Electricity Market Report

July 2021

INTERNATIONAL ENERGY AGENCY

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Abstract

When the IEA published its first Electricity Market Report in December 2020, large parts of the world were in the midst of the Covid-19 pandemic and its resulting lockdowns. Half a year later, electricity demand around the world is rebounding or even exceeding pre-pandemic levels, especially in emerging and developing economies. But the situation remains volatile, with Covid-19 still causing disruptions. Despite record additions of renewable generation capacity, fossil fuel-based generation and associated emissions are rising along with electricity demand. This mid-2021 edition of the Electricity Market Report highlights recent developments and forecasts demand, capacity, supply and emissions through 2022. The report also analyses electricity market prices and electricity security.

Executive summary

Executive summary

Global electricity demand will rebound strongly in 2021 and 2022. After falling by around 1% in 2020, global electricity demand is set to grow by close to 5% in 2021 and by 4% in 2022. The majority of these increases will take place in the Asia Pacific region. More than half of global growth in 2022 will occur in the People's Republic of China (hereafter, "China"), the world's largest electricity consumer. India, the third-largest consumer, will account for 9% of global growth.

Renewable electricity generation continues to grow strongly – but cannot keep up with increasing demand. After expanding by 7% in 2020, electricity generation from renewables is forecast to increase by 8% in 2021 and by more than 6% in 2022. Despite these rapid increases, renewables are expected to be able to serve only around half of the projected growth in global demand in 2021 and 2022. **Nuclear power generation** will grow by around 1% in 2021 and by 2% in 2022.

Fossil fuel-based electricity is set to cover 45% of additional demand in 2021 and 40% in 2022. **Coal-fired electricity generation**, after declining by 4.6% in 2020, will increase by almost 5% in 2021 to exceed pre-pandemic levels. It will grow by a further 3% in 2022 and could set an all-time high. After declining by 2% in 2020, **gas-fired generation** is expected to increase by 1% in 2021 and by close to 2% in 2022. Gas growth lags behind coal, as it plays a smaller role in the fast-growing Asia Pacific region, and as it faces increasing competition from renewables in the United States and Europe.

CO_2 emissions from the electricity sector are set to increase in 2021 and 2022. After falling by 1% in 2019 and by 3.5% in 2020, CO_2 emissions from the electricity sector are forecast to increase by 3.5% in 2021 and by 2.5% in 2022, which would take them to an all-time high. The decline in the emissions intensity of global electricity generation slows from more than 3% in 2020 to around 1% in 2021 and 2022.

Stronger policy actions are needed to reach climate goals. In the IEA Net-Zero Emissions by 2050 Scenario, nearly three-quarters of emissions reductions between 2020 and 2025 take place in the power sector, where emissions decline by 4.4% per year on average. To achieve this decline, coal-fired electricity generation needs to fall by more than 6% a year, partially replaced by gas, which grows by around 5% a year.

Wholesale electricity prices have recovered. The IEA Wholesale Electricity Market Price Index, which tracks price movements in major advanced economies, shows that prices were 54% higher in the first half of 2021 compared with the same period in 2020. This is after average prices for the full year 2020 declined by 25% compared with 2019. The reasons for these large swings are strong variations in fossil fuel prices caused by the Covid-19 crisis during 2020 as well as related changes in electricity demand.

Recent extreme weather events have threatened security of supply. The first half of 2021 saw supply shortfalls in multiple regions caused by extreme cold, heat and drought. In order to categorise outages, we have introduced a new Electricity Security Event Scale, which rates the severity of events based on the proportion of affected customers and the duration of the supply disruption. The Texas power crisis in February, during which customers were without power for up to four days, was assigned the highest rating on this scale.

Higher shares of variable renewables are having a measurable impact on the operation and design of electricity systems. Analysis of selected markets shows that the hourly changes in demand that have to be matched by flexible generation and consumption are increasing. Additionally, the gap between the maximum and minimum levels of flexible generation required each day is growing. This is making it increasingly important for electricity systems to become more flexible to complement generation from variable renewables like wind and solar PV.

Introduction and recent developments

Electricity markets are crucial for reaching climate protection targets – and face challenges

Around 70% of global emissions today come from countries with a government pledge to achieve net-zero emissions, with the United States notably joining this group in April 2021. Other economies with net zero pledges include the People's Republic of China (hereafter, "China"), the European Union, Japan and Korea. China is aiming to achieve carbon neutrality by 2060 and the remainder by 2050. There has also been an increase in net zero pledges from coalitions and corporations.

While this coverage is extensive, less than one-quarter of regions with a pledge have this set in law, and most lack a detailed implementation pathway. Nonetheless, the momentum towards emissions-neutral energy systems is already affecting the electricity sector. Where governments follow through on these ambitions, the impacts on the power sector will be even more profound.

In May, the IEA released its roadmap to global net-zero emissions, analysing the implications of existing net zero pledges and showing a pathway to achieving net-zero emissions globally by 2050.

The electricity sector sits at the centre of the net zero pathway, requiring rapid and deep decarbonisation even as electricity demand grows more than 2.5 times, partly due to massive electrification of end-uses now served by fossil fuels.

Huge growth of renewables generation is at the core of this decarbonisation. Solar PV and wind power are expected to play the largest role, together growing by 20 times from 2020 to 2050. Hydropower, bioenergy and geothermal combined increase nearly 2.5 times, complemented by nuclear power doubling.

With these long-term goals and developments in mind, this report has three main elements. First, we take stock of recent trends in electricity supply and demand for major regions. Additionally, we analyse the impact of extreme weather such as exceptionally cold and hot temperatures that affected electricity consumption in the first half of 2021, and drought in several regions affecting hydropower production. This analysis underpins the subsequent outlook for 2021 and 2022.

The second part presents the key factors that determine electricity demand and the supply mix: economic development, fuel prices, and capacity additions and retirements. This is followed by the core analysis, encompassing our demand, supply and emissions outlook for the electricity sector to 2022.

As growing renewables are at the centre of changes in upcoming years, in part three we track recent trends and events for two critical components affected by this transition: competitive market outcomes and security of supply.

Our analyses show that the short-term trend in global electricity markets is not consistent with a zero emissions pathway. After a slight drop in global electricity demand in 2020, caused by the Covid-19 pandemic, we expect strong growth in 2021, led by the Asia Pacific region. While renewable energy sources are expected to continue to grow rapidly, they will only be able to serve around half of the net demand increase in 2021 and 2022. Additional output from nuclear plants will only be able to close a small part of the gap.

As a result, fossil-fuel based electricity generation, and primarily coal, will fill the gap between additional electricity demand and additional low carbon generation. After declining in 2019 and 2020, electricity-related CO_2 emissions will increase again, resulting in a new all-time high in 2022. This indicates a discrepancy between current market trends and stated medium- and long-term climate protection targets.

Transforming the electricity system to use low-carbon technologies requires overcoming challenges that range from setting the right incentives for market participants to safeguarding security of supply in systems with large shares of variable renewables. Many of these challenges can already be observed in today's markets, indicating where future action may be needed.

In wholesale electricity markets, dispatchable as well as variable renewables generators are confronted with declining revenues from electricity, raising questions about whether current remuneration schemes are sufficient in competitive electricity markets.

In addition, several trends expected in the coming years increase the importance of focusing on electricity security: the shift in the supply mix towards variable renewables, increasing reliance on electricity through electrification of end uses, and an increasing risk of extreme weather events. To complement an increasing focus on electricity security at the IEA, we track recent supply security incidents as well as metrics for variable renewable integration challenges in regions that are at the forefront of renewables integration.

Extreme weather events have been a major factor in several recent security of supply incidents, such as unusually cold weather and related spikes in demand in Texas and Japan. Although flexibility needs related to variable renewable electricity generation are growing and were amplified by the low electricity demand in 2020, flexibility was handled well in all analysed systems.

Rebound of electricity demand is very region specific

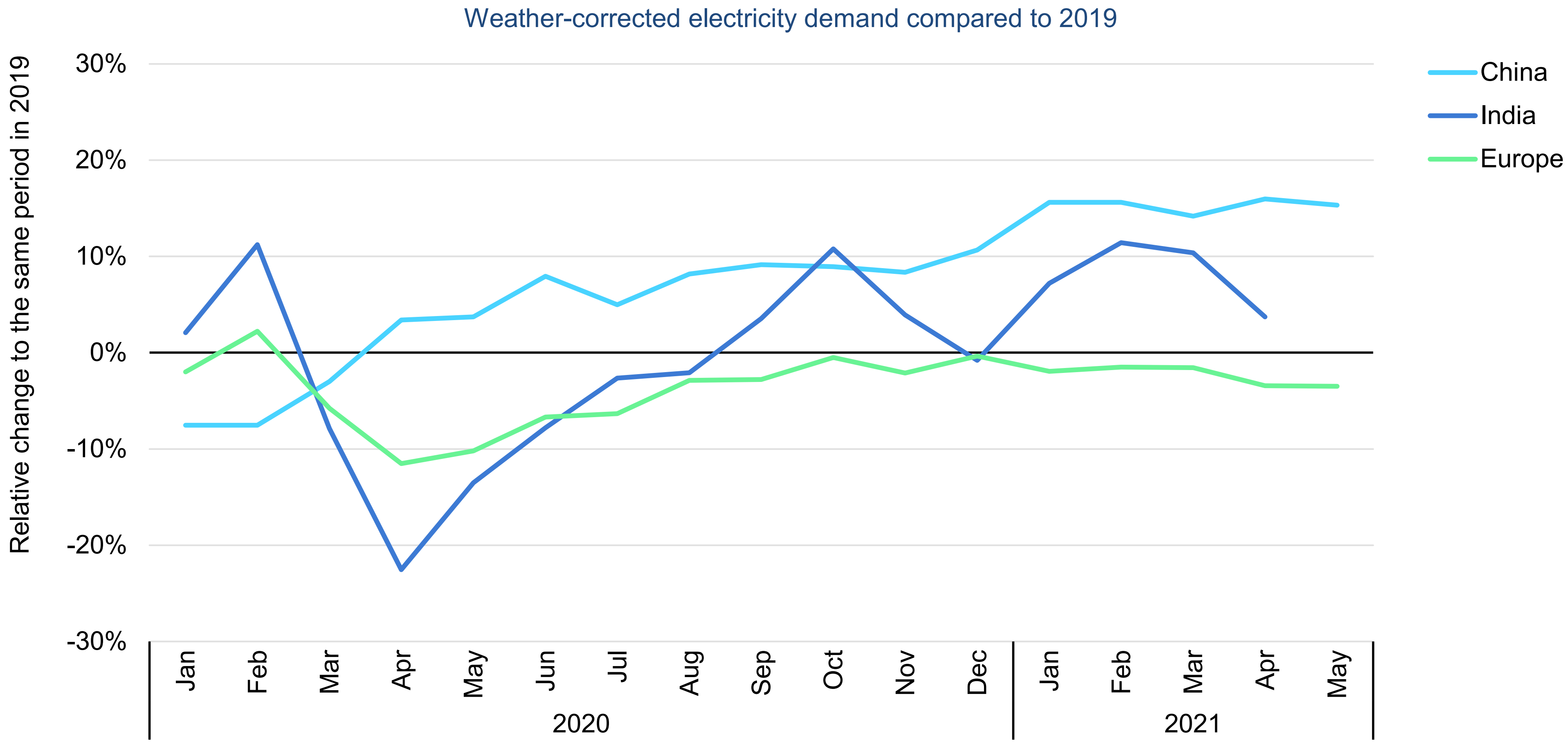
The Covid-19 pandemic affected all countries and economies across the world significantly and led to strong decreases in electricity demand. The recovery that started in 2020 continued during the first quarter of 2021, although its intensity varied strongly from region to region.

In **China,** which is leading the global recovery, demand grew 4% year-on-year in 2020. In the first quarter of 2021, weather-adjusted demand grew by 22.5% year-on-year, in contrast to the 6% drop in the first quarter of 2020 following lockdown measures. Compared with pre-pandemic levels of 2019, weather-corrected demand in the first quarter of 2021 was 15% higher, confirming the strong rebound observed in the second half of 2020. With weather-corrected growth of 16% in April and 15% in May 2021 compared with 2019, Chinese demand continued its growth spurt through the spring.

In **India**, during the first quarter of 2021, weather-corrected electricity demand was almost 10% higher than in the same period in 2019. The second wave of Covid-19 that hit India by mid-April 2021 slowed the pace of the growth: although electricity demand in April 2021 was still 7% higher than in April 2019, this was 3 percentage points below the growth in March. In the first four weeks of May 2021, growth declined to close to 6% compared with 2019. In spite of its severity, the second wave affected Indian electricity demand less than the first wave in 2020. After strict lockdown measures started mid-March 2020, power demand sustained a decrease of 25% (compared with 2019) for five consecutive weeks, from the end of March to early May.

As in India, weather-corrected electricity demand in **Europe** declined gradually from the start of 2021 as new restrictions were implemented to contain the pandemic, reversing the gradual build-up seen in the second half of 2020. The non-weather related decline was masked by exceptionally cold temperatures early in the year, however. The United Kingdom experienced the lowest average minimum temperatures since 1922 in April, with similar cold temperatures in Germany (coldest April in 40 years), France and Austria (both coldest in 20 years) – pushing up electricity demand for heating purposes. In May 2021, the aggregated weather-corrected electricity demand of France, Germany, Italy, Spain and the United Kingdom was down 3% from 2019 (with non-weather-corrected demand being similar). The current trend remains ambiguous and much less marked than in other regions of the world. During the second quarter of 2021, weather-corrected electricity demand is higher than in the same quarter of 2020, but is far from displaying a complete recovery.

China is leading the global rebound of electricity demand



Note: European values are based on a weighted average of France, Germany, Italy, Spain and the United Kingdom. Demand values are weather-corrected to isolate the impact of higher or lower temperatures.
Sources: IEA analysis based on China Statistical Information Network, *www.stats.gov.cn*; India POSOCO, *https://posoco.in/* and ENTSO-E, *https://transparency.entsoe.eu/*.

Hot and cold – weather-related electricity demand is set to bounce back in 2021

Global electricity demand decreased by around 1% in 2020, pushed down not only by the Covid-19 pandemic, but also by milder temperatures that reduced consumption. In 2021, we expect temperature driven consumption to pick up again, particularly due to an increase in cooling demand in the Northern Hemisphere, although the trends are highly region-specific.

In 2020, if temperatures had been similar to those in 2019, global demand would have fallen by around 0.3% instead of 1%. Milder temperatures during the cold season reduced the global need for space heating (heating degree days were down by 4%) and a slightly cooler hot season decreased the need for space cooling (cooling degree days were down by 0.6%). In France, milder temperatures caused demand to drop by 5% instead of 3% and in the United States, annual demand fell by 3% instead of 2%.

In the first five months of 2021, colder temperatures in the Northern Hemisphere pushed up global heating degree days by 13% compared with the same period in 2020, with North America and Europe experiencing particularly severe cold waves in February.

In June and July 2021, extremely hot temperatures in several regions could result in a global increase in electricity demand for cooling. In British Columbia, Canada, a new heat record of 50 degrees Celsius was reached. Temperatures in several cities in the northwest of the United States reached new all-time highs. In the Middle East, several countries registered more than 50 degrees Celsius. In India's northern states, a heatwave caused temperatures to reach a nine-year high in the country's capital New Delhi, and also parts of Europe had a hot start to the summer.

Looking more closely at regional trends, in several **European** countries, electricity demand for cooling fell in 2020 as a result of a cooler summer: by 14% in Italy, for example, and 6% in France. In early 2021, electricity demand for heating rose due to colder temperatures. The United Kingdom experienced the lowest average minimum temperatures for April since 1922 in 2021, with similar cold temperatures in Germany (coldest April in 40 years), France and Austria (both coldest in 20 years). For the first half of 2021, we estimate a year-on-year increase in heating demand of 33% in France and 21% in Norway and Sweden. We also expect that higher early-summer temperatures in Northern Europe will drive up electricity demand for cooling in 2021. In June, some regions saw their hottest days on record, including Finland (31.7°C), Moscow (34.8°C), Belarus (35.7°C) and Estonia (34.6°C).

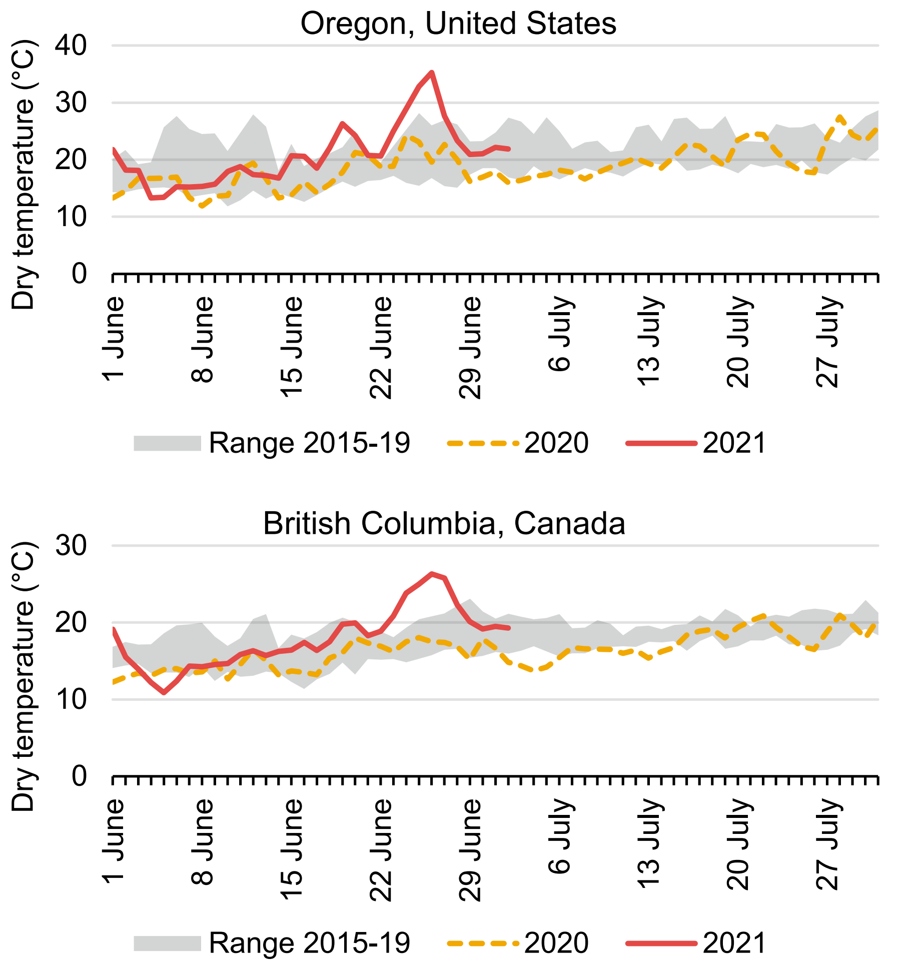
The impact of weather on electricity demand is mixed in **North America**: following a mild winter in 2020 that drove heating related demand in the United States down by 14%, electricity demand for heating rebounded by 13% in the first half of 2021, due to a record-breaking cold snap. Following record-breaking high temperatures which affected multiple regions in the northwest of the United States and in Canada, we estimate that overall electricity demand for cooling for the summer of 2021 will increase relative to 2020. In June 27 of 2021, some areas in Oregon, Washington and British Columbia saw air temperatures that were more than 15°C higher than the 2014-2020 average for the same day.

The weather in some regions of **Central and South America** has been slightly cooler in 2020-2021 compared with 2019. In Brazil, we estimate a year-on-year decrease in electricity demand for cooling of 10% in 2020 and of 1% in the period January to May 2021.

The impact of weather in the **Asia Pacific** region is also mixed. China, the world's biggest consumer of electricity for heating, experienced lower temperatures during the winter in 2020 that pushed up electricity demand for heating by 2%. The first half of winter in 2020-2021 hit record-breaking low temperatures. However, the first five months of 2021 have been milder on average, slightly reducing electricity demand for heating. In India, a heat wave in the early summer months increased the need for cooling.

An early-summer heatwave in the **Middle East** is expected to bring up electricity demand for cooling. During June 2021, temperatures climbed above 50°C in multiple regions, including the Islamic Republic of Iran (hereafter "Iran"), Kuwait, Oman, the United Arab Emirates and Iraq.

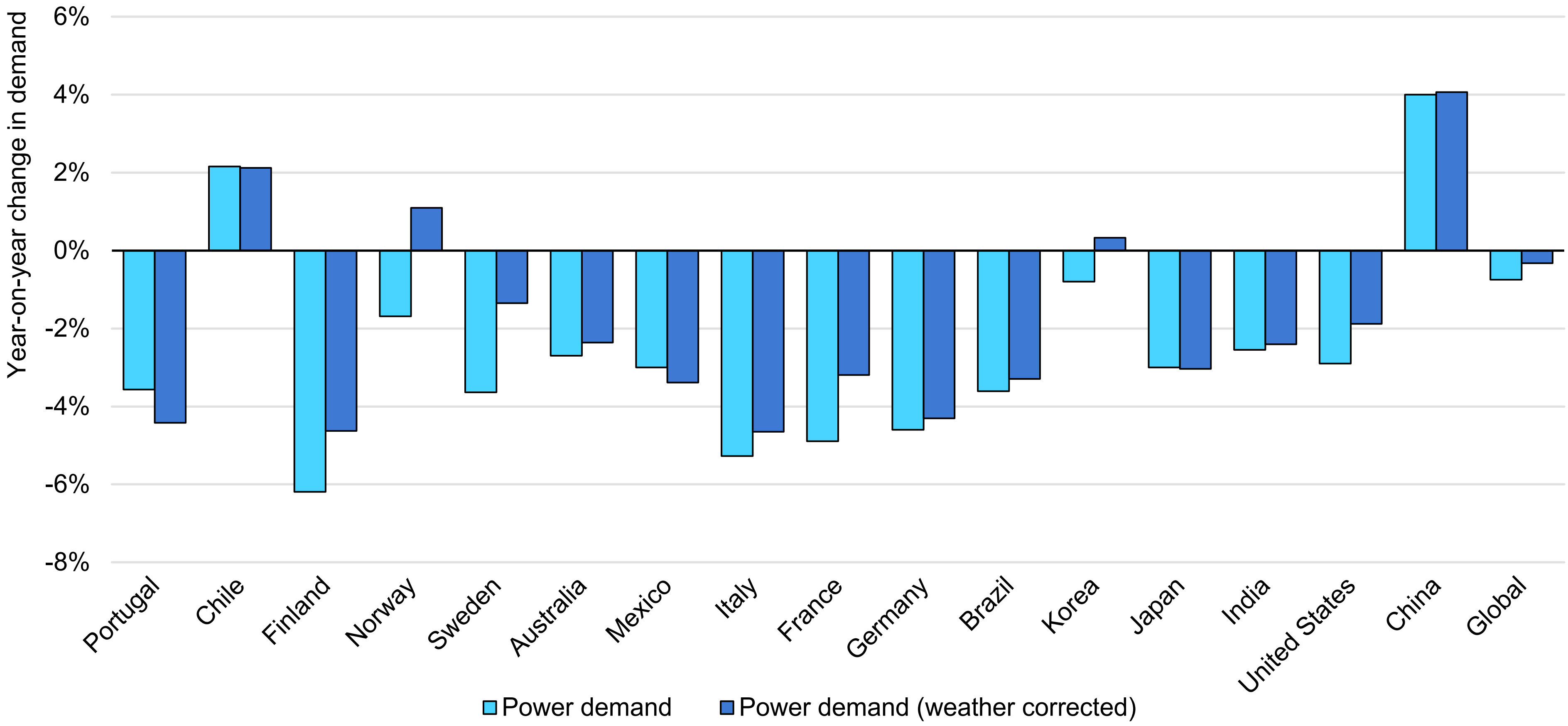
Average daily dry temperatures in selected areas of the United States and Canada



Note: the temperatures were measured in Portland International Airport (Oregon, USA) and Vancouver International Airport (British Columbia, CA).
Source: NOAA (2021), Global Surface Summary of the Day.

Milder weather was an important contributor to the electricity demand decline in 2020

Year-on-year change in electricity demand in 2020 for selected countries

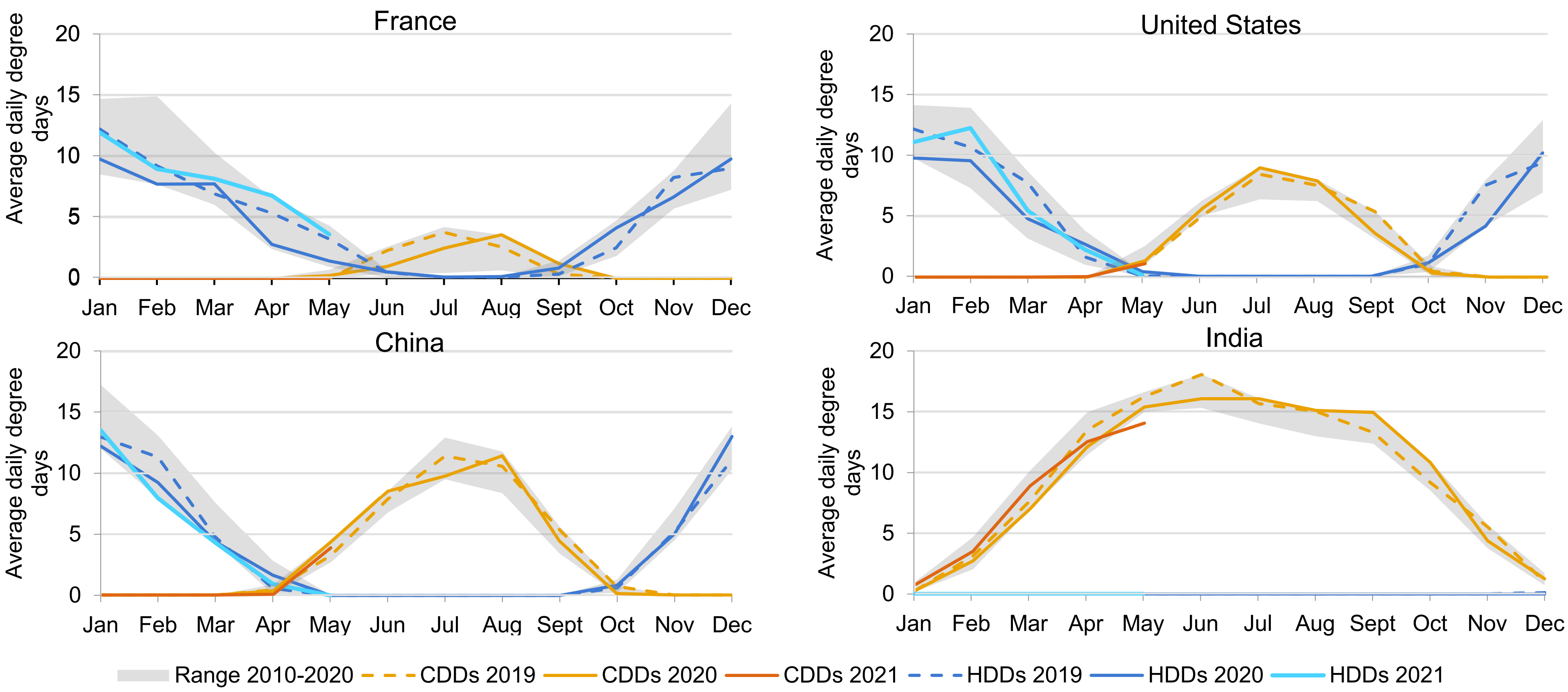


Note: Weather-corrected power demand represents the change in demand if weather in 2020 had been the same as in 2019. For calculating the impact of weather on demand we take into account the change in heating and cooling degree days, the effect of yearly improvements in the energy efficiency of heating and cooling technologies, and the changing stock of heating and cooling appliances.

Sources: IEA analysis with data from IEA and CMCC (2020), *Weather for Energy Tracker*; IEA (2020), *Energy Efficiency Indicators*; IEA (2020), Heating; IEA (2020), Cooling; IEA (2020), *The Future of Cooling*.

Cooler temperatures in early 2021 compared to early 2020 pushed up electricity demand in France and the United States

Monthly heating degree days (HDDs) and cooling degree days (CDDs) for selected countries



Note: Base temperatures (16°C for HDDs and 18°C for CDDs) are constant for all regions to facilitate comparison; however, comfort temperatures can vary by region.
Source: IEA analysis based on data from IEA and CMCC (2020), *Weather for Energy Tracker*.

Commercial and industrial demand booming in China, bumpy recovery in the US and Europe

While measures to contain the pandemic supported higher residential electricity demand, particularly in developed economies, both the commercial and industrial sectors experienced a strong decline in electricity consumption in many countries. While China reached a low in the first quarter of 2020, many countries followed in the second. In the United States and Europe, demand in both sectors gradually recovered in the second half of 2020 as restrictions were lifted. In the first quarter of 2021, when increasing Covid-19 cases were met by new restrictions, industrial and commercial demand fell again in Spain and growth halted in the United States. In China, demand continued to grow rapidly.

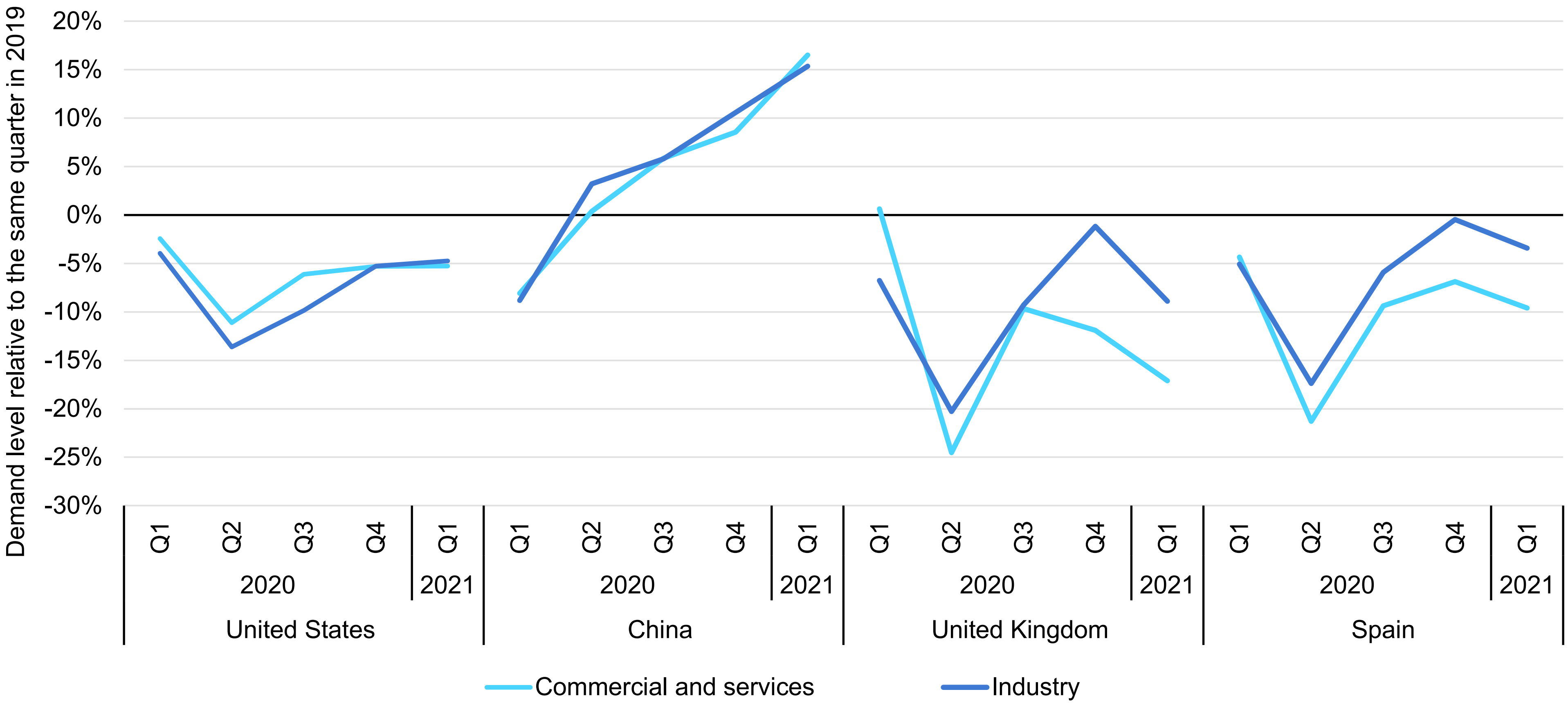
After strict lockdown measures in the first quarter of 2020 and a subsequent drop in demand, **China** reached pre-pandemic demand levels in the second quarter of 2020, reflecting a rapid economic recovery. In the second half of 2020, electricity demand significantly exceeded 2019 levels. This trend continued in the first quarter of 2021, with industrial demand exceeding the first quarter of 2019 by more than 15%. Commercial electricity demand in the first quarter of 2021 exceeded 2019 demand for the same period by 16.5%.

In the **United States**, the recovery of electricity demand in the industrial as well as the commercial and services sector has slowed in recent quarters. Commercial sector demand remained around 5% below the same quarters in 2019 from the third quarter of 2020 to the first quarter of 2021. After recovering in the second half of 2020, industrial demand stagnated in the first quarter of 2021 at 5% below the 2019 level. Despite an overall positive trend, the US Energy Information Administration projections from July 2021 show that demand in both sectors will remain below 2019 levels until 2022.

In Europe, countries pursued individual strategies against the Covid-19 pandemic, affecting the commercial and industrial sectors to different extents. Electricity demand in **Spain** and the **United Kingdom** in both sectors reached its lowest point in the second quarter of 2020 and recovered afterwards – only to fall again during the winter. In the United Kingdom, demand from the commercial sector fell in the second quarter of 2020 to -25% relative to the same period in 2019 and recovered to -10% of the 2019 value in the next quarter. With new lockdown measures coming into force towards the end of 2020 and early 2021, demand dropped to -12% in the fourth quarter of 2020 and -17% in the first quarter of 2021. Demand from UK industry in the fourth quarter of 2020 recovered to 1% below the same period in 2019 before dropping to 9% below 2019 in the first quarter of 2021. In Spain, industrial demand recovered to pre-pandemic levels in the fourth quarter of 2020 before dropping again to -3% in the first quarter of 2021, also due to new restrictions. Commercial demand over the same period fell from -7% to -10%.

Commercial and industrial demand: fragile recovery and new heights

Electricity demand trends by sector



Sources: IEA analysis based on data from EIA (2021), *Electric Power Monthly: Sales of Electricity to Ultimate Customers*; China Energy Portal (2020, 2021), *Electricity and other energy statistics*; UK Department for Business, Energy & Industrial Strategy (2021), *Energy Trends June 2021*; Red Eléctrica de España (2021), *Indice de Red Electrica: Industria y Servicios*; Red Eléctrica de España (2021), *Daily Balance Report*.

