Coal 2019

Analysis and forecast to 2024

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INTERNATIONAL ENERGY AGENCY

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Foreword

Despite the growth in low-carbon fuels in recent decades, the reality is that coal remains a major fuel in global energy markets while accounting for over 40% of global energy-related CO_2 emissions. While more and more industrialised countries have announced plans to phase out the use of coal in the years to come, the world consumes 65% more coal today than in the year 2000.

That is the hard reality we must address when balancing the urgency of reducing greenhouse gas emissions with rising energy needs in many parts of the world, mainly in emerging markets. Coal provides one-quarter of global primary energy demand. Today, it is the world's largest source of electricity generation and a crucial part of steel making and cement production.

As the global energy authority that covers all fuels and technologies, the International Energy Agency (IEA) is committed to regular and rigorous analysis of coal markets, to forecasting their future trends and to highlighting technologies that can help tackle coal's emissions footprint. This report is intended as a reference point for those with a stake in coal's future, as well as for those interested in the relationship between energy and climate change.

The continued use and growth of coal worldwide is largely supported by a group of fast-growing Asian economies that account for half of the world's population: the People's Republic of China, India, Indonesia, Pakistan, Bangladesh, the Philippines and Viet Nam. Coal power plants in Asia are young – 12 years old on average – making it possible that they can operate for many decades to come.

How we address this issue in Asia is critical for the long-term success of any global efforts to reduce emissions. A range of low-carbon technologies are needed to put the world on a sustainable energy path, including carbon capture, utilisation and storage (CCUS). The adoption of CCUS in many of Asia's young power plants would be necessary to bring the world into line with a pathway for achieving international goals on climate, air quality and energy access. Furthermore, the decarbonisation of major heavy industries such as steel and cement would be extremely difficult without CCUS.

Over the past several years, the IEA has opened its doors to major emerging economies and increased its global engagement, working closely with many countries to help them accelerate their clean energy transitions. Building on this successful momentum, our recent Ministerial Meeting has given the IEA a strong mandate to step up its role leading global clean energy transformations. We will continue helping governments around the world to provide the most appropriate solutions to their energy challenges, while ensuring that the changes happen in a fair, just and affordable way for all citizens.

Dr. Fatih Birol

Executive Director

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Highlights

- **The rebound in global coal demand in 2017 continued in 2018,** driven by growth in coal power generation, which reached an all-time high. Global coal power generation is estimated to have declined in 2019, but this appears to have resulted from particular circumstances in some specific regions and is unlikely to be the start of a lasting trend.

- **Coal demand will remain stable through 2024,** as increasing demand in India and a few other countries in Asia offsets declines in the United States and European Union. Electricity generation will be the main driver of these dynamics, but the significant growth of coal consumption for industrial uses in Asia will also be influential.

- **Chinese coal demand is forecast to increase only slightly and to plateau around 2022.** Policy measures will very much determine the actual trajectory of China's coal demand and therefore global trends as China still represents half of global coal consumption.

- **Uncertainty continues to be the main feature in the trade forecast,** owing to the policy-sensitive supply and demand balance in China and India. Exporters in the Pacific Basin will do better than will those in the Atlantic. Colombia and the United States will struggle with the collapse of European Union imports and competition from Russian producers.

- **Investments in coal-mining assets are facing strong headwinds.** Most of the projects likely to move ahead for steam coal mining are brownfield ones. Metallurgical coal projects, by contrast, are progressing more swiftly.

Executive summary

A (slight) coal rebound

Coal use grew again in 2018. Global coal demand increased by 1.1%, continuing the rebound that began in 2017 after three years of decline. The main driver was coal power generation, which rose almost 2% in 2018 to reach an all-time high. Coal maintained its position as the largest source of electricity in the world with a 38% share. The People's Republic of China (hereafter, "China"), India and other Asian economies led the expansion, while coal power generation fell in Europe and North America. In non-power sectors, despite a lot of coal-to-gas switching in China, demand remained stable. The international coal trade grew by 4% in 2018, surpassing 1.4 billion tonnes.

A big production jump. Production grew by 3.3% in 2018, mainly driven by the demand growth. Four of the world's six largest coal-producing countries increased their output, with three of them – India, Indonesia and the Russian Federation (hereafter, "Russia") – producing their largest outputs ever. Indonesia and Russia recorded all-time high coal exports. Average prices in 2018 were more than 60% higher than in 2016, making coal very profitable. Export revenues of USD 67 billion – the highest ever – made coal Australia's top commodity export.

Coal use will flatten through 2024

No surge, but no collapse. When the Paris Agreement was signed in 2015, coal demand was in the midst of a three-year decline. The investment climate has also shifted. Non-governmental players, such as investors and companies have shown a strong commitment to acting on climate change. Public opposition to fossil fuels, particularly coal, is growing. Competition from natural gas and, increasingly, from renewables is coinciding with carbon pricing and policies to phase out coal in power generation. Together, these factors are shrinking the role of coal power generation in advanced economies. These shifts have raised expectations once again that demand for coal is about to collapse. However, global coal demand has rebounded since 2017. Although it will probably decline in 2019, we expect it to remain broadly steady thereafter through 2024.

Expectations of an imminent coal collapse have come and gone before. The adoption of the Kyoto Protocol in 1997 coincided with a three-year decline in global coal consumption (1997-99), and the imminent end of coal was heralded. But the decline turned out to be the result of some specific circumstances such as the Asian financial crisis and did not last. Between 2000 and 2013, global coal use rebounded spectacularly. It soared 75%, more than it had done over the entirety of the previous nine decades. A similar upsurge is not expected in today's context, but neither is a sudden plunge.

India and Southeast Asia rely on coal to develop

Coal still fuels India's robust economic growth. India aims to become an economy of USD 5 trillion by 2024, in part by investing heavily in infrastructure. This will boost energy demand for industry and, especially, for electricity production. Although India has succeeded in bringing some form of electricity access to almost all of its citizens, the country's per capita power consumption is still low, giving it significant scope to grow. Power generation from renewables is forecast to expand strongly, with wind capacity doubling and solar photovoltaics (PV) increasing fourfold between 2018 and 2024. But that is not enough to prevent coal power generation increasing by 4.6% per year through 2024. Overall, India's coal demand is expected to grow by more than that of any other country, in absolute terms, over the forecast period.

Vigorous growth in Southeast Asia, new plants in South Asia. Coal demand in Southeast Asia is forecast to grow by more than 5% per year through 2024, led by Indonesia and Viet Nam. The region's strong economic growth will drive electricity and industrial consumption, which will both be fuelled in part by coal. South Asian countries are also in need of more electricity supply for the growing populations, and they are often turning to coal to provide it. Pakistan has recently commissioned over 4 GW of new coal power plants, with similar capacity under construction. Bangladesh is about to commission the first unit of the 10 GW it has in the pipeline.

Chinese coal demand is very resilient

In China, the world's biggest coal producer and consumer, consumption will plateau around 2022. Stronger-than-expected electricity consumption and infrastructure development have pushed coal use up in the last few years. In our forecast, the decline of coal use in the residential and small industrial sectors continues because of air pollution concerns. Coal use in heavy industry also drops, driven by structural changes in the economy as well as macroeconomic conditions in the coming years. Our forecast sees coal power generation growing, although at a slowing rate. Its share of the power generation mix is expected to fall from 67% in 2018 to 59% in 2024. Overall, coal demand in China plateaus by 2022 and then starts to decline slowly.

The five-year-plan factor. The trajectory outlined above remains subject to the policies and targets that will be included in the Chinese government's 14th five-year plan (which will be released in 2020). Future coal demand will potentially be affected by the government's economic growth objectives as well as its policies on nuclear power, wind and solar, and coal conversion projects. While reducing air pollution and CO_2 emissions will be policy priorities for China, coal is expected to continue play an important role in sustaining economic growth and guaranteeing energy security.

Coal use in Europe and the United States sinks further

Cheap natural gas has shattered coal's competitiveness in the European Union in 2019. Coal use in the European Union was already under heavy pressure from policies to reduce air pollution from coal plants and increase carbon prices, as well as decisions by several countries to adopt plans to phase out coal power generation. Wind and solar PV continued to increase their shares of power generation in 2019, and unusually low gas prices pushed a lot of coal out of the market. In our forecast, coal recovers part of its competitiveness in the coming years. But coal plant retirements and further growth in renewables combine to reduce coal generation by more than 5% per year through 2024.

In the United States, the shale gas boom is coal's undoing. The federal government and some coal-producing states still provide support for coal power plants, yet coal's destiny in the United States continues to be determined by the shale gas revolution. Cheap and abundant natural gas combined with the climate policies of many states will continue to squeeze coal out of the electricity market. In our forecast, US coal demand declines by almost 4% per year over the forecast period. Coal's share in electricity supply, which had been as high as 50% in 2007, declines from 28% in 2018 to 21% in 2024. The decline in production is a bit lower because of the resilience of exports. But the collapse of the European market and the lack of export infrastructure on the West Coast limit future prospects.

The coal trade's shift to the Pacific continues

Exporters in the Pacific Basin will do better than will those in the Atlantic. Asian demand continues to be strong. With the collapse of the European market, Atlantic producers, including the United States and Colombia, struggle whereas Australia and South Africa fare better. Russia is progressively oriented towards Asian markets. Increasing domestic needs eat into Indonesian exports. Demand from China and India remains strong in our forecast but is an area of uncertainty because of government policies to limit reliance on imports.

Investment conditions for coal mines are becoming more challenging. We observe increasing difficulties for approval or financing of new mines. For instance, the start of construction of the Carmichael mine in Queensland, Australia – the most prominent coal investment of 2019 – came after a process that took more than a decade. Metallurgical coal projects in Australia, the United States and Russia, by contrast, progressed more swiftly.

Coal in South Africa is at a crossroads. The government's Integrated Resource Plan has brought broad clarity for the future of the country's energy sector, but other uncertainties are still hanging over the coal industry. These include the financial difficulties of electricity utility Eskom, changes in coal mine ownership, and the shift away from Mpumalanga, the country's coal-mining heartland, to other areas. Overall, we see South Africa's demand, production and exports remaining stable through 2024, but the factors mentioned above could change that trend.

A final caveat

Our coal demand forecast has not changed much from last year. Despite all the policy changes and announcements, our forecast is very similar to those we have made over the past few years. There are few signs of change. In 2019, for example, a combination of unusual circumstances appears to have led to the largest ever drop in coal power generation, which will most likely give rise to a decline in global coal consumption. However, this is within the range of the annual fluctuations over the course of a decade in which global demand is set to remain broadly stable.

Climate policy, natural gas prices and China could change coal's future course. The main difference in this report from last year is that the downside potential is increasing. Stronger-than-expected climate policies targeting coal are probably the main factor that could affect coal demand. Lower natural gas prices could also change our forecast, as well as slower economic growth. Last but not least, as already discussed above, China will ultimately determine global coal trends through 2024 and beyond since it currently accounts for half of global consumption.

1. Recent demand and supply trends

- **The rebound in global coal demand continued in 2018, driven by increased coal use for power generation in Asia**. Global demand growth of 1.1% in 2018 confirmed the rebound in 2017 after three years of decline.

- **Power sector demand was largely responsible for the increase**, as coal-based power generation grew 2% in 2018 to reach an all-time high, surpassing the 10 000-terawatt hour (TWh) mark. The Asia Pacific region, which consumes 73% (5 605 million tonnes [Mt]) of the world's coal, was responsible for nearly all the growth, while coal-fired generation fell significantly in the European Union and the United States. In non-power sectors, global demand remained stable despite intensive coal-to-gas switching in the residential sector in the People's Republic of China ("China").

- **New production records were reached in India, Indonesia and the Russian Federation** ("Russia"). To meet increased demand for coal, major Asian producers and Russia all raised production, while output was lower in Australia and the United States. China recorded the largest absolute increase, adding 153 Mt (+4.5%) and strengthening the 2017 rebound. Production reached record highs in India, Indonesia and Russia.

- **Indian producers nearly kept up with the country's surging demand in 2018**. With India recording the second-highest demand increase (+47 Mt; 5%) in absolute terms in 2018, its coal miners boosted production by 6.3% (+45 Mt). Coal India Limited recorded the largest expansion in 2018. Even more, the profitability of all its subsidiaries increased.

- **Coal remains the top fuel for power generation and second for primary energy supply**. Coal kept its position as the world's primary resource for electricity generation with a 38% share, and with a 26% portion of global primary energy supply, it is the second-largest energy source after oil.

Demand

As coal accounted for 26% of global primary energy consumption in 2018, it remains the second-largest energy source after oil. Measured in physical tonnes, 77% of the world's coal consumption was steam coal and 10% was lignite, both used mainly to generate electricity. The remaining 13% was metallurgical (met) coal, used mostly for iron and steel production.

Global coal consumption in physical tonnes continued to increase in 2018, by 1.1% (+82 Mt) from 2017. Coal-fired power generation, which accounts for 63% of global coal consumption, expanded 2%. As electricity production from coal exceeded 10 000 TWh, coal remains the largest source of global electricity supply with a share of 38%. Demand remained mostly stable in non-power sectors, except in China.

Rising demand in Asia (especially China, India and Southeast Asia) and Russia drove global consumption growth (Table 1.1). The largest declines in 2018 were in the European Union, with a reduction of 5.1% (-32 Mt) from 2017, and the United States, where consumption fell 4.3% (-27 Mt). The substantial drop in EU coal consumption resulted primarily from higher renewables-based generation, mainly hydro and wind. In the United States, renewable expansion (mainly wind and solar) and low natural gas prices (which led to significant coal-to-gas-switching in the power sector) reduced coal consumption.

Table 1.1. Total coal consumption (Mt), 2017-18

				2017-18*		2008-18*
Country	2017	2018*	Share	Change	%	CAAGR
China	3 719	3 756	49%	37	1.0%	2.6%
India	938	985	13%	47	5.0%	5.4%
United States	642	614	8%	-27	-4.3%	-5.0%
European Union	632	600	8%	-32	-5.1%	-2.5%
Southeast Asia	259	278	4%	19	7.4%	7.8%
Russia	219	232	3%	13	5.8%	0.1%
Japan	188	186	2%	-2	-1.2%	0.0%
World	**7 638**	**7 720**	**100%**	**82**	**1.1%**	**1.2%**

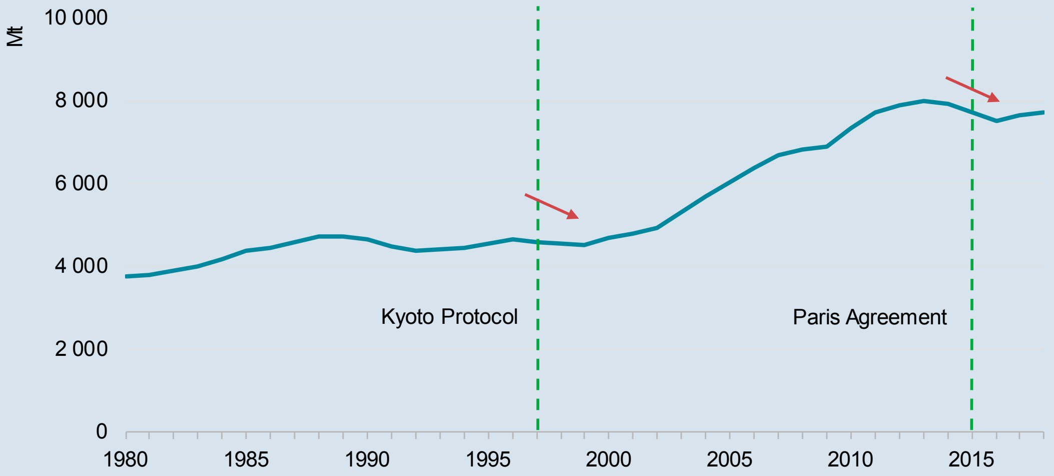
* Estimated.
Notes: CAAGR = compound average annual growth rate. Differences in totals are due to rounding.

Box 1.1. From Kyoto to Paris

Since its adoption in 1997, 84 countries have signed the Kyoto Protocol, an international agreement linked to the United Nations Framework Convention on Climate Change (UNFCCC) that commits some of its parties to setting internationally binding emissions reduction targets. After 1997, global coal consumption declined for three consecutive years due to the latent effects of the collapse of the former Soviet Union and the Asian financial crisis. Since 2000, however, coal consumption has surged, mostly because of China's fast-growing economy. In fact, global coal demand increased more between 1999 and 2013 (by 2.4 billion tonnes of coal equivalent [Btce], or 3.5 billion metric tonnes [Bt]) than in the preceding 90 years. China, which was exempted from the Kyoto Protocol, contributed around 80% of total coal consumption growth during that period, and the United States announced it would not ratify the Kyoto Protocol only two years after signing it.

In 2015, the Paris Agreement was signed with the aim of strengthening the global response to climate change by keeping global temperature rise this century to well below 2 degrees Celsius (°C) above pre-industrial levels and pursuing efforts to limit it to 1.5°C. A total 195 signatories agreed to the treaty. Coal-use trends were similar to the Kyoto era, with global consumption declining for three years in a row from 2014 to 2016, to rebound in 2017 and 2018, with a big difference: coal consumption in 2015 was around 75% higher than in 1997. Furthermore, in 2017 the United States announced its intention to withdraw from the Paris Agreement, an action that cannot take effect before November 2020.

Global coal consumption, 1980-2018



Despite their similarities, there are some significant differences between the Kyoto Protocol and the Paris Agreement. Unlike the Kyoto Protocol, the Paris Agreement has set a quantified temperature target. In addition, the measures adopted by the parties are self-proposed and based on Nationally Determined Contributions (NDCs), making the implementation of effective climate policies more likely. The Paris Agreement has also garnered a lot more attention and social acceptance, reflecting a rise in public opinion against fossil fuels and giving momentum to a concerted movement that is slowly turning public and private investment banks and institutions away from coal.

The shale gas revolution, which has made inexpensive energy resources readily available, has changed the profile of US domestic energy supplies and is now affecting global energy markets. In addition, the technological options of 2019 are different from those of 1997, as the costs of renewable energy technologies have dropped significantly while their productivity has increased. The capital costs of utility-scale solar power have fallen 75% since 2010, while those of onshore wind power have declined 20% (IEA, 2019a). This offers countries (and their respective climate policies) opportunities to reduce greenhouse gas (GHG) emissions and to replace coal with other resources, at least in part. A second global coal resurgence is therefore highly unlikely.

Asia Pacific

In 2018, the Asia Pacific region accounted for 73% (5 605 Mt) of global coal consumption (Table 1.2). China remains the world's largest coal consumer by far, with a 49% share of global consumption. Higher Asia Pacific coal consumption has been the main driver of global coal demand growth, with total consumption increasing 2% (+109 Mt). As coking coal demand rose only slightly, steam coal for electricity production accounts for most of the growth, with Asia Pacific coal-fired electricity generation expanding 4.3% to reach 7 253 TWh.[1] The resulting coal demand accounts for around 45% of total global consumption, a share that increased by 1.4% from 2017. China and India are the largest producers of coal-based electricity in the world. Global coal use for power generation outside these two countries accounts for one-quarter of total global consumption.

Table 1.2. Coal consumption in selected Asia Pacific countries by type (Mt), 2017-18

	Steam coal			Lignite			Met coal		
Country	**2017**	**2018***	**CAAGR**	**2017**	**2018***	**CAAGR**	**2017**	**2018***	**CAAGR**
China	3 136	3 169	1.0%	-	-	-	583	587	0.8%
India	834	878	5.3%	46	45	-1.2%	58	62	5.7%
Japan	141	139	-1.1%	-	-	-	47	47	-1.3%
Korea	104	107	2.3%	-	-	-	36	37	2.0%
Indonesia	101	108	6.6%	-	-	-	5	7	65.1%
Chinese Taipei	58	59	1.2%	-	-	-	9	9	3.1%
Australia	53	55	3.5%	57	46	-19.0%	4	4	0.8%
Viet Nam	51	61	20.1%				-	-	-
Malaysia	33	35	6.5%	-	-	-	-	-	-
Philippines	29	31	5.6%	-	-	-	-	-	-
Thailand	19	17	-12.8%	16	14	-11.1%	-	-	-
Asia Pacific	**4 616**	**4 724**	**2.3%**	**138**	**128**	**-7.0%**	**742**	**753**	**1.5%**

* Estimated.
Notes: Differences in totals are due to rounding.

China

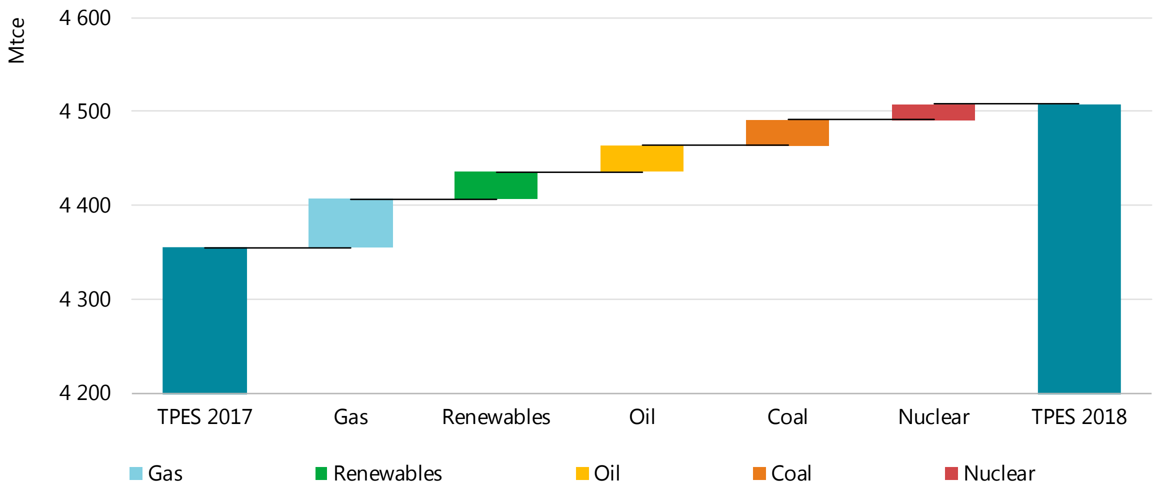
Coal consumption rose in China for the second consecutive year in 2018, with demand increasing by 1% (+37 Mt) to 3 756 Mt (Figure 1.1). At the same time, total Chinese energy consumption expanded 3.5%, the highest growth since 2012. The share of coal in primary energy demand thus declined from 64% to 62%. This drop follows China's 13th Five-Year Plan (FYP) that aims to reduce the share of coal in primary energy consumption to less than 58%[2] and the 2018-20 Three-Year Action Plan for Winning the Blue Sky War, which targets to replace inefficient and highly polluting coal-based boilers in the industrial and residential sectors with cleaner-burning natural gas.

China's power sector is the world's largest consumer of thermal coal, using almost 2.2 gigatonnes (Gt) in 2018. Coal fuelled 67% of total electricity generation, which increased by 6.8% to 7 089 TWh. Electricity consumption in the industry sector, which accounts for 68% of power consumed, increased by 7.1% (+319 TWh) owing to higher industrial output. Electricity consumption in the services sector (16% of total consumption) and the residential sector (14%) grew more quickly, with an additional 12.7% (+126 TWh) for services and 11.3% (+94 TWh) for residential, in which higher cooling demand propelled power output. China's coal-fired electricity generation rose an estimated 5% (+225 TWh) in 2018. Coal consumption resulting from this growth

[1] Unless otherwise specified, all generation figures in this publication are for gross generation.
[2] Chinese statistics on primary energy are not comparable with the IEA's because a different methodology is used to calculate total primary energy supply (TPES).

in electricity generation therefore increased by around 5%. Hence, the efficiency of coal-fired power plants improved only slightly, from 309.4 grammes of coal equivalent per kilowatt hour (gce/kWh) (39.8%) in 2017 to 307.6 gce/kWh in 2018 (40%).[3] Solar photovoltaic (PV) generation expanded 35.9% (+47 TWh) and wind power rose 24.1% (+71 TWh) while hydropower, China's second-largest electricity source, increased 5.2% (+60 TWh).

Figure 1.1. China's primary energy demand growth by fuel, 2018



Note: TPES = total primary energy supply.

Key message: Gas contributed the most to China's primary energy demand growth in 2018.

In 2018, around 41 gigawatts (GW) of coal-based generation capacity were commissioned in China's electricity system and 3 GW were decommissioned, resulting in a total coal capacity of 1 015 GW at the end of the year.

As in the power sector, China dominates non-power coal consumption. In 2018, thermal non-power coal consumption decreased by 6.7% as a result of the three-year action plan's strong environmental policies. The plan focuses on the Beijing, Tianjin and Shanghai areas and the key cities of Hebei, Henan, Shaanxi, Shanxi, Shandong, Jiangsu, Zhejiang and Anhui. In the residential sector, it aimed to reduce air pollution by converting 50% of northern China to clean heating by 2019 (i.e. by switching from bulk coal to cleaner sources such as natural gas). For Beijing, Tianjin and 26 cities in Hebei, Shanxi, Shandong and Henan, the target was 90% by 2019. According to the Chinese government, 4.8 million households switched their heat source from coal to natural gas and electricity in 2018 – an increase of 20% from 2017. In addition to residential heating, China has strengthened governance and control of scattered coal use in the industry sector and continued to replace coal with natural gas. The stricter environmental protection policies and long-term environmental monitoring mechanism introduced by the government focus especially on industrial coal use in the Hebei, Shandong and Anhui provinces. In response to rising natural gas demand and the associated problems (e.g. supply shortages as well as insufficient distribution and storage systems), China introduced industry reforms in 2018 to improve market mechanisms and ensure a reliable natural gas supply. Guidelines cover the entire industry chain, including boosted upstream production, midstream infrastructure construction and market-oriented reforms in the

[3] This small increase in efficiency represents an emissions reduction of 23 million tonnes of carbon dioxide ($MtCO_2$) in 2018.

downstream sector. In addition, cement production, a sector which accounts for 10% of the country's coal consumption, fell by around 11% year-on-year (y-o-y) to 2.2 Bt in 2018 (Global Cement, 2019). Since 2014, cement sales have fallen by over 300 Mt; this drop is larger than cement production in any country except India.

Non-power thermal coal consumption increased in 2018 in China's coal conversion sector, which is the largest in the world and includes conversions of coal-to-chemicals, coal-to-liquids and coal-to-gas. Consumption for the latter two conversions increased by around 5 Mt (+21%) to 29 Mt. There is currently strong momentum for coal-to-liquids transformations, as coal conversion is perceived in China as a way to raise energy security, monetise otherwise stranded coal and contribute to the economic development of certain regions. Most demand growth in the sector stems from coal-to-liquids conversions, as the country's largest coal-to-liquid project of the state-owned Shenhua Group (now China Energy Investment Group) began operating in Ningxia at full capacity – 4 million tonnes per annum (Mtpa) of oil products (~80 thousand barrels per day [kb/d]) – at the end of 2017. Despite the Clean Air Strategy's policies to promote the use of gas, the coal-to-gas sector has been struggling with poor economics and technical problems.

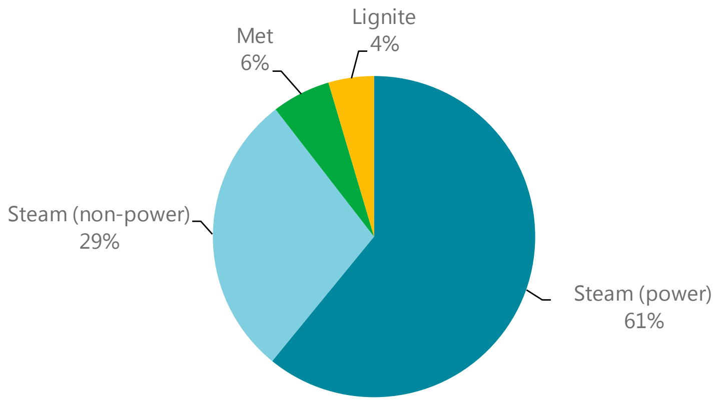
Met coal consumption increased 5 Mt (0.8%) to 587 Mt in 2018. China continued to be the largest steel producer in the world, covering approximately 51% of global production. While crude steel production expanded 6.6%, pig iron manufacturing rose by only 3% as a result of greater scrap metal use (World Steel Association, 2019) as well as efficiency gains, although there is some statistical uncertainty. The steel supply has changed significantly since 2016, in line with the 13th FYP. Roughly two years ahead of schedule, the country has already achieved its target of eliminating 150 Mtpa of steel production capacity during 2016-20, and an additional 140 Mtpa of induction furnace capacity was removed in 2017. Furthermore, steel mills have been ordered to upgrade their environmental protection facilities to meet specific emissions targets. In 2015, prior to the supply-side reforms, more than half of the steel producers in China's Iron and Steel Association posted losses totalling around USD 9 billion (United States dollars) (S&P Global Platts, 2019), but most showed profits in 2018 as a result of the reforms.

India

India, the world's second-largest coal consumer, recorded the largest increase in absolute terms (+47 Mt) in 2018. This growth of 5% surpasses India's 4% increase in total primary energy consumption, indicating that reliance on coal is increasing in India. Nevertheless, coal consumption growth in 2018 was lower than the 6.5% recorded in 2017 and the compound annual growth rate (CAGR) of 5.4% in the last decade. Decelerating growth is mainly the result of a slowdown in the electricity sector and rising shares of renewables such as wind and solar.

Thermal coal made up 90% of India's coal consumption, or 878 Mt in 2018 – a 5.3% (+44 Mt) increase from 2017 (Figure 1.2). Most of the thermal coal (68%) is consumed in the power sector, as 74% of India's power mix is coal-based. Total electricity generation rose by 5.1% (+79 TWh), a relatively moderate increase compared with growth rates of the past decade. Coal-based generation grew by around 50 TWh, while wind and solar power each expanded by 10 TWh, which is a record increase for these technologies. In contrast, India's second-largest electricity source, hydropower, remained stable at 142 TWh. While annual average capacity additions during the last decade were around 14 GW, approximately 8 GW of new coal-fired capacity was commissioned in 2018.

Figure 1.2. India's coal consumption by type and use, 2018



Note: All percentages are estimated.

Key message: 35% of India's coal consumption in 2018 was for non-power applications such as cement and steel production.

Thermal non-power coal consumption increased 10% to meet greater demand for the production of direct reduced iron and cement-making. India is the largest producer of direct reduced iron, mostly using thermal coal, and its production rose 3.1% in 2018. Cement production increased 6.4% owing to sustained construction activity.

India consumed 62 Mt of met coal in 2018,[4] with demand rising 5.7% (+3 Mt) consequent to a 4.9% steel production increase. The country replaced Japan as the world's second-largest steel producer, with growth driven mainly by domestic steel consumption, since India's steel exports are negligible compared with its production (World Steel Association, 2019). It was the government's implementation of large-scale infrastructure projects, such as power transmission and railways as well as housing, which raised domestic steel consumption (OECD, 2019). The Indian steelmaking industry has invested heavily in expansion and new projects in recent years and continues to do so, and the 2017 National Steel Policy gave the industry a further boost, as it favours locally manufactured steel and iron products for government projects. Pig iron production rose at a higher rate than that of steel (+7%), as growth in steel production was supported mainly by the use of blast furnaces.

India's lignite consumption (around 45 Mt in 2018) has been relatively stable since 2012. Around 88% of it is used in power stations and the remaining 12% is consumed in the industry sector.

Japan

Japan consumed 186 Mt of coal in 2018, a slight decrease of 1.2% (-2 Mt) owing to lower coal-fired power generation as well as reduced steel production.

Coal demand from the power sector declined as additional generation from restarted nuclear power plants and solar PV reduced electricity generation from fossil fuels. Of all coal consumed,

[4] As this report reassigns coking coal used by the power sector as thermal coal, coking coal figures may differ from other publications.

75% (139 Mt) was thermal coal used mostly for power generation. Two coal-fired power plants, Hibikinada (112 megawatts [MW]) and Kamisu (112 MW) – both co-fired with biomass – were commissioned in 2018. However, the Hokaido earthquake-enforced outages at two coal-fired power plants (the 1.7-GW Tomato-Atsuma coal station and the 0.4-GW Naie power plant) contributed to the decline in power sector coal demand in 2018. While Naie suspended operations only briefly, the last power unit of Tomato-Atsuma resumed generation two months later.

Met coal demand also decreased in 2018, although to a lesser extent (-1 Mt; -1.3%). Consumption was 47 Mt, with the decline resulting mostly from a 1.3% decrease in pig iron production (World Steel Association, 2019). Even though steel demand has been firm, especially from the construction, industrial machinery and automobile sectors, steel exports of the third-largest steel-producing country in the world fell, leading to reduced domestic production (OECD, 2019). Natural disasters (heavy rainfall, typhoons, earthquake) and technical challenges at steel mills have influenced production volumes, while domestic steel production growth has been further impaired by some Japanese producers (such as Nippon Steel Corp and Kobe Steel) establishing production capacity abroad (e.g. in Thailand, China and Mexico).

Korea

After a strong demand increase in 2017, Korea's growth in coal consumption slowed in 2018. Total coal consumption rose 2.2% (+3 Mt) to 144 Mt, with both thermal and met coal contributing to the increase.

Thermal coal makes up 74% (107 Mt) of Korea's coal consumption, with 94% used in the power sector. Thermal coal consumption rose by 2 Mt (+2.3%) due mainly to a modest increase in coal-fired power generation (+1.6%). Even though power demand expanded and the nuclear energy supply fell significantly in 2018, coal could not make up the difference because of regulations restricting the operation of coal-fired units. To limit air pollution, five units (accounting for 2.3 GW) were not permitted to operate during March through June. New limits on fine dust, introduced on a trial basis between October and December of 2018, also affected the operations of most plants. As a result, most of the difference was met by gas-fired power generation.

Korea's met coal consumption rose only slightly, by 2% (+1 Mt) to 37 Mt in 2018, accounting for 26% of the country's coal consumption. Growth was driven mostly by a 2.1% increase in steel production.

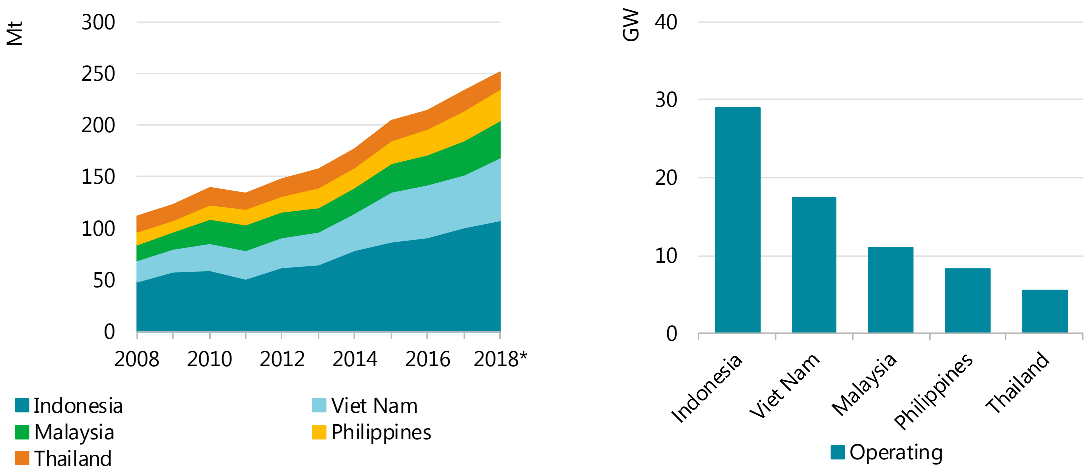
Southeast Asia

Coal consumption in Southeast Asia continued to grow by a strong 7.4% (+19 Mt) to 278 Mt in 2018. Higher steam coal consumption, which rose 7.5% from 2017 (to 256 Mt), accounted for most of the growth, and met coal consumption expanded to 7 Mt (+65.1%) while lignite decreased slightly by 1 Mt (to 15 Mt). Viet Nam, and to a lesser extent Indonesia, contributed most of the growth.

Most coal consumed in Southeast Asia (92%) is thermal coal, with Indonesia being the largest consumer (108 Mt), followed by Viet Nam (61 Mt), Malaysia (35 Mt), the Philippines (31 Mt) and Thailand (17 Mt) (Figure 1.3). Supported by substantial gross domestic product (GDP) growth of around 5% in Southeast Asia, power generation in the region increased 7.2% to 1 055 TWh in 2018. As hydropower generation declined by 20% (-33 TWh), coal-fired generation expanded 9% (+32 TWh) and its share in the energy mix increased to 39%. With coal-based generation expanding more quickly than overall power generation, Southeast Asia is the only region where coal's share in the power mix increased in 2018. The remaining thermal gap was filled by higher gas-fired generation. Coal-fired capacity continued to expand. In 2018, 4 GW of net capacity were added, with the majority commissioned in Indonesia, Viet Nam and the Philippines. Lignite-based generation capacity and output, mostly situated in Thailand and the Lao People's Democratic Republic (Laos), remained stable. Non-power thermal coal consumption rose slightly.

Met coal consumption increased by around 3 Mt in Indonesia, the region's most important met coal consumer, as infrastructure projects supported increased steel demand and pig iron production.

Figure 1.3. Thermal coal demand, 2008-18 (left), and coal-fired generation capacity, 2018 (right), of the major coal consumers in Southeast Asia



* Estimated.

Key message: Southeast Asia's coal consumption continued to increase as Indonesia and Viet Nam drove coal-fired power generation growth in 2018.

Other Asia Pacific

Australia

In 2018, Australia consumed 105 Mt of coal, a significant drop (-7.8%) from 2017. Much of the decline can be attributed to the power sector, which accounts for most of Australia's coal consumption (55 Mt of thermal coal and 46 Mt of lignite). Lignite use declined a significant 11 Mt (-19%) owing to closure of the 1.6-GW Hazelwood lignite power station in March 2017 and several outages at other lignite-fired power plants. One of the most affected plants was Loy Yang A, the country's largest lignite power plant with a total capacity of 2.2 GW. The resulting lack of availability led to an 8-TWh (17.3%) reduction in lignite-based power generation. This electricity was partially replaced by hard coal-fired generation from New South Wales and Queensland, resulting in a 3.5% (2 Mt) increase in thermal coal consumption, with additional gas-fired generation as well as wind and solar making up the remainder. Australia's met coal consumption remained stable at 4 Mt in 2018.

Chinese Taipei

Chinese Taipei consumed 68 Mt of coal in 2018, 59 Mt of which was thermal coal and 9 Mt met coal. Total coal consumption increased a slight 1.4% from 2017. Met coal consumption remained flat, whereas thermal consumption increased 1 Mt, mainly due to rising electricity generation (+1.5%), for which most of Chinese Taipei's thermal coal is used. Coal's share in the energy mix continues to be the largest. The restarting of nuclear reactors that had been in maintenance mode since 2016 boosted nuclear electricity generation by 19 TWh (+83%), mainly displacing gas-fired electricity production.

Pakistan

In 2018, Pakistan's coal consumption rose 6% to 19 Mt. On top of the 2017 commissioning of the 1.3-GW Sahiwal coal-fired power station, the 120-MW Fatima Energy co-generation thermal power project and the 120-MW Fauji Fertilizer power station, two Port Qasim power project supercritical units (total capacity of 1.2 GW) were commissioned in 2018. However, electricity generation growth (+5.9%) was mostly supported by hydropower. Non-power coal consumption slowed after the country's cement production hit a record level in 2017.

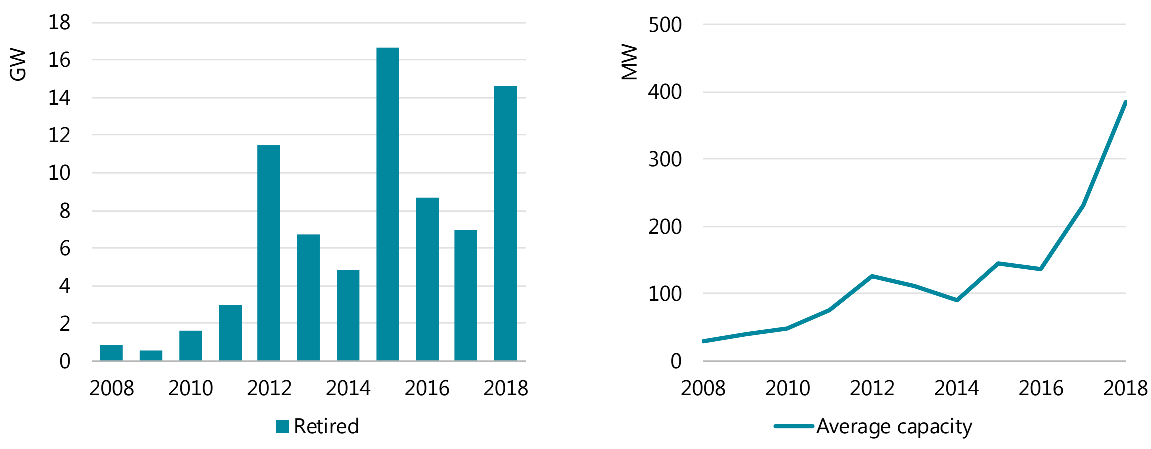
North America

North America accounts for 9% (665 Mt) of global coal consumption, with the United States being the largest hard coal consumer in North America and within the Organisation for Economic Co-operation and Development (OECD) by far. Compared with the beginning of this millenium, however, the share has dropped significantly, as the region accounted for 22% of global coal demand in 2000.

United States

While US steam coal consumption declined by 16 Mt (-2.9%) to 544 Mt, met coal consumption remained stable at 18 Mt.

Figure 1.4. Total nameplate capacity of retired coal plants (left) and their average capacity (right), 2008-18



Source: Adapted from EIA (2019a), "Preliminary Monthly Electric Generator Inventory".

Key message: Since 2016, the average capacity of retired coal power plants increased compared to preceding years.

The United States recorded the world's largest absolute drop in coal-fired electricity generation in 2018. While total generation increased by 150 TWh (+3.5%) to 4 413 TWh, coal-based power output decreased by 68 TWh (-5.1%) to 1 250 TWh owing to considerable growth in wind and solar generation (+41 TWh) and, more significantly, gas-fired generation (+176 TWh) despite the slight rise in natural gas prices.

Between 2008 and 2018, US power sector CO_2 emissions fell by 610 Mt (-27%), with a large part of this decline attributed to coal-to-gas switching (IEA, 2019c; Mohlin et al., 2019).

The declining competitiveness of coal-fired power generation has led to rising retirement of coal-fired power plants: in 2018, a total nameplate capacity of 14.6 GW was retired, the second-highest capacity reduction after 2015 (Figure 1.4). A total 75.9 GW of coal power capacity has been retired in the last decade, and while most of the plants had relatively low nameplate capacities until 2016, larger units have been disconnecting from the grid recently, leading to a tighter electricity market. Although most of the closures have been hard coal power plants, in 2018 two large lignite generation units closed in Texas, reducing lignite consumption to 52 Mt (-18.7%).

In contrast with developments in the power sector, US met coal consumption increased by 1 Mt to 18 Mt in 2018 as pig iron production rose 7.5% (World Steel Association, 2019) to meet increased demand for US steel. Domestic steel production expanded to replace imported steel mill products subject to trade remedies (International Trade Administration, 2019).

Other North America

Outside the United States, coal's contribution to the electricity mix in North America is relatively low, and, like in the United States, also declining.

Canada

In 2018, Canada consumed 31 Mt of coal. With a small and stable met coal consumption of 2 Mt, most of the consumption is thermal coal used for electricity. Since closure of the Brandon Station (110 MW) in Manitoba in August 2018, the country's coal-fired power generation capacity of around 9 GW has been concentrated in only four provinces – Alberta, Saskatchewan, Nova Scotia and New Brunswick. Three coal-fired power units in Alberta, the Battle River 3 plant (150 MW) and Sundance 1 and 2 (2 x 280 MW), have also ceased operations.

Canadian coal consumption dropped 5 Mt (-13.9%) in 2018 due to a 9-TWh (15.1%) decline in coal-fired power generation. While total electricity production decreased by 1.1% and imports from the United States rose, gas-fired generation surged 16.9%. Natural gas has mostly replaced coal-based power generation and substituted for decreasing hydropower generation.[5] As North America's natural gas markets are closely interconnected through pipeline networks, Canada's natural gas prices, much like those in the United States, were at low levels (even lower in the case of Alberta).

Mexico

Mexico consumed 19 Mt of coal in 2018, 1 Mt less than in 2017. Thermal coal consumption remained stable at 14 Mt, as most additional electricity production (+5.9%) was fuelled by gas and renewables. Met coal consumption declined by 1 Mt (-16.5%) as steel production stagnated.

[5] Hydropower generation was exceptionally high in 2017, but it returned to normal levels in 2018 in accordance with lower precipitation.

Europe

Despite economic expansion of 1.8% in 2018, Europe's primary energy demand increased by only 0.2% and coal consumption declined 2.6% (-21 Mt) to 794 Mt (Table 1.3). Thermal coal use, which accounted for 25% of Europe's coal consumption, dropped 15 Mt (-7.2%), while met coal decreased only slightly (by 2 Mt; -2.5%). Volume-wise, lignite makes up most of Europe's coal use (519 Mt); in 2018, its consumption decreased 3 Mt (-0.7%). Despite the overall drop, coal consumption in Europe outside the European Union grew strongly.

Table 1.3. Steam coal and lignite consumption in selected European countries (Mt), 2017-18

	Steam coal			Lignite		
Country	**2017**	**2018***	**CAAGR**	**2017**	**2018***	**CAAGR**
Bulgaria	0.9	1.0	8.3%	34	30	-10.5%
Czech Republic	3.4	2.8	-19.0%	39	39	1.0%
France	8.4	6.7	-20.2%	-	-	-
Germany	33	30	-9.1%	171	166	-2.9%
Greece	-	-	-	38	37	-4.4%
Hungary	-	-	-	8.1	8.2	0.2%
Italy	12	11	-11.9%	-	-	-
Netherlands	10.3	8.8	-14.3%	-	-	-
Poland	61	63	3.0%	61	59	-4.3%
Portugal	5.4	4.5	-15.9%	-	-	-
Romania	0.8	1.0	17.4%	26	25	-3.5%
Spain	21	15	-26.3%	-	-	-
United Kingdom	11	10	-15.0%	-	-	-
European Union	**180**	**165**	**-8.3%**	**382**	**369**	**-3.6%**
Serbia	-	-	-	40	38	-5.4%
Turkey	33	32	-2.1%	72	85	18.5%
Bosnia and Herzegovina	-	-	-	14	14	0.2%
Europe	**214**	**198**	**-7.2%**	**523**	**519**	**-0.7%**

* Estimated.

Note: Differences in totals are due to rounding.

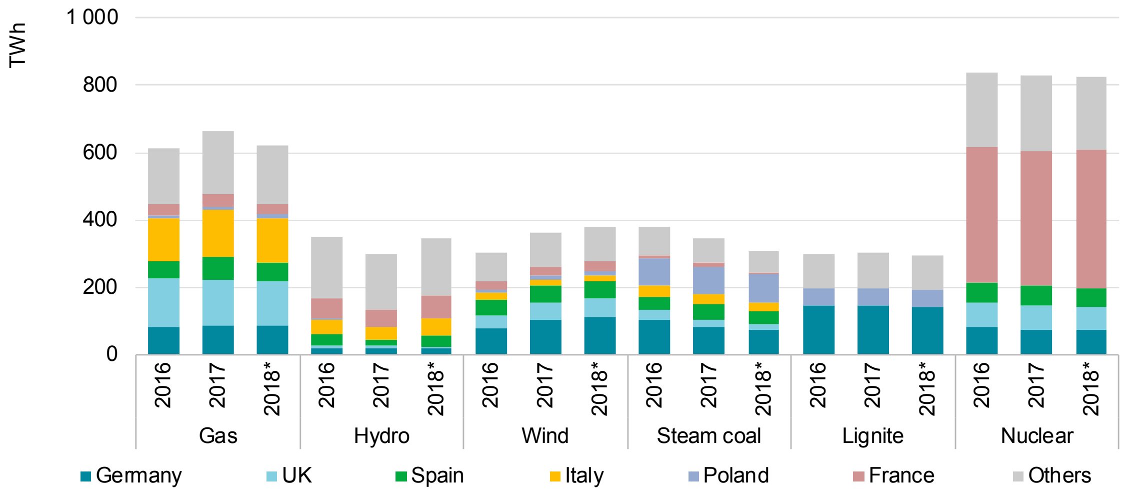
European Union

The European Union consumed 600 Mt of coal in 2018. With lignite consumption of 369 Mt, it is the world's largest lignite-consuming region. In contrast, thermal (165 Mt) and met coal (66 Mt) consumption is moderate compared with other regions. The most important EU coal consumers are **Germany** (215 Mt) and **Poland** (134 Mt), followed by the **Czech Republic** (46 Mt), **Greece** (37 Mt), **Bulgaria** (31 Mt) and **Romania** (26 Mt), with most of the coal used in the power sector. In units of energy, the EU power sector accounted for 70% of European coal consumption in 2018. Considering only thermal coal and lignite, the share is even higher (90%), with lignite being used mostly for electricity production. Compared with 2017, coal consumption in 2018 was 32 Mt (-5.1%)

lower. Thermal coal and lignite contributed to this decline equally, as thermal use decreased by 15 Mt (-8.3%) and lignite shrank 14 Mt (-3.6%).

EU electricity generation decreased 0.8% (-25 TWh) to 3 244 TWh. Coal-fired electricity production declined 46 TWh (-6.6%) to 649 TWh, with hard coal-fired generation being more affected than lignite-fired. While gas-fired electricity production dropped even more, by 43 TWh (-6.5%), renewable generation (from PV, wind and hydro) expanded 72 TWh (+9.2%) to make up 26% of the electricity mix. As CO_2 prices rose 174% (to USD 19 per tonne of carbon dioxide [/tCO2]), gas prices rose more sharply (+38%) than coal prices (+9%), making coal-to-gas switching less likely until the fourth quarter of 2018, when prices were more favourable for gas-fired generation (IEA, 2019c). In addition, increased hydro generation reversed the temporary rise in gas- and coal-fired power generation that happened in 2017 (Figure 1.5). Hydropower rose by 15.2% (+46 TWh), recovering to normal levels. In southern Europe especially, hydro generation was above average, while it was below average in the north. Hence, more hydro in Spain, Italy and France reduced thermal generation in the EU power system.

Figure 1.5. Generation of selected energy sources in the EU (TWh), 2016-18



* Estimated.

Key message: Higher renewables-based output in 2018 displaced steam coal- and gas-fired power generation in the European Union.

In addition to reduced generation, coal power capacity declined in 2018. Around 3 GW of hard coal-fired generation was retired, of which one station alone – the Eggborough power station in North Yorkshire – had a capacity of 2 GW. In contrast, lignite-fired capacity declined only slightly. Non-power coal demand remained flat over the course of the year.

Compared with thermal coal, the absolute drop in met coal consumption was low, with a decline of 3 Mt (-5.0%) to 66 Mt owing to greater scrap use. This led to a 2.4% reduction in pig iron production (World Steel Association, 2019).

Germany

Germany consumed 215 Mt of coal in 2018 – 10 Mt (4.4%) less than in 2017. While steam coal consumption decreased 3 Mt (-9.1%), lignite consumption fell 5 Mt (-2.9%).

Electricity production remained flat at 644 TWh, while net exports declined slightly to 47 TWh. Lignite is the country's largest single power source, accounting for 22% of the electricity produced in 2018 and making Germany the largest lignite consumer in the world. Nevertheless, wind power generation is on the rise and is rapidly approaching lignite's share in the electricity mix (17% in 2018).

Coal-based electricity generation declined by 11 TWh to 241 TWh as output fell both from plants using hard coal (-8 TWh) and lignite (-3 TWh). Lignite power production declined mostly as a result of regulations. The Act on the Further Development of the Electricity Market forced the mothballing of eight lignite-fired power plant units with a total net capacity of 2.7 GW, placing them in a mode known as secure and reliable standby reserve. The affected units (Table 1.4), which are not to be shut down permanently for a period of four years, are available exclusively for the needs of transmission grid operators during this time.

Table 1.4. Lignite-fired power plant secure standby reserves

Unit	Net generation capacity (MW)	Date of preliminary retirement
Buschhaus	350	1 October 2016
Frimmersdorf-P	284	1 October 2017
Frimmersdorf-Q	278	1 October 2017
Niederaußem-E	295	1 October 2018
Niederaußem-F	299	1 October 2018
Jänschwalde-F	465	1 October 2018
Jänschwalde-E	465	1 October 2019
Neurath-C	292	1 October 2019
Total	**2 728**	-

Hard coal consumption fell mostly due to higher renewables-based generation and, to a lesser extent, to price developments in the second half of the year (see above). Higher wind output (+6 TWh) resulted from both weather conditions and capacity expansions, causing thermal coal output to drop significantly. Several smaller generation units were decommissioned in 2018 (e.g. Mark-E's last Werdohl-Elverlingsen power station units [around 600 MW]), and the STEAG Völklingen power plant (179 MW) was mothballed from April until September because it was not economically viable.

Only a small share of German coal is consumed outside the main energy sectors. Met coal consumption decreased to 19 Mt (-9.8%) due to declining pig iron production and higher scrap steel utilisation for steel production.

Poland

In 2018, Poland consumed 134 Mt of coal: 63 Mt of thermal coal, 59 Mt of lignite and 13 Mt of met coal; it was the European Union's largest hard coal consumer. Overall consumption remained stable in 2018, as a slight increase in hard coal consumption (+2 Mt; +3.0%) offset a decrease in lignite use (-3 Mt; -4.3%).

