Electricity Market Report 2023

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Abstract

Electricity is central to many parts of life in modern societies and will become even more so as its role in transport and heating expands through technologies such as electric vehicles and heat pumps. Power generation is currently the largest source of carbon dioxide (CO_2) emissions globally, but it is also the sector that is leading the transition to net zero emissions through the rapid ramping up of renewables such as solar and wind. At the same time, the current global energy crisis has placed electricity security and affordability high on the political agenda in many countries.

The International Energy Agency's *Electricity Market Report 2023* offers a deep analysis of recent policies, trends and market developments. It also provides forecasts through 2025 for electricity demand, supply and CO_2 emissions – with a detailed study of the evolving generation mix. This year's report contains a comprehensive analysis of developments in Europe, which faced a variety of energy crises in 2022. The Asia Pacific region also receives special focus, with its fast-growing electricity demand and accelerating clean energy deployment.

The IEA's *Electricity Market Report* has been published since 2020. Its relevance goes beyond energy and climate issues, since electricity supply impacts economies, regional development, the budgets of businesses and households, and many other areas. It is indispensable reading for anyone interested in the multifaceted importance of energy in our economies and societies today.

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Executive Summary

Global electricity demand growth slowed only slightly in 2022 despite energy crisis headwinds

World electricity demand remained resilient in 2022 amid the global energy crisis triggered by Russia's invasion of Ukraine. Demand rose by almost 2% compared with the 2.4% average growth rate seen over the period 2015-2019. The electrification of the transport and heating sectors continued to accelerate globally, with record numbers of electric vehicles and heat pumps sold in 2022 contributing to growth. Nevertheless, economies around the world, in the midst of recovering from the impacts of Covid-19, were battered by record-high energy prices. Soaring prices for energy commodities, including natural gas and coal, sharply escalated power generation costs and contributed to a rapid rise in inflation. Economic slowdowns and high electricity prices stifled electricity demand growth in most regions around the world.

Electricity consumption in the European Union recorded a sharp 3.5% decline year-on-year (y-o-y) in 2022 as the region was particularly hard hit by high energy prices, which led to significant demand destruction among industrial consumers. Exceptionally mild winter added further downward pressure on electricity consumption. This was the EU's second largest percentage decrease in electricity demand since the global financial crisis in 2009 – with the largest being the exceptional contraction due to the Covid-19 shock in 2020.

Electricity demand in India and the United States rose, while Covid restrictions affected China's growth. China's zero-Covid policy weighed heavily on its economic activity in 2022, and a degree of uncertainty remains over the pace of its electricity demand growth. We currently estimate it to be 2.6% in 2022, substantially below its pre-pandemic average of over 5% in the 2015-2019 period. Further data expected in due course will provide greater clarity on trends in China in 2022, which could also have implications for the global picture. Electricity demand in India rose by a strong 8.4% in 2022, due to a combination of its robust post-pandemic economic recovery and exceptionally high summer temperatures. The United States recorded a significant 2.6% y-o-y demand increase in 2022, driven by economic activity and higher residential use to meet both heating and cooling needs amid hotter summer weather and a colder-than-normal winter.

Low-emissions sources are set to cover almost all the growth in global electricity demand by 2025

Renewables and nuclear energy will dominate the growth of global electricity supply over the next three years, together meeting on average more than 90% of the additional demand. China accounts for more than 45% of the growth in renewable generation in the period 2023-2025, followed by the EU with 15%. The substantial growth of renewables will need to be accompanied by accelerated investments in grids and flexibility for their successful integration into the power systems. The increase in nuclear output results from an expected recovery in French nuclear generation as more plants complete their scheduled maintenance, and from new plants starting operations, largely in Asia.

Global electricity generation from both natural gas and coal is expected to remain broadly flat between 2022 and 2025. While gas-fired generation in the European Union is forecast to decline, significant growth in the Middle East will partly offset this decrease. Similarly, drops in coal-fired generation in Europe and the Americas will be matched by a rise in Asia Pacific. However, the trends in fossil-fired generation remain subject to developments in the global economy, weather events, fuel prices and government policies. Developments in China, where more than half of the world's coal-fired generation occurs, will remain a key factor.

China's share of global electricity consumption is forecast to rise to one-third by 2025, compared with one-quarter in 2015. Over the next three years, more than 70% of the growth in global electricity demand is set to come from China, India and Southeast Asia combined. Emerging and developing economies' growth is accompanied by a corresponding rise in demand for electricity. At the same time, advanced economies are pushing for electrification to decarbonise their transportation, heating and industrial sectors. As a result, global electricity demand is expected to grow at a much faster pace of 3% per year over the 2023-2025 period compared with the 2022 growth rate. The total increase in global electricity demand of about 2 500 terawatt-hours (TWh) out to 2025 is more than double Japan's current annual electricity consumption. Nevertheless, uncertainties exist regarding the growth of electricity demand in China. While the country recently eased its stringent Covid restrictions in early December 2022, the full extent of the economic impacts remain unclear.

After reaching an all-time high in 2022, power generation emissions are set to plateau through 2025

Global CO_2 emissions from electricity generation grew in 2022 at a rate similar to the 2016-2019 average. Their increase of 1.3% in 2022 is a significant slowdown from the staggering 6% rise in 2021, which was driven by the rapid economic recovery from the Covid shock. Nonetheless, electricity generation-related CO_2 emissions reached a record high in 2022.

The share of renewables in the global power generation mix is forecast to rise from 29% in 2022 to 35% in 2025. As renewables expand, the shares of coal- and gas-fired generation are set to fall. As a result, emissions of global power generation will plateau to 2025 and its CO_2 intensity will further decline in the coming years.

The European Union saw gas-fired generation increase during a turbulent 2022

Due to historic drought conditions, hydropower generation in Europe was particularly low in 2022. Italy saw a drop in hydropower generation of more than 30% compared with its 2017-2021 average, followed closely by Spain. Similarly, France recorded a 20% decline in its hydro output compared with the previous five-year average.

Nuclear generation in the European Union was 17% lower in 2022 than in 2021 due to closures and unavailabilities. Plant closures in Germany and Belgium reduced the available nuclear capacity in 2022. At the same time, France faced record-low nuclear availability due to ongoing maintenance work and other challenges in its nuclear fleet. The constrained nuclear output and low hydropower supply in Europe – combined with reduced dispatchable capacity due to previous retirements of thermal generation plants – put additional pressure on remaining dispatchable capacities to meet demand. As a result, although variable renewable generation grew and record-high gas prices supported fuel-switching from gas to coal, gas-fired generation grew in 2022 by 2% in the European Union. These factors have also contributed to significant changes in the traditional import-export structure of electricity in Europe: France became a net importer and the United Kingdom a net exporter for the first time in decades.

In order to increase the security of electricity supply, reserve capacities of conventional power generation have been brought back in Europe for the 2022-2023 and 2023-2024 winters. Similarly, some plants that were previously set to be decommissioned were also extended. Germany had the highest share of such plants in Europe, having delayed the planned shutdown of its three remaining nuclear reactors, as well as delaying the closure or reactivating fossil-fired plants that make up 15% of its current fossil-fired generation capacity. An increased risk of power outages was reported in some European countries during several weeks of cold weather combined with lower-than-average hydro and nuclear output. Security of supply was achieved through successful short-term planning and management.

While the CO_2 intensity of global power generation decreased in 2022, it increased in the European Union

After 2021, 2022 marks the highest percentage growth in CO_2 emissions of EU power generation since the oil crises of the 1970s, recording a 4.5% year-on-year growth. Excluding the 2021 post-pandemic rebound, the European Union also saw in 2022 the highest absolute growth in power generation emissions since 2003. This was mainly due to a rise in coal-fired generation of more than 6% in stark contrast to the almost 8% average annual rate of decline in coal-fired generation over the pre-pandemic period of 2015-2019.

The setback in the European Union will be temporary, however, as power generation emissions are expected to decrease on average by about 10% annually through 2025. Both coal- and gas-fired generation are expected to see sharp falls, with coal declining by 10% and gas by almost 12% annually on average over the outlook period as renewables ramp up and nuclear generation recovers.

Electricity prices remain high in many regions, with risks of tight supply in Europe next winter

The increase in wholesale electricity prices was most pronounced in Europe in 2022, where they were, on average, more than twice as high as in 2021. The exceptionally mild winter so far in 2022/23 in Europe has helped temper wholesale electricity prices, but they remain high compared with recent years. Elevated futures prices for winter 2023/24 reflect the uncertainties regarding gas supply in Europe over the coming year.

In the European Union, a wide range of responses to the energy crisis have been observed. In order to reduce reliance on fossil fuels and to increase resilience to price shocks, the European Commission published its REPowerEU plan in May 2022 to accelerate clean energy deployment. At the same time, discussions about electricity market design gained momentum due to soaring wholesale prices, and the Commission launched a consultation on market design reform. To dampen the effects of high electricity prices on consumers, many countries introduced measures such as the regulation of wholesale and retail prices; revenue caps on infra-marginal technologies such as renewables, nuclear and coal-plants; reductions of energy taxes and VAT; and direct subsidies.

While such market interventions can help mitigate the impacts of the energy crisis, the potential creation of uncertainty in the investment landscape needs to be minimised to ensure that responses to the crisis do not come at the expense of much-needed investment.

Affordability will continue to be a challenge for emerging and developing economies

Globally, higher electricity generation costs in 2022 were driven by surging energy commodity prices. While the cost increases were more moderate in countries with regulated tariffs and long-term fuel supply agreements (oil-indexed LNG, long-term contracts or fuel supply contracts), regions dependent on short-term markets for fuel procurement were severely affected. In particular, record-high LNG prices led to difficulties for South Asian countries trying to procure gas for the power sector, which contributed to blackouts and rationing of electricity in the region. If prices of energy commodities remain elevated, fuel procurement will continue to be a serious issue for emerging and developing economies.

Nuclear power is gathering pace in Asia, curbing the CO_2 intensity of power generation

The energy crisis has renewed interest in the role of nuclear power in contributing to energy security and reducing the CO_2 intensity of power generation. In Europe and the United States, discussions on the future role of nuclear in the energy mix have resurfaced. At the same time, other parts of the world are already seeing an accelerated deployment of nuclear plants. As a result, global nuclear power generation is set to grow on average by almost 4% over 2023-2025, a significantly higher growth rate than the 2% over 2015-2019. This means that in every year to 2025, about 100 TWh of additional electricity is set to be produced by nuclear power, the equivalent of about one-eighth of US nuclear power generation today.

More than half of the growth in global nuclear generation to 2025 comes from just four countries: China, India, Japan and Korea. Among these countries, while China leads in terms of absolute growth from 2022 to 2025 (+58 TWh), India is set to have the highest percentage growth (+81%), followed by Japan. This results from the Japanese government's push to ramp up nuclear generation in order to reduce reliance on gas imports and strengthen energy security. Outside Asia, the French nuclear fleet provides more than one-third of the absolute growth in global nuclear generation to 2025 as it gradually recovers.

Extreme weather events highlight the need for increased security of supply and resilience

In a world where both the demand and supply of electricity are becoming increasingly weather-dependent, electricity security requires increased attention. Along with the high cost of electricity generation, the world's power systems also faced challenges from extreme weather events in 2022. In addition to the drought in Europe, there were heatwaves in India, where the hottest March in over a century was recorded, resulting in the country's highest ever peak in power demand. Similarly, central and eastern China were hit by heatwaves and drought, which caused demand for air conditioning to surge amid reduced hydropower generation in Sichuan. The United States saw severe winter storms in December, triggering massive power outages. Mitigating the impacts of climate change requires faster decarbonisation and accelerated deployment of clean energy technologies. At the same time, as the clean energy transition gathers pace, the impact of weather events on electricity demand will intensify due to the increased electrification of heating, while the share of weather-dependent renewables will continue to grow in the generation mix. In such a world, increasing the flexibility of the power systems while ensuring security of supply and resilience will be crucial.

Global overview

Demand

Global electricity demand growth eased in 2022, but is set to accelerate from 2023, led by Asia

The energy crisis sparked by the Russian Federation's (hereafter "Russia") invasion of Ukraine has been characterised by record-high commodity prices, weaker economic growth and high inflation. Higher fuel prices increased the cost of electricity generation around the world, putting downward pressure on consumption in many regions. Despite the worsening crisis, global electricity demand remained relatively resilient, growing by almost 2% in 2022.

By 2025, for the first time in history, Asia will account for half of the world's electricity consumption and one-third of global electricity will be consumed in China. Over the outlook period, global electricity demand is set to grow at an accelerated pace, by an annualised 3%, as electricity consumption increases in emerging markets and developing economies (EMDEs), led by the People's Republic of China (hereafter "China"), India and Southeast Asia.

As the energy crisis abates, global electricity demand growth is set to rise from 2.6% in 2023 to an average 3.2% in 2024-2025. This stronger growth is well above the pre-pandemic rate of 2.4% observed in the 2015-2019 period. Indeed, by 2025 demand will increase by 2 500 TWh from 2022 levels, which means that over the next three years the electricity consumption added each year is roughly equivalent to that of the United Kingdom and Germany combined. More than half of the increase will come from China. The remaining growth will largely take place in India and Southeast Asia.

In **China,** electricity demand growth was subdued on weaker economic activity in 2022, rising at an estimated 2.6%, and significantly below its trend of 5.4% in 2015-2019. China is by far the world's largest electricity consumer at 31% of global demand in 2022. For 2023-2025 we expect an average annual growth of 5.2%.

In **India**, the robust post-pandemic recovery continued to support strong electricity demand of over 8.4% in 2022, which was substantially higher than the average annual growth rate of 5.3% seen in the 2015-2019 period. The peak summer season also arrived early in 2022, resulting in the hottest March in over a century. Electricity demand from March to July was 12% higher than the same period in 2021. For the 2023-2025 period, we expect slightly slower growth, averaging 5.6% per year.

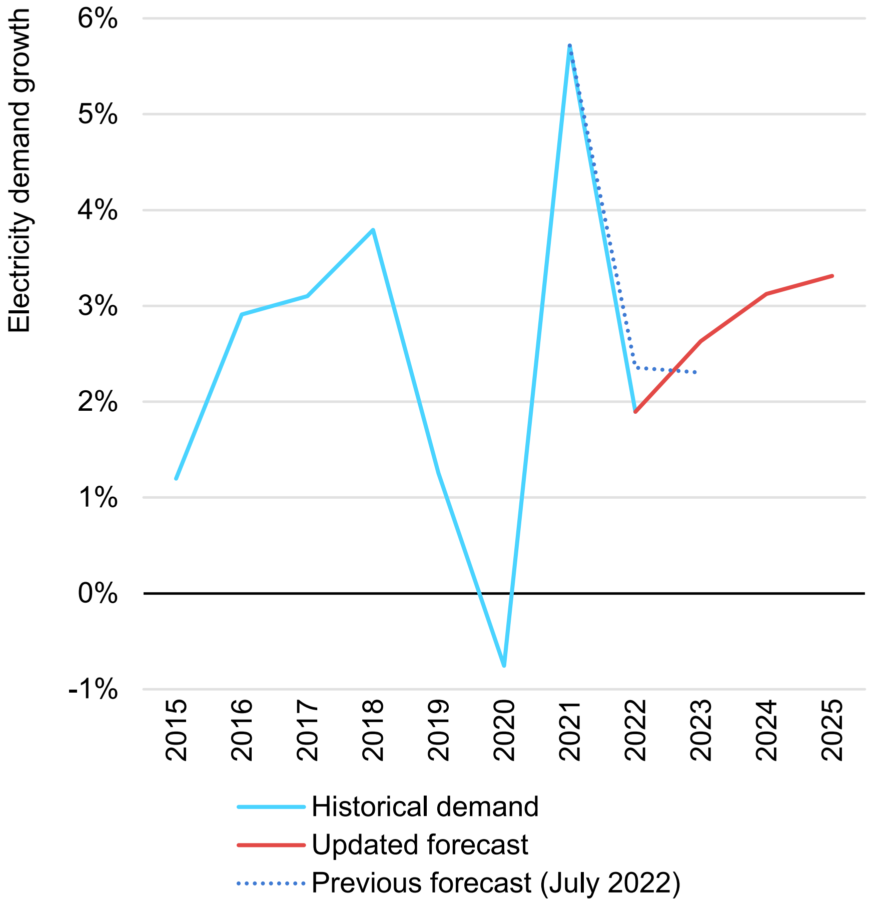
Electricity demand in the **European Union** (EU) fell 3.5% in 2022, with spiking electricity prices, demand destruction in electricity-intensive industries, energy saving measures and a mild winter all contributing to the decline. We expect EU demand to grow by around 1.4% on average in 2023-2025.

In the **United States,** electricity demand rose by 2.6% in 2022, surpassing pre-Covid levels. But an expected economic slowdown in 2023 is expected to lead to a decline of about 0.6%, before returning to growth of 1.2% in 2024 and 1.3% in 2025.

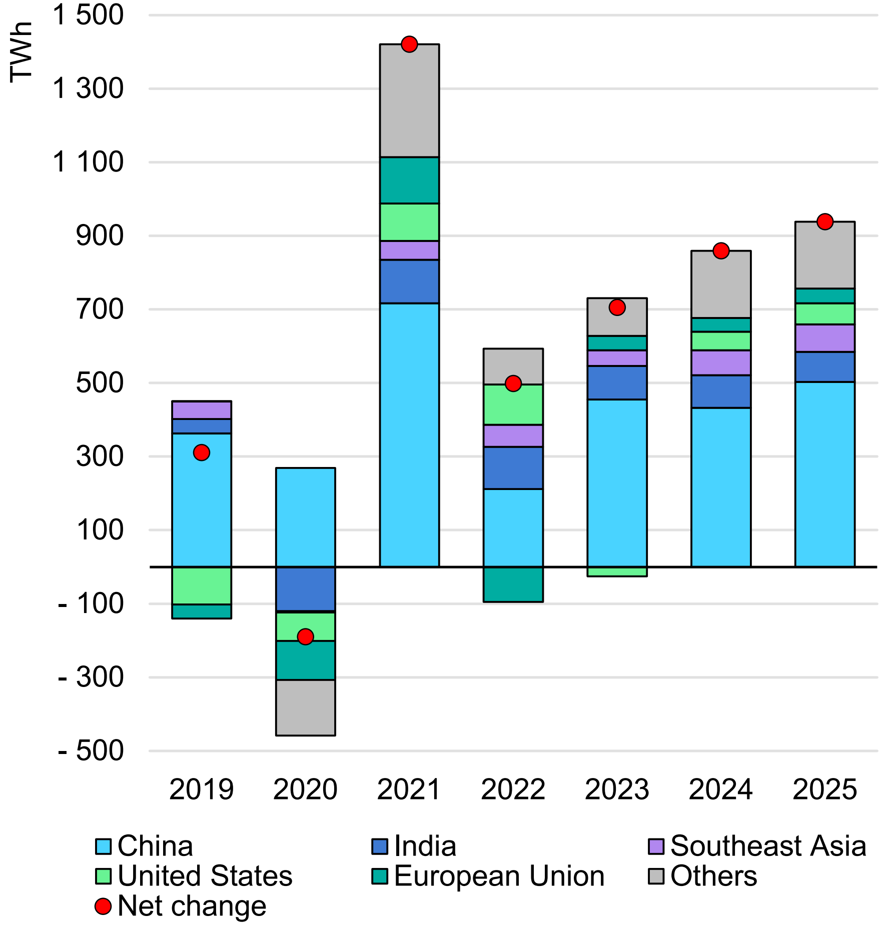
In **Africa,** electricity demand rose by 1.5% in 2022, with growth tempered by both lofty energy prices and high inflation rates. Our 2023-2025 outlook for the region shows much stronger growth of an average 4.1%, led by a post-crisis economic recovery.

Out to 2025, more than 70% of the growth in global electricity demand is set to come from China, India and Southeast Asia combined

Year-on-year relative global change in electricity demand, 2015-2025

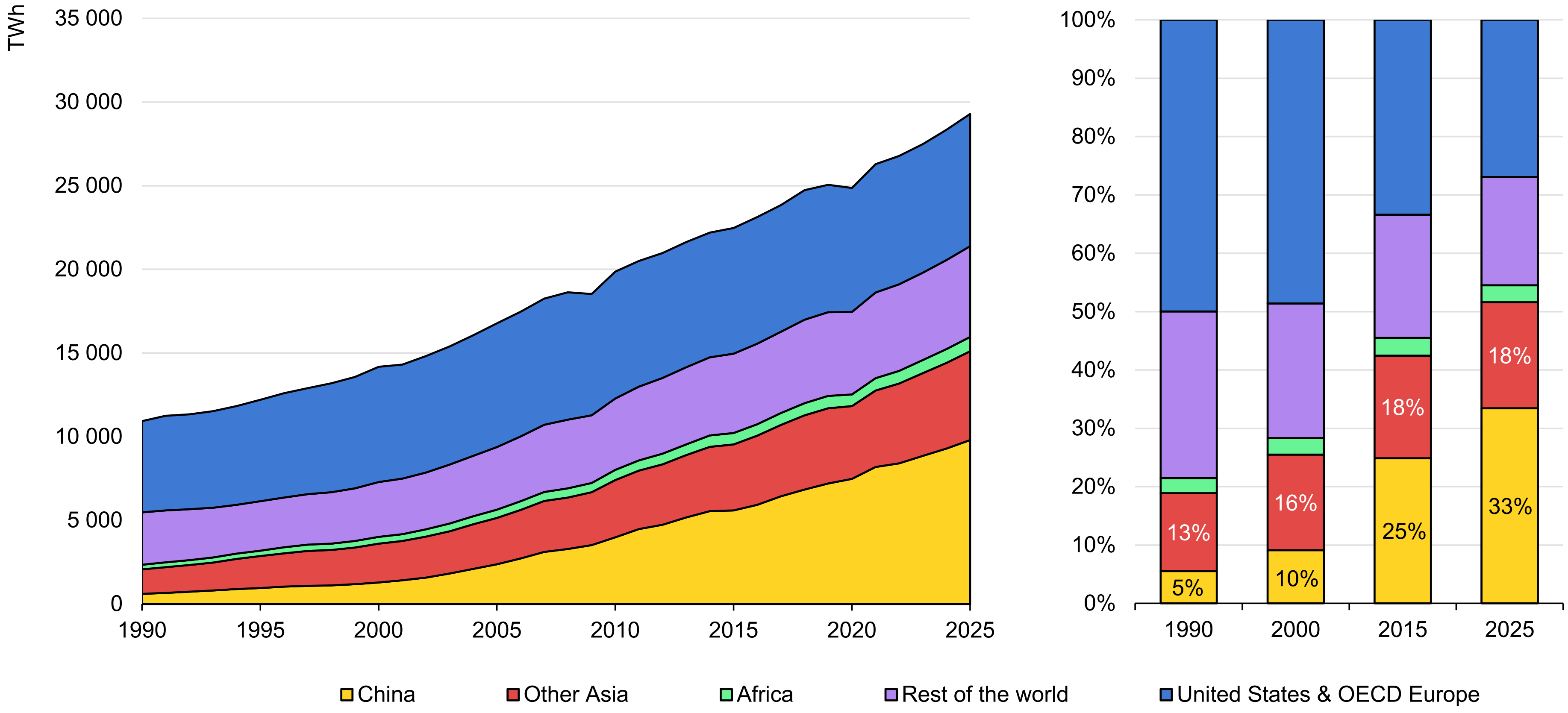


Year-on-year change in electricity demand by region, 2019-2025



By 2025, Asia will account for half of the world's electricity consumption and one-third of global electricity will be consumed in China

Evolution of global electricity demand by region (left) and regional shares (right), 1990-2025



Global economic growth shows signs of resilience but continues to face challenges

The global economy continues to face myriad challenges in the wake of Russia's war in Ukraine and the rise in central bank rates aimed at combating persistent inflation. The International Monetary Fund's (IMF) January 2023 World Economic Outlook provides forecasts up to 2024 and shows global GDP growth of 6.2% in 2021 contracting to 3.4% in 2022 and easing to 2.9% in 2023. By 2024, growth inches higher again, to 3.1%. The latest forecast represents downward revisions of 0.2%, 0.7% and 0.3%, respectively, compared with the April 2022 forecast, which underpinned our July update. The January 2023 outlook, however, was slightly more optimistic than the previous October 2022 forecast for the short term, with global GDP growth for both 2022 and 2023 raised by 0.2 percent points. The October outlook, which provided projections up to 2027, forecast a global GDP growth rate of 3.4% in 2025.

For the **United States**, the IMF revised its latest GDP estimate to 2% for 2022 from 3.7% in April and its outlook to 1.4% from 2.3% for 2023. Growth is forecast at a slower 1% in 2024. The contracting trend reflects persistent and broadening inflation pressures and higher interest rates that will continue to temper purchasing power. 2025 growth from the October outlook is 1.8%.

For the **Euro area**, GDP growth is estimated in the January outlook at 3.5% for 2022 before plummeting to just 0.7% in 2023 and then recovering to 1.6% in 2024. The latest forecast shows a sharp downward revision from the April estimate of 2.3% for 2023. The weaker outlook largely reflects the spillover effects from the war in Ukraine and rate hikes from the European Central Bank, which are partially offset by lower wholesale energy prices and support from energy price controls. For 2025, a growth of 1.9% was forecast in the October outlook.

Under pressure from its zero-Covid policy, **China**'s economy slowed from the pre-pandemic average growth of 6.7% between 2015-2019 to 3% in 2022. However, the country's sudden easing of its stringent pandemic restrictions prompted an upward revision to 5.2% for 2023, up three percentage points from the October projections but similar to its 5.1% estimate in April. Growth is forecast to slow to 4.5% in 2024. The October forecast estimated growth of 4.6% for 2025.

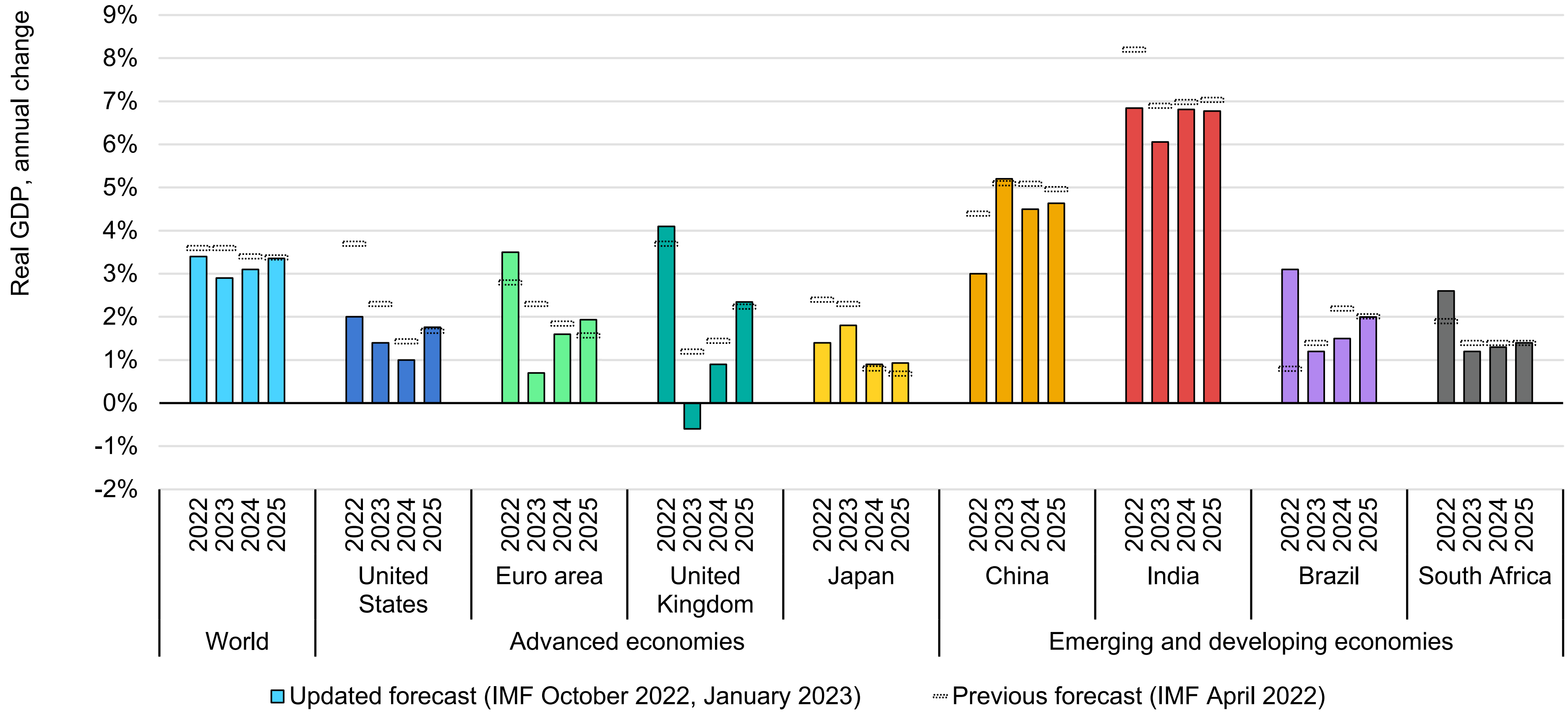
The GDP growth for **India** is estimated at 6.8% for 2022.The outlook was revised downward in January to 6.1% from 6.9% for 2023, largely due to slow economic growth in its trading partner countries. GDP growth for 2024 was unchanged at 6.8%. The 2025 forecast from the previous October outlook is 6.8%.

Sub-Saharan Africa's GDP growth is estimated to ease from 4.7% in 2021 to 3.8% in 2022, due to higher inflation and slower-than-expected progress on poverty reduction. However, economic growth will speed up from 3.8% in 2023 to above 4% in 2024 and 2025.

The IMF expects **Latin America and the Caribbean**'s GDP to grow by 3.9% in 2022, 1.8% in 2023 and 2.1% in 2024. October forecast for 2025 was 2.5%.

The war in Ukraine, energy crisis and persistent inflation suppress the economic outlook

Gross domestic product growth assumptions by country and region, 2022-2025



Notes: The bars represent annual changes in GDP relative to the previous year. The hollow lines show the previous April 2022 forecast. 2022-2024 values are from the January 2023 World Economic Outlook Update of International Monetary Fund (IMF). 2025 values are from IMF's October 2022 outlook.

Sources: Based on International Monetary Fund (2023), World Economic Outlook October 2022 Database, World Economic Outlook Update January 2023, 1 February 2023.

Industrial electricity demand plummeted to historic lows in multiple countries in 2022

In 2021, many countries started to gradually phase out Covid-19 public policy measures and return to more normal economic activity. However, some economies (e.g. China) still imposed lockdowns in 2022, which had an impact on both residential and industrial electricity consumption. Equally, persistently high electricity prices continued to add downward pressure on consumption, particularly in the residential and industrial sectors.

Comparing the first three quarters of the years, both the United Kingdom and Spain experienced the lowest industrial electricity consumption in over 20 years in 2022. Spain saw a decrease of more than 10% compared to 2019, while the United Kingdom posted a drop of almost 15% in 2022 versus 2019. Spain's electricity-intensive manufacturing activity was especially hard hit by the rise in prices. The country's industrial electricity consumption posted a similar y-o-y decline in 2022 as it did in 2020 when severe Covid-related lockdowns led to substantial demand destruction. Of the countries surveyed, the United Kingdom saw the sharpest rise in average wholesale electricity prices. Spain followed with the second highest level, despite the June 2022 implementation of the Iberian exception, a cap on wholesale gas prices adopted to reduce the cost of electricity.

In the United Kingdom and Spain, as elsewhere, residents spent more time at home during widespread Covid-19 lockdowns in 2021, which led to higher residential electricity consumption that was well above the subsequent 2022 levels when pandemic restrictions were eased. Although formal Covid restrictions were lifted in the United Kingdom in July 2021, many employees continued to telework through the end of the year, which was less the case in 2022. In addition to the surge in prices amid the energy crisis, a return to more normal work patterns and warmer temperatures weighed heavily on UK residential consumption in 2022.

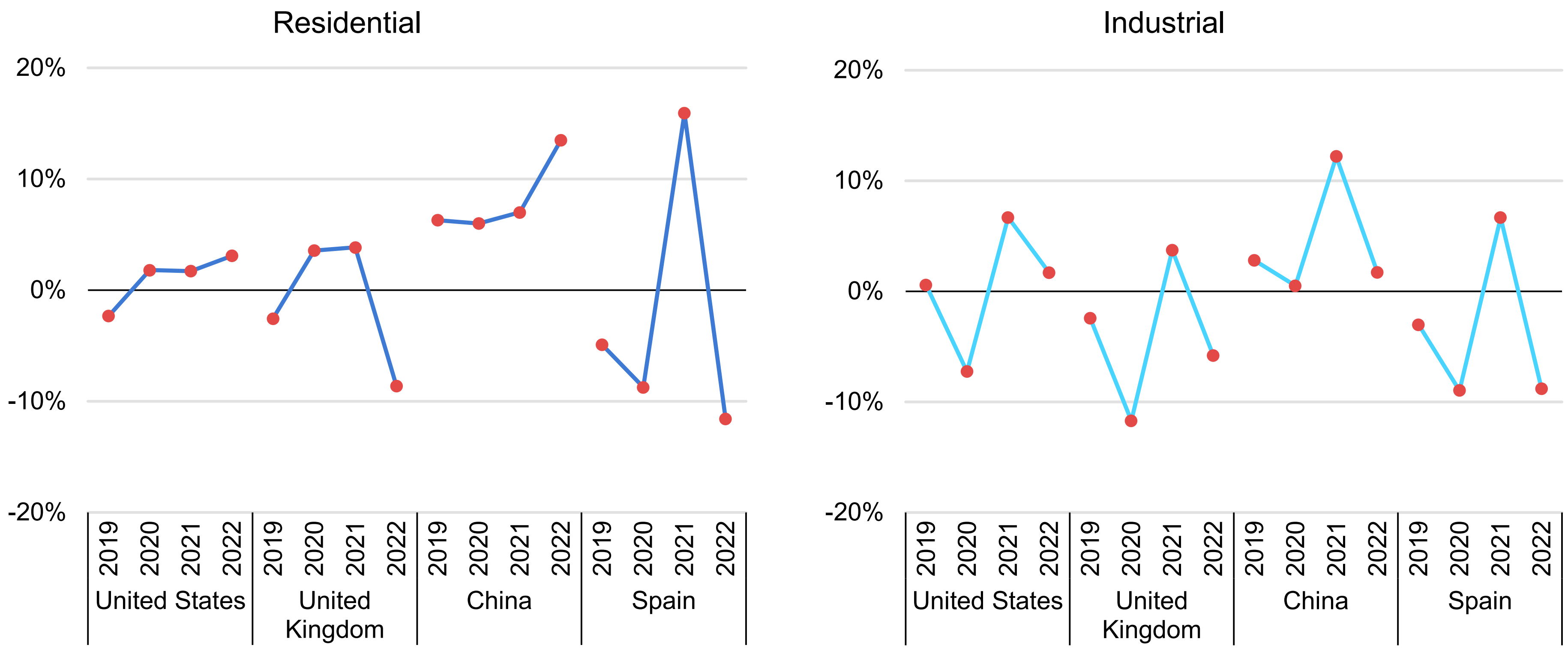
China's zero-Covid policy in 2022 boosted residential electricity demand while growth in the industrial sector was tempered by weaker economic activity. Residential power consumption has been steadily increasing as the electrification of homes rapidly expands, with a growing share of electricity used in cooling, heating, cooking and appliances. The country's house-bound population propelled residential electricity demand up by a sharp 13.5% in 2022.

By contrast, China's strict pandemic restrictions and lockdowns disrupted the country's economic activity. As a result, electricity demand in the industrial sector was up a modest 1.7%. Coal supply shortages also caused power restrictions and outages in industrial hubs such as in Northeast China and the provinces of Guangdong and Hunan, further contributing to the slowdown.

In the United States, residential electricity consumption saw a similar y-o-y growth in 2022 as in the previous two years. Weaker industrial electricity demand growth mainly reflected the slowdown in the economy.

The United Kingdom and Spain saw a decline in industrial electricity consumption in 2022

Year-on-year change in sectoral electricity consumption in selected large economies, 2019-2022



Note: The analysis is based on data for the first three quarters of 2019-2022.
Sources: IEA analysis using data from the China Electricity Council (China) (2023), U.S. Energy Information Administration (United States) (2023), GOV.UK (United Kingdom) (2023), Red Eléctrica (Spain) (2023), 31 January 2023.

Supply

Low-carbon sources set to cover almost all the growth in global electricity demand by 2025

Power systems faced challenges in multiple regions in 2022 due to extreme weather events. Heatwaves and droughts strained the supply situation in both China and India. A historic drought in Europe resulted in low hydropower output, putting increased pressure on dispatchable capacities amid record-low nuclear generation in France. In the United States, winter storms caused widespread power outages. These extreme events reinforce the urgent need to increase the flexibility of the power system and enhance security of electricity supply to better cope with weather-related contingencies.

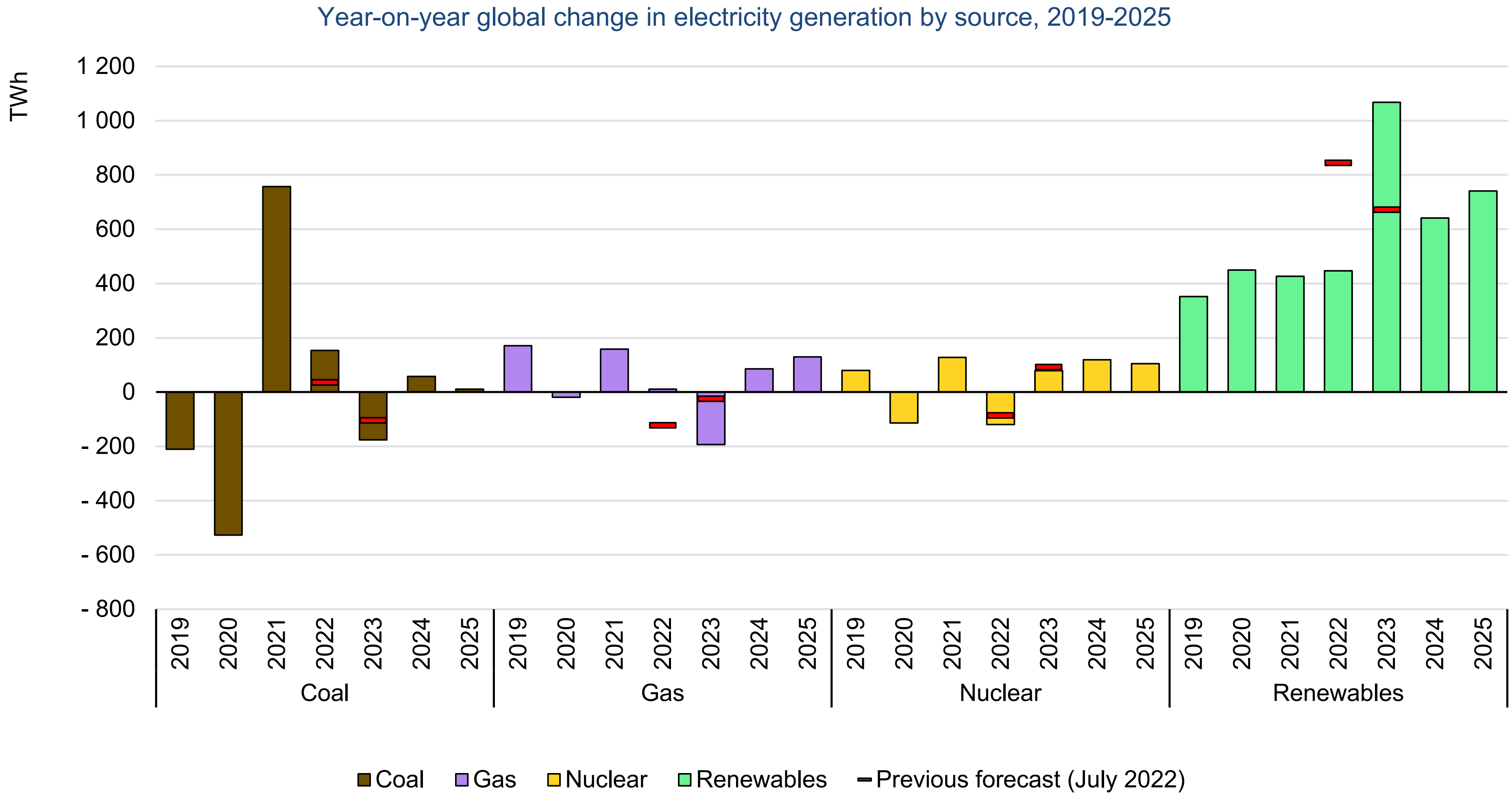
In 2022, the surge in fossil fuel prices following Russia's invasion of Ukraine also compounded the supply situation, especially for gas. The relatively higher increase in natural gas and LNG prices prompted a wave of fuel switching in the world to coal for use in power generation. Global **coal-fired generation** rose by 1.5% in 2022, with the largest absolute increases in the Asia Pacific region. Coal-fired generation also rose significantly in the European Union amid low hydro and nuclear output. However, 2022 is likely to be an exception and global coal-fired generation is forecast to plateau in 2023-2025, as higher output in the Asia Pacific region is offset by declines in Europe and the Americas.

