)**






Source: AEMO (2020), Statistical reporting streams.

# Europe

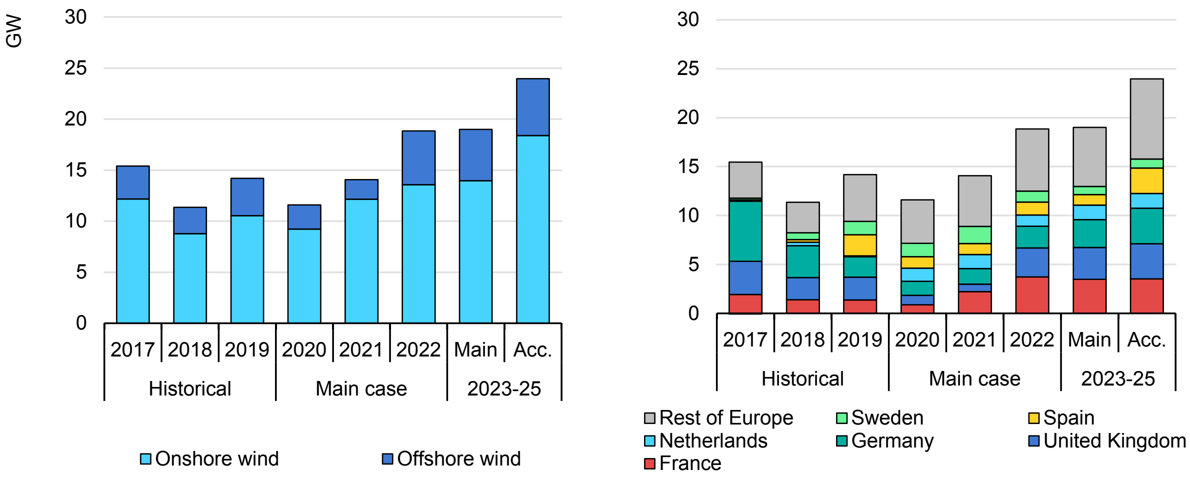
## Annual additions accelerate to meet 2030 targets, but growth could be faster if grid constraints and permitting challenges were addressed

Europe's wind capacity additions in 2020 are expected to decline by 18% compared with 2019. The contraction results from slowdowns in offshore wind pipelines in the United Kingdom, Germany and Denmark; transitions to auctions for onshore wind in France and Italy; and sharp declines in Spain after a commissioning deadline boosted growth in 2019. These declines offset the growth seen in other markets such as the Netherlands, Norway and Poland.

Yet, expansion returns in 2021, driven by rebounds in onshore wind in France and Poland as new auctions there begin to yield growth and as a slate of offshore projects is commissioned in Denmark. Additions continue to increase in 2022 and remain stable around 18 GW in total over 2023-25.

For onshore, annual growth averages 14 GW per year over 2023-25, driven mostly by either new or continuing auction schemes to meet 2030 targets in many countries. Onshore growth is led by France, Germany and Spain. Also supporting the forecast are corporate PPAs in Sweden and Italy. For offshore wind, growth is forecast to average around 5 GW per year during 2023-25, led by the United Kingdom, the Netherlands, France and Germany.

**Figure 4.11 Europe annual wind capacity additions 2017-22, average annual additions 2023-25 by technology (left) and country (right)**






However, grid constraints and permitting challenges stemming from local opposition and minimum distance requirements pose a downside risk to the onshore wind forecast. Should these issues be addressed, average annual growth between 2023-25 could be 26% higher with increased capacity allocated to auction schemes and more demand for corporate offtake. Lifetime extensions for older wind turbines would also result in higher net capacity additions.

## Germany

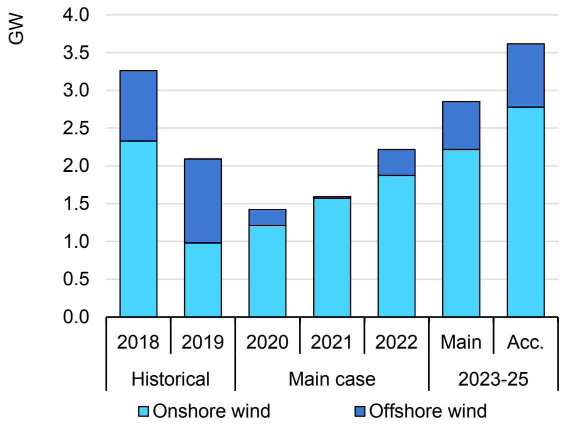
## Permitting challenges and decommissioning of ageing fleet slow net onshore wind additions

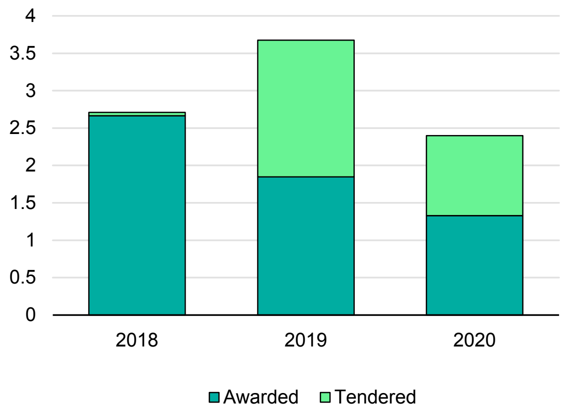
Germany's wind capacity additions will continue to decline in 2020 due to the lull in offshore wind project development created during the policy transition from FiTs to competitive auctions. Conversely, onshore wind capacity is expected to increase slightly as projects from previously held auctions continue to be commissioned amid the lockdown measures.

Over 800 MW of onshore wind capacity were installed in the first eight months of 2020 (Bundesnetzagentur, 2020), but the impact of the lockdown on construction timelines, coupled with the six-month extension of commissioning deadlines granted by the government, could push the commissioning of late-stage projects into 2021.

The pace at which early projects will be decommissioned remains a key uncertainty in the forecast of Germany's net wind capacity growth. By 2021, 2 GW of wind projects will have reached the end of their 20-year support payments. Whether their operations are extended depends on the business case, which may be jeopardised by a weaker economic climate. Already in the first half of 2020, 84 MW have been taken offline (Deutsche Windguard, 2020), an amount that could rise further in the second half of the year.

**Figure 4.12 Germany annual wind capacity additions 2018-22, average annual additions 2023-25 (left) and onshore wind auctions 2018-20 (right)**






Note: The bar representing onshore wind auctions in 2020 does not include auctions after August 2020.

Growth in onshore wind capacity is expected to increase in 2021-22, and overall capacity expansion accelerates slightly during 2023-25 as new offshore wind projects are commissioned. Competitive auctions to support new 2030 targets for both onshore wind (71 GW) and offshore wind (20 GW) are the main driver for growth. However, undersubscription in onshore auctions remains a risk due to ongoing permitting challenges. Since 2017, 10.5 GW of onshore wind have been on offer in auctions, but only 6.6 GW were awarded because administrative complexity and local opposition created long permitting wait times.

Germany's net onshore wind growth could be 25% higher during 2023-25 if policies address permitting and decommissioning challenges. The Investment Acceleration Act proposes allowing construction to continue during any litigation processes, while a new draft of the EEG (EEG 2021) was introduced to provide financial incentives for local communities to accept new projects and to remove restrictions on new constructions in northern Germany while also creating a quota for new-builds in the south.

While the decommissioning of 12 GW of onshore wind turbines remains a risk for net growth over the forecast period, the new EEG 2021 proposes extending payments to projects reaching the end of their support scheme term. This would avoid decommissioning and instead encourage refurbishment and repowering.

# Spain

## The new auction design and economic attractiveness of corporate PPAs will determine onshore wind additions

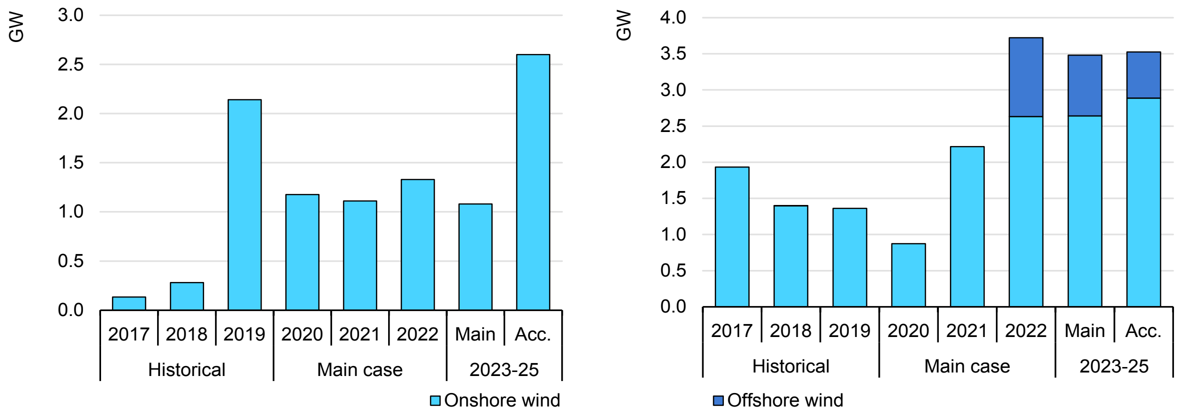
Spain's onshore wind capacity is expected to increase 1.2 GW in 2020. This is less than growth in 2019, when additions rose to above 2 GW for the first time since 2009. Although the spike in 2019 was created by commissioning deadlines for competitive auctions held in 2016 and 2017, only half of the awarded 4.6 GW had been commissioned before the 1Q 2020 deadline, and uncertainty over when the remaining projects will commission threatens growth in 2020. Long lead times – stemming from permitting and financing challenges, Covid-19 construction halts, and limited grid access – could delay projects originally scheduled for 2020. By the end of the first half of 2020, only 500 MW of the remaining 2.4 GW had been commissioned.

Additions are expected to rebound in 2021 and 2022 as remaining projects under construction are completed and the first projects with corporate PPAs are commissioned. Beyond 2022, growth is expected to increase to 1 GW annually with the resumption of competitive auctions, but the amount of capacity that will be awarded is a key forecast uncertainty.

A new auction regime was approved in October 2020 to reach 2030 targets, but details regarding tender design and the timeline had yet to be announced at the time of writing. The design of the new auctions will strongly influence the amount of wind capacity awarded, with the latest announcements indicating that projects will be awarded on a MWh-basis with auctions opening in the second half of 2020. This forecast therefore assumes 1 GW will be awarded per year starting in 2021 and begin to be commissioned in 2023.

Average annual growth between 2023 and 2025 could be more than twice as high if more capacity is earmarked for onshore wind in the new auctions and the recent regulatory reforms regarding permitting dramatically reduce project lead times. More attractive economics for corporate PPAs post-2022 would also boost growth if power demand increases and electricity prices rise.

**Figure 4.13 Annual wind capacity additions 2017-22 and average annual additions 2023-25 for Spain (left) and France (right)**






# France

## Permitting challenges remain for onshore wind, but offshore capacity finally takes off

France is expected to add just under 1 GW of onshore wind capacity in 2020, one-third less than last year. Among projects coming online this year are the ones awarded in the 2018 auction and under the former FiT and FIP schemes. Annual onshore wind additions are expected to accelerate in 2021 and 2022, with 1.8 GW awarded in various auction rounds since 2018. Furthermore, the multiannual energy plan (the PPE) has scheduled tenders for 1.9 GW of onshore wind capacity per year until 2024, supporting the forecast for 2023-25.

Having been awarded in 2012 and renegotiated in 2018, France's first large-scale (480-MW) offshore wind project (Saint-Nazaire) closed financing this year and is expected to come online in 2022, while another 2.9 GW of auctioned projects are scheduled for commissioning during 2022-25. Although offshore wind is expected to make up one-fifth of wind capacity additions over the entire forecast period, meeting the government's 2.4-GW offshore wind target by 2023 will depend on the resolution of social acceptance challenges and timely project commissioning.

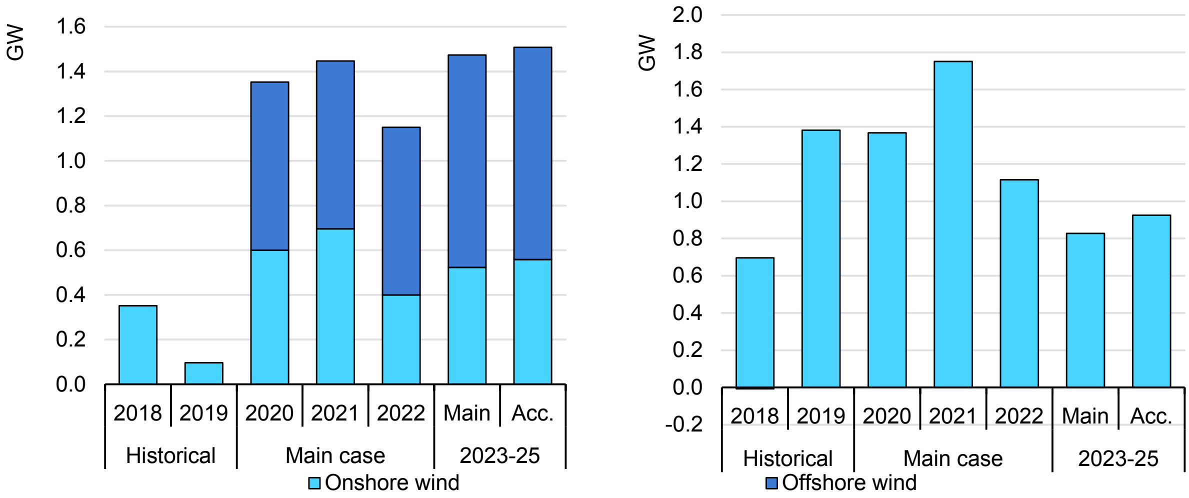
# The Netherlands

## Offshore installations make up the majority of wind capacity additions, as onshore projects face grid constraints and public opposition

The Netherlands will add over 1 GW of new wind capacity in 2020, with over 50% coming from offshore wind projects auctioned in 2016. Onshore wind additions are expected to continue to be strong in 2021 and 2022 as the remaining 1 GW of the 1.5 GW auctioned in 2016 and 2017 is commissioned. However, long project lead times due to land rights, social acceptance and grid constraint challenges hamper faster onshore wind deployment over the forecast period. A new 2019 rule requiring projects to prove local grid capacity could facilitate deployment.

Wind additions of more than 4 GW are anticipated during 2023-25, with two-thirds coming from the Hollandse Kust (Noord) and Hollandse Kust Zuid III and IV offshore projects. For onshore wind, the new SDE++ support scheme is expected to stimulate growth. As capacity in the final SDE+ auction was too low to supplement the current project slate (at 90% less capacity than in the 2019 auctions), additional projects must be attracted through the SDE++ scheme to ensure growth.

Figure 4.14 Netherlands wind capacity additions 2018-22 and average annual additions 2023-25 (left), Sweden wind capacity additions 2018-22 and average annual additions 2023-25 (right)



## Sweden

## Corporate PPAs create a strong market, but grid constraints and lower remuneration pose future risks

Sweden is expected to add more than 1.3 GW of new wind capacity this year, consistent with 2019 additions, mostly through corporate PPAs. However, construction delays and supply chain disruptions resulted in lower-than-expected additions in the second quarter of 2020, despite continuous construction activity since the onset of the pandemic.

The forecast anticipates nearly 3 GW of wind growth in 2021 and 2022 as previously contracted projects are completed to meet their PPA obligations. Given the numerous projects currently under construction in Sweden, the country's delays related to Covid-19 and its high volume of turbine orders, 2021 is forecast to be a record year for additions. Growth beyond 2021 is contingent on a follow-up programme to the green-certificate scheme and the resolution of grid congestion issues.

## Poland

## Auctions revive wind installations, but growth will be temporary if new permitting rules are retained

Wind capacity in Poland is expected to increase 0.4 GW in 2020 – the first expansion since investments began to stall in 2017. Auctions held in 2018-19 and planned for 2020 are expected to spur approximately 3 GW of onshore wind expansion in 2020-22.

Beyond 2022, however, the regulation stipulating that turbines must be constructed at a distance of more than ten times their height from residential and mixed-use buildings will make further growth of onshore wind challenging. Achieving faster growth in the accelerated case therefore hinges on the easing of turbine placement restrictions and the expansion of auctions. In addition, a stable regulatory environment that supplies a long-term national energy strategy and targets as well as auction schedules would provide longer-term visibility for developers, reduce risks and support investment.

## Italy

## Auctions and PPAs encourage wind deployment, but not a rapid acceleration

Italy's wind capacity additions are expected to be 55% lower than in 2019, falling to only 0.2 GW in 2020. Wind market activity has been curtailed since 2013 due to lack of a support scheme, but the new auction scheme introduced in 2019 is expected to change this trend during the forecast period. Wind developers won 90% of the 1 GW auctioned last year, at a rate of EUR 57/MWh in the first round and EUR 64.9/MWh in the second. Most of these projects are expected to come online in 2022.

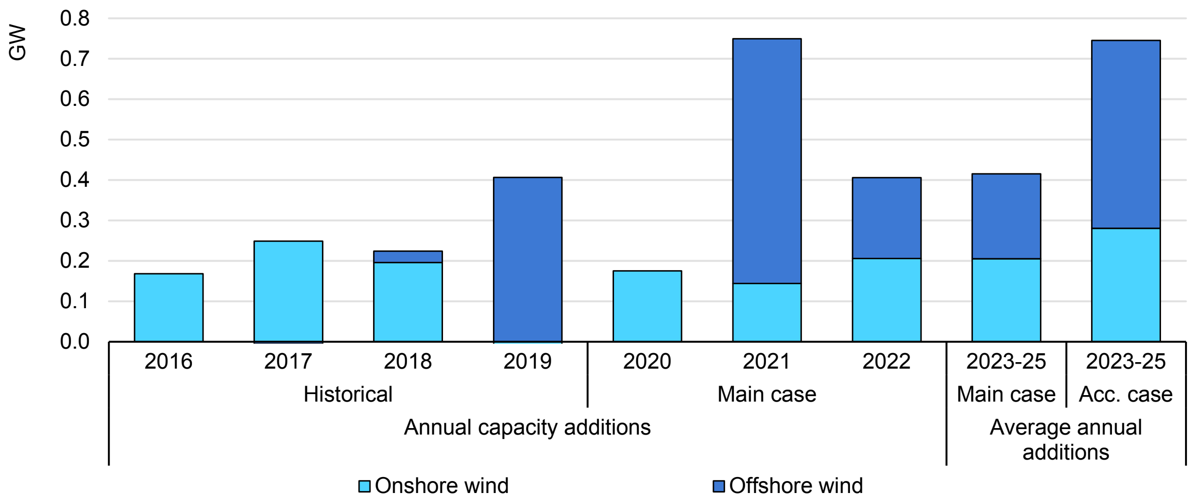
To meet the National Energy and Climate Plan's target to achieve almost 9 GW of additional wind capacity by 2030, the government plans to auction almost 5 GW of wind and PV capacity by the end of 2021. Annual installations are therefore expected to remain at 1 GW during 2023-25 thanks to auctions and the development of corporate PPAs, but 1.7 GW could be achieved in the accelerated case with auction expansions and the facilitation of permitting process. In addition, 5.8 GW of wind capacity will have been operating for more than 15 years by 2025, calling attention to repowering potential.

## Denmark

## Offshore wind continues to lead wind growth

With no offshore projects scheduled for 2020, Danish wind power capacity additions are forecast to be less than half the 2019 level, when growth from offshore wind had produced the highest additions since 2013. Having stalled in 2019, onshore wind capacity growth is bound to take off again in 2020. Several projects awarded in the first two rounds of technology-neutral tenders will reach completion in 2020-22. Commissioning of the 605-MW Kriegers Flak offshore farm will lead to record growth in 2021, raising offshore wind capacity by 36%.

**Figure 4.15 Denmark net wind capacity additions 2016-22 and average annual additions 2023-25**






From 2023 onward, the tender scheme is expected to yield sustained onshore wind additions. This trend is underpinned by the government's recent postponement of its

2030 target of cutting the number of turbines on land by more than half, as well as the introduction of citizen participation schemes to address local acceptance issues. Average annual additions between 2023 and 2025 could be more than 80% higher if future technology-neutral tenders allocate higher volumes and the commissioning of offshore projects can be accelerated, including two open-door wind projects that recently stalled due to sharply climbing costs from new EIA regulations.

# Latin America

## Brazil

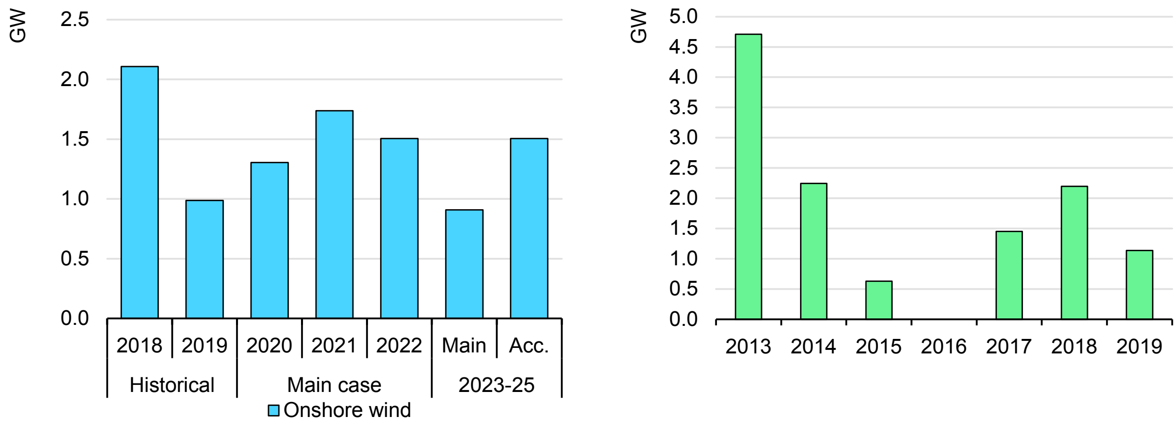
## Reduced auction capacity will require higher deployment outside the regulated market, with lower power demand introducing uncertainty

Brazil is forecast to add over 1.3 GW of wind capacity in 2020 – over 30% more than 2019 owing to government auctions and projects developed in the unregulated market through bilateral contracts. The Covid-19 crisis has had minimal impact on wind construction activity overall.

Despite the slight rise this year, onshore wind additions in 2019 and 2020 are significantly below historical levels due to low auction capacities in the last five years. For instance, awarded wind capacity declined from 10 GW per year during 2011-15 to 5 GW in 2016-20.

Annual expansions of more than 1.5 GW are expected in 2021 and 2022, with over half of the growth contracted outside the government auction scheme. However, the number of free-market bilateral contracts and government auctions depends on future electricity demand, which is highly unpredictable because Brazil is expected to enter a deep recession due to Covid-19 economic upheaval (OECD, 2020).

Figure 4.16 Brazil wind capacity additions 2018-2022 (left), average annual additions 2023-25 and auctioned wind capacity 2013-19 (right)





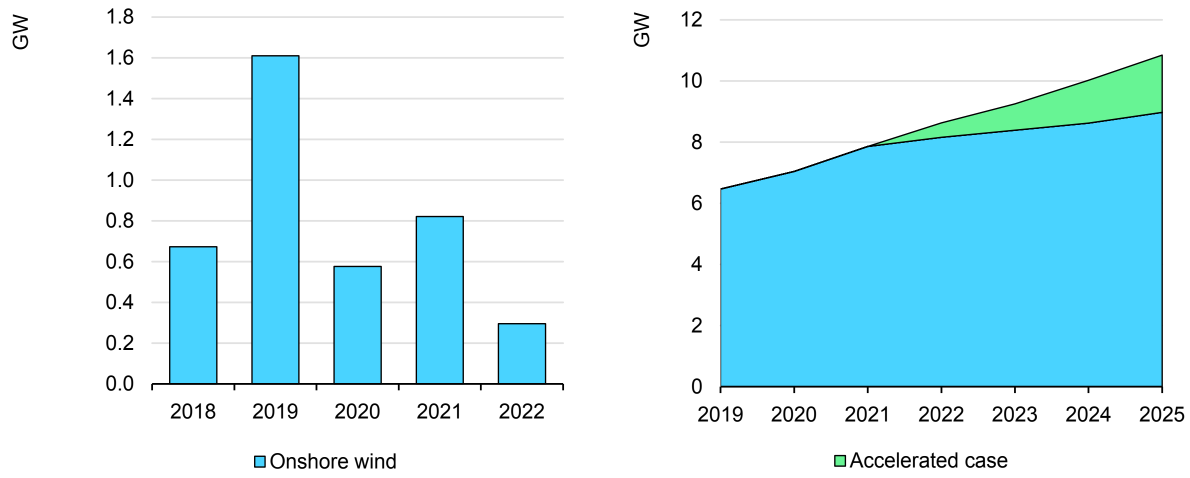

Considering macroeconomic uncertainties and postponement of the 2020 A-4 auction, Brazil's annual average wind capacity growth during 2023-25 could range from 1 GW in the main case to 1.5 GW in the accelerated case. The accelerated case assumes higher wind capacity procured through the unregulated market and a larger amount of capacity auctioned in 2021 as electricity demand recovers.