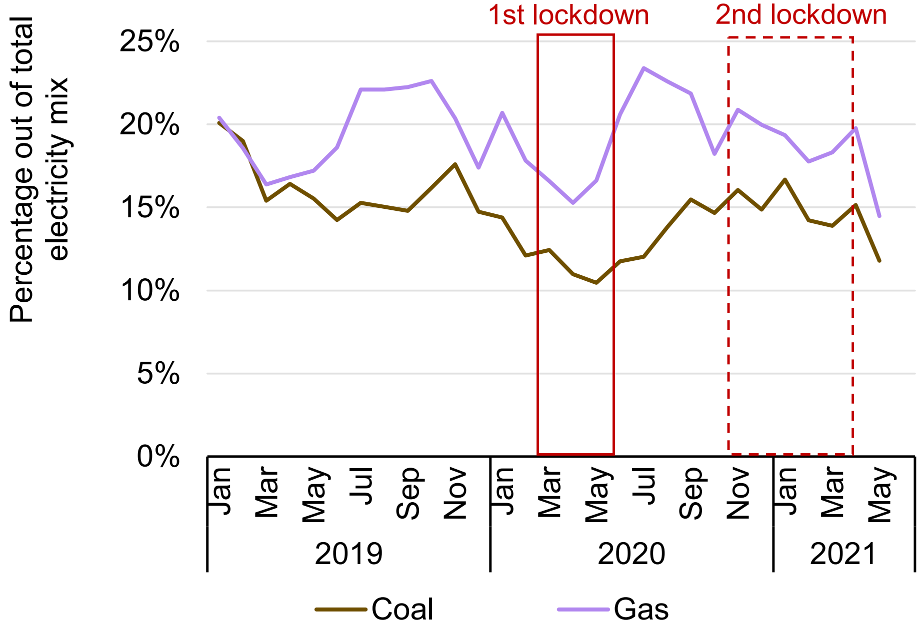
In 2021, coal generation returns to pre-crisis levels in the European Union

In the European Union, the share of coal in the electricity mix returned to average pre-pandemic levels in the first quarter of 2021, following an increase that started in the second half of 2020. This growth was facilitated by lower nuclear generation, which fell by 1% year-on-year in the first quarter of 2021, and lower wind power output, which fell by 14%. Additionally, gas prices increased significantly in Europe in the fourth quarter of 2020, recovering to rise well above 2019 levels. Despite strong growth in EU Emissions Trading System prices from December 2021 onwards, this gas price rise reduced coal-to-gas fuel switching, especially in mid-2020.

The return of coal is likely to be short-lived, as several European countries accelerated their coal phase-out plans. Austria and Sweden shut down their last single-fired coal power plants in 2020. Portugal brought forward its coal phase-out plan to close its biggest coal power plant (Sines Power Station, 1.3 GW) in January 2021.

Gas-fired electricity generation increased significantly in the first five months of 2021 compared with the same period in 2020, rising by 20% while coal rose 14%. While this leaves coal still 15% below pre-pandemic levels, gas-fired generation shows a 4% increase when comparing January to May 2021 with the same period in 2019. In the second quarter of 2021, fossil fuel-based generation decreased as renewables picked up and electricity demand fell with increasing temperatures.

Coal and natural gas shares in the European Union



Note: The lockdown periods are indicative and represent periods when confinement measures were strictest.

Sources: IEA analysis based on ENTSO-E (2020) for 25 EU countries (Luxembourg and United Kingdom excluded), Transparency Platform. Bundesnetzagentur (2020), *SMARD.de* for Germany. See also IEA (2020), *Covid-19 impact on electricity*.

After record lows, coal's share of Chinese generation picks up again

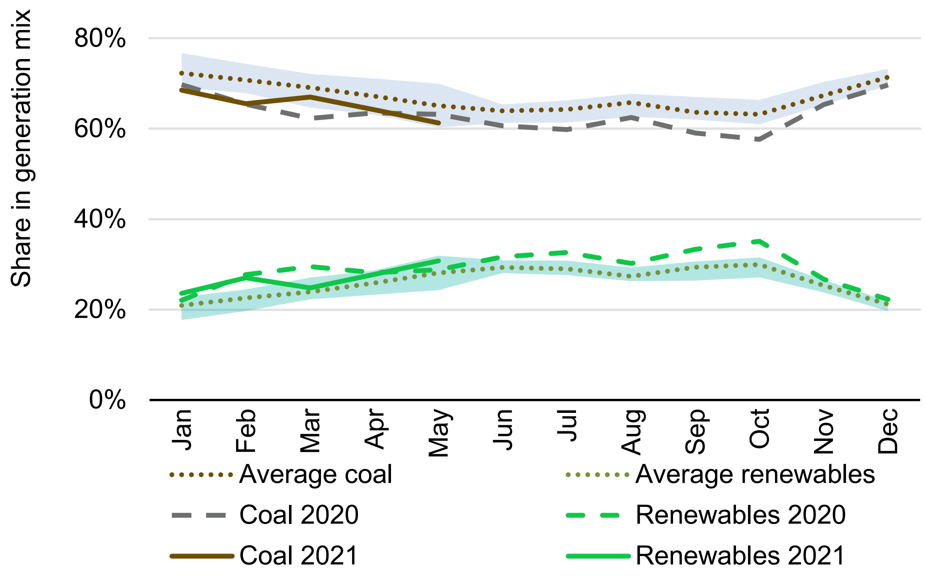
From late 2020 through to early 2021, coal's share in the Chinese generation mix bounced back from record lows earlier in 2020. The rebound was bolstered by reduced hydropower availability in the dry winter period and rapidly growing demand.

Record expansion of renewables in China in 2020 pushed renewable generation between July and October 2020 to more than 210 TWh – the highest monthly level in the 2015-2020 period. This helped reduce coal's share of generation to a new record low of 58% in October. Since November 2020, coal's share has increased, remaining above 64% until April 2021. Over the first four months of 2021, the share was 66.5%, higher than in the same periods in 2019 and 2020.

The shift back towards coal from late 2020 is not entirely unexpected – renewable electricity generation in China is strongly seasonal, with increased renewable generation typically seen in summer months during the rainy season in southern China. Accordingly in May 2021, the increased availability of hydro, solar PV and wind led the share of coal drop again to 61%.

In light of China's recent pledge to achieve net-zero emissions by 2060, this seasonal shift back to coal signals the challenge China faces, at least in the short- to medium-term, in reducing coal-fired generation even as electricity demand grows strongly.

Share of coal and renewables in China's electricity mix



Note: "Renewables" include electricity generation from hydro, solar, wind, geothermal, and combustible renewable sources. Shaded areas indicate the range from 2015 to 2019, average values are related to this period.
Source: IEA, based on China Statistical Information Network, www.stats.gov.cn.

Coal's share in India's electricity supply exceeded pre-crisis levels

In early 2021, coal-fired generation in India reached a monthly share of 79% in the mix, the highest level since early 2019, as demand growth was met by coal-fired generation and availability of hydropower and wind was low.

Generation of electricity in India in the first quarter of 2021 was around 10% higher than in the same period in 2019. In January and February it was 5% higher than in the same period in 2020, before Covid-19 restrictions started.

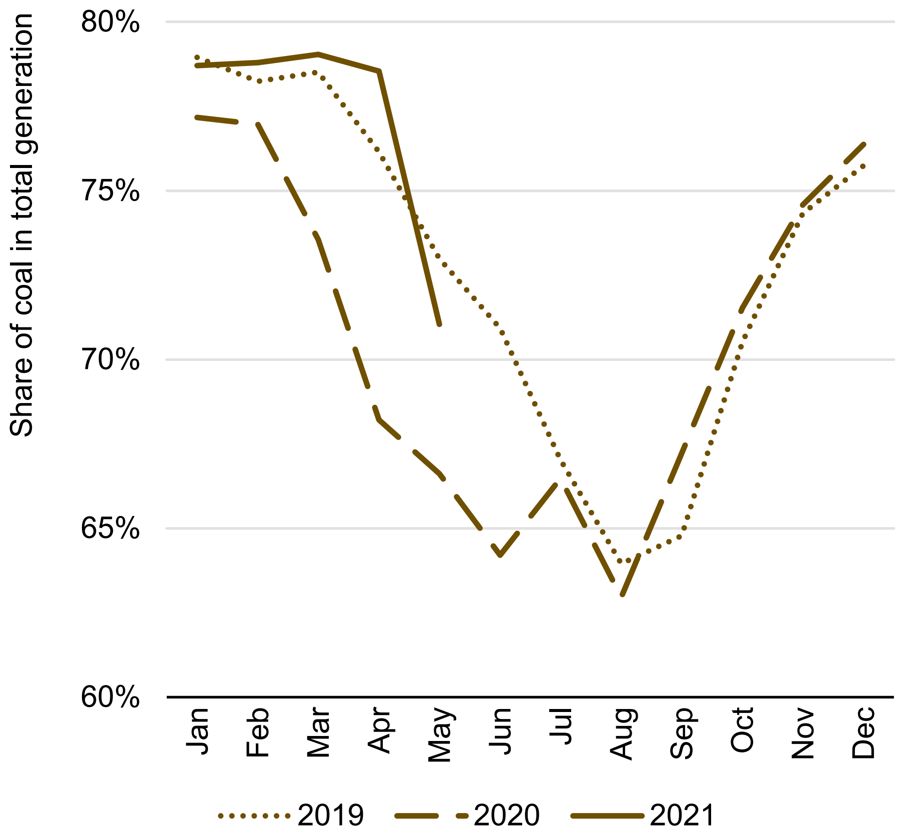
Coal and renewables generation have both grown more quickly than overall generation over the past two years, reducing the shares of nuclear and gas in the mix. Coal-fired generation grew by 11% from the first quarter of 2019 to the first quarter of 2021. Renewable generation increased by 13% in the same period. At the same time, nuclear generation grew only 2% and gas-fired generation declined by 4%.

Although deployment of renewables capacity has continued strongly in India, total renewables generation for the first quarter of 2021 fell slightly relative to the first quarter of 2020 – by 0.1% – due to unfavourable weather conditions for hydropower and wind. As a result, renewables growth in this period was insufficient to match demand growth, leaving space for additional coal-fired electricity generation.

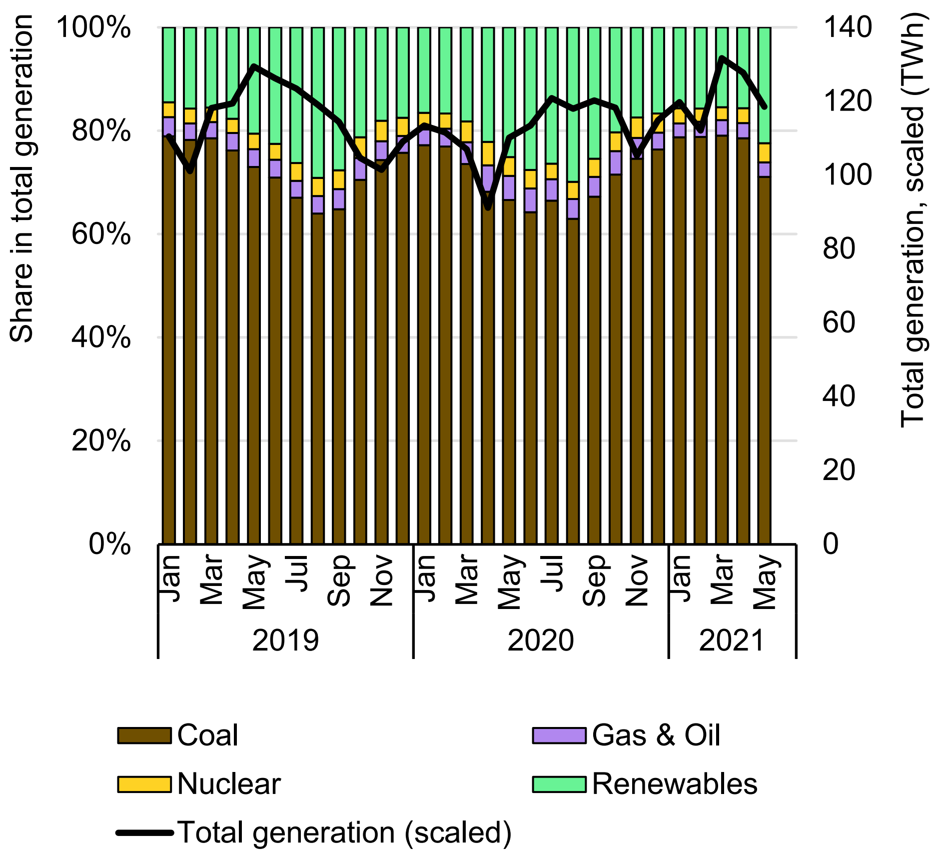
Electricity demand dipped after the second wave of the pandemic started in mid-April 2021. Total generation in May was still 8% above the level of 2020 but 8% below 2019. This triggered an increase in renewables' share of generation as variable renewables were given priority dispatch, from 20% in May 2019 to 22% in May 2021, despite a similar absolute generation level.

India's coal generation is recovering

Share of coal in India's electricity supply



Coal's share in India's generation mix



Note: Generation is scaled using yearly data from India's Central Electricity Authority to ensure coherence between IEA annual statistics and balances and the figures reported here.
Source: IEA based in POSOCO data, https://posoco.in/.

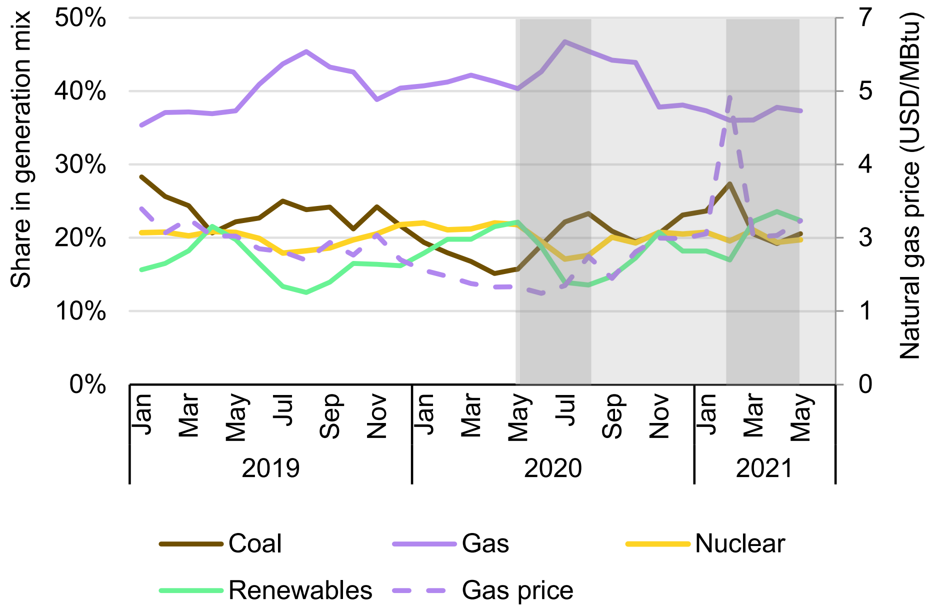
Rising gas prices bring back coal-fired electricity generation in the United States

After peaking in July 2020 at 44%, the share of gas-fired generation in the electricity supply mix of the United States declined to around 35% in the last two months of the year. This decline was set off by gas to coal switching as gas prices began to climb after their Covid-19 lows of below USD 2/MBtu in July 2020, and by higher renewable generation. In the first five months of 2021, the share of gas in generation remained between 33% and 34%.

In contrast, coal's share picked up after a monthly low of 15% in April 2020, which was also the month with the lowest electricity demand that year. The weekly share peaked at 30% in February 2021 during a cold wave with peaking gas prices and forced gas power plant outages. From March to May 2021, coal's share went back to around 20% of the mix, as renewable output increased. After absolute coal-fired generation fell by 34% in the first five months of 2020 compared with the same period in 2019, it rose by 36% during the same months of 2021 compared with 2020.

Renewables share traditionally peaks in the spring when demand is relatively low and output is high. In May 2020, when electricity demand was particularly low, renewables reached a new all-time record share of 25% of the mix – exceeding nuclear and coal-based electricity generation. After the share declined to around 16% in the third quarter of 2020 due to seasonal lower production, it went back to to 25% in April and May of 2021.

United States electricity mix and natural gas price



Note: The intensity of the grey shade reflects the intensity of the lockdown.
Source: IEA based on U.S. Energy Information Administration (2021), Short-Term Energy Outlook.

A dry hydro year is shaping up in 2021…

Low hydropower output in key electricity markets in the first five months of 2021 led to the burning of additional fossil fuel and contributed to a pronounced rise in carbon emissions. Due to local droughts, several hydropower shortages impacted security of supply around the world.

The hydro-rich western region of the **United States** entered a period of extreme and exceptional drought during summer 2020 that continued into mid-2021 and is curbing hydroelectric generation. US hydropower output, making up 8% of total generation in 2020, fell by over 10% (about 12 TWh) in the first five months of 2021 compared with the same period in 2020. The drop in the Northwest region accounted for over 40% of the national decline. In California, where 7% of US hydroelectricity was generated in 2020, snowpack and precipitation feeding rivers and streams this spring have declined. As a result, major storages' filling levels dropped to 70% of average levels at the beginning of April. The California Department of Water Resources forecasts that hydro production will drop to 30% of the 10-year average. This and an expected reduction in electricity imports due to reduced hydropower availability in the Northwest may further tighten electricity supply when demand peaks due to higher temperatures in summer. Lower hydro output, together with recovering electricity demand, provided additional market space to fossil fuel-based generation, most of which has been captured at the national level by coal-fired generation.

Brazil, where hydro typically accounts for close to 70% of total power generation, is enduring its most severe drought in almost a century. While hydro-based generation remained at 2020 levels in the first five months of 2021, precipitation fell by 8% and runoff levels by 7%, leaving overall stored water at 40% of total capacity in June 2021. This level is significantly below the five-year average of 53%. Lower hydro generation and increased electricity demand led to strong growth in thermal generation, which rose by 40% year-on-year in the first five months of 2021, with gas-fired power plants accounting for 60% of incremental thermal generation.

The availability of hydro is low in some regions but not in others. The National Water and Basic Sanitation Agency in Brazil has declared a critical situation of scarcity of water resources in the hydrographic region of Paraná. This affects the Southeast/Midwest subsystem, where more than 60% of national hydropower was generated in 2020. Brazil's third-largest hydro reservoir, Ilha Solteira, is located in this subsystem, and produced 5% of the region's hydropower in 2020. Its power generation was down by 19% in the first three months of 2021 compared with the same period in 2020 – 3% below the range from 2016 to 2020. Also storage levels are low this year. For example, the storage level of the Nova Ponte reservoir, which has almost 5% of the subsystem's storage capacity, dropped to 15% in June 2021 from 51% in June 2020. As the overall low hydro availability in the Southeast/Midwest region may constrain local electricity supply, Brazil's Electric Sector Monitoring Committee has eased restrictions on some hydroelectric dams to avoid supply disruptions.

In contrast, hydro generation levels have increased by 4% in the Tucuruí reservoir (Northern subsystem) and 6% in the Sobradinho reservoir (Northeast subsystem) and reservoirs are well filled because of higher inflow.

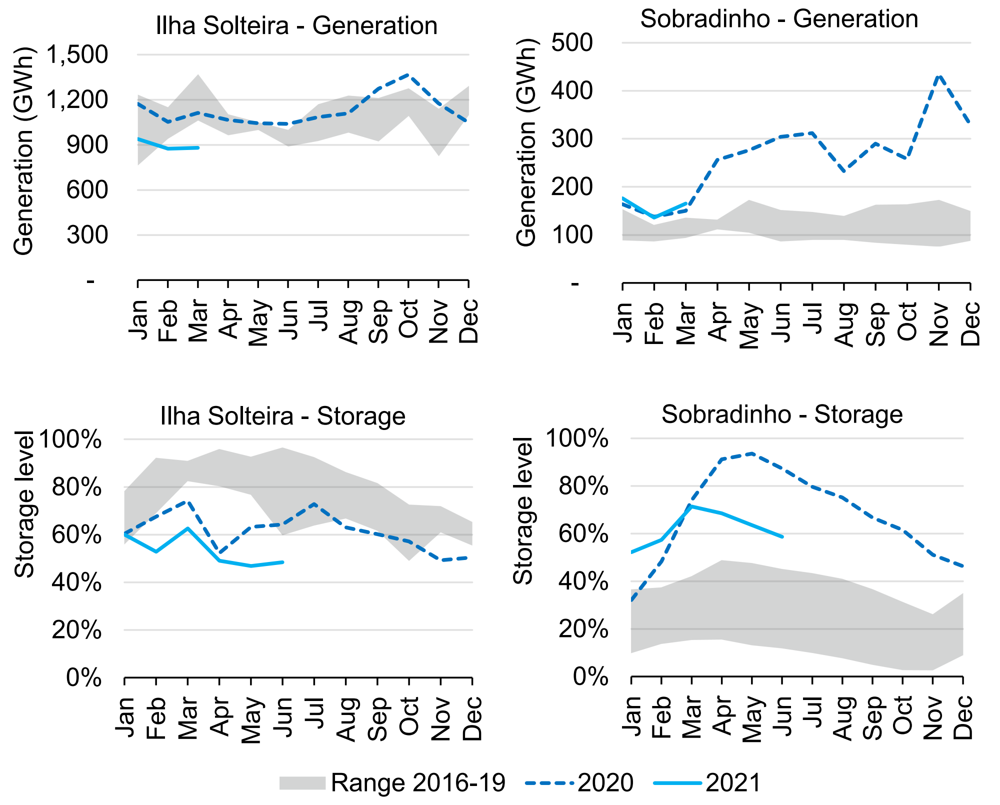
While overall hydro generation in **China** rose by over 3.5% in the first five months of 2021 compared with 2020, south and southeast regions are facing droughts. Hydro output dropped by over 7% in the southern coastal provinces and by close to 14% in Sichuan. Hydropower increased in Yunnan, where energy-intensive industries like tin, zinc and aluminium smelters are located, but at the expense of reservoir levels. In early May, the local grid operator issued a note asking companies to reduce power consumption. In the southern province of Guangdong, a large manufacturing hub, limited hydro availability, together with strong economic recovery and associated high electricity demand, resulted in electricity shortages leading to production halts.

Hydropower in **India**, accounting for 12% of total electricity generation in 2020, fell by 15% in the first five months of 2021 compared with the same period in 2020, and by 10% relative to 2019. In the Northern Region, which accounted for 39% of India's total hydropower output in 2020, but is prone to droughts, hydropower generation decreased by 25%. Two of the northern states were particularly affected. In Punjab, water storage levels in mid-June were 25% below the last ten years' average. In Himachal Pradesh, storage levels were down by more than 60%. The decline of hydropower together with higher electricity demand resulted in a 33% increase in thermal generation in the Northern Region in the first five months of 2021.

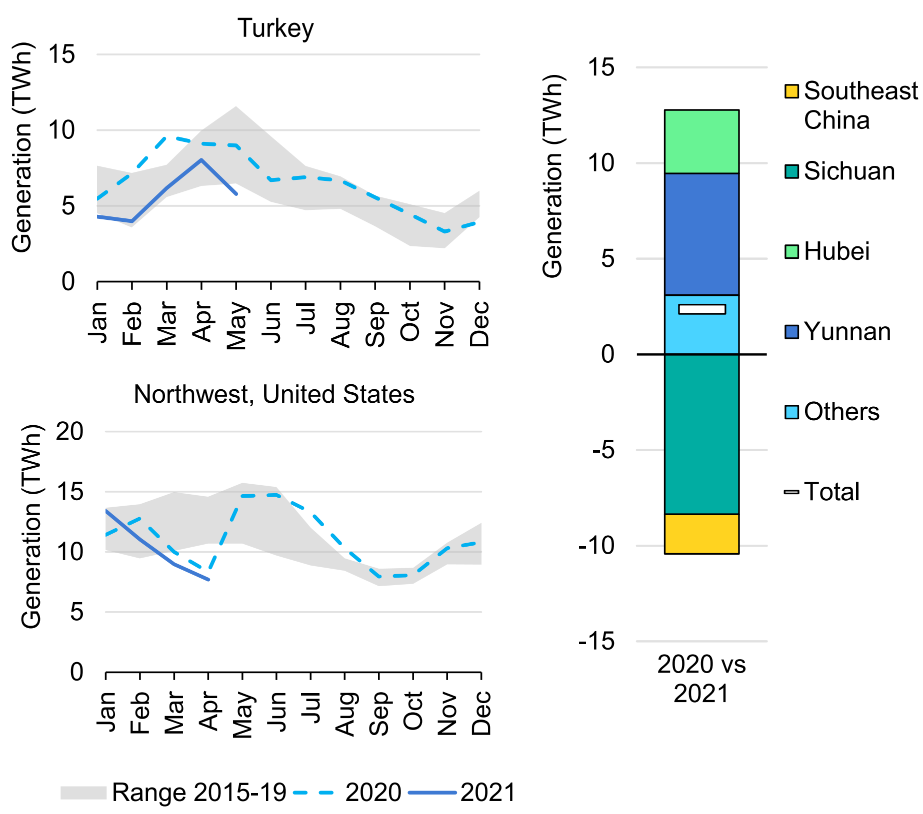
In **Europe**, hydropower generation increased on average by around 1% in the first five months of 2021, with significant differences between countries. Hydropower in Spain increased by more than 11%. In Norway, by far the largest hydropower producer in Europe, output rose by around 2%, with reservoir levels well above the five-year average. In **Turkey**, where hydropower accounted for 27% of total electricity generation in 2020 and which is the only country in Europe investing significantly in new hydropower, output fell by almost 30%. This low level of generation was a continuation of levels in Q4 2020 and was compensated by strong growth in thermal generation. In the first five months of 2021, output of gas-fired plants doubled and lignite-based generation increased by 19% compared with the same period in 2020. Reservoir levels in several regions have reached very low levels.

…with hydro output down in most of the key hydro markets

Hydro generation and storage levels in selected reservoirs in Brazil



Hydro generation in the United States, Turkey and China



Note: Storage level is referring to the available useful volume of water in each reservoir.
Sources: IEA analysis using data from ONS (2021), Datos Hidrológicos/Volumes; ONS (2021), Geração de energia; NBS (2021), *Data Statistics*.

Assumptions

Economies are expected to recover in 2021

The Covid-19 pandemic had far-reaching effects on the global economy. In 2020 global GDP fell by 3.3%, its steepest decline since the mid-20th century. Now the economy is showing signs of a recovery: we expect global GDP to grow by 6% in 2021 and 4% in 2022. Additional fiscal support mechanisms and the spread of vaccine campaigns will accelerate the pace of the global economy, helping it return to its pre-Covid-19 level. In early 2021 the International Monetary Fund (IMF) increased the initial growth expectations it had made in late 2020, by 0.8 percentage points for 2021 and 0.2 percentage points for 2022. The economic repercussions of the pandemic are smaller than those of the global economic crisis of 2008.

For the **United States,** a high GDP growth rate of 6.4% for 2021 is assumed. The pre-Covid-19 economic level is expected to be reached in the second half of 2021, with growth supported by the economic relief package worth USD 1.9 trillion that was put in place in March. Job retention supports, like the US *Paycheck Protection Program*, have also helped to reduce the harm that would be caused by significant job losses.

Similar programmes were pursued in the **Euro Area**, such as the policy program for *Kurzarbeit* in Germany, the *Expediente de Regulación Temporal de Empleo* in Spain and the *Cassa Integrazione Guadagni* in Italy. In addition, the European Union put in place the Next Generation EU Fund stimulus package, which provides structural aid worth EUR 750 billion. In the euro zone, the IMF forecasts a GDP growth rate of 4.4% for 2021 and 3.8% for 2022.

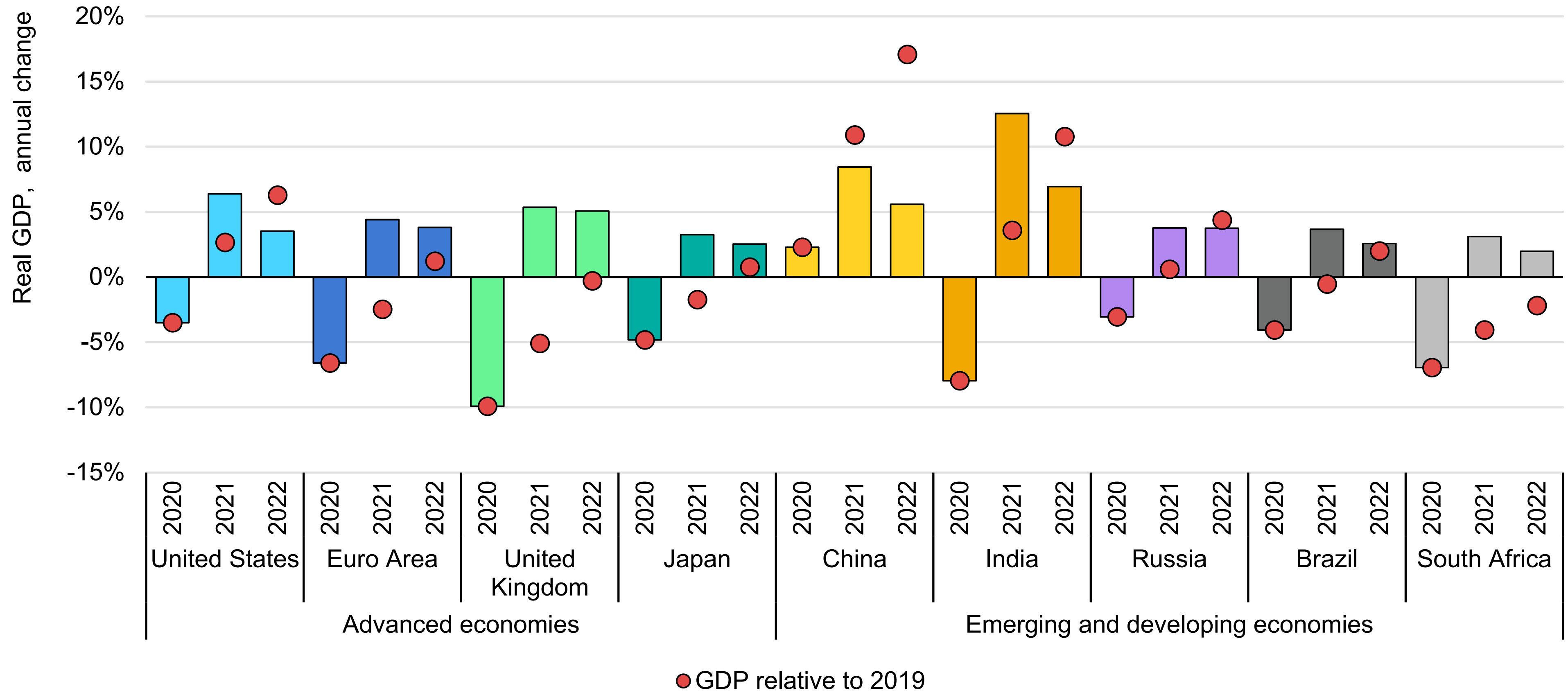
Japan's economy is expected to return to pre-Covid-19 levels in the second half of 2021, but only in 2022 in the **United Kingdom**.

China's economy recovered the quickest, showing economic growth in 2020. An increase in GDP of 8.4% in 2021 is forecasted, which will flatten slightly to 5.6% in 2022. For **India**, the IMF predicted high GDP growth rates of 12.5% in 2021 and 6.9% in 2022. Given the health crisis in the second quarter of 2021, however, the economic outlook is uncertain.

Sub-Saharan Africa experienced its largest recorded contraction ever of -1.9% in 2020. A GDP growth rate of 3.4% is forecast for 2021. The IMF does not expect low-income developing countries to reach their pre-pandemic GDP levels before 2023.

Strong growth expected in major economies

GDP assumptions by country and region



Note: Due to surging new Covid-19 cases in the second quarter of 2021, the economic outlook for India is uncertain.
Source: Based on IMF, *World Economic Outlook*.

Gas and coal prices are expected to ease from current high levels, and carbon prices to rise

After dropping steeply in 2020, natural gas prices recovered sharply in the first half of 2021, reducing the cost-competitiveness of gas-fired power plants in key power markets. Competitiveness is expected to rebound in 2022 as natural gas supply improves, new infrastructure is built and carbon prices remain robust in Europe.

In the **United States,** gas prices increased recently. In the first half of 2021, Henry Hub gas futures traded 78% higher than last year, at USD 3/MBtu – their highest level for this period of the year since 2014. Natural gas prices gained support from colder than average weather in the first quarter of 2021, combined with lower production (-2% year-on-year) and a sharp increase in liquefied natural gas (LNG) exports (+38% year-on-year) through the first half of the year. By contrast, US coal prices changed little. Central Appalachia coal prices increased by 5% year-on-year in the first half of 2021. The improved competitiveness of coal led to a sharp rebound coal-fired electricity generation, up by 34% year-on-year in the first half of 2021 (around 110 TWh), primarily at the expense of gas-fired power generation, which fell by 9% (around 60 TWh). At the end of June, forward curves indicated that Henry Hub prices would average 5% above the first half year levels through the second half of 2021, providing further downward pressure on gas-fired power generation

US natural gas production is expected to increase by 3% per year between 2022 and 2024. Improved supply is likely to push gas prices down to 10% below their 2021 levels in 2022, while coal prices remain broadly flat. As gas-fired power plants become cost-competitive again, some generation will switch from coal to gas.

In Europe, gas prices on the Title Transfer Facility (TTF) in the Netherlands rose almost three-fold in the first half of 2021 compared with the same period last year, to an average of USD 7/MBtu. Gas prices were supported by a strong, largely weather-driven demand recovery (+14% year-on-year) combined with lower LNG inflow (-10% year-on-year) and extensive maintenance work on the Norwegian continental shelf. Imported coal prices gained 67% year-on-year in the first half of 2021 to average USD 77/tonne. The strong rebound in gas and coal prices has been accompanied by substantial growth in carbon prices, which more than doubled year-on-year to a record high of USD 55/tCO_2eq by mid-April of 2021. Several key factors pushed up carbon prices. An agreement was reached in December 2020 to raise the 2030 emissions-reduction target from 40% to 55%. Proposals for European Union Emissions Trading System cap adjustments are expected in the EU Fit for 55 package, published in mid-2021. Additionally, more fossil fuels were burned through the 2020/21 heating season than expected due to cold temperatures.

The UK Emissions Trading Scheme opened for trading on 19 May 2021, with emissions allowances trading slightly above EU Emissions Trading System (EU ETS) levels. Coal-fired power generation grew more strongly (+20% year-on-year) than gas (+9%) in the European Union and the United Kingdom in the first half of 2021. Considering the mid-2021 forward curves of coal, carbon and gas prices, gas-fired power plants are expected to remain competitive through the second half of 2021.

European gas-fired power generation's competitive position is expected to improve in 2022. Forward curves at the end of June indicate that TTF prices are expected to average 10% below their 2021 levels in 2022, largely due to improving natural gas supply conditions in Europe. Carbon prices are expected to remain robust, averaging close to USD 65/tCO_2eq through 2022. Imported coal prices are set to average at USD 85/tonne

In **Asia**, spot LNG prices followed a similar trajectory to TTF, increasing by more than three-fold in the first half of 2021 from the same period last year, to an average of USD 10/MBtu. The surge in spot prices has been largely driven by strong LNG import growth in northeast Asia, in combination with several outages that limited LNG supply during the first quarter of 2021. In contrast, oil-indexed LNG prices declined by an estimated 10% year-on-year in the first half of 2021. Given that oil-indexation dominates LNG trade in the region, the LNG import prices of OECD member countries in Asia declined by 10% year-on-year in the first five months of 2021.