Global **gas-fired generation** remained relatively unchanged in 2022 compared to 2021, as declines in China, India and other regions were largely offset by a rise in gas-fired output in the United States. We expect global gas-fired generation to stagnate to 2025 on average, after declining by 3% in 2023, then growing by 1.4% in 2024 and 2% in 2025. Substantial declines in the EU will partly be offset by significant growth in the Middle East.

Low-carbon generation from renewables and nuclear had diverging trends in 2022. **Renewables** saw a year-on-year rise of 5.7%, making up almost 30% of the generation mix. A surge in renewable generation in the Asia Pacific region accounted for more than half of the increase, followed by Americas. By contrast, **nuclear** output fell 4.3%. This was due to maintenance outages at a large number of French plants, decommissioning of units in Germany and Belgium, and reduced Ukrainian output.

Our **outlook for 2023 to 2025** shows that renewable power generation is set to increase more than all other sources combined, with an annualised growth of over 9%. Renewables will make up over one-third of the global generation mix by 2025. This trend is supported by government pledges to increase spending on renewables as part of economic recovery plans such as the Inflation Reduction Act in the United States. Nuclear output is expected to grow by 3.6% per year on average, mainly due to the increase in Asia Pacific, plus French generation returning to normal. As a result, low-carbon generation sources – renewables and nuclear together – are expected to meet on average more than 90% of the additional electricity demand over the next three years, unless developments in the global economy and weather events change the trends in electricity demand and fossil-fired generation.

Renewables growth dampens fossil fuel-fired generation from 2023 to 2025



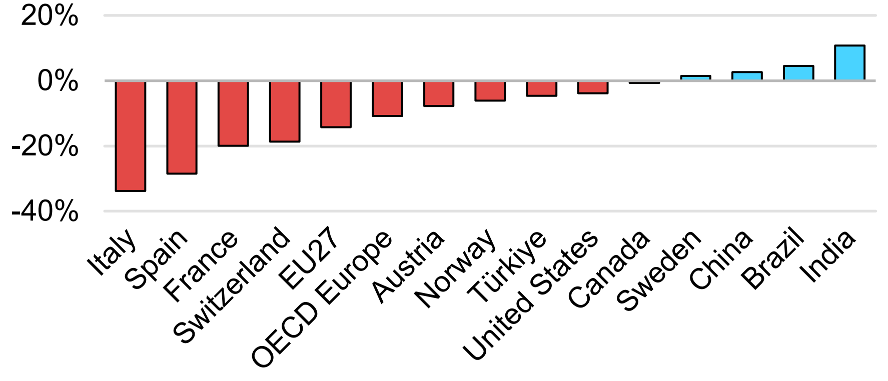
Hydropower generation exceptionally low in Europe in 2022 due to the historic drought

The year 2022 was characterised by heatwaves and droughts in many regions, causing significant declines in hydropower output. This has underscored the potential impacts of changing climate patterns on power systems as low hydropower generation puts additional strain on the remaining dispatchable conventional fleet and increases the cost of electricity supply. Despite these uncertainties, our current outlook sees global hydropower supply grow in 2023 to 2025 on planned capacity expansions.

Europe saw its worst drought in 500 years in 2022. Italy had a record drop in hydropower output, posting its lowest hydropower generation in the last two decades in the February-April 2022 period. Italy's hydro use was down more than 30% compared to 2017-2021 averages, followed closely by Spain at 29% and France at 20%. Norway had the driest 12-month period in 26 years, with hydro reservoir levels in September declining to the lowest monthly output in the last decade. Republic of Türkiye (hereafter "Türkiye"), which saw its lowest hydro output in 2021 since 2014, had a strong 20% year-on-year rebound in 2022 but remained 5% below its 2017-2021 average.

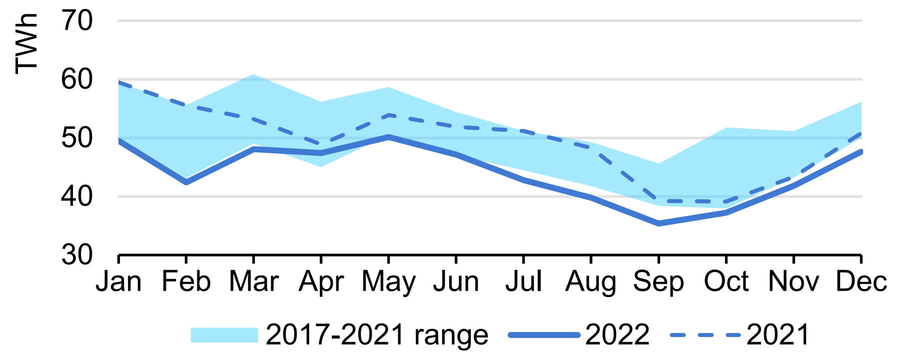
In **China**, drought conditions in Sichuan caused a significant drop in hydropower output during August and September, depressing annual growth to just below 1% in 2022. In **India**, despite a record heatwave in 2022, hydropower generation increased more than 10% above its 2017-2021 average.

Percentage change in hydropower generation in 2022 compared to the 2017-2021 average in selected countries and regions



Source: IEA (2023), Monthly Electricity Statistics, 31 January 2023.

Monthly hydropower generation in OECD Europe, 2017-2022



Source: IEA (2023), Monthly Electricity Statistics, 31 January 2023.

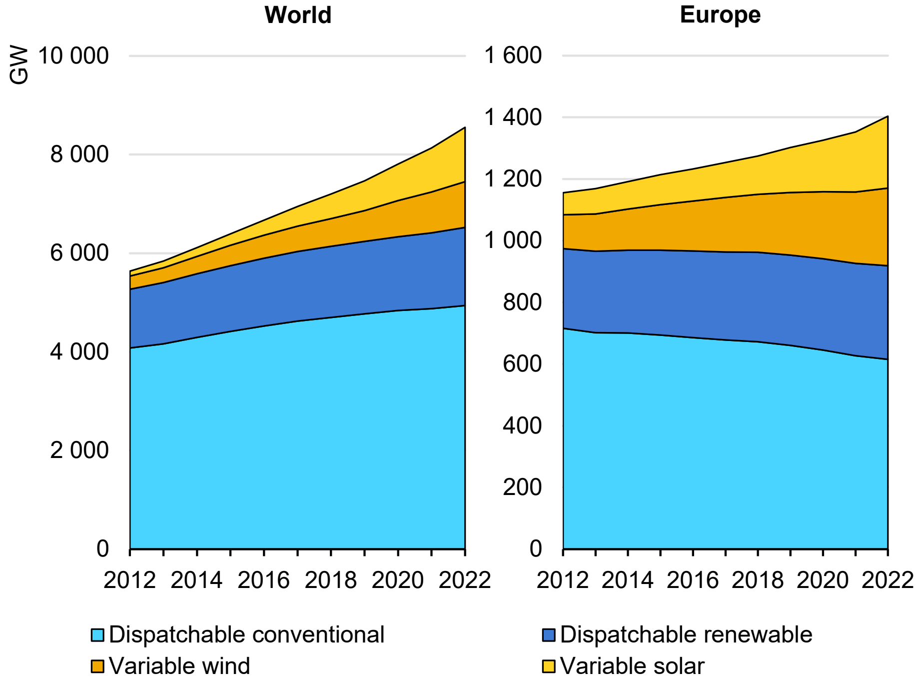
Significant potential to integrate more renewables in the world's electricity generation fleet

Global installed capacity of renewables is estimated to have increased at a faster year-on-year rate of almost 11% in 2022 compared to the average 9% growth seen in the 2017-2021 period. Variable renewables – wind and solar PV – continued to see strong growth in combined capacity, up nearly 18%. This corresponds to about 300 GW in additional installed capacity of variable renewables, which is greater than the current combined wind and solar PV cumulative capacity in the United States (approximately 280 GW).

Despite continued growth in 2022, the share of variable renewable capacity in the total generation fleet remains below 25% in the world, whereas in Europe it is 35%. In countries with high variable renewables penetration, variable wind and solar PV can make up more than 60% of the total generation capacity (e.g. Denmark, Germany). From a global perspective, there is enough potential for further capacity expansions of variable renewables in many regions of the world without facing major system integration bottlenecks.

As the share of variable renewables increases in the generation fleet, their successful integration into the power system will increasingly become more challenging. For the balancing of variable generation, apart from expanding storage capacities and increasing demand-side flexibility, having sufficient dispatchable capacity will be crucial. In a decarbonised electricity sector, dispatchable renewables such as hydro reservoir, geothermal and biomass plants will be essential for complementing the variable renewables.

Evolution of dispatchable and variable generation capacities in the world and in Europe, 2012-2022



Note: Dispatchable renewable capacity in the figure also includes run-of-river hydropower plants.
Sources: IEA (2022), World Energy Outlook 2022; IEA (2022), Renewables 2022.

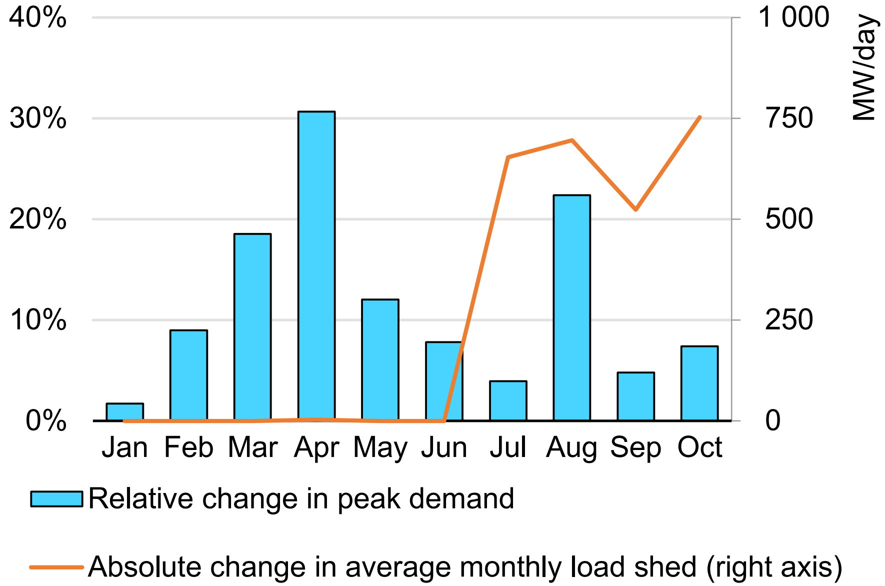
Affordability of energy remains a challenge for emerging and developing economies

The cost of electricity generation in 2022 increased in many parts of the world, led by surging energy commodity prices. The rise in generation costs has been more moderate in places with regulated tariffs and long-term fuel supply agreements. However, regions depending on short-term markets for fuel procurement were severely affected by the steep rise in prices. In particular, record-high LNG prices created financial hardships for South Asian countries – most notably Bangladesh and Pakistan – trying to procure gas for the electricity sector, and significantly contributed to power outages and rationing.

In **Bangladesh**, natural gas plays a prominent role in electricity supply, making up about 80% (2018-2022 average) of the generation mix. At the same time, Bangladesh relies on LNG imports to meet fuel demand for power generation and was therefore hit hard by high LNG prices in 2022. LNG accounts for approximately [20% of the total natural gas] consumption of Bangladesh. Because of a notable decrease in its [foreign exchange reserves], the government stopped buying LNG from the spot market during the period of July-November 2022, which resulted in fuel shortages for the power sector.

Following the LNG shortage, Bangladesh faced harsh power disruptions due to load shedding, where forced supply interventions were carried out to resolve the imbalance between electricity demand and supply. During these outages, electricity supply to areas [with industrial production activities] were given priority to minimise the impact on the industrial sector. Nevertheless, industries as well as households faced electricity scarcity and outages.

Year-on-year monthly change in electricity peak demand and load shedding, Bangladesh, January-October 2022 vs. 2021



Note: Average load shed is calculated as an average of day peak and evening peak load shed.

Source: IEA analysis based on Ministry of Information and Broadcasting (Bangladesh) (2023), [Monthly Management Report], 10 January 2023.

Pakistan was also severely affected by the high prices of fossil fuels due to its strong reliance on fossil fuel imports, as gas (20%) and coal (30%) play a significant role in its power generation mix. In 2022, electricity production from imported LNG fell by approximately 13% compared to 2021. The reduced LNG imports were attributed to the country's inability to afford the supplies at the sharply elevated price levels.

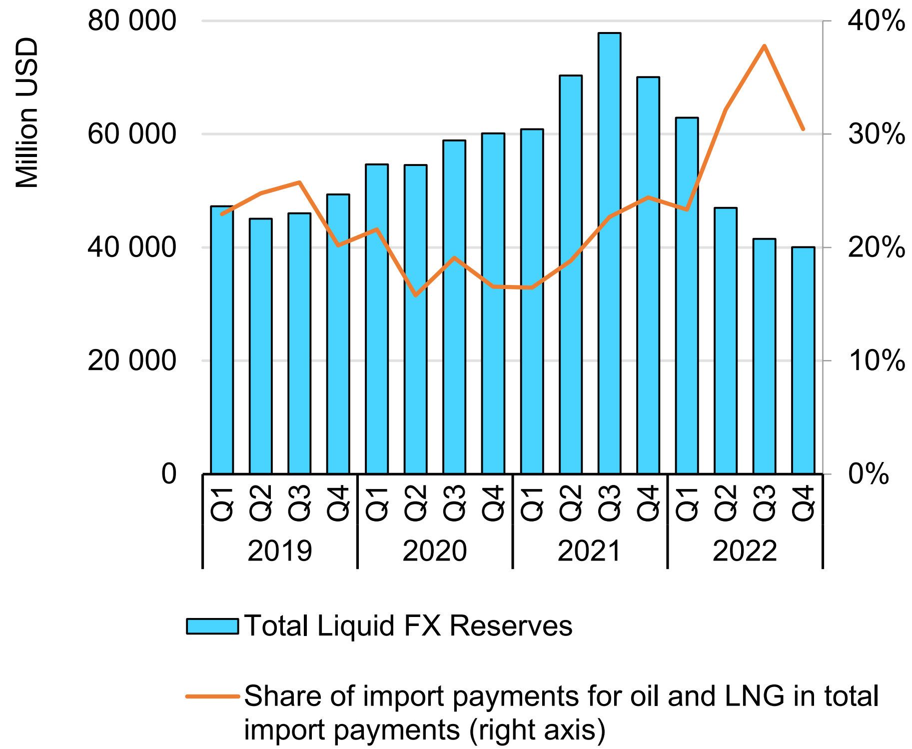
Similarly, in the face of a tight coal market, imports of high calorific-value coal declined in 2022, leading to closures of coal-fired power plants. By contrast, lignite-fired plants experienced a surge in output during 2022, attributed to an increase in domestic lignite production coupled with a fourfold expansion in imports from Afghanistan, payable in Pakistani rupees, in H1 2022.

Fuel shortages for the power sector were further exacerbated by the country's severe flooding between July and September. Consequently, a quarter of the total operational power generation capacity had to be shut down. This contributed to scarcity of electricity supply and subsequent power outages.

In 2022, Pakistan's liquid foreign exchange reserves reached their lowest level since 2014, leading to the prioritisation of energy imports to the detriment of other imports. This caused the shutdown of some industrial facilities due to a lack of imported raw materials.

For emerging markets and developing economies, fuel procurement will continue to be an important issue if energy commodity prices remain high in the coming years. Increased integration of renewable energy sources will not only serve to decarbonise the energy sector but would also reduce reliance on fossil fuel imports and help shield the economies from external fuel price shocks.

Quarterly evolution of liquid foreign exchange reserves and the share of payments for oil and LNG imports in the payments for total imports, Pakistan, 2019-2022



Note: Oil refers to petroleum products and crude oil.
Sources: IEA analysis based on State Bank of Pakistan (2023), Import Payments by Commodities and Groups, Gold and Foreign Exchange Reserves of Pakistan, 10 January 2023.

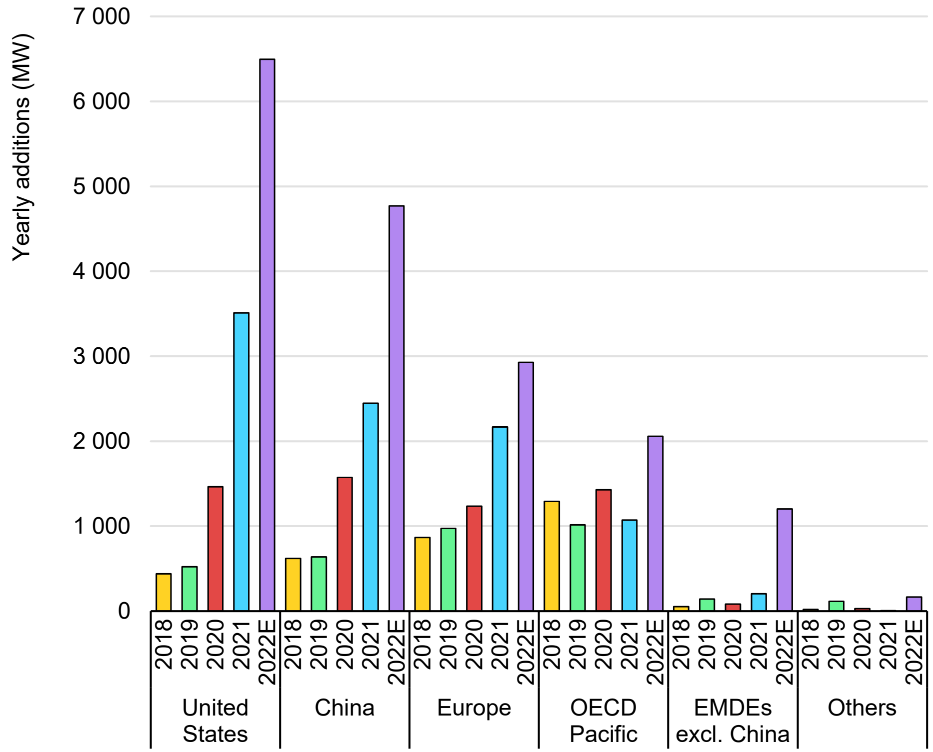
Stationary battery storage capacity additions are speeding up in emerging economies

As the share of variable renewable sources in electricity systems further increase globally, battery systems are expected to play a growing role by providing frequency control and operational reserves as well as for wholesale arbitrage, while helping reduce grid integration costs. The deployment of stationary battery systems is speeding up. In absolute magnitude, the United States, Europe and China are leading the latest annual capacity additions. However, based on our 2022 estimates, emerging markets and developing economies are on the way to catching up.

Compared with 2021, capacity additions in 2022 rose by over 80% in the United States, almost 100% in China, roughly 35% in Europe, 90% in OECD Pacific (i.e. Japan, Korea, Australia and New Zealand) and about sixfold in EMDEs, excluding China. In 2022, the largest fleet of cumulative battery systems installed remains in the United States while China surpassed Europe in cumulative capacity, reaching a total of 10 500 MW compared to Europe's 9 400 MW.

The deployment rate in EMDEs gathered pace in 2022, with capacity additions more than twice as high as the total cumulative additions in 2015-2021. In China and the United States, over 45% of the installed cumulative capacity was deployed in 2022. By contrast, in EMDEs (excluding China), capacity additions in 2022 had a relatively much higher impact, accounting for almost 70% of the total cumulative capacity in these regions.

Yearly stationary battery system additions by country and region, 2018-2022



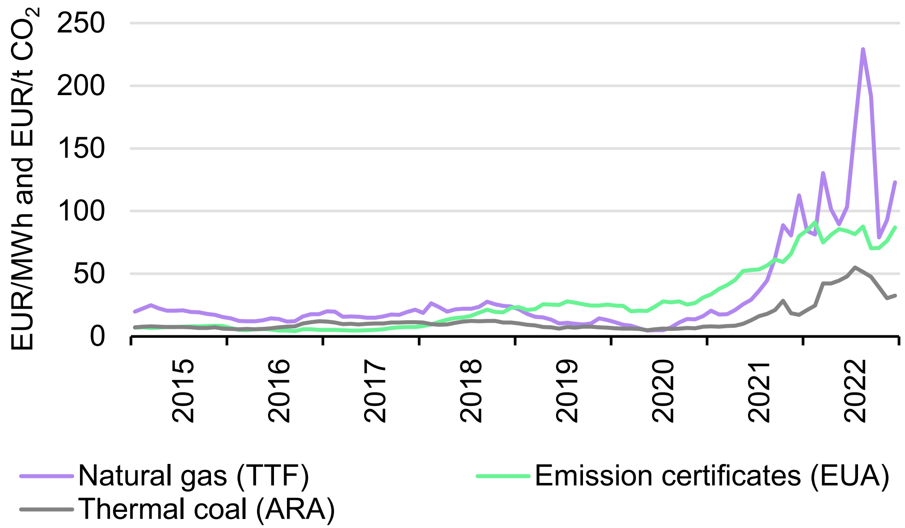
Note: 2022 values are estimates.
Sources: IEA calculations based on Clean Horizon (2022), BNEF (2022), China Energy Storage Alliance (2022).

The surge in coal and gas prices raised thermal generation costs to decade highs in 2022

Russia's invasion of Ukraine put unprecedented pressure on European and global energy markets. Natural gas and thermal coal prices in Asian and European spot markets rose to all-time highs throughout 2022, sharply increasing the cost of thermal generation in those markets. In the United States, tight supply and demand fundamentals drove both coal and natural gas prices to decade highs. Thermal generation costs are expected to remain well above historical averages out to 2025, further eroding their competitiveness compared to low-emission alternatives.

In the **European Union**, estimated gas-based thermal generation cost more than doubled in 2022 compared to the previous year, to an average of USD 350/MWh. Coal-based thermal generation costs almost doubled to an average of USD 190/MWh. This has been primarily driven by the rapidly tightening gas and coal market fundamentals. Russia more than halved its pipeline gas supplies to the European Union in 2022 – a year-on-year drop of 80 bcm in absolute terms. Consequently, European gas prices soared to record highs. Gas prices on the Title Transfer Facility (TTF) in the Netherlands, the region's leading hub, averaged USD 37/MBtu (EUR 123/MWh) in 2022 – more than five times their 2016-2021 average. The strong increase in gas prices provided upward pressure on thermal coal prices through fuel-switching dynamics in the power sector. Rotterdam thermal coal prices averaged at an all-time high of USD 290/t (EUR 40/MWh) in 2022. Despite record-high prices for coal and gas, gas- and coal-fired generation rose in the European Union by about 2% and 6% y-o-y, respectively, as low hydro and nuclear power output increased the call on thermal power plants.

Monthly average prices of natural gas, thermal coal and emission certificates, Europe, 2015-2022



Sources: Natural gas prices from TTF; coal prices are CIF ARA; emission certificate prices are EUA prices from EU ETS.

The price of the emissions allowances (EUA) on the EU Emissions Trading System (EU ETS) saw record highs, reaching almost EUR 100/t CO_2 in August 2022. The surge in emission prices was mainly driven by the increase in coal-fired generation, which then resulted in stronger demand for the allowances. Later in 2022, carbon prices fell, as lower gas prices reduced gas-to-coal switching in power generation. Despite this, in 2022 EU ETS prices at an average EUR 81/t CO_2 were 50% more expensive than in 2021. Even with the rising costs of CO_2 emissions in 2022 – which weigh proportionally on coal power much more due to higher CO_2 emission factors – the generation cost of coal-fired power plants in Europe remained substantially below that of gas-fired plants.

Forward curves as of late January 2023 indicate that, despite declining, both natural gas and coal prices remain well above their pre-2021 historical averages through to 2025, at USD 15-20/MBtu and USD 130-170/t, respectively. By 2025 generation costs from gas are expected to decline and approach coal-fired generation cost levels.

In **Asia**, estimated gas-based thermal generation costs in Japan and Korea rose by 65% in 2022, to an average of USD 135/MWh. Coal-based thermal generation costs increased by more than 70% to over USD 100/MWh. The steep drop in Russian piped gas supply to the European Union was largely offset by LNG, driving up competition between Asian and European buyers. This put strong upward pressure on Asian spot LNG prices, which averaged an all-time high of USD 30/MBtu in 2022. Oil-indexed LNG prices displayed less volatility, averaging about USD 15/MBtu. High spot LNG prices and flood-induced supply outages in Australia also drove Newcastle coal prices to peak levels, to an average of USD 360/t.

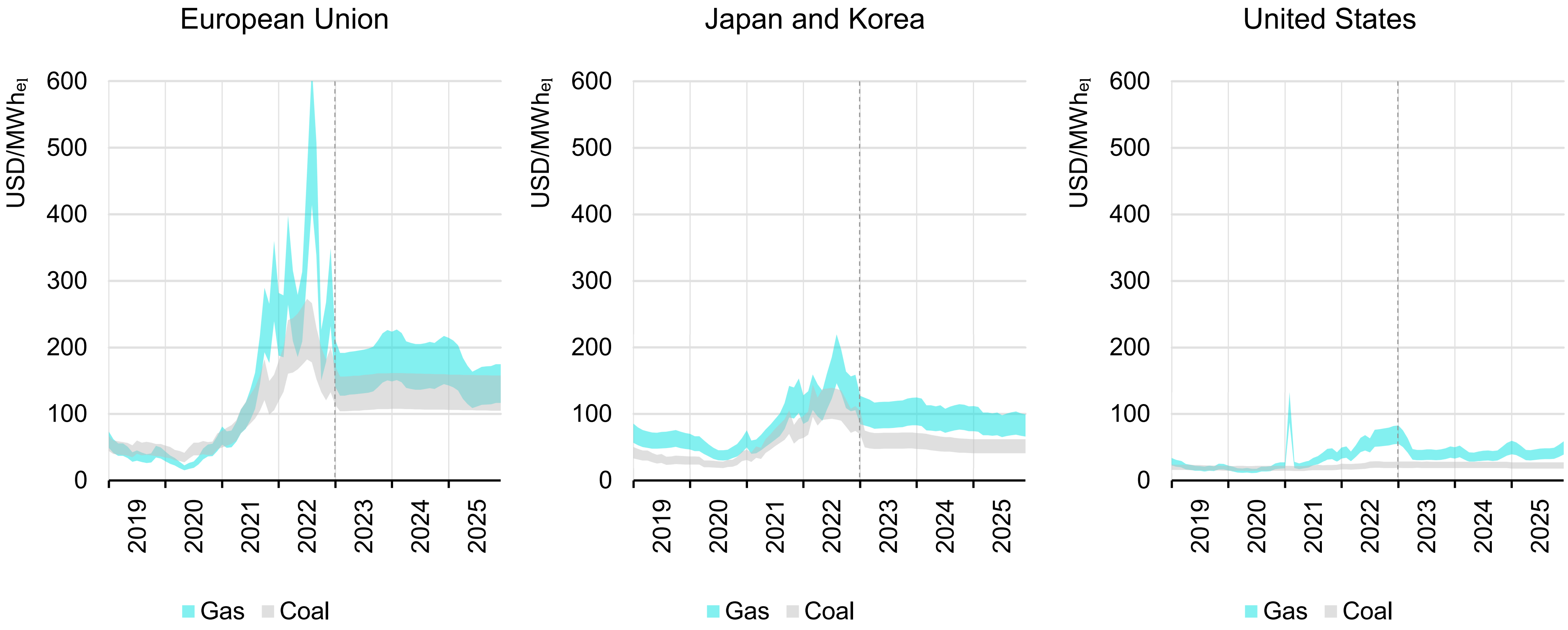
Forward curves as of late January 2023 indicate that spot LNG and thermal coal prices are expected to remain elevated, putting upwards pressure on thermal generation costs out to 2025. Despite this, the thermal generation costs in Korea and Japan would be roughly half that of Europe in 2025 according to the forward prices.

In the **United States**, the cost of gas supplied to power plants increased substantially, by more than 50% y-o-y, driving up the cost of gas-fired generation by a similar magnitude in 2022. This was driven by a number of factors: supply constraints and low inventory levels elevated thermal coal prices; the Central Appalachia benchmark averaged USD 170/t – its highest level since 2010; reduced availability of thermal coal increased the call on gas-fired power plants; and higher gas burn in the power sector, together with below-average gas storage levels and rising LNG exports, tightened gas market fundamentals. As a result, Henry Hub prices rose by more than 60% y-o-y, to an average of USD 6.50/MBtu in 2022.

Tight market conditions are expected to linger into the medium term based on forward curves at the start of January 2023 that show natural gas and coal prices remaining above their historical averages, at USD 3-5/MBtu and USD 110-150/t, respectively, in 2023-2025. The generation cost gap between electricity generation from coal and gas narrows based on the forward prices.

Large regional differences in thermal generation costs by 2025, with Europe about twice as high as Asia

Generation costs of coal- and gas-fired power plants including emission costs, 2019-2025



Notes: Coal range reflects 33-45% efficiency; gas range reflects 43-55% efficiency. Due to the large geographic areas covered in each region, costs can differ between and within countries and should therefore be interpreted as general trends. In the United States, natural gas prices increased significantly (exceeding USD 15/MBtu) in February 2021 due to supply constraints. 2023-2025 costs for the regions are based on forward prices of fuels as of end of January 2023 and should not be interpreted as forecasts, rather as costs reflecting the current market expectations. Fuel price assumptions for the model forecasts presented in this report are based on average forward prices.

Sources: United States: based on EIA (2023), STEO January 2023. European Union: natural gas prices TTF; coal prices CIF ARA; emission costs EU ETS. Japan and Korea: natural gas prices reflect estimated LNG import prices, including via oil-indexed LNG contracts and spot procurements; coal prices are Japan marker prices. Latest update: 31 January 2023.

Emissions

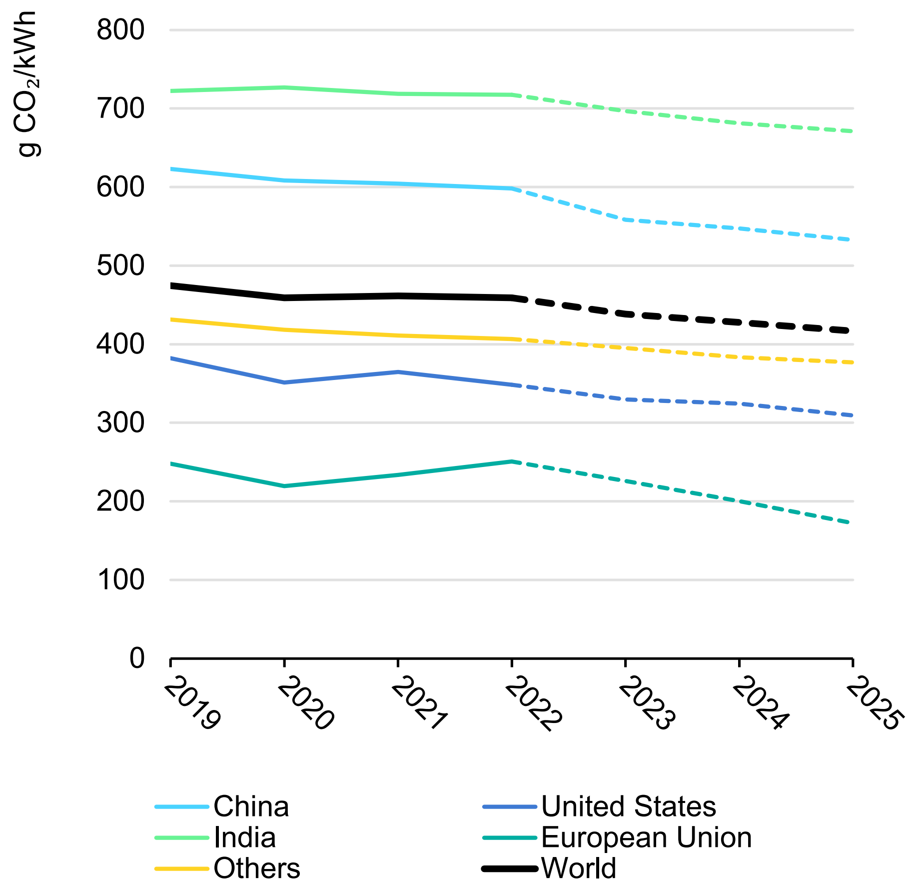
The world reached a new all-time high in power generation-related emissions in 2022

We estimate that the world reached a new all-time high of about 13.2 Gt CO_2 in power sector emissions in 2022, a year-on-year increase of 1.3%. Record-level emissions in 2022 were mainly due to growth in fossil-fired generation in Asia Pacific. Europe and Eurasia also contributed to this increase. Similar to what was highlighted in the IEA's World Energy Outlook 2022 for the overall energy sector, the rise in power sector emissions in 2022 was still less than the y-o-y change in 2021 related to the post-pandemic rebound.

After a projected decline in global electricity generation CO_2 emissions in 2023 due to lower gas- and oil-fired generation, we forecast that emissions will plateau out to 2025. In the 2023-2025 period, lower emissions in regions such as Europe and the Americas (each down roughly 70 Mt/yr on average) partly offset the significant increases in Asia Pacific (up 100 Mt/yr on average), mostly attributed to China and India. By 2025, the Asia Pacific region will account for 67% of global power sector emissions (up from 64% in 2022). Trends from other regions show mild growth or remain flat.

In 2025, CO_2 intensity of global power generation would reach 417 g CO_2/kWh, a decline of 3% on average each year to 2025. The average annual rate of decline from 2023 to 2025 is markedly steeper in Europe (-12%) and the United States (-4%).

Regional evolution of power system CO_2 intensity, 2019-2025

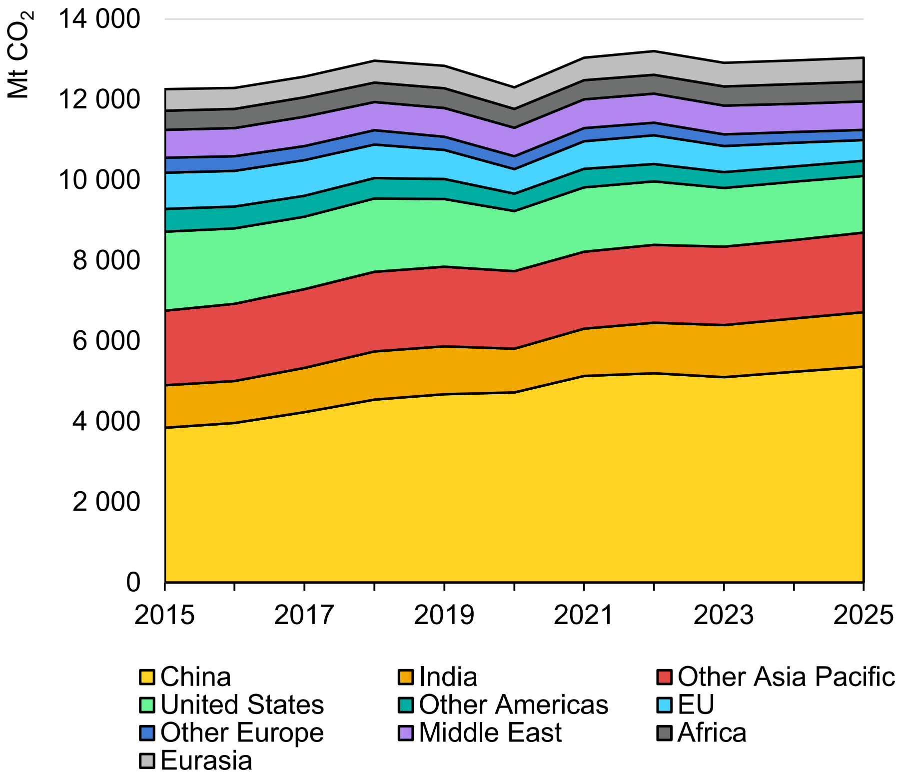


IEA. CC BY 4.0.

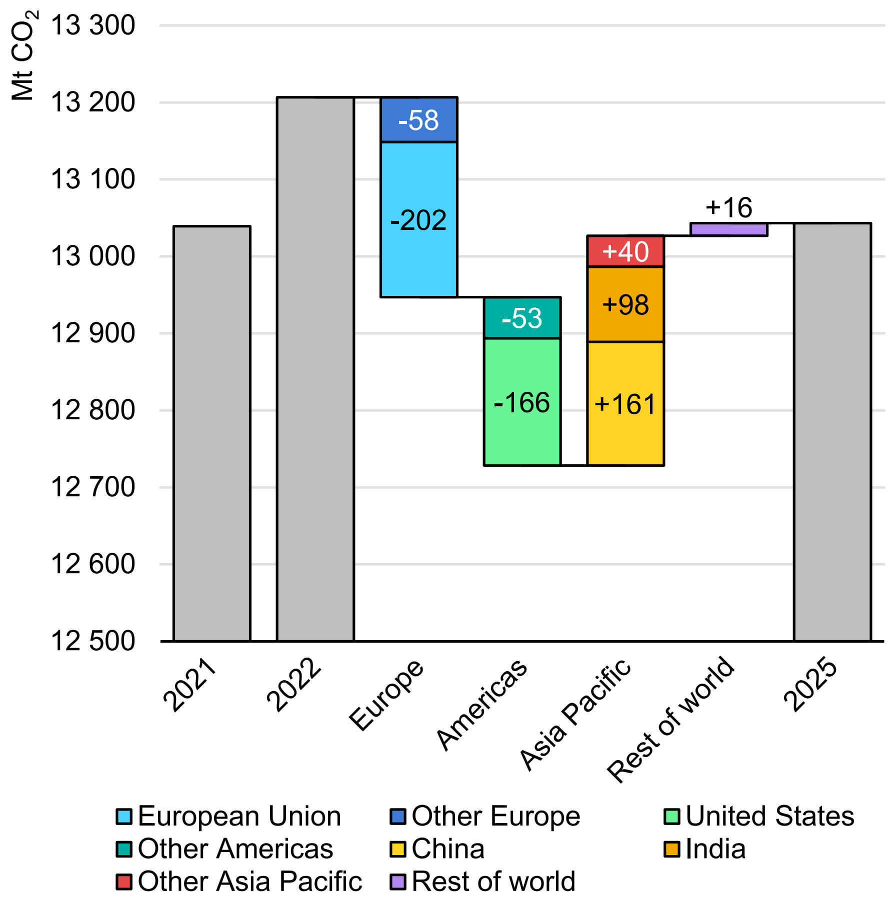
Note: The CO_2 intensity is calculated as total CO_2 emissions divided by total generation.

Global emissions of power generation are expected to plateau from 2023 through 2025

Global emissions of power generation, 2015-2025



Changes in global emissions of power generation, 2021-2025



Wholesale prices

Electricity prices remain elevated in many regions, led by the high cost of energy commodities

The global energy crisis, with soaring prices of energy commodities combined with the pandemic rebound and supply chain issues, has resulted in substantially higher wholesale electricity prices in many regions of the world in 2022 over year-ago levels.

In a large number of **European** countries, wholesale electricity prices (i.e. day-ahead spot prices) in H2 2022 exceeded the second-half average prices between 2019 and 2021, e.g. fourfold in France. In H2 2022, the average wholesale price reached almost EUR 330/MWh in Germany and surpassed EUR 320/MWh in France, exacerbated by nuclear unavailabilities. By contrast, in Spain, average prices were much lower for the same time period at about EUR 130/MWh due to the Iberian price cap. The demand-weighted average price for Germany, France, Spain and the United Kingdom in H2 2022 was almost four times as high as the H2 2019-2021 average.

The elevated futures prices in Europe for winter 2023/24 reflect the continued uncertainties associated with gas supply for Europe. Futures with delivery in Q4 2023 are EUR 227/MWh in France and EUR 184/MWh in Germany while those for Q1 2024 are EUR 258/MWh in France and EUR 186/MWh in Germany.

On the **Nord Pool** power exchange, average wholesale electricity prices remained at unprecedented high levels in H2 2022, exceeding EUR 150/MWh. Low hydro availability in the Nordics and increased cross-zonal demand pushed prices up by almost 90% year-on-year, yet they remained below European averages.

In the **United States**, the average wholesale price in H2 2022 stood at about USD 91/MWh, more than twice the 2019-2021 second-half average, and 65% higher than the price in H2 2021. This increase was driven by exceptionally high gas prices.