Poland's electricity generation remained stable at 169 TWh, and as coal is the main electricity source, it accounted for 78% (133 TWh) of the power mix. Around 48% of total electricity generation comes from hard coal and the remaining 29% from lignite. The decline in lignite-based generation resulted mainly from closure of the 600-MW Adamów lignite power plant in 2017. In addition, a slight decrease in renewable generation was substituted by higher gas-fired production.

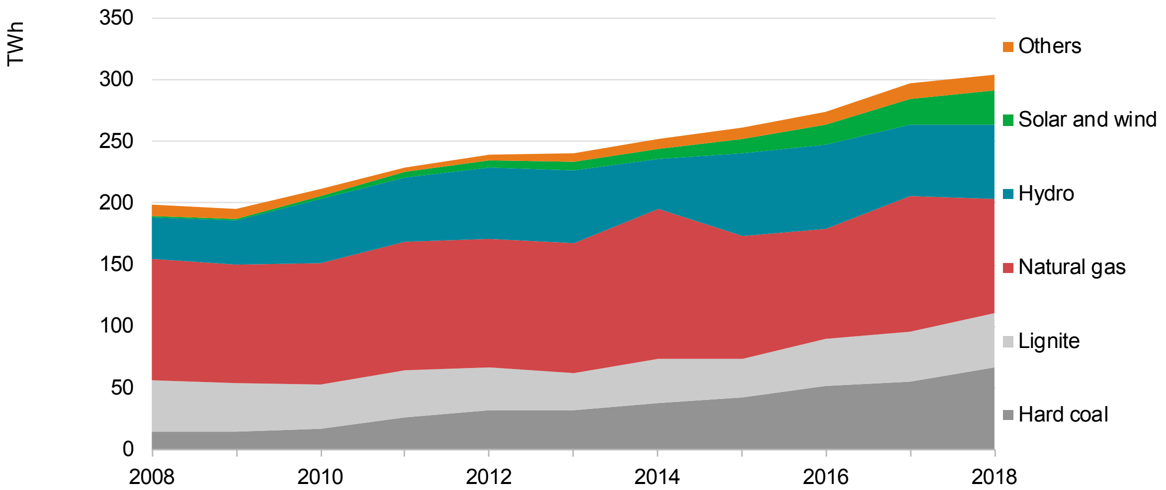
Other European Union

Spain consumed 17 Mt of coal in 2018, 25% (6 Mt) less than in 2017 as hydroelectric output recovered (see above). Something similar occurred in **Italy**, where coal consumption declined to 14 Mt, or 1 Mt (9%) less than in 2017. In **Greece**, coal consumption (almost entirely lignite) decreased by 4.4% to 37 Mt, with hydro and wind power generation compensating slightly for a decline in gas- and coal-fired power generation as overall electricity demand fell by around 4%. The **United Kingdom** continues to reduce its coal consumption as the country's carbon price floor keeps coal-based generation uneconomic relative to gas, and as wind output continues to grow. However, the 2018 reduction to 12 Mt (-2 Mt) has been the smallest decrease since 2012.

Other Europe

Coal consumption expanded in Europe outside the European Union. **Turkey's** coal consumption increased 14 Mt (+12.5%) to reach 126 Mt in 2018, as coal (+16 TWh) replaced natural gas (-18 TWh) in the power sector and for the first time became the leading source of electricity generation (Figure 1.6).

Figure 1.6. Turkey's electricity mix, 2008-18



Key message: Coal-fired power generation replaced electricity output from natural gas in 2018, becoming the largest source of electricity generation.

Three-quarters of coal-fired power generation growth (12 TWh) was imported hard coal, while the rest was domestic lignite. Additionally, non-power steam coal consumption, e.g. in the cement industry and residential sector, declined by around 34%. This was mainly driven by an economic slowdown.

Eurasia

Coal consumption in Eurasia increased 20 Mt (+5.7%) to 379 Mt in 2018, of which 199 Mt was thermal coal, 96 Mt met coal and 84 Mt lignite. Most of the growth was in thermal coal, which increased by 18 Mt (+9.9%).

Russia

In Eurasia, Russia is the largest consumer of coal, accounting for 61% (232 Mt) of total consumption within the region, and in 2018 its consumption increased by 13 Mt (+5.8%). Most of the coal consumed (164 Mt) is thermal coal and lignite, of which 93% is used in the power sector. Russia's electricity generation increased by around 1% to 1 107 TWh, with most (46%) generated from natural gas. However, coal-fired generation rose by 4.5% to make up 16% of the electricity mix.

Met coal consumption in Russia, the world's sixth-largest steel producer, remained flat at 67 Mt, in line with steel production.

Other Eurasia

In 2018, **Ukraine** consumed 47 Mt of coal, 5 Mt (+10.9%) more than in 2017, with consumption split between 29 Mt of thermal coal and 18 Mt of met coal. While thermal coal consumption remained stable, met coal demand drove consumption growth as a result of higher pig iron production.

Kazakhstan's consumption increased slightly by 2 Mt (+2.8%) to 88 Mt. Met coal consumption dropped a substantial 5 Mt (-31.6%) due to decreasing pig iron production. At the same time, steam coal use increased considerably, by 8 Mt (+11.5%). This jump was driven by higher coal-based electricity production, which rose 4.4 TWh (+5%) in 2018 (Table 1.5). Gas-fired power generation is also on the rise.

Table 1.5. Electricity generation in Kazakhstan (TWh), 2016-18

Energy Source	2016	2017	2018	Difference 2017-18	Growth 2017-18
Coal	74.7	82.4	86.8	4.4	+5%
Gas	7.4	8.4	9.1	0.7	+9%
Hydro	11.6	11.2	10.3	-0.9	-7%
Others	0.4	0.4	0.5	0.1	+26%
Total	**94.1**	**102.4**	**106.7**	**4.3**	**+4%**
Coal-share	79%	81%	81%		

Note: TWh = terawatt hour.

Africa

In 2018, African countries consumed 207 Mt of coal, a slight increase of 3 Mt (+1.3%). Most of the coal (96%) is thermal coal, with South Africa accounting for 91% of the continent's total coal consumption.

South Africa

South Africa's coal consumption increased slightly, by 3 Mt (+1.6%) to 189 Mt, with 186 Mt of thermal coal and 3 Mt of met coal. More than half of South Africa's coal consumption (56%) is for power generation. The largest non-power thermal coal consumer is Sasol Limited, which uses coal for producing synfuel and a variety of chemicals. Other major industrial coal consumers are cement and brick producers.

South Africa generated 249 TWh of electricity in 2018, 90% of it coal-fired. Total and coal-based electricity output decreased slightly, while wind and solar generation increased.

The public utility Eskom, which supplies around 95% of the country's electricity, owns and operates most of South Africa's coal-fired electricity generation capacity, making it the country's largest domestic coal consumer. The utility procures more than half of its coal under a cost-plus model whereby it provides mine owners with capital to develop and expand their mines. It failed to commit sufficient capital for this purpose in recent years, however, and announced in 2015 that it intended to withdraw from the cost-plus mines.

Eskom commissioned three new coal-fired power plant units with a combined capacity of around 2 GW in 2017, and no additional capacity was commissioned in 2018.

Other Africa

At 8 Mt, **Morocco** was Africa's second-largest coal consumer in 2018. In December 2018, electricity production in the north African country was boosted by commissioning of the ultra-supercritical coal-fired Safi plant, with a capacity of 1.4 GW. In addition, both **Zimbabwe** and **Botswana** each consumed 2 Mt. In all these countries, coal is used primarily for electricity generation.

Central and South America

All the countries of Central and South America together consumed around 57 Mt of coal in 2018 (39 Mt of steam coal, 16 Mt of met coal and 1 Mt of lignite), or 4 Mt (+7.6%) more than in 2017. While coal consumption in most countries remained stable, Colombia's rose substantially. As Central and South American electricity generation is dominated by hydropower, coal accounted for 5% of the region's generation mix in 2018, a slight decline from previous years.

Within the region, **Brazil** is the largest consumer of coal, with consumption split almost equally between thermal (13 Mt) and met coal (11 Mt), and its consumption did not change significantly from preceding years. The country is one of the ten largest steel producers in the world, and its steel production did not change substantially in 2018.

In 2018, **Chile** consumed 13 Mt, only slightly less than in 2017, as the country is the second-largest thermal coal user in the region. It generated 29 TWh of coal-based electricity, 36% of its total electricity generation.

Colombia was the main driver of the region's coal consumption growth in 2018. The country consumed 3 Mt (+42.3%) more than in 2017, which is a recovery after the sharp drop in 2017 when hydro generation was unusually high.

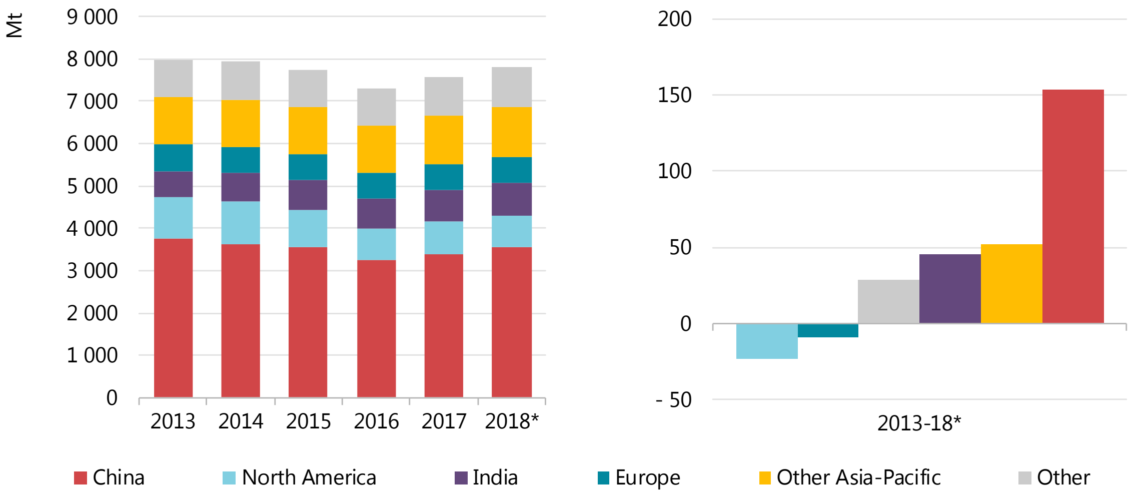
Middle East

Owing to the region's oil and gas endowment, coal consumption in the Middle East is very low. Total coal demand remained flat at 14 Mt in 2018, with the region's primary coal consumer being Israel, which alone used 8 Mt – all steam coal for power generation.

Supply

Global coal production continues to expand to meet rising demand: total production in 2018 rose to 7 810 Mt, an increase of 3.3% (+247 Mt). Asia's three largest coal producers – China, India and Indonesia – accounted for most of the increase (Figure 1.7). While production in China and India was propelled by rising domestic demand, in Indonesia it was additionally driven by greater seaborne coal trade. Globally, four out of the world's six largest coal producers increased their output in 2018, with China, India and the United States remaining the top three.

Figure 1.7. Total coal supplied by the main producers, 2013-18



* Estimated.

Key message: Global coal production continued to rise in 2018, driven mainly by China, India and Indonesia.

Asia Pacific

The Asia Pacific region is responsible for 71% (5 523 Mt) of the world's coal production, the main suppliers being China, India, Indonesia and Australia. The region's production rose by 4.8%, accounting for a net increase in global production. Demand growth as well as rising exports boosted domestic production.

China

China is the world's largest coal producer, holding a 45% share of total production. Although the restructuring of China's domestic coal mining industry led to a drop in coal production from 2013 to 2016, it has grown the last two years. In 2018, Chinese coal output rose 4.5% (+153 Mt) to 3 550 Mt.

China's supply-side reforms aimed to raise coal sector efficiency by replacing unsafe, high-cost mines with safer, lower-cost ones; consolidating mines and companies to improve their profitability was also an important aspect of the reforms. The 13th FYP recommendation to shut down 500 Mtpa of coal mining capacity has been exceeded, as 290 Mtpa of coal production capacity was removed in 2016 and 250 Mtpa in 2017, although the retirement rate decelerated in 2018. In 2019, 150 Mtpa of capacity are expected to close (Argus Media, 2019). Furthermore, the number of coal mines in China fell sharply from 10 800 in 2015 to 5 800 at the end of 2018, and average production capacity increased to about 0.92 Mtpa from 0.5 Mtpa in 2015 (Xinhua, 2019). Amid the mine closures, total new capacity of 25 Mtpa had received approval by the end of 2018 (Reuters, 2019). In addition, the Chinese government has implemented measures to improve rail transport capacity and increase supply chain efficiency from the main mining regions to the demand centres. This has helped the supply side to respond effectively to higher prices and growing domestic demand.

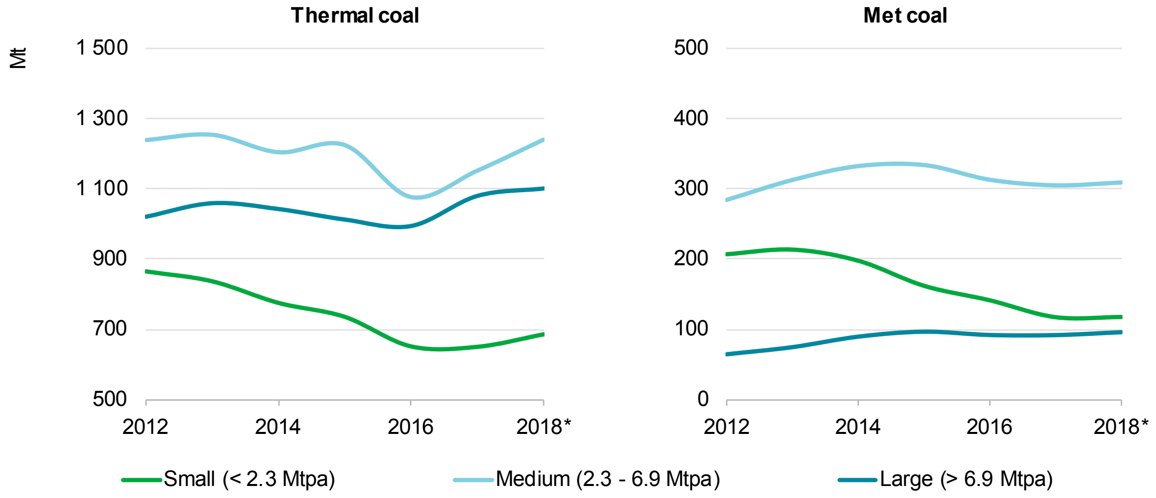
85% of China's coal production is thermal coal – the grade that increased the most, as it expanded by 5% (+144 Mt) while met coal production rose by only 1.7% (+9 Mt). Met coal production could have been higher in 2018 had it not been hindered by supply disruptions, the main one being the campaign of safety inspections in Shanxi. Following an accident, Shandong province in eastern China temporarily suspended operations at 41 of its 115 coal mines (the suspended mines, which had around 80 Mtpa of capacity, produced mostly met coal). Supply-side reforms targeting smaller mines also had a great impact, as around 82% of China's met coal is produced by small or medium-sized mines with capacities below 6.9 Mtpa, while only 64% of thermal coal comes from such mines (Figure 1.8).

Most of the new mining capacity that came online was for thermal coal, so met coal producers were not able to respond as flexibly as thermal coal producers to growing demand and higher prices.

In 2018, the four major coal-producing provinces – Inner Mongolia, Shanxi, Shaanxi and Xinjiang – provided 75% of China's coal production (Figure 1.9). All these regions ramped up production in 2019, with Inner Mongolia having the largest absolute production growth (+70 Mt) and Shaanxi increasing production the most in relative terms (+9%). At the same time, most of the smaller coal-producing regions decreased their output, e.g. Guizhou (-24 Mt; -15%).

Since 2011, coal production has shifted towards China's western regions, where the mines tend to be larger and more productive (IEA, 2018). In fact, most of the decline in production has taken place in small mines in the southern provinces (Figure 1.10). Production increased the most in Shaanxi from 2011 to 2018 – nearly four times more than in the other major coal regions (Inner Mongolia and Shanxi). Most of the production increase was supplied by large mines, in line with the goals of the supply-side reforms.

Figure 1.8. Chinese coal production by mine size, 2012-18

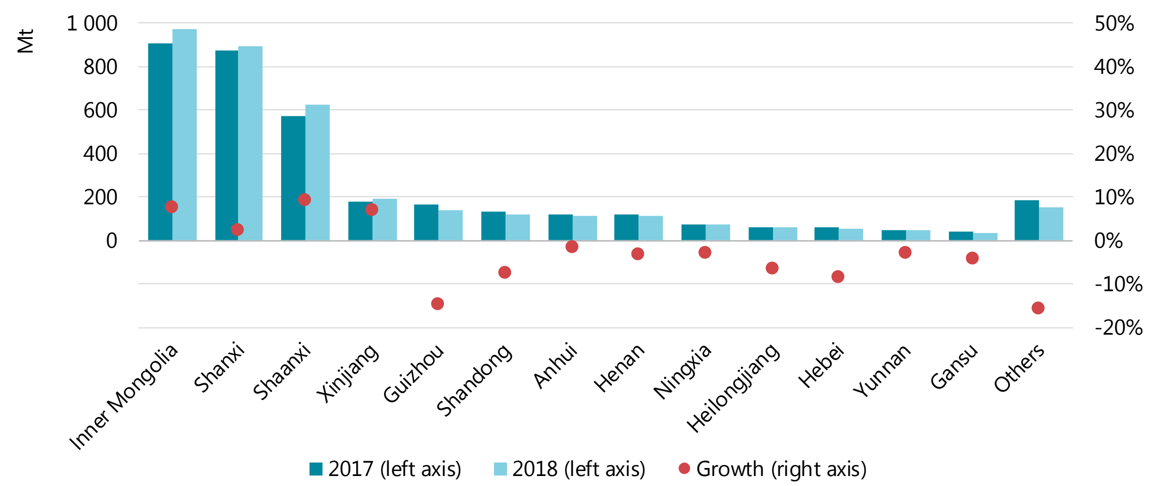


* Estimated.

Key message: China's supply-side reforms affected met coal production more strongly than thermal coal in 2018, as the share of small and less-efficient mines was higher.

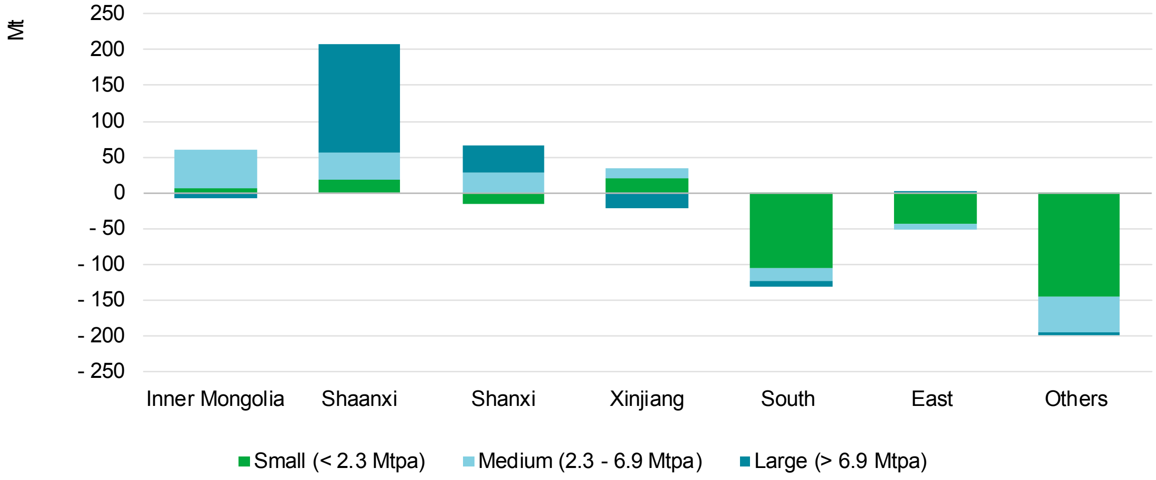
Capacity cuts and demand growth supported Chinese coal prices, which rose by about 6% to USD 94/t. Despite a small increase in mining costs, this led to a 5.2% rise in profitability for the Chinese coal mining industry in 2018, according to the China National Coal Association (Xinhua, 2019).

Figure 1.9. Chinese coal production by province, 2017 and 2018



Key message: Inner Mongolia and Shaanxi were the fastest-growing coal-producing regions in China in 2018.

Figure 1.10. Coal production change in China's major coal-producing regions, 2011-18



Note: South includes the provinces of Henan, Hubei, Hunan, Guangxi, Guangdong, Hainan, Yunnan and Guizhou; East includes Shandong, Jiangsu, Anhui, Jiangxi, Fujian and Zhejiang.

Key message: Chinese coal production increased the most in Shaanxi between 2011 and 2018, while most of the smaller closed mines were in the South.

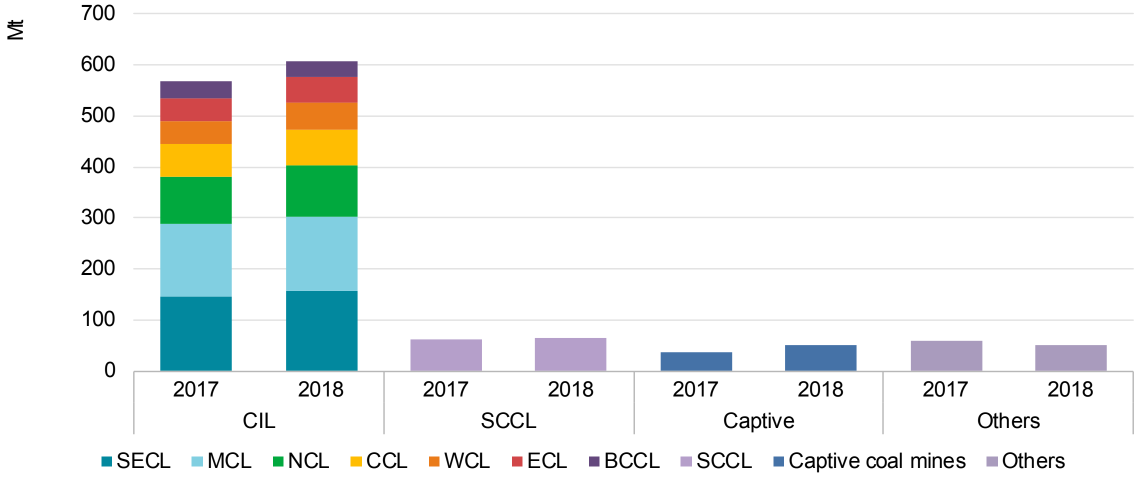
India

India, the world's second-largest coal producer, continued to increase production to 771 Mt in 2018, 6.3% (+45 Mt) more than in 2017. Most of this growth was in thermal coal, which increased 6.4% (+43 Mt) to 720 Mt. Met coal output remained stable at 6 Mt, while lignite production dipped slightly by 1 Mt to 45 Mt.

India's government has been consistently trying to increase domestic coal production to address the supply shortages consumers have faced in recent past, especially trying to avoid shortages at coal-fired power plants. In the Three-Year Action Agenda prepared in 2017 by the country's premier planning agency, NITI Aayog laid out a nine-point plan for boosting coal production to meet rising demand from India's coal power sector. Therein, the government set ambitious production targets for state-owned mining companies, including the auctioning of captive mines from which coal is allocated for a specified end use or for self-consumption, e.g. for power generation or steel production. Participation in the auctions was relatively low in 2018, however, so they were postponed. To increase the attractiveness of captive mines, the government has permitted captive coal block owners to sell 25% of their production on the open market and has provided some flexibility in coal output.

In 2018, state-owned Coal India Limited (CIL), the country's largest mining company, was responsible for 79% of India's total coal production. The company produced 606 Mt of coal, 7.1% more than in 2017 and close to the production target (610 Mt) set by the government. The largest subsidiaries of CIL, South Eastern Coalfields (SECL), Mahanadi Coalfields (MCL) and Northern Coalfields (NCL), account for 67% of the company's production. All CIL's subsidiaries were able to increase their output in 2018 (Figure 1.11). While the largest absolute rise in production (+12 Mt; +9%) was realised by SECL, the output of the smaller subsidiaries Western Coalfields (WCL) and Eastern Coalfields (ECL) expanded at the highest rate (15%). In addition, India's second-largest coal producer, Singareni Collieries Company Limited (SCCL), raised production by 4% (+2 Mt).

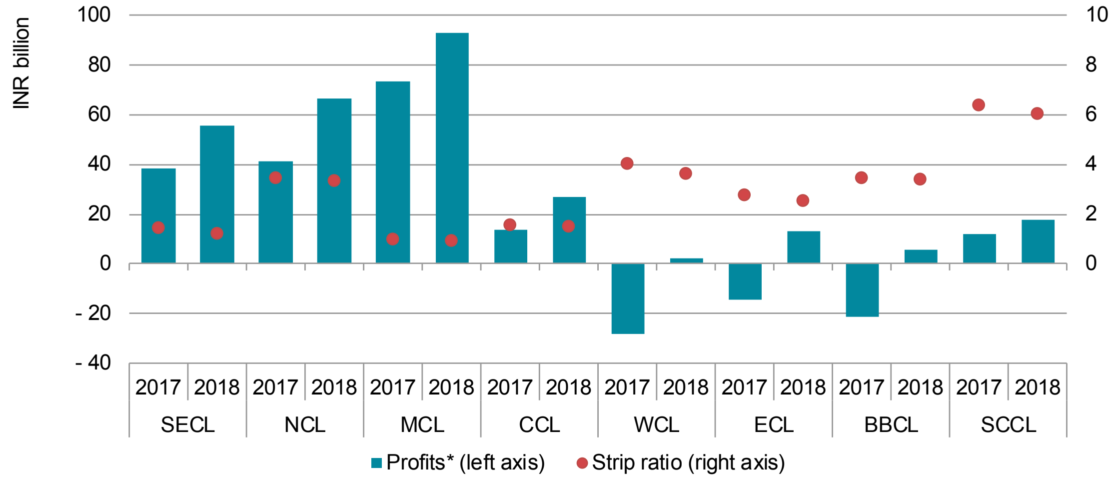
Figure 1.11. Coal production in India by company, 2017-18



Notes: CCL = Central Coalfields. BCCL = Bharat Coking Coal.
Source: Government and company announcements.

Key message: All major Indian coal companies increased production in 2018.

Figure 1.12. Strip ratios and profits of Coal India's subsidiaries and the Singareni Collieries Company, 2017-18

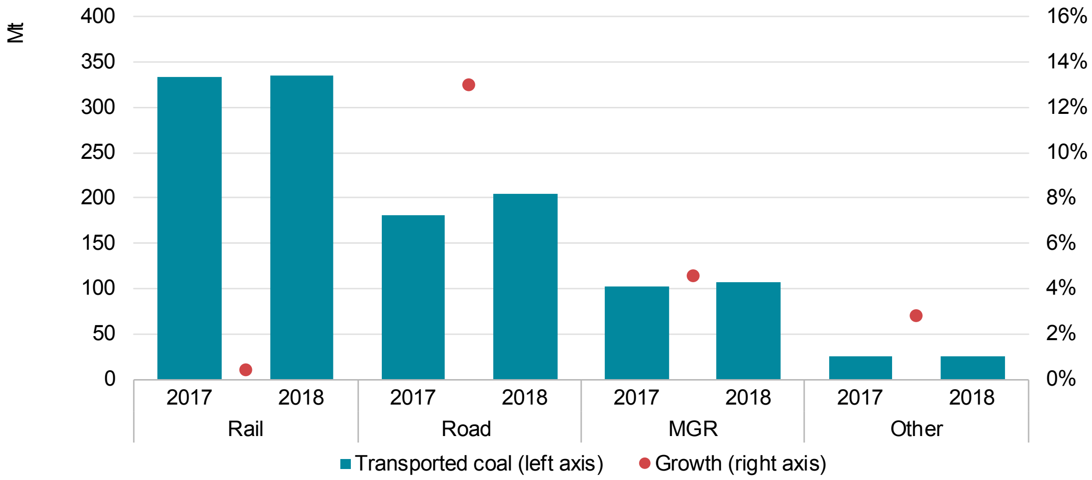


* All profits are before taxes, except for SCCL.
Source: Government and company announcements.

Key message: Mining productivity increased significantly in India in 2018, boosting the profits of its major mining companies.

Output growth was driven mainly by an increase in productivity. During 2018, while 29 coal and lignite mines were granted permission to open or re-open, CIL closed 25 mines, all underground ones. As India's underground mines are less efficient and productive, their closure freed up labour and capital resources for the remaining mines. In 2018, CIL operated 369 mines: 193 underground, 177 opencast and 24 mixed. SCCL added only one underground mine (Ministry of Coal, 2019). At the same time, strip ratios decreased for all of India's major mining companies (Figure 1.12). The weighted-average strip ratio dropped around 9% to 1.9:1, which is well below the estimated global production-weighted average of 6.0:1 (CRU, 2019). In addition, labour productivity increased in almost all mining companies, by an average of 13%.[6]

Figure 1.13. Means of transport for coal dispatch in India, 2017-18



Key message: The use of road-based transport increased to cover 30% of India's coal production in 2018.

These productivity improvements raised India's coal mining profits, and even subsidiaries that had previously been yielding losses became profitable. Total profits before taxes across all major mining companies increased by INR 166 billion (Indian rupees, around USD 2.3 billion). Around 80% of CIL and SCCL's combined coal production was sold to the power sector, making it the main revenue stream. Although rail was used to transport 50% of the coal, a substantial portion (30%) was still transported by road, and merry-go-round (MGR) trains using dedicated railways moved around 15%. Reducing the amount of coal conveyed by truck could cut transport costs and further raise the competitiveness of India's mining sector, but in the last year approximately 2% of coal sales were switched from rail to road (Figure 1.13).

Indonesia

Indonesia's coal output increased significantly to 549 Mt in 2018, its highest production ever. This 10.9% (54 Mt) increase makes the country the fourth-largest coal producer by volume, surpassing Australia. Because Indonesia is a relatively flexible and highly price-sensitive producer with comparatively low labour costs, it was able to ramp up production fairly quickly after thermal coal prices rose in 2018. In September 2018, the government increased its 2018 coal production target to 507 Mt (+22 Mt for the year) to support the rupiah, but production actually exceeded the national target by about 8.3%.

The country produced mostly thermal coal in the main coal-producing regions of Kalimantan and Sumatra. The disadvantage of Indonesian steam coal is that it has a high moisture content and low calorific values, which reduces its price. However, it has low sulphur content and usually low ash,

[6] Contracted labour is not included in this estimate. The statistics of CIL's subsidaries, which publish data on contractors, indicate that expenditures for contractors did not increase in 2018.

and is well suited for blending with bituminous coal, e.g. from Australia and South Africa. Most of Indonesia's coal production is exported, but the domestic market obligation (DMO) rule establishes that one-quarter of production must be sold on the domestic market. Moreover, the Indonesian Ministry of Energy and Mineral Resources (ESDM) re-established a domestic price cap for coal supplied to the state-owned utility PLN. In 2018, the ESDM threatened sanctions if miners disregarded domestic coal needs, especially for the power sector.

Australia

Australia produced 483 Mt of coal in 2018, a 3.3% (16 Mt) decline from 2017. Around 53% (258 Mt) was thermal coal and 37% (179 Mt) met coal, most of it destined for export. The remaining 46 Mt was lignite, which is used solely for power generation. While thermal coal production increased slightly (+2.0%; +5 Mt), substantial reductions were recorded for lignite (-11 Mt) and met coal (-11 Mt).

The drop in lignite production resulted from closure of the Hazelwood lignite power station and its associated mine, as well as from some subsequent outages at other lignite-fired power plants.

Met coal production declined due to several production disruptions. Yancoal's Austar met coal mine in New South Wales had to halt production for several months following a succession of dangerous coal-burst incidents, and in September 2018 a fire stopped production at Peabody's North Goonyella underground coking coal mine in Queensland (Peabody is aiming to resume operations in 2019). South32 suffered a 3-Mt drop in met coal production due to an extended outage at the Appin colliery that created high gas levels and caused the mine to suspend operations. Production at several mines was also impeded by strikes.

Thermal coal production rose slightly, as the Baralaba Coal Company has started production at its Baralaba North Mine in Queensland. The mine is ramping up to a targeted production of around 2.5 Mtpa. In addition, MACH Energy has commissioned its Mount Pleasant mine, the first new thermal coal mine in New South Wales since 2014. It only began operating in December, however, so contributed little to 2018 production.

Mongolia

In 2018, Mongolia's coal production rose by 2 Mt (+5.6%) to 41 Mt. Output comprised 6 Mt of lignite for domestic consumption, 28 Mt of met coal for export and 7 Mt of steam coal, partially for export. The production increase was driven mostly by met and steam coal exports, which expanded to meet rising import demand in China, Mongolia's only major export destination.

Most of Mongolia's coal production is in the Gobi Desert close to the Chinese border, particularly from the two major coalfields of Tavan Tolgoi and Ovoot Tolgoi/Nariin Sukhait. There are also some mines near the Mongolian-Russian border, such as the Ulaan Ovoo coal project, which is an open-cut thermal coal mine in the Zelter River valley approximately 17 km from Russia. The mine resumed activities in March 2019 after an undisclosed lessee company entered into a lease agreement with Prophecy to operate it.

Other Asia Pacific

After some years of decline, thermal coal production in **Viet Nam** rose to 41 Mt, a 3-Mt (8.2%) increase from last year. Domestic coal production recovered owing to the government's efforts given imports growth. **Thailand** produced 15 Mt of lignite, 2 Mt less (-9.5%) than in 2017, and for the first time since 2015, thermal coal production in the **Philippines** stagnated at the previous year's value (12 Mt). **Pakistan's** coal production remained flat at 4 Mt – 3 Mt of hard coal and 1 Mt of lignite.

North America

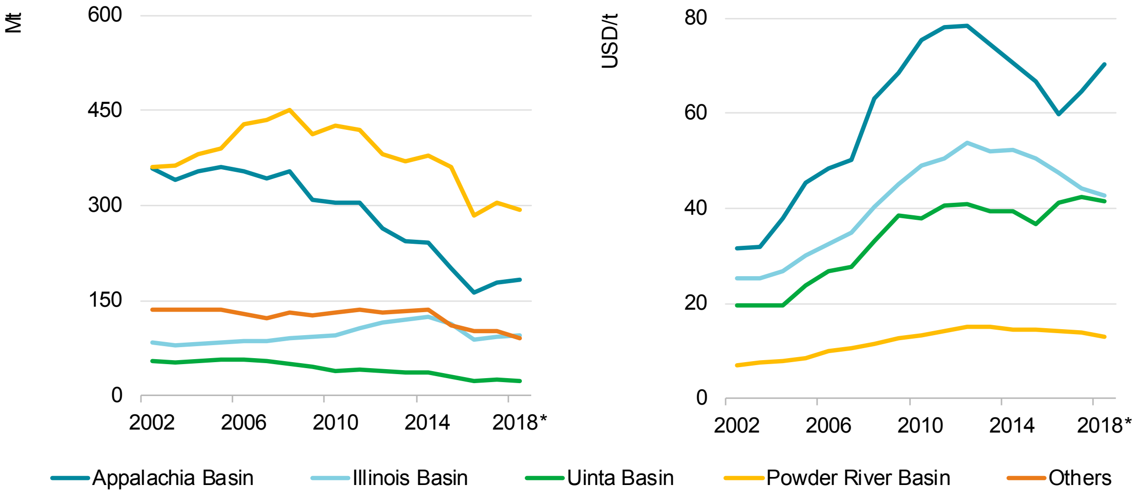
North America is the world's second-largest coal-producing region, with a 10% share of global coal production. Most (91%) of North America's coal is produced in the United States. Following the recovery of coal production in 2017, the downward trend of the previous decade returned in 2018, driven by shrinking domestic demand. The region produced a total 752 Mt of coal, a decline of 23 Mt (-3%) from 2017.

United States

The United States remains the world's third-largest coal producer behind China and India. In 2018, its total coal production decreased to 685 Mt, a 17-Mt (2.5%) drop. Thermal coal production shrank by 12 Mt (-2.1%) and lignite production declined by 12 Mt (-18.6%). The decrease in lignite production was associated mostly with the closure of lignite-fired generation units and associated mines in Texas. In contrast, met coal production rose 6 Mt (+9.9%) as a result of increasing export demand.

The regional development of coal production differs between the western and eastern basins (Figure 1.14).

Figure 1.14. US regional coal production (left) and average market price (right), 2002-18



* Estimated.

Source: Adapted from EIA (2019b), "In 2018, U.S. coal production declined as exports and Appalachian region prices rose".

Key message: Until recently, the Appalachia region of the United States benefited from high coal prices as well as its attractiveness for exports.

East of the Mississippi River, where the Illinois Basin as well as the Central and Northern Appalachian Basins are located, the coal has a higher heat content than the sub-bituminous coal produced in the west (Powder River Basin). It is much costlier to mine, however, which caused production to fall by half between 2007 and 2016 – a trend that was reversed in 2017-18. Some coal from Appalachia is valued for its coking properties, and the region's mines benefit from their proximity to existing coal-exporting infrastructure at Atlantic and Gulf Coast ports. In the last two years, coal production in the east has risen as a result of strong export demand for coking coal. In 2018, production climbed 4% in the Central Appalachian Basin and 2% in the Illinois Basin (EIA, 2019b). However, these regions account for only around 23% of the country's total production. The production of western coal, which is used mainly for power generation and for which export infrastructure is more limited, continues to decline, with reductions of 12% in the Uinta Basin and 3% in the Powder River Basin. These regions accounted for around 56% of US production, with the Powder River Basin alone responsible for 43%.

Other North America

Canada's coal production fell by 10.3% to 55 Mt in 2018. Steam coal decreased by 4 Mt, mostly as a result of shrinking exports to Northeast Asia, accounting for most of the decline. Production of lignite (8 Mt) and met coal (27 Mt) remained relatively stable. While lignite is almost entirely consumed domestically, met coal production was mostly for export.

Mexico produced 12 Mt of coal in 2018, roughly the same as in 2017. Production consisted of 7 Mt of thermal coal and 5 Mt of met, all consumed domestically, mostly for power and steel production.

Europe

By volume, Europe is by far the world's largest lignite producer,[7] with lignite accounting for 87% of the region's coal output. European coal production declined by 1.4% to 598 Mt in 2018, and it was used mainly for power generation in the country of production. There are basically no exports from Europe.

European Union

In 2018, the European Union produced 444 Mt of coal, 74% of Europe's total production. With an output of 367 Mt, the European Union is the world's largest producer of lignite. In contrast, production of thermal coal (61 Mt) and met coal (16 Mt) is negligible compared with the rest of the world. The most important EU coal producers are **Germany** (169 Mt) and **Poland** (122 Mt), followed by the **Czech Republic** (44 Mt), **Greece** (36 Mt), **Bulgaria** (31 Mt) and **Romania** (24 Mt). Compared with 2017, coal production dropped 20 Mt (-4.4%) in 2018. All types of coal contributed to this decline.

Germany

Owing to its lignite production, **Germany** is the European Union's largest coal producer by volume. The country produced 169 Mt of coal in 2018, a 6-Mt (3.5%) drop from 2017. The decline almost solely concerned lignite production, as some lignite-based power units had been transferred to the secure and reliable standby mode. Still, lignite accounted for 98% of total coal production in 2018, as Germany's last hard coal mine closed in December 2018. In line with Germany's pledge to phase out hard coal mining by the end of 2018, production activity ceased at the Prosper-Haniel mine in September, on the heels of the Ibbenbüren anthracite mine that had ended production in August 2018. Prosper-Haniel produced 1.3 Mt in 2018 and Ibbenbüren around 1.4 Mt. However, this is not the end of Germany's mining industry (Box 1.2).

[7] In China, lignite is reported as thermal coal.

Box 1.2. Coal mining in Germany not yet over but end is on the horizon

After having a 200-year history, domestic hard coal mining officially ended in Germany in December 2018, with imports fully replacing domestic supplies. However, the end of hard coal mining does not mean the overall end of mining in Germany, as lignite mining seems likely to continue for at least another decade. Germany's total lignite production amounted to 166 Mt in 2018, mainly from domestic production, as imports are negligible. Because of its 55% average moisture content, transporting raw lignite over long distances is not economically viable. This is why raw lignite is used primarily near open-pit mines and/or is upgraded into lignite products.

Open-pit lignite mining is concentrated in three regions: the Rhenish District, the Lusatian District and the Central German District. In the Rhenish area, RWE Power AG's lignite output amounted to approximately 86 Mt in 2018, and in the Lusatian District the Lausitz Energie Bergbau AG (LE-B) company extracted 61 Mt of lignite in 2018. The most important company in the Central German District is the Mitteldeutsche Braunkohlengesellschaft mbH (MIBRAG), which realised a total lignite output of 19 Mt in 2018.

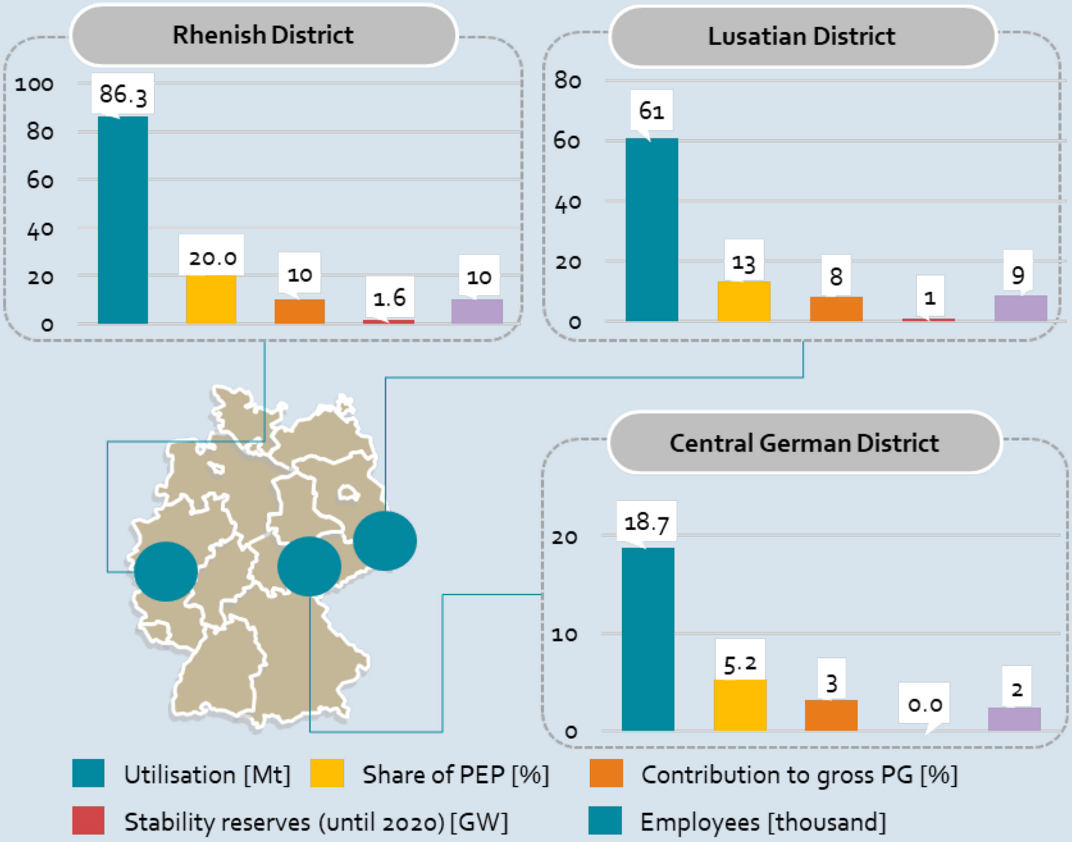
With an output of 51 million tonnes of coal equivalent (Mtce), lignite accounted for 38.4% of Germany's primary energy production in 2018 – the second-highest share after renewables (45.5%). Thus, the share of lignite in primary energy consumption is 11.3%, placing lignite fourth in Germany's energy consumption balance, behind oil (34.3%), natural gas (23.7%) and renewables (14.0%). Hard coal accounted for 10.0%.

Lignite is used primarily for electricity production: in 2018, Germany's power plants used 148 Mt (almost 90% of total domestic lignite extraction) for power generation and district heating. Total gross lignite-fired electricity production of 144 TWh accounted for 22% of all power generation, second behind renewables-based (35.0%). Lignite-fired power plant capacity, which was operated with an average of 6 500 full-load hours in 2018, amounted to 22 448 MW (gross) at the end of 2018.

Lignite mining and its associated power generation is crucial to the economic and social framework of lignite-mining districts. As of 31 December 2018, the lignite mining industry and lignite-fired utility power plants, which are operated by lignite-extraction companies, employed 20 851 people, 4 979 of which worked in lignite-fired utility power plants.

However, the contribution of lignite to the German electricity market is set to decrease soon. The Act on the Further Development of the Electricity Market of 29 July 2016 requires that eight lignite-fired power plant units (total gross capacity of 3 002 MW) be placed in secure and reliable standby mode. The affected units will be available only for the needs and requirements of transmission grid operators during this time. Operators will be remunerated for guaranteeing secure and reliable standby power and for decommissioning the units, at a total cost of roughly EUR 230 million per year for seven years. The decommissioning of this capacity will cut lignite-based electricity production 15% by 2023 and curtail lignite output by 21 Mt, reducing CO_2 emissions from lignite combustion by approximately 21 Mt per year.

In addition, the Hambach open-pit mine in the Rhenisch District was at the centre of media attention in 2018, as the German Federation for the Environment and Nature Conservation (BUND) had filed a complaint against approval of the main operating plan and initiated an expedited proceeding against the order of immediate enforcement. Accompanied by protests, court proceedings are ongoing as to whether the forest in Hambach should be cleared. As the case will likely not be concluded before the end of 2020, RWE Power has reduced its coal mining activities and electricity production has also been curtailed in early 2019. These measures are temporary, until a decision on the principal proceedings has been reached.



Note: This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries, and to the name of any territory, city or area. PEP = Primary energy production; PG = Power generation.

In late January 2019, the Coal Commission appointed by the federal government submitted its final report, which also included recommendations for gradually reducing and ultimately terminating coal-fired power generation in Germany. According to this report, decreasing requisite outputs for lignite-fired power plants to about 15 GW is to be implemented by 2022 – a decline of almost 5 GW compared with the end of 2017. By 2030, their capacity (without reserves) is to be reduced to 9 GW maximum, or 10.9 GW less than in 2017.

This exit plan for coal-fired power generation is linked to a number of energy and social policy conditions and is to be verified in 2023, 2026 and 2029, as the Coal Commission recommends that coal-fired power generation cease completely by the end of 2038. By implementing these recommendations, Germany will discontinue coal-based power generation approximately ten years earlier than had initially been planned for the individual mining districts.

Poland

In 2018, Poland produced 122 Mt of coal, consisting of 52 Mt of steam coal, 12 Mt of coking coal and 58 Mt of lignite, making Poland the largest EU steam and coking coal producer by far. With a drop of 3.7% (-5 Mt) in 2018, however, the country's coal output continues to decrease. As coking coal production remained flat, this decline concerns mostly steam coal and lignite. Since the early 1990s, the Polish mining industry has been going through a transformation to reduce excess coal production capacity and adapt the industry to market conditions. In 2016, Polska Grupa Górnicza (PGG), the Polish state-controlled mining group that accounts for half of thermal coal production, emerged from restructuring. After several years of underinvestment due to low coal prices and huge company losses, coal production first declined in 2017, and again in 2018.

Other European Union

The coal produced in the rest of the European Union is mainly lignite. Production of the **Czech Republic**, the third-largest EU coal producer, remained stable at 44 Mt. The country's main lignite deposit is the Northern Bohemian Basin along the border with Germany.

While production in other major EU coal countries (Greece, Romania, Hungary) remained stable, in **Bulgaria** it decreased by 10.8% (-4 Mt). In 2017, the Babino lignite mine stopped operations, ending employment for 650 workers, and at the end of 2018 the largest mine (Bobov Dol) ceased production. The mines have closed because of high costs.

Other Europe

Outside the European Union, coal production increased by 8.1% (12 Mt) to 154 Mt. It has been on the rise since 2013, and current production volumes in this region have reached decade-high levels. **Turkey**, the main driver of this growth, produced 85 Mt of lignite and 3 Mt of hard coal in 2018 – a 19.2% (+14 Mt) jump in lignite production from the previous year. Lignite is Turkey's most important indigenous energy resource, with deposits spread across the country. The largest one is in the Afşin-Elbistan basin in south-eastern Anatolia, which has economic reserves of around 7 Bt, and the Soma basin is its second-largest lignite mining area. Most lignite production is from opencast mines, and the scale of Turkey's surface mining operations allows lignite to be produced at a relatively low cost, making it competitive with imported energy resources. To reduce energy imports, the government encourages lignite production growth by developing lignite power generation projects. In line with the government's overall privatisation drive for the Turkish economy, the coal industry has gradually been transferred from public to private ownership in the last ten years. Other European producers are **Serbia** (38 Mt of lignite), **Bosnia and Herzegovina** (14 Mt of lignite), **Kosovo** (7 Mt of lignite) and the **Republic of North Macedonia** (5 Mt of lignite).

Eurasia

Eurasia's production rose by 6.7% (+36 Mt) to 568 Mt in 2018. The majority of the coal (64%) is steam coal, while met coal accounts for 19% and lignite for 17%. Russia is the largest coal producer in the region.

Russia

In 2018, Russia's total production increased 8.3% (+32 Mt) to 420 Mt, an all-time high triggered by rising exports to Europe and East Asia. Thermal coal production expanded 19 Mt (+8.3%) and met coal grew 7 Mt (+7.9%). SUEK continues to be the largest producer at 110 Mt, a 2% y-o-y increase, and Kuzbassrazrezugol's output was 45 Mt, a 3% y-o-y drop. The third-largest producer in 2018 was Vostibugol at 16 Mt, a 12% increase from 2017. With this rise in production, maintenance and unplanned disruptions are putting a strain on Russia's coal transport network in the Kuzbass region.

Other Eurasia

Kazakhstan produced 114 Mt of coal in 2018, with mining concentrated in two key regions: Pavlodar (73 Mt) and Karaganda (41 Mt). While thermal coal production expanded 6.1% (+6 Mt) from 2017, met coal output decreased 31.3% (-5 Mt) and lignite output remained flat. Met coal production fell primarily due to a significant drop in exports, as sales to Italy – Kazakhstan's second-largest met coal export destination after China – collapsed.

Ukrainian coal production recovered in 2018 following supply disruptions in the major coal-producing Donbas area (the Donetsk and Luhansk regions) the previous year. The country produced 26 Mt of coal, a 7.7% (+2 Mt) increase from 2017 resulting mostly from higher coking coal production.

Africa

Coal production in Africa in 2018 amounted to 276 Mt, roughly the same as in 2017. Most of it is thermal coal produced in South Africa, the continent's largest producer by far with 94% of total output.

South Africa

In 2018, South Africa produced 259 Mt of coal, most of it (98%) thermal coal. Coal output remained stable from 2017, so the country continues to be the world's sixth-largest coal producer and most mines are currently producing at peak capacity. Because of its geological properties, South Africa's coal deposits are generally suitable for opencast and shallow underground mining, with a high degree of mechanisation. Most mining is in the fast-depleting Mpumalanga coalfields – which account for 83% of total production – with smaller quantities mined in the expanding Limpopo region.

State-owned power utility Eskom consumed roughly half of South Africa's coal, while 81 Mt were exported. The country's largest producers are Anglo American, Exxaro, Sasol Mining, South32 and Glencore, which together account for three-quarters of the country's coal output. However, ownership structures within the mining industry are changing: in 2018, Anglo American sold the New Largo coal project to a consortium owned by Seriti Resources, Coalzar and the Industrial Development Corporation. With this transaction, Anglo American sold all Eskom-oriented mines and projects, but it continues to produce at its export-oriented facilities. Furthermore, South32 – itself a spinoff of BHP Billiton – spun off its energy-related coal mining operations into a separate company, South Africa Energy Coal (SAEC).

Some mines also resumed operations or began production in 2018. After a standstill of roughly two months, Wescoal reopened its 3-Mtpa Vanggatfontein (VGF) thermal mine after firing all the mine's employees in the wake of a series of violent strikes. Sasol, South Africa's third-largest coal producer, officially opened its Impumelelo colliery in April 2018, providing 10.5 Mtpa of coal for its synthetic fuel operations. The company also opened its new Shondoni mine in Mpumalanga to replace the depleted Middelbult colliery. The new mine has a capacity of 8 Mtpa to 9 Mtpa and is expected to produce coal for 30 years. Finally, two mines opened at Bronkhorstspruit, a small town 50 km from Pretoria. The first was the Chilwavhusiku mine owned by Black Royalty Minerals (BRM), expected to produce 1 Mtpa and to supply Eskom for power generation. In November 2018, South Africa's mining minister officially opened the second mine, the Khanye Colliery, which will produce up to 2.4 Mtpa of thermal coal for export.

Other Africa

Mozambique produced 12 Mt of coal in 2018, roughly the same as in 2017, with thermal coal accounting for 6 Mt and met coal for 6 Mt. Coal mining in Mozambique began in 2010 when Riversdale Mining started production at its mine in the Moatize basin. Mozambique's largest producer is Brazil's Vale company. In **Botswana** production rose 12% from 2.2 Mt to 2.5 Mt, whereas in **Zimbabwe** it declined 36% to 2.1 Mt due to shortages and mining input price hikes.