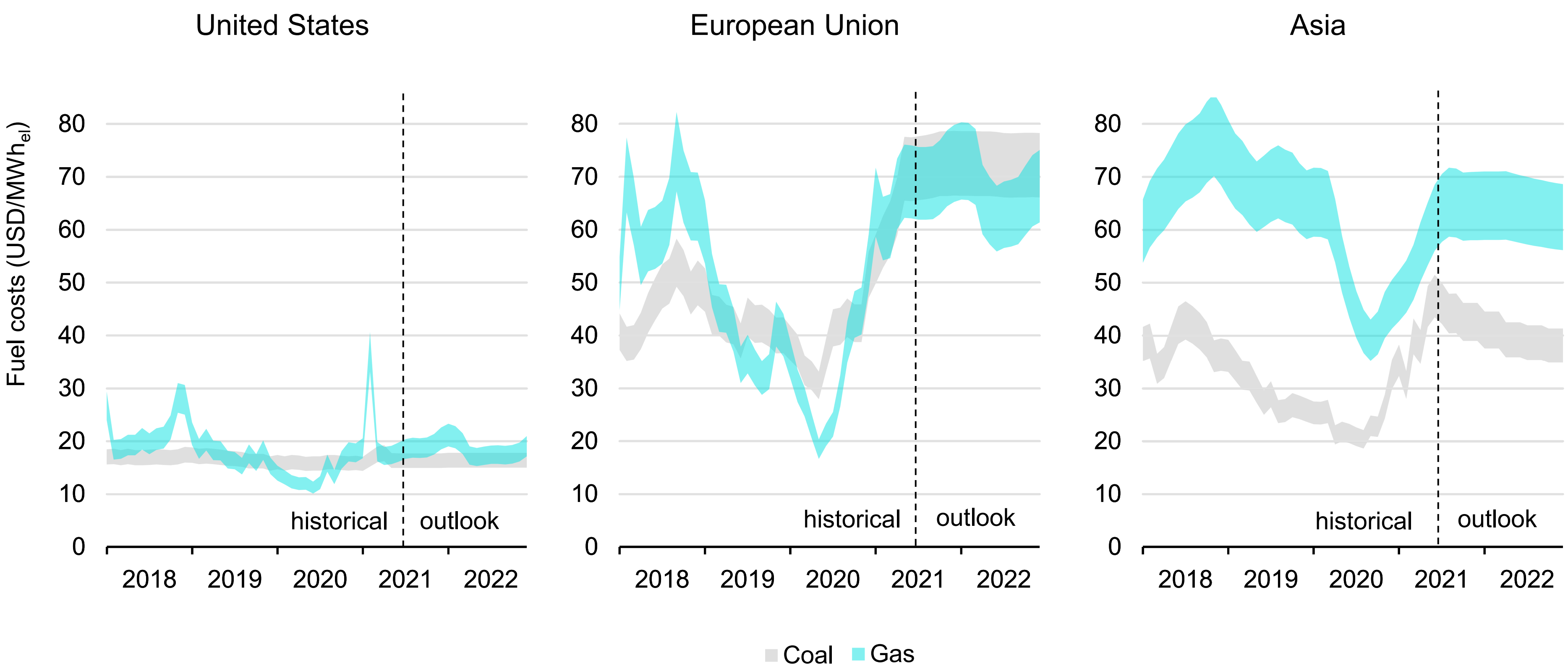
During the same period, Newcastle coal prices increased by 40% to USD 90/tonne, partly supported by demand recovery in northeast Asia and flood-related supply disruptions in March 2021. Mid-2021, forward curves indicate that oil-indexed LNG prices are projected to average 14% above their 2021 levels in 2022, while Newcastle coal forward prices show a decline of 5%. This would reduce the competitiveness of gas-fired power plants vis-à-vis coal-fired power generation.

In Korea, the third phase of the country's emissions trading scheme (KETS) started in 2021 and runs to 2025. The system's scope has been expanded to include construction companies and large transport companies, bringing its coverage up to 73.5% of national emissions. In response to falling carbon prices, the Korean Ministry of Environment introduced a temporary carbon floor in April 2021, set at USD 11.57/tCO_2eq for a period of one month.

China's national emission trading scheme was launched in January 2021, with the first trading of allowances expected in June. It first covers the power sector (including combined heat and power) and is by far the world's largest emission trading scheme – almost three times larger than the second-largest, the EU system. In its first year, China's scheme is likely to have an oversupply of allowances. Over time, it can play an important role in decreasing CO_2 emissions.

Gas-fired generation costs increase relative to coal – but emission costs can compensate

Fuel (including emission) costs of coal- and gas-fired power plants



Note: Coal range reflects 38-45% efficiency; gas range reflects 45-55% efficiency. Due to the large geographic areas covered in each region, costs can differ between and even within countries and should therefore be interpreted as general trends.

Sources: Natural gas prices in the United States: Henry Hub; coal prices in the United States: historical data EIA (2021), STEO June 2021, trend based on Appalachian coal; natural gas prices in the EU: TTF; coal prices in the EU: CIF ARA; emission costs: EU ETS; natural gas prices in Asia: oil-indexed LNG prices; coal prices in Asia: Japan marker price.

Investments and capacity

Renewables and network infrastructure dominate investments in the power sector

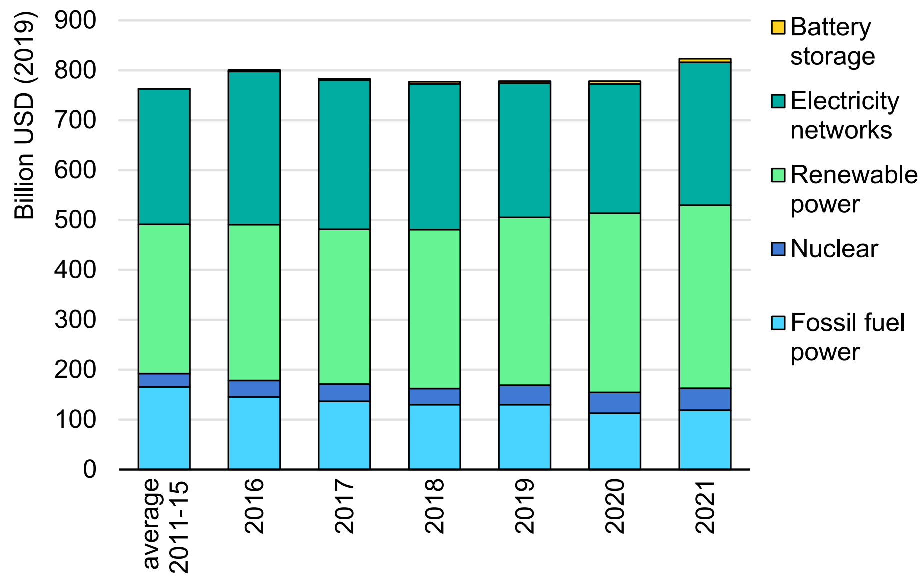
Investments in the global electricity sector are expected to increase by 5% in 2021, after remaining flat in 2020 because of the Covid-19 pandemic. The major areas of spending are renewable energies, with a share of more than 45% of investment, and electricity networks (30%).

Annual grid investments, which had been falling since 2016, are expected to increase again, boosted by large expansion plans for 2021 and onwards and by Covid-19 recovery packages.

Final investment decisions for coal power plants have fallen significantly in recent years. In 2020, however, they reached 20 GW, the first increase since 2015. China accounted for almost 13 GW of the total, a rise of 45% from 2019.

Despite the difficult economic climate in 2020, investments in battery storage increased by almost 40%. Average costs continued to decline, falling by 20%. Spending on grid-scale batteries grew by more than 60%, as shares of variable renewables increased and a growing number of hybrid auctions encouraged the use of energy storage to supplement variable renewable capacity. As a result of pandemic-related economic turbulence, investments in “behind-the-meter” battery storage by households and small and medium companies fell by 12%.

Annual global power sector investments



Source: IEA (2021), *World Energy Investment 2021*.

Wind and solar PV dominate renewable capacity additions

The IEA forecasts in its *Renewable Energy Market Update 2021* that high levels of renewable capacity will continue to be added in the next couple of years, after a record-setting year 2020. Global net renewable capacity increased by almost 280 GW in 2020 – 45% more than in 2019. Almost 50% of the new capacity is in China, which more than doubled its capacity additions from 2019.

The largest increase in capacity was of solar PV (48% of net additions), followed by wind (41%) and hydro (7%). Given the higher capacity factor of wind, wind continues to be the fastest-growing source of renewable electricity generation in absolute terms.

The annual growth rate of renewable capacity expansion is forecast to decline in the coming years, from more than 10% in 2020 to slightly above 9% in 2021 and slightly below 9% in 2022. Still, renewables are expected to account for more than 90% of global new generation capacity during that time.

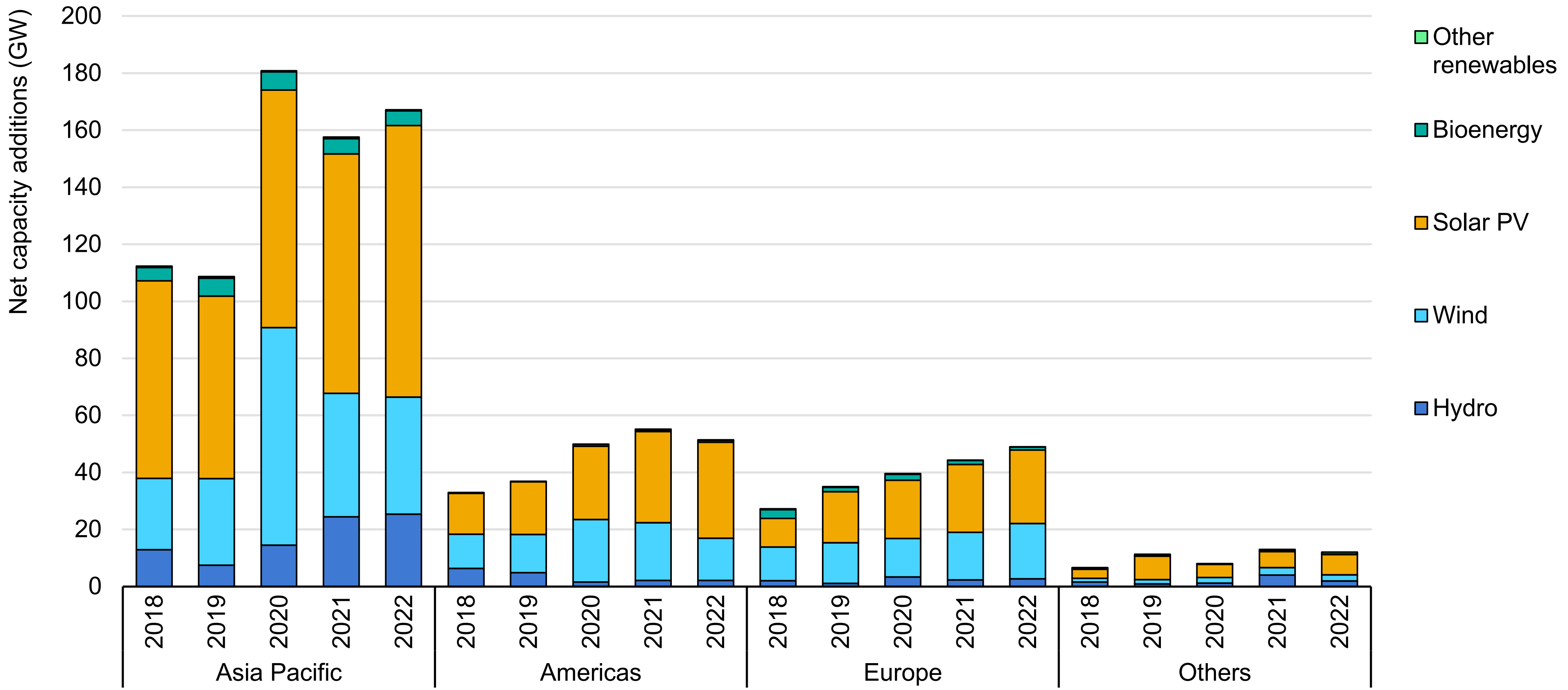
By far the largest net additions in the next two years are expected in the **Asia Pacific** region. Although annual growth in **China** will slow down – a result of the exceptionally high levels of new installations in 2020 before the end of certain subsidy programmes – net additions remain high. **India** and **Japan** are expected to add significant new renewable capacity to their electricity systems, especially solar PV. Although India's PV capacity additions in 2020 declined by almost 60% from 2019, we expect new expansion records in 2021 and 2022 as delayed projects from previous auctions are commissioned – if scheduled projects go ahead as planned despite the Covid-19 crises in the first half of 2021.

In the **Americas**, the **United States** is expected to continue with high annual capacity additions of solar PV of more than 20 GW until 2022, boosted by an extension of the solar Investment Tax Credit programme. Wind power capacity additions are expected to decline, on the other hand, following record new installations in 2020 driven by tax incentives. In **Brazil**, the second-largest contributor to renewables growth in the region after the United States, distributed solar PV is expected to grow significantly, buoyed by a generous net metering scheme.

In **Europe**, annual renewable capacity additions are forecast to increase by 11% in 2021 (44 GW) and 2022 (49 GW). Germany is expected to show the largest renewable capacity additions, followed by France, the Netherlands, Spain, the United Kingdom and Turkey. The strong growth is due to policy measures to meet the EU 2030 climate target and the increasing popularity of corporate power purchase agreements.

Global renewable generation capacity will continue to grow strongly

Net annual renewable capacity additions by region and technology



Source: Based on IEA (2021), *Renewable Energy Market Update 2021*.

Global gas-fired power fleet is set to expand by close to 5% by the end of 2022…

Global gas-fired power generation is expected to expand by close to 5% – over 80 GW – between the end of 2020 and the end of 2022. The Asia Pacific region, North America and the Middle East will account together for almost 80% of the capacity additions. Expansion of the gas-fired power fleet will support coal-to-gas and oil-to-gas switching in these regions.

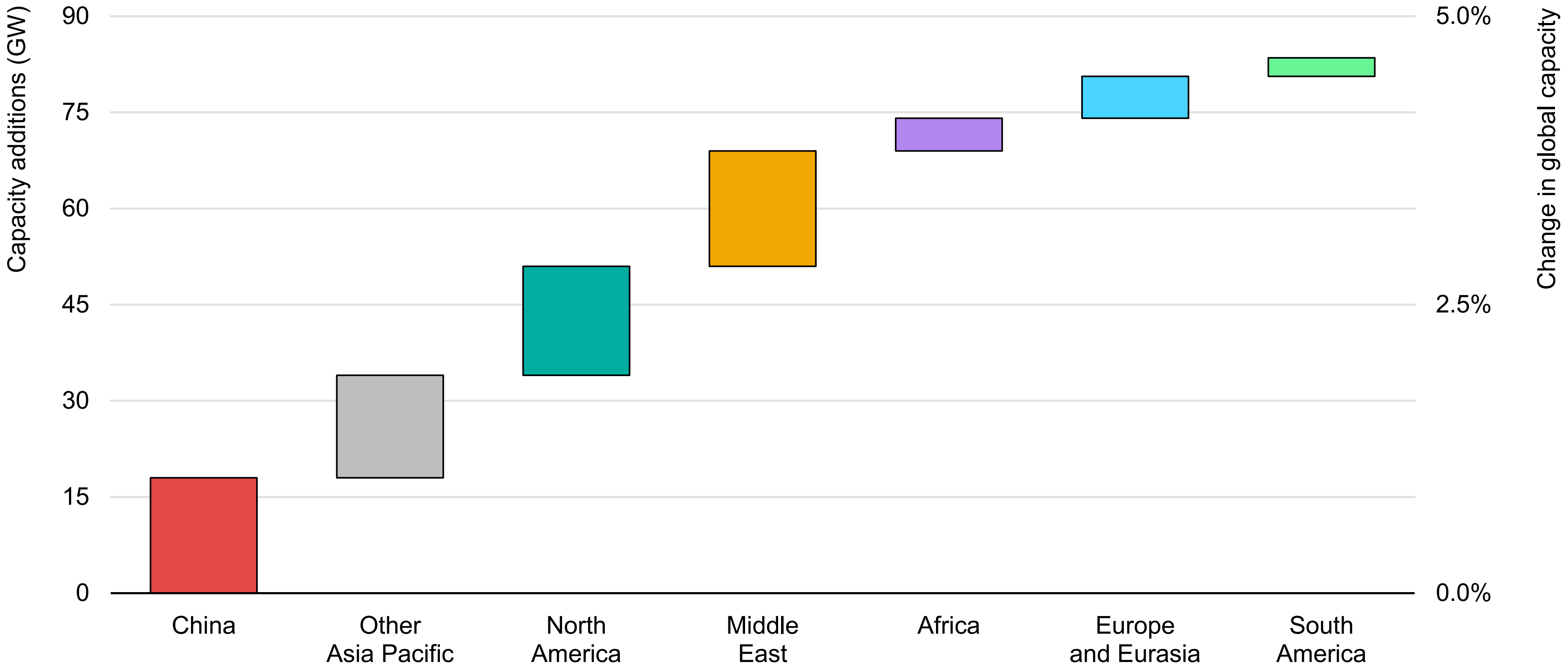
The Asia Pacific region is set to lead gas-fired power generation capacity additions until 2022, driven by growing electricity demand and coal-to-gas switching policies. **China** alone is expected to add almost 20 GW of gas-fired power generation capacity by 2022 based on recent investment decisions. The country's gas-fired power fleet rose by 6.5 GW between November 2020 and the end of the first quarter of 2021 to reach over 102 GW. Around 16 GW of capacity is set to be commissioned elsewhere in the region. In Malaysia, the 1.4 GW combined cycle gas turbine (CCGT) plant in Pasir Gudang will reach full capacity and the 2.2 GW CCGT in Alor Gajah will be commissioned. Thailand will commission the 2.5 GW CCGT in Chonburi, and Bangladesh will commission the Ashuganj and Rupsha power plants. In the **Middle East**, capacity will be added mainly in Iraq (including the next phases of the Rumaila power plant), Iran and Saudi Arabia.

In **North America**, net gas-fired power generation capacity is set to expand by close to 17 GW between the end of 2020 and the end of 2022. In **the United States,** 17 GW of new gas-fired capacity is set to start commercial operation, while 2.5 GW are expected to be retired. Almost 85% of new capacity will be added in Texas, Ohio, Florida, Minnesota and Pennsylvania. Retirements are set to be concentrated in Texas, where plant closures will account for one-third of the US total by 2022 and older, less efficient steam turbines will be replaced with new combined-cycle units and combustion turbines. In **Canada**, Alberta is set to lead gas-fired capacity additions as it aims to become coal-free by 2023. Construction of the 900 MW Cascade CCGT started in August 2020, and some coal plants are being converted into gas-fired plants (including Keephills Unit 2 and 3). The Keephills plant is expected to be commissioned by the fourth quarter of 2022 and reach its full capacity by mid-2023. In **Mexico**, close to 2.4 GW of gas-fired power generation capacity is expected to come online through the forecast period, based on projects under construction.

In other regions, capacity additions are expected to be more limited. Several projects are under development in **Africa**, including the 300 MW Cap des Biches project in Senegal, expected to be commissioned by 2022, which will support the country's oil-to-gas switching in power generation. In **Europe**, most new capacity will be added in Germany (including the coal-to-gas conversion at Scholven by 2022), Greece (Agios Nikolaos CCGT by 2021/22) and Poland (Żerań power plant by mid-2021).

…with the Asia Pacific region accounting for around 40% of capacity additions

Gas-fired power generation capacity additions by region, 2020-2022



Sources: IEA analysis based on EIA (2021), Electricity Data; IEA (2021), *World Energy Investment 2021*; S&P (2021), Energy Power Plant Project List; various companies and news reports.

Global coal capacity continues to increase, despite many cancellations and retirements

An increasing number of countries are announcing targets to phase out coal. Canada and the United Kingdom, which are leading the way, have set up the Powering Past Coal Alliance, a coalition of national and sub-national governments, businesses and organisations to advance the transition from coal to clean energies. Most countries have set 2030 as their target, though there are some exceptions. Germany, with a target of 2038, is the largest coal power generator among those committed to phasing out coal plants. Given the distant targets set up by most countries, the impact of phase-out policies on coal power generation capacity in 2021-2022 is limited.

In 2020, global coal power generation capacity increased 15 GW, or less than 1%, up to 2 115 GW. This last number is based on “nameplate” or official capacity, from which the real value can vary slightly due to differences in summer/winter capacities and the intermittent operation of plants acting as reserve or using multiple fuels. China’s growth was almost fully offset by a decrease elsewhere. In North America and Europe, coal plant retirement continues whereas in Asia, the coal fleet is still growing, although at slower pace than in the past. We expect those trends to continue through 2024, with China leading the commission of new units and the United States and the European Union leading the retirements. Elsewhere in Asia, coal projects are being scaled back, as policy risks and public opposition increase. In addition, financing is becoming more challenging as an increasing number of financial institutions commit to stopping their involvement in coal.

China put 29 GW of new coal-fired power capacity into operation in 2020, more than three times the capacity built elsewhere. At the same time, China retired at least 137 outdated units with a combined capacity of 10 GW in 2020, following closures of 20 GW in 2019. Overall, China’s coal-fired capacity rose by a net 19 GW in 2020 to reach 1 080 GW, more than half of the global capacity. In addition, China approved the construction of 38 GW of new coal-fired capacity last year, three times more than a year earlier. In total, 90 GW of capacity is under construction.

Coal power policy seems to be pulled in two directions. On the one hand, President Xi Jinping’s pledges to ensure CO_2 emissions peak before 2030 and to reach carbon neutrality by 2060 or earlier sends a clear signal that the role of unabated coal power generation will decline. However, in December 2020 and amid an exceptional cold snap, there were serious problems in the electricity supply in several provinces in China. Hunan, Zhejiang, Guangxi, Jiangxi, Guangzhou (Guangdong) and Wulanchabu (Inner Mongolia) reported power shortages and mandates to reduce electricity because of coal shortages, grid maintenance problems or lack of generation capacity. Therefore, it seems likely that coal capacity will increase until 2025 and then plateau before it starts falling.

In **India**, where only 2 GW were commissioned in 2020, the average load factor of coal plants has decreased below 60% in the last few years and the expansion of renewable energy is on its way. However, 40 GW of capacity is still under construction. Over 20 GW of outdated plants are expected to be retired in the coming years.

Several countries in Asia intend to significantly reduce coal capacity. In **Korea**, the government is planning to reduce its coal reliance, which implies some capacity reductions. In **Japan**, two announcements have shaken the coal landscape. In July 2020, the minister of economy, trade and industry announced the closure by 2030 of more than 100 units with a combined capacity of over 30 GW. In April 2021, the prime minister announced a target of a 46% reduction in CO_2 emissions by 2030 compared with 2013. In the meantime, from December 2019 to June 2021, over 46 GW of new coal capacity have been commissioned and another 540 MW are expected soon. An important part of Japan's climate strategy is to burn low-carbon fuels – biomass, hydrogen and ammonia – in thermal plants.

In the Association of Southeast Asian Nations (**ASEAN)** region, the only additions in the short term are expected in Indonesia (11 GW under construction), Viet Nam (7 GW), Philippines (2 GW) and Cambodia (1 GW). Viet Nam is a paradigm of coal capacity reduction: the latest Power Development Plan proposed 37 GW capacity by 2030, up from 30 GW today – but less than half the 75 GW proposed in the former plan.

In Bangladesh, similarly, although the 1.32 GW Maitree coal plant was commissioned in 2020, only 5 GW of the previously announced more than 20 GW are in development, while most of the rest will be cancelled. In Pakistan, the minister announced the end of coal power development, but this will not affect the 5 GW currently under construction, on top of the 5 GW commissioned from 2017.

The **Australian** coal fleet is currently declining, with no new capacity coming online. The Liddell power station is set to retire one 500 MW capacity unit in April 2022 and the remaining three units the following year.

In the **United States**, the coal fleet continues to shrink. After the retirement of 14 GW in 2019 and 8.8 GW in 2020, 4.4 GW are scheduled to be retired in 2021 and 8.8 GW in 2022. In 2020 a new coal plant was commissioned in Alaska, but with a capacity of only 17 MW. Despite challenging circumstances for coal, research and development on coal power generation continues. In addition to a few projects to retrofit coal power plants with carbon capture, utilisation and storage (CCUS) (San Juan, Gerald Gentleman, Project Tundra and Prairie State), new concepts under the umbrella of coal FIRST programme continue. Some of the most promising include Prairie State's combined 270 MW ultra-supercritical (USC) coal plant, 87 MW gas turbine, 50 MW battery storage plus a system of algae to absorb the CO_2 and produce synthetic fuel;

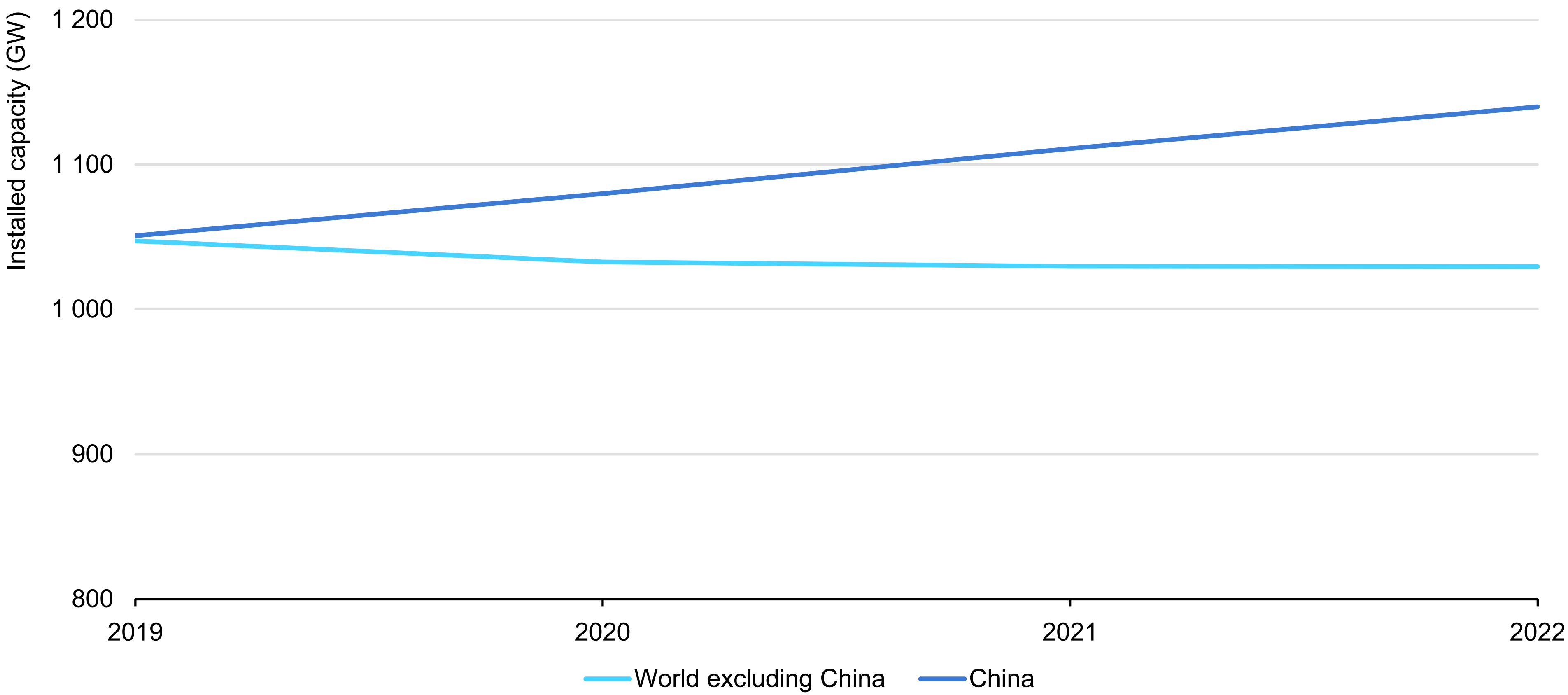
Consol Energy's project to use coal washing rejections as fuel while applying CCUS; and the use of coal in the supercritical CO_2 Allam cycle.

In the **European Union**, coal generation faces major obstacles in the form of a CO_2 price of over USD 50 per tonne and the Market Stability Reserve ensuring that surplus allowances will be retired. On top of this, political commitments to phase out coal in most countries are obliging utilities to retire coal plants one after another. Austria and Sweden closed their last coal plants in 2020, and Portugal will do the same in 2021. Spain retired 5 GW, half of its installed capacity, in 2020. Coal units are also being retired in Denmark, Italy and Poland. In Germany, 4.7 GW were retired on 31 December 2020 as the result of the first auction to remove coal capacity. Given the design of the auction, some of the most efficient plants won the auction and have been retired while older and less efficient plants continue in operation. Only new units for which the investment decisions were made some time ago are coming online. After Datteln 4 (Germany) and Jaworzno 3 (Poland, 900 MW) were commissioned in 2020 and a new unit in Ostroleka (Poland) was definitively shelved, the Turow 7 plant (Poland, 496 MW), commissioned in May 2021, seems to be the last new coal power plant in the European Union for the years to come.

In **Africa**, Egypt cancelled all coal projects, in total 15 GW, including Hamrawein (6.6 GW), which would have been the second-largest coal plant in the world. Projects were also cancelled in Kenya (1 GW) and Ghana (2 GW). In South Africa, the third unit of the Kusile plant (600 MW) was connected to the grid in 2020. A further three units under construction will be connected soon. There are two independent power producers but, challenged by financing, their future is not clear. Likewise, the 3 GW Musina-Makhado plant to feed the Limpopo Special Economic Zone is facing challenges during the approval process. A few other projects are more likely to go ahead, although not by 2022, including 350 MW in Mozambique, 300 MW in Tanzania and 300 MW in Botswana. In Zimbabwe, mostly through Chinese finance and construction, there are proposals for over 7 GW in new capacity, but their future is uncertain.

Coal-fired power plant capacity in China continues to grow

Development of global coal-fired generation capacity



Source: IEA estimates.

Nuclear power: from new constructions to phase-outs

After a peak in nuclear capacity additions in the late 1970s and 1980s, annual capacity additions constantly declined until about 10 years ago.

The negative trend reversed in the past decade, mainly driven by **China**, which added 40 GW to its nuclear fleet. Worldwide, 54 reactors are under construction, with a total capacity of about 58 GW. China heads the list of current construction (17 GW), followed by Korea (around 5 GW), India (4 GW) and the United Arab Emirates (4 GW).

Several countries are building or have recently started to operate their first nuclear reactor. In the **United Arab Emirates** the first reactor of the Barakah power plant started regular operations in August 2020, with the second scheduled to follow in late 2021. The first reactor in **Belarus** started operating in November 2020. **Turkey** and **Bangladesh** are building their first nuclear power plants. In total for 2021 we expect 8.7 GW of new nuclear capacity to come on line or return to service, while 9.2 GW are retired. After this slight decline in total capacity, we expect a net increase of 3.7 GW in 2022, when 10.5 GW will become available and 6.8 GW will leave service.

The **Russian Federation** (hereafter "Russia") plans to extend the role of nuclear power. The goal by 2030 is to increase the nuclear share of electricity production to 20%. Two new nuclear units are under construction, totalling 2.5 GW.

The **United States** is confronted with an aging nuclear fleet with an average age of 41 years; less than 2% of the fleet has been commissioned in the past 20 years. To advance construction and licensing of new nuclear reactors, the Nuclear Energy Innovation and Modernization Act was passed in 2019. The Vogtle units 3 and 4 (1.1 GW each), whose construction began in 2013, are the only additions expected in the next few years – and the first ones after the Watts Bar Nuclear Plant (1.3 GW) in 2016. After problems found during testing, the start-up date of Vogtle 3 was pushed back to the first quarter of 2022. Unit 4 still remains scheduled for November 2022. After the retirement of 1.7 GW in 2019 and 2 GW in 2020, 1 GW has already been retired in 2021 (Indian Point 3) with 4.5 GW more being expected (the Exelon plants Dresden and Byron, two units each). For 2022, the closure of the 0.8 GW Palisades plant is expected.

In **Japan,** 54 nuclear reactors had been operating before the nuclear accident in Fukushima in 2011. In March 2021, ten years later, five plants with nine reactors have restarted operation, while 21 have been decommissioned. Due to concerns over non-compliance with some regulations, the restart of the Kashiwazaki-Kariwa plant, originally scheduled for 2021, is unlikely to happen before 2022. For 2021, the restart of Mihama 3 (0.8 GW) and units 1 and 2 of the Takahama plant (0.8 GW each) are expected.

While some countries in **Europe** are phasing out nuclear power plants, others are aiming to increase or at least maintain their existing capacity.

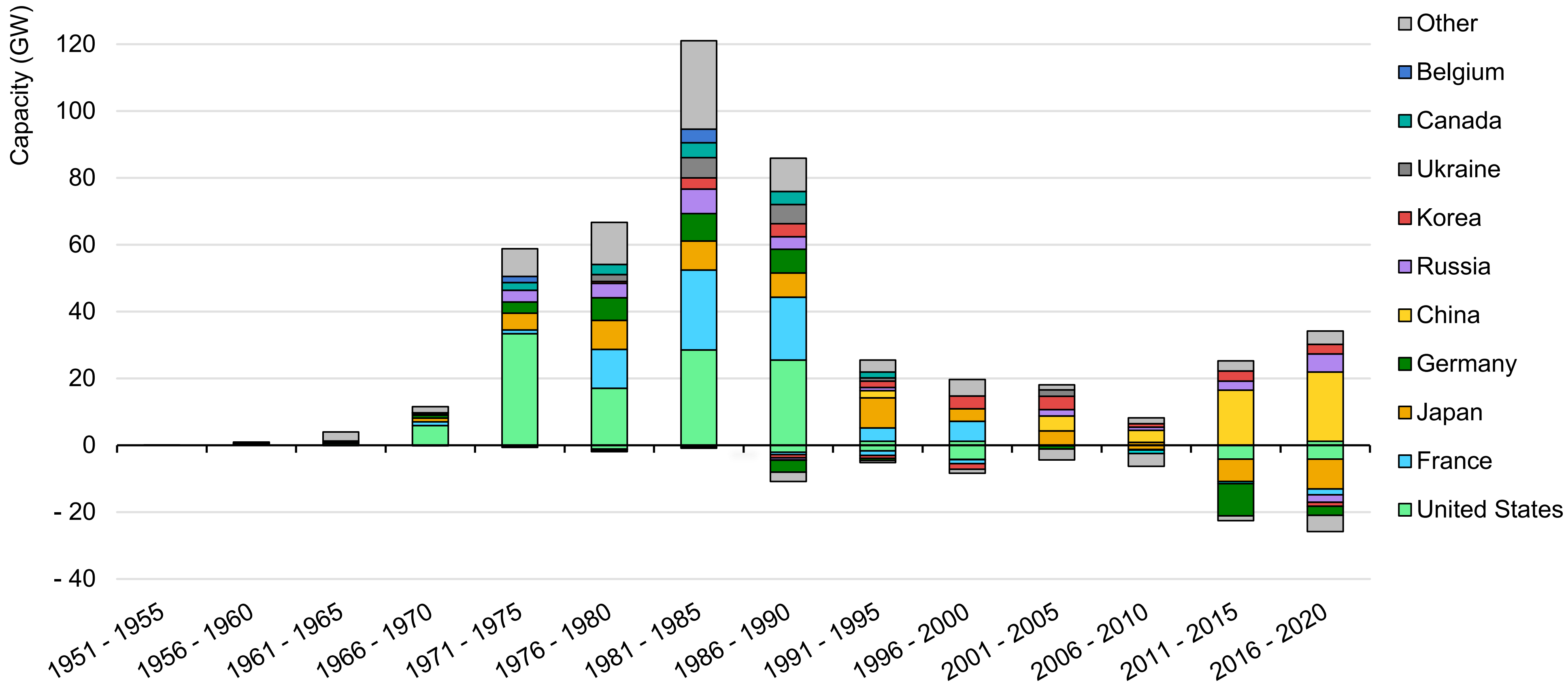
The Olkiluoto 3 plant in **Finland** (1.7 GW), under construction since 2005, is expected to begin commercial operation in 2022. A new plant at Hanhikivi is now expected to begin construction in 2023. **France**'s Flamanville 3 plant (1.7 GW) remains under construction, with the latest in-service date of 2023. In 2020, France closed two units at Fessenheim (together 1.8 GW), consistent with its strategy to reduce nuclear's share of generation to 50% by 2035. The **United Kingdom** has two units under construction at Hinkley Point (together 3.4 GW), with the first expected to enter service in 2026. In **Hungary**, construction is expected to start in 2022 of units 5 and 6 (each 1.2 GW) at the Paks nuclear power plant. **Poland** has expressed interest in constructing its first nuclear power plant.