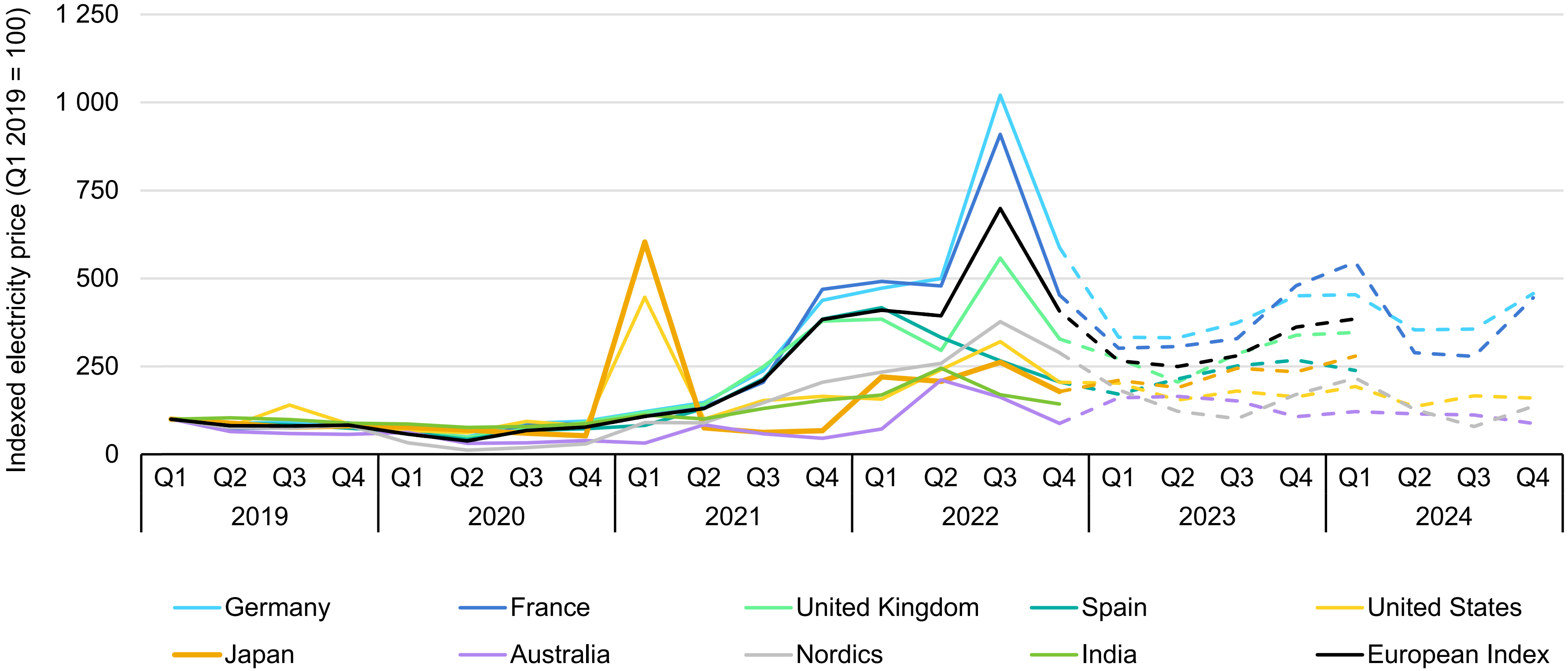
Japanese wholesale prices in H2 2022 averaged almost YEN 22 000/MWh (EUR 155/MWh), three times higher compared to H2 2021 because of the tight supply situation. The increased prices of fossil fuels also affected Japan because of its low energy self-sufficiency ratio. However, the majority of the imported LNG volumes is contracted under oil-indexed long-term contracts which alleviated some of the effects of soaring spot prices.

In 2022, **Australian** wholesale prices averaged AUD 170/MWh (Australian dollars; EUR 110/MWh), more than double the H2 2021 levels. This was due to surging electricity demand and gas prices.

In **India**, despite increased coal stocks, higher electricity consumption resulted in a 10% price rise in H2 2022 over the H2 2021 level. The average wholesale price in H2 2022 was INR 5 000/MWh (Indian rupees; EUR 55/MWh). Strong growth of solar PV helped to meet peak loads driven by higher refrigeration and space cooling.

Elevated futures prices in Europe reflect risks of tight supply in the winter of 2023/24

Indexed quarterly average wholesale prices for selected regions, 2019-2024

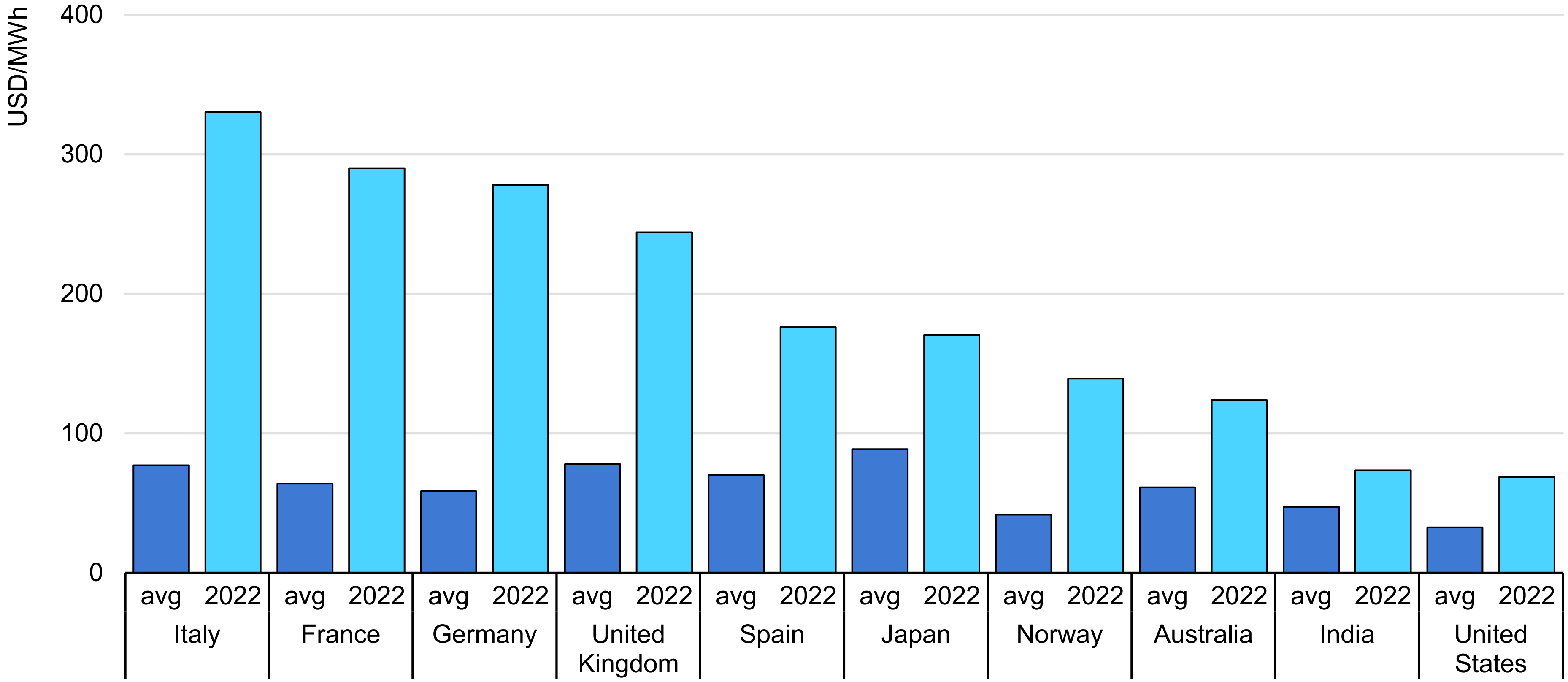


Notes: The European Index is calculated as the demand-weighted average of the prices for the European countries included in the analysis. For the Nordics region, the Nord Pool system price is used for the historical prices and EEX Nordics futures are used for forward prices. The prices for Australia and the United States are calculated as the demand-weighted average of the available prices of their regional markets. Continuous lines show historical data and dashed lines refer to forward prices. Price estimates for Q1 2023 and beyond are based on the historical prices and the latest forward baseload electricity prices, except for the United States, where we use EIA (2023) values. The forward prices for Japan are volume-weighted estimates of the latest JPX settlement prices, considering the baseload contracts (areas B1 and B3).

Sources: IEA analysis using data from RTE (France) and Red Eléctrica (Spain) – both accessed via the ENTSO-E Transparency Platform; Bundesnetzagentur (2023), SMARD.de; Elexon (2023), Electricity data summary; AEMO (2023), Aggregated price and demand data; EIA (2023), Short-Term Energy Outlook January 2023; Nord Pool (2023), Market Data; IEX (2023), Area Prices; EEX (2023), Power Futures; JPX (2023), Daily Data (Electricity Futures); ASX (2023), Electricity Futures © ASX Limited ABN 98 008 624 691 (ASX) 2020. All rights reserved. This material is reproduced with the permission of ASX. This material should not be reproduced, stored in a retrieval system or transmitted in any form whether in whole or in part without the prior written permission of ASX. Latest update: 31 January 2023.

Electricity markets were impacted differently across the world – Europe being hit the hardest

Annual wholesale prices in selected countries, 2022 and 2017-2021 average



Notes: Avg refers to an average of the years from 2017 to 2021. The annual averages are calculated from the daily wholesale electricity prices.

Source: IEA analysis using data from RTE (France) and Red Eléctrica (Spain) – both accessed via the ENTSO-E Transparency Platform; Bundesnetzagentur (2023), SMARD.de; Elexon (2023), Electricity data summary; AEMO (2023), Aggregated price and demand data; EIA (2023), Short-Term Energy Outlook January 2023; Nord Pool (2023), Market Data; IEX (2023), Area Prices. Latest update: 31 January 2023.

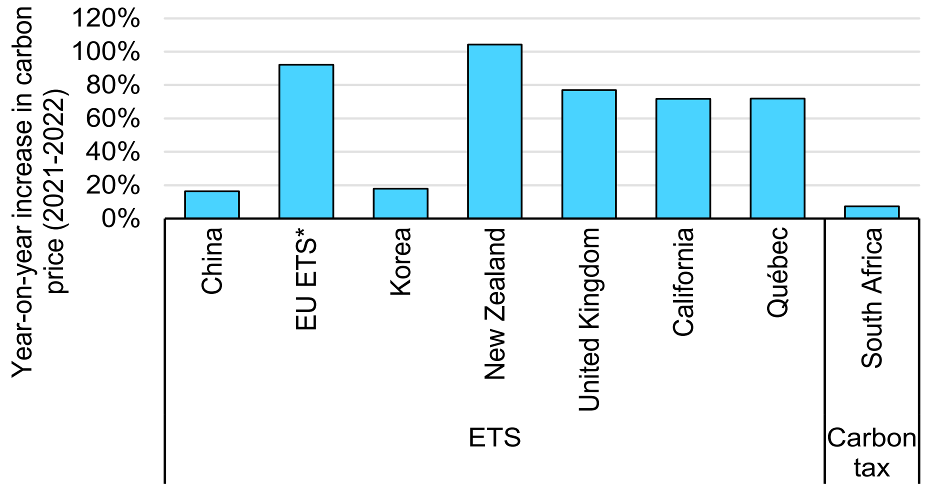
Carbon pricing trends

Status and trends of carbon pricing mechanisms in 2022

Carbon pricing is a key instrument to mitigate emissions, incentivise investments in low-carbon technologies and reduce demand for greenhouse gas (GHG)-intensive activities. Such policy instruments usually take the form of a carbon tax, an Emission Trading System (ETS) or a hybrid of the two. Due to the ongoing energy crisis, carbon pricing policies have entered uncharted territory, and are facing new challenges hindering their effectiveness. While the EU's carbon price influences the variable generation cost, and hence the merit-order of the power plants, carbon pricing is currently unable to perform its traditional role of incentivising a coal-to-gas switch in electricity production given exceptionally high gas prices. Nevertheless, carbon pricing still has a crucial role to play in maintaining a long-term investment signal and making carbon-intensive fossil generation such as coal-fired electricity an economically unattractive solution. In addition, it can be a useful instrument to generate additional revenue for governments to support faster clean energy transitions, and mitigate social and competitiveness impacts.

As of April 2022, 68 carbon pricing initiatives were in place worldwide, covering over 23% of GHG emissions, with the majority in the form of an ETS. Many of them saw carbon price increases compared to 2021. The price of allowances in the EU ETS, the most established ETS globally, rose from an average of USD 50/t CO_2-eq to more than USD 90/t CO_2-eq for January to April 2022. Prices in the UK ETS rose to more than USD 100/t CO_2-eq, and doubled in the New Zealand ETS (USD 50/t CO_2-eq) and in state-level systems in the United States. Allowance prices in Korea (USD 19/t CO_2-eq) and China's national ETS (USD 9/t CO_2-eq) increased only slightly. Despite these increases, less than 10% of global emissions are covered by a carbon price that is higher than USD 10/t CO_2-eq. In some jurisdictions in 2022, carbon pricing instruments have had difficulty incentivising a fuel switch to lower-carbon sources due to high natural gas prices. For example, EU coal-fired generation rose by 6% in 2022.

Price evolution of selected carbon pricing instruments (as of April 2022, annual average levels)

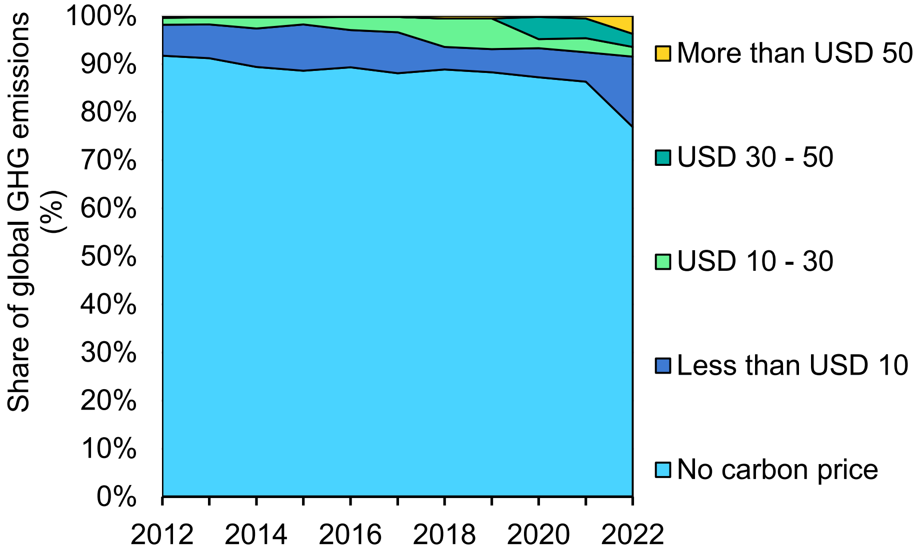


*The EU ETS operates in all EU countries, Iceland, Liechtenstein and Norway.

Notes: The year-on-year increase compares the 2021 full-year averages versus the 2022 January-April averages.

Sources: World Bank Carbon Pricing Dashboard, ICAP, and Ember.

Share of global GHG emissions covered by a carbon price, by price level, 2012-2022



Source: World Bank (2022), Carbon Pricing Dashboard, 15 November 2022.

Increases in carbon prices and coverage have led to a new record of revenues raised by these instruments, reaching USD 140 billion in 2021, with ETS revenues more than doubling within a year (USD 26 billion to USD 56 billion). Schemes differ in the use of their revenues. California's Cap-and-Trade, for example, returns the majority of revenues to power companies and, ultimately, electricity consumers, while another part is used for carbon mitigation programmes through its Greenhouse Gas Reduction Fund. This notably includes programmes on renewable energy integration towards low-income households.

China's national ETS, introduced in 2021 and covering the power sector only, is the biggest carbon market, and accounts for about 9% of global GHG emissions. The introduction of partial auctioning of allowances – instead of free allowance allocation – in the power sector as well as expansion to industry are currently being considered. Japan's GX League, composed of over 500 companies, has started pilot trading in its voluntary carbon market, with official trading starting in April 2023. This includes major participants in the electricity, gas and heat and water sectors, such as TEPCO, Kanden and Chuden. India also recently adopted a carbon market framework legislation, envisioning the construction of a national carbon market.

Electricity projects are also being affected by rules decided in voluntary carbon markets. Most notably, since 2020 the two biggest carbon credits standards issuers, Gold Standard and Verra, decided to no longer register new renewable projects, except for those located in Least Developed Countries[1]. This is because large-scale renewable electricity projects are already cost-effective, not requiring further support from carbon markets.

[1] Least Developed Countries is a UN classification for "low-income countries confronting severe structural impediments to sustainable development".

Regional perspectives

Asia Pacific

Asia Pacific's major generation source remains coal, but low-carbon sources are catching on

Electricity demand grew by an estimated 3.3% in 2022 in the Asia Pacific region, led by a strong rise in India (8.4%) that was partially offset by subdued growth in China (2.6%) due to the slowdown in the economy stemming from its zero-Covid policy. Demand in the two countries represented about 70% of the region's total electricity use of 13 500 TWh, which accounts for approximately 50% of global consumption. More than half of the increase in 2022 was met by renewables, of this renewable output almost 60% was from China.

The majority (57%) of the region's electricity was generated by coal in 2022, with low-carbon sources, such as nuclear and renewables, contributing to 32% of the mix. As a result of its strong reliance on coal for power, Asia Pacific has the highest electricity generation CO_2 intensity of our analysed regions, at 590 g CO_2/kWh in 2022, compared to a global average of 460 g CO_2/kWh.

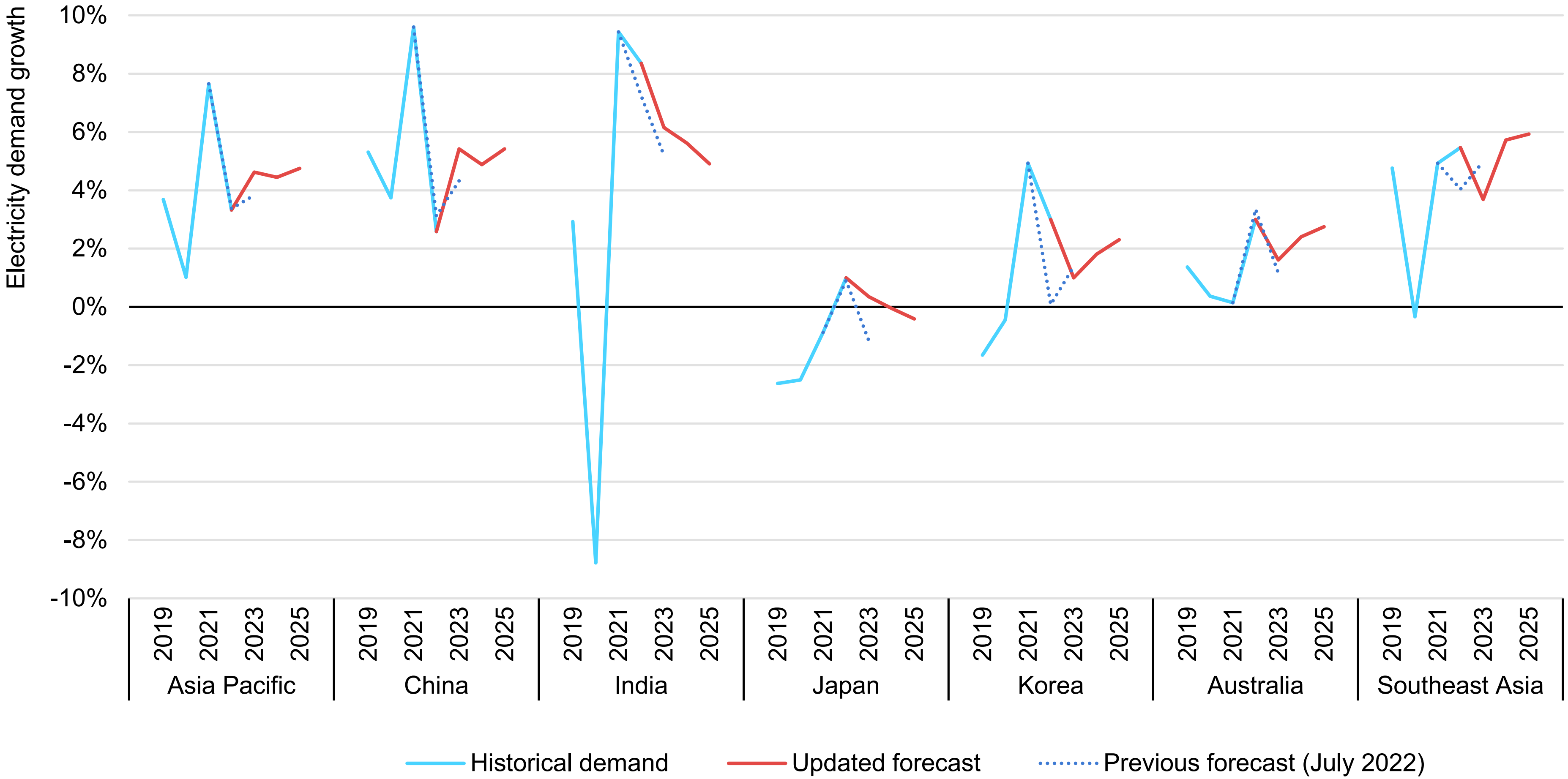
Power systems in several countries came under severe pressure during 2022, due to both sharply elevated global energy prices and extreme weather events, highlighting the critical need for electricity security. China experienced its longest heatwave in decades, worsening drought conditions that left the Yangtze river at record-low water levels. South Asia was similarly affected, with heatwaves in India starting exceptionally early in the spring and the worst recorded in 122 years. These extreme weather events led to record-breaking electricity demand for cooling, which was compounded by a fall in hydropower generation and coal supply shortages. In Japan, the government issued a power shortage warning for the first time ever, calling for reduced electricity consumption as very low temperatures and a 7.4 magnitude earthquake in March 2022 put the power system at risk of not being able to meet demand. Similar calls to reduce power use amid tight supply were made in Thailand, a gas-dependent country sensitive to high prices.

The convergence of weather events and record-breaking gas prices led to higher coal use in electricity generation for the Asia Pacific region in 2022 (+2.5% on 2021 levels), but going forward its share in the mix will decline. Coal power is expected to fall to 52% in the electricity mix in 2025, with the share of low-carbon sources rising to 38%, driven mainly by strong y-o-y growth of almost 12% annually in renewable electricity generation, which will raise its share in the mix from 26% in 2022 to 32% in 2025. The share of gas-fired generation will decrease slightly from 10% in 2022 to reach 9% in 2025. Steady growth in electricity consumption on average of 4.6% every year is forecast in the next three years, with renewables meeting almost two-thirds of that additional demand.

The higher share of renewables in the mix will help reduce the average CO_2 intensity in the region to 535 g CO_2/kWh in 2025. However, CO_2 emissions from power generation will continue to rise by an average 1.2% per year to 2025, as coal-fired generation, despite having a diminishing share in the generation mix, remains the main fuel in the region and grows on average 1.3% per year. In 2025, the CO_2 intensity of the Asia Pacific region remains the highest globally.

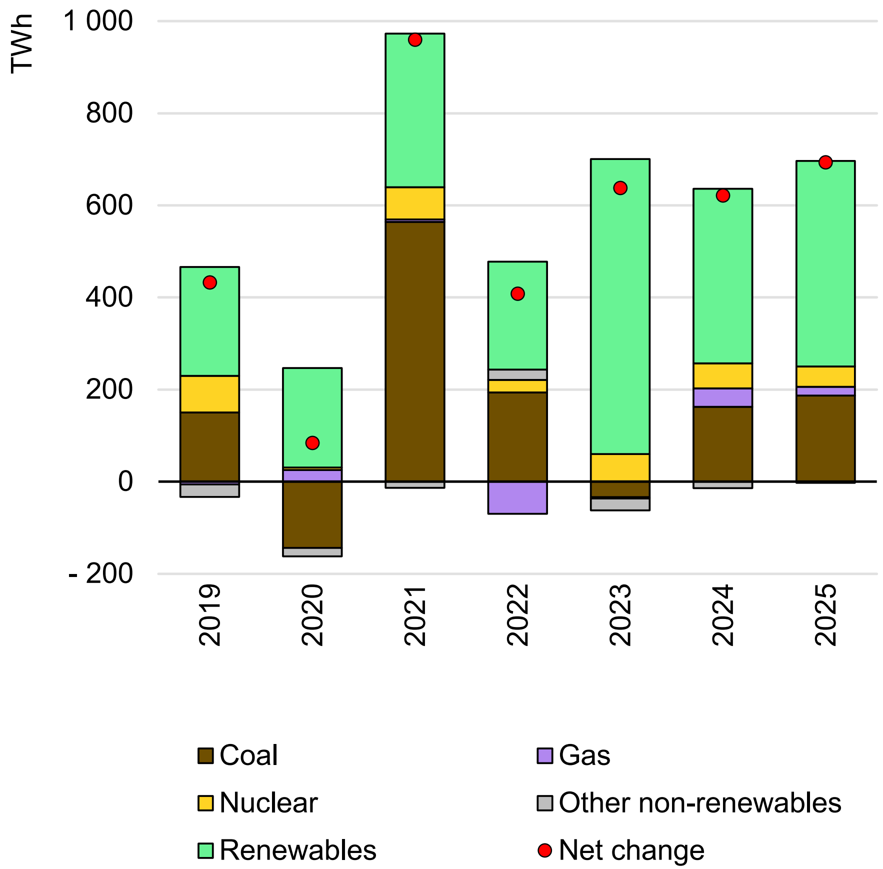
Amid post-pandemic economic recovery, Asia Pacific demand sees sustained growth to 2025

Year-on-year relative change in electricity demand, Asia Pacific, 2019-2025

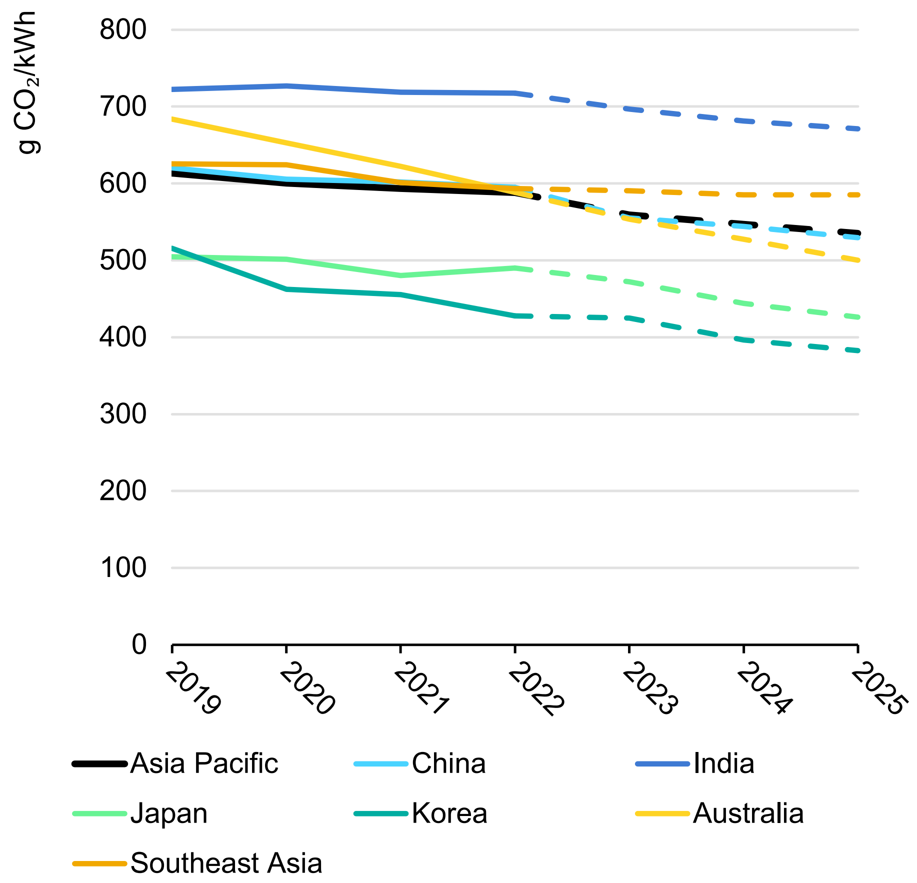


Carbon dioxide intensity falls as most of the additional demand is met by low-carbon electricity

Year-on-year change in electricity generation, Asia Pacific, 2019-2025



Development of average CO_2 intensity, Asia Pacific, 2019-2025



Note: *Other non-renewables* includes oil, waste and other non-renewable energy sources. The CO_2 intensity is calculated as total CO_2 emissions divided by total generation.

China

Electricity demand growth slowed in 2022 as the zero-Covid policy weighed heavily on economic activity

Under pressure from the large-scale lockdowns affecting the economy, electricity demand growth in China slowed to an estimated 2.6% y-o-y in 2022 (significantly below pre-pandemic rates). With industrial electricity consumption growth subdued, the increase was mainly driven by residential sector demand.

China's decision to ease severe pandemic restrictions on 7 December has paved the way for a recovery in its economy, and, in tandem, a rebound in electricity growth from 2022 lows. Between 2023 and 2025, demand growth is forecast to grow by 5.2% per year on average, led by continued electrification across the energy sector, especially in buildings and transport. Nonetheless, our forecast is slightly below the pre-pandemic trend of 5.4% in 2015-2019. Uncertainty remains around the pace of China's economic recovery, which could affect our forecast.

China's historic heatwave hit the central and eastern regions of the country from June to August 2022, which led to surging demand for air conditioning. Sichuan province, which produces 30% of China's hydroelectricity, faced power outages during several weeks as its generation fell by half due to drought conditions and unusually low rainfall during what is normally Sichuan's rainy season.

Inflexible long-term contracts worsened the situation, with exports continuing to eastern provinces, despite local shortages. China's power supply is likely to remain tight during winter 2022/23 as the drought left Sichuan's main reservoirs 77% lower at the end of August 2022 than at the same time in 2021.

Renewables grow in parallel with coal as policy prioritises electricity security

The reintroduction of an energy security narrative that followed the 2021 power crunch, as well as the "dual carbon" policy goals (carbon peaking before 2030 and carbon neutrality before 2060), imply that coal will possibly expand alongside renewable energy in the short- to medium-term horizon.

Coal remains the backbone of the Chinese electricity system, representing over 62% of the power generation in 2022, even though the share of renewables (30%) has increased. Hydropower accounts for half of the renewable electricity generation, followed by wind (29%) and solar PV (15%). While coal-fired supply increased over the summer to make up for weak hydro output, its average growth in 2022 compared to 2021 remained modest (+1.5%), with renewables covering about 60% of the rise in electricity demand.

The share of gas in the generation mix was under 3% and is set to stagnate in the coming years, as limited domestic production and high global prices reduce its competitiveness compared to coal in the power system.

We expect low-carbon energy to account for 41% of electricity generation by 2025, thus exceeding the objective set at 39% in China's 14th Five-Year Plan, owing to the fast development of wind and solar PV. Capacity additions of both technologies reached new records in 2022, and we expect their cumulative capacity to exceed 1250 GW by 2025, up from over 630 GW in 2021.

Distributed solar in particular is developing rapidly in eastern and central provinces following a national pilot programme launched in 2021 to promote solar rooftop PV at the county level. Construction of utility-scale wind and solar PV power plants is underway in northern and western desert areas, with a new batch of projects announced in 2022.

In parallel, new coal-fired plants continue to be added to the grid (11 GW in 2022) and more permits granted (15 GW in H1 2022). Energy security concerns, the willingness to accompany variable renewable sources with dispatchable power sources and local economic interests are behind these additions. However, they raise the risk of future under-utilised assets, considering the lack of profitability of existing coal-fired plants and their declining utilisation rate.

High coal prices could reduce coal power companies' operations of their assets and slow investments in new ones. Fuel prices were exceptionally high in 2022, regularly exceeding the level at which thermal power plants can breakeven. Despite government efforts to set price caps on thermal coal and deregulate coal-fired power tariffs following the autumn 2021 power crunch, more than half of state-owned coal power companies have recorded deficits.

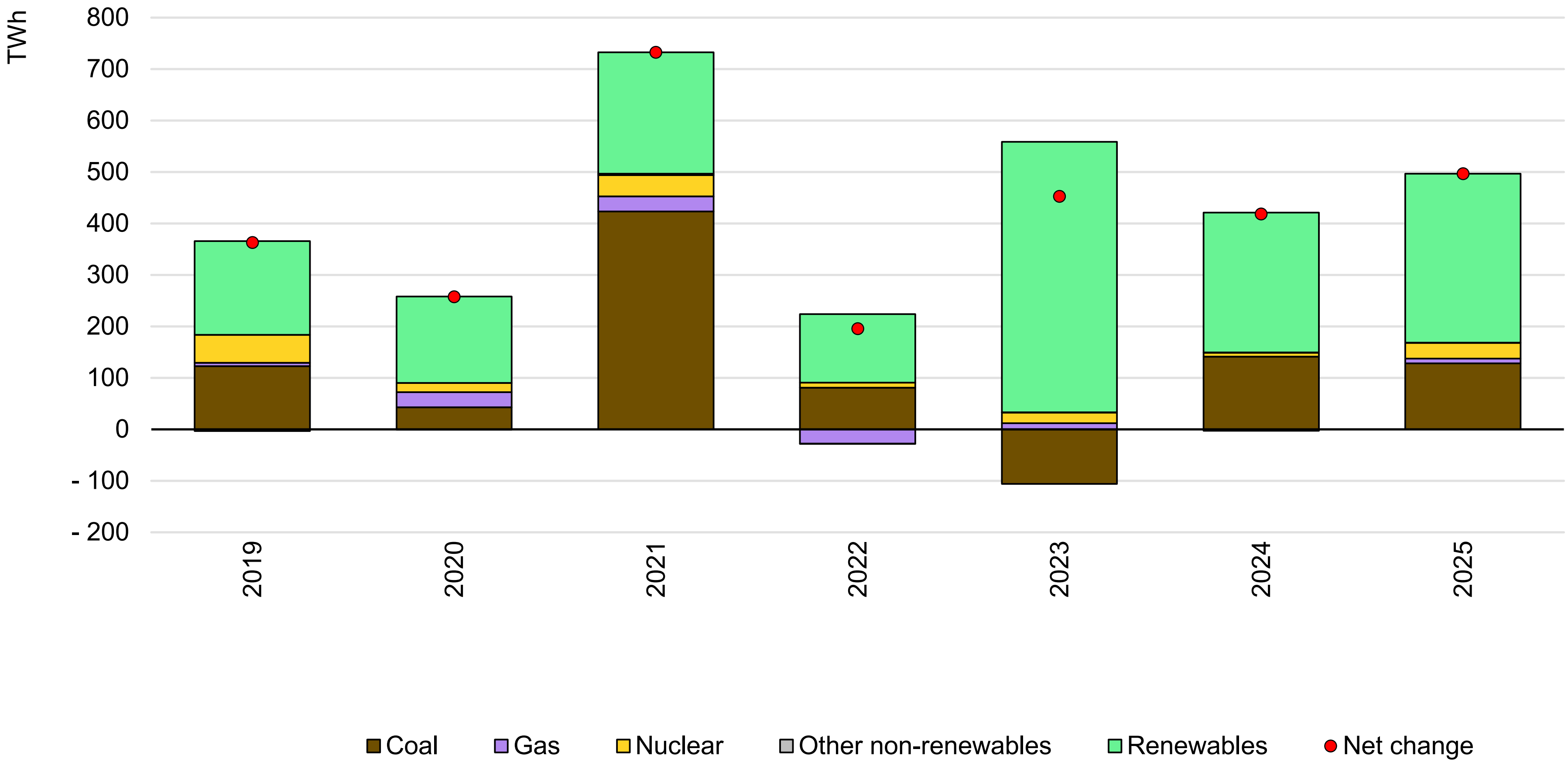
Power market reforms accelerate to support the transformation towards a modern energy system

China is increasingly relying on markets to support its "dual carbon" goals and transition towards a modern energy system. Power market reforms are moving forward with the issuance in early 2022 of high-level guidance to establish a unified national electricity market system, requiring full implementation by 2030. However, interprovincial and short-term trading remain limited, with 80% of the electricity being traded within provincial mid- and long-term markets through auctioning. The new reforms are expected to harmonise trading rules and technical standards across China to hasten the integration of existing provincial and regional markets. China's southern region took the lead in August 2022 with the launch of the trial operation of a unified regional power market in the five provinces covered by China Southern Power Grid. The development of spot power markets is also progressing, with trading and market supervision rules released in November 2022 for consultation.

Meanwhile, the regulator of the national carbon market is proposing to tighten coal power plants' emissions benchmarks for its second compliance period running to the end of 2023 and covering 2021-2022 power sector emissions. This should strengthen the system's stringency and help support carbon price signals, although market liquidity could remain a challenge. The system's expansion to industry sectors will only take place from 2023 at the earliest, and uncertainties remain for the timeline on the development of carbon derivatives and inclusion of non-compliance entities.

Most of the Chinese demand growth out to 2025 is met by renewables, followed by coal

Year-on-year change in electricity generation in China, 2019-2025



Note: *Other non-renewables* includes oil, waste and other non-renewable energy sources.

India

Strong demand growth in 2022 led by record heatwaves and economic recovery

Electricity demand in India grew strongly in 2022, by 8.4%, driven by a combination of continued economic recovery after the Covid-19 pandemic slowdown and peak summer temperatures. We expect demand growth to continue at close to 5.6% on average per year during 2023-2025.

India experienced extreme heatwaves in 2022. The hot season arrived earlier than usual, resulting in the hottest March in over a century. Electricity demand from April to July was 14% higher than the same period in 2021 and heatwaves led to a record peak power demand of 211 GW on 10 June 2022.

The sharp growth in summer demand was primarily met by coal-fired generation, which registered a significant year-on-year growth of 21.3% in April-July 2022 from April-July 2021. Following from this, India experienced coal supply shortages and the Ministry of Power directed state generating companies and independent power producers to meet a 10% blending requirement, meaning that 10% of their coal demand should be met by imported coal. This was required to ensure adequate coal stocks before the onset of monsoons. In August 2022, the government withdrew these blending requirements when adequate stock levels at power plants were reached.

While retirement of coal power is lagging, measures are being taken to accelerate renewable expansion

As of the end of 2022, India has an installed capacity of 410 GW, of which 236 GW comes from fossil-fired power plants (coal, gas and oil), 52 GW from hydro, 115 GW from renewable energy plants such as solar PV and wind, and the rest from nuclear power plants. The retirement of coal power plants has lagged over the years with about 14 GW of the capacity initially scheduled for closure over the 2017-2022 period still in operation and used for balancing purposes.

The government is taking actions to accelerate the deployment of renewable energy capacity, in line with the target of 500 GW of non-fossil capacity by 2030 announced in the updated Nationally Determined Contributions. The government established a plan for the integration of this additional capacity within the transmission grid that includes grid expansions and additional storage capacity. Further, as per Central Electricity Authority (CEA), about 3 GW of thermal power capacity planned for retirement by 2030, will potentially be replaced with equivalent renewable energy capacity.

Measures to hasten renewable capacity additions are, first, to increase renewable purchase obligations (to 2029-2030) with a greater focus on wind, hydropower and energy storage to facilitate round the clock power from renewable energy sources. Second, the green open access electricity rules (notified in June 2022 and launched in November 2022) are expected to boost renewable energy procurement. Third, the Energy Conservation (Amendment) Bill 2022 mandates the use of non-fossil sources for designated industrial and commercial consumers, and establishes carbon markets. India also encourages the production of green hydrogen/ammonia through waivers of inter-state transmission charges for a period of 25 years under the green hydrogen policy.

Presently, coal dominates the Indian electricity mix (74%). We expect nuclear output to rise by over 80% during the forecast period, to 83 TWh, but to remain a small component at 4% of the mix in 2025. Coal-fired generation rose by 7.7% in 2022, while gas-fired output fell by 36% in 2022 due to higher imported gas prices. While total coal-fired generation is set to rise to 2025, we expect its share to fall to 69% in the generation mix in 2025, as the share of renewables reaches 25%. Because of higher coal-fired generation, total power generation CO_2 emissions rise by 8% from 2022 levels by 2025, despite falling CO_2 intensity.