## Mexico

## Regulatory certainty, faster grid connections and higher corporate demand are needed for strong development

Mexico's annual wind additions are expected to decline over 60% from 2019 to 2020 due to commissioning delays caused by regulatory uncertainty over renewable energy plants' grid connections. Furthermore, public opposition has hampered wind project development in Mexico. In 2015, the Kabil I and II wind parks (30 MW each) were awarded and it was expected that they would be operational in 2018, but social acceptance challenges have pushed the commissioning date to the end of 2020. Limited grid connection availability, especially in central and southern Mexico, also continues to be a key obstacle to faster onshore wind deployment.

**Figure 4.17 Mexico actual and forecast annual wind capacity additions (left) and cumulative capacity (right)**






In 2021 and 2022, expansion will result from capacity awarded in previous Clean Energy Certificate (CEL) auctions. In the absence of new CEL auctions organised by the government, onshore wind deployment during 2023-25 will have to be encouraged by corporate PPAs and utilities buying wind power to meet their CEL requirements by 2024.

The cancellation of CEL auctions has created policy uncertainty, which threatens further renewable capacity development, and the lingering possibility of additional regulatory changes in 2021 is also undermining investor confidence. A decrease in average capacity additions is therefore forecast for 2023-25.

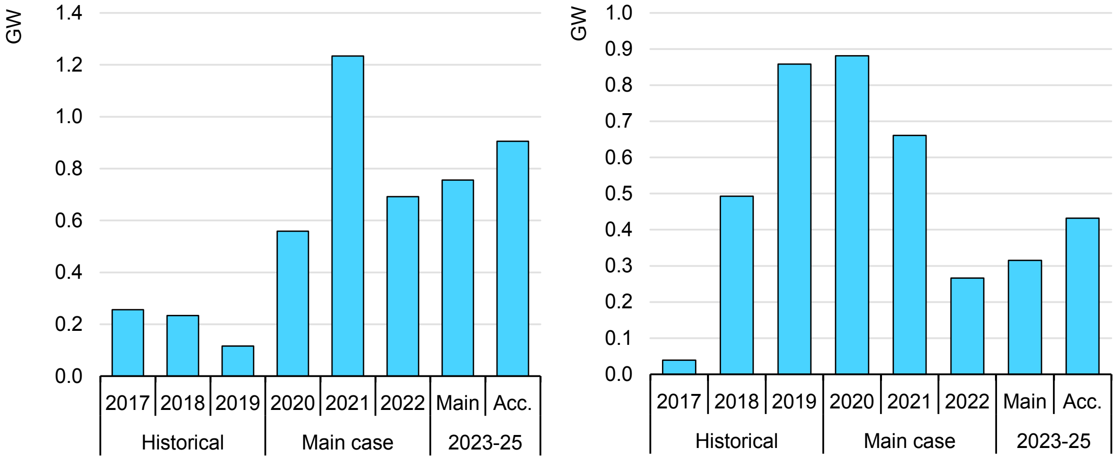
Mexico's wind capacity could, however, be 20% higher in 2025 with greater regulatory certainty, faster grid connections, higher corporate demand and affordable financing.

## Chile, Argentina and Colombia

## Renewable energy auctions are essential for capacity growth through 2025

Prompted by past auctions (in 2016 and 2017), **Chile's** wind capacity additions will reach almost 600 MW in 2020 – a record level despite the Covid-19 crisis. Furthermore, a peak in additions is expected in 2021, followed by a slowdown in 2022 as projects acquired in the last auction (of 2017) are commissioned.

**Figure 4.18 Annual onshore wind capacity additions 2017-22 and average annual additions 2023-25 in Chile (left) and Argentina (right)**






Capacity additions in Chile are expected to regain momentum after 2022, as a 2.7-TWh technology-neutral electricity auction is expected in the first half of 2021 to meet the estimated demand of regulated clients in 2026. (According to the regulator, an additional 3.7 TWh will also be awarded to meet 2027 electricity demand.) The forecast expects that some wind projects from these auctions will be commissioned early to take advantage of high spot market prices. In addition, the government has also held an auction to allocate public land for renewable energy projects to address acquisition challenges. All together, these auctions are expected to lead to 2.3 GW of wind additions during 2023-25.

**Argentina's** onshore wind capacity will expand almost 900 MW in 2020, slightly more than last year. Additions result from capacity previously auctioned under the RenovAR programme, despite Covid-19-related delays that caused grid connection setbacks and temporarily halted construction. Wind additions are expected to lose speed in 2021 and 2022, as auction volumes fell from 1 GW in 2017 to only 128 MW in 2019.

The share of renewables in electricity demand needs to more than double to reach the government's target of 20% by 2025. Argentina's already-challenged macroeconomic environment was profoundly affected by the Covid-19 crisis, so limited access to affordable financing and weak grid infrastructure threaten wind capacity growth in spite of the country's excellent resource availability and cost-competitiveness.

The accelerated case therefore assumes that projects obtain financing sooner; transmission infrastructure improves; and the number of corporate PPAs increases quickly, allowing for almost 5 GW of total installed capacity by the end of the forecast period.

**Colombia's** installed wind capacity is expected to start increasing in 2021, thanks to two auctions held in 2019. Together, the long-term renewable auction and the reliability charge auction will bring over 1.5 GW of additions online. However, the social consultation process as well as the delay of a new 500-kV transmission line required to connect capacity in northern La Guajira may prevent some projects from being commissioned on time (i.e. by 2022).

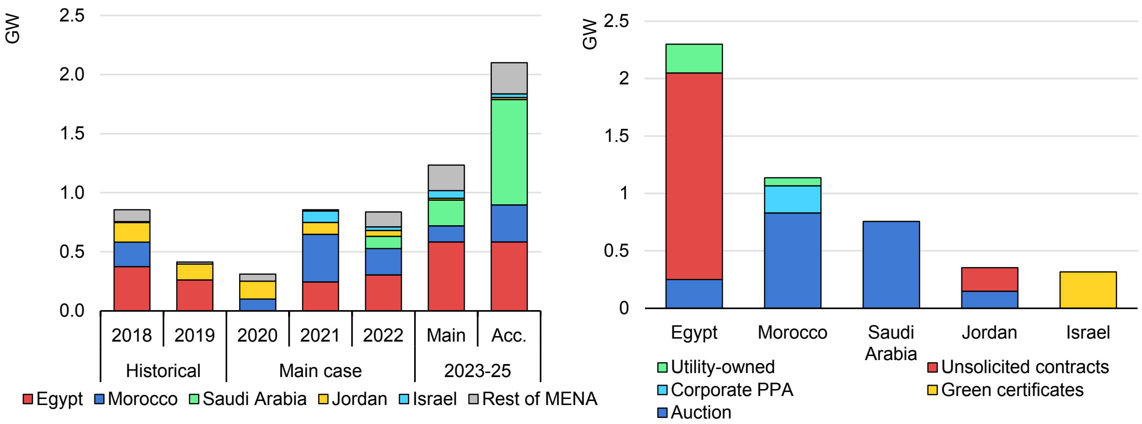
In 2023 and beyond, Colombia's capacity expansion is spurred by projects remaining from the 2019 auctions and from a third renewable auction expected in 2021.

# Middle East and North Africa

## Policies to attract private investment stimulates MENA wind expansion

Annual wind additions in the Middle East and North Africa (MENA) region are set to decline in 2020 relative to 2019. Lower growth results from lengthy auction processes and stalled utility-owned development, which delays projects under development. Growth in 2020 will be bolstered by the commissioning of late-stage IPP projects in Morocco and Jordan, developed under bilateral contracts with large consumers or the utility outside of dedicated auction schemes. However, construction delays stemming from the Covid-19 crisis threaten the forecast.

**Figure 4.19 MENA annual wind additions 2018-22 and average annual additions 2023-25 (left), and incremental growth by procurement type for selected countries 2020-25 (right)**






Note: The statistical data for Israel are supplied by and under the responsibility of the relevant Israeli authorities. The use of such data by the OECD is without prejudice to the status of the Golan Heights, East Jerusalem and Israeli settlements in the West Bank under the terms of international law.

Growth is forecast to rebound in 2021 and 2022 – exceeding the 2019 level – as projects from Morocco's and Egypt's competitive auctions are commissioned. Morocco's robust project slate results from a shift in institutional responsibility for wind procurement, from the state utility to the Moroccan Agency for Sustainable Energy Development (MASEN), the country's dedicated organisation for achieving national renewable energy targets. In 2019, MASEN helped 400 MW of stalled wind projects sign PPAs and opened the EPC tender for Africa's first repowering project.

Average annual growth is expected to increase further to 1.2 GW during 2023-25. Most of the expansion is in Egypt, stimulated by unsolicited bilateral IPP contracts between developers and the power utility. Over 2 GW are currently under development, as developers have been approaching the utility directly to negotiate contracts because other schemes have either been abandoned due to insufficient remuneration (under the FiT scheme) or have been slow to advance (IPP competitive bidding or state-owned projects). The increase is also supported by additional capacity from competitive auctions in Morocco as well as by newer markets such as Saudi Arabia and Oman implementing auctions for the first time.

Competitive auctions are also a key driver of onshore wind additions, accounting for 20% of the region's growth during 2020-25. However, lengthy procedures, delayed and rescheduled requests for bids, and long implementation procedures are major threats to the forecast. For instance, almost four years elapsed between the announcement of a winner and the signing of the PPA in Egypt's latest auction, and in Saudi Arabia, no project has yet emerged from the 400-MW tender opened in 2017. Inadequate grid integration is also preventing faster onshore wind expansion in Jordan and Tunisia. The accelerated case demonstrates that average annual growth could be almost 70% higher if these challenges were addressed.

# Sub-Saharan Africa

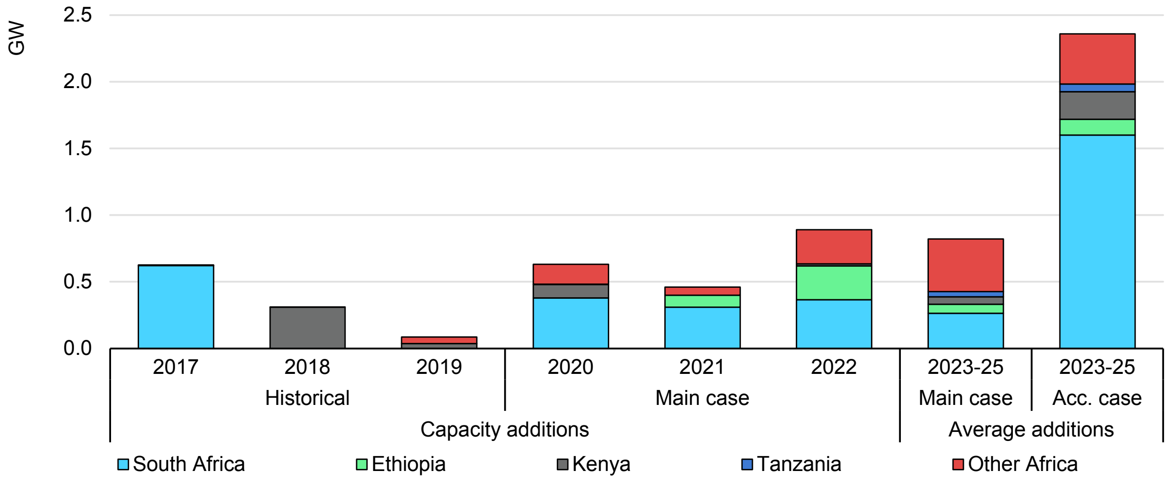
## Previous auctions in South Africa propel short-term wind capacity growth, but additions will remain stunted without infrastructure upgrades and a clear policy trajectory

South Africa will add around 380 MW of new capacity in 2020, reversing the stalled growth of the past two years. This capacity was tendered in 2015 with PPAs signed in 2018, and the outstanding capacity from the tender (600 MW) is forecast to be connected in 2021 and 2022. As the 2020 technology-neutral emergency tender requires strict operating standards and project commissioning by 2022, it implicitly excludes wind projects because of their long developmental lead times and low capacity factors.

Capacity additions lose momentum again after 2022 due to policy uncertainty. A tender for 6.8 GW of renewable capacity was announced in September 2020 with an expected auction round scheduled for Q2 2021, so an additional 500 MW is forecast for 2025, taking previous auction volumes and timelines into account. Force majeure notices for curtailment (sent by Eskom to wind power producers during the Covid-19 lockdown) add an additional investment risk, as compensation for future curtailment has yet to be agreed upon.

Additional expansion in the accelerated case, based on the government's targets for new wind power procurement (1.6 GW per year beginning in 2022), assumes greater policy certainty and the mitigation of network availability and curtailment risks.

**Figure 4.20 Sub-Saharan Africa wind capacity additions 2017-22 and average annual additions 2023-25**






**Wind energy development has been slow in Kenya, Ethiopia and Tanzania due to a variety of risks, including financial exposure, land acquisition challenges and lack of critical infrastructure for power projects.**

**Kenya** will add 100 MW of new wind capacity in 2020. The development required a new 17-km transmission line to connect to the grid, exemplifying the type of network upgrades needed for large-scale wind projects. Additions are expected to increase during 2023 to 2025, as two projects with a combined capacity of 170 MW are to be commissioned. Both projects have been delayed by land disputes, even after their PPAs were signed (ESI Africa, 2017; Nigeria Electricity Hub, 2020).

**Table 4.2 Sub-Saharan Africa selected forecast wind projects, 2020-25**

| Country | Project | Capacity (MW) | Forecast CoD |
|---|---|---|---|
| Ethiopia | Aysha Phase II | 120 | 2021 |
| Ethiopia | Assela | 100 | 2021 |
| Ethiopia | Aysha Phase I | 60 | 2022 |
| Ethiopia | Aysha Phase III | 120 | 2022 |
| Ethiopia | Adama Phase III | 150 | 2022 |
| Kenya | Kipeto | 100 | 2020 |
| Kenya | Meru Phase 1 | 80 | 2023 |
| Kenya | Lamu County | 90 | 2025 |
| Tanzania | Rift Valley Mufindi | 2.4 | 2020 |
| Tanzania | Miombo Hewani | 100 | 2022 |

**Ethiopia** is forecast to start commissioning projects totalling over 500 MW of new capacity between 2021 and 2022. This capacity has received multiple streams of financing from international organisations, including a new round of capital in 2020 (ReveNews, 2020). Land rights issues have led to delays, as resettlement negotiations were conducted only after financial close (The Reporter Ethiopia, 2018). Although Ethiopia's government has identified areas for additional wind development through 2025, it has not announced a policy scheme to support the plan.

The first onshore wind project in **Tanzania** was commissioned this year, with another 120 MW expected during 2022-25 thanks to a grant from the Government of Finland (Windlab, 2018). A tender launched in 2018 for 200 MW is still under review and is included in the accelerated case.

As potential for wind energy development in sub-Saharan Africa is strong, the accelerated case demonstrates over 30% more additional capacity than the main case. However, creating policy frameworks to engage local communities and raising investments in transmission infrastructure will be necessary to facilitate increased development and shorten project timelines. Ensuring early access to financing would also reduce projects' risk exposure, encouraging greater investment.

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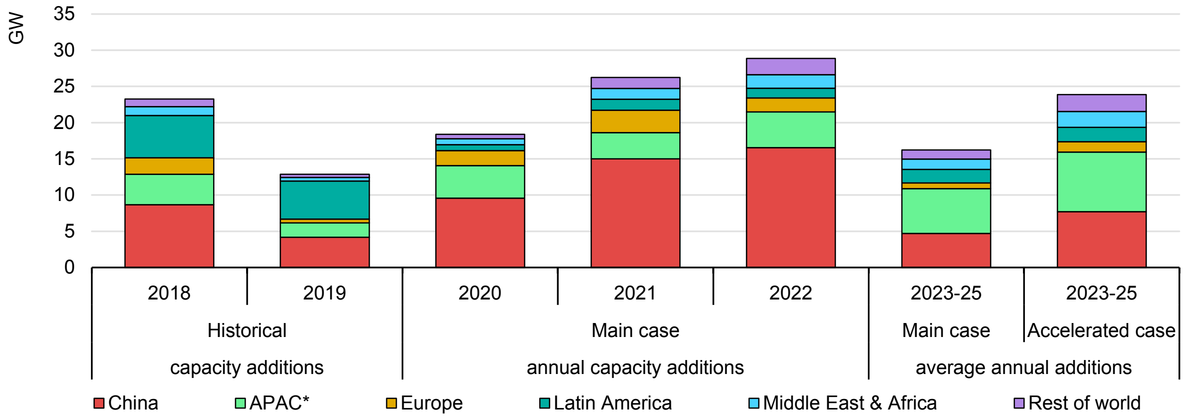
# Hydropower, bioenergy, CSP and geothermal

## Hydropower

Global annual net hydropower additions are expected to increase to more than 18 GW in 2020 owing to an uptick in large project activity in China. Almost half of China's growth is from installation of the first units of the Wudongde plant (10 GW); each unit is 850 MW and several were already commissioned this year. The next-largest source of growth is Asia, accounting for 24% of global additions, with significant capacity coming from Lao People's Democratic Republic ("Lao PDR"), India, Nepal, Viet Nam and Indonesia. Large dams in Turkey and pumped storage in Portugal also drive Europe's increase in 2020.

**Figure 5.1 Hydropower net capacity additions by country/region, 2018-25**






*Asia Pacific region.

Capacity additions continue to increase in 2021 and 2022, averaging 28 GW per year owing to the commissioning of two flagship projects in China. These two projects, Wudongde and Baihetan, have a combined capacity of 26 GW and should be commissioned in 2020-21 (Wudongde) and 2021-22 (Baihetan), with the Covid-19 crisis expected to have minimal impact on their construction lead times. After these two projects are completed, annual growth in China is expected to slow to an average of 4.7 GW per year during 2023-25, with pumped storage accounting for more than half of annual additions.

Excluding China, global hydropower additions are expected to be stable during the remainder of the forecast period (2021-25), ranging from 10 GW to 13 GW per year. Asia accounts for 43% of cumulative growth, led by India and Pakistan, with most of the remainder in Southeast Asian countries where the private sector is expected to become increasingly involved in hydropower development. Deployment in Southeast Asia is led by Lao PDR as the country enlarges domestic access to electricity and positions itself as a regional electricity exporter. Rising power demand and affordable universal electricity access also boost capacity additions in Viet Nam and Myanmar, while multipurpose water use spurs dam development in Indonesia.

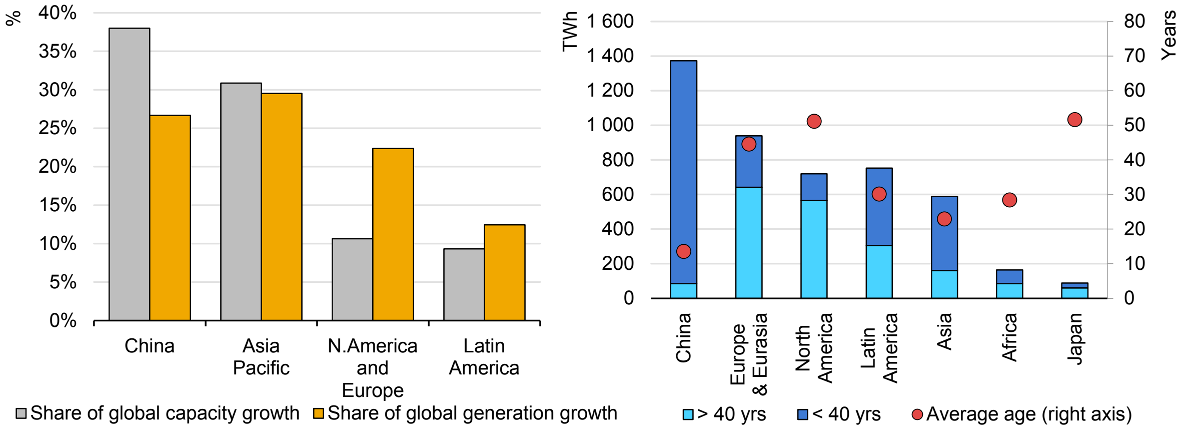
In Latin America, more than half of growth in 2021-25 is in Colombia, Argentina and Brazil. Large reservoir projects in Colombia and Argentina are expected to be commissioned at the end of the forecast period, while annual additions slow in Brazil after commissioning of the last phases of Belo Monte in 2019. Small-scale hydroelectric projects awarded through recent tenders make up new capacity additions in Brazil through 2025.

Europe's growth between 2021 and 2025 is led by Turkey, with large projects driving development in 2020 and 2021 and slower deployment during 2023-25 as the FiT for small and medium-sized run-of-river plants is phased out. Excluding Turkey, more than half of new hydropower capacity additions in Europe will be pumped storage, notably in Switzerland, Portugal and Austria. Europe's pumped storage growth is prompted by the need for system flexibility to integrate increasing shares of variable renewable electricity. Hydropower development in Africa is led by the commissioning of units in Ethiopia, Nigeria and Angola.

Nevertheless, hydropower capacity growth during 2023-25 could be 50% higher per year on average if project development were accelerated. This would require earlier commissioning of pumped storage plants currently under development in China and fewer interruptions of projects under construction in Africa and Latin America. Development lead times could also be shortened with improved financing conditions, fewer construction delays, and more efficient permitting and licensing within sustainability guidelines.

Global hydropower generation (excluding pumped storage) is forecast to increase 9.5% over the forecast period, rising from 4 250 TWh in 2019 to 4 650 TWh in 2025, and to remain the world's largest source of renewable generation. The increase results mainly from new capacity in markets that lead greenfield project development. The largest single increase (+107 TWh) is in China, followed by the Asia Pacific region, where capacity growth is accelerating.

**Figure 5.2 Global hydropower generation and capacity growth 2020-25 (left) and generation according to plant age vs weighted average fleet age by region, 2025 (right)**






Note: In the left-hand graph, capacity shares exclude pumped storage. In the right-hand graph, *Asia* excludes Japan.

However, another reason for the generation increase is the assumption that operating conditions over the forecast period will return to pre-2019 levels in several countries after weather conditions caused output to fall from 2018 to 2019. This expectation is prevalent in parts of North America, Europe and Latin America, which are forecast to account for a higher share of the increase in global generation during 2020-25 despite having a lower share of new capacity additions.