By contrast, several advanced economies plan to retire nuclear units because of both policy and economic considerations. **Germany** will shut down three of its remaining six units at the end of 2021 (in total 4.3 GW), with the remaining 4.3 GW following at the end of 2022. **Belgium** plans to phase out nuclear (almost 6 GW) by 2025. However, there are considerations to keep two units in service. **Spain** plans to shut down all of its seven units by 2035, with no retirements expected in the next few years. **Switzerland**, which operates four nuclear reactors (in total 3.1 GW), decided after the Fukushima accident not to build new nuclear plants. Existing plants will be allowed to remain operating, however, as long as they are considered safe.

The future of nuclear power is uncertain in **Chinese Taipei**, where four nuclear reactors produce roughly 10% of electricity generation. Despite a planned phase-out by 2025, a national referendum is scheduled for 28 of August 2021 on restarting construction of two nuclear units at Lungmen.

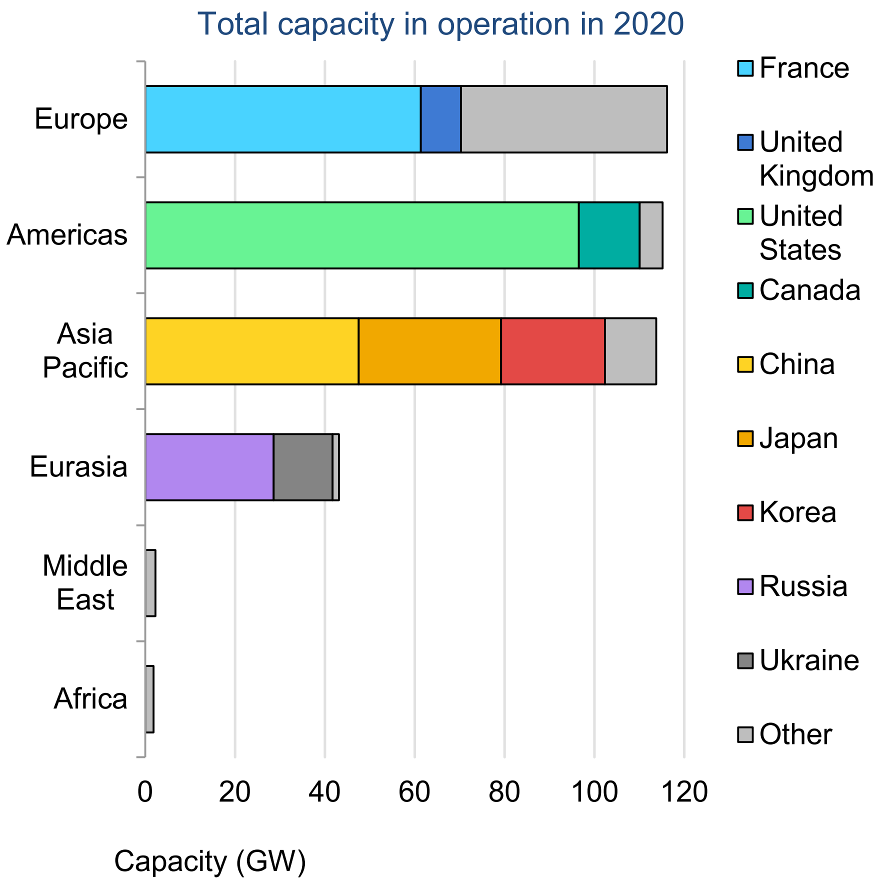
The majority of nuclear capacity additions in the past 20 years were concentrated in China…

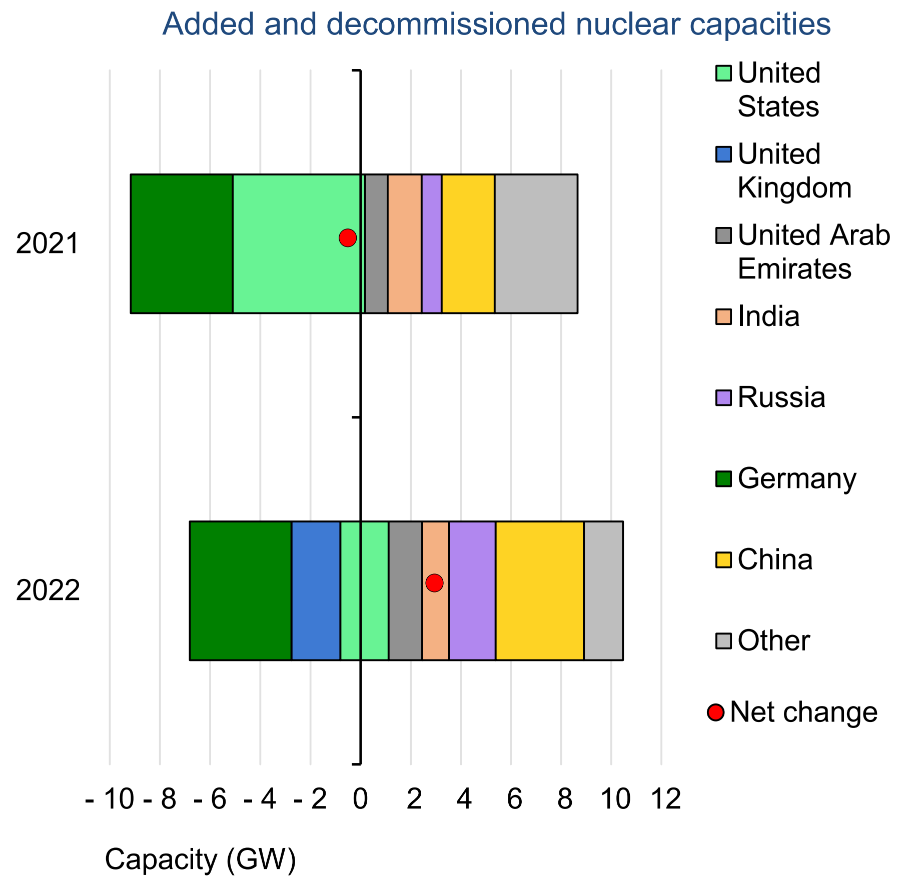
New added and decommissioned capacities in five year periods by country



Sources: IEA analysis based publicly available sources, including World Nuclear Association (2021), *Power Reactor Information System*.

… and more plants will be starting to operate in the next two years





Sources: IEA analysis based publicly available sources, including World Nuclear Association (2021), [Power Reactor Information System](#).

Lifetime extension of existing nuclear plants faces challenges

The long-term operation of nuclear power plants refers to operation beyond the initially intended lifetime, which is typically 40 years. When comparing nuclear long-term operation with new nuclear and other technologies, levelised generation costs appear very competitive. Long-term operation is particularly relevant in advanced economies where many units started to operate in the 1970s and 80s. Decisions need to be made now about whether these units will be retired or investments made in extending their lifetimes.

In the United States, for example, 90% of nuclear units have already been granted license extensions from 40 to 60 years. There are no limitations on how often a license can be renewed. In late 2019 and early 2020, the first two subsequent license renewals were approved, allowing two units each at the Peach Bottom and Turkey Point nuclear plants to operate up to 80 years.

Renewable energies are rapidly expanding and provide carbon-free electricity at increasingly competitive prices. If significant nuclear capacity was retired, however, fossil-fuel based generation and therefore emissions would increase, unless renewables are scaled up substantially, along with investments in grid infrastructure and storage.

Some companies are facing difficult market conditions that pose a barrier to investments needed to prolong operation of nuclear plants. In August 2020, Exelon Corporation announced the closure of the Byron and Dresden nuclear power plants in the United States in 2021, due to both being unprofitable.

While low wholesale prices in certain markets have pushed down profits, this does not necessarily indicate the need for market interventions. In certain markets, however, the contribution of low-carbon and dispatchable electricity generation (including nuclear) is not fully remunerated – for example, due to the absence of appropriate pricing of CO_2 emissions related to fossil-fuel based electricity generation.

An alternative to pricing CO_2 emissions is supporting low-carbon electricity generation directly. In the United States, five states with competitive wholesale markets have introduced support programmes for nuclear power plants, which are benefiting 14 units (10 plants) with almost 14 GW capacity. Although varying in their structure, most programmes involve zero emission credits, of which utilities are required to buy a certain amount.

Demand, supply and emissions forecast

Global overview

Global electricity demand set to rebound in 2021 and 2022

After global electricity demand declined by about 1% in 2020, we expect strong growth of close to 5% in 2021 and 4% in 2022, resulting in average annual growth in the years 2020 to 2022 similar to the average growth in the three years before the Covid-19 pandemic.

We expect the majority of demand growth to occur in the Asia Pacific region. **China** has contributed the majority of electricity demand growth in the past two decades. After accounting for 10% of global electricity demand in 2000, China's share increased to 20% in 2010 and above 30% in 2020. From 2000 until today, more than 50% of the global net increase in demand took place in China, increasing the country's per capita consumption more than five times to a level similar to the European average. In 2020, China was the only major economy where electricity demand grew, although at a rate (4%) significantly below average growth in the three preceding years (6.6%). Given the strong demand growth towards the end of 2020 and in the first half of 2021, we expect annual consumption to grow by 8% in 2021 and 6.5% in 2022.

In **India**, the third-largest electricity consuming country after China and the United States, annual demand decline by 2.4% in 2020, with a low point in March, when demand fell by 23% year-on-year. India's per capita electricity consumption of slightly above 1 MWh per year is significantly below the region's average of 3.3 MWh and shows potential for future growth. After a strong consumption increase in the first quarter of 2021 compared with the previous year, demand fell significantly in April as Covid-19 cases surged. Assuming a return to first quarter-level growth in the second half of the year, demand could grow by more than 6% in 2021 and more than 8% in 2022.

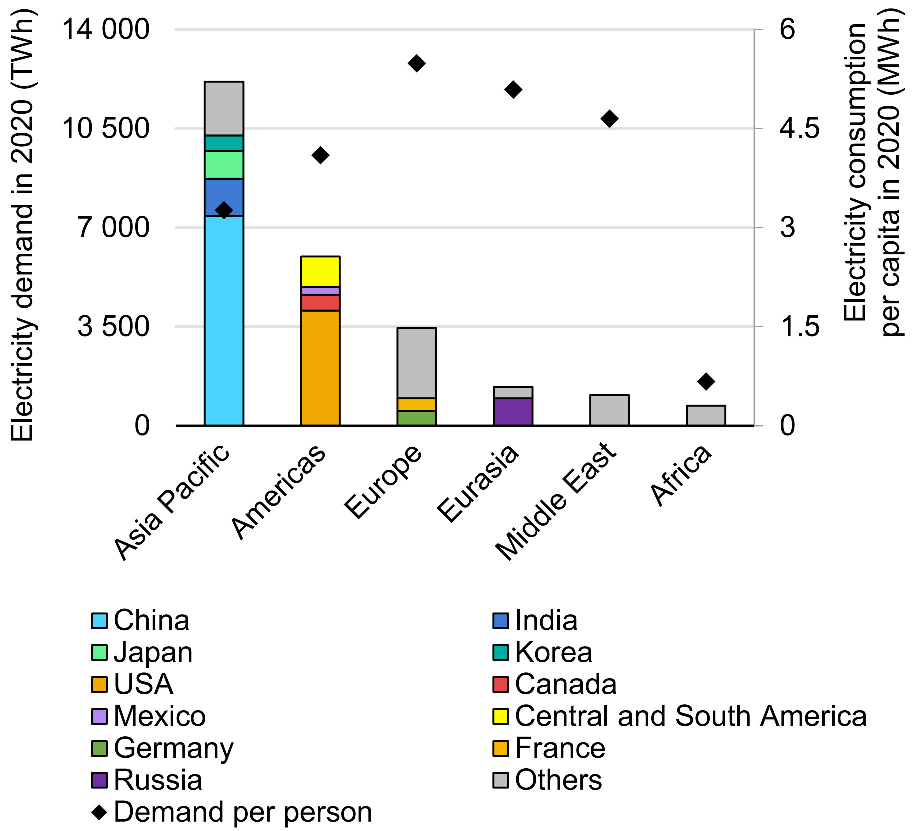
We expect demand in the **United States** to recover in 2021. However, in line with the declining trend in recent years, it will remain around 0.5% below the 2019 pre-pandemic level. For 2022, we expect slight growth of below 1%.

Demand decreased across **Europe** in 2020 by 4% on average and especially strongly in Italy, Spain and the United Kingdom, with drops of 6%. As vaccination programmes advance and the commercial sector reopens, we expect demand to rebound by close to 4% in 2021 – supported by cold temperatures early in the year – and 2% in 2022.

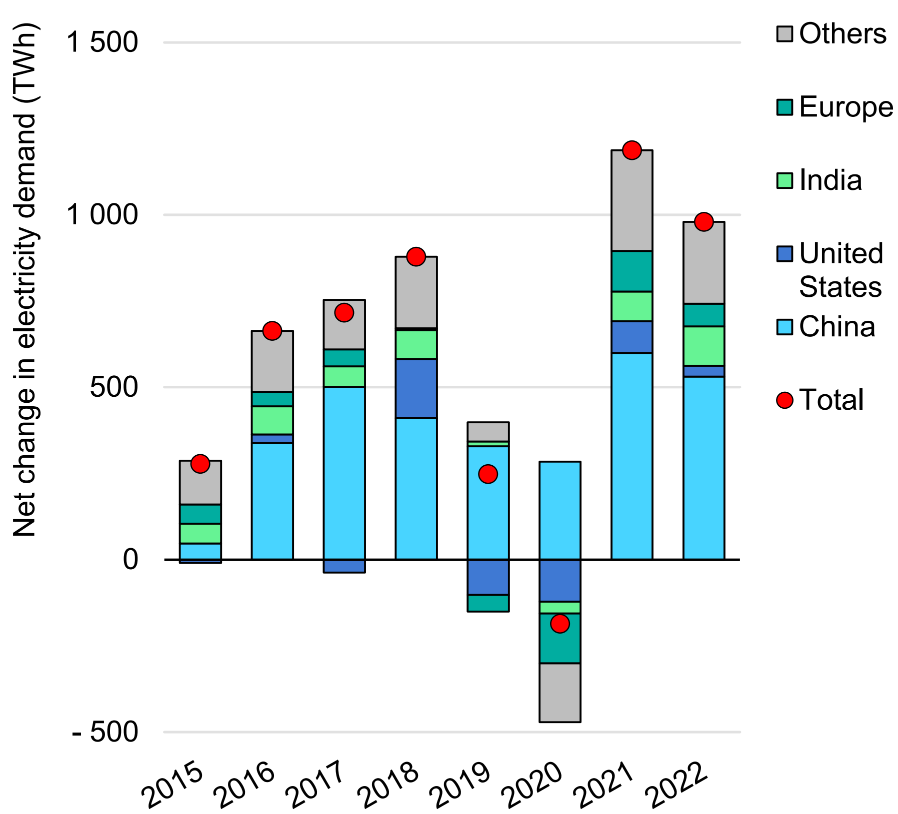
Electricity demand in **Russia**, by far the largest consumer in Eurasia and the fourth-largest in the world, grew significantly early this year. After a 3% year-on-year drop in annual demand in 2020, demand was 2.8% higher than 2019 in the first third of the current year. For 2022, we expect demand to return to recent trends and grow by about 1%.

Significant recovery of global electricity demand expected in 2021

Distribution of electricity demand in 2020



Historical and expected changes until 2022



Source: IEA analysis based on data from IEA (2021), *Data and statistics*.

Growth in low-carbon generation is insufficient to cover growing demand…

Fossil fuels are still the dominant energy sources for generating electricity. Coal made up 34% and gas 25% of global generation in 2020, while low-carbon generation (renewables and nuclear) together accounted for 37%, up from 32% in 2015.

Renewable electricity generation has been on the rise for around 15 years. While hydro is still the largest renewable electricity source, wind was responsible for 40% and solar PV 30% of renewable generation growth between 2015 and 2020. In 2020 wind provided 22% of renewable generation and solar PV 11%, while hydro provided 58%. Total generation from renewables grew by 7% in 2020. We expect growth of 8% in 2021 and more than 6% in 2022.

Nuclear generation has declined recently, with production almost 3% lower in 2020 than ten years earlier, partly because of low demand levels forcing plants to produce below maximum capacity, especially in Europe. Nuclear generation declined by 4% in 2020. We expect it to recover by 1% in 2021 and 2% in 2022.

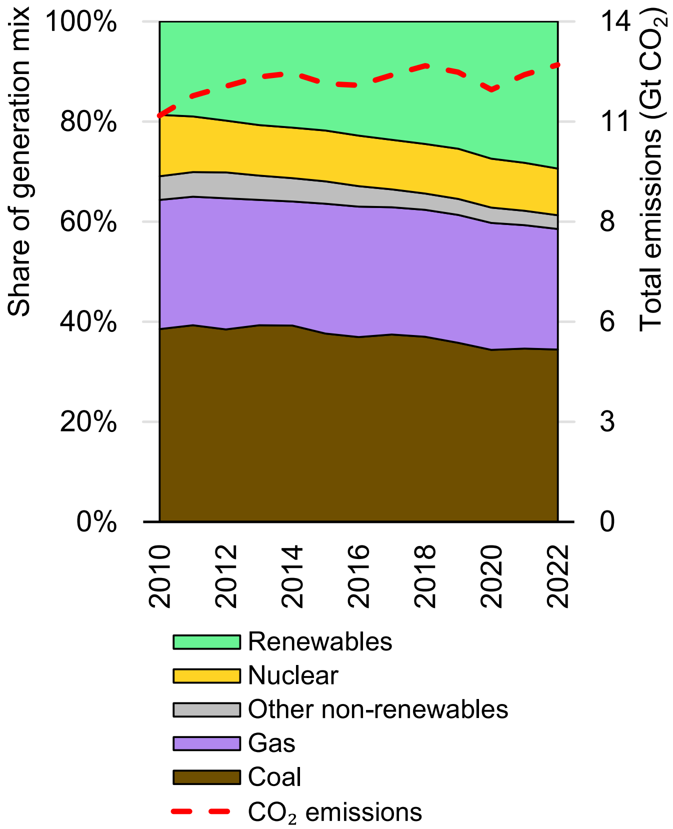
Despite rapid growth, low-carbon generation is struggling to keep up with electricity demand growth. Before the Covid-19 pandemic, growth of low-carbon generation exceeded demand growth only once, in 2019, and came close once, in 2015 – both years with exceptionally low demand growth. The expected strong demand growth in 2021 and 2022 is likely to significantly exceed growth of low-carbon generation. We expect **coal-fired electricity generation**, supported by increasing gas prices, to increase by almost 5% in 2021 and a further 3% in 2022, after having declined by 4.6% in 2020. As a result, coal-fired electricity generation is set to exceed pre-pandemic levels in 2021 and reach an all-time high in 2022.

Gas-fired generation, after declining in 2020 by 2%, is expected to increase by 1% in 2021 and 2% in 2022 – and is thus growing more slowly than coal-based electricity generation. Reasons for this slow growth include the small role of gas in fast-growing countries in the Asia Pacific region, its loss of market share in the United States, the largest gas-consuming country, and increasing competition from renewables in Europe.

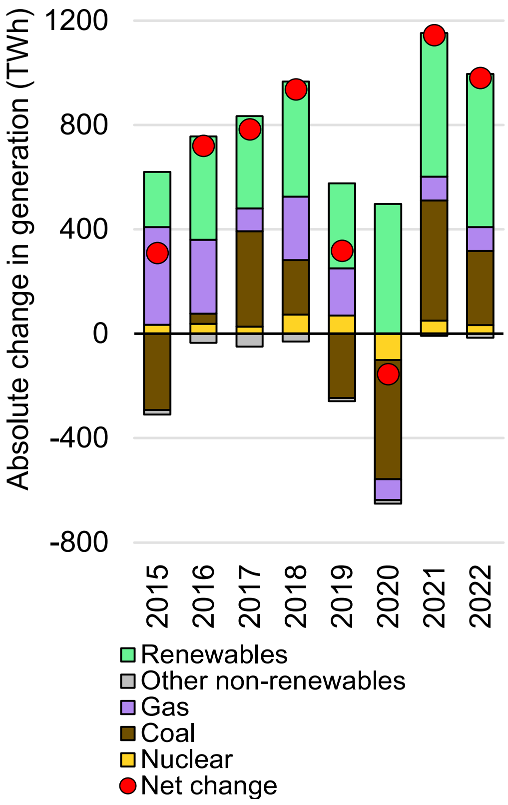
We expect **oil** to continue its decline, with the drop of 4% in 2020 followed by reductions of 2% in 2021 and 4% in 2022.

…resulting in additional fossil-fuel based electricity generation and CO_2 emissions

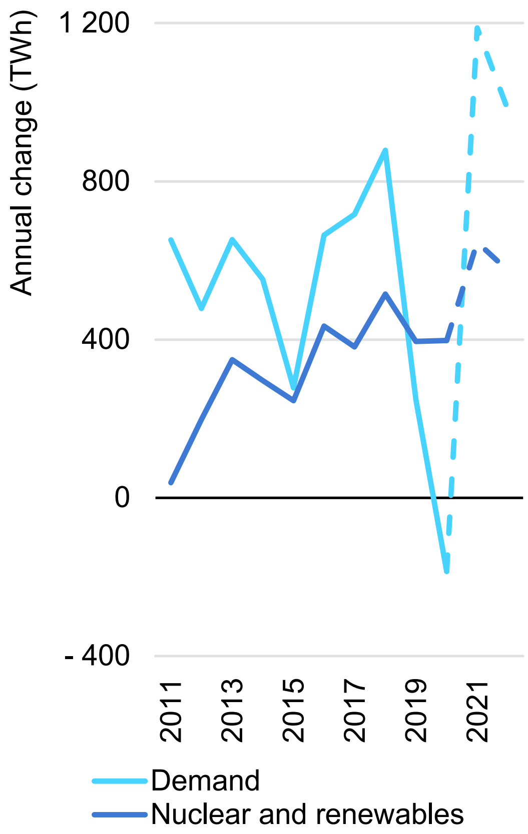
Global generation mix and emissions



Change in electricity generation generation growth



Annual demand and low-carbon



Source: IEA analysis based on data from IEA (2021), *Data and statistics*.

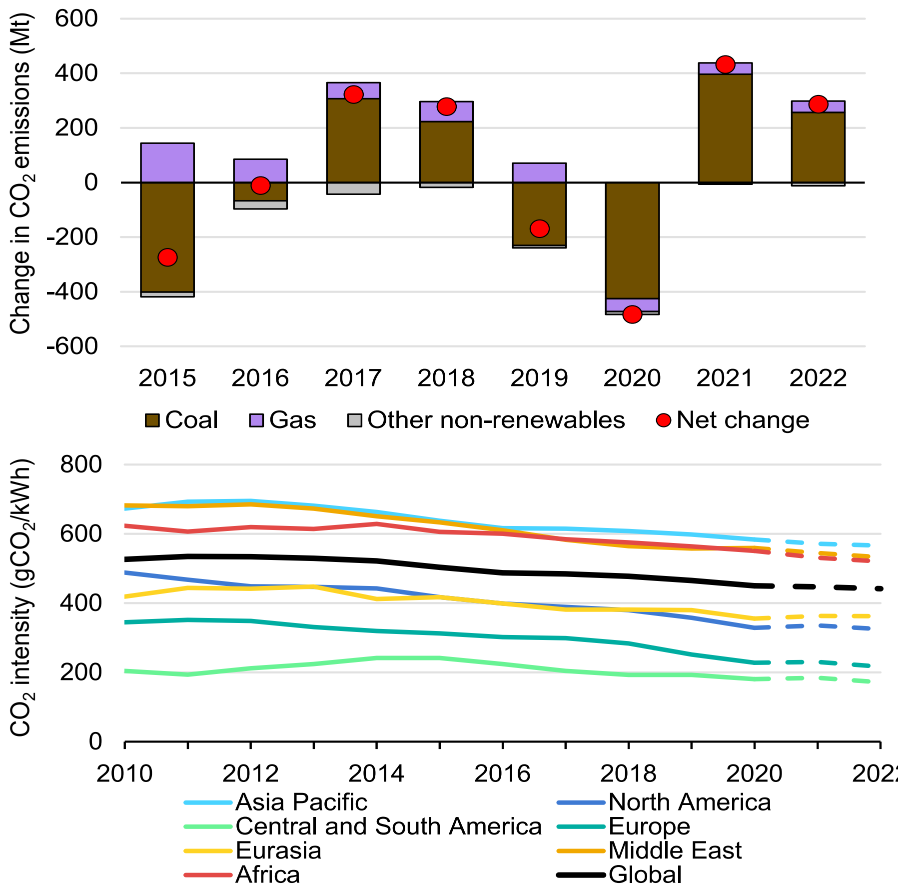
CO_2 emissions are expected to increase again in 2021 and 2022

Due to increasing fossil fuel-based electricity generation, we expect global CO_2 emissions from the sector to rise, reversing the decline of the past two years. After reductions of 1% in 2019 and 3.5% in 2020, forecast increases of 3.5% in 2021 and 2.5% in 2022 would result in sectoral emissions reaching an all-time high in 2022, exceeding the 2018 peak by close to 0.5%.

The global emissions intensity of electricity generation declined by more than 3% in 2020, after a 2% reduction in 2019. In both years, weak demand meant that low-carbon generation was able to squeeze out fossil fuels, in particular coal, and thus accelerated emissions intensity reductions. With coal-fired generation coming back, emissions intensity reduction will slow to around 1% per year in 2021-2022.

In the IEA's Net-Zero Emissions by 2050 Scenario, the emissions intensity of electricity generation declines by 6% a year on average between 2020 and 2025, while demand grows by an average of 2.8% annually. By contrast, emissions intensity fell by only 3% in 2020, enabled by a decline of demand of 1%, illustrating the extent to which the electricity system has to change to reach the net-zero emissions by 2050.

Emissions and emissions intensity of electricity generation



Source: IEA analysis based on data from IEA (2021), *Data and statistics*.

Europe

Electricity demand in Europe is expected to reach pre-pandemic levels in 2022

Demand in Europe fell significantly because of the Covid-19 pandemic and the measures governments took to contain the virus. During the first restrictions in the second quarter of 2020, demand on individual days in some countries dropped by as much as 20% and even more in some countries – for example, in France, Italy and Spain – compared with weather-corrected demand during the same period in 2019. After measures were relaxed, European demand recovered but remained below pre-pandemic levels throughout the year, resulting in an overall annual decrease of 4%. Demand from the six largest electricity consumers dropped by 4.6% (Germany) to 5.8% (Spain). The only exception was Turkey, with 0.6% growth.

Demand rebounded in many countries in the second half of 2020, but increasing Covid-19 cases and subsequent new restrictions impeded the recovery. As vaccination campaigns progress, however, and all parts of the economy reopen completely during the second half of 2021, we expect European demand to grow by more than 3%. Demand will be supported by the strong economic outlook, with economic growth of 4.3% after a 5.8% decline in 2020, and colder temperatures early in the year.

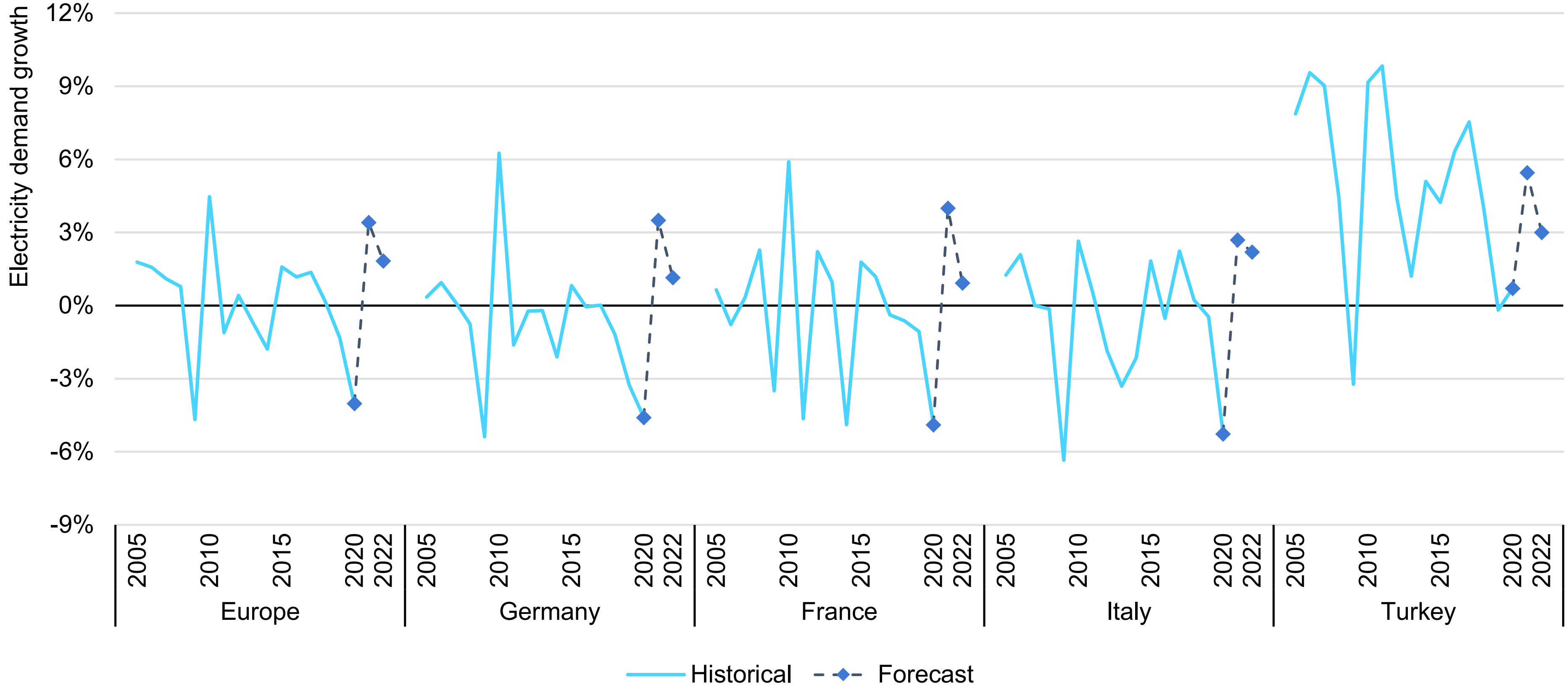
We expect European electricity demand to increase again in 2022, by almost 2%. In total, this means 2022 demand would exceed the 2019 level by 1%.

The demand trend differs significantly between countries, however. Electricity demand peaked in many European countries a few years ago and then remained unchanged or declined. In both Germany and the United Kingdom, for example, there was a 1% average annual decline between 2015 and 2019, while France and Spain were almost stable. Other countries showed growth over the same period, including Turkey (+4.4%), Poland (+2%), the Czech Republic and Romania (1% each) and Italy (+0.4%). Overall average European demand growth was 0.3%.

We expect demand in 2022 to exceed 2019 demand primarily in countries that also grew before the pandemic. Turkey is likely to contribute the majority of the absolute growth, for two main reasons. First, despite rapid growth in recent years, Turkey's average annual electricity consumption per capita of 3.4 MWh is, still significantly below the European average of 5.6 MWh in 2018. Second, the economic outlook in Turkey, where GDP in 2022 is expected to be 11.7% above the 2019 level, significantly exceeds the European average of 2.2%.

Slow demand recovery in Europe

Development of electricity demand in Europe



Source: IEA analysis based on data from IEA (2021), *Data and statistics*.

Low wind-based generation in early 2021 leaves room for coal and gas

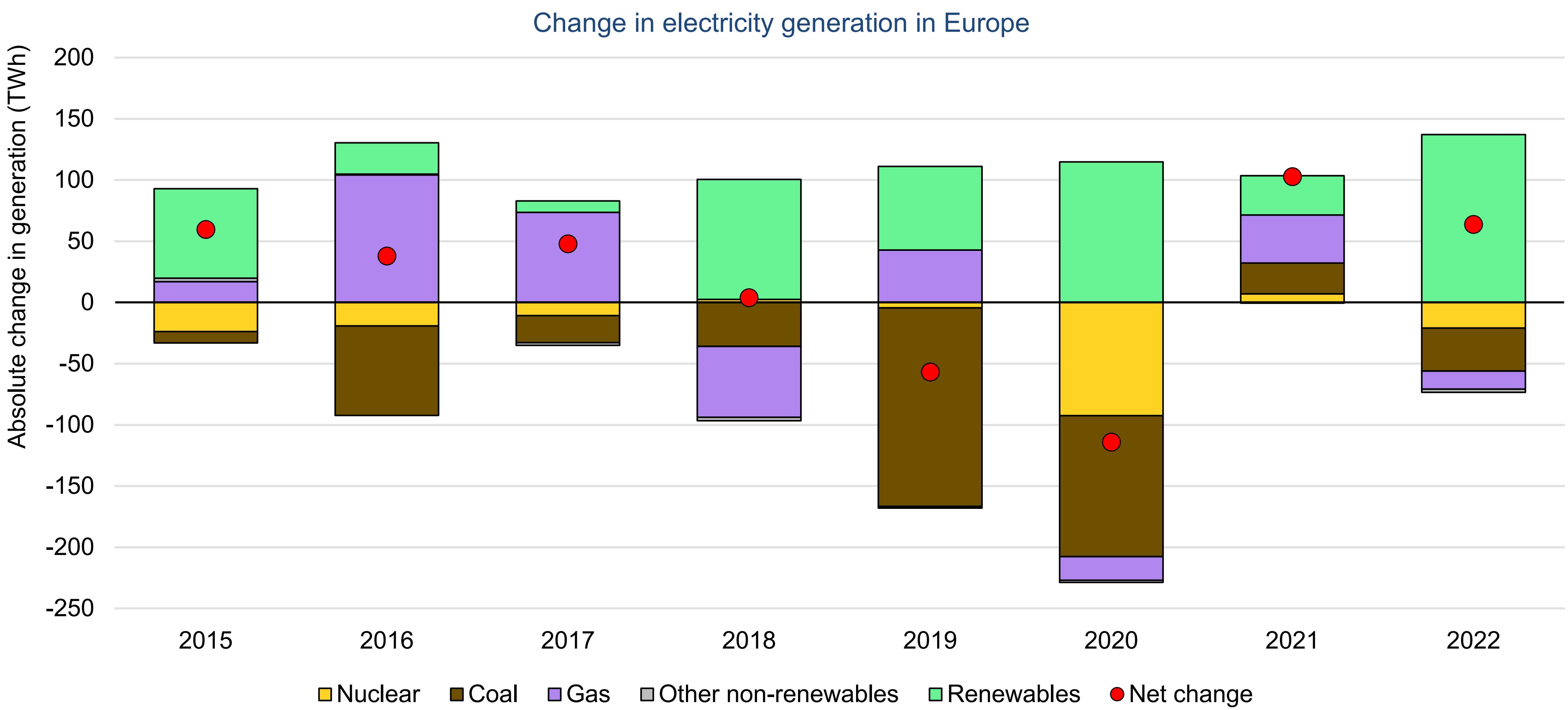
Renewables are replacing thermal generation in the supply mix in Europe. With demand growth being moderate, additional renewable results directly in reduced fossil fuel-based generation. However, the seasonal and annual variability of variable renewables can be significant. Although capacities are expected to grow strongly in 2021 – by more than 7% for wind and 14% for solar PV – total generation stagnated in the first half of the year compared with the same period in 2020, mostly because wind generation fell by 7%. We expect renewables to pick up in the second half of 2021, resulting in an overall increase of more than 2%, the lowest since 2017. In 2022, growth could reach 9% if capacity factors return to historical averages.