Several measures are underway to modernise the power system

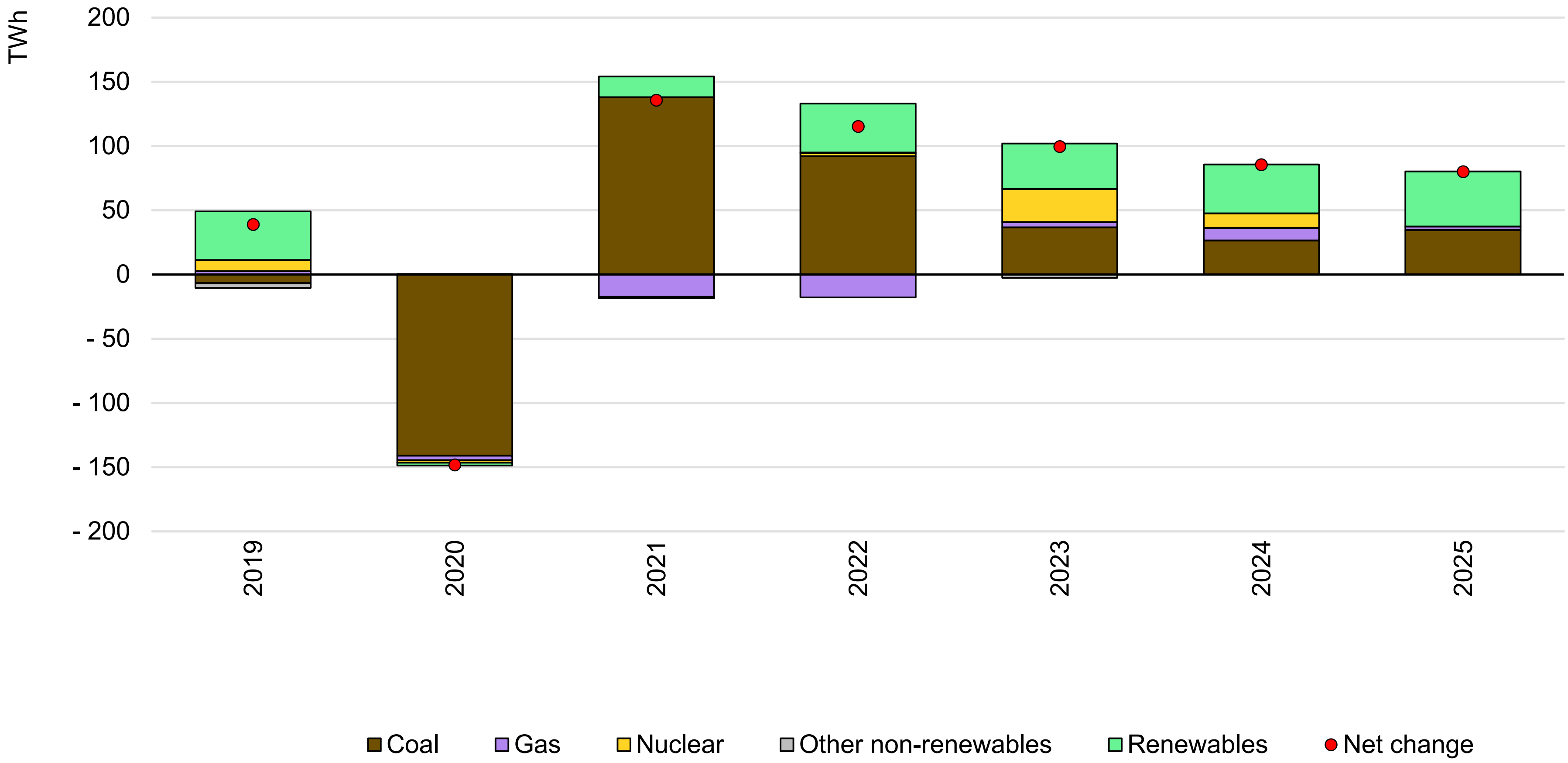
While short-term markets (trading of bilateral contracts of less than a one-year period) still represent 14% of the total generation and power exchanges cover 6% of that total generation, these markets are expected to grow. Across all market segments, the volume traded on the Indian Energy Exchange (IEX) rose by 38% year-on-year in the fiscal year 2022 (April 2021 to March 2022). In addition to IEX and Power Exchange India Ltd (PXIL), a third power exchange, Hindustan Power Exchange started operations in July 2022. During the 2022 summer supply shortages, demand on power exchanges doubled, resulting in price hikes. To safeguard the interest of consumers, the Central Electricity Regulatory Commission (CERC) announced a cap of INR 12/kWh on the market clearing price. The price cap was initially proposed to last until 30 September 2022, but was later extended to end-year to allow for higher demand in the festive season and onset of winter.

India plays a major role in cross-border trade and regional connectivity in South Asia. Presently, India benefits from hydropower imports from Bhutan, and imports from Nepal are expected to increase in the next 3-5 years, based on Nepal's 5 000 MW surplus hydropower. Nepal, which started trading hydropower on India's power exchange in 2021, increased its traded capacity to about 364 MW of hydropower in June 2022. Investments for further development of new hydro projects (about 1 200 MW) have been agreed upon in a MoU in summer 2022.

The distribution sector, which reported an increase in aggregate accumulated losses from INR 300 billion in FY 2019/2020 to INR 500 billion in FY 2020/2021, remains stressed. To address this, the government launched the revamped distribution sector scheme to provide financial assistance with the modernisation of infrastructure, and the clean electricity authority provided guidelines on a resource adequacy planning framework.

Low-carbon power sources to provide bulk of India's additional supply from 2023 onward

Year-on-year change in electricity generation in India, 2019-2025



Note: *Other non-renewables* includes oil, waste and other non-renewable energy sources.

Japan

Electricity demand in Japan rose by 1% year-on-year in 2022 in tandem with the economic recovery but growth will continue to be curbed by Covid-19 measures and concerns about electricity shortages.

The Japanese government issued a power shortage warning in March 2022 for the first time since their warning system was enacted in 2012. They called on businesses and the public to cut electricity use, emphasising that the combination of very cold temperatures and a lack of generation capacity due to the earthquake risked plunging the capital into blackouts. A similar alert was issued at the end of June 2022, triggering discussions on how to secure stable electricity, especially with regards to the possibility of restarting Japan's nuclear plants. The government is mobilising a number of measures to secure the minimum required power buffer reserve of 3%.

The overall generation mix in Japan is still dominated by gas and coal, which have a combined share of over 65%. However, the renewable output is growing, with an estimated 4% y-o-y increase in 2022. In 2025, we expect renewable generation will reach 21% above 2022 levels, partially offsetting declines in coal and gas-fired generation.

A sharp 15% y-o-y reduction of nuclear generation was reported in 2022 due to the shutdown of some reactors that require periodic or special inspection. After this decline, nuclear electricity output is set to continuously increase out to 2025, driven by policies aimed at reducing reliance on LNG and strengthening energy security in the wake of the global energy crisis. In August 2022, the Prime Minister announced that the government would push for an accelerated restart of the nuclear fleet, with the target of having 17 reactors operational after mid-2023. While some uncertainty remains as approvals need to be secured at the municipal level, this could further boost nuclear generation.

Although electrification in the residential, commercial, and services sectors has continued to increase, electricity demand is expected to be flat from 2023 to 2025 due to energy conservation measures and tight supply.

Korea

Korea saw strong electricity demand growth of about 3% in 2022, led by the commercial, services and industrial sectors. We expect continued growth of around 1-2% out to 2025.

Around 4 GW of renewable capacity was added in 2022, mainly solar PV, in line with the trend in recent years. We expect this development to continue in similar amounts over our forecast horizon, supported by Korea's renewables portfolio standard and the introduction of a direct power purchase agreement system in September 2022.

Gas-fired capacity will also increase out to 2025. Coal-fired capacity is expected to rise until 2024, due to capacity already under construction, and then will start to decline from 2025 onwards. New nuclear capacity is also coming online, with the Shin-Hanul No.1

reactor (1.4 GW) having started operations in December 2022 and reactor No. 2 expected to begin operating in late 2023. In July 2022, the government announced plans to resume construction of the Shin-Hanul No. 3 and No. 4 nuclear reactors.

Demand growth in 2022 was mainly met by renewable electricity and nuclear generation. Renewables grew by around 26% y-o-y, reaching 8% of the electricity generation mix. Nuclear rose by 15% y-o-y, accounting for 29% of the mix, whereas coal fell to 33%. Absolute generation from gas declined slightly, and its share fell by around 2 percentage points to 29%. By 2025, we expect renewables to grow to 12% of the mix and nuclear to reach 32%, while the shares of gas (27%) and coal (29%) both decline.

CO_2 emissions from Korean power generation fell slightly in 2022 due to a small decline in fossil fuel-fired generation. Average CO_2 intensity declined in 2022 due to higher renewable and nuclear output, and we expect a continued decrease through 2025. We see absolute emissions also entering a decline by 2025. From January 2022 onward Korea's environmental dispatch system included a price component reflecting greenhouse gas emissions, although at present the impact on dispatch is limited and emissions reductions are primarily driven by the increased availability of clean supply.

Korea released the working draft of the 10th Basic Plan for Electricity Supply and Demand (BPLE) in August 2022. This included adjustments to the targeted electricity mix in 2030, increasing the contribution of nuclear relative to the previously released enhanced NDC plan. The 10th plan draft proposes changes to the current wholesale market bidding system, which would mean generation companies offer supply within a range of a benchmark fuel cost and prices are set differentially by generation company. Korea is also looking to introduce real-time electricity markets for energy and ancillary services in addition to the existing day-ahead market. Korea Power Exchange is planning to begin a pilot in Jeju in October 2023 to be extended to the mainland by the end of 2025.

To manage the energy crisis, the government introduced a System Marginal Price (SMP) upper limit system in the electricity market from December 2022. The system limits electricity purchase prices paid by Korea's utility in charge of generation, transmission and distribution, KEPCO, in the context of surging fuel costs. The price cap, which will operate until November 2023, cannot be activated for more than three consecutive months.

Australia

Australia's economic activity posted a strong rebound in 2022, with GDP growth above 3%. The recovery reflected the high levels of Covid-19 vaccinations and a progressive relaxation of the measures in place during 2021. Australia opened its borders to all vaccinated people from February 2022.

Australia's electricity consumption grew by around 3% in 2022, after two years of relatively flat demand. We expect growth to continue out to 2025 at slightly above 2% per year on average. Expanded growth for large industrial customers in Victoria and South Australia contributes to the increase for 2022-2023.

Continuing the trend of recent years, Australia's capacity additions in 2022 are dominated by more than 5 GW of new renewables, including over 4 GW of solar PV. Growth in renewables is expected to continue at a similar pace out to 2025, supported by auctions to meet state-level targets and corporate purchasing. Renewable Energy Zones (REZ), or identified renewables-rich areas which are targeted for coordinated infrastructure development, are expected to enhance renewables deployment, and different states declared multiple zones in 2022 following the first zone announced in November 2021. The retirement of the first unit of the coal-fired Lidell Power Station (500 MW) took place in April 2022 as anticipated and the remaining three units (1 500 MW) are on schedule to retire in April 2023.

Battery capacity in Australia, which increased markedly in 2021, approximately doubled in 2022. This is driven both by the start of operations of the many utility-scale projects in the second half of the year, and by growth in installation of residential battery systems.

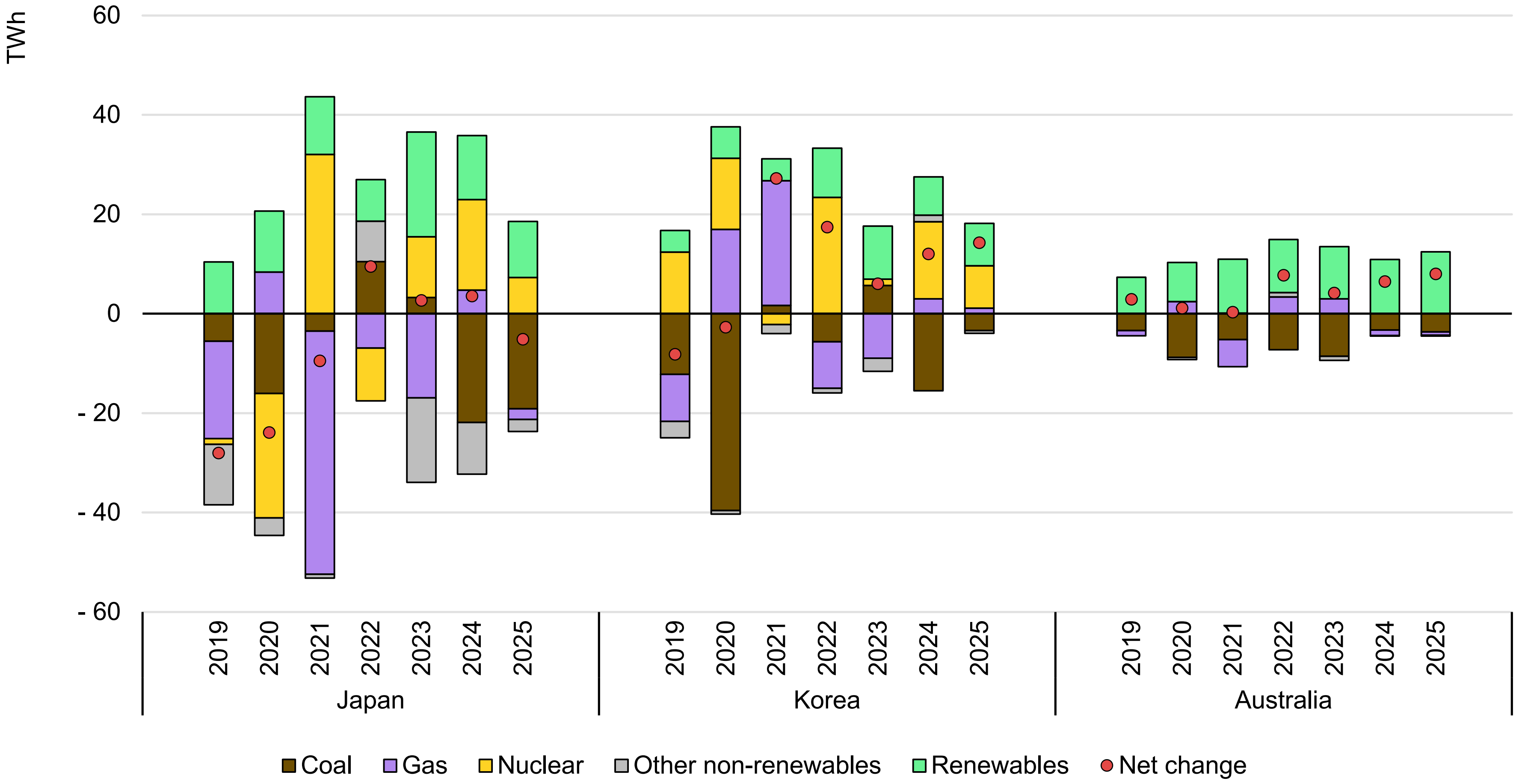
2022 saw a continued decrease in generation from coal-fired plants, which made up 49% of the mix relative to 53% in 2021. Demand growth was met by increases in both renewable and gas-fired generation. Over the forecast horizon, we see continued growth in renewables output of around 12% annually as a result of ongoing capacity growth. We expect gas-fired generation to remain stable to 2025. The power generation sector's total CO_2 emissions, as well as its average CO_2 intensity, will decrease as renewables output increases and coal-fired generation declines.

Surging wholesale prices amid the energy crisis saw the Australian Energy Market Operator suspend the National Electricity Market from 15 June to 24 June 2022. The market suspension was necessitated by sustained high prices that triggered the Administered Price Cap, which was accompanied by reduced generation volumes offered to the market and heightened risks to security of supply. Generation companies indicated that offers were lower because the price cap had affected the profitability of some bids. The Australian Energy Market Commission has subsequently introduced a rule change to double the Administered Price Cap, applicable from 1 December 2022 to 30 June 2025, and in December 2022 also introduced a wholesale price cap for gas and coal.

In July the government introduced the Climate Change Bill 2022, legislating the country's commitment to reduce GHG emissions 43% from 2005 levels by 2030 and achieve carbon neutrality in 2050. The bill passed both houses in September 2022.

Nuclear generation ramps up in Japan and Korea out to 2025; renewables expand in Australia

Year-on-year change in electricity generation in selected countries in Asia Pacific, 2019-2025



Note: *Other non-renewables* includes oil, waste and other non-renewable energy sources. The CO_2 intensity is calculated as total CO_2 emissions divided by total generation.

Southeast Asia

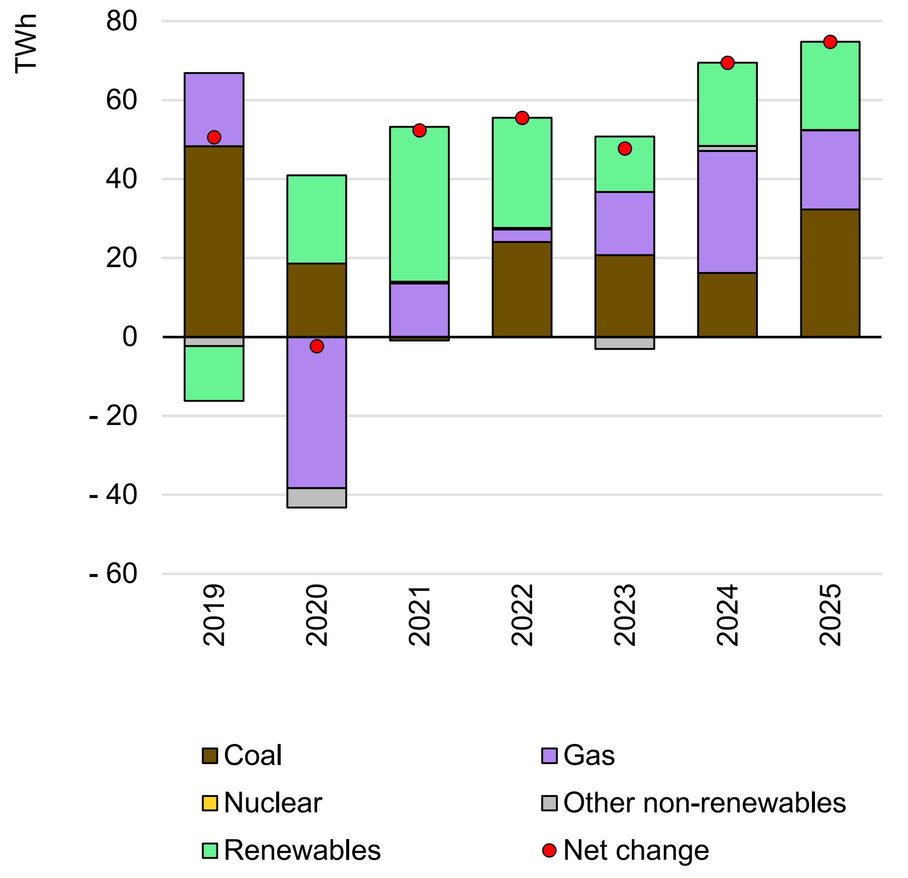
In 2022, we estimate electricity demand grew by 5.5% in Southeast Asia. This trend is in line with the economic recovery in the region after countries reopened their borders to international tourism, a significant economic driver in many Southeast Asian countries.

The region's power generation is based mainly on coal (43% in 2022), gas (29%) and renewables (27%). While the share of coal-fired generation in the mix is expected to decrease slightly in the coming years, the absolute generation from coal is increasing every year by 4% on average up to 2025 in the region, led by capacity additions in Indonesia and Viet Nam. High global energy prices and supply shortages have further contributed to the lifetime extension of some coal-fired power plants in some countries, such as in Thailand.

We estimate that electricity demand will continue rising by 4-6% per year until 2025. Most of that additional demand will be met by fossil fuels, with renewables meeting about a third of that demand growth. The share of renewables in the generation mix will rise slightly to below 28% in 2025. This leads to a decrease in the emission intensity of the region's generation mix by over 1% in 2025 compared to 2022, but at 585 g CO_2/kWh it is set to remain among the highest globally.

Several countries in the region have set carbon neutral or net zero targets, and aim to accelerate renewable energy capacity deployment. As such, the region is targeting the addition of 50 GW of solar and wind capacity by 2030, and over 250 GW by 2050.

Year-on-year change in electricity generation in Southeast Asia, 2019-2025



Note: *Other non-renewables* includes oil, waste and other non-renewable energy sources.

Indonesia

In 2022, Indonesia's share of coal in the electricity mix rose to 64% of total power generation (from 61% in 2021), and provided the majority of the electricity needed to meet the estimated 6.6% y-o-y demand increase. Gas-fired output made up 15% of the Indonesian mix in 2022, and renewables 20%, with hydropower, geothermal and biofuels making up the largest share of the renewable mix.

In the coming years, electricity demand is expected to rise steadily (ranging from 3% to 7% per year), in line with Indonesia's projected GDP growth of more than 5% per year in this decade, and supported by government plans for electrifying mobility and cooking. While the long-awaited Presidential Decree 112 on the acceleration of renewable energy development for electricity generation was published in September 2022, it is expected to come into effect only gradually with the release of Ministerial Regulations to implement the Decree. We expect renewables to reach almost 22% of electricity generation in 2025, falling slightly short of the target of 23% by 2025 established in the 2014 national energy plan.

While the generation expansion programme announced in 2015 continues to add coal-fired plants, with a total 13 GW in the 2021-2030 project pipeline for which tenders have been held, the Just Energy Transition Partnership will support an accelerated phase-out of coal-fired output in the mid- to long-term. Indeed, one of the measures of this partnership, launched in November 2022, is the freeze of the current planned pipeline of coal-fired plants. Other targets in this framework to accelerate the decarbonisation of the power sector include achieving peak power sector emissions by 2030 of no more than 290 Mt CO_2, and reaching a share of 34% of renewables in the generation mix by 2030.

Due to its coal-heavy generation mix, Indonesia's CO_2 intensity is among the highest in the Southeast Asia region. CO_2 emissions from the power sector in Indonesia rose by 6% in 2022, and are estimated to further increase by about 4% per year up to 2025.

Viet Nam

The impact of high global commodity prices in Viet Nam is relatively subdued due to a strong domestic market. Economic and electricity demand growth are thus expected to remain high. We estimate electricity consumption rose by 6% in 2022 and that it will grow by about 6% per year on average in 2023-2025.

Alongside this high demand growth comes a challenge to provide matching supply. The approval of Viet Nam's main planning document, the Power Development Plan 8, has been delayed to incorporate recent developments such as the country's recently committed decarbonisation targets, changing global fuel prices, and plant financing challenges. These include COP26 commitments to net zero emissions by 2050 and the phase out of coal power generation by 2040. In the most recent draft (October 2022), 6.8 GW of coal-fired capacity was withdrawn from the planning process, either due to investor withdrawal or proposals to shift from coal to other fuels. Nonetheless, 3.8 GW of new coal-fired capacity is still expected to be commissioned by 2030, in addition to the Nghi Son 2 (1.2 GW) and Song Hau 1 (1.2 GW) power plants that started operations in 2022. About 32% to 44% of the annual increments from 2023 to 2025 would therefore be met by coal power. Its share in the generation mix will remain constant at 41% in 2022-2025.

The current draft development plan includes an additional 6 GW of LNG-based power generation by 2030 to help replace the planned coal capacity that has been withdrawn. The ongoing build-up of the first LNG terminals is therefore critical. The Hai Linh LNG terminal (1.5 Mt/yr) is intended to supply a 1.2 GW power plant that is already constructed but not yet operational. The Thi Vai LNG terminal (1 Mt/yr) is expected to be finished by the end of 2023, supplying 1.5 GW of power capacity. The Son My LNG terminal (3.6 Mt/yr) designed to supply 2.3 GW of gas-fired capacity is expected to begin commercial operations only by 2026.

Issues on the policy measures to increase renewable capacity have still not been resolved. The phase-out of feed-in-tariffs has reduced renewable capacity additions and extending these tariffs further is still under discussion. Nonetheless, the growth is expected to continue, such that about 40% of the demand increases in 2023-2025 would be satisfied by renewables. In 2025, we expect renewables to provide 46% of the total generation mix.

Moreover, a new pricing framework and rooftop PV regulations are being considered in order to strike a balance between the government's fiscal capabilities and reducing the risk for investors. The planned pilot projects for direct power purchase agreements with renewable developers have yet to take place. Such mechanisms allow companies to procure clean electricity directly to reach their corporate net zero goals and alleviate pressure on the government's renewable subsidy budgets.

Thailand

Thailand's economic recovery continued in 2022, with an estimated GDP growth of 3.2%. Peak demand in 2022 increased by 7% to 32.3 GW, compared to 30.1 GW in 2021. We estimate overall y-o-y growth in electricity consumption of almost 4% in 2022. Reported data for the first eight months of 2022 show electricity consumption rose by 4%, led by the commercial (11%) and industrial (4%) sectors, which represent 23% and 45%, respectively, of total demand. The residential sector, which accounts for 28% of demand, has stagnated in the same period.

Thailand, which depended on gas for 61% of its power generation in 2022, was strongly impacted by the rise in global fuel prices, which led the energy regulatory commission to increase the fuel tariff – a component of the electricity price – for the last quarter of 2022 by 18%. Indeed, the country faced gas supply challenges due to a combination of lower domestic production, import disruptions and high prices. Thailand further decided to extend the lifetime of some of its coal-fired power plants and implemented plans to reduce power consumption. To lower the burden of the high prices on households, the government announced in September 2022 an extension of the electricity bill subsidy for vulnerable consumers.

We expect electricity demand in Thailand to grow by 3-4% per year until 2025. Gas will remain Thailand's dominant generation source in the coming years, with 1.3 GW of gas capacity commissioned in

2022, and a new combined-cycle gas plant with four units of 660 MW each expected to be fully operational between 2023 and 2024, which will bring gas-fired output's market share to 63% of the mix in 2025. Per the goal to be carbon neutral by 2050, Thailand aims renewables to account for 50% of the electricity mix by this target date. This will require an accelerated deployment of renewables, as we expect their share in the generation mix to decrease in the coming years, from 19% in 2022, to 17% in 2025.

With the new Power Development Plan (PDP) currently under discussion, some targets such as the planned deployment of 16 hydro-floating solar hybrid projects for a total of 2.7 GW of capacity have already been announced. The government further introduced a feed-in tariff mechanism, starting in 2025-2026, which regulates the sale of renewable electricity generated by small (under 90 MW) and very small (under 10 MW) power producers.

Philippines

The Philippines' economic rebound from the easing of lockdowns underpinned an estimated GDP growth of 7% in 2022. It is expected to dip slightly to 5% in 2023 due to high commodity prices, before rising again to rates above 6% through 2025. We forecast annual average demand growth of about 5.5% for the next three years. Coal and renewables are expected to meet incremental demand until the new gas-fired power plants start operation by 2024.

Coal made up 58% of the generation mix in 2022. About 1.6 GW of new coal-fired capacity is committed and projected to become operational between 2023 and 2025, with an additional 720 MW expected by 2027. These projects were all approved prior to the moratorium on new coal-fired power plants in 2020. Gas-fired units are expected to meet a large part of future additional growth, primarily driven by LNG imports given the depletion of the country's only domestic gas field. However, the LNG terminal build-up has faced delays attributed to Russia's war in Ukraine and the Covid-19 pandemic affecting the supply chain for materials. The delayed 5.2 Mt/yr import facility in Batangas is intended to supply an existing 1.2 GW gas power plant and another planned 850 MW gas power plant expansion. Moreover, the constructed 650 MW Pagbilao gas power plant set to start in 2022 is delayed due to financing issues of the associated transmission substation. We expect the share of gas generation in the mix to reach 19% by 2025, from 17% in 2022.

Despite early legislation to support renewables development in the Philippines, growth has been limited so far. Renewables had a 22% share of the generation mix in 2021, with solar PV and wind making up less than 3%. Additional policy changes were introduced in 2022 to further stimulate investment for renewables to help achieve the country's 2030 target of reaching a 35% share of renewables in the energy mix. This includes allowing 100% foreign ownership of renewable assets which was limited to 40% before, and maintaining priority dispatch for biomass and maintaining "must-dispatch" for variable renewables after the expiry of the feed-in-tariff programme on which the special dispatch condition depends. It also extended priority dispatch privileges to geothermal and dammed hydro. In addition, the Green Energy Option Program started operation in January 2022. The initiative allows consumers with a peak demand of at least 100 kW and equipped with a 5-minute metering unit to enter into direct procurement of renewables.

The Philippines' electricity market continues to develop with the integration of the island system of Mindanao at the end 2022 and opening of the reserves market by 2023. Furthermore, the Renewable Energy Market (REM), where renewable energy certificates are traded, started operations in summer 2022.

Finally, electricity security and resilience continue to be key concerns for the country. The recent typhoon Noru impacted thirteen 69-kV and four 230-kV transmission lines, resulting in 20 out of 51 public distribution areas to experience partial or total power interruption. This year, the country also announced the inclusion of nuclear energy in its long-term energy policy.

Singapore

Electricity demand in Singapore grew by 2% in 2022 as the impact of the Covid-19 pandemic on the economy eased. We forecast an increase of over 1% in 2023, due to higher demand in electricity-intensive sectors (industry is the largest electricity consuming sector in the country) and a growing EV adoption rate. Our outlook for 2024 and 2025 shows growth above 1% per year. According to the Singapore Green Plan 2030, the country will double the target number of EV charging points from 28 000 to 60 000 by 2030 and will phase out of all internal combustion engine vehicles by 2040. In addition, the Minister of Transportation aims for electrification of half of the public buses and taxis by 2030.

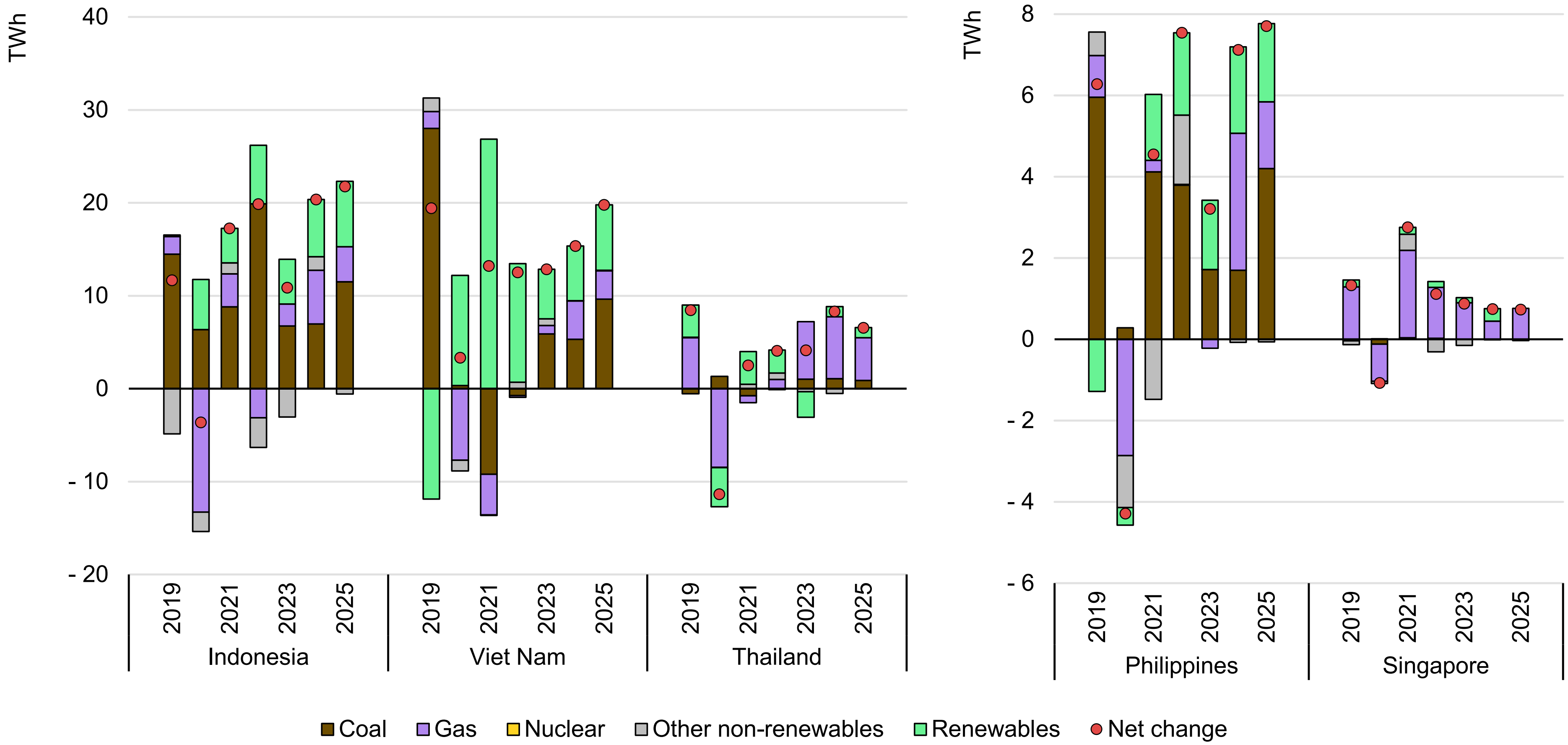
Singapore relied on imported natural gas to generate around 95% of its electricity in 2022, making domestic energy prices highly vulnerable to volatile of global energy markets. In October 2022, Singapore announced that they will maintain extraordinary measures as a buffer, including standby fuel facilities from which generation companies can draw fuel when their gas supplies are disrupted. Authorities also required generation companies maintain enough fuel in addition to the existing reserve requirements.

In the coming years Singapore plans on increasing electricity imports to diversify its supply as their domestic output with existing thermal power plants cannot meet rising demand. In line with that plan, Singapore had its first renewable electricity imports in 2022. The Lao PDR-Thailand- Malaysia- Singapore Power Integration Project (LTMS-PIP) enables trade up to 100 MW of hydropower from Lao PDR to Singapore via Thailand and Malaysia utilising existing infrastructure. This is the first multilateral cross-border power trade including four countries of the Association of Southeast Asian Nations (ASEAN). EMA also envisions importing 100 MW equivalent of electricity from a solar farm in Pulau Bulan, Indonesia through a new interconnector around 2024.

By 2025, while gas will remain the major source of electricity (95% of the mix), the share of renewables is expected to rise to 3.4% (from almost 3% in 2022), which is driven by solar – there is a target to reach 1.5 GW of solar PV by 2025 (from 0.4 GW in 2021).

Coal- and gas-fired generation set to remain significant in meeting Southeast Asia's demand

Year-on-year change in electricity generation in selected countries in Southeast Asia, 2019-2025



Note: *Other non-renewables* includes oil, waste and other non-renewable energy sources.

Americas

Renewables meet most of additional demand in the Americas while coal-fired power declines

Electricity demand in the Americas region rose for the second year in a row, up by 2.3% in 2022, though slightly below growth in 2021. Regional demand declined in both 2019 and 2020. We expect electricity consumption to stagnate in 2023 due to weaker economic growth, before rebounding to 1.5% per year in 2024 and 2025.

The recovery is largely driven by the United States, which accounts for two-thirds of overall regional electricity demand. US electricity consumption rose by 2.6% in 2022, but demand is forecast to decline by 0.6% in 2023 before increasing to an average of 1.2% in 2024 and 2025. Canada, the third largest consuming nation in the Americas (behind the United States and Brazil), mirrors the US trend, as demand rose by almost 2% in 2022 before declining 1% in 2023 and then recovering to growth of an average 2.5% in 2024 and 2025. We estimate that demand in Mexico rose by almost 4% in 2022, but expect growth to average 2.3% over the next three years.

In Central and South America, annual demand growth moderated to an estimated 1% in 2022 from 4.4% in 2021. For 2023-2025, we forecast electricity consumption to increase at an annual average rate of 2%. Weaker growth in 2022 was largely due to a slowdown in Brazil, the region's second largest consumer. Brazilian demand growth rose by a modest 0.3% in 2022, down from 6% in 2021. We forecast an annual average increase of 2% for the country over the 2023-2025 period. In 2022, electricity demand in Argentina (0%), Colombia (1%) and Chile (2%) saw modest increases while Peru posted more robust growth (4%). Going forward, we expect growth to accelerate in Colombia and Chile while the pace slows in Peru and Argentina in 2023-2025.

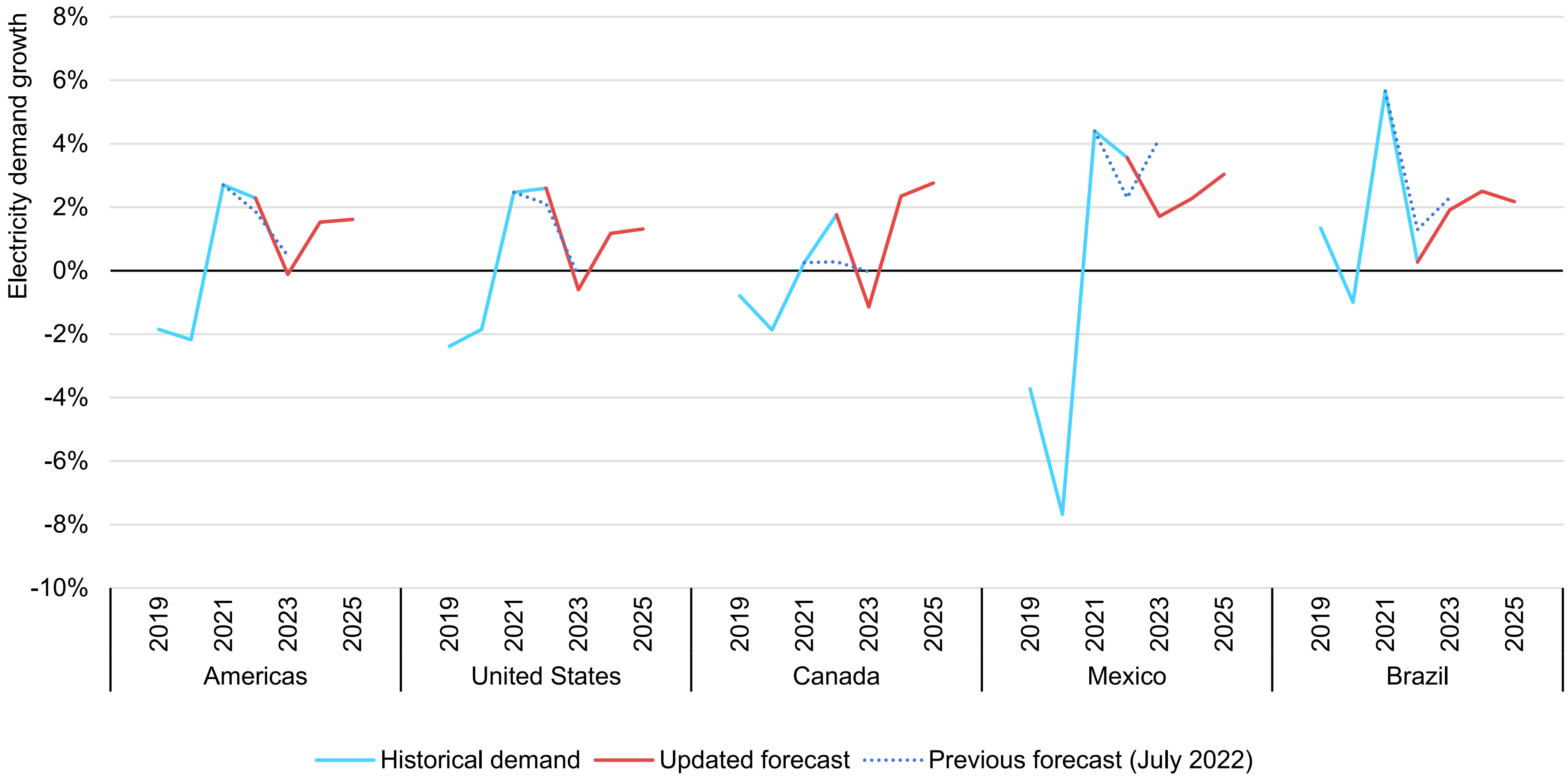
An increase in coal-fired output due to fuel switching from comparatively higher natural gas prices and lower hydro availability in the region in 2021 proved to be short-lived. After growth of 13% in 2021, coal generation fell by 7% in 2022 and is forecast to decline 8% per year on average for the 2023-2025 period. Hydroelectric output rebounded by an estimated 4% in 2022 as severe drought conditions eased, particularly in Brazil and the United States. This rise, as well as additions of wind and solar capacity, drove year-on-year growth in renewables generation up 9% in 2022, from 2% in 2021. Renewables growth will then moderate to an average 5% per year in the 2023-2025 period as hydroelectric generation levels out.

Renewables including hydro accounted for 36% of annual generation in the region in 2022, the largest share of all sources, followed by gas at 33%, coal at 15%, nuclear at 14% and oil at 2%. By 2025 we expect renewables to account for over 40% of the Americas electricity generation mix, with its share increasing almost entirely at the expense of coal, which is expected to decline to a share of 12% (from 15% in 2022).

