Electricity Market Report

December 2020

Abstract

This is the first ever Electricity Market Report produced by the International Energy Agency (IEA). Designed to complement other reports in the Market Report Series on energy efficiency, renewables, coal, natural gas and oil, this report focuses on developments in the world's electricity markets amid the Covid-19 pandemic. It includes an assessment of 2020 trends and 2021 forecasts for electricity demand, supply, capacity and emissions – both globally and by country. Starting in 2021, the IEA will publish a new edition of the report on a half-yearly basis with the latest updates on key developments in global electricity markets.

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Executive summary

Executive summary

Global electricity demand in 2020 is projected to fall by around 2%. This is the biggest annual decline since the mid-20th century and far larger than what followed the global financial crisis, which resulted in a drop in electricity demand of 0.6% in 2009. The contraction this year is a result of the Covid-19 pandemic and its impact on economic activity – the assumed 4.4% decline in global GDP in 2020 is significantly larger than the 0.1% reduction in 2009 – and the measures taken to prevent the further spread of the virus.

China will be the only major economy to see higher electricity demand in 2020. However, projected demand growth of around 2% in the People's Republic of China (hereafter, "China"), which represents about 28% of global electricity consumption, is still significantly below its average since 2015 of 6.5%. After implementing strict health measures early in the year and experiencing subsequent drops in electricity demand in the first quarter, China has seen year-on-year demand growth every month since then. Although demand recovered in many economies during the Northern Hemisphere's summer and autumn, major consumers including the United States, India, Europe, Japan, Korea and Southeast Asia are all set to experience declines for the year as a whole.

Renewable electricity generation is projected to grow by almost 7% in 2020, squeezing conventional generation. Long-term contracts, priority access to the grid and sustained installation of new plants are all underpinning strong growth in renewable electricity production. The decline in electricity demand combined with a rise in renewable supply has accelerated the squeeze on coal, gas and nuclear power. **Coal-fired generation** is estimated to fall by around 5% in 2020, the largest decrease on record, bringing it back to levels last seen in 2012. **Nuclear power generation** is set to decline by around 4% in 2020, affected both by the pandemic and lower capacity availability, especially in the first half of the year. China was the main exception to this: its nuclear output increased by about 6% thanks to new capacity coming into service. **Gas-fired electricity generation** is projected to fall by 2%, its decline cushioned by lower natural gas prices enabling it to take market share away from coal, particularly in the United States and Europe. Overall, electricity generation-related CO_2 emissions are expected to fall by 5% in 2020, a much bigger decline than the forecast decline in global electricity demand.

Wholesale electricity prices have plummeted in 2020. Falling demand, lower fuel prices and the increase in renewable generation units with zero marginal costs have dragged down prices. The IEA's wholesale electricity market price index, which tracks price movements in major advanced economies, shows an average price decline of 28% in 2020, after having already fallen by 12% in 2019.

Following the shock of 2020, we expect a modest rebound in 2021. With the recovery of the global economy in 2021, global electricity demand is expected to grow by around 3%. This rebound is rather low compared with 2010, the year following the global financial crisis, when electricity demand grew by 7.2%. The increase in demand is expected to be driven by emerging and developing economies, particularly China and India.

The growth of renewables should remain the lead story in 2021, but coal is expected to bounce back. Electricity output from renewables, particularly wind and solar PV, is expected to continue to set new records in 2021, expanding their market share to 29% from 28% in 2020. Nuclear power is also set for growth of 2.5% owing to a rebound in France and Japan and new plants coming online in China and the United Arab Emirates. In advanced economies, the growth of renewables and nuclear will continue to shrink the space remaining for fossil fuel generation. Natural gas is likely to be impacted more than coal as a result of an assumed rise in natural gas prices. In emerging and developing economies, demand growth is projected to outpace increases in renewables and nuclear, leaving some room for coal and gas generation to expand. The expected net result globally is that coal-fired generation increases by around 3%, while gas-fired plants increase output by roughly 1%. This would lead to a rise in CO_2 emissions from the power sector of around 2% in 2021.

2020 – Decline and recovery

Global overview

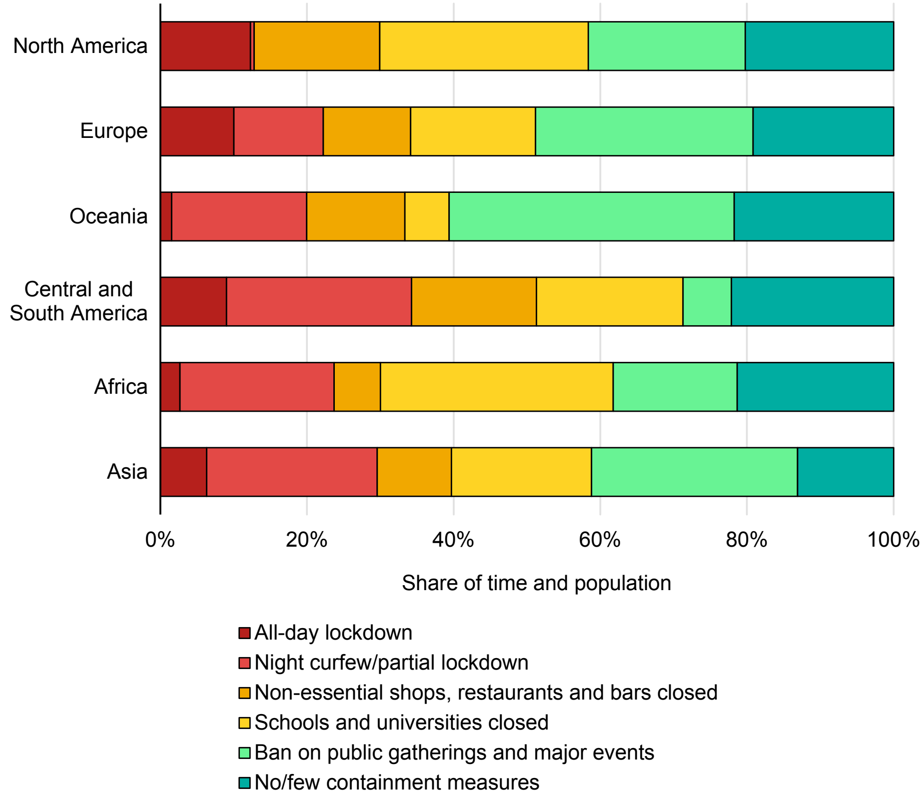
The Covid-19 pandemic

The first case of Covid-19 infection was officially reported to the World Health Organization by the People's Republic of China (hereafter, "China") on 8 December 2019. The virus originated in Wuhan, Hubei province, and spread rapidly, with initial cases being identified as early as January in numerous countries including Japan, Korea, the United States, France, Germany and the United Kingdom.

Due to concerns about public health and fearing that the increasing number of infected citizens would overwhelm national healthcare systems, countries introduced restrictions on both the international and internal movement of people to reduce the rate of spread of the disease. The rapid spread of the virus also led many countries to introduce lockdowns and other restrictive measures.

Being under lockdown generally had wide-ranging implications. Among other impacts, commercial activities were suspended apart from shopping at supermarkets and pharmacies, and working from home, where possible, became the standard. In some countries separate shopping hours were designated for the elderly to protect the most vulnerable group from the virus. The stringency and length of measures varied from country to country and also at the subnational level. Governments followed different strategies in balancing the trade-off between containing infection and maintaining economic activity and social interaction.

Population affected by Covid-19 measures in the first half of 2020



Note: Countries are categorised according to the strictest measures in place.

Sources: IEA analysis based on Lejeune, O. (2020), Coronavirus Counter Measures; World Bank (2020), World Population.

The global economy in 2020 and 2021

The lockdown measures in response to the global pandemic led to severe economic consequences. Global GDP in 2020 is estimated to fall by 4.4% compared to 2019, the most severe decline since 1960 – exceeding by far the drop of 0.1% which followed the global financial crisis in 2009. Whereas the latter originated in events unfolding since 2007 (and thus over time), the pandemic affected global markets within a single quarter. In a sample covering 49 countries representing 87% of global manufacturing value added, 81% of surveyed countries showed an average 6% decrease in seasonally adjusted industrial production in March in comparison with December 2019. In April industrial production was down in 93% of the countries, by 20% on average (again compared to December 2019).

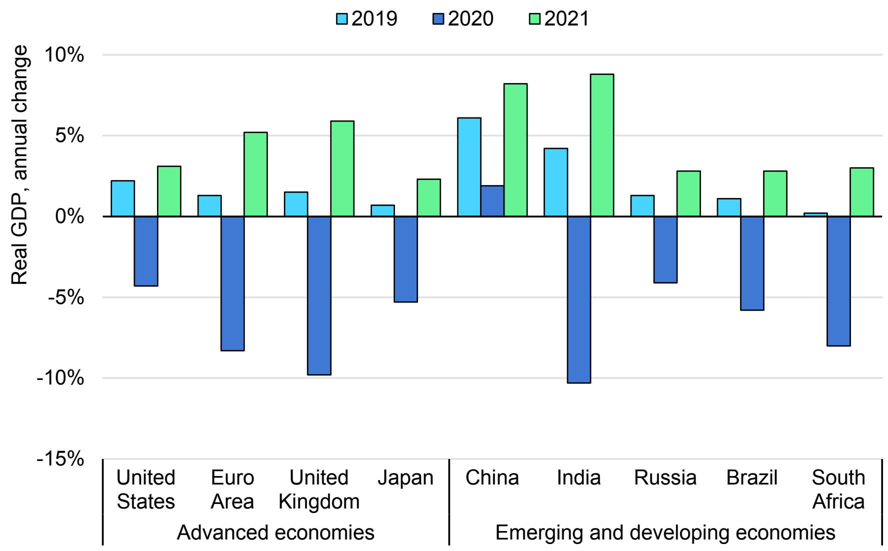
As a result, governments have implemented a variety of measures to support their national economies. The deferment of taxes and social security contributions is the most common fiscal instrument implemented by governments, followed by credit subsidies to firms, income support for households and wage subsidies.

In many regions the economic impact was most severe in the second quarter of 2020. In the European Union seasonally and calendar adjusted GDP decreased by 12.1% after a 0.9% decrease in the first quarter as compared to 2019. Compared to the first quarter, US real GDP decreased at an annual rate of 31.4% in the second quarter of 2020 (it was down 5% in the first quarter) – and rebounded significantly in the third (up 33.1%). The Chinese economy shrank by 6.8% in the first quarter of 2020, but recovered to 3.2% and 4.9% growth in the second and third quarter respectively, compared to the same periods in 2019.

The economic impact of the pandemic is spread unevenly. European countries are among the hardest hit, with an annual estimated GDP decline of 8.3% for the Euro area. India saw a sharp contraction in consumption and a collapse in investment following the drop in domestic demand in the second quarter. China is the only large economy to grow in 2020, although estimated growth for 2020 of 1.9% is significantly less than the 6% expected at the beginning of the year.

For 2021 current forecasts see world economic output at about the same level as in 2019, driven by a strong recovery in emerging and developing Asia, especially China and India. Advanced economies are expected still to fall short of pre-pandemic levels.

Estimated GDP growth by region



Source: IMF (2020), World Economic Outlook, October 2020.

Global electricity demand on track to decline 2% in 2020

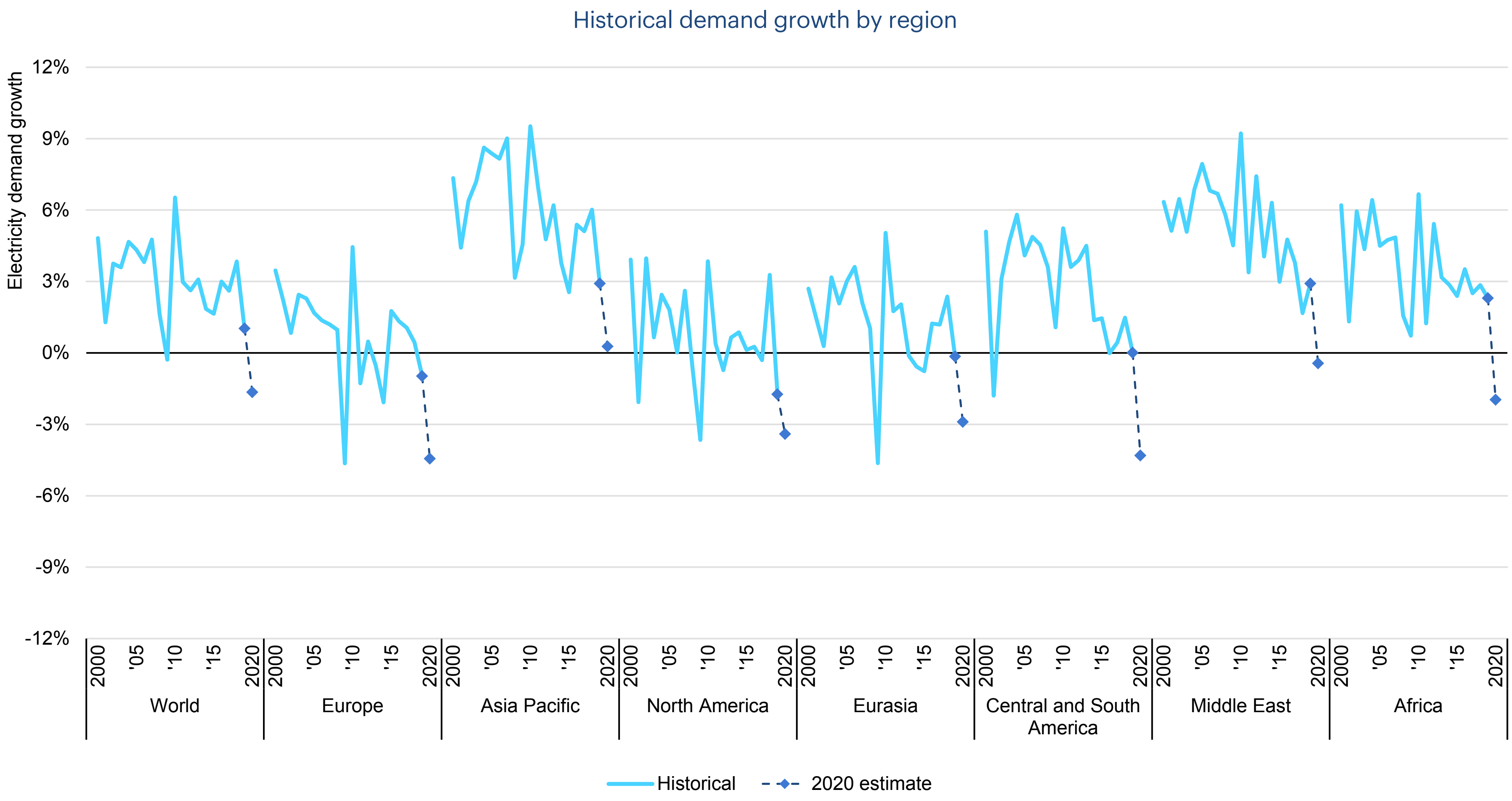
As around 42% of global final electricity demand is from industry, and 22% is from the commercial and public services sector, economic activity and electricity consumption are closely connected. In advanced economies both sectors are responsible for roughly equal shares (around 32%). In emerging and developing economies, industry dominates by consuming around half of final demand, with the commercial and public services sector accounting for around 14%.

Global electricity consumption is on track to fall by 2% in 2020. This is significantly less than the 5% decrease we had forecast in the Global Energy Review in April, in large part due to a strong recovery in China and to a lesser extent in India. Demand dropped by more than 3% in the first quarter due to lockdowns in China and a very mild winter in the northern hemisphere. The second quarter dip was similar: although lockdown measures depressed demand in many markets by 20% or more for several weeks, the recovery in China (demand was up 3.9% compared to the second quarter in 2019) prevented a higher global reduction. Demand recovered in the third quarter as lockdowns ended and China, responsible for 28% of the world's electricity consumption, grew by 6% year-on-year (y-o-y). Recovery in the fourth quarter has been hampered by new control measures in Europe and North America to contain the pandemic.

Demand for 2020 as a whole is expected to see the greatest decline in Europe, decreasing by more than 4%. Large decreases are in Italy, the United Kingdom and Spain (around 6% each) as well as France and Germany (5% each). In Asia Pacific, together responsible for 48% of global electricity demand, declines in Japan (around 4%), Korea (3%) and India (2%), and Southeast Asia (1%) are offset by the increase in China (2% growth). North American demand declines by 3%, with the United States decline slightly higher (3.6%). Demand in Central and South America is down by 4%, the same as Brazil. Eurasian demand is down by around 3% due to a decline in the Russian Federation (hereafter, "Russia") of around 3%. Africa, with only 3% of the world's electricity consumption despite having one-sixth of the world's population, has seen electricity demand decline by 2% compared to 2% growth the year before. The decline in the Middle East is modest.

Economic structure plays a major role in determining the impact of the pandemic on the economy and electricity demand. Countries where most electricity consumption is in the industrial or residential sectors have been less affected. In China industry accounted for more than 60% of final electricity consumption in 2019, compared to 16% for households. By contrast, in the United States industry only accounts for 20% of final electricity demand, with residential demand at 37%. In Europe, however, the contribution of the service sector, particularly the heavily affected hospitality and tourism sectors, has led to a much greater impact on the economy and electricity consumption.

Largest decline in global electricity demand in more than 50 years



Commercial sector is hit the hardest

The public health crisis caused by the Covid-19 pandemic forced most countries to introduce lockdowns in the first and second quarters of 2020 – and in some areas again towards the end of the year. With restaurants, shopping malls and factories closed and office-based companies introducing home working, many countries experienced a drop in industrial and commercial consumption and an uplift in residential demand.

Spain, one of the hardest-hit countries in the European Union, saw a significant drop in its electricity consumption in both the industrial and commercial sectors. The fall in demand started to be visible in March. In the first quarter of the year industrial demand fell by 3.4% and commercial demand by 2.8% below the same period in 2019. Electricity demand reached its lowest point in April, resulting in a 10.6% and 20.8% decline in the industrial and commercial sectors in the second quarter compared with 2019. In the following months electric power consumption increased again, reaching March's levels in August.

Similar trends were seen in the United Kingdom, where industrial electricity consumption fell by 17% in the second quarter of 2020 compared to the same quarter in 2019, and commercial electricity demand dropped by 19%. In the meantime, the United States commercial sector only saw an 11% drop during the same period, and a 9% drop in industrial demand, due to lockdowns being less severe and varying by state.

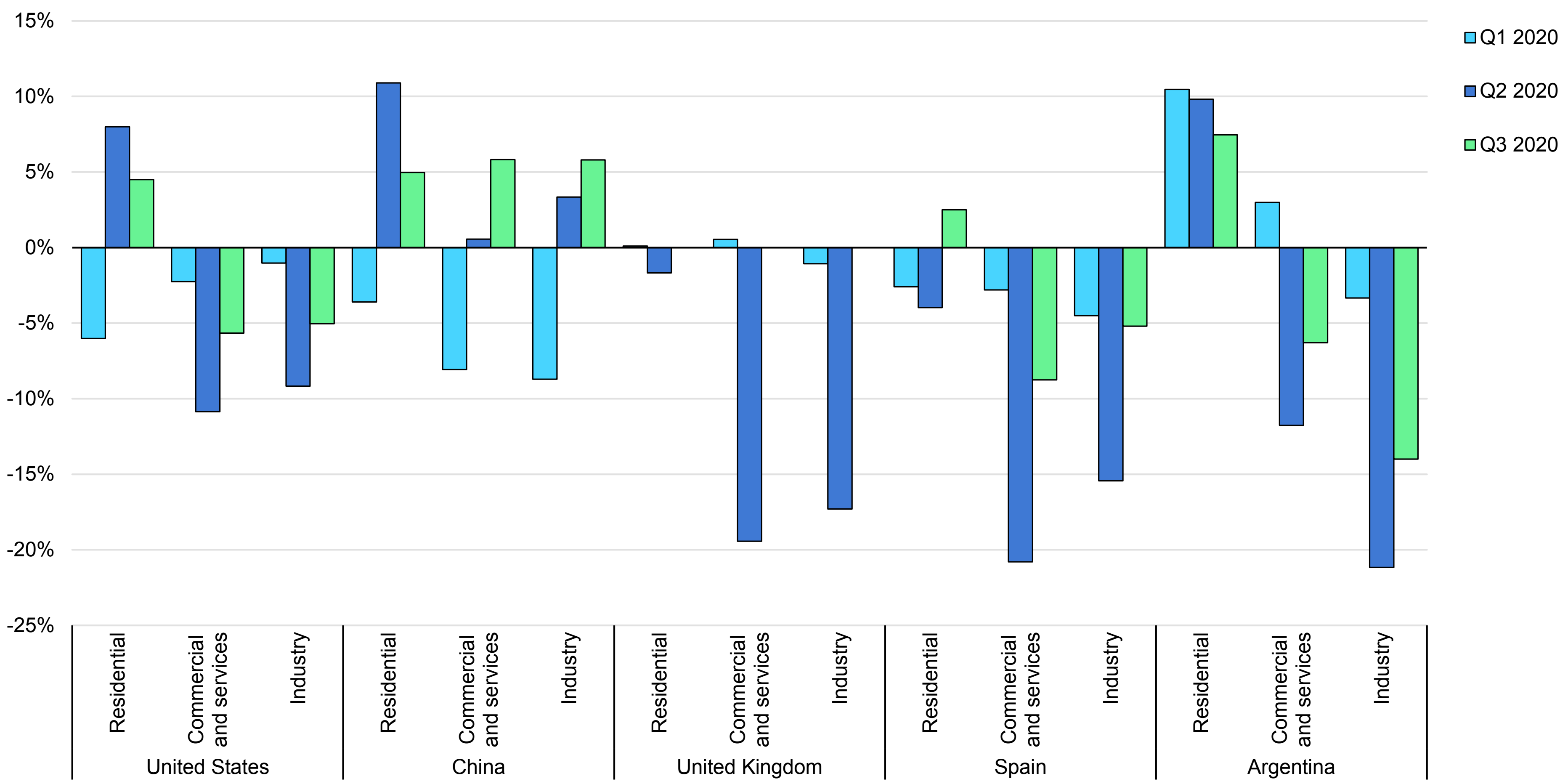
In Argentina, which at the end of March introduced relatively strict lockdown measures compared to other countries in the region, experienced a particularly strong decrease in industrial electricity demand, down 21% year-on-year in the second quarter, while commercial demand dropped by 15%.

The United States and China observed a year-on-year increase in residential electricity demand in the second quarter of 2020, which can only partly be explained by higher weather-induced heating and cooling energy demand.

Decreasing economic activity throughout the first and second quarters of 2020 can be detected in most European countries. Industrial activity saw a significant drop, mainly in the second quarter, in Germany, Spain, France, Italy and the United Kingdom. Manufacturing activity was significantly down in Germany, partly due to reduced production in the car industry (responsible for around 19% of GDP in the German manufacturing sector). Other countries, such as the United Kingdom and France, saw their most significant decrease in economic activity in the wholesale and retail trade, transport, accommodation and food service activities.

The third quarter of 2020 saw a recovery in electricity demand in commercial and industry sectors in the United States, Spain and Argentina. Nonetheless, consumption was still below 2019 levels.

Y-o-y changes in electricity demand in the first three quarters of 2020



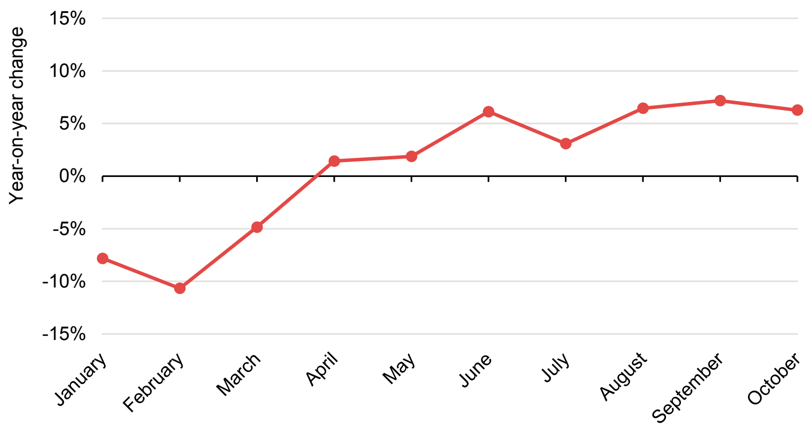
Sources: IEA analysis based on EIA (2020), Electric Power Monthly; China Energy Portal (2020), Growth in power production in quarter two 2019-20; GOV.UK (2020), Electricity: DUKES 5.1; Red Eléctrica de España (2020), Evolución de la demanda de electricidad de grandes consumidores [Evolution of electricity demand of large consumers]; Cammesa (2020), MEMNET.

Electricity demand rebounded sharply after initial shock, and is back to pre Covid-19 trends in 2020 third quarter

Electricity demand rebounded sharply after a deep decrease during lockdowns, recovering as they were lifted. This is especially apparent in China, the world's largest electricity consumer, where the first lockdown (in the city of Wuhan, where the pandemic originated, and later expanded to the whole Hubei province) began on 23 January and ended on 8 April.

China's electricity demand dropped under lockdown in January and more strongly in February (down 11% compared to February 2019, leap year and weather corrected). As confinement measures were eased, electricity demand showed the first signs of recovery. By June 2020 electricity demand had recovered completely and was even higher than last year's levels, back onto pre Covid-19 trends. For the first ten months of 2020, weather-corrected electricity demand in China is 1.2% higher than the previous year.

Weather-corrected y-o-y comparison of demand in China to 30 October



Source: IEA analysis based on China Statistical Information Network (2020).

Other major markets in advanced economies experienced a similar pattern of decline and recovery – but have not recovered to quite the same levels as a year ago. In several European countries the initial local restrictions were soon replaced by full population lockdown measures: in the timeframe of two weeks, between 11 and 25 March, Italy, Spain, France and the United Kingdom asked their populations to stay at home and closed non-essential activities; in Germany measures were more or less strict depending on the individual Bundesländer (states), but most imposed curfews, restrictions on meetings and closed schools, restaurants and non-essential services.

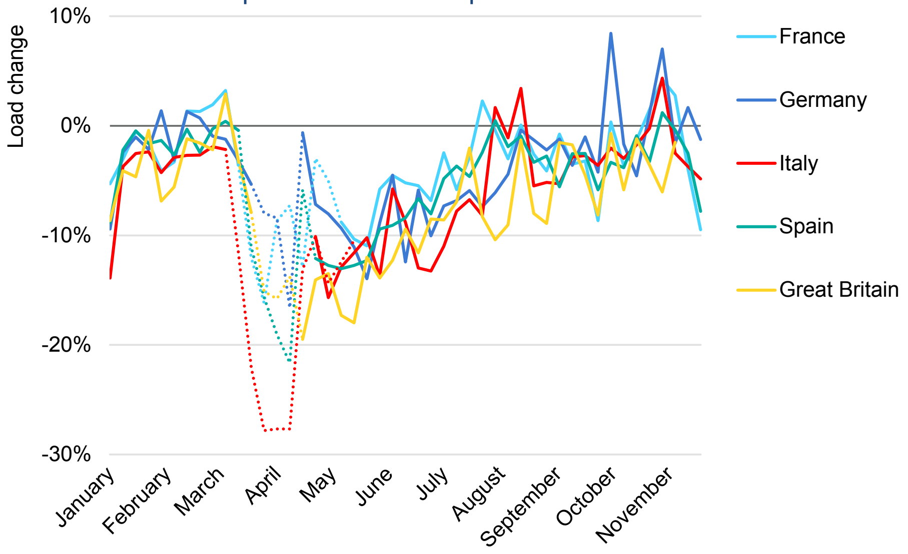
Full lockdown measures pushed electricity demand down by 20% or more, with smaller effects for partial lockdowns. The most dramatic decreases were observed in Italy, where in the last week of March demand dropped by 28% compared to the previous year, weather corrected. For most others, the maximum decrease was in the 15-20% range. Those economies with a greater reliance on services, particularly in the tourism and hospitality sectors, were more strongly affected.

Since lockdowns were lifted, demand has gradually recovered to levels around 5% lower than the previous year owing in large part to the lower levels of economic activity related to ongoing restrictions. With the tightening of restrictions towards the end of the year, including new lockdowns, it is possible that fourth-quarter demand will be significantly lower than in the previous year.

United States electricity demand has shown similar behaviour, with demand recovering in the summer after falling by about 6.5% in the period March-May. Growth in residential demand has been much smaller than the decline in industrial and commercial consumption. As in Europe, new restrictions on activity in the fourth quarter are expected to lower consumption for the year.

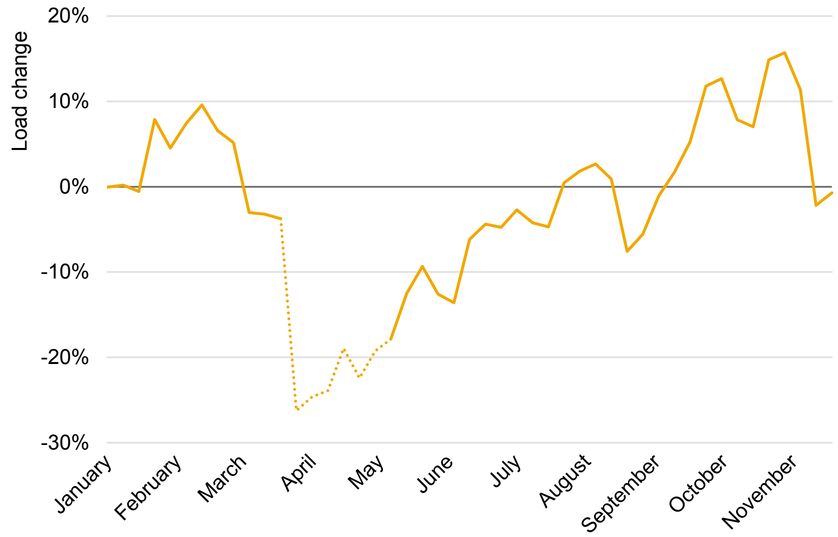
India also entered lockdown in March and falls somewhere between the patterns seen in advanced economies and in China – demand had recovered to above the previous year's levels by September 2020. In mid-November however, demand returned to last year's levels due to the Diwali festival (taking place around two weeks later this year compared to last year) and strikes in the agriculture sector. Overall demand for the year is expected to be down by 2%.

Weather-corrected year-on-year comparison of demand in selected European countries up to 18 November



Note: Dashed lines represent periods of deepened lock-down. Data are corrected for weather effects.
Sources: IEA analysis based on RTE (France), TERNA (Italy), Red Eléctrica (Spain) – all three accessed via the ENTSO-E (2020), Transparency Platform; Bundesnetzagentur (2020), SMARD.de (Germany); National Grid (2020), Historic demand data (Great Britain).