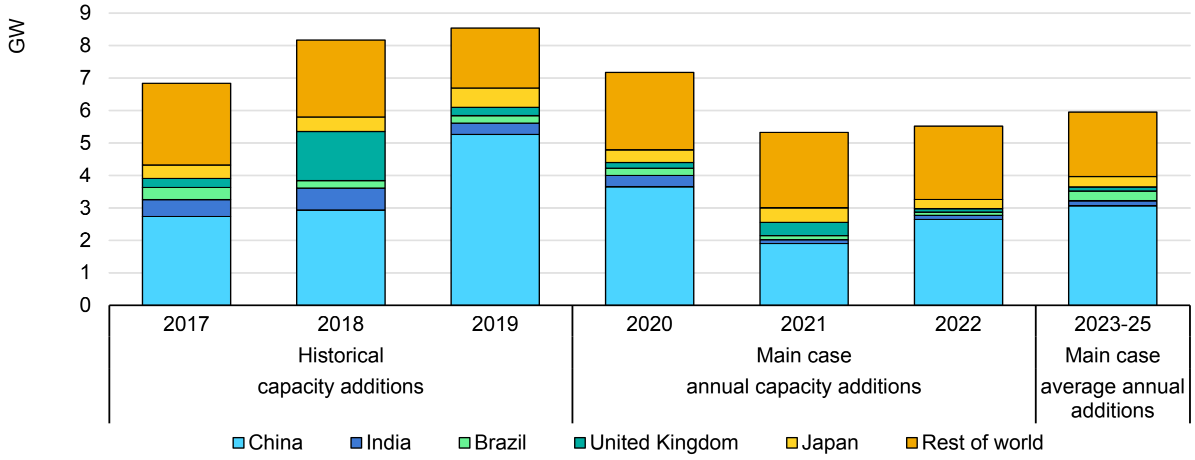
Hydropower generation in the United States was down 21 TWh (-7%) in 2019 due to droughts and wildfires in the Pacific Northwest, while droughts also caused substantial declines in Argentina, Paraguay and Mexico. Lower precipitation in parts of Europe, coupled with a heatwave, caused 2019 year-on-year declines of 10% in Norway, 31% in Spain and 13% in France, which have one-third of Europe's fleet. Load factors in these seven countries are assumed to return to pre-2019 levels by 2025, and their increased output is forecast to make up 16% of the global increase in hydropower generation.

Hydropower will therefore account for 16% of the world's electricity generation by 2025. To sustain this level, output from existing hydropower plants needs to be maintained; however, substantial amounts of generation will come from fleets that are ageing. By 2025, 40% of the world's hydropower output will be from countries with fleets that are more than 40 years old, the age at which the first major refurbishments are undertaken to either maintain or increase performance. Roughly two-thirds of this generation is in North America and Europe, where the weighted average age of the fleet is 45 to 51 years old. Maintaining output from these fleets over the forecast period will therefore require significant investments in refurbishment and modernisation.

# Biomass electricity

Global biomass electricity capacity expanded 8.5 GW in 2019, the second-highest level of annual additions on record. China accounted for 60% of last year's new capacity, primarily made up of energy-from-waste projects. The next-largest market, Japan, was one-tenth of the size of the Chinese market.

**Figure 5.3 Biomass electricity capacity additions by country**






The forecast anticipates a 16% decline in bioenergy capacity additions in 2020. Major deployment of biomass power projects is concentrated in relatively few countries, with just ten nations accounting for 90% of new capacity in 2019. Of these, China, Brazil, Japan and the United Kingdom have been the most affected by the pandemic, so potential exists for some project delivery delays. Nevertheless, with forestry activity ongoing and ports operational, widespread supply disruptions of biomass fuels (e.g. wood chips and pellets) for existing projects have not been observed.

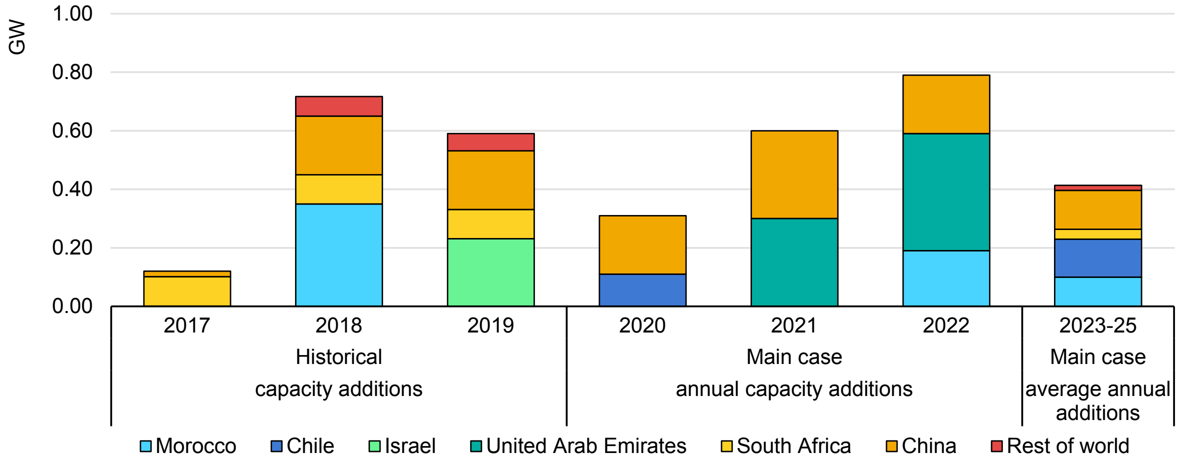
Annual additions fall to around 5 GW to 6 GW per year over the remainder of the forecast period. One factor is the transition from policy support through FiT and certificate schemes to competitive auction frameworks in key bioenergy markets (e.g. Japan, Germany and the United Kingdom). Capacity awarded in technology-neutral auctions has been relatively low because of generally higher generation costs for bioenergy compared with wind or utility solar PV technologies, and limited cost reduction potential for bioenergy technologies. Technology-specific auctions for bioenergy are not widespread.

China has also announced that subsidies for biomass-based power projects will switch from the current FiT system to auctions in 2021, with a strong emphasis on projects that harness co-generation and utilise fuels produced from agricultural or municipal waste.

# CSP

Global CSP additions in 2020 are forecast to be half the 2019 level. China leads expansion, with 200 MW expected to come online this year under the generous FiT scheme. However, growth in China falls short of government targets due to high costs and financing challenges. Commissioning of Chile's 110-MW Cerro Dominador plant with 17.5 hours of molten salt storage – the largest in Latin America – accounts for the remainder of global CSP capacity growth this year.

**Figure 5.4 CSP capacity additions by country**






Note: The statistical data for Israel are supplied by and under the responsibility of the relevant Israeli authorities. The use of such data by the OECD is without prejudice to the status of the Golan Heights, East Jerusalem and Israeli settlements in the West Bank under the terms of international law.

In 2021 and 2022, phase four of the Dubai Electricity and Water Authority (DEWA) Mohammed bin Rashid Al Maktoum Solar Park is expected to start coming online, adding 300 MW of capacity in 2021 and 400 MW in 2022. Its plants will contribute to Dubai's 2050 Clean Energy Strategy, which aims to achieve 75% clean energy by 2050. The project has closed financing and construction has already begun, with the base of the tower completed in mid-2019.

Morocco's Noor Midelt I is expected to come online in 2022, adding 190 MW. Preliminary infrastructure work has already begun on the USD 782-million project, which is expected to close financing from multiple development banks including KfW, World Bank, the African Development Bank and the European Investment Bank. The project will have five hours of molten salt and battery storage capacity.

China's CSP additions are projected to peak in 2021 as developers rush to complete projects before phaseout of the FiT scheme. However, local governments are expected to provide additional fiscal incentives for the commissioning of various projects under development beyond 2021. Nonetheless, the generation costs of CSP projects are three times higher than for utility-scale PV plants, leading developers to abandon projects.

Capacity additions beyond 2022 are expected to be dominated by China, South Africa, the United Arab Emirates and Morocco, with projects such as Noor Midelt II (which is still in phase of putting out tenders for developers) and the Likana project in Chile, which was acquired by the Cerro Dominador group in 2019. The group plans to bid on the 450-MW CSP project in a power auction in Chile in 2021.

### Table 5.1 Large-scale CSP projects under construction

| Country | Project name | Capacity (MW) | Technology | Storage (hours) |
|---|---|---|---|---|
| Chile | Cerro Dominador | 110 | Central receiver tower with molten salt storage | 17.5 |
| Greece | MINOS | 50 | Central receiver tower with molten salt storage | 5 |
| South Africa | Redstone | 100 | Central receiver tower with molten salt storage | 12 |
| Morocco | Noor Midelt I | 190 | Parabolic trough with molten salt storage and battery storage | 5 |
| United Arab Emirates | Al Maktoum IV Phase I | 600 | Parabolic trough | |
| United Arab Emirates | Al Maktoum IV Phase II | 100 | Central receiver tower with molten salt storage | 15 |
| China | Yumen Xinneng | 50 | Central receiver tower with molten salt storage | 9 |
| China | Changzhou Yumen Dongzhen | 50 | Parabolic trough with molten salt storage | 7 |
| China | Beijing Guohua | 100 | Central receiver tower with molten salt storage | 10 |
| China | Dahua Shangyi | 50 | Central receiver tower with molten salt storage | 6 |
| China | Jinta | 100 | Central receiver tower with molten salt storage | 12 |
| China | Huanghe Qinghai Delingha phase I | 135 | Central receiver tower with molten salt storage | 3.7 |
| China | Shenzhen Jinfan Akesai | 50 | Parabolic trough with molten salt storage | 15 |

| Country | Project name | Capacity (MW) | Technology | Storage (hours) |
|---|---|---|---|---|
| China | Zhongyang Chabei | 64 | Parabolic trough with molten salt storage | 16 |
| China | Yumen Xinneng | 50 | Beam-down with molten salt storage | 9 |
| China | CECIC Gansu Wuwei Gulang | 100 | Parabolic trough with molten salt storage | 7 |
| China | Zhangjiakou | 50 | Linear Fresnel reflector with solid state concrete storage | 14 |
| China | Urat Banner | 50 | Linear Fresnel reflector with molten salt storage | 6 |

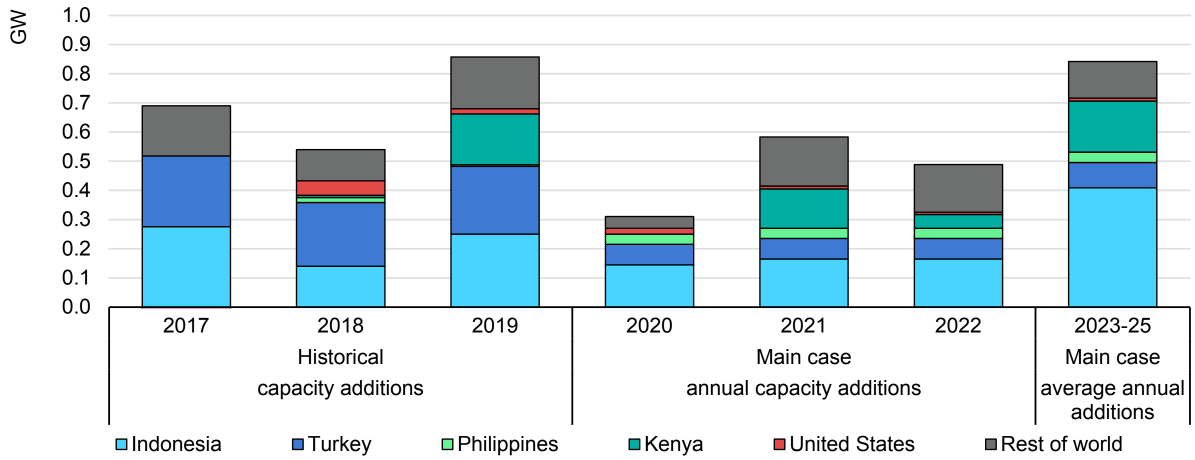
Sources: Nur Energie (2020), Nur Energie in Greece; NOMAC (2020), Redstone CSP IPP; HELIOCSP (2019), Noor Midelt winner optimizes Concentrated Solar Power trough, storage to hit record price; Morocco World News (2019), EDF Renouvelables Wins Bid for Morocco's Noor Midelt I Solar Plant; DEWA (2019), Mohammed bin Rashid Al Maktoum Solar Park: A leading project that promotes sustainability in the UAE; ACWA Power (2020), NOOR Energy 1; CSP Focus (2020), Yumen Xinneng 50MW molten salt tower CSP plant; CSP Focus (2017), Urat 50MW Fresnel CSP project; Solar Paces (2016), Concentrating solar power projects; AALBORG CSP (2020), 50MWE SGS4 steam generation system for CSP plant; Solar Paces (2018a, 2018b), Concentrating solar power projects.

# Geothermal

Global geothermal capacity additions are projected to amount to 0.3 GW in 2020, one-third of last year's level, which was the highest ever recorded. This year, Indonesia is again expected to lead new development, with 145 MW of capacity added (90 MW from the Rantau Dedap plant and 45 MW at the Sorik Marapi plant), followed by Turkey (+70 MW). These two countries are expected to account for more than two-thirds of new capacity additions in 2020, while the Philippines, the United States and Bolivia are responsible for most of the rest.

A number of projects have been delayed by disruptions to the global supply chain for machinery and materials and by deferrals of strategic decisions (including for financing) caused by the Covid-19 crisis. Therefore, several small and medium-sized projects originally scheduled to come online in 2020 are expected to be commissioned in 2021 instead. In Turkey, the 10-year FiT scheme for new plants, originally scheduled to end at the end of 2020, has been extended until mid-2021 to cover projects affected by such delays.

**Figure 5.5 Geothermal capacity additions by country**






Global cumulative geothermal capacity is forecast to increase 7% to 16.5 GW by 2022, with Indonesia, Kenya, Turkey and the Philippines responsible for two-thirds of this growth. In Indonesia, the state-owned company PT Geo Dipa Energi (GDE) has received a USD 300-million loan from the Asian Development Bank for the 110-MW expansion of the Dieng and Patuha plants, expected to be carried out during 2020-23. In Kenya, the county of Nakuru is host to various projects, including an additional 83-MW unit for the Olkaria power plant expected to come online in 2021. Beyond 2022, Indonesia, Kenya and Turkey continue to lead capacity additions, which are projected to exceed 0.8 GW per year globally on average.

The Indonesian government recently prepared a roadmap for geothermal energy, with the goal of having 8 GW of installed capacity by 2030 (up from 2.1 GW in 2019). However, wider exploitation of the country's considerable geothermal potential will require the resolution of a number of challenges, including low energy prices, limited local electricity demand, a lack of capital investments, and environmental and social issues.

The government plans to conduct exploration and drilling in 20 geothermal areas during 2020-24, with a view to reduce development risks for future auction plans. Policies aimed at providing better economic incentives to geothermal projects are also under consideration. Provided that Indonesia overcomes the abovementioned obstacles, it could have as much accumulated installed capacity as the United States by 2025.

Finally, geothermal power is also receiving greater interest from oil companies, which recognise opportunities to diversify their activities while capitalising on their drilling expertise.

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# Transport biofuels

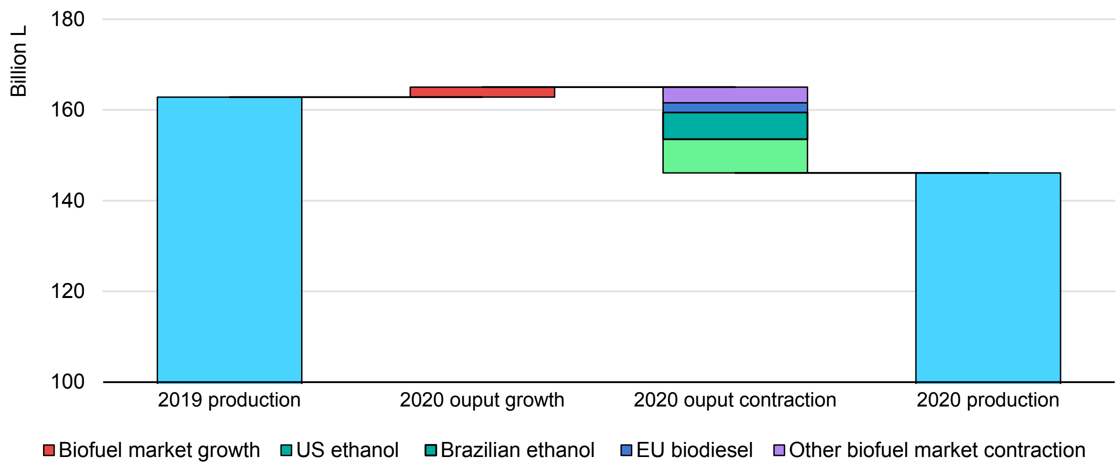
## Forecast summary

### Covid-19 causes the first contraction in biofuel output in two decades

The biofuels industry has been strongly impacted by the Covid-19 pandemic. Global transport biofuel production in 2020 is anticipated to be 144 billion litres (L), equivalent to 2 480 thousand barrels per day (kb/d) – an 11.6% drop from 2019's record output and the first reduction in annual production in two decades.

While this projection is a slight upward revision from the IEA forecast update in May, it is far below the 3% growth anticipated for 2020 in our pre-pandemic forecast. The greatest year-on-year (y-o-y) drops in output are for US and Brazilian ethanol, and European biodiesel.

**Figure 6.1 Global biofuel production 2019 and breakdown for 2020**



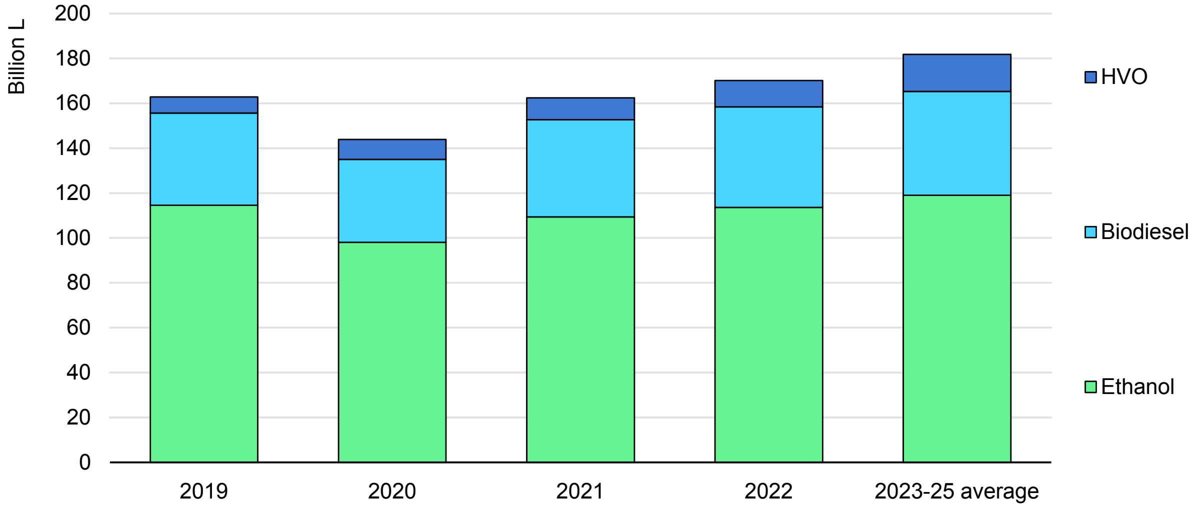



Sources: IEA (2020a), Monthly Oil Data Service (MODS), August 2020; IEA (2020b), Oil Information (database); IHS Markit (2020), Biofuels market; MAPA (2020), Agroenergia; US EIA (2020), Petroleum and Other Liquids.

Lower transport fuel demand resulting from the Covid-19 crisis reduces biofuel consumption in countries where mandate policies require a set percentage of biofuels to be blended with fossil transport fuels. Overall, global gasoline demand is anticipated to contract by 10%, and diesel by 6% in 2020. Diesel is less affected, as a substantial share of its consumption is for the transport of goods, which the crisis has impacted less than personal mobility.

A lowering of crude oil prices since the start of the pandemic has made biofuels less competitive with fossil transport fuels. The average crude oil price for 2020 is currently estimated at around USD 40/bbl, down from USD 64/bbl in 2019. This has reduced unblended ethanol purchases in Brazil (-17% in the first half of 2020) and delayed increases to biofuel blending rates in the Association of Southeast Asian Nations (ASEAN) region because this would imply higher costs for governments that subsidise biofuels to ensure their competitiveness with gasoline and fossil diesel. Lower crude oil prices have also caused biofuel prices to fall, albeit generally to a lesser extent, which challenges production economics for some plants.

**Global biofuel production 2019 and forecast to 2025**






Note: HVO = hydrotreated vegetable oil, also known as renewable diesel.
Sources IEA (2020a), Monthly Oil Data Service (MODS), August 2020; IEA (2020b), Oil Information (database); IHS Markit (2020), Biofuels market; MAPA (2020), Agroenergia; US EIA (2020), Petroleum and Other Liquids.

## Fuel demand recovery and stronger policies in key markets can spur production rebound in 2021

If fossil transport fuel demand rebounds to close to pre-pandemic levels and policy support in key markets continues to expand, transport biofuel production could reach 162 billion L in 2021, a return to the 2019 level. This is contingent, however, on the health crisis being brought under control and the avoidance of further widespread mobility restrictions.

Output in 2022 is anticipated to increase a further 4% y-o-y to 169 billion L. Growing fuel demand and strengthened biofuel policies in Asian and South American countries enable those markets to account for the majority of the additional growth. Countries in these regions are also reinforcing biofuel policy support to boost demand for nationally important agricultural commodities.

During 2023-25, average global output of 182 billion L is anticipated, with the greatest production increases being for ethanol in China and Brazil, and for biodiesel and HVO in the United States and the ASEAN region. Biofuels are expected to meet around 5.4% of road transport energy demand in 2025, rising from just under 4.8% in 2019.

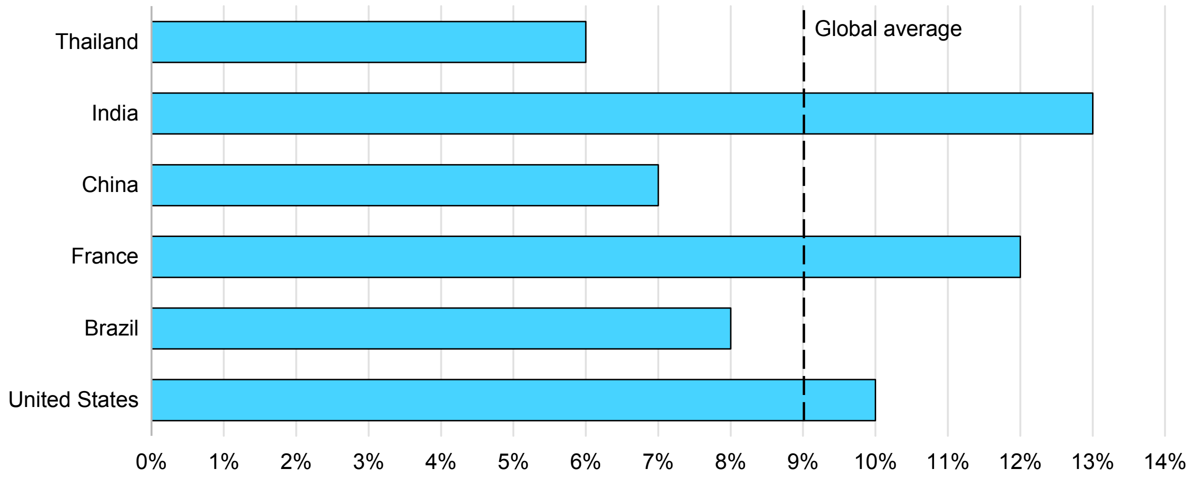
# Ethanol markets

## Global ethanol production to drop almost 15% in 2020, mainly due to lower output in Brazil and the United States

Fuel ethanol production reached 115 billion L globally in 2019. However, global output has been strongly impacted by the Covid-19 crisis. Production is therefore anticipated to contract 14.5% to 98 billion L in 2020 – a return to 2015 production levels. Around 80% of the y-o-y fall in output occurs in the key markets of Brazil and the United States.

A strong dip in gasoline demand in several key ethanol markets is the primary reason for lower ethanol production in 2020, with the drop in some ethanol-producing countries surpassing the global average. If gasoline demand rebounds in 2021, production could increase to 109 billion L before returning to close to 2019 levels by 2022. In 2023-25, average output is anticipated to be 119 billion L, with Brazil, China and India the key growth markets over this period.

**Figure 6.2 Y-o-y gasoline demand contraction (by volume) in key ethanol markets, 2020**






Sources: IEA (2020a), Monthly Oil Data Service (MODS), August 2020; IEA (2020b), Oil Information (database).

In the **United States**, ethanol production reached 59.5 billion L in 2019. A similar level was expected for 2020, but the pandemic has severely affected the US ethanol industry. Despite another bumper corn crop, a 12% drop to 52 billion L of production in 2020 (the lowest output since 2014) is anticipated owing to 10% less y-o-y gasoline demand.

Output fell approximately 40% between February and April, as many plants idled or reduced output in response to the sudden drop in gasoline demand, negative operating margins and constrained storage capacities. However, output has since improved and by September was only 9% below the 2019 level.