This will drive emissions down, both in their overall level and intensity. We estimate CO_2 intensity will fall to about 260 g CO_2/kWh in 2025, down from 300 g CO_2/kWh in 2022 and 380 g CO_2/kWh in 2015. Regional emissions are set to decline to 1.8 Gt CO_2 in 2025, from 2.5 Gt CO_2 in 2015.

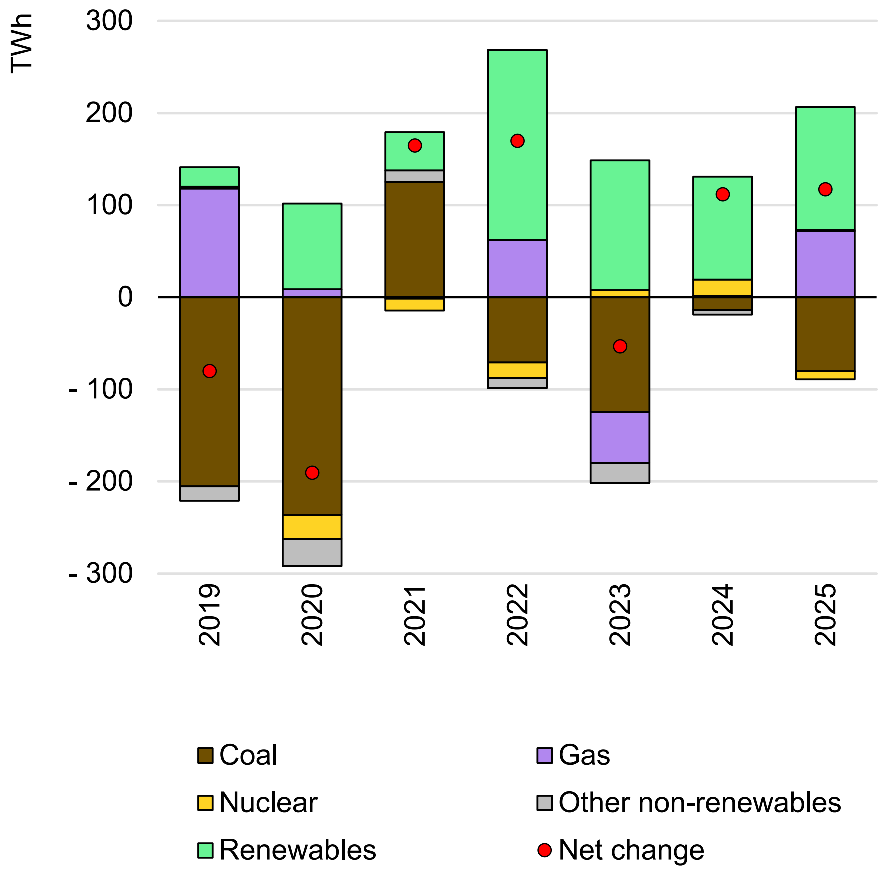
Electricity demand growth will slow along with economic activity in 2023, but rebound in 2024

Year-on-year relative change in electricity demand, Americas, 2019-2025

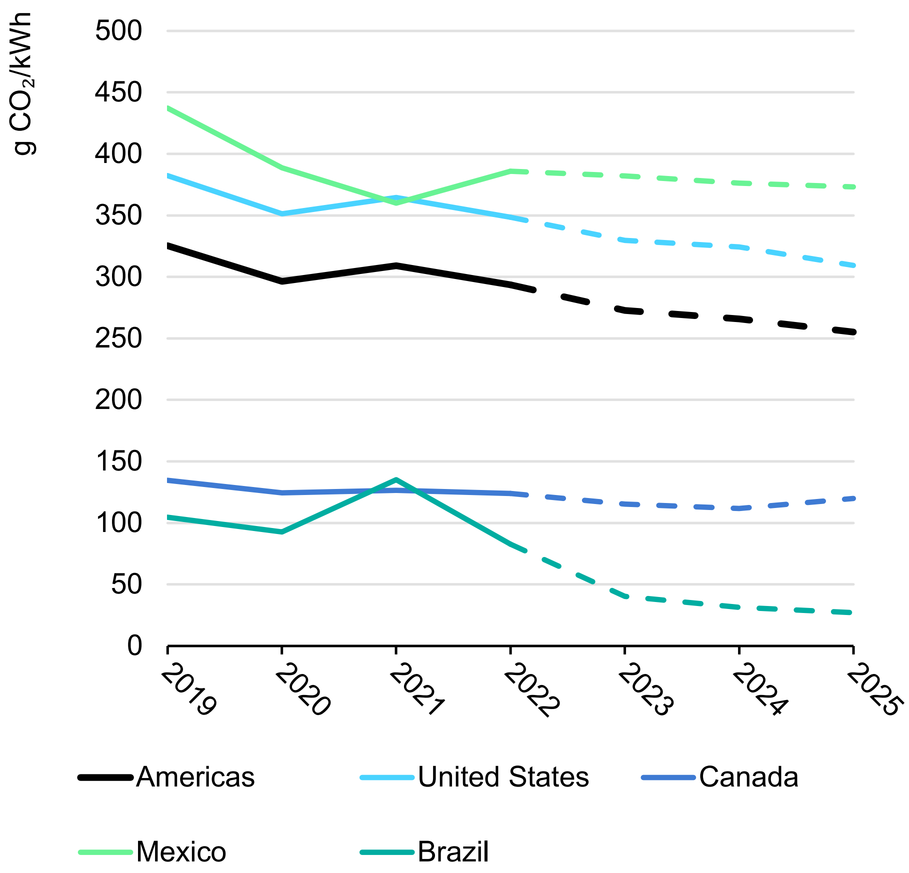


Renewable generation ramps up, driving down emissions across the Americas

Year-on-year change in electricity generation, Americas, 2019-2025



Development of average CO_2 intensity, Americas, 2019-2025



Note: *Other non-renewables* includes oil, waste and other non-renewable energy sources. The CO_2 intensity is calculated as total CO_2 emissions divided by total generation.

United States

Electricity security remains at risk in many regions

Electricity security in the United States remains at risk during the winter of 2022/23. Outages that occurred in Texas in February 2021 exposed the country's vulnerabilities to extreme weather and prolonged cold periods. The winter reliability assessment released in November 2022 by the North American Reliability Corporation (NERC), reports that the US Southeast, Texas, the Midwest and New England regions could see load shedding due to generation and transmission outages, fuel supply shortages and natural gas infrastructure unavailability. In December 2022, a strong winter storm left over 1.5 million customers without power.

Electricity demand growth is set to slow in 2023; policies boost low-carbon power in the coming years

Electricity use rose by 2.6% in 2022, surpassing pre-pandemic levels, led by economic growth coupled with higher air conditioning and heating use. However, demand is forecast to fall by 0.6% in 2023 due to an expected slowdown in economic activity, before returning to annual growth of around 1.2% in 2024 and 2025.

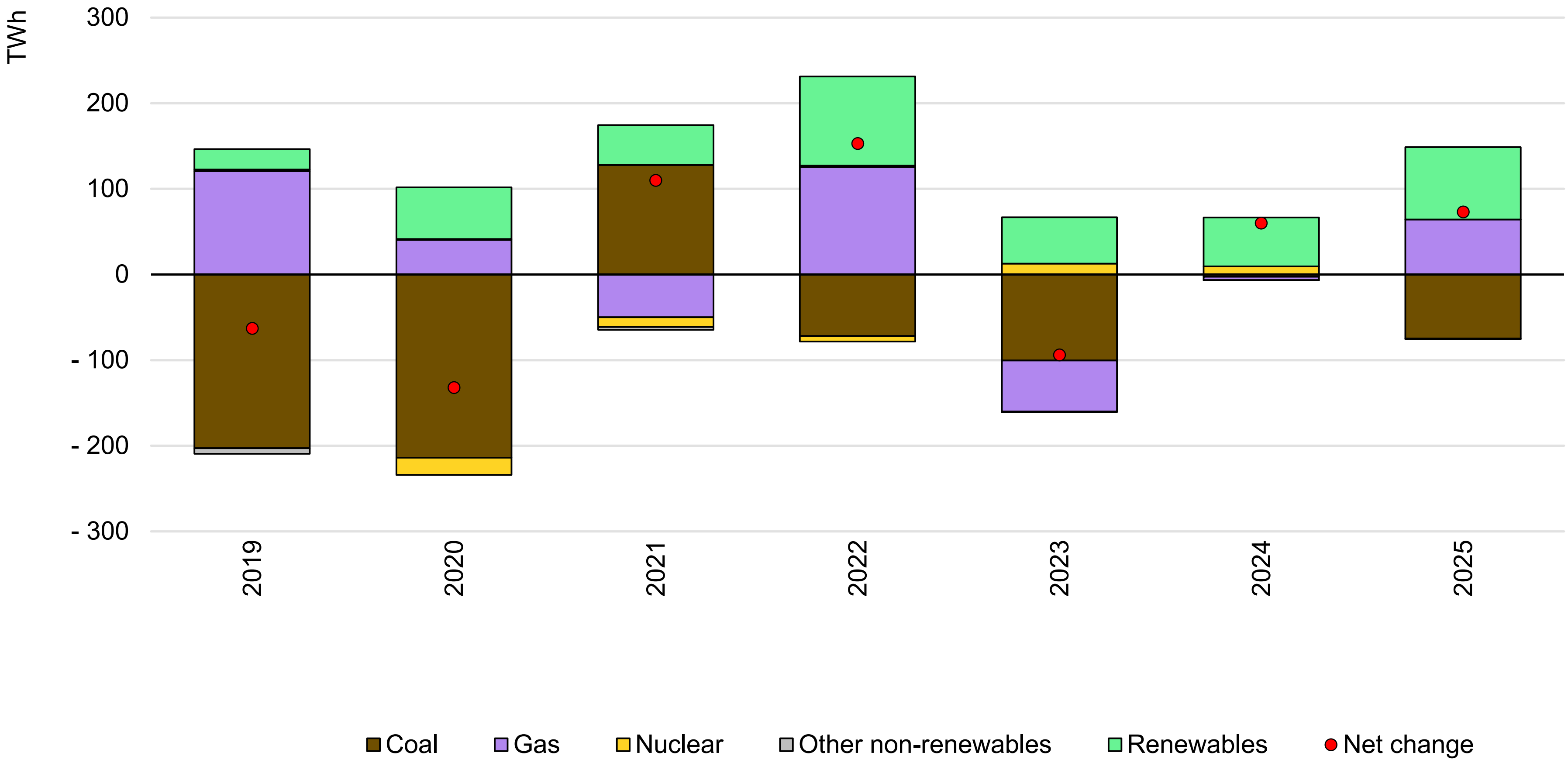
Gas-fired generation grew by 8% in 2022, reversing a decline of 3% in 2021, as gas prices moderated due to mild temperatures and the loss of LNG export capacity at the Freeport facility. The overall slowdown in electricity demand is expected to reduce gas-fired generation by 3% in 2023. Coal-fired generation fell year-on-year by 7% in 2022, reversing a 15% rise in 2021, which was the first annual increase since 2014. Out to 2025, falling natural gas prices are expected to support an increase in coal-to-gas switching, with growth in renewables reducing total fossil fuel-fired generation. Coal-fired output is set to fall by an average 7% per year in the 2023-2025 forecast period.

Hydropower output rose by about 3% in 2022 as long-term drought conditions eased in many hydro-producing regions, nevertheless hydro output remained slightly below the 2017-2021 average by 4%. Wind and solar PV posted continued strong growth in 2022. Wind generation rose by 14%, while solar output grew by 27%. By 2025, wind generation is expected to grow by 19% compared to 2022, and solar PV generation up by 56% over the same period. This will be supported by the August 2022 passage of the Inflation Reduction Act, which included USD 30 billion in targeted grant and loan programmes for clean electricity investments.

Nuclear output showed no significant change between 2021 and 2022, following two years of slight declines due to three reactors retiring. We expect that the commissioning of Vogtle Units 3 and 4 in Q1 and Q4 2023, respectively, will raise nuclear output by 2% in 2023. Further, the California legislature passed a bill to extend the life of Diablo Canyon Units 1 and 2 from 2024 and 2025 to 2029 and 2030, respectively, which will boost mid-term generation.

Coal-fired generation in the United States down in 2022, reversing a sharp increase in 2021

Year-on-year change in electricity generation in the United States, 2019-2025



Note: *Other non-renewables* includes oil, waste and other non-renewable energy sources

Canada

Electricity security also remains a concern in Canada. The NERC's November 2022 winter reliability assessment cites Alberta and the Maritimes as being at risk of insufficient electricity this winter due to higher-than-average peak electricity demand growth combined with the potential for high generator unavailability. The continued economic recovery from the pandemic-induced slowdown, as well as Canada's position as a commodities exporter, has sheltered it from high input costs, resulting in electricity demand growth of 2% year-on-year in 2022. The expected economic slowdown in 2023 will lead to a decline in demand of 1%.

Total thermal generation is expected to remain steady over our forecast period, but gas will increasingly replace coal in the generation mix. This will result in an 18% share for gas and 2% share for coal in 2025, compared to roughly equal shares of 10% in 2015. For nuclear output, the refurbishment programme at the Darlington and Bruce reactors will intensify in 2023, resulting in the temporary shutdown of five out of ten units in the second half of the year for refurbishment. This will decrease output of the overall fleet by almost one-quarter over 2023-2025 compared to 2015-2019 averages.

The government's Fall Economic Statement proposed a refundable tax credit of 30% for clean energy investments of up to CAD 6.7 billion over five years, including solar PV, wind, storage and small modular nuclear reactors. We expect this policy to contribute to strong growth in renewable generation, with wind and solar PV growth forecast to rise by about 6% and 14% per year, respectively, between 2023 and 2025.

Mexico

After the quick recovery in energy demand following the pandemic, electricity demand grew by almost 4% y-o-y in 2022. After an expected slowdown to less than 2% growth in 2023, the pace is set to pick up continuously, reaching 3% by 2025, which equates to an increase from about 300 TWh in 2022 to almost 330 TWh by 2025. In 2022, the rise in demand was met by a mix of sources, mainly by wind and solar PV, but also a small absolute increase in coal-fired generation.

The Mexican government announced a more ambitious GHG reduction target at COP27, shifting from the original 22% to 35% by 2030 as part of a joint investment project with the United States. The average CO_2 intensity of Mexican power generation, on the other hand, has risen by 7% y-o-y in 2022 to reach 385 g CO_2/kWh, due to the increased share of fossil-fired generation. CO_2 intensity growth is expected to decline out to 2025, to 370 g CO_2/kWh, as renewables and gas-fired output growth meets incremental demand, while oil-fuelled generation remains flat on average.

In the coming years, growth in renewables such as solar PV and wind from private sector companies is expected to slow. Auctions, which resulted in much of the growth in renewable energy, were halted in 2019. This follows a series of disconnections of private sector renewable energy projects due to generation permit expiry, permit cancellation or fines as a result of deviations from their original arrangement. In January 2022 a plant in the northern state of Nuevo Leon ceased operations after being fined USD 467 million for selling surplus generation to third parties instead of to CFE.

Despite the slowdown of private sector activity in Mexico's electricity market, the government has announced a number of clean energy projects in collaboration with state governments. These include a new 18 MW solar PV rooftop installation on top of Mexico City's largest market, and most notably an ongoing development of the solar PV plant in the northern state of Sonora, that should add 420 MW by the end of February 2023 and reach a total of 1 000 MW by the end of the fourth phase in 2027.

In the coming years, CFE plans the addition of around 16 new gas-fired power plants along with the repowering of ten of the hydropower plants run by the state company.

Brazil

Despite the strong post-pandemic rebound, Brazil's electricity demand in 2022 increased only very slightly, by 0.3% year-on-year, but is set to rise by around 2% per year in the 2023-2025 period. Hydropower generation rebounded in 2022 with a y-o-y increase of about 17% after the country's most severe drought in 90 years, and led to a decrease in power system emission intensity from 135 gCO_2/kWh in 2021 to 80 gCO_2/kWh in 2022. The CO_2 intensity is expected to continue decreasing towards 30 gCO_2/kWh in 2025.

We expect hydropower's share of generation to rise from 55% to 63% between 2021 and 2025, which will drive the emissions reduction along with an increase in the share of wind and solar PV generation, from 11% to 17% and 3% to 11%, respectively.

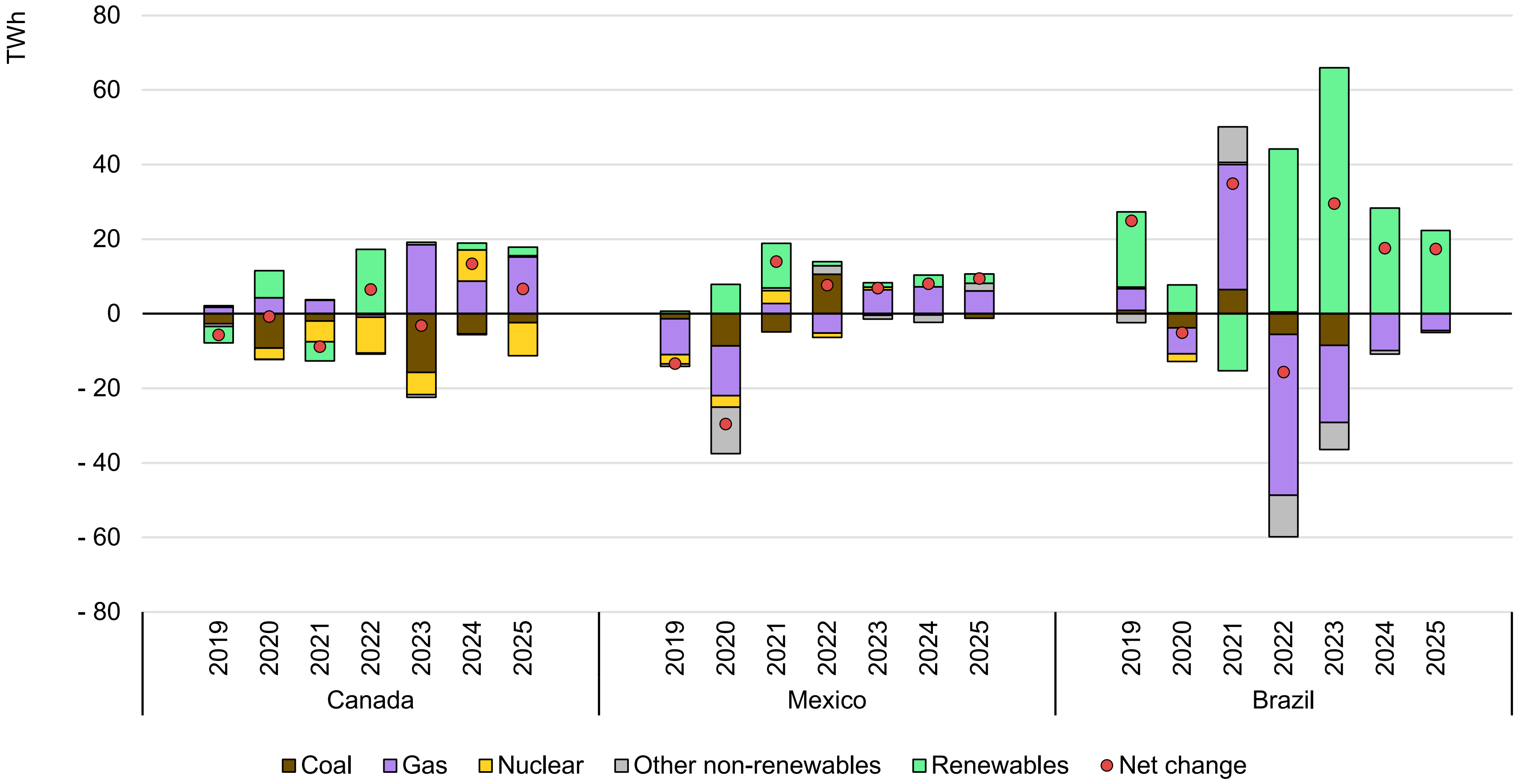
In the coming years, several proposed updates, which are part of the country's power system modernisation programme, may alter the rate at which renewables are deployed and how different actors interact in the power system. On 1 November 2022, the regulator ANEEL launched a consultation to alter solar PV net-metering incentives, leading to a decrease in the number of incentives for distributed generation (DG). The document also details new financing schemes for new installations through a special energy development account (CDE) from 2023. The CDE will be financed by all captive consumers, reducing the burden in regions with high penetration of renewables. Additionally, in 2023, the free market reserve for renewables ends and from 2024 they will have to participate in the wholesale market.

Brazil's Law 14 300, published in January 2022, sets a gradual transition path for distributed generation; current contracts will be grandfathered and a de facto net billing system will be introduced in January 2023. After a transition period, new DG clients will only be able to compensate for the energy component of their bills and they will be obliged to pay all distribution components of the tariffs. Additionally, 514/18 regulation will expand access to the liberalised retail market for consumers with loads between 0.5-1 MW, and from 2024, high-voltage customers of any level of demand will have access to the free market.

These new rules spurred the acceleration of decentralised solar PV deployments in 2022, totalling 10.7 GW. However, as the gradual opening of the energy market may offer customers an alternative to investing in distributed PV generation in order to decrease their electricity bills, it may slow the deployment of the distributed generation, which is the regulator’s aim due to the impact of DG on wider system operation.

While gas dominates incremental supply in Canada and Mexico, renewables expand in Brazil

Year-on-year change in electricity generation in selected countries in the Americas, 2019-2025



Note: *Other non-renewables* includes oil, waste and other non-renewable energy sources.

Market trends in selected other countries in the Americas

In **Chile**, electricity demand grew by about 2% in 2022, following the end of lockdowns in 2021. For 2023-2025, we expect an average annual growth of 4% in electricity demand, supported by economic growth and increased electrification (for example, in transport). Given the country's coal-power phase-out plan by 2040 at the latest, coal-fired generation is forecast to decline by an average of more than 7% per year in 2023-2025, due to some of these plants being decommissioned in this period (about 1 GW). Benefiting from its large wind and solar power potential, the decline in coal-fired power in the coming years is more than offset by growth in renewables. We forecast total renewable output will reach over 65% of the country's electricity generation mix by 2025.

Addressing concerns over renewable curtailment related to transmission bottlenecks (for example, between northern and central regions) and increasing flexibility requirements, the Chilean government passed a law to support energy storage development in October 2022. Additionally, a new electricity tariff stabilisation fund law was passed in July 2022 aimed at avoiding price hikes that would put additional pressure on households' expenses. This stabilisation fund was first implemented in October 2019 in the wake of public demonstrations and social unrest.

Electricity demand in **Colombia** fell below 1% in 2020 due to public health measures to combat the pandemic, and then recovered by 1.6% in 2021. Supported by increased economic activity, electricity consumption rose by about 1% in 2022. Despite being a significant hydrocarbon producer, Colombia's renewable capacity has helped limit fossil fuel-powered electricity to under 25% in recent years. Renewable output could surpass 80% of Colombia's generation mix by 2025.

To avoid further increases in end-user electricity prices, the Colombian government passed three resolutions in September 2022. These allow, for example, to renegotiate some supply bilateral contracts among market agents, optimise the operation of thermal power plants, and to decouple price increases from the consumer and producer price indexes. Additionally, the government presented an offshore wind roadmap.

Costa Rica's electricity system is already almost fully renewable due to high hydropower availability. After falling by 3% in 2020 amid Covid-19-related restrictions, electricity demand grew by 5% in 2021. In 2022, consumption rose again, by 3%. Costa Rica's transmission system is connected to Panama and Nicaragua, as it is part of SIEPAC (the Central American interconnected system). Electricity trade with neighbouring countries in recent years has usually remained under 1 TWh (less than 10% of national demand).

In order to lower electricity prices, the government of Costa Rica signed a decree in October 2022 that will allow the state-owned electricity ICE to buy electricity from private generators that did not already have a contract (and many of which were not selling electricity in recent months).

Europe

Renewables will lead to a sharp decline in fossil fuel-fired generation from 2023 onward

Electricity consumption in the European Union rebounded to almost 5% in 2021, in line with the economic recovery, following a substantial year-on-year decline of 4% in 2020. The return to growth reversed in 2022 when Russia's invasion of Ukraine triggered an unprecedented energy crisis, with Europe at the epicentre. As a result of demand destruction in electricity-intensive industries, energy saving measures and unusually mild winter, EU electricity consumption declined by 3.5% in 2022 – its largest percent decrease since the Great Recession in 2009, excluding the exceptional contraction due to Covid-19 in 2020. We forecast EU electricity demand to rebound slightly from 2023 onwards, with an average annual growth rate of 1.4%, on expectations of lower energy prices and the push for electrification.

The energy crisis and its wide-reaching impacts has led to a significant shift in policy priorities in the European Union. As a response to the crisis, the European Commission published on 18 May 2022 its REPowerEU plan to reduce the EU's dependence on Russian fossil fuels by hastening the clean energy transition. This was followed in December by the adoption of a Council regulation that will set a temporary framework to accelerate the deployment of renewables. Record-high electricity prices also prompted discussions on electricity market design and the Commission launched a consultation in early 2023 on this subject.

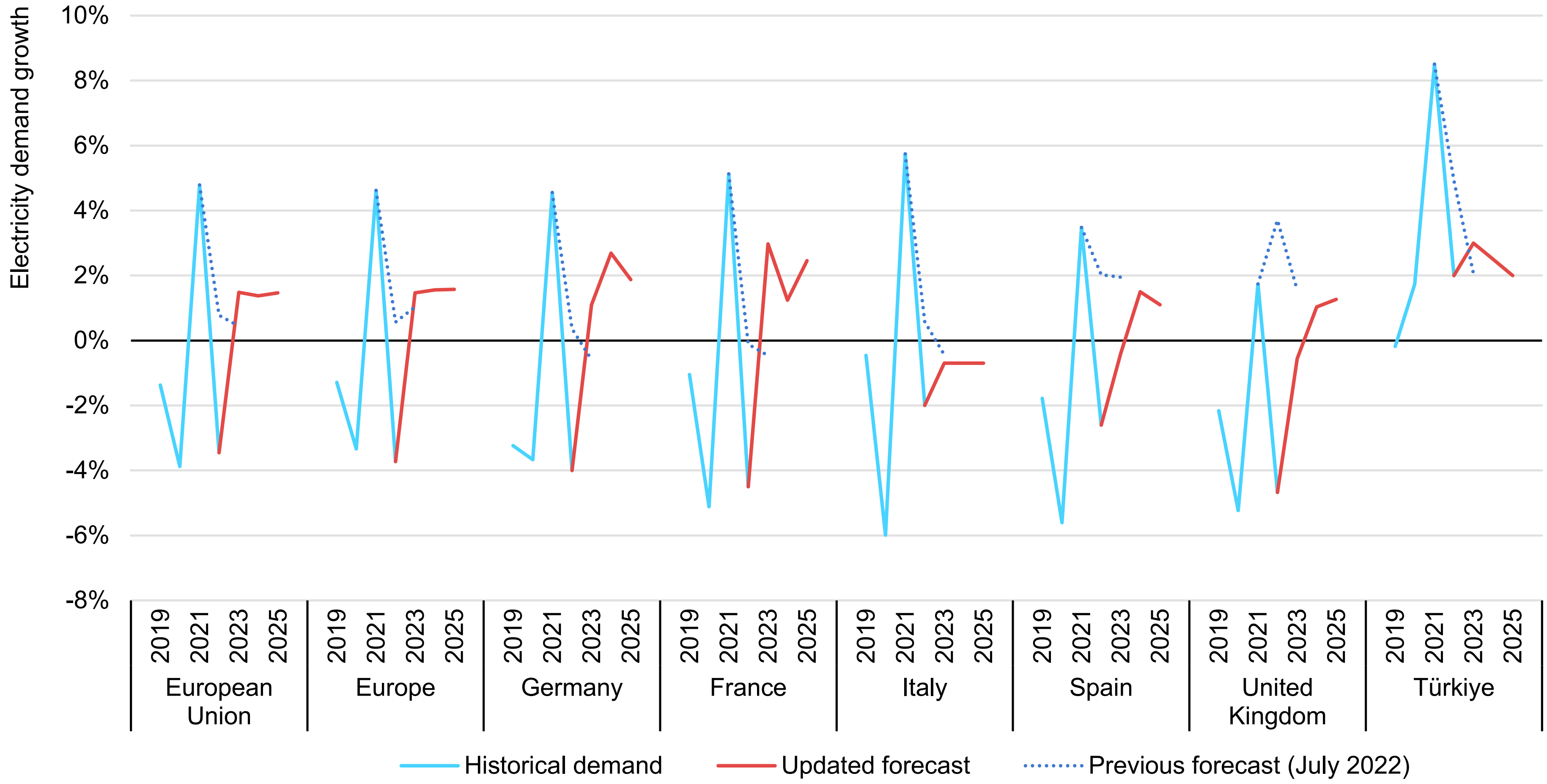
Short-term measures on a national scale were implemented to ease the tight market situation and provide relief to consumers, such as the introduction of price caps, reduction of energy taxes and regulation of retail tariffs, among various other initiatives. To reduce power sector gas demand and increase the security of supply over the 2022/23 winter, several countries have brought reserve generation capacities back online, mainly consisting of coal-fired plants. In Germany, the operation of the remaining three reactors has been extended until April 2023. Belgium has decided to extend the operation of Doel 4 and Tihange 3 by ten years, to 2035.

Coal-fired generation in the European Union increased again in 2022, rising over 6%. Despite high gas prices, gas-fired supply actually grew by about 2%, largely to offset reduced nuclear power and low hydro output. Over 2023-2025 we expect a sharp decline in fossil fuel-fired generation, as strong growth in generation from renewables of 34% from 2022 levels displaces fossil generation. Significant increases in nuclear generation occurs only after 2023, as French plants gradually conclude their maintenance schedules.

After the more than 11% y-o-y rise in 2021 due to the post-pandemic rebound, the 4.5% growth in 2022 was the highest percentage growth in power generation emissions in the European Union since the oil crises of the 1970s. While the global CO_2 intensity of power generation fell in 2022, it increased in the EU by 7% due to the higher share of coal-fired output. With the expansion of renewables and the decline in coal- and gas-fired supply, we forecast a decline of 28% in the EU power sector's CO_2 emissions by 2025 from 2022 levels, and by 31% in CO_2 intensity.

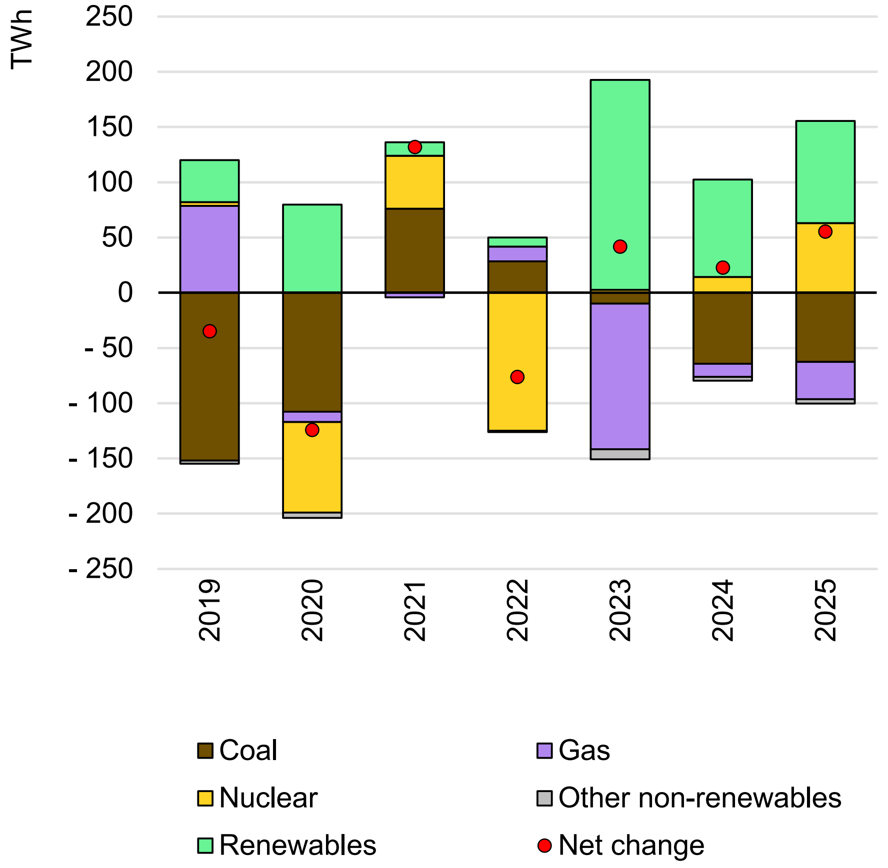
After significant decline in 2022, European electricity demand is set to recover

Year-on-year relative change in electricity demand, Europe, 2019-2025

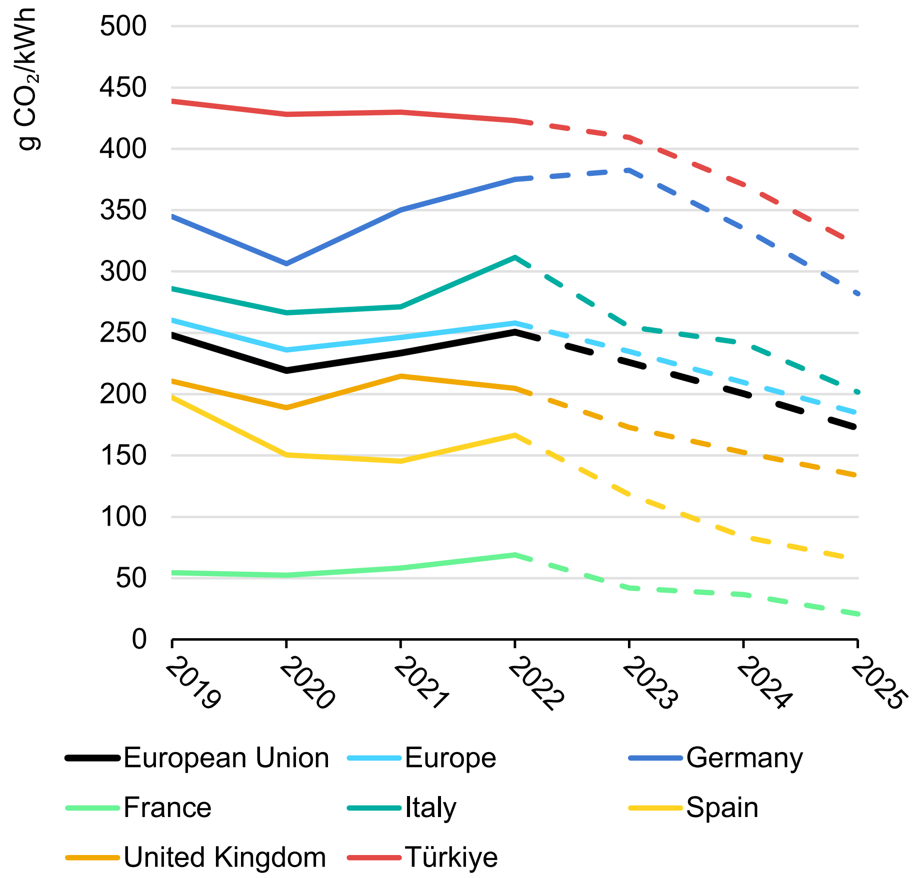


Following two years of increases, CO_2 intensity starts to decline again from 2023 onward

Year-on-year change in electricity generation, European Union, 2019-2025



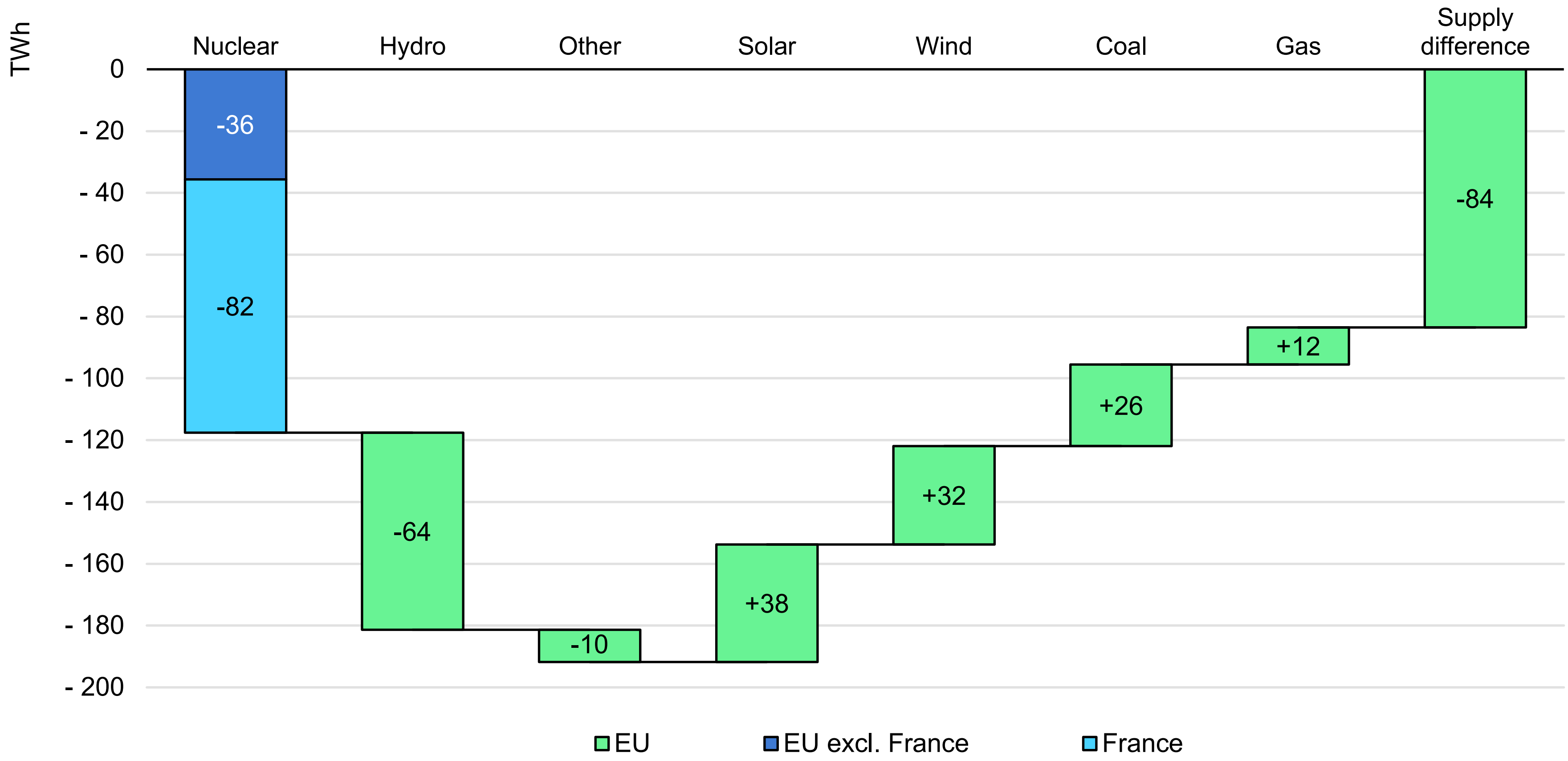
Development of average CO_2 intensity, Europe, 2019-2025



Note: *Other non-renewables* includes oil, waste and other non-renewable energy sources.