We expect **nuclear**-based production to recover slightly in 2021, rising 1% after having fallen by 11% in 2020. Utilisation rates are rebounding together with demand. In addition, the Mochovce 3 unit (0.5 GW) in the Slovak Republic is expected to start commercial operation in 2021. These increases are counterbalanced, however, by the retirement in 2020 of the Fessenheim plant in France (1.8 GW) and Ringhals in Sweden 0.9 GW. With the retirement of 4.3 GW at the end of 2021 in Germany, 2 GW in the United Kingdom and 1 GW in Belgium before the end of 2022, nuclear electricity generation is likely to drop again in 2022, by 3%, even if the Olkiluoto 3 unit in Finland starts commercial operation.

Gas-fired plants have taken over market share from **coal** in recent years because gas prices have been low and EU Emissions Trading System carbon prices have risen in tandem with coal phase-outs. Especially low gas prices in 2020 enabled gas to limit its decline to below 3%, while coal fell by 17%. In the first half of 2021, however, coal and gas grew strongly due to recovering electricity demand and low renewable generation. For the full year, we expect gas to increase by 5.5% and coal by 4.5%. In 2022, due to higher renewable generation and continued coal-phase outs, we expect gas to decline by 2% and coal by more than 6%. Evolution of the generation mix will vary across the region. Although gas-fired plants increasingly outcompete coal plants, they will be under pressure from rising renewable generation. This is particularly the case in countries that have or are close to phasing out their last coal power plants – a process that accelerated in 2020 – including Italy, Spain and the United Kingdom.

Several new **interconnectors** will help Europe achieve ambitious trade capacity targets, including IFA-2 between the United Kingdom and France (1 GW, 2021), North Sea Link (United Kingdom-Norway, 1.4 GW, 2022) and NordLink (Germany-Norway, 1.4 GW, 2021). By connecting demand, supply and storage capacities over large geographical areas, they will facilitate the integration of rising variable renewable generation and contribute to security of supply.

In Europe, renewable electricity generation is replacing fossil fuels



Source: IEA analysis based on data from IEA (2021), *Data and statistics*.

The emissions intensity of European electricity generation continues to decline despite reduced nuclear-based generation

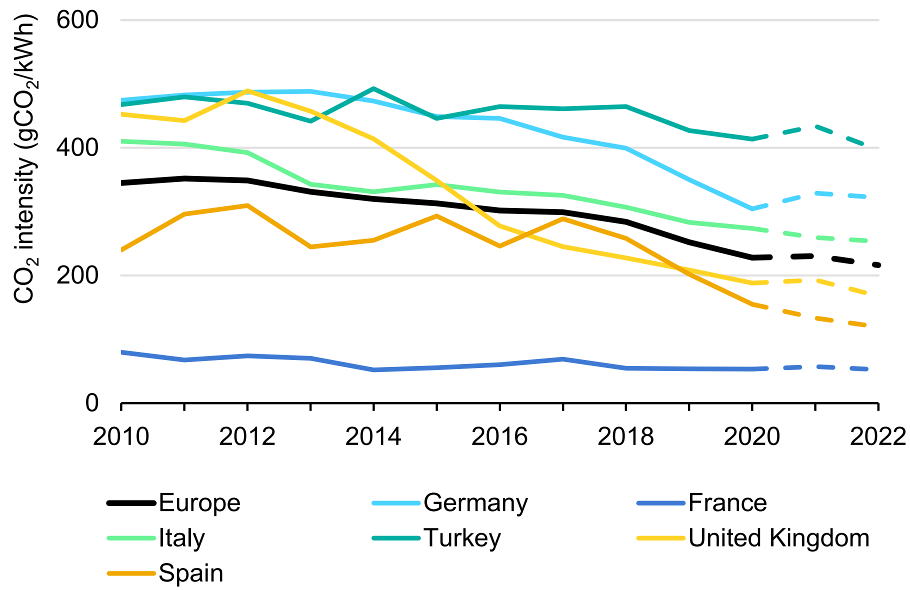
Overall, we expect emissions from electricity generation in Europe to increase by 4% in 2021 as fossil fuels fill the gap left by low renewables generation. In 2022, assuming that renewable capacity factors return to historical averages, emissions could decline by 5%.

The CO_2 emissions intensity of electricity generation is also affected by this development: After an average annual decline of almost 9% between 2017 and 2020, we expect an increase of around 1% in 2021, the first since 2011. However, in 2022 emissions intensity could drop again, by 6%.

Having left the European Union, the United Kingdom is no longer participating in the EU Emissions Trading System. In its place, the UK Emissions Trading Scheme started in January 2021. When trading started in mid-May, prices ranked around GBP 50/tCO_2, slightly above EU ETS prices.

The European Union is in the process of updating its targets to a net emissions reduction of 55% by 2030 compared with 1990 levels, up from 40%. To this end, proposals for adjusting the EU Emissions Trading System will be brought forward by the European Commission by July 2021. A further tightening of the emissions cap will put additional pressure on fossil fuel-based electricity generation and could speed up the phase-out of coal power plants.

CO_2 emissions intensity in Europe



Source: IEA analysis based on data from IEA (2021), *Data and statistics*.

Americas

Demand will rebound to 2019 levels in 2021 but moderate in 2022

Demand in the Americas was pushed down significantly by the Covid-19 pandemic and the measures taken by governments, particularly lockdowns in the first half of 2020. Demand recovered in the second half of the year but remained below pre-pandemic levels, resulting in an overall annual decrease of almost 3% in 2020. In Canada, Mexico and the United States, demand fell uniformly by 3%. In South America, demand declined in most countries, including by 3.6% in Brazil. In Chile, exceptionally, demand increased by 1.2%.

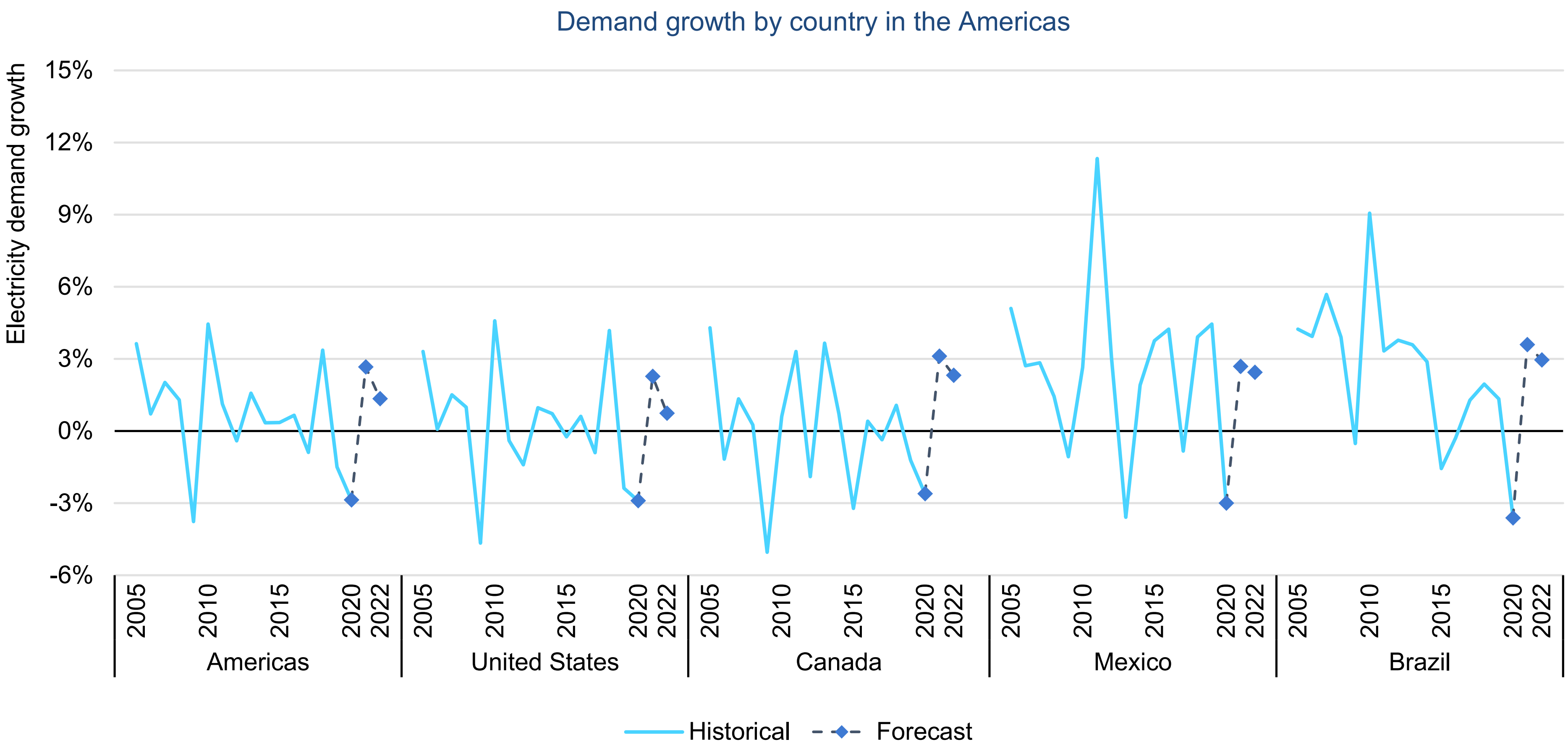
As economies recover from the Covid-19 pandemic, GDP growth will rebound in all countries in the region in 2021. A strong rollout of vaccinations boosted economic activity in the United States in the first half of the year and continued recovery in the second half could result in annual GDP growth of 7%. GDP is expected to grow by around 5.5% in Canada and Mexico and 3.8% in Brazil.

Electricity demand will follow a similar trajectory to that of GDP but changes will be more muted. The pace of the return to normal activities will dictate the size of the rebound in different countries. We expect electricity demand to increase by 2.7% overall compared with 2020, leaving the region slightly below 2019 levels. Demand in the United States will be 0.7% below 2019 levels in 2021, while demand in Brazil, Canada and Mexico is expected to return to roughly its 2019 levels. Demand in Argentina is expected to grow by 2.7% over 2019 levels in 2021.

In 2022, a return to long-term GDP growth trends will translate into a reduction in demand growth in the region. In 2022 GDP is expected to grow by 3.5% in the United States, 4.7% in Canada, 3.0% in Mexico and 2.6% in Brazil. We expect demand growth of 1.3% in the Americas overall, around 1% in the United States, 2% in Canada and Mexico, and 3.0% in Brazil.

Commercial and industrial demand were the two sectors most affected by the Covid-19 pandemic. In the United States, commercial demand is expected to increase by 1.4% in 2021 after falling by 6.3% in 2020. Residential demand grew by 1.5% in 2020 as more people worked from home and is expected to increase by 2.8% in 2021. Industrial demand is expected to expand by 2.8% in 2021 after falling by 8.3% in 2020 but will remain nearly 12% below the historical peak it reached in 1999, continuing its long-term downward trajectory.

After the Covid-19 related drop, electricity demand in the Americas will only exceed 2019 values in 2022



Source: IEA analysis based on data from IEA (2021), *Data and statistics*.

Renewables supply is growing in the Americas and gas-fired generation declines

Renewable generation continues its increase in both absolute and relative terms in the Americas overall. Total renewable generation, including wind, solar and hydro, reached 2 200 TWh in 2020, an increase of 38% since 2010. The pace of growth is accelerating, almost doubling from an average of 42 TWh per year between 2011 and 2015 to reach 81 TWh per year between 2016 and 2020. We forecast that annual renewable generation will further increase by more than 6% in 2021 and 7% in 2022, with a fairly even share of wind and solar PV additions.

Hydro generation is expected to decline in Canada and the United States in 2021 because water supplies are dwindling. The water supply at the Dalles dam in Oregon, a benchmark for production on the Columbia River system that supplies one-third of US and close to 20% of Canadian hydropower, is forecast to flow at only 83% of its 30-year average for the April to September 2021 runoff season. While individual years show significant volatility (2020 runoff was 104% of the 30-year average), there is a longer-term pattern of decreased runoff volumes for power generation. The most recent 30-year normal flow volume (1981-2010) is more than 6% below the previous 30-year normal from 1971-2000.

Natural gas-fired generation is expected to decline by more than 3% in 2021 after a steady increase in total output and share of generation since 2010. This decline is the result of an expected increase in competition between the electric power sector and other uses of natural gas as economic activity rebounds, including exports of liquefied natural gas (LNG) to lucrative overseas markets. In the United States, LNG export capacity grew strongly in the past five years to reach 10% of the daily average production by the end of 2020. Further capacity is under construction and expected to be in service before 2025.

The competition for use of natural gas as economic activity increases is reflected in the trajectory of natural gas prices. From an average of USD 2.67 per million British thermal units (MBtu) in 2019, the benchmark Henry Hub natural gas price fell to USD 1.70/MBtu in September 2020 on weak domestic and foreign demand. The price has since rebounded to USD 2.77/MBtu in April 2021. Futures prices indicate continued strengthening in 2021 to USD 3.34/MBtu in December 2021.

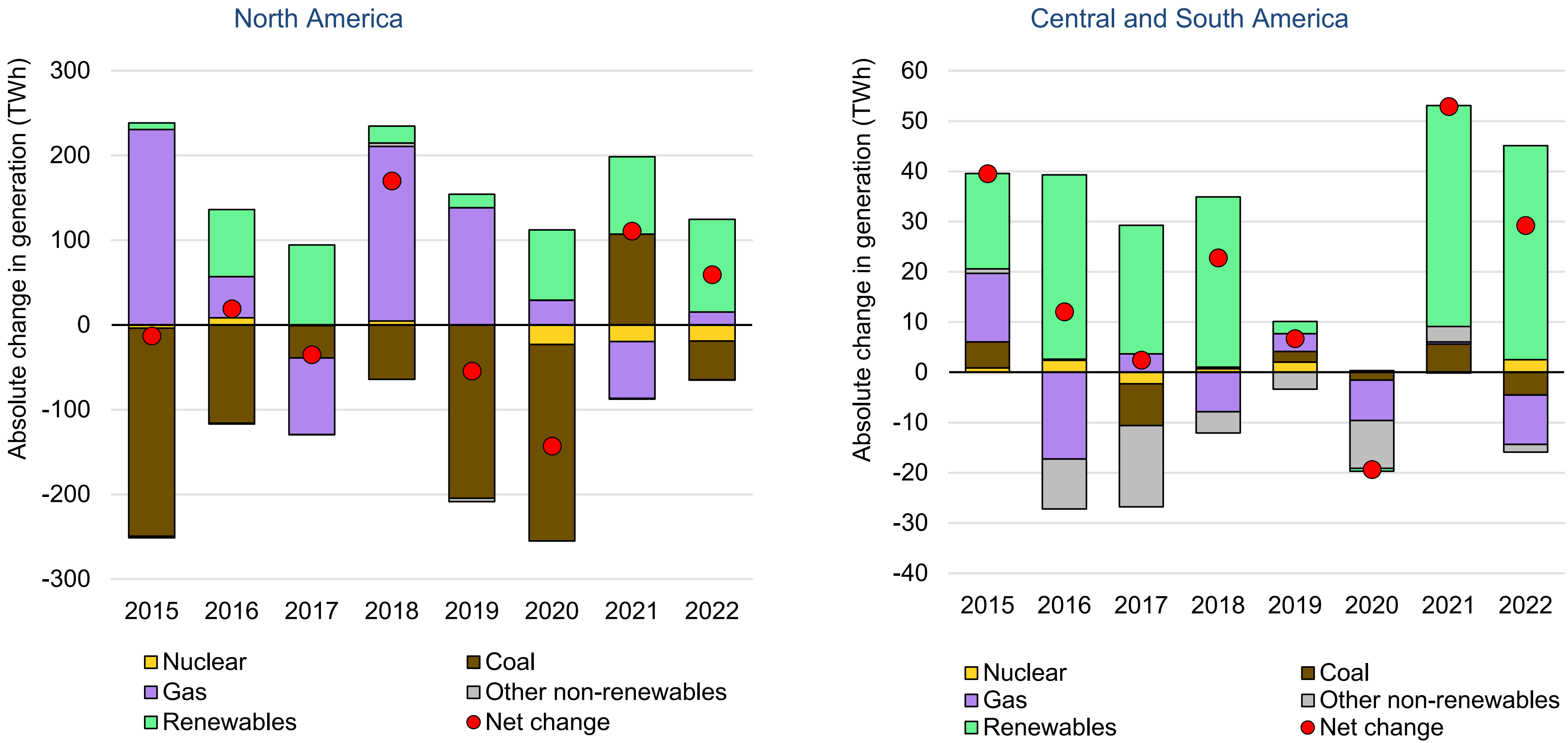
We expect gas-fired electricity generation to remain stable in 2022 in the Americas, with some gains in the United States at the expense of coal and a decline in Central and South America caused by an increase in renewables.

Coal-fired generation will be the main beneficiary of the increase in natural gas prices, with output in the region expected to increase by 12% in 2021 after falling by 19% in 2020. This is reflected in data for the first five months of the year in the United States, where coal output is up 36%. The rebound in generation is expected to be short-lived as 2.7 GW of capacity is due to be retired in the United States in 2021. In Canada, total capacity is expected to decline from 8.4 GW at the end of 2020 to 2.8 GW in 2023 as utilities in the province of Alberta have announced plans to retire coal-fired plants or convert them to run on natural gas.

We expect capacity retirements, increasing renewables and increasing gas competitiveness to push down coal-based generation by almost 5% in 2022.

Nuclear power plant output is expected to decline by almost 2% in 2021. Five units will be retired across three plants in the United States, decreasing capacity by 5.1 GW. In addition, outages due to refurbishment operations at two units in Ontario will lower output in Canada. The Indian Point 3 plant, close to New York, closed in April and two nuclear plants in Illinois (Byron and Dresden) will close in the second half of the year, – contributing to a further 2% decline in the region in 2022.

Renewables electricity generation continues to expand in the Americas



Source: IEA analysis based on data from IEA (2021), *Data and statistics*.

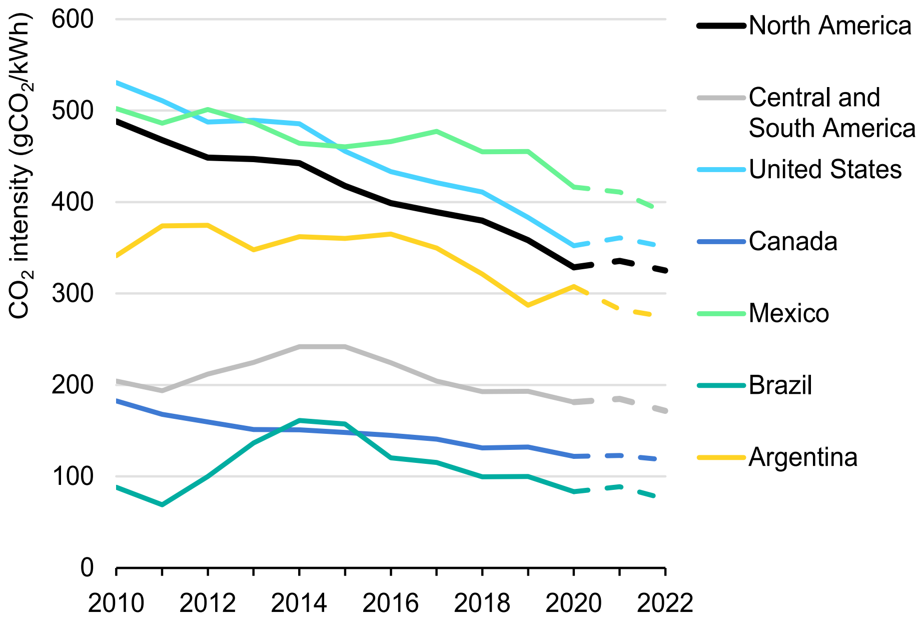
Emissions declines take a pause due to the increase in coal generation in the Americas

The intensity of emissions in the Americas will continue on a downward trajectory in most countries due to the long-term replacement of coal-fired generation with gas and renewables. In the United States, CO_2 intensity decreased by 34% between 2010 and 2020. In Canada over the same period, the drop was almost 32%, though starting from a much lower level.

Declines were less pronounced in Mexico (17%) and Brazil (5%). Unlike Canada and the United States, Mexico lacks abundant coal generation so emissions intensity can primarily be reduced by increasing the share of low-carbon generation. Today, Mexico's overall emissions intensity is higher than others in the region, despite minimal coal-fired generation, as it lacks abundant low-carbon generation from renewable or nuclear sources. Brazil's hydro-dominated system is reflected by an absolute CO_2 intensity of below 100 gCO_2/kWh since 2018, the lowest of the major economies in the region.

The increase in coal output in the region in 2021 will slow the rate of emissions declines in the short term, particularly in the United States. We project that emissions intensity will actually increase slightly in the United States in 2021, by 2.5%, before returning to the 2020 level in 2022.

CO_2 emissions in the Americas



Source: IEA analysis based on data from IEA (2021), *Data and statistics*.

Asia Pacific

Demand in the Asia Pacific continues to grow

Electricity demand grew in the Asia Pacific region as a whole in 2020 in spite of contractions in many countries. Overall demand was powered by China, where Covid-19 hit earliest but a recovery soon followed.

In early 2021, the pandemic's impact ranged widely across the region, with some countries sustaining very low numbers of new cases and others experiencing the most severe waves of new infections to date. Demand growth is expected to rebound in most countries this year but uncertainty regarding the further impact of the pandemic remains.

Demand in the Asia Pacific region is expected to continue growing strongly in 2022, pushed up by emerging and developing economies. In developed economies, a rebound for 2021 is expected to stabilise to low growth in 2022.

China is the largest contributor to demand growth in the region. The majority of absolute demand growth in China comes from industrial demand, despite a year-on-year growth rate for the sector slightly below the residential and commercial sectors. Following a drop in electricity demand in the first quarter of 2020, China recovered as normal activities resumed with the support of stimulus measures, leading to year-on-year growth of 3.1%. Demand from the primary industry sector grew by 10% in 2020. In the first quarter of 2021, overall demand in China continued to grow rapidly, reaching 21.2% year-on-year, dominated by the industrial and manufacturing sectors. In total, we expect 8% demand growth in 2021. In 2022, strong demand growth is expected to continue at above 6% year-on-year.

This year, a humanitarian crisis has emerged in **India** with severe new waves of Covid-19 infection. While electricity demand has remained more robust than during the first lockdowns last year, an atypical drop in April demand is likely to reflect the impact of the current health crisis on economic activity. Due to strong demand growth early in 2021 after the decline in 2020, we still expect 6% annual growth in 2021, followed by 8% in 2022. However, this will depend on the evolving pandemic situation.

In **Japan** and **Korea,** demand fell in the year before the Covid-19 pandemic, as well as falling slightly last year. Although new waves of infections in both countries in 2021 have exceeded reported cases from last year, we expect electricity demand to rebound this year in line with the positive economic outlook, by about 1% in Japan and 2% in Korea, with gradual growth in 2022 of 1% in each country.

In **Thailand,** electricity demand has fallen since the beginning of 2020 compared with previous years because of Covid-19 and unusual weather. Compared with 2019, overall electricity demand dropped by 3%, with the largest decrease in the business and agriculture sectors, where demand fell by more than 10%. Industrial demand dropped by almost 5%. The drop in electricity demand continued in the first quarter of 2021 as the country faced a new outbreak of Covid-19, which is the largest that the country has experienced and has continued through a large part of the first half of the year. This has led to tighter restrictions on business and social activities, which are expected to continue in the second half of 2021. We therefore expect demand to remain below the 2019 level in 2021, at 2.5% above 2020, and grow by more than 4% in 2022.

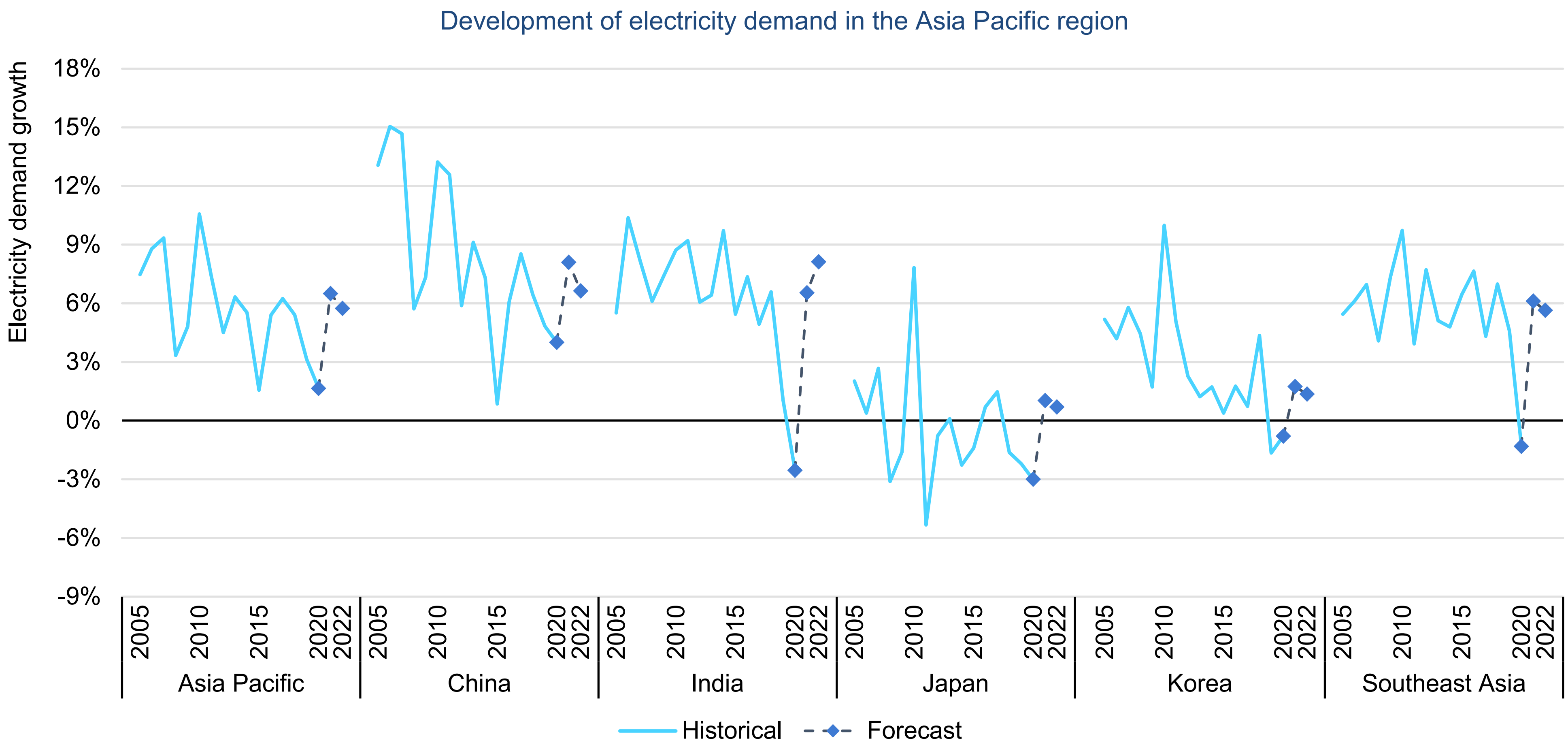
In **Viet Nam**, due to effective control of the pandemic, the economy experienced only minor interruptions in 2020. Electricity demand grew by 4%, although this represented a slowdown from an annual rate close to 10% in recent years. In 2020 GDP grew by 2.9%, powered by the industrial sector. Industrial production is expected to sustain growth of around 10% in the coming years, boosted by new trade agreements covering light manufacturing sectors. The commercial sector is only expected to fully recover from Covid-19 interruptions by 2022. In total, we expect 11% growth in 2021 and 7.5% in 2022.

Singapore experienced a dip in demand in April and May 2020 due to the pandemic. However, by August 2020 peak demand had rebounded as health measures kept the pandemic under control. Demand is expected to continue to increase for Singapore in the coming years, augmented by growing sectors such data centres.

In **Indonesia,** several waves of infections led to changes in activity such as work-from-home measures, reducing demand by 2.6% year-on-year in 2020. We expect demand to recover this year and grow by 6% year-on-year in 2021 and 2022. However, the pandemic has increased uncertainty about the growth rate of electricity demand in years to come, leading the utility Perusahaan Listrik Negara (PLN) to incorporate several demand projections into their power development plans.

After a contraction in electricity demand of 3% in 2020 due to Covid-19 in **Australia,** a return to the recent trend of slow positive growth of under 2% is expected for this year, dampened by mild summer weather. Industrial demand is the main contributor to growth, with demand reduction due to energy efficiency expected to offset growth in the residential and commercial sectors. While underlying demand is increasing gradually, operational demand (excluding behind-the-meter generation) is expected to decline slightly in the main electricity markets due to ongoing uptake of rooftop solar PV.

Strong demand growth is expected in the Asia Pacific region, led by emerging and developing economies



Source: IEA analysis based on data from IEA (2021), *Data and statistics*.

Renewables and coal generation are both growing in the Asia Pacific region

The Covid-19 pandemic suppressed electricity demand growth in the Asia Pacific region in 2020. At the same time, deployment of renewables continued. As a result, all of the region's growth in electricity demand was able to be met by increased renewables supply, while coal generation reduced slightly from 2019.

As electricity demand growth rebounds in 2021, however, only half of the increased supply is expected to be provided by renewable energy, with coal supplying almost 40% of new demand. These shares are largely shaped by China, which is expected to contribute 80% of the increase in total generation for the region this year.

In 2022, all regions are expected to add significant solar and wind capacity, continuing the increase in renewable energy supply, although this falls to below 40% of the total supply increase. Coal supplies over half of new demand while nuclear contributes 8% of the supply increase.

Coal generation will continue to increase in the region in the coming years because year-on-year demand growth is still strong in several countries, including China, India, Indonesia and Viet Nam.

In **China**, hydropower, wind and solar accounted for almost 70% of the newly installed generation capacity in 2020 of over 190 GW. Despite this strong increase in renewables, coal generation still rose by almost 60 TWh in 2020, and is expected to increase further by an annual average of 300 TWh in 2021 and 2022. Renewables generation rose by 190 TWh or close to 10% year-on-year in 2020, and is expected to climb by 9% in 2021 and 15% in 2022. This means that for 2021 and 2022 combined, absolute coal-based electricity generation is growing faster than all renewables combined.

In India, which is continuing its renewables ambition, we expect one-fourth of new demand to be met by renewables in the next two years. At the same time, we expect increased coal generation to supply more than two-thirds of growth. Nuclear generation is expected to make up most of the remainder of increased supply.

After a reduction in demand last year in **Indonesia**, a return to growth in 2021 is expected to be met by a fairly balanced combination of coal-fired generation, renewables and gas. Coal is expected to take a larger role in 2022, accounting for three-quarters of increased supply, with the remainder coming from renewables and gas. The Ministry of Energy and Mineral Resources is discussing how to scale up deployment of renewables with the utility PLN, delaying an update of its power development plan.

Indonesia's generation resources range widely across the country's islands. The main islands, including Sumatra, Java and Bali, have large capacity margins. The situation is very different on more remote islands, which are exploring microgrids. Existing targets for

23% deployment of renewables by 2025 are expected to require an increase from 8 GW today to 20 GW, necessitating additions of hydro, solar, biomass, geothermal and wind capacity.

In **Viet Nam**, demand grew in 2020 despite a slowdown due to the pandemic, with two-thirds of the increase met by renewables and the remainder by coal-fired generation. In the coming years, both renewables and coal-fired generation are expected to continue increasing, with each meeting close to half of new generation in 2022 alongside a small increase in gas. Viet Nam's recent draft power development plan expects up to 9 GW of coal-fired capacity to be added by 2025 despite reported funding challenges, alongside 3.5 GW of new and retrofitted LNG-to-power plants and 0.6 GW of new solar PV.

Growth of solar PV in Viet Nam will be boosted by the rollout by the end of 2021 of a corporate power purchase agreement platform, aimed at the manufacturing industries that contribute much of the country's economic growth. The country is also piloting its retail electricity market before full operation in 2023, after a successful launch of its wholesale electricity market in 2019.

In several countries with slow demand growth, including Japan, Korea and Australia, we expect a continual reduction in coal-fired generation over the next two years.

Last year's reduction in demand in **Japan** pushed down coal, nuclear and gas generation, but renewables still increased. Slow demand growth in 2021 and 2022 is expected to be met by renewables and nuclear, while coal- and gas-fired generation continue to decline gradually.

In **Korea**, coal-fired generation decreased in 2020 by more than the demand increase, and was balanced by an increase in both renewables and nuclear. Over the next year and to a lesser extent in 2022, coal-fired generation is expected to continue falling, despite long-planned new additions of 3 GW of coal power units in 2021. This decline is a result of the government's continued green policy and its emissions trading mechanism, leading to lower utilisation of coal plants while nuclear, gas and renewables increase to meet slowly growing demand.

In **Australia**, coal and gas generation are both expected to decline in the coming years, replaced by increasing renewables generation. Australia exceeded its large-scale renewable energy target in 2020, resulting in an oversupply of generation certificates and reduced incentives for utility-scale projects. However, distributed solar PV is continuing to grow, supported by state-level incentives.