Weather-corrected year-on-year comparison of demand in India up to 18 November



Note: Dashed lines represent periods of deepened lock-down. Data are corrected for weather effects.

Sources: IEA analysis based on POSOCO (2020).

Falling wholesale electricity prices around the world

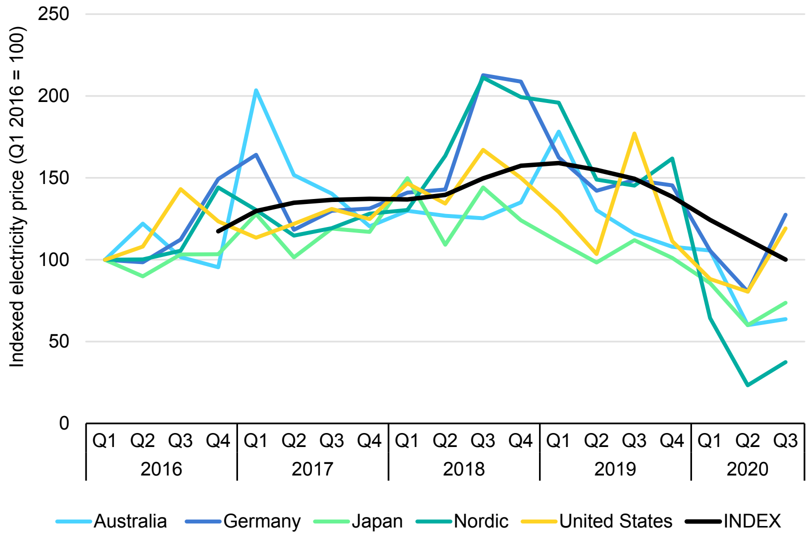
While wholesale electricity prices are determined by a large number of factors specific to each electricity market, changes averaged over a quarter are most often due to shifts in the balance of supply and demand and in the price of key input fuels. Prices are also highly seasonal due to heating and cooling needs, with the highest prices normally experienced in the summer (United States, Japan, Australia) or winter (Europe). A quarterly wholesale price index, therefore, can be a useful tool to track the changes in individual markets and deduce overall trends.

Since 2016 the IEA has been tracking wholesale prices in the main advanced economy electricity markets and in selected emerging and developing economy markets. The graph shows a selection of these markets, with prices indexed to 100 for the average in the first quarter of 2016.

To understand the underlying trends, we have combined the four-quarter rolling average indexed prices (to smooth seasonal effects) of advanced economy wholesale electricity markets, weighted by demand, to create an advanced economy **wholesale electricity price index**. This is shown as the thick black line. The index increased by 34% between the fourth quarter of 2016 and that of 2018. This trend began to reverse in 2019, when the index fell by 12% due to falling electricity demand in advanced economies, increased renewable production that ensured a plentiful supply in most markets, and falling natural gas prices.

2020 has seen an acceleration of this decline. Dramatically lower demand for electricity, increases in renewable production and a fall in spot natural gas prices of between 20% and 50% (depending on the market) drove down wholesale electricity prices in the second quarter to their lowest levels since we began tracking. The most dramatic price fall took place in the Nordic electricity market, owing to abundant hydro supply. While market prices recovered in the third quarter, thanks to higher demand and higher natural gas prices, the rolling 12-month average electricity price index continued to fall to a level 28% below the level seen in the final quarter of 2019 – and in fact below the level observed in quarter four of 2016. Results for the final quarter of 2020 are expected to be similar to Q3.

Quarterly average electricity prices in selected markets, 2016-2020



Note: INDEX refers to the four-quarter rolling average of all indexed advanced economy markets.

Sources: IEA analysis using data from Bundesnetzagentur (2020), SMARD.de; Elexon (2020), Electricity data summary; AEMO (2020), Aggregated price and demand data; OCCTO (2020), OCCTONET; EIA (2020), Short-Term Energy Outlook November 2020, Nordpool (2020), System price.

Taxes play a significant role in electricity end-user prices in many advanced economies

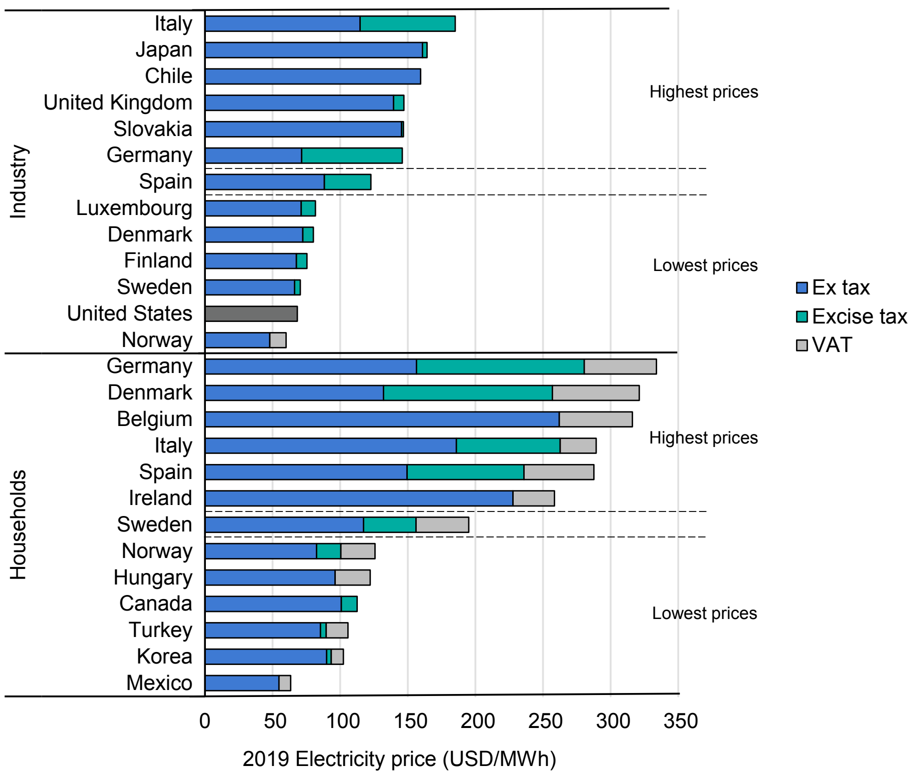
Electricity end-user prices differ significantly between countries. Some influencing factors are: the type of end-user price (i.e. regulated or market based) and the composition of the tax structure (e.g. VAT, excise taxes, renewable energy and capacity levies, environmental taxes).

Industrial sector prices are especially high in Italy, Japan, Chile, the United Kingdom, Slovakia and Germany. In Italy and Germany this is due to relatively high excise taxes, which many other countries do not impose on industrial consumers. At the lower end of industrial prices are Norway (despite charging VAT), Sweden and Denmark together with the United States. These markets benefit from low production costs due to access to favourable renewable sites (Scandinavia) and low fuel costs (United States).

In most countries, household prices are significantly higher than industrial prices due to the presence of higher taxes and network charges (the provision of electricity at lower voltages to households requires more infrastructure and incurs higher costs, which leads to a higher price). Very high spreads can be observed in Denmark, with household prices being four times the price for industry, and Norway, Sweden, Spain, and Germany, where household prices are double those for industry.

In many countries with the highest household electricity prices – including Germany, Denmark and Italy – relatively high excise taxes are collected. In Germany, for example, the EEG surcharge for renewables is borne by residential customers while large industrial consumers are exempt, which partly explains the high household cost of electricity. Mexico has the lowest electricity prices for households by far (close to half the value of Korea's as the second-lowest price). This is due to consumption being subsidised in part by the federal government and in part by the state-owned electric utility, resulting in the rare case of household prices being lower than those for industry.

End-user electricity prices in selected OECD countries in 2019



Note: Representation of the OECD countries with the highest and lowest end user electricity prices in 2019. The price breakdown for the United States is not available. The ex tax price was calculated by subtracting the applicable legally established tax components (excise and VAT) from the end-user price.

Source: IEA (2020), Energy Prices 2020; Eurostat (2020), Electricity price statistics (Spain).

Pattern of end-user prices

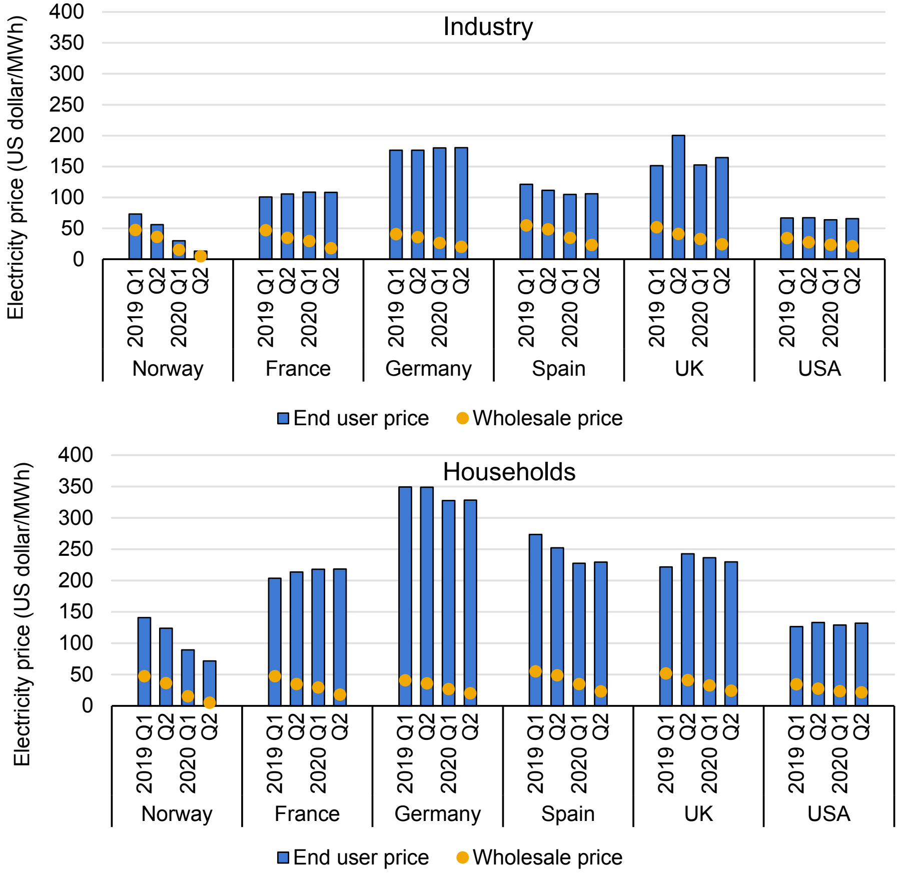
The pattern of end-user electricity prices has been affected by different factors this year. Among them is the drop in wholesale prices caused by the fall in electricity demand and higher levels of renewables in the system. These are reflected to various extents in the countries we have selected for analysis.

The highest impact was observed in Norwegian end-user prices. The declines of around 77% for industry and 42% for households were closely coupled with the fall in wholesale prices (down by 86% in quarter two of 2020 compared to the same quarter of 2019), caused by low demand and exceptionally high hydro and wind generation.

Most other countries do not show such close coupling of wholesale and end-user prices. This is especially true for household prices, which on average consist to a larger extent of fixed grid charges, taxes and levies (for example, around 77% in Germany). Also, a higher share of customers are still subscribed to regulated tariffs (e.g. 78% in France in 2018), which could explain a delay until lower procurement costs are reflected in end-user prices. Households in Spain, Germany, the United Kingdom and the United States paid on average 9%, 6%, 5% and 1% less in quarter two of 2020 compared with the same period in 2019 – whereas wholesale prices dropped by much more. Prices for industrial customers did not closely follow wholesale prices in this quarter either (except as previously mentioned in Norway).

In Europe dynamic pricing contracts are only available in seven EU countries and Norway. As pointed out by the European Commission, these contracts could help to reduce the energy supply component of electricity prices significantly – and at the same time offer incentives to final consumers to participate in demand response and thereby foster the integration of renewable energy in regions with a high share of variable renewables and increasing levels of electrification.

Development of end-user electricity prices in 2019 and 2020



Note: Representation of the quarterly evolution of end-user electricity prices for selected countries.

Source: European Commission (2019 and 2020), Electricity Market Report.

Status of market liberalisation

Globally the status of market liberalisation varies. Wholesale markets that are fully competitive comprise 40% of global demand, with a further 47% having some form of hybrid competition, such as unbundled generation and transmission ownership with state-owned companies or independent power producers, or full competition in a portion of a jurisdiction. Vertically integrated utilities comprise the remaining jurisdictions that make up 13% of global demand.

Retail markets are liberalised to a lesser extent than wholesale markets, with fully competitive markets accounting for 22% of global demand, partially competitive accounting for 45%, and fully regulated monopolies the remaining 33%.

Europe is the region in which markets operate under the greatest degree of liberalisation: 93% of demand in Europe operates under full wholesale market competition, with 85% under full retail competition. In North America 48% of demand is in fully competitive wholesale markets, with 29% under full retail competition. Central and South America (25% under full wholesale competition), Asia (18%), and the Middle East and Africa (0%) show lower levels of liberalisation.

In the western United States wholesale market competition has been limited by the lack of a transparent and efficient mechanism to facilitate trade and allocate transmission among neighbouring utilities. The California independent system operator (CAISO) spearheaded the creation of the Western Energy Imbalance Market in 2014 in an attempt to address this issue by creating a real-time wholesale market. While not a truly regional system with fully competitive energy and ancillary services markets, it operates 15-minute and 5-minute dispatch markets that allocate available transfer capability on an economic basis. Its membership stands at 11 balance areas today, with eight others planning to join by 2022. By then, the footprint will extend to 10 US states and British Columbia.

The southeast is another region in the United States in which market competition is limited to independent power producers operating within franchised monopoly service territories. In Alabama, Georgia, Florida and South Carolina the loads of all customers, accounting for 2.5% of global demand, as well as large portions of North Carolina, Tennessee and Mississippi, are served by vertically integrated utilities. In July two of the largest utilities in the region (Duke Energy and Southern Company) announced that discussions were taking place to potentially create a regional wholesale market, which would be modelled on the Western Energy Imbalance Market. A recent study reviewed the potential benefits for consumers, new entrants, carbon emissions and system efficiency if realised.

In China dispatch reform is being considered as a mechanism to improve efficiency and accommodate more variable renewables. Currently the fair dispatch system allocates energy volumes administratively rather than through economic optimisation. In 2016 the government released Document No. 9, a major energy market reform package, which foresees the withdrawal of the administrative system in favour of economic dispatch. In June 2019, eight provinces began spot market pilots, which the government hopes will reduce the number of renewable curtailments and lower power prices.

New investment in renewables was delayed in the first half of 2020...

Global renewable electricity capacity additions were 11% lower in the first half of 2020 than in the same period in 2019. Solar PV expansion was down by 17% and wind by nearly 8%. Hydropower capacity, in contrast, increased in the first half of 2020, driven by large-scale projects in China. Despite initial delays, available data indicate that in most countries new installation activity ramped up after restrictions were eased, compensating for previous lags.

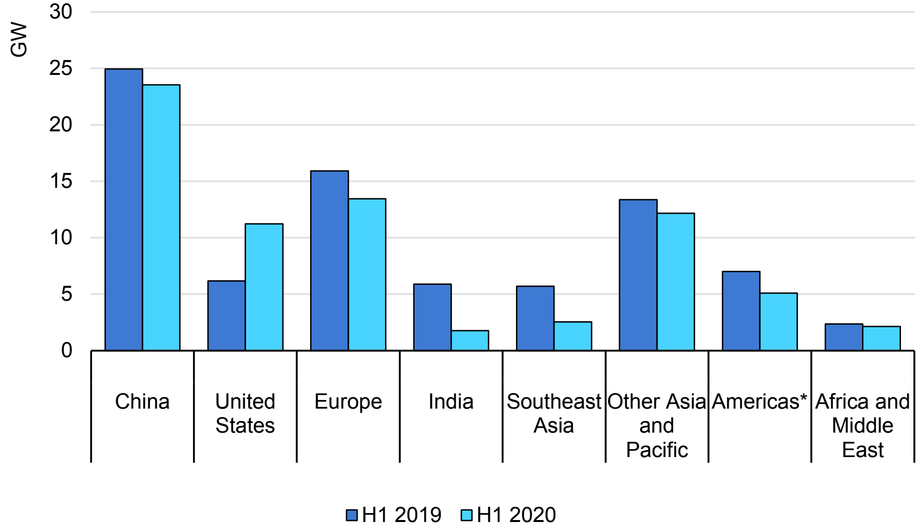
In the first quarter of 2020 capacity additions slowed for all technologies except hydro, by 25% for both solar PV and wind compared with 2019. China was the main factor for wind and solar PV, as Covid-19 measures led to labour shortages and consequently reduced construction activity. New wind installations declined by 50% and solar PV by 25% in the first three months of the year. With lockdown measures being eased, capacity additions in China picked up again, headed by utility-scale PV, wind and large hydropower plants.

In the United States policy deadlines dictated wind and solar PV expansion, resulting in almost twice the renewable capacity additions in the first half of 2020 than in the same period last year. This was mainly due to wind developers rushing to commission projects to meet federal tax incentive deadlines. During the same period, growth in renewable capacity in India slowed significantly before the nationwide lockdown was imposed at the end of March. This resulted largely from the persistent challenges of utilities' poor financial health and project delays.

In Europe new renewable capacity additions were lower in the first half of 2020 than in 2019, increasing in the second quarter with the easing of lockdowns and movement restrictions. In Germany the installation of ground-mounted PV installations slowed, but then recovered rapidly in May and June, outpacing 2019 installations during the same period. In Italy capacity additions rebounded to pre-pandemic levels in May, after a 90% decline from February to April. In the Netherlands the pace of combined wind and solar installations slowed during March and April, but recovered again in June.

The ASEAN region installed nearly 60% less capacity from January to June this year than during the same period in 2019 – mostly due to the unrepeated strong growth last year in Viet Nam, when developers rushed to complete PV projects before policy deadlines. Lockdown measures slowed construction activities in Thailand and Indonesia.

Renewable electricity capacity additions, H1 2019 and H1 2020



* Excluding the United States.

Source: IEA (2020), Renewables 2020.

... but still achieve another record

Despite delays in the first half of the year, renewables are on track to achieve a new record of net capacity additions (198 GW, 4% higher than in 2019).

In 2020 global **solar PV** net capacity additions are expected to reach 107 GW, 1% lower compared to 2019. Despite the slowdown, global solar PV capacity will exceed wind capacity for the first time, claiming second place among renewables behind hydropower. Deployment remains sluggish for distributed PV applications in large markets such as China and the United States, although activity in most European markets, Australia and Brazil has not seen a significant slowdown. Still, the share of distributed applications in total PV deployment is expected to decline to 37%, the lowest since 2017.

Annual net **wind** capacity additions are expected to reach around 65 GW (of which about 5 GW are offshore wind), 8% more than in 2019. Covid-19 measures led to construction activity slowing from February to April due to supply chain disruption and logistical challenges in many countries. The offshore wind sector has been only mildly affected.

After six years of consecutive declines, net global **hydropower** additions are expected to increase in 2020, topping 18 GW, driven by an uptick in large project activity in China and large projects in Laos, India, Nepal, Viet Nam and Indonesia.

Nuclear power sees significant growth in new capacity in 2020, as new units in China, India, Russia, Belarus, Korea, Slovakia (potentially delayed to early next year) and the United Arab Emirates add over 8 GW of new capacity, most of it late in the year. This more than offsets the closure of units in France, Sweden and the United States, which will remove about 5 GW from service.

Coal-fired generation capacity in 2020 remains flat at 2 125 GW, but could decline if some of the expected new plants are delayed or retirements are brought forward. If this occurs, 2020 would be the first year this century in which coal capacity declines.

As with most coal-related issues, the story of coal capacity varies considerably between advanced economies and those which are emerging and developing. While no new plants have been planned in Europe or the United States for some time (Datteln 4 was commissioned in Germany in 2020 following delays in construction), decommissioning of coal plants is accelerating. Austria and Sweden, having closed their last coal plants, joined Belgium as EU countries where coal power generation is in the past. Over 20 GW will be decommissioned in the European Union and the United Kingdom in 2020, headed by Germany, Spain (which had closed about half of its total coal capacity by the end of June) and the United Kingdom. France confirmed its closure date of 2022, and Italy's is 2025. Portugal brought forward its coal phase-out date by two years to 2023. Most EU countries are planning to close all coal plants by 2030, except Poland, the Czech Republic, Germany and a few others. Germany has passed an act to phase out coal-fired power plants, which will see them all closed by 2038, and possibly even by 2035.

In the United States, where 49 GW were retired between 2011 and 2019, an additional 10 GW have been retired in 2020. By contrast, in Japan 2 GW have been commissioned, with 7.4 GW under construction.

In the emerging and developing world, where plants are three decades younger on average, decommissioning is unusual except as replacement for capacity in China and, to a lesser extent, India. New construction, on the other hand, has slowed not only as a result of Covid-19, but also as a consequence of the headwinds that coal-fired generation has been facing for several years. China sees the most additions, with the commissioning of around 30 GW, in line with 2019. In India only a small number of new plants were commissioned, resulting in 2 GW of additional coal-fired generation capacity (with around 35 GW under construction). In the ASEAN region close to 5 GW of capacity additions are expected, as some plants have been delayed by Covid-19.

But even if capacity remains stable in 2020, it was a year in which many countries around the world reconsidered the role of coal. Korea, Japan, the Philippines, Viet Nam, Egypt and Bangladesh are just a few of the countries that have changed their vision of the role of coal power generation in the future. Lower electricity demand driven by the Covid-19 crisis, lower costs for renewables and low gas prices – as well as the reduction in air pollution that came with lower coal-based electricity generation in 2020 – have changed the perception in many countries that coal is the only way to have affordable, dispatchable and secure electricity. Difficulties in financing and growing international pressure against coal are also playing a role. As a result, the combination of renewables plus gas is gaining ground in many jurisdictions.

In contrast to coal, global **natural gas** power plant capacity continued to expand in 2020, with over 40 GW of new capacity expected to be commissioned, primarily driven by the Middle East, the United States and China.

With over 500 GW of capacity, the United States has by far the largest gas-fired power plant fleet in the world (about 28% of the global total). Capacity continued to expand in 2020 – uninterrupted for the past 20 years. New capacity additions amounted to 7 GW by the end of September, with California, New York and Louisiana accounting for almost 60% of the newly commissioned capacity. An additional 0.65 GW is under construction and is expected to be commissioned by the end of the year. Plant retirements are set to exceed 2 GW, with over 40% of them in California.

The Middle East has just over 220 GW of gas-fired capacity, set to expand as electricity demand is rising rapidly and the region strives to diminish its reliance on oil-fired power generation. In 2020 gas-fired power capacity has continued to expand, led by Iran, Iraq and Saudi Arabia. This includes the giant 3 GW Rumaila power plant under construction near Basra in Iraq. The first two phases of its construction were completed by June 2020, bringing 1.5 GW of generation capacity online, while the remaining two phases involving an additional 1.5 GW of capacity are scheduled for commissioning by 2022.

Gas-fired capacity additions in Asia are led by China, accounting for almost half of the region's incremental capacity in 2020. China's gas-fired power capacity stood at 90 GW at the end of 2019 and around 5 GW were added in the first three quarters of the year. In total, close to 6 GW of capacity is expected to come online in 2020.

In Europe just over 1 GW of gas-fired capacity was added in 2020, the largest being the Stalowa Wola (450 MW) combined-cycle gas turbine plant in Poland. The completion of the 430 MW Iernut CCGT plant in Romania is facing delays due to the Covid-19 outbreak and is now expected to be commissioned by the end of 2020. Moreover, Units 4 and 5 of the Irsching gas-fired power plant in Germany (with a total capacity of 1.4 GW) returned to commercial service in October 2020 amidst improving market conditions, after being mothballed in 2016.

Renewables growth and demand drop squeeze fossil fuels

The significant global fall in electricity demand in 2020 affected generation technologies to different extents. While the increase in renewable generation of about 6.6% was the largest ever in absolute terms, fossil fuel and nuclear generation felt the impact of declining electricity consumption.

Wind and solar PV electricity generation continued to grow by more than 10% and 20% respectively, now being responsible for more than 9% of global electricity supply (around 8% in 2019). With 16% of total global production, hydropower plants still constitute by far the largest source of renewable electricity generation. In total, renewables grew by around 7% and provided 28% of global electricity, up around two percentage points compared to 2019.

The rise in renewable generation and the fall in demand resulted in a squeeze on other generation technologies, namely coal, gas and nuclear power.

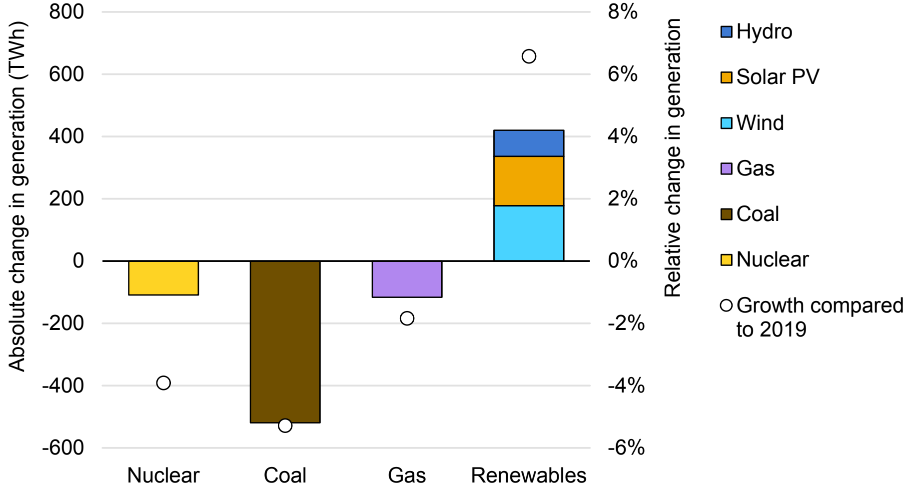
Coal-fired generation was affected the most. Global coal power generation is expected to drop by more than 5% in 2020, the largest decrease ever. This comes on the heels of a 3% fall in 2019 and brings coal-fired generation back to levels last seen in 2012. Due to a mild winter, gas prices in the United States and the European Union were already low when power demand plummeted as a result of measures to contain the Covid-19 pandemic. The strongest impacts were felt in the European Union, where we expect a decline in coal-fired power generation of more than 20%, and in the United States (a 19% decline). Coal-fired generation is on track to fall by 3% in Japan and by 10% in Korea, where term contracts ensure more stability in the mix. In India coal power generation will gain some ground in the last quarter after a double-digit decline in the first half of the year, to end with a 5% drop. In contrast, coal-fired power generation in China and in Southeast Asia is expected to stay about the same as in 2019.

Gas-fired generation, although not immune from the squeeze, is on track to fall by about 2% in 2020, as in many markets it has been able to outcompete coal to retain its market share. Natural gas prices, already low before the pandemic, fell much more quickly than those of coal. Even in Asia, where LNG prices are commonly linked to the price of oil, the fall in oil prices has gradually improved gas's competitive position. In addition, in those markets where carbon pricing is relevant, particularly the European Union, the cost of carbon has given gas a further edge.

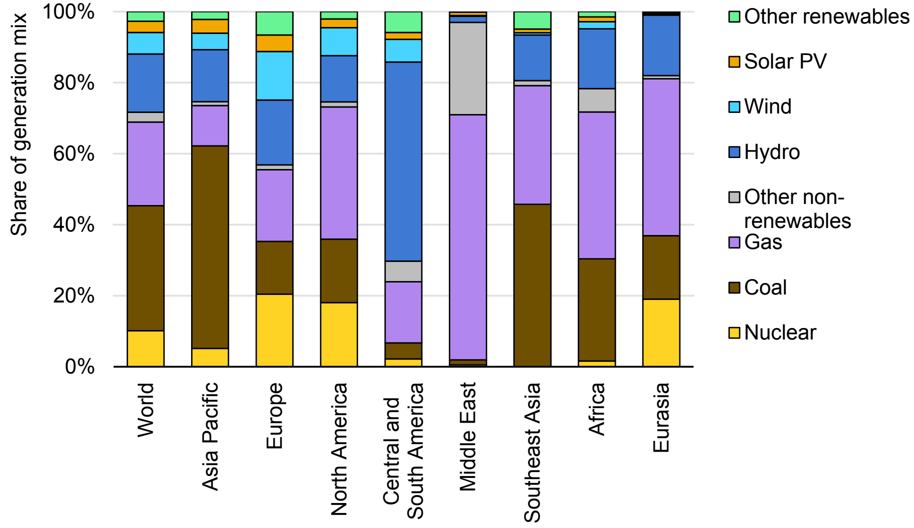
Nuclear power was affected by the squeeze, its output declining by around 4% compared to 2019. Much of the demand squeeze took place in the first half of the year, but less capacity was available all year as plant closures in France, Sweden, Germany, Switzerland and the United States occurred in late 2019 and early 2020. Japan's output in 2020 is also down significantly mainly due to the removal from service of two units early in the year to install backup control centres. China was the main exception to the trend as nuclear output increased by about 6%, reflecting new capacity coming into service.

Oil, which accounts for only 3% of global electricity generation, was also affected by the shrinking market space for thermal generation and saw declines in many markets, partly offset by some increases in the Middle East.

Global electricity supply change in 2020



Electricity supply mix in 2020



Fuel competition is heating up between thermal generation sources

Falling electricity consumption combined with the growth in renewable output weighed on thermal power generation across key energy markets in 2020. This has been accompanied by increasingly fierce competition between coal and gas for a rapidly shrinking market space.

The particularly mild 2019/20 winter in the northern hemisphere – the second warmest since records began – and the imposition of Covid-19-related lockdowns in the second quarter of 2020 depressed natural gas prices to multi-decade lows across key gas-consuming regions. Importantly, gas prices fell more steeply than coal benchmarks, which increased the cost-competitiveness of gas-fired power generation vis-à-vis coal-fired plants.

In the United States gas prices at Henry Hub fell by 29% y-o-y and averaged at USD 1.9/MBtu during the first three quarters – their lowest price level for that period since 1995. During the same period, the main US coal benchmarks declined in a range of 5-25% y-o-y. As gas prices fell more steeply, coal-fired power generation plummeted by about 23% as it not only bore the brunt of falling electricity consumption (down 3.9% y-o-y), but has been increasingly losing market space to gas-fired power plants, a trend ongoing since 2012. Gas-fired plants increased their output by 4.4% y-o-y and, as a result, saw their share of power generation for US electricity supply rise to 40% during the first three quarters.