The European Union faced a multi-crisis year in 2022 amid low nuclear and hydropower output

Year-on-year change in electricity generation by technology in the European Union, 2021-2022



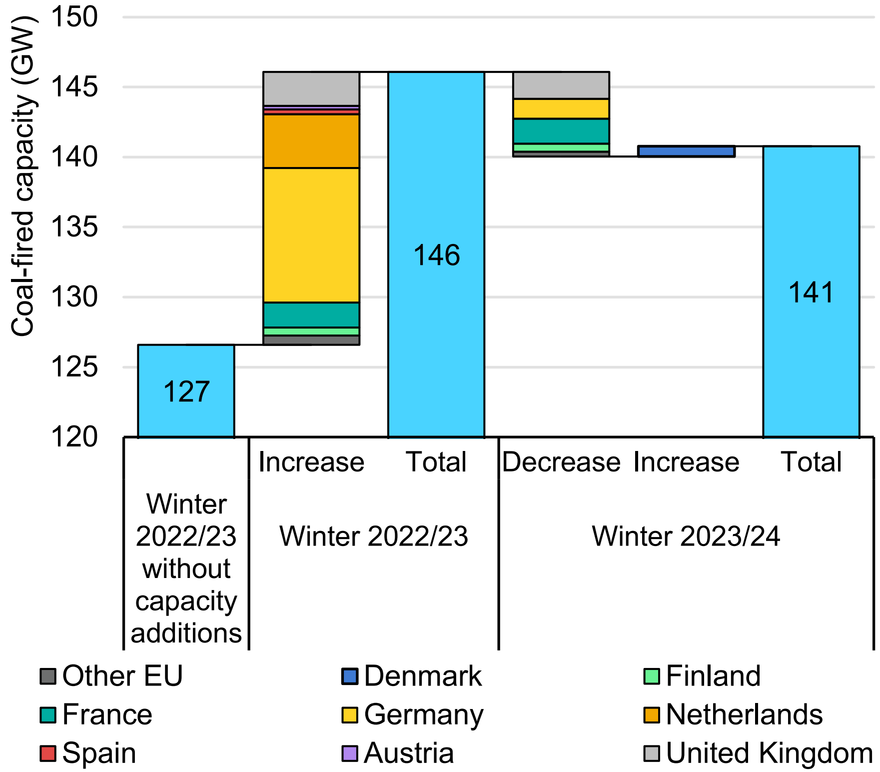
Note: *Other* includes oil, other renewable and other non-renewable energy sources. Generation numbers shown in this figure are net generation.

Countries in Europe have resorted to coal to increase security of electricity supply

To enhance security of supply amid low nuclear availability and tight gas markets, several countries in the European Union and the United Kingdom have decided, or are discussing plans, to add short-term conventional capacity to the market by bringing reserve capacity back into the market or postponing closure dates, lifting production caps and reviving idled power plants. Of the additional capacity of about 24 GW now in place until the end of winter 2022/23, 19 GW is coal-fired, which comes on top of the existing 127 GW that would be in place without these measures. Germany accounts for most of the additional coal-fired capacity, with almost 10 GW for the 2022/23 winter. In Netherlands, the removal of the 35% production cap on coal-fired plants will add another 3.8 GW. Under confirmed plans, overall coal-fired capacity will increase by about 15% (19 GW) to 146 GW in the European Union and the United Kingdom combined.

According to current government plans, coal-fired power plant capacity will fall again to about 141 GW during the 2023/24 winter after the temporary return of capacity ends. As some of the revived coal-fired generating capacity is idled again after winter 2022/23, output of the French nuclear power plants are expected to start increasing following maintenance in 2022. Nevertheless, depending on developments in the ongoing energy crisis, further capacity increases in European coal-fired generation is possible.

Breakdown of coal-fired capacity and capacity extensions in selected European countries, 2022-2024



Note: The analysis is conducted with available data and information as of 30 November 2023.

Sources: IEA analysis based on ENTSOE (2022), Transparency Platform, 30 November 2022; Bruegel (2022), National energy policy responses to the energy crisis, 30 November 2022.

Soaring energy prices led to emergency interventions in Europe

The sharp escalation in electricity prices, starting in the second half of 2021 and propelled higher by Russia's invasion of Ukraine in early 2022, compelled governments to implement measures aimed at reducing energy prices and mitigating their impact on both consumers and the wider economy. We explored some of these measures in our Electricity Market Report – July 2022 Update, such as the EC toolbox, the introduction of exceptional taxation and the establishment of market regulation schemes. Since then, national governments and the European Union have introduced new initiatives and continue with discussions on further measures to address the crisis. These range from non-targeted support that generally does not distinguish by the beneficent (e.g. wholesale price regulation, VAT/energy tax reduction or retail price regulation) to targeted programmes such as supporting vulnerable groups or businesses.

Several initiatives are particularly noteworthy. One example is the Iberian exception, which is a form of non-targeted support that caps gas and coal prices for power generation in Spain and Portugal. However, since differences in national measures might distort the European single market, efforts have been made to coordinate the implemented measures, such as the package with emergency plans introduced on 30 September 2022 by European Council. This emergency response entails introducing market revenue caps and solidarity contributions.

The Iberian model and its consequences

In June 2022, the governments of Spain and Portugal were granted an exemption by the European Commission that allowed them to cap the price of gas and coal for electricity generators. The measure started on June 14 and will run until May 31 2023. It limits the maximum price of gas and coal as an input to generation at EUR 40/MWh during the first six months and then increases by EUR 5/MWh per month before reaching EUR 70/MWh. Thus, this measure reduces the price of electricity and limits windfall profits of the inframarginal electricity producers. Under the measure, gas- and coal-fired generators are paid the difference between the market price of the fuels and the cap, financed through congestion rents for cross-border trade and an extra charge to consumers with contracts based on regulated tariffs. The exemption was granted due to the sufficient availability of gas in the region thanks to its ample LNG regasification capacities, and also because the potential impact on the EU internal power market would be limited by its marginal interconnection with the rest of Europe .

The Iberian model has succeeded in lowering electricity prices in Spain but, at the same time, it has had various other consequences. The price cap led to an increase in gas consumption in Spain. At the same time, lower Spanish wholesale prices as also led to increased and relatively cheaper power exports to neighbouring countries, which benefited Portuguese[2], Moroccan, and especially French consumers. This caused distortions in the EU internal electricity market, as well as in Iberian spot and futures markets. These issues, while important, were limited in scope due to the low level of interconnection between Spain and the rest of Europe.

Coordination package by the European Council

On 30 September 2022, the Council reached an agreement on a set of emergency market interventions. Thanks to this agreement, a Council Regulation on emergency interventions to address high energy prices was published on 6 October. These measures, which are deeper and broader than previous interventions at the European level, are a new attempt of controlling the price surge, addressing both the supply and demand sides.

These temporary measures on the electricity markets include a binding demand reduction of 5% during selected peak hours and a cap on market revenues for inframarginal technologies set at a maximum of EUR 180/MWh. This revenue cap is applicable for the period between 1 December 2022 and 30 June 2023. As the measures are being implemented at the national level, it is too soon to assess their effects, and key aspects of the implementation remain to be clarified. Some countries (e.g. France, Belgium and the Netherlands) decided to set the market revenue cap below the maximum level, for instance, and in the case of the Netherlands at EUR 130/MWh. Particularly, the interaction between the revenue cap for inframarginal generators and forward markets, where many of these generators may have already sold their energy, will be key for the success of the measure.

A temporary solidarity contribution (in place until June 2023) was also introduced, which entails additional taxation of at least 33% of the excess profits received by companies active in the petroleum, natural gas, coal and refinery sectors during 2022. The solidarity measure aims at capturing windfall profits without modifying the market price, and therefore without distorting the operation and clearing of the markets. The implementation of the solidarity contribution mechanism is not uniform across the EU member states. Some EU member countries, such as the Czech Republic, Greece and Italy, have set their rates much higher at 60%, 90% and 50%, respectively, than the reference rate of 33%. The Czech government also extended the solidarity tax not only to energy companies, but also to some banks. Similarly, Spain imposed this tax, which was originally targeted at energy companies, to some domestic banks.

Disparity in magnitude of support across Europe

The vast majority of countries in the European Union introduced some form of business support. However, the targeted direct financial supports and retail price measures differ significantly

[2] The benefit to Portugal is due to a bigger share of Portuguese consumers with fixed contracts and so less contribution to compensating gas generators.

among the member countries. As a result, the heterogeneity of the implemented relief measures may lead to discrepancies in the prices perceived by industrial consumers among European countries, harming competition.

The German industry support scheme is a part of a EUR 200 billion energy relief plan (called Economic Defence Shield), of which EUR 25 billion will be dedicated to the industrial scheme. Consequently, electricity tariffs for industrial consumers will be capped at EUR 130/MWh for 70% of their 2021 consumption (to motivate electricity savings) whereas the cap for residential consumers was set at EUR 400/MWh for 80% of the 2021 consumption. In Spain, over EUR 500 million has been dedicated to shielding large industrial consumers. Additionally, a plan was introduced to decrease the transmission and distribution network fees paid by electricity-intensive industries.

The total magnitude of the financial resources dedicated to shielding household and industrial consumers also differ widely among European countries. For example, while the German energy support scheme was above 7% of the German GDP, the subsidies in Sweden amount to less than 0.3% of its GDP.

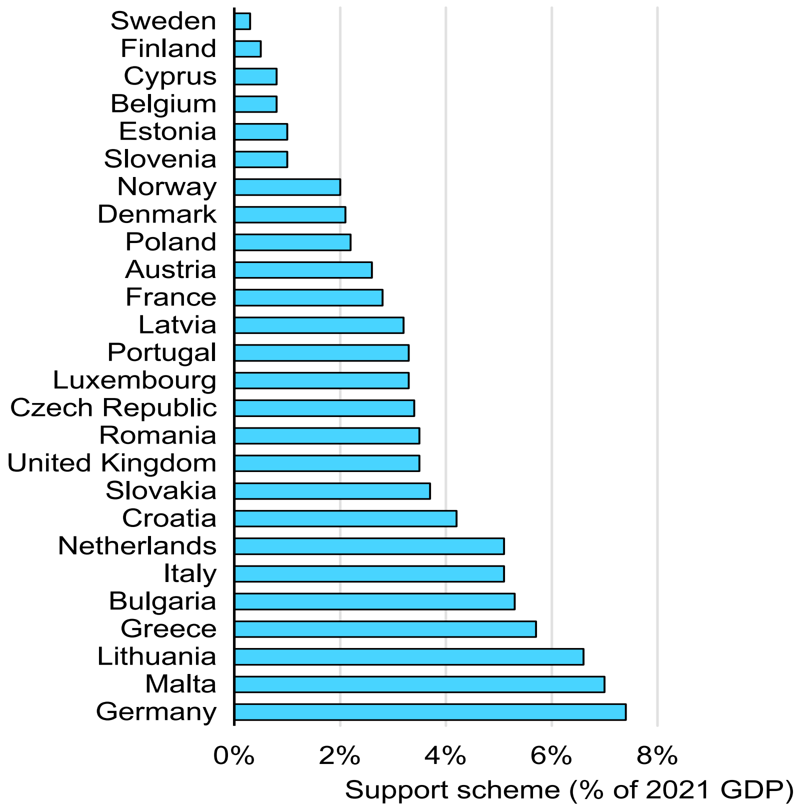
Shielding residential consumers via support measures

In a large majority of countries in the European Union as well as Norway and the United Kingdom, reductions in energy taxes or VAT were introduced. Similarly, many countries strengthened financial transfers to vulnerable consumers. Sixteen member states of the European Union introduced retail price regulations. Some of the introduced measures incentivise energy consumers to reduce their consumption while others do not, which then act as consumption subsidies. To illustrate, the Greek government implemented an across-the-board relief package which subsidises consumption based on the end-user. In this scheme, households can receive up to EUR 436/MWh (industrial consumers can receive up to EUR 398/MWh). In Norway, a subsidy scheme was introduced to cover exposed industrial consumers: those with more than 3% of their costs spent on electricity will be compensated 25% of the electricity rate if it exceeds a threshold of about EUR 68/MWh.

The implementation of support measures in Europe have helped dampen the effects of the current crisis on residential electricity prices. Based on VaasaETT's analysis of selected European capital cities, the measures by governments have prevented on average a 14% price spike in new household electricity contracts in 2022, considering estimates of mean annual prices with and without measures.

Support measures in Europe helped dampen the impact of high prices on consumers

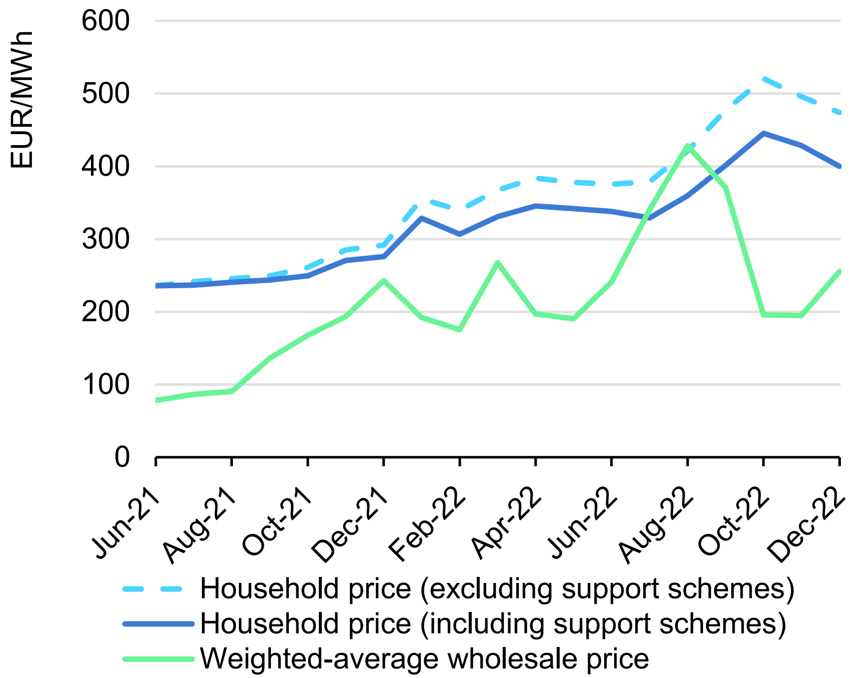
Magnitude of support schemes to residential and industrial consumers in the European Union, Norway and the United Kingdom, September 2021- November 2022



Note: Data based on a percentage of GDP in the European Union, Norway and the United Kingdom.

Source: Bruegel (2022), National fiscal policy responses to the energy crisis, 3 December 2022.

Representative household prices including and excluding support schemes in the European Union, June 2021 to December 2022



Notes: The household price analysis focuses on general measures affecting typical consumers and selected capital cities which have applied such measures during the period analysed. Electricity demand-weighted wholesale price for the following EU countries: Austria, Croatia, Czech Republic, France, Finland, Germany, Italy, Poland, Romania, Slovak Republic, Slovenia, and Spain. Household prices consider new tariff offers.

Source: Based on data and analysis provided by VaasaETT (2023), © 2023 VaasaETT Ltd.

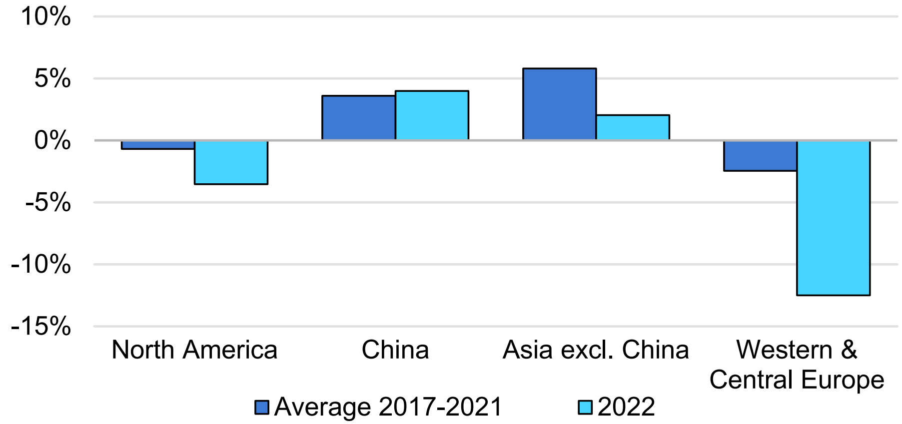
European electricity-intensive industries decrease their production

Exceptionally high prices are having a significant impact on some industrial sectors with high electricity use, which has led to a sharper drop in national electricity consumption. Among energy-intensive industries (e.g. chemical, iron and steel, non-ferrous metal production, paper mills, and others), aluminium production seems to be hit the hardest by steep electricity prices in Europe.

Permanent downsizing of European BASF's capacities due to high natural gas and electricity prices underscore concerns about declining competitiveness of European production. Similarly, non-ferrous metal producers have voiced their concerns over continuing operations with the current energy prices. For example, in August 2022, aluminium smelters in Slovakia halted their production until energy prices reach acceptable levels. The largest aluminium producer in Germany, Trimet, decreased production in multiple sites due to the high energy prices, with the production capacity in Essex halved in March 2022. Stainless steel production stopped in fifteen plants across the European continent. Thus, some metal producers have requested to be shielded by political interventions. However, metal producers are also hit by a decrease in demand caused by slowing economic activity. Hence, the current crisis is affecting both the demand and supply sides.

After the Russian invasion of Ukraine, not only were European metal producers hit by soaring energy prices, but metal supply chain issues also occurred due to the decline of Ukrainian metal production. As a result of the tight supply and increasing production costs for metals in Europe, China is turning into a metal exporter from being a metal importer. However, higher European reliance on critical raw material imports also raises environmental concerns, for instance in China, where aluminium production is three times more carbon-intensive than in Europe.

Year-on-year growth rate of primary aluminium production in selected regions, 2022 and 2017-2021 average



Note: See the IAI website for the country groupings for the shown regions.
Source: IEA analysis based on International Aluminium Institute (IAI) (2022), Primary Aluminium Production, 1 December 2022.

Germany

Germany's electricity demand declined by 4% in 2022 amid higher prices, public calls to save energy and an exceptionally mild winter. Renewable power generation rose 9% from 2021, when it was lower than average due to reduced wind speeds. The expansion of renewable capacity also continued in 2022. In particular, solar power installation accelerated, driven by private investments in the wake of high electricity prices.

Low water levels on the Rhine during the summer of 2022 disrupted the transport of coal to plants located along the river, causing a reduction in their output during the period. Despite this, and the growth in renewable generation, coal-fired power generation in Germany increased by more than 10%. for the second year in a row in 2022, lifting the power sector's coal use above 2019 levels. Several factors contributed to this. The natural gas supply shortage in Europe, resulting in high gas prices, made coal a comparatively cheap source of electricity. At the same time, low availability of nuclear power plants in France led to higher imports from Germany in 2022. Nevertheless, coal fired-generation in Germany was still much lower (-20%) than its average during the period 2015-2019.

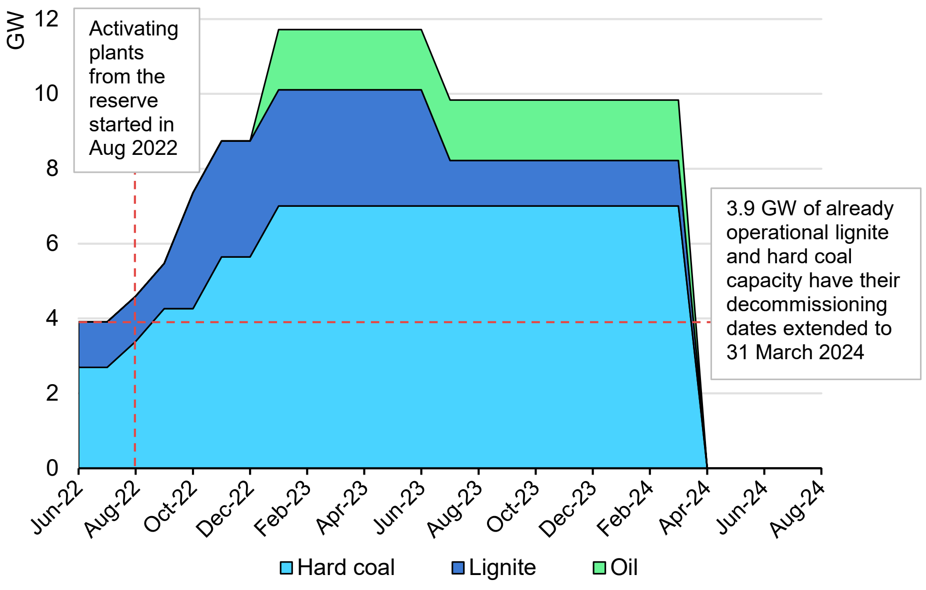
Germany activated a gas replacement reserve from fossil fuel power plants that are not gas-fired on 13 July 2022. This includes 4.3 GW of hard coal and 1.6 GW of oil-fired plants until 31 March 2024, which were previously put in grid reserve. In addition, about 1.9 GW of lignite-fired capacity – originally planned to be decommissioned by 1 October 2022 – was brought back from the security readiness reserve. These plants will remain operational until 30 June 2023.

A further 2.2 GW of hard coal-fired plants that was slated to be decommissioned by 31 October 2022 according to the auctions under the Act of Phasing Out Coal-fired Power Stations and about 0.5 GW of hard coal capacity that would similarly be decommissioned by 1 July 2023 have had deadlines extended until 31 March 2024. Additionally, 1.2 GW of lignite-fired capacity that would have to be decommissioned by 31 December 2023 will also be extended until 31 March 2024.

Germany's remaining 4.1 GW of nuclear capacity, initially set to be shut down at the end of 2022, was put in emergency reserve instead, allowing it to run during the winter until April 2023. However, the plants will not be refuelled and therefore have a reduced total output of an estimated 5 TWh for the duration of the extension. In 2022, nuclear power provided about 6% of Germany's total electricity generation.

In 2023, we expect coal-fired generation to increase another 4%, as more of the reserve capacity will be operational while gas prices are set to remain high. Renewables are set to grow strongly by 12%, while gas-fired generation similarly records a sharp decline of 15%.

Evolution of the German gas replacement reserve, 2022-2024



Source: IEA analysis based on data from BNetzA (2022), Power plant list, 15 December 2022; ENTSO-E (2022), Transparency Platform, 15 December 2022.

In 2024-2025, we expect Germany to fully return to its coal phase-out plan and, hence, coal-fired power generation to decline. By then, renewable power generation is forecast to grow significantly, driven by increased renewable targets, reduced bureaucratic hurdles and high energy prices. The government aims to install a total of 38 GW of solar capacity, 19 GW of onshore wind and 3.5 GW of offshore wind capacity from 2023 to 2025. Acceleration of the permitting procedures and grid build-out will be important factors to achieve these targets. While our forecast shows Germany will likely continue to be a net exporter of electricity also in 2023 after 2022, the likelihood increases significantly that it switches from being a net exporter of electricity to a net importer from 2024 onward.

France

After posting a 5% recovery in electricity demand back to pre-pandemic levels (475 TWh) in 2021, demand declined by 4.5% in 2022. This was principally driven by higher energy prices amid the energy crisis in Europe and – despite lawmakers approving a 4% annual price increase cap on electricity bills in 2022 – as well as by the mild winter.

Total electricity generation fell by a sharper 15% (-83 TWh) in 2022, where nuclear reactors produced almost a quarter less (-87 TWh) than the year before, slightly offset by a 30% increase (+9.5 TWh) in gas-fired power generation. France also became a net importer of electricity for the first time in more than two decades, to cover about 4% (18 TWh) of its needs. Power generation from renewables decreased by 4% in 2022, due to lower hydropower generation than in 2021.

France's supply imbalance stems from the nuclear fleet undergoing continuous maintenance work since 2014, slowed further by safety obligations in 2020-2021 and exacerbated by corrosion problems that led to longer maintenance and unplanned shutdowns of 12 additional reactors (about 15 GW). This represents about 17% of the peak load observed in 2021. In November 2022, out of the 56 total nuclear reactors, 26 were offline. Above average temperatures, along with droughts and heat waves, further magnified the electricity generation shortfall by creating cooling issues at nuclear reactors and markedly lowering hydroelectricity output, with reserves depleted in 2022 to below historical lows.

Several recent developments in France are set to improve its demand-supply balance in the 2023-2025 period. The country is aiming to reduce its primary energy consumption 10% by 2024 compared to 2019, with emergency measures announced during the summer to both accelerate the development of renewable sources of electricity and to enhance energy security. France's first commercial-scale offshore wind farm, with a capacity of 480 MW, became fully operational in November 2022. Additionally, the coal-fired power station Saint-Avold (0.5 GW) was temporarily restarted in November 2022 to boost winter electricity supplies.

In 2023, despite the setbacks experienced by EDF in restarting all of its reactors in 2022, nuclear power is expected to reach a gross output of 326 TWh (+11% y-o-y). Power generation from fossil-fired sources is expected to decrease by more than 40%, down to 33 TWh. A 7% growth in French power generation is expected, with a decline in imports. Start of operation of Flamanville 3 is expected to be delayed to Q4 2024.

On top of the 10% primary energy consumption decrease target by 2024, the French government's longer-term objective is to be carbon-neutral by 2040 with a 40% reduction in energy consumption.

Italy

Italy's electricity consumption fell by 2% year-on-year in 2022. All-time high electricity prices weighed on industrial and commercial activity, resulting in slower GDP growth which in turn slowed electricity consumption. In addition, milder temperatures in Q4 2022 reduced space heating requirements in the residential and commercial sectors. Energy efficiency improvements and slower economic growth are set to weigh on electricity consumption going forward. Italy's electricity demand is set to fall at an average annual rate of 1% in 2023-2025, and it is not expected to recover to 2022 levels throughout this period.

Dry weather led to a steep drop in Italy's hydropower generation in 2022, down by 35% (-16 TWh) compared to 2021. Wind power generation fell y-o-y by 3%. This was only partly compensated for by higher solar PV generation, increasing by 11% (+3 TWh). Lower renewables output contributed to higher thermal generation. Coal-fired generation rose by 50% (+8 TWh), while gas-fired electricity decreased by 2% (-2 TWh) compared to 2021.

We expect renewable output to rise by 20% (+20 TWh) by 2025 compared to 2021 levels. This will be primarily driven by strong growth in solar PV. Lower electricity use, together with rapidly expanding renewables, will reduce Italy's reliance on thermal power. Coal is set to be phased out by 2025, while gas-fired generation is expected to fall at an average rate of 4.5% per year between 2023 and 2025.

Spain

Electricity demand in Spain increased by 3.5% in 2021, but was still below 2019 pre-pandemic levels. However, electricity demand fell by 2.6% to about 243 TWh in 2022, mainly due to demand destruction related to high prices.

Despite this, power generation in 2022 increased by 6% (+16 TWh) year-on-year, surpassing 285 TWh. Royal Decree-Law 10/2022, also known as the "gas cap" or "Iberian exception", entered into force on 15 June following its presentation to the European Council on 26 March. In 2022, the Iberian exception has resulted in Spain achieving lower wholesale prices at the expense of increasing electricity exports, and boosting gas-fired generation by about 25% (+18 TWh) above 2021 levels.

Coal-fired power generation rose by about 50% (+3 TWh), in 2022, but still accounted for only 3% of electricity generation. Power generation from solar PV increased by about 23% y-o-y (+5 TWh) in 2022. Solar PV reached an installed capacity of 20 GW, surpassing hydro as the technology with the third-highest installed capacity. An unusual event was seen this year, with a sharp drop in solar PV electricity output in March due to the haze coming from the Sahara Desert that affected the Iberian Peninsula. This led to a decrease of 14% (-0.2 TWh) compared to the same month of the previous year. At the same time, record drought in Spain decreased hydro generation by more than 30% y-o-y in 2022. The aforementioned cap on gas prices resulted in a further y-o-y decline in power generation from CHP plants by 23% (-3 TWh), considering the January-August 2022 period, since these facilities were not eligible for the cap until an announcement from the Spanish Government on 6 September.

Another series of measures, included in the recent More Energy Security Plan, have been taken to better protect consumers, including electricity-intensive industry, whose access charges have been reduced by 80%. Additionally, there has been a temporary reduction of VAT for gas prices from 21% to 5% as well as the creation of a new mechanism to manage demand in the event of excess electricity consumption.

We expect electricity use to decrease by about half a percent during 2023, before growth recovers to 1% annually in both 2024 and 2025. During that three-year period, we forecast total renewable output to increase by over 15% annually, together with a moderate rise in electricity imports. As a consequence of lower utilisation rates for thermal generation plants due to higher renewable output and lower gas-fired exports, CO_2 emissions will drop by close to 60% in 2025 compared to 2022 levels.

United Kingdom

After increasing by 1.7% in 2021, electricity consumption in the United Kingdom declined by almost 5% in 2022, driven by energy saving measures, high energy prices, sluggish economic growth, and milder temperatures. 2022 saw a year-on-year decline of coal-fired power (-20%), whereas gas rose 3% and nuclear increased by 2%. Renewable generation grew by 6%.

Concerns for security of electricity supply over the winter led system operator National Grid ESO to take a number of actions. In August it secured emergency contracts to keep coal-fired plants available during the winter months. In early October 2022, they warned consumers about winter power outage risks in a worst-case scenario. Later in the month, they announced financial incentives for consumers to shift their electricity consumption.

In 2022, the United Kingdom also became a net electricity exporter on an annual basis for the first time on record, which accounts for the positive net change in higher generation despite a decline in domestic demand. Continental Europe increased purchases of wholesale power from the United Kingdom to offset sharply lower European nuclear and hydro power output in 2022 and also to take advantage of cheaper UK wholesale electricity prices. UK prices were relatively lower as comparatively lower gas prices than in continental Europe due to excess regasification capacity fuelled higher gas-fuelled generation, and combined with record-breaking renewable electricity, supported exports. As a result, the United Kingdom became a net electricity exporter in Q2 2022, which was the first quarter with net exports in 12 years, with flows particularly strong to France. Later in 2022, during September, the United Kingdom sent exports to Norway, which was affected by low hydro availability. By the end of 2022, the United Kingdom had a total net export balance of about 5 TWh.

As of October 2022, Great Britain's interconnector capacity stands at 8.4 GW (4 GW with France, 1.4 GW with Norway, 1 GW with Belgium, 1 GW with the Netherlands, 500 MW with Ireland and 500 MW with Northern Ireland). However, the UK-France IFA1 interconnector (2 GW nominal capacity) suffered fire damage in September 2021, which left it operating at partial capacity. After repair works, the interconnector began to operate again at full capacity by the end of January 2023.

Great Britain continues to strengthen its electricity interconnections, with capacity set to almost double by 2025. Capacity is set to reach almost 16 GW, with the commissioning of interconnectors both with Germany and Denmark (1.4 GW each), and additional capacity with France (2.8 GW), Ireland (0.5 GW) and Norway (1.4 GW).

For the 2023-2025 period, we forecast electricity consumption in the United Kingdom to grow by around half a percent per year on average. We expect demand to decline in 2023 with a slight recovery in 2024 and 2025. In these three years, electricity generation from gas and nuclear energy is expected to decline. Due to high gas prices, coal-fired generation is forecast to remain at just above 5 TWh in 2022 and 2023 (less than 2% of the electricity mix), then drop to almost zero by 2025. Finally, from 2023 to 2025, renewable output is expected to grow by an average of more than 10%, led by wind and solar PV power additions, supported by the Energy Security Strategy.

In 2022, the United Kingdom launched a consultation for the Review of Electricity Market Arrangements with the aim of ensuring the UK power market is fit for purpose to support the national goal of a fully decarbonised power supply by 2035.

Republic of Türkiye

Türkiye's electricity demand rose by 2% (+6 TWh) year-on-year in 2022. This was supported by strong GDP growth of 7.5% y-o-y in the first half of 2022 and an estimated 5.5% for the full year. The country's electricity demand is expected to increase at an average rate of close to 2.5% per year over the 2023-2025 period, supported by expanding economic and industrial activity.

Following the drought of 2021, Türkiye's hydropower output rose by 20% (+11 TWh) in 2022, recovering close to its 2020 levels. Wind and solar generation expanded by 12% (+4 TWh) and 80% (+1.2 TWh), respectively. As a consequence, the share of renewables in total power generation rose to 42% compared to 35% in 2021. Higher renewables-based generation weighed on thermal power, although gas- and coal-based generation posted differing results. The rapid increase in natural gas import prices led to gas-to-coal switching dynamics in the power sector. While gas-fired power generation fell by over 25% (-27 TWh) in 2022, coal-fired output rose by 8% (+8 TWh) in 2022 compared to the previous year. Improved hydro availability allowed Türkiye to export close to 2 TWh of electricity into neighbouring markets. By contrast, the country imported about 2 TWh in 2021.

Türkiye announced at COP27 that it increased its 2030 emissions reduction target from 21% to 41%. We forecast that Türkiye's power generation will increase at an average rate of 2.5% per year over the 2023-2025 period. Renewable generation is expected to increase by almost 30% by 2025 compared to 2022, and will account for almost half of the power generation mix. The first reactor of the Akkuyu Nuclear Power Plant is expected to be commissioned by the end of 2023 and gradually ramp up production through 2024-2025. Fossil-based thermal generation is forecast at 15% below its 2022 levels by 2025. Over the 2023-2025 period, coal- and gas-fired generation are expected to decline by an average rate of 8% and 3% per year, respectively, reducing the emission intensity of Türkiye's power sector.

Ukraine

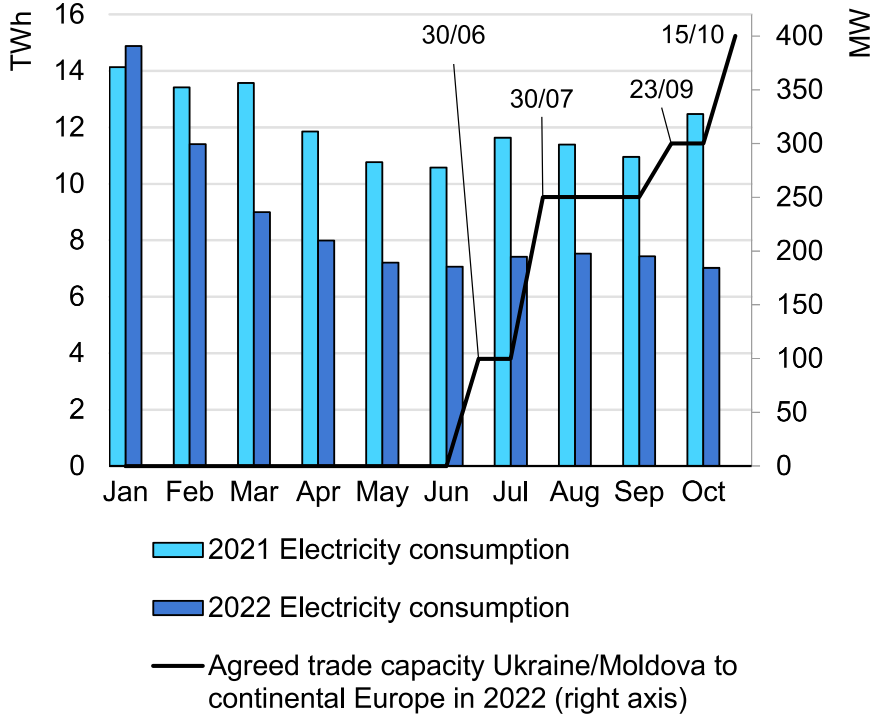
Since the invasion of Ukraine by Russia in February 2022, electricity consumption has plummeted. It was cut by one-forth within a week and by 40% two months later. Demand profiles clearly highlight both the start of the war on 24 February and the intensification of missile strikes on Ukraine since 10 October, which led to massive destruction of infrastructure and power outages. Between March and end October 2022, electricity consumption fell by about 30% year-on-year.

The security of Ukraine's nuclear facilities almost immediately became a serious issue after the invasion, in particular for the 6 GW Zaporizhzhia nuclear power plant, whose grid connection was lost on multiple occasions since the Russian army attack on 3 March. The plant stopped injecting power into the Ukrainian power grid on 25 August 2022.

Another factor influencing the share of nuclear power in the Ukrainian generation mix is the ability to export excess power to European neighbours. Ukraine and Moldova were synchronised with the continental European grid on 16 March. Trading with European neighbours started on 30 June, with capacity gradually rising in 100-150 MW increments. On 15 October, TSOs set the export limit of Ukraine/Moldova to 400 MW and the import limit to 500 MW. The power exchange between Ukraine/Moldova and continental Europe is beneficial for both parties; with increased financial revenues for the former and help in balancing tight electricity markets for the latter. While Ukraine was initially exporting power in the face of a depressed demand, the situation changed following the infrastructure damage on 10 October. Following that, electricity exports were banned by Ukrainian authorities to ensure local demand was met. Moldova swiftly received support from EU neighbours (e.g. Romania and others) to fill the gap of the lost electricity imports from Ukraine (which used to cover 30% of Moldova's electricity demand).

The outlook for future developments is highly uncertain. The end of the war is not yet in sight and many factors may influence the post-war recovery, including the state of the energy infrastructure. More than half of the Ukrainian energy infrastructure was destroyed at the end of 2022.

Monthly electricity consumption in Ukraine and the evolution of allowed trade capacity Ukraine/Moldova and continental Europe, 2021-2022

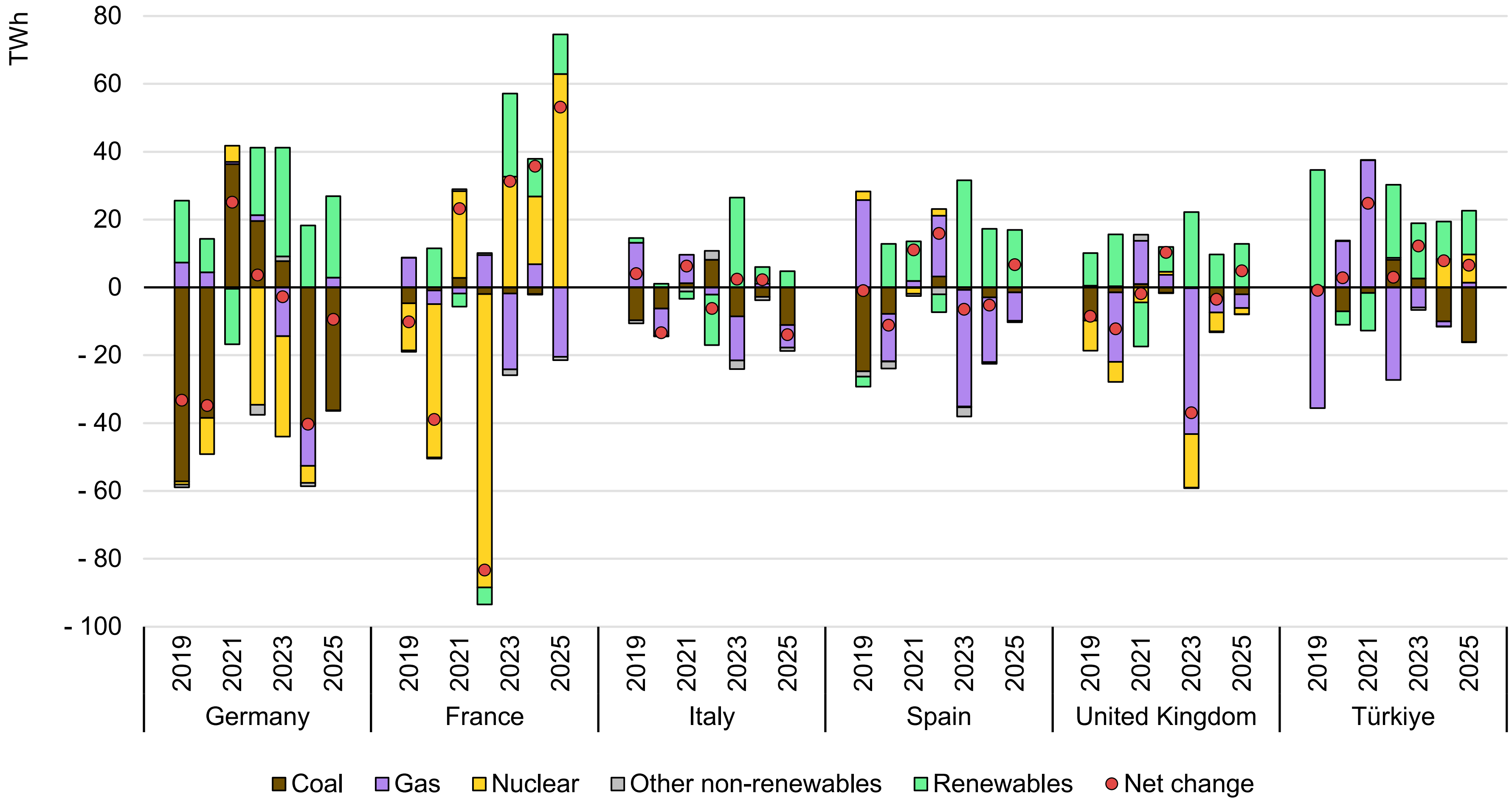


Notes: The maximum allowed exchange capacity does not include the already existing export capacity to Poland of approximately 215 MW from the Ukrainian Dobrotvirska power plant. Other changes in the allowed exchange capacities might have occurred after 15 October 2022.

Sources: UKRENERGO (consumption data available until 27 October 2022) and ENTSO-E (export).

Renewables lead generation growth in most large European countries until 2025

Year-on-year change in electricity generation in selected countries in Europe, 2019-2025



Note: *Other non-renewables* includes oil, waste and other non-renewable energy sources.

Eurasia

Eurasia's electricity demand growth slowed in 2022 amid the worsening economic outlook

Russia's war in Ukraine has cast a long shadow over its domestic macroeconomic outlook and could have negative spillover effects on other countries in the region who share close economic or political ties with Russia.