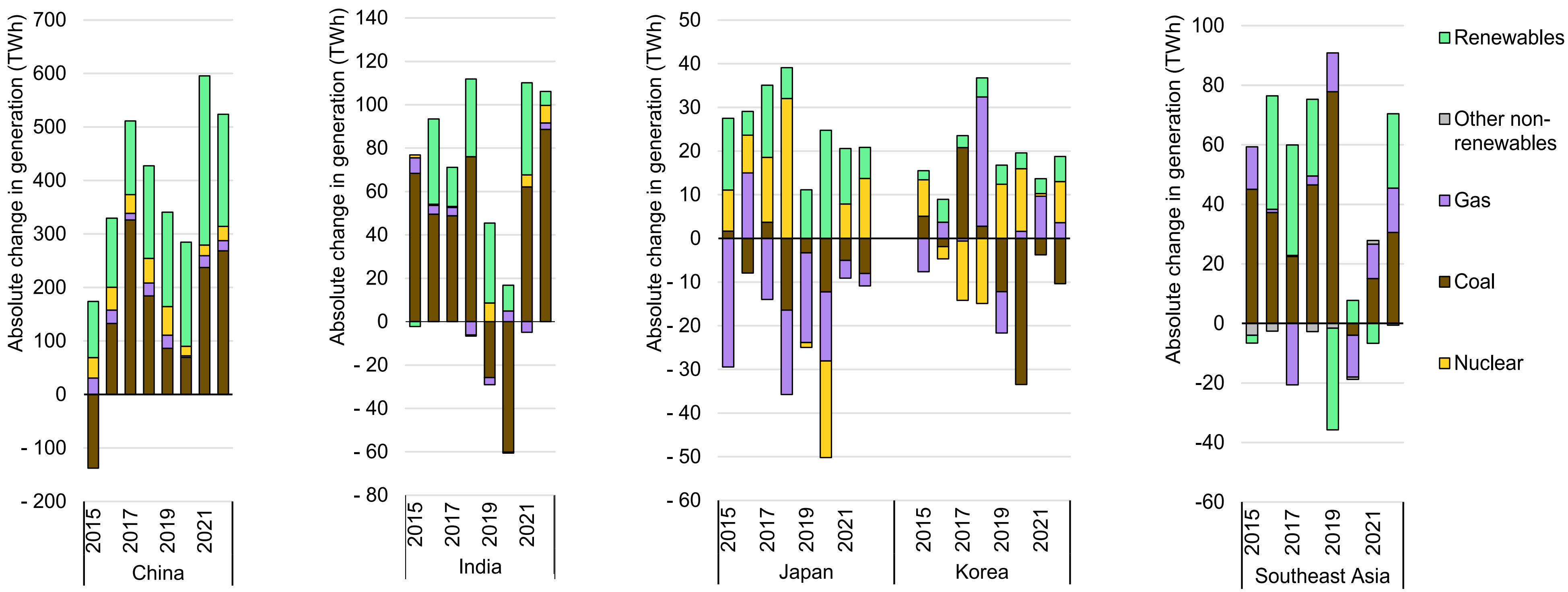
In **Singapore** and **Thailand**, the decline in demand in 2020 mainly affected gas-fired generation, which is expected to increase again in 2021-2022 with the return to gradual demand growth. Both countries also anticipate renewables increasing to meet growing demand.

Singapore is expected to start importing 100 MW from Laos in 2022 via Thailand and Malaysia as part of the Laos-Thailand-Malaysia-Singapore integration project as well as an additional 100 MW from Malaysia as a trial. Further generation is expected to come from refurbishment and reactivation of mothballed projects, bringing Singapore's reserve margin close to 30% by 2022.

Thailand's power sector is undergoing a transition towards clean energy with key governmental stakeholders considering revising the current Power Development Plan (PDP 2018 Rev.1) to support a net zero emissions target. The current renewable energy target of close to 30% in 2037 (excluding imported hydro) is being reviewed to promote greater investment in low-carbon energy. The system currently has a large surplus of generation capacity, which is expected to continue in coming years. In the longer term, new capacity is likely to consist largely of low-carbon resources, particularly utility-scale, rooftop and hybrid floating solar PV.

Renewables and nuclear generation in the Asia Pacific region are increasing alongside coal-fired power

Change in electricity generation in the Asia Pacific region



Source: IEA analysis based on data from IEA (2021), *Data and statistics*.

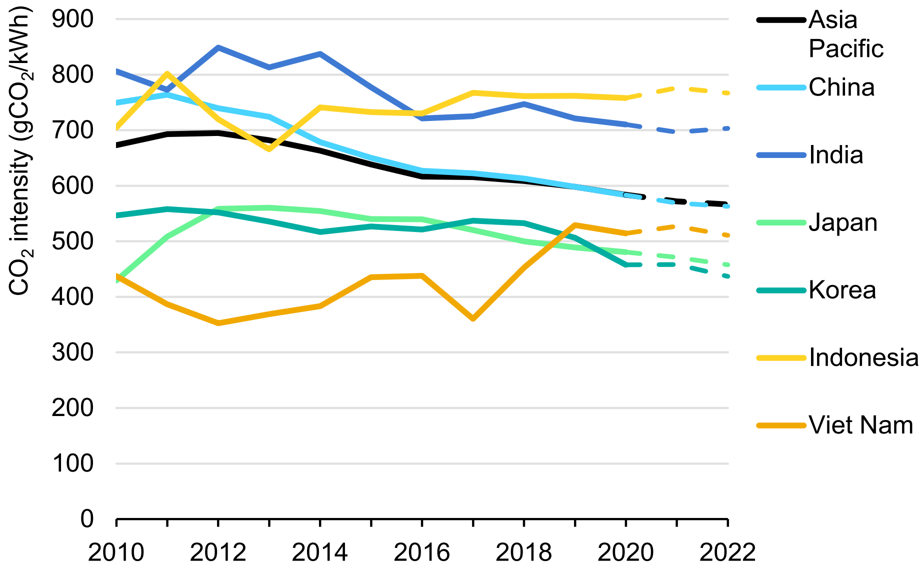
Emissions intensity in the Asia Pacific region is declining while overall emissions increase

Overall emissions intensity in the region is expected to continue the decline of recent years, due to continued solar PV and wind deployment, as well as nuclear generation. At the same time, absolute emissions in the region will continue to rise as around half of demand growth is met by coal generation.

This rise is largely due to coal-fired generation in China, which is expected to keep growing to 2022, with increased emissions as a result. Emissions in India, Indonesia and Viet Nam are also growing, similarly due to increasing coal-fired generation. In Thailand and Singapore, emissions are increasing more slowly, as demand growth is gradual and a larger share of generation is gas-fired.

In line with the decrease in emissions intensity, countries with stable electricity demand are expected to see a gradual decline in absolute emissions, including Japan, Korea and Australia.

CO_2 emissions in the Asia Pacific region



Source: IEA analysis based on data from IEA (2021), *Data and statistics*.

Africa

Moderate demand growth in Africa

After falling in 2020 due to Covid-19 and its impact on the economy, electricity demand in Africa is expected to grow from 2021 onwards by 3% year-on-year as economies recover across the continent. GDP is forecast to rebound in 2021, although it will remain below 2019 levels in several countries – including South Africa, which accounted for almost 30% of electricity demand on the continent in 2020. Recovery and growth in both the industrial and residential sectors are expected to boost demand.

In South Africa, electricity demand is forecast to remain below 2019 levels to 2022, on account of suppressed demand as certain sectors struggle to operate in the current climate of electricity shortages. These shortages are expected to continue until new generation comes online in 2022 at the earliest, and more likely in 2023, under the recently concluded Risk Mitigation Independent Power Producer Procurement Programme (RMIPPPP).

Of the other large economies, Egypt – which accounted for 22% of Africa's demand in 2019 – was the least affected by Covid-19, with economic growth of 3.6% in 2020. Electricity demand fell by about 1%, however. Despite the economy slightly slowing in 2021, we expect electricity to catch up with 2019 levels and grow by 3% as economic activity increases significantly in 2022.

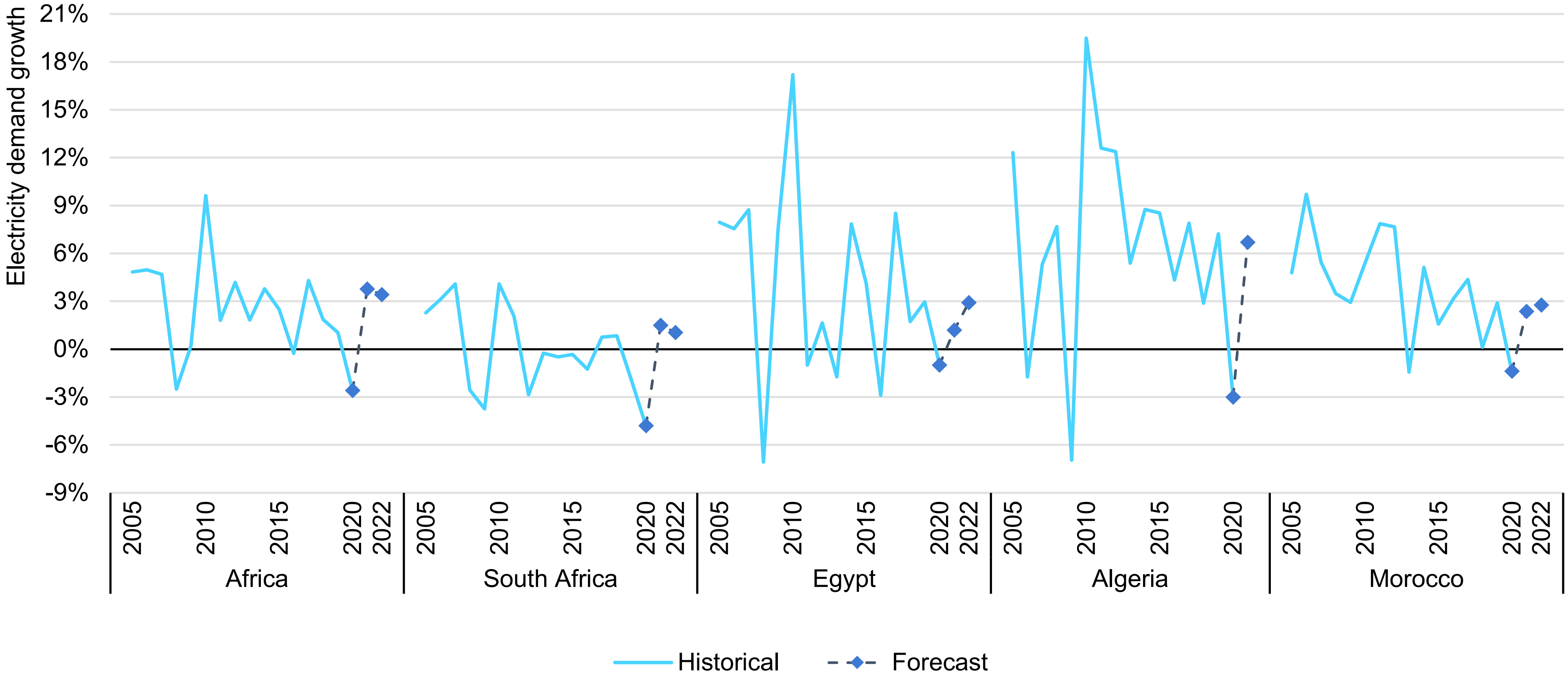
Electricity demand in Algeria – which accounted for 10% of Africa's demand in 2019 – fell in 2020 for the first time since 2009, by 3%. The decline coincides with a severe contraction of the economy due to the crash in global oil prices. Given the expected economic recovery and strong growth rates in recent years, we expected a return to electricity demand growth in 2021 and 2022 by close to 7% annually on average.

Morocco's economy contracted by 7% in 2020, pushing demand down in 2020 by 1.4% year-on-year relative to 2019. Similarly, peak demand fell by 1.5% in 2020 relative to 2019. During the height of lockdown during April 2020, the peak fell by as much as 12% relative to the same period in 2019. We expect electricity demand in 2021 to slightly exceed 2019 demand, due to a strong economic recovery, and continue solid growth in 2022 thanks to the industrial, residential and commercial sectors.

While North Africa is already close to universal electricity access, at more than 99%, as of 2019 only 42% of the population in sub-Saharan Africa had access to electricity. In the coming years, electrification can be a key way to boost growth in the continent's residential sector, which accounts for almost 30% of electricity demand. This, however, will require generation capacity shortages and electricity affordability to be addressed.

Electricity demand recovers in Africa

Development of electricity demand in the Africa



Source: IEA analysis based on data from IEA (2021), *Data and statistics*.

Gas and renewables cover majority of demand growth in Africa

The decline of demand due to Covid-19 pushed down thermal generation in Africa in 2020, mostly accounted for by a large reduction in output from coal plants in South Africa. At the same time, renewable generation increased as a trickle of plants came online across the continent, including wind, solar PV, hydro and biomass, despite delays caused by the pandemic.

The growth in renewables is expected to continue across Africa. In many countries, additional generation from renewables is expected to absorb the majority of new demand. For example in **Morocco**, we expect new renewable capacity not only to meet demand growth from 2020 to 2022 but also to displace coal from the generation mix.

Interest is also keen across Africa in developing gas and LNG infrastructure to provide firm capacity. **Ghana** looks set to become the first sub-Saharan African country to begin importing LNG, with an LNG terminal due to be completed by the end of June 2021. This will supplement Ghana's own production of gas as well as gas imports from Nigeria via the West African Gas Pipeline, which has been notorious for its frequent interruptions.

Other countries are also eyeing their first LNG terminals. **South Africa** is keen to develop LNG infrastructure to aid its clean energy transition by using gas as a transitional fuel to move away from coal-fired generation. These developments – along with demand growth in regions with a large share of gas in the current generation mix (for example Egypt and Nigeria) – will push up growth of gas-fired generation in Africa to 3% year-on-year in 2022. This growth is expected to displace oil products as well as coal from the generation mix.

Senegal is expected to start LNG imports with the arrival of the Karmol floating storage regasification unit at the end of March 2021. The unit will support oil-to-gas switching, with the 235 MW Karadeniz Powership Aysegul Sultan set to switch from low-sulphur fuel oil to LNG.

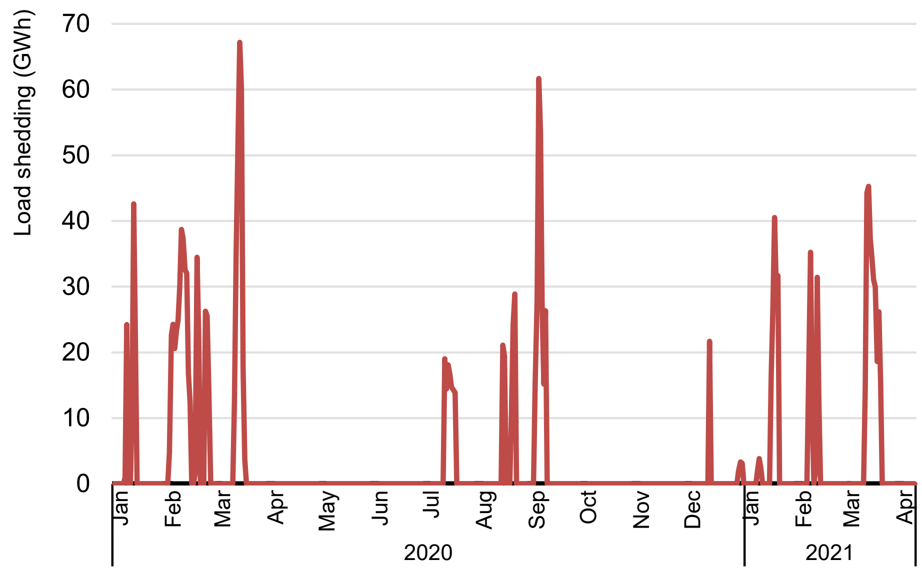
South Africa has been suffering from capacity shortages since 2016 as the availability of its coal fleet has steadily decreased. The shortages have been partly caused by delays to two new coal-fired megaprojects. At the end of October 2020, the second unit of the Kusile coal-fired plant brought an additional 800 MW onto the system. The second megaproject, Medupi Power Station – of which four out of the six 800 MW units are already online – is expected to be fully operational by the end of 2021. In addition, several renewable plants from the last bid window of the Renewable Energy Independent Power Producer Procurement Programme in 2018 came online in late 2020 and early 2021, while further projects from this bid window are expected to come online until 2022.

Despite the new capacity, the fortunes of the South African power system have not improved, with significant load shedding occurring in late 2020 and continuing in early 2021. This has also resulted in the increased use of gas turbines, which are burning diesel due to the lack of gas infrastructure.

South Africa is planning to close its energy and capacity shortage gap by procuring almost 14 GW of new capacity by 2030 as per the Integrated Resource Plan, which was last updated in October 2019. The first part of that capacity is being procured under the RMIPPPP, which seeks to obtain 2 GW of firm capacity based on an auction process, with the aim of going online by the end of 2022. The preferred bidders were announced in March 2021. More than half of the allocated capacity (1.15 GW) will come from three LNG powerships at different locations on the coastline. However, this increase in gas generation in the supply mix, will depend on the rollout of the aforementioned LNG infrastructure.

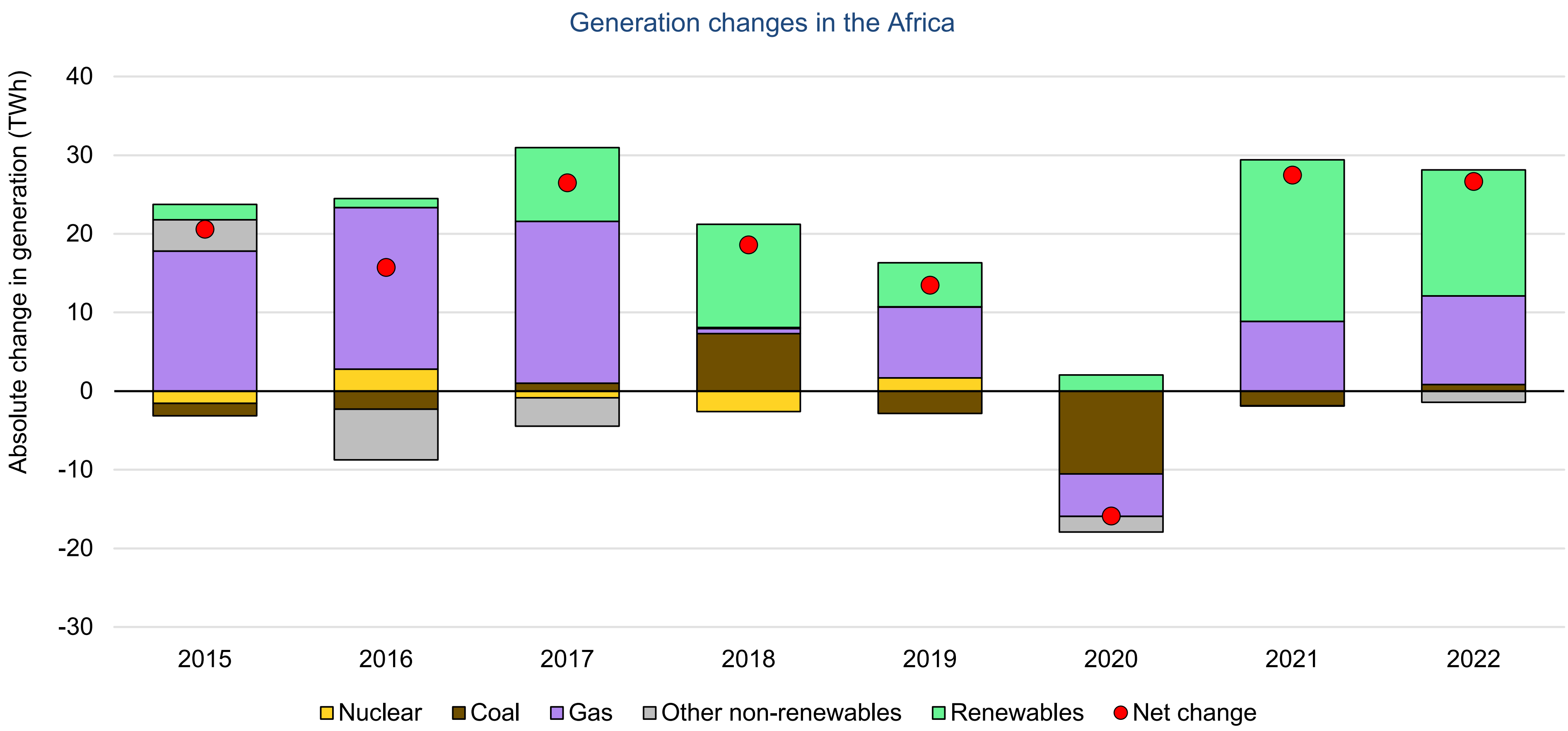
The remaining preferred bidders from the RMIPPPP consist of hybrid renewable projects made up of solar and/or wind with either battery storage or LNG to firm up capacity. All except one of the plants with battery storage will also use diesel-fired generation to further firm the output and fulfil certain technical criteria of the auction. These plants, along with those from the previous bid window, are forecast to add 3.6 TWh of renewables to the generation mix between 2020 and 2022.

Daily load shedding in South Africa



Source: Eskom (2021), *Data Portal*.

Gas-fired electricity generation is growing in Africa



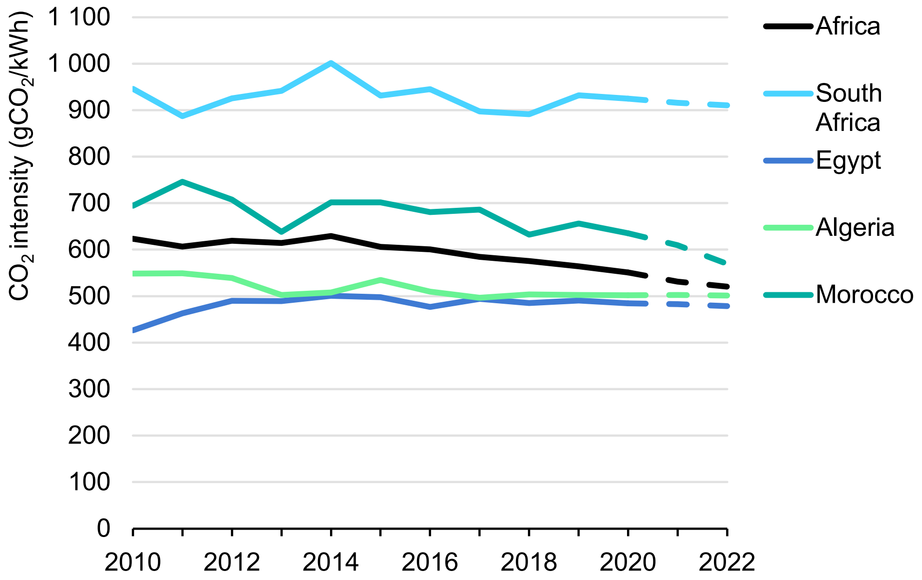
Source: IEA analysis based on data from IEA (2021), *Data and statistics*.

Despite a rebound in demand, emissions intensity is expected to decline in Africa

While demand in Africa is forecast to rebound from the impact of Covid-19 in 2020, emissions intensity is expected to decline as generation from coal and oil is slowly replaced by renewables and gas.

In both Morocco and South Africa, emissions are also expected to decline in absolute terms. In South Africa, this drop is partly due to the lower emissions intensity of its coal fleet as more efficient units come online, but more so due to new renewable and gas generation coming online. Morocco's emissions are expected to fall as renewables displace both coal generation and a small portion of gas generation.

CO_2 emissions intensity in Africa



Source: IEA analysis based on data from IEA (2021), *Data and statistics*.

Markets

Wholesale and end-user prices

Increasing demand, fuel and CO_2 prices are pushing up electricity wholesale prices

Higher natural gas and carbon prices, together with recovering demand, boosted wholesale electricity prices in most countries from Q3 2020. The wholesale electricity price index, which tracks price movements in major advanced economies, increased by 54% in the first half of 2021 compared with the same period in 2020. In Q1 2021, the increase was supported by supply and demand disruptions caused by extreme weather events in Japan and the United States, pushing the index past the value observed in Q4 2018 for the first time.

Wholesale prices in **France**, **Germany**, **Spain** and the **United Kingdom** slowly increased after reaching their lowest level during Q2 2020. This rise tracks a rebound in demand that increased gas prices by 171% and EU Emissions Trading System prices by 95% in the first half of 2021 compared with the first half of 2020. The **Nordic region** experienced warmer temperatures in Q4 2020 compared with the same period in 2019. This dampened electricity demand for heating and slowed the recovery of wholesale prices. Temperatures fell in January and February 2021, which boosted prices in Q1 2021 three times higher than in Q4 2020.

In the **United States**, wholesale prices increased in the second half of 2020. High temperatures and thus high demand levels increased Q3 wholesale prices in California to a level three times higher than in the previous quarter. In the winter of 2020-21, extreme cold disrupted energy supply and demand in the South and Southwest regions. As a result, the area experienced record-breaking high wholesale electricity prices, set at the market cap of USD 9 000/MWh for just over three days.

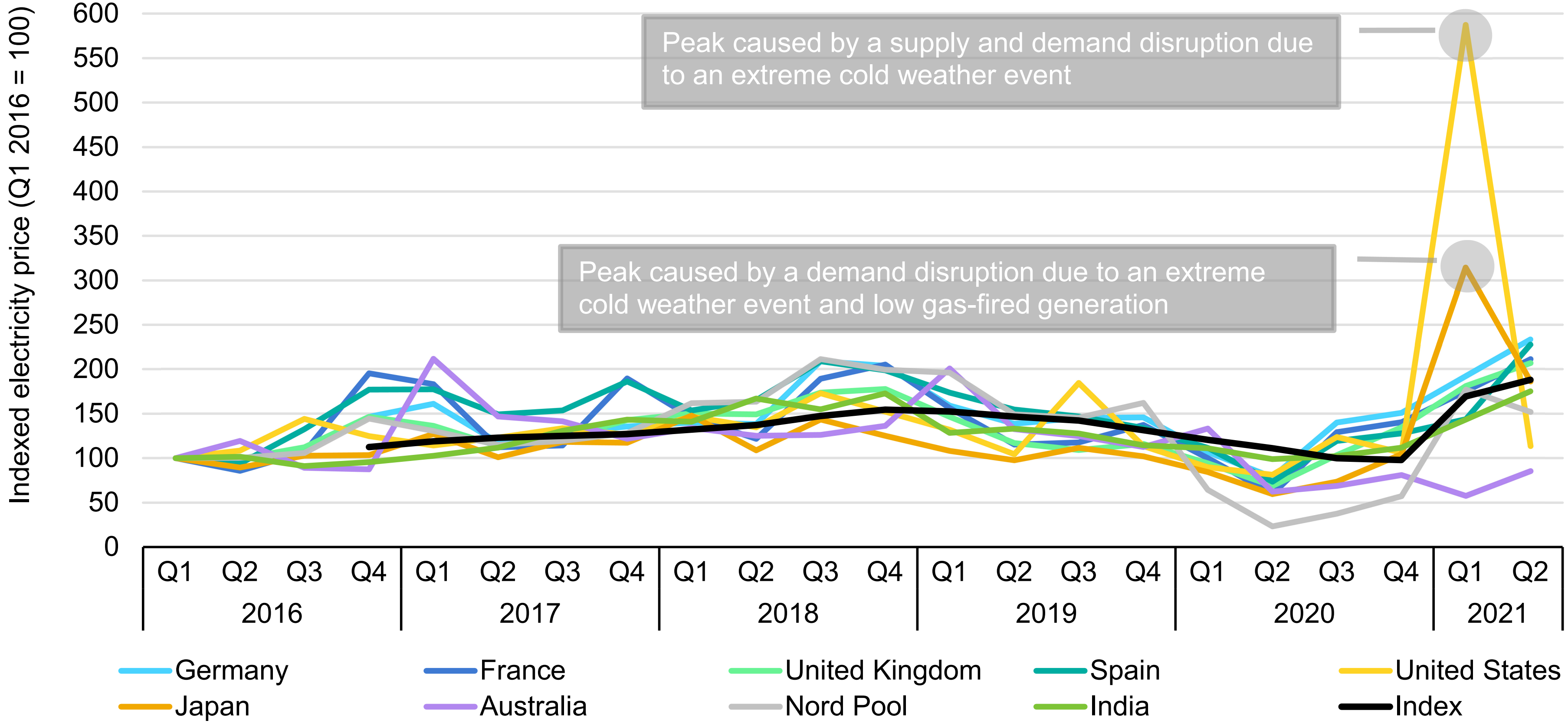
Weather also influenced prices in **Japan**. Wholesale electricity prices hit record highs of more than JPY 200/kWh during cold weather in January 2021, leading the Ministry of Economy, Trade and Industry to approve special measures to put an upper limit on the unit price. The extreme cold affected much of the country, increasing electricity demand for heating. At the same time, limited gas supply led to low gas-fired electricity generation.

In **Australia**, by contrast, record renewable generation (especially rooftop solar and wind) and low levels of demand (caused by mild summer temperatures) pushed Q4 2020 wholesale prices down to their lowest quarterly level since 2015 – most notably in the states of Victoria and South Australia. High solar PV and wind production continued during Q1 and Q2 2021, putting pressure on fossil fuel plants and, as a result, wholesale prices.

In **India**, wholesale electricity prices were 29% higher in Q1 2021 than in Q1 2020. From Q3 2020 on, prices started to increase steadily, especially in Q1 2021, due to low hydro and a consequent increase in fossil fuel generation.

Wholesale market prices have been climbing since the second half of 2020

Quarterly average wholesale prices for selected regions (2016-2021)



Note: The wholesale electricity price index is calculated as the demand-weighted rolling average of the respective current and previous three-quarter indexed prices of selected wholesale electricity markets. The prices for Australia and the United States are calculated as the demand-weighted average of all the regional markets. Regional prices for Australia are volume-weighted.

Sources: IEA analysis using data from RTE (France) and Red Eléctrica (Spain) – both accessed via the ENTSO-E Transparency Platform; Bundesnetzagentur (2021), SMARD.de; Elexon (2021), *Electricity data summary*; AEMO (2021), *Aggregated price and demand data*; AER (2021), *Wholesale statistics*; EIA (2021), *Short-Term Energy Outlook June 2021*; Nordpool (2021), *Historical Market Data*; IEX (2021), *Area Prices*.

Electricity wholesale prices set by coal and gas generation costs

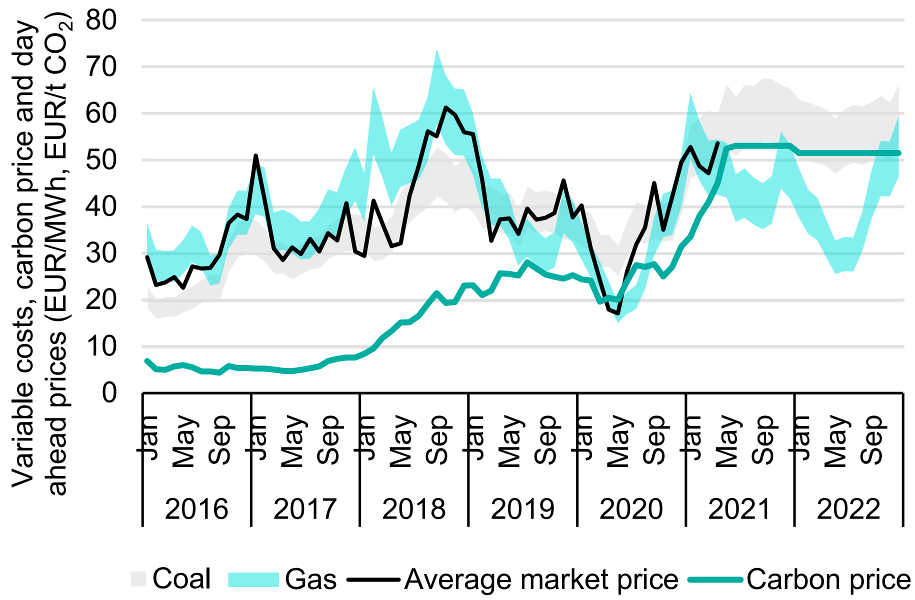
Wholesale electricity prices in Germany display a high correlation with the fuel costs (including CO_2) of coal- and gas-fired power plants, illustrating that both technologies are typically setting market prices. The correlation coefficient for the observation period is almost 0.8 for both fuels, assuming 40% efficiency for coal and 49% for gas plants.

This link also explains the low electricity prices in 2020, especially in the summer. Not only was electricity demand low, taking higher-cost plants out of the market, but coal and especially gas prices have also been low, further dragging down electricity prices.

The upward trend in CO_2 prices in the EU Emissions Trading System since the end of 2017 has improved the competitiveness of gas plants relative to coal. From 2019 on, gas-fired plants have typically been cheaper than coal during the summer, due to lower gas prices outside the heating season.

The uncertain economic outlook during the initial phase of the Covid-19 pandemic, together with low gas prices, temporarily put pressure on EU Emissions Trading System prices. As growth resumed, CO_2 prices continued their upward trend and exceeded EUR 55/tCO_2 at the end of June, up from a low of EUR 16/tCO_2 in March 2020.

Fuel and CO_2 costs compared with day ahead prices in Germany



Note: Prices are non-weighted averages for each month. Variable costs include only fuel and CO_2 costs. Assumed generation efficiency ranges are 36-45% for coal and 43-55% for gas. CO_2 prices until the end of 2021 are based on December 2021 forwards, 2022 prices are based on December 2022 forward (values from 18.05.2021).

Sources: Natural gas prices: TTF; coal prices: CIF ARA; emission costs: EU ETS.

End-user prices have been increasing alongside wholesale prices in recent months…

In the second half of 2020, end-user electricity prices for most of the countries included in the analysed sample picked up, as did wholesale prices.

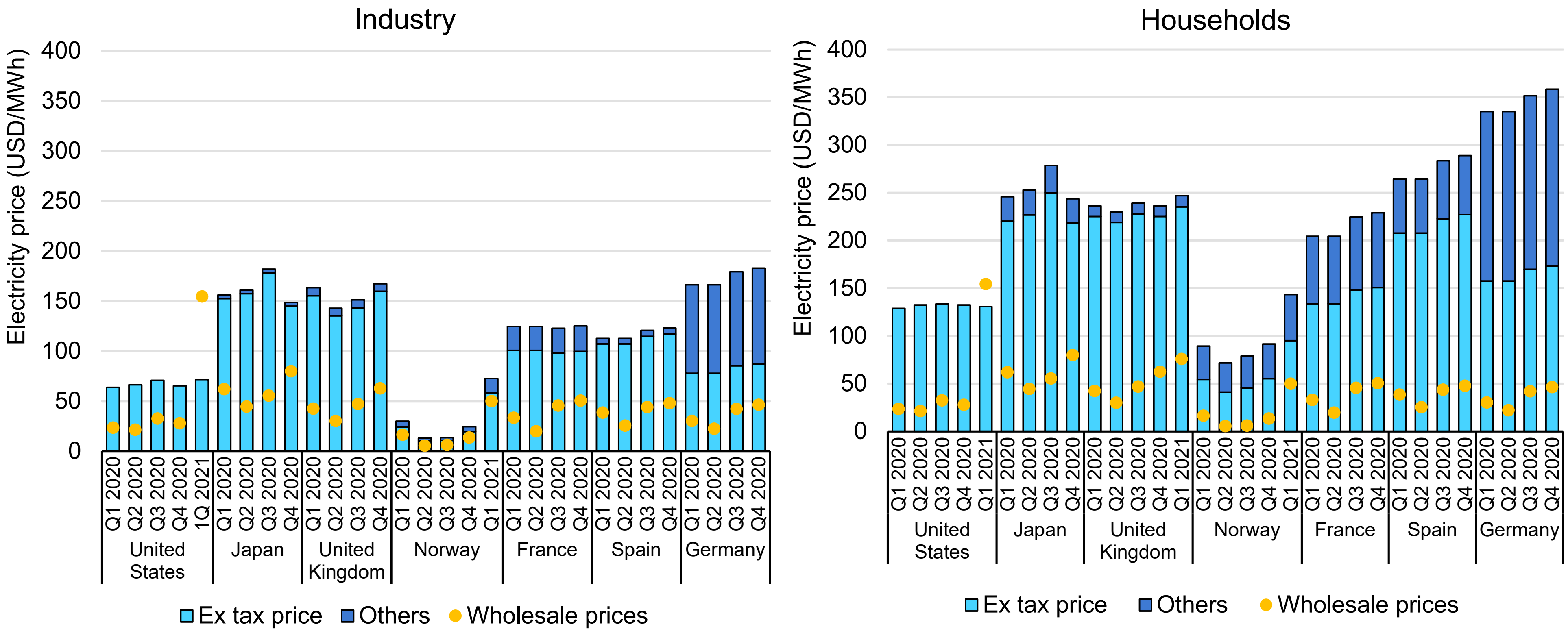
In **Europe**, both household and industry prices increased from Q3 2020. An exception to this were industry prices in France, which remained almost stable throughout 2020. Compared with Q2 2020, household prices grew in the third quarter in Norway and France (both 10%), Spain (7%), Germany (5%) and the United Kingdom (4%). Industry prices increased in Germany (8%), Spain (7%) and Norway (4%). Prices rose more slowly in Q4 2020 for all countries but Norway, where they increased by 16% for households and 80% for industry compared with Q3 2020. Prices in Norway continued to rise during Q1 2021, by 197% for industry and 57% for households compared with Q4 2020. Despite this growth, Norway continues to have the lowest end-user prices in the sample. Norwegian prices display such a high dynamic because a large proportion of consumers are enrolled in dynamic pricing plans that closely link end-user to wholesale prices.