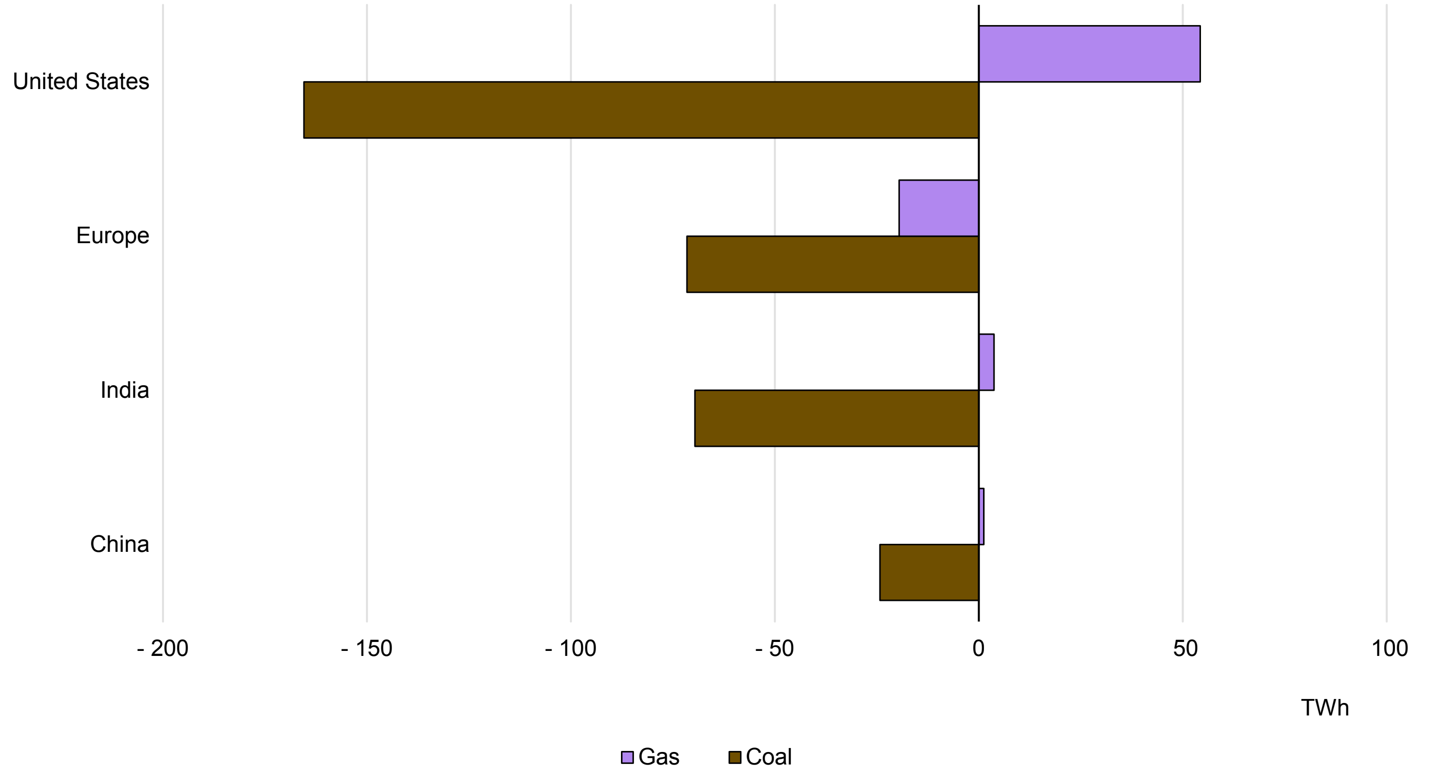
In Europe spot prices on TTF fell by 45% y-o-y in the first three quarters of 2020, to an average of USD 2.5/MBtu – their lowest level since the Dutch gas hub was established in 2003. In contrast, Rotterdam coal, the benchmark for European coal, saw its price fall by 24% and carbon prices traded just 4% below last year's average. As a consequence of these price dynamics, similar to the United States, coal- and lignite-fired power plants in the European Union and the United Kingdom were most affected by the 6% y-o-y decline in power consumption. Their combined output plummeted by close to 25% in the first three quarters of 2020. In contrast, gas-fired power generation fell more moderately, by 6% y-o-y. After the heavy losses during the first half of the year (down 10%), gas-fired power generation returned to positive growth during the third quarter – largely at the expense of coal- and lignite-fired power plants. However, the sharp recovery in gas prices since the beginning of June has started to erode the competitive position of gas-fired power plants since September.

The largest contributor to additional gas burn in the European power sector was Turkey, where gas-fired power generation rose by an impressive 11% y-o-y, despite overall electricity consumption declining by 1.3%. This has been primarily driven by lower output from lignite-fired power plants (down 20%) as some units had been halted for not complying with environmental regulations. Altogether, gas-fired power generation accounted for 58% of thermal generation in Europe during the first three quarters.

In India total electricity consumption fell by 5% in the first three quarters of the year. Amid this overall decline, gas-fired generation increased by 10% y-o-y, while coal- and lignite-fired generation dropped by 9% – in absolute terms significantly more than gas's gain. Growing gas-fired generation was fuelled by a sharp rise in spot LNG imports during the first nine months. At well below USD 3/MBtu, imported spot LNG proved highly competitive vis-à-vis coal in power generation, especially in the western part of India near the existing import terminals.

China's thermal generation fell by 0.3% y-o-y in the first three quarters of 2020, while overall electricity consumption increased by 1.3% y-o-y during the same period. Against the trend in thermal generation, gas-fired electricity supply increased by around 1%. However, this expansion has mainly been driven by new gas-fired capacity additions and guaranteed operating hours under China's "fair dispatch" model, as the transition to a competitive wholesale electricity market with economic dispatch is at a relatively early stage. A purely market-driven coal-to-gas switch would require an average carbon price of around USD 45 per tCO_2-eq, although the required carbon price varies widely by region due to the differences in relative fuel costs across China.

Change in coal- and gas-fired power generation in Q1-3 (2020 vs 2019)



Oil-fired generation makes a comeback in some Middle East OPEC producers

This year's OPEC+ agreement imposed an initial 9.7 mb/d oil production cut between May and July before tapering down to 7.7 mb/d in the remainder of 2020. It put significant pressure on associated gas production in a number of OPEC producers in the Middle East. The squeeze on associated gas availability coincided with peak electricity demand in the summer, which was further accentuated this year as record temperatures and Covid-19-related travel restrictions lifted air-conditioning demand across the region. This combination of lower gas availability and increased electricity demand led to a resurgence of oil use – including direct crude burning – in power generation in the majority of Middle Eastern OPEC producers.

Kuwait, which reports the most detailed electricity data, illustrates this dynamic well. Total electricity output rose by 1% y-o-y in the third quarter of the year (following a 3% y-o-y decline in the first half of 2020) as travel restrictions prompted residents to stay at home during the hot summer season. This, in turn, boosted air-conditioning needs and pushed peak power demand to an all-time high in July. Gas burn in the electricity and water desalination sector fell by 7% as OPEC+ production cuts squeezed associated gas output, while the power sector use of crude oil and oil products increased by 11% in the first nine months.

Saudi Arabia, the biggest electricity producer in the Middle East, also experienced steep declines in associated gas production following the implementation of the OPEC+ oil production cuts. These reportedly offset incremental non-associated output from the recently completed Fadhili gas processing plant. Limited gas availability left oil burning to meet increased electricity demand, which was further boosted by travel restrictions during the peak summer months. Direct crude burning (which is the least desirable fuel source and has been subject to concerted government efforts to phase it out from power generation) was up by 7% y-o-y in the first nine months of the year, while the use of heavy fuel oil increased by 2% over the same period.

The United Arab Emirates, which uses only minimal amounts of oil in its predominantly gas-fuelled generation fleet, responded to record-high peak summer demand by breaching its oil production quota in August (a rare occurrence in one of OPEC's most compliant members) in an effort to boost associated gas production to meet rising power needs.

Iraq reported a sharp 60% y-o-y rise in direct crude burning amid an estimated 4% increase in electricity generation during the January to September period.

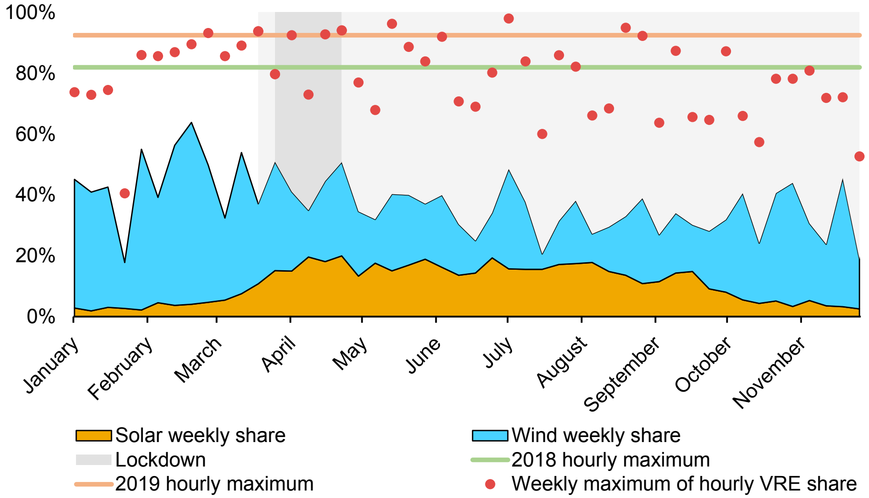
Iran, which has been exempt from the OPEC+ production cuts, reported that electricity consumption increased by 5% y-o-y in the first nine months of the year. Gas burn in the power sector rose by 6%, while the combined use of diesel and heavy fuel oil shot up by nearly 30% to compensate for lower hydro availability over the same period.

A record jump in variable renewables share

Reduced electricity demand in most markets and increasing solar and wind power, or variable renewable energy (VRE) supply, has meant that the share of variable generation has increased rather dramatically in 2020, more than any single year in history. Many regions broke new records in hourly VRE infeed levels during lockdown including Italy, Germany, Belgium, Hungary and eastern parts of the United States.

From an operational perspective, critical system conditions are often associated with periods of very high demand, low generation availability (VRE, hydro or thermal), or both. Conversely, periods of high VRE generation and low demand can also expose systems to stress as a result of the high share of variable generation and reduced contribution of conventional generators.

Maximum hourly VRE generation relative to demand in Germany, January-November 2020

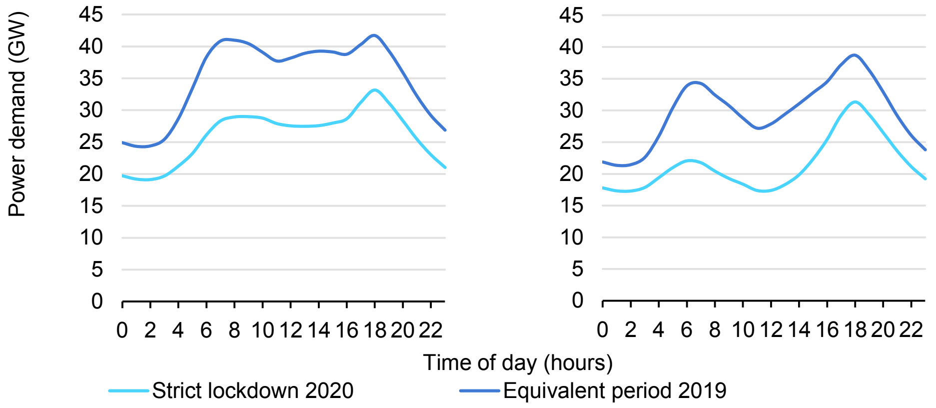


Source: Bundesnetzagentur (2020), SMARD.de.

While most systems worldwide did not experience reliability issues, the Covid-19 lockdowns were a stress test that did expose systems to new operational and planning challenges.

Increased VRE penetration caused greater variability in the net demand profile – demand minus variable renewable generation – which affects the flexibility requirements needed to meet minimum net demand and the system ramp. In some instances, depending on the market design, this led to increases in balancing payments to generators, reducing the benefit of lower market prices. In the United Kingdom, for example, balancing costs increased by 96% compared to the previous year. In France, coal power plants were restarted to address the flexibility issues after lockdown. The reduced demand during lockdowns in countries with high VRE resulted in a lower minimum demand during the day. For example, in Italy the average minimum weekday net load during lockdown fell by close to 10 GW relative to the same period in 2019.

Changing average weekday load (left) and net load (right) patterns in Italy during lockdown relative to the same period in 2019

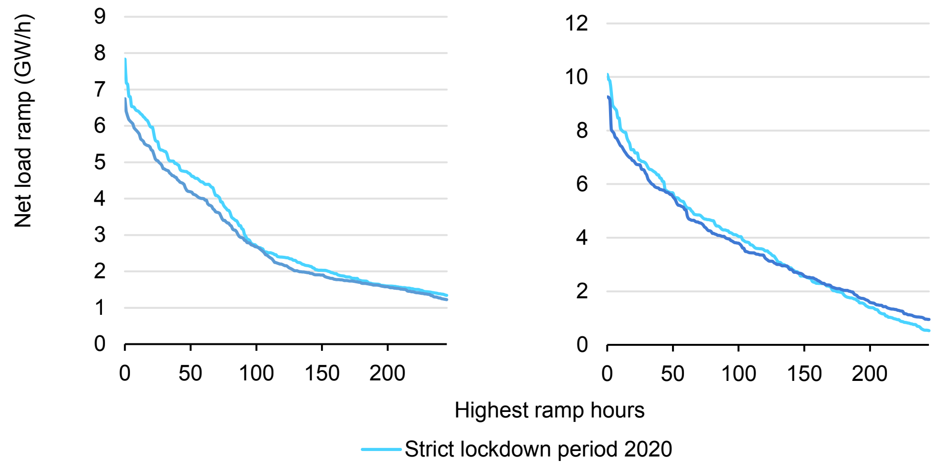


Note: The full lockdown period is compared with the same period in 2019.

Source: TERNA accessed via ENTSO-E (2020), Transparency Platform.

In most systems, demand fluctuations during the day during lockdown were dampened because of lower demand rise in the morning. However, for some systems the decrease in midday demand can also lead to a greater ramp from a very low minimum during the day into the evening peak, which can be more pronounced in systems with a considerable share of solar PV. Some systems with higher solar, such as Germany and California, experienced steeper hourly ramps than during the equivalent period in 2019. However, these issues during lockdown periods have been manageable.

Net load ramp duration curve for California (left) and Germany (right) during their strict lockdown periods in 2020 and the same period in 2019



Note: A load (or net load) duration curve is a load profile which is sorted by magnitude as opposed to chronologically, with the highest value in a given period at the left of the curve.

Sources: Bundesnetzagentur (2020), SMARD.de; EIA (2020), Open Data.

Lower demand during lockdown also played a role in curtailment in some regions. There can be multiple drivers for renewables curtailment, including inflexible power plants and grid congestion, and it can be aggravated by reduced demand. For example, in April 2020 the California system operator (CAISO) curtailed a record amount of renewables at over 318 GWh, 67% higher than in 2019 and reaching 7% of variable renewable generation in that month. The monthly VRE share reached a record high of 29% in April 2020, driven by weekly load falling by around 8% compared to last year at midday when solar output peaks. In addition, California added 1 GW of wind and solar PV from May 2019 to March 2020, contributing to the increase in VRE output.

During Covid-19 containment measures, some systems also saw new record lows in minimum net load and reduced synchronous generation, but no system reportedly had issues with low inertia or frequency management as a result. However, systems like that of Great Britain, where coal-fired generation has been declining for several years, had to advance new procurement schemes for flexibility services to cope with such situations. Procurement of flexibility services can include a range of market products that expand on ancillary service products, incentivising more flexible operation (e.g. fast ramping products) or compensating for declining system inertia (e.g. fast frequency response).

On 3 April 2020, during the Covid-19 crisis, India's population responded to Prime Minister Modi's appeal to "Challenge the darkness of Covid-19" and switched off their lights for nine minutes at 9 pm. The national system operator POSOCO successfully managed the demand reduction event together with the regional and state-level system operators. This event highlighted the flexibility of India's electricity system, which successfully accommodated a total reduction in all-India demand of 26% within half an hour and the challenging ramp down and up resulting from this. Despite a demand reduction of 31 GW versus an anticipated 12-14 GW, the co- ordinated response between state and national dispatch centres enabled the event to be managed smoothly, with hydropower in particular playing a key role in providing the needed flexibility.

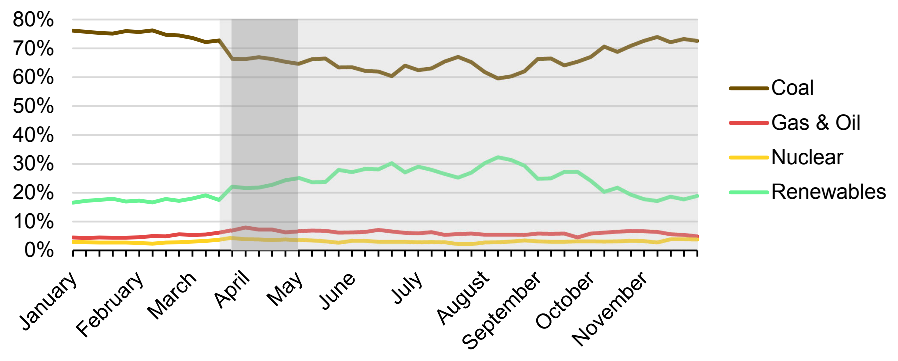
Renewables take market share from coal as electricity demand drops

In most countries where partial or total lockdowns were implemented to limit the expansion of the pandemic, electricity demand decreased quickly and significantly – by between 15% and 30% after a few weeks of population confinement. This has significantly affected the electricity mix in those countries.

In China and India, where coal dominates the electricity mix, its share has decreased to the benefit of renewables because of the declining demand. In India the share of coal has consistently stayed under 70% between initial lockdown and September. Furthermore, the share of renewables in the mix jumped from 18% to 23% in the week after the first lockdown measures were enacted, and has stayed above 20% since then. Its fluctuations reflect renewables' seasonal availability: in June and August their share rose above 30%, driven by strong winds and hydro generation. In September and October electricity demand was back on its path of growth seen before Covid-19 and the generation mix was comparable to 2019, reflecting seasonal trends.

In China under confinement, as electricity demand decreased a large reduction in coal-fired power generation occurred. Reductions were pronounced in February and March, as significant lockdowns spanned both months, and the share of renewables grew above 25%. After lockdown measures started being eased in late March, the coal share recovered slightly while renewables maintained a high share in the mix. In June and July renewables resumed the expansion of their share of the mix, rising above 30%, driven by growing hydroelectricity generation from additional capacity and heavy rains. Since August the trends of coal and renewables generation have adapted to the availability of hydro.

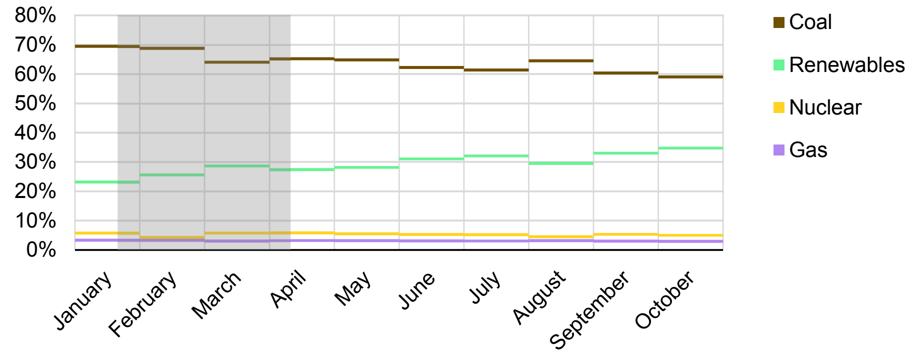
Weekly supply mix in India during 2020



Note: The intensity of the grey shading reflects the intensity of the lockdown.

Source: IEA analysis based on POSOCO (2020). See also IEA (2020), Covid-19 impact on electricity.

Monthly supply mix in China during 2020



Note: The grey shading denotes the period of lockdown.

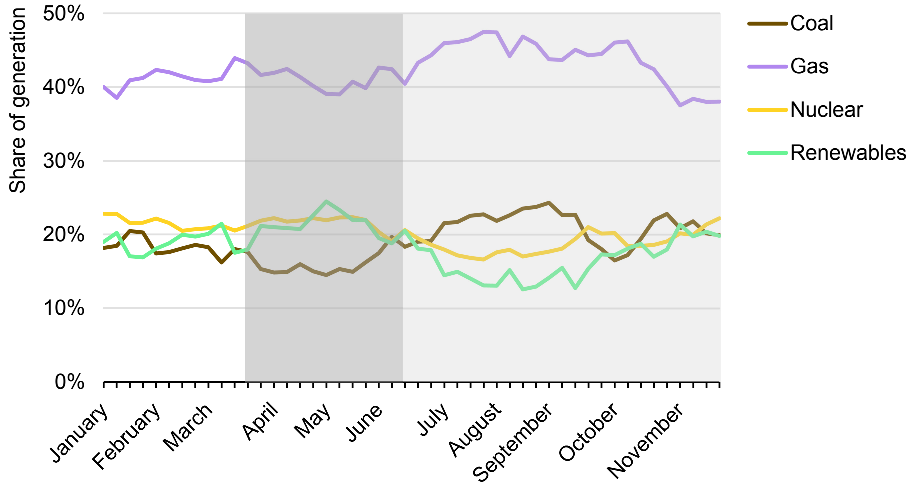
Source: IEA analysis based on China Statistical Information Network (2020). See also IEA (2020), Covid-19 impact on electricity.

Lower demand under lockdown reduced non-renewables' share – lifted restrictions generally meant demand recovery and usual seasonal patterns

In the United States natural gas has remained the leading source of electricity in 2020, keeping almost consistently above 40% of the mix and being less affected by variations in demand than coal. From March onwards as the first confinement measures were put in place and demand decreased, the coal share dropped to 15% of the mix, outpaced by renewables, which rose above 20%. From June onwards as the stringency of the response to Covid-19 softened and demand increased, natural gas consolidated its leading position, oscillating around 45% of the mix. Coal rallied in response to growing demand. Coal and nuclear outpaced renewables generation, which decreased in the wake of the seasonal decline in wind and hydro. In September a significant temperature drop led to a decrease in cooling demand, and total generation fell to lower levels than in 2019, affecting coal power production. In October, total generation levels were on par with 2019, and the electricity mix trends (increase of wind, decrease of natural gas) seasonal.

In the European Union renewables together form the leading source of electricity. With lockdown, the fall in electricity demand and higher renewable production caused by favourable weather conditions drove non-renewable generation down. From February to the first week of July weekly renewable production was consistently higher than fossil fuel generation and the share of renewables in the mix stayed above 40%. However, it shifted markedly in July as a result of lower wind production. The drop in electricity demand and historically low nuclear production levels from January to August 2020 led to nuclear's share of the generation mix remaining largely static. Several units extended outages due to the delays caused by lockdowns, and efforts to avoid maintenance and allow continuous supply of power during the winter. During the same period, coal power output was also lower to accommodate both lower demand levels and phasing-out targets in most of the European Union. In September and October nuclear power output rose gently towards seasonal averages, while coal-fired production levels increased and are equivalent to 2019 levels. Renewable production rose in late September and throughout October due to strong wind conditions. Higher renewable and nuclear production levels have pushed demand for natural gas in the electricity mix down – in late October the share of natural gas in the electricity mix was as low as during lockdown and on a par with coal.

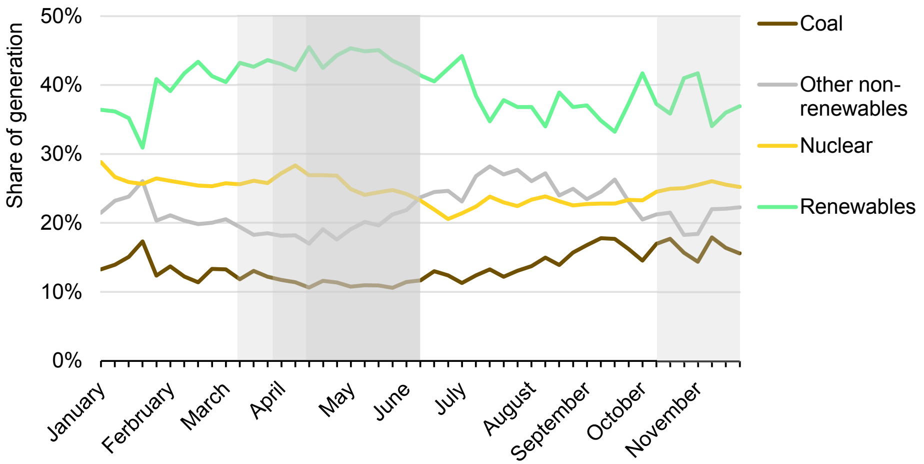
Weekly supply mix in the United States in 2020



Note: The intensity of the grey shade reflects the intensity of the lockdown.

Sources: IEA analysis based on EIA (2020), Open Data. See also IEA (2020), Covid-19 impact on electricity.

Weekly supply mix in the European Union in 2020



Note: The intensity of the grey shade reflects the intensity of the lockdown.

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

Electricity sector CO_2 emissions

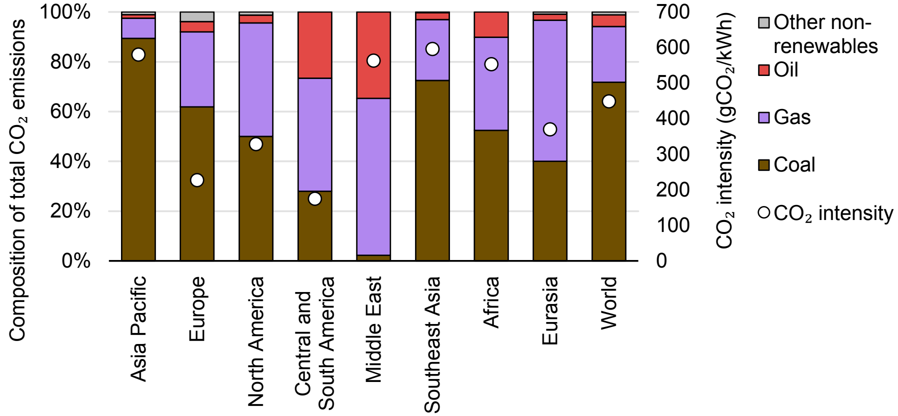
Coal is by far the largest contributor to CO_2 emissions associated with electricity generation. Responsible for around 72% of the activity's emissions globally, it outpaces gas (22%) and oil (5%) by far. At a regional level these shares vary significantly: in Asia Pacific and Southeast Asia, fuel-based carbon emissions predominantly stem from burning coal (89% and 73% respectively), whereas gas-based electricity generation is by far the main source of emissions in the Middle East (63%), Eurasia (57%), and Central and South America (45%).

Central and South America has the lowest CO_2 intensity of electricity generation, benefiting from the large share of renewable energy – primarily hydro (57% of total generation). Particularly carbon intensive is electricity generation in the Asia Pacific and Southeast Asia regions.

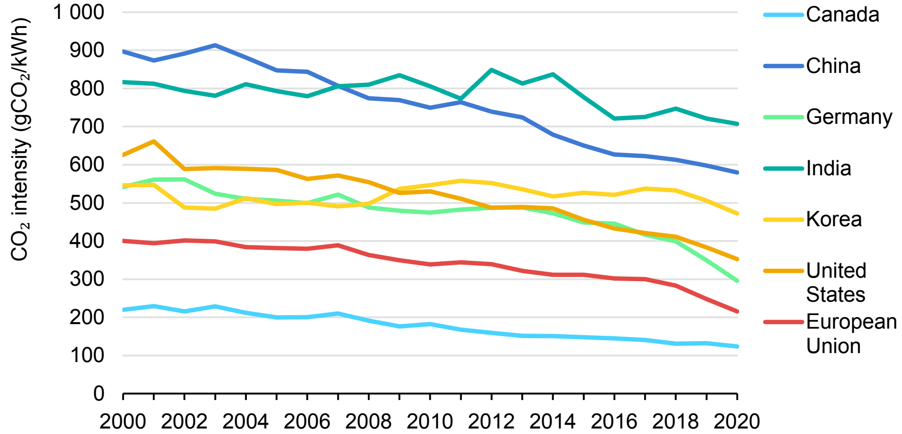
The carbon intensity of supply dropped significantly in many countries in 2020: as demand decreased due to the global pandemic, but renewable energy generation continued to grow in many regions, fossil-fuelled production lost market share. This resulted in an estimated 3% reduction in the carbon intensity of production. Total electricity-related emissions dropped by 5%. Especially remarkable was the drop in the European Union (17%) and North America (10%) due to a combination of lower demand, intense coal-to-gas competition and growing renewable generation.

Many of the largest electricity-consuming countries have been able to achieve significant improvements in emission intensity during the past two decades. China, starting with the highest carbon intensity in 2000, was able to cut emissions by 35%. The United States and Canada are both down by 44%, Germany by 45%. Germany particularly improved in 2020 (down 10 percentage points) due to a significant reduction in coal-fired generation.

Composition of CO_2 emissions and emission intensity in 2020



Development of CO_2 emission intensity of electricity generation



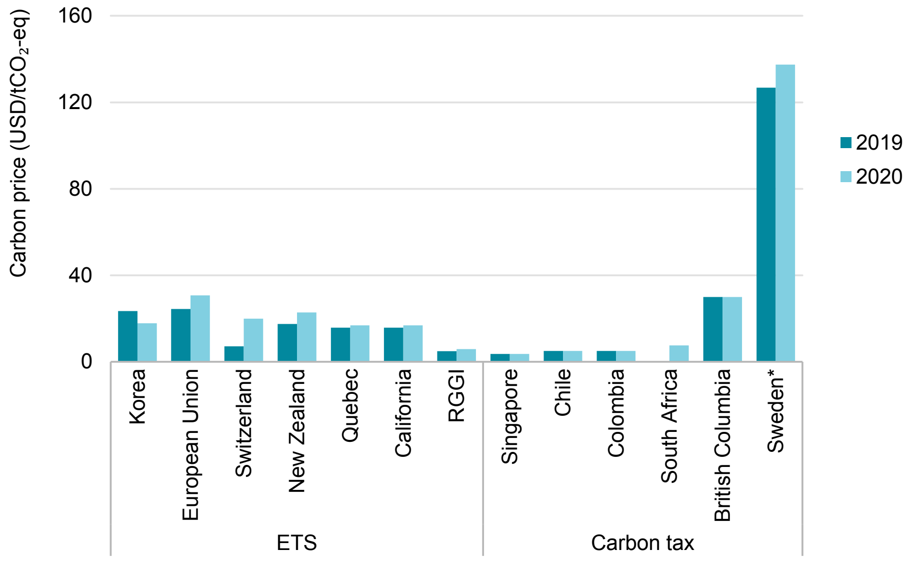
Source: IEA (2020), CO_2 emissions statistics.