Eurasia's electricity consumption increased by an estimated 1.5% (+24 TWh) year-on-year in 2022 – a marked slowdown compared to the record growth of 75 TWh in 2021. Over 70% of incremental electricity demand was concentrated in the first half of the year. Electricity consumption growth slowed to below 1% y-o-y in the second half of the year amid the worsening economic performance. Fossil-based thermal generation rose by over 3%, offsetting lower hydropower output and meeting the incremental electricity demand.

The region's electricity demand growth is expected to slow to an average annual rate below 1% from 2023 to 2025.

Fossil-fired generation is set to continue to dominate Eurasia's electricity mix, at a share of around 65% over the 2023 to 2025 forecast period. While the deployment of renewables remains slow at the current pace, the commissioning of new nuclear plants, including in Belarus and Russia, is set to slightly reduce the CO_2 intensity of power generation over our forecast period.

Russia

Russia is by far the largest power consumer in Eurasia, with annual consumption of over 1 000 TWh, and accounts for just over three-quarters of the region's electricity demand.

Russia's electricity consumption grew by over 6% in 2021, or close to 60 TWh – its highest increase in absolute terms since the demise of the Former Soviet Union. This was largely supported by a strong economic recovery (the country's GDP grew by 4.7%) and adverse weather conditions, i.e. a cold and long winter season. Power generation rose by 6.3% (+69 TWh), largely supported by the country's significant thermal fleet. Gas-fired power generation surged by over 10%.

Russian electricity consumption is estimated to have increased by 1.5% (+16 TWh) in 2022. Demand growth was almost entirely concentrated in the first half of the year, when it rose by 2.2% y-o-y. Depressed industrial and commercial activity moderated electricity demand growth to 0.7% year-on-year in Q3 and Q4 2022.

In 2022, fossil-fired generation – including coal, natural gas and fuel oil-fired power plants – rose by over 3% (+24 TWh) compared to 2021 levels and accounted for over 60% of total power supply. The strong growth was primarily supported by lower hydro output, which fell by 8% (-17 TWh) y-o-y.

Russia's power generation capacity increased by a marginal 0.5% y-o-y through the first ten months of 2022. Gas-fired generation capacity grew by close to 1 GW, more than compensating for a reduction of 0.3 GW capacity in coal-fired power plants. Nuclear and hydropower generation capacity remained stable, while solar power capacity was up by close to 8% (+0.25 GW).

In Russia, lower industrial and commercial activity is expected to weigh on electricity demand growth. The country's generation mix is set to remain broadly unchanged over the medium term, with fossil-fired generation maintaining its share of over 60%. There are currently two nuclear reactors under construction and expected to come online before 2026, Kursk II-1 and Kursk II-2, with a combined capacity of 2.5 GW. They are expected to be commissioned over 2023-2024 and will match the retirement of the first two old Kursk units. Russia is also undertaking a large-scale modernisation programme of its thermal fleet, with the target to refurbish over 20 GW between 2022 and 2026. According to initial estimates, this could decrease the carbon footprint of Russia's power system by 5%. In 2022, power generation companies requested to postpone the modernisation of 26 thermal power plants (with a combined capacity of close to 6 GW) by one year or a year and a half in some cases. This is primarily due to the delayed delivery of gas turbines due to Western sanctions imposed on Russia's technology procurement.

Kazakhstan

Kazakhstan is the second largest electricity consumer in Eurasia, with annual demand of over 100 TWh. Electricity consumption rose by 7% (+7 TWh) in 2021, driven by a recovery in industrial and commercial activity. Higher demand was primarily met by fossil-fired generation, which increased by 2% (+2 TWh) and compensated for the decline in hydro output of 9% (-0.6 TWh).

Power generation fell by an estimated 1% (-1.1 TWh) in 2022 amid slower economic growth. According to preliminary data, fossil-fired generation declined by over2% (-2 TWh) y-o-y in 2022 . Hydropower outputremained broadly flat compared to 2021. .

Kazakhstan's electricity demand is forecast to increase by 1.7% per year over the 2023-2025 forecast period, largely to be met by expanding gas-fired power generation and renewable sources of electricity supply. According to the country's development plan for the natural gas sector, published in July 2022, gas consumption in the power sector is expected to rise 55% by 2025 from 2022 levels. This would translate into an estimated 14 TWh of gas-based electricity supply. While the growing share of renewable and gas-based generation is set to reduce the power sector's emissions intensity, coal-fired generation will retain its dominant position, accounting for more than half of the generation mix in 2025.

Other Eurasia

Similar to Russia and Kazakhstan, electricity consumption also grew strongly (over 6% y-o-y) in other Eurasian countries in 2021, supported by recovery in economic and industrial activity after the start of Covid-19 in 2020. Preliminary estimates indicate that electricity demand growth in those markets slowed to around 4% in 2022.

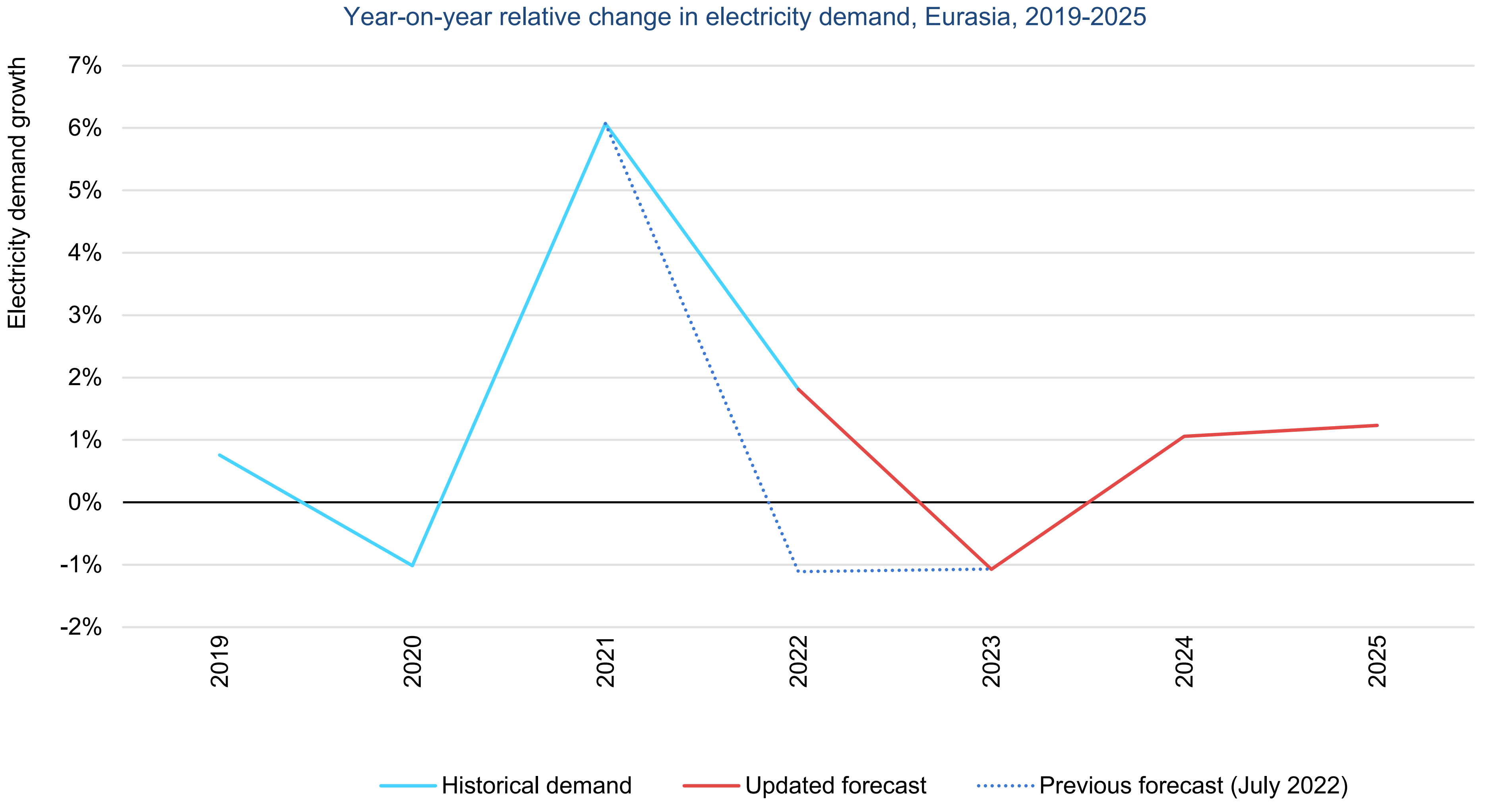
In **Uzbekistan**, the region's third largest electricity consumer, electricity demand rose by 7% (+4.1 TWh) in 2021 and declined by an estimated 1% in 2022. In the first eleven months of 2022, Uzbekistan commissioned six thermal power plants with a combined capacity of 1.4 GW and one solar power generation complex with a capacity of 100 MW. According to the Ministry of Energy, the new and more efficient power plants could save around 1.5 bcm of natural gas per year by replacing older units. Uzbekistan continues to face electricity supply cuts due to natural gas supply shortages for power plants. Natural gas output fell by 4% (-2 bcm) y-o-y in 2022 due to ageing fields with rapidly deteriorating production rates. As of mid-November 2022, Uzbekistan stopped natural gas exports, with officials suggesting a supply-demand gap of 20 mcm/d in the country.

In gas-rich **Turkmenistan** electricity generation rose by an estimated 11% y-o-y in 2022, largely driven by the country's electricity exports, which increased by 30% compared to 2021. These strong export gains were due to growing output from the giant gas-fired power plant complex in the Mary province. For 2022, Turkmenistan had planned exports of around 9 TWh of electricity into neighbouring markets, including Afghanistan, Iran, Kyrgyzstan and Uzbekistan. Turkmenistan started electricity exports to Kyrgyzstan in August 2021, with deliveries rising to 1.7 TWh in the first half of 2022. In October 2022, Turkmenistan and Uzbekistan agreed to ramp up electricity supplies to 4 TWh/yr, which could improve electricity supply security in Uzbekistan.

In **Azerbaijan**, electricity consumption grew by 7% (+1.5 TWh) in 2021, largely supported by the strong growth in fossil-fired generation (up by 5%). Electricity demand grew by 4% y-o-y in 2022, supported by the economic growth. The country's generation mix continues to be dominated by gas-fired thermal generation.

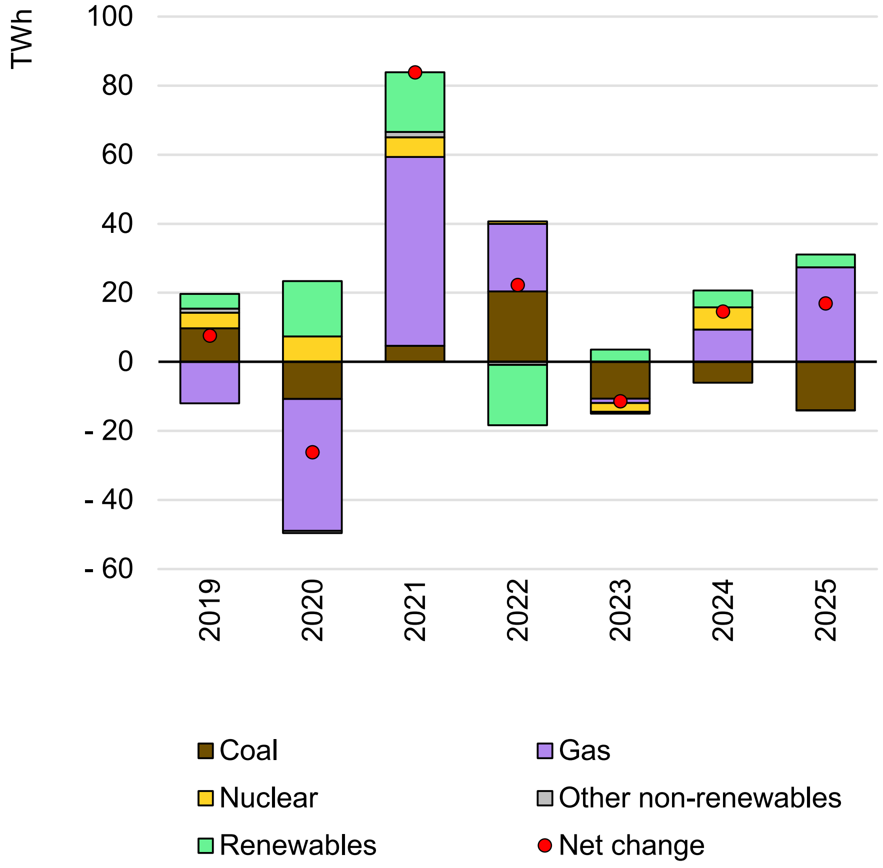
Electricity demand in Eurasia (excluding Kazakhstan and Russia) is expected to increase at an average growth rate of 2% per year over the 2023-2025 forecast period. This will be largely supported by the region's rising population and economic expansion, although the region's macroeconomic outlook has worsened since Russia's invasion of Ukraine.

Russia's bleak economic outlook weighs on Eurasia's electricity demand growth

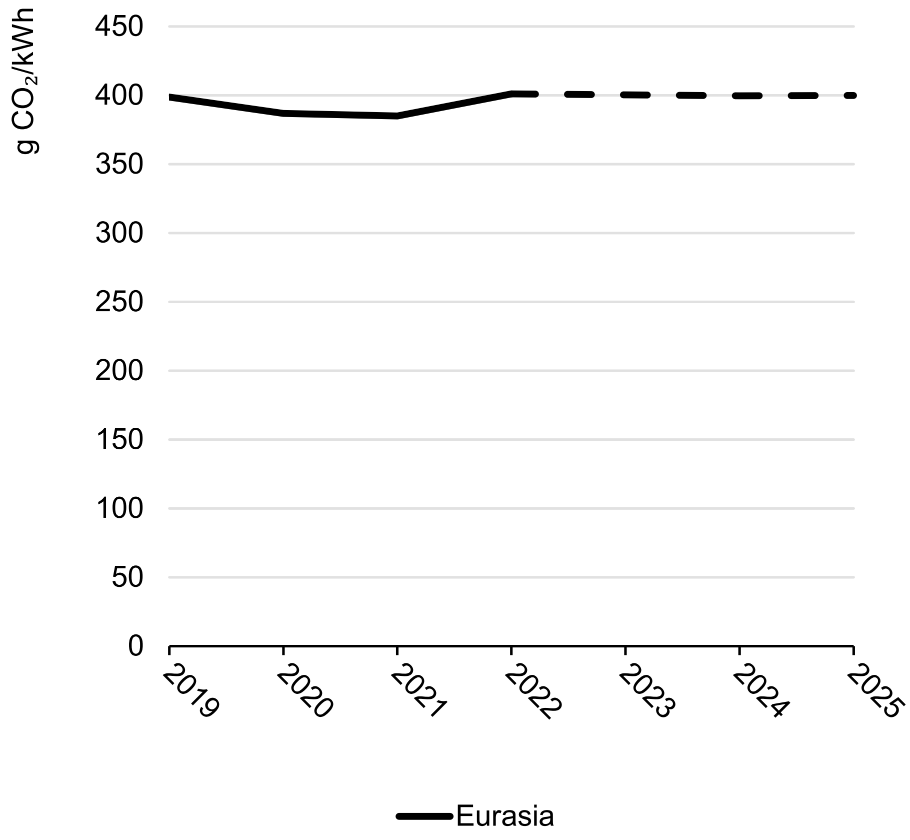


Gas-fired power generation dominates incremental electricity supply in Eurasia

Year-on-year change in electricity generation, Eurasia, 2019-2025



Development of average CO_2 intensity, Eurasia, 2019-2025



Notes: *Other non-renewables* includes oil, waste and other non-renewable energy sources. The CO_2 intensity is calculated as total CO_2 emissions divided by total generation.

Middle East

Middle East electricity demand to grow 2% annually in 2023-2025 while CO_2 intensity declines

Electricity demand in the Middle East grew by about 4% in 2021 following a 1% decline in 2020 due to Covid-19 lockdowns. Members of the Gulf Cooperation Council (GCC) – particularly Saudi Arabia, Iraq, Oman, and the United Arab Emirates (hereafter "UAE") – saw the strongest absolute increases in electricity consumption. However, lower-income countries in the region – including Iraq, Lebanon and Iran – experienced periodic electricity shortages throughout the year 2021.

We estimate that electricity consumption rose by 2.6% in 2022 across the region and expect growth to continue at a similar but slightly reduced rate in the 2023-2025 forecast period. Electricity demand in the Middle East is primarily driven by a growing population, rising demand for cooling and water desalination, and the continued expansion of energy-intensive industries. In the near term, power demand will receive additional support from surging GDP growth and higher public spending in the region's leading oil and gas exporters amid the current high energy price environment.

Multiple projects to enhance regional interconnections progressed in 2022: a 150 MW line to export power from Jordan to Iraq in 2023 started construction in 2021, a 3 GW interconnection between Saudi Arabia and Egypt secured financing, and an agreement on a 1.8 GW direct link between Iraq and the GCC grid (via Saudi Arabia) was reported to have been finalised.

Gas remains the dominant fuel for electricity production across the region, and its share in total generation is on course to increase from 72% in 2022 to 77% by 2025 as it captures market share from both oil- and coal-fired generation. The share of oil in the generation mix is set to drop from 21% to 14% between 2022 and 2025, led by steep declines in Saudi Arabia, Iraq, Iran and Kuwait in particular. Coal is projected to see its share diminish from 1% to just under 0.3% over the same period due to Israel's decision to phase out coal-fired generation by the end of 2025 and the recent conversion of the new Hassyan power plant in the UAE from coal to gas.

Nuclear generation is expected to nearly double between 2022 and 2025, reaching 50 TWh (or 3.5% of total generation) by the end of our forecast period, as the UAE's Barakah nuclear plant ramps up to full capacity. Renewable generation (led by solar PV) is set to increase by 50% from 2022 levels and account for more than 5% of total generation by 2025. The biggest increments are expected in Saudi Arabia, Israel, Oman and the UAE, while the rollout of renewables in the rest of the region remains slow or non-existent.

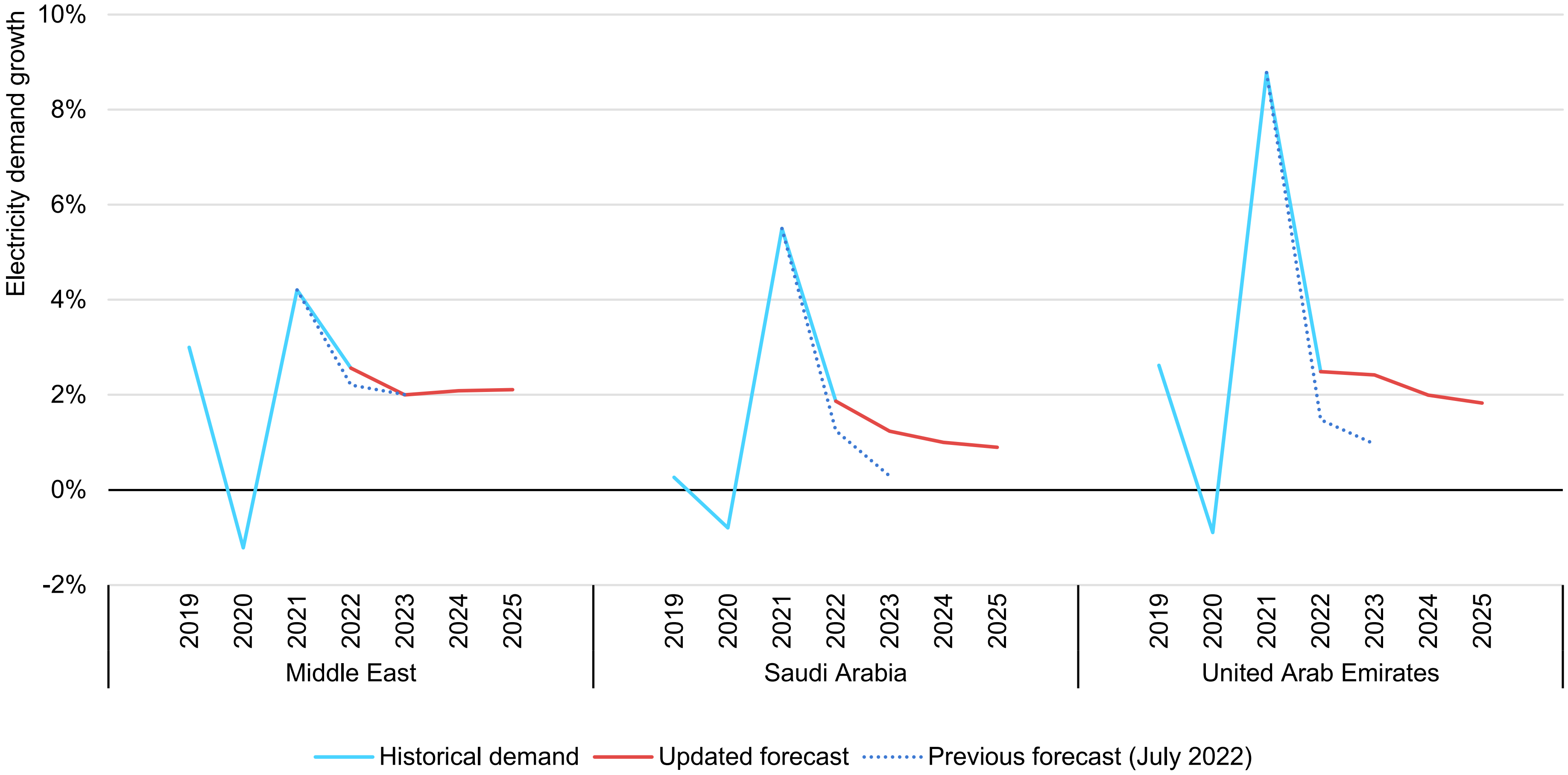
Annual power generation emissions increased only marginally (by around 0.7%) in 2022 as higher gas-related emissions were largely offset by lower emissions from oil- and coal-fired output. Total power generation emissions are set to fall by 2% between 2022 and 2025 to around 710 Mt CO_2. The biggest emission declines are expected in the UAE (thanks to the rapid rise of renewables and the ramp up of nuclear output), Israel (due to the phase-out of coal) and Saudi Arabia (as a result of a steep drop in oil-fired generation).

However, these declines are partly offset by growing emissions in the rest of the region, mainly due to rising gas-fired generation.

The regional CO_2 intensity of power generation fell by nearly 2% in 2022, reaching about 540 g CO_2/kWh. It is on course to drop by another 7% in 2025 compared with 2022 levels, as the share of coal and oil declines while the share of nuclear and renewables increases in the region’s electricity mix.

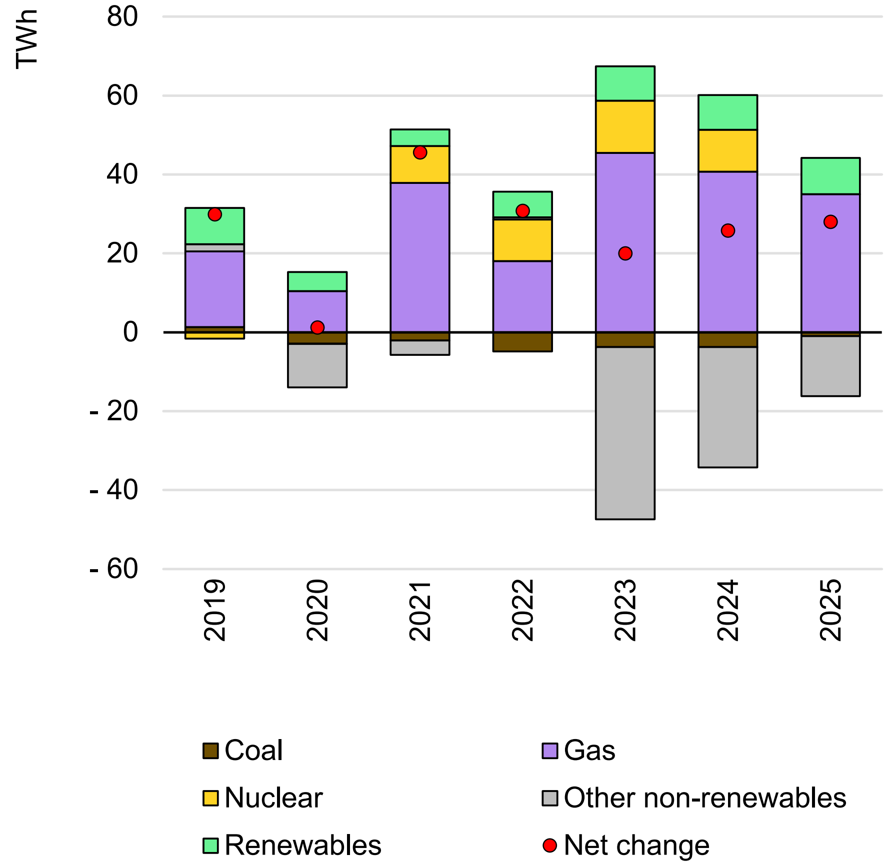
Electricity demand growth in the Middle East moderates in 2022-2025 following the 2021 spike

Year-on-year relative change in electricity demand, Middle East, 2019-2025



Gas-fired generation is set to continue to be the largest source of additional supply to 2025

Year-on-year change in electricity generation, Middle East, 2019-2025



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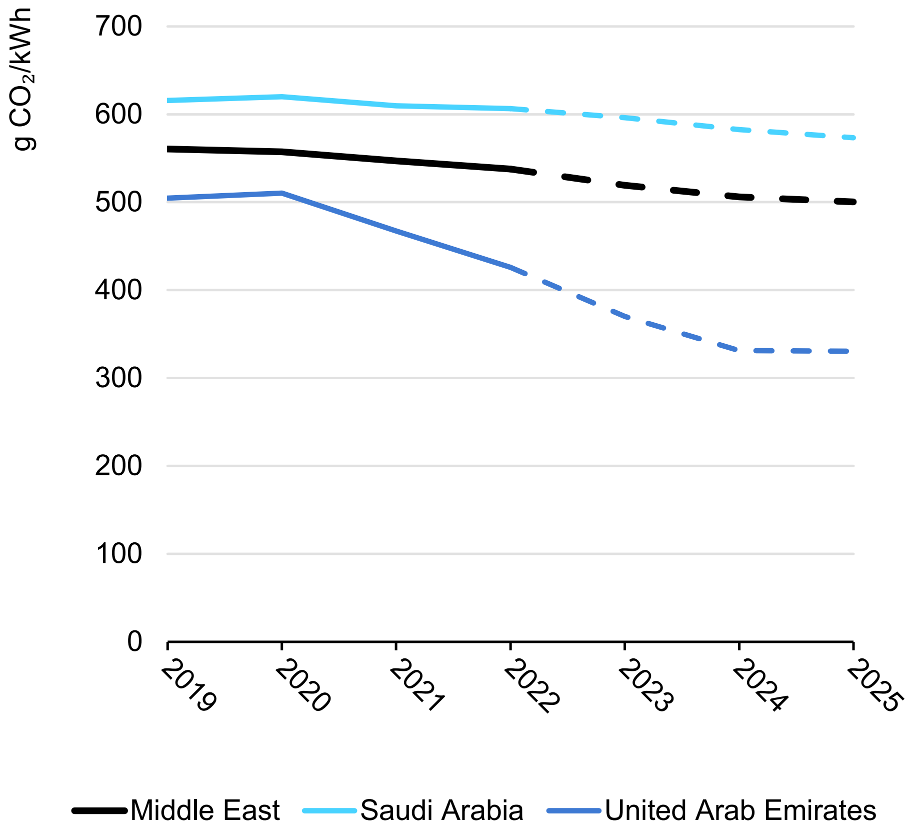
Development of average CO_2 intensity, Middle East, 2019-2025



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Notes: *Other non-renewables* includes oil, waste and other non-renewable energy sources. The CO_2 intensity is calculated as total CO_2 emissions divided by total generation.

Saudi Arabia

Saudi Arabia's electricity consumption rose by 5.5% in 2021 (following a Covid-induced dip of 0.8% in 2020) with commercial users and public sector entities registering the strongest recovery. In the first half of 2022, power demand was up by 2.3% y-o-y, led higher by commercial, government and industrial consumption as well as water desalination. For 2022, we estimate electricity demand increased by 2%. However, the average growth rate is expected to slow to around 1% per year in the 2023-2025 forecast period, as the demand boost from new grid connections is tempered by earlier price reforms in 2018 (when tariffs for some residential users were increased by as much as 260%). Moreover, a smart meter rollout is proceeding rapidly, with more than 10 million installed in 2020 and 2021 alone. This can potentially help increase energy efficiency.

Saudi Arabia's total generating capacity stood at 83 GW at the end of 2021, which included 710 MW of renewable capacity. The Saudi Electricity Company, the country's state-owned power utility, plans for the addition of another 2.1 GW of solar capacity and 7.2 GW of combined-cycle gas turbine (CCGT) capacity by private operators during the 2022-2025 period. We expect gas-fired generation to increase by nearly 30% (+67 TWh) from 2021 to 2025, supported by a string of high-profile gas developments (namely Hawiyah, Tanajib, and the initial phase of the Jafurah unconventional gas project), which are scheduled to begin operating between 2023 and 2025. At the same time, we project oil-fired output to decline by 35% (-57 TWh) and its share in total generation drops from 39% to 25% by 2025 as higher gas burn in new and existing thermal plants reduce costly oil-fired power in the generation mix. Renewable generation, though growing rapidly, is expected to account for less than 3% (11 TWh) of Saudi Arabia's total generation in 2025. The most notable renewable projects in the pipeline include the Sudair (1 500 MW), Jeddah (300 MW) and Rabigh (300 MW) solar developments.

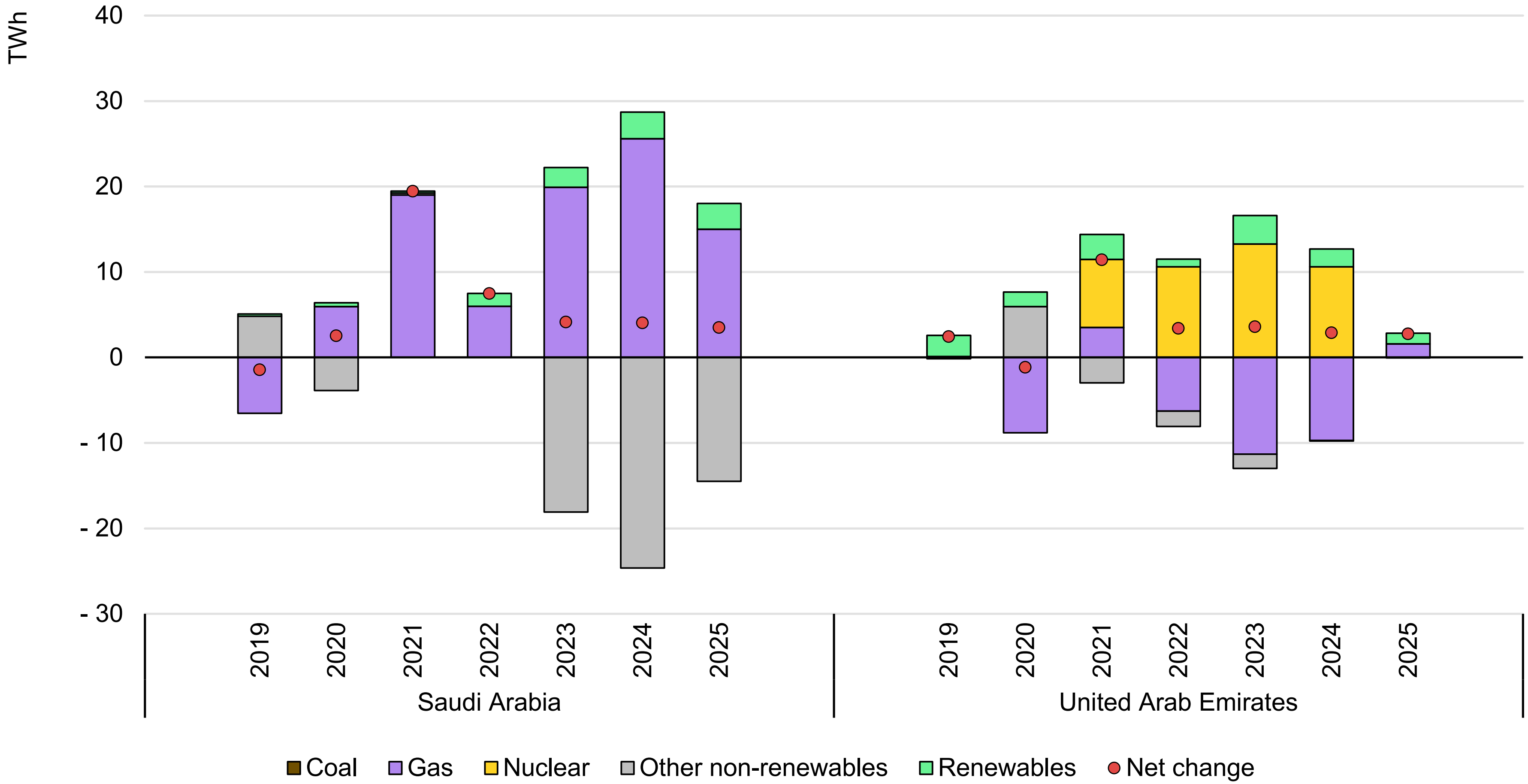
United Arab Emirates

In the UAE electricity consumption increased by 9% in 2021 following a slump of about 1% in 2020 due to Covid-related restrictions. Growth has continued in 2022 as well. The Dubai Electricity and Water Authority (DEWA), which serves about 35% of UAE demand, reported a strong 5% year-on-year growth in the first nine months of 2022. For the whole country, we estimate total demand growth in 2022 was slightly below 3%. We anticipate total electricity consumption to expand at a 2% annual average rate in the 2023-2025 period on the back of strong economic growth (averaging about 4% per year, according to the IMF).

Installed generation capacity across the UAE reached 35 GW in 2021, of which 31 GW was gas-fired, 2.6 GW solar and 1.4 GW nuclear. Following the grid connection of 4.2 GW of nuclear, 3.6 GW of gas-fired and 4.8 GW of solar capacity during the 2022-2025 period, the respective shares of gas, renewables and nuclear in the generation mix are projected at 64%, 10% and 26% by 2025.

Gas fuels most of the additional generation in Saudi Arabia, nuclear increments lead in the UAE

Year-on-year change in electricity generation in selected countries in the Middle East, 2019-2025



Note: Other non-renewables includes oil, waste and other non-renewable energy sources.

Market trends in selected Middle Eastern countries

Kuwait's installed generation capacity stood at just over 20 GW at the end of 2021, of which 84% (17 GW) was simple steam or gas turbine, 15% (3 GW) was CCGT and only about 0.3% (70 MW) was renewable capacity. While the government has plans to add 9 GW of gas-fired and 5 GW of solar capacity by 2030, stalled progress on these projects means they are unlikely to be added to the generation mix before 2026. Electricity consumption is expected to grow at an average annual rate of 2% between 2022 and 2025, driven by increasing demand for cooling and water desalination.

Israel's electricity consumption rose by 1% in 2021 (following minimal growth in 2020) and is expected to grow by 3% per year on average during the 2022-2025 period, driven by population growth, rising water desalination requirements and the electrification of energy end-uses. Gas-fired generation in 2025 is projected to be 30% above 2021 levels (increasing 4 TWh/yr), thanks to the ramp up of the Karish gas field in 2022-2024, whose production is solely dedicated to the domestic market. Renewable output in 2025 is set to reach 15% of the generation mix following a 110% (+6 TWh) increase from 2021 levels, while coal-fired power drops to close to zero by the end of 2025. This is in line with the government's plan to phase out all coal-fired power and convert the remaining coal plants to natural gas by 2025.

Qatar's electricity demand grew by about 5% in 2021 following a small 1% decline in 2020. We expect demand to grow at an annual average of 3% during the 2022-2025 period, driven by population growth, rising demand for cooling and water desalination, and expanding infrastructure. Incremental generation will mainly come from gas (on top of Qatar's 10.6 GW of existing gas-fired capacity), but solar projects adding 1.7 GW of capacity between 2022 and 2025 are set to contribute 4% of the generation mix by 2025.

Oman's electricity consumption posted a sharp 8% rebound in 2021 (after a 2% drop in 2020) and is projected to rise at an annual average of 2.6% over the 2022-2025 period. The government plans to add 1.9 GW of renewable capacity by 2026 (on top of the existing 550 MW of grid-connected capacity) to meet growing demand and reduce dependence on gas-fired generation, but only 1 GW of this is slated to come online by 2025. We estimate that the share of gas in total generation will decline from 97% in 2021 to 87% in 2025, while the share of renewables is on course to rise from below 2% in 2021 to around 11% by 2025. Oman's long-term plans target a renewable generation share of 39% by 2040. In an effort to increase system-wide efficiency and support energy transition goals, the government of Oman launched the first spot electricity market in the Middle East in 2022.

Jordan's total electricity demand rose by about 2% in 2021 (after remaining flat in 2020) and we expect it to grow at an annual average of 2.6% in the 2022-2025 period. In 2021, 77% of total generation was fuelled by gas, 23% by renewables and under 1% by oil. Of the country's 6.2 GW of installed capacity, 3.7 GW (60%) was thermal capacity (capable of burning oil or natural gas) and 2.5 GW (40%) was renewable. The government's long-term plan calls for a 50% renewable share in the generation mix by 2030; we forecast a 26% renewable share to be achieved by 2025.

Africa

Africa's electricity consumption growth is set to accelerate to 2025

Electricity demand in Africa increased by an estimated 5.7% in 2021, rebounding from a 3.3% decline in 2020 due to the Covid-19 pandemic impact on the economy. We estimate that electricity demand in the region grew by 1.5% in 2022, down from our previous forecast of 4%. Russia's invasion of Ukraine triggered a downward revision in economic growth prospects in Africa due to a combination of record-level energy prices and high inflation rates, which weighed heavily on our forecast for electricity demand across the region. In addition, electricity consumption in South Africa was revised lower – the continent's largest electricity consumer – because of production capacity constraints that turned out to be worse than previously expected.

Natural gas-fired output, which accounted for an estimated 42% of Africa's electricity generation in 2022, remained stable in volume compared to 2021. However, coal and nuclear (accounting for a respective 27% and 1% share of Africa's generation mix) both saw their output decline in relation with supply shortages, while oil-fired generation (5% of the mix) jumped by an estimated 24% year-on-year. Supply from renewables (24% of the generation mix) increased by 2% in 2022.

Electricity demand growth on the continent is expected to rebound in 2023 to over 3%, thanks to an improvement in South African production capacity as well as slightly enhanced macroeconomic conditions, followed by an average 4.5% regional growth for 2024 and 2025.