In the **United States,** average industry prices in the winter of 2020-21 were higher because of extreme weather events that affected energy supply and demand in California (in Q3 2020), and the South and Southwest regions (in Q1 2021). In Q3 2020, industry prices were 7% higher than in the previous quarter. After returning to Q2 levels in Q4 2020, average retail prices for industry rose even higher in Q1 2021, up by 9% compared with Q4 2020. The impact for most residential customers was less severe: prices rose by 1% in Q3 2020 and fell by 1% in Q1 2021, as fixed-rate plans protected them from wholesale price increases. In Texas, however, adjustments in electricity bills may mean higher prices for residential customers in coming years.

As of April 2019, 78% of low-voltage customers in **Japan** pay regulated tariffs, which shields them from large price changes. However, average end-user prices increased in Q3 2020 from the previous quarter by 10% for households and 13% for industrial users, following a jump in wholesale prices. Prices for both sectors decreased again in Q4 2020, falling by 12% for households and 18% for industry compared with Q3 2020, despite rising wholesale prices.

… but the link between wholesale and end-user prices is mostly weak

Quarterly end-user electricity prices in selected markets



Note: The price breakdown for the United States is not available. We calculate the ex tax price by subtracting the applicable legally established tax components (excise and VAT) from the end-user price. Prices differ significantly between countries depending on factors including the type of end-user price (regulated or market-based) and the composition of the tax structure (e.g. VAT, excise taxes, renewable energy and capacity levies, environmental taxes).

Sources: RTE (France) and Red Eléctrica (Spain), both accessed via the ENTSO-E Transparency Platform; Bundesnetzagentur (2021), SMARD.de; Elexon (2021), Electricity data summary; EIA (2021), Short-Term Energy Outlook June 2021; Nordpool (2021), Historical Market Data; IEA (2021), Energy Prices.

Revenues and profits

Coal-fired power plants' earnings are under pressure in Europe…

Electricity market participants typically have several sources of income, depending on the market set-up and technical capabilities. For example, generators can sell electricity via forward, day-ahead and intraday markets, offer system services via balancing markets and participate in capacity remuneration schemes. Selling energy is usually the main source of income for large-scale generation units like nuclear, coal- or gas-fired power plants. However, system services may become more important as shares of variable renewable energies increase.

Power plants in competitive markets typically sell at least some energy in advance, although this depends on the type of plant and sales strategy. This is done in forward markets, for example, or via long-term contracts, to hedge against the price risks of volatile short-term markets. But day-ahead and intraday markets typically serve as a reference for the achievable energy revenues.

The interaction of different markets within a system – for example, energy, ancillary and capacity markets – and the impact of market design choices make the interpretation of absolute energy market earnings difficult. For these reasons, we focus on comparing the relative development of potential earnings of different technologies, using observed wholesale prices in recent years (2016-2020) and historical generation costs.

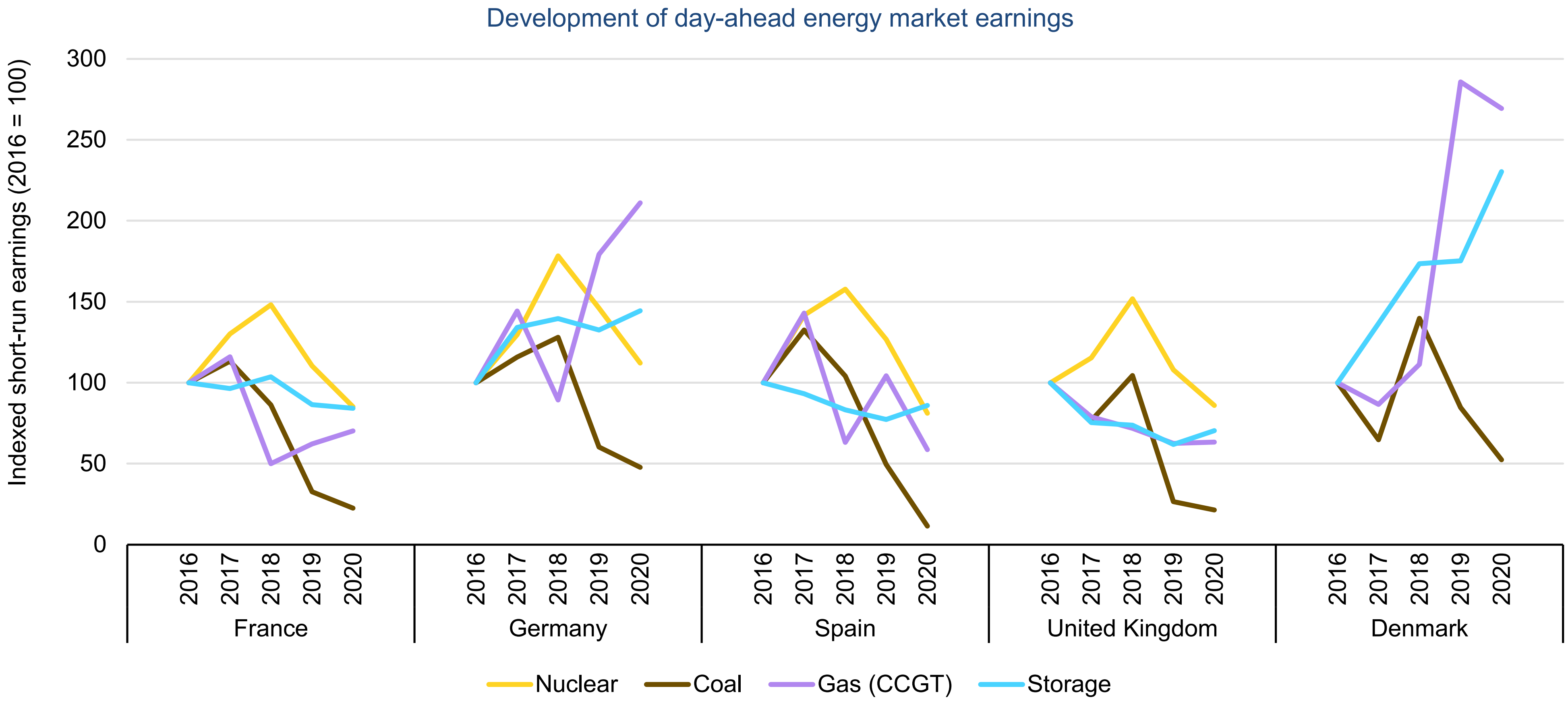
The change in earnings over time is determined by several factors, including the development of a technology's generation costs – and thus its cost competitiveness – as well as the level of total capacity relative to demand.

Nuclear plants typically operate close to their maximum availability due to their low variable costs. Earnings thus closely follow wholesale prices.

For **coal**-fired power plants, earnings have declined in the analysed markets in recent years. Low electricity demand, low gas prices and increasing CO_2 prices have pushed down wholesale prices and resulted in coal-to-gas switching. Especially in 2019 and 2020, the loss of market share put coal plants under economic pressure and accelerated the phase-out of coal-based electricity generation.

Gas-fired plants in some countries benefited from gas prices falling relative to coal prices. In Denmark and Germany, where coal exceeds the use of gas, this improved potential earnings for combined cycle gas turbine plants (CCGTs) in 2019 and 2020. In Spain, gas benefited from reduced coal-based generation in 2019 but CCGTs felt the brunt of declining wholesale prices in 2020 as no significant coal-fired generation was left. In France and the United Kingdom, where coal has played only a minor role for electricity generation for some time, gas-fired plant revenues have declined along wholesale prices in recent years.

… while gas-fired plants' earnings show mixed results



Note: We use a simplified model assuming reference technologies that maximise profits given observed wholesale prices. Efficiency: nuclear 33%, coal 42%, gas CCGT 52%, battery storage 90%; storage with four hours capacity. Ramping costs and limits are not taken into account. Taxes and other charges, for example on fuel, revenues or profits, are also not taken into account.

Sources: IEA analysis using data from RTE (France) and Red Eléctrica (Spain), both accessed via the ENTSO-E Transparency Platform; Bundesnetzagentur | *SMARD.de* (Germany); *National grid* (United Kingdom); *AEMO* (Australia); *ERCOT* (United States); Nordpool (2021), *Historical Market Data*.

Daily wholesale energy price spreads show no clear trend

Growing penetration of variable renewable generation is expected to increase spreads between the lowest and highest prices in a given day. This in turn will create arbitrage opportunities for flexible resources like storage technologies, including pumped hydro storage and batteries, as well as demand-side flexibility.

Price spreads are influenced by the slope of the merit order as well as variations in residual demand (total demand minus variable renewable energies). Despite growing shares of variable renewables, no obvious trend with regard to the daily spread between the minimal and maximal wholesale energy price is observable between 2015 and 2020.

In the **United Kingdom**, wind is the dominant form of renewable electricity. Between 2015 and 2020, its share in the generation mix increased from 12% to 24%. The average daily price spread fell by 7% during the same period. One reason could be the higher uniformity of the dispatchable power plant fleet in 2020, flattening the merit order. This counterbalances the higher volatility of residual demand. Whereas in 2015 gas provided 29% of electricity, nuclear 19% and coal 12%, in 2020 36% of total generation came from gas, 15% from nuclear and only 2% from coal.

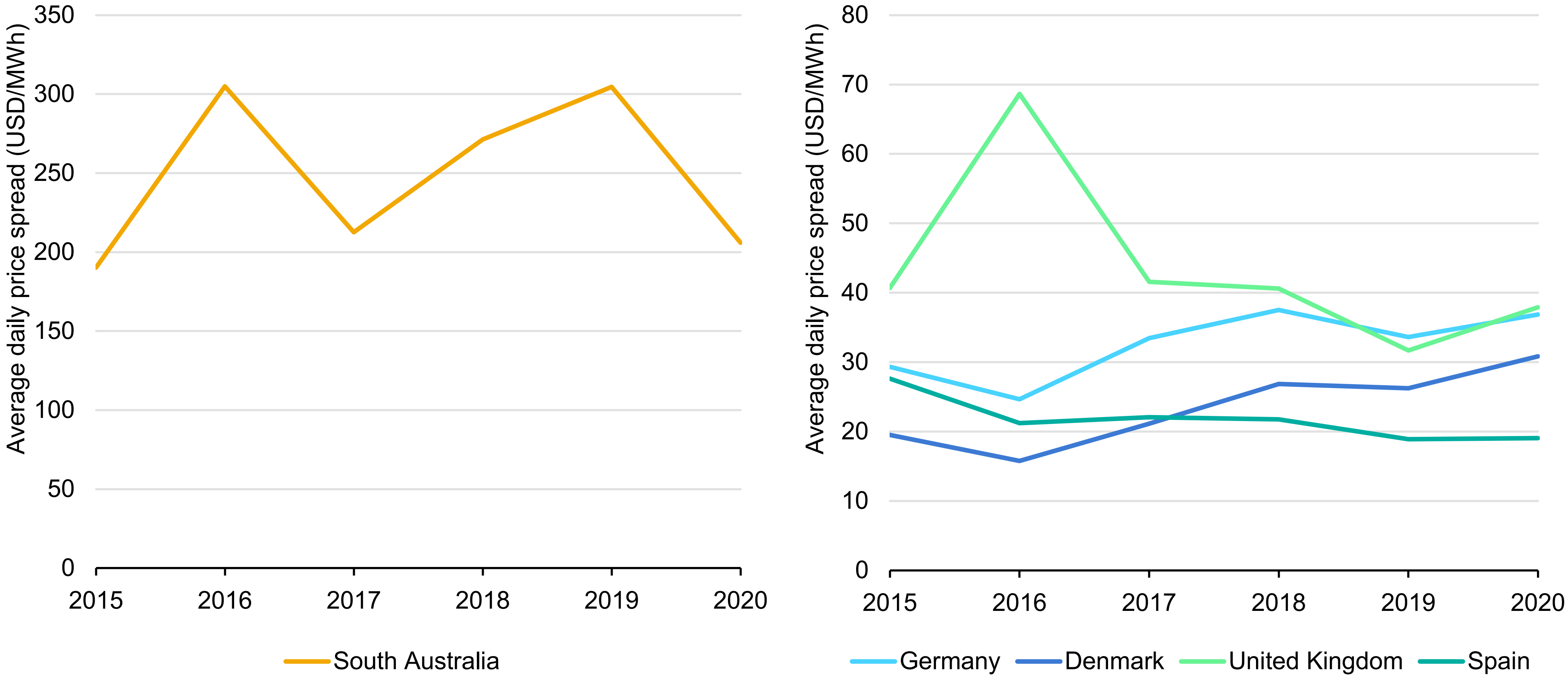
In **Spain**, as in the United Kingdom, coal-fired generation declined to around 2% in 2020 from 19% in 2015, resulting in a dispatchable power plant fleet dominated by nuclear and gas – and declining average price spreads despite an increase in variable renewables from 21% in 2015 to 30% in 2020.

Only in **Germany** and **Denmark** did average price spreads seem to follow an increasing trend. In both countries, the share of variable renewables increased significantly between 2015 and 2020. In Germany, wind rose from 12% to 26% and solar PV from 6% to 10%. In Denmark, wind increased from 49% to 60% and solar PV from 2% to 4%. Due to decreasing coal-fired electricity generation, both countries have a more even mix of dispatchable gas- and coal-fired plants today than five years ago.

In **South Australia**, average daily price spreads are higher than in Denmark, with a similar variable renewables share but more solar PV (17% in 2020) and less wind (43%). High scarcity prices (exceeding AUD 5 000/MWh in every year since 2016) and negative prices (down to minus AUD 900/MWh in 2019 and 2020) are not unusual. The spreads attract battery investments. Batteries in South Australia reaped windfall profits for services to maintain grid stability in January 2020, when a severe storm cut off the state electricity system from the east coast grid for 17 days. As a result, the Hornsdale battery was able to recover around 30% of its investment cost in two weeks.

High daily price spreads in South Australia

Average daily price spreads



Sources: IEA analysis using data from Red Eléctrica (Spain), accessed via the ENTSO-E Transparency Platform; Bundesnetzagentur | SMARD.de (Germany); National grid (United Kingdom); AEMO (Australia); Nordpool (2021), Historical Market Data.

Declining market value of renewable generation

Renewable energy sources today are seldom exposed to market prices: revenues per generated unit of electricity are guaranteed by feed-in tariffs or power purchase agreements.

In recent years however, more countries have been moving to more market-based remuneration schemes to provide incentives for renewables to adjust to market demands and therefore facilitate renewable integration.

When shares of variable renewables are low, wind and solar PV will not have a notable impact on energy prices. As solar PV generation typically occurs during high demand hours (and therefore higher prices), it will be able to receive above average revenues.

However, as renewables capacity increases, systems experience hours where the renewables share is high, while still having periods of low output, since wind turbines are subject to similar wind conditions within a region and solar PV generates only during the day. If the annual share of variable renewables is high, electricity prices will be suppressed whenever renewable generation is plentiful and increase in the absence of wind and sunshine. This deteriorates renewables' revenue prospects.

Although market prices are subject to certain market design choices and imperfections, potential wholesale energy revenues can be used as an indicator for the value of electricity generation. As the value depends on the overall system configuration, it can also be seen as an indicator for the extent to which systems are flexible enough to integrate large shares of variable renewables.

One indicator of insufficient flexibility is an increase in hours with negative wholesale prices. Negative prices tend to occur when renewables generation is high and electricity demand is low. Negative price periods were particularly pronounced in 2020 when Covid-19 suppressed electricity demand.

Negative prices are possible when support premiums enable renewables generation to make a profit in spite of a negative wholesale price, and when dispatchable generators have financial incentives to offer their supply for negative prices. Examples of such incentives are to avoid shutting down, which incurs start-up costs when the plant needs to begin operating again, or because plants are at the same time earning revenues on other markets such as balancing or heating markets.

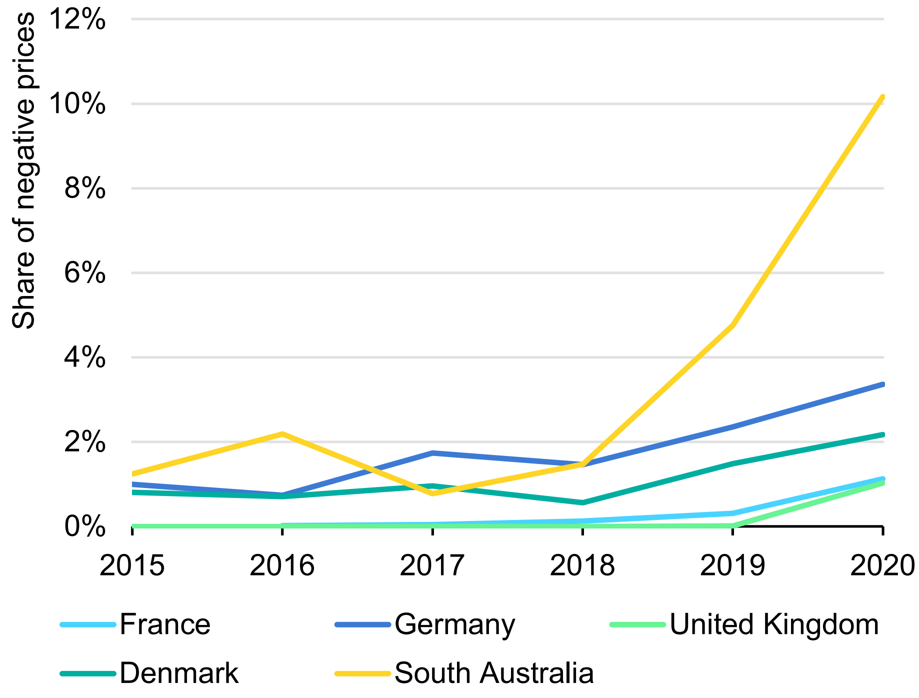
Longer periods of negative prices may imply a need for higher flexibility in the system. Demand-side management, storage, power-to-X technologies and retrofitting power plants to achieve a lower technical minimum generation without shutting down are possible options. Curtailing renewable generation, which occurs frequently in some power systems, is also an option. However, curtailing a large share of variable renewable electricity would indicate possible inefficiencies.

Our analysis shows that average prices received by renewable sources seem to decline with a growing share in the supply mix. For solar PV, as generation coincides with high demand during the day, average received prices rank above average market prices in many of the analysed years and markets. Especially in Texas, where solar PV generation is still far below 5% of the total and peak demand is typically reached during hot summer days, solar PV benefits from its generation pattern. In South Australia, however, where solar PV reached a market share of more than 10% in 2019 and 2020 – and for the first time [100% of demand] during an hour last October – average prices received were far below average market prices.

Onshore wind reached more than 30% market share in Denmark and South Australia in the majority of years between 2015 and 2020. After receiving prices around 10% lower than average in Denmark for some years, onshore wind received around 26% lower prices in 2020 – similar to the range of -20% to -26% that South Australia's wind turbines faced in the past five years.

The record offshore wind generation of 24% of total generation in Denmark in 2020 was accompanied by a market value 20% below average, significantly below the values in previous years.

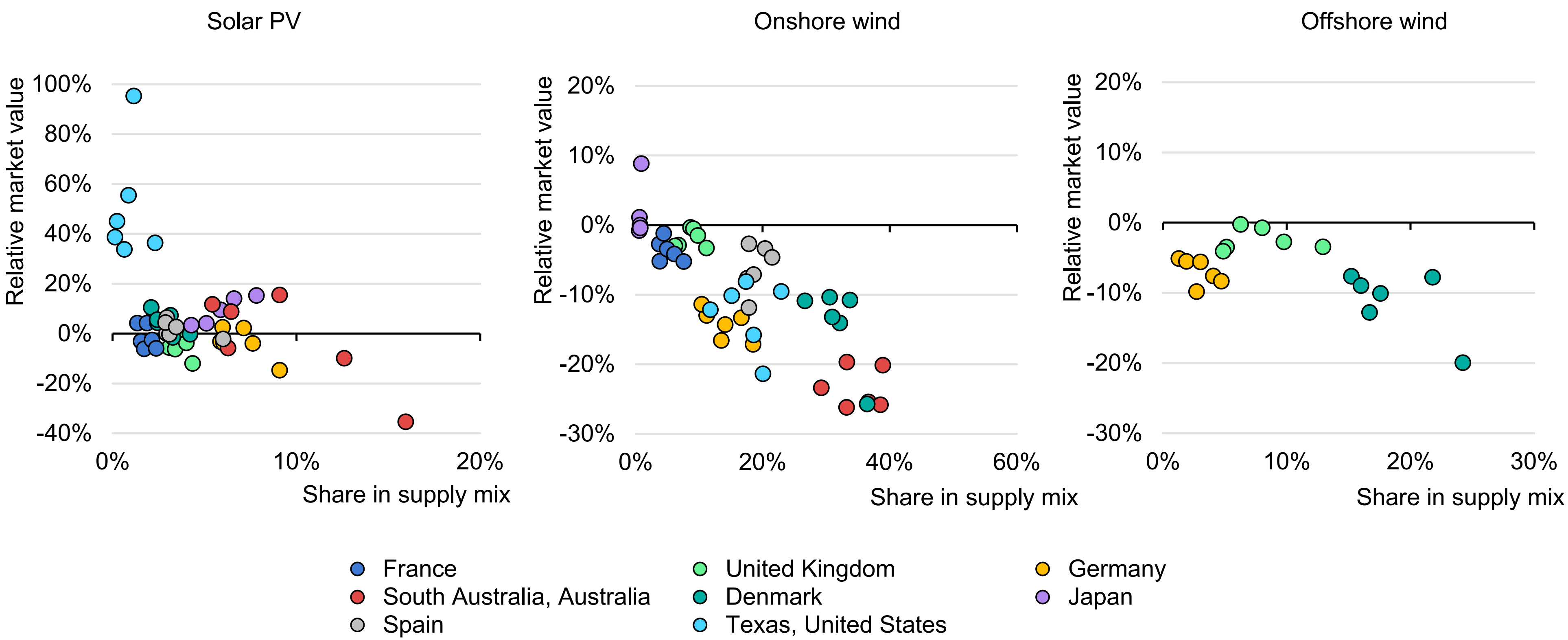
Share of negative wholesale prices



Sources: IEA analysis using data from RTE (France), accessed via the ENTSO-E Transparency Platform; Bundesnetzagentur | *SMARD.de* (Germany); *National grid* (United Kingdom), *AEMO* (Australia); Nordpool (2021), *Historical Market Data.*

A high share of variable renewables pushes down revenues

Market value of renewable electricity generation relative to average prices, 2015-2020



Note: The relative market value is calculated as the difference between the average production-weighted wholesale price and the non-weighted average price.

Sources: IEA analysis using data from RTE (France) and Red Eléctrica (Spain), both accessed via the ENTSO-E Transparency Platform; Bundesnetzagentur | *SMARD.de* (Germany); *National grid* (United Kingdom); *AEMO* (Australia); *OCCTONET* (Japan); Nordpool (2021), *Historical Market Data*.

Trade

Multilateral cross-border power trading arrangements are growing in interconnected systems

Power systems integrated across borders bring economic and electricity security benefits, as they take advantage of regional resources and increase diversity on both the supply and demand sides. Areas with high shares of variable renewable sources like wind and solar PV benefit further from the smoothing effect of larger systems.

For decades, neighbouring systems have entered into bilateral trading agreements to share resources and reserves. Multilateral trading arrangements are appearing in a growing number of regions. Participants from several jurisdictions trade with one another through a central platform, facilitated by a regional authority. This enables the optimal use of available resources within larger areas. Multilateral trading is mainly implemented for the so-called short-term markets (day ahead to real time) through a competitive auction at pre-defined closure times. Bilateral agreements remain common for longer time horizons.

The most integrated trading models are found in Europe, across some American states and in Australia. All market participants from several states trade on the same regional platform, and for most electricity products there is little need for local level markets. Implementing this model requires a high level of harmonisation, such as defining regional technical standards for connection and operations, and methodologies for transit grids and cross-border capacity calculation. The vast majority of generating units bid competitively on this market. We call these **primary** arrangements.

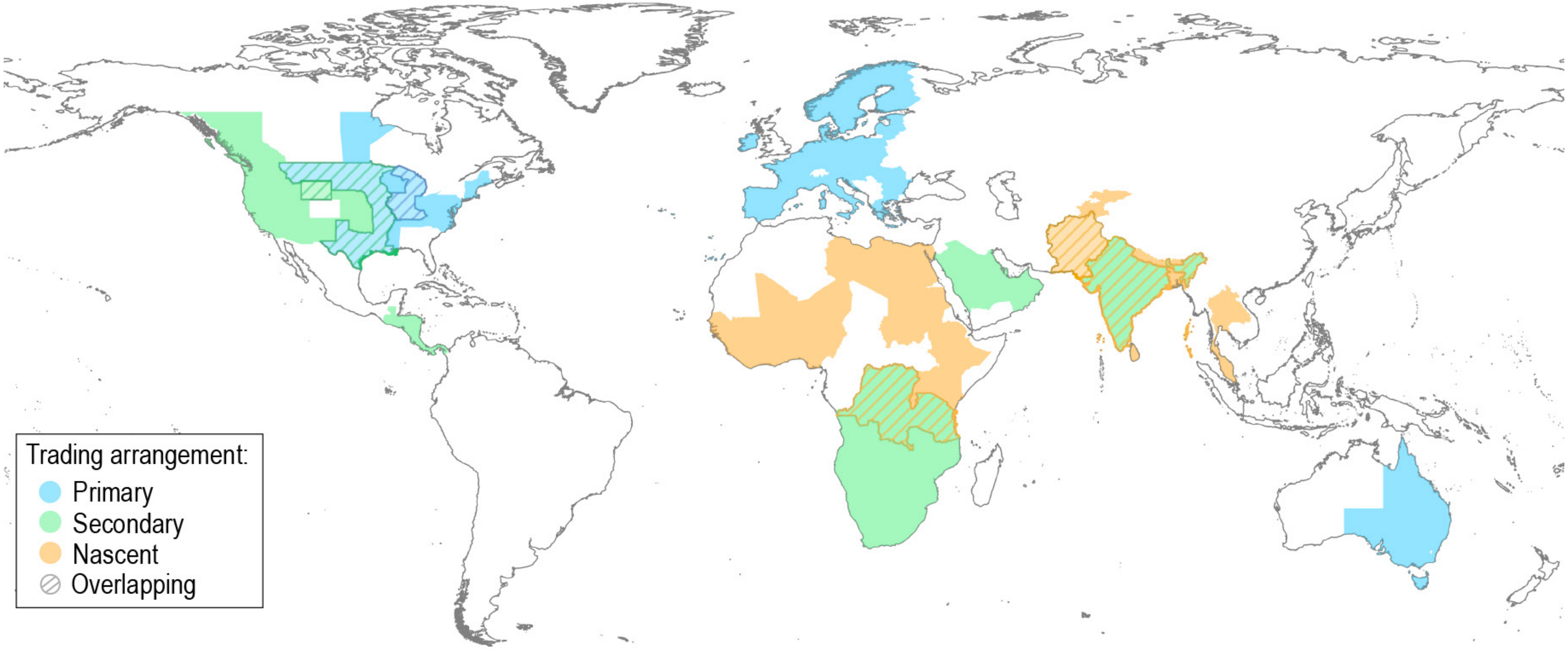
Multilateral trading may also take place between jurisdictions with different power sector organisations. In such a model, an integrated national utility can trade with market players from countries with a domestic market. We call this a **secondary** model, since the domestic markets (where they exist) have the main responsibility for matching demand and supply, while the regional market comes in complement to exchange power surpluses.

Established secondary markets are the Southern African Power Pool, the Western Energy Imbalance market in North America, the Central American Electrical Interconnection System and the Gulf Cooperation Council Interconnection Authority in the Middle East. In India, the national market across 36 states is multilateral by default but most conventional units are not bidding competitively yet.

A growing number of regions are moving towards multilateral trading. We consider as **nascent** markets those regional systems where a multilateral market is in preparation but trade is currently organised bilaterally. This is the case for the South Asia Regional Initiative on Energy Integration, the Central Asia-South Asia CASA-100, the Lao PDR-Thailand-Malaysia-Singapore Power Integration Project, and the power pools in West and East Africa.

Trading agreements exist in many regions around the world

Regional power trading arrangements



This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

Note: The areas shown are those of the multilateral trading arrangements. Interconnections and bilateral trade may extend further. Beside the arrangements reflected on the figure, there are about a dozen early stage initiatives.
Source: IEA analysis.

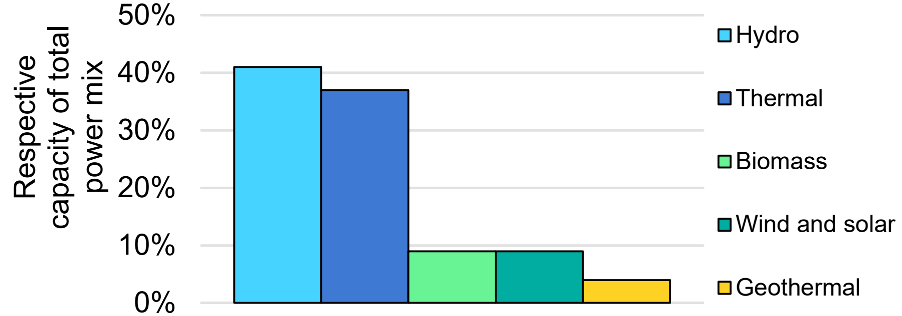
Multilateral cross-border power trade facilitates the growth of variable renewables

The Central American Electrical Interconnection System (Sistema de Interconexión Eléctrica de los Países de América Central, or SIEPAC) is an example of a **secondary** multilateral trading arrangement. A regional entity manages dedicated 230 kV transmission lines and the regional market (Mercado Eléctrico Regional, MER) that together enable six countries in Central America to exchange power multilaterally. The interconnection was recently extended further to Mexico to the north and Colombia to the south, although these two countries do not yet participate in the multilateral exchange.

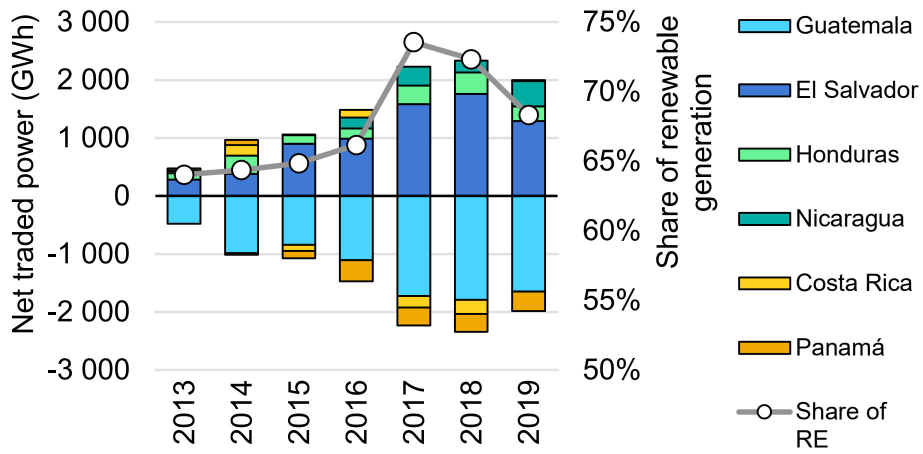
The regional market operates on top of the six national markets, each of which has its own local arrangements. Costa Rica and Honduras participate in the MER through their vertically integrated national utilities, while market players from the remaining four countries – generators, traders and large customers – participate directly in the MER.

The power mix is dominated by hydropower, but wind and solar are growing. SIEPAC has been operating since the early 2000s; trade was boosted by the increase in available cross-border capacity between 2013 and 2015. Droughts in 2018 and 2019 constrained the exchange in this hydro-dominated interconnection. Trade may increase in the future if Mexico and Colombia are integrated in the regional market.

Power mix in the Central American interconnection SIEPAC



Trade and share of renewables in SIEPAC



Note: Net traded power is the difference between purchased (positive) and sold (negative) energy on a yearly basis.
Sources: Based on CEPAL (2021), *Estadisticas e Indicadores*; Ente Operador Regional (2021), *Estudio de Máximas Capacidades*.

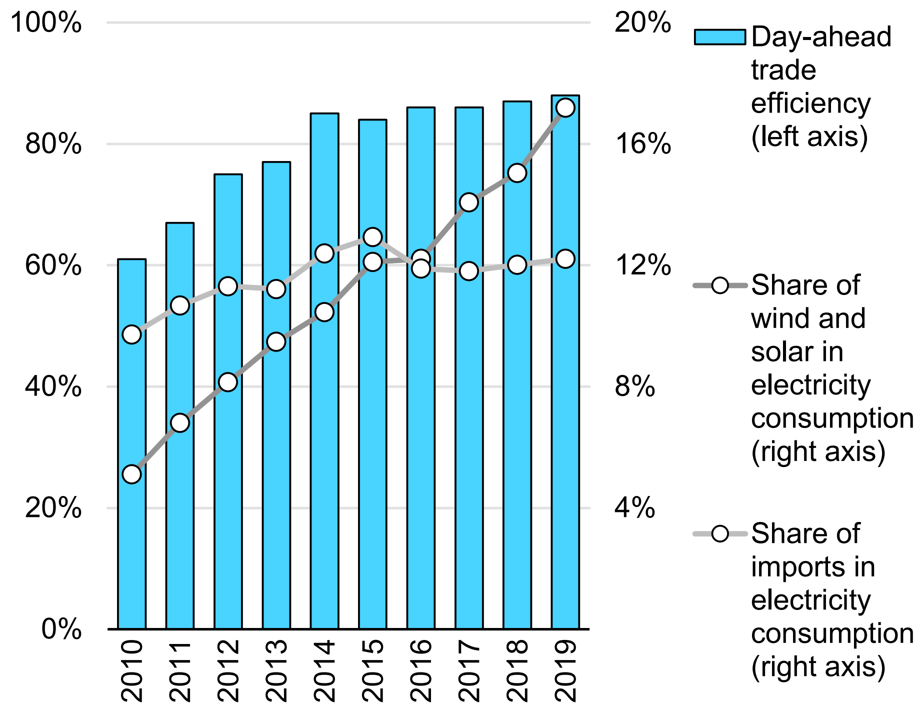
Regional operations support efficient power markets in meshed systems

European countries trade power in large quantities through their meshed, interconnected grids. Trading was historically organised around large resources such as hydropower (mainly located in the Alps and Scandinavia) and national nuclear fleets. In recent decades, the benefits of cross-border trading have become more obvious, particularly its usefulness to smooth out the variability of wind and solar power. These are rapidly growing and are unevenly distributed: wind power along the Atlantic coast and in the North and Baltic seas, solar in southern locations.