The financial impact of the pandemic on the biofuels industry has been cushioned by the Renewable Fuel Reimbursement Programme, which provided USD 0.12/L to eligible producers for output between 1 January and 1 May 2020.

Ethanol consumption has remained steady at around 10% of variable gasoline demand in 2020. As gasoline consumption recovers, US ethanol production is expected to increase to 55-58 billion L over 2021-22. During 2023-25, output is expected to stabilise at around 55 billion L as greater passenger vehicle efficiency reduces gasoline demand and, in turn, the volume of ethanol needed for blending.

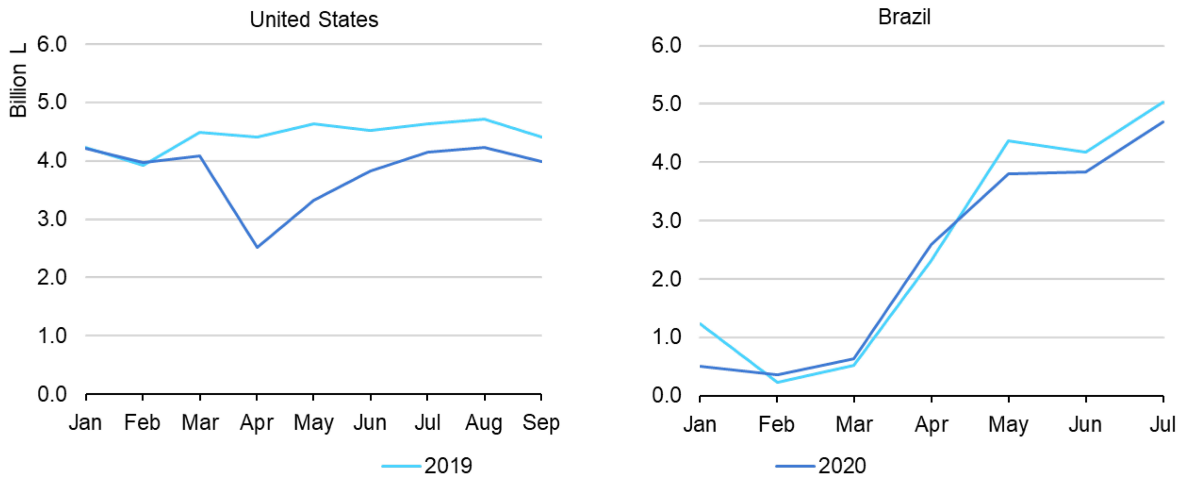
Higher production would require an increased uptake of ethanol blends such as E15 or E85.[2] However, despite support from the Higher Blends Infrastructure Incentive Program, they continue to account for a small portion of the market and scaling up their availability is not likely to noticeably affect ethanol demand nationwide before the end of the forecast period.

The other key means to enable higher production is to increase ethanol exports. However, given the drop in gasoline demand, matching 2019 production in 2025 would require a doubling of the record export levels of 2018, which will be challenging.

[2] These refer to 15% and up to 85% ethanol by volume blended with gasoline. References to E10 and E20 later in this section refer to 10% and 20% ethanol blends.

**Figure 6.3 US and Brazil ethanol production, 2019 and 2020**






Sources: MAPA (2020), Agroenergia; US EIA (2020), Petroleum and Other Liquids.

**Brazil** produced 36 billion L of ethanol in 2019, with output anticipated to fall 16.5% to 30 billion L this year. Brazil is facing dual pressure in 2020: an 8% drop in gasoline demand that is curbing consumption of ethanol blended under the 27% mandate; and low oil prices that reduce gasoline prices, which in turn affects the competitiveness of unblended ethanol versus gasoline at the pump.

Brazilian ethanol output has also fallen in 2020 because mills are expected to maximise sugar production at the expense of ethanol during the 2020-21 sugar cane harvest season. The higher profitability of the sweetener in current market conditions means that the use of recoverable sugars for sugar rather than ethanol is anticipated to rise by 10 percentage points, reversing the trend of the last two years.

Partial output recovery is expected in 2021 (33 billion L) and 2022 (34 billion L) as ethanol production from corn feedstocks expands rapidly. Corn-based production is anticipated to increase to 2.5 billion L by 2021, 85% higher than the 2019 level, with a number of plants in development and corn supplies ample. Although this output is low compared with sugar cane-derived ethanol, corn-based production is anticipated to continue expanding throughout the forecast period.

Over 2023-25, average ethanol production of 37 billion L is forecast with y-o-y production growth expected as gasoline demand is anticipated to rise 1% per year. In addition, the RenovaBio policy improves the economics of biofuel production by introducing emissions reduction targets that fuel distributors can meet by obtaining traded emissions reductions certificates (called CBIOs) awarded to biofuel producers.

RenovaBio rollout began this year, and by June more than 200 producers had been certified to receive CBIOs. In September, the certificates traded at around USD 3.8 to

USD 4.6 per certificate, which equates to an emissions reduction of 1 tonne of $CO_2$ equivalent. Due to lower transport fuel demand during the Covid-19 crisis, the original RenovaBio target for 2020 was adjusted down by 50% to 14.5 million CBIOs.

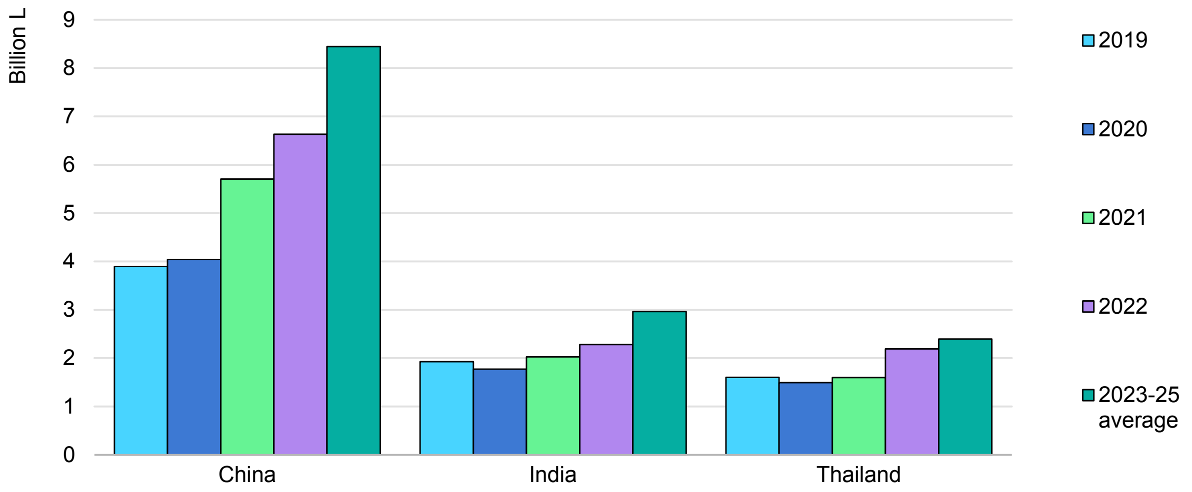
## Medium-term ethanol production growth is robust in key Asian markets

Ethanol production in **China** reached 3.9 billion L in 2019, and this level is expected to remain stable at around 4 billion L in 2020. Despite a 7% contraction in gasoline demand, some ethanol production growth is expected from the expansion of 10%-ethanol (E10) supplies to new provinces. Production capacity has doubled since 2017, and several large new plants are in development.

The depletion of China's previously large grain reserves has caused the government to delay the nationwide rollout of 10% ethanol blends planned for 2020. Nevertheless, extending E10 supplies to more areas is ongoing, with eight provinces offering complete coverage and another six in the process of expanding its availability.

China's Annual Energy Plan indicates that policy adjustments will be made to improve ethanol deployment prospects though steady expansion of production capacity and the promotion of ethanol-gasoline blending. Consequently, during 2023-25, average production is expected to reach 8.5 billion L, more than double 2019 production.

**Figure 6.4 Ethanol production overview for key Asian markets**






Fuel ethanol output in **India** reached 1.9 billion L in 2019, but it is expected to drop 8% to 1.8 billion L in 2020. Production prospects have been impacted by a 13% reduction in gasoline demand, while lower oil prices mean that ethanol is less affordable than unblended gasoline. In addition, constrained ethanol storage capacity at mills has compromised production.

However, production could rebound to a record 2 billion L in 2021 as gasoline demand recovers and molasses feedstocks become more available. Over 2023-25, average output of 3 billion L per year is anticipated, reflecting expected investments to increase production capacity.

Although India's ethanol production is anticipated to expand, domestic output is expected to fall short of the country's biofuel policy goal for 2022. While the target is for 10% ethanol blending nationwide, the production forecast for 2025 equates to around 7% of gasoline demand.

In **Thailand**, ethanol production is expected to shrink 7% in 2020 to 1.5 billion L. Output is impacted by a 6% decrease in gasoline demand and lower molasses feedstock availability. During 2023-25, average yearly production of 2.4 billion L is expected, with growth spurred by expanded production capacity and a shift to make E20 the principal blend consumed by passenger vehicles. This change was originally planned for 2020 but was delayed by the Covid-19 pandemic.

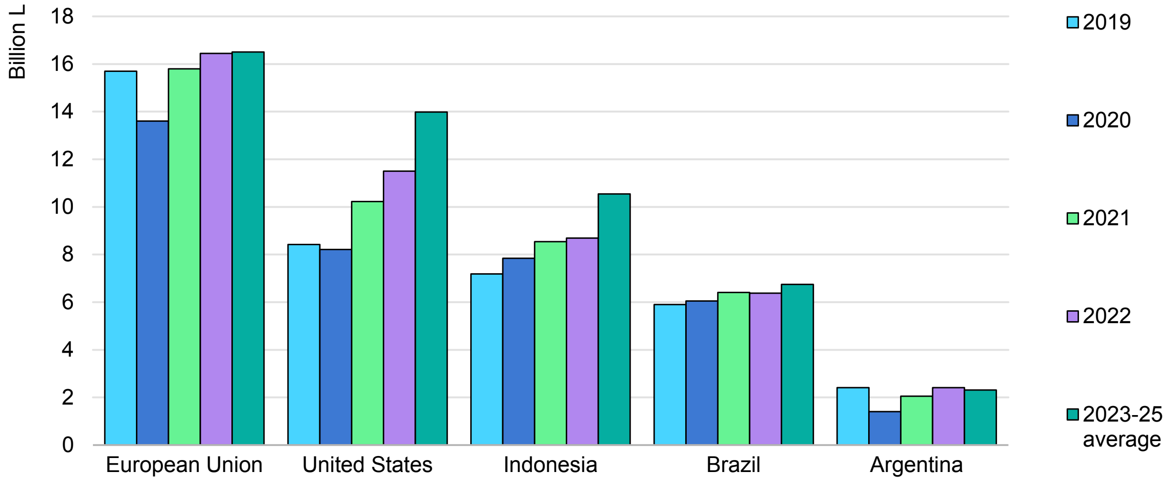
# Biodiesel and HVO markets

## Higher blending mandates in key markets support global biodiesel and HVO output in 2020

Global biodiesel and HVO production reached 48 billion L globally in 2019. The Covid-19 crisis has impacted global output to a lesser extent than ethanol, as the reduction in diesel demand has been less pronounced than for gasoline, and key markets introduced higher blending mandates in 2020 despite the pandemic. Production is expected to contract by around 5% to 46 billion L in 2020, with most of the reduction in European markets.

European production is expected to bounce back in 2021, which, combined with ongoing growth in ASEAN countries and the United States, causes global output to reach 53 billion L in 2021 and 56 billion L by 2022. Over 2023-25, average output is anticipated to be 63 billion L, 30% higher than the 2019 level. Expanding HVO production in Singapore and the United States accounts for over half of this increase.

**Figure 6.5 Biodiesel and HVO production overview, key global markets**






Output of biodiesel and HVO in the **European Union** reached a record 15.7 billion L in 2019.[3] Production is anticipated to decrease 13.5% to 13.6 billion L in 2020. A key factor in this reduction is the Covid-19 pandemic, which reduced EU diesel demand by 10.5% in 2020. Furthermore, storage capacity is saturated and the price of biodiesel has fallen more quickly than the cost of feedstocks, challenging biodiesel production economics. Two-thirds of production is from France, Germany, Spain and the Netherlands, and about one-quarter of total EU output comes from HVO.

The production decline would have been even greater if not for the biofuel mandates of various member states (e.g. France, Italy, Poland and Spain) linked to the Renewable Energy Directive (RED) 2020 target of 10% renewable energy in transport. Germany's Climate Protection Quota also reinforced its carbon intensity target in 2020, notably boosting biodiesel and HVO demand. In addition to these favourable policy changes, a rebound in diesel demand in 2021 could cause output to increase to 15.8 billion L.

Over 2023-25, average output of 16.5 billion L is expected across the EU. HVO use expands considerably owing to its advantageous technical characteristics and the specifications of the updated RED for 2021-30. However, only 30.5% of all passenger car registered in the European Union in 2019 were diesel-fuelled (ACEA, 2020). Fewer diesel car registrations and increasingly efficient passenger and road freight vehicle fleets therefore means diesel consumption drops 10% over the forecast period, reducing biodiesel and HVO demand created by mandate policies.

[3] EU27 production, excluding the United Kingdom for consistency with forecast numbers.

## US investments and stronger ASEAN and Brazilian policy support stimulate medium-term HVO production growth

In the **United States**, biodiesel and HVO production was a record 8.4 billion L in 2019. In 2020, output is expected to hold steady at around 8.2 billion L. The drop caused by the Covid-19 pandemic is counterbalanced by policy-driven demand from the federal Renewable Fuel Standard (RFS2), California's Low Carbon Fuel Standard (LCFS) and the reintroduced Blender's Tax Credit, resulting in 3% lower diesel demand. Anti-dumping duties on imports from Indonesia and Argentina, which rendered them uneconomic, also underpin domestic output.

Average yearly biodiesel production of 14 billion L is expected over 2023-25. The main driver for growth is a fourfold increase in HVO output arising from a flurry of investments in production capacity, including the conversion of several fossil fuel refineries. Tighter annual LCFS carbon intensity requirements in California, Oregon and the Canadian province of British Columbia will stimulate demand for low-carbon HVO from waste and residue feedstocks, but scaling up production will likely require that a new policy continue to stimulate the demand created by the RFS2 after its expiry in 2022.

In **Indonesia**, a record 7.2 billion L of biodiesel were produced in 2019. Output in 2020 is expected to increase slightly to 7.9 billion L. The rise in the national blending mandate from 20% to 30% at the beginning of 2020 offset a 12.5% reduction in diesel demand due to Covid-19. The pandemic has, however, delayed the commissioning of some new production facilities.

Continued policy support over the forecast period is anticipated, as Indonesia's oil import dependency is increasing. Improving security of supply is therefore a key aim of measures that support domestically produced biofuel consumption in transport. The biodiesel mandate is expected to rise to 40% during the forecast period, with vehicle testing already under way.

During 2023-25, average yearly output of 10.5 billion L is therefore expected, with higher biodiesel consumption from the transport mandate spurred by 10% diesel demand growth over 2021-25. Increased production is delivered by new plants coming online and underutilised capacity ramping up output.

Low-level HVO production has begun in Indonesia, with plans to launch production at several refineries. HVO blending with biodiesel, which is generally not constrained by blend limits, is considered one way to make vehicles suitable for the 40% mandate.

**Brazil** produced a record 5.9 billion L of biodiesel in 2019. A good soybean harvest and stronger demand resulting from an increase in the blending mandate (to 12%) this year is anticipated to raise production slightly to 6 billion L in 2020.[4]

Production could scale up to 7 billion L by 2025, reducing current biodiesel plant overcapacity. The primary impetus for higher output would be a staged mandate increase to 15% by 2023 and the introduction of the RenovaBio policy, which is likely to stimulate more output from lower-carbon waste oil and animal fat feedstocks.

Biodiesel production in **Argentina** amounted to 2.4 billion L in 2019, but the sector has been hit hard by the Covid-19 crisis and output is expected to drop 40% to 1.4 billion L in 2020. Not only will a roughly 9% decrease in diesel demand reduce local consumption under the 10% blending mandate, but exports to the United States also remain closed due to trade tariffs. Although average yearly production over 2023-25 is anticipated to recover to 2.3 billion L, this will depend on how biofuel policies are revised in 2021.

[4] Although the biodiesel mandate was temporarily reduced from 12% to 10% in September and October.

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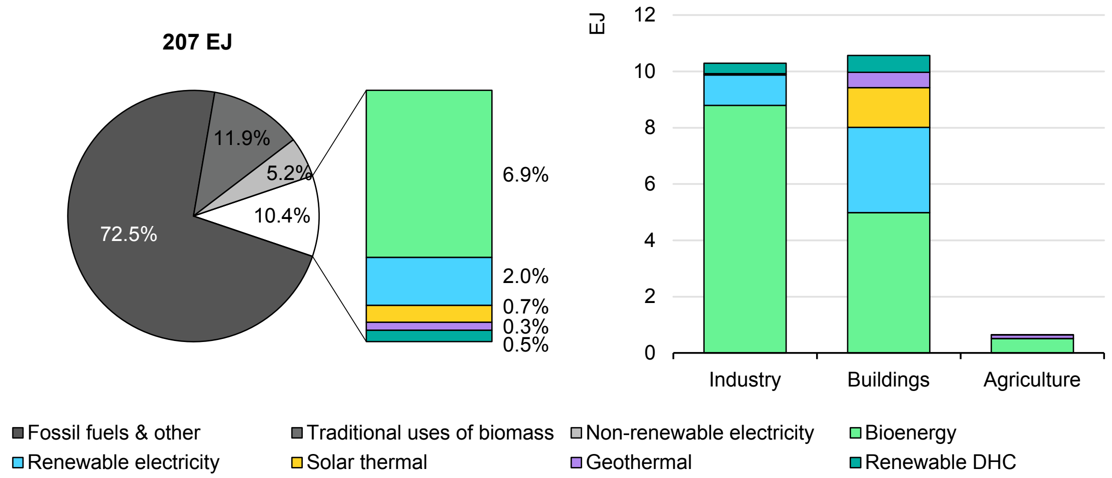
# Renewable heat

## Modern renewables account for only 11% of global heat supply today

Heat is the largest energy end-use, accounting for half of global final energy consumption, significantly more than electricity (20%) and transport (30%). With modern renewables[5] meeting only 11% (21.5 exajoules [EJ]) of global heat demand in 2019, fossil fuels continue to dominate heat supplies, which contributed 40% (13.3 gigatonnes [Gt]) of global $CO_2$ emissions in 2019.

About 50% of total heat consumed in 2020 is used for industrial processes, another 47% is consumed in buildings for space and water heating, and, to a lesser extent, cooking; the remainder is used in agriculture, primarily for greenhouse heating. More than one-quarter of global heat consumption takes place in China – two-thirds of which is for industry – while the United States, the European Union, India and the Russian Federation ("Russia") together account for another 35%.

**Figure 7.1 Global renewable heat consumption by fuel and technology, 2019**






Note: DHC = district heating and cooling.
Sources: IEA (2020), World Energy Statistics and Balances 2020 (database); IEA (2020), World Energy Outlook 2020.

[5] In this report, "modern renewable energy" excludes the traditional uses of biomass. "Modern renewable heat" covers direct and indirect (i.e. through district heating) final consumption of bioenergy, solar thermal and geothermal energy, as well as renewable electricity for heat based on an estimate of the amount of electricity used for heat production and on the share of renewables in electricity generation. For the sake of simplicity, "modern renewables" is referred to as "renewables" in the remainder of this report.

In **industry**, bioenergy accounts for the large majority of renewable heat consumption (almost 90% in 2019, including indirect consumption via district heat networks). It is used predominantly in industries that produce biomass waste and residues: food and tobacco, sugar and ethanol (Brazil and India), and especially pulp and paper (mainly in North America, Europe and Brazil). The cement industry is also boosting industrial bioenergy consumption as municipal waste is increasingly used in China and the European Union. Most of the remaining renewable heat consumed in industry is supplied by renewable electricity, used in steel recycling and aluminium production as well as by large-scale heat pumps for low-temperature processes such as drying. However, renewable electricity represents only 1% of current total industrial heat consumption.

Bioenergy also leads renewable heat consumption in **buildings**, used mainly in wood and pellet stoves and boilers as well as in district heating networks, for which municipal waste and biomass comprise the majority of renewable supply. With around 11% of global electricity generation used by electric heaters, boilers and heat pumps for buildings, renewable electricity is the second-largest renewable energy commodity used for heat in buildings after bioenergy.

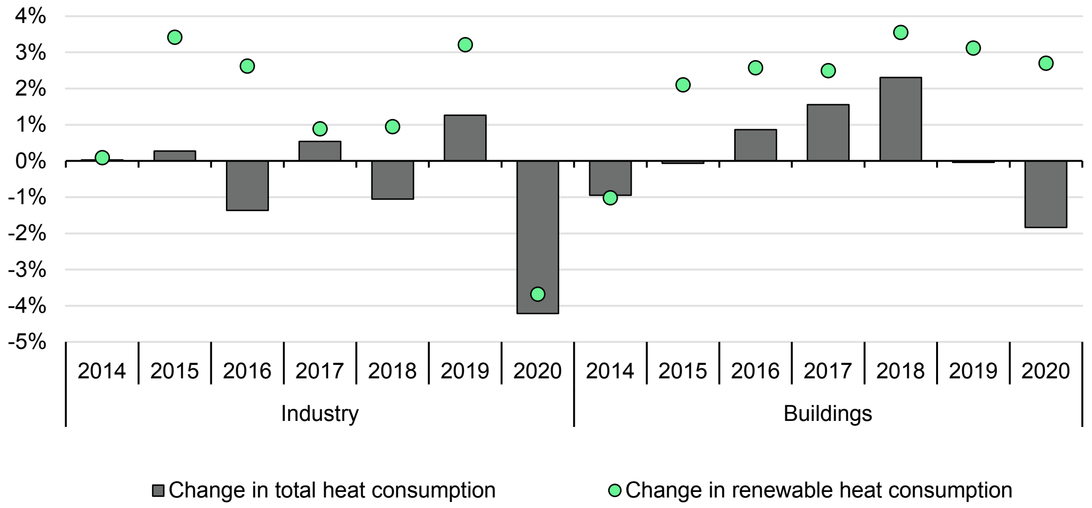
The rapid spread of heat pumps over last decade is making ambient heat an increasingly important renewable heat source, although its importance globally is difficult to estimate because data are unavailable for some markets. In the European Union, about 0.5 EJ of ambient heat are transferred to buildings annually by the 13.5 million heat pumps in operation at the end of 2019 (EHPA, 2020; Eurostat, 2019). Finally come solar thermal – used essentially for domestic water heating – and geothermal heat, of which almost 60% is harnessed by ground-source heat pumps (Lund and Toth, 2020).

# Covid-19 impact on global heat demand

## The Covid-19 crisis has reduced global heat demand in 2020, especially in industry

Total global heat consumption in 2020 is expected to decline 3.1% from 2019 – the largest drop recorded since the IEA began to collect and process harmonised statistics on heat. The curtailment of economic activity due to the pandemic is forecast to impact heat consumption in industry (-4.2%) more than in buildings (-1.8%). For the latter, the lockdown measures and teleworking practices of numerous countries have reduced heat consumption in the commercial subsector, which has been partially offset by a small increase in residential heat consumption, primarily for cooking. In industry, supply chain disruptions in various manufacturing subsectors, followed by a challenging economic recovery in a context of high uncertainty and cash-constrained markets, are curtailing demand for materials from heat-intensive industries, including steel, aluminium, cement and chemicals.