Low-carbon policies to achieve electricity sector transitions: Focus on carbon pricing

To achieve clean energy transitions, countries are implementing a suite of policies that work together towards the decarbonisation of the electricity sector. National policy objectives and constraints, alongside local power market structures, shape each jurisdiction's particular policy mix. In addition to fuel taxes, and efficiency and renewable support measures, they can also incorporate market mechanisms. For example, Japan implemented an innovative non-fossil fuel certificate trading framework in 2020, which also includes renewable and low-carbon energy sources not covered by Japan's feed-in tariff. This year is also notable for the first implementation stages of China's emissions trading system, covering its power sector. An increasing number of countries and jurisdictions are introducing carbon pricing instruments. These comprise carbon taxes, emissions trading systems or hybrids of the two, and can be an effective complementary policy in the arsenal of instruments that governments can use to decarbonise their electricity sector, alongside other low-carbon, sector-specific policies. The electricity sector is included in the overwhelming majority of carbon pricing instruments.

Carbon pricing introduces a price signal for the cost of carbon emissions with two main impacts. First, it provides a signal for investment decisions, including in the long term. Second, it impacts the merit order of electricity dispatch, which can lead to a shift from high- to lower-carbon generation sources. The use of carbon pricing is growing, albeit from a low base. Reflecting historical energy competitiveness and affordability concerns, power markets are regulated to various degrees and in ways that can impact the desired effect of carbon pricing. The degree and form of these effects will vary in different market contexts; for example, effects on dispatch will be strongest where economic dispatch and liquid wholesale markets prevail. In the United Kingdom the introduction of a carbon price floor in addition to the EU emissions trading system allowance price has substantially contributed to the reduction of the share of electricity supplied by coal, from 39% in 2012 to only 5% in 2018.

Price level of selected carbon pricing instruments covering the power sector (as of April 2020)



* The Swedish carbon tax applies a lower tax rate to district heating plants.

Note: RGGI = Regional Greenhouse Gas Initiative (in 2020: Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, Vermont; Virginia from 2021).

Source: World Bank (2020), Carbon Pricing Dashboard.

2020 has so far recorded some notable developments in carbon pricing instruments that cover the electricity sector around the world. The national emissions trading system of China is set to begin during 2020 and 2021, and will initially cover electricity and heat generation from coal- and gas-fired power plants. When operational it will be by far the world's largest emissions trading system, alone covering more than 14% of global CO_2 emissions from fossil-fuel combustion.

At the beginning of 2020 the EU emissions trading system linked with the Swiss emissions trading system, and started implementing the regulatory provisions on carbon leakage, free allocation and auctioning ahead of the next trading phase starting in 2021.

The US Regional Greenhouse Gas Initiative (RGGI), a power sector cap-and-trade programme operational since 2008 in some states in the northeastern United States, experienced further growth in the past year. The state of New Jersey rejoined the initiative in 2020 and Virginia is set to join as well in 2021, increasing the emissions covered by RGGI by 36%.

The New Zealand emissions trading scheme underwent significant legislative changes in 2020, including an updated purpose for the scheme (to support Paris Agreement and domestic mitigation targets), the introduction of a rolling cap on emissions aligned with emissions budgets, and the introduction of auctioning with the simultaneous phase-down of industrial free allowance allocation.

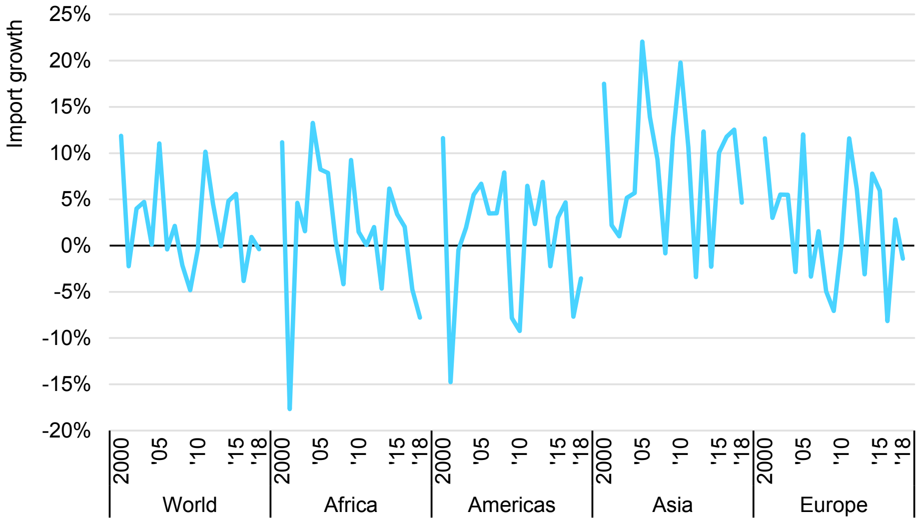
The Korea emission trading scheme also announced in 2020 important changes for its third phase starting in 2021, which include a stricter emissions cap in line with the country's 2030 GHG emissions target, an increase in auctioning of allowances and various measures to boost market liquidity.

In line with its impacts on the energy sector more broadly, Covid-19 had impacts on both pricing and trading systems, including extending the deadlines for compliance obligations and suspended market transactions. Carbon price declines in the EU emissions trading system were not sustained for long, likely due to a combination of factors including the use of the market stability reserve and an overall policy context of more ambitious GHG targets. Indeed, a notable trend in 2020 was the announcement of net-zero targets by many countries, including the European Union, China, Japan and Korea. This may impact the design and operation of their climate policies generally, and for some countries their emission trading systems in particular.

Cross-border electricity trade around the world

Global cross-border electricity trade, measured by gross imports in each country, was 728 TWh in 2018 or about 2.8% of total electricity supplied, an increase from 588 TWh in 2010 (24%, or 2.7% per annum).

Growth in electricity trade by region, 2000-2018



European countries trade cross-border electricity most extensively – imports accounted for 9.1% of total electricity supplied in 2018, compared to 4.5% in Africa, 2.2% in the Middle East, 1.9% in the Americas and 0.6% in Asia. European countries have much stronger interconnection capability between them and the most harmonised energy markets. In addition, border regions are more densely populated and developed than other regions where borders are shaped by physical barriers. In the European Union VRE growth has also been a catalyst for increasing trade, while excess nuclear generation makes France a large exporter.

The top five countries, based on total final consumption, which are China, the United States, India, Japan and Russia, trade less extensively, due to having large domestic markets and limited interconnections with neighbouring regions. The United States is the largest importer by volume (58 TWh) and as a percentage of total consumption (1.4%). Additionally, trade does occur on a large scale within these countries among neighbouring states and provinces, particularly in the United States.

Power trading in North America

Robust power trading between the United States and Canada continued in the first six months of 2020, despite the coronavirus-related decline in economic activity. US imports from Canada reached 27.4 TWh in the first six months of 2020, up from 25.0 TWh in the same period in 2019. US exports to Canada declined to 6.5 TWh from 7.4 TWh in the same period. Exports from Mexico to the United States declined, dropping from 3.5 TWh to 1.8 TWh in the first six months of 2020. As a result, Mexico was a net importer from the United States of 322 GWh in the first half of 2020, versus net exports of 342 GWh in the first half of 2019.

Impact of Covid-19 on electricity trade in Europe

National electricity systems are interconnected in Europe and markets are coupled, which means that Covid-19 impacts in one country can easily spill over into others. If one country experiences significant declines in demand – and therefore potentially declining market prices – this could affect the entire market, depending on available transmission capacity.

Demand dropped significantly and simultaneously in several markets across Europe due to the Covid-19 pandemic. A year-on-year comparison of demand in the first half of 2019 and 2020 shows a 6.6% decrease in demand in the United Kingdom, France and Germany combined. For the months of March, April and May the decline was even more significant, with a year-on-year decline of 9.1%.

During 2020 generation from non-fossil fuel sources (nuclear and renewables) has remained relatively stable compared to 2019. Nuclear in itself was down, but this was compensated by a rise in renewables. French nuclear output was notably lower in 2020 compared to 2019. Fossil-fuelled generation has declined markedly. In the first half of 2019 Denmark, Norway, the Netherlands, France, Germany and Italy generated 573 GWh from fossil fuels, while the comparable amount in 2020 was just 474 GWh. Declining demand in Europe was primarily accommodated by falling fossil fuel-based generation.

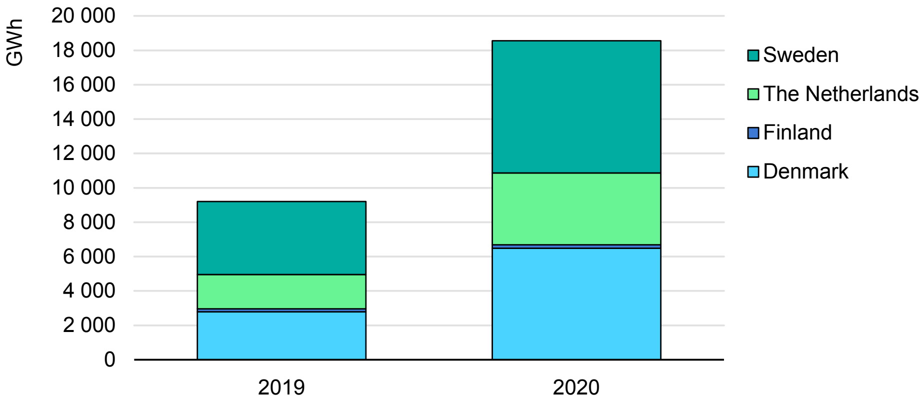
When demand and generation patterns change, the flows in the European market also change. An example of this is the trade between the Nordic market and continental Europe. In the first half of 2020 the flow from Germany to Sweden amounted to 129 GWh, about half the value of the same period in the previous year. Similarly, the flow from Germany to Denmark was 2 158 GWh in the first six months of 2020, a year-on-year drop of about 30%.

The Nordic market is typically a low-price market due to relatively high share of hydro and wind compared to continental Europe. In a situation where demand drops drastically, for example due to a lockdown, it will affect the cross-border flows in such a way that the more expensive generation sources, such as fossil fuel-based plants, are pushed out of the merit order.

In addition to lower demand across Europe, the water resources of the Nordic region were particularly plentiful in the spring and summer – additionally contributing to the power flows from the Nordic region to continental Europe.

An example of how the changed fundamentals affected cross-border power flows can be seen in Norway. In April and May 2020 hydropower production was around 46 TWh, or about 25% higher than in the same period in 2019. This, together with low demand, resulted in higher exports from Norway.

Export flows from Norway by destination in H1 2019 and H1 2020



Source: ENTSO-E (2020), Transparency Platform.

In 2020 exports from Norway to its neighbours were significantly higher than in 2019. When demand drops and water levels are high, prices in Norway fall – resulting in higher exports all else being equal. It is not clear, however, how much impact the drop in demand has had, since this trend would also be prevalent in other wet years. Flows from Sweden and Denmark to Germany would equally see an increase, in order to distribute the large amount of renewables in the Nordic market to continental Europe.

Heating and cooling needs around the world

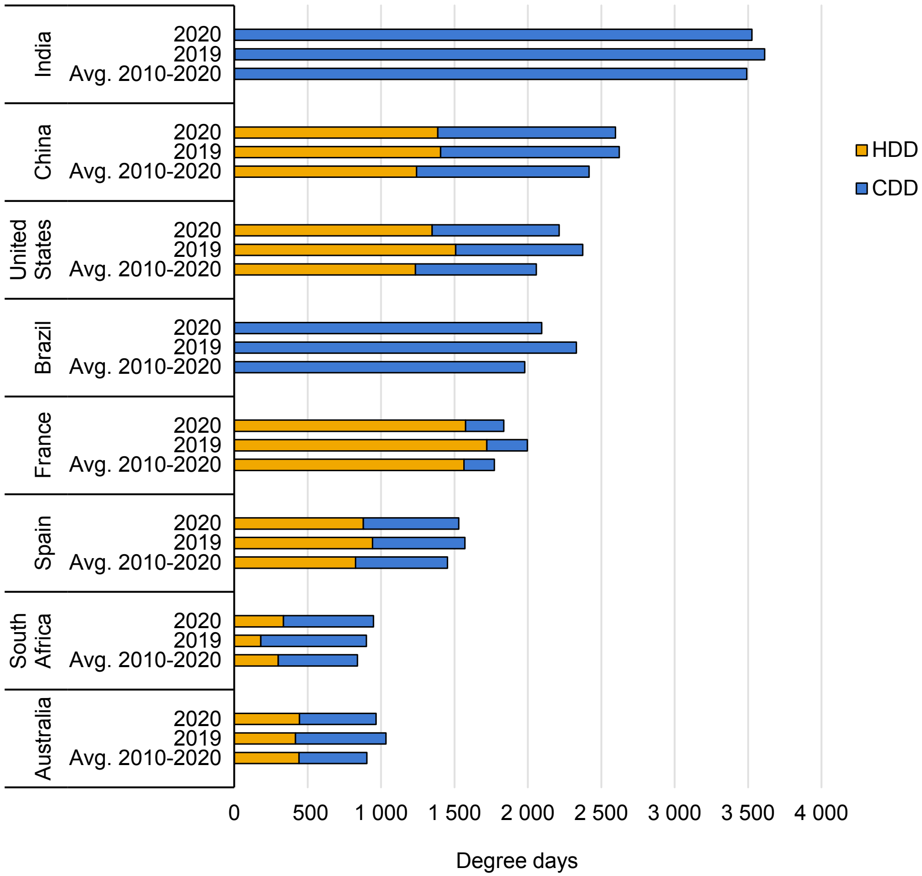
The use of space heating and cooling differs between regions and is greatly influenced by temperature and humidity. In areas with cold weather, such as central and northern Europe, space heating prevails. Due to high temperatures throughout the year in India, cooling requirements dominate. In some countries, such as the United States and China, the need for space heating and cooling is almost equivalent and varies from region to region.

Heating degree days (HDDs) and cooling degree days (CDDs) try to capture weather-induced space heating and cooling needs by comparing the outside temperature with a reference value, which varies regionally and depends on the population's comfort temperature. If, for example, the temperature falls below the reference value (e.g. 16°C), the resulting HDDs are the difference between the reference and the actual temperatures.

Depending on each country's technology mix for heating and cooling, the yearly fluctuation of weather can considerably affect electricity consumption. For example, France experienced milder weather during 2020 compared to 2019 (HDDs down 8% and CDDs down 6%), which has been reflected in lower power demand for heating and cooling. Meanwhile, Spain had a warmer summer (CDDs up 3%), resulting in increased electricity demand for cooling. A warmer winter in the United States resulted in a drop of 10% in the number of HDDs, and subsequently lower electricity demand for heating in some regions. In South Africa, Australia and Brazil the greatest difference from 2019 was observed during the summer season, where lower temperatures led to a drop in CDDs of 15% (South Africa and Australia) and 10% (Brazil).

In addition to yearly weather variations, long-term trends are influencing heating and cooling demand. This can, for example, be observed in Europe, where increasing temperatures resulted in a drop of 17% in population-weighted average HDDs and an increase of 96% in CDDs between 1980 and 2017.

Population weighted heating and cooling degree days



Notes: Base temperatures (16°C for HDDs and 18°C for CDDs) are kept constant for all regions to facilitate comparison; however, these temperatures can vary by region.

Source: IEA (2020), Weather for energy tracker.

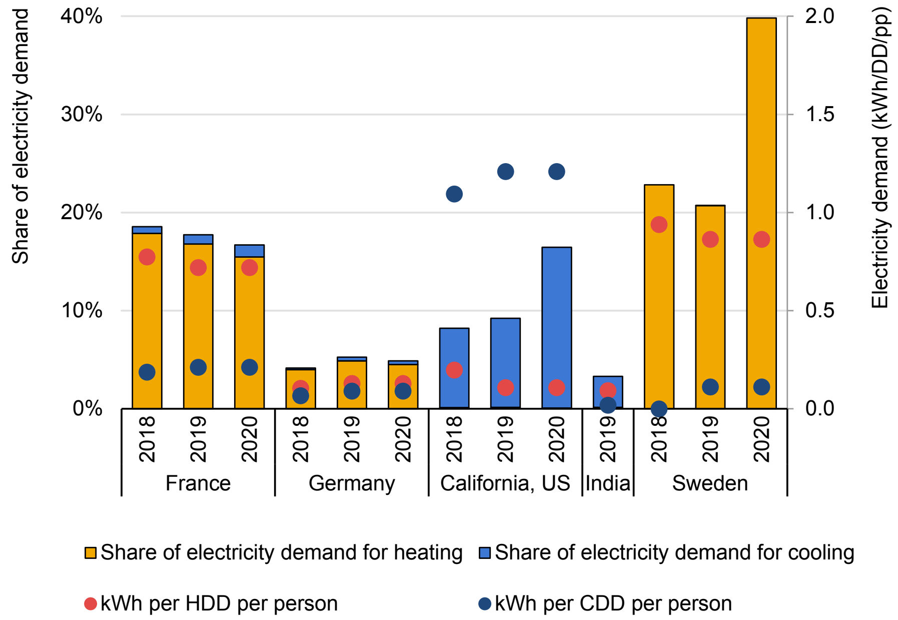
Temperature impact on electricity demand

Annual electricity consumption for heating and cooling depends not only on the weather, but also on the mix of technologies. For example, although Germany was 35% colder than France in 2018, only 4% of its electricity demand was heating related, while in France it was 18% – this is due to the higher share of electricity in total energy use for space heating in France compared to Germany (15% and 2% respectively). This is also reflected in the higher electricity consumption per HDD per person in France than in Germany. In northern Europe, Sweden had one of the highest shares of electricity demand for heating in 2018 (23%), driven by the cold weather in Scandinavian countries and the high share of electric heating (26%).

In contrast to heating, for which a variety of fuels are deployed, electricity is the predominant energy source for cooling – but the distribution and type of appliances varies significantly. In California, which experienced a very hot summer in 2020 (CDDs up 35%), more than 16% of electricity consumption could be attributed to cooling – almost twice the share of in 2019. Although average temperatures in India are much higher than in California (with 4.2 times the number of CDDs in 2020), only 3% of electricity was used for cooling in 2019. This means that India used only 1.7% of the electricity used per person per CDD in California, due to lower access to cooling appliances and the frequent use of fans instead of air conditioners. This illustrates the large potential for increasing electricity demand for cooling in India.

Electric heating and cooling systems have a large potential for demand response by supporting the balancing of demand and supply. In systems with a large share of renewables, they can help to avoid curtailment, stabilise the grid and reduce the need for storage deployment.

Electricity demand for heating/cooling as a share of the total and per person per degree day, 2018-2020



Note: Based on a multivariable regression model using humidity-adjusted HDDs and CDDs, daylight hours and the type of day (weekday/weekend/holiday).

Source: IEA analysis based on IEA (2020), Weather for energy tracker.

Regional focus: Europe

Electricity demand and supply in Europe in 2020

Electricity demand significantly decreased all across Europe as a consequence of the Covid-19 pandemic, the subsequent preventive measures and economic recession. High decreases were observed in Italy, Spain and the United Kingdom, with drops in demand of around 6% – significantly above the average 4 to 5% drop for the region as a whole.

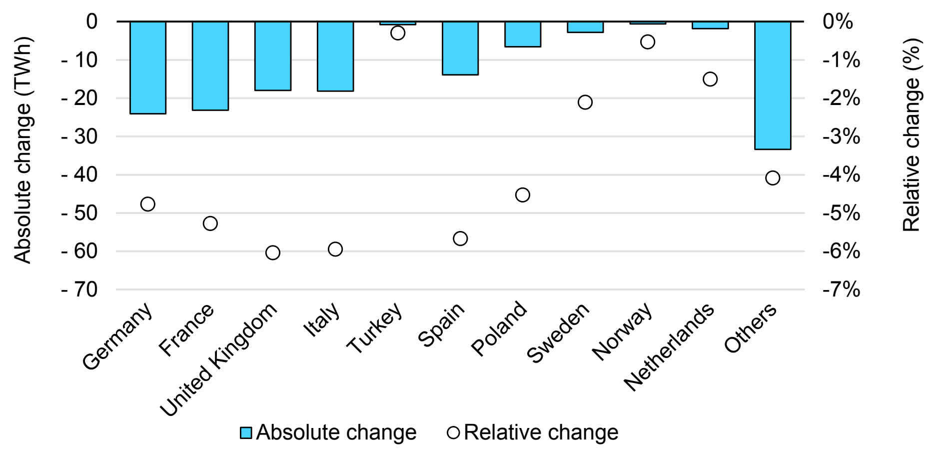
The uncertain environment created by the outbreak of Covid-19 also affected emission allowance prices in the EU emissions trading system. After a long period of prices below EUR 10/tCO_2-eq in the years 2012 to 2017, prices reached a peak of around EUR 30/tCO_2-eq in July and August 2019. With the increasing visibility of the scale of the global pandemic, at times prices dropped below EUR 15/tCO_2-eq in March, April and May – before reaching EUR 30/tCO_2-eq again in September.

Electricity supply from renewable energy has continued to gain a larger market share across Europe. Despite falling demand, especially in the second quarter of the year, and record high renewable levels relative to demand, integration issues were scarce. On average, renewables in Europe are expected to provide around 42% of all generation in 2020, a significant increase from the 37% in 2019.

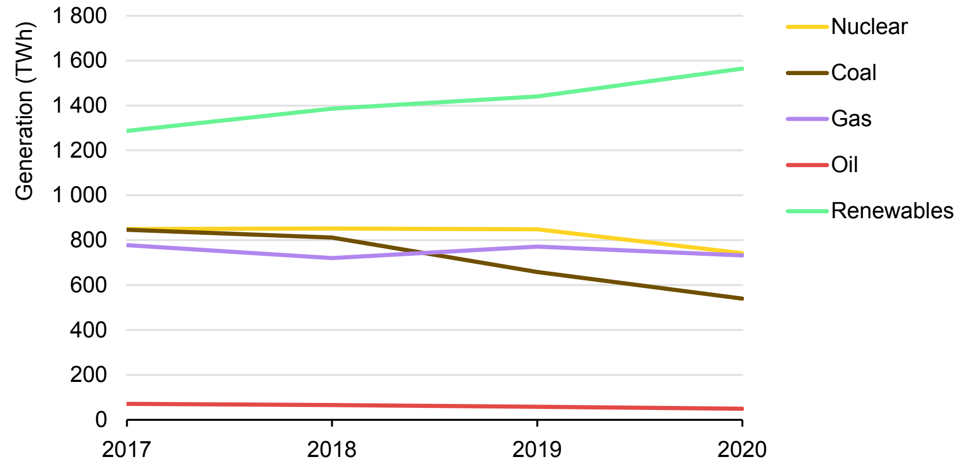
Coal-fired generation, by contrast, is experiencing the largest decrease, down around three percentage points to provide around 15% of total generation in 2020.

In September 2020 the European Commission proposed to raise climate ambitions and cut emissions by 55% by 2030 (compared to 1990). This follows the 2050 climate-neutrality target agreed by EU leaders at the end of 2019.

Estimated electricity demand changes in Europe in 2020



European electricity supply in 2020



European nuclear power generation in a year of lockdowns plummeted to its lowest level in over two decades

European nuclear power generation fell by close to 12% (or 86 TWh) y-o-y in the first eleven months of 2020, to its lowest output in at least 20 years. The steep drop has been driven by a number of factors, including optimisation of fuel usage amid reduced electricity demand, plant retirement, rescheduling of maintenance work and unexpected outages caused by low river levels. Most of the additional market space has been captured by gas-fired power plants, which benefited from low gas prices and the sharp recovery in carbon prices, putting them in a more competitive position vis-à-vis coal- and lignite-fired generation.

France alone accounted for over half of the net drop, with nuclear generation decreasing by 16% (or 45 TWh) y-o-y. In addition to the closure of the Fessenheim 1 and 2 nuclear reactors in February and June 2020 respectively, the maintenance schedule of multiple reactors has been rescheduled as a consequence of the Covid-19 outbreak. The outages at the Flamanville 1 and 2 and Paluel 2 nuclear reactors – offline since September 2019, January 2019 and October 2019 respectively – were all extended by several months and are due back online in late 2020.

As a consequence of the steep fall in nuclear power output and reduced electricity demand, France's net electricity exports plummeted by over 22% (or 12 TWh) y-o-y in the first eleven months of 2020. Net exports to Spain fell by over 40% (or 4 TWh) and more than halved to Belgium (down by 1.6 TWh). In September France's electricity imports surpassed exports for the first time since November 2017. France returned to net export status in October and export flows rose significantly above last year's levels in November, amidst improving nuclear availability.

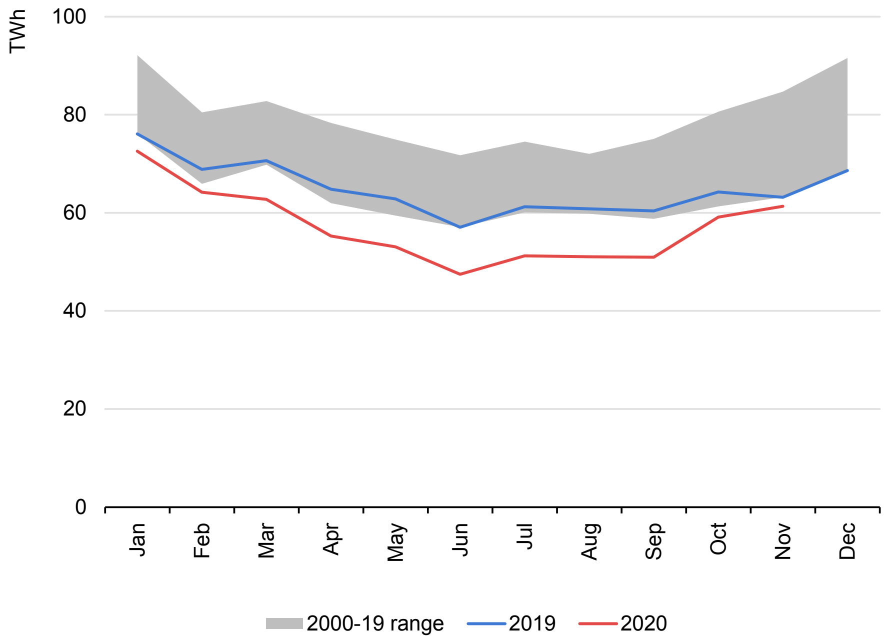
Similar to France, the Belgian nuclear fleet faced extended outages. The restart of the Tihange 1 reactor was delayed from July to the end of the year, due to a failure in a cooling water reservoir tank. This coincided with the planned maintenance of Tihange 3 from June until mid-October, altogether resulting in Belgian nuclear output falling by 22% (or 8 TWh) y-o-y.

Nuclear generation in Sweden decreased by over 27% (or 16 TWh) y-o-y in the first eleven months of 2020. This was partly due to the decommissioning of the Ringhals 2 nuclear reactor at the end of 2019. In addition, weak electricity prices on subdued demand combined with ample hydro availability (up 14% y-o-y) further weighed on nuclear output. In March 2020, due to low electricity prices, reactor Ringhals 1 was stopped temporarily and in April Ringhals 3 was also taken offline because of low prices and reduced demand due to the Covid-19 crisis.

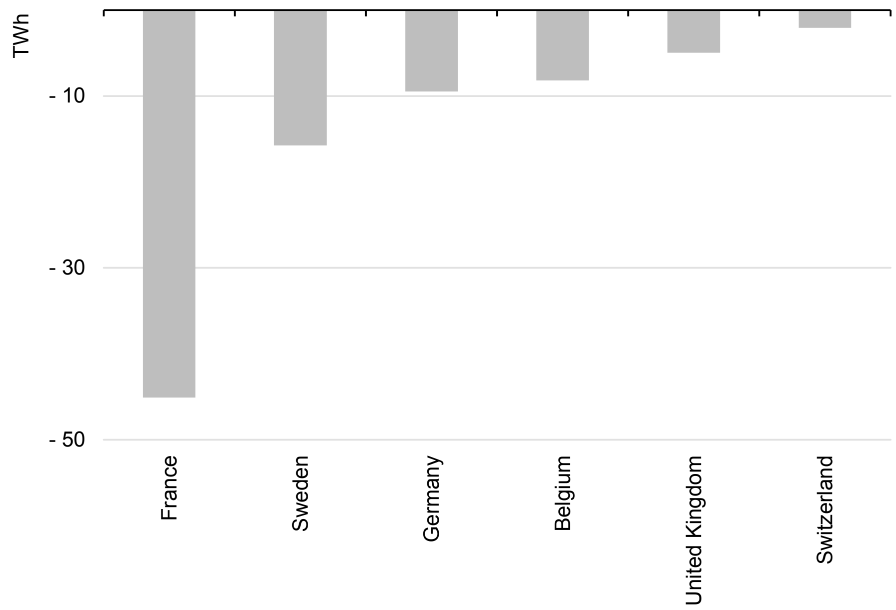
In the United Kingdom several outages were extended over the summer. Moreover, an agreement was reached between National Grid ESO and EDF Energy to reduce the output from the Sizewell B power station until the end of September to make it easier to manage the system with low demand and relatively high levels of VRE. Altogether, nuclear power output fell by 10% (close to 4 TWh) during the first eleven month of the year. In Germany nuclear output was down by 15% (almost 10 TWh) during the same period of the year, primarily due to the closure of the Phillipsburg 2 reactor at the end of 2019.

European nuclear power generation started to recover in October, with the y-o-y decrease moderating in November to a fall of 3% on rising nuclear availability.

European nuclear power generation 2000-2020



European nuclear power generation by country, Q3 2020 compared to Q3 2019



Sources: IEA based on ENTSO-E (2020), Transparency Platform.

Spain

In 2019 electricity demand in Spain declined by 1.6%, or 2.5% after weather and calendar adjustment, despite the country's GDP growth of 2%, mainly due to lower industrial demand. In 2020 the drop in electricity demand accelerated, caused by Covid-19-related lockdowns in the spring and later in the year, as well as the slow economic recovery afterwards. In the first three quarters of 2020 electricity demand declined by 6.7%, or 6.9% when weather and calendar adjusted.

Renewables expansion slowed in 2020 compared to 2019. In the full 12 months of 2019 solar PV capacity increased by almost 5 GW (up 90%) and wind capacity grew by around 2.4 GW (up 10%). In the first three quarters of 2020 only just over 1 GW of PV and 650 MW of wind were commissioned. Given Spain's endowment of good wind and solar resources, and the government's forthcoming renewable capacity auctions – which will improve project bankability by reducing risk – an acceleration of renewable capacity additions is expected in the coming years.