The integrated market model, established in the early 2000s in Europe, is being improved continuously as implementation progresses. The day-ahead spot market is organised as a competitive auction; coupling across all member states is scheduled for completion in 2021. The next steps are strengthening the coupling of intraday and balancing markets. These short-term markets are particularly important as variable renewable generation forecasts are more accurate for short time horizons.

Despite remarkable progress, integration of a system as large and meshed as Europe is challenging. Integration first needs to take place at the sub-regional level, where coordination entities can be established to support increasing the share of interconnection capacities available for trade.

Market integration in the European power system



Note: The EU Agency for the Cooperation of Energy Regulators defines the trade efficiency in a market as the percentage of available capacity (NTC) used in the “right economic direction” (from lower to the higher priced areas) in presence of a significant price differential (>EUR 1/MWh).

Source: ACER (2021), *Market Monitoring Report 2019*.

Electricity security

Security of supply incidents

Weather triggered many recent electricity security challenges

In the first half of 2021 there were shortfalls in supply in several regions. Cold weather triggered the Texas power crisis in February, as well as supply shortages in Japan and China. In addition to weather-related events, there were large-scale outages in Mexico as a result of technical failures, and in Pakistan and Chinese Taipei due to operator error. While renewable energy generators were among those with reduced availability in some of these events, they have not been the cause of any shortfalls.

Outages caused by cold weather have highlighted the need for system planners to ensure that power systems, including dispatchable power plants, are resilient to increasing weather extremes. Energy systems that depend heavily on electricity for space heating and cooling face particular challenges from exceptional temperatures.

From 15-18 February this year, exceptionally cold weather in the United States set off electricity shortages in several states. Texas was the hardest hit, while neighbouring regions in the Southwest Power Pool, Midcontinent ISO and Mexico also suffered outages.

In **Texas**, cold weather simultaneously drove record demand and reduced availability of generation capacity. Texas households rely on a higher proportion of electric resistance heating than most US states and home efficiency standards are geared towards cooling rather than heating needs. As a result, the impact of cold temperatures was magnified, leading to demand forecasts 20% higher than expected winter peaks, and close to record demand, which historically occurs during the summer.

At the same time, several factors reduced the availability of electricity supply. Natural gas generation was the worst affected, with 27 GW of capacity unavailable. Frozen gas wells reduced natural gas supply and cold weather led to the failure of gas generators and other equipment. The availability of coal also fell, by up to 6 GW, and nuclear by around 1 GW. Wind generation was 3 GW on average during the period, around half the seasonal average, as a result of blade icing and low wind speeds, but still above the lowest levels considered in contingency planning.

The impacts were severe, with some consumers experiencing long outages during extreme weather conditions. The incident underlined the key role of gas-fired generation (including gas supply) in some systems, where the resilience of the power system depends on the resilience of the natural gas system.

In **China,** the most extensive energy rationing in a decade affected 10 southern provinces from early December 2020 to the end of January 2021. Higher than expected demand played an important role, as the coldest winter recorded since 1966 coincided with the rapid recovery of the Chinese economy following Covid-19. This combination resulted in record peaks in consumption during

December for several of the most affected provinces. Furthermore, certain provinces were struggling to meet their "dual control" targets in December, which limit energy intensity and set caps on total energy consumption on a provincial level. To meet these targets, there were planned power outages in provinces such as Zhejiang.

On the supply side, unit failures increased as generators operated at high load to meet demand, placing strain on the coal fleet. The period also coincided with the dry season, limiting the ability of hydropower to compensate. Limited interconnection capacity was also a factor, both within and between regions, particularly in the central region. In May 2021, another electricity supply crunch occurred when industrial users in Guangdong were urged to stop production at certain times to alleviate strain on the power system arising from a combination of hot weather and high factory use.

In **Japan** there were electricity supply challenges in January 2021, with limited LNG availability resulting in very high wholesale prices. Japanese utilities entered the heating season at the end of 2020 with lower than average LNG inventories. When a cold snap pushed up demand for gas and electricity, the need to purchase LNG increased. The LNG market was already under pressure because of higher demand from China and Korea, which were also experiencing a cold snap, and liquefaction and supply outages in Australia, Indonesia and Malaysia. The United States provided almost all of the required extra LNG supply, leading to longer shipping routes that drove up spot charter rates and ultimately led to higher LNG prices. US LNG supply was also affected by traffic congestion in the Panama Canal.

The availability of other generation sources in Japan was also reduced. The 1 GW Matsushima coal power plant was forced to halt operations from early January due to an equipment malfunction and 15% of solar PV generation was lost due to snowfall. Gas generation increased, but with the pressure on the LNG market the result was a very tight electricity supply situation. Customers were urged to reduce electricity use to alleviate the supply shortage, however power cuts were not needed.

In the past six months major outages not caused by weather have taken place in Chinese Taipei, Mexico and Pakistan.

In **Pakistan** a technical fault occurred at the Guddu power plant at the centre of the Pakistan grid, which according to an official inquiry was related to a failure to follow standard operating procedures during maintenance work. The initial fault was followed by a sudden drop in frequency and a cascading blackout within 1 second, causing the grid to collapse and the entire country to lose power, which was fully restored 18 hours later.

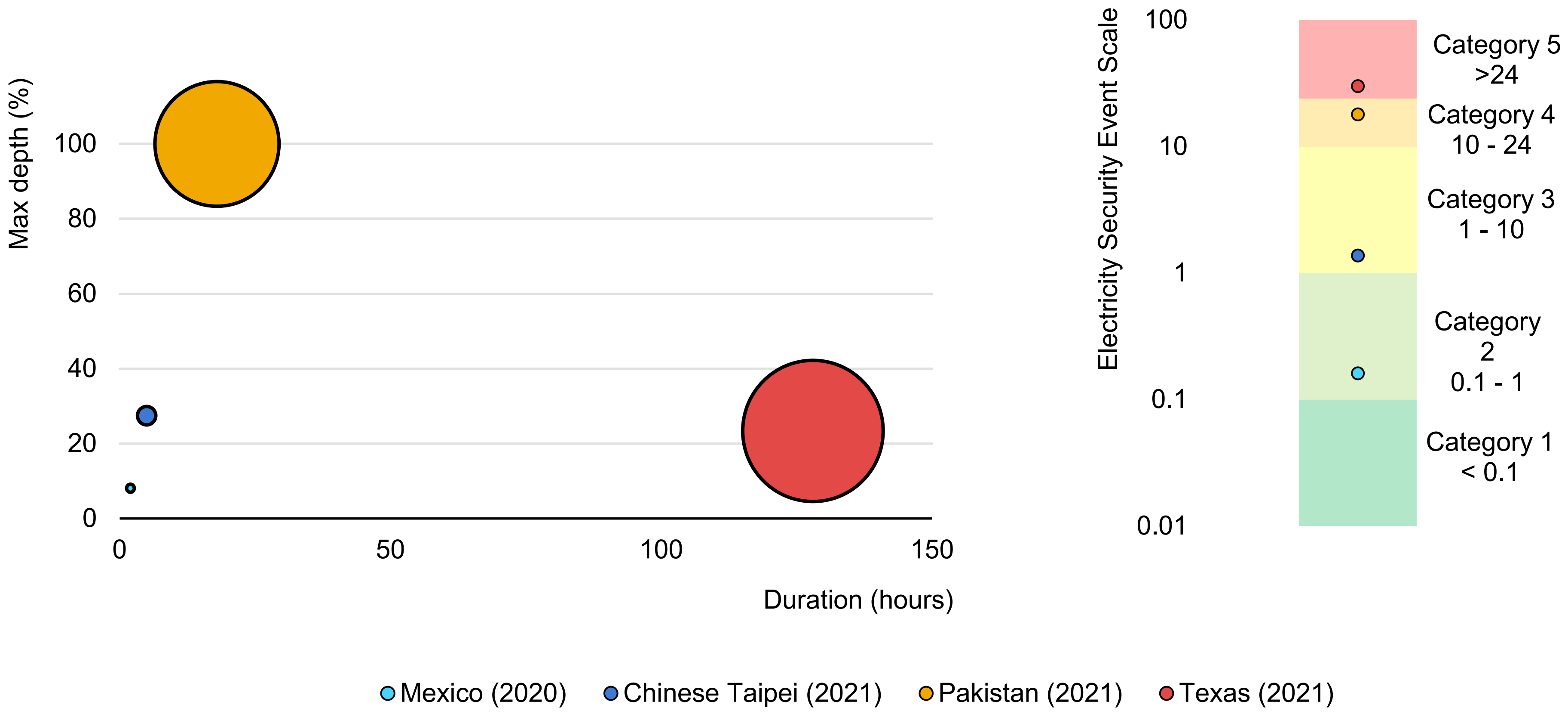
In **Mexico**, failure of two transmission lines in the northeast on 28 December 2020 resulted in a nationwide imbalance of supply and demand, triggering the disconnection of power plants amounting to around 9 GW. This led to load shedding that interrupted power supply for around 10 million customers or one quarter of the country for around two hours.

Rolling outages in **Chinese Taipei** on 13 May 2021 were triggered by an operator error, causing four units to trip at the Hsinta power plant. The outages affected around 4 million households and supply was fully restored five hours later. Taiwan Power Company has announced that customers will be compensated for the outages by a total of USD 16.8 million (TWD 470 million).

To categorise outages, we calculate an Electricity Security Event Scale (ESES) based on the maximum share of affected customers multiplied by the number of hours until service was restored. We use five categories from very minor events (a score of 0-0.1) to very severe events (greater than 24).

Outages in Texas and Pakistan were rare, high-impact electricity security events

Duration, maximum customers affected, and share in annual electricity demand (bubble size) for different electricity outage events (left) and Electricity Security Event Scale (ESES) rating (right)



Note: ESES rating is based on the maximum share of customers affected multiplied by the duration of the event. Maximum share of customers is relative to the named region rather than the entire interconnected system, e.g. as a share of Texas only and not including the rest of the United States.
Sources: IEA analysis based on *EIA Open Data*, *CPPA Power Purchase Price Forecast*, South China Morning Post, Reuters.

Resilience of integrated systems: the split of continental Europe on 8 January 2021

On 8 January 2021, Europe's largest synchronous electricity supply area, continental Europe, split into a north-west and a south-east block with different frequencies for approximately one hour following a series of cascading outages. No significant disconnection of load or disruption of wholesale power markets occurred, illustrating the capability of well-co-ordinated regional operation and defence plans to manage critical events in a highly interconnected system.

Interconnection brings many benefits, in particular to systems with high shares of solar and wind generation. At the same time, managing intensifying cross-border transfers increases operational complexity – especially in highly meshed systems – and reinforces the need for preparedness in the event of grid disturbances.

In case of an overload, protection devices – meant to avoid damage to substation assets – may trip and create overload in parallel circuits. This may lead to a cascade and, in extreme cases such as in January, to a complete separation of the system. The split location is often not predictable and once a split occurs, the separated regions typically experience an imbalance between supply and demand that needs to be corrected rapidly to prevent a cascading blackout.

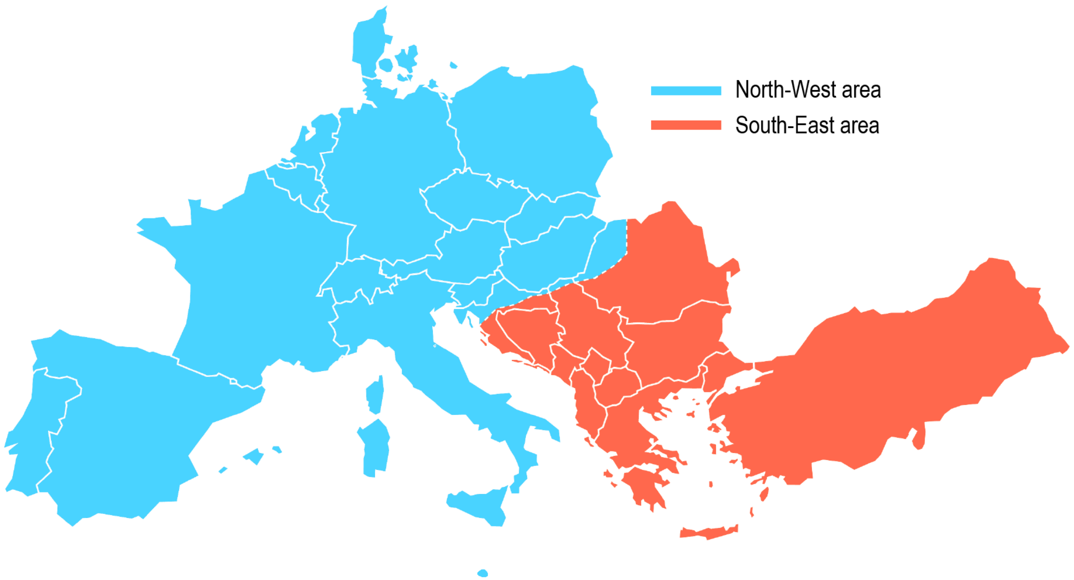
The 8 January event illustrates the need for corrective emergency means to be spread homogeneously across the system so that regardless of where a split occurs, each block can control its frequency in most emergency scenarios. In this event, the north-west block benefited from frequency stabilisation from two sources: 1.7 GW of automatic interruptible load in France and Italy (industrial consumers disconnected according to contractual conditions) and frequency support over high-voltage direct current (HVDC) links from other synchronous areas, including Great Britain and Nordic areas.

In the south-east block, which experienced over-frequency following the split, stability was never a concern. The steep voltage change resulted in consumers being disconnected in the direct vicinity of the splitting interface but they were reconnected soon after. Manual actions then reduced the frequency progressively.

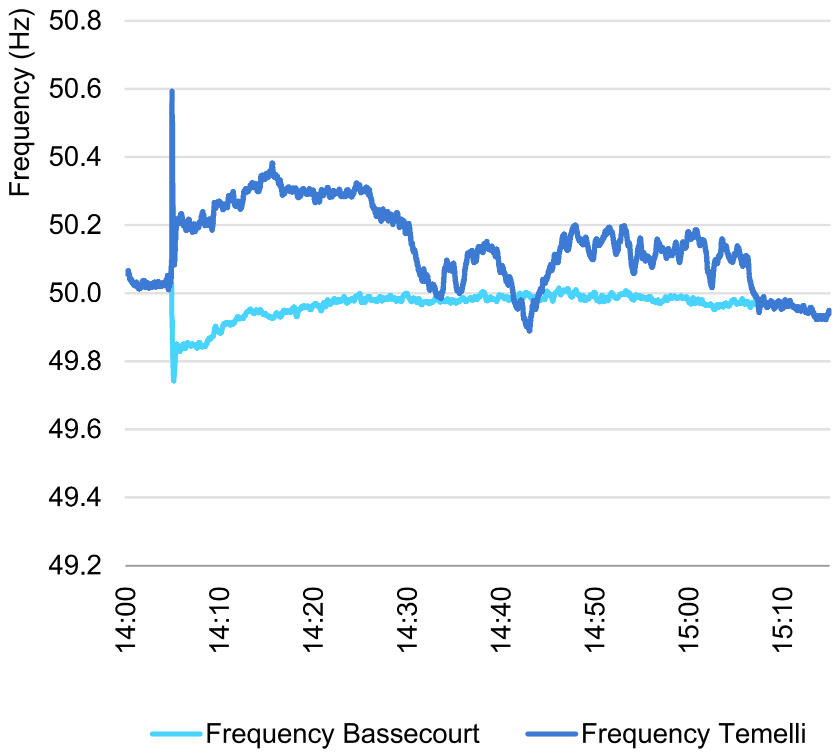
Thanks to quick stabilisation of the frequency, power markets were not affected. Operational co-ordination among transmission system operators rapidly brought frequencies back to operating ranges and resynchronisation was completed within about an hour from the start of the event.

Split of the continental European electricity system on 8 January 2021

Layout of the two separate areas



Frequency during the event



Source: ENTSO-E (2021), *Interim Report*.

Challenges of integrating renewables

Managing challenges of integrating variable renewables to ensure electricity security

To ensure electricity security, power systems need not only to maintain system adequacy – that is, have sufficient resources to meet peak demand – but also to be flexible enough to balance supply and demand at all times. Such flexibility can be difficult to ensure in low-carbon power systems with high shares of variable renewable energy (VRE) sources like wind and solar PV. As many countries around the world are boosting VRE capacity to meet decarbonisation objectives, it is becoming increasingly important to continuously monitor and manage possible integration challenges. In this section, we look at several metrics that can be used for this task.

Understanding flexibility requirements, from short-term to long-term, can support the effective utilisation of, and levels of investment in, different flexibility resources and the services they provide. Such resources include power plants, grids, storage and distributed energy resources such as demand response.

In the short term (seconds to hours), flexibility is needed to handle variations in net load, which refers to load minus generation from solar and wind. System frequency deviations and system ramps (hour-to-hour or sub-hourly variations) both provide a robust indication of short-term flexibility challenges. With larger VRE shares in a system, the degree of correlation between demand and VRE generation patterns is a key factor that influences the challenges in integrating renewables. For the medium and long term (days to seasons and years), the system is required to balance daily and seasonal changes in net load. Key indicators in this timescale include the gap between minimum and maximum daily net demand and the variation of average weekly net load from the seasonal average, as well as variation between years.

Several jurisdictions with rapid growth of VRE, including California, Ireland, Germany, South Australia, Spain, Texas and the United Kingdom, are facing growing flexibility needs across different timescales. These needs depend not only on the share of VRE, but also other factors including generation mix, interconnections and demand patterns. Many systems have recently set new records of VRE penetration, leading to greater integration challenges. In 2020, VRE penetration in Texas reached its highest hourly level, accounting for 59% of hourly electricity demand, up from a maximum of 56% in 2019. In the last year, some high-solar regions saw solar PV generating more than 100% of daily regional demand for the first time: in the state of South Australia, where the annual share of VRE is more than 50%, solar power met 100% of state-wide demand on a Sunday in October 2020.The state was exporting power at the time, however, and local thermal generation remained online during the entire day. In Kyushu, Japan, solar also provided more than 100% of daily demand in May this year, with part of the PV electricity used for pumped storage hydropower.

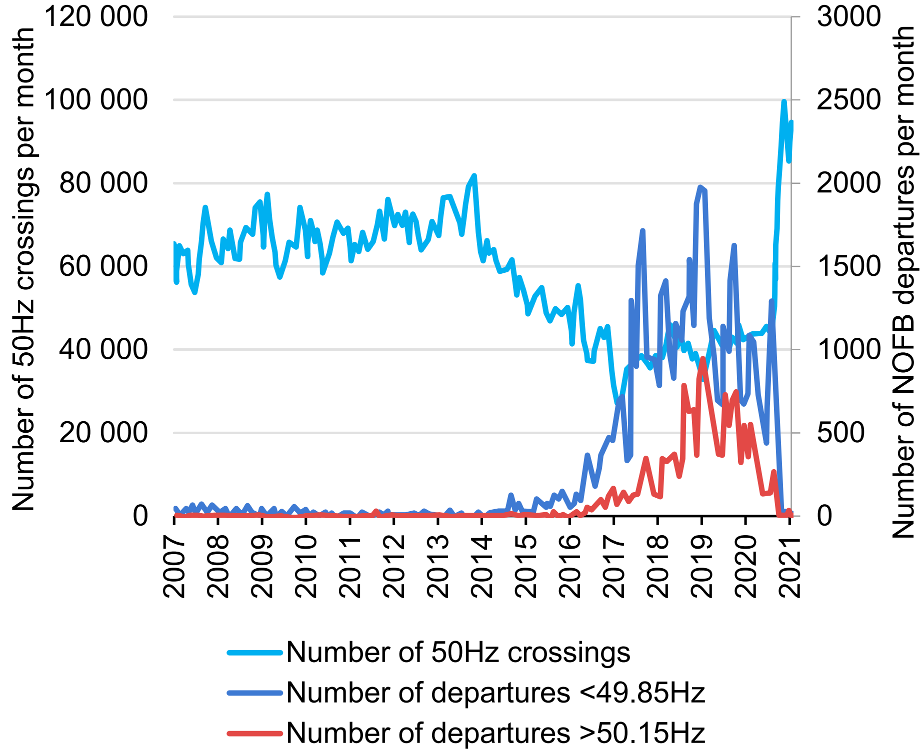
More VRE generation can increase system frequency deviation challenges

System frequency deviations can affect power system operation and connected power plants, and damage equipment. Frequency performance provides an indication of the stability of the system. Operating close to the reference frequency improves the prospect of rapid recovery during system events. It can therefore indicate how well a system is handling the challenges of more variable net demand caused by VREs.

In general, the normal operating frequency has to be maintained within a certain range of the reference value (50 Hz or 60 Hz). While tolerances are allowed after events (e.g. outages or faults), the frequency should be restored within this range within a certain time interval. Some operating frequency ranges are ±0.03 Hz for ERCOT (United States), ±0.2 Hz for EirGrid (Ireland), ±0.1 Hz for many systems in Europe and ±0.15 Hz for Australia's National Electricity Market (NEM).

A high share of non-synchronous sources like wind and solar PV, as well as imports via HVDC lines, can increase frequency range violations as they do not provide the frequency stabilising inertia offered by conventional generators like nuclear, hydro and thermal plants. In the NEM, the number of such events increased from around 2015 until the last quarter of 2020, when the implementation of a mandatory primary frequency response rule significantly improved frequency performance.

Number of frequency crossings outside normal operating frequency bands (49.85-50.15 Hz) in the Australian National Electricity Market



Source: AEMO (2021), Frequency and Time Error Monitoring.

Hourly net load ramps and the gap between minimum and peak net load are increasing…

Hour-to-hour variations in net load (net load ramp) are another key indicator of the need for short-term flexibility, which has to be provided by flexible resources like dispatchable power plants, storage and demand response. With increasing VRE shares, net load variations become more pronounced, as experienced in many systems. In Ireland, where instantaneous non-synchronous penetrations reached almost 70% in 2020, the highest hourly ramping requirement was almost 31% of the daily peak demand. In Spain, which has added substantial capacity in the last year, a clear upward shift is visible in the top 500 net load ramps in 2020 relative to 2019. In Texas, the highest hourly upward ramp in 2020 was 8.6 GW, or 25% of the daily peak demand, compared with 7 GW in 2019 (with a low relative spread).

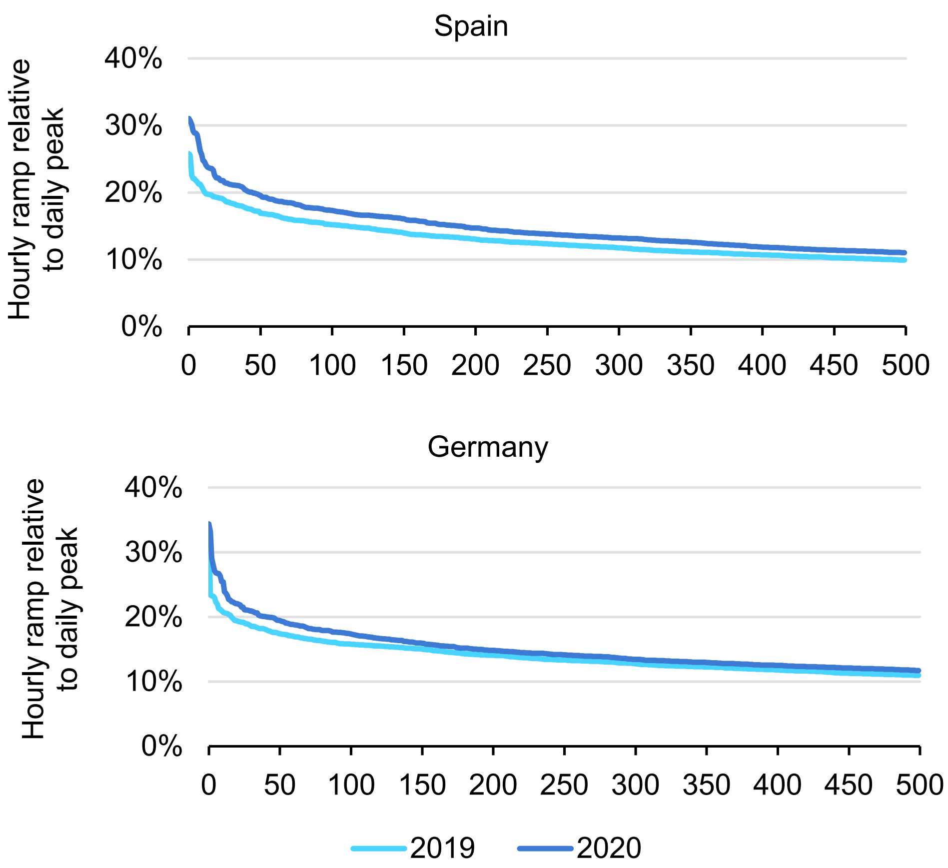
The correlation between demand and VRE generation patterns influences net load ramps. If demand and VRE supply typically increase at the same time in a system, high ramps become less frequent. In Texas, hourly demand changes and VRE went in the same direction in around 51% of hours in 2020. In Europe this combination occurred for around 60% to 70% of hours. Such correlations typically remain similar in the short to medium term since they largely depend on the location of VRE plants and demand patterns. The impact of VRE capacity additions on net load ramps can be mitigated by taking into account the interaction between the expected generation profile of new VRE plants and the demand pattern. Demand response can also play an important role by better aligning demand with renewables generation.

The gap between daily minimum and peak demand provides a good indication of the integration challenges and flexibility requirements on a daily timescale. This challenge is typically associated with frequent start-ups, shutdowns and cycling of conventional power plants in the system. In 2020, the largest gap between the daily minimum and peak demand in Texas was 35 GW (60% of daily peak), which occurred in summer. Such a sizeable gap also occurred in a number of other days in summer. The daily gap depends on the region-specific demand profile and VRE generation pattern. Demand flexibility has the potential to reduce the daily gap, by shifting loads from high demand periods to low net load periods, such as hours of high solar output.

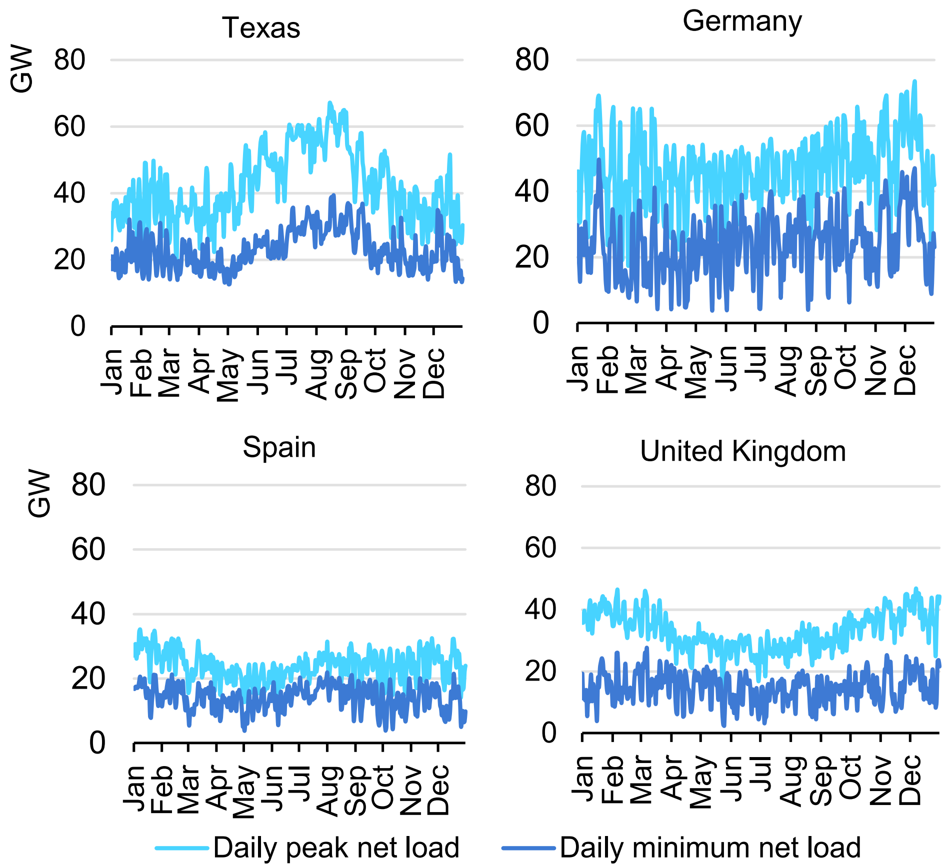
In Europe, where the largest gaps typically occur during winter, there are generally fewer days with a sizeable gap than in Texas.

… and depend on region specific supply and demand patterns

Hourly net load ramps relative to daily peak net load for top 500 net load ramp hours in Spain and Germany in 2019 and 2020



Daily peak and minimum net load, 2020



Sources: Red Eléctrica (Spain), accessed via the ENTSO-E Transparency Platform, Bundesnetzagentur | SMARD.de (Germany), *EIA Open Data*.

Annexes

Regional and country groupings

Africa – Algeria, Angola, Benin, Botswana, Cameroon, Congo, Democratic Republic of the Congo, Côte d'Ivoire, Egypt, Equatorial Guinea, Eritrea, Ethiopia, Gabon, Ghana, Kenya, Libya, Mauritius, Morocco, Mozambique, Namibia, Niger, Nigeria, Senegal, South Africa, South Sudan, Sudan, United Republic of Tanzania, Togo, Tunisia, Zambia, Zimbabwe and other African countries and territories.[1]

Asia Pacific – Australia, Bangladesh, Brunei Darussalam, Cambodia, Chinese Taipei, India, Indonesia, Japan, Korea, Democratic People's Republic of Korea, Lao People's Democratic Republic, Malaysia, Mongolia, Myanmar, Nepal, New Zealand, Pakistan, People's Republic of China,[2] Philippines, Singapore, Sri Lanka, Thailand, Viet Nam and other Asian countries, territories and economies.[3]

Central and South America – Argentina, Bolivia, Brazil, Chile, Colombia, Costa Rica, Cuba, Curaçao, Dominican Republic, Ecuador, El Salvador, Guatemala, Haiti, Honduras, Jamaica, Nicaragua, Panama, Paraguay, Peru, Suriname, Trinidad and Tobago, Uruguay, Venezuela and other Latin American countries and territories.[4]

Eurasia – Armenia, Azerbaijan, Belarus, Georgia, Kazakhstan, Kyrgyzstan, Republic of Moldova, Russian Federation, Tajikistan, Turkmenistan, Ukraine and Uzbekistan.

Europe – Albania, Austria, Belgium, Bosnia and Herzegovina, Bulgaria, Croatia, Cyprus,[5,6] Czech Republic, Denmark, Estonia, Finland, North Macedonia, France, Germany, Gibraltar, Greece, Hungary, Iceland, Ireland, Italy, Kosovo,[7] Latvia, Lithuania, Luxembourg, Malta, Montenegro, Netherlands, Norway, Poland, Portugal, Romania, Serbia, Slovak Republic, Slovenia, Spain, Sweden, Switzerland, Turkey and United Kingdom.

European Union – Austria, Belgium, Bulgaria, Croatia, Cyprus,[5,6] Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Ireland, Italy, Latvia, Lithuania, Luxembourg, Malta, Netherlands, Poland, Portugal, Romania, Slovak Republic, Slovenia, Spain and Sweden.

Middle East – Bahrain, Islamic Republic of Iran, Iraq, Israel, [8] Jordan, Kuwait, Lebanon, Oman, Qatar, Saudi Arabia, Syrian Arab Republic, United Arab Emirates and Yemen.

North Africa – Algeria, Egypt, Libya, Morocco and Tunisia.

North America – Canada, Mexico and the United States.

Southeast Asia – Brunei Darussalam, Cambodia, Indonesia, Lao People's Democratic Republic, Malaysia, Myanmar, Philippines, Singapore, Thailand and Viet Nam. These countries are all members of the Association of Southeast Asian Nations (ASEAN).

Advanced economies – OECD member nations, plus Bulgaria, Croatia, Cyprus, Malta and Romania.

Emerging markets and developing economies – All other countries not included in the advanced economies regional grouping.

[1] Individual data are not available and are estimated in aggregate for: Burkina Faso, Burundi, Cabo Verde, Central African Republic, Chad, Comoros, Djibouti, Gambia, Guinea, Guinea-Bissau, Lesotho, Liberia, Madagascar, Malawi, Mali, Mauritania, Reunion, Rwanda, Sao Tome and Principe, Seychelles, Sierra Leone, Somalia, Eswatini and Uganda.

[2] Including Hong Kong.

[3] Individual data are not available and are estimated in aggregate for: Afghanistan, Bhutan, Cook Islands, Fiji, French Polynesia, Kiribati, Macau (China), Maldives, New Caledonia, Palau, Papua New Guinea, Samoa, Solomon Islands, Timor-Leste, Tonga and Vanuatu.

[4] Individual data are not available and are estimated in aggregate for: Anguilla, Antigua and Barbuda, Aruba, Bahamas, Barbados, Belize, Bermuda, British Virgin Islands, Cayman Islands, Dominica, Falkland Islands (Malvinas), Grenada, Guyana, Montserrat, Saba, Saint Eustatius, Saint Kitts and Nevis, Saint Lucia, Saint Pierre and Miquelon, Saint Vincent and the Grenadines, Sint Maarten, and the Turks and Caicos Islands.

[5] 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 United Nations, Turkey shall preserve its position concerning the "Cyprus issue".

[6] 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.

[7] The designation is without prejudice to positions on status, and is in line with the United Nations Security Council Resolution 1244/99 and the Advisory Opinion of the International Court of Justice on Kosovo's declaration of Independence.

[8] 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 and/or the IEA 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.

Abbreviations and acronyms

ASEAN	Association of Southeast Asian Nations
CCGT	combined cycle gas turbine
CDDs	cooling degree days
CO_2	carbon dioxide
ESES	Electricity Security Event Scale
ETS	emission trading scheme
EU ETS	European Union Emissions Trading System
FIDs	final investment decisions
FSRU	floating storage regasification unit
GDP	gross domestic product
GHG	greenhouse gas
HDDs	heating degree days
HVDC	high-voltage direct current
IEA	International Energy Agency
IMF	International Monetary Fund
ITC	investment tax credit
KETS	Korea Emissions Trading Scheme
LNG	liquefied natural gas
LTO	long-term operation
MER	Mercado Eléctrico Regional
NEM	National Electricity Market
OECD	Organisation for Economic Co-operation and Development
OPEC	Organization of the Petroleum Exporting Countries
PLN	Perusahaan Listrik Negara
PPA	power purchase agreement
REIPPPP	Renewable Energy Independent Power Producer Procurement Programme (South Africa)
RMIPPPP	Risk Mitigation Independent Power Producer Procurement Programme
PV	photovoltaic
TTF	Title Transfer Facility
UK	United Kingdom
USC	ultra-supercritical
VRE	variable renewable energy
WHO	World Health Organisation
ZEC	zero emission credit

Units of measurement

bcf	billion cubic feet
$GtCO_2$	gigatonnes of carbon dioxide
GW	gigawatt
GWh	gigawatt-hour
Hz	hertz
km	kilometre
kV	kilovolt
kWh	kilowatt hour
MBtu	million British thermal units
MW	megawatt
MWh	megawatt-hour
MWh_{el}	megawatt-hour electricity
gCO_2	grams of carbon dioxide
tCO_2eq	tonne of carbon dioxide equivalent
TWh	terawatt-hour

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