**Figure 7.2 Y-o-y change in global and renewable heat consumption in industry and buildings, 2014-20**

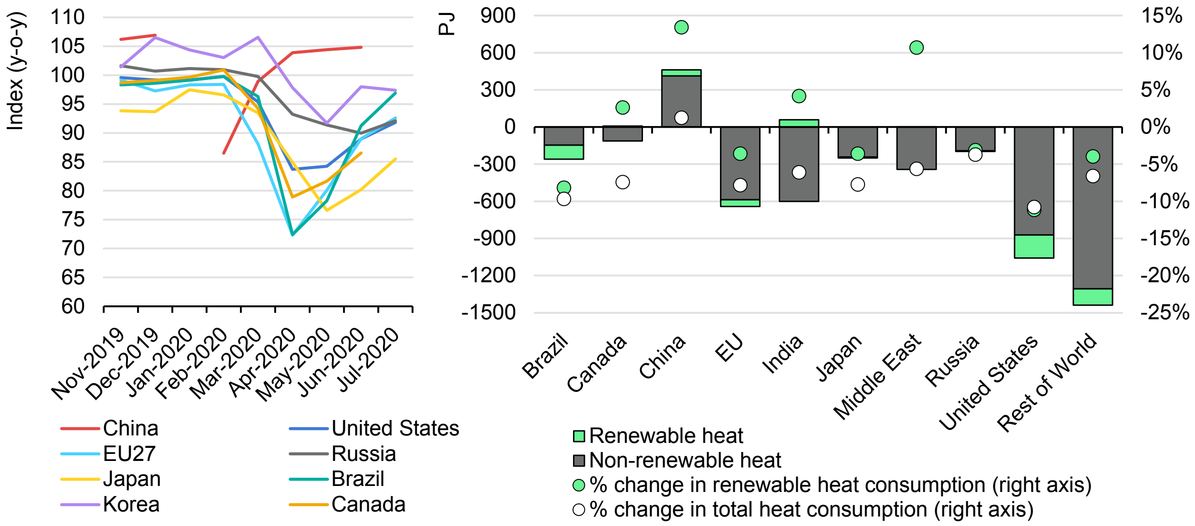





Sources: IEA (2020), World Energy Statistics and Balances 2020 (database); IEA (2020), World Energy Outlook 2020.

China is the only major economy in which heat demand is expected to increase this year with a rapid recovery of industrial production. Outside of China, industrial heat consumption will be 7% lower on average in 2020 than in 2019. In India, a double-digit contraction of steel production strongly affects heat demand while the largest annual drop in industrial heat consumption (-1 EJ) is expected to come from the United States due to a significant decline in chemicals, cement, iron and steel, pulp and paper production (World Steel, 2020).

**Figure 7.3 Index of industrial production (left) and y-o-y change in industrial heat consumption (right), selected regions, 2020**






Notes: PJ = petajoule. The industrial production index in the left figure expresses volume changes (in terms of production units) from the same month of the previous year (same month of previous year = 100) for industry sector output. It is calculated based on OECD (2020), Industrial production.
Sources: IEA (2020), World Energy Statistics and Balances 2020 (database);IEA (2020), World Energy Outlook 2020.

# Renewable heat demand in 2020-22

## The share of renewables in heat consumption will increase minimally during 2020-22

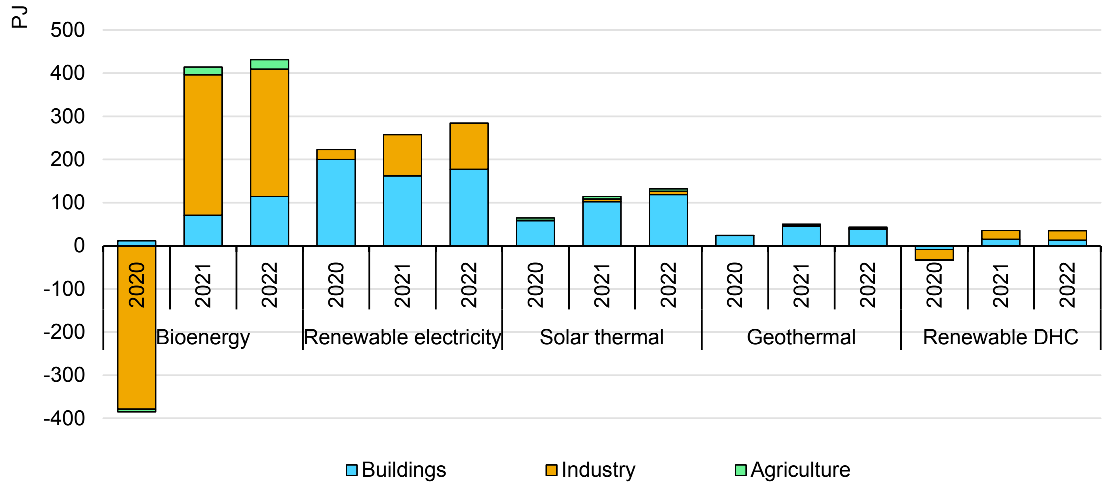
In **industry**, the share of renewables in heat consumption globally is expected to remain almost unchanged at 10% in 2020, as the heat demand shock also affects bioenergy-intensive subsectors (for instance pulp and paper). The consumption of other renewables in industry is expected to expand slightly this year, but not enough to counterbalance the overall trend because their share is small in absolute terms and therefore cannot make up for the significant drop in bioenergy use.

Industrial heat demand is expected to recover during 2021-22 and even exceed the 2019 level, resulting in a global increase in non-renewable heat consumption – despite expansion of bioenergy-intensive subsectors in India, higher bioenergy consumption in China, and greater renewable electricity and heat pump use, especially in China, the European Union and the United States.

In **buildings**, while heat demand falls somewhat, expanding solar thermal, geothermal and – most of all – heat pump and renewable electricity contributions raise renewable heat consumption slightly, allowing renewables – excluding ambient heat – to meet 11.5%

of global demand in 2020 (an increase of 0.5 percentage points from 2019), despite bioenergy consumption remaining unchanged. Furthermore, this share is expected to rise slowly to 12.3% during 2021-22, owing primarily to the continued expansion of renewable electricity use for heat, then to the progression of solar thermal and bioenergy consumption, and finally to the wider utilisation of geothermal energy through both ground-source heat pumps and district heating.

**Figure 7.4 Annual global change in renewable heat consumption by source, 2020-22**





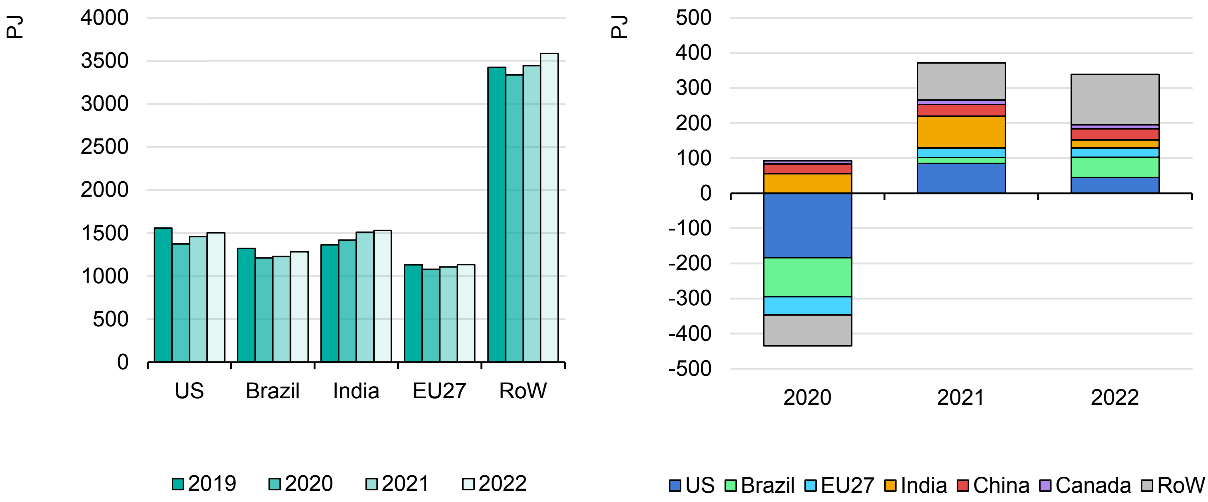

Sources: IEA (2020), World Energy Statistics and Balances 2020 (database); IEA (2020), World Energy Outlook 2020.

## Apart from bioenergy use in industry, Covid-19 has a limited direct impact on short-term renewable heat consumption

The heat demand shock translates into a temporary 4% drop in global **industrial bioenergy** consumption in 2020, since less commercial, industrial and construction activity has implied lower demand for a variety of products manufactured in bioenergy-intensive subsectors (e.g. printer paper, cement and lumber). The United States is expected to record the largest drop in industrial bioenergy consumption this year, followed by Brazil and the European Union.

At the global scale, assuming industrial activity rebounds during 2021-22, bioenergy consumption is projected to exceed the 2019 level as early as 2022 due to continued growth in India, China and, to a lesser extent, Canada. Higher municipal waste use in the cement subsector is expected to play a key role in China, while expanding sugar and ethanol production is the main driver in India.

**Figure 7.5 Industrial bioenergy consumption (left) and y-o-y change in industrial bioenergy consumption (right), 2019-22**





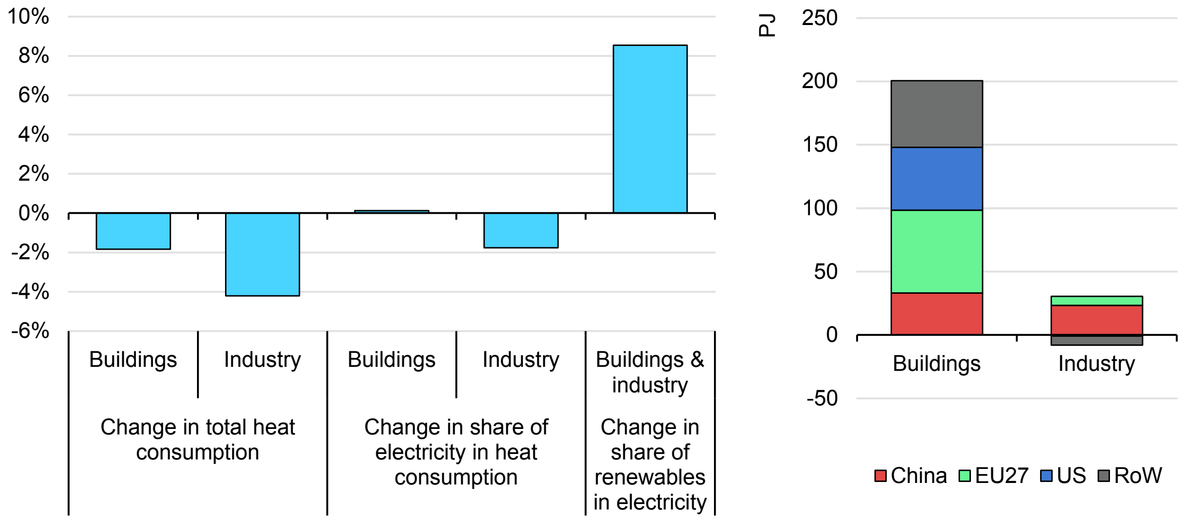

Notes: RoW = rest of the world
Sources: IEA (2020), World Energy Statistics and Balances 2020 (database); IEA (2020), World Energy Outlook 2020.

The trends are different for other renewable sources and technologies, for which the largest applications are in the buildings sector, or for which demand has not been affected to the same extent.

## Rising shares of renewables in power generation have a spillover effect on the heat sector

Even with global electricity demand for heat falling in the industry and buildings sectors in proportion with heat demand, heat-related **renewable electricity** consumption rises in both sectors in 2020 owing to higher shares of renewables in electricity generation. This results not only from renewable capacity additions in the power sector, but also from lower operating costs and priority access to the grid in many markets leading to greater shares of renewables in electricity generation when demand decreases. In 2020, the United States, China and the European Union together comprise three-quarters of the annual increase in renewable electricity used for heat, of which the buildings sector accounts for more than 85%. Overall, heat uses continue to claim 16% of global renewable electricity generation.

**Figure 7.6 Global changes in factors contributing to renewable electricity consumption for heat (left), and annual increase in consumption (right), 2020**






Sources: IEA (2020), World Energy Statistics and Balances 2020 (database); IEA (2020), World Energy Outlook 2020.

Heat-related renewable electricity consumption is projected to continue trending upward in 2021 and 2022. While rebounding industrial heat consumption (+5% globally during 2021-22) and greater reliance on electricity for heat (especially for industrial use in China) will have a noticeable effect, expanding shares of renewables in electricity generation is expected to remain the strongest factor globally.

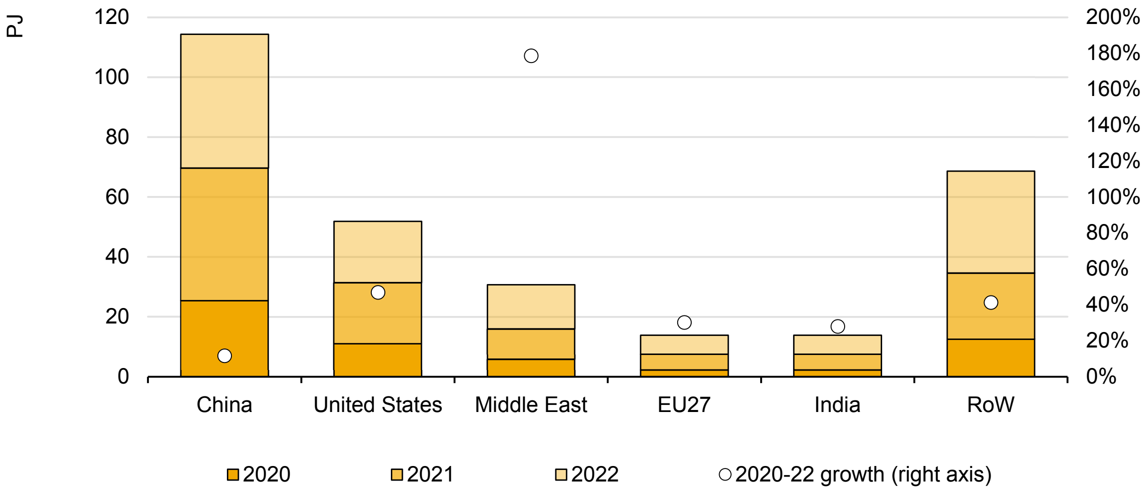
## Solar thermal demonstrates resilience with continued expansion

Despite lockdowns disrupting new installations in many countries during the first half of the year, global solar thermal consumption – more than 90% of which is for domestic water heating – is expected to increase more than 4% in 2020, similar to the year before. Despite shrinking of its domestic market, China continues to lead this expansion, followed distantly by the United States, the European Union and countries in the Middle East. Positive developments have recently been observed in key European markets: in Germany, for instance, the number of collectors sold from January to July 2020 was 14% higher than during the same period last year, thanks to improved financial support for clean heating projects under the Market Incentive Programme (Solarthermalworld 2020).

Global solar thermal consumption is projected to accelerate during 2021-22 (+8% annually) with the key markets of China, the United States, the European Union and the Middle East together responsible for more than 70% of the growth. In these large markets, however, limited policy attention and increasing policy-maker interest in electrification of heat end-uses mean that small-scale solar water heating systems face competition not only from heat pumps but from rooftop PV systems as well (IEA SHC, 2020).

In developing countries, the technological simplicity and limited maintenance of standalone systems remain an important asset. Policy support, in the form of regulations (Greece, Denmark, South Africa) or economic incentives (Cyprus),[6] sometimes linked to social housing programmes (Namibia, Brazil), will remain a determining factor for future solar thermal markets.

**Figure 7.7 Growth in solar thermal heat consumption, selected regions, 2020-22**






Sources: IEA (2020), World Energy Statistics and Balances 2020 (database); IEA (2020), World Energy Outlook 2020.

## Geothermal development slows in 2020

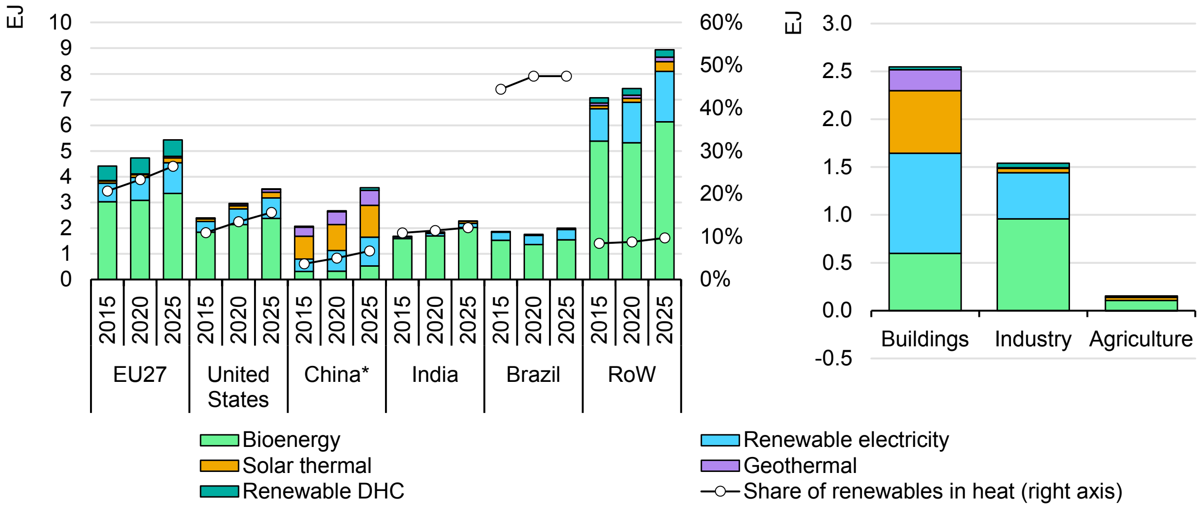
After increasing twofold over the last seven years, global **geothermal** heat consumption has risen very little in 2020. Growth is forecast to resume in 2021 and 2022, albeit still at half the pace of the last ten years. China, the United States and the European Union together are expected to be responsible for more than 80% of the increase in 2021-22, primarily benefitting the buildings sector.

[6]Note by Turkey: The information in this document with reference to "Cyprus" relates to the southern part of the Island. There is no single authority representing both Turkish and Greek Cypriot people on the Island. Turkey recognises the Turkish Republic of Northern Cyprus (TRNC). Until a lasting and equitable solution is found within the context of the United Nations, Turkey shall preserve its position concerning the "Cyprus issue".
Note by all the European Union Member States of the OECD and the European Union: The Republic of Cyprus is recognised by all members of the United Nations with the exception of Turkey. The information in this document relates to the area under the effective control of the Government of the Republic of Cyprus.

# Renewable heat prospects towards 2025

Global renewable heat consumption is projected to be 20% higher in 2025 than in 2019, with a stronger increase in the buildings sector (+24%) than in industry (+15%). Despite this rise, renewables are expected to represent only 12% of global heat consumption by 2025, as the latter is expected to recover simultaneously, driven by industrial activity. Without a significant change in non-renewable heat consumption, total heat-related $CO_2$ emissions in 2025 are expected to be only 2% lower than in 2019.

**Figure 7.8 Renewable energy consumption by source, 2015-25 (left) and global increase in renewable energy consumption by source and sector, 2020-25 (right)**



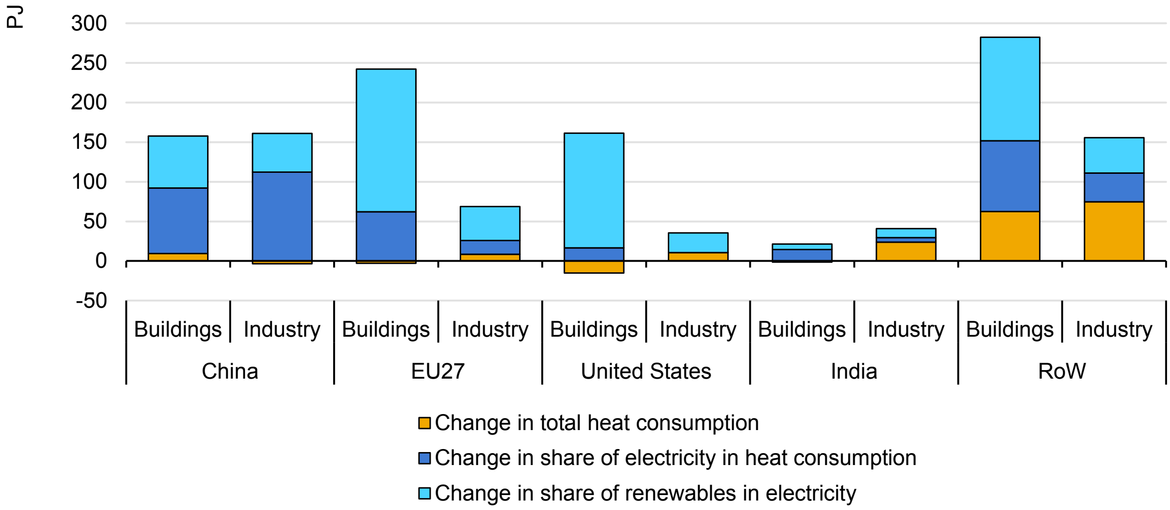



*Although China does not currently report bioenergy use in industry in its statistics, some bioenergy is consumed.
Note: RoW = rest of the world
Sources: IEA (2020), World Energy Statistics and Balances 2020 (database); IEA (2020), World Energy Outlook 2020.

In **industry**, bioenergy makes the largest contribution to increased renewable heat uptake, with consumption in 2025 expected to exceed the 2019 level by over 10% (1.0 EJ). In addition to the progressive recovery of US and Brazilian consumption, India and China lead this growth and are together responsible for over half of the additional industrial bioenergy consumption in 2025 compared with 2019.

Owing to the electrification of process heat and increasing shares of renewables in electricity generation, industrial consumption of renewable electricity is projected to increase more than 40% (0.5 EJ) globally over the next five years, with China accounting for one-third of this growth and the European Union, India and the United States together for another third. Industrial heat pump applications are expected to continue expanding thanks to recent technological advancements making them suitable for a variety of low-temperature (<200°C) processes (IEA HPT TCP, 2019).

**Figure 7.9 Contribution of different factors to changes in renewable electricity consumption in selected regions, 2021-25**






Source: Based on IEA (2020), World Energy Outlook 2020.

Despite a threefold increase expected by 2025, solar heat for industrial processes remains a niche market, with just under 40 PJ of additional consumption projected. Half of this growth is expected to be in India and the United States, with most applications in the food and textile sectors.

Solar thermal applications for agriculture (for instance for greenhouse heating and aquaculture) are also expected to be developed, especially in Mexico, the Middle East, the United States and China, but are forecast to represent only 30 PJ by 2025.

In the **buildings** sector, further deployment of electric heat pumps and boilers is expected to allow for a 1.3-EJ (+26%) increase in heat-related renewable electricity consumption during 2021-25. Two-thirds of this growth will be in the European Union, China and the United States, with the EU share being the largest. The amount of heat delivered by aerothermal heat pumps is projected to increase at an average annual rate of 5% globally and 15% in the European Union during 2021-25.

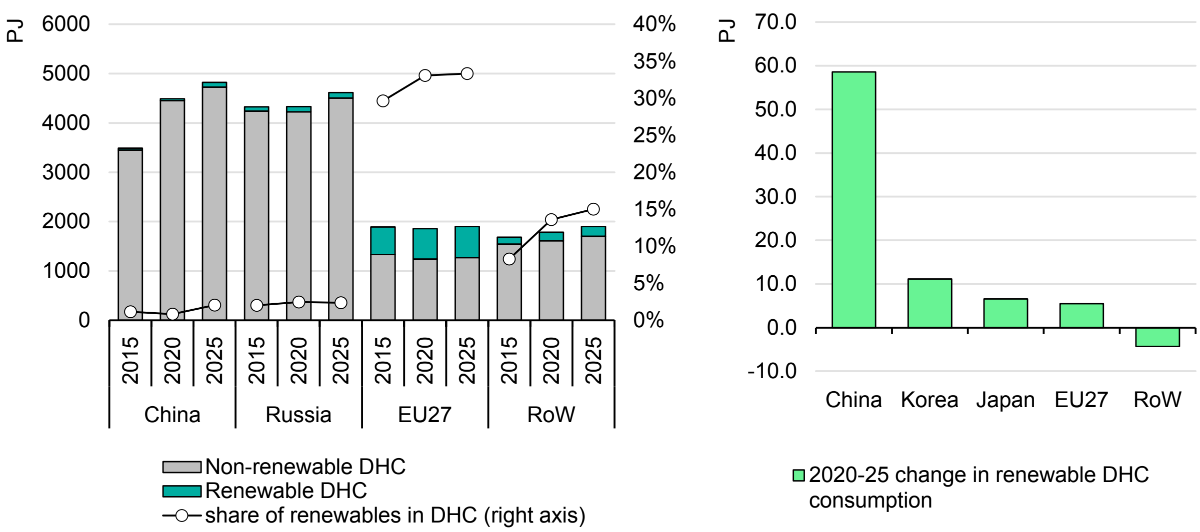
Direct bioenergy use in buildings rises by just over 10% during 2021-25, accounting for one-quarter of the sector's increase in renewable heat consumption. More than half of this expansion is forecast to take place in Africa and India, owing to the deployment of improved biomass cook stoves, while one-quarter of growth comes from new installations of wood and pellet stoves and boilers the European Union.