Electricity generated by natural gas combined-cycle plants had already become cheaper than coal in 2019 as a result of low gas and robust CO_2 prices. This boosted CCGT output, which increased by 84% in 2019, and led to a decline in coal power generation of 70%, down to levels not seen since the first oil shock in 1973-74.

Coal-fired generation has virtually disappeared in 2020. Stagnating electricity demand, increasing renewable output, robust CO_2 prices and stable gas prices, together with investments required to comply with more stringent European environmental standards, led to the retirement of 4.8 GW of coal capacity at the end of June.

The prospect for CCGTs is also challenging – not least due to the extensive availability of capacity. Despite the virtual elimination of coal-fired generation, average working hours of CCGTs in 2019 were around 2 100 hours (an average capacity factor of 24%). Lower electricity demand and higher renewable generation in 2020 might push working hours below 2 000.

Italy

Italy, one of the European countries hit hardest by Covid-19, introduced its first quarantine on 22 February in 11 municipalities of the Lombardy region. By 9 March the whole of Italy was under lockdown, with nearly all commercial activity suspended two days later, except for supermarkets and pharmacies. On 21 March the Italian government closed all non-essential businesses and industries, and restricted the movement of people. Later on in May restrictions were gradually lifted, and on 3 June freedom of movement across regions and other European countries was restored.

With the drop in electricity demand, imports also decreased: whereas in 2018 and 2019 net monthly imports never fell below 2.2 TWh, they dropped in April and June 2020 to 0.8 TWh and 0.5 TWh respectively, driven by exports more than doubling in the second quarter of 2020 compared to the same period in 2019.

In recent years electricity demand has been rather stable in Italy. However, demand significantly dropped in 2020: in the first half of the year, demand was down by 9% compared to the corresponding period in 2019 – for the full year, a drop of around 6% is estimated. Electricity demand finally started reaching 2019 values again in August and eventually stabilised in September with industrial electricity consumption recovering. In a monitored industry sample, consumption in oil refineries and coke works increased by 42.4% in September, paper mills by 29.6% and companies producing construction materials by 9.7% compared to previous months.

With significant changes in demand came significant changes in supply. Natural gas has accounted for the majority of the reduction in power generation, with lower imports accounting for most of the rest. Slightly lower coal demand was offset by higher renewables output, mainly from hydro.

France

France is among the European countries to see a higher number of coronavirus cases and put tight measures in place accordingly, ranging from the closing of all non-essential businesses to restrictions on movement outside the home. After lifting many of these restrictions during the summer, renewed lockdown measures were introduced in the autumn. In total, electricity demand in France is estimated to drop by about 5% in 2020, with the largest fall of around 17% in April compared to the same month in 2019.

As in other countries, the drop in demand coincided with higher renewable generation, putting pressure on supplies from other sources. The majority of thermal generation had to be halted – gas- and coal-fired power generation decreased by 75% between April and May, a decline of around 2.7 TWh. As this was insufficient to compensate for the reduction in demand of around 10 TWh, and export opportunities were limited due to low demand in neighbouring countries, nuclear power generation also fell. Overall, nuclear generation is expected to decrease by around 16% in 2020, due to the combined effect of the decommissioning of the two units at the Fessenheim plant in February and June, comprehensive maintenance works and lower export demand.

United Kingdom

The United Kingdom was heavily affected by the Covid-19 pandemic in 2020. After a mild decrease of demand in the first quarter (less than 1% year-on-year), demand dropped by 12% in the second quarter. With household consumption almost stable (down 1.7%), the decline was primarily due to a 17% drop in the industrial sector and 20% in the commercial and other sectors. Higher renewable output and lower demand meant that the share of renewables in the generation mix rose to 47% in the second quarter, a record high.

The overall fall in demand in the second quarter was followed by a steady recovery in the third quarter, which has since been halted by fresh restrictions in the final quarter of the year. It is estimated that UK demand will fall by around 6% for the entire year.

The reduction in demand combined with higher renewables output (up around 10%) has meant lower generation from fossil fuels. Gas-fired generation has borne the brunt of this reduction, while nuclear power is down 10%. In the second quarter of the year, coal accounted for only 0.5% of total generation – a record low. Between March and June coal was not used at all in Great Britain for 67 consecutive days.

Germany

Germany imposed milder restrictions on the movement of people than other large European countries. As the number of Covid-19 cases and deaths per capita rank at the lower end, no nationwide lockdown was put in place. Nonetheless, starting in the second half of March a range of restrictions were introduced, such as a ban on public gatherings of more than two people and the closing of restaurants, hair salons and schools.

Despite milder measures, the overall 5% drop in electricity demand anticipated for 2020 does not differ greatly from other large European countries. This is due to a significant slowdown in industrial activity, which was responsible for around 45% of total electricity demand in 2019.

Renewables continue to grow. Onshore wind is now the largest source of electricity generation in Germany, exceeding lignite (which had been top since 2007) for the first time. After shutting down the nuclear unit Philippsburg 2 (1.5 GW) at the end of 2019, six nuclear reactors remain in operation in Germany (due to be decommissioned in two steps at the end of 2021 and 2022 with three retirements per year). For the full year, despite the estimated drop in nuclear generation (down around 15%), the sum of low-carbon generation (i.e. nuclear and renewables) could slightly increase due to the growth of renewable energy. It is anticipated to account for about 56% of total electricity generation (up about 4 percentage points).

Gas was able to hold its share of electricity generation as the fall in demand and rise of renewables were reflected in lower production from coal combustion – both hard coal and lignite declined as low gas prices and high carbon prices favoured gas until late in quarter three.

Germany put a new law into place in July 2020 that stipulates the complete national phasing out of coal in 2038 at the latest, and potentially in 2035 if certain criteria are met. To facilitate the roughly linear capacity reduction path, annual auctions are being held to determine cost-efficient decommissioning until 2027. The first auction for 4 GW ended in September of this year.

Regional focus: Americas

Electricity demand and supply in Americas in 2020

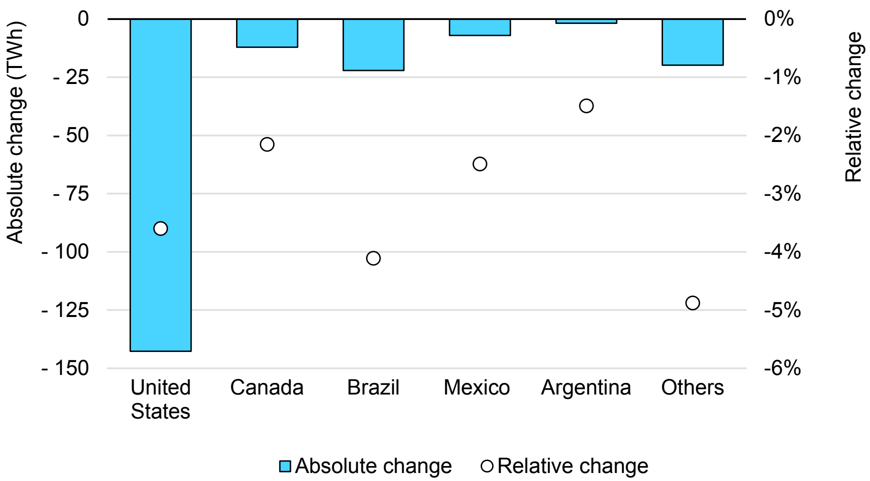
As a consequence of the Covid-19 pandemic and the subsequent preventive measures and economic recession, electricity demand decreased significantly throughout the region. Region-wide demand is expected to decline by 3.5% in 2020 and of the five largest countries in the region, Brazil is expected to see the greatest drop at around 4%. The United States declines by 3.6%, while Mexico (2.5%), Canada (2.2%) and Argentina (1.5%) are expected to decline less severely.

Hydropower is estimated to account for 21% of electricity generation in the region in 2020. This share rises to 57% in Central and South America, with the North American countries expecting a 13% share.

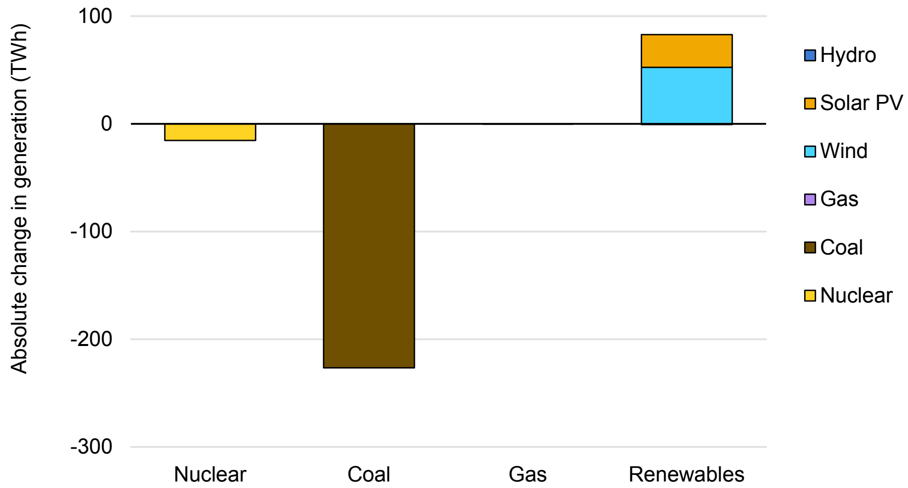
Gas-fired generation accounts for a 33% share of the region's electricity generation, while coal and nuclear both have a 15% share, wind 8% and solar 2%.

The change in the generation mix in 2020 shows a steep decline for coal of around 230 TWh, mainly due to decreased economic competitiveness with natural gas, as well as continued deployment of renewables.

Estimated electricity demand changes in the Americas in 2020



Change in electricity generation mix in 2020



United States

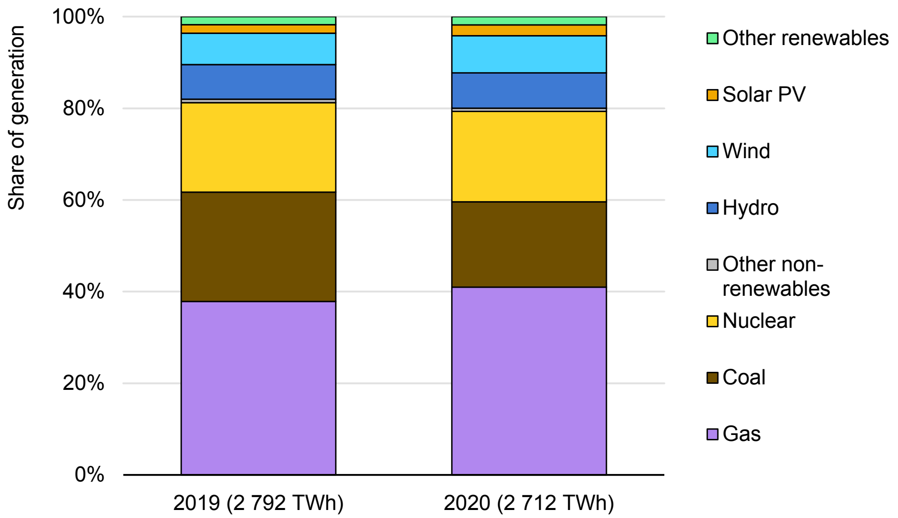
Electricity demand slows while gas gains in power generation

Overall electricity demand in the United States fell by 3.8% from January to August 2020 compared to the same period last year, from 2 792 TWh to 2 712 TWh. Commercial and industrial demand fell by 6.4% and 9.2% respectively, while residential demand increased by 2.4% to 1 000 TWh. The overall decline was driven by both the coronavirus-related slowdown in economic activity and the relatively mild winter heating season.

Heating degree days decreased by 10.2% in the first 8 months of 2020, declining in every region of the country, but particularly in the Midwest (12.2%) and West South Central (17.0%). This was somewhat offset by a stronger summer cooling season, with cooling degree days increasing by 5.8% in the first 8 months of 2020, including increases of 21.3% in New England and 13.1% in the Mid-Atlantic states.

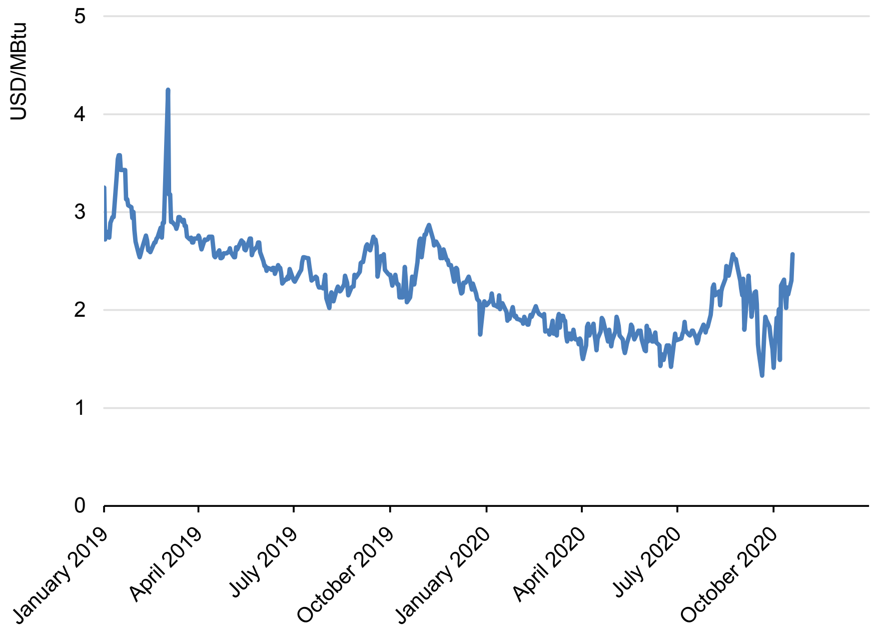
Owing to the decline in overall consumption and the rise in renewable generation output, the share of fossil fuel-based generation fell from 62.4% in the first eight months of 2019 to 60.2% in the same period of 2020. Generation from wind and solar sources increased by 14.4% and 24.8% respectively. Generation from hydropower (down 0.2%) and nuclear plants (down 2.0%) was relatively flat. Coal has seen the steepest drop of 24%, from 664 TWh to 505 TWh. The share of coal in US power generation fell from 23.8% to 18.6% as a result.

US electricity generation between 1 January and 30 August



Natural gas-fired generation increased from 1 055 TWh to 1 109 TWh, a gain of 5.1%. The share of natural gas in the power mix thus increased from 37.8% to 40.9%. Low domestic natural gas prices, caused in part by the reduction in global demand for LNG, increased the competitiveness of natural gas plants compared to coal. The price of Henry Hub gas, the US benchmark, fell to USD 1.33/MBtu in early September, but has risen steadily in response to renewed LNG demand to USD 3.06/MBtu in early November.

Natural gas prices in the United States (Henry Hub) from 2019 to 2020



Source: S&P Global (2020), Platts.

Natural gas is also showing strength relative to coal in terms of generation investment. Net additions to natural gas capacity were around 5 GW in January to August 2020 compared to a net decrease of 5.8 GW in coal capacity.

California faces adequacy challenge

California experienced rolling blackouts on 14 and 15 August 2020, the first since the western energy crisis of 2001, as record temperatures drove demand and contributed to challenging operating conditions for both conventional thermal and variable renewable generation. Demand on 14 August reached 46.78 GW, which was above the one in five year forecasted peak load from the California ISO (CAISO) and 10 GW higher than the previous week. Supply, particularly imports, was reduced by the presence of high temperatures and loads, and unfavourable wind patterns throughout the western United States. Significant gas-fired units were also forced out of service. As a result, 1 000 MW of firm load was shed between 6:36 pm and 7:56 pm on 14 August and 470 MW was shed between 6:25 pm and 6:47 pm on 15 August. While this amounts to less than 0.1% of the energy served over the two-day period, the 1 500 MWh of total unserved load represents about 400 000 unit hours of air conditioning, or about USD 15 million in lost load.

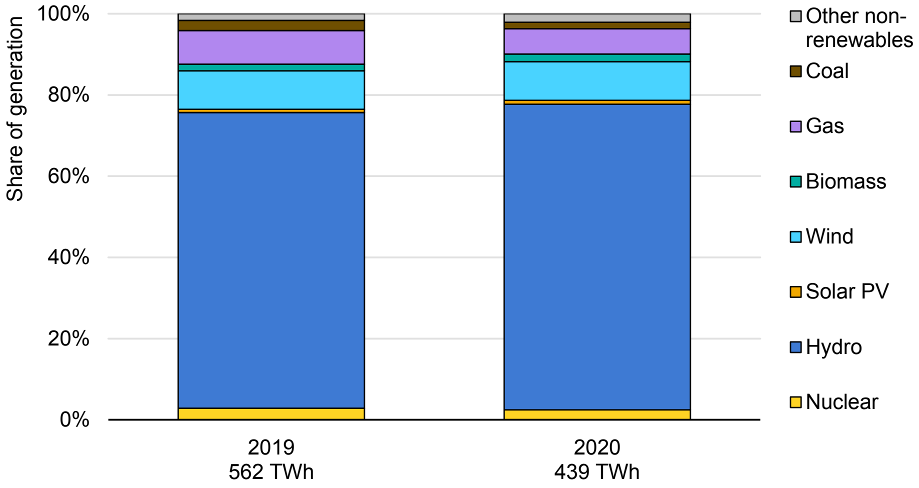
In the subsequent weeks CAISO needed to rely on significant voluntary load reductions, called flex alerts, on seven occasions to the end of September to avoid shedding further load, matching the total number of flex alerts issued between 2002 and 2019.

California cites climate change-induced weather patterns, alongside insufficient resource planning targets and certain day-ahead market practices (such as under-scheduling of load by utilities, which led to CAISO exporting energy during critical hours), as the main causes of the rolling blackouts in their preliminary report. The IEA has also issued a commentary that addresses the causes and potential solutions, recommending that California, and other regions likely to face similar circumstances, update their planning framework to incentivise adequacy and flexibility, strengthen regional co-operation to ensure the availability of remote supplies and integrate resilience to extreme weather events into their processes.

Brazil

Brazil's power system is characterised by its abundance of hydropower generation, which along with other clean energy technologies make it one of the least carbon-intensive power systems globally. In the first 10 months of 2020, hydropower, nuclear, wind, solar PV and biomass accounted for close to 90% of total generation, up 2% on the same period in 2019. This has been driven mainly by a proportional increase in hydropower generation, marginal increases in solar PV and wind generation and the response to the Covid-19 pandemic.

Electricity generation in Brazil between 1 January and 19 October

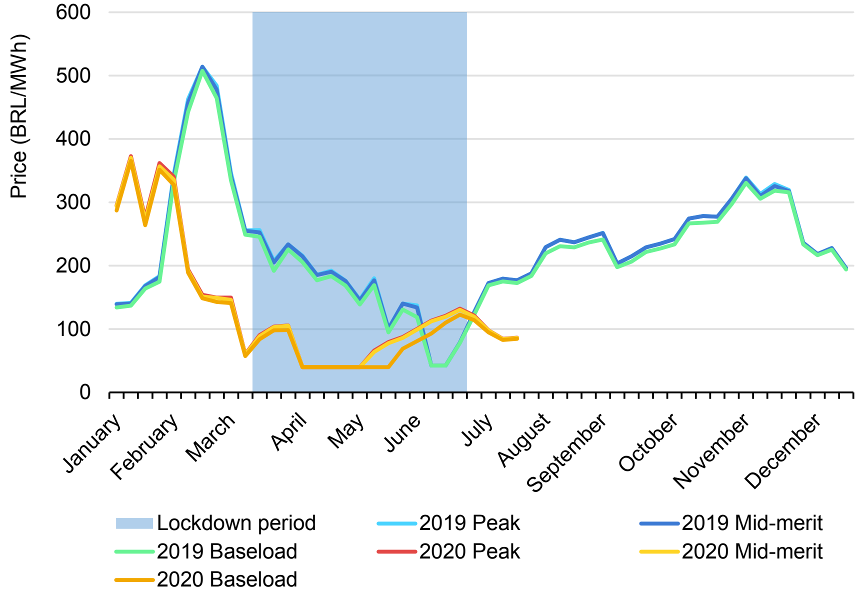


Source: SINTEGRE ONS (2020).

In the first 10 months of 2020 overall electricity demand decreased by 2.9% compared to 2019. In Brazil public health measures are implemented independently by the states and municipalities. Nevertheless, a common timeframe of response can be seen across the country, spanning from the second week of March to roughly the end of July. During this period, electricity demand across the whole system was 6% lower than in 2019, with the largest decreases taking place in the Northeast region (7.7%) and the Southeast-Central-West region (7.1%).

The drop in electricity demand and subsequent recovery are reflected in the weekly baseload price, which has been on average 15% lower than in 2019. Baseload, mid-merit and peak-load prices in the North and Northeast regions during the period of public health measures remained at roughly the same levels as in 2019. By contrast, weekly prices in the South and Southeast-Central-West regions, which account for most electricity demand in the country, have shown the greatest decrease compared to 2019. The average baseload price was 36% lower in the period between January and mid-July, and 67% lower during the strictest period of measures. For both the South and Southeast-Central-West power regions, prices started increasing in the week starting 18 April, while for the Northern region prices only started increasing along with electricity demand in the week starting 16 June 2020.

Weekly electricity prices in 2019 and 2020 in Brazil's Southeast-Central-West region



Source: CCEE (2020), Prices.

As regards the year-on-year changes in generation by technology, solar PV has seen the greatest increase. Solar PV output in the first 10 months of 2020 was 26% higher than in the same period in 2019, particularly driven by the rapid increase in installed capacity under the country's net-metering scheme. Nevertheless, solar PV is still expected to contribute only slightly over 1% of total generation in 2020.

Mexico

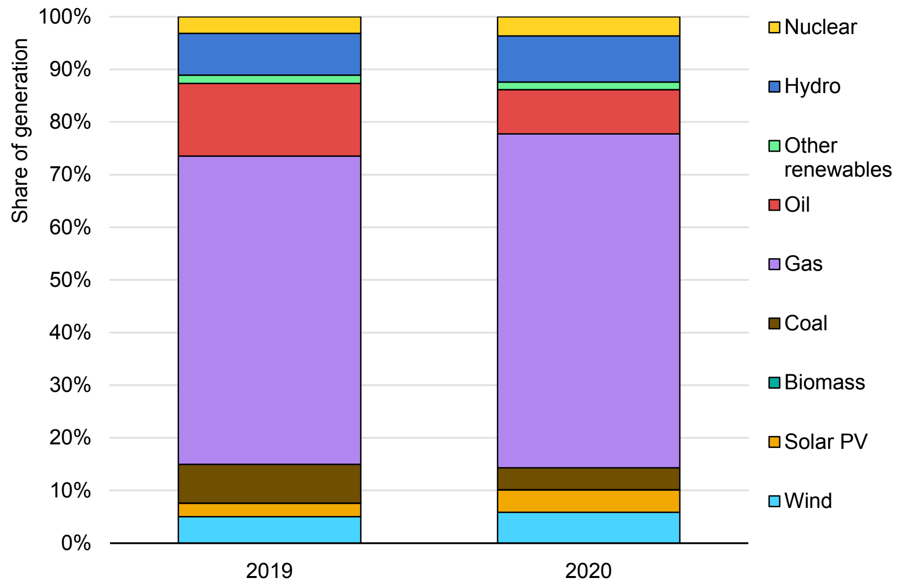
Electricity demand in Mexico at the start of 2020 was slightly higher than in 2019. This pattern, however, was reversed with the onset of the public health measures to deal with Covid-19 and the corresponding drop in commercial and industrial activity. The decrease in overall electricity supply, as well as recent developments in the country's power sector, have contributed to reshaping Mexico's generation mix in 2020.

Compared to the same period in 2019, electricity demand between 1 January 2020 and 30 September 2020 was around 2% lower. The decrease was most pronounced during the strictest period of lockdown measures spanning from 30 March to 31 May. Electricity generation during this period was down around 8% compared to the previous year. However, the loosening of restrictions and eventual uptick in industrial activity led to a system peak load of around 46.2 GW, which took place on 27 August, being only 2.7% lower than the 2019 peak.

Regarding the generation mix, Mexico's power system is still dominated by gas-fired generation, which constituted 53% and 58% of total generation in the first 10 months of 2019 and 2020 respectively. New solar PV generation coming online has also led to a significant increase in solar generation of 62% relative to last year. However, variable renewables' – solar PV and wind – share of generation only increased from 7.5% of generation in the first 10 months of 2019 to 10% in the same period in 2020.

In the first 10 months of 2020 coal-fired generation decreased compared to 2019, from 7.3% to 4.1% in the same period.

Electricity generation in Mexico between 1 January and 30 September



Source: CENACE (2020), [Energía generada por tipo de tecnología [Energy generated by type of technology]].

Canada

Canada's electricity demand is expected to decrease by about 2.2% in 2020. From a generation perspective, about two-thirds of this decrease has been offset by increased net exports to the United States. Renewables (including hydro, biomass, wind and solar PV) are expected to be slightly higher this year thanks mainly to higher hydro and wind output. Natural gas-fired generation is expected to be down slightly (2 TWh) compared to last year's levels, with nuclear power also down (5 TWh or 5%) as more units undergo refurbishment. Coal-fired generation is likely to see a decline of around 12% or 6 TWh. Most of this decline in coal is taking place in the province of Alberta, where lower demand, competitive natural gas, increased wind and carbon pricing are putting sustained pressure on the fuel.

Some parts of Canada have seen significantly higher peak demand in 2020. On 14 January at 6 pm, before the pandemic, Alberta set a new record for provincial demand of 11 698 MW during a cold spell when temperatures were -30°C. Despite having good wind generation resources, which over the previous 30 days had averaged a 42% capacity factor, on this day the output from wind farms averaged just 5% as the weather was both very cold and very calm. In Ontario summer peak demand was higher than it had been for nine years, thanks a combination of hot weather and suspension of a key demand response programme in response to the pandemic.

Investment in Canadian low-carbon electricity capacity continued in 2020. A major nuclear refurbishment is underway in Ontario, with the first unit (Darlington 2) returning to service after a 40-month outage and two others (Darlington 3 and Bruce 6) beginning multi-year outages. Muskrat Falls, a new 824 MW hydro facility in Labrador, produced its first electricity and will enter into service in 2021 – as will the Keeyask project (700 MW) in Manitoba and the 4th unit of the La Romaine project in Quebec. A major hydro project under construction in British Columbia (Peace River Site C, 1 100 MW) faces significant delays to address geological challenges that have arisen.

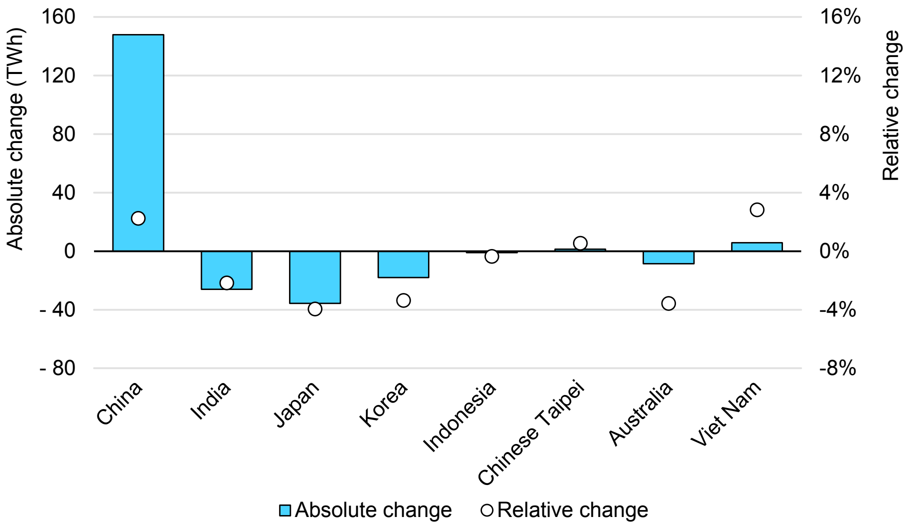
Regional focus: Asia Pacific

Asia Pacific regional overview

The Asia Pacific region saw a diverse range of electricity sector experiences in 2020, particularly in relation to the impact of the Covid-19 pandemic. The effects of containment measures on electricity demand were seen first in China, with the first three months of the year showing marked declines in demand. In April to May, as demand was already recovering in China, the largest decreases in electricity demand were seen in other countries such as India, Japan and Australia.

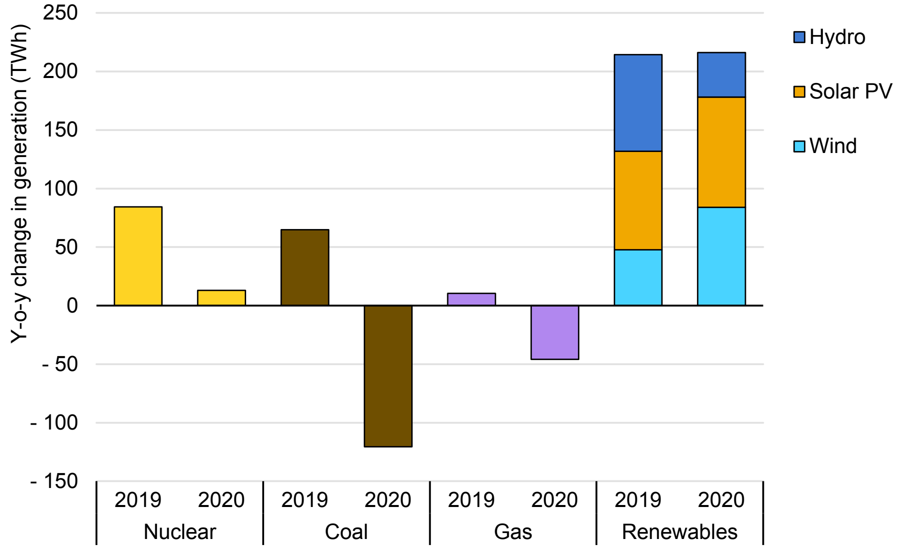
While the extent of the health crisis has varied greatly between countries, and differing degrees of containment measure have remained in effect at national and local levels, all countries saw demand recover following their strict confinement periods as many economic activities resumed. However, most also saw overall demand decline in 2020 relative to 2019, with some exceptions such as China and Viet Nam.

Estimated relative and absolute y-o-y change in electricity demand in selected Asia Pacific countries in 2020



Across the region coal is quite dominant in the generation mix, while renewables are playing an increasing role as countries advance their clean energy ambitions, with China, Japan and Korea all announcing ambitious net-zero carbon targets for 2050-60. In most countries coal-fired generation was most affected by demand reductions caused by Covid-19 containment measures. Gas-fired generation also saw an overall reduction relative to 2019, while renewables maintained or increased their share.