Central and South America

Central and South America accounted for 1% of the global coal supply in 2018, with Colombia providing 91% of the region's production.

Colombia

Colombia produced 83 Mt of coal in 2018, most of it (93%) thermal coal. This drop of 8.3% (-8 Mt) from 2017 resulted mostly from import demand conditions (see Chapter 2) and was attributed mainly to the top three coal producers (Drummond, Cerrejón and Glencore), whose output fell by 7% (-6 Mt). The main reason for the decline from all three operations was higher rainfall than expected during the country's two rainy seasons and a change in mining plans at Glencore's Calenturitas mine. Cerrejón's output was less impacted by the rain because its main operations near the La Guajira region received less precipitation (IHS Markit, 2019).

Other Central and South America

Brazil's coal production remained flat at 5 Mt in 2018. Most of the coal was consumed by power plants close to the mines, as Brazilian coal is of relatively low calorific value.

Like Brazil, **Chile's** coal production remained stable. The country produced 2 Mt of thermal coal in 2018, all of it at the Mina Invierno mine.

Middle East

Coal production in the Middle Eastern region is negligible. The only producer is the Islamic Republic of Iran (Iran), and it mined only 1.5 Mt of coal in 2018. Most of it was coking coal for domestic steel production.

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2. Recent international coal trade trends

- **International and seaborne coal trade continued to expand in 2018.** Internationally traded volumes, including both coking and thermal coal, rose by 4% in 2018 to surpass 1.4 billion tonnes (Bt); seaborne thermal coal trade reached nearly 1 Bt. Indonesia and the Russian Federation ("Russia") recorded their highest-ever coal exports, with Russia's exceeding 200 million tonnes (Mt).

- **Higher imports by the People's Republic of China ("China") and India raised seaborne market volumes.** Contraction in the European market was more than offset by increasing demand in China and India. Although import quotas at Chinese ports reduced volumes somewhat in the fourth quarter of 2018, the shift to Pacific markets continued.

- **Indonesian and Russian exports increased the most.** Whereas Indonesia's exports rose to take advantage of high coal prices, Russia's increase reflects expansion of its export infrastructure, with exports clearly shifting from European to Pacific markets. In contrast, Colombia's exports fell as a result of the shrinking Atlantic market and some supply issues.

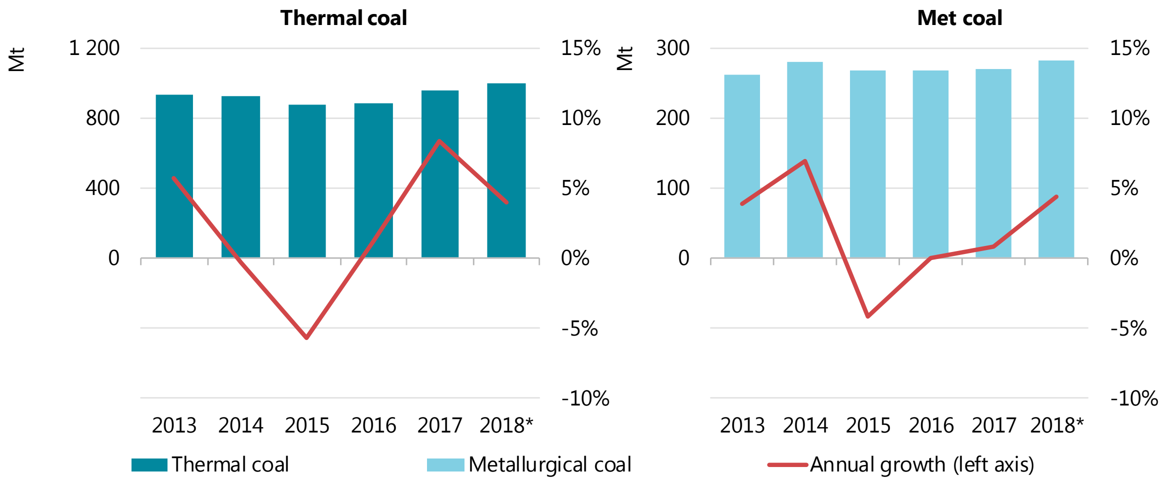
- **Increasing import demand kept prices high.** The average price climbed to USD 105 per tonne (/t) in 2018 (Newcastle free-on-board [FOB] price), compared with USD 65/t in 2016. Australia's coal export revenues of USD 67 billion made coal its largest export commodity in 2018, and also broke the record for highest export earnings ever for coal.

- **Higher fuel prices raised production costs.** With higher oil prices, supply costs increased – especially for open-pit mines, meaning that thermal coal production was more affected than coking coal. However, robust coal prices throughout 2018 generally ensured a good profit margin for producers.

Market volumes

Global coal trade growth remains solid. It increased by 4.3% to 1 418 Mt in 2018, accounting for 18% of global consumption; both thermal and metallurgical (met) coal markets contributed to this growth (Figure 2.1). Thermal coal accounted for 75% of the global coal trade in 2018, and met coal for 24%; the remaining 1% was in lignite. In 2018, Indonesia remained the world's largest exporter of coal (by weight) with total exports of 439 Mt. Australia ranked second, at 382 Mt, although the economic values of the exports are completely different, with Australia leading by far (Box 2.1).

Figure 2.1. Seaborne trade development for thermal (left) and met coal (right), 2013-18



* Estimated.

Source: IEA (2019), *Coal Information* (database), www.iea.org/statistics.

Key message: Seaborne coal trade reached almost 1 Bt in 2018.

Box 2.1. Ranking exports by value

Indonesia was once again the largest coal exporter by tonnage in 2018. However, coal is not a homogeneous product. Diverse properties distinguish met from steam coal, and the different quality grades of steam coal are based mostly on calorific value (CV). The various coal qualities are assigned different prices, and consequently the FOB price difference between 6 000 kilocalorie-per-kilogramme (kcal/kg) coal and sub-bituminous coal of 3 800 kcal/kg can vary as much as USD 70/t (United States dollars) (a difference of around 200%). In addition, hard coking coal prices can be twice as high as for steam coal.

Indonesia produces mostly sub-bituminous coal of relatively low CV and high moisture content. In contrast, almost half of Australia's coal production is met coal, and its thermal coal is mostly high quality with higher CVs.

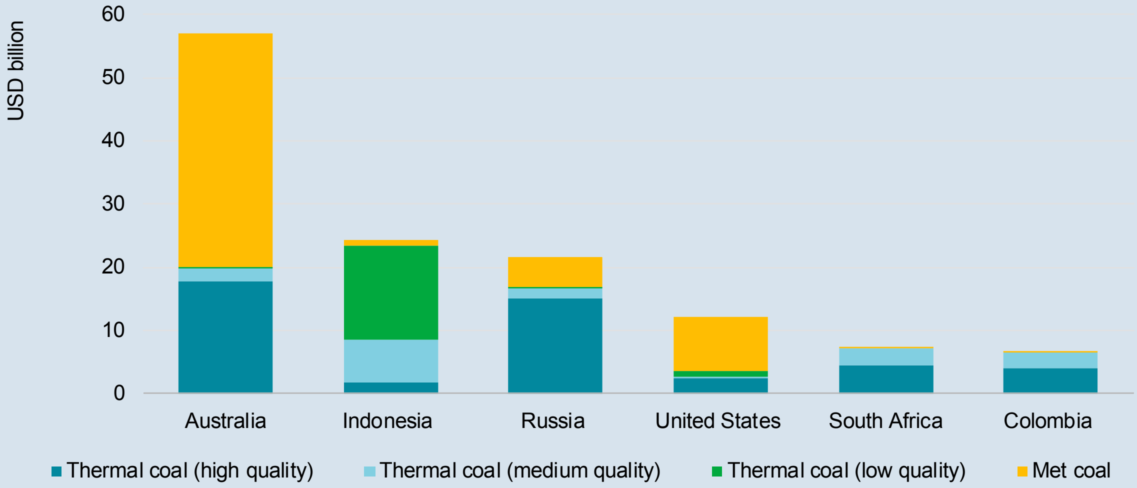
Exported coal volumes and weighted average calorific value by country

Country	Met coal exports [Mt]	Thermal coal exports [Mt]	Weighted average CV of thermal coal* [kcal/kg]
Indonesia	4	435	4 781
Australia	179	203	5 984
Russia	26	173	5 991
United States	56	49	5 969
Colombia	2	80	5 853
South Africa	1	81	5 770

*Adapted from CRU (2019), *Thermal Coal Cost Model* (database). The figures might differ from IEA statistics.

As Russia, Australia and the United States all export higher-CV coal while Indonesia's exports have far lower heat content, the financial value of Indonesia's exports is lower.

Economic export revenues by coal type and country, 2018*



* Not based on fiscal data, so figures may diverge from official export valuations. Economic valuations are assigned according to the quality of the exporting mine (based on CRU, 2019) and FOB prices for the coal qualities exported (based on IHS Markit, 2019a). Calculations are therefore inexact, e.g. Australia's official figure is USD 67 billion, while Indonesia's state revenue from coal exports accounted for USD 21 billion (IHS, 2019b).

Considering coal quality as well as underlying price, Australia is in first place in terms of economic export valuation. Although Indonesia's thermal export volumes are more than double Australia's, the economic volume of these exports is only 17% higher and Australia's large met coal exports put its total export revenues at more than double Indonesia's. At the same time, Russia's export revenues are almost as high as Indonesia's (with a difference of 12%) even though its total export volumes are less than half.

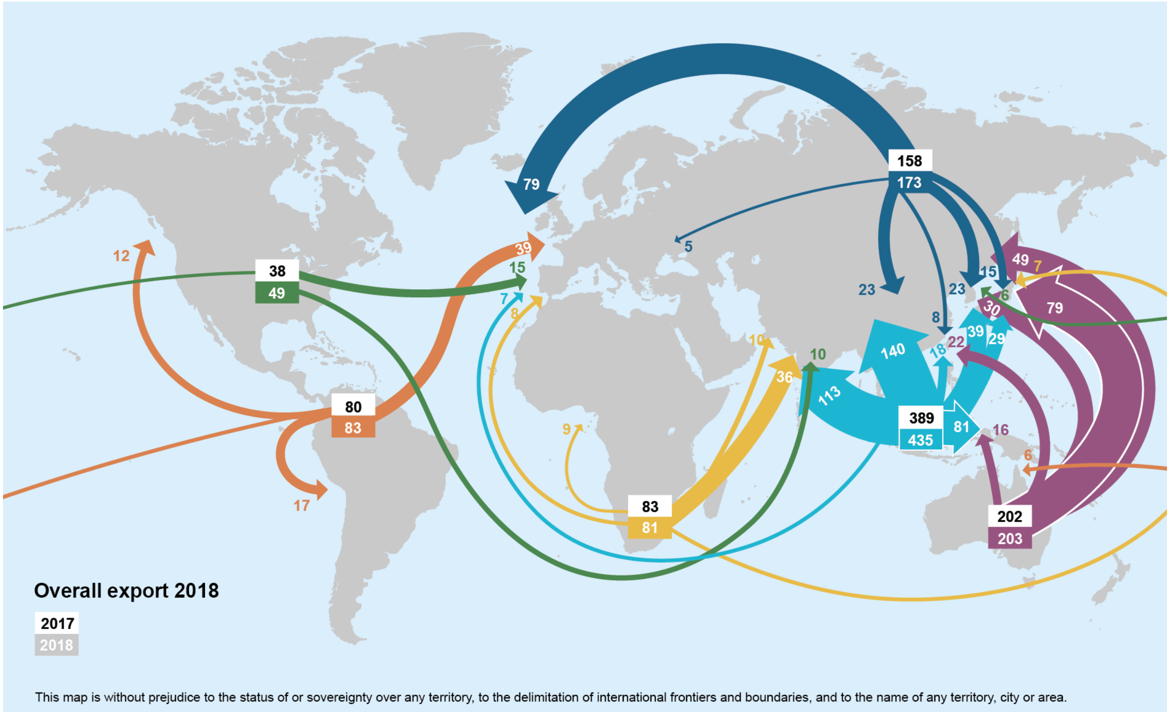
Thermal coal

Overall, 1 063 Mt of thermal coal were traded internationally in 2018. Approximately 94% of this trade was seaborne, which is an increase of 5.6% from 2017. Absolute growth remained stable at 56 Mt, as did the share of global annual thermal coal consumption traded (18%). Hence, most thermal coal is still produced and consumed locally.

Figure 2.2, which illustrates the main trade flows in the global thermal coal market using different colours for each major exporter, shows that the Pacific Basin is of significant importance for seaborne thermal coal trade, with the largest importers and exporters both concentrated in this region. Indonesia, which could further expand its market share, provided 41% of globally traded thermal coal, and Australia ranked second with 19%. Russia (16%), Colombia (8%), South Africa (6%) and the United States (5%) were also important market participants.

Indonesia, the United States and Russia significantly increased their exports in 2018, building on the export growth of 2017, and imports increased especially in India, China and Southeast Asia (Table 2.1). Chinese imports from countries other than the major exporters declined significantly as exports from the Democratic People's Republic of Korea (North Korea) (5 Mt in 2017) were halted due to an embargo. In addition, Chinese imports from countries such as the Philippines decreased. In contrast, Indonesian exports shifted from countries categorised as "other" (Bangladesh, the United Arab Emirates) to China.

Figure 2.2. Main trade flows in the seaborne thermal coal market, 2018 (Mt)



Note: Exports from Russia include exports via railway.

Sources: Adapted from IHS Markit (2019a), *Coal McCloskey Price and Statistical Data*, https://connect.ihs.com/industry/coal; IEA (2019), Coal Information (database), www.iea.org/statistics.

Key message: Seaborne thermal coal trade was concentrated in Asia in 2018, with China and India being the primary importers.

Table 2.1. Thermal coal exports in 2018 (Mt) and net changes from 2017

From \ To	China	India	Japan	Korea	Southeast Asia	Europe	North America	Central and South America	Other	TOTAL
Australia	49	5	79	29	16	1	0	1	23	203
Indonesia	140	113	29	39	81	7	1	0	26	435
South Africa	0	36	0	7	1	8	0	1	28	81
Colombia	0	0	1	5	0	39	12	17	5	80
United States	0	10	4	6	0	15	5	2	6	49
Russia	23	4	15	23	7	79	0	1	20	173
Other	17	25	10	0	3	6	0	4	0	66
Total	230	188	138	108	108	154	18	26	109	0

-15 Mt 0 Mt +20 Mt

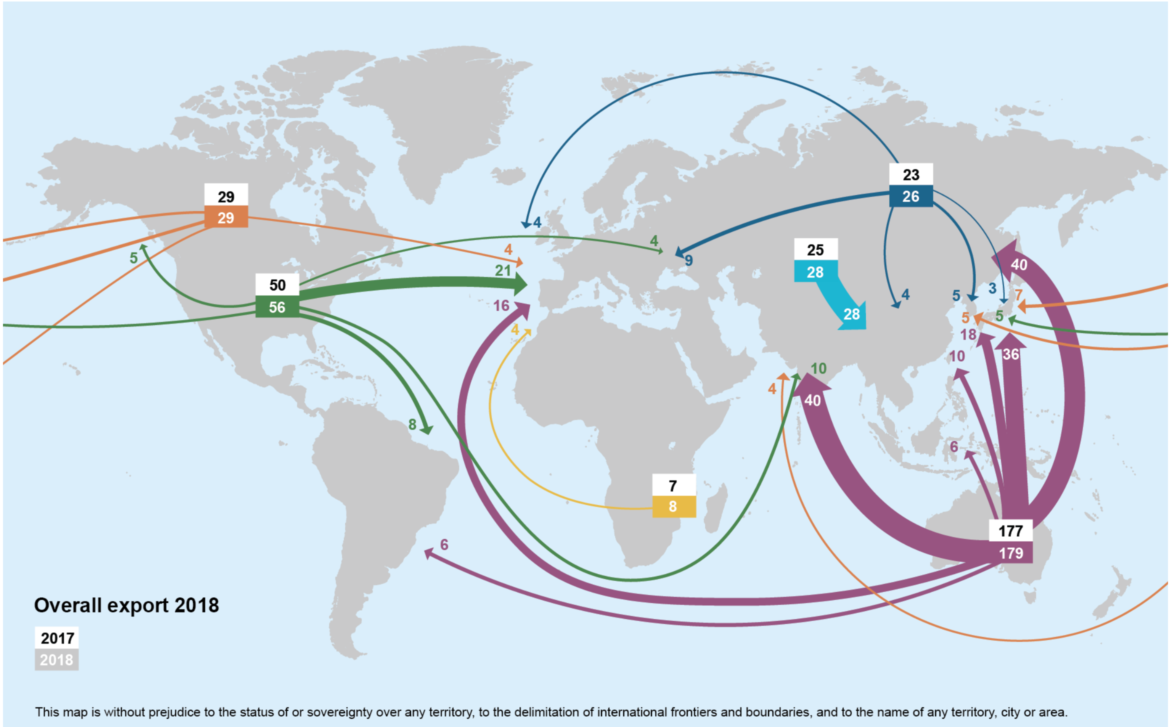
Source: IEA (2019), *Coal Information* (database), www.iea.org/statistics.

Metallurgical coal

Although the met coal market has only one-third the volume of thermal coal, international trade plays a more important role. About 35% of total annual met coal consumption is traded internationally, 83% of it by sea. In contrast, the share of steam coal consumption that is imported is about 18%. The total traded volume of met coal grew to 339 Mt in 2018, a 4.4% increase from 2017.

Figure 2.3 shows the main trade flows for met coal in 2018 using a different colour for each major coal exporter. The market was highly concentrated, with Australia holding a share of around 53% as the dominant supplier to the Asia Pacific region. The United States (17%) and Canada (9%), as well as Mongolia and Russia (both 8%), also hold significant market shares. Russia, Mongolia and the United States were the main countries to have increased their exports since 2017, with the main met coal importers being in Asia (e.g. China, India, Japan and Korea). Although Asia Pacific countries accounted for 72% of all trade, Europe as a whole remained one of the greatest importers because of its large iron and steel production capacities and shortage of domestic met coal resources. While most of the imports remained relatively stable, China showed a significant decrease of around 5.2% (-4 Mt), as domestic coking coal production increased more than demand growth.

Figure 2.3. Main trade flows in the seaborne met coal market (Mt), 2018



Note: Values for 2018 are estimates.

Source: IEA (2019), *Coal Information* (database), www.iea.org/statistics.

Key message: Australia dominated seaborne met coal trade in 2018, especially in Asian markets.

Regional analysis

Exporters

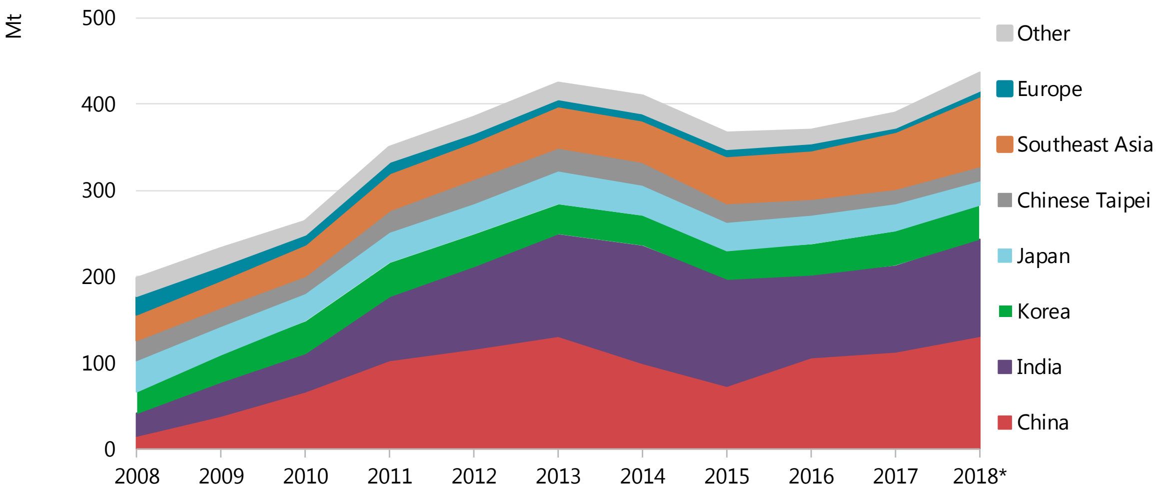
Indonesia

In 2018, Indonesia not only remained the world's largest exporter of coal (by weight) but strengthened its market position. Indonesian coal exports showed the largest increase of any country in absolute terms (+45 Mt) and a new high for export volumes (439 Mt) (Figure 2.4).

99% of Indonesia's exports are thermal coal, mostly of relatively low calorific value, supplying Asian markets – principally China, India and Southeast Asia. All regions imported more Indonesian coal in 2018.

Owing to their production flexibility and a relative lack of infrastructure capacity constraints, Indonesian producers were able to increase production in response to rising import demands and higher seaborne market prices in 2018. Only exports to Japan and Korea fell as the country focused more on exporting to China. Indonesia's met coal exports remained flat at 4 Mt.

Figure 2.4. Indonesian thermal coal exports, 2008-18



*Estimated.

Sources: Adapted from IHS Markit (2019a), *Coal Price Data and Indexes*, https://ihsmarkit.com/products/coal-price-data-indexes.html; IEA (2019), *Coal Information* (database), www.iea.org/statistics.

Key message: Indonesia's exports surged in 2018, especially to China and India.

Australia

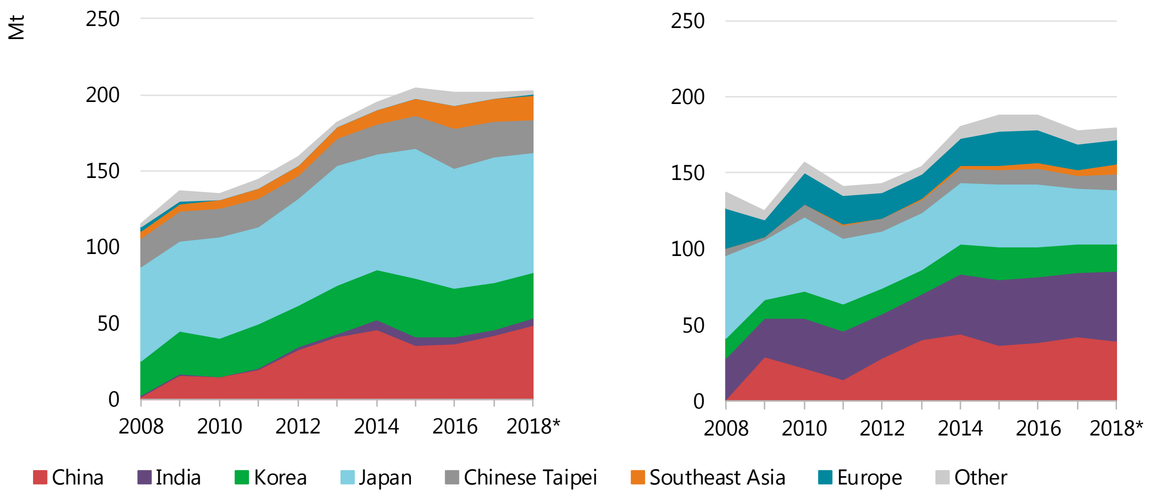
Australian exports were 382 Mt in 2018, an increase of about 3 Mt (+0.8%). Thanks to higher volumes and prices, export revenues amounted to USD 67 billion, making coal the country's most valuable export commodity.

The export ratio increased by 3% – to 79% of total production – since domestic consumption dropped significantly (e.g. due to a lignite power plant closure; see Chapter 1).

Thermal coal exports, which accounted for 53% of Australia's exports in 2018, remained stable at around 203 Mt. Japan is the main consumer of Australian thermal coal, receiving 39% of its exports in 2018 (Figure 2.5). The country prefers Australian steam coal for power generation because of its high and consistent quality. China (24%), Korea (15%) and Chinese Taipei (11%) follow Japan as Australia's largest customers. China's rising import demand (+7 Mt) stabilised Australian exports in 2018, since exports to all other main destinations decreased: e.g. -3.9% to Japan, -5.9% to Korea and -5.6% to Chinese Taipei. Despite firm Newcastle prices, this drop resulted mainly from the rising competitivity of other exporting countries/regions such as Russia, Colombia and North America.

In addition, weather and transport issues prevented Australia from increasing its seaborne thermal coal trade: at the beginning of 2018, several major Queensland terminals announced heavy maintenance schedules, which affected export shipments for two months, and rail capacity was also reduced temporarily. Despite these logistical issues, however, consumption remained flat in the countries that currently consume most of Australia's exports. Faster-growing export destinations for thermal coal, such as India and Southeast Asia, are mostly using low-grade coal instead of Australia's high-quality production, favouring lower prices.

Figure 2.5. Australian exports of thermal coal (left) and met coal (right), 2008-18



*Estimated.

Sources: Adapted from IHS Markit (2019a), *Coal Price Data and Indexes*, https://ihsmarkit.com/products/coal-price-data-indexes.html; IEA (2019), *Coal Information* (database), www.iea.org/statistics.

Key message: Australian exports remained stable in 2018 even though global trade expanded.

Met coal accounted for 47% of Australia's coal exports. The slight increase of around 2 Mt indicates that production has slowly recovered from the disruptions caused by Cyclone Debbie in 2017. As a result of its surge in steel production, India replaced China as Australia's most important customer for met coal. In contrast, Chinese imports of met coal in general – and Australian met coal in particular – declined.

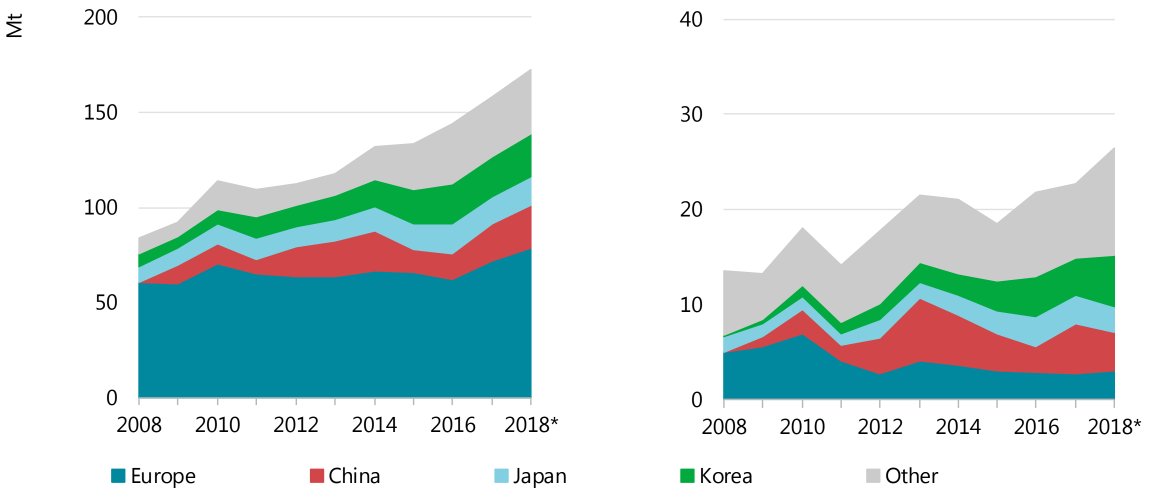
Russia

Russia accounted for around 15% of global coal exports, making it the world's third-largest coal exporter. With total Russian exports rising 10.6% (+20 Mt) to 210 Mt in 2018, this was the first time they surpassed 200 Mt. With half of its production exported, Russia recorded the second-highest absolute export growth after Indonesia.

In 2018, 82% (173 Mt) of Russian exports were thermal coal (Figure 2.6) – solid growth of about 9.1% (+14 Mt) from 2017. Russia's exports grew in essentially all markets, with the largest share (46%) delivered to Europe. The rise in European imports (+7 Mt or +9.6%) significantly propelled growth in Russia's thermal exports. This growth happened despite a decrease in total European imports, as Russia gained market shares from South Africa and Colombia (which had production constraints).

China, Korea and Japan were also significant importers: Chinese demand for Russian thermal coal increased to 22 Mt (+15.3%), while Korean imports from Russia rose by 1.4 Mt (+6.8%). Japanese imports remained flat.

Figure 2.6. Russian exports of thermal coal (left) and met coal (right), 2008-18



*Estimated.

Sources: Adapted from IHS Markit (2019a), *Coal Price Data and Indexes*, https://ihsmarkit.com/products/coal-price-data-indexes.html; IEA (2019), *Coal Information* (database), www.iea.org/statistics.

Key message: Russia's thermal and met coal exports both surged in 2018, especially thermal coal to Europe and met coal to Korea.

In 2018, met coal exports rose to 26 Mt (+16.1%). Ukraine remained the main consumer of Russia's met coal, with an import volume of 7 Mt (+1 Mt from 2017), and Korea replaced China as the second-largest importer. Korea's imports from Russia rose to 5 Mt (+1 Mt), mostly to replace Australian met coal. At the same time, Chinese imports decreased by 1 Mt.

Additionally, Russia exported 11 Mt of lignite, an increase of 2 Mt (+24%). Most of the lignite was shipped to China and South Korea.

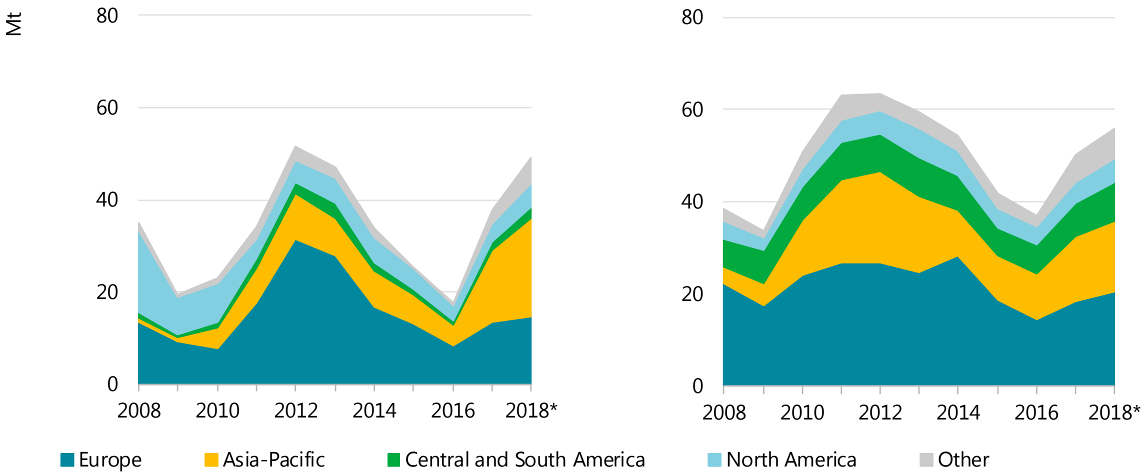
United States

US exports continued to increase at a high rate (+19.3%) in 2018, to reach a total volume of 105 Mt. High demand and firm prices for both thermal and met coal boosted US exports, as the United States remains a highly price-sensitive swing exporter, with most US exporters considered high-cost suppliers. The steady decline in domestic thermal coal consumption caused the export ratio to rise to 15% of total production (a 3% increase from 2017). While US exports increased in 2018, US export prices did not surge as much as FOB prices from other main exporting countries such as Australia, South Africa and Colombia. For the first time in decades, 2 Mt from the Uinta Basin in Utah were exported through Mexico. India became the largest destination of US coal.

In 2018, 53% (56 Mt) of exports from the United States were met coal (Figure 2.7), 11.3% (+6 Mt) higher than in 2017. This makes the United States the second-largest met coal exporter after Australia. Most US exports (37%) went to Europe, despite Europe's shrinking import total, and also increased strongly in other markets, e.g. in the Asia Pacific region (+1 Mt; +8.7%) and Central and South America (+1 Mt; 15.3%).

Thermal coal exports rose by 29.8% (+11 Mt) in response to rising Asia Pacific demand.

Figure 2.7. US exports of thermal coal (left) and met coal (right), 2008-18



*Estimated.

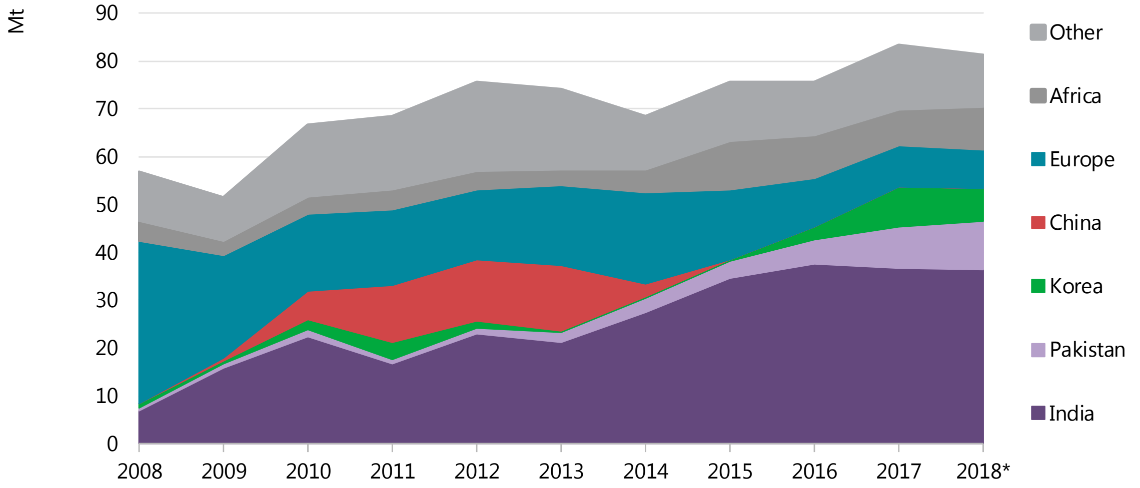
Sources: Adapted from IHS Markit (2019a), *Coal Price Data and Indexes*, https://ihsmarkit.com/products/coal-price-data-indexes.html; IEA (2019), *Coal Information* (database), www.iea.org/statistics.

Key message: US coal exports to Asia increased substantially in 2018.

South Africa

In 2018, South African exports, mainly steam coal, decreased by 2.5% (-2 Mt) to 81 Mt (Figure 2.8). Smaller volumes of export-quality coal (in the low CV range of export specifications) were available, as some such coal had been acquired by Eskom for use in the power sector. Although exports to India remained stable at 36 Mt, it became the most important destination, accounting for 45% of total South African exports in 2018. Exports to Pakistan, the second-largest market for South Africa's exports, grew by 1 Mt. Pakistan relies mainly on South Africa for its coal imports, as the technical characteristics of its power plants favour South African coal. In contrast, exports to Korea decreased by 2 Mt while those to Europe declined 1 Mt. In addition, exports to other regions such as Chinese Taipei, the Middle East and Eurasia declined by 3 Mt.

Figure 2.8. South African exports of thermal coal, 2008-18



*Estimated.

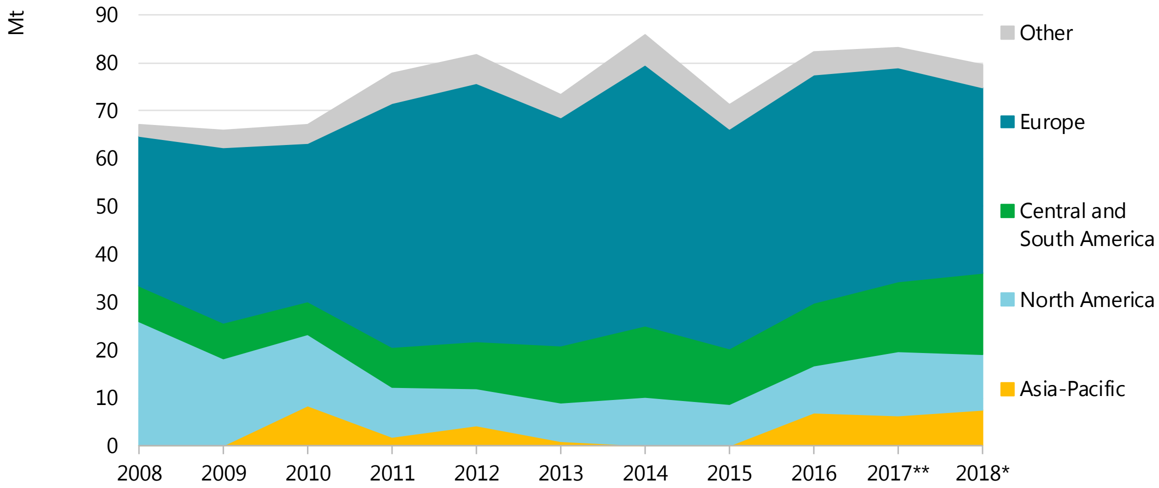
Sources: Adapted from IHS Markit (2019a), *Coal Price Data and Indexes*, https://ihsmarkit.com/products/coal-price-data-indexes.html; IEA (2019), *Coal Information* (database), www.iea.org/statistics.

Key message: South Africa did not benefit from increasing seaborne trade in 2018 due to domestic supply constraints affecting export-oriented coal.

Colombia

In 2018, Colombia exported more than 96% of its coal production, almost entirely steam coal. Its exports fell by 3 Mt (-3.3%) to 82 Mt as inclement weather hampered production (Figure 2.9).

Figure 2.9. Colombian exports of thermal coal, 2008-18



*Estimated.

**Based on own assumptions, so numbers diverge from official data.

Sources: Adapted from IHS Markit (2019a), *Coal Price Data and Indexes*, https://ihsmarkit.com/products/coal-price-data-indexes.html; IEA (2019), *Coal Information* (database), www.iea.org/statistics.

Key message: Colombia's exports decreased in 2018 with falling European import demand.

Other countries

Canada

Canada was the third-largest met coal exporter after Australia and the United States in 2018. Its coal exports decreased slightly to 30 Mt, while the share of met coal in total exports increased from 93% in 2017 to 97% in 2018. Nearly all of Canada's met coal production is exported, mainly to Japan (7 Mt), Korea (5 Mt), India (4 Mt) and China (3 Mt). Europe (mostly Turkey, Ukraine and Germany) received another 14% (4 Mt) of Canadian met coal exports. The slight decrease in Canada's exports resulted mostly from a reduction in steam coal sent to Northeast Asia (Japan, Korea and Chinese Taipei) due to greater competition from the United States.

Mongolia

Mongolia's coal exports, which are pivotal to the country's economic performance, increased by 13% (+4 Mt) to 33 Mt in 2018. The increase resulted solely from a rise in met coal exports, which amounted to 28 Mt. All met and steam coal exports went to China, but because it has an insufficient railway system, they had to be transported by diesel-fuelled trucks to the Chinese border and then moved by rail to China's demand hubs. While solid met coal prices stimulated Mongolian exports to China, rising fuel prices and supply constraints limited export expansion.

Kazakhstan

A 12% drop in coal exports was recorded in Kazakhstan – from 29 Mt in 2017 to 26 Mt in 2018. Virtually all exports from Kazakhstan went to Russia.

Mozambique

After a significant increase in 2017, Mozambique's coal exports remained stable at 12 Mt in 2018. The share of total coal production exported is relatively balanced between steam and met coal. Roughly 40% of the thermal coal was shipped to Europe, while most of the rest went to Korea and Japan. For met coal, the trade flow was the inverse, with Europe importing 68% and Korea and Japan the remaining volumes.

Poland

Poland's coal exports decreased to 5 Mt (-2 Mt). While met coal exports remained stable and accounted for araound 60% of all exports, thermal coal decreased by over 50%. All of Poland's exports went to Europe, with the Czech Republic, Germany and Austria being the main markets.

Philippines

Exports from the Philippines fell further in 2018, to 5 Mt from 6 Mt in 2017. It began exporting coal in 2006 from its Panian open-pit mine, all sub-bituminous steam coal and nearly all delivered to China.

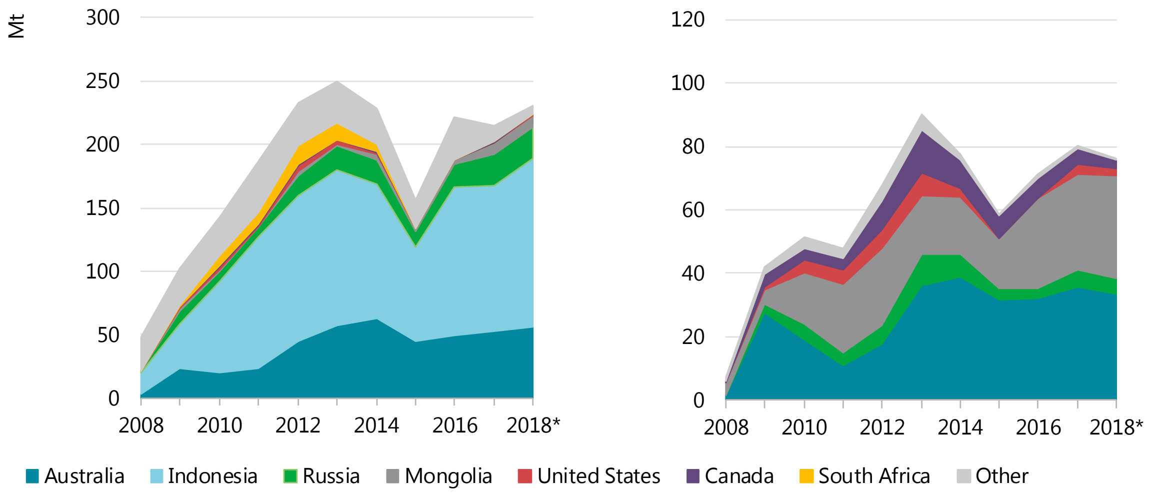
Importers

China

Chinese coal imports expanded by 3.9% (+11 Mt) to 306 Mt in 2018 (Figure 2.10). The country is the largest importer of both thermal and coking coal, with a total market share of 22%, although imports cover only 8% of China's total consumption.

Thermal coal, accounting for 75% of China's total imports, was the main driver of import growth as rising electricity demand was met by higher thermal power generation. Most of the additional imports were provided by Indonesia, which is China's main supplier of imported thermal coal (and whose dominant market share could expand further). Australia also benefited from China's expanding market.

Figure 2.10. Chinese imports of thermal coal (left) and met coal (right), 2008-18



*Estimated.

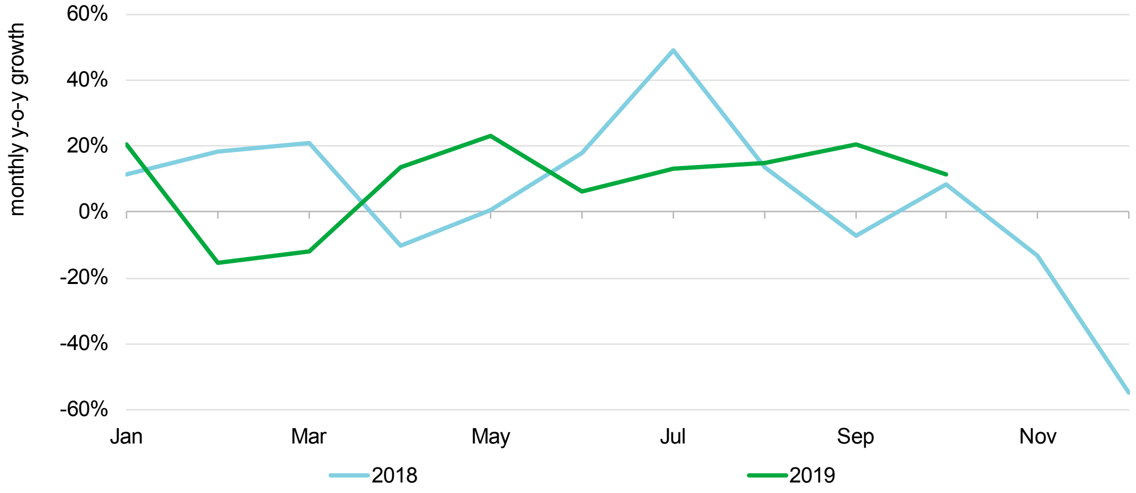
Sources: Adapted from IHS Markit (2019a), *Coal Price Data and Indexes*, https://ihsmarkit.com/products/coal-price-data-indexes.html; IEA (2019), *Coal Information* (database), www.iea.org/statistics.

Key message: While Chinese thermal coal imports increased in 2018, met coal imports decreased.

In contrast with thermal coal, China's met coal imports decreased in 2018 for the first time since 2015. Despite a 3% expansion in pig iron manufacturing, met coal imports declined by 5% to 76 Mt. The met coal demand growth was supported by higher domestic production, reducing the need for additional imports. Mongolia, a major supplier of met coal to China, was the only supplier that increased its exports to China (+2 Mt; +8%). All other exporters including Australia, China's most important supplier, decreased their deliveries. Plus, the trade dispute with the United States caused China to impose a 25% import tax on US coal, so China's met coal imports from the United States dropped 30% to 2.3 Mt.

In the fourth quarter of 2018, a clear shift in Chinese imports occurred. After increasing year-on-year (y-o-y) over almost the entire year, imports started to fall during the last quarter (Figure 2.11). According to market participants, a quota – determined at the regional or even port level – was in place to limit imports. Whereas the exact terms of such a policy are unknown, China's import volume trend follows a pattern compatible with such quotas: delaying customs clearances, China barely allowed any coal imports in, especially at its southern ports. These import constraints influenced global prices significantly. In January 2019, however, import demand surged again, reflecting the appetite of China's coal users for imported coal.

Figure 2.11. Monthly year-on-year development of Chinese coal imports, 2018-19



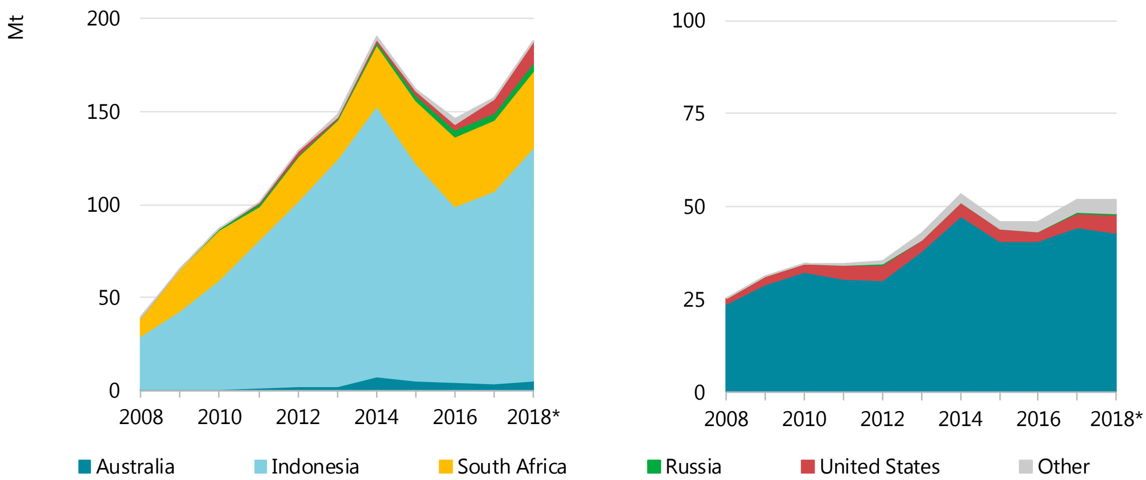
Source: Adapted from IHS Markit (2019a), *Coal Price Data and Indexes*, https://ihsmarkit.com/products/coal-price-data-indexes.html.

Key message: Chinese imports decreased significantly y-o-y towards the end of 2018, after showing growth during almost all previous months.

India

India, the world's second-largest coal importer, received 240 Mt of coal in 2018, thereby importing 24% of its total coal consumption (Figure 2.12).

Figure 2.12. Indian imports of thermal coal (left) and met coal (right), 2008-18



*Estimated.

Sources: Adapted from IHS Markit (2019a), *Coal Price Data and Indexes*, https://ihsmarkit.com/products/coal-price-data-indexes.html; IEA (2019), *Coal Information* (database), www.iea.org/statistics.

Key message: India's thermal coal imports surged in 2018 as domestic production could not keep pace with rising domestic demand.

Indian coal imports increased drastically – by 14.7% (+31 Mt) – to meet steam coal requirements, as the rise in domestic production was not adequate to meet growing needs. Imports for power plants rose from 56 Mt in 2017 to 61 Mt in 2018, but coal demand for power increased at a higher rate than import expansion. To meet the remaining demand, the government allocated most domestic coal production to the power sector. Hence, most additional imports went to other industries such as cement and sponge iron production.

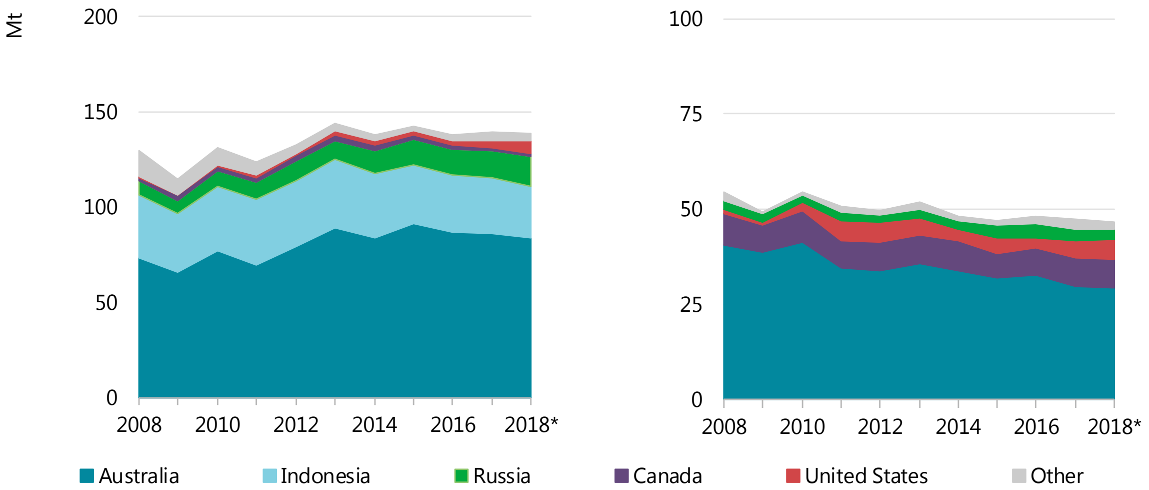
Due to their geographical proximity compared with other export countries, Indonesia and South Africa were the main Indian import suppliers, with a combined market share of 88%. Indonesia met most of the increase in demand, with exports increasing by 21 Mt (+20.2%). In contrast, South Africa's exports to India rose by only 3 Mt (+6.7%) as supply-side constraints prevented further export expansion (see above). In addition, the US exports to India expanded by 5 Mt (+64%). Despite the long distance to India, eastern US exporters profit from the Indian cement industry's need for high-CV coal for which high sulphur content is not important.

Met coal imports were stable at 52 Mt in 2018. Australia is the dominant met coal supplier for India, providing 83% of the country's imports, with another 9% supplied by the United States. Compared with 2017, the United States won only 1 Mt of Australia's export market share.

Japan

In 2018, Japan imported 185 Mt of coal (all its consumption) (Figure 2.13). Imports declined a slight 2 Mt (-1%), reflecting lower demand.

Figure 2.13. Japanese imports of thermal coal (left) and met coal (right), 2008-18



*Estimated.

Sources: Adapted from IHS Markit (2019a), *Coal Price Data and Indexes*, https://ihsmarkit.com/products/coal-price-data-indexes.html; IEA (2019), *Coal Information* (database), www.iea.org/statistics.

Key message: In line with Japanese demand development, the country's imports decreased only slightly in 2018.

Steam coal accounted for 75% of the imports. Australia remained Japan's primary coal supplier, delivering 84 Mt of thermal coal in 2018, or 61% of Japan's total steam coal imports. Japanese utilities prefer the high quality and consistency of Australian steam coal for their highly efficient coal-fired power plants. The second-largest supplier was Indonesia, with a market share of 20%.

Russia, the third-largest thermal coal exporter to Japan, holds a market share of 9%. Russian (+1 Mt) and US (+2 Mt) exports to Japan were the only ones that increased in 2018, replacing lower imports from Australia and Indonesia. Spurred by greater price competitivity among coal suppliers (e.g. US exporters), in 2018 Japanese utilities began to diversify their procurements in response to the energy market liberalisation of 2016. Australian and Indonesian exports still dominated the market, however.

Met coal imports contracted by 1 Mt (-1%) in 2018 as Japan's pig iron production decreased. Import volumes provided by most countries remained stable from 2017, with only those from the United States expanding (by 1 Mt).