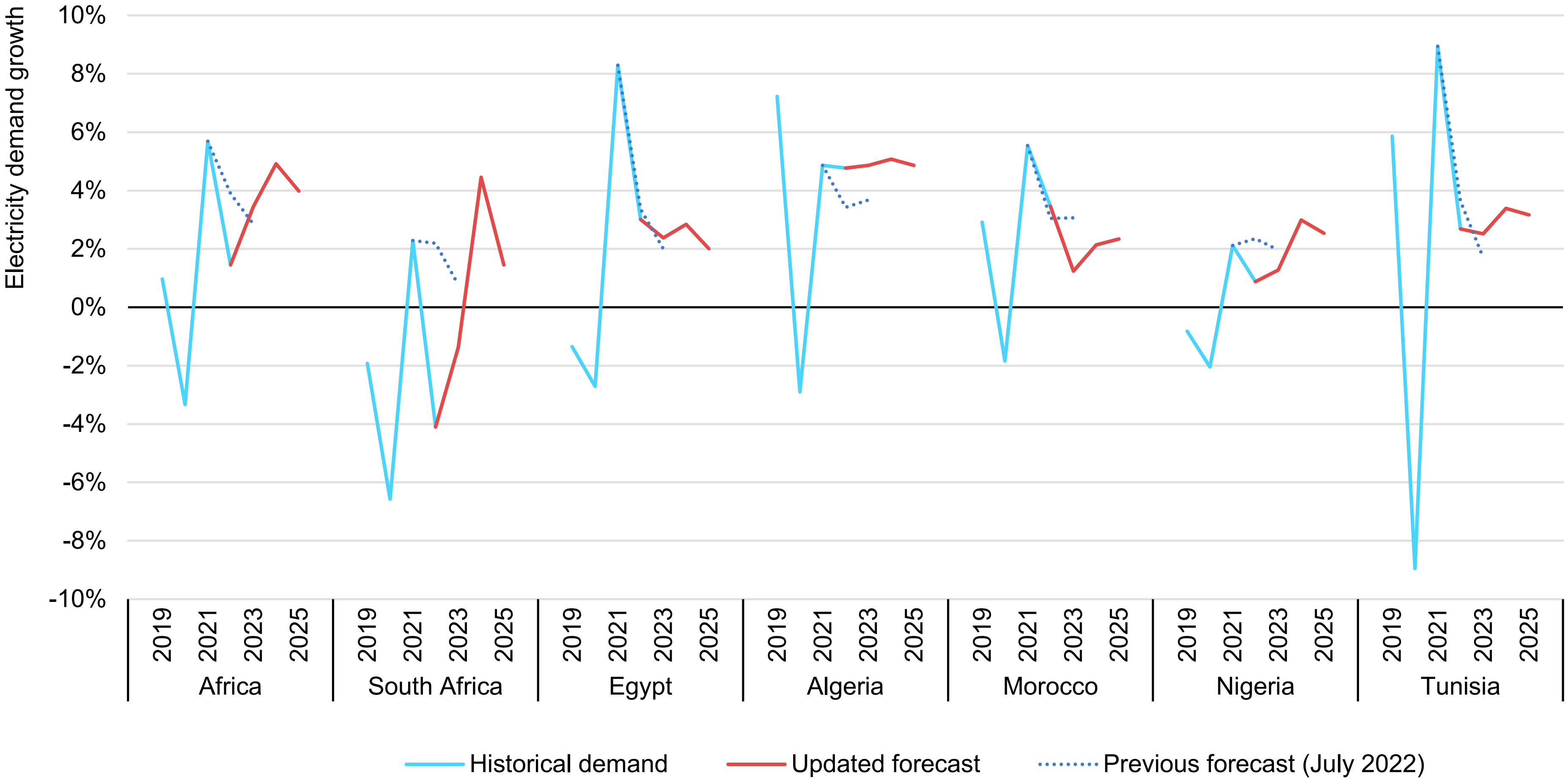
The large majority of incremental generation to 2025 will come from renewable sources, followed by natural gas. We expect electricity delivered from renewable sources to increase by over 60 TWh in 2023-2025, to reach almost a 30% share of total generation by the end of the forecast period (from 24% in 2021), replacing coal as the second largest source of electricity in Africa.

Natural gas is expected to remain the largest source of electricity in Africa through 2025, rising by around 30 TWh from 2022 to 2025, to close to 400 TWh. However, despite this increase, gas sees its share in the power generation mix decline slightly from 42% to 41% over the same period as renewables expand. Coal-fired electricity generation is expected to remain stable in output at around 240 TWh, declining in terms of share from 28% in 2021 to 24% in 2025.

The declining share of fossil-fuelled generation to 2025 results in lower power generation CO_2 intensity in the region by the end of our forecast period. We expect CO_2 intensity to decrease from about 540 g CO_2/kWh in 2021 to around 500 g CO_2/kWh in 2025. In the same period, electricity generation CO_2 emissions would increase slightly (+18 Mt CO_2), reaching almost 490 Mt CO_2, mainly due to higher gas-fired generation than in 2021.

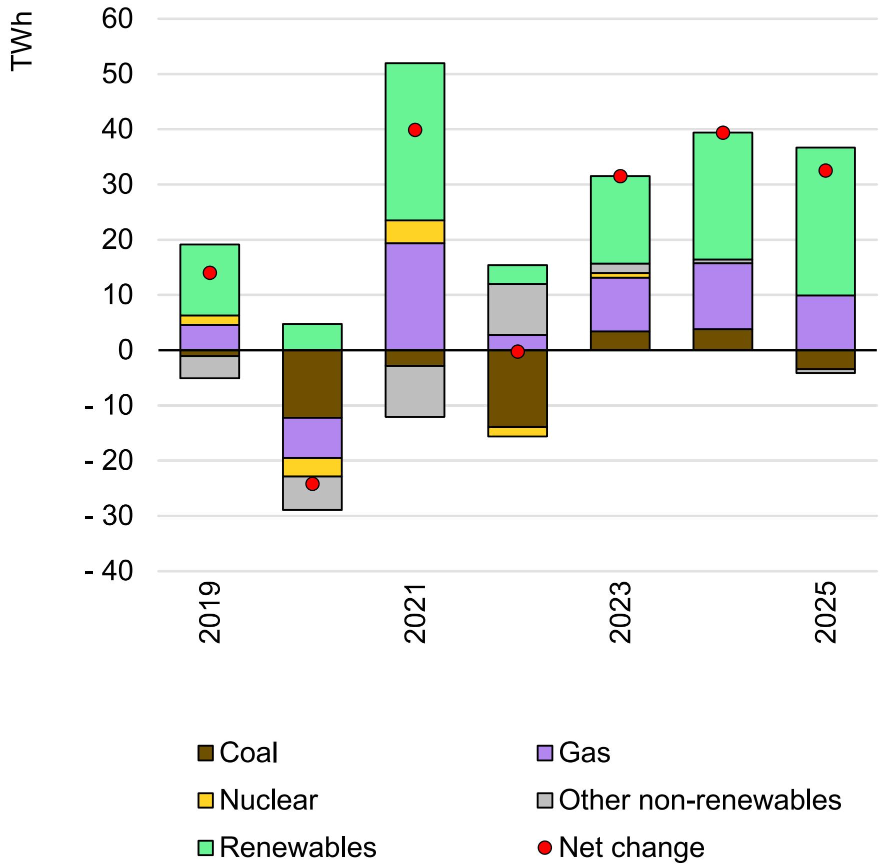
South Africa deviates in its demand growth trend from other countries in Africa

Year-on-year relative change in electricity demand, Africa, 2019-2025



Renewables lead the race in terms of generation increases, followed by natural gas

Year-on-year change in electricity generation, Africa, 2019-2025



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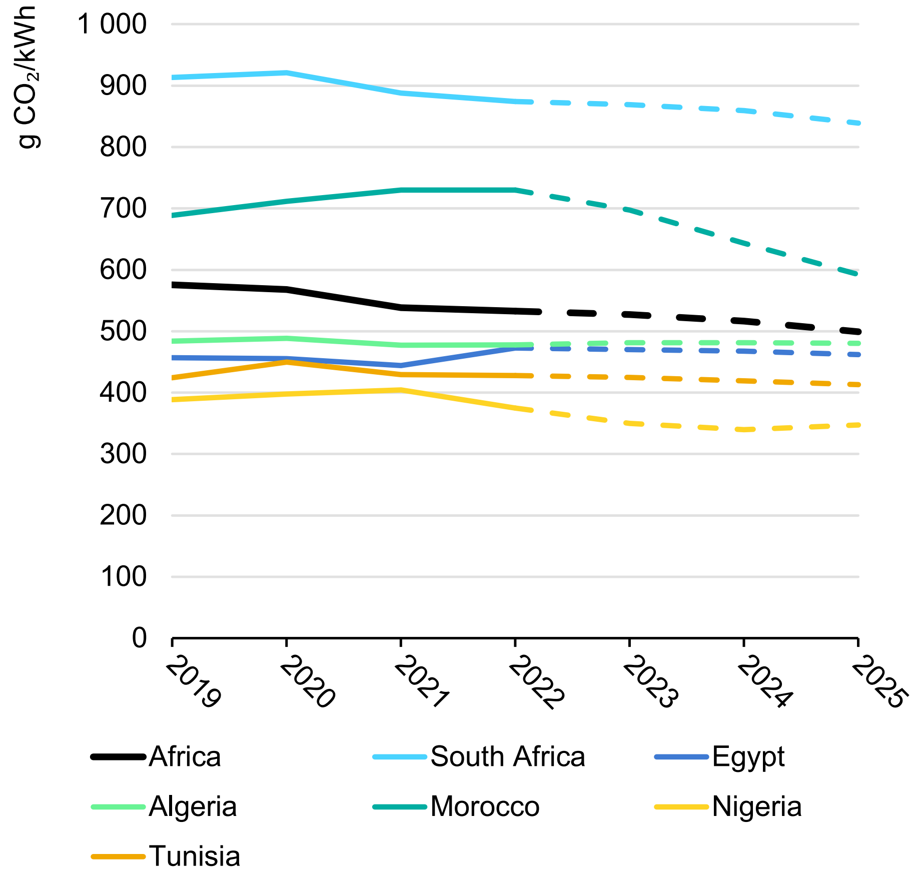
Development of average CO_2 intensity, Africa, 2019-2025



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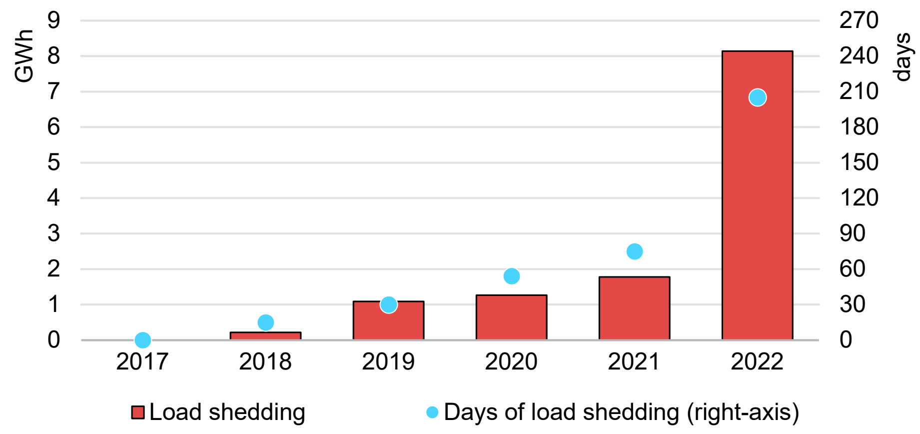
Notes: *Other non-renewables* includes oil, waste and other non-renewable energy sources. The CO_2 intensity is calculated as total CO_2 emissions divided by total generation.

South Africa

Electricity consumption in South Africa fell by less than 4% y-o-y in 2022, due to declining availability of its ageing coal fleet and delays in construction and commissioning of new generation projects. This has resulted in unprecedented amounts of load shedding, with over 8 TWh (or 5% of forecasted annual demand) being reduced through load shedding during 2022. This represents a fourfold increase in unmet demand compared to 2021. In addition, load shedding was implemented 205 days during 2022, approaching almost a threefold increase on the 75 days in 2021.

At the end of August 2022, Eskom, the state-owned utility, released their System Status and Outlook for 2022/23, where its base case scenario for the period September 2022 to August 2023 would see a reduction in load shedding to only 24 days. However, due to ongoing issues with the commissioning of its new-build coal generation, it has already seen 46 days of load shedding across September and October 2022 alone. This aligns with the middle of its most pessimistic scenarios, which forecasts between 203 and 326 days of load shedding over the September 2022 to August 2023 period, painting a potentially sombre picture for the South African power sector in 2023, with new sources of generation needed to lift the country out of this crisis. This is not aided by the fact that one of the units of its only nuclear plant is also due to be taken out of service for most of the first half of 2023, which will result in an even tighter system. The outlook could be even more dire after reports that Eskom had spent its entire budget for the financial year (April 2022-March 2023) for diesel used in its 3 GW of gas peaking plants, and therefore this capacity will not be available until the start of the next financial year in April 2023.

Volume and number of days of load shedding, South Africa, 2017-2022



Source: IEA analysis based on hourly data from Eskom (2023), Data Portal, 18 January 2023.

In July 2022, President Cyril Ramaphosa announced a 10-point plan to address the ongoing power crisis in South Africa. Measures included the removal of licensing requirements for private energy projects, although still retaining the requirement for registration with the regulator. This builds upon the earlier relaxation of licensing requirements, which raised the licence exemption threshold from 1 MW to 100 MW in June 2021. In coming years this should accelerate Eskom's and the municipalities' ability to procure clean power directly. Already, the change in the licence exemption threshold in 2021 led to a number of announcements from major industrial consumers, including many large mining companies, to power their own operations using a combination of renewable technologies.

Another measure announced was the almost doubling of the allocated capacity for procurement in the latest renewable energy auction (i.e. Bid Window 6 of the REIPP Procurement Programme) from 2 600 MW to 4 200 MW. This sixth auction round was concluded in December 2022, with South Africa selecting five solar PV projects for a total capacity of 860 MW, significantly lower capacity compared to the originally planned allocation. The auction also saw no wind power project selected, due to a lack of grid capacity for connection.

This is the second auction of this kind after a seven-year disruption following the refusal of Eskom to sign power purchase agreements (PPAs) with the preferred bidders of the fourth bid window. While the preferred bidders for Bid Window 5 have been announced, only three of the bidders have signed a PPA as the others have struggled to reach financial close due to delays in receiving quotations on connection infrastructure from Eskom. An initial deadline at the end of April 2022 was continuously delayed, then extended until the end of October 2022 and has been extended beyond this date in November. There are also ongoing delays with the Risk Management IPP Procurement Programme (RMIPPPP) that aimed to procure 2 GW of firm capacity and was concluded in 2021, but which has been continuously delayed since.

It is expected that capacity from these auctions, along with the coming online of the two coal megaprojects Kusile and Medupi and improvements to performance of the existing coal fleet, will lead to an increase in available capacity and a recovery of demand. Given the uncertainty due to the tight supply situation, we estimate South African demand and generation could recover to 2021 levels in 2024-2025. While we expect coal to continue making up the majority of the South African generation mix (82% in 2025), our forecast sees the share of renewables increasing to 12% in 2025, from 9% in 2022.

Egypt

Electricity consumption in Egypt increased by 8% in 2021 after a 2.7% decline in 2020. Growth slowed down in the first seven months of 2022 to an estimated 3% y-o-y increase, against the backdrop of domestic economic pressures and the global energy crisis. The continuous weakening of the Egyptian pound and spiralling inflation (24.5% core inflation annualised rate in 2022) since the beginning of the year puts the country's economy under pressure and resulted in a record USD 7.3 billion deficit in the balance of payments in the first nine months of 2022. For the third time since 2020, the Egyptian government decided in June to postpone its planned increase in electricity tariffs until early 2023 in order not to add new burdens on citizens. The country took measures to reduce its natural gas consumption in power generation (which provides up to 90% of total generation) in order to maximise its LNG export volumes and generate revenue in foreign currencies. This included substantial switching back to oil-fired generation, with fuel oil burn averaging above 100 kb/d in the first nine months of 2022, its highest level in four years.

Demand-side measures were also adopted in order to reduce electricity consumption. In August 2022, the government implemented electricity rationing measures targeting reductions in lighting and air conditioning in administrative buildings, commercial and leisure facilities, as well as for street lighting.

We estimate a 3% y-o-y growth in electricity demand in Egypt for 2022, and an average annual 2.4% growth rate in 2023-2025 based on the combination of an expected prolonged preference for gas exports against domestic use and planned continuation of electricity tariff rises as part of a government programme to lift subsidies by 2025.

Egypt has shifted its priority for new capacity from conventional thermal to low-carbon sources of power generation over recent years, after strong development of its gas-fired generation fleet in the mid-2010s. The country currently has 3.1 GW of installed wind and solar capacity on top of 2.8 GW of hydropower, and an additional 2.8 GW of planned renewable capacity to be commissioned by the end of 2023. Diversification and decarbonisation of the generation mix also includes nuclear, with the start of construction work for the 4.8 GW El Dabaa plant in July 2022, which is scheduled for commissioning in 2026. Egypt aims at using its rising electricity surplus to become a regional hub for the east Mediterranean, with several transmission projects under way, including a 3 GW interconnection with Saudi Arabia under construction and scheduled for 2026, and plans to develop a 3 GW interconnection with Europe via Greece.

Algeria

Algeria's installed production capacity grew by 3.2 GW, or about 13%, between September 2021 and August 2022, according to the government's policy statement to the parliament in September 2022. State-owned utility Sonelgaz indicated in September that a new consumption peak record was reached in August 2022 at 16 822 MW. Algeria's domestic electricity consumption increased by an estimated 5% in 2021, after a 3% decline in 2020 and an average 6% growth rate during 2015-2019. The country's continuous rise in electricity consumption is supported by substantial subsidies. In spite of its growing deficit and a quadrupling of its debt in two years, Sonelgaz' confirmed in August that tariffs would not be revised. This forecast expects Algeria's electricity demand to increase at an average rate of about 5% per year in 2022-2025.

Algeria seeks to expand its electricity exports to neighbouring countries in North Africa and Southern Europe, thanks to planned development of its renewable generation capacity over the next decade. The country's energy strategy has set a target of developing 15 GW of renewable capacity by 2035. Renewable development operator Shaems announced in July that first production of 50 MW from solar should be expected by end 2023 from the 1000 MW solar project currently underway. A potential project of a subsea interconnection with Italy was announced in July and is currently being studied.

Morocco

Electricity consumption increased by 5.5% in 2021 in Morocco, recovering from a 1.8% decline in 2020. This was supported by a 16% rebound from high-voltage customers, while residential consumption increased by 2%. Domestic generation grew by 6.7% year-on-year, principally driven by thermal generation from state-owned ONEE (up 11.9%), while electricity supplied by independent power producers (which account for about 60% of total domestic generation) and from renewable sources both increased by close to 5%. According to statistics from the Ministry of Economy and Finance, electricity demand rose by 4.8% y-o-y in the first eight months of 2022, down from 6.5% over the same period in 2021, principally driven by medium- and low-voltage electricity customers (up by 7% and 3.8% y-o-y, respectively) while demand from high-voltage users rose 1.5%. Domestic production was up by 3% y-o-y in the first eight months of 2022, with renewable generation growing by 8.6% and thermal from ONEE up by 22.6%. Output declined 3.2% from independent producers. The balance of trade, which had shifted to net electricity exports in 2021, returned to net imports, with a more than doubling of imports while exports declined by 29%.

Morocco has experienced strong growth in renewables over the past several years. As of end 2021, renewable capacity accounted for 3 950 MW, or 37% of the country's installed electricity generation capacity – with 1 770 MW of hydro, 1 430 MW of wind, and 750 MW of solar. The country aims to increase the share of renewable capacity to 52% by 2030, 70% by 2040 and 80% by 2050, and to gradually expand its exports to Europe over the period. The European Union signed in October 2022 a Green Partnership on energy, climate and the environment with Morocco, the first of its kind with a partner country, which will contribute to scale up cooperation on energy transition and decarbonisation. We forecast Morocco's electricity demand to grow at an average annual rate of 2% between 2023 and 2025, similar to generation – with renewables growing at an average 19% per year while thermal declines by an annual average of 5% over the same period.

Tunisia

Tunisia's final consumption of electricity increased by 9% y-o-y in 2021, driven by all types of consumers – the residential sector is the largest and accounted for 38% of total electricity consumption, followed by industry with 30%, commercial at 20%, and other sectors for the remaining 12%. In 2022, total electricity demand (including the sector's own consumption and exports) increased by 10%. In comparison, electricity generation grew by 2% to 22 TWh, principally from gas-fired generation which accounted for close to 94% of total generation. The remaining supply requirements were met by 1 TWh of renewable electricity generation and by a strong increase in electricity imports from Algeria (up by close to 1 TWh) and reduced exports to Libya (down by close to 0.6 TWh). Statistics from the Ministry of Industry, Energy and Mines indicate that Tunisia's reliance on electricity imports further increased in the first ten months of 2022 due to higher gas import prices, up by a sharp 150%, from 864 GWh to 2 169 GWh, a jump from less than 5% of total supply to over 11%. This stems from a 2% decline in domestic generation from gas-fired plants from independent power producers (down 74% from 2 725 GWh to 706 GWh over January to October) while generation from state-owned STEG (also primarily gas-driven) increased by 12% to 16 024 GWh to bridge the gap. Electricity consumption increased by 6% y-o-y in January through October, driven by low- and medium-voltage customers (up by 9% and 6%, respectively) while demand from high-voltage customers declined 7%.

We forecast an average 3% growth per year in Tunisia's electricity consumption in the 2023-2025 period, principally met by growing domestic renewable generation. Generation from renewable sources is expected to increase by 80% between 2022 and 2025 and reach around 2 TWh by the end of the period – or the equivalent of close to 8% of Tunisia's electricity consumption, against less around 5% in 2022. Tunisia's energy strategy plan to 2030 targets a 30% share of renewables by the end of the decade.

Nigeria

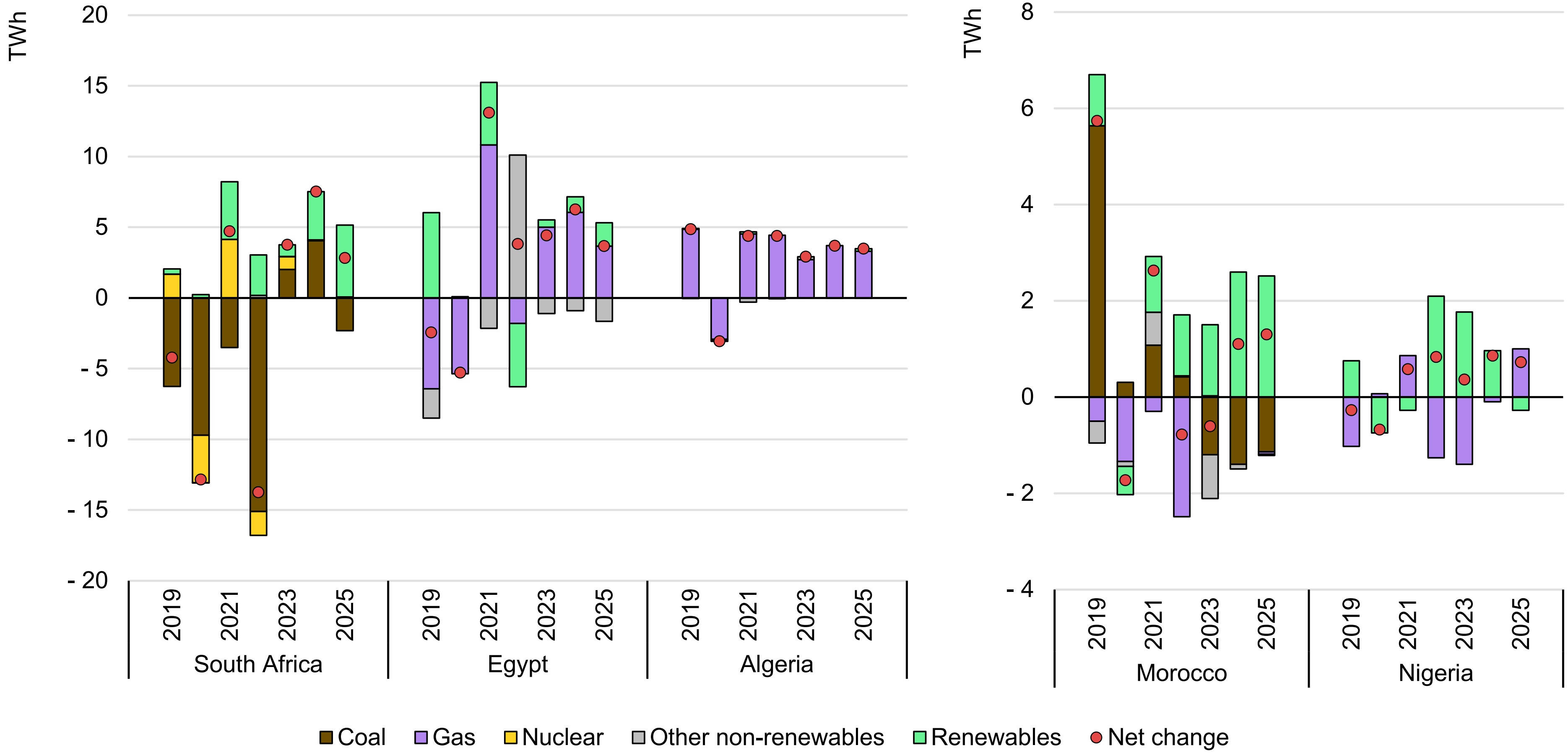
Access to electricity in Nigeria is hampered by insufficient available power generation and transmission capacity, and is further constrained by grid collapses. According to industry data, Nigeria's power grid collapsed seven times in January through to September 2022. This is higher than in 2020 and 2021, when there were four grid collapses each year according to the Nigerian Electricity Regulatory Commission, but still shows some improvement compared to the average rate of default observed since 2015, which averaged 13 collapses per year (with a peak of 28 in 2016).

Earlier this year, President Buhari announced that electricity availability issues were mainly caused by low gas-fired generation (which represents 73% of the electricity mix in 2022) resulting from sabotage of gas pipelines. A report from Nigeria's Association of Power Generation Companies showed that the country's average available generation capacity fell to its lowest level in seven years in 2022 (January to August) with 5 634 MW available, 20% below an annual average of 7 078 MW over the reported period, and 28% below the highest capacity – recorded in 2020 (7 792 MW).

New capacity is expected to be commissioned in early 2023, with the start-up of the 700 MW Zungeru hydroelectric power plant scheduled for the first quarter. President Buhari reaffirmed in October 2022 the country's dedication to the Presidential Power Initiative, an ambitious electricity development plan launched in 2019 with Siemens and with the support of the German government, which would raise the country's total available generation capacity to 25 GW by 2025. The Senate passed a constitutional amendment bill in July 2022 that would allow states to own and develop electricity generation, transmission and distribution capacity. This proposed removal of the federal state's monopoly on the electricity system would contribute to foster investment in new capacity through public-private partnerships.

Morocco set to see the highest relative growth in renewables in Africa, followed by South Africa

Year-on-year change in electricity generation in selected countries in Africa, 2019-2025



Note: *Other non-renewables* includes oil, waste and other non-renewable energy sources.

General annex

Summary table: Demand

Regional breakdown of electricity demand, 2020-2025

TWh	2020	2021	2022	2025	Growth rate 2020-2021	Growth rate 2021-2022	CAAGR 2023-2025
Africa	707	747	758	856	5.7%	1.5%	4.1%
Americas	6 037	6 200	6 342	6 535	2.7%	2.3%	1.0%
of which United States	4 109	4 211	4 320	4 402	2.5%	2.6%	0.6%
Asia Pacific	12 118	13 045	13 479	15 428	7.7%	3.3%	4.6%
of which China	7 471	8 188	8 400	9 790	9.6%	2.6%	5.2%
Eurasia	1 234	1 309	1 332	1 349	6.1%	1.8%	0.4%
Europe	3 648	3 817	3 675	3 846	4.6%	-3.7%	1.5%
of which European Union	2 625	2 751	2 656	2 773	4.8%	-3.5%	1.4%
Middle East	1 115	1 162	1 192	1 268	4.2%	2.6%	2.1%
World	24 860	26 281	26 779	29 281	5.7%	1.9%	3.0%

Notes: CAAGR = compounded average annual growth rate. For the CAAGR 2023-2025 reported, end of 2022 data is taken as base year for the calculation. For the entire period European Union data is for the current 27 member states. Data for 2021 are preliminary; 2022 data are estimated; 2023 to 2025 are forecasts. Differences in totals are due to rounding.

Summary table: Supply and emissions, world

Breakdown of electricity sector supply and emissions, 2020-2025

TWh	2020	2021	2022	2025	Growth rate 2020-2021	Growth rate 2021-2022	CAAGR 2023-2025
Nuclear	2 676	2 803	2 684	2 986	4.8%	-4.3%	3.6%
Coal	9 414	10 171	10 325	10 217	8.0%	1.5%	-0.3%
Gas	6 330	6 489	6 500	6 522	2.5%	0.2%	0.1%
Other non-renewables	776	764	785	611	-1.5%	2.7%	-8.0%
Total renewables	7 475	7 902	8 349	10 799	5.7%	5.7%	9.0%
Total generation	26 671	28 129	28 642	31 135	5.5%	1.8%	2.8%
Mt CO_2	**2020**	**2021**	**2022**	**2025**	**Growth rate 2020-2021**	**Growth rate 2021-2022**	**CAAGR 2023-2025**
Total emissions	12 302	13 039	13 207	13 043	6.0%	1.3%	-0.4%

Notes: CAAGR = compound average annual growth rate. For the CAAGR 2023-2025 reported, end of 2022 data is taken as base year for the calculation. Data for 2021 are preliminary; 2022 data are estimated; 2023-2025 are forecasts. Differences in totals are due to rounding. Unless otherwise specified, generation numbers refer to gross generation.

Summary table: Supply and emissions, Asia Pacific

Breakdown of electricity sector supply and emissions, Asia Pacific, 2020-2025

TWh	2020	2021	2022	2025	Growth rate 2020-2021	Growth rate 2021-2022	CAAGR 2023-2025
Nuclear	653	723	750	908	10.8%	3.7%	6.6%
Coal	7 334	7 898	8 092	8 407	7.7%	2.5%	1.3%
Gas	1 502	1 508	1 438	1 495	0.4%	-4.6%	1.3%
Other non-renewables	162	148	172	129	-8.2%	15.5%	-9.0%
Total renewables	3 190	3 524	3 758	5 224	10.5%	6.6%	11.6%
Total generation	12 841	13 801	14 209	16 163	7.5%	3.0%	4.4%
Mt CO_2	**2020**	**2021**	**2022**	**2025**	**Growth rate 2020-2021**	**Growth rate 2021-2022**	**CAAGR 2023-2025**
Total emissions	7 739	8 224	8 395	8 694	6.3%	2.1%	1.2%

Notes: CAAGR = compound average annual growth rate. For the CAAGR 2023-2025 reported, end of 2022 data is taken as base year for the calculation. Data for 2021 are preliminary; 2022 data are estimated; 2023-2025 are forecasts. Differences in totals are due to rounding. Unless otherwise specified, generation numbers refer to gross generation.

Summary table: Supply and emissions, Americas

Breakdown of electricity sector supply and emissions, Americas, 2020-2025

TWh	2020	2021	2022	2025	Growth rate 2020-2021	Growth rate 2021-2022	CAAGR 2023-2025
Nuclear	954	941	924	941	-1.4%	-1.8%	0.6%
Coal	973	1 098	1 027	808	12.9%	-6.5%	-7.7%
Gas	2 162	2 160	2 223	2 241	-0.1%	2.9%	0.3%
Other non-renewables	180	192	182	156	7.0%	-5.6%	-5.0%
Total renewables	2 213	2 255	2 461	2 847	1.9%	9.1%	5.0%
Total generation	6 482	6 646	6 816	6 993	2.5%	2.6%	0.9%
Mt CO_2	**2020**	**2021**	**2022**	**2025**	**Growth rate 2020-2021**	**Growth rate 2021-2022**	**CAAGR 2023-2025**
Total emissions	1 927	2 062	2 008	1 789	7.0%	-2.6%	-3.8%

Notes: CAAGR = compound average annual growth rate. For the CAAGR 2023-2025 reported, end of 2022 data is taken as base year for the calculation. Data for 2021 are preliminary; 2022 data are estimated; 2023-2025 are forecasts. Differences in totals are due to rounding. Unless otherwise specified, generation numbers refer to gross generation.

Summary table: Supply and emissions, Europe

Breakdown of electricity sector supply and emissions, Europe, 2020-2025

TWh	2020	2021	2022	2025	Growth rate 2020-2021	Growth rate 2021-2022	CAAGR 2023-2025
Nuclear	834	885	746	845	6.1%	-15.7%	4.2%
Coal	584	653	681	513	11.7%	4.4%	-9.0%
Gas	801	844	822	581	5.3%	-2.6%	-10.9%
Other non-renewables	87	87	86	69	0.4%	-0.6%	-7.4%
Total renewables	1 577	1 579	1 593	2 086	0.1%	0.9%	9.4%
Total generation	3 884	4 047	3 929	4 095	4.2%	-2.9%	1.4%
Mt CO_2	**2020**	**2021**	**2022**	**2025**	**Growth rate 2020-2021**	**Growth rate 2021-2022**	**CAAGR 2023-2025**
Total emissions	925	1 005	1 023	763	8.6%	1.8%	-9.3%

Notes: CAAGR = compound average annual growth rate. For the CAAGR 2023-2025 reported, end of 2022 data is taken as base year for the calculation. Data for 2021 are preliminary; 2022 data are estimated; 2023-2025 are forecasts. Differences in totals are due to rounding. Unless otherwise specified, generation numbers refer to gross generation.

Summary table: Supply and emissions, Eurasia

Breakdown of electricity sector supply and emissions, Eurasia, 2020-2025

TWh	2020	2021	2022	2025	Growth rate 2020-2021	Growth rate 2021-2022	CAAGR 2023-2025
Nuclear	219	224	225	229	2.6%	0.3%	0.6%
Coal	256	261	281	251	1.8%	7.8%	-3.8%
Gas	604	659	679	714	9.1%	3.0%	1.7%
Other non-renewables	12	13	12	12	12.8%	-6.5%	-1.4%
Total renewables	277	294	277	289	6.2%	-6.0%	1.4%
Total generation	1 368	1 452	1 474	1 495	6.1%	1.5%	0.5%
Mt CO_2	**2020**	**2021**	**2022**	**2025**	**Growth rate 2020-2021**	**Growth rate 2021-2022**	**CAAGR 2023-2025**
Total emissions	530	560	592	599	5.6%	5.8%	0.4%

Notes: CAAGR = compound average annual growth rate. For the CAAGR 2023-2025 reported, end of 2022 data is taken as base year for the calculation. Data for 2021 are preliminary; 2022 data are estimated; 2023-2025 are forecasts. Differences in totals are due to rounding. Unless otherwise specified, generation numbers refer to gross generation.

Summary table: Supply and emissions, Middle East

Breakdown of electricity sector supply and emissions, Middle East, 2020-2025

TWh	2020	2021	2022	2025	Growth rate 2020-2021	Growth rate 2021-2022	CAAGR 2023-2025
Nuclear	6	15	26	50	160.8%	70.2%	24.5%
Coal	20	18	13	4	-10.7%	-27.4%	-30.6%
Gas	917	955	973	1 094	4.1%	1.9%	4.0%
Other non-renewables	288	285	285	196	-1.3%	0.2%	-11.8%
Total renewables	40	44	50	77	10.5%	14.7%	15.3%
Total generation	1 270	1 316	1 346	1 420	3.6%	2.3%	1.8%

Mt CO_2	2020	2021	2022	2025	Growth rate 2020-2021	Growth rate 2021-2022	CAAGR 2023-2025
Total emissions	708	720	725	711	1.7%	0.7%	-0.6%

Notes: CAAGR = compound average annual growth rate. For the CAAGR 2023-2025 reported, end of 2022 data is taken as base year for the calculation. Data for 2021 are preliminary; 2022 data are estimated; 2023-2025 are forecasts. Differences in totals are due to rounding. Unless otherwise specified, generation numbers refer to gross generation.

Summary table: Supply and emissions, Africa

Breakdown of electricity sector supply and emissions, Africa, 2020-2025

TWh	2020	2021	2022	2025	Growth rate 2020-2021	Growth rate 2021-2022	CAAGR 2023-2025
Nuclear	10	14	12	13	41.9%	-12.0%	2.3%
Coal	247	244	231	234	-1.1%	-5.7%	0.5%
Gas	344	363	366	398	5.6%	0.8%	2.8%
Other non-renewables	48	38	48	49	-19.3%	23.9%	1.1%
Total renewables	178	206	209	275	16.0%	1.7%	9.5%
Total generation	826	866	866	970	4.8%	0.1%	3.8%
Mt CO_2	**2020**	**2021**	**2022**	**2025**	**Growth rate 2020-2021**	**Growth rate 2021-2022**	**CAAGR 2023-2025**
Total emissions	472	469	464	487	-0.6%	-1.1%	1.6%

Notes: CAAGR = compound average annual growth rate. For the CAAGR 2023-2025 reported, end of 2022 data is taken as base year for the calculation. Data for 2021 are preliminary; 2022 data are estimated; 2023-2025 are forecasts. Differences in totals are due to rounding. Unless otherwise specified, generation numbers refer to gross generation.

Regional and country groupings

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

Asia – 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, Pakistan, People's Republic of China,[2] Philippines, Singapore, Sri Lanka, Thailand, Viet Nam and other Asian countries, territories and economies.[3]

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.[4]

Central and South America – Argentina, Bolivia, Brazil, Chile, Colombia, Costa Rica, Cuba, Curaçao, Dominican Republic, Ecuador, El Salvador, Guatemala, Haiti, Honduras, Jamaica, Nicaragua, Panama, Paraguay, Peru, Suriname, Trinidad and Tobago, Uruguay, Venezuela and other Latin American countries and territories.[5]

Eurasia – Armenia, Azerbaijan, Georgia, Kazakhstan, Kyrgyzstan, Russian Federation, Tajikistan, Turkmenistan and Uzbekistan.

Europe – Albania, Austria, Belgium, Belarus, Bosnia and Herzegovina, Bulgaria, Croatia, Cyprus,[6,7] Czech Republic, Denmark, Estonia, Finland, France, Germany, Gibraltar, Greece, Hungary, Iceland, Ireland, Italy, Kosovo[8] Latvia, Lithuania, Luxembourg, Malta, Montenegro, Netherlands, North Macedonia, Norway, Poland, Portugal, Republic of Moldova, Romania, Serbia, Slovak Republic, Slovenia, Spain, Sweden, Switzerland, Republic of Türkiye, Ukraine and United Kingdom.

European Union – Austria, Belgium, Bulgaria, Croatia, Cyprus,[6,7] 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[9], Jordan, Kuwait, Lebanon, Oman, Qatar, Saudi Arabia, Syrian Arab Republic, United Arab Emirates and Yemen.

Nordics – Denmark, Finland, Norway, Sweden

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

North America – Canada, Mexico and 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, Guinea, Guinea-Bissau, Lesotho, Liberia, Madagascar, Malawi, Mali, Mauritania, Reunion, Rwanda, Sao Tome and Principe, Seychelles, Sierra Leone, Somalia, Eswatini and Uganda.
[2] Including Hong Kong.
[3] Individual data are not available and are estimated in aggregate for: Afghanistan, Bhutan, Macau (China), Maldives and Timor-Leste.
[4] 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.
[5] Individual data are not available and are estimated in aggregate for: Anguilla, Antigua and Barbuda, Aruba, Bahamas, Barbados, Belize, Bermuda, British Virgin Islands, Cayman Islands, Dominica, Falkland Islands (Malvinas), Grenada, Guyana, Montserrat, Saba, Saint Eustatius, Saint Kitts and Nevis, Saint Lucia, Saint Pierre and Miquelon, Saint Vincent and the Grenadines, Sint Maarten, and the Turks and Caicos Islands.
[6] Note by Türkiye: 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. Türkiye recognises the Turkish Republic of Northern Cyprus (TRNC). Until a lasting and equitable solution is found within the context of United Nations, Türkiye shall preserve its position concerning the "Cyprus issue".
[7] 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 Türkiye. The information in this document relates to the area under the effective control of the Government of the Republic of Cyprus.
[8] 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.
[9] 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
CAAGR	Compound average annual growth rate. Throughout the report we refer to the CAAGR when talking about average growth.
CCGT	combined-cycle gas turbine
CFE	Federal Electricity Commission (Mexico)
EC	European Commission
EMDEs	Emerging Markets and Developing Economies
ETS	emissions trading system
EU	European Union
EUA	European Union Allowance (emissions)
EU ETS	European Union Emissions Trading System
FY	fiscal year
GCC	Gulf Cooperation Council
GDP	Gross Domestic Product
GHG	greenhouse gas
IEA	International Energy Agency
IEX	Indian Energy Exchange
IMF	International Monetary Fund
LNG	liquefied natural gas
MoU	memorandum of understanding
NDCs	Nationally Determined Contributions
NERC	North American Electric Reliability Corporation (US)
OECD	Organisation for Economic Co-operation and Development
PPA	power purchase agreement
RE	renewable energy
REIPPPP	Renewable Energy Independent Power Producer Procurement Programme (South Africa)
RES	renewable energy sources
RMIPPPP	Risk Mitigation Independent Power Producer Procurement Programme (South Africa)
TSO	transmission system operator
PV	photovoltaic
TTF	Title Transfer Facility (the Netherlands)
UAE	United Arab Emirates
UK	United Kingdom
US	United States
UN	United Nations
VAT	value-added tax

Units of measure

CO_2	carbon dioxide
g CO_2	gramme of carbon dioxide
g CO_2/kWh	gramme of carbon dioxide per kilowatt hour
Gt CO_2	gigatonne of carbon dioxide
GW	gigawatt
kWh	kilowatt hour
MBtu	million British thermal units
mcm/d	million cubic metres per day
Mt CO_2	million tonnes of carbon dioxide
Mt/yr	million tonnes per year
MW	megawatt
MWh	megawatt-hour
t CO_2	tonne of carbon dioxide
t CO_2-eq	tonne of carbon dioxide equivalent
TWh	terawatt-hour

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