Solar thermal heat consumption in the buildings sector is forecast to rise 40% (+0.6 EJ) in 2021-25, similar to bioenergy in absolute growth. China leads expansion over the outlook period, followed by the United States, the European Union (with half of these additions attributed to France, Italy and Germany) and the Middle East. Benefitting from substantial irradiation potential, solar thermal consumption by buildings in the Middle East is expected to more than quadruple during 2021-25.

New ground-source heat pump installations in China, the United States and Europe are expected to spur the majority of geothermal heat development, with consumption projected to increase by one-third globally, amounting to 0.9 EJ by 2025. Although the buildings sector is expected to be responsible for more than 90% of this consumption, geothermal heat still meets less than 1% of the sector's total heat demand. Deep geothermal heat is also expected to receive growing interest from oil companies, for which it offers opportunities to diversify their activities while building on their drilling expertise.

Finally, limited renewable district heating and cooling (DHC) development is anticipated, with global consumption expected to be only 8% higher in 2025 than in 2019. The large majority of DHC expansion is expected to take place in China and Russia, which combined represent 70% of total district heat consumption but less than one-fifth of renewable district supplies. Yet, of these two countries, only China is projected to contribute significantly to an increase in renewable district supplies by 2025, thanks to greater use of municipal waste and biomass. Korea and Japan are forecast to account for most of the remaining growth in renewable DHC over 2020-25.

**Figure 7.10 District heat consumption, 2015-25 (left) and change in renewable district heat consumption, 2020-25 (right), selected regions**






Sources: IEA (2020), World Energy Statistics and Balances 2020 (database); IEA (2020), World Energy Outlook 2020.

# Renewable heat in stimulus packages

Despite heat accounting for a large share of final energy consumption, it has so far received limited policy attention globally compared with other end-use sectors. The number of countries with national targets for renewable heat is less than one-third those with targets for renewable electricity – and fewer than half of the countries that have a renewable heat goal currently have nationwide regulatory heat policies in force (REN21, 2020).

At the end of 2019, more than half of global heat consumption was not subject to any regulation, and more than one-quarter was not covered by national financial incentives or regulatory policies. These numbers have remained stable over the past three years.

However, given contextual specificities and the local nature of heat supply, an increasing number of policy initiatives are being developed at the subnational level, with cities and local governments using their regulatory and purchasing authority to encourage the use of renewables through municipal mandates for buildings or through their management of urban district networks (REN21, 2019; 2020).

Notable recent policy updates pre-Covid-19 include the European Union's indicative target of a 1.3-percentage-point annual increase in the share of renewables in heating and cooling for 2020-30, introduced in the 2019 revision of the Renewable Energy Directive (RED II). Also in 2019, a number of jurisdictions, including the countries of Austria, Norway and the United Kingdom, as well as the cities of Vienna (Austria), Berkeley (California) and Montreal (Canada), also committed to ban the use of certain fossil fuels in some categories of buildings (REN21, 2020). France, Germany and Lithuania also reinforced financial incentives for more efficient and renewable heating systems.

More recently, the critical economic situation created by the pandemic has led to a wave of government policy responses. Among them, various measures announced as part of economic recovery and stimulus plans are expected to benefit renewable heat directly or indirectly. Most fall under the category of energy efficiency measures, the largest recipient of clean energy stimulus packages. Some measures consist of extending or boosting existing policies (e.g. New Zealand's Warmer Kiwi Homes programme and France's MaPrimeRénov scheme), while others implement new support schemes (e.g. Finland's grants to phase out oil-based heating in residential and municipal buildings).

Some of these stimulus measures consist of new or additional financial support in the form of grants or tax credits for electric and renewable heat technologies such as heat pumps[7] in Denmark, France, Italy, New Zealand and the United Kingdom, renewable district heating in Denmark and the United Kingdom, or wood and pellet burners in New Zealand.

Other policies do not explicitly target renewable heat but support building insulation retrofits (e.g. France, Germany, Italy, Sweden, Denmark, Korea and the United Kingdom), which can create new opportunities for renewable heat technologies. For example, by

[7] In the European Union, ambient thermal energy extracted from a heat pump source is credited as renewable energy, provided the heat pump meets a minimum seasonal performance factor value.

lowering heat demand, well-insulated buildings make it possible to downsize heat pumps and operate them at lower output temperature, hence more efficiently. This reduces both the upfront and operating costs of heat pumps, improving their economic case and making them more cost-competitive with fossil fuel-based technologies.

Energy efficiency requirements for buildings can also spur the replacement of fossil fuel heating systems with heat pumps or other renewable technologies, depending on their design. For example, the EU Renovation Wave Strategy, which was published in October 2020 and aims to double renovation rates during 2020-30 through multiple integrated areas of intervention, may be an effective driver for renewable heat integration in buildings (EC, 2020).

In the long term, other measures could pave the way to further renewable heat uptake in hard-to-abate industrial subsectors. This is the case for support given to renewable or "green" hydrogen projects in countries such as Australia, France, Germany and Korea. It also applies to material efficiency measures, such as steel recycling in the United Kingdom, which can engender heat savings and encourage greater shares of (renewable) electricity in the steelmaking process.

Although they may not directly spur renewable heat uptake, other policies support heat decarbonisation by reducing the demand for non-renewable heat and carbon-intensive products. For example, Finland's promotion of wood construction could reduce demand for cement.

Although most stimulus measures consist of economic incentives such as grants, tax credits and loan schemes, a variety of non-economic challenges to renewable heat uptake will persist, including consumer inertia and lack of awareness, and split incentives in the buildings sector (IEA, IRENA and REN21, forthcoming). With low fossil fuel prices currently making renewables less cost-competitive, regulatory policies may also be instrumental to scale up the use of renewables for heat.

**Table 7.1 Recovery measures that encourage renewable heat uptake (directly and indirectly)**

| Country /region | Support |
|---|---|
| **Australia** | - Funding for renewable hydrogen<br>- Tasmania's renewable hydrogen action plan |
| **Canada (British Columbia)** | - Low-interest loans to replace fossil fuel-based heating with efficient electric heat pumps |
| **Denmark** | - Funding for social housing energy renovations, including replacing oil-fired heating systems with renewable district heating and electric heat pumps<br>- Proposed support for green gases for use in hard-to-decarbonise industries<br>- Grants for electrification and energy efficiency in industry |

| Country /region | Support |
|---|---|
| **Finland** | - Grants in 2020 to phase out oil-based heating in residential and municipal buildings |
| **France** | - Investment support to convert to low-carbon industrial technologies (including electrification of heat, biomass, and solar thermal)<br>- Compensation for additional cost of low-carbon heat sources compared with fossil fuels in industry<br>- Extended and increased support for energy retrofits to residential private buildings and social housing, and refurbishment of public buildings, including replacement of oil and gas heating systems ("MaPrimRénov" and "Coup de pouce" for comprehensive retrofits)<br>- Funding for a national hydrogen strategy<br>- Financial support for repair centres, recycling and waste-to-energy facilities |
| **Germany** | - Increased funding for building renovation programme<br>- National hydrogen strategy |
| **Italy** | - 110% Superbonus tax deduction scheme for energy efficiency retrofits and heating and cooling system renovations (including heat pump installations) |
| **Korea** | - Funding to decarbonise state-run facilities<br>- Additional support for green hydrogen technologies |
| **New Zealand** | - Expansion of the Warmer Kiwi Homes programme for low-income households, with subsides for insulation and heating retrofits |
| **Portugal** | - Support programme for sustainable buildings, including for heat pump installations |
| **Sweden** | - Funding for energy renovation of apartment buildings |
| **United Kingdom** | - Green Home Grant, Public Sector Decarbonisation Scheme, and Social Housing Decarbonisation Fund for energy efficiency and low-carbon heat upgrades in the buildings sector<br>- Clean Growth Fund for innovation projects, including for renewable heating<br>- Support for material efficiency (through the use of innovative materials) in heavy industry, with initial projects including steel recycling<br>- Funding for innovative energy projects, including heat networks through the Low Carbon Infrastructure Transition Programme (LCITP) |

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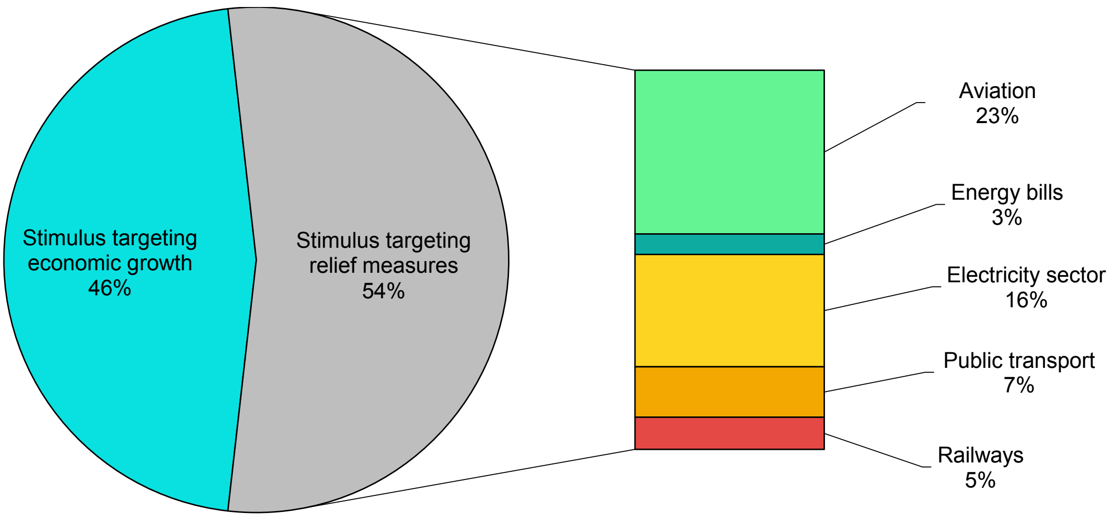
# Key trends to watch

## Where are we at with clean energy stimulus?

### Relief measures took priority over stimulus packages

As of the end of October 2020, governments around the world have announced USD 470 billion worth of energy-related stimulus packages targeting production and consumption. This stimulus is offered in the form of rebates, grants, loans and tax incentives/exemptions. The majority of these measures aim primarily to provide relief to public and private companies or consumers affected by the economic downturn arising from the Covid-19 pandemic.

**Figure 8.1 Announced stimulus packages targeting major energy production and consumption**






Note: Total stimulus includes national and sub-national announcements as of the end of October 2020 and amounts to USD 470 billion, excluding Next Generation EU stimulus.

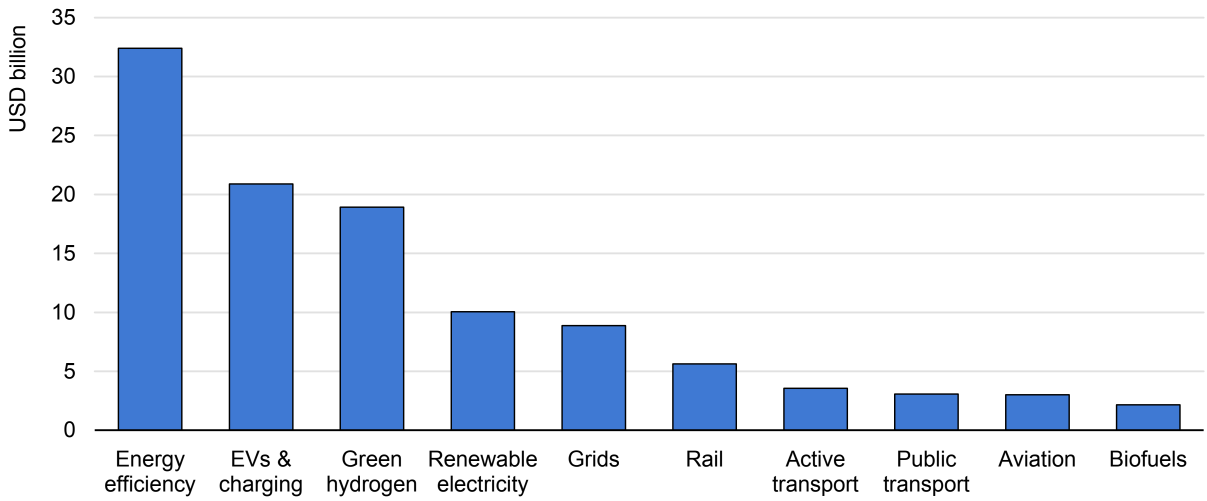
The aviation sector, including airlines and airports, is the largest stimulus recipient (USD 108 billion of which USD 76 billion of airline bailouts), as movement restrictions have reduced the number of flights significantly. The ultimate goal of airline/airport bailouts was to prevent bankruptcies and layoffs (see Biofuels chapter for more detailed analysis of sustainable aviation fuels).

However, only the Air France-KLM, Austrian Airlines and Swiss Air stimulus packages set "green" conditions for bailout. Similarly, public sector transportation and railway companies together received USD 55 billion to maintain minimum operations. As part of the relief measures, governments have provided almost USD 90 billion to the electricity sector, not only to ensure the secure continuation of services but to reduce the energy bill burden of companies and individuals.

## Energy efficiency and transport take priority over renewable energy in stimulus packages

In addition to relief measures, governments (excluding the EU plan for economic recovery) also announced around USD 220 billion worth of energy-related stimulus packages, of which half (around USD 110 billion) targets clean energy technologies. The largest share of aid is aimed at raising the energy efficiency of existing buildings (through renovations), industrial processes, cars and ships. Renewable heat technologies are also expected to benefit from measures targeting energy efficiency (see Renewable Heat chapter for more details).

**Figure 8.2 Announced clean energy stimulus packages by sector**






Note: An additional USD 5.2 billion is spent on other clean energy technologies such as nuclear andCarbon capture, utilisation and storage (CCUS). “Active transport” represents bicycling and walking infrastructure.
Stimulus analysed includes national and sub-national announcements as of the end of October 2020.

The transport sector (including rail infrastructure, electric vehicles and charging infrastructure, aviation, biofuels, as well as active and public transport) receives one-third of the funds, mostly owing to stimulus packages in Canada, China, Germany and France.

New renewable electricity plants, mostly wind and solar PV, are expected to receive about USD 10 billion from announced stimulus packages (excluding the EU plan for economic recovery). Green hydrogen programmes are also expected to raise renewable capacity, although investors could also use existing wind, solar PV and hydropower plants for hydrogen production.

Announced stimulus packages for renewable electricity fall significantly short of the IEA's sustainable recovery plan, in which around USD 180 billion would be spent globally each year from 2021 to 2023 on new wind and solar PV projects. Similarly, for biofuels the IEA plan envisions annual spending of USD 20 billion – ten times more than what governments had committed as of mid-September 2020.

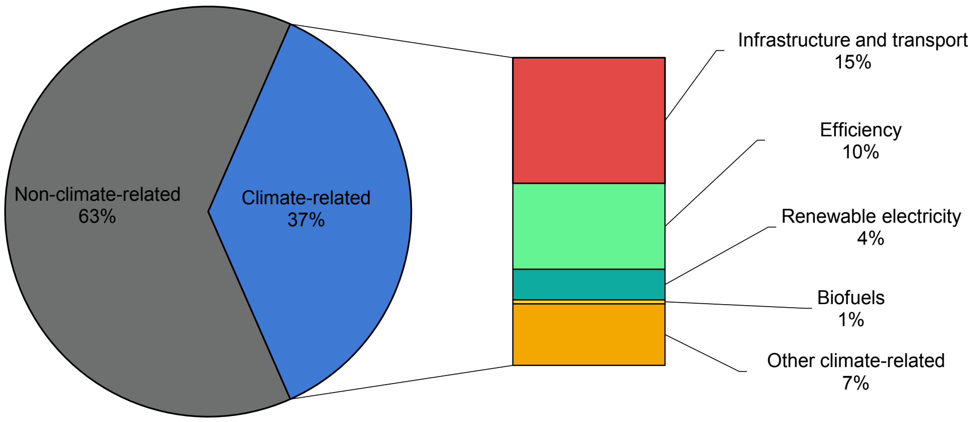
## EU stimulus is a champion of "green" economic recovery

With Next Generation EU, the European Union has put together EUR 750 billion (USD 840 billion) worth of stimulus to help member states recover from the pandemic, build up resilience and kick-start their economies. Stimulus is to be spent over 2021-23, making additional resources of 1.6 times the EU annual budget available each year.

The package consists of grants (51%), loans (48%) and guarantees (1%) and is distributed across seven funds, with the Recovery and Resilience Facility (RRF) accounting for 90% of the total stimulus budget. Member states are expected to invest RRF funds in the seven priority areas of: clean energy technologies; energy-efficient building renovations; sustainable transport; broadband rollout; digitalisation of public administration; European cloud computing capacities; and mainstreaming digital skills into education systems.

In line with the European Green Deal, EU countries have agreed to explicitly include clean energy transitions at the heart of their economic recovery, with around 37% of total recovery money targeting climate-related expenditures, including clean energy technologies. Based on past (2014-20) funding patterns, we estimate that the majority of climate-related investments are expected to materialise in infrastructure and transport (around USD 126 billion), followed by energy efficiency in buildings and industry (around USD 86 billion). We also anticipate that around USD 30 billion could be spent on new renewable electricity capacity and another USD 4 billion on biofuels.

**Figure 8.3 Next Generation EU total and expected climate- and energy-related spending, 2021-23**



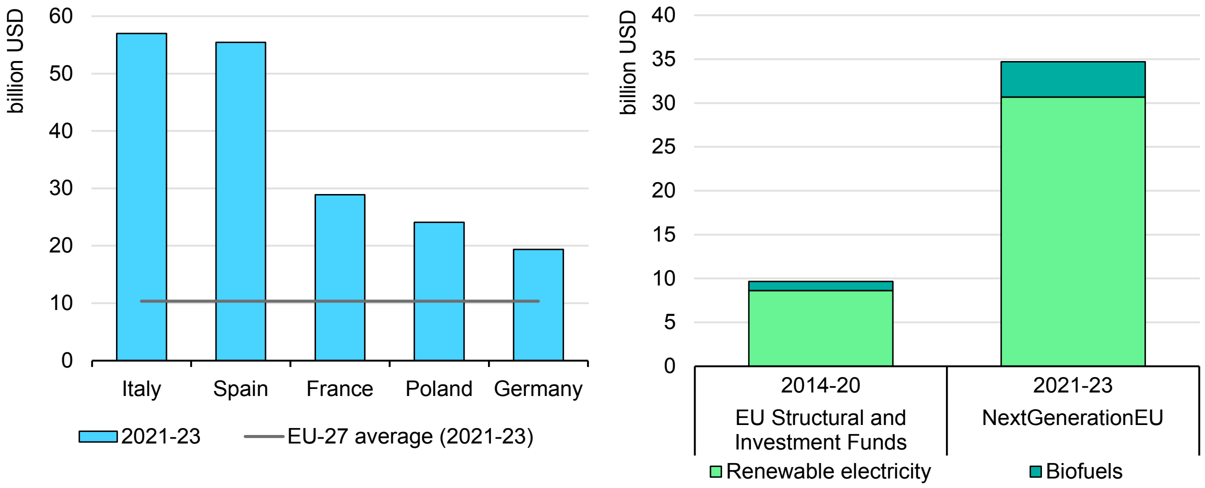



Note: Total stimulus: USD 840 billion. Percentage values are estimations based on current proposals by the European Commission and past funding patterns.
Sources: Based on EC (2020a), EUCO 10/20, and EC (2020b), European Structural and Investment Funds 2020 (database).

The distribution of stimulus money across member states is based on country size, GDP and unemployment rate. Over two-thirds of total funds are thus likely to be allocated to Italy, Spain France, Poland and Germany. These countries could invest between EUR 19 billion and EUR 56 billion in areas with climate impact including energy, but concrete spending allocations across sectors will be not be known until member states submit their recovery and resilience plans between mid-October and the end of April 2021.

For renewable electricity alone, we estimate total 2021-23 funds available to member states to be more than three times the amount allocated through the European Structural and Investment Funds for 2014-20. These loans and grants are likely to leverage additional private sector investments, which could be up to three times as high as stimulus funding. If 80% of total stimulus money for renewable power generation were spent on wind and solar PV equally, it could finance 20-40 GW of solar PV and 10-20 GW of wind plants across the European Union. As countries have already engaged in long-term planning to reach their 2030 renewables targets, this money is mainly expected to create additional liquidity to support those plans, rather than trigger additional capacity expansions.

**Figure 8.4 Clean energy stimulus by EU member states 2021-23 and cumulative renewable electricity and biofuels spending from dedicated EU funds 2014-20**






Note: Spending is in 2018 prices.
Sources: Based on EC (2020c), Annexes to Regulation COM(2020) 408 final, and EC (2015), Contribution of the European Structural and Investment Funds to the 10 Commission Priorities.

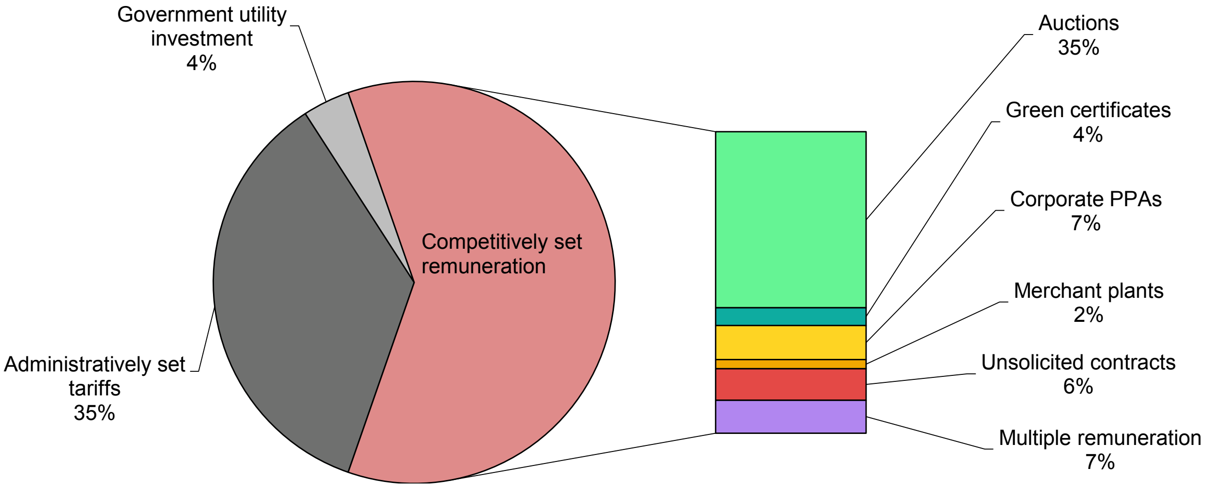
# Are wind and PV expansion emerging beyond common policy schemes?

Policy support for renewable energy remains strong despite the Covid-19 crisis. Although some governments have postponed the implementation of wind and PV auctions since March, the crisis has not provoked the cancellation of any major policy targets or incentives. In fact, some countries have announced ambitious decarbonisation plans and long-term net-zero emissions goals, including the European Union, China and Japan.

Policies have been key to achieve large-scale renewable energy deployment, costs reductions and innovation. The role of policies is changing, however, as wind and solar PV costs have fallen drastically in the past decade. Since 2015, countries have been rapidly transitioning from administratively set FiTs or floating FIPs to competitively set remuneration schemes (auctions, green certificates, etc.) for utility-scale or large-scale distributed PV projects. In the next five years, policy and regulatory frameworks enabling competition will underlie 60% of all renewable capacity expansion globally.