Estimated supply changes in the Asia Pacific region in 2019 and 2020

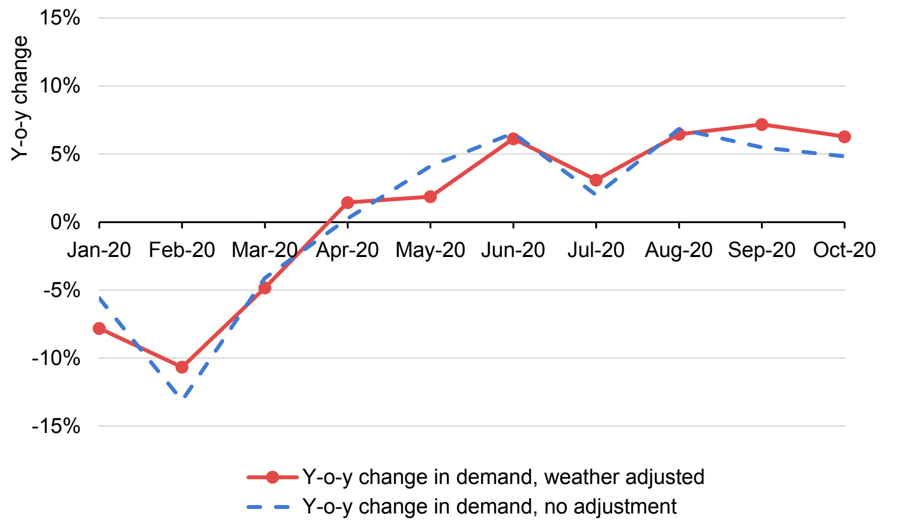


China

China is the world's second-largest economy and accounted for 16% of global GDP and 24% of energy demand in 2019. China also accounts for 28% of the world's electricity generation and is the only major economy to see an increase in electricity demand this year.

China was the first country affected by Covid-19, with the impact on electricity demand starting in January 2020 when strict confinement was first implemented. Economic activity experienced severe disruption during the lockdown between January and March, with the trough in February, which led to a significant drop in electricity demand. In the first quarter electricity demand dropped by around 8%, with the largest decline of 11% in February compared to the same period in 2019, weather adjusted.

Y-o-y change in monthly demand in China, 2020, with and without adjustment for weather differences



Source: IEA based on China Statistical Information Network (2020).

China was also the first country to begin recovery as normal activities gradually resumed from the second half of March and electricity demand began to pick up. Economic stimulus measures were also implemented by approving new investment in infrastructure, which drives electricity consumption. From April to October electricity demand was higher than the same period in 2019, with an increase of 6% for the month of October 2020 (weather corrected). The China Electricity Council is expecting the total demand in 2020 to be 2-3% greater than 2019.

The reduction in electricity demand particularly affected coal-fired generation, which experienced a decline of close to 10% during the confinement compared to 2019. This has also resulted in a decline in coal demand. By contrast, wind and solar PV generation increased by 20% year-on-year in the first quarter of 2020.

Electricity generation began to pick up after the confinement as electricity demand recovered. Coal is the main source of electricity in China, making up almost 64% of total generation, with an installed capacity of around 1 060 GW in 2020. China continues to add coal capacity at a rate of around 30 GW or 3% of current capacity per annum in recent years. However, in the context of the policy objective of reducing air pollution, these additions are increasingly selective and are dominated by plants close to coal mines or mining hubs. China is the world's largest consumer of coal-fired electricity and in 2020, for the first time ever, will produce over half of the world's total.

Coal also began to generate more than last year from April on, with the highest increase of 9% in May and 6% in August. But low-carbon sources are also increasing their share of the electricity supply. Nuclear generation is expected to increase by around 6% to reach a share of 5%, and renewables to reach a share of 28%, up around 1.5 percentage points compared to last year.

These increases in low-carbon generation result in a lower market share for fossil fuels. Although coal and gas-fired generation remain almost the same in absolute terms, their aggregated share in the mix is set to fall by almost two percentage points to around 66% in 2020.

2020 is also expected to see the first operation of the national-level emissions trading scheme in China. The first regional pilot was launched in 2013 under the 12th five-year plan, and eight regional pilots are now active. The national-level scheme was announced in the 13th five-year-plan, to be gradually implemented in three phases from 2017, with the aim to start the third operational phase by the end of 2020. The previous phases focused on constructing market infrastructure, collecting data, training and simulating allowance options and trading. In contrast, the third phase will begin operation of the scheme, starting with the power sector, including allowance trading for compliance purposes. The initial focus will be on supporting efficiency improvements at fossil fuel power plants. In the future the scope will gradually be extended to other energy-intensive sectors.

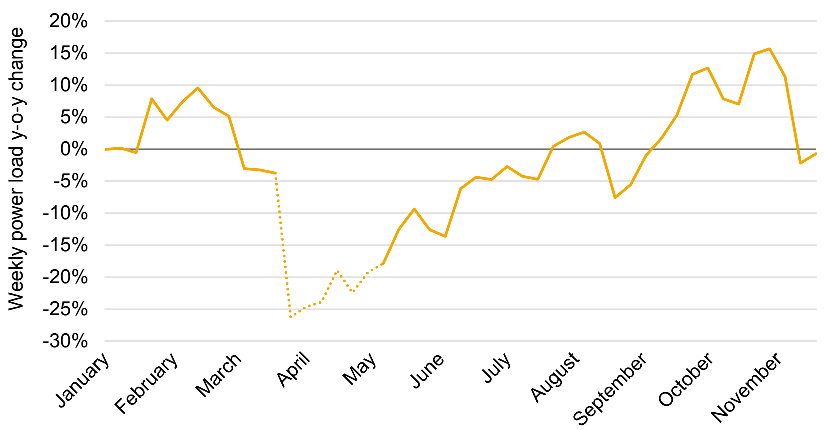
The 14th five-year-plan is currently being finalised, which will guide the development of the energy sector in China to 2025 and beyond. The post-Covid-19 stimulus measures to drive investment in electricity infrastructure include power generation assets, ultra-high-voltage transmission and EV charging stations. The recent announcement to the UN General Assembly of China's intention to reach net-zero carbon emissions by 2060 will also play a key role in the 14th five-year plan.

India

The impact of Covid-19 on the Indian electricity sector and electricity demand has been significant. India began a nationwide lockdown on 25 March 2020, which was relaxed progressively between the end of May and end of June. Since then local restrictions have been in place in line with local government decisions.

Following the start of the lockdown, weather-corrected electricity demand relative to the same period in 2019 initially fell by 17%, followed by a further decline to reach a 28% reduction by the end of March. From the end of May electricity demand began to recover, reaching 2019 levels by early August, and showing year-on-year growth into September and October. Total electricity demand for 2020 is anticipated to be down 2% from last year, with a rebound expected in 2021.

Weekly y-o-y demand change in India, January to November 2020, weather corrected



Note: Dashed line represents period of deepened lockdown.

Source: IEA based on POSOCO (2020).

Cross-border imports in financial year 2019/20 were 7 TWh from Bhutan. Total losses on the transmission and distribution networks in India, including non-technical losses, fell from their 2001 high of 33% to 21% in 2018, which is still significantly higher than other emerging economies such as Brazil at 16% or China at 7%, or the world average of 8.5%.

India's power system is undergoing a transformation towards cleaner electricity, driven by a national-level renewables target of 175 GW by 2022 and a national renewables ambition of 450 GW by 2030. However, as of 2020 conventional generation still dominates India's capacity mix, with coal and lignite making up 205 GW (55%) and gas representing 25 GW (7%) of 373 GW total capacity. There is an embedded capacity surplus of around 10% on the basis of the 2020 annual peak demand of 177 GW (as of September 2020) and considering non-firm capacity, losses and outages (60-90 GW). Renewables (including small hydro, biomass, waste, solar PV and wind) represent the second-largest source at over 88 GW (24%) followed by large hydro at over 45 GW (12%). There are numerous new coal-fired power plants planned in the short term, while a few states, such as Gujarat, have committed to no new coal power plants beyond 2021.

In 2020, around 70% of India's electricity is set to be generated by coal-fired power plants, while renewables including hydro are also playing a significant role (23%). 2020 also sees a 4% fall in conventional generation relative to 2019, mainly driven by a decline in coal-fired generation. Gas-fired generation increases by 10%, fuelled by a sharp rise in spot LNG imports and prices below USD 3 per MBtu, while gas plant capacity factors remain low. As demand fell earlier in 2020, renewable energy generation continued because of its "must-run" status and played a larger role in the electricity mix. The daily share of national generation from renewables combined (excluding large hydro) went up to 12% on 31 March, one of the highest levels of recent years. Meanwhile conventional supply including coal declined, in line with the drop in overall industrial demand.

Between 2016 and 2019 solar PV and wind generation increased from 4% to 12% of annual electricity generation. At state level the picture is very diverse. Andhra Pradesh, Gujarat, Karnataka, Rajasthan, Tamil Nadu and Telangana have a higher share of solar and wind, reaching 25%, and are already facing significant system integration challenges. These include solar and wind curtailment in Karnataka and Tamil Nadu, restrictions on coal generation and congestion on medium- and high-voltage transmission lines during periods of high solar and wind generation across all states. On an hourly basis solar and wind have reached levels of 60-70% of generation in both Karnataka and Tamil Nadu.

End-user industrial electricity prices in India at USD 99/MWh are significantly higher than residential prices at USD 69/MWh on a nominal basis. This is due to significant government support to vulnerable household and agricultural users through cross-subsidisation from industry. High industrial prices drive large numbers of industrial users in India to seek the benefit of open-access contracts, with prices that are on average 20% to 30% lower than utility prices. Electricity affordability is still a significant issue in India in 2020, again highlighted by Covid-19. Residential prices based on purchasing power parity are very high in international comparison, despite being subsidised and significantly lower than industrial prices.

The Indian wholesale power market is the most significant in South Asia and the ASEAN region. India has had competitive power markets since 2008, although only a fairly small share of all electricity is traded through power exchanges. Over 95% of the electricity that was traded in 2019 was sold on the India Energy Exchange (IEX), and the remainder on Power Exchange India Limited (PXIL).

Covid-19 and the related fall in demand had a significant impact on the electricity wholesale trade. Firstly, wholesale prices in 2020 have been approximately 20-29% lower than the previous year at INR 2.5/kWh on average (in the range of INR 2-4/kWh) in the day-ahead market between March and September. Secondly, the traded volume has increased compared to the previous year; this increase stood at around 44% in September 2020 for all market segments. The increase in volume has been driven by multiple factors: utilities prefer short-term trade as opposed to business-as-usual three to nine month contracts in light of unforeseeable demand patterns; additionally, utilities offer their surplus volumes due to lower electricity demand for sale on the market; and finally, driven by lower prices, some utilities have replaced their contracted generation with cheaper market purchases.

In 2020 the power market has reached two historical milestones:

- June 2020 saw the launch of the real-time power market in India, filling an important gap by providing real-time corrections (an hour ahead) for intermittent and variable generation such as solar and wind. The market has already seen significant trading volume and a large number of participants just a few months after market launch. The price volatility of the real-time market has been greater than that of the day-ahead market, but on average prices are typically lower, at INR 2.36/kWh on average, and prices show a trend towards convergence with the day-ahead market.
- August 2020 marked the launch of the "Green Market" on the IEX, where green electricity is traded at a premium (compared to the regular day-ahead market) at INR 3.4/kWh (within the range of INR 3-3.8/kWh) for clients looking to fulfil their Renewables Purchase Obligations through market purchases.

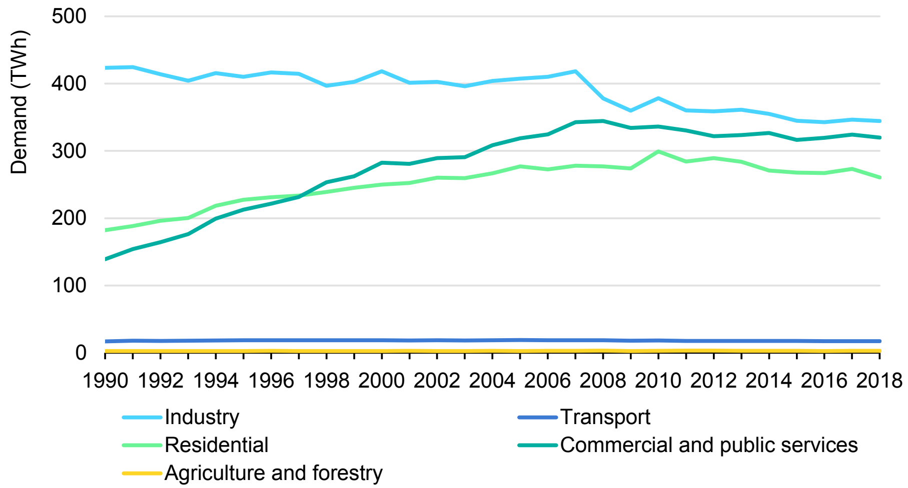
Japan

Overall electricity consumption in Japan has been declining over the past decade despite electrification in the residential, commercial and services sectors. Since the accident at the Fukushima Daiichi nuclear power station following the Great Japan Earthquake of 2011 and the rolling outages following it, all sectors have accelerated their energy conservation activities. These included measures such as higher set temperatures for air conditioning, reduced lighting and use of LED bulbs, as well as increased focus on energy efficiency. A relatively larger decrease in 2019 can be attributed to a mild winter and summer, resulting in reduced heating and cooling demand respectively, compared with 2018.

Y-o-y change in annual demand in Japan, 2014-2019

2014	2015	2016	2017	2018	2019
-1.6%	-2.5%	0.0%	1.6%	-2.0%	-5.5%

Annual demand by sector in Japan, 1990-2018



The further effects of the Covid-19 pandemic on power demand in Japan have been limited. A state of emergency was declared by the government on 7 April 2020 and continued until 25 May. This state of emergency entailed a request from the government to refrain from activities that involve human contact, applying first to large cities and then expanded nationwide. There were no mandatory transport restrictions or closure of businesses.

A relatively sharp decrease in demand was seen during this period, with an almost 10% year-on-year decrease in the month of May, followed by gradual recovery in the following months. The industrial sector saw a larger decrease; however, this was partially offset by an increase in residential demand due to increased working from home and reduced travel and leisure activities outside the home. Summer cooling demand increased the demand for electricity in August, September and October.

Later in the year, ongoing Covid-19 preventative measures may have actually increased electricity consumption, due to recommendations to use air ventilation and air conditioning indoors. Teleworking and use of water for handwashing and home cooking may also have affected power demand.

The overall generation mix in Japan is dominated by gas and coal with an increasing role for renewables. A sharp reduction in nuclear generation is expected in 2020, down 23% year-on-year. This is driven by the shutdown of some reactors that require work to meet new anti-terrorism safety measures coming into effect this year, such as Kyushu Electric's Sendai 1 and 2 reactors, which ceased operations on 16 March and 20 May

respectively. Sendai 1 is expected to resume operations on 26 November this year, while Sendai 2 is scheduled to return to operations one month later.

Due to reduced overall demand, and despite a small decline in total coal-fired generation of around 3%, coal is set to retain a constant share of the generation mix in 2020 (around 32%). The share of gas is expected to fall to around 32% (down almost two percentage points), with a relative decline of around 9%. Only renewables generation has seen an absolute increase, over 9% in 2020 relative to last year, bringing it to a share of around 21% of the mix. This is due largely to ongoing deployment and the government targeting 22-24% of energy from renewables by 2030. In addition, in October of 2020 in his speech at the Diet, Japan's Prime Minister Suga announced Japan's ambition to achieve net-zero emissions by 2050.

Korea

While electricity demand in Korea did not go through the same drastic decline as others thanks to its relatively successful management of the pandemic, the industry-heavy economy is set to contract by 1.9% in 2020 and with it electricity demand is on track to decline by an even greater amount, over 3%.

Coal-fired generation in 2020 is expected to see the largest year-on-year decline among fuels at 10%, with its share of the generation mix falling from 40% last year to 38% this year. This is both due to the economic fallout of the global pandemic and the government's mandated shutdown of 28 coal-fired power plants during March. The shutdown order is part of the government's continued push for green policies since taking office. This September, President Moon Jae-in announced a plan to shut down 30 additional coal power plants by 2034, in line with the country's ambition to cut greenhouse gas emissions and promote eco-friendly energy sources.

Nuclear power generation has held up relatively well, with a more than 4% year-on-year increase expected and its share rising from 25% to 27% in 2020. Despite a strong domestic backlash against new additions to the nuclear power fleet, long-planned nuclear generation capacity (5.6 GW) is already under construction and likely to be completed in the next couple of years. Natural gas also played a large role in power generation, replacing much coal-fired power in the winter period and on track to increase its share slightly to 27% this year (up one percentage point).

Renewables also increase their share, to around 6% from 5% last year. According to the government's 9th Basic Plan for Electricity Supply and Demand, released in May, a large amount of both natural gas and renewable generation capacity is set to be added up to 2034, with a target to increase renewables to 40% of the generation mix by 2034.

In late September the government finalised the rules for Phase 3 of the Korean Emissions Trading Scheme, which runs from 2021 to 2025. The scheme began in January 2015 with three phases of trading (Phase 1: 2015-17; Phase 2: 2018-20; and Phase 3: 2021-25), with the aim of reducing greenhouse gas emissions. According to the latest rules, the total allowance for the third phase rises to 609.7 $MtCO_2$-eq/yr from 509.2 $MtCO_2$-eq/yr in Phase 2, partly due to the addition of the transport and construction sectors. For the power sector, allowances have been increased from 37% to 39%, equivalent to 235 $MtCO_2$-eq/yr in 2021-23 and 217 $MtCO_2$-eq/yr in 2024-25. In Phase 3, 90% will be allocated for free, down from 97% in Phase 2.

Changes in power sector allocations – in addition to low gas prices in the spot market this year – are likely to further narrow the gap in fuel costs between coal and gas in the medium term, in favour of gas. This new scheme is in line with the government's green agenda. In October President Moon Jae-in announced that the country will commit to achieving carbon neutrality by 2050, putting an emphasis on reducing reliance on coal-fired power generation. The government is likely to announce new electricity policies in the 9th long-term power plan (to be released late this year), providing greater incentives for coal-to-gas switching in the country's power mix.

Australia

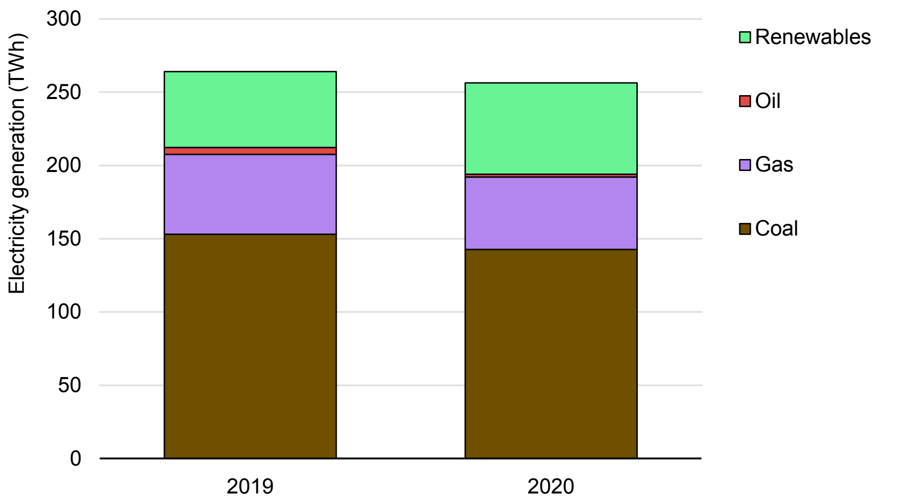
Electricity demand has been relatively flat in Australia for the past decade despite economic and population growth, with 2018 and 2019 seeing small year-on-year increases of 1.1% and 1.6% respectively.

With the first case of Covid-19 in Australia identified in late January and initial cases of community transmission in early March, nationwide lockdown measures were introduced from mid-March with Australian borders closed to all non-residents from 20 March. Nationwide restrictions within Australia were eased from early May on, although a second outbreak in Victoria resulted in new containment measures in that state from early July, which were further tightened in August, and only began to be gradually eased from mid-September.

Despite the significant economic impact of Covid-19 restrictions, the effect on electricity demand in Australia was relatively minor, with a substantial decline in commercial demand largely compensated by an increase in residential demand. For the National Electricity Market, which makes up around 80% of all Australian electricity demand, first quarter demand was down by around 4% on the same quarter in 2019. However, the Australian Energy Market Operator assessed this to be largely due to reduced daytime cooling requirements, with no substantial impact from lockdown measures introduced late in the quarter. Second quarter demand, by contrast, was the most affected, with a 2% fall in demand relative to the same quarter in 2019. The market operator considers this as arising from Covid-19 containment measures, with other factors such as weather causing a very slight mitigation of the decline. In the third quarter Covid-19 effects on demand were mainly confined to Victoria due to its second lockdown. All-Australia electricity demand for 2020 is expected to see a decline of between 3 and 4% year-on-year.

Generation capacity in Australia is still dominated by fossil fuels and particularly coal, although with increasing renewables in the mix – driven by federal renewables targets as well as state-level policies. As Australia has now met the federal-level Large-scale Renewable Energy Target, utility-scale deployment is expected to decline while distributed solar continues to be driven by the small-scale target and state-level feed-in tariff schemes.

Projected annual generation by technology in Australia, 2019 and 2020



Following this continued deployment, the share of total renewables including hydropower in 2020 is set to rise to 24%, up from 19% last year. Coal continues its ongoing decline, falling by around two percentage points to around 56% of total generation. Due to the very low fuel cost of brown coal-fired power stations in Australia, the increasing renewables share has mainly affected black coal-fired generation, although the closure of the Hazelwood power station in 2017 resulted in a drop in brown coal's share. Brown coal-fired generation for 2020 is set to increase slightly relative to last year, likely due to recovery from extended outages at Loy Yang station during 2019.

The issue of electricity system reliability and security has received considerable attention in Australia in recent years, triggered by a series of events including the Basslink interconnector failure in 2015, a state-wide blackout in South Australia on 28 September 2016, and severe heatwaves provoking load-shedding events in February 2017 in several states and again in Victoria in 2019.

In 2017 the Council of Australian Governments requested an extensive review into how to ensure reliability and security of the power system during the energy system transformation. The proposals were accepted by the council in July 2017, contributing to a process of ongoing reform including a strengthened risk management framework and fine-tuning of the energy market design.

In the context of an increasing share of renewables, the market operator is currently undertaking a multi-year plan to maintain system security in a future market with a high share of renewable resources, starting with a Renewables Integration Study released earlier this year. Market reforms are also being undertaken to increase the contribution of flexible resources such as demand response and batteries. For example, in July 2020 the Australian Energy Market Commission announced that five-minute settlement windows for spot prices in the National Electricity Market are to be implemented from 21 October 2021, which is expected to increase opportunities for battery storage.

Regional focus: Southeast Asia

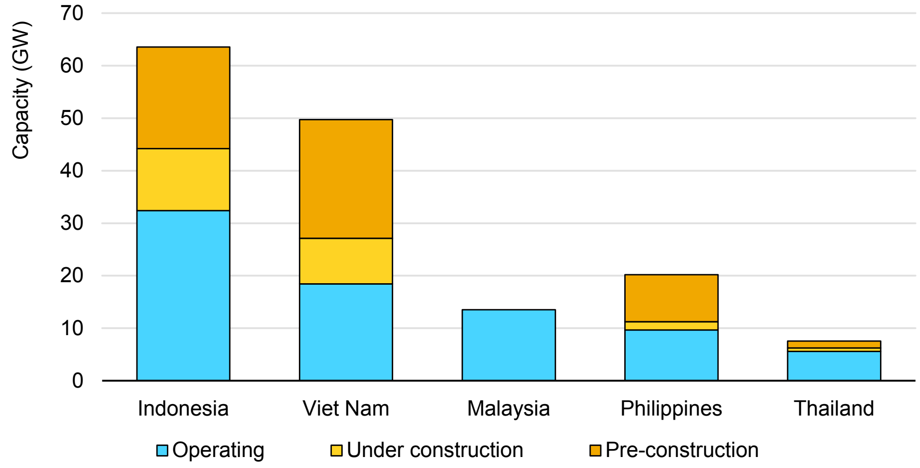
Developments in Southeast Asia

Southeast Asia is, in terms of electricity demand, one of the fastest-growing regions in the world. Driven by the growing ownership of household appliances and air conditioners, as well as increasing consumption of goods and services, demand has grown by more than 6% annually over the past 20 years on average. Of the region's ten countries, the four largest by electricity consumption, Indonesia (26%), Viet Nam (22%), Thailand (19%) and Malaysia (15%), make up more than 80% of total demand in the region.

The economic impact of the Covid-19 pandemic in the ASEAN countries is visible in reduced electricity demand, which is expected to drop by around 1% this year. For the full year, Indonesia's demand is expected to stagnate, after a reduction of almost 11% in May. Viet Nam's demand in the first ten months of the year is reported to be 3.2% above the same period of 2019 – after around 10% average growth in the past ten years. Compared to the respective periods in 2019, Thailand's demand dropped by 3.7% in the first eight months, while Malaysia's was down by 5% in the first ten months.

Southeast Asia is one of the few regions of the world where coal-fired generation has been expanding, with close to 20 GW of new coal-fired generating capacity under construction, mostly in Indonesia (a major coal producer), Viet Nam and the Philippines. Significantly more capacity is at the pre-construction stage, but some plans are being reconsidered and greater emphasis is being placed on natural gas as well as the expansion of renewables. One example of this is the Philippines, which at the IEA System Integration of Renewables Ministerial Conference, held on 27 October 2020, announced a moratorium on new coal-fired power generation.

Capacity of coal-fired power plants in Southeast Asia in 2019

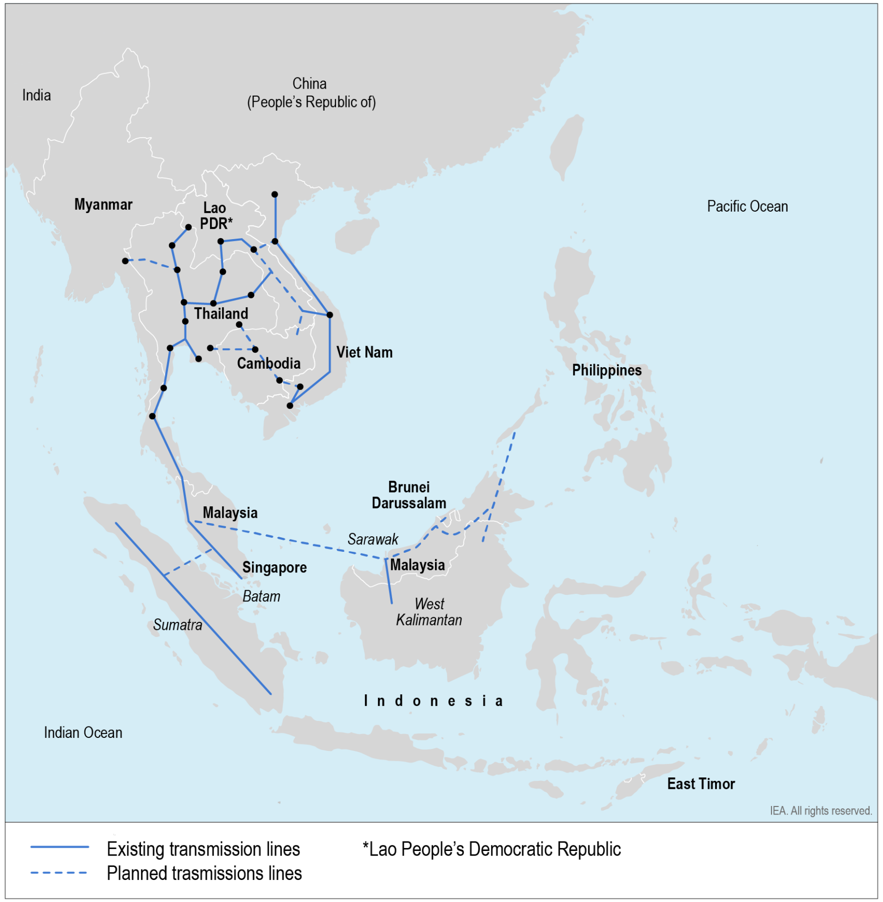


The ASEAN community has put forward an ambitious project of regional development in order to support economic growth and the integration of higher shares of renewable energy. ASEAN as a region has a target of integrating 23% renewable energy by 2025. One of the ways of reaching that target is regional interconnection and trade.

A major project for regional integration is the ASEAN Power Grid – an initiative to connect the region, initially on cross-border bilateral terms, then gradually expanding to the sub-regional level and finally to a totally integrated Southeast Asia power grid system.

Studies are being undertaken to identify what interconnection projects are beneficial for the region. One such study is the ASEAN Interconnection Masterplan Study, currently being carried out as Version III. The study evaluates outline interconnection projects that will facilitate the ASEAN Power Grid.

The ASEAN Power Grid



Note: Lao PDR = Lao People's Democratic Republic.
Source: IEA (2019), Establishing multilateral power trade in ASEAN.

In order to optimise the use of the physical infrastructure, work is also being undertaken to develop the institutions of ASEAN. ASEAN has a project to develop multilateral power trade, which was supported by the 2019 IEA study Establishing Multilateral Power Trade in ASEAN, recommending clear actions to establish cross-border power trade in the region. Several institutions are involved in the project, including the Heads of ASEAN Power Utilities/Authorities and the ASEAN Energy Regulatory Network.

The Lao PDR-Thailand-Malaysia power integration project is one example of cross-border power trade in the region. The project has enabled 100 MW of power transfer from Lao PDR via Thailand to Malaysia. Work is already underway to extend the framework to include Singapore.

Indonesia

Due to the effects of the Covid-19 pandemic on the economy, Indonesia's electricity demand is expected to stagnate in 2020 compared to 2019. This constitutes a significant reduction compared to the average annual growth rate of around 6% in the previous five years.

Indonesia is expected to become the fourth-largest economy in the world by 2040. Coal dominates the Indonesian power mix, supplying around 60% of its electricity in 2019, with natural gas and oil together accounting for around a quarter of the supply, with the remainder from renewables, mostly hydro and geothermal.

Current government policy aims to increase the role of renewables in the power mix, increasing their share of primary energy supply from 9.15% in 2019 to 23% in 2025 and 31% in 2050. A new presidential decree is expected that will introduce a feed-in tariff for projects smaller than 10 MW, while projects larger than 10 MW will be awarded via auctions. The legislation is intended to incentivise more renewable investment from both domestic and foreign investors in order for Indonesia to achieve its renewables targets. The state-owned utility PLN plans to increase its renewables capacity from around 8 GW in February 2020 to around 24 GW in 2028. In addition to PLN's renewable capacity, independent power producers are also able to invest in renewable generation. At a national level 10.7 GW of renewable energy is currently installed. Hydro and geothermal make up 57% and 21% of this generation capacity, followed by biofuels (18%) and solar PV (3%).