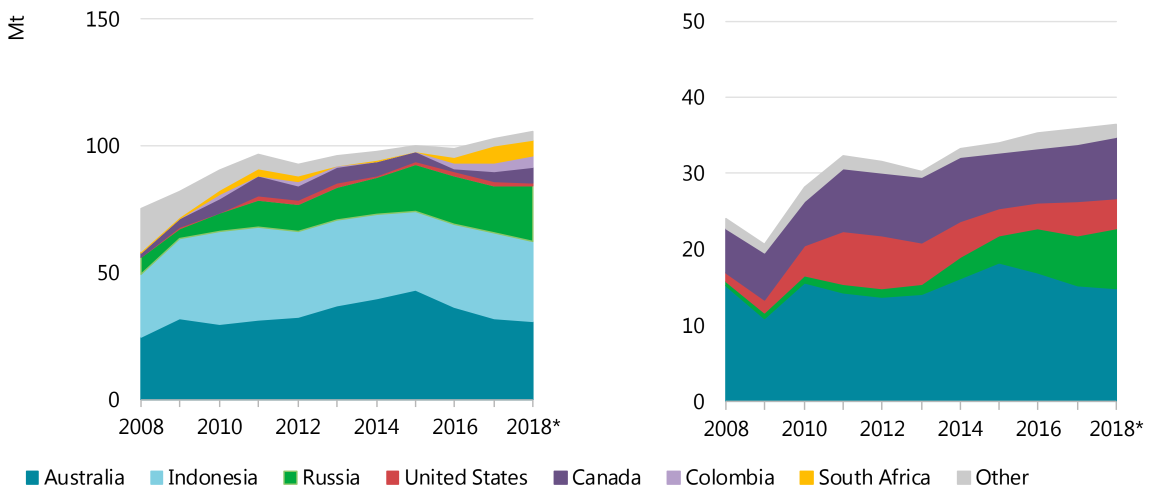
Korea

Because its indigenous resources are scarce, Korea, like Japan, depends considerably on energy resource imports. Its imports increased by 3 Mt (+2.2%) to 142 Mt in 2018 (Figure 2.14). Thermal coal imports, which make up 74% of Korea's total coal imports, increased by around 2 Mt (+2.4%) as a result of higher electricity production (see Chapter 1). The market shares of Korea's two primary suppliers continued to drop, however: Australia's exports decreased by 1 Mt (-2.7%) and Indonesia's fell by 2 Mt (-6.9%). At the same time, imports increased from Russia (+3 Mt), Canada (+2 Mt) and Colombia (+1 Mt).

As part of efforts to tackle air pollution, Korea has put a cap of 0.4% on the sulphur content of its thermal coal imports, which is less than half the amount of the previous standard. While this cap favoured low-sulphur Russian and West coast US imports, Australian and Indonesian imports declined because their sulphur content is typically around 0.8% (IHS Markit, 2018b).

Concerning met coal, while demand and imports remained stable in 2018, Russian (+1 Mt) and Canadian (+1 Mt) imports into Korea increased to the detriment of Australian and US supplies.

Figure 2.14. Korean imports of thermal coal (left) and met coal (right), 2008-18



*Estimated.

Sources: Adapted from IHS Markit (2019a), *Coal Price Data and Indexes*, https://ihsmarkit.com/products/coal-price-data-indexes.html; IEA (2019), *Coal Information* (database), www.iea.org/statistics.

Key message: Korea's imports rose slightly and showed a tendency towards diversification in 2018.

European Union

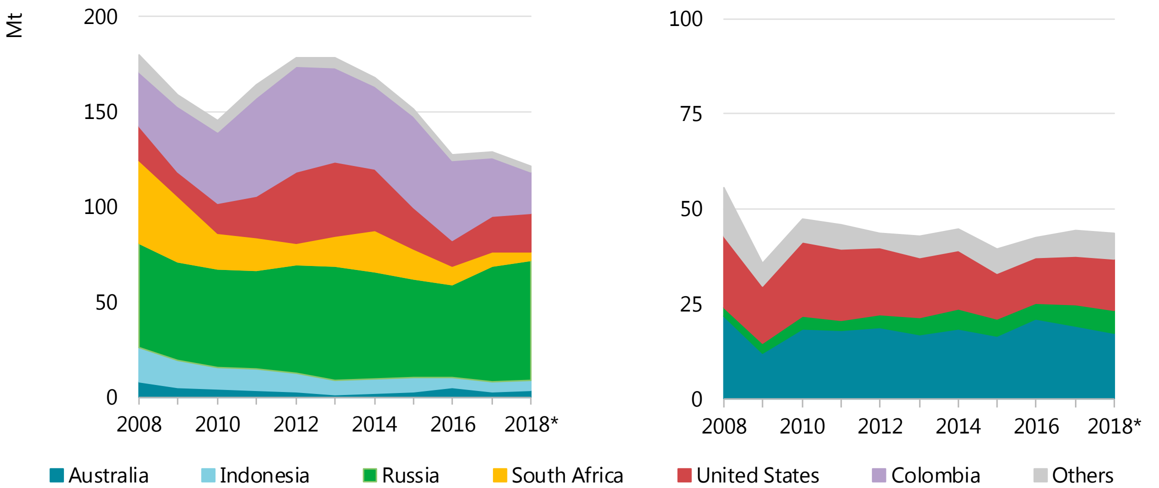
EU coal imports continued to decline in 2018, amounting to 166 Mt – or 8 Mt less than in 2017 (-4.8%) (Figure 2.15). The share of imports in EU coal consumption remained stable, however, at 28%.

The European Union imported 121 Mt of thermal coal in 2018, mostly from Russia (52%), Colombia (18%) and the United States (17%). Compared with 2017, imports from Russia increased by 5.4% (+3 Mt) and from the United States by 9.6% (+2 Mt). In contrast, Colombia's exports to the European Union continued to shrink substantially, by 29.3% (-9 Mt) to 21 Mt. Imports from South Africa also continued to decline (-4 Mt).

EU met coal imports showed only a limited decline at 44 Mt, with supplies shifting slightly from Australia, Europe's largest met coal supplier, to the United States. Remaining imports were provided mainly by Russia and Canada.

Germany imported 44 Mt of coal in 2018, 12% less than in 2017 (-6 Mt). This substantial drop resulted from lower total electricity production and significantly higher renewable power generation. Partial coal-to-gas switching also led to less hard coal-fired power generation. **Spain's** coal imports dropped by 3 Mt (-17%) to 16 Mt owing to lower coal demand. In contrast, **Italy's** coal imports remained relatively stable, declining by only 1 Mt to 14 Mt in 2018. Despite its continuously declining coal consumption, the **United Kingdom** – the European Union's fourth-largest coal importer – increased its imports by 1 Mt (+16.7%), which is the first growth since 2012.

Figure 2.15. European imports of thermal coal (left) and met coal (right), 2008-18



*Estimated.

Sources: Adapted from IHS Markit (2019a), *Coal Price Data and Indexes*, https://ihsmarkit.com/products/coal-price-data-indexes.html; IEA (2019), *Coal Information* (database), www.iea.org/statistics.

Key message: European coal imports declined steadily in 2018 as power sector consumption continued to drop, and Colombia lost market shares to Russia in this unsteady market.

Other Countries

In 2018, **Chinese Taipei** was the world's fifth-largest coal importer. Its imports declined slightly, by 1.6% to 67 Mt, and around 89% were made up of steam coal. Australia, its main supplier, provided 50% of the imports, an increase of 2 Mt (+4.6%). In contrast, its second-largest import source, Indonesia, delivered 4.4% less to Chinese Taipei in 2018 than in 2017.

Turkey's imports stagnated at 38 Mt in 2018. Around 56% came from Colombia, 35% from Russia and 5% from South Africa, with Colombia gaining some market shares from Russia. Met coal imports increased by 2 Mt (+30%) to account for 18% of total imports.

The coal imports of **Malaysia** rose 8% to 33 Mt in 2018. The additional coal was provided primarily by Indonesia, which already held a dominant (72%) share of the Malaysian coal market.

Thailand's coal imports amounted to 25 Mt in 2018, 6% more than in 2017. It imported mostly thermal coal and, as in Malaysia, the dominating supplier is Indonesia with a share of 65%.

Prices

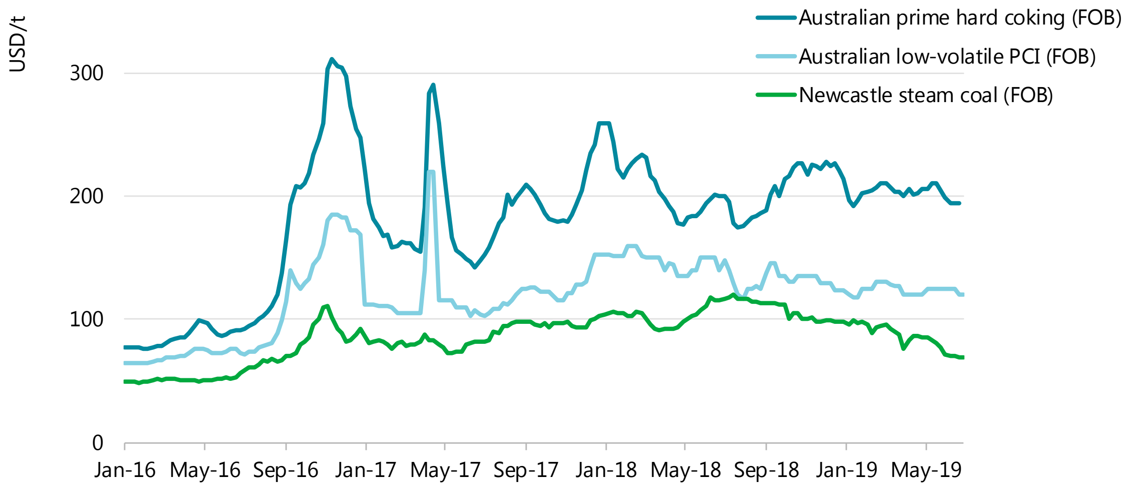
Coal prices vary not only by region but by grade and quality. Nonetheless, prices rose all around the world in 2018, continuing the trend of 2017, albeit more slowly. On average, FOB prices for thermal coal with a CV of 6 000 kcal/kg increased by 13.4% in 2018, whereas they had risen 36.1% in 2017. The same applies to met coal prices, which rose 38% in 2017 and 16% in 2018.

Australian thermal coal export prices increased the most (by around 20%) in 2018 (Figure 2.16). Prices for Newcastle coal began to increase sharply for various coal types in 2016 when China enacted supply-side policies and its domestic demand rose, but they have not returned to their early-2016 level.

This is especially the case for met coal, as demand remained strong in 2018 because capacity cuts in China continued to restrict output growth and kept import requirements high. Chinese measures to control coal prices (e.g. port handling limits and import restrictions) have also affected met coal price movements. In addition, because the global seaborne met coal supply is highly concentrated in Australia, every supply-side disruption there affects global prices.

In 2018, thermal coal prices began to return to the previous levels of early 2016 as Chinese imports contracted and there was little prospect of demand recovery elsewhere in northeast Asia. Indonesia's and Russia's thermal coal supplies further loosened the market, widening the price spread between met coal and thermal coal. Occasional temporary price movements also occurred: for example, Australian low-volatile coal used for pulverised coal injection (PCI) reached the same price as steam coal in August 2018 even though PCI coal has a higher calorific value than Newcastle steam coal. Because Queensland PCI producers do not have the option to blend at some load ports, the low-volatile PCI could not be blended and used as thermal coal to take advantage of arbitrage. Low-volatile PCI producers therefore had to accept the prices of steel-producing consumers (IHS Markit, 2018a), although the market quickly adapted to the situation.

Figure 2.16. Marker prices for different types of coal, 2016-19



Source: IHS Markit (2019a), *Coal Price Data and Indexes*, https://ihsmarkit.com/products/coal-price-data-indexes.html.

Key message: High thermal coal prices began to fall in 2018, while met coal prices remained steady.

Box 2.2. Coal rank, coal type and coal quality

When describing coal, the terms rank, type, grade and quality are often used interchangeably, when in fact they represent very different concepts.

Coal rank refers to its degree of coalification, which largely depends on the age of coal and the pressure and temperature to which it has been subjected. From less to more coalification (which almost equates with younger to older), from more moisture to less, and from less carbon to more, coal is classified as lignite, sub-bituminous coal, bituminous coal and anthracite.

Although in common language coal type usually refers to rank or grade (coking or thermal), strictly speaking, coal type is a geologic classification based on the appearance of the coal. There are two types: humic, which is banded, and sapropelic, which is non-banded. Plus, there are different lithotypes within each type and further subdivisions, or microlithotypes, called macerals. Macerals in coal are analogous to minerals in rocks, and the three macerals are: vitrinite, liptinite and inertinite.

Most coal (including lignite) is used for thermal purposes, i.e. it is used directly through burning to produce heat and/or steam, or it is passed through a turbine to generate electricity only or a combination of both electricity and heat (called combined heat and power [CHP]). Calorific value (or the amount of heat that can be produced per unit of mass) is the main parameter used to determine thermal coal quality, but concentration of impurities such as sulphur, ash and trace elements are also relevant. Coal characterisation also relies on many other factors – some more relevant for certain uses than for others – including ash fusion temperature, grindability and fixed carbon.

In contrast, coking coal is not burned but is subjected to pyrolysis to produce metallurgical coke in a coke oven. The procedure consists of heating coal in an oxygen-free atmosphere at a temperature of 1 000-1 100°C for 10 to 20 hours. During this process, the coal loses moisture and volatile components while softening, swelling and re-solidifying to become coke, a porous, hard solid containing a higher proportion of carbon and minerals than the original coal. The crucible swelling number (CSN) (3-6 for semi-soft coking coal and >7 for hard coking coal) is the prime index to assess coking characteristics, i.e. the capacity of coal to become coke. Coke oven by-products are used to heat the oven or are collected as tars and other chemicals, often used in industrial applications; coke oven gas is a fuel that can be used in steelmaking or for power generation. Although metallurgical coke is used for a variety of applications (in ferroalloy production, in the reduction of metal oxides, phosphates and sulphates, and in the production of carbides), the vast majority of metallurgical coke is used to produce pig iron in a blast furnace.

In the blast furnace, coke has three functions: it is the energy source for producing heat through combustion with hot air; it is the source of reducing gas (carbon monoxide [CO]) after reacting with the hot air; and it serves as the permeable support for the burden (the raw materials charged into the blast furnace) allowing gases to flow through it at the same time. As it moves downwards in the blast furnace, coke is subjected to mechanical degradation and chemical attack. Its quality is therefore defined mainly by its mechanical strength (i.e. the coke strength after reaction [CSR]) and its reactivity with CO_2 at high temperatures (i.e. its coke reactivity index [CRI]). Sulphur, phosphorus and ash content are also important, as a high concentration of any of these elements is counterproductive in steelmaking.

In practice, rather than introducing a homogeneous coal into the coke oven, usually a blend of different coals is used, optimised for cost and coke quality. In the case of coking coal, although blend optimisation depends on the composition of the individual coals, the properties of the blend are not based on the addition or average of the individual coals, as many different reactions and reconfigurations take place during the process of coke-making. Fluidity, for example, typically changes with different blends.

The PCI process was first used by Japanese steelmakers, and it is now in common use worldwide. PCI coal, while classified as metallurgical coal in this report, is a high-quality non-coking coal. The calorific value of PCI coal is typically over 7 000 kcal/kg, with low volatiles (<20%), low ash (<10%) and low sulphur content (<0.5%). The main purpose of using PCI coal (or gas, oil products, plastics or other alternative fuels) instead of expensive coke is to save money. The use of PCI coal has raised coke quality requirements; specifically, using higher shares of PCI coal requires lower coke reactivity.

Thermal coal

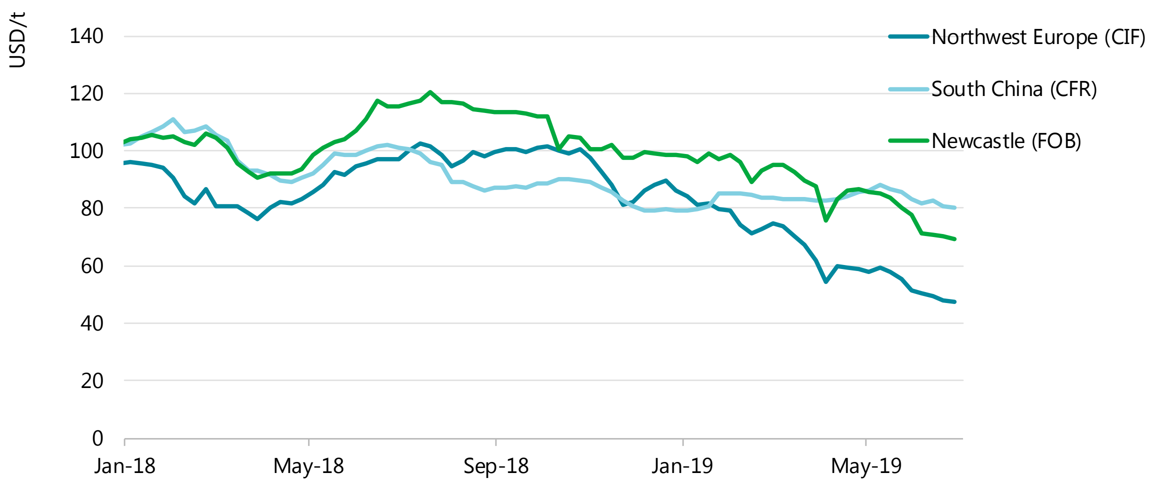
Regardless of calorific value, prices for thermal coal increased on average in all major coal regions in 2018 due to rising demand in the Asia Pacific region.

At the beginning of 2018, strong seasonal demand was met with tight supplies, as monsoon rains challenged Indonesian producers of higher-quality coal. After subsiding briefly, demand regained strength and supplies tightened further, leading to a near-term high FOB price of about USD 120/t for Newcastle steam coal in July 2018 (Figure 2.17).

Import demand from China increased due to hotter-than-average temperatures, weak hydropower output, and limited domestic supply growth, and Korea's imports increased as a result of substantially lower nuclear power output. At the same time, supply in South Africa was diverted to domestic power-generating facilities, impacting exports.

The high price could not be sustained, however, as most of the contributing factors were temporary. Prices steadily declined to below USD 100/t, primarily as a result of falling import demand from China as domestic production increased and power demand dampened. The decrease was further sustained by changes to China's import policies and a reduced heating demand from Northeast Asia owing to a mild winter.

Figure 2.17. Thermal coal price markers (6 000 kcal/kg) in the Atlantic and Pacific basins, 2018-19



Notes: CIF = cost, insurance and freight; CFR = cost and freight. The South China (CFR) price does not include Chinese taxes.
Source: IHS Markit (2019a), *Coal Price Data and Indexes*, https://ihsmarkit.com/products/coal-price-data-indexes.html.

Key message: Chinese import prices remained relatively steady while Australia's export prices and Europe's import prices fell, especially in the first half of 2019.

Low coal demand in Europe starting in the fourth quarter of 2018 and going into 2019 diverted Russian exports towards other markets, mainly China. Indonesia's exports also increased in the first half of 2019, putting pressure on Newcastle coal prices, as China has been one of the key importers of Australian thermal coal. However, a decoupling of the Newcastle steam coal (FOB) price and the South China (CFR) price occurred because, in addition to competition from Russia, Chinese customs issues pushed Newcastle steam coal prices down and the Chinese yuan also lost strength. This explains the different trends in Newcastle and South China price indices in 2019.

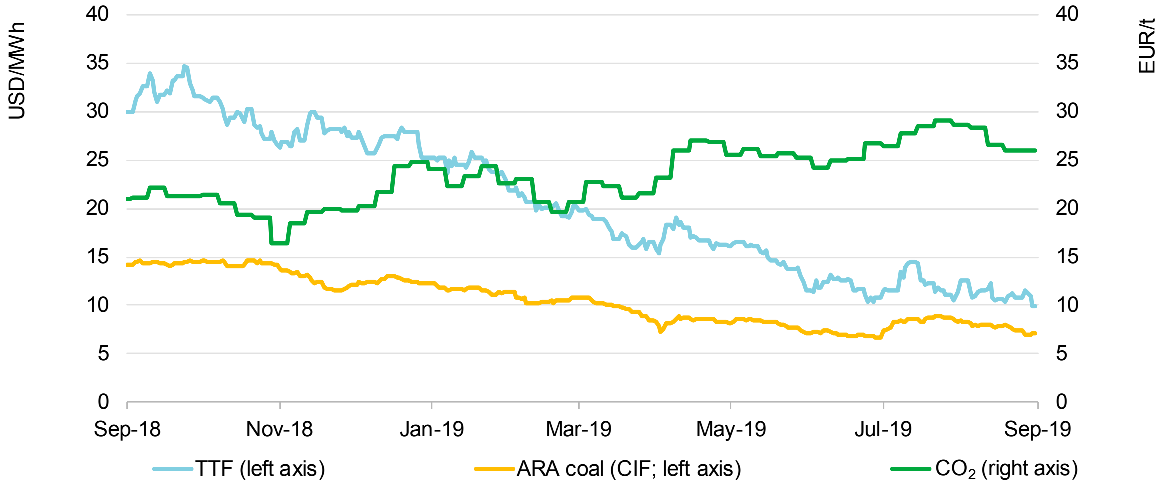
The price spread between the Atlantic and Pacific basins has widened since January 2018, with Asian prices buoyed by strong demand growth and tight supplies as well as falling European coal demand.[1] Widening-spread signals create arbitrage opportunities for producers, which have been partially exploited by Colombian exporters who increased their exports to the Asian market (Figure 2.9). Price spreads have, however, persisted to some extent.

[1] The FOB price for coal at Puerto Bolivar (Colombia) mainly follows the trend of European import prices.

Falling gas prices resulting from above-average temperatures and rising CO_2 prices have been putting downward pressure on coal prices in Europe since late 2018, with coal-based power generation facing strong competition from relatively inexpensive gas-fired production (Figure 2.18). European gas prices (e.g. the Title Transfer Facility [TTF] price) dropped substantially during this period, even falling to below the Henry Hub price at times. This led to a decline in coal demand and a consequent price collapse, with prices falling more than 40% from the beginning of 2019 to September 2019.

In the price correlation between coal and gas, price movements decouple when a certain CO_2 price is reached. This shows that there is a reserve price for coal competitivity in the power sector. If the price of gas is very low, reducing the coal price further (to below the reserve price) will not make it more competitive with gas in the power sector, so instead the sales focus shifts to other market participants (e.g. CHP plants or non-power uses).

Figure 2.18. European prices for different energy carriers and CO_2, 2018-19



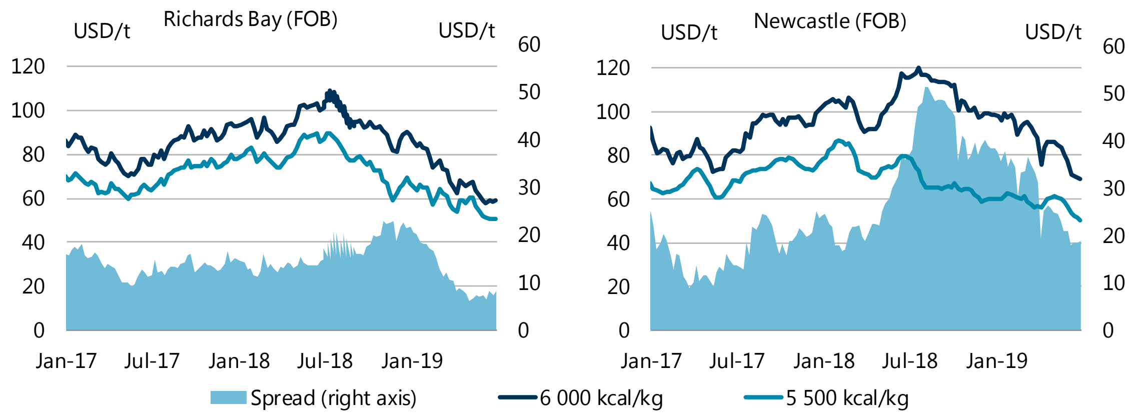
Notes: MWh = megawatt hour; ARA = Amsterdam-Rotterdam-Antwerp (price index).
Source: IHS Markit (2019a), *Coal Price Data and Indexes*, https://ihsmarkit.com/products/coal-price-data-indexes.html.

Key message: Due to high CO_2 and low gas prices, coal demand from the EU power sector fell in the first half of 2019 along with coal prices.

Price spreads narrowed among different thermal coal qualities in Richards Bay, South Africa, and Newcastle, Australia, after having been wider because the supply of lower-quality thermal coal had been growing more quickly than that of higher grades. In Australia, the effect was compounded by supply tightness in the Hunter Valley and rising demand from Japan and Korea for higher-CV Australian thermal coal. Chinese customs issues at coal terminals in southern China further dampened demand for lower-quality Australian thermal coal, and the spread remained wide (at around USD 40/t) until the beginning of 2019 (Figure 2.19). Later, the spread began to narrow as supply tightness in Hunter Valley was eased and Chinese restrictions relaxed.

For South African thermal coal, the spread between the 6 000-kcal/kg and 5 500-kcal/kg price markers narrowed around 55% (USD 9.1/t) between January 2017 and June 2019. Eskom, South Africa's public utility that typically consumes lower-CV coal, ramped up its spot coal purchases for blending to make up for supply shortfalls at its affiliated mines. Demand for Richards Bay 5 500-kcal/kg coal was therefore stabilised by domestic demand, while prices for 6 000-kcal/kg coal were exposed to an export decline to Asia at the beginning of 2019.

Figure 2.19. Price markers for different thermal coal qualities in South Africa and Australia



Source: IHS Markit (2019a), *Coal Price Data and Indexes*, https://ihsmarkit.com/products/coal-price-data-indexes.html.

Key message: In 2018, spreads among the different coal qualities varied regionally depending on demand, especially for domestic consumption.

Met coal

Met coal is used primarily to produce steel through the blast furnace process; therefore, the amount of pig iron produced by blast furnace (i.e. blast furnace iron [BFI]) largely determines the demand and price of met coal. Even though met coal is traded internationally, the United States and Australia focus on different markets, with the United States delivering mainly to Europe and Australia focusing on the Asian market.

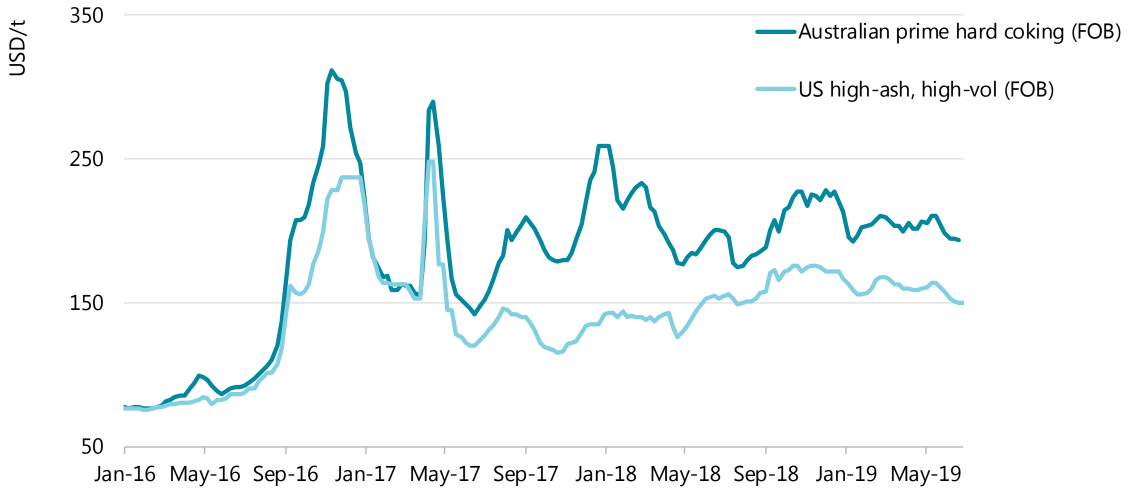
In the last quarter of 2016, met coal prices skyrocketed, driven by supply-side restrictions and a concurrent demand increase, particularly in China, and further supply disruptions associated with Cyclone Debbie in Queensland led to another price spike in mid-2017 (Figure 2.20). The price of Australian prime hard coking coal remained high as further supply-side constraints persisted and Chinese demand for high-grade coking coal increased. Spot prices for met coal declined sharply from March 2018 as a result of subdued import demand from China, but a subsequent rebound in demand from Asia and concerns over supply shortages have provided price support, with the spot price returning to over USD 200/t in June 2018.

In the last quarter of 2018, an outage at Australia's North Goonyella and partial idling of Mozambique's Moatize mine further shortened supplies (S&P Global, 2018). In addition, export-oriented producers from the United States and domestic producers in China faced supply disruptions. Amid strong demand from India and China, this contributed to market tightening.

Following a sharp decline in January 2019, prices rose again in February after Anglo American suspended operations at its Moranbah North coking coal mine in Australia due to a collision between a personnel carrier and a grader. The accident resulted in a loss of about 1.2 Mt of coking coal output (S&P Global, 2019). Additionally, the Australian mining company Wollongong Coal closed its last remaining operations at the Wongawilli colliery in 2019 following a number of health and safety violations. The suspension of mining operations at the Wongawilli colliery will subtract around 1 million tonnes per annum (Mtpa) of production capacity from the market.

Another factor was the collapse of Brumadinho dam at Vale's Corrego do Feijao iron ore mine in Brazil. The resulting loss of high-grade iron ore for the seaborne market accounted for around 3% of the global iron ore market. Using lower-grade iron ore in steelmaking requires more met coal. However, this effect is not likely to persist, as low steel margins (due to high iron ore prices) could drive an overall decrease in steel output, resulting in lower overall met coal demand.

Figure 2.20. Coking coal prices, 2016-19



Source: IHS Markit (2019a), *Coal Price Data and Indexes*, https://ihsmarkit.com/products/coal-price-data-indexes.html.

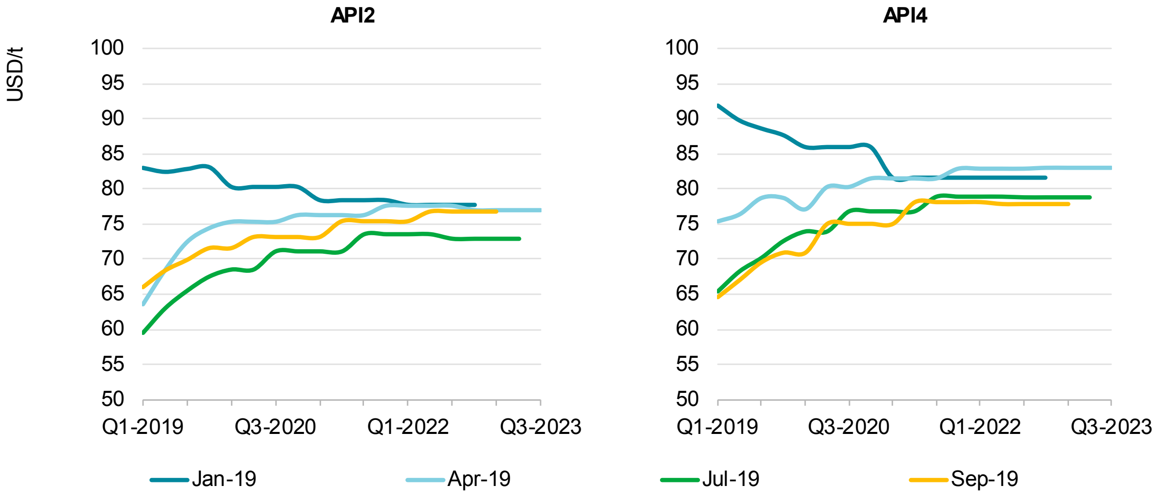
Key message: Dependency on Queensland coal meant that disruptions there triggered high volatility in met coal prices in 2018.

In June 2018, the price spread between Australian prime hard coking coal and US high-ash, high-volatile coking coal began to widen. As the quality of Australian coking coal is superior to that of the United States, this spread restores the usual relationship between the two price markers, which had vanished in 2015 due to the closure of high-cost mines in the United States.

Coal forward prices

Coal futures markets started the year in backwardation, following the trend prevailing since 2015 after many years of contango. The curve flipped during the first quarter of 2019 to a contango in April 2019, and the Argus/McCloskey's Coal Price Indexes (API 2 and API 4) demonstrate similar developments. Actually, prices for the 2022 and 2023 calendar years did not change significantly, whereas the month ahead, quarter ahead and 2020 calendar year fall substantially. This appears to indicate a consensus among market participants that the price will move into the USD 70/t to USD 80/t range (USD 75/t to USD 85/t for API 4) (Figure 2.21).

Figure 2.21. Forward curves of API 2 (left) and API 4 (right), 2019



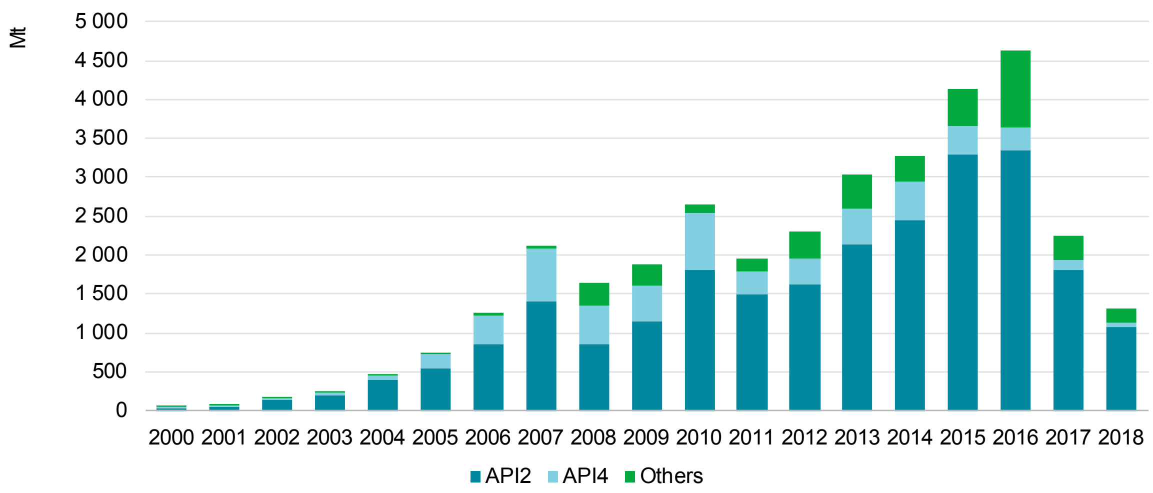
Source: IHS Markit (2019a), *Coal Price Data and Indexes*, https://ihsmarkit.com/products/coal-price-data-indexes.html.

Key message: After prevailing backwardation, the forward curve flipped to a contango in 2018.

Coal derivatives

After exponential growth in the 2000s and continuous increase in 2011-16, coal-derivative trade volumes collapsed in 2017 and declined further in 2018 (Figure 2.22). There are two important caveats, however: the chart is only a gross estimate based on some simple assumptions, as over-the-counter (OTC) volumes not cleared are difficult to estimate. In addition, the chart does not include volumes in the Zhengzhou Commodity Exchange (ZCE).

Figure 2.22. Trade volumes for coal derivatives, 2000-18



Source: IEA estimates from various sources.

Key message: Coal-derivative trade volumes continued to plummet in 2018 with less arriving at ARA ports and consumption becoming concentrated in Asia.

At ZCE, billions of tonnes of coal are traded every year. Given that seaborne market trade continued to expand in 2018, the churn rate for thermal coal is declining to a level not seen since the 2000s.

Uncertainty over how coal derivative markets will evolve continues, as physical volumes based on API 2 are expected to collapse in the future owing to the falling European coal demand. It remains to be seen whether API 2 will continue to be a reference index for coal trade once physical volumes drop to a minimum. In addition, lower-grade coals are more popular in Asia than in Europe, so derivatives based on a lower-grade index should be preferred by many market participants rather than one based on 6 000 kcal/kg. Whereas the commoditisation of electricity in Europe was pivotal for developing financial markets to trade fuels used for power generation, Asia is not experiencing the same electricity market development, reducing the incentive to develop Asian coal-derivative trading.

Coal supply costs

Coal mining is less capital-intensive than oil or gas extraction. The cost structure is therefore determined mostly by operating expenses such as mining cash costs (for labour, fuel, taxes and royalties, etc.) and transportation expenditures (for inland transportation, port fees, seaborne freight rates, etc.). The proportions of these costs are strongly contingent on mining method, such as surface or underground mining, and can vary significantly depending on producer, country and specific mine location. In countries such as Colombia, Indonesia and South Africa, labour costs are low and the share of materials in mining expenditures is generally higher than in Australia or the United States. Costs for other inputs, such as electricity and water, are also associated with national price trends. In addition, currency exchange rates can have a significant influence on the cost-competitiveness of an exporter, as most operating costs are incurred in the local currency, but coal is traded in US dollars.

Development of input factor prices

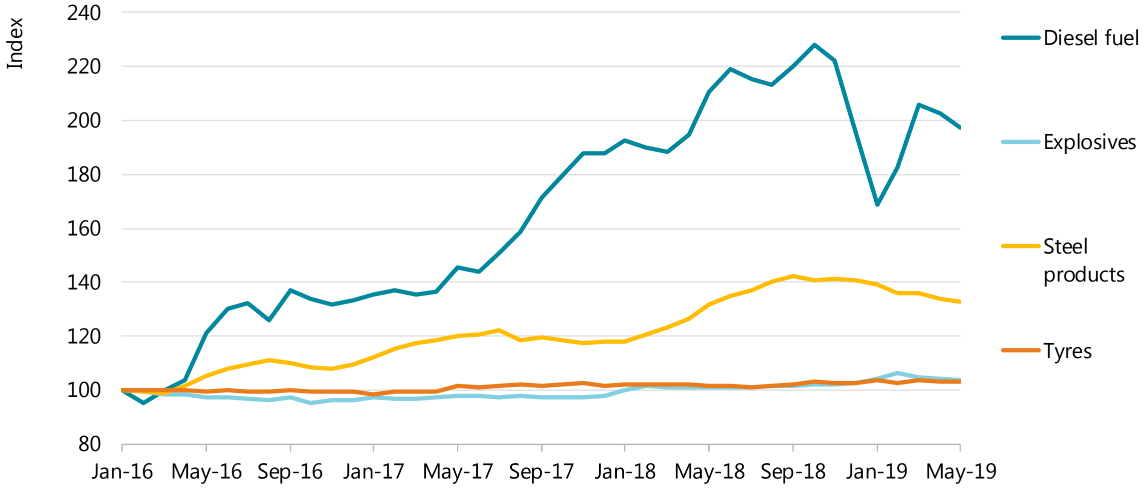
Coal supply costs are determined mainly by mining cash costs. These include inputs such as materials and labour as well as royalties and taxes, which account for more than two-thirds of mining cash costs in most coal-producing countries.

Figure 2.23 illustrates the development of indexed nominal prices for selected input factors used in coal mining; these factors are internationally traded and follow global trends. Prices for tyres and explosives generally remained stable over the period.

Prices for steel products had been rising continuously since 2016, when the steel market was oversupplied and prices were relatively low, but in the last quarter of 2018 they began to decline again, indicating that the market recovery of 2017 was losing momentum. Important determinants of this trend include trade friction, new capacity investments, and the persistence of excess capacity (OECD, 2019b). In addition, the price of diesel fuel – closely linked to that of oil – recovered after dropping to a multi-year low in January 2016. The price continued to climb in 2019. As a result, the cost of diesel doubled between 2016 and 2019.

Rising diesel prices boosted operating costs, especially for operators of opencast mines that rely on a multitude of diesel-consuming trucks and other equipment. Accordingly, the countries with mainly opencast mines (e.g. Indonesia and Russia) faced the largest average fuel cost increases in both absolute terms and as a share of total mining costs (Figure 2.24).

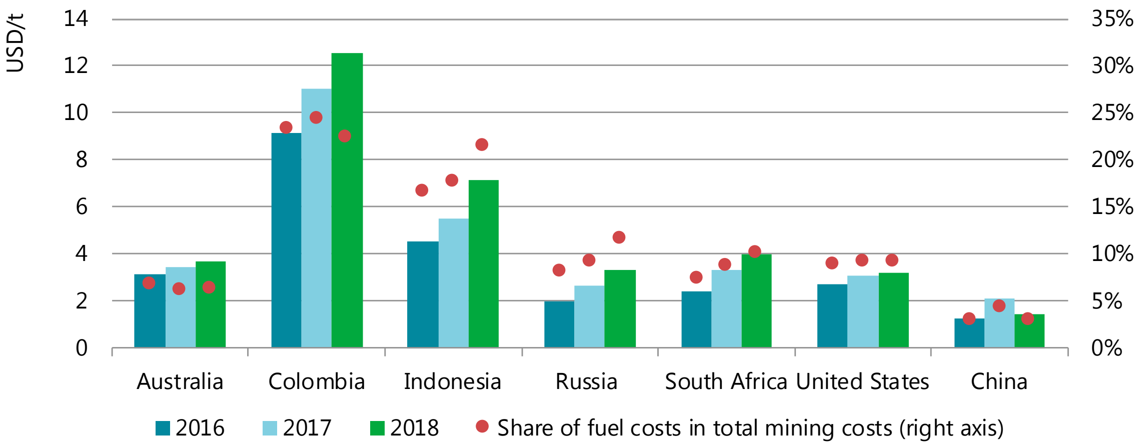
Figure 2.23. Indexed nominal prices of selected commodities and input factors used in coal mining



Source: US Bureau of Labour Statistics (2019), *Producer Price Data*, www.bls.gov/data.

Key message: Prices for diesel and steel products increased significantly in 2018, mainly affecting the cost of surface-based mining.

Figure 2.24. Average fuel costs (left axis) and their share in total coal mining costs (right axis), 2016-18



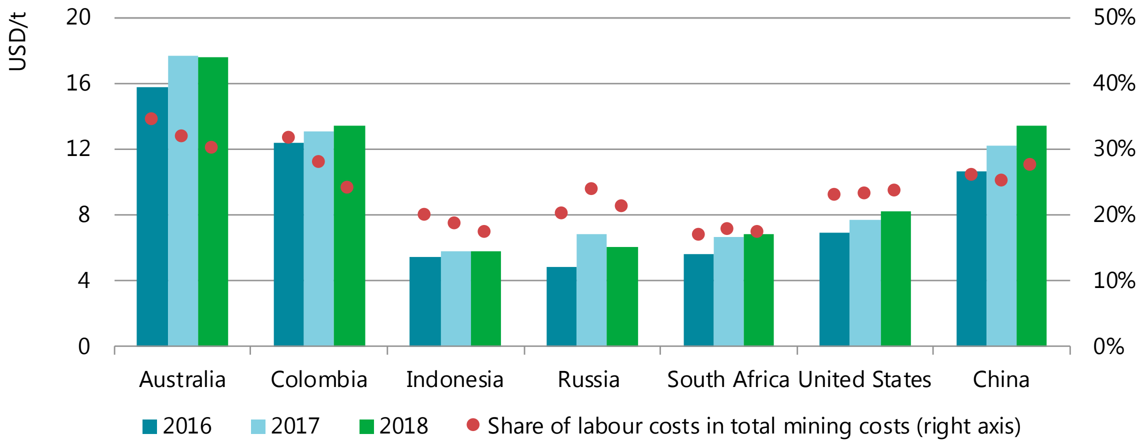
Source: Adapted from CRU (2019), *Thermal Coal Cost Model* (database).

Key message: The share of fuel costs in total mining costs rose significantly in 2018 for countries that produce coal mainly from opencast mines.

Australia, with about 80% of its mining capacity surface-based, and the United States, with 67% surface-based mining, were also confronted with higher fuel costs, but the share in total coal mining costs remained relatively stable. In Colombia, a country where surface mining accounts for over 80% of all coal produced, producers encountered a sharp increase in fuel costs, whereas in China more than 90% of coal production is from underground mines that are not as strongly affected by rising fuel prices.

Coal mining labour costs in Indonesia and South Africa are lower than for other exporters, especially Australia (Figure 2.25). The development of labour costs varies significantly among coal-producing countries: for most, total average labour costs have increased since 2016, but their share in total mining costs has remained mainly stable or even decreased because this relative development is associated with price increases for other inputs, e.g. fuel. After supply disruptions raised average output-weighted labour costs in Australia in 2017, labour costs remained high. In Russia, appreciation of the RUB against the USD drove up average labour costs in 2017 (see next section), whereas in China labour costs rose due to supply-side restrictions. In Australia, the share of labour costs in total mining costs declined because higher royalties linked to higher prices claimed a larger share.

Figure 2.25. Average labour costs (left axis) and their share in total coal mining costs (right axis), 2016-18



Source: Adapted from CRU (2019), *Thermal Coal Cost Model* (database).

Key message: Regional labour cost increases were uneven in 2018; in China, they rose significantly as a result of supply-side reforms.

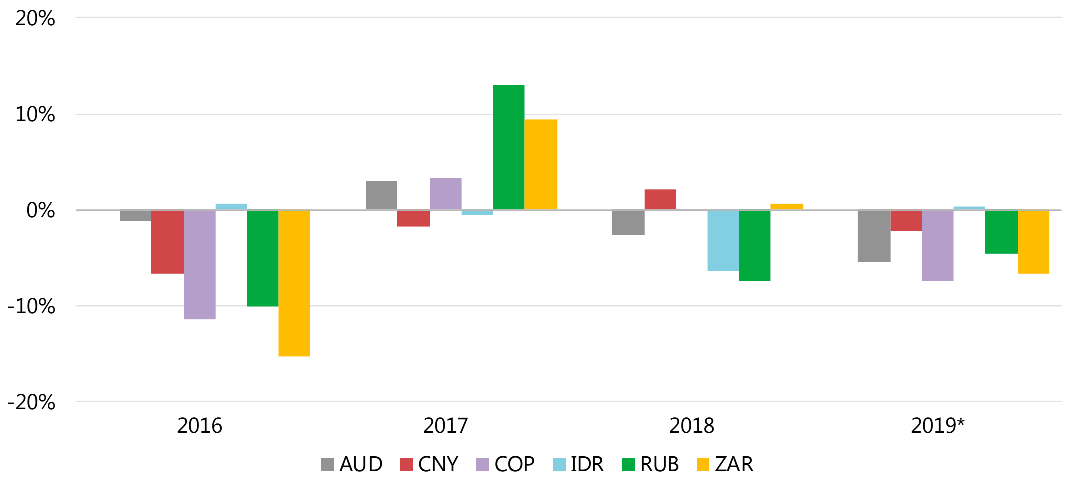
Currency exchange rates

Currency exchange rates can significantly affect an exporter's competitiveness: revenue streams for coal are largely in US dollars, whereas operating costs such as labour, railway tariffs, port charges and royalties are settled in local currency. A depreciation in local currency implies a reduction in supply costs for the domestic producer, making its coal more competitive on the international market. In contrast, local currency appreciation infers an indirect increase in costs, reducing the producer's competitiveness. Fluctuations in local currency also affect an importer's purchasing power and the relative competitiveness of coal against alternative fuels such as lignite or natural gas.

Of the selected currencies presented in Figure 2.26, most depreciated against the US dollar until 2017, as the US dollar was supported by strong growth in developed economies and by the Federal Reserve System's interest rate hikes.

The Colombian peso (COP) and the Russian ruble (RUB) in particular depreciated considerably. Colombia's and Russia's economies are heavily oil-dependent and oil prices remained relatively low. In the case of Russia, depreciation of the RUB resulted from Western sanctions related to its annexation of Crimea in 2014. However, both currencies began to appreciate against the USD as oil prices recovered. The Indonesian rupiah (IDR) remained relatively stable over the period, although it depreciated by roughly 6% in 2018 due to its account deficit and the mayhem in emerging markets caused by the Turkish lira crisis. In 2017, the South African rand (ZAR) recovered as commodity prices rose, but it weakened at the beginning of 2019 due to concerns about the country's domestic economic outlook and whether it would be able to retain its credit rating. This was closely related to the financial crisis of Eskom, South Africa's state-owned power giant (see Chapter 3).

Figure 2.26. Year-on-year development of selected currencies against the USD, 2016-19



*Average exchange rates up to May 2019.

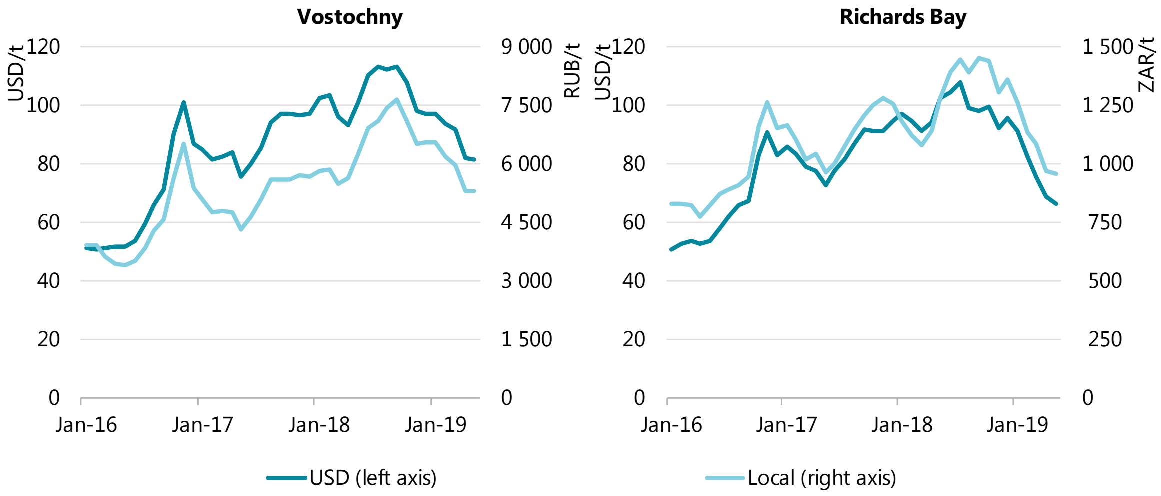
Notes: AUD = Australian dollar; CNY = Chinese Yuan renminbi; ZAR = South African rand; RUB = Russian ruble; IDR = Indonesian rupiah; COP = Colombian peso; EUR = Euro. The chart displays the y-o-y average exchange rate development of the selected currencies, expressed in percent change from the previous year. For example, in 2016 the RUB depreciated 10% against the USD compared with 2015.

Source: OECD (2019a), *Main Economic Indicators* (*MEI*), https://stats.oecd.org.

Key message: A strong US dollar increases the competitiveness of most exporters.

Figure 2.27 charts the development of per-tonne coal prices in US dollars as well as in Russian rubles (left) and South African rands (right) to illustrate the effects of local currency depreciation. The price of coal in USD increased until the beginning of 2019 (see above). However, appreciation of the RUB in 2017 widened the price spread for Russian coal in the local currency and in USD, as prices in RUB did not increase as much as prices in USD. With depreciation of the RUB in 2018 and early 2019, this spread began to close again. Conversely, appreciation of the ZAR in late 2017/early 2018, led to a price decline for Richard's Bay coal sold in the local currency.

Figure 2.27. FOB steam coal prices in USD and local currencies, 2016-19



Sources: OECD (2019a), *Main Economic Indicators (MEI)*, https://stats.oecd.org; IHS Markit (2019a), *Coal Price Data and Indexes*, https://ihsmarkit.com/products/coal-price-data-indexes.html.

Key message: Appreciation of the Russian ruble in 2017 was an anomaly in the five-year trend.

Dry bulk shipping prices

As 90% of internationally traded coal is transported by ship, seaborne dry bulk shipping is an important pillar of global coal trade. Dry bulk vessels are categorised according to their deadweight tonnage (dwt), which is a measure of how much weight a ship can carry. A ship classification can be found in the *Coal 2018* report.

In 2018, global seaborne dry bulk trade amounted to 3.5 Bt of goods, an increase of 1.3% from 2017. Coal accounts for about 34% of global seaborne dry bulk trade, while the rest is associated with the transport of iron ore (44%), grains (15%) and other materials (7%).

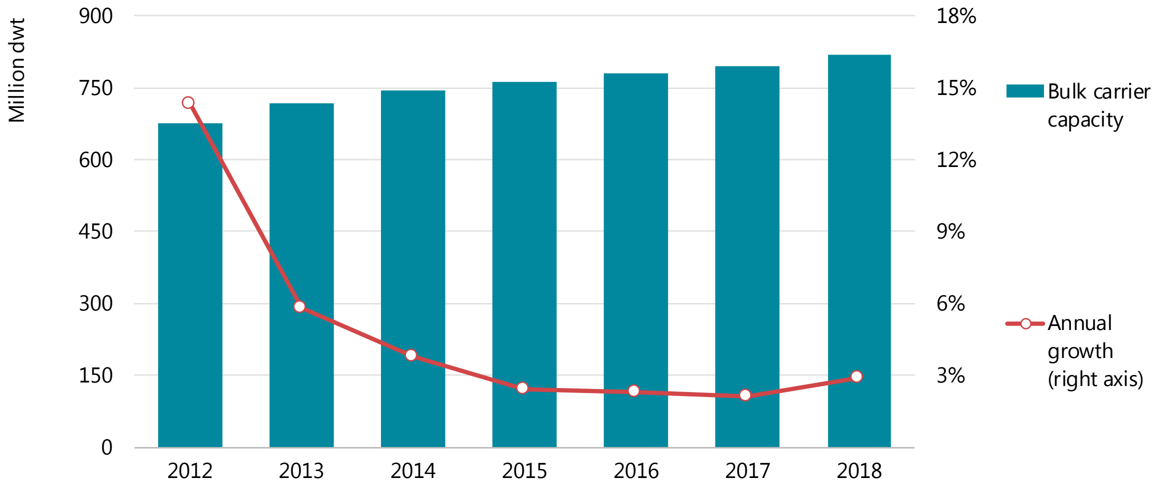
Building new vessels is capital-intensive and takes up to two years. Hence, dry bulk carrier supplies are rather fixed, although scrappage and other factors do lend some flexibility. In addition, the number of assembly docks is restricted, which also limits production.

Figure 2.28 illustrates growth in bulk carrier capacity, which has slowed since the overcapacity construction of 2008-12. After a slight uptick in 2017-18, capacity growth is expected to be stagnant for 2019 due to negative market trends and especially the slowdown of the world economy, including China, and important commercial tensions among countries. Furthermore, a dam collapse in Brazil is expected to significantly affect the iron ore supply and hence seaborne trade. However, market participants are expected to react through flexibility measures such as slow steaming.