While auctions will remain the preeminent policy scheme, renewable energy expansion outside of government policies is emerging as a key trend. Corporate PPAs, merchant plants and projects receiving multiple revenue streams from tenders, spot markets and bilateral contracts are demonstrating new ways to allocate and diversify risks for wind and PV developers. From 2020 to 2025, the main driver of 9% of renewable capacity expansion is expected to be corporate PPAs and merchant plants, while another 7% is forecast to rely on multiple revenue remuneration schemes. In 2019, only less than 5% of renewable capacity additions were installed outside of main government policy schemes.

**Figure 8.5 Renewable electricity capacity remuneration policy types, 2020-25**






Note: Unsolicited contracts are bilateral contracts between a power producer and the utility.

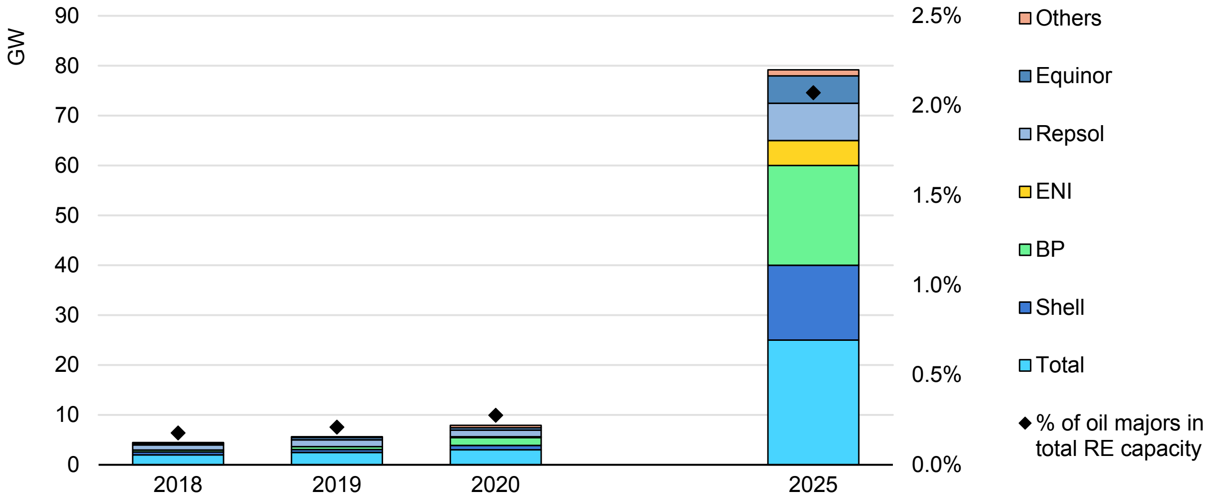
Tariffs that are set administratively will continue to be important for renewable energy expansion in China, as the government has phased out wind and PV subsidies. After 2021, new projects will receive fixed remuneration for 20 years at provincial benchmark electricity prices set by the government. Outside of China, FiTs and FIPs account for only 11% of global renewable energy expansion.

## Will large oil and gas producers become major renewable electricity investors?

Since 2018, several oil and gas companies have announced ambitious emissions reduction targets through 2025-30, with targets initially including scope 1 (direct) and scope 2 (indirect) emissions within company operations. As part of their strategies, oil and gas majors are increasingly involved in renewable electricity as equity investors, developers and/or off-takers of power. In 2019, oil and gas companies that are part of the Oil and Gas Climate Initiative (OGCI) had equity ownership in, and bought power from, about 5 GW of renewable electricity capacity, mostly wind and solar. In 2020, their involvement (including equity investments and power purchases in the renewable electricity sector) is expected to increase by over 50% to more than 8 GW, as many projects are already financed and under construction.

According to the announced targets and strategies of OCGI members, major oil and gas companies' investments in new renewable electricity capacity are expected to increase ten-fold in the next five years. However, renewable energy growth will largely be driven by oil companies in regions where there are strong policy targets in place to reduce emissions. European companies are therefore projected to make up 95% of the renewable electricity capacity growth of oil majors through 2025. Oil producers in the United States and the Middle East have yet to announce significant renewable energy targets as part of their emissions reduction strategies.

**Figure 8.6 Installed and contracted renewable capacity by major oil and gas companies, 2018-25**






Note: Companies analysed include OGCI members such as BP, Chevron, CNPC, ENI, Equinor, ExxonMobile, Oxy, Petrobas, Repsol, Saudi Aramco, Shell and Total.

Long-term net-zero emissions targets in the European Union and the United Kingdom are responsible for the sharp geographical variation. Despite significant growth, the oil and gas companies' share of renewable capacity ownership and energy purchases remains minimal, projected to reach only 2% of total renewable installed capacity globally by 2025. Oil and gas production and sales are expected to remain their primary business activity in the upcoming decade.

# Are system operators curtailing too much wind and solar electricity?

New load patterns caused mainly by the Covid-19 demand shock and extreme weather conditions in some countries/regions have raised electricity security concerns. The curtailment, constraining or "dispatching down" of renewables has been receiving attention as a way for system operators to deal with the inflexibility of power systems during periods of oversupply. However, even though the amount of dispatched-down VRE-based electricity has increased in absolute terms, most systems have been able to evolve to accommodate more VRE.

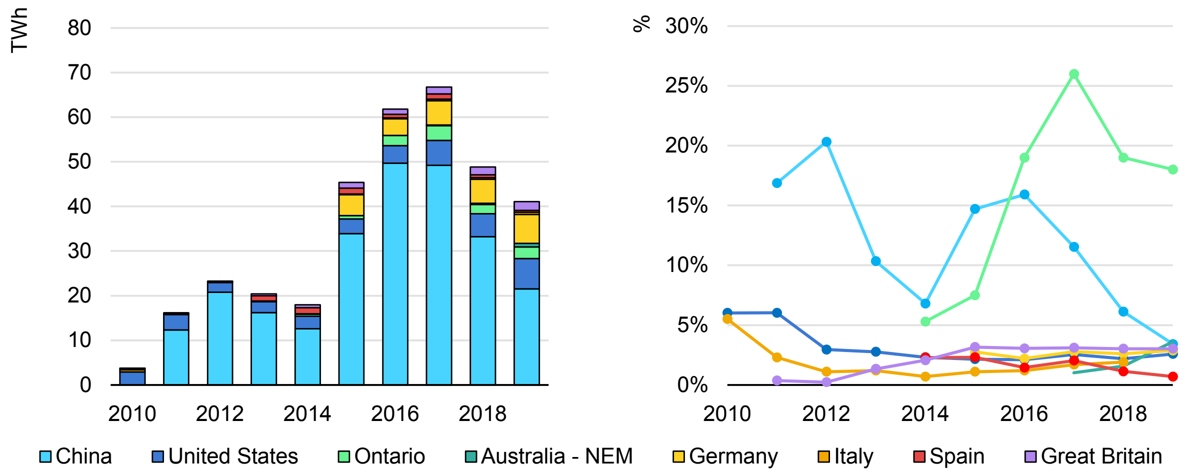
The amount of dispatched-down energy in a region varies by month and season, depending on a variety of factors associated with system-wide reasons for **curtailment** (e.g. inertia, ramping limitations, contractual arrangements such as priority dispatch, etc.) and local network limitations or **constraints** (e.g. grid congestion, faults, etc.) (EirGrid, 2019). Moreover, changes in demand or supply due to climatic and weather conditions, which also affect wind and solar output, also determine how much energy is dispatched-down.

Furthermore, factors such as inadequate market design or system planning to integrate VRE sources; inappropriate locations and volumes for VRE installations; and a lack of flexibility in the electricity system and in infrastructure planning have led to the rise of dispatched-down electricity.

In key markets such as China and Germany, the absolute amount of dispatched-down wind and PV electricity rose 20-fold from 2010 to 2017, with most of the increase coming from China. Over 250 TWh of variable renewable electricity was curtailed – nearly the equivalent of Spain's annual electricity demand. Had it been possible for this generation to be dispatched or stored for later use, emissions of 180 Mt $CO_2$[8] could have been avoided, which is 3% of total US $CO_2$-equivalent emissions in 2018 (EPA, 2020a).

[8] Based on US national weighted average $CO_2$ marginal emission rate.

**Figure 8.7 Dispatched-down wind and solar PV generation (left) and share of dispatched-down generation (right)**






Note: The graphs represent officially reported curtailed or constrained energy and also combine various schemes depending on the country. In the case of Ontario, a greater proportion of wind energy was dispatched down in 2016 than in 2015, due to a market rule change for the floor price of renewables in February 2016. Additionally, the reporting scheme changed from covering just wind to all VRE sources 2017.

Sources: Bundesnetzagentur (2020), Netz- und Systemsicherheit; China Energy Portal (2020), 2019 wind power installations and production by province; LBNL (2020), Curtailment data; IESO (2019), 2019 year in review; AEMO (2020), Statistical reporting streams; GSE (2019), Rapporto delle attivita 2019; REE (2019), El sistema eléctrico español síntesis; REF (2020), Balancing Mechanism Wind Farm Constraint Payments.

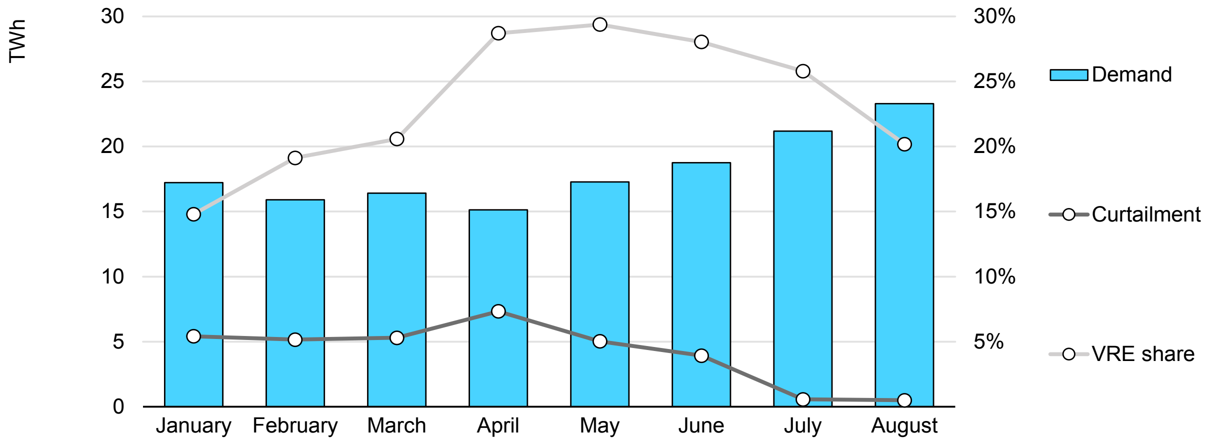
China sustained high levels of dispatched-down VRE from 2011 to 2017 (7-20%), reaching an absolute historical high at almost 50 TWh in 2016. This resulted from rapid deployment of wind capacity in northern provinces, where relatively low provincial demand, limited flexible generation, inadequate dispatch arrangements and interconnection capacity, and interregional trading constraints prevented maximum renewable output dispatch (IEA, 2019). In the same period, Germany, Spain, the United States and Australia also began to significantly dispatch-down wind and solar electricity, reaching almost 20 TWh in 2017.

Since 2017, however, China's dispatch-down rates have declined significantly, mainly owing to the commissioning of additional interprovincial transmission capacity and improved market operations. The implementation of "investment warning" mechanisms that discourage new installations and project approvals in provinces with high curtailment rates has also helped. As a result of these measures, the share of curtailed VRE dropped from 17% in 2012 to less than 4% in 2019.

Even though dispatched-down VRE electricity overall has increased in absolute terms in the United States, Germany and Italy since 2017, the share of dispatched-down wind and solar PV output has remained stable at 1-3%, which means that most systems have been able to evolve to accommodate increasing VRE generation as the capacity expands.

Record curtailment levels were reached in California in 2020, with the system operator (CAISO) curtailing over 318 GWh in April (7% of VRE output) – 67% more than in 2019. California had added 1 GW of wind and solar PV capacity from May 2019 to March 2020, raising VRE output, so monthly VRE shares over demand were at a record high of 29% in April 2020, driven by load-dropping of around 8% (mainly as a result of Covid-19-related measures) at the same time as solar output peaked. Even though California's maximum share of instantaneous VRE over demand has reached only 80%, the system's lack of flexibility to accommodate this electricity has resulted in curtailment.

**Figure 8.8 California demand, curtailment and VRE shares, 2020**






Source: CAISO (2020), Managing oversupply.

It must be remembered, however, that the optimal curtailment level is not necessarily zero. Dispatching-down can also be an effective way to cut peaks in generation, as it is not efficient for an entire system to have to accommodate exceptional periods of high VRE generation. Furthermore, it is not always logical from an economic perspective to build all the infrastructure that would be required to avoid dispatching-down (e.g. transmission lines, energy storage or more flexible capacity), as the costs may outweigh the benefits up to a certain point.

A transition to more system-friendly integration of variable renewables is needed, for example by complementing policy support schemes with exposure to competitive market outcomes, since there is little incentive for assets with fixed prices and prioritised dispatch to control outputs.

As VRE shares expand, incentivising (or removing barriers to) storage systems could further limit curtailment as well as foster demand-side flexibility. Storage systems incorporate not only large-scale batteries and pumped hydro, but distributed battery storage and technologies that can absorb electrical energy and then return it the same way later. Electricity storage technologies, including PSH and batteries, can provide multiple flexibility services ranging from the ultra-short to the long term, helping to accommodate increasing VRE shares (IEA, 2020). Batteries can contribute to ultra-short-term (sub-seconds) and short-term flexibility (hours to days), providing value by offering services such as fast frequency response and operational reserve.

As levels of absolute "wasted" (i.e. dispatched-down) renewable electricity rise, appropriate market designs; changes to the grid and to market operations; better forecasting; and efficient co-ordination and operation of interconnectors will cost-effectively reduce curtailment. Modifying existing system assets (e.g. power plants and grids), investing in infrastructure and developing storage technologies and advanced VRE resources that have the capability to provide flexibility services, will also be necessary for reliable VRE integration.

It has been demonstrated that investments, along with important policy changes and co-ordination, can significantly reduce curtailment. In Texas, for example, wind curtailment declined from 17% in 2009 to 3% in 2019 thanks to the Competitive Renewable Energy Zone (CREZ) policy, which directed transmission investments to high-potential areas where investments were most needed and also improved forecasting and regional co-ordination for a larger balancing area. In China, transmission infrastructure investments, flexibility retrofitting of existing coal-fired power plants in some provinces, and the softening of administrative allocations to coal power plants in some provinces have reduced curtailment rates significantly.

Various actions on diverse fronts could be taken to eradicate system-wide barriers and permit proper VRE integration. Enabling VRE to compete in balancing markets would encourage the remuneration of real-time balancing costs and provide additional income for renewable generation, while exposing VRE to imbalance penalties would give producers an incentive to smooth their output and provide better forecasts either at the plant or regional level to reduce uncertainty. Furthermore, incentivising demand-side response, storage technologies and power to X to unlock flexibility and respond to shifts in demand would reduce the need to dispatch-down VRE generation, while designing markets to reflect actual system constraints by giving the right pricing signals would allow better allocation of investments. Some of these practices are already in place in markets such as Great Britain, Spain, Denmark and Australia, and among some system operators in the United States.

# Are governments missing an opportunity to accelerate sustainable aviation fuel (SAF) deployment?

The Covid-19 crisis has had a severe economic impact on the global aviation industry, with a significant proportion of airlines in need of financial assistance. Governments around the world have therefore acted swiftly to provide billions of dollars of financial support through direct subsidy payments, loans, loan guarantees and higher levels of ownership. This opens the door for governments to exert greater influence on airlines to reduce their climate impact.

However, most support has been provided free of any environmental or climate conditions, making a significant boost in the deployment of low-carbon aviation fuels unlikely. While SAF use is an important component in the aviation industry's long-term $CO_2$ emissions reduction goals, it accounted for only 0.01% of last year's global aviation fuel consumption. Had government support been linked to SAF consumption, production could have been significantly accelerated, building on existing airline activities to develop lower-carbon fuels.

## Governments act to support airlines in economic difficulty as the Covid-19 crisis is an unprecedented shock for aviation

The Covid-19 crisis has had severe repercussions for the aviation industry. National and regional lockdowns have restricted travel, and even after their abrogation, ongoing travel restriction uncertainty has kept aviation activity well below pre-pandemic projections for 2020.

The International Air Transport Association (IATA), which represents the global airline industry, has indicated that air travel demand was almost 60% lower in the first half of 2020 than in 2019. The economic impact of the Covid-19 crisis on the aviation industry could reach around USD 420 billion in 2020 (IATA, 2020).

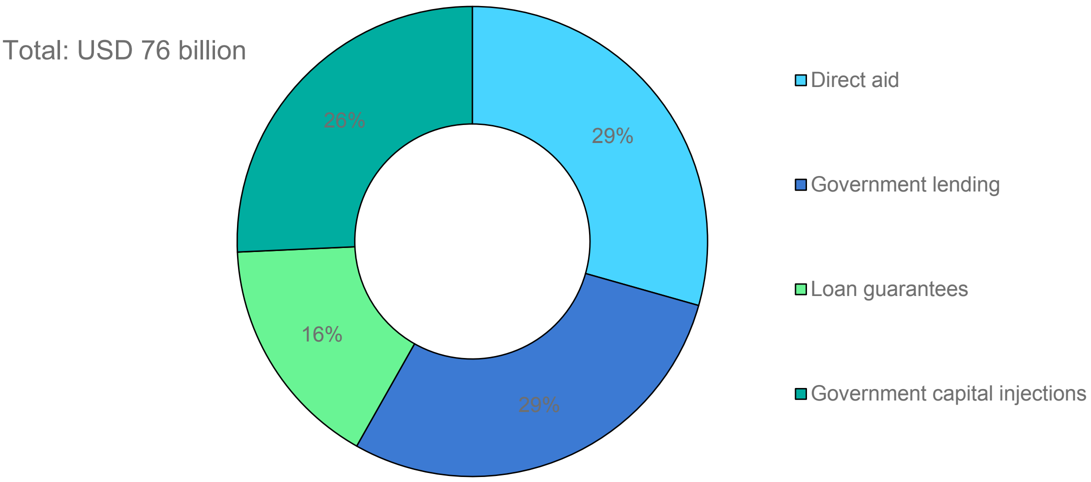
In response to these unprecedented economic challenges, governments have rapidly provided financial support to the aviation industry. The IEA has analysed government financial support of 30 airlines across 21 countries, with these airlines representing 40% of the airline revenue passenger kilometres (RPK)[9] registered in 2019, a key metric of passenger activity. This analysis revealed government support of around USD 76 billion as of August 2020, which is part of a wider USD 108 billion of support for the aviation industry as a whole. This figure is likely to increase over the coming months as other airlines also seek government support.

The government support can be broadly divided into four categories: direct financial aid, such as to cover salary payments or compensate financial losses due to the pandemic;

[9] RPKs indicate the distance travelled by paying passengers, i.e. the number of revenue passengers multiplied by the number of kilometres travelled.

government lending via state-owned banks; government guarantees for loans at commercial banks;[10] and capital injections whereby governments raise their equity stakes in the airline.

**Figure 8.9 Financial support to the aviation industry**






Note: The value of government capital injections was quantified in approximately half of the cases only, so this share of overall financial support is likely to be higher.

For 12 of the 30 airlines analysed, governments increased equity stakes through the injection of capital. This is more prevalent when other elements of the overall rescue package are publicly funded and the corresponding financial obligations for the airline are relatively low. When governments provide a loan guarantee, increased equity is less likely.

**Table 8.1 Government financial support in relation to increased equity in airlines**

| Type of support | Financial value (USD billion) | | Cases in which governments also increased equity in the airline |
|---|---|---|---|
| Direct aid | 22.0 | | 4 out of 8 (50%) |
| Government lending | 21.5 | | 7 out of 16 (44%) |
| Loan guarantees | 13.0 | | 1 out of 10 (10%) |

When the share of government ownership in airlines increases, there is more potential to influence the airline’s activities to reduce its climate impact and support government

[10] Typically covering 70-90% of the total loan amount.

efforts to meet climate change targets. Therefore, when governments with ambitious GHG emissions reduction targets increase their equity in airlines or introduce other policies to decarbonise aviation, they could spur greater SAF deployment.

This is already happening in the Nordic region. Norway established a 0.5% biofuel blending mandate for aviation fuel this year, and Sweden plans to introduce a GHG emissions reduction mandate for aviation fuel next year, starting at 0.8% and increasing gradually to 27% by 2030. France has proposed a 2% SAF blending level for 2025.

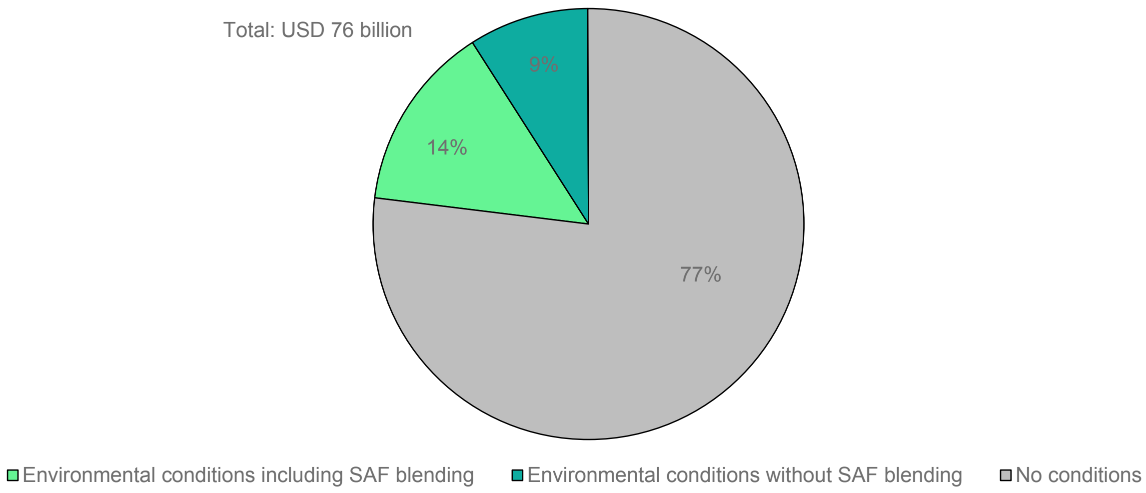
GHG emissions from international aviation fall outside of countries' Nationally Determined Contributions (NDCs) under the COP21 global climate agreement, which may blunt the initiative of some countries to financially support emissions-reduction initiatives. GHG emissions from domestic aviation do, however, count towards NDC targets.

## Most support is not conditional on environmental or climate action, neglecting an opportunity to scale up SAF use

To understand how the Covid-19 pandemic may impact SAF deployment, government financial support was assessed for the extent to which it is conditional upon companies altering their environmental and climate-related behaviours, including meeting low-carbon fuel blending requirements.

Overall, more than three-quarters of the government support analysed has been provided without any links to environmental performance. Of the 30 airlines, just four have to meet such conditions, which include reducing $CO_2$ emissions; sustaining efficiency increases; and discontinuing some domestic routes that could be served by existing high-speed rail. Two airlines are subject to a 2% SAF blending requirement in the future. As these financial support packages are still under development, in many cases the finer details of the commitments and the extent to which they are binding remain unclear.

**Figure 8.10 Government financial support to the aviation industry by type of conditions attached**






Current conditions attached to financial support for airlines to combat the Covid-19 crisis will not provide the considerable boost needed to accelerate low-carbon fuel deployment. If fulfilled, the two cases in which governments require SAF blending would result in 110 million L of total consumption, assuming 2019 activity levels – equal to just over twice the 2019 SAF production of 50 million L (IATA, 2020). This additional demand is also relatively minor compared with the 6 billion L of multi-year SAF offtake agreements that several airlines had already entered into with production facilities for current and future supplies prior to the Covid-19 pandemic.[11]

Had all 30 airlines been obligated to meet a 2% SAF blending requirement to receive financial support, this would have created around 2.7 billion L of demand annually, which is more than 50 times current production levels. This assumes a return to 2019 aviation activity levels,[12] which may not occur until 2024 (IATA, 2020).

Although current SAF production capacity cannot service this demand level, establishing widespread blending requirements for the future (e.g. 2025) would provide demand certainty, which is essential to stimulate investment in SAF production facilities and scale up supply.