One innovative new development is the 145 MW Cirata floating solar PV project. It is a hybrid of floating solar PV and hydropower. The solar panels will be installed on a reservoir of the Cirata hydroelectric power plant, and smart controllers are due to be installed so that the hydro plant can help balance the intermittency of generation from the PV cells, which is especially variable in the rainy season. Being the largest solar PV project to be constructed to date, the project represents a milestone for Indonesia, taking advantage of innovative solutions and hybrid technology to ensure secure and affordable integration of variable renewable energy.

As an archipelago, Indonesia has not yet achieved 100% electrification, which is mainly due to the difficulty in electrifying remote islands. Those electrified to date rely on diesel generation units, although the utility PLN is implementing a plan to convert 152 of these units to use natural gas.

For the smaller systems, micro grids and small-scale renewable energy may be relevant, since it may not be economical to interconnect these regions to the rest of Indonesia.

Singapore

As a land-constrained country, Singapore has to be innovative and creative to make the most of its limited space for electricity generation. With this in mind, Singapore has announced a target of 1.5 GW of solar by 2025 and 2 GW solar by 2030. The solar target is expected to be met by both rooftop and utility-scale floating solar.

To balance the variable production of the solar capacity, Singapore has a target to increase its energy storage. By 2025 Singapore aims to have 200 MW of storage, which in combination with advanced forecasting will help balance the system.

Singapore is involved in developing multilateral power trade. It is engaged both in ASEAN's regional work and in the ambition to expand the Lao PDR-Thailand-Malaysia power integration project to include Singapore. Singapore is connected to Malaysia via two 230 kV AC lines, which allow the transfer of power from Malaysia to Singapore.

In its power sector strategy, Singapore relies on the so-called four switches – solar, regional integration, low-carbon alternatives and natural gas. As for low-carbon alternatives, Singapore is studying emerging technologies to further reduce carbon emissions such as hydrogen and CCUS. Natural gas is the main source of fuel for generating electricity. As such, one focus is on fuel security by ensuring import facilities through Malaysia and LNG terminals.

Peak demand in 2020 was affected by the Covid-19 pandemic, with May in particular seeing lower peak demand. Singapore saw peak demand in May 2019 of 7 404 MW, around 10% higher than during the same period in 2020. June and July 2020 also saw lower peak demand than the year before, while peak demand recovered in August, at 7 376 MW being slightly higher than in August 2019 (7 358 MW).

Generation in Singapore is almost entirely fuelled by natural gas: in 2019 almost 96% of its electricity was generated in this way. In the fourth quarter of 2019 total solar PV capacity was 353 MW, increasing to 388 MW in Q2 2020. The majority of the capacity comes from utility-scale solar PV, with residential PV making up just 13.5 MW of the total installed capacity.

Thailand

In January Thailand was the second country in the world to confirm a Covid-19 case. The government's response to an increasing number of cases, considered a success by the WHO, included a wide-ranging lockdown declared on 21 March and followed by a night-time curfew from early April to mid-June. The measures taken were reflected in falling electricity demand. A 2.9% year-on-year reduction in March (after more than 3% growth in January and February) was followed by between 7% and 10% lower demand from April to June compared to the same months in 2019 (demand was additionally dampened by large storms in June). In July and August demand started to recover, but was still around 3% lower in August compared to the previous year.

Thailand's power sector has been heavily reliant on gas-fired generation in recent decades, accounting for around 70% of the total in the early 2000s. In the past few years the generation mix has become more diversified, with the share of gas-fired generation falling to close to 60% in 2019, followed by coal at around 20%. The share of clean energy in Thailand has been increasing for the past few years, from around 12% in 2017 to almost 20% in 2019, consisting of hydropower, biomass, wind and solar PV. Electricity generation has continued to grow by about 2% annually over the past few years.

Thailand's total installed generation capacity was 47 GW in 2019, with 30 GW from gas-fired power plants, 6 GW from coal and 11 GW from renewables (including 4 GW of hydropower capacity built in neighbouring countries specifically to export their power to Thailand). Peak electricity demand in 2019 was around 30 GW. CO_2 emissions from the power sector have plateaued since 2013, due to the increasing share of clean energy resources.

With the global trend towards energy transition and renewable energy, Thailand has a broad set of policies to cost-effectively accelerate the uptake of cleaner energy This includes renewable energy as well as LNG as part of Thailand's Energy Master Plan. Under this plan sit the Power Development Plan, the Alternative Energy Development Plan, the Energy Efficiency Plan, and Oil and Gas plans. Recent versions of these plans were endorsed by the Cabinet in October 2020.

The latest Power Development Plan (PDP 2018 Rev.1) aims to provide a transition roadmap for the power sector with three key principles: energy security, economic sustainability and environmental sustainability. The renewable energy target for electricity (excluding imported hydro) is set at 29% of total generation by 2037, with an additional 6% energy efficiency target. In terms of capacity, renewables are expected to reach 29 GW, which accounts for around 35% of total capacity in 2037. The transition in the power sector is supported by policy development that covers digitalisation, decarbonisation, decentralisation, deregulation and electrification.

Grid modernisation is a prominent part of the latest Power Development Plan to improve the reliability, resilience and flexibility of the power system in response to the rapid uptake of emerging technologies, particularly VRE. As recommended in the Thailand Renewable Grid Integration Assessment conducted by the IEA in 2018, a number of flexibility options could be implemented to enable the cost-effective and reliable integration of VRE. This has subsequently led to the launch of power plant flexibility pilot projects in Thailand by the national electric utility. There are also other pilot projects to provide system flexibility, including a 45 MW hybrid hydro floating solar PV and utility-scale battery energy storage system.

With the lower than expected demand growth in recent years (less than 3% annual growth), Thailand’s power sector is facing the issue of generation overcapacity and a high reserve margin, which has been in the range of 40%. This situation is expected to become more prominent in the coming years due to the impact of Covid-19. A number of options are being considered, including retirements of ageing power plants with relatively low efficiency and delaying investments in large-scale fossil fuel power plants to allow for an effective utilisation of existing power plants in the system.

Covid-19 has reduced overall electricity demand in Thailand since March 2020 compared to the same period last year, as a result of lower economic activity in the commercial and industrial sectors and despite increases in residential demand. The impact is expected to continue in the medium to long term. As a result stimulus and recovery measures have been put in place to counter the shocks to the economy and to support the growth of renewable energy. One of the priorities is implementation of the “energy for all” policy, which promotes community-based power plants using local infrastructure and renewable energy resources, particularly biofuels in rural areas. This policy aims to boost the economic benefits and create jobs in local communities, as well as raise the value added of agricultural products.

Regional focus: Africa

Africa regional overview

Although accounting for 17% of the global population, only 2.5% of recorded global deaths resulting from Covid-19 were recorded in Africa by the end of October 2020. This is attributed at least partly to the young median age of the population in many African countries.

Despite relatively low case fatality rates related to Covid-19, Africa experienced a significant economic impact of the pandemic – with only 15% of Africa's trade occurring within the continent (36% of annual trade volume is with Europe, 14% is with China and 6% is with the United States) and 8.5% of Africa's GDP stemming from tourism, the economy is closely connected to global markets.

GDP in sub-Saharan Africa is expected to contract by 3% in 2020 and return to 2019 levels in 2021. South Africa, the second-largest economy by GDP on the continent, is particularly affected by the economic slowdown, and is forecast to decline by 7.8% in 2020 and to see only a mild rebound of 3.1% in 2021.

The impact of an economic downturn on the general population and utilities has also reversed some of the progress that had been made on electrification in Africa. Recent analysis from the World Energy Outlook 2020 estimates that 6% of the population of sub-Saharan Africa who already have electricity access will lose the ability to afford basic electricity services during 2020, with those in Nigeria, the Democratic Republic of the Congo and Niger amongst the hardest hit. Meanwhile, the economic impact on entities that have been working to improve electrification means they are also facing serious financial difficulty, further stifling progress.

The impact on demand was significant, driven by the contraction of the economy and measures to contain the pandemic. South Africa, for example, experienced a 23% year-on-year drop in electricity demand in April, and lower, but still significant, reductions in May (14%) and June (5%). Overall, South Africa's electricity demand is expected to decline by more than 5% in 2020 compared to the previous year. For the whole continent, a demand reduction of around 2% is expected.

The African electricity sector is characterised by its large geography, limited interconnection and trade, improving electrification and prevailing system adequacy issues. In the most recent World Bank Doing Business 2020, customers in 10 of the 24 African participants (42%) experienced on average at least 24 hours of outages over the period May 2018–May 2019, while 19 (79%) experienced at least 2 hours of outages. In comparison, only 5% of European countries had customers experiencing at least 24 hours of outages, while Asia reported 13%.

While some unbundling of utilities has occurred in Africa over recent decades, the majority of countries have vertically integrated utilities with little or no private participation. This limits the development of the grid and generation to public funds from either governments themselves or development finance institutions and export credit agencies. Of the 54 countries in Africa, only ten have unbundled utilities with either an independent transmission system operator or a legally unbundled transmission system. A majority of countries (29 out of 54), however, allow private-sector participation to varying degrees. This includes IEA association members South Africa and Morocco.

While electricity trade between countries is relatively small due to poor interconnection, a number of regional power pools exist to encourage regional co-operation through the development of projects of regional importance.

The five regional power pools have a wide variation in their range of maturity and activity. Regional pool plans that have been developed and adopted by the East African Power Pool, Southern African Power Pool and West African Power Pool. Although these should be regularly updated to reflect changing assumptions in, inter alia, technology costs, fuel cost, demand growth and policy changes, only the latter two have updated their plans in the last five years. Pool plans play an important role by helping to mobilise funds for the building of projects of regional importance, including interconnectors and multinational hydropower projects. This is important as the level of investment that is needed for Africa to achieve its Sustainable Development Goals for electricity access and clean energy (as per the IEA Sustainable Development Scenario) would require annual investment in the power sector to more than double up to 2040.

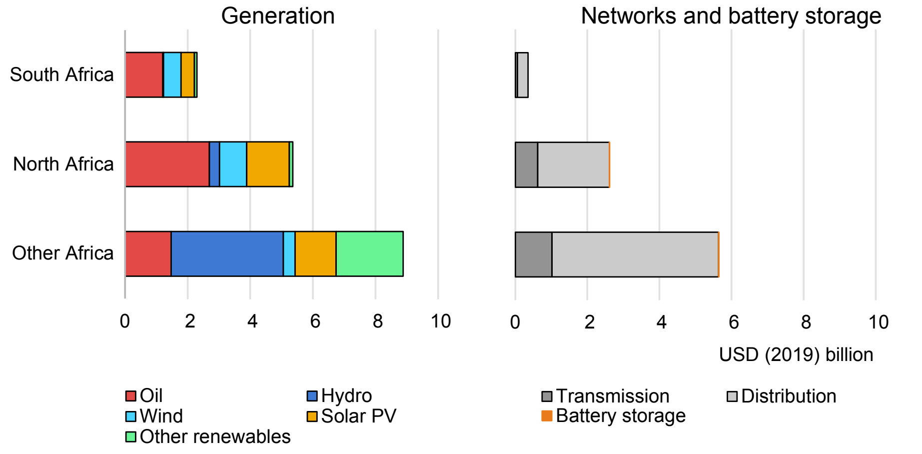
Several regional projects made progress during 2020. For example, a contract was awarded for the construction of the 18 MW Gourbassi hydropower project on the Senegal-Mali border, which will be the fifth hydropower project under the Organisation pour la Mise en Valeur du Fleuve Sénégal, otherwise known as the Senegal River Basin Development Authority. The Grand Renaissance Ethiopia Dam also passed a significant milestone in its development, as it saw its first filling following the completion of the lower section of the dam. The first two turbines of the 6 GW hydropower plant are expected to be commissioned towards the end of 2021. The project is a major driver for regional interconnection in the East African Power Pool, with the construction of a 2 000 MW, 1 055 km bipolar HVDC interconnector between Ethiopia and Kenya expected to be completed in early 2021.

Meanwhile, in southern Africa a tender was launched in February 2020 for the construction of an interconnector between Mozambique and Malawi, which would connect Southern African Power Pool member Malawi to the rest of the power pool for the first time.

According to the IEA report World Energy Investment 2020, investment in Africa in 2020 was dominated by renewables. This coincided with announcements on financing and signed contracts for a number of wind, solar, hydro and geothermal projects across the continent. For example, a renewable auction programme for 120 MW of wind and solar projects was launched in Mozambique, while a tender for up to 80 MW of solar PV projects was launched in Togo. Tunisia also awarded a 100 MW project and launched a tender for another 70 MW as a continuation of the international tender it launched in 2018, which has already awarded 500 MW of solar projects. Additionally, several solar PV and wind plants were commissioned in South Africa, where a number of projects from the last bid window of its renewable auction programme in 2015 have come online following the resolution of an impasse between developers and state-owned utility Eskom in 2018.

In addition to generation capacity, utilities in South Africa, Morocco and Senegal have been actively pursuing storage projects to increase the flexibility of their systems, with these entering different phases of development. Senelec, the state-owned utility in Senegal, started feasibility studies for a potential battery storage project at the 159 MW Parc Eolien Taiba N'Diaye wind plant which, when commissioned by the end of 2020, will be the largest wind plant in West Africa. The plant, which will increase the installed capacity in Senegal by 15%, demonstrates the growing need for flexibility in Africa's power systems, which are both growing and transitioning to cleaner power systems.

Investment in generation capacity in Africa in 2020



Source: IEA (2020), World Energy Investment 2020, October update.

South Africa

While load shedding is something that is endured throughout the continent due to capacity shortages, persistent drought and a lack of investment, this has not always been the case in South Africa.

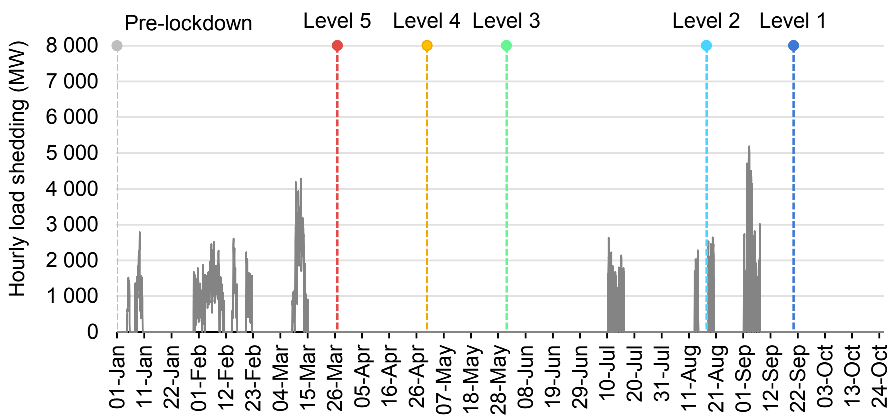
However, after almost 15 years without investment in new capacity and the declining availability of an ageing coal fleet, power shortages first surfaced in 2007 and 2008. At this time, the government was able to act swiftly to increase generation availability and Eskom, the state-owned vertically integrated utility, started construction of two new coal-fired power plants, each 4 800 MW in capacity. Fast forward to 2014, and the current era of load shedding in South Africa began due to the continual decline of the availability of its coal fleet, coupled with continuous delays to its 9 600 MW of coal-fired generation under construction. As a result, a staged approach to load shedding was developed by Eskom in a way that it could address capacity shortages in a fair manner by rotating across all of its customers according to a predefined schedule. The load-shedding schedules comprise eight stages (Stages 1-8), whereby each stage provides for an expected reduction in demand of 1 000 MW. This persisted across 2014 and 2015, before a two-year lull in 2016 and 2017.

However, in 2018 the current electricity crisis in South Africa was demonstrated again via load shedding and has been worsening ever since, culminating in 2019 when load shedding reached Stage 6 (or a capacity shortage of 6 000 MW) for the first time in December of that year. Prior to this, the worst load shedding that had been experienced was Stage 4, or a shortage of 4 000 MW.

At the beginning of 2020 a similar trend continued until demand greatly reduced in late March due to a lockdown to contain Covid-19. The lockdown, one of the hardest in the world, where freedom to travel and non-essential services were severely limited, began on the 27 March 2020 and was gradually relaxed from 1 May in a staged approach. During the initial lockdown, the deviation of net demand from original forecasts was in excess of 11 000 MW, and on average almost 6 000 MW during weekdays.

While the lockdown-induced suppression of demand in South Africa has gradually subsided as the various restrictions have been lifted, the underlying problems of capacity and energy shortage remain. This was revealed when, from July 2020 onwards, intermittent load shedding periods resumed following the relaxation of lockdown restrictions to Level 3, which allowed the resumption of most economic activity.

Load shedding in South Africa, January to October 2020



Note: Lockdown in South Africa was imposed under different sequential levels. Level 5 was the strictest, with only essential services allowed and very restricted movement. Under Level 3 most economic activity was allowed to resume.

Source: ESKOM (2020), Data Portal.

As of 25 October 2020, 1 240 GWh of load shedding had already occurred in 2020, despite the relief over the period of hardest lockdown. This included 837 hours of load shedding, which is already higher than the 530 hours that occurred in 2019, with estimates[1] suggesting that the volume of load shedding for the year has already surpassed that of 2019.

While South Africa has allowed private-sector participation in the electricity industry since 2004 when a single-buyer model was introduced, Eskom has remained a vertically integrated utility. This has opened the way for investment from the private sector, notably the 4.1 GW of connected renewable projects procured through auctions under the Renewable Energy Independent Power Producer Procurement Programme (REIPPP), including 2.1 GW and 1.5 GW of wind and solar PV respectively. However, following an impasse between developers and Eskom, where the state utility and designated single buyer refused to sign power purchase agreements with the selected bidders, combined with a prolonged conclusion to the now-adopted Integrated Resource Plan 2019, no subsequent renewable auction has followed as yet.

South Africa is now actively trying to address its capacity constraints since the most recent electricity crisis and adoption of the Integrated Resource Plan 2019, which led to ministerial determinations for the procurement of around 11.8 GW of new generation capacity. In addition, the government of South Africa released the Economic Reconstruction and Recovery Plan in October 2020, which details the steps to rebuild the economy post-Covid-19, with energy security one of the key components highlighted in the plan.

The plan outlines many ongoing activities in the electricity sector as part of the recovery. This includes the launch of an auction in August 2020 which aims to procure 2 000 MW of firm capacity in the short term to address current capacity shortages. However, these will only begin to have an impact from 2022 onwards. The recovery plan also highlights the push to enable self-generation, where South Africa relaxed regulations in March 2020 that will allow embedded generation with less than 1 MW capacity, such as rooftop PV, to be connected to the grid without obtaining a licence from the regulator.

Meanwhile, the latest bid window (Bid Window 5) of the REIPPP is also expected to be launched before the end of January 2021, which would see the resumption of the programme and lead to the procurement of up to an additional 6 800 MW of renewables in the form of wind and solar PV. In addition, Eskom have launched a tender for an 80 MW/320 MWh battery storage project at a range of locations across the country, which will form part of the first phase of Eskom's 800 MWh battery storage programme.

The South African government also published its own roadmap for unbundling of the state-owned utility in 2019 in an effort to offer more transparency in the governance of the utility, while improving operations and cutting wasteful expenditure, amongst other proposed benefits. The Department of Public Enterprises proposed a deadline to achieve unbundling at the end of 2021 to which Eskom has committed itself, although the CEO of Eskom did indicate that full legal unbundling may only be achieved in 2023 considering the broad stakeholder consultation required.

[1] Estimates are based on publicly released load-shedding schedules; however, exact data were only available for the period from 1 April 2019.

Morocco

As with South Africa and other parts of Africa, the effect of Covid-19 and subsequent lockdowns was equally felt in Morocco. In Morocco peak demand decreased by 12% at the height of lockdown measures in April, while year-on-year demand decreased by between 6.6% and 8.6% across the period from April to July.

Morocco, which has a partially unbundled electricity sector, has steadily allowed an increasing amount of private participation through series of reforms introduced since the mid-1990s. This has seen the concentration of generation in state-owned utility ONEE decrease to approximately 30%, with the remaining coming from imports and independent power providers, who achieved a majority share of 50.8% of generation in 2019. This has also allowed the private sector to make necessary investments in generation capacity, leading to a steady reserve margin in the range of 20-30% over the last 15 years.

At the same time, investment in new generation has involved a wide range of technologies, including gas, hydro, wind and solar PV, which has allowed for the diversification of its generation mix away from oil and coal, while building up a cleaner portfolio of generation.

The procurement of renewables is handled by the Moroccan Agency for Sustainable Energy, which has overseen growth in renewable generation to almost 20% in 2018, up from only 6% in 2008. This will only increase over the next few years, as Morocco looks to expand the share of generation from renewables to 52% by 2030, with new projects using solar PV, wind, hydro and concentrated solar power.

Recent capacity additions to the Morocco generation mix include 22 MW of thermal capacity from 2019, while over the course of 2020 and 2021, over 2 GW of further renewables (603 GW of wind, 1 315 MW of solar and 100 MW of hydro) is expected to be installed.

This shift towards renewables has continued in 2020, with Morocco launching a call for tenders for another 400 MW of solar PV generation as part of Phase I of the Noor PV II Multi-Site Solar Programme, which aims to procure 3 000 MW of renewable generation over the next 10 years. This in addition to the 825 MW first phase of the Noor I Midelt hybrid park (525 MW of solar PV and 300 MW of concentrated solar with 5 hours of storage), which had a successful tender in July. Meanwhile, Morocco also launched a tender for the extension of Koudia Al Baida Park wind farm from 50 MW to 120 MW in April 2019, and is set increase its wind capacity even further with the 850 MW Integrated Wind Energy Project.

With the increase in wind and solar PV on the Moroccan system, ONEE is actively seeking new flexibility options in its system in the form of flexible power plants, storage and strengthened interconnection. By 2030 it aims to install a 450 MW CCGT plant and 950 MW of pumped storage hydro. Towards the latter target, Morocco released a call for tenders for detailed studies and technical specifications for a 300 MW pumped storage hydro plant in El Menzel, which would supplement the 350 MW Abdelmoumen pumped storage, under construction since 2018.

Meanwhile, Morocco is looking to strengthen its interconnection to neighbouring systems in both Europe and Africa. In February 2019 the governments of Spain and Morocco signed a memorandum of understanding, which mandates that system operators in both countries analyse, design and build a third 400 kV interconnector to Spain for commissioning by 2026. This interconnector will increase the transmission capacity between the countries from 1 400 MW to 2 100 MW. The governments of Morocco and Portugal have also signed an agreement to pursue feasibility studies towards a 1 000 MW interconnection between the two countries. Finally, Morocco is also pursuing an interconnection project with Mauritania. While a draft memorandum of understanding has been prepared, it is subject to discussion between the two governments before signing. If realised, it would interconnect the power pool of North Africa, Comité Maghrébin de l'Electricité [Maghreb Electricity Committee], with the West African Power Pool, allowing regional integration with the electricity systems of Mauritania, Senegal and Mali.

Outlook 2021

Historical development of global electricity demand

Between 62% and 68% of final electricity demand originated in the industrial sector and the commercial and public services sector in the past 30 years, suggesting a close relationship between economic activity and electricity consumption. Although the industrial sector only accounts for around 28% of global GDP, compared to services at 67%, it comprised 42% of final electricity demand in 2018, while services stood at just 22%.

In the past 15 years electricity demand has almost stagnated in developed economies, seeing 0.4% average annual growth despite economic activity growing on average by 1.6% per year. In emerging and developing economies, 5.4% average annual economic growth during the same period was accompanied by an annual 5.7% increase in electricity demand on average. In total, this means that 93% of the worldwide net growth in electricity demand from 2005 to 2019 originated in emerging and developing economies – and 58% in China alone.

The majority of the additional global electricity consumption during 2005-18 was used by industry (39%), followed by residential (22%), and the commercial and services sector (15%). The industrial sector also recorded the highest average annual rate of growth in electricity consumption (3.1%) compared to 2.8% and 2.3% in the residential sector and commercial and services sector respectively.

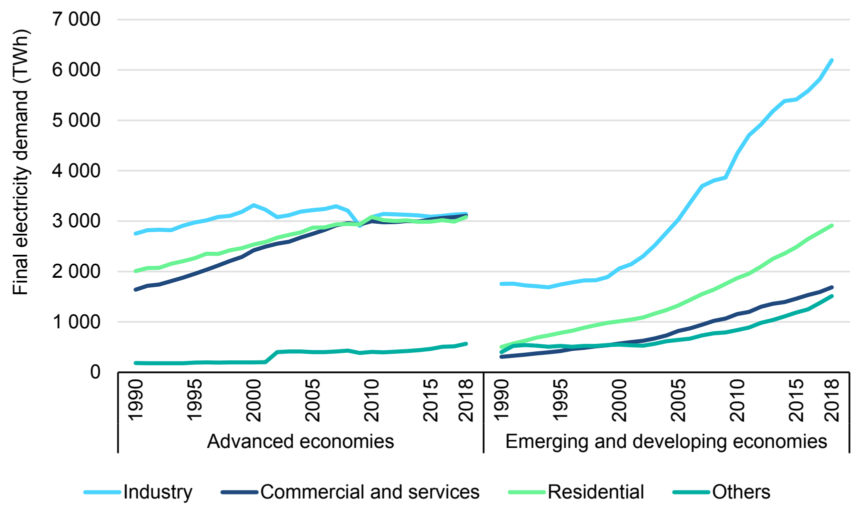
In 2009 – the most recent global economic recession before 2020 – global real GDP decreased by 0.1% and electricity demand dropped by 0.6% (net 103 TWh). While demand in emerging and developing economies continued to grow by 3.6%, it fell by 3.8% in developed economies. With a decline of 3.5%, industrial electricity demand dramatically reversed in comparison to the average 2005-18 growth rate.

Demand growth in the commercial and services sector slowed to 0.6%, and only the residential sector continued to grow significantly (2.3%).

A larger drop in global demand was prevented by China and India, where consumption continued to grow by 7.2% (238 TWh) and 7.4% (50 TWh) respectively.

The strong rebound in global electricity demand in 2010 (up 7.2%, 1 340 TWh) was headed by China (up 13.1%, 460 TWh), the United States (up 4.6%, 182 TWh), Japan (up 7.8%, 82 TWh) and India (up 9.1%, 65 TWh). In total, developed economies grew by 4.8%, while electricity demand in emerging and developing economies in 2010 exceeded 2009 by 10.2%.

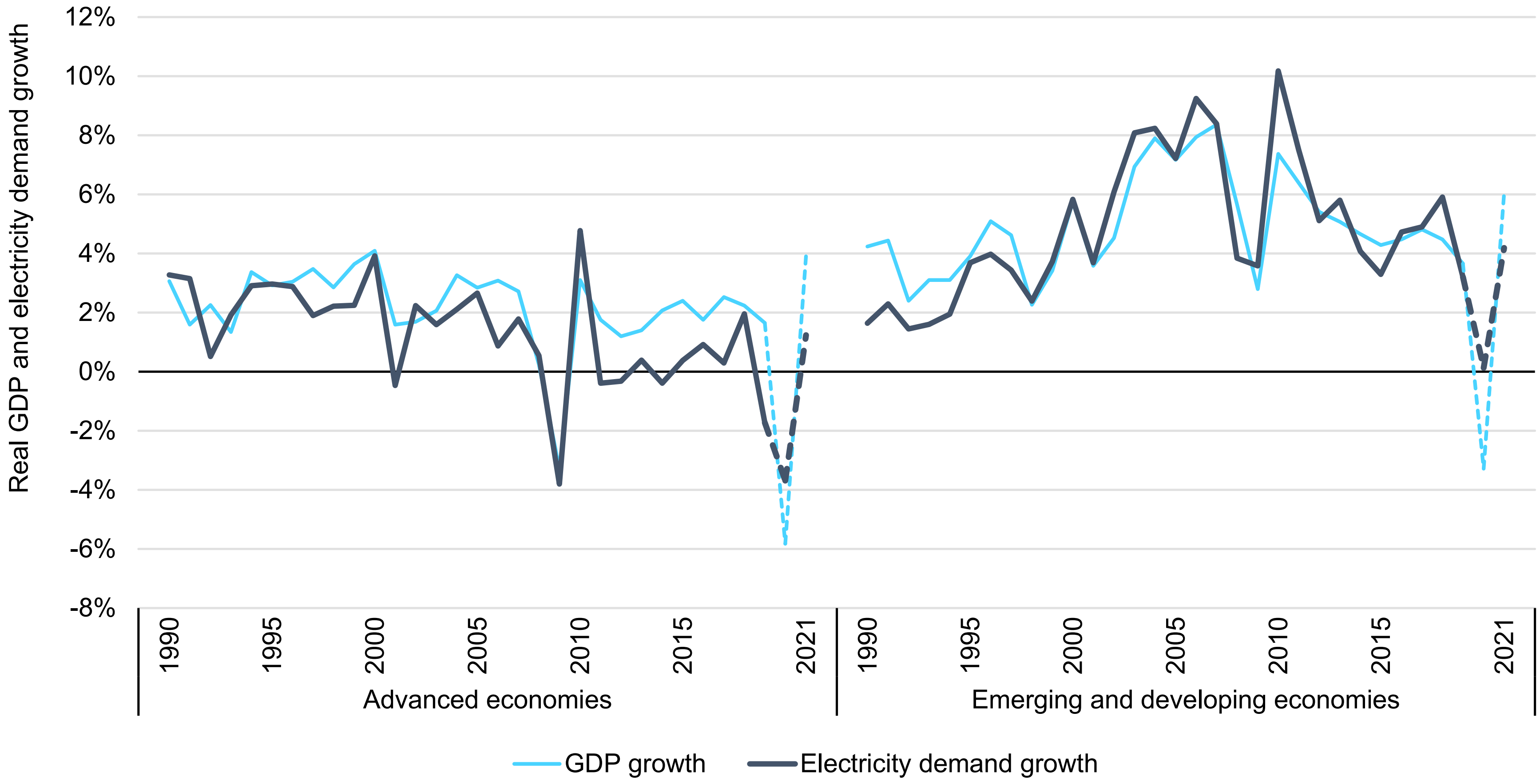
Electricity demand by sector (1990-2018)



Source: IEA (2020), Data and Statistics.

Electricity demand expected to rebound in 2021

Electricity demand and GDP growth



Sources: IEA (2020), Data and Statistics; IMF (2020), Real GDP Growth.

Global electricity demand expected to recover in 2021

In 2020, due to the nature of measures taken against Covid-19, the commercial sector has been particularly affected, with the drop in global electricity demand expected to be around 2% and GDP 4.4% down. Relative electricity consumption fell less than GDP (in 2009 this was the reverse) due to the lower electricity intensity of the commercial sector compared to industry.