The operational supply costs of coal dry bulk shipping are largely determined by marine fuel prices. The final freight rates are further determined by the specific supply and demand situation.

The development of seaborne coal freight rates is illustrated by the Queensland-Rotterdam and Richards Bay-Rotterdam routes (Figure 2.29). Rates recovered slightly to the end of 2016 with higher coal imports from China, and then showed a slight upward trend as the price of oil rose.

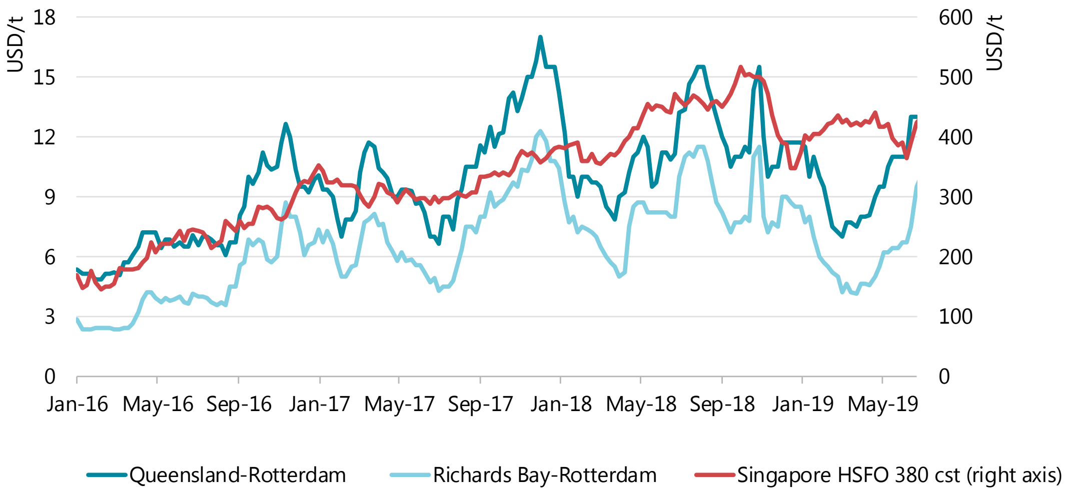
Figure 2.28. Bulk carrier fleet, 2012-18



Sources: UNCTAD (2018), *UNCTAD Statistical Database*, https://unctadstat.unctad.org; IHS Markit (2019a), *Coal Price Data and Indexes*, https://ihsmarkit.com/products/coal-price-data-indexes.html; Argus Media (2018), Singapore high-sulphur fuel oil 380-cst spot price.

Key message: Growth in bulk carrier capacity rebounded in 2018, but far from 2012 levels.

Figure 2.29. Selected freight rates and fuel oil price, 2016-19



Note: HSFO = high-sulphur fuel oil.

Sources: IHS Markit (2019a), *Coal Price Data and Indexes*, https://ihsmarkit.com/products/coal-price-data-indexes.html; Argus Media (2018), Singapore high-sulphur fuel oil 380-cst spot price.

Key message: Freight rates increased when ships were taken out of service for retrofitting in 2019.

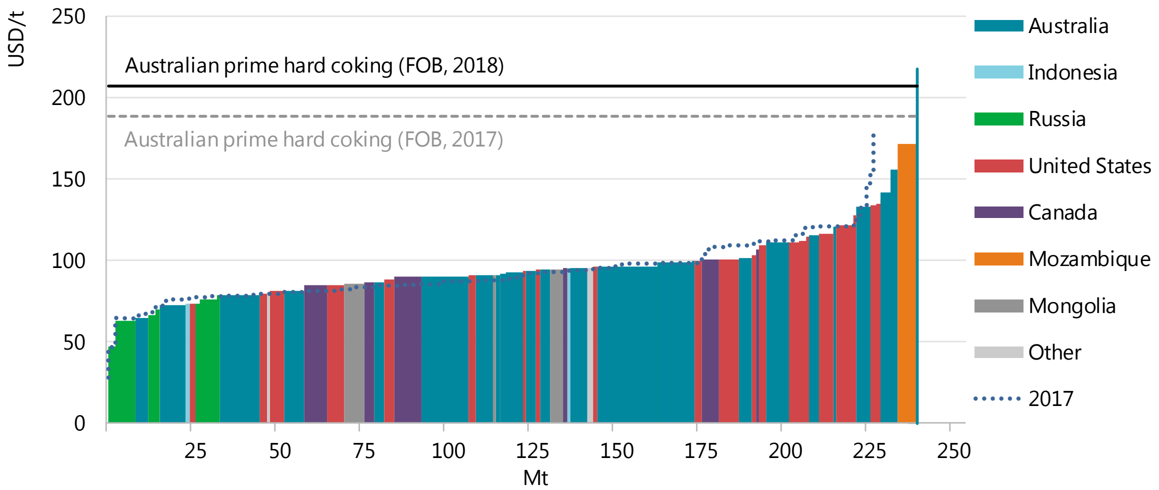
Chinese imports of iron ore further influenced prices and contributed substantially to short-term freight rate fluctuations, i.e. China's near-term low iron ore imports, in combination with moderate coal imports at the beginning of 2019, put pressure on freight rates. At the same time, coal imports into Europe were low.

The freight rate increase since May 2019 is partially related to vessels being retrofitted with scrubbers to comply with the new IMO regulation on sulphur, which is to be implemented on 1 January 2020. There is a shortage of retrofitting capacity, so the work can take up to six weeks. As of July 2019, around 3% of the total dry bulk carrier fleet had been retrofitted and another 8% was pending. The overall effect of the IMO regulation remains to be seen; at the time of writing there is rising confidence that ports, ship owners and fuel suppliers are generally well placed to meet the challenge of complying with the new fuel specifications. However, it is likely that there will be logistical issues at some locations

Development of coal supply cost curves

After increasing in 2017, coal supply costs for coking coal remained relatively stable in 2018. In contrast, thermal coal supply costs, especially for countries with surface-based mining, rose further due to rising fuel costs. Figure 2.30 depicts the met coal FOB supply curve as well as average met coal prices for 2017 and 2018. The cost curves account for variable production costs, overburden removal, royalties, inland transportation and port usage fees. In 2018, the average FOB price for Australian prime coking coal was about USD 207/t, an increase of roughly 10% from 2017. With high coking coal prices in 2018, more mines were profitable and total production increased from 2017 as some producers (e.g. Mozambique, Mongolia and Australia) were able to increase their output. In light of the relatively stable supply cost curves and a further increase in met coal prices, it appears that the profitability of met coal production – especially hard coking coal –increased further in 2018.

Figure 2.30. Indicative hard coking coal FOB supply curve and annual average FOB marker price

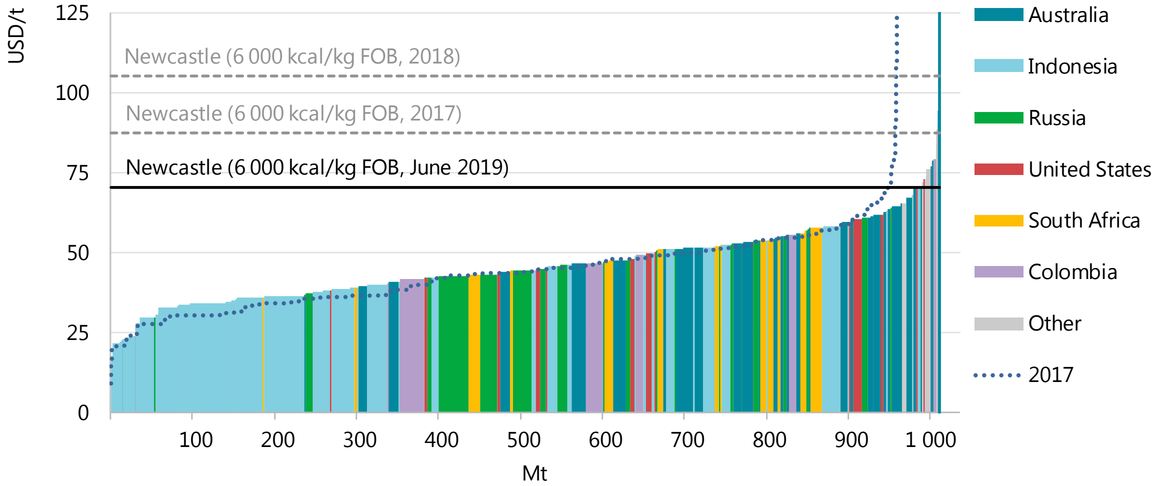


Note: The annual average FOB marker price is based on the monthly average index for Australian prime hard coking coal.
Sources: Adapted from CRU (2019), *Thermal Coal Cost Model* (database); IHS Markit (2019a), *Coal Price Data and Indexes*, https://ihsmarkit.com/products/coal-price-data-indexes.html.

Key message: The profitability of coking coal producers increased in 2018.

The supply cost curve for thermal coal rose slightly from 2017 (Figure 2.31). Low-cost producers especially – those using mostly surface-based mining, such as Indonesia – faced higher costs due to rising fuel prices. Nevertheless, they remained among the lowest-cost producers of thermal coal. The total seaborne thermal coal supply increased by around 50 Mt in 2018, and considering the simultaneous price increase, thermal coal production profitability also grew. However, the recent price drop in 2019 indicates that this situation might not be sustained. In Figure 2.31, the transportation costs given are to the closest port, so the FOB costs of Russian producers in Asia are somewhat higher than the figure shows.

Figure 2.31. Indicative thermal coal FOB supply curve and annual average FOB marker price



Note: The annual average FOB marker price is based on the monthly average index for Australian Newcastle steam coal.
Sources: Adapted from CRU (2019), *Thermal Coal Cost Model* (database); IHS Markit (2019a), *Coal Price Data and Indexes*, https://ihsmarkit.com/products/coal-price-data-indexes.html.

Key message: The profits of most thermal coal producers increased in 2018.

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3. Medium-term demand and supply forecast

- **Global demand remains solid with annual fluctuations.** Although global coal demand continues its decade of stagnation at an average growth of 0.5% per year, demand in 2024 (5 624 million tonnes of coal equivalent [Mtce]) will be similar to 2014, the highest consumption level ever. Coal-fired power generation accounts for the slight increase. Even though global coal-fired capacity outside the People's Republic of China ("China") and India is set to decline through 2024, coal consumption for power generation outside these two countries makes up only one-quarter of global demand.

- **Regional trends remain unchanged from last year's forecast.** In India, Southeast Asia and other Asian countries, growth continues based on rising industrial demand, higher electricity demand and new coal-fired power plants. EU and US prospects are lower than last year, as in addition to stronger climate policies and increasing renewables expansion, gas prices have dropped; anticipated coal-fired power generation is one-quarter lower as a result. Excluding Germany and Poland, the share of total EU coal consumption in global coal demand therefore shrinks to less than 2% in 2024. As trends offset one another, the overall global movement will be determined by China.

- **Coal consumption resilience in China is strong**, as rising electricity demand and the coal conversion sector stimulate greater coal use. In contrast, coal consumption declines for the small residential and industry sectors as well as heavy industry. The balance is a small increase that will raise coal demand in 2024 to the level of 2013.

- **China leads production to 2024, but India has the most growth.** Production in China, which moves into the north-western part of the country, is expected to be robust, but India's coal consumption growth is the largest – although its production rates could be affected by plans to open the market. US producers continue to struggle in a shrinking domestic market, with opportunities in the Atlantic market also limited.

- **Downside potential is increasing**. In any forecast, there is both upside and downside potential for most countries. However, in this year's forecast most of the uncertainty has downside potential. Lower-than-expected gas prices, stronger climate policies, greater deployment of renewables and increasing opposition to coal could curtail coal consumption. China's 14th Five-Year Plan (FYP) will be especially relevant for the coal sector.

Methodology

This section presents the global coal demand and supply forecasts, separating the different coal types into two groups: (1) thermal coal and lignite, and (2) metallurgical (met) coal. This approach is market-oriented, as these two groups of products are priced and traded differently and are used in separate final markets for various purposes. Forecasts are provided for several large countries and regions.

Coal use is driven by many factors, such as the price relationships between coal and its substitutes (particularly for electricity generation and industrial consumption, but also for heat production, especially in developing countries); economic and population growth; and electrification rates. Because these drivers vary among countries, this *Coal 2019* market report employs country-specific econometric estimations, such as the elasticity of non-power thermal coal demand in relation to a country's gross domestic product (GDP) or population growth.

Demand projections for the respective countries and coal types are based on assumptions of various relevant parameters (e.g. GDP and population growth forecasts provided by the International Monetary Fund [IMF], fuel prices and efficiency of coal-fired power plants). The International Energy Agency's (IEA's) broad expertise on primary energy markets enables consistent demand estimates that account for development in other primary energy markets such as natural gas, renewable energies and oil. The forecasts within the report cover country-level demand for more than 60 countries and particularly emphasise coal demand in the power sector.

Most coal is used for power generation, making it the sector with the highest potential to trigger consumption growth. However, it is also the sector in which a great number of alternatives to coal exist (e.g. hydro, wind, solar, gas, oil, biomass and nuclear). This makes the electricity sector the most complex and the most sensitive regarding coal demand. While many alternative energy sources have low marginal costs and are thus dispatched ahead of coal, gas-fired power generators compete directly with (hard) coal. Power sector coal demand is therefore strongly dictated by power demand fluctuations, the share of low-marginal-cost generation, and coal-gas price spreads.

Climate policies (e.g. carbon prices), air pollution regulations and phaseout policies now need to be considered in an increasing number of jurisdictions. Government policy is a crucial driver of coal consumption. The assumptions of this report are based on policies already in force or very likely to be in force during the forecast period. Whereas in the past power demand generally followed GDP evolution, in developing economies this relationship still holds, but in most developed ones it is no longer the case, with electricity use stagnating or even sometimes declining with GDP growth.

Because the power sector is so important for forecasting coal demand, the IEA has developed a dedicated model to simulate the complex competition of generation technologies in this sector. This improved model was used for the first time in this year's coal market report to support power sector coal demand forecasts for certain countries. Based on exogenous generation capacities, forecast electricity demand and fuel and CO_2 price developments, the model simulates hourly power plant dispatch (including storages and taking into account combined heat and power [CHP] plant requirements) for each year, under the assumptions of competitive markets – i.e. generation technologies are assumed to be dispatched according to their respective short-run variable costs. Short-run costs consist mainly of fuel and, if applicable, CO_2 costs. Hourly electricity demand as well as intermittent renewable generation structures are based on historical values and weather profiles.

Electricity systems are simulated by assuming markets at the country level. Markets can trade electricity in accordance with their respective grid capacities, with generation capacity exogenous to the model. For renewables, generation assumptions are based on the IEA's latest renewables market report (IEA, 2019c). For conventional and nuclear power plants, assumptions are based first on the existing fleet. Existing plants are assumed to leave the market at the end of their assumed technical lifetime or – if applicable – based on political phaseout plans (especially relevant in some countries in Europe for coal and nuclear plants). New generation capacity is calculated based on plants that have been announced or are already under construction. In case additional capacity is required to serve demand, it is added according to policy targets and the individual market environment of each country.

Steel production, or more precisely pig iron, which uses most of the coke-oven coke, is the main driver of met coal demand. GDP growth therefore strongly influences met coal demand, as do the structure and maturity of the economy as well as other factors such as plans for new blast furnaces and trends in steelmaking (basic oxygen versus the electric arc furnace) and plans for direct iron reduction.

Supply forecasts, which are also prepared country-by-country, are based on demand forecasts plus or minus exports and imports (see Chapter 4 for details on the trade model used). Companies' and countries' investment plans, as well as future costs (based on the CRU's supply model) are also essential inputs for supply forecasts. Historical values and forecasts need to be compared cautiously, however, as the forecasts do not include stock changes.

Assumptions

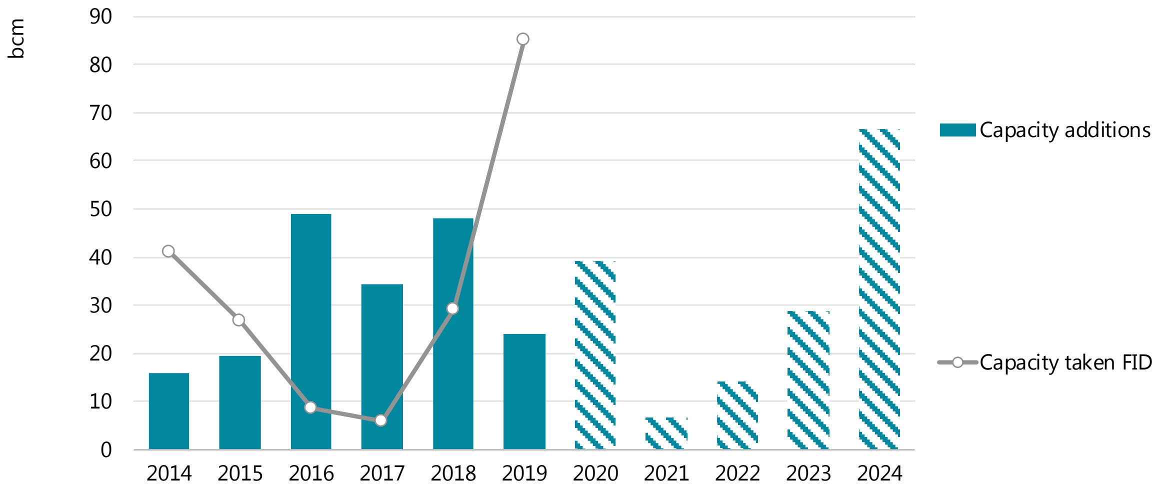
Because GDP growth is an important driver of coal consumption, and therefore an essential element for forecasting future coal demand, *Coal 2019* demand projections rely heavily on the GDP forecasts of the April 2019 *World Economic Outlook* (IMF, 2019). According to the IMF, the global economy will grow 3.6% each year over 2019-24, and for advanced economies the IMF projects sustainable growth of 1.7% through 2024. Yearly GDP growth is anticipated to be 2% for the United States; 1.6% for the European Union; 0.6% for Japan; and 2.8% for Korea. For emerging markets and developing economies, the IMF projects an average increase of 4.8% per year over 2019-24. With a rise in GDP of 5.9% per year, China will contribute a large share of global growth over the period, although less than during the last decade. For India, the IMF predicts average annual growth of 7.6% through 2024.

Fuel prices are another important driver of coal consumption. The underlying prices for crude oil, natural gas and coal are in line with other IEA market reports (IEA, 2019a; 2019b), and calculations were based on forward curves with some adjustments.

Natural gas price assumptions are based on the gas forward curves of early October 2019. In Europe, Title Transfer Facility (TTF) prices averaged USD 3.1 (United States dollars) per million British thermal units (/MBtu) in September 2019, their lowest monthly average for at least 15 years. During the forecast period, European gas prices are set to recover to an average of USD 6/MBtu as the market gradually tightens following the 2019-20 liquefied natural gas (LNG) supply wave. Henry Hub (HH) natural gas spot prices in the United States averaged USD 2.6/MBtu in September 2019, and they are expected to remain at this level until 2024. Oil-linked LNG prices are assumed to be in the range of USD 7-8/MBtu, and LNG spot prices are forecast to remain lower, averaging USD 6.5/MBtu. US LNG exports are expected to support further convergence of regional price benchmarks, although they will differ at least in transport and transaction costs. Furthermore, extrapolated from September 2019 futures, an EU emissions trading system (EU ETS) allowance price of EUR 27 per tonne of carbon dioxide equivalent (/tCO_2-eq) is assumed to persist over the period.

Downside potential for thermal coal consumption stems from uncertainty regarding the development of natural gas prices. In some regions, such as the United States, coal-to-gas switching in the electricity sector is already reducing coal consumption significantly, and in other regions such as Europe, partial switching is expected. Natural gas availability and pricing are therefore crucial to forecast coal consumption in gas-importing regions such as Europe. Figure 3.1 shows the upside potential for LNG export capacity. Whereas forward prices should account for these investments, there seem to be significant capacity additions over the forecast period and substantial upside potential based on the announcements made so far. How these capacity additions will influence prices is crucial for the future of coal consumption.

Figure 3.1. Expected LNG export capacity additions, 2014-24



Notes: bcm = billion cubic metres; FID = final investment decision.

Key message: There is significant upside potential for LNG export capacity.

Assumptions for oil prices are aligned with the IEA *Oil 2019* market report of March 2019, with the underlying futures strips updated in October 2019 when they were at USD 61/ barrel (bbl) (Brent) and projected to decrease slightly to USD 59/bbl.

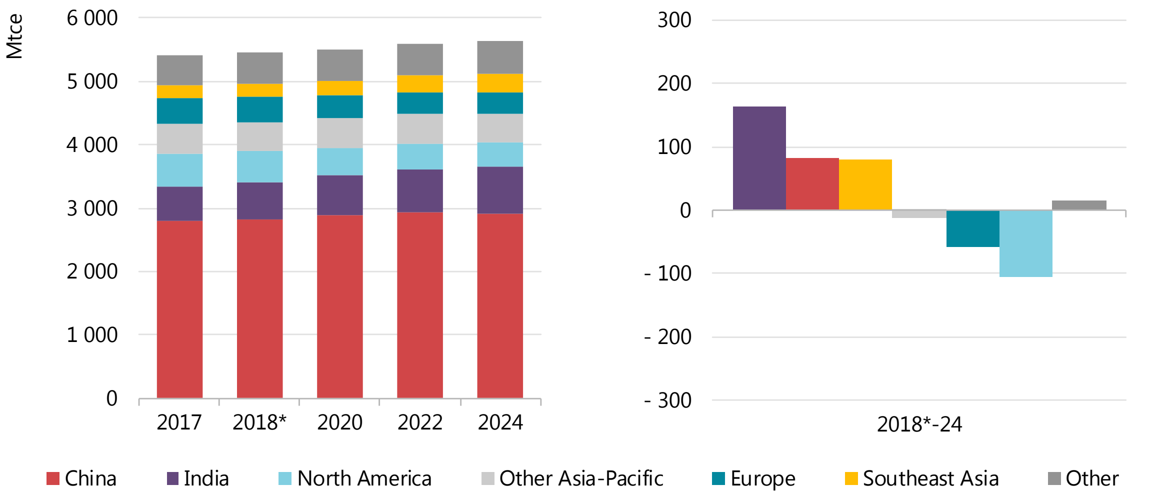
Coal price assumptions are also based on forward prices with some adjustment. The price of coal imported into Europe is expected to increase over the outlook period, from USD 60.5/t in 2019 to USD 75/t in 2024, with similar trends for other prices internationally. All values are expressed in real terms.

Global coal demand forecast, 2019-24

World coal demand is forecast to expand at a compound annual growth rate (CAGR) of 0.5% over the forecast period, reaching 5 624 Mtce in 2024 (Figure 3.2). While demand is expected to remain stable for met coal at 1 032 Mtce and for lignite at 259 Mtce, thermal coal demand rises 151 Mtce – from 4 182 Mtce in 2018 to 4 333 Mtce in 2024. Met coal demand is anticipated to peak in 2021 before it begins declining. This is due to subdued global steel demand, with average yearly growth of 2.8% forecast for the next two years (World Steel Association, 2019a). After peaking in 2021, several factors compound the decline in met coal demand, including a decrease in steel intensity (the amount of steel required to generate one unit of GDP), more efficient use of materials, and a higher degree of digitalisation. In addition, the coal intensity of steel production declines due to higher scrap metal utilisation.

Uncertainty about the global trade environment and financial market volatility could pose downside risks to the forecast, e.g. steel demand in China could decelerate as a result of rebalancing and trade tensions with the United States. For thermal coal, the downside risk stems from climate policies, financial constraints and public opposition.

Figure 3.2. Global coal demand development, 2017-24



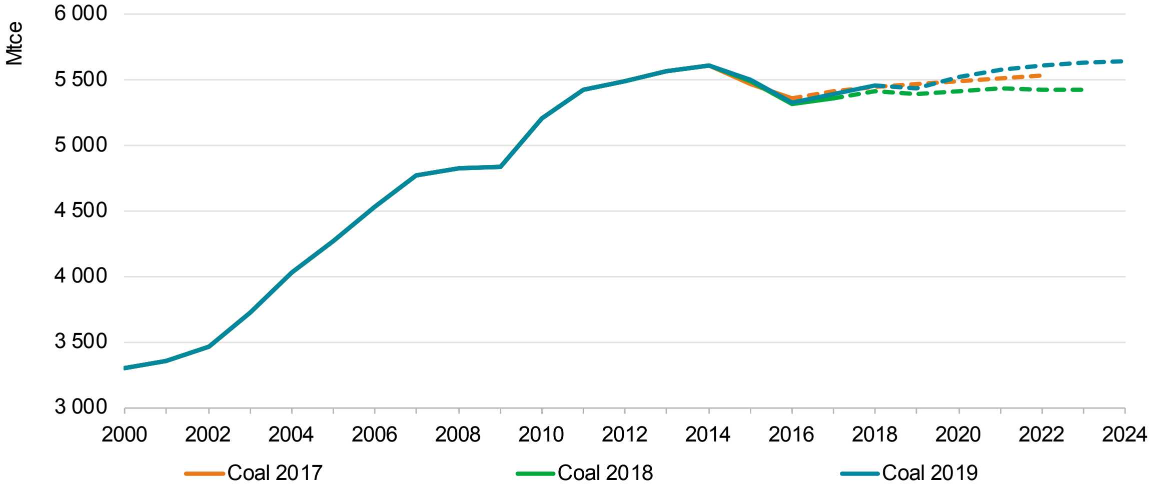
*Estimated.

Key message: Total coal demand remains solid, while the development varies highly regionally.

Coal demand development is expected to vary by region. While demand in Europe and North America continues to decline over the forecast period, consumption in the Asia Pacific region is expected to expand. China, the world's largest coal consumer, continues to increase its demand slightly through 2022, reaching 2013 consumption levels and then declining somewhat for an overall CAGR of only 0.5%. In India, rapid economic growth necessitates higher coal-fired electricity generation. Its coal demand therefore grows almost twice as much as China's and on its own offsets declining demand in North America and Europe. Another driver of consumption is Southeast Asia, which has the highest CAGR over the forecast period to meet rising power demand. Low gas prices continue to push coal-fired power generation out of the market in the United States, and in Europe coal demand falls as a result of higher gas availability and efforts to decarbonise the energy sector.

The role of coal in the future energy mix is hotly debated in energy and climate policy, and a growing number of countries are phasing out coal-fired power generation. Divestments and moves away from coal are gaining significant media attention, but market trends are proving resistant to change. In Asia especially, coal remains the largest source of electricity and is seen as abundant and affordable, so coal demand is expected to be stable through 2024. Therefore, despite the numerous policy changes and announcements regarding coal's future, this year's forecast for global coal demand does not differ substantially from last year's, and even increases slightly (Figure 3.3). This increase from the *Coal 2018* forecast results partially from the upward revision of historical data for some countries.

Figure 3.3. Comparison of *Coal 2017* through *Coal 2019* global coal demand forecasts



Key message: Despite numerous policy changes and announcements, the *Coal 2019* coal demand forecast does not differ substantially from that of last year.

Although prospects for substantial technology innovation surpass the outlook period of this forecast, carbon capture, utilisation and storage (CCUS) could have a demand-side impact, not only for power generation. CCUS in the industry sector could be crucial in abating carbon emissions and enabling the continued use of fossil fuels (Box 3.1).

Asia Pacific

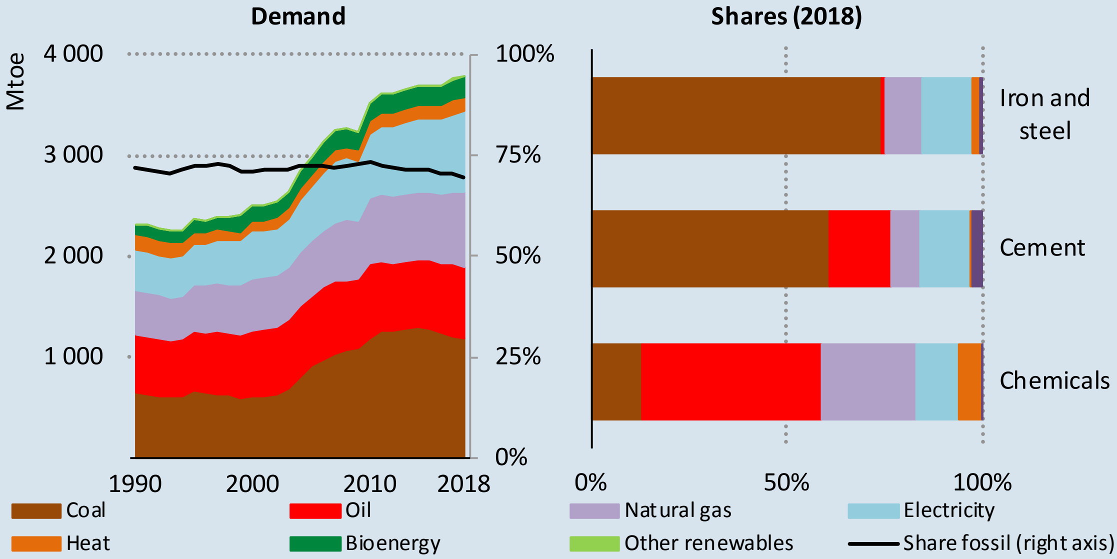
In the Asia Pacific region, coal demand is expected to increase 1.3% per year over the forecast period, with consumption reaching 4 402 Mtce in 2024. Except for Japan, Korea and Chinese Taipei, coal demand will rise for all other major coal consumers in the region. Although coal is more cost-competitive than gas for power generation, some fuel-switching could occur depending on underlying price movements.

Box 3.1. CCUS is key to future coal use in industry

Demand for coal for industrial uses has almost doubled since 2000, as coal is the dominant fuel in the iron and steel (74%), and cement (61%) subsectors, and has a substantial share (13%) in the chemicals subsector. The share of coal in industrial energy use increased from 24% in 2000 to around 31% in 2018, but it is typically also important in the production of electricity and heat for industry.

The industry sector accounts for one-quarter of CO_2 emissions from energy and industrial processes, and industrial emissions are among the most difficult to abate in the energy system. CCUS is expected to be critical in the portfolio of technologies needed to significantly reduce industrial emissions, particularly for producing iron and steel, cement and chemicals.

Global industrial energy use by fuel (left) and energy mixes of selected subsectors (right)



Recent IEA analysis highlighted three key challenges for industrial decarbonisation:

- **Process emissions**: One-quarter of industry emissions are non-combustion process emissions that result from chemical or physical reactions, and therefore cannot be avoided by switching to alternative fuels. This is particularly challenging for the cement subsector, as 65% of emissions result from the calcination of limestone, a chemical process basic to cement production. CCUS is one of few solutions to address process emissions, allowing direct capture and removal of the CO_2.
- **High-temperature heat**: One-third of industrial energy demand is for the provision of high-temperature heat. Switching from fossil to low-carbon fuels or electricity to generate this heat would require facility modifications and substantially increase electricity requirements. CCUS can enable the continued use of fossil fuels with very low or no CO_2 emissions.
- **Infrastructure lock-in**: As industrial facilities are long-lived assets with lifetimes of up to 50 years, they "lock in" emissions for decades. Retrofitting with CCUS is an important strategy for near-term emissions reductions from existing facilities.

CCUS is already being applied in the industry sector: of the 19 large-scale CCUS facilities in operation globally, 17 are in industry or fuel transformation and a further 5 industrial CCUS facilities are being constructed. Several of the existing facilities have been operating for decades, a reminder that CO_2 capture and separation is not new, but is in fact an inherent part of some industrial and fuel transformation processes (e.g. refining and natural gas processing). Three-quarters of the CO_2 capture capacity built since 2010 is in processes related to hydrogen production from fossil fuels, natural gas processing and biomass fermentation for ethanol production. These applications account for almost half of all CCUS investment in the last decade.

The profile of current facilities and investments illustrates that CO_2 capture costs vary greatly by point source and by capture technology. Costs range from USD 15 per tonne of carbon dioxide (/tCO_2) to USD 60/tCO_2 for concentrated CO_2 streams (e.g. natural gas processing and bioethanol production through fermentation), to between USD 40/tCO_2 and USD 80/tCO_2 for coal- and gas-fired power plants, to over USD 100/tCO_2 for smaller or more dilute point sources (e.g. industrial furnaces).

Although CCUS is anticipated to play an important role only in the long term, it makes significant inroads in industry in the late 2020s, capturing around 450 million tonnes of carbon dioxide (MtCO_2) in 2030, and expands rapidly thereafter.

China

China is forecast to continue accounting for half of global coal demand and be a key market force: global trends, including prices, hinge on developments in China.

Coal demand in China is expected to rise slightly until 2022 to once again reach the all-time high level of 2013, then decline slowly. Consumption of 2 906 Mtce is forecast for 2024. The demand analysis retains the sectoral breakdown of former years for China's four major coal-consuming sectors, following different trends with different drivers. Coal-fired power generation, the main coal-consuming sector, is expected to expand continuously through 2024, although decelerating over the forecast period, whereas coal demand from the steel industry peaks around 2020-21. As a result of China's efforts to reduce air pollution (its "blue sky" policy), coal consumption in the residential, commercial and small-scale industry sectors decreases. However, the decline is losing speed, at least in absolute terms, as the greatest gains have already been made and further coal replacement will be more challenging owing to gas availability and infrastructure. Coal conversion (coal-to-gas, coal-to-liquids and coal-to-chemicals) is expected to expand over the forecast period, although the increase is uncertain.

Electricity generation is China's main coal demand driver, with power generation expected to increase 3.6% per year, adding 1 700 terawatt hours (TWh) over the forecast period. This is a significant slowdown, as electricity generation grew by 6.8% in 2017 and 6.7% in 2018. Several factors are reducing electricity consumption growth in China: efficiency measures; a different economic structure (e.g. sectoral distribution of growth, i.e. services vs. heavy/light industry); and slower economic growth.

In the near term, China's GDP grows steadily but more slowly than in the past, with the ongoing trade dispute with the United States posing a further downside risk. The recent economic stimulus package aims to affect the infrastructure and real estate sector rather than industry (see below). Meanwhile, electrification of the heating and transport sectors as well as greater urbanisation of the rising middle class supports electricity consumption.

While electricity demand from China's industry sector is expected to grow only 2.5% per year until 2024, from the services sector it climbs the quickest (+9% per year). Additional electricity demand is mostly met by non-hydro renewables (i.e. wind and solar), for which output increases by well over 600 TWh until 2024, while coal-based generation rises by around 500 TWh (at a yearly growth rate of 1.7%). Thus, the portion of coal in the power mix falls to 58%, its lowest share ever.

Although new and highly efficient coal-fired power plants are commissioned to replace some of the old plants, the potential for improvement is limited, as Chinese power plants are already quite efficient (around 40% on a lower-heating-value [LHV] basis). China's coal-fired power capacity is expected to continue expanding during the forecast period: according to the 13th FYP, coal-based power capacity could be up to 1 100 gigawatts (GW) by 2020. Current capacity is just over

1 000 GW, and while an additional 120 GW of capacity are under construction, older and less-efficient power plants are likely to go offline. Furthermore, plant construction has slowed due to the lower load factors of coal-fired power plants (just over 4 000 hours per year).

The construction of new coal-fired power plants varies by region. Based on the National Energy Administration's Coal Alert policy, 32 provincial regions within China are rated, affecting the planning and construction of coal-fired power plants. One of three grades (red, orange or green) is assigned to a region based on three key indexes – capacity adequacy, resource constraints, and new project economics. While a green ranking implicates no restrains on new projects, a red grade results in the suspension of new project approvals and a delay of projects under construction. The number of provinces with green grades increased to seven in 2019, with no impacts on new power plants in Inner Mongolia, Hubei, Chongqing, Guizhou, Hunan, Guangdong and Hainan. Most of these provinces are in the Central South or adjacent regions.

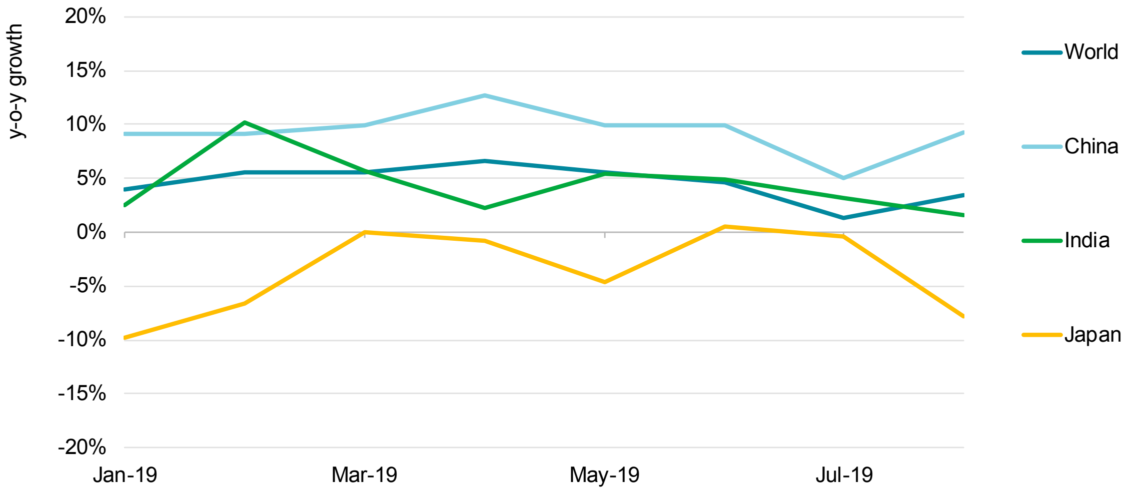
Another driver of coal demand growth is the coal conversion sector (i.e. coal-to-gas, coal-to-liquids and coal-to-chemicals). Coal consumption in this sector is expected to increase 65 Mtce by 2024. China favours coal conversion mostly because it contributes to energy security, as imports currently cover 45% of the country's natural gas consumption and 70% of its oil (see Chapter 1). New production capacity is needed for this growth, so under the 13th FYP, coal-to-gas capacity is to reach 17 bcm and coal-to-liquid capacity 13 million tonnes per annum (Mtpa) (270 000 barrels per day [kb/d]) by 2020. Additional demand from coal conversion projects is therefore expected to contribute to overall coal demand during the forecast period; however, the economics of the sector depend highly on the underlying commodity prices. Some companies appear to be struggling with poor economics and technical problems, especially in the coal-to-gas subsector. The forecast therefore does not assume that all announced projects get implemented as planned (if that were the case, coal use in this sector could be up to 50% higher).

Non-power thermal coal demand from the industry and residential sectors is forecast to decline significantly as a result of efforts to reduce air pollution. The use of coal in small, inefficient and polluting residential and industrial boilers is a major contributor to air pollution, and replacing these boilers is a policy priority. Although some will be replaced by electric boilers or CHP (in many cases coal-based), most of the phased-out boilers will be replaced by gas. The primary replacement in the residential sector is expected to be wall-hung gas-fired boilers. Substitution will be implemented in 12 million households by 2021 in the six provinces and cities of Beijing, Tianjin, Hebei, Shandong, Shanxi and Henan. Gas co-generation is also expected to expand significantly, according to the Winter Clean Heating plan. How much coal is substituted will depend on the availability and affordability of natural gas.

Furthermore, China is expected to continue shifting away from an investment-driven, capital-intensive model of growth to a more service-oriented economy. As a result, coal demand for producing cement and other energy-intensive goods will decline, despite limited substitution for coal in some energy-intensive industries (e.g. cement production). In the future, infrastructure development – and coal demand in this sector – will depend on economic growth. If it slows, investment in infrastructure could be a tool to increase growth; in contrast, if the economy overheats, this energy-intensive sector might be targeted to cool it down.

Chinese met coal demand is expected to rise until 2021 and decline thereafter. Met coal consumption is forecast to remain stable, reaching 643 Mtce in 2024, an increase of 8 Mtce from 2018. The initial increase stems mainly from economic development and infrastructure investment. In the first half of 2019, China's average year-on-year growth rate for monthly steel production was around double the global average (Figure 3.4). This hike results from the government rolling out more stimulus for infrastructure expansions in response to the US trade dispute. Chinese banks issued around USD 840 billion in loans in the first quarter of 2019, with local government bonds totalling around USD 200 billion – more than five times the amount of one year earlier. Infrastructure and real estate projects were a crucial part of these investments, keeping steel demand high. China could ramp up stimulus measures even further if the trade dispute with the United States becomes more serious. The worse trade frictions become, the more likely China will be to stimulate construction to sustain its economic growth, which will reinforce steel demand and met coal consumption. In addition to the stimulus, China implemented new construction standards in 2019, which increases the steel intensity in new buildings by around 5% (World Steel Association, 2019a).

Figure 3.4. Year-on-year steel production growth of the major steel-producing countries, January to August 2019



Source: World Steel Association (2019b), "Crude steel production monthly".

Key message: Government stimulus is propelling China's steel production growth to considerably above the rate globally and in other major steel-producing countries.

The stimulus effects are expected to subside in 2021 and economic growth is forecast to decelerate, stabilising Chinese steel demand and met coal consumption (World Steel Association, 2019a). The implementation of measures to cut debt is also expected to contribute to a decline in steel demand, and further supply-side reforms are also anticipated.

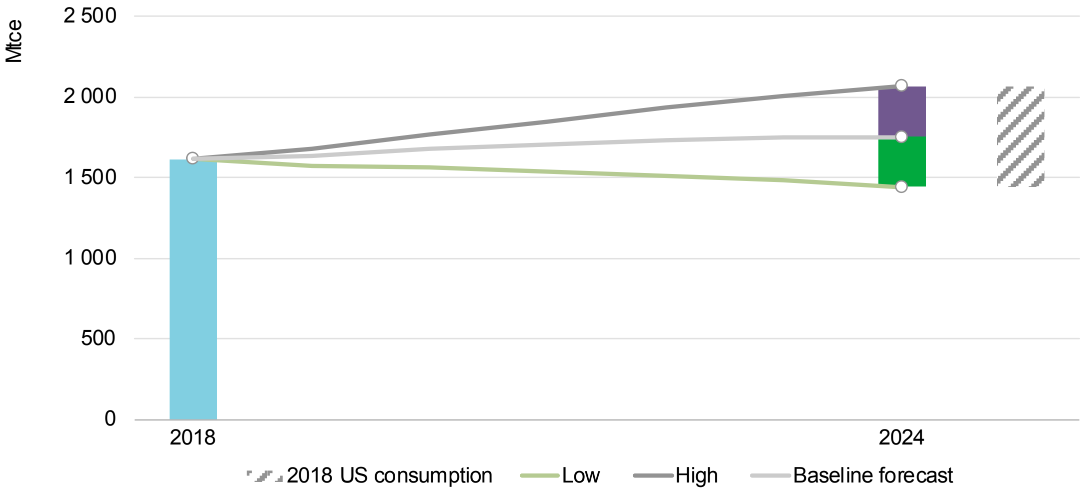
The steel sector has been undergoing significant changes since 2016 (see Chapter 1). The net result is that production capacity started to rise again in 2018. Over 2019 and 2020, there will be around 140 Mtpa of new crude steel capacity commissioned in China (S&P Platts, 2019). As China enforces stricter environmental regulations, the new capacity will mostly replace old and loss-making steel facilities with similar capacity, boosting supply-side production efficiency by 2021.

In addition, greater scrap steel usage will reduce met coal demand. The potential for scrap use to curtail met coal demand is considerable, as the scrap value chain is still immature and large amounts of unutilised scrap are available, but at a high cost. As a result of all these factors combined, met coal consumption is forecast to revert almost to the 2018 consumption level.

This trajectory does, however, hinge on the policies and targets to be established in the 14th FYP in 2020. The plan will determine Chinese coal demand by defining the direction of the economy at the macro level, the pace of nuclear, wind and solar development, and the course of coal conversion projects. Reducing air pollution and CO_2 emissions as well as overcoming other environmental hurdles will be key components of the plan, posing a downside risk for forecast coal consumption. At the same time, sustaining economic growth and guaranteeing energy supply security are objectives that favour coal.

To illustrate the uncertainty stemming from China's electricity sector, Figure 3.5 shows the differences in coal consumption according to assumptions of the electricity elasticity of GDP growth (resulting from different sectoral shares in GDP, different energy efficiency trajectories, etc.).

Figure 3.5. Variation in Chinese power sector coal consumption depending on different electricity elasticities of GDP



Key message: Depending on the evolution of electricity elasticity of GDP growth in China, coal consumption in its power sector could vary more than the current US coal consumption.

Considering the baseline forecast of this report, the calculation uses a ±0.3 variation in elasticity, i.e. a narrower range than variations in past years. Coal is assumed to account for 90% of the difference in total electricity production, so that if electricity generation increases, coal will provide 90% of this addition and vice versa. Under such assumptions, by 2024 the development of electricity elasticity of GDP growth could result in a Chinese coal consumption variation of a magnitude greater than total US coal consumption in 2018.

India

Total coal demand in India is forecast to rise 4.2% per year, from 585 Mtce in 2018 to 748 Mtce in 2024. Demand for thermal coal increases to 656 Mtce (+141 Mtce from 2018), while met coal consumption grows 4.8% (to 73 Mtce) and lignite rises 4.8% (to 20 Mtce). This makes India the world's fastest-growing coal consumer in absolute terms.

As coal is the major source of power generation in India, the power sector accounts for more than two-thirds of the country's coal consumption. It is also the main reason for the forecast rise in coal demand. Driven by strong GDP growth of 7.6% per year and persistently low per-capita electricity consumption, total power generation is expected to increase 6.4% yearly. Although most of the additional electricity demand is met by coal, the rise in coal demand does not quite keep pace with the increase in coal-fired generation because the thermal efficiency of the power plant fleet also increases.

To meet growing demand, new coal-fired generation capacity is expected to be commissioned – around 45 GW by 2022, which will raise coal capacity to 238 GW (excluding captive power plants) (Reuters, 2019a); approximately 37 GW are already under construction. India's largest electricity generator, state-run NTPC Ltd, alone wants to expand its coal-fired capacity 38 GW by 2032. Around 23 GW of old, inefficient power plants could be retired by 2022 as a result of stricter environmental standards introduced in 2015.

The expansion of other energy sources, particularly renewables, has an important influence on projections, as India's government has set an ambitious target to reach 175 GW of renewable capacity by 2022. Considering current progress in renewable capacity additions, the country's power minister has indicated that 225 GW of renewables will be possible at the current pace of growth (Reuters, 2019b). The majority of renewable capacity (around 112 GW) is expected to be solar, with 67 GW of wind-based generation capacity by 2024 (India's government officially targets 100 GW of solar and 50 GW of wind by 2022). The share of renewables in total power generation thus rises to 21% in 2024, an increase of around 6 percentage points. Expansions in gas-fired generation and nuclear power (4GW under construction) have only a minor effect on the forecast.

Economic growth and infrastructure development also stimulate coal consumption outside the power sector, with non-power thermal consumption expected to increase 28 Mtce, to 165 Mtce in 2024. Although cement and sponge iron production are the largest consumers, growth in thermal coal demand from outside the power sector is forecast to decelerate. Although interest in coal gasification is rising, no major developments are anticipated during the forecast period.

In 2018, India overtook Japan to become the world's second-largest crude steel producer, and by the early 2020s it will also become the second-largest pig iron producer; the ratio of pig iron to steel production is expected to increase over the forecast period. Met coal demand rises substantially, by 4.8% per year to 73 Mtce in 2024, boosted by the National Steel Policy (NSP) approved in 2017 by India's government, which aims to create a globally competitive steel industry in India. Starting at 138 Mtpa of steelmaking capacity in 2017-18, the NSP 2017 envisages 300 Mtpa by 2030-31 (IBEF, 2019). New projects for steel production facilities are already in construction or planning, for a total production capacity of over 50 Mtpa. Most are brownfield projects in eastern India.

Box 3.2. India's infrastructure programme boosts coal consumption

India wants to become a USD-5 trillion economy. However, economic growth slowed in 2018 to its lowest annual rate since 2013 (World Bank, 2019). To counter this trend, India's government announced stimulus measures including tax breaks and the intention to invest USD 1.4 trillion in infrastructure development within the next five years. For the financial year (FY) 2019-20, India's government allocated around USD 63 billion to the infrastructure budget. The infrastructure programme acknowledges the need to invest around USD 700 billion between 2018 and 2030 for railway infrastructure, and in the 2019-20 Union Budget, the Ministry of Railways allocated USD 14 billion for FY 2019-20. The government also aims to further expand the road network: under the existing scheme, it plans to upgrade 125 000 km of roads connecting rural areas over the next five years, at an estimated cost of USD 11 billion.

India's government has already introduced measures to unblock institutional bottlenecks as well as an infrastructure programme that includes the ongoing Delhi-Mumbai Industrial Corridor (DMIC) project. An estimated USD 100 billion will be spent on the DMIC, which is 1 500 km long and has as its spine a high-speed rail system linking the New Delhi Capital Region with India's largest container port in Navi, Mumbai. Other factors include continued growth of the construction sector as a result of strong housing demand, initiatives to connect states through waterways to reduce logistics and transport costs, and the Made in India scheme that aims to transform India into a global design and manufacturing hub.

India's recent infrastructure investments have already affected coal demand, and implementation of the massive investment programme it has announced is expected to support demand for both thermal and met coal even further. The infrastructure sector accounts for 9% of steel consumption and is expected to increase to 11% by 2025-26, with this higher steel consumption raising met coal use. According to the Indian Steel Association, the country's steel demand is forecast to grow by over 7% in both FY 2019-20 and FY 2020-21 as infrastructure construction, automobile and railway activities increase. The National Mineral Development Corporation is expected to raise iron ore production 75 Mtpa by 2021, indicating new opportunities in the sector, and steel production capacity already expanded to 138 Mtpa in FY 2017-18, while the National Steel Policy 2017 targets 300 Mtpa of capacity by 2031.

Thermal coal demand is expected to increase in response to rising power demand (see above) as well as cement and sponge iron production and industrial activity. The housing and real estate sector accounts for nearly 65% of India's total cement consumption, while another 25% is used for public infrastructure (IBEF, 2019). Measures such as the affordable housing programme (also known as Housing for All) propelled cement production, as did a 19.4% (USD-18 billion) surge in national highway construction. As a result, the cement industry was the country's fastest-growing infrastructure sector during FY 2018-19 (with growth of 13.3%) (IBEF, 2019).

This growth may be sustained by government infrastructure investments, as India is expected to become the world's third-largest construction market by 2022 (IBEF, 2019). Cement production capacity is thus expected to reach 550 Mtpa by 2025, an increase of around 50 Mtpa from 2018. Most of the current capacity is installed in the North (e.g. Rajasthan, Punjab and Haryana) and in the South (e.g. Tamil Nadu, Andhra Pradesh, Karnataka). These two regions account for 60% of current production.

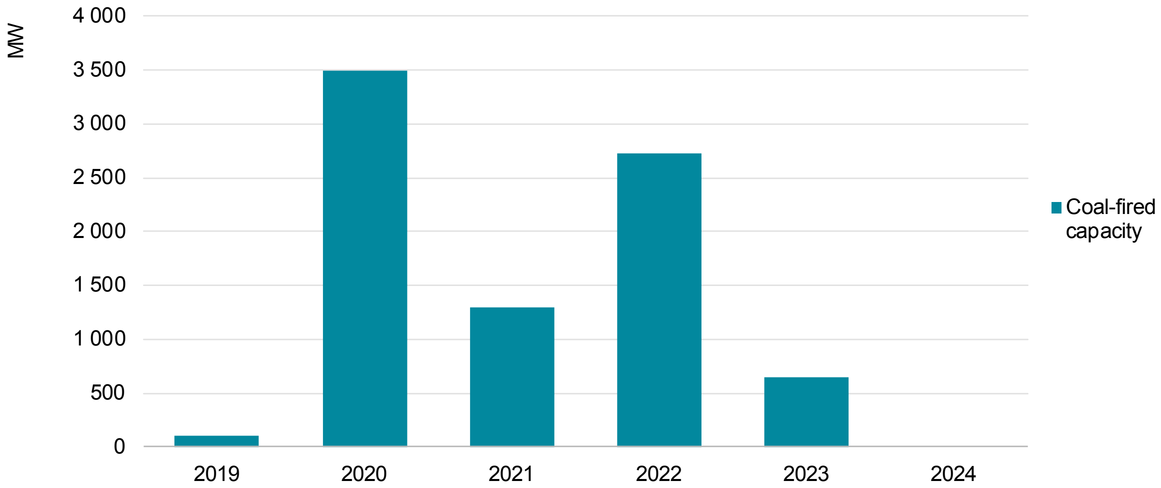
The domestic coal supply could also benefit from infrastructure investments, as coal accounted for 48% of the freight handled in 2017. Although using rail to move freight is forecast to expand at a lower rate than other modes (heavy truck use in particular), rail retains its predominant role as a carrier of bulk materials such as coal. Strong growth in non-bulk materials, usually carried by road (freight trucks) means that the overall share of rail freight in the delivery of goods and materials is under pressure from other modes.

Japan

In Japan, coal consumption is expected to remain relatively stable, decreasing by only 7 Mtce to 158 Mtce in 2024, with the power sector consuming around 60% of total coal demand. Coal-fired power generation provides baseload power in the country and is less sensitive to renewable output than natural gas. While power demand declines 1.1% over the forecast period, several nuclear power plants are expected to restart and others might follow. In 2018, 6.3 GW of restarts had been approved by the Nuclear Regulation Authority, so the forecast assumes nuclear generation of 110 TWh by 2024.

Renewable energy generation is also forecast to expand, producing around 35 TWh of additional generation. Although this additional electricity will mainly replace gas-fired power generation, it will also affect coal generation. Concurrently, around 8.3 GW of additional coal capacity is under construction and expected to come online by 2023 (Figure 3.6).[1] At the same time, less than 1 GW of coal plants will retire, while several oil-fired power units (less than 1 GW of capacity) are set to be decommissioned and other oil units will be under planned outages for several years. This is contributing to the resilience of coal-fired generation in Japan's future power system.

Figure 3.6. Coal-fired power plant projects in Japan, 2019-24



Note: MW = megawatt.

Key message: A total 8.3 GW of new coal-based generation capacity is expected to begin operations in Japan by 2024.

Public opposition to coal is growing, however. Japan's Environment Ministry announced in March 2019 that it would oppose any additional new coal-fired power stations that do not have emissions-reduction plans. This coincides with the announcement that several large companies, including Mitsui, Mitsubishi and Itochu, will be scaling down coal business outside Japan because some proposed coal power projects have been cancelled. However, the effect of these announcements is not likely to be felt until after the forecast period of this report. In the long term, Japan still appears to recognise coal as an important baseload power supply, according to its long-term energy supply and demand outlook. Furthermore, the government of Japan released a Roadmap for Carbon Recycling Technologies in June 2019 to promote carbon utilisation.

Japanese steel production is expected to decline gradually as the temporary boost – probably associated with the 2020 Olympics – diminishes and exports continue to fall. Met coal consumption decreases slightly as a result (-1.5% per year) to 41 Mtce in 2024.

[1] The interested reader is referred to last year's report, which presents a detailed table of current projects.

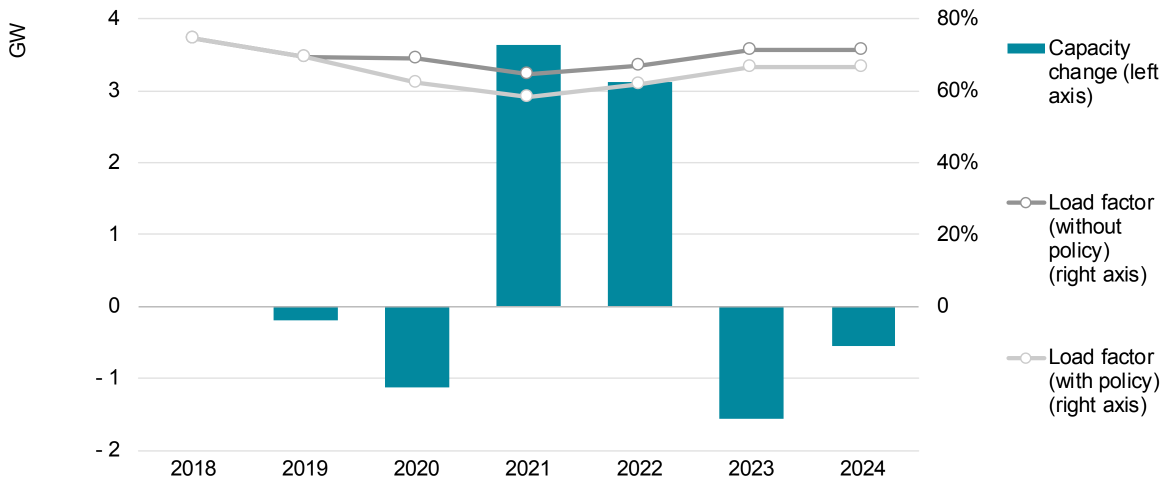
Korea

Korea's coal consumption is expected to decline 1.8% per year on average, or 13 Mtce by 2024. Most of the decrease (9 Mtce) is expected in power generation, despite electricity demand growth. Increased nuclear and renewables output, and strong environmental regulations will reduce the role of coal.

Due to local air pollution, Korea has introduced strong environmental regulations to reduce emissions and improve air quality. These regulations limit the maximum output of 60 coal plants across the country to below 80% of their respective capacity when fine dust in the atmosphere rises to a harmful level. Additionally, there are four coal-fired power plant units that must stop or decrease their generation during the spring when fine dust is most prevalent. It is expected that companies will schedule plant maintenance during this period to limit the impact of these regulations on annual production.

In 2019, a committee consisting of ministers, lawmakers and non-governmental organisations (NGOs) submitted a recommendation to support the government's air pollution regulation. The recommendation is likely to be adopted and includes an expansion of the enforced shutdowns. It would require 8 to 15 units to stop operations for the winter season (December-February), and up to 27 power plants (nearly half of the current coal fleet) to stop in March-June.

Figure 3.7. Korean coal-fired power plant capacity and load factor changes under additional air pollution policy, 2018-24



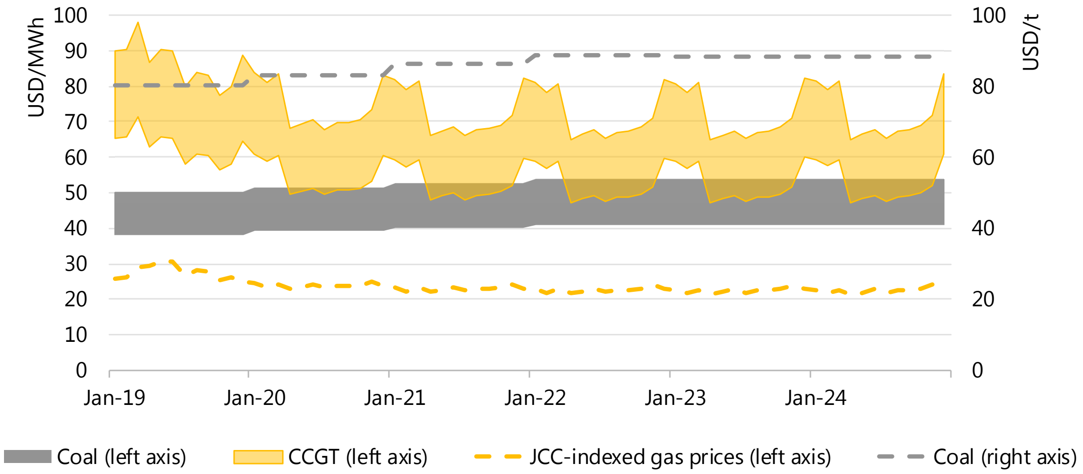
Key message: Korea's new policy to tackle air pollution is expected to reduce load factors by about 4 percentage points.

The demand forecast assumes that the policy will be implemented but not take effect before 2020; it is therefore estimated that it will reduce the load factor of the coal fleet by 4 percentage points (Figure 3.7). Additionally, around 7.5 GW of new coal plants are forecast to be commissioned by the end of 2022, replacing some older capacity and improving the efficiency of coal-fired power generation. The largest capacity additions are the Goseong GreenPower 1 and 2 (2.1 GW) as well as the Gangneung EcoPower 1 and 2 (2.1 GW).

In addition to these regulatory instruments to reduce coal-fired generation, Korea's government has revised the taxation of coal and LNG. In May 2019, it introduced a new tax scheme to support

LNG imports and gas-fired over coal-fired generation. The consumption tax on LNG was reduced by 80%, while taxes for coal increased almost 30%. In addition, import taxes on LNG, which do not apply to coal, were reduced by 85%. These tax changes further improve the competitivity of LNG-fuelled combined-cycle gas turbines (CCGTs), which have already benefitted from falling LNG prices in recent years.

Figure 3.8. Marginal Korean hard coal- and gas-fired power generation costs, 2019-24



Notes: MWh = megawatt hour; JCC = Japan Crude Cocktail. CCGT net efficiency: 40-58%; coal net efficiency: 35-46%.

Key message: In Korea, coal-fired power generation faces increasing competition from natural gas.

As a result, calculations based on our price assumptions show that the fuel costs of the most efficient CCGTs are lower than those of the least-efficient coal plants (see Figure 3.8, in which a range of efficiencies is considered for both coal and gas plants for the prices plotted in the chart).

Table 3.1. Plants switching to gas in Korea

Unit	Fuel	Utility	Capacity (MW)	Start of commercial operations
Samcheonpo #1	Coal	KOEN	560	Aug-1983
Samcheonpo #2	Coal	KOEN	560	Feb-1984
Taean #1	Coal	KOWEPO	500	Jun-1995
Taean #2	Coal	KOWEPO	500	Dec-1995
Honam #1	Coal	EWP	250	Oct-1972
Honam #2	Coal	EWP	250	Oct-1972
Boryeong #1	Coal	KOMIPO	500	Dec-1983
Boryeong #2	Coal	KOMIPO	500	Sep-1984
Total			**3 620**	

Although there have been plans to retire 2.8 GW of coal-fired power plant capacity by 2022 (see last year's report), utilities may decide to retain the profits of operating these plants. In 2019, several utilities submitted plans to the Ministry of Trade, Industry and Energy (MOTIE) to modify 1.2 GW of oil-fired power plants and 3.6 GW of coal capacity to burn natural gas (Table 3.1); these plans include some of the coal-fired power plants previously slated for retirement. The plans are not yet confirmed, but it seems likely to happen in the medium-term.

Building on the momentum of the new central government, South Chungcheong province joined the Powering Past Coal Alliance (PPCA) in October 2018. The province contains nearly half of Korea's coal-fired power plants and is the first jurisdiction in Asia to join the alliance. As part of South Chungcheong's 2050 Energy Vision Plan, the province vowed to shut down 14 coal power plants (18 GW of capacity) by 2026, reducing Korea's coal-based power generation by around 45%. However, the success of this plan hinges largely on the central government's willingness to revise the subsequent national energy roadmap.

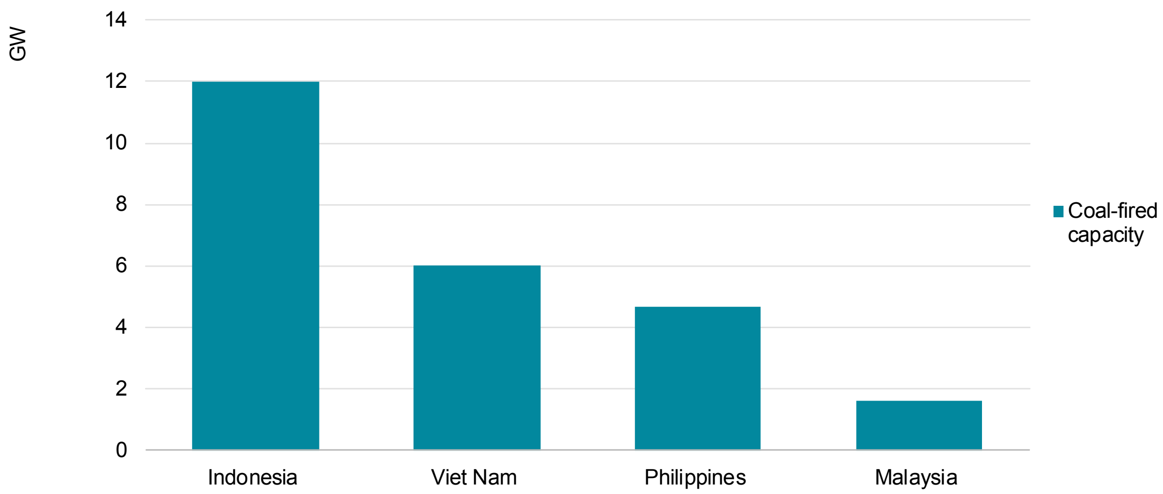
South Korea's met coal consumption is forecast to remain relatively stable in the near term and to eventually decline 3 Mtce by 2024 (to 32 Mtce). As the economy's steel intensity is currently at a high level, steel production is expected to begin declining soon.

Southeast Asia

Southeast Asia's coal demand is forecast to increase at the highest rate globally (+5.6%), rising from 204 Mtce in 2018 to 283 Mtce in 2024.

Strong economic and population growth in the region result in a robust rise in power demand (4.6% per year). Coal-fired power generation, which is expected to contribute a substantial share of the additional demand, increases 150 TWh by 2024 (expanding at 5.5% per year), whereas gas-fired generation increases 136 TWh over the outlook period. The share of coal in power generation therefore increases by 1 percentage point to 40% in 2024, with new coal-based capacity installed to provide the additional generation (Figure 3.9).

Figure 3.9. Additional coal-fired generation capacity in Southeast Asia



Key message: Around 24 GW of new coal-based generation capacity is expected to begin operating in Southeast Asia by 2024.

In **Indonesia**, coal-fired capacity is expected to expand almost 12 GW by 2024. In contrast with the current predominantly subcritical fleet, new capacity will be supercritical and increase overall generation efficiency. According to the **Viet Nam** Power Development Plan, 49% of the country's total installed generation capacity will be coal-fired by 2025, and the forecast assumes that coal generation capacity reaches 25 GW by 2024, an addition of approximately 6 GW. Coal-fired capacity is also under development in the **Philippines** (5 GW) and **Malaysia** (2 GW). Lignite demand in Thailand and the Lao People's Democratic Republic (Laos) is forecast to remain flat.

Strong economic growth over the outlook period continues to support expanding crude steel and cement production in Southeast Asia, so non-power thermal and met coal consumption are also expected to increase. Met coal demand grows from 7 Mtce in 2018 to 17 Mtce in 2024 as new blast furnaces are expected in Malaysia, Indonesia and Viet Nam. Laos plans to build 2.4 GW of coal-fired capacity to export electricity to Cambodia, but it will probably not be operational before 2024.

Other Asia Pacific

Coal demand in **Australia** declines slightly from 61 Mtce in 2018 to 58 Mtce in 2024. The Australian energy provider AGL announced in 2019 that it will postpone closing three of the four generation units at its 2-GW Liddell hard coal-fired power station until 2023. In addition, Western Australia's government announced the retirement of two of the four operating units at the Muja power station by the end of 2022 (the two units have an approximate capacity of 0.4 GW). The decommissioning of these power plant puts further pressure on coal consumption, which has already been partially replaced by renewables. While most of the decline is in thermal coal (from 42 Mtce in 2018 to 38 Mtce in 2024), lignite consumption remains flat at 16 Mtce in 2024, as does that of met coal at 4 Mtce.

In **Chinese Taipei**, coal consumption remains stable, with total demand rising 1 Mtce to around 61 Mtce in 2024. As a result of the referendum held in November 2018, Chinese Taipei will not build any more coal-fired power plants (76% of voters opposed the expansion of coal capacity). In addition, met coal demand is expected to remain stable at 8 Mtce.

Pakistan's coal consumption grows strongly at 9% per year over the forecast period, to reach 24 Mtce in 2024. The country has a population of around 200 million people and annual per-capita electricity consumption of 650 kilowatt hours (kWh), whereas the United States, for example, has an annual per-capita consumption of 13 500 kWh. Gas and oil currently account for around 50% of power generation. In 2019, the 1.3-GW imported coal-fuelled Hub power plant and the 660-MW domestic lignite-fuelled Engro Power Gen Thar started operations, raising coal-fired power generation to over 5 GW by the end of 2019. In addition, around 5 GW of new coal-fired capacity are under development, mostly using lignite from the Thar field. The share of coal in power generation is therefore expected to rise from almost zero in 2016 to 15% in 2024.

With a population of 160 million and even lower annual per-capita electricity consumption of 500 kWh, **Bangladesh** is in a similar situation to Pakistan. Natural gas fuels the majority of power generation, while oil supplies most of the rest. Coal's share in the power mix is expected to rise from 2% in 2016 to 20% in 2024. The first unit of the imported coal-based 1 320-MW Payra power plant is about to start operations, with the second unit expected in 2020. There are more than 10 GW of total capacity under development, with over 20 GW having been proposed. As a result, coal consumption is forecast to increase to 14 Mtce in 2024.

North America

In North America, coal consumption is forecast to decrease at a rate of 3.9% per year, dropping from 490 Mtce in 2018 to 385 Mtce in 2024. Coal demand is declining in all countries of the region.

United States

US coal consumption has decreased significantly in recent years, falling 4.2% in 2018 to 453 Mtce. Coal demand is expected to shrink to 358 Mtce in 2024 (at a CAGR of -3.8% over the forecast period). The decline is swift until 2020 and slower thereafter. As around 90% of coal consumption in the United States is used for power generation, future coal demand is driven mainly by the electricity market, with several elements shaping the US power landscape.

Sluggish power demand growth of 1% per year is expected over the forecast period. The considerable increase in 2018 was exceptional, mainly the result of a cold winter and hot summer (EIA, 2019a).

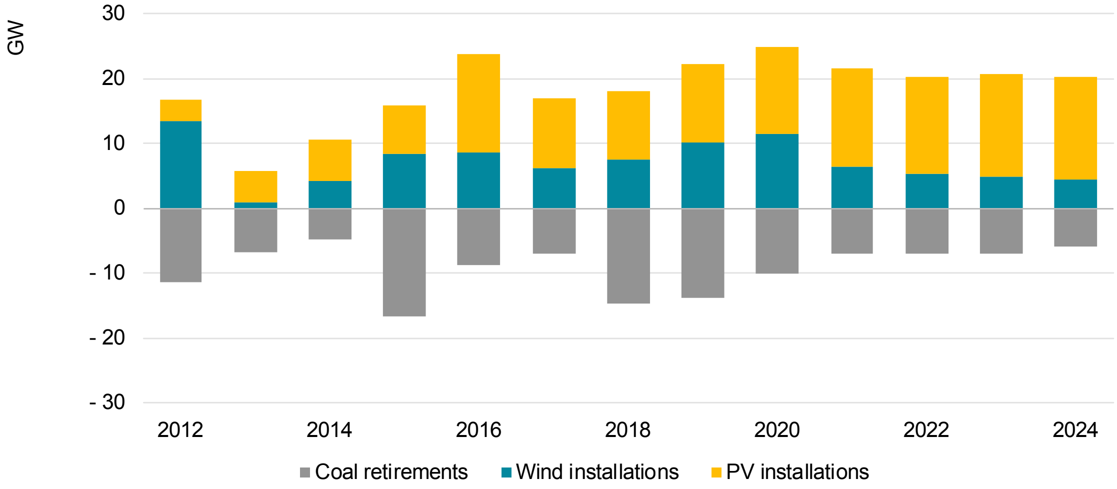
Regarding the regulatory framework, the current US administration publicly supports coal-fired power generation as an important element of the electricity system. Accordingly, it is reversing numerous rules that had previously been helping to curb coal-fired generation. One of the major changes is the introduction of the final Affordable Clean Energy rule (ACE) by the Environmental Protection Agency (EPA) in June 2019. The ACE, which replaces the Clean Power Plan (CPP), aims to provide existing coal-fired power generators with "achievable and realistic standards for reducing greenhouse gas (GHG) emissions" (EPA, 2019). The ACE encourages efficiency upgrades by establishing CO_2 emissions guidelines for states to use when developing plans. The regulation may improve coal power plant economics and slow retirements compared with the CPP.

The US Department of Energy's (DOE's) Coal FIRST (Flexible, Innovative, Resilient, Small, Transformative) programme aims to develop the next generation of coal plants by dramatically changing performance, efficiency and emissions, and the 45Q tax break offers opportunities for CCUS. The DOE recently announced financial support to several CCUS projects for the Front-End Engineering and Design (FEED) studies, to use the 45Q and CO_2 sales for enhanced oil recovery. Relevant coal-fired power plants receiving funds are: Prairie State Energy Campus (1.6 GW), San Juan Generating Station (1.8 GW), Gerald Gentleman (1.4 GW), Dry Fork (0.4 GW) and Milton Young (0.7 GW) (DOE, 2019). Most of the plants are in oil-extracting regions such as North Dakota or Wyoming, which could enhance the business case and possibly reduce coal capacity retirements in the mid-2020s.

Although these projects and policy changes are beneficial for the US coal industry, they are not expected to significantly alter the current coal demand trajectory through 2024. Aside from some smaller testing units, there will be no investments in new coal-fired generation capacity in the United States, and the drivers of the decline of recent years are still present.

Robust renewable energy expansion, stimulated by tax breaks and state portfolios as well as rapidly falling costs, is expected to persist, limiting generation from fossil fuels (Figure 3.10). Plus, a higher feed-in tariff for intermittent and weather-dependent renewables is shifting coal plants from baseload to mid- and peak-load generators, reducing the full-load hours of coal-fired power plants.

Figure 3.10. Capacity changes by technology, 2012-24



Source: Adapted from EIA (2019b), "Preliminary Monthly Electric Generator Inventory".

Key message: In US, coal retirements will continue, while renewable expansion soldiers on.

Natural gas prices are expected to remain low throughout the forecast period, so aside from the winter period, even the least efficient gas-fired CCGTs are less costly to operate than the most efficient coal plants in the eastern markets. In the west, however, where coal prices are lower and gas prices can be higher, there is more scope for competition with gas.[2] It is expected that in addition to the 23 GW of coal capacity officially announced for retirement another 28 GW will be retired by 2024 (Figure 3.10). The load factors of lignite-fired plants are expected to decrease as intermittent wind and solar electricity production expands, with lignite demand consequently falling from 25 Mtce in 2018 to 19 Mtce in 2024. Only a minor amount of lignite-fired power capacity (170 MW) is scheduled for decommissioning.

Even though import tariffs on steel products could strengthen domestic steel production, the more widespread use of the electric arc furnace decreases met coal consumption slightly (-1% per year) to 19 Mtce in 2024.

However, other non-power coal usage could support demand. In June 2019, the Indiana Department of Environmental Management (IDEM) approved an air permit for Riverview Energy to build a coal-to-diesel plant in Dale. The plant would use 1.6 Mt of coal and produce 4.8 million barrels (mb) of low-sulphur diesel and 2.5 mb of naphtha each year, although it is unlikely that the plant will be commissioned before 2024.

Other North America

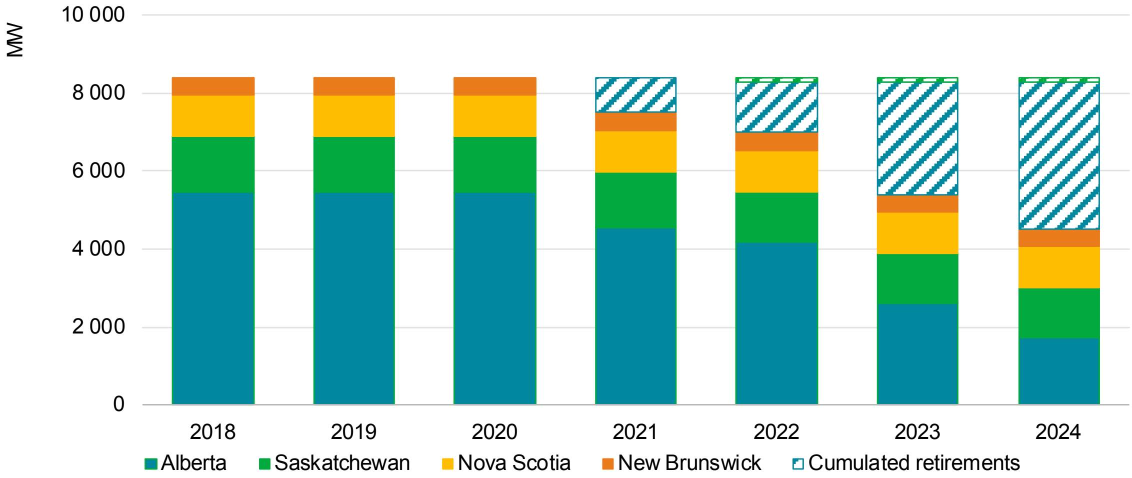
Coal demand will also decline in Canada and Mexico.

Canada's coal consumption is forecast to drop significantly, by around 9.1% per year, to 11 Mtce in 2024. The country is a co-founder of the Powering Past Coal Alliance and is therefore committed to phasing out unabated (non-CCUS) coal by 2030. Canada's coal-fired power fleet is situated in four provinces, with more than two-thirds of the total capacity in Alberta. While no retirements are

[2] In the west, low mining costs in the Powder River Basin make fuel-switching in the electricity sector difficult.

expected for Nova Scotia and New Brunswick, Alberta will retire almost 70% of its current coal-based power generation capacity (Figure 3.11). The province is rich in resources and has the largest coal reserves of the country, but it also has major natural gas resources, and since gas prices are currently below USD 2/MBtu, gas is an affordable substitute for coal-fired electricity generation. This will result in a regional shift in remaining coal consumption, with coal-fired capacity (and plant output) dropping by nearly half over the forecast period.

Figure 3.11. Coal-fired power plant retirements in Canada, 2018-24



Key message: Canada's coal-fired capacity will decline by half, with most retirements in Alberta.

In **Mexico**, coal demand declines only slightly, from 16 Mtce in 2018 to 15 Mtce in 2024. Even though Mexico has joined the PPCA, significant power plant capacity reductions are not expected before 2024.

Central and South America

After a sharp increase in coal consumption in 2018, coal demand in Central and South America is expected to decline slightly (1% per year), from 50 Mtce in 2018 to 47 Mtce in 2024.

Higher thermal coal demand may result from new coal-fired power plants. One of the largest power plants under construction is the ultra-supercritical La Luna plant (3 x 375 MW) in **Colombia**, which is to start production in 2022. Another project is Punta Catalina (2 x 376 MW) in the **Dominican Republic**, which will provide up to 30% of the national power demand. In **Brazil**, the coal-fired Pampa Sul power plant (345 MW) started operations in July 2019. Load factors for coal plants in Brazil are difficult to forecast, as seasonal variations in hydro production are a crucial factor in Brazil.

In June 2019, **Chile** (the region's largest consumer of coal for power generation) announced its plans to shut down eight coal-fired power plants by 2024, accounting for around 1 GW. This represents 20% of the country's coal-based generation capacity.

Met coal demand is expected to remain stable, amounting to 16 Mtce in 2024. Brazil prevails as the region's largest met coal consumer by far, with annual consumption of 12 Mtce in 2024.

Europe

In Europe, coal demand continues to fall. Consumption is forecast to decrease 2.6% per year, from 391 Mtce in 2018 to 333 Mtce in 2024. The region's overall decline results from the sharp drop in consumption within the European Union, as coal demand in eastern and southern Europe (non-EU countries) remains stable and Turkey's consumption is expected to increase.

European Union

Coal demand in the European Union is forecast to drop 4.5% per year, to 234 Mtce in 2024. Germany and Poland are the major consumers, together accounting for 56% of total EU demand. This combined share is expected to increase to 58%. While Germany intends to reduce its coal consumption, Poland's remains stable. Excluding Germany and Poland, the share of total EU coal consumption in global coal demand shrinks to less than 2% in 2024.

The decline in consumption is driven mainly by the power sector. While total electricity consumption is expected to remain nearly constant over the outlook period, competition from gas-fired generation as well as energy policies supporting higher renewables use lead to decreasing coal consumption. As a result, thermal coal demand is forecast to drop substantially, by 5.6% per year, from 134 Mtce in 2018 to 95 Mtce in 2024. Lignite demand is also expected to fall, but at a slower pace (4.7% per year to 81 Mtce in 2024).

A clear divide between eastern and western EU member states is apparent in the medium-term outlook for coal-fired power generation. While most western members have agreed to phase out coal-fired generation with more or less firm schedules by 2030, eastern EU countries continue to consider coal-generated power a pillar of the electricity supply. Since last year's report, three countries – Germany, Greece and Hungary – have announced coal phaseouts, to take place after 2024.

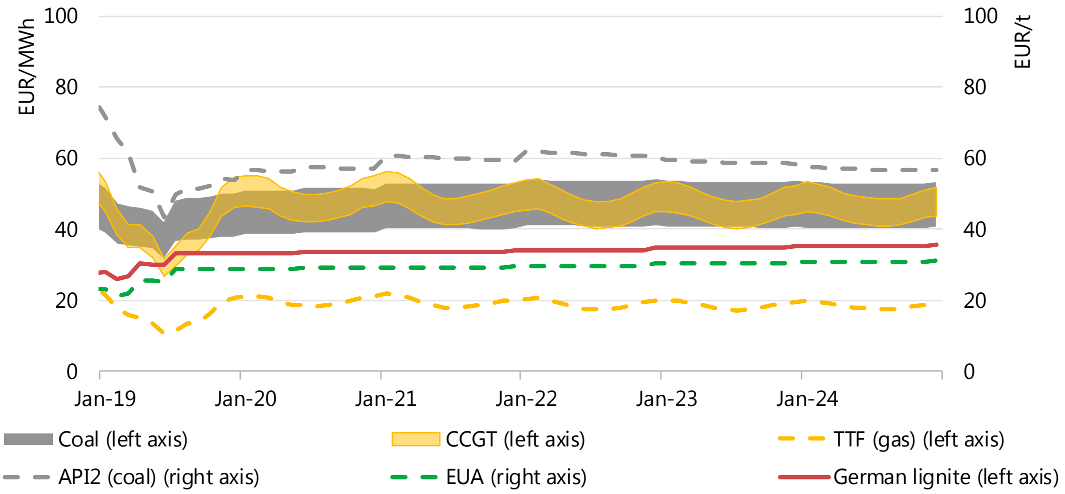
The European Union has ambitious decarbonisation targets: as outlined in the 2030 climate and energy framework of 2014, it plans to reduce GHG emissions by at least 40% (from 1990 levels) by 2030 and increase the share of renewable energy sources to 27%. Declining renewable capacity costs and ambitious renewables targets are expected to substantially augment generation from renewable energy sources (by around 7.7% per year over the forecast period), pushing thermal generation capacity out of the market. The share of coal in the electricity mix is therefore forecast to decline from 19% in 2018 to 13% in 2024 (less than half the share of renewables).

In addition, climate policies, air pollution regulations and phaseout policies aim to reduce coal consumption. Air pollution regulations, such as the Large Combustion Plants Directive, have led to substantial capacity closures across Europe. Even more stringent standards were established under the Industrial Emissions Directive, which obligates many plant owners to invest in emissions-reduction technologies or to shut down operations.

The second pillar of reducing coal consumption is energy resource competition. It is supported by the EU ETS, which monetarises the external effects of CO_2 emissions. The ETS has been reinforced with additional policies in recent years, namely the backloading mechanism and the Market Stability Reserve (MSR). As expected, the most recent EU ETS reform raised the price of emissions permits to EUR 23/tCO_2 in December 2018, up from EUR 8/tCO_2 in January 2018. Prices jumped further in July 2019, to around EUR 29/tCO_2 and are expected to remain high.

At the same time, natural gas prices have dropped significantly since mid-2018, owing to warmer winter temperatures and a loose LNG market. As US and Australian LNG exports have expanded, Europe's natural gas supplies have diversified. According to the gas forward curve, market participants expect the market to remain loose into the future and gas prices to be low. These two factors combined alter the competitiveness of coal with gas and the dispatch order of power plants to some extent (Figure 3.12).

Figure 3.12. Marginal EU hard coal- and gas-fired power generation costs, 2019-24



Notes: API = Argus/McCloskey's Coal Price Index; EUA = European Union Allowance. CCGT net efficiency: 46-58%; coal net efficiency: 35-46%.

Key message: Competition between gas-fired and coal-fired power generation in the European Union is becoming fierce.

Less efficient coal-fired power plants especially will face fierce competition from gas-fired ones. In addition, the cost trends of coal-fired plants are showing increasing seasonality as they basically follow gas price variations between winter and summer. In some cases, such as CHP plants, additional revenue streams have to be considered when assessing the profitability of generation units.

As stated above, EU coal consumption is sensitive to CO_2 and gas prices. To illustrate this price-sensitivity, Figure 3.13 presents the outputs generated by hard coal and lignite power plants as functions of their prices, where the centre represents the base case considered in the forecast of this report.

Intuitively, an increase in gas prices favours coal-fired electricity output, while a higher CO_2 price produces the opposite effect. Within the given price range, coal-based power generation can vary by up to 230 TWh, which is almost 40% of estimated production in the base case, reflecting the uncertainty stemming from underlying price assumptions. This uncertainty is skewed, however, even though the price deviations are evenly distributed. While the upside potential for coal amounts to a maximum increase of 40% compared with the baseline, the downside potential is -24%.[3] This can be explained by the prevailing must-run capacities resulting from CHP plants, and the relationship between existing power plant capacities and the peak load.

[3] These upside and downside potentials assume a fixed renewable feed-in tariff and fixed coal prices as stated at the beginning of this chapter. Indeed, higher-than-forecast renewable generation represents additional downside potential for coal.

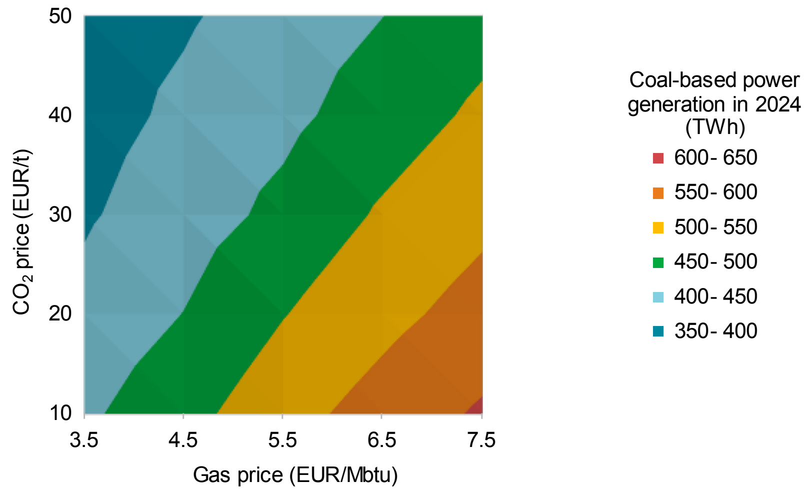
Another factor is the differing price sensitivities of hard coal- and lignite-fired power generation: lignite-fired is more sensitive to rising CO_2 prices than hard coal power output, as the underlying lignite capacity is dispatched in the baseline scenario while hard coal capacity already faces competition from gas-fired plants. The upside potential for hard coal is therefore higher than for lignite, and the considerably larger amount of hard coal capacity means that the total upside potential is greater than the downside.

This also contributes to the sensitivity of coal-based generation in the individual countries. Due to the high shares of lignite in its energy mix, Germany's coal-fired generation is especially sensitive to CO_2 prices, resulting in stronger downside potential. In contrast, Poland's coal-based generation is less sensitive because its coal capacity utilisation factors are much higher. In other countries such as Italy and the Netherlands, coal plants face a wider range of utilisation factors depending on the underlying price assumptions.

In addition to the respective differences between lignite and hard coal-based generation, countries' trade positions shift significantly as underlying price assumptions change. Countries that have coal power plants, including Germany, have a better net trade position when price conditions favour coal over gas. Likewise, net trade positions for countries without coal plants are better when the pricing system puts coal at a disadvantage. In some cases, the net power trade position is expected to flip during the forecast period: for instance, under the price assumptions of this forecast, Germany shifts from being a net exporter of around 50 TWh in 2018 to a net importer of around 55 TWh in 2024. This level of imports could increase or decrease by 25 TWh, depending on the underlying price assumptions.

In addition, industrial use will decline after phase 4 of the EU ETS enters into force. A CO_2 border tax to protect European industries and avoid carbon leakage is under discussion. In combination with efficiency gains and increased scrap steel use, phase 4 enforcement could also cause future steel demand to fall. Steel tariffs further complicate the outlook, but it is forecast that met coal demand will decline by 2.1% per year to 58 Mtce in 2024.

Figure 3.13. Estimated price-sensitivity of EU coal-based power generation, 2024



Key message: Large thermal spare capacity and generation costs in a similar range give rise to high price-sensitivity in the EU.

Germany

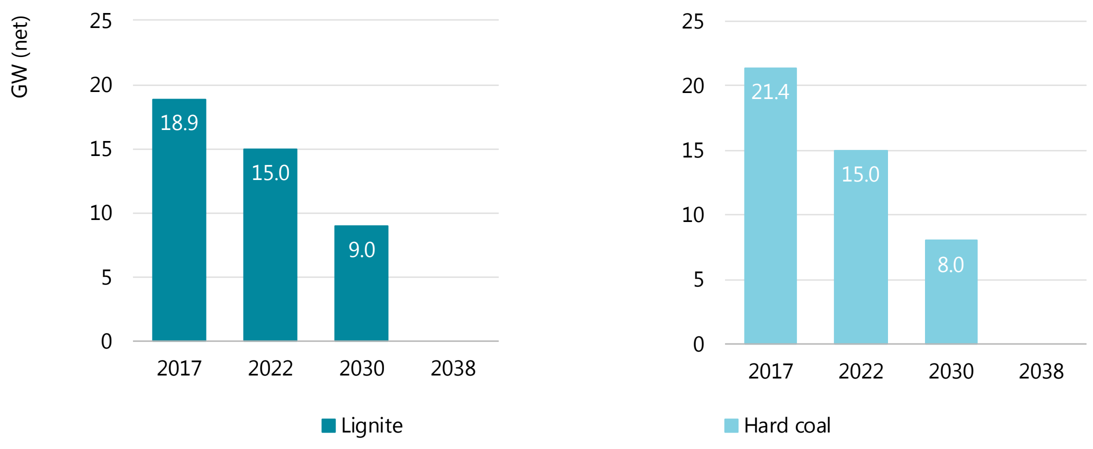
Germany, with a coal demand of 95 Mtce, accounted for around 31% of total EU coal consumption in 2018. Its demand is forecast to drop to 62 Mtce by 2024, declining 6.9% each year. Even though the country will phase out its nuclear power plants by 2022 (current nuclear capacity is 9.5 GW), mainly gas-fired power plants and renewables will substitute for the missing generation. While total electricity consumption remains nearly stable, electricity generation from renewable sources expands strongly through 2024. As early as 2019, renewable electricity generation from wind and solar could surpass output from lignite and hard coal, as indicated by the generation mix in the first half of the year (Frauenhofer, 2019).

Around 1.5 GW of coal capacity is planned to be decommissioned (in addition to the nuclear shutdowns) (BNetzA, 2019). STEAG announced it would decommission its power units at Luenen (500 MW) at the beginning of 2019 due to a lack of economic prospects for the coal-fired power plant. Furthermore, the Commission on Growth, Structural Change and Employment was tasked with drawing up a phaseout plan for coal power and published its results in January 2019 (Figure 3.14). Even though the commission's recommendation to phase out coal has not been fixed by law or regulations as of December 2019, the model and the forecast applied in this report assume acceptance of the proposal as given. For 2024, lignite capacity is forecast to decrease to 13.5 GW and hard coal capacity to 13 GW.

Due to regulatory uncertainty, some commissioning of coal-fired capacity is being delayed or may even be cancelled. For example, the new 1.1-GW Datteln 4 hard coal plant with 45% efficiency, initially set to begin production in 2018, has been further delayed. It is uncertain whether the almost-completed power plant will ever operate amid the regulatory phaseout of coal.

Met coal consumption is expected to remain relatively stable at 17 Mtce in 2024.

Figure 3.14. Recommendations of the Commission for Growth, Structural Change, and Employment on Germany's coal phaseout



Notes: Capacity as of the end of the year (without plants in secure standby for backup purposes).

Key message: Coal-fired power generation in Germany may end in 2038.

Poland

Poland is the European Union's second-largest coal consumer; it is also the most coal-dependent, with a 77% share of coal in its power mix. Poland's electricity consumption is expected to grow 2% per year throughout the forecast period. There are currently 3.2 GW of new coal-fired generation capacity under construction, mostly replacing older, less-efficient capacity. The planned Ostroleka power plant, with a capacity of 1 GW, was supposed to be the last coal-based project in Poland according to the country's energy minister. However, state-run utility Enea's decision to participate in the project, which is expected to be completed in 2023, was declared invalid by a court ruling. It seems that substantial growth in Poland's coal demand is therefore unlikely.

Consequently, most growth in electricity demand will be covered by an expansion in renewable energy generation and gas-fired power plants. Coal-fired generation will increase only slightly, by an average of 0.5% per year through 2024. Given Poland's large domestic coal reserves, the high rate of employment in the coal industry and strong government support, coal will remain the most important energy source in the Polish power sector. It is forecast that coal demand in Poland will decrease by only a marginal 0.9% per year, to 73 Mtce in 2024.

Other European Union

In the rest of the European Union, thermal coal and lignite consumption is also expected to decrease. Demand is forecast to fall to 99 Mtce in total in 2024 (a reduction of 5.1% per year).

In **Spain**, the future of the coal fleet is gloomy. Most of the 10 GW of coal capacity in existence at the end of 2018 will close during the outlook period. Iberdrola was the first company to announce the closure of all its coal units, Guardo (486 MW) and Lada (348 MW). Soon after, Naturgy also announced the closure of all its coal power plants: Anllares (347 MW), Narcea (502 MW), La Robla (615 MW) and Meirama (557 MW). Endesa announced the closure of Compostilla (1 005 MW) and Teruel (1 056 MW), and later added Litoral de Almería (1 120 MW) and As Pontes (1 403 MW). Alcudia (468 MW) in Mallorca (Baleares) is under consideration, and it is assumed that Viesgo will close Puentenuevo (300 MW) but that Los Barrios (570 MW) will continue operating. Hidrocantábrico is also assumed to continue the operations of its Aboño 1 (570 MW) and Soto de la Ribera (346 MW) plants, while closing Aboño 2 (342 MW). The share of coal in the electricity mix will therefore be negligible, with coal consumption dropping rapidly by 2020 as a result. It then remains almost flat, amounting to 7 Mtce in 2024.

Italy's coal demand falls by around 4 Mtce over the forecast period (a decline of 7% per year), whereas **Greece**'s remains stable at 7 Mtce, resisting the trend of the rest of the European Union as power demand recovers after Greece's economic crisis. The **United Kingdom** continues to reduce its coal consumption to 2 Mtce by 2024, after which time it is assumed to have no coal-fired power plants. Around 4 GW of coal-based capacity are expected to close as early as 2019 (IEA, 2019c). RWE recently announced its intention to shut down its 1.5-GW Aberthaw B coal-fired power plant in Wales in 2020 due to challenging market conditions. In addition, SSE announced closure of its 1.5-GW Fiddler's Ferry plant in 2020.

Other Europe

Turkey is currently the third-largest thermal coal and lignite consumer in Europe. It is diversifying its energy sector and reducing power sector dependency on energy imports, mainly gas, by focusing on its local resources for power generation. The country's coal demand is expected to grow significantly at 3.7% per year over the forecast period, rising to 76 Mtce by 2024 and overtaking Germany and Poland to become Europe's largest coal consumer. Rising electricity demand (+5.3% per year) and expanding coal-fired power capacity drive the country's growth in coal consumption. Construction of the 1.3-GW Hunutlu coal power plant began in 2019, with operations expected to commence in 2021. Demand for lignite, which forms the majority of Turkey's domestic resources, rises for power generation.

Turkish met coal demand is forecast to remain stable at 9 Mtce per year until 2024, as crude steel production is highly influenced by trade tariffs. Given that Turkey is a net exporter of steel products, future developments will depend on trade tariff evolution.

Middle East

In the Middle East, coal consumption is expected to increase 4.7% per year, from 12 Mtce in 2018 to 16 Mtce in 2024. The demand of the region's two major coal consumers is developing in opposite ways. The largest consumer, **Israel**[4], which joined the Powering Past Coal Alliance at the end of 2018, is expected to decrease consumption by around 8.9% per year on average, for a total of 4 Mtce in 2024. Since the discovery of the Leviathan gas fields, Israel has been gradually replacing imported coal-based power generation with domestic natural gas. In contrast, the **United Arab Emirates (UAE)** is expected to expand its coal consumption to 7 Mtce in 2024. The four-block Hassyan coal-fired power station, part of China's ambitious Belt and Road Initiative (BRI), is expected to make its 2.4 GW of ultra-supercritical power units operational in 2020. The forecast does not include the 1.8-GW Ras Al Khaimah coal power plant of the UAE's Federal Electricity and Water Authority (FEWA) or the 1.2-GW Duqn power plant in Oman, which would imply higher coal consumption if completed by 2024.

Eurasia

Coal demand in Eurasia remains stable over the projection period, increasing only slightly at 0.1% per year to 279 Mtce. Met coal demand makes up this marginal increase in consumption.

Russia

The Russian Federation's ("Russia") coal demand is expected to remain stable at 175 Mtce in 2024. While met coal consumption increases 3 Mtce by 2024, thermal coal decreases by roughly the same amount. Most of the rise in electricity demand (+99 TWh by 2024) is met by natural gas as it gradually replaces coal-based power generation, which contracts 0.7% per year. In January 2019, Russia approved a programme to modernise thermal power generation units by upgrading up to 41 GW of capacity to higher technical and efficiency standards between 2022 and 2031 (IEA, 2019b).

Higher steel exports are forecast to support domestic crude steel production, raising Russia's met coal demand to 68 Mtce in 2024.

Other Eurasia

The demand of Eurasia's second-largest coal consumer, **Ukraine**, is expected to fall by around 2.6% per year, from 40 Mtce in 2018 to 34 Mtce in 2024. **Kazakhstan's** consumption increases slightly, from 56 Mtce in 2018 to 61 Mtce in 2024, as more coal-fired electricity generation is needed to meet rising electricity demand. The 1 320-MW Balkhash coal power plant is under construction, and unit 1 (500 MW) of the Ekibastuz GRES-1 plant is to restart by 2021.

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

Africa

Coal demand in Africa is expected to remain stable at 161 Mtce over the outlook period, although development varies slightly by region.

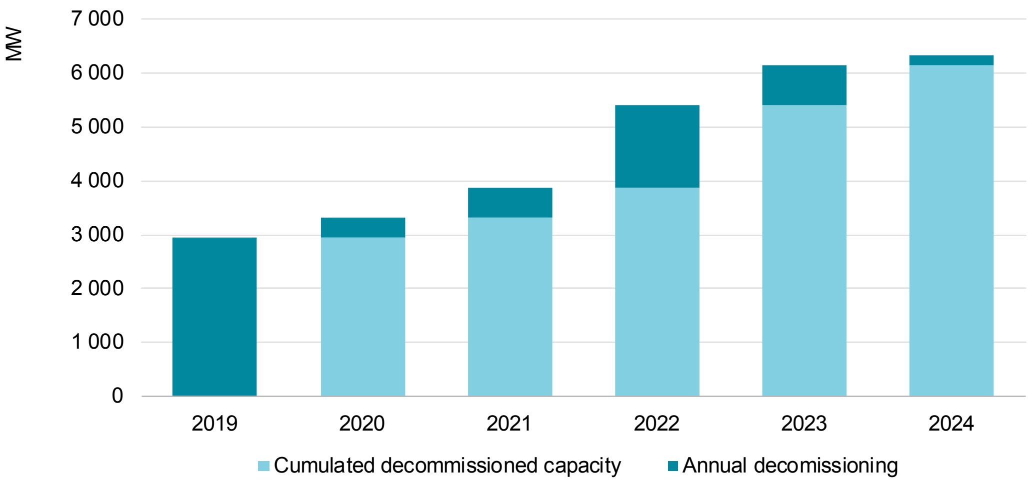
South Africa

South Africa's coal demand decreases only slightly, by 0.4% per year. In 2024, the country is expected to consume 140 Mtce of coal, compared with 143 Mtce in 2018. However, four key issues will determine the future of coal in South Africa: the new mine ownership (see Supply section); the new Integrated Resource Plan (IRP); decisions on Eskom's difficult situation (see Box 3.3); and the social unrest.

Coal remains South Africa's dominant source of electricity, holding a 90% share of the electricity mix. Electricity demand is forecast to remain roughly the same as in 2018 due to a slowdown in economic growth, while renewable electricity generation from wind and solar expands 8.5% each year, replacing some coal.

The IRP is the part of the National Development Plan that identifies possible pathways to reach the country's medium- and long-term economic and social objectives for the electricity system. The IRP provides a technology investment roadmap spanning several decades, which is essential for investor certainty. Updating the IRP of 2010, a new one was approved by the government on 17 October 2019. Coal-based capacity of 33 360 MW is targeted for 2030, down from the current 37 150 MW, as 1 500 MW of new capacity are more than offset by the retirement of old plants. As power generation expands only slightly and production from solar, hydro and wind resources increases, the share of coal in the energy mix drops significantly.

Figure 3.15. Decommissioning of South African coal-fired power plants, 2019-24



Key message: Up to 6.3 GW of South Africa's coal-fired capacity is expected to be gradually decommissioned by 2024.

To achieve South Africa's emissions-reduction commitments, the government introduced a carbon tax that took effect 1 June 2019. The first phase of the tax, from June to December 2022, imposes a rate of around USD 8.34 per tonne of carbon dioxide equivalent (/tCO_2-eq). However, tax breaks could reduce the effective rate by 60% to 95%. After a review of the tax's impact, the second phase will run from 2023 to 2030. Eskom, already in financial distress, accounts for about 42% of the country's GHG emissions, and although it will benefit from exemptions in the first phase, it expects carbon-pricing costs of up to USD 813 million in the second phase.

Two massive coal-fired power plants – Medupi power station at Limpopo (4.8 GW, of which 3.2 GW are operational) and the Kusile power plant at Mpumalanga (4.8 GW, of which 2.4 GW are operational) – are expected to be completed, although their future is uncertain. Initially thought to be initial-stage problems, the performance issues of the operational Medupi and Kusile units have now been put down to more fundamental problems, related particularly to the functioning of the boilers, grinding mills and fabric filters.

Further upside potential is presented by the Thabametsi and Khanyisa coal-fired power plant projects, which amount to a capacity addition of around 0.9 GW. The two projects are being developed by independent power producers (IPPs) but are having difficulties gaining environmental approvals and finding finance, so are unlikely to start operating within the forecast period. At the same time, up to 6.3 GW of capacity could retire by the end of the forecast period (Figure 3.15).

Non-power thermal coal consumption is forecast to increase slightly (+2 Mtce by 2024) for Sasol's coal-based production of synfuel and various chemicals, while met coal consumption remains stable at 3 Mtce. These numbers could rise, however, with the creation of industrial clusters such as the Limpopo Eco-Industrial Park (LEIP). The project includes a coal-to-liquid plant that could require around 2.9 Mtpa of thermal coal, as well as other industrial facilities. In addition, development of the Energy and Metallurgical Special Economic Zone could increase South Africa's coal consumption. The project involves a 4.6-GW coal-fired power plant as well as coke ovens, iron and steel production, and ferroalloy production, which could demand around 15 Mtce of thermal and met coal, but no progress has been reported.

Box 3.3. Eskom facing dire straits

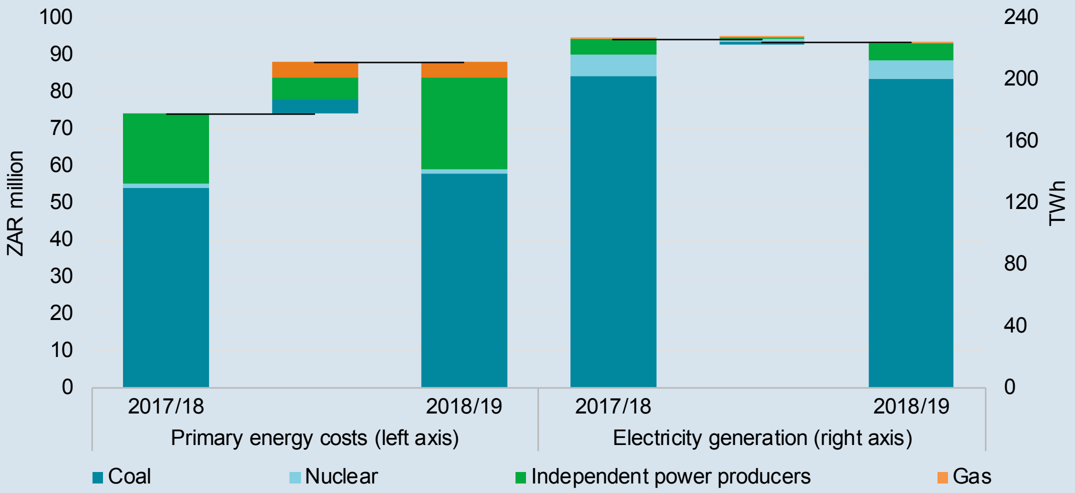
Eskom, South Africa's largest utility, is unlikely to invest in further coal-fired generation capacity projects, as the company is in a deep financial crisis. At the beginning of 2019, South Africa suffered one of its worst series of power cuts for over a decade. The electricity supply was compromised when Eskom was forced to shed 594 gigawatt hours (GWh) of load for more than ten consecutive days. Unplanned breakdowns amounted to a failure of more than 12 GW, while Cyclone Idai interrupted the interconnector to Mozambique. Plus, Eskom ran short of diesel reserves for its open-cycle gas turbines and water at its pumped-hydro plants. At the height of the crisis, between 4 GW and 5 GW of load were shed.

As a result, Eskom introduced a nine-point recovery plan to return to an energy availability factor of 75%. These points include improved maintenance planning, appropriate emergency management and, most importantly, investments in existing power plants as well as units under construction.

Eskom's ballooning debt is putting the utility under severe financial strain, following credit-rating agency downgrades of ten notches over the past decade. In addition, Eskom's coal costs have surged fivefold in the past 11 years and its employee costs have increased substantially, as staff numbers have risen by 10 000. Additionally, payments to renewable IPPs made up 22% of total costs while accounting for only 4.8% of total production.

Neither tariff increases nor a USD 1.6 billion-a-year commitment by the government solved Eskom's financial problems. Eskom ran out of funds and approached complete collapse on multiple occasions in 2019, as it was increasingly unable to repay its mostly state-guaranteed debt of more than USD 30 billion. Eskom's CEO stated in a presentation that the company is in a "utility death spiral with an outdated and unsustainable business model, operational and structural inefficiencies, and a lack of transparency in a rapidly changing energy landscape".

Comparison of Eskom's primary energy costs and corresponding electricity generation, 2017-18



Source: Based on Eskom's integrated reports.

Because of Eskom's importance to South Africa, the government has committed to a bailout of around USD 19 billion over three years. However, the bailout comes with conditions, the main one being the restructuring of Eskom. In February 2019, the government announced that the vertically integrated utility would be split into three separate subsidiaries for power generation, transmission and distribution. The transmission unit will be separated first, as Eskom's transmission activities and assets are generally considered to be relatively well managed, well maintained and reliable.

With Eskom no longer able to fund new power generation projects, there are plans to enable South Africans to participate in electricity generation by freeing up the market for self-generation and distributed energy resources. Licensing for small-scale embedded generation (SSEG) for capacities of between 1 MW and 10 MW has been simplified, so that businesses can generate their own electricity and feed it into the grid. The national energy regulator approved about 0.5 GW of SSEG, without the developer having to seek permission for a deviation from the IRP.

Other Africa

Morocco's coal consumption is expected to increase to 8 Mtce per year, as the 1.4-GW Safi power station started operations in the fourth quarter of 2018. By 2025, Morocco plans to increase its coal-fired capacity by 2.5 GW, gas-fired by 1.5 GW, and renewables by 2.9 GW. One of the proposed projects is the 1.3-GW Nador power plant, but it will not be online before 2024. Coal consumption in **Egypt** is forecast to surge to 4 Mtce by the end of the outlook period, with demand driven by rising cement production and the increasing use of coal for power production. Several power plants are currently under development, although only Hamraweim is likely to go ahead (see Box 4.2).

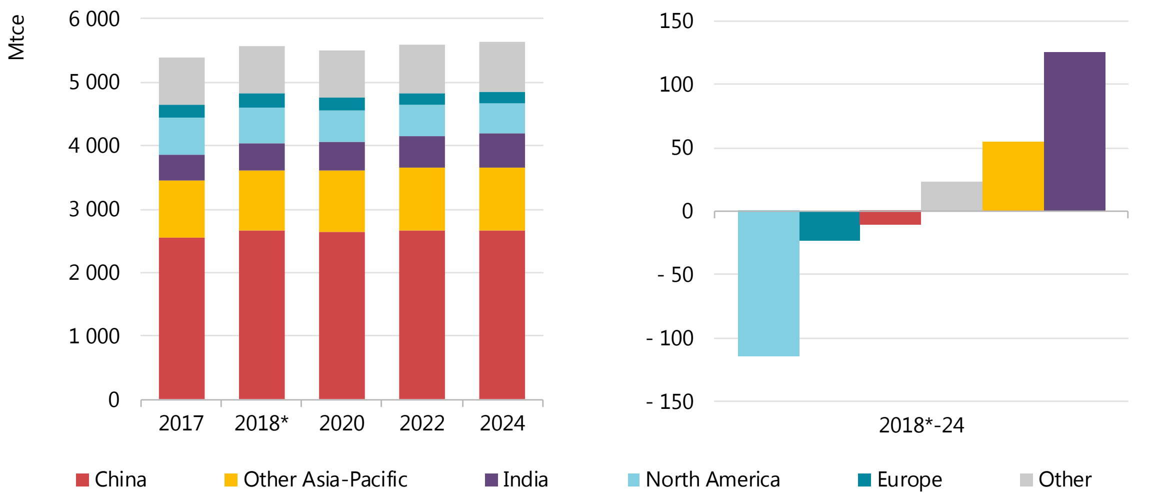
There is potential for rising coal consumption in other African countries as well, but it is still difficult to know if it will materialise, given the obstacles to new project development, i.e. governance, local and international opposition, and financial (especially since the President of African Development Bank announced it will not support coal in Africa). Among the most significant projects, in **Botswana**, Kibo is trying to develop a 300-MW power plant for a coal-to-liquids plant, a 300-MW plant to supply the grid, and the coal-to-liquids plant with the potential to consume 5 Mtce. In **Ivory Coast**, San Pedro Port coal power plant (2 x 350-MW) has not reported any recent progress. In **Tanzania**, Kibo is developing the 300-MW Mbeya coal-to-power project. In **Kenya**, there has not been any progress on the Lamu power plant (1 000 MW) due to licensing issues, financing difficulties and local opposition. Likewise, no progress has been reported for **Nigeria**'s 1 000-MW Nasarawa coal power plant that would use domestic coal. In **Zimbabwe**, China's Tsingshan is planning to build a 600-MW power plant to meet demand from a 2-Mtpa integrated steel factory.

It seems more likely that some small projects could go ahead, such as the Imaloto power plant (60 MW) in **Madagascar**, the Kam'mwamba coal plant (300 MW) in **Malawi**, and the Tete power plant (300 MW) in **Mozambique**.

Global coal supply forecast, 2019-24

Total global coal supply is forecast to remain mostly stable from 2018 (5 570 Mtce) to 2024 (5 624 Mtce) (Figure 3.16). Thermal coal production increases by 58 Mtce to 4 333 Mtce, while met coal production grows by 10 Mtce to 1 032 Mtce. Lignite production decreases around 18 Mtce to 259 Mtce by 2024.

Figure 3.16. Global coal production development, 2017-24



*Estimated.

Key message: Total coal supply stagnates over the outlook period, while development varies considerably from one region to another.

Asia Pacific

China

China is forecast to remain the largest coal producer by far. The country's total production is roughly stable, falling 11 Mtce from 2 664 Mtce in 2018 to 2 653 Mtce in 2024 . In energy terms, 47% of the world's total coal production is expected to come from China by 2024, one percentage point less than today.

China's coal production depends mainly on the evolution of domestic demand and costs, which will determine imports. As a result of offsetting effects in the different consumption sectors, coal demand is forecast to remain roughly stable. China's production forecast is hence driven by the cost-competitiveness of domestic coal with imports from other countries.[5]

Supply-side reforms in China's coal industry, initiated at the end of 2015, will affect production during the outlook period. The reform involves several emendations, but replacing unsafe, polluting, high-cost mines with safer, cleaner, lower-cost ones is the cornerstone. Consolidating mines and companies is also an important aspect.

According to the 13th FYP, China intends to replace 500 Mtpa of coal mining capacity to increase efficiency. In addition, 300 Mtpa of mining capacity are planned to be shut down. By 2018, China had reduced its coal production capacity by at least 690 Mtpa (Argus Media, 2019). Hence, mine closures should now be less rapid because no more than 110 Mtpa need to be cut in 2019 to reach the 800-Mtpa capacity reduction target set for 2020. Production at small mines is expected to fall by 130 Mtce (-20%) by 2024, while from medium-sized mines it increases by around 47 Mtce and from large ones by 72 Mtce (Figure 3.17).

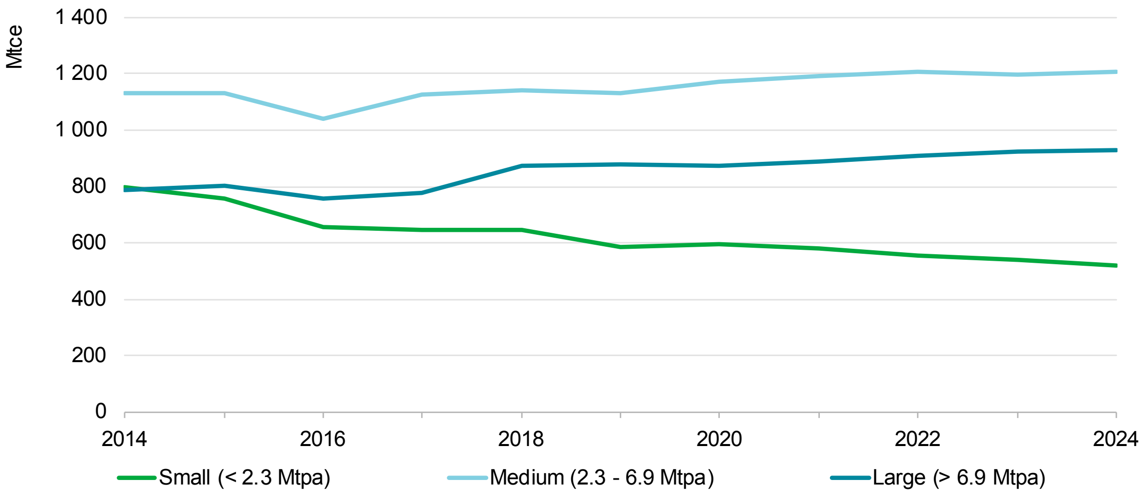
Steam coal production is forecast to remain roughly the same, dropping 4 Mtce from 2018 to amount to 2 083 Mtce in 2024. The same applies for met coal production, which is likely to decline at a slightly higher rate to total 570 Mtce in 2024 (-7 Mtce from 2018). Since coking coal is produced mostly at smaller and less-efficient mines, China's mine restructuring is likely to affect met coal more strongly (see Chapter 1).

In the first half of 2019, China's energy regulator approved construction of 162 Mtpa of new coal production capacity, adding to its approval of 25 Mtpa in 2018. Around 200 Mtpa were commissioned in 2018, with another 340 Mtpa having started trial operations. In total, around 1 billion tonnes per annum (Btpa) of coal capacity has either been approved, is under construction or is in trial operation. Most of the projects involve new mines in the major coal regions of Inner Mongolia, Xinjiang, Shanxi and Shaanxi and focus on consolidating output at dedicated coal production bases, as well as expanding existing collieries (Reuters, 2019c). Many of the newly approved projects are likely to replace small or depleted mines.

Development is likely to accelerate, as in mid-2019 the National Development and Reform Commission (NDRC) announced plans for a new phase in China's supply-side reforms, mostly addressing smaller mines. China plans to shut down more small-scale coal mines, to cut the number of mines with capacities below 0.3 Mtpa to less than 800 by 2021. In addition, local authorities are not allowed to approve or review the construction of new coal mines with annual capacities of less than 0.3 Mtpa, and newly approved mines in the main coal regions of Shanxi, Shaanxi, Inner Mongolia and Ningxia need to produce at least 0.6 Mtpa.

[5] This applies especially to the coastal regions.

Figure 3.17. Distribution of China's coal production by mine size, 2014-24



Source: CRU (2018), *Thermal Coal Cost Model* (database).

Key message: Production from small coal mines will decrease significantly, but mine closures will slow down.

Furthermore, policies promoting mergers of large state-owned companies could impact coal supplies and favour larger coal mines. In 2018, the NDRC announced its intention to consolidate numerous small producers to form several large mining companies, each with enough capacity to produce 100 Mtpa or more of coal (only six are currently able to produce more than this). The mergers, which are to be completed by the end of 2020, will limit the supplies available outside of these companies and further raise the proportion of larger mines responsible for total production.

To promote domestic supply during peak coal demand periods, rail system planner and operator China Railway has laid out a plan to increase rail capacity for transporting coal and removing bottlenecks caused by limited rail capacity (see Chapter 4). As a result of heavy rail investments, thermal coal supply costs are expected to increase (IEA, 2018). However, some new railway connections could also cut costs, as less costly trains partially substitute for coal trans-shipments at east China ports to smaller vessels, which are suitable to serve the river ports in central China, e.g. at Hubei and Hunan. These substitutions are expected to reduce delivery costs by 5-25%.

India

The strongest increase in coal production is expected in India, with growth of 4.5% per year taking production from 412 Mtce in 2018 to 537 Mtce in 2024. While thermal coal production increases 120 Mtce (+4.5% per year) by 2024, lignite expands 5 Mtce (+4.8% per year) and met coal production remains flat at 3 Mtce. These growth projections are supported by various policies to incentivise domestic production.

As coal demand continues to rise, the Indian government aims to reduce imports and raise production. The government's strategy has three pillars: to increase production by state-owned miners, mainly Coal India Limited (CIL), even if it involves company restructuring; to boost production from the captive blocks (NTPC Limited is probably the best example); and to create new coal sources with the introduction of commercial mining. Last, but not least, logistics need to improve to avoid bottlenecks and reduce costs.

State-owned CIL, which produces around 85% of domestic output, has set ambitious targets. It aims to produce 1 000 Mt in 2026 – 65% more than in the 2019 fiscal year – so is investing heavily in new production capacity, including 55 new mines (92 Mtpa) and expansion of 193 mines (310 Mtpa). The additional mining capacity scheduled for commissioning in the next few years is supposed to ensure steady coal production expansion over the outlook period, but permitting issues are challenging new projects. Amid its targets for production expansion, the government aims to improve CIL's efficiency.

In February 2018, India's government introduced a reform that allows private companies to develop new mines and sell coal in the free market without price or end-use restrictions. In a forward auction, companies can bid on new mine blocks that are, very importantly, characterised by their size, location and coal quality.

In August 2019, the cabinet further opened the coal mining sector to 100% foreign direct investment (FDI) for coal mining, along with the associated processing infrastructure and the sale of coal. FDI is intended to attract international companies, to create an efficient and competitive coal market. This could support production growth, as the companies are expected to be more flexible than the national coal giant CIL. India is expected to invite the first bids from global firms for coal mining blocks before end-2019 (Reuters, 2019d).

However, any commercial miner would have to compete with coal from CIL, which is expected to remain inexpensive. CIL sells 80% of its coal production through long-term fuel supply agreements, with prices well below those obtained in the free market, so it is critical for commercial miners to be able to undercut those prices economically. Besides international investors, domestic companies could also benefit from the reforms. These could be electricity generators without long-term agreements with Coal India, companies from non-regulated sectors (steel, cement and other industries) that are dependent on coal, and larger companies currently exploiting captive blocks.

India's second-largest coal producer, Singareni Collieries Company Limited (SCCL), supplies around 9% of domestic production and aims to produce 68 Mtpa by the end of 2019. The company is expected to increase its coal output by expanding outside of Telangana province, where most of its operations are located currently.

India's captive coal producers account for around 5% of domestic production. Power giant NTPC aims to secure 33% of its coal consumption, which currently amounts to around 190 Mt, through captive coal blocks by 2030. The state-run company is expected to increase production by around 170% (5 Mt) in 2019 by raising production at its Pakri Barwadih coal mine by around 4 Mt while launching the operation of its Dulanga mine at Odisha. Overall, the company allocated ten captive coal mines to partially serve the steam coal demand of its 55-GW fleet of coal-fired power stations. These mines have an estimated production capacity of 107 Mtpa. However, ramping up production at some of these captive coal mines is challenging due to geological and financial issues. To increase flexibility, NTPC implemented a policy, introduced in February 2019, to incorporate a mining-focused subsidiary, NTPC Mining Ltd. In addition, India's cabinet has approved a policy allowing owners of captive coal mines to sell 25% of their output on the open market; this should increase competitiveness and raise interest in coal mine auctions. NTPC's subsidiary aims to sell coal to other companies from its mines on the open market, after NTPC's own requirements have been met.

State-owned NLC India Limited (NLCIL) plans to double lignite-based power generation capacity by 2025, which is supposed to be accompanied by a doubling in lignite production. By the end of 2019, production at Mine-IA in the Cuddalore district is expected to double, and by mid-2020 a third pit at the Neyveli mine is expected to start producing with a capacity of around 12 Mtpa. Other projects, such as the Palayamkottai and Vellar mines, are currently awaiting approval and expected for mid-2022.

India's met coal reserves are rather limited and the potential to ramp up production is lower than for thermal coal.

To accommodate mining capacity expansion, transport infrastructure from the coal mines to consumption centres must be developed. This has traditionally been problematic in India, given that 60% of coal is transported by rail and 45% of Indian Railways' revenue therefore comes from coal transport. As cross-subsidisation between coal freight and passengers persists, the level of coal freight charges determines both the competitiveness of coal mining and the social acceptance of rail passenger charges. The coal industry has recently reacted by developing more mines close to power plants to reduce freight costs, and the government has also made considerable progress in allocating coal linkages (i.e. buying coal from mines close to power plants to save money on transport/logistics). Furthermore, the country is offering support for the construction of infrastructure projects to connect domestic coal mines with coal-fired power plants in urban and coastal areas.

Australia

In Australia, coal production is expected to increase around 1.4% per year, from 409 Mtce in 2018 to 444 Mtce in 2024. As no lignite power plants are assumed to close during the forecast period, lignite production remains stable at 16 Mtce. However, met coal output rises 20 Mtce (1.8% per year) and thermal increases 15 Mtce (1.1% per year).

In September 2019, QCoal's and JFE Steel's 10-Mtpa Byerwen coking coal mine opened in Queensland; its coal will be exported to Asian steel markets over the mine's 50-year lifetime. As the Byerwen project is only the first of a number of met coal projects being realised in Queensland, additional capacity is expected to come online (see Chapter 5). Mount Pleasant (New South Wales), which started production in December 2018, is planned to produce 10.5 Mtpa of thermal coal for exports to Japan, Korea and other Asian countries.

Most of Australia's met and thermal coal production is designated for export (around 86%), so the forecast is highly dependent on the global seaborne coal market. A detailed outlook for the market is presented in Chapter 4, and projects to enable a production increase are detailed in Chapter 5.

Indonesia

Indonesia's coal production is expected to remain roughly stable at 420 Mtce in 2024. In Indonesia, production is heavily dependent on the export market, as 75% of the country's coal production is exported. The substantial increase in domestic demand (+29 Mtce over the forecast period) is expected to offset decreasing exports (see Chapter 4).

Besides the ramp-up of production in Indomet's Haju coal mine through 2024, two other coal mines are expected to start production, Arni Bersaudara and Indo Bara Pratama. In 2018, Australian-listed Indonesian coking coal producer Cokal secured funding to develop a pulverised coal injection (PCI) mine at its 60%-owned Bumi Barito Mineral (BBM) coal project in Central Kalimantan. The open-pit mine started production in the fourth quarter of 2018 and is expected to produce up to 2 Mtpa.

As coal sector regulations are always important in Indonesia, some current uncertainties stem from how domestic market obligations will affect producer economics in the context of soaring domestic demand and a price cap on supplies for the PLN corporation. Plus, the obligation for exporters to have insurance issued by national entities was due to enter in force in February, but was delayed because of implementation issues. Last, but not least, there is a concern about how the first generation of coal contracts of work (CCoWs) will be extended, as they are due to expire (this affects main producers such as Bumi Resources, Adaro, Kideco and Berau). However, the forecast is based on the track record of Indonesian producers to overcome any regulatory hurdle if prices are attractive enough.

Mongolia

In Mongolia, coal output is expected to decrease 5 Mtce (-2.2%) to 32 Mtce in 2024. Thermal coal output remains stable over the forecast period, at around 6 Mtce, as does lignite production at 3 Mtce. In contrast, met coal production decreases 2.7% per year to 23 Mtce in 2024 as import demand from China (Mongolia's main export destination) declines. As Mongolian exports are transported long distances by truck and rail, high transportation costs make Mongolian coal costly for Chinese importers. Hence, as China's import demand is highly price-sensitive, a less tight global market puts Mongolian exports out of favour.

North America

North America's coal production is forecast to decrease 114 Mtce over the forecast period (-3.6% per year), to 461 Mtce in 2024. Most of the decline results from falling domestic demand in the region as less coal is used in the power sector.

United States

US coal production drops a substantial 3.8% per year, from 526 Mtce in 2018 to 416 Mtce by 2024, as domestic demand for coal-fired power generation falls continuously (see above). Higher coal exports will not be able to offset this decline because consumption by the main US export destinations is also dropping, so additional mine closures are expected over the forecast period. In the Powder River Basin, consolidation includes a joint venture between the two largest producers, Peabody Energy and Arch Coal, to operate their mines more economically.

Some new projects will add production capacity, however. Paringa Resources Limited (PNL) commenced production at the Poplar Grove Mine at the end of 2018, and once fully developed, the mine should produce 2.8 Mtpa of thermal coal. In February 2019, thermal coal producer Foresight Energy's Hillsboro Energy division resumed production at the Deer Run mine in Montgomery County, Illinois, after a four-year break due to an underground fire. The mine's last production in 2015 amounted to between 1 Mtpa and 2 Mtpa.

Canada

In Canada, coal output drops from 40 Mtce to 35 Mtce (around -2.1% per year) over the outlook period.

As domestic coal demand from the power sector falls substantially, steam coal production is forecast to decrease 9% per year to 7 Mtce in 2024. Furthermore, lignite production declines slightly to 3 Mtce in 2024. In contrast, met coal production expands 1.1% per year to 25 Mtce in 2024 in response to increasing met coal trade with the European Union and India (see Chapter 4).

Production of the Donkin coal mine, which had been suspended after a roof collapsed in December 2018, resumed fully in May 2019. The mine is expected to produce around 2 Mtpa of met coal in 2019.

Central and South America

Coal production in Central and South America is expected to remain flat at 83 Mtce by 2024, although it peaks during the forecast period and then returns to the current production level. Colombia continues to account for 95% of the region's production, and output in the other countries (mainly Brazil) remains stable, unless Chile's only operational mine, Mina Invierno, must close following a court challenge about the use of explosives.

Colombia's coal production is forecast to remain roughly the same, amounting to 78 Mtce in 2024. Thermal coal output accounts for 73 Mtce and met coal for 5 Mtce in 2024. As there have not been any significant investments in Colombia's mining sector, production remains flat over the forecast period. Most production is exported, with exports historically targeting the shrinking European market. Exports to Asia are difficult for Colombia's producers for geographical reasons (see Chapter 4).

Europe

European coal production is forecast to contract 1.9% per year over the outlook period, with total production falling from 215 Mtce in 2018 to 192 Mtce in 2024. While lignite drops at the highest absolute value (-16 Mtce), met coal declines at the highest ratio (-4% per year; -4 Mtce).

Poland remains Europe's primary coal-producing country, with total output expected to remain at the current level (67 Mtce in 2024). While steam coal production increases slightly (+1 Mtce to 41 Mtce in 2024), lignite production drops 2 Mtce to 14 Mtce by the end of the forecast period and met coal output remains steady at 12 Mtce. Even though the government aims to raise coal production by 5 Mt to 6 Mt by 2025, investments have been minor to date. While Polish state-run coal mining company Jastrzębska Spółka Węglowa (JSW) has received approval for its new coking coal mine Bzie-Debina 1-Zachód with a capacity of 2.4 Mtpa, PGG's Imielin North project is more uncertain. Other mine closures are likely to offset this production increase.

Germany already stopped producing hard coal in 2018. The country's lignite output is projected to fall 21 Mtce, from 51 Mtce in 2018 to 30 Mtce in 2024, as lignite-fired power generation declines. The only European country with a substantial increase in coal production is **Turkey**, with output expected to grow from 26 Mtce in 2018 to 35 Mtce in 2024. This growth is driven by the commissioning of additional lignite-fired power plants and their associated mines, as hard coal production remains stable.

The **Czech Republic's** coal production declines 7.2% per year to 13 Mtce in 2024, with most output being lignite. Lignite production is also expected to remain stable in **Bulgaria** (7 Mtce per year), **Greece** (6 Mtce per year) and **Romania** (6 Mtce per year). In the **United Kingdom,** coal production is projected to drop to 1 Mtce in 2024. Although new projects have been announced – the Woodhouse Colliery project with a coking coal capacity of 3 Mtpa, Bradley Mine at Pont Valley, Hightorn Mine at Druridge Bay and Dewley Hill at Throckley – it is uncertain whether the projects will be realised. In **Spain**, subsidies ended in 2018 and the closure of most coal power plants has been announced, so only negligible production from some small mines will remain.

Middle East

Coal output in the Middle East grows up to 3 Mtce per year, all of it produced in **Iran**.

Eurasia

Eurasia's coal production is expected to remain stable, with only a marginal increase of 0.2% per year raising it from 440 Mtce in 2018 to 446 Mtce in 2024.

Russia continues to be the region's largest coal producer, responsible for 75% of the total, although its output is forecast to decline slightly, by 7 Mtce to 336 Mtce in 2024. Met coal output is expected to increase by 2 Mtce (0.4% per year) to 93 Mtce by the end of the forecast period, with this marginal growth driven by rising exports as well as increasing domestic demand. In contrast, thermal coal output decreases slightly at 0.5% per year, from 212 Mtce in 2018 to 205 Mtce in 2024. This is mostly due to lower exports, especially to Europe. Exports generally have a significant influence on the Russian production forecast (see Chapter 4). At the same time, lignite production decreases from 41 Mtce in 2018 to 38 Mtce in 2024. As 2018 was exceptional for lignite production (9% increase), this represents a normalisation of lignite production levels.

Although **Kazakhstan**'s government plans to increase production, the country is landlocked, which limits export prospects, and domestic demand is expected to increase only moderately.

Africa

In Africa, coal production grows 1.0% per year over the forecast period, reaching 238 Mtce in 2024. Most of the growth takes place in Mozambique, while South Africa's coal production remains stable.

South Africa

South African coal production remains stable at 214 Mtce in 2024 (+4 Mtce from 2018). Most of the production is thermal coal (209 Mtce in 2024), while met coal accounts for only 5 Mtce. Domestic demand is not expected to increase significantly over the forecast period, and exports expand slightly, but not enough to ramp up production (see Chapter 4).

Several mining projects are set to start production during the outlook period, the most notable being MC Mining's Makhado hard coking and thermal coal mining project (1.1 Mtpa capacity). It is the largest coking coal mine in South Africa and the first mine in the Greater Soutspanberg coalfield, although the potential for new mines is limited by geological and logistical challenges. Other major projects such as the Boikarabelo open-cut coal mine are not certain to start operations in the forecast period. The mine is expected to extract 12 Mtpa of thermal coal, but it faces financing issues. In addition, the lack of investment in South Africa's coal mining industry for the past few years could reduce production from existing mines, which is likely to offset any capacity additions.

Overall, the main challenge for South Africa's mining industry will be to replace the Mpumalanga reserves when the mines have been exhausted, as the quality and geological conditions of the Waterberg and Free State coal reserves are worse than in Mpumalanga. This will be difficult, as mining industry ownership structures are changing (see Chapter 1). International companies are leaving South Africa's coal mining sector and projects will be more difficult to finance due to investor constraints on financing coal.

Anglo America, after having sold Eskom-tied thermal coal operations to Seriti Resources, has not been clear on whether it will also sell its export-oriented mines. South32 spun off its energy-related coal mining operations into a separate company, South Africa Energy Coal (SAEC). South32 then sold its share of SAEC, which holds all the company's thermal coal assets, to Seriti Resources and two trusts. If the transaction receives all the necessary approvals, Seriti will gain four collieries in the Mpumalanga coalfields – Khutala Colliery, Klipspruit Colliery, Middelburg Colliery and the

Wolvekrans Colliery – as well as three processing plants; production of the four collieries amounted to 26 Mtpa in 2018. A good test will be New Largo, a project tied to the Kusile power plant that Seriti bought from Anglo America and that is in need of substantial investment, as Seriti does not have the same financial capacity as Anglo America.

The new mining charter imposes considerable requirements on mining companies, which could further deter companies, particularly major international ones, from doing business in the country, reducing the potential for coal output growth over the forecast period. The charter, ratified in December 2018, aims to promote Broad-Based Black Economic Empowerment (B-BBEE) in the mining industry. It obligates new companies to raise the B-BBEE shareholding requirements from the previous 26% to at least 30% within five years.[6] Additionally, the charter imposes "carried interests" of 5% each for workers and community groups or the payment of an "equity-equivalent" benefit to communities instead. Finally, it states that 70% of total expenditures on mining goods must be procured from South African companies. Compared with previous drafts, the government has renounced the "once empowered, always empowered" principle. Companies will not have to issue shares to black investors now to meet the policy's criteria if they have met them previously. In addition, under the final version of the mining charter, licence-holders are not required to pay employees and local communities 1% of their earnings before interest, tax, depreciation and amortization (EBITDA). These changes offer some relief for South Africa's mining companies.

Other Africa

Mozambique's coal production rises by 9 Mtce to 20 Mtce by the end of the forecast period. Most of the expansion is accounted for by met coal, which increases by around 7 Mtce to 13 Mtce by 2024, mainly from Vale's Moatize mine and transported through the Nacala Logistics Corridor (NLC), for which Vale entered into a strategic partnership with Mitsui.

Botswana's Minergy began production at its Masama mine, the first open-pit coal mine in the country, and the first to be privately owned. It is expected to produce around 1.2 Mtpa of thermal coal. Other projects such as Mmamabula and Mabesewa are more uncertain in the current price environment.

[6] This does not apply to existing mines.

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4. Medium-term international coal trade forecast

- **Seaborne trade will increase only slightly (less than 1% per year) through 2024.** Whereas seaborne thermal coal volumes by 2024 will be similar to 2018 levels, metallurgical (met) coal seaborne trade will expand 1.2% per year.
- **A surge in South Asia offsets the collapse of thermal coal imports in Europe.** The major drop in European imports as well as smaller declines in Japan and Korea are offset by increasing import demand in Viet Nam, the Philippines, Pakistan and Bangladesh. The rise in imports in these countries, together with those of well-established importers such as Malaysia and Thailand, means that South Asian imports are similar to those of the People's Republic of China ("China") or India.
- **India is the growth engine for met coal.** Increasing steel demand in India and a shortage of high-quality coking coal prompts India to increase its imports, driving global seaborne trade growth.
- **Coal import quantities into China and India continue to be uncertain.** This caveat has been maintained since 2013 for China, and more recently been expanded to include Indian imports. Given the sheer size of their domestic markets compared with the amount of imports, as well as policies designed to rein in imports, forecasts for China and India are fraught with considerable uncertainty, especially for thermal coal. For coking coal, quality requirements reduce the uncertainty somewhat, especially for India.
- **Pacific exporters benefit from the geographical shift in coal-trade activity.** Movement of the market to the Pacific Basin limits prospects for Colombian and US exporters, while South African and Russian exporters turn increasingly eastwards. Indonesian exports contract through 2024 as a result of lower prices and rising domestic demand, and Australian exporters continue to be well placed both in terms of geography and cost, especially for the coking coal market.

Methodology and assumptions

This section provides a forecast for international thermal and met coal trade through 2024. Trade flows among countries/regions for both thermal and met coal are derived using the Reinforced Model for Coal Flow Analysis (RMCFA), a spatial equilibrium model developed at the International Energy Agency (IEA). The model has two modules: the first is an optimisation model that computes cost-minimal allocation among production, consumption, exports and imports, subject to mining and infrastructure capacity constraints. According to economic theory, the outcome reflects trade flows in a well-integrated and competitive market, an assumption justified by the rather low market concentration in international seaborne coal trade. However, coal is not a uniform commodity: quality is highly variable, and the existence of market concentrations for specific qualities is debatable. Therefore, the second module is a tool that allows coal volumes to be allocated from "exporting nodes" to "importing nodes", taking quality requirements into account. Outputs from both modules were analysed and compared to produce the actual forecasts.

Box 4.1. Impact of the IMO sulphur cap on coal markets

The IMO is implementing a new low-sulphur bunker fuel regulation on 1 January 2020, imposing a global 0.5% cap for sulphur in fuel oil used for shipping. Vessels sailing in the Emission Control Areas (ECAs) of Northwest Europe and North America will continue to be subject to a 0.1% sulphur limit. However, vessels targeting the ECA also need to adapt, as they use ultra-low-sulphur fuel only when sailing in the ECAs. With the IMO 2020 regulation, ships will need to comply with the sulphur limits all the time. Although the shipping and refining industries had several years' notice of the regulation, uncertainty about enforcement and the cost of compliance options as well as the lack of a meaningful enforcement mechanism kept most shippers and refiners on the sidelines. However, actions to comply with the regulation are advancing and are already affecting freight rates (see Chapter 2).

Ship owners are free to choose how to comply. They can continue to use high-sulphur fuel oil (HSFO) in conjunction with exhaust gas cleaning systems, known as scrubbers. Alternatively, vessels can burn oil products that contain less sulphur, e.g. marine gasoil (MGO), or a new product with a maximum sulphur level of 0.5%, called very-low-sulphur fuel oil (VLSFO), or various blends that are gradually being made available to the market. Finally, they can use liquefied natural gas (LNG).

Dry bulk carriers, the vessels for coal shipping, will not use LNG extensively, as bunkering infrastructure remains minimal. LNG is more likely to be used by vessels following fixed routes, e.g. container ships and cruise liners (IEA, 2019a). Hence, coal-shippers will have to choose between investing in scrubbers or higher operational costs by switching fuel to MGO or VLSFO.

Coal is most commonly shipped by big dry bulk carriers, such as Panamax (60 000 deadweight tonnage [dwt] to 80 000 dwt) and Capesize (over 80 000 dwt). In 2018, there were 11 125 vessels with an average size of 74 000 dwt (UNCTAD, 2019). These large ships have a significant fuel consumption, and thus a high interest in using a low-cost feedstock such as HSFO. It is therefore more attractive for dry bulk tankers to install scrubbers, so on-board ship scrubbers will be the primary choice for large ships. The cost of installing a scrubber on a dry bulk carrier is approximately USD 3.5 million (United States dollars), and it takes up to six weeks. With the current price differential between MGO and HFSO, retrofitting a large ship with a scrubber should earn a positive return within two years, making such investments profitable for large ships (IEA, 2019a).

The economics may not remain attractive, however. Because refiners will be increasing their gasoil output significantly, the price spread between gasoil and fuel oil will narrow in the near term, making scrubber investments less profitable. Plus, scrubbers can malfunction, increasing the risk of noncompliance, and third, future environmental regulations may mean the chosen scrubber technology needs upgrading.

The current rate of scrubber installations is low but rising. By the end of 2018, only 4% of all dry bulk carriers were scrubber-fitted, while Capesize vessels had a significantly higher adoption rate of 10%. Scrubber installation in the total bulk carrier fleet is expected to rise to 6% by the end of 2019 and 10% by the end of 2020. Only 13% of all dry bulk carriers will be equipped with scrubbers, three-quarters of which will be open-loop systems. Scrubber installations are expected to peak in 2019-20, and retrofitting with scrubbers is expected to be a short-lived phenomenon. It means that the burst of scrubber investments just before and after 2020 will lead to under 1 700 bulk carriers equipped globally by end-2024, out of a fleet of around 11 700. Over time, however, installing scrubbers on new-build vessels will become more widespread, as these scrubbers are less costly and can be easily added as part of the vessel's construction.

It appears that switching to low-sulphur fuel is likely to be the default solution for coal-shippers, which will drive up MGO and VLSFO demand and prices to incentivise refiners to adjust their output. The main appeals of switching to low-sulphur fuel are the low up-front capital expenses (capex) and the guaranteed compliance, although this certainty comes at the cost of paying the highest fuel prices.

To cover these higher fuel costs, freight rates are expected to rise. While shippers have not historically had much pricing power, rates will still need to cover the operating expenses (opex) of marginal suppliers in order to keep adequate supplies in the market. Using MGO or VLSFO should therefore initially be a margin-neutral solution for shipping companies, although fleet renewal and higher scrubber installation over time will eventually depress the profit margins of high-cost shippers.

The significant rise in operating costs will lead to higher freight costs worldwide. Assuming a premium of USD 215/t between the 0.5% and 3.5% sulphur fuels, the cost of receiving coal at Rotterdam in a Capesize vessel would increase by around USD 140 000 from Colombia and USD 230 000 from Richards Bay (IHS Markit, 2018). Considering the size of the vessels, this is an increase of USD 1-2 per tonne of coal. Compared with the historical weekly Amsterdam-Rotterdam-Antwerp (ARA) price variation, this is not a huge increase and should not have a major influence on coal trade.

Finally, some vessels might not comply with the IMO 2020 regulation and continue to use HFSO without a scrubber, either because they do not have access to a compliant fuel (and are therefore "forced" to use fuel oil) or because of patchy government enforcement in some areas when the regulation first comes into effect. However, non-compliance is not expected to be a lasting phenomenon.

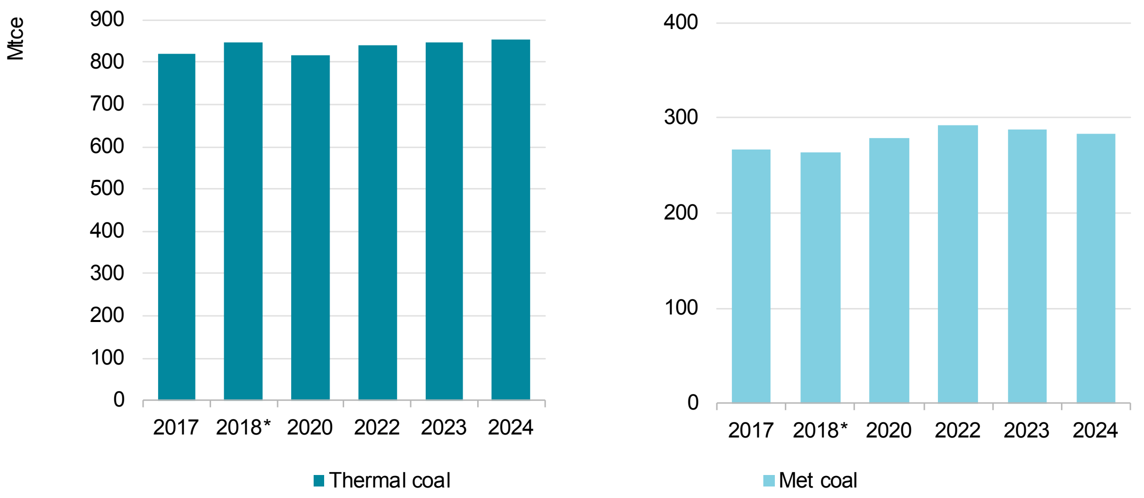
For most countries, import demand is an input. In other cases, however, optimisation of domestic and overseas supplies causes imports to become the model's output. The simulation model covers major coal-mining regions and demand hubs, and it incorporates detailed datasets for mining and transport costs as well as port, railway and mine capacities. Detailed mine and infrastructure capacity expansions are factored in, as are variations in coal quality by type (thermal or met) and energy content. Mining cost developments are estimated based on the assumed price evolution of inputs such as diesel fuel, steel products and labour. Due to input price escalation and deteriorating geological conditions, productivity gains are assumed to be lower than rising infrastructure and mining costs (with some adjustments, cost assumptions were based on the CRU Coal Cost Model). Main policies concerning coal, such as export quotas, taxes and royalties, are assumed to be constant throughout the outlook period unless changes have been firmly committed.

Regarding freight rates, although yearly additions to total dry bulk carrier capacity are decreasing, there is still transport overcapacity in the dry bulk shipping market. However, the upcoming International Maritime Organisation (IMO) sulphur cap regulation on marine fuel oil already impacts freight rates and is expected to further influence the market. Nevertheless, freight rates are not expected to rise to the high levels of before the 2008 financial crisis.

Seaborne coal trade forecast, 2019-24

Total seaborne coal trade is expected to remain stable over the forecast period. Starting from 1 110 Mtce in 2018, total seaborne coal trade is forecast to amount to 1 136 Mtce in 2024. After the peak volumes in 2018-2019, seaborne thermal coal trade is expected to initially decrease slightly and stabilize thereafter (see Figure 4.1). In contrast, seaborne met coal trade rises 1.2% per year from 263 Mtce in 2018 to 283 Mtce in 2024.

Figure 4.1. Seaborne exports of thermal coal (left) and met coal (right), 2017-24



* Estimated.

Key message: Seaborne coal trade is expected to remain stable over 2019-24.

Seaborne thermal coal trade forecast

Overall seaborne thermal coal trade is forecast to remain stable, rising only slightly from 847 Mtce in 2018 to 853 Mtce in 2024. Traditionally, this forecast is highly uncertain regarding Chinese imports, given the role of imports in balancing its immense domestic market and ambiguities about the evolution of China's economy and policies.[1] In recent years, similar challenges have also begun to undermine the forecast for India, as its current policy to reduce imports as much as possible has raised uncertainty as to what could be the lowest level. In addition, imports

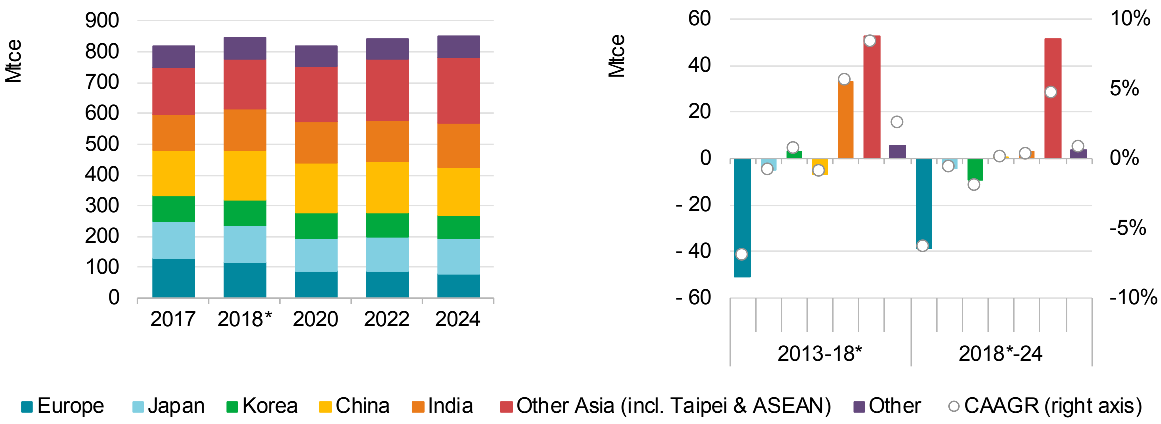
[1] IEA coal market reports have been addressing this issue since 2013.

into Japan and Korea especially are subject to uncertainty, depending on policies. Price-sensitive exporters such as Indonesia and the United States are most affected by potential import swings.

Importers

As noted above, seaborne thermal coal trade is expected to remain stable with annual fluctuations through 2024. This results from a drop in imports by Europe as well as by two large Asian importers – Japan and Korea – offset by surging demand in Southeast Asia, Pakistan, Bangladesh and others (Figure 4.2).

Figure 4.2. Seaborne thermal coal imports, 2017-24



* Estimated.

Notes: Taipei = Chinese Taipei; ASEAN = Association of Southeast Asian Nations; CAAGR = compound average annual growth rate.

Key message: The drop in seaborne thermal imports by Europe (and Korea and Japan) is offset by higher demand in South Asia.

Chinese thermal coal imports, currently the largest in the world, remain stable at 160 Mtce in 2024. China's imports are the result of considerable arbitrage occurring in coastal China between supplies shipped from the Northern ports, which arrive by rail from Inner Mongolia, Shaanxi and Shanxi, and international supplies from Indonesia, Australia, the Russian Federation ("Russia") and others. It is therefore a question of international prices versus domestic prices. Policies that change the relative competitiveness of domestic coal with international supplies are key to determining imports, as are policies that directly curtail imports through quotas or technical restrictions. Logistical improvements will help reduce supply costs, but mining costs are probably the most important single factor.

Chapter 3 details the shift in production to north-western China and the significant new mining capacity to come online. Infrastructure improvements and expansions are increasingly connecting domestic supplies with demand centres and raising the competitiveness of domestic supplies. The expansions focus on the channels that serve the key coal-producing regions of Inner Mongolia and Xinjiang, Shanxi and Shaanxi provinces, major coal-handling coastal ports and Yangtze river ports.

A major achievement, after over four years of construction, is the commissioning of the Haoji railway (formerly the Menghua railway) in October 2019. This is a coal-dedicated rail line, starting in western Inner Mongolia and crossing Shaanxi, Shanxi, Henan, Hubei, and Hunan, before terminating in Jiangxi province. Capacity of 40 million tonnes per annum (Mtpa) is planned for the initial stage, to be raised to 60 Mtpa by 2020 before finally achieving full capacity of 200 Mtpa. This new railway cuts coal delivery times by around 17 days (e.g. from Shaanxi to Jiangxi), increasing the flexibility of power producers (BNN Bloomberg, 2019).

In addition, China Railway plans to upgrade the Tanghu and Wari lines that connect Shanxi and Inner Mongolia with ports in northern China. It will also raise the capacity of the Ningxi and Houyue lines by 12 Mtpa to increase transport capacity between Shaanxi and eastern China's Jiangsu province as well as Shanxi and central China's Henan province. These forecasts are somewhat uncertain, however: in addition to the ambiguities mentioned in the demand section, policies affecting the coal supply and those targeting imports (such as quotas or shipping caps at the Bohai Rim ports) or prices, will affect imports significantly. Given the potential volatility of Chinese imports, it is difficult to determine a clear trend for the future.

Likewise, **India's** thermal coal imports are expected to increase to 141 Mtce in 2024. Higher domestic production is forecast to meet most of the surge in Indian coal demand; however, significant investments, productivity gains and progress in land acquisition and forest clearance are required to enhance production and to stabilise imports. The outlook is also uncertain due to policy measures and investments.

Whether imports decline will depend on how successful the three actions to boost production and improve logistics are (see Supply section). But no matter how much production increases, coastal plants, accounting for 18 gigawatts (GW) of generation capacity and designed to consume imported coal, will consume around 35 Mtce. Some plants, however, are blending domestic and imported coal to reduce their environmental footprint: around 50 GW of capacity have been importing coal for blending for the past two years. Whereas their imports are lower than for pure-import plants, it is difficult to reduce volumes significantly.

In **Japan**, thermal coal imports decrease slightly throughout the outlook period, from 119 Mtce in 2018 to 114 Mtce in 2024. As Japan imports basically all its coal supply, the decline results from a marginal drop in demand. As in the past, Australia is expected to remain Japan's main supplier, as Japan's high-efficiency coal-fired power plant fleet is better adapted to Australia's high-quality, quality-consistent coal. Further diversification of coal providers is expected, however, owing to liberalisation of the power market.

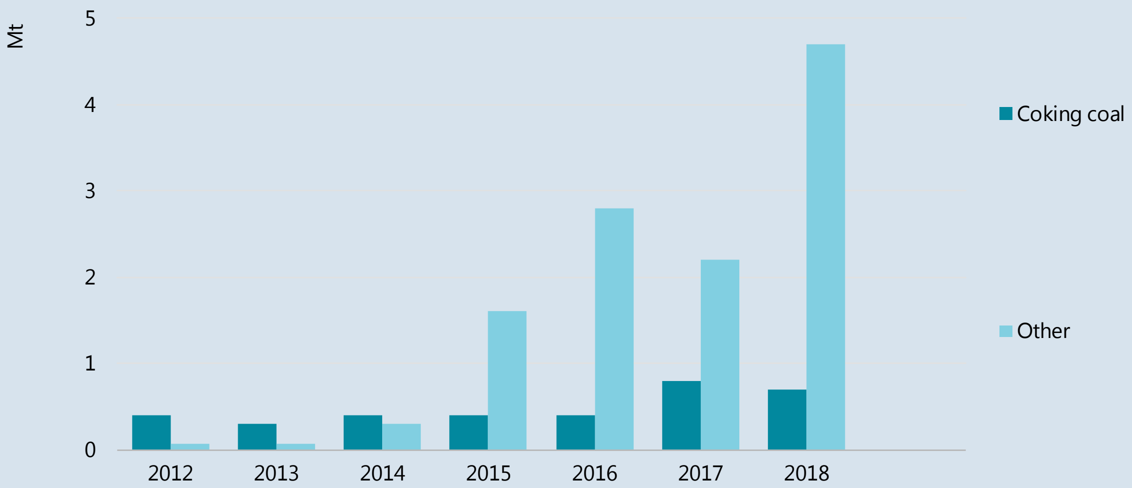
Box 4.2. Egypt, the latest major coal-trading spot?

With its 100 million inhabitants, Egypt is the third most-populated country in Africa after Nigeria and Ethiopia, the third-largest energy user after Nigeria and South Africa, and the second-largest electricity consumer after South Africa. Because Egypt has only limited coal reserves, oil and gas have traditionally supplied the bulk of its primary energy; for many years coal has been used only marginally, for iron, steel, coke and aluminium production.

After peaking in 2008, natural gas production began to decline, making Egypt a gas importer in 2015 after having been an exporter since 2004. At the same time, power blackouts were frequent between 2011 and 2014. Under these circumstances, coal was perceived as a viable alternative to compensate for gas shortages and to end power outages. In April 2014, the government authorised coal use for cement and electricity production.

The 2015 discovery of the Zohr gas field – the largest field ever to be found in the Mediterranean Sea – has turned Egypt into a gas exporter once again and put a damper on plans to expand coal-fired power plants. Many cement kilns have switched from gas to coal since 2014, triggering coal imports, but now that most of the kilns have been switched to coal, growth potential is limited.

Coal imports into Egypt



Source: IEA (2019b), *Coal Information* (database), www.iea.org/statistics/.

With the renaissance of domestic gas production, the question is whether any of the 14 GW of planned coal-fired generation capacity will be built. At the moment, the Hamraweim plant, which would be one of the largest coal-fired power stations in the world at 6.6 GW of capacity, is the only proposal at an advanced stage. An engineering, procurement and construction (EPC) contract has already been signed between the consortium (composed of Dongfang Electric Corp and Shanghai Electric Group) and the Ministry of Electricity and Renewable Energy. If completed as proposed, Egypt would become a 25-Mt market, forming together with Turkey the focal point for coal outside the Asia Pacific region. Project completion cannot be taken for granted, however, as Egypt's electricity ministry has just cancelled another project, Ayoun Moussa, with a capacity of 2.6 GW in Sinai.

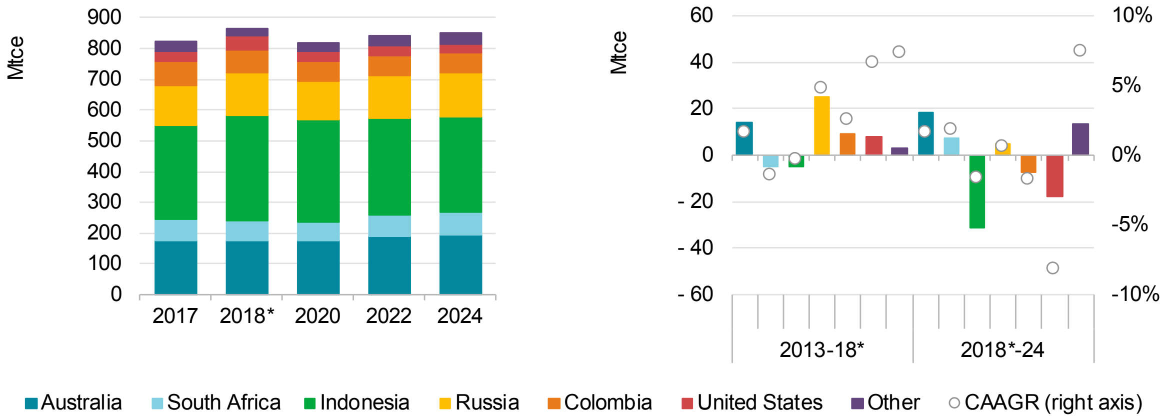
Thermal coal imports in **Other Asia** grow substantially throughout the outlook period, rising at 4.7% per year, from 161 Mtce in 2018 to 212 Mtce in 2024. This results mainly from various countries expanding their coal-fired power generation: Viet Nam, the Philippines, Malaysia, Pakistan and Bangladesh. Other imports, e.g. from Chinese Taipei, remain stable over the period.

Europe's thermal coal imports continue to decline through 2024. Overall, European thermal coal imports decrease by 6.4% per year, dropping from 118 Mtce in 2018 to 79 Mtce in 2024. Shipments to the ARA hub are projected to contract more than imports into coal terminals in the Mediterranean, which are declining at a substantially lower rate, as increasing imports to Turkey partially offset the falling imports of Italy and Spain.

Exporters

Seaborne thermal coal exports were dominated by Indonesia and to a lesser extent Australia in the last decade. Indonesia will remain the world's largest thermal coal exporter by far through 2024, despite a substantial decrease in exports over the forecast period (Figure 4.3).[2] The export forecast is subject to similar uncertainties as the import demand forecast, although not all exporters are equally affected. For example, Indonesian exporters are more exposed to a drop in Chinese imports than other exporters.

Figure 4.3. Seaborne thermal coal exports, 2017-24



* Estimated.

Key message: Indonesia remains the largest thermal coal exporter by far through 2024.

Despite a decline of 1.6% per year, from 342 Mtce in 2018 to 311 Mtce in 2024, **Indonesia** is expected to account for 36% of total seaborne trade in 2024 in energy terms. Indonesia's coal exports are very price-sensitive, as production within the country is high-cost, so its exports are expected to decrease as prices decline. Based on the current forward curve, thermal coal prices are likely to soften during the forecast period and, in addition, Indonesia's coal mining costs are expected to rise as a result of higher strip ratios, so that its less-competitive exports will be even more dependent on international price evolution. Although Indonesian producers react more quickly than elsewhere to higher prices, their capacity to adjust to lower production is hampered by commitments with suppliers of heavy equipment.

As domestic Indonesian thermal coal demand is forecast to increase strongly (see Chapter 3), less coal will be available for seaborne exports. Indonesian coal exporters must comply with a domestic market obligation (DMO) that requires Indonesian producers to sell at least 25% of their production to the domestic market at a regulated price. Nevertheless, exports to Indonesia's neighbours, such as other ASEAN countries, are expected to increase despite DMO constraints.

In **Australia**, thermal coal exports are expected to grow 1.6% per year over the forecast period, reaching 196 Mtce in 2024 (+18 Mtce from 2018). The country thus remains the second-largest exporter of seaborne traded steam coal, with its market share increasing slightly. Owing to its

[2] Imports and exports do not have the same growth ratios through 2024 because, although the model matches both in the forecast, the historical data do not match due to statistical differences.

extensive high-quality thermal coal reserves, its relatively low extraction costs and its efficient mining industry and supply chain, Australia's exports are expected to ramp up. Several projects aim to increase export capacity volumes (see Chapter 5) and there are also some infrastructure projects such as the Hunter Valley Corridor Capacity Strategy in New South Wales and the Abbot point port expansion, but the export volumes assumed in this forecast do not require infrastructure expansion. India also presents an important export opportunity for Australia, as the upside potential is substantial and the future of Australian exports to China is uncertain.

Russia's seaborne thermal coal exports are expected to increase 0.6% per year, from 137 Mtce in 2018 to 142 Mtce in 2024. Its low-cost coal reserves and continually expanding export capacity have made Russia's exports competitive in the past, and its government aims to expand coal exports even further. To do so, the country is upgrading its transportation links to boost shipments, particularly to customers in the Asia Pacific region. As European coal imports decline, there will be a regional shift in Russian thermal coal exports towards Asia, where demand for coal is increasing. At the same time, exports to Europe will focus on the southern regions.

In contrast, **Colombia's** thermal coal exports decline from 74 Mtce to 66 Mtce over the forecast period (at a rate of 1.8% per year) as underinvestment in the coal sector hampers future production. Furthermore, Colombian exporters will struggle because their exports have historically focused Europe and this market is shrinking, with most global demand growth taking place in Asia. As most of Colombia's coal mines are on the Caribbean coast, its coal producers are faced with higher shipping costs than their competitors in Asia.

South Africa's seaborne thermal coal exports are expected to increase by 1.8% per year to 73 Mtce in 2024, from 65 Mtce in 2018, shifting from the declining European market towards India, where 45% of South African exports are already sent. In addition, South Africa could target other countries in the Asian market, such as Pakistan and Korea.

The **United States** is forecast to export 18 Mtce less in 2024 than in 2018 as exports drop 8.1% annually to 27 Mtce in 2024. Even though declining domestic demand will free up significant mining capacity throughout the country, producer prospects are limited in the east by the collapse of Atlantic market and generally high mining costs, and in the west by a lack of infrastructure. The United States will remain a swing supplier to the seaborne market, with price-sensitive export volumes, but since US coal exports will not be able to compensate for the decline in domestic consumption, additional mine closures are expected over the forecast period.

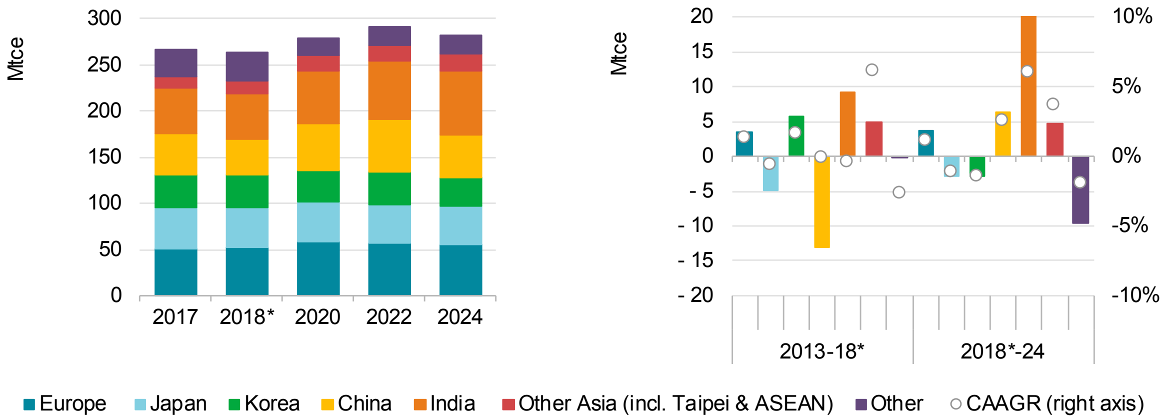
Seaborne met coal trade forecast

Seaborne met coal trade is forecast to increase around 20 Mtce through 2024 at a growth rate of 1.2% per year, rising to 283 Mtce in 2024 from 263 Mtce in 2018. Australia alone accounts for 67% of global seaborne exports in energy terms and is expected to maintain this dominant position throughout the forecast period. Due to this market concentration, the met coal market is sensitive to any supply-side disruptions in Australia and especially Queensland, where most of the met coal is mined. The possibility of these disruptions creates forecast uncertainty and can result in significant price spikes. On the demand side, import tariffs on steel products also result in uncertainty for the met coal market.

Importers

Met coal imports into the Asia Pacific region (especially India, and to a lesser extent China and Southeast Asia) are expected to offset declining imports by the European Union and stagnating sales to Japan and Korea (Figure 4.4).

Figure 4.4. Seaborne met coal imports, 2017-24



* Estimated.

Key message: India's met coal imports more than offset drops elsewhere.

India's overseas met coal imports grow by 6.3% per year, from 49 Mtce in 2018 to 69 Mtce in 2024, as a result of rising demand and stagnating met coal production. Even though the government aims to reduce coal imports by increasing production and washing capacity, it is unlikely that India will be able to reduce its met coal imports, as quality coking coal reserves in India are limited. India's imports are expected to shift gradually towards Russia, as the countries have signed a memorandum of understanding (MoU) on energy co-operation that specifically includes coking coal.

China's seaborne met coal imports are forecast to increase over the outlook period to 46 Mtce in 2024. As supply-side reforms in the mining sector will affect China's met coal production more strongly than thermal coal production, imports are expected to rise. There is demand-side uncertainty, however, as increasing scrap utilisation could put downward pressure on China's coking coal demand.

Europe's met coal imports remain stable over the outlook period, as the decline in the EU area is offset by rises in other European countries. Seaborne imports reach 56 Mtce in 2024, but demand-side uncertainty stems from steel tariffs, efficiency improvements, increasing scrap use and the effects of phase 4 of the EU ETS.

Japan's crude steel production decreases and the country becomes the world's third-largest crude steel producer. Steel production is forecast to stagnate through 2024, leading to a slight reduction of imports from 44 Mtce in 2018 to 41 Mtce in 2024.

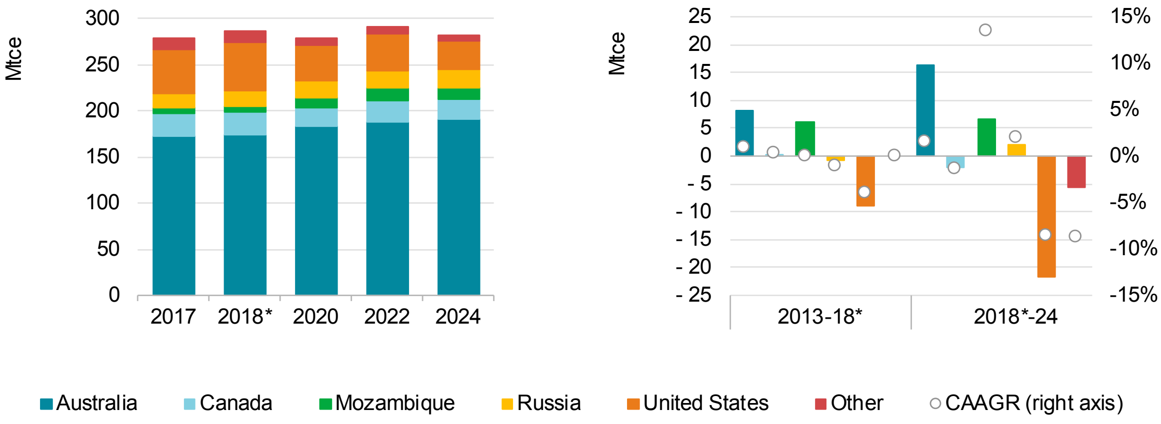
Met coal imports by **Korea** are also projected to decrease, following demand trends. Starting from 35 Mtce in 2018, imports fall to 32 Mtce in 2024.

In Southeast Asia, new blast furnaces come online during the forecast period, so met coal consumption grows and leads to higher imports. Imports by **Other Asia** rise from 7 Mtce in 2018 to 14 Mtce in 2024, and those of Chinese Taipei increase to around 8 Mtce per year.

Exporters

The supply side of seaborne met coal trade is highly concentrated and exposed to supply chain disruptions. Australia, the United States, Canada and Russia are together responsible for over 95% of seaborne exports (Figure 4.5). Growth in Mozambique contributes only slightly to diversification of the market.

Figure 4.5. Projected seaborne met coal exports, 2017-24



* Estimated.

Key message: Seaborne exports increase slightly during 2019-24, with a small shift from the United States to Australia and Mozambique.

Australia is projected to maintain its market share and even increase it slightly, as it will be responsible for most supply-side growth. Met coal exports are expected to increase to 191 Mtce in 2024 – an annual increase of 1.5% – with high prices triggering investments in coking coal projects. Most of Australia's near-term hard-coal mining projects categorised as "more advanced" focus on producing coking coal rather than thermal coal, e.g. the Wilton-Fairhill and Ironbark projects, which could add over 10 Mtpa of coking-coal mining capacity by 2020.

Coking coal exports from the **United States** are expected to fall by around 8.5% per year to 31 Mtce in 2024. This drop of 22 Mtce from 2018 is partially linked to decreasing deliveries to Europe, the main US export destination, as it is difficult for US producers to outcompete Australian ones in terms of both cost and quality. However, the United States will maintain its position as swing supplier and increase production if prices are favourable.

Canada will remain the third-largest exporter of seaborne-traded met coal, with exports stable at 22 Mtce in 2024.

Met coal exports from **Russia** and **Mozambique** are projected to surge throughout the forecast period. While Russian growth is 2% per year – to 19 Mtce in 2024 – exports from Mozambique expand 13.4% per year, reaching 13 Mtce in 2024. Several port capacity extensions in Russia will facilitate greater exports, and in September 2019 it also launched a third export line from its largest coal terminal at the port of Vostochny, expanding capacity from existing 22 Mtpa to 40 Mtpa. The port of Taman on the Black Sea will reach 50 Mtpa, targeting the Indian market. Mozambique's exports will benefit from the Nacala Logistics Corridor rail line and expansion of the Nacala port; most of the country's exports are expected to go to India.

The landlocked country of **Mongolia** influences the seaborne met coal market by its trucked exports to neighbouring China. As Mongolian exports are very price-sensitive, lower global prices result in lower export volumes. China is expected to continue importing a considerable amount of coal from Mongolia over the outlook period, and Mongolia also anticipates higher exports as a result of China's One Belt, One Road strategy, as it includes a China-Mongolia-Russia corridor. In addition, Mongolia is engaged in a joint transport terminal project with Russia, which could handle 10 Mtpa of coal and make Mongolia a seaborne exporter. This project is not likely to be completed within the forecast period, however, so is not incorporated into the forecast.

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5. Capacity investment outlook

- **Mining capacity under development continues to increase**, with 200 million tonnes per annum (Mtpa) currently being developed, compared with 140 Mtpa in 2018. Likewise, the total number of more and less advanced projects in development has also increased, although this results more from a lack of project progress than from an increase in coal mining investments, although the price hike since 2016 may have helped.
- **Most capacity is coking coal.** 60% of advanced projects are metallurgical (met) coal projects, even though the thermal coal market is three times larger than the met coal market. Demand for coking coal is less threatened than thermal coal, and financing coking coal projects is less challenging than thermal coal.
- **Brownfield projects dominate investments.** With it being increasingly difficult to get support for project financing, 80% of projects are brownfield expansions, often financed from the balance sheet of the developer. The licensing process partially explains this trend.
- **After more than 10 years spent obtaining the necessary approvals, construction of the Carmichael mine began in June 2019.** The mine in Queensland, Australia, has become iconic owing to the unique support and opposition it has received. In June, after having obtained its last two licences, Adani announced the start of construction. It plans to begin exporting by 2021.

Investment overview

Coal prices rose further in 2018, reaching their highest point since 2012 in almost all regions of the world. Although rising seaborne coal trade in the past couple of years has been providing signals to coal-exporting companies to increase capital spending, the trend of stagnating investments in new coal production capacity persists (IEA, 2019a). Most investments are intended to sustain production rather than to increase it, mainly at existing mines. Greenfield expansions are very rare and mostly restricted to met coal.

The rationale behind this is manifold; although the price increase resulted partly from rising production costs such as labour inflation and especially oil prices, profit margins for 2018 remained solid (see Chapter 2). Investments by coal consumers, e.g. in new coal-fired power plants, are fairly low, and the consumption of coal is expected to be relatively stable during the forecast period. Finally, financing new coal projects is becoming more difficult, as the divestment movement is gathering momentum. The Powering Past Coal Alliance, co-funded by the United Kingdom and Canada, assembles countries, sub-national governments and businesses committed to abandoning CO_2-unabated coal-fired power generation by 2030 and stopping the financing of coal plants.

Thermal coal is subject to more restrictions than coking coal. For example, BNP Paribas Asset Management has announced a tighter exclusion policy on companies engaged in mining thermal coal, but it exempts met coal "as there are currently no viable alternatives to metallurgical coal in the steel-making process" (BNP Paribas AM, 2019). Likewise, BHP, one of the largest diversified mining companies in the world, has stated that it will focus on its met coal operations.

In this environment, financing new developments under project financing schemes, especially thermal coal projects, is increasingly difficult. While Rio Tinto has abandoned the coal business entirely, BHP and Anglo American have stopped investing in thermal coal, and this has had an impact even on their assets acquired by others. The New Largo project in South Africa is a good example: Anglo American sold the project to Seriti Resources together with three mines supplying Eskom. New Largo is in the proximity of Kusile, a plant with annual thermal coal needs of 13 Mt to 15 Mt, and it is therefore a feasible project given the extraction costs. Whereas Anglo American had the financial capacity to develop the project, it is not clear whether Seriti does. Carmichael mine is another example: in this case Adani, the owner, has had to finance the project after having failed to find investors. While the finance is still flowing, financial burden for coal mining projects are on the rise. The *World Energy Outlook 2019* (IEA,2019b) has a section that discusses this issue in depth.

The resulting increase in capex for new investments and difficulties to finance them favour low-investment-cost options such as restarting mines that have been idling for some time, or brownfield expansions of existing mines. Hence, very few new export-oriented greenfield mines are being proposed. However, a handful of countries are resisting this global trend: the Russian Federation ("Russia") and Indonesia are continuing to develop greenfield projects and trying to increase their shares of globally traded coal.

Furthermore, companies typically rely on significant debt financing to fund projects. They may initially invest in stage 1 of a new mine based on sales contracts already secured, including sales to their parent company or subsidiaries, but they then need to generate production-dependent cash flows to pay down these borrowings. In the future they may try to secure further sales contracts to underpin expansions. Examples are the Carmichael, Makhado and Boikarabelo mines.

The landscape for coal, and for investing in it, could change with some technological breakthroughs (Box 5.1), but it appears that its long-term future is ultimately linked with carbon capture, utilisation and storage (CCUS) technologies.

Box 5.1. Coal-based hydrogen

The idea of using hydrogen to produce energy is not new. Hydrogen is versatile, as it can be used for heating and in transportation or electricity production, and it is clean: reacting it with oxygen produces only heat and water vapour. However, hydrogen is an energy carrier rather than an energy source, as it does not exist free in the Earth and must first be produced using energy. Hydrogen is currently used in refineries, in ammonia production and in other industries, but not in the energy sector at scale, despite its potential uses in industry and heavy transportation, or to provide long-term energy storage. There are, however, some promising initiatives to exploit the full potential of hydrogen in the energy sector (IEA, 2019c). If the use of hydrogen takes off, the relevant question for the coal industry is what role, if any, coal may have.

Natural gas reforming is currently the most popular way to produce hydrogen outside the People's Republic of China ("China"), where coal gasification is the main source of hydrogen. In a low-carbon economy, however, renewable electricity is an obvious energy choice to produce hydrogen through water electrolysis. Renewables-based hydrogen production today is two to three times more expensive than production from fossil fuels, but costs are set to decline significantly with economies of scale. Another possibility is to use fossil fuels with CCUS. In Victoria (Australia), a Japanese consortium is developing the Latrobe Valley project (also called the Hydrogen Energy Supply Chain project), which consists of a pilot plant for lignite gasification to produce hydrogen. The plan is to integrate it with sequestration and storage of CO_2, and the hydrogen is to be liquefied and transported to Japan, one of the countries leading the campaign for hydrogen.

In February 2018, the China Energy Investment Corporation (CEIC) and 18 other enterprises and institutions launched the China National Alliance of Hydrogen and Fuel Cell, devoted to drawing up strategies to explore opportunities in hydrogen production and its upstream and downstream industries. Coal, the dominant energy source in the country, could play an important role in hydrogen production. As in the Latrobe Valley project, however, hydrogen makes sense only if it is low-carbon, which necessarily implies the use of CCUS.

Cost estimates for large-scale hydrogen production from coal in China are about CNY 0.8 per cubic metre, which means it is the lowest-cost technology. Nevertheless, this cost advantage versus zero-carbon hydrogen needs to be fairly adjusted to include CCUS costs. Hydrogen energy in China is expected to be applied commercially on a large scale by 2030. That said, the hydrogen energy market faces competition from the entire industry sector, not only coal. Scaling up is crucial for commercial operations of coal-based hydrogen production.

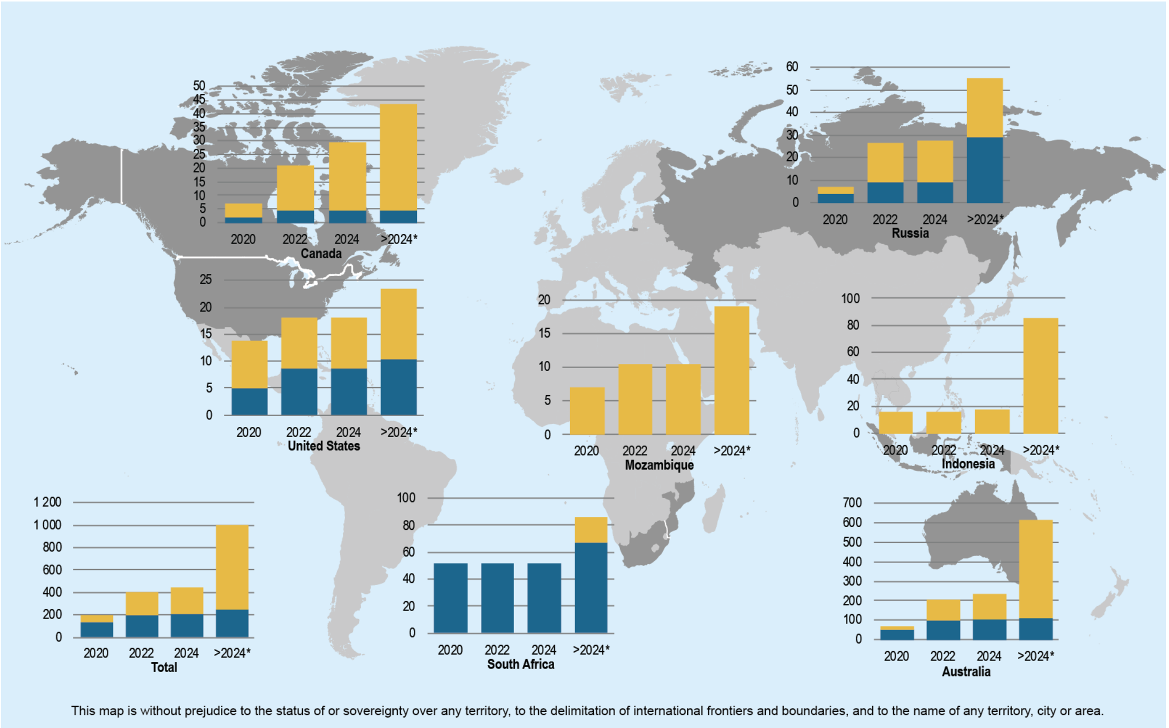
Investment in export mining capacity

Numerous coal-mining projects are under consideration and in various stages of development, but most of them are not likely to go ahead before 2024. This report therefore classifies projects as more advanced and less advanced. Projects in the more-advanced category are at a minimum approved, committed, have obtained a final investment decision, or are under construction. In contrast, less-advanced projects are at the feasibility or environmental impact study stage, or they are awaiting approval.

Around 202 Mtpa of coal-mining capacity is currently under development and characterised as more advanced. The majority of these projects (58%) are brownfield developments. Globally, more-advanced mining projects focus mainly on coking coal, with 115 Mtpa under development, of which 37 Mtpa would also produce some thermal coal. The remaining 87 Mtpa produce only thermal coal. Even though thermal coal has triple the market size of met coal, met coal projects appear to be less targeted by the divestment movement.

Most of the projects characterised as more advanced are in either Australia (52%) or South Africa (25%) (Figure 5.1), and the coal grade tendency varies considerably by region: while in Australia most of the projects focus on met coal, the majority of South African projects are meant to produce thermal coal. In addition to these two countries, Russia is expanding its production capacity considerably, mainly for the purpose of exporting coking coal.

Figure 5.1. Cumulative capacity of hard coal export mining projects (Mtpa), 2020-24



Capacity of "more-advanced" projects   Capacity of "less-advanced" projects

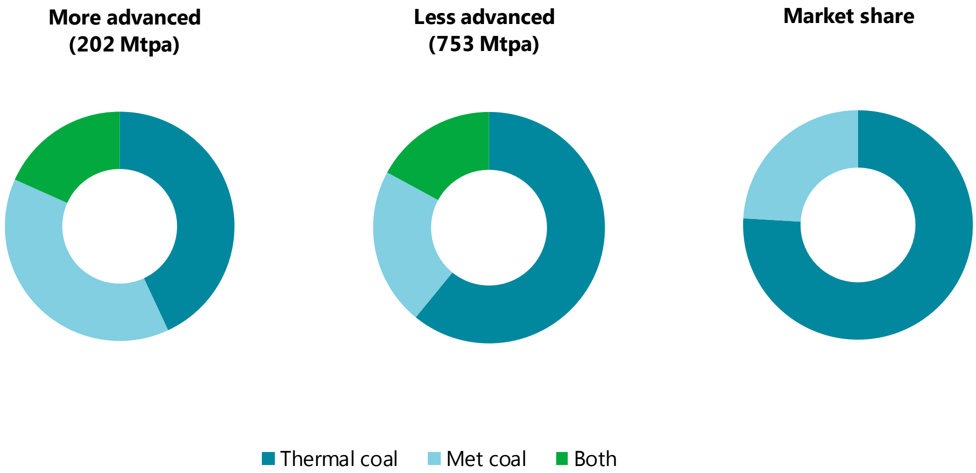
Key message: Most of the more-advanced coal mining projects are in either Australia or South Africa.

Less-advanced projects are either proposed to begin after the forecast period or have not stated a start-up year. The potential of less-advanced projects is 753 Mtpa, with the majority also planned for Australia (67%), while Indonesian projects rank second (11%). This is due partly to Australia being more transparent than other countries, but the country's resources also seem to attract project development companies. Less-advanced coal mining projects show a significant tendency towards thermal coal (71%) compared with coking coal (29%) (Figure 5.2). This is approximately representative of the market sizes of these two coal types, and the difference in focus between more-advanced and less-advanced mining projects indicates the expectations of market participants regarding the profitability of the different markets.

Market participants appear to value the met coal market more in the long term, so invest more strongly in new mining facilities of this coal grade. The two main reasons for this investment preference are, first, that prices for met coal have historically been higher than for thermal coal and offer a better profit margin.[1] Because coal is generally a marginal supplier of electricity, thermal coal demand is very sensitive to changes in power demand and/or the output of other energy sources. Second, the risks and uncertainties posed by climate policies and public opposition are higher for thermal coal. Whereas there is considerable emphasis on wind and solar photovoltaic (PV) for power generation, producing steel from iron ore at scale without coal is not expected any time in the near future.

[1] This can differ regionally depending on mining costs.

Figure 5.2. Coal type shares in hard coal export mining projects (Mtpa) and market shares (Mt)



Key message: Despite met coal having a smaller market share, more-advanced mining projects focusing on met coal production appear to prosper.

Investment in export infrastructure capacity

Investments in coal-related infrastructure projects, especially for export capacity, are highly dependent on development expectations for the global coal market. As the development of new production capacity stagnates, so does progress in export infrastructure projects. Only Russia expands its export infrastructure to take advantage of its cost-competitiveness in coal exports. In Australia, the most significant expansion is led by the Indian company Adani Mining. The company proposes enlarging the Abbot Point coal terminal, which is closely linked to the mining projects in the Galilee Basin, namely Adani's Carmichael mine. In addition, for Queensland's largest coal terminal, the Dalrymple Bay Coal Terminal, an export capacity expansion of around 13 Mtpa (+16%) is planned. The additional capacity is expected to come online within the next five years and to mainly benefit met coal, which accounts for 82% of the terminal's current exports. Another project in North America, expansion of the Fraser Surrey Docks in Vancouver, was annulled due to a permit cancellation.

Regional Analysis

This section introduces progress in export mining and infrastructure projects in major coal-exporting countries since the publication of *Coal 2018*. The focus is on projects expected to be realised within this report's forecast period (2019-24) and assumed to be in the more-advanced category; these projects have therefore already been integrated into the previous chapters' forecasts. Information was obtained from a range of public and non-official sources, including company statements and annual reports, newspaper articles, official documents and permits, databases and interviews.

Australia

Most projects categorised as more advanced are in Australia (52%). Several mines are under construction or have at least obtained a final investment decision, the majority of which are in Queensland and New South Wales. A total mining capacity of 110 Mtpa is considered to be at the more advanced stage and likely to start production within the forecast period. Of these plans, 79% are greenfield projects proposed to commence in the next few years.

The Carmichael mine, probably the most controversial coal project currently under development, has confronted numerous challenges. The thermal coal project is linked to a rail scheme in central Queensland, but due to difficulties and market conditions, Adani has scaled it back from the original price of USD 16.5 billion (United States dollars). In December 2018, Adani confirmed that the Carmichael mine would be financed completely through the company's own resources, and in June 2019 it received the final environmental approval to commence work, for production of up to 60 Mtpa. Adani is currently working on the mine plan for Stage 1 of 10 Mtpa, with the construction phase now under way. This allows Adani to begin box-cut mining at the site, but further testing needs to be completed to carry out underground mining. The firm expects to ship the first coal from this mine in two years. The Carmichael mine approval opens up a new coal basin, the first such development in Australia for decades.

MacMines Austasia's China Stone project, another thermal coal mine in the Galilee Basin, received conditional environmental approval in November 2018. The USD-4.84 billion open-cut and underground thermal coal mine is planned to produce up to 38 Mtpa, but no progress has been reported. Approval of the China Stone and Carmichael projects may influence the future of other large projects in the Galilee Basin, such as GVK Hancock's Alpha Coal (32 Mtpa) and Kevin's Corner (30 Mtpa) mines, and Waratah Coal's China First mine (40 Mtpa).

Whitehaven's Vickery extension project in the Gunnedah basin aims to produce a mix of 6 Mtpa of met coal and 4 Mtpa of thermal coal, starting production by the end of 2020. The company submitted its revised environmental impact statement (EIS) in August 2018 and expects construction of the open-cut mine to begin in 2019-20.

In January 2018, the EIS for KORES' Wallarah 2 thermal coal project was approved. Most of the project is owned by the Korean government's mining division, and the proposed underground mine is in New South Wales with 5 Mtpa of production planned over the course of 28 years. Production is to begin in 2022 and the coal will be transported by rail to the Port of Newcastle. However, as Korea's attitude towards coal investments has cooled, it is uncertain whether KORES will fund the project even when final approval has been obtained. The project ownership structure may even change.

The Watermark project, backed by the Chinese state-owned company Shenhua Energy, is a 10-Mtpa open-cut mine planned to produce coal over 30 years. The project includes a coal handling and preparation plant (CHPP) as well as a rail connection to Newcastle. In July 2018, New South Wales authorities renewed a scaled-back version of the exploration lease for a further five years. Production is planned to start in 2022, but project progress remains uncertain.

Malabar Coal acquired the closed Drayton open-cut coal mine, including the CHPP, and as well as the Spur Hill coking coal project in 2018. The company aims to use the corresponding infrastructure of the Drayton mine for developing the Spur Hill and Maxwell projects, which are planned to produce around 5 Mtpa of met coal and 2 Mtpa of thermal coal by the end of the forecast period. The scoping study for the underground mine was completed in August 2018 to prepare the EIS for submission in 2019.

Box 5.2. Carmichael, in the spotlight

Carmichael mine, planned to produce 10 Mtpa (1.5% of Australia's coal production), has provoked immense controversy. Probably the first reason for great environmental concern was that the project would open the Galilee Basin for coal development, as investment in associated infrastructure (e.g. rail) accompanies the mine. At a time when coal is perceived by many as a thing of the past, opening a new coal-producing basin is consequential.

The Carmichael project was initially designed for 60 Mtpa. If all the proposed projects for the Galilee Basin had proceeded, they would have produced around 300 Mtpa of coal, releasing over 600 million tonnes of carbon dioxide ($MtCO_2$) per year – 2% of global CO_2 emissions – during final-use combustion. When the Carmichael project was first proposed, global coal demand and Chinese import demand were still growing strongly, but now it is difficult to envision a market for such volumes.

In addition to the mine, expansion of the associated port at Abbot Point to accommodate the initial size of the mine also raised environmental concerns, as Abbot Point port is close to the Great Barrier Reef.

The developers, however, have a strong business case for the mine. Adani, the owner of the mine, has a 4.6-gigawatt (GW) coal power plant at Mundra designed for imported coal, and has plans to build another one in East India (Godda), which Carmichael could supply. Moreover, Adani is also the operator of Abbot Point port, which is not working at its full capacity of 50 Mtpa.

In May 2019, Yancoal's project to expand the Cameby Downs thermal coal mine in the Surat Basin received approval from the Queensland government. It allows Yancoal to increase the mine's output from 2.8 Mtpa to 3.5 Mtpa, and the expansion is expected to be finished within the next year.

The joint venture BHP Mitsubishi Alliance (BMA) sold the Gregory Crinum coking coal mine in central Queensland to Japan's Sojitz, a deal valued at USD 70.9 million. Sojitz aims to rebalance its existing coal mining portfolio biased towards thermal coal due to increasing concerns about the resource's sustainability. In January 2016, the Gregory Crinum Mine was put in care and maintenance mode, but Sojitz is expected to restart operations within the next year, restoring its output of 6 Mtpa of hard coking coal.

Sedgman was further awarded a USD-131.96 million EPC contract by Pembroke Resources for a CHPP at the greenfield Olive Downs coking coal project in Central Queensland. The project's EIS recently received approval and is fully funded by a private equity firm, Denham Capital. Olive Downs is a greenfield met coal mine with a production capacity of up to 15 Mtpa for almost 80 years; production is expected to begin within the next year.

In 2019, New Hope made further progress in gaining approval for its proposed extension of the New Acland mine in the Darling Downs region. The proposed USD-670 million expansion is expected to extend the life of the mine to 2029 while increasing its thermal coal output by 2.3 Mtpa (to 7.5 Mtpa).

In 2018, semi-soft coking coal producer Stanmore Coal acquired the Wotonga project in the Bowen Basin from Peabody Australia for USD 22.8 million, aiming to extend the life of its adjacent Isaac Plains Complex by more than 15 years. The open-cut mine is expected to produce 15 Mt to 20 Mt of coal over its eight- to ten-year lifetime.

The Korean company POSCO has suffered a setback regarding its greenfield Hume Coal underground mine project in the Southern Highlands. The government of New South Wales published a communiqué stating that the state's Independent Planning Commission found that Hume Coal needs to address certain environmental and social issues before receiving approval for construction of the project. If approved, Hume's mine is expected to produce 3.5 Mtpa of thermal and met coal over 23 years.

The Rocky Hill project, a comparatively small open-cut mine for thermal and met coal in New South Wales, faced a new challenge in the approval process. The NSW Land and Environment Court considered an appeal on the Rocky Hill project but upheld its original decision to deny a licence. The judge added that a further reason for the denial is the mine's contribution to climate change, citing an increase in scope 3 greenhouse gas emissions, as well as uncertain economic benefits and adverse social and visual impacts. Since then, two more mine approvals have been denied with reference to climate change, the larger of which is KEPCO's Bylong thermal coal project with a projected capacity of 6.5 Mtpa. The NSW government subsequently announced that it will address the issue of scope 3 emissions, which should not be taken into account, and provide certainty for mining project approvals. The new arrangements are yet to become law.

South Africa

South Africa has the second-highest share of more-advanced projects within the forecast period, amounting to about 52 Mtpa, most of which are greenfield projects.

The largest project in South Africa is the Boikarabelo two-phase open-cut coal mine being developed in the Waterberg coalfield in Limpopo province. The mine is planned to extract 12 Mtpa of thermal coal over its expected lifetime of more than 40 years. Ledjadja Coal has entered into an offtake agreement with Noble Resources for Boikarabelo's supply of over 0.8 Mtpa of coal for the first three years. In June 2019, another member of the proposed lending syndicate for construction of the mine confirmed its participation, but financing issues persist. Although coal production is planned to start within the next year, postponement seems likely.

The Boikarabelo project is closely linked with the expansion of rail infrastructure capacity. Rail operator Transnet has embarked on a programme to sustain and create rail infrastructure capacity to unlock the Waterberg, Limpopo and Mpumalanga coal reserves for Eskom power stations, domestic and industrial users, and export markets. The programme involves the enlargement of rail network capacity from the Waterberg area to Richards Bay, Maputo and various inland destinations (currently at the pre-feasibility stage). Furthermore, the Clewer inland terminal is a future project aimed at facilitating the movement of coal supplies from Matimba in Limpopo to the Kusile and Kendal power stations near Clewer.

Another important project in South Africa is MC Mining's Makhado hard coking and thermal coal mining project. In January 2019, MC Mining completed the acquisition of two properties that gave the company key surface rights. It secured conditional approval from its directors to begin the first phase of development in March 2019, and in July it announced that the state-owned Industrial Development Corporation had approved a loan facility to fund construction of the first phase.

MC Mining's wholly owned subsidiary Limpopo Coal Company has concluded a coal sale and purchase agreement with a company that produces and markets bulk commodities, and MC Mining has secured a three-year offtake agreement with China's Huadong Coal Trading Center (HDCTC) to supply at least 0.4 Mtpa of hard coking coal from its South African Makhado mining project. MC Mining noted that the Phase 1 construction period is expected to start in the third quarter of 2019 and will continue for nine months. Mining will start at the project's west pit, with run-of-mine coal production of around 3 Mtpa. After the initial phase, the plant will produce 1.1 Mtpa of saleable coal – 0.54 Mtpa of coking coal and 0.57 Mtpa of thermal. With completion of this project, MC Mining will have initiated one of the first coking coal mines in South Africa and opened a new coal basin with potential for future mining projects.

Russia

Russia's Ministry of Energy announced that it aims to raise coal production to 480 Mtpa by 2030, which is a 60-Mtpa increase. About 15% of the additional capacity is categorised as more advanced and most projects are expected to produce coking coal, which is considerable given the size of the market.

Mechel, one of Russia's leading mining and metals companies, began work on a new longwall project at its Southern Kuzbass underground mine in November 2018. The new longwall mine could produce 1.8 Mtpa of coal for the next two years.

Because Russia's coal mining centres are far from ports and logistical costs are therefore high, increased mining capacity requires expanded coal export facilities. The Russian coal industry has already been hampered by infrastructural limitations for some time, with inadequate port and railway transport capacity restricting exports to significantly below the actual production capacity of coal mines. Russia has announced an investment of USD 22.4 billion for coal mining and port infrastructure development by 2025, and in June 2019 it issued a directive concerning Port Dickson in the Krasnoyarsk Territory for construction of a terminal to ship coal from the field near the Lemberova River. In addition, a terminal for the transshipment of coal from the Syradasaysky coal deposit is planned, with the aim of increasing cargo traffic along the Northern Sea Route.

SUEK, Russia's largest coal miner, is expanding the port of Vanino in Russia's Far East. The port began commercial operations in 2009 and is expected to ship around 20 Mtpa of coal. SUEK has announced its intention to raise the port's annual export capacity by 80% to 40 Mtpa, with exports directed mainly towards Asian markets.

In 2018, the government approved a concession agreement for the new Lavna coal terminal at the port of Murmansk. Construction of the terminal has begun, and the port is expected to reach full capacity of 18 Mtpa in 2022. Railway infrastructure connecting the terminal is also being expanded.

Additionally, Russia plans to build a 10-Mtpa coal terminal at Zarubina in Primorsky Krai, Posyet Bay. The greenfield project is a joint venture between FESCO (one of Russia's largest public transportation and logistics companies) and Erdenes Tavan Tolgoi (Mongolia's coking coal mining company). The port is planned to begin operating in 2023 with a capacity of 10 Mtpa, delivering coal to the Asia Pacific region.

Mongolia

A potential coal export capacity expansion of about 33 Mtpa is anticipated for Mongolia before the end of the outlook period. The expansion focuses on met coal only and is mainly associated with the world's largest undeveloped coking coal mine, Tavan Tolgoi, which has estimated reserves of 7.4 billion tonnes (Bt).

Mongolia's parliament has approved plans to sell up to 30% of the state-owned Tavan Tolgoi coal mine in a proposed initial public offering (IPO). This project's potential is immense because of its proximity to China, but railway capacity is a key constraint to developing this market. Mongolia aims to complete a railway from Tavan Tolgoi to the Chinese border by 2021, enabling exports of 30 Mtpa to China. Construction between Tavan Tolgoi and Gashuun Sukhait in China started in 2019, and the 200-km railway is planned to be commissioned in 2021. In China, the railway will be connected to the Ganquan railway to deliver coal to Chinese ports via Shenhua rail lines.

TerraCom aims to increase annual production at its Baruun Noyon Uul (BNU) coking coal mine complex in Mongolia's South Gobi province to 3 Mtpa by early 2019. The company plans to open additional pits at the mine complex, which it says will improve efficiency.

In addition to the railway expansion, Mongolia is collaborating with Russia on a joint transport terminal project (see above).

United States

The United States has about 9 Mtpa of new capacity classified as more advanced during the forecast period. In 2019, the US Department of the Interior's Bureau of Land Management (BLM) approved the Alton Coal Tract coal lease in Kane County and two lease modification proposals for the SUFCO Mine in Sevier County, Utah. The proposals will extend the mine's lifespan by around five years. The underground mine currently produces 5 Mtpa to 6 Mtpa of thermal coal.

In addition, Arch Coal announced development of the new Leer South longwall mine in Barbour County, which is expected to start operations in late 2021 and produce 3 Mtpa of high-vol A coking coal. The company expects to invest USD 360 million to USD 390 million to develop the mine over the next three years, with the objective of selling the coal mainly into the seaborne coking coal market.

Paringa Resources Limited (PNL) is assessing further greenfield development options for the adjacent Cypress Mine, which has an additional production capacity of 3.8 Mtpa.

Canada

Most of Canada's ongoing development projects focus on the production of coking coal. The capacity outlook for more-advanced projects is relatively small, however.

At the end of 2018, Allegiance Coal signed a joint venture agreement with Japanese company Itochu for its Tenas met coal project in northwest British Columbia. While Allegiance will operate the Tenas mine, the Japanese firm will be responsible for marketing, selling and delivering the mine's coal. Met coal production of 0.75 Mtpa is targeted, and the project currently is undergoing a definitive feasibility study (DFS) and permitting procedures.

Very recently, the US company Conuma announced development of the Hermann project, a satellite of its Wolverine mine in British Colombia. The coking coal mine is expected to produce 2.2 Mtpa starting in 2021.

In February 2019, the Port of Vancouver cancelled Fraser Surrey Docks' permits for development of a coal terminal. The terminal was supposed to handle 4 Mtpa of coal shipped from the United States.

Europe

Despite the pledge of most of western EU member states to phase out coal, some smaller coal mining projects are being developed even under challenging conditions.

Following the 2015 shutdown of the last deep mine in the United Kingdom (the Kellingley Colliery in North Yorkshire), the Woodhouse Colliery project proposes a new underground met coal mine near Whitehaven, West Cumbria. This is the first deep coal mine development project in the United Kingdom for 30 years. At a cost of USD 218 million, it is planned to produce 3.1 Mtpa of met coal over its operational lifetime of at least 40 years. West Cumbria Mining secured planning approval from the Cumbria County Council in March 2019, and the first coal production has been announced for 2021. The project is likely to face significant public opposition, however.

Also in the United Kingdom, Celtic Energy has received permission to restart mining temporarily at the closed Nant Helen surface coal mine near Ystradgynlais; it had been mothballed in 2016 due to a decline in electricity production at the neighbouring power plant. Celtic Energy aims to produce 0.4 Mtpa of thermal coal over two years and expects to complete restoration of the pit in 2023.

In Poland, the government is reportedly planning to raise domestic coal production to reduce the country's reliance on imports, with output to ramp up 5 Mt to 6 Mt by 2025. In June 2019, the Polish state-run coal mining company Jastrzębska Spółka Węglowa (JSW) received approval for its new coking coal mine Bzie-Debina 1-Zachód. The mine is expected to produce 2.4 Mtpa of coking coal starting in 2022. JSW reportedly aims to increase production and exports of coking coal to Asia.

Additionally, Prairie Mining is developing two met coal projects in Poland: the Jan Karski Mine (6 Mtpa) and the Debiensko mine (3 Mtpa). Balamara Resources is developing Nowa Ruda (coking coal) and Sawin (thermal coal) projects.

Indonesia

Indonesian coal mining projects focus mainly on thermal coal. All projects are categorised as less advanced, however, so none are likely begin operating before the end of 2024.

In 2019, the Indonesian government terminated the mining rights of coking coal producer Asmin Koalindo Tuhup (AKT). AKT's plans to increase its output of hard coking coal to 3 Mtpa from 2018 onwards are therefore on hold until the end of the legal process.

Colombia

Colombia's overall export capacity expansion is estimated at 41 Mtpa, mostly focused on thermal coal. However, most of the expansion plans are in the less-advanced category and have made very little progress since the last report.

In January 2019, the Colombian government granted Drummond a 20-year extension to operate La Loma mine in Cesar province. In November 2018, Drummond broke off sales of its Colombian coal assets, which include the Pribbenow and El Descanso mines in the Cesar Coal Basin, and instead announced its intention to continue operating them.

No progress has been reported for the P40 project to expand the capacity of Cerrejon, Colombia's largest thermal coal mine, by 8 Mtpa. It would involve the construction of additional loading facilities at Puerto Bolivar as well as improvements to existing road and rail infrastructure. The expansion is opposed by local tribes and appears to be proceeding very slowly. Plans to build a new coal port in the La Guajira department (designed to facilitate exports from Yildirim Holdings) appear to be on hold, like the development of the mines themselves.

Mozambique

Vale-Mozambique, the local subsidiary of the Brazilian mining giant Vale, announced it plans to increase production at the Moatize mine by up to 20 Mtpa by 2021. However, infrastructure limitations are restricting output growth. While there is increasing momentum to build a third rail line and a port link that could add 40 Mtpa of export capacity, conflicting agendas of developers and investors could delay the plans of the project's main developer, Thai Mozambique Logistica SA (TML), to finish the infrastructure by 2023. Customers using the Macuse port would have to sign up for take-or-pay agreements at USD 25/t.

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General annex

Tables

Table A.1. Coal demand (Mtce), 2017-24

Region	2017	2018*	2020	2022	2024	CAAGR
Asia Pacific	**3 998**	**4 080**	**4 224**	**4 347**	**4 402**	**1.3%**
China	2 794	2 823	2 894	2 929	2 906	0.5%
India	554	585	630	688	748	4.2%
Japan	166	164	156	160	158	-0.7%
Korea	118	120	116	114	108	-1.8%
Southeast Asia	190	204	235	260	283	5.6%
North America	**514**	**490**	**427**	**403**	**385**	**-3.9%**
United States	474	453	390	370	358	-3.8%
Central and South America	**46**	**50**	**49**	**49**	**47**	**-1.0%**
Europe	**406**	**391**	**359**	**347**	**333**	**-2.6%**
European Union	327	308	271	254	234	-4.5%
Middle East	**12**	**12**	**11**	**12**	**16**	**4.7%**
Eurasia	**260**	**276**	**271**	**275**	**279**	**0.1%**
Russia	165	174	171	175	175	0.1%
Africa	**156**	**159**	**159**	**160**	**161**	**0.2%**
World	**5 393**	**5 458**	**5 500**	**5 595**	**5 624**	**0.5%**

* Estimated.

Notes: Mtce = million tonnes of coal equivalent; CAAGR = compound average annual growth rate. Differences in totals are due to rounding.

Table A.2. Thermal coal and lignite demand (Mtce), 2017-24

Region	2017	2018*	2020	2022	2024	CAAGR
Asia Pacific	**3 222**	**3 291**	**3 392**	**3 511**	**3 585**	**1.4%**
China	2 169	2 188	2 223	2 264	2 263	0.6%
India	500	530	569	621	676	4.1%
Japan	121	120	112	117	117	-0.4%
Korea	83	85	82	80	76	-1.9%
Southeast Asia	185	197	224	245	266	5.2%
North America	**487**	**463**	**399**	**376**	**359**	**-4.2%**
United States	455	434	370	350	340	-4.0%
Central and South America	**30**	**34**	**33**	**33**	**31**	**-1.4%**
Europe	**327**	**314**	**286**	**277**	**265**	**-2.8%**
European Union	258	242	209	194	176	-5.2%
Middle East	**9**	**8**	**7**	**7**	**10**	**3.7%**
Eurasia	**172**	**187**	**182**	**186**	**188**	**0.1%**
Russia	100	109	105	108	106	-0.4%
Africa	**152**	**154**	**154**	**154**	**155**	**0.0%**
World	**4 399**	**4 451**	**4 453**	**4 544**	**4 591**	**0.5%**

* Estimated.
Note: Differences in totals are due to rounding.

Table A.3. Metallurgical (met) coal demand (Mtce), 2017-24

Region	2017	2018*	2020	2022	2024	CAAGR
Asia Pacific	**777**	**790**	**833**	**836**	**818**	**0.6%**
China	626	635	671	665	643	0.2%
India	54	55	60	67	73	4.8%
Japan	45	45	44	43	41	-1.5%
Korea	35	35	34	34	32	-1.6%
Southeast Asia	4	7	11	15	17	15.4%
North America	**27**	**27**	**28**	**28**	**26**	**-0.4%**
United States	19	20	21	20	19	-1.0%
Central and South America	**16**	**17**	**16**	**16**	**16**	**-0.3%**
Europe	**78**	**76**	**72**	**70**	**69**	**-1.8%**
European Union	69	66	63	60	58	-2.1%
Middle East	**4**	**4**	**4**	**5**	**6**	**6.6%**
Eurasia	**88**	**89**	**88**	**89**	**91**	**0.3%**
Russia	65	65	66	67	68	0.8%
Africa	**4**	**5**	**5**	**6**	**6**	**6.2%**
World	**994**	**1 007**	**1 048**	**1 051**	**1 032**	**0.4%**

* Estimated.
Note: Differences in totals are due to rounding.

Table A.4. Coal production (Mtce), 2017-24

Region	2017	2018*	2020	2022	2024	CAAGR
Asia Pacific	**3 848**	**4 031**	**4 044**	**4 147**	**4 202**	**0.7%**
China	2 551	2 664	2 632	2 667	2 653	-0.1%
India	385	412	437	487	537	4.5%
Australia	419	409	419	437	444	1.4%
Indonesia	375	416	420	415	420	0.1%
North America	**586**	**575**	**509**	**491**	**461**	**-3.6%**
United States	533	526	459	439	416	-3.8%
Central and South America	**89**	**82**	**83**	**85**	**83**	**0.1%**
Europe	**220**	**215**	**200**	**194**	**192**	**-1.9%**
European Union	178	170	152	142	136	-3.7%
Middle East	**1**	**1**	**1**	**1**	**3**	**10.3%**
Eurasia	**412**	**440**	**437**	**441**	**446**	**0.2%**
Russia	317	343	333	335	336	-0.3%
Africa	**224**	**225**	**226**	**236**	**238**	**1.0%**
World	**5 381**	**5 570**	**5 500**	**5 595**	**5 624**	**0.2%**

* Estimated.
Note: Differences in totals are due to rounding.

Table A.5. Thermal coal and lignite production (Mtce), 2017-24

Region	2017	2018*	2020	2022	2024	CAAGR
Asia Pacific	**3 067**	**3 244**	**3 225**	**3 332**	**3 394**	**0.8%**
China	1 987	2 087	2 042	2 087	2 083	0.0%
India	383	410	435	484	535	4.5%
Australia	234	235	232	245	250	1.1%
Indonesia	371	411	407	399	403	-0.3%
North America	**494**	**477**	**424**	**401**	**382**	**-3.6%**
United States	469	455	400	379	367	-3.5%
Central and South America	**85**	**77**	**78**	**80**	**78**	**0.3%**
Europe	**202**	**199**	**186**	**181**	**179**	**-1.8%**
European Union	161	154	138	130	123	-3.6%
Middle East	**0**	**0**	**0**	**0**	**1**	**48.2%**
Eurasia	**313**	**339**	**330**	**333**	**336**	**-0.1%**
Russia	233	253	242	243	243	-0.6%
Africa	**213**	**214**	**210**	**217**	**221**	**0.5%**
World	**4 374**	**4 549**	**4 453**	**4 544**	**4 591**	**0.2%**

* Estimated.
Note: Differences in totals are due to rounding.

Table A.6. Met coal production (Mtce), 2017-24

Region	2017	2018*	2020	2022	2024	CAAGR
Asia Pacific	**781**	**787**	**819**	**815**	**807**	**0.4%**
China	564	577	590	580	570	-0.2%
India	2	3	3	3	3	0.0%
Australia	185	174	188	192	194	1.8%
Mongolia	25	27	25	24	23	-2.7%
North America	**93**	**98**	**86**	**90**	**79**	**-3.6%**
United States	64	71	59	60	49	-5.8%
Central and South America	**4**	**6**	**5**	**5**	**5**	**-3.2%**
Europe	**18**	**16**	**14**	**13**	**13**	**-4.0%**
European Union	0	0	0	0	0	0.0%
Middle East	**1**	**1**	**1**	**1**	**1**	**0.0%**
Eurasia	**99**	**102**	**107**	**108**	**110**	**1.2%**
Russia	84	90	91	92	93	0.4%
Africa	**11**	**11**	**16**	**19**	**18**	**8.2%**
Mozambique	7	6	11	14	13	13.6%
World	**1 007**	**1 022**	**1 048**	**1 051**	**1 032**	**0.2%**

* Estimated.
Note: Differences in totals are due to rounding.

Table A.7. Seaborne thermal coal imports (Mtce), 2017-24

Region	2017	2018*	2020	2022	2024	CAAGR
Europe	132	118	88	87	79	-6.4%
Japan	120	119	108	113	114	-0.6%
Korea	83	84	82	80	75	-1.9%
Chinese Taipei	53	52	53	52	53	0.1%
China	148	159	173	163	160	0.1%
India	116	138	135	137	141	0.3%
South Asia	99	109	127	144	160	6.6%
Other	70	68	63	66	71	0.8%
World	**821**	**847**	**827**	**842**	**853**	**0.1%**

* Estimated.
Note: Differences in totals are due to rounding.

Table A.8. Seaborne thermal coal exports (Mtce), 2017-24

Region	2017	2018*	2020	2022	2024	CAAGR
Australia	177	178	175	190	196	1.6%
South Africa	67	65	62	69	73	1.8%
Indonesia	306	342	330	315	311	-1.6%
Russia	131	137	136	137	142	0.6%
Colombia	77	74	67	69	66	-1.8%
United States	34	45	30	29	27	-8.1%
Other	32	25	27	33	38	7.4%
World	**824**	**866**	**827**	**842**	**853**	**-0.2%**

* Estimated.
Note: Differences in totals are due to rounding.

Table A.9. Seaborne met coal imports (Mtce), 2017-24

Region	2017	2018*	2020	2022	2024	CAAGR
Europe	51	52	58	57	56	1.2%
Japan	45	44	43	43	41	-1.1%
Korea	34	35	34	34	32	-1.4%
China	45	39	52	57	46	2.5%
India	49	49	57	63	69	6.0%
Other	42	45	36	38	40	-1.9%
World	**267**	**263**	**279**	**292**	**283**	**1.2%**

* Estimated.
Note: Differences in totals are due to rounding.

Table A.10. Seaborne met coal exports (Mtce), 2017-24

Region	2017	2018*	2020	2022	2024	CAAGR
Australia	172	174	184	188	191	1.5%
Canada	24	24	20	23	22	-1.4%
Mozambique	7	6	11	14	13	13.4%
Russia	16	17	18	18	19	2.0%
United States	47	53	38	40	31	-8.5%
Other	13	13	8	8	8	-8.7%
World	**279**	**287**	**279**	**292**	**283**	**-0.2%**

* Estimated.
Note: Differences in totals are due to rounding.

Mining projects

Table A.11. Current coal mining projects

Country	Project	Company	Type	Earliest proposed start-up	Estimated capacity (Mtpa)	Resource	Status
Australia	Alpha Coal Project	GVK Hancock	N	2021	32	TC	LA
Australia	Appin Area 9	South32	E	2016	3.5	CC	MA
Australia	Arcturus	Adamelia Resources	N	2023+	5	TC	LA
Australia	Alpha North Coal Project	Waratah Coal	N	..	40	TC	LA
Australia	Alpha West Coal Project	GVK Hancock	N	..	40	TC	LA
Australia	Ashton South East opencut	Yancoal Australia	E	2017	3.6	TC, PCI	LA
Australia	Baralaba South	Cockatoo Coal	E	2019	4	PCI, TC	LA
Australia	Belview	Stanmore Coal	N	2023+	0	CC	LA
Australia	Bluff	Carabelle Resources	N	2017	1.2	PCI	LA
Australia	Broughton Coal Project	U&D Mining Industry	N