Existing HVO plants and new HVO projects in development would have been able to meet some of this hypothetical demand by dedicating a larger share of their refinery slate to hydro-processed esters and fatty acids (HEFA) aviation biofuel. To fully meet such

[11] Actual offtake levels depend on SAF availability at predetermined prices.
[12] It also assumes a 1.5% annual fuel efficiency improvement for the fleet overall.

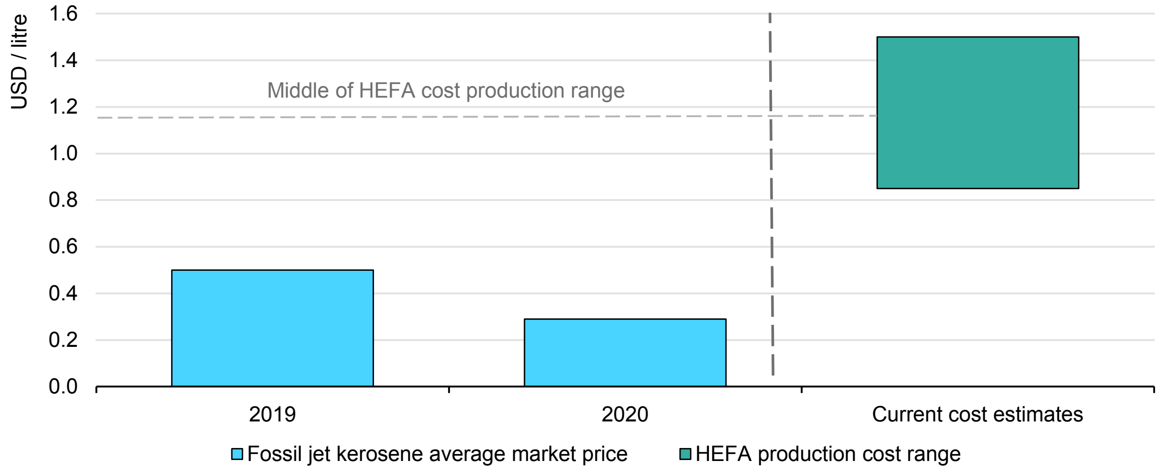
a scale-up in demand would also require investments of around USD 2 billion in further SAF production capacity – just a small fraction of the Covid-19 support provided to the aviation industry.

## Given the current crisis, is now the right time for SAF blending requirements?

Is linking financial support for the aviation industry to the use of higher-cost SAFs feasible given the current economic strain on airlines? Fuel represents around 20% of operating costs on a global average basis, and more in some regions and certain market segments. Therefore, any requirement for airlines to use a higher-cost fuel raises questions about competitiveness with other airlines that do not have such a requirement – unless any requirement for airlines to use a higher-cost fuel applies to all companies operating in a given market, which is complex given the international nature of the aviation industry.

Even the most commercially available form of low-carbon aviation fuel, HEFA, is considerably more expensive than fossil jet kerosene. In 2019, the median HEFA production cost was roughly twice the market price of fossil jet kerosene. As jet kerosene costs have fallen by around 40% this year as a result of lower crude oil prices since the onset of the Covid-19 pandemic, the cost of HEFA fuel is currently almost four times that of fossil jet kerosene.

**Figure 8.11 Fossil jet kerosene market price compared with HEFA aviation biofuel production cost**






Although SAFs are currently considerably more expensive than fossil-based jet fuel, it can also be argued that airline fuel costs have fallen significantly in 2020 owing to the lower cost of fossil jet kerosene. Globally, the aviation industry's 2020 fuel bill could be as much as USD 110 billion, or 72%, lower than in 2019 (IATA 2020), although this reduction also results from lower industry activity, which affects profitability.

Nevertheless, a 1% SAF blend rate applied across the entire industry in 2019 would have increased the aviation industry's fuel bill by only USD 2.1 billion – equivalent to just 3% of the financial support provided to the 30 airlines analysed. Such a global SAF mandate would avoid giving any airline an unfair advantage and have a marginal impact on ticket prices. This measure would, however, require global approval through the International Civil Aviation Organization (ICAO) to apply to international aviation.

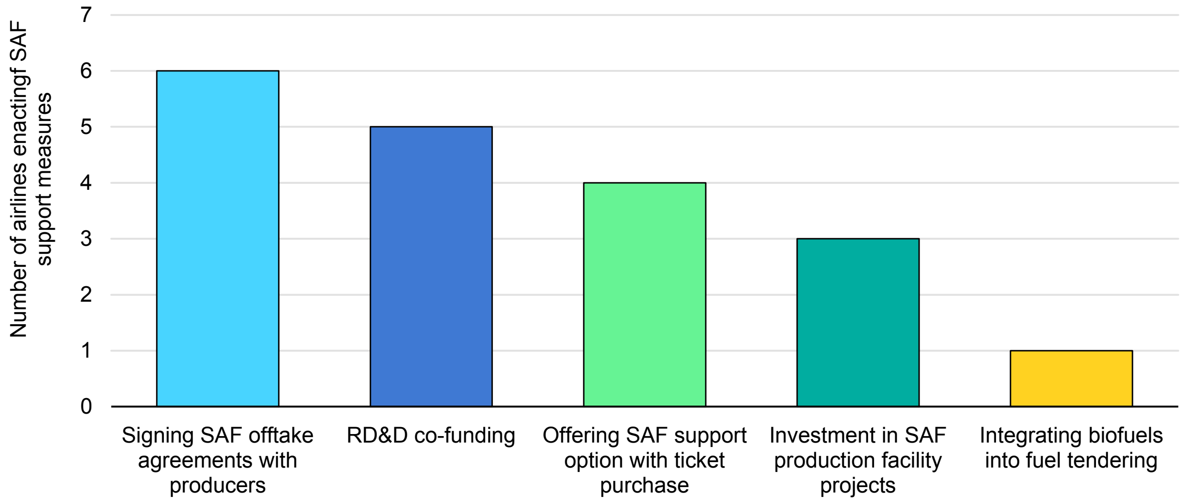
In the United States, eligibility for RFS2 policy support, the blender's tax credit and opt-in provisions for aviation within California's LCFS significantly reduces the cost premium of SAF consumption. Such robust policy support is not widely available, however.

Scaling up SAF output would also unlock the potential to realise economies of scale in production and supply, and to reduce non-feedstock costs. While nearly 80% of HEFA fuel production costs can be related to feedstocks, maximising production-per-cost potential in other areas of the SAF value chain will be crucial for commercial uptake. Furthermore, had further SAF requirements been imposed, this could also have delivered a boost to the production of other SAF technologies (such as Fischer-Tropsch aviation fuels) at an earlier stage of commercialisation than HEFA.

## Many airlines supported SAF deployment and other emissions reduction initiatives prior to Covid-19

Airlines were already actively involved in SAF initiatives prior to the Covid-19 crisis. Of the assessed companies receiving government support, almost half (14) from Asia, Europe and the United States already supported the use of alternative low-carbon fuels through a variety of means, as outline below. More widely, other airlines apart from those assessed have also been undertaking SAF initiatives.

**Figure 8.12 SAF initiatives by assessed airlines**






Note: RD&D = research, demonstration and deployment.

While such initiatives will support greater SAF adoption over the medium term, current low-carbon fuel consumption remains minimal even among the airlines advancing its use. Airlines conducting regular flights with SAF blends account for only a very small share of overall aviation activity, and low-carbon fuel blending levels are generally low.

Furthermore, employing lower-carbon fuels is only one element of a wider range of measures that must be taken to robustly decrease GHG emissions from aviation. According to analysed airlines' annual reports, $CO_2$ emissions per passenger-kilometre generally fall within the range of 70-95 grammes of $CO_2$ per RPK. Budget airlines demonstrate some of the lower emissions levels on an RPK basis, indicating that their very high passenger load factors offset higher fuel demand from short-haul flights. However, because budget airlines follow a cost-minimisation business model, reducing absolute $CO_2$ emissions through the use of higher-cost SAFs is unlikely to occur without policy obligations.

Of the airlines analysed, some have ambitious long-term GHG emissions reduction targets that exceed the airline industry's goal to cut net aviation $CO_2$ emissions to 50% of the 2005 level by 2050. Several have even committed to reach net-zero GHG emissions by 2050 as part of the 13-airline "oneworld Alliance". The airlines receiving government support have stated they intend to reduce their $CO_2$ emissions through fleet renewal to improve fuel efficiency; research and development to raise aircraft energy efficiency; and optimisation of ground operations.

$CO_2$ emissions-offsetting is also being used, either through direct pledges from airlines or voluntary commitments by passengers. This is unsurprising, as emissions-offsetting is the easiest way for airlines to comply with the Carbon Offsetting and Reduction Scheme for International Aviation (CORSIA), at least initially.

# Is it "full steam ahead" for renewable shipping fuels?

Unless renewable fuel consumption rises considerably, maritime shipping will have an increasingly negative long-term impact on the climate as international trade expands. A variety of low-carbon fuels are available for the shipping industry, and momentum for their use had increased prior to the Covid-19 crisis. Currently, however, they all cost more than fossil marine fuels, which is the primary obstacle to increased consumption. The Covid-19 crisis has further challenged the affordability of higher-cost fuels for marine shipping and uptake through corporate purchases.

## Shipping's climate impact is under the microscope

Shipping accounts for three-quarters of all freight transport activity,[13] with an overall energy demand of 221 million tonnes of oil equivalent (Mtoe) in 2019 (IEA, 2020a) – only slightly less than the final energy consumption of Brazil. Consequently, shipping accounted for 2.7% of all energy sector $CO_2$ emissions in 2019 and one-tenth of emissions from transport, creating a greater climate impact than any individual EU member state.

Unless actions are taken to reduce maritime shipping's GHG emissions, its climate impact will increase considerably over the long term as international trade expands. If the shipping sector maintains its current policies while other parts of the energy system (e.g. the electricity sector, industry and other transport modes) embark on ambitious emissions reductions, its share of global $CO_2$ emissions could rise to as much as 7% in 2040, putting shipping in the spotlight.

Consequently, the International Maritime Organisation (IMO) has committed to the long-term target of reducing absolute GHG emissions by 50% by 2050 (versus the 2008 level) and $CO_2$ emissions per transport activity 40% by 2030. A comprehensive package of measures to achieve these targets is not yet in place, but a more detailed IMO strategy is due in 2023. Some industry participants have set more ambitious targets: for instance, Maersk, the world's largest container ship operator, aims to attain net-zero emissions by 2050.

[13] Including inland shipping.

The key to reducing shipping's climate impact is to tackle emissions from oceangoing vessels such as container ships and bulk carriers. Although these large vessels make up only one-fifth of the global shipping fleet, international marine bunker fuels account for 80% of all $CO_2$ emissions from shipping.

## Using low-carbon fuels is essential to meet the shipping sector's climate goals

Shipping is considered a hard-to-abate sector. Current regulations to address GHG emissions from ships[14] are expected to raise average fleet energy efficiency by only 1.5% annually between 2015 and 2025. Even once design, technical and operational improvements have been maximised, the gap to meet the IMO's emissions reduction target will likely still be considerable. Marine transport therefore needs to switch to very-low-carbon fuels.

The 20- to 35-year lifespan of marine freight vessels is a key consideration in the transition to alternative fuels. A significant proportion of the largest vessels currently in operation still have many years of service left, with two-thirds under 14 years of age (Equasis, 2018). "Drop-in" low-carbon shipping fuels suitable for the current shipping fleet with no or minimal modification to propulsion systems and associated infrastructure are therefore needed.

Long-term projections for international maritime freight indicate that the direct use of low-carbon hydrogen[15] as well as ammonia produced from hydrogen and nitrogen from the air could be key future fuels for a low-carbon shipping sector. These are not drop-in fuels, however, so appropriate vessels, storage tanks and bunkering infrastructure are required for their use. Given that ships launched today may still be operational in 2050, suitable vessels need to be introduced by 2030 to maximise the potential of hydrogen and ammonia to help meet the IMO's emissions goals.

[14] The Energy Efficiency Design Index (EEDI) for new ships, and the Ship Energy Efficiency Management Plan (SEEMP).
[15] For example, produced through electrolysis using renewable electricity or through steam methane reforming of natural gas equipped with carbon capture and storage (CCS).

**Table 8.2 Alternative shipping fuels overview**

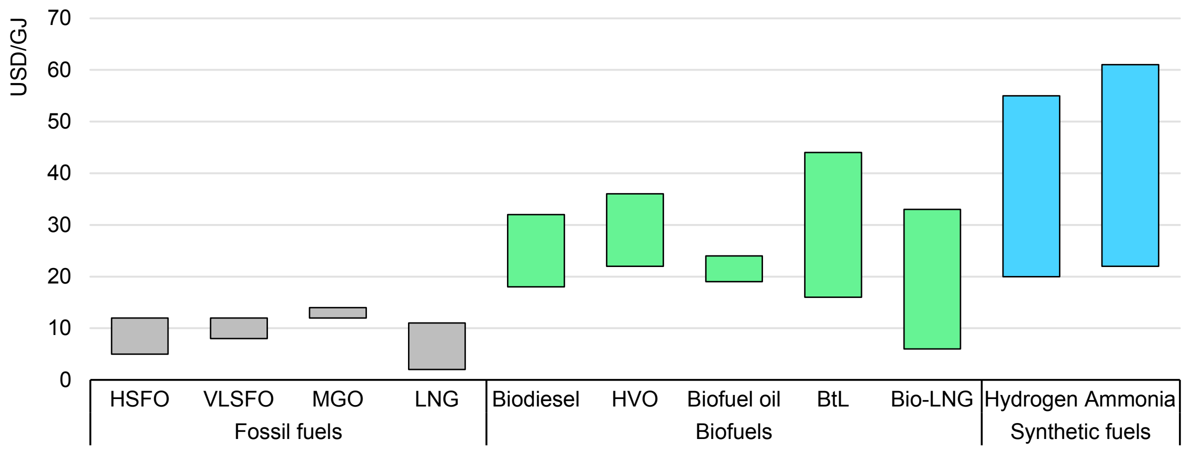
| Fuel(s) | Drop-in? | Production status | Considerations and market developments |
|---|---|---|---|
| Biodiesel, HVO | Yes, for HFO and MGO ships | Commercialised | Specification superior to what is required for HFO ships, and better suited to vessels that use higher-cost MGO or in road transport. Have been consumed in demonstration initiatives. |
| Biofuel oil | Yes, for HFO ships | Output currently low, technology mature with certain feedstocks | Can be consumed with good performance in HFO-fuelled engines after little or no upgrading, offering more competitive pricing than alternatives (e.g. HVO). Have been consumed in demonstration initiatives. |
| BtL | Yes, for HFO and MGO ships | Not commercialised | Can potentially be produced from widely available forestry and agricultural residues. Would require minimal upgrading for use in HFO ships. Demonstration project in the Netherlands to produce marine BtL fuels in development. |
| Bio-LNG | Yes, for LNG ships | Commercialised | LNG demand as a shipping fuel set to increase tenfold by 2025 with fleet expansion (IEA, 2020b). EU funding allocated to establish bio-LNG bunker infrastructure in the Netherlands. Norwegian coastal ferry operator integrating biomethane consumption into its vessels. |
| Low-carbon hydrogen and ammonia | No, requires dedicated ICE or fuel cell propulsion | Early stage, currently limited availability | Increasing number of hydrogen strategies set to accelerate output. Ammonia shipping initiatives under way in Japan and the Nordic region. Testing of ammonia in marine engines has begun, and two ship OEMs planning to develop ammonia-fuelled engines for operation within the next five years. |
| Electricity | No | Currently unsuitable for international marine freight | Batteries need significantly higher energy density, and lower weight and cost, to be suitable for international shipping. Could be used for inland and short sea routes. |

Notes: HFO = heavy fuel oil. MGO = marine gasoil. BtL = biomass-to-liquid fuel produced through thermochemical technologies such as gasification and pyrolysis. LNG = liquefied natural gas; bio-LNG signifies LNG produced from biomethane. Renewable hydrogen and ammonia are produced through electrolysis using renewable electricity, biomass gasification or steam methane reforming of natural gas with CCS. ICE = internal combustion engine. OEM = original equipment manufacturer. Hydrogen strategies have been released in several EU member states, in the European Union as a whole, and in Australia and Japan, among others. The logistical requirements for ammonia transport are already known owing to its established industrial uses, which is not the case for hydrogen.

## Fuel costs are the main barrier to sustainable shipping fuel uptake

Competitive bunkering costs are essential for commercial marine logistics services. Fuel can make up 50-60% of a shipping company's operational expenses (Felby, 2018), although it varies according to the type of ship, service and oil prices. All low-carbon marine fuels currently cost more than incumbent fossil shipping fuels.

**Figure 8.13 Indicative shipping fuel cost ranges**






Notes: GJ = gigajoule. HSFO = high-sulphur fuel oil. VLSFO = very-low-sulphur fuel oil. Fossil fuel price ranges based on 2019 global market values. VLSFO has a cost premium over HSFO at equivalent oil prices. Biofuel oil costs estimated based on a USD 200-300/tonne premium over fuel oil. Bio-LNG based on global cost estimates of biomethane production with additional liquefaction cost. BtL fuels are not in commercial production, so production cost range is not reflective of current market prices. Hydrogen and ammonia cost range based on production through electrolysis using renewable electricity; the bottom of the cost range requires renewable electricity costs of around USD 25/MWh. Potential exists to reduce costs for a given electricity input price by reducing electrolyser capital costs.

Sources: Based on IEA (2020c), Outlook for biogas and biomethane: Prospects for organic growth; IEA Bioenergy TCP (2020), Advanced biofuels: Potential for cost reduction

Given these higher costs, stimulating low-carbon fuel consumption is challenging in the absence of a comprehensive policy framework to reduce emissions from international shipping, as well as incentives for low-carbon fuel use and widespread carbon pricing to cover shipping. Renewable fuels must also compete with an expanded use of LNG, which emits less $CO_2$ than fuel oil, but not enough to fully meet the IMO's 2050 goal on its own. The IMO strategy anticipated for 2023 will therefore be critical to facilitate cost reductions and provide a framework for low-carbon fuel deployment despite its higher cost.

IMO regulations that came into force in 2020 to reduce sulphur emissions from marine fuel use[16] have prompted a switch from HSFO to more expensive VLSFO[17] and distillate oil product fuels such as MGO. VLSFO consumption is therefore set to increase sixfold this year. All the low-carbon fuels in the table above are low in sulphur and comply with the IMO's sulphur cap regulation.

[16] These regulations limit the sulphur content of maritime fuel used on board vessels trading outside sulphur Emission Control Areas to a maximum of 0.5%. Heavy Fuel Oil typically has 2.7% sulphur.

[17] VLSFO is more expensive than HSFO because it contains more gas oil and enables shippers to meet the IMO regulations. Premium ultra-low-sulphur fuel oil (ULSFO) also exists.

From January to August 2020, VLSFO was 35-50% more expensive than HSFO at equivalent crude oil prices. Although market circumstances have been altered by the Covid-19 pandemic and it is the first year of the IMO sulphur cap regulations, the pricing environment is dynamic.

Nevertheless, VLSFO becoming the dominant fuel for international shipping over the next few years should generally reduce the cost premium of sustainable shipping fuels – although most low-carbon alternatives will continue to be significantly more expensive. In addition, approximately 2 500 ships had been fitted with scrubbers by the end of 2019 and will still be able to use HSFO, representing around 6% of the total applicable HSFO fleet.

## Other measures are also needed to boost renewable shipping fuel use

Increased standardisation (e.g. of fuel quality and bunkering) for all alternative shipping fuels will encourage their use. Unlike aviation, there is no legally binding fuel standard for the marine sector. Consequently, ship owners and operators eager to make their operations more sustainable are still wary about using new fuels and require assurance (e.g. through comprehensive trials) that their use will not have adverse effects.

The port of Rotterdam, one of the top three ports globally by bunker fuel sales, is home to a cluster of biofuel trial activity. Biofuel use is currently supported economically by a national scheme that allows renewable marine and aviation fuels to be used to meet EU RED targets.[18] Tickets are awarded per unit of energy and have reached a value of up to EUR 0.60 per litre of biofuel, depending on fuel quality and feedstock. The scheme is currently undergoing revision. Rotterdam also intends to become a hub for low-carbon hydrogen.

Ports are also central in facilitating bunkering for renewable fuels. Just seven ports account for around 60% of global bunker fuel consumption (IRENA, 2020), so establishing supply chains to serve even one key port could extend the availability of alternative fuels to a considerable share of marine freight vessels. Reduced port fees for vessels using sustainable fuels is one means to stimulate demand.

Although providing regular sustainable-fuel supplies may be easier for liner vessels that have fixed schedules and routes, ensuring a suitable scale of production to meet demand remains a key challenge. In energy terms, the annual fuel demand of just one large seagoing container ship can be the same as for more than 100 000 gasoline-fuelled cars.

[18] The Netherlands is the only EU member state so far to apply this provision of the directive.

## Could the Covid-19 crisis steer low-carbon marine fuels off course?

The global pandemic has created a more challenging environment for marine freight companies to adopt renewable fuels. In the first half of 2020, cargo and container volumes at ports across Asia, North America and Europe dropped by 10-17%. In response to lower demand, container shipping companies have idled vessels and cancelled services (termed "blank sailings"), which may cause up to a 7% drop in activity (IEA, 2020d).

This difficult economic climate compounds the pressures of underlying debt burdens for container-shipping operators. The combined debt of 14 major companies reached USD 95 billion in 2019 (ITF, 2020), while last year's profits amounted to only USD 6 billion (Financial Times, 2020). This clearly impairs the ability of companies to transition to higher-cost renewable fuels in considerable volumes.

At the same time, the drastic contraction in fuel demand caused by Covid-19 has resulted in significantly lower fossil shipping fuel prices. Between December 2019 and early summer 2020, HSFO prices dropped 50%, LSFO 65%, MGO 60% and LNG around 60%.[19] This obviously raises the relative cost of sustainable shipping fuels, and may consequently slow the uptake of demonstration initiatives in the absence of formal decarbonisation targets for maritime shipping. Realising the economies of scale in production and market development that are necessary to reduce the cost of sustainable fuels would therefore be delayed.

The crisis could also discourage companies that would normally procure lower-carbon shipping services to demonstrate their corporate social responsibility. For example, companies such as Ikea and BMW have supported biofuel consumption to reduce the climate impact of shipping their products. This kind of corporate offtake is important to enable investment in renewable marine fuel supplies, and can be encouraged by dedicated marine biofuel initiatives such as the GoodShipping Program.

With very few companies untouched by the crisis, the commitment to pay more for greener shipping services may be put to the test. Without a notable drop in the cost of sustainable fuels, their consumption in considerable volumes could translate into higher logistics costs for customers. This raises the prospect of some customers switching allegiance to companies that continue to use fossil fuels and can offer more affordable services.

However, transferring of business could also happen in places where government policies (e.g. carbon pricing) raise the cost of fossil shipping fuels, causing ships to change their bunkering location to areas where such policies are not in force. The

[19] The 60% LNG reduction refers to Asian spot and European prices; US prices fell less (by around 25%).

inclusion of ships of 5 000 gross tonnage and above within the EU Emissions Trading Scheme (EU ETS) from 2022 was approved by the European Parliament in September 2020 and will be subject to further discussions with member states before introduction (European Parliament, 2020), while the European Green Deal has indicated that a review of tax exemptions for maritime fuels will be undertaken.

Conversely, measures included in some stimulus packages may boost the development of low-carbon shipping fuels. This includes EUR 1 billion of support pledged in Germany's stimulus package for marine transport, as well as funds to develop hydrogen refuelling infrastructure for multiple transport modes. Meanwhile, Norway's green transition package outlines support for "green shipping".

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**Renewables 2020 – Analysis and forecast to 2025**

In May 2020, the IEA market update on renewable energy provided an analysis that looked at the impact of Covid-19 on renewable energy deployment in 2020 and 2021. This early assessment showed that the Covid-19 crisis is hurting – but not halting – global renewable energy growth. Half a year later, the pandemic continues to affect the global economy and daily life. However, renewable markets, especially electricity-generating technologies, have already shown their resilience to the crisis. Renewables 2020 provides detailed analysis and forecasts through 2025 of the impact of Covid-19 on renewables in the electricity, heat and transport sectors.