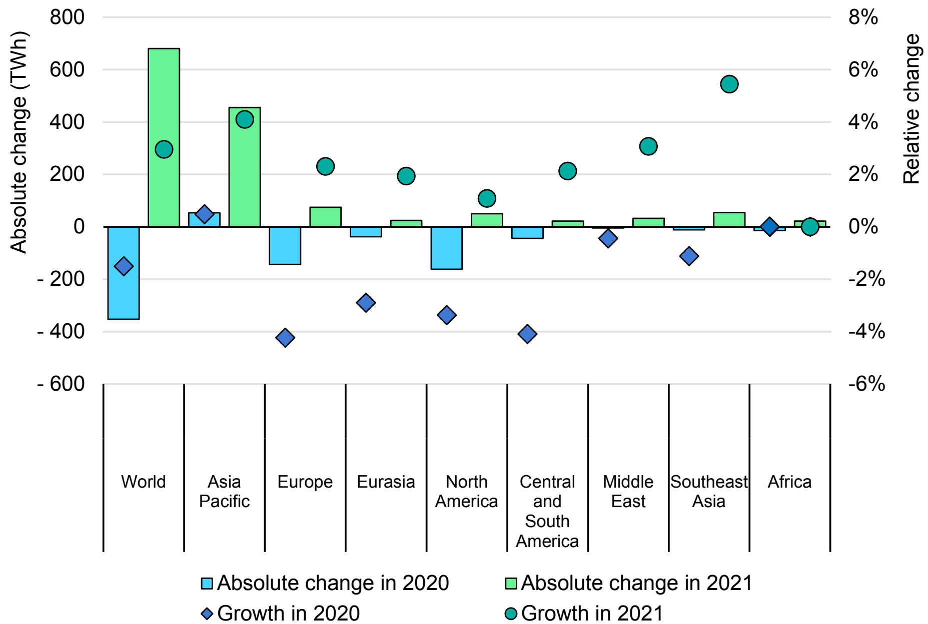
In 2021 electricity demand is anticipated to grow by 3% (around 700 TWh), slower than the projected 5.2% real GDP growth. In total, this means global demand would be higher than in 2019.

Two-thirds of the additional demand is expected in the Asia Pacific region. Most of the growth is concentrated in China and India, expected to grow by 5.2% (350 TWh) and 3.6% (40 TWh) respectively compared to 2020. Both countries have already recorded significant growth rates towards the end of 2020 compared to 2019 demand. Also in Southeast Asia electricity demand in 2021 is expected to significantly exceed demand in 2019. Southeast Asia, one of the fastest-growing regions in electricity demand terms in recent decades, is expected to return to previous growth rates and add 5.4% of demand in 2021 compared to 2020.

In the United States only a slight recovery of around 1% is expected, after a fall of 3.6% in 2020. Although demand is expected to grow by 2.3% in Europe, this still means it would be 2% lower than in 2019.

The greatest uncertainty for electricity demand in 2021 is the further development of the Covid-19 pandemic, the measures taken by governments to prevent it spreading and the availability, speed of distribution and effectiveness of vaccines. This will significantly affect the commercial and services sector, which was hit hard by repeated lockdown measures towards the end of 2020. Additionally, economic prospects depend on government stimulus packages and their success in triggering new investment and supporting businesses that have experienced economic pressure in 2020.

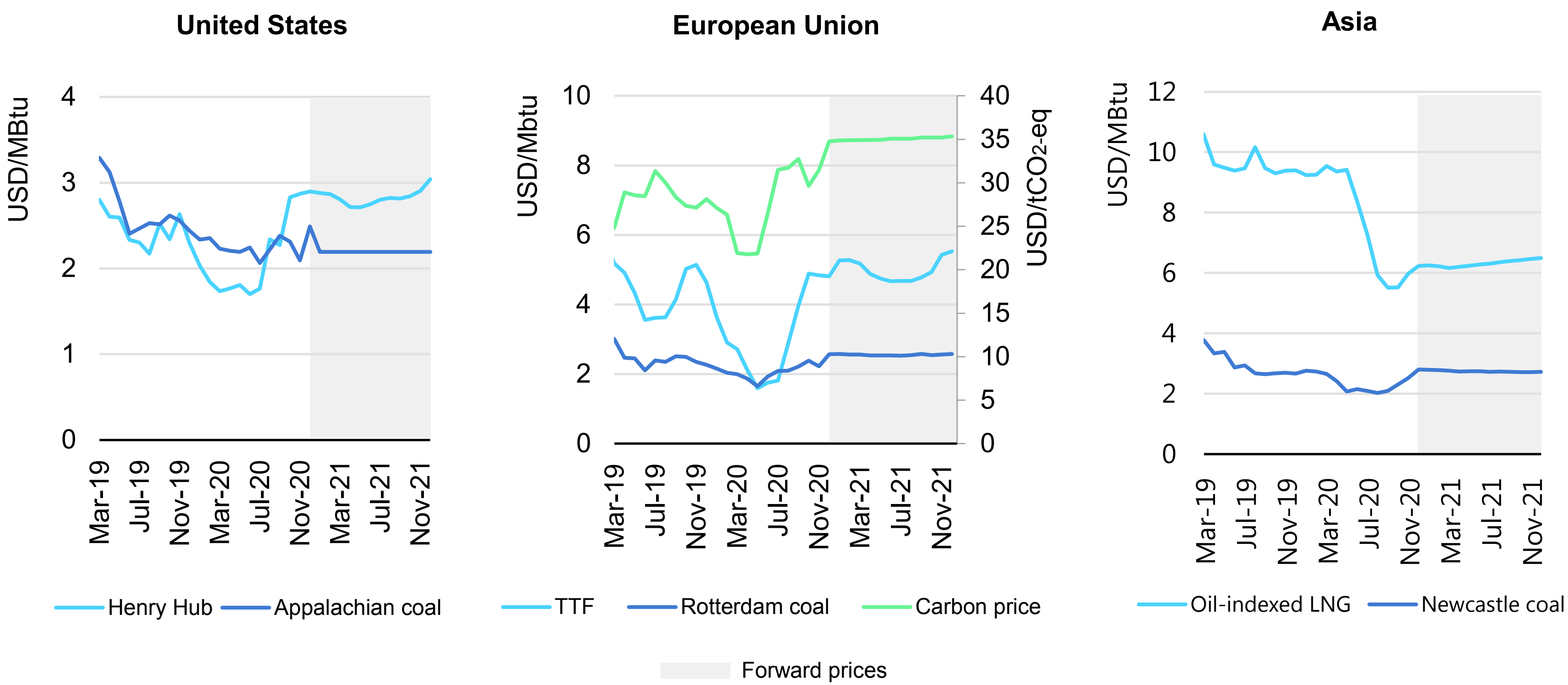
Estimated electricity demand growth by region



Development of input prices: Steady coal and volatile gas

Following the steep fall in spot gas prices during the first half of 2020, the key benchmarks in the United States and Europe started to recover in the third quarter and climbed 0.5% and 20% above last year's respective price levels in October and November. At the beginning of December forward curves suggested that in 2021 Henry Hub will average over 35% above 2020 price levels, at USD 2.8/MBtu. In contrast, coal prices are expected to remain steady, hovering slightly below this year's price levels.

Fuel and emission costs

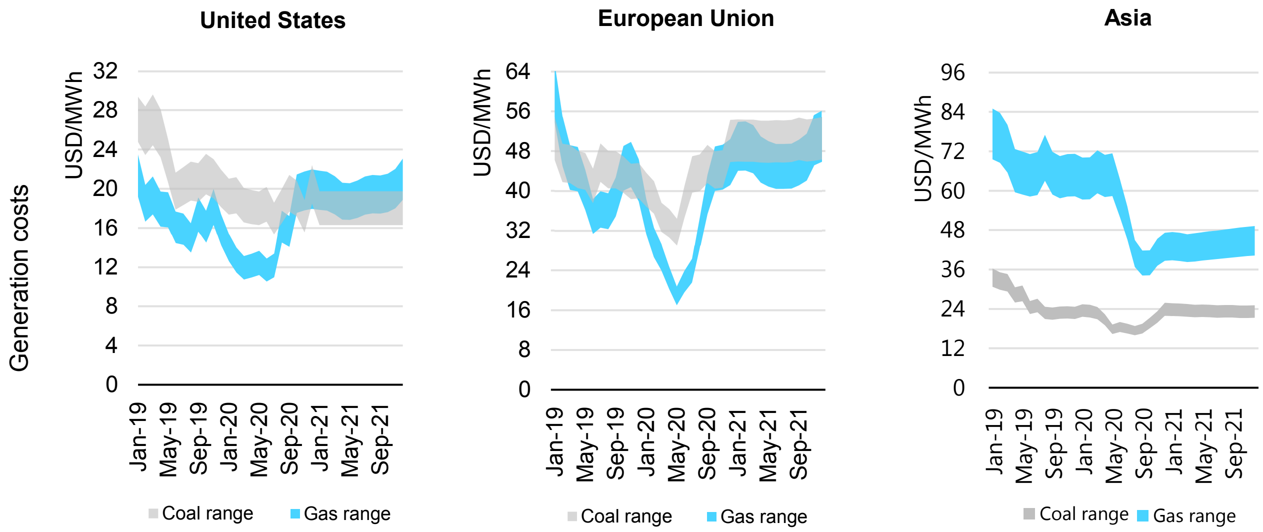


Recovering spot gas prices limit the competitiveness of gas-fired generation in 2021

The expected sharp recovery in gas prices in the United States and Europe (Henry Hub and TTF respectively) would diminish the competitive advantage of gas-fired power plants vis-à-vis coal-fired generation. In the United States coal-fired power generation is expected to recover by 12% y-o-y, driven partly by higher electricity demand (up 1% y-o-y) and lower output from gas-fired power plants, declining by 8% y-o-y. In Europe gas- and coal-fired power generation are expected to remain stable, declining only marginally by less than 1% as most of the market space from recovering demand is expected to be captured by nuclear power generation and renewables.

Markets in OECD Asia should benefit from lower oil-indexed gas prices. However, the drop is unlikely to be enough to trigger a market-based coal-to-gas switch. In Japan both coal- and gas-fired power generation are expected to decline, by 3% and 7% respectively, amid higher nuclear power generation. In Korea gas-fired power generation is expected to increase by close to 6%, supported by recovering electricity demand as well by the start of the third phase of the carbon emission scheme, whilst coal-fired power output is expected to drop by almost 7%.

Generation costs of coal- and gas-fired power plants



Notes: Coal range reflects 38-45% efficiency; gas range reflects 45-55% efficiency.

Renewables lead capacity additions in 2021

After net additions of renewable capacity reached a new record of almost 200 GW in 2020, total capacity is expected to grow by around 218 GW in 2021, almost 10% more than 2020. The strong growth is driven by projects delayed this year going ahead in 2021 (several governments have granted extensions to implementation deadlines) and newly financed capacity. Additionally, distributed solar PV is expected to slowly pick up again due to economic recovery and policy support. Renewable capacity additions are led by solar PV and wind, responsible for around 54% and 31% of net additions respectively.

The majority of **solar PV** net capacity additions are expected in China, making up around one-third (38 GW) of the global total – more than double the expected additions in the United States, which accounts for another 15% of the total. Further major absolute additions are expected in Europe (21 GW), India (11 GW) and Japan (7 GW).

Although being surpassed by solar PV in installed capacity terms, **wind** turbines remain the fastest-growing form of renewable energy in terms of generation, with around 68 GW of net additional capacity in 2021 (of which 89% is onshore). The majority of additions take place in China (39%), Europe (21%) and the United States (16%). In 2021 offshore wind capacity additions are expected to reach a record level of 7 GW, led by China with more than half of the total. The first large-scale offshore wind project is expected to become operational in Chinese Taipei.

Around 13 GW of **nuclear** power units are scheduled to start operating in 2021. Out of the 13 units, three are located in China and two in India. After the United Arab Emirates commissioned its first nuclear unit in 2020, the second unit of the Barakah power plant is scheduled for 2021 – with two more units planned for the two subsequent years. After a construction start in 2005, the Olkiluoto 3 unit in Finland is expected to be connected to the grid at the end of 2021, with commercial operation starting early in 2022. In the United States 5.5 GW of nuclear capacity is expected to retire in 2021, while in Germany three out of the remaining six units are due to be decommissioned at the end of next year – the remaining three will follow at the end of 2022.

In 2021 global coal generation capacity is expected to reach as much as 2 140 GW, predominantly driven by 30 GW of new capacity expected in the People’s Republic of China (hereafter, “China”). Coal capacity outside China is not anticipated to change much, with new capacity in Asia offset by retirements in Europe and North America. In 2021 India, Japan, Indonesia, Viet Nam and Bangladesh are set to commission a number of coal-fired plants that are currently in the final stages of construction, although it is difficult to make an accurate estimate as projects have been delayed by the Covid-19-induced crisis. Unit 1 of the Hassyan plant in the United Arab Emirates will become the first coal power plant in the Middle East outside Israel.

Coal power plant retirements continue in Europe and North America in 2021. In the United States, after 10 GW being decommissioned in 2020, another 3 GW are planned for retirement in 2021, although the final figure could be higher if some units scheduled for 2022 close earlier. In Europe decommissioning will continue in Spain, the United Kingdom, Germany and in particular Italy, where the units Brindisi 2 (600 MW), Fusina (1 600 MW) and La Spezia (600 MW) are expected to close by early 2021, while others could follow soon. After the closure of the Pego and Sines coal-fired power plants, Portugal will follow Belgium, Austria and Sweden to end coal power generation in the country. Overall, over 12 GW are expected to be retired in Europe in 2021.

Natural gas power plant capacity is expected to continue to rise by just over 30 GW in 2021. In the United States just over 7 GW of new capacity is scheduled, with Texas and Ohio accounting for over half of the incremental capacity. In terms of technology, combined cycles account for over 50% and combustion turbines for over 40%. Almost 0.4 GW of gas-fired capacity is set to retire.

In the Middle East 7 GW of capacity is expected to be added, mainly driven by plant developments in Iran, Saudi Arabia and the United Arab Emirates. In Asia gas-fired capacity continues to expand by over 10 GW, with China and Malaysia accounting for almost two-thirds of the incremental capacity.

In Europe 0.9 GW of gas-fired generation capacity is expected to be commissioned in 2021, including the Żerań co-generation plant (490 MW) in Poland and the Landivisiau CCGT plant (446 MW) in Brittany, France.

Electricity supply and related emissions in 2021

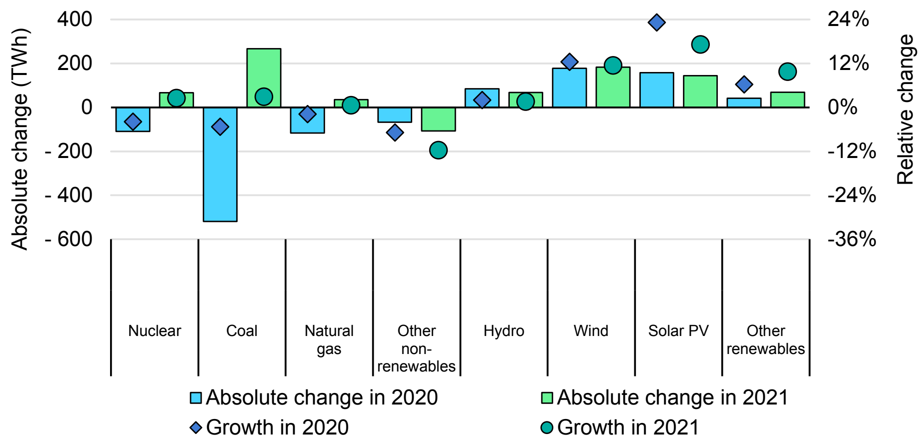
With the expected recovery of electricity demand in 2021, it appears likely that fossil fuel-based generation will be able to regain some of the ground it lost in 2020. Coal in particular is expected to see a relatively large recovery in absolute terms – but having suffered great losses in 2020, this means still being more than 2% down compared to 2019. Whereas a large comeback in Europe is unlikely due to strong competition from renewables, globally coal is expected to recover about half of its losses in 2020 due to increasing gas prices.

Renewable energy, mainly solar PV and wind, is expected to claim further market share, growing by 17% and 11% respectively. In total, renewables are approaching a collective global market share of 29% (up one percentage point).

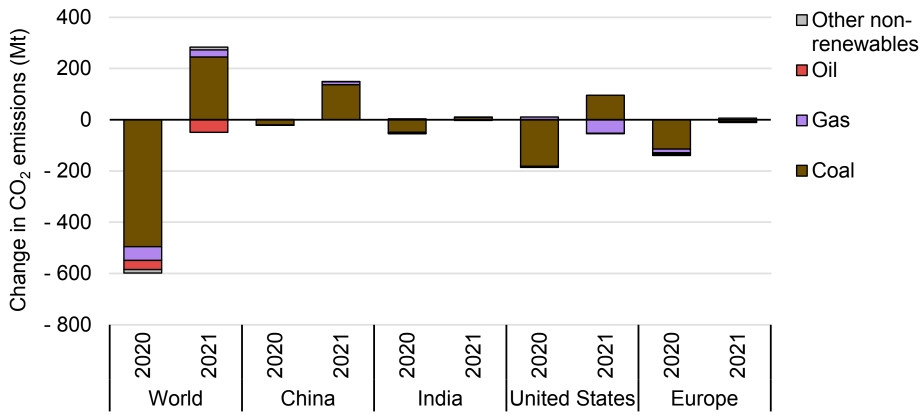
Although the absolute growth of low-carbon electricity generation is expected to exceed fossil-fuel based growth in 2021, global emissions could rise again. After the approximately 5% emissions reduction in 2020 compared to the previous year, emissions are projected to increase by around 2% compared to 2020.

An anticipated increase in coal-fired electricity generation is expected to cause additional emissions, especially in China and the United States. In the case of China, this is due to a continued strong growth of electricity demand which is served by coal-fired power plants. In the United States increasing gas prices could cause a fuel switching from gas to coal.

Projected global change in power supply in 2020 and 2021



Projected global change in emissions in 2020 and 2021



Annual renewable generation can vary significantly

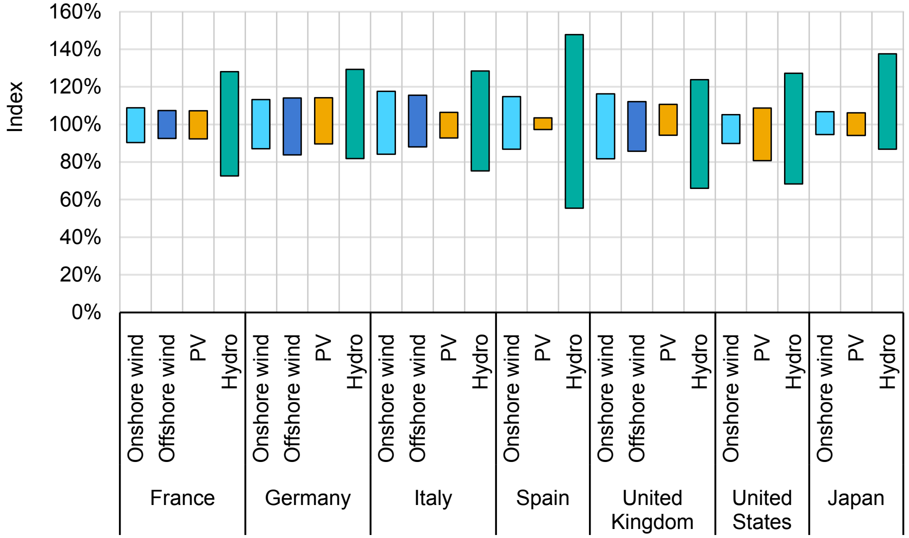
With the increasing share of renewables in the generation mix, their dependence on weather conditions increasingly affects electricity markets around the world. Not only do variable renewables fluctuate from hour to hour, but also annual capacity factors can differ significantly between years. This is the case for wind, solar PV and hydropower plants. Reservoirs, for example, are very flexible in their short-term production, but are dependent on water inflow over longer periods.

We analysed data from seven countries and found that compared against an average year, hydro generation varies within wider ranges than wind and solar. This is especially notable in Spain, where annual hydropower generation, normalised for capacity changes, has oscillated between 55% and 148% of the average in the period between 1991 and 2019.

Solar generation fluctuates within smaller ranges than wind and hydro. Spain (97-103%), Japan (94-106%), Italy (93-106%) and France (92-107%) show the lowest variability from the baseline. Of the evaluated countries, wind stands between solar and hydro in terms of annual variability. The United States (90-105%) and Japan (95-107%) vary the least while the United Kingdom presents the highest variability (85-112%).

In Germany wind, solar PV and hydro are projected to reach a combined capacity of 134 GW in 2021. This could mean a total generation from these sources of between 186 TWh and 246 TWh, or 38% to 51% of projected electricity demand in 2021.

Variability of annual generation of wind, solar PV and hydropower



Notes: Normalised for capacity changes. Wind and solar PV are based on a fixed generation fleet (except for the United States, Japan and India). Hydro is based on annual capacity factors. Considers 1991-2019 for hydro, 1986-2015 for solar (2010-19 for the United States, Japan and India), and 1980-2019 for wind (2010-19 for the United States, Japan and India).

Sources: IEA analysis based on IEA (2020), Renewables 2020; Pfenninger, S. and I. Staffell (2016), Long-term patterns of European PV output using 30 years of validated hourly reanalysis and satellite data; Staffell, I. and S. Pfenninger (2016), Using bias-corrected reanalysis to simulate current and future wind power output.

The variability of renewables affects residual demand

Due to the annual variability of certain renewable energy sources, the residual demand that has to be covered by non-renewable generation depends on the characteristics of the individual weather year.

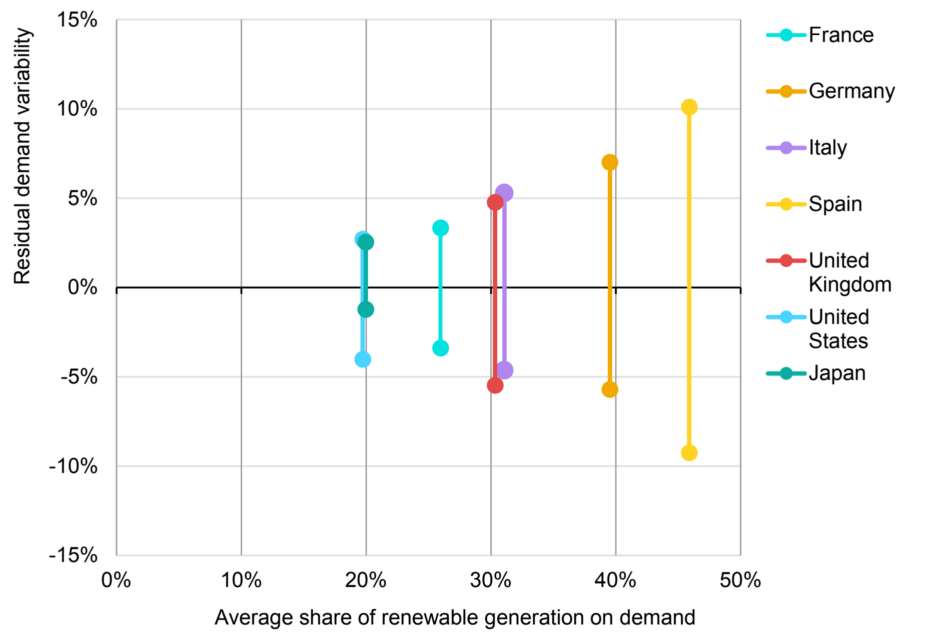
Countries with higher shares of wind, solar PV and hydro generation tend to have a higher relative uncertainty regarding residual demand – depending on the individual composition of renewables and national weather characteristics. Depending on the year's weather, residual demand in Spain may be between 9% lower and 10% higher in 2021 than given average weather conditions. With hydro, wind and solar PV expected to cover 46% of demand, Spain has the highest share of renewables in the sample. For the United States, Japan, and France, at the lower end of the range of renewables share in the sample, residual demand uncertainty is lower than 4% in both directions.

The variability of annual renewable generation has a direct impact on the need of future electricity systems for long-term storage – especially in the context of a very high share of renewables and zero-emission targets.

Additionally, conventional generation technologies are directly impacted. Although some of the variability of renewables might be balanced through trade in interconnected systems, a year with unfavourable weather conditions will, in most systems, result in additional generation from coal- or gas-fired power plants – resulting in additional CO_2 emissions.

High levels of renewable generation can result in lower electricity market prices and lower market share for conventional power plants, thereby reducing their revenues. To balance these risks between the supply side and the demand side, appropriate market mechanisms need to be in place to allow for efficient hedging.

Residual demand variability for different shares of wind, solar PV and hydro generation in 2021



Sources: IEA analysis based on IEA (2020), Renewables 2020; Pfenninger, S. and I. Staffell (2016), Long-term patterns of European PV output using 30 years of validated hourly reanalysis and satellite data; Staffell, I. and S. Pfenninger (2016), using bias-corrected reanalysis to simulate current and future wind power output.

Power systems need to adapt to the seasonal variability of renewables

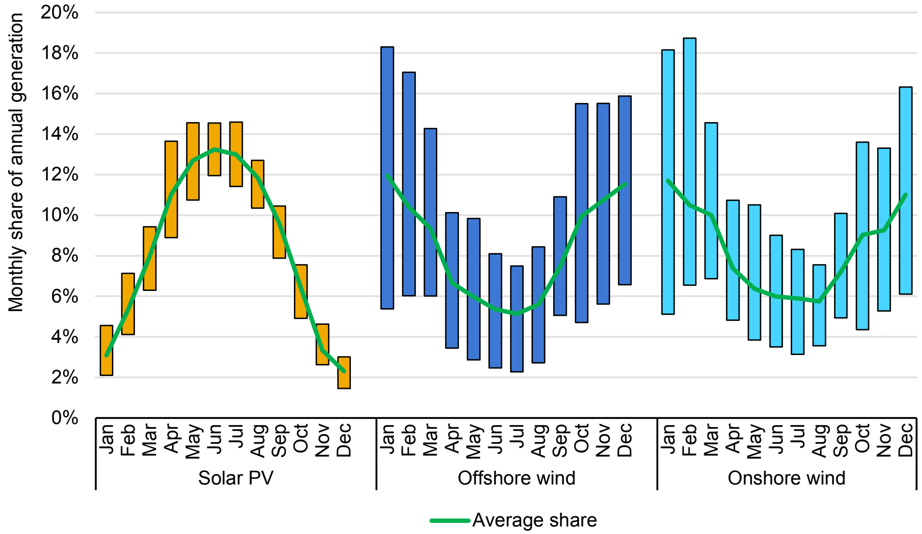
Wind and solar PV show a greater variability on a monthly basis than on a yearly basis, driven by changing weather conditions throughout the year. Hydropower plants with reservoirs can be dispatched flexibly and are frequently used as seasonal storage; thus they are less dependent on short-term weather influences.

The monthly generation patterns of wind and solar PV are similar for the analysed countries of France, Germany, Italy, Spain and the United Kingdom. Solar PV mostly generates reliably during the summer months. In the case of Germany, between 48% and 54% of annual generation takes place in the four months from May to August, and 69% to 75% in the sunny half of the year (April to September).

Wind generation shows a U-shaped pattern indicating higher productivity in the cold season – with similar variability in monthly generation for on- and offshore wind. Compared to solar PV, the variability of the monthly distribution is much larger. In Germany onshore wind production is on average at its highest in January (12% of the annual total). This share can go down to 5% given unfavourable weather conditions – but also up to 18% given strong winds. In the six months with the highest average production, 54-66% (onshore) and 55-69% (offshore) of the annual total are produced.

The complementarity between wind and solar can be used to reduce the variability of their combined electricity production – but some monthly variability of renewables generation is inevitable. While demand-side response is a promising option for short-term balancing of generation and demand, flexibility options like seasonal storage and the use of hydrogen are needed to integrate large shares of renewables into the energy system.

Monthly generation of wind and solar PV in Germany



Note: Based on weather data for 1980-2019 and a constant generation fleet.

Sources: IEA analysis with data from Pfenninger, S. and I. Staffell (2016), Long-term patterns of European PV output using 30 years of validated hourly reanalysis and satellite data; Staffell, I. and S. Pfenninger (2016), Using bias-corrected reanalysis to simulate current and future wind power output.

Annex

Regional and country groupings

Africa – Algeria, Angola, Benin, Botswana, Cameroon, Congo, Democratic Republic of the Congo, Côte d'Ivoire, Egypt, Eritrea, Ethiopia, Gabon, Ghana, Kenya, Libya, Morocco, Mozambique, Namibia, Nigeria, Senegal, South Africa, 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, Dominican Republic, Ecuador, El Salvador, Guatemala, Haiti, Honduras, Jamaica, Netherlands Antilles, Nicaragua, Panama, Paraguay, Peru, 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, Cape Verde, Central African Republic, Chad, Comoros, Djibouti, Gambia, Equatorial Guinea, Guinea, Guinea-Bissau, Lesotho, Liberia, Madagascar, Malawi, Mali, Mauritania, Mauritius, Niger, 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: Includes 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
CAISO	California Independent System Operator
CCGT	combined cycle gas turbine
CDDs	cooling degree days
CO_2	carbon dioxide
EEG	Erneuerbare Energien Gesetz
ERCOT	Electric Reliability Council of Texas
EU ETS	European Union Emissions Trading System
GDP	gross domestic product
GHG	greenhouse gas
HDDs	heating degree days
HVDC	high-voltage direct current
IEA	International Energy Agency
IEX	India Electricity Exchange
IMF	International Monetary Fund
ISO	independent system operator
Lao PDR	Lao People's Democratic Republic
LED	light-emitting diode
LNG	liquefied natural gas
OECD	Organisation for Economic Co-operation and Development
OPEC	Organization of the Petroleum Exporting Countries
POSOCO	Power System Operation Corporation (India)
PPA	power purchase agreement
REIPPP	Renewable Energy Independent Power Producer Procurement Programme (South Africa)
RGGI	Regional Greenhouse Gas Initiative
PV	photovoltaics
TTF	Title Transfer Facility
VAT	value added tax
VRE	variable renewable energy
WHO	World Health Organization
y-o-y	year-on-year (compared to the same period of the previous year)

Units of measurement

b/d	barrels per day
GW	gigawatt
GWh	gigawatt-hour
km	kilometre
kWh	kilowatt-hour
MBtu	million British thermal units
$MtCO_2$-eq/yr	million tonnes of CO_2 equivalent per year
MW	megawatt
MWh	megawatt-hour
tCO_2eq	tonne of CO_2 equivalent
TWh	terawatt-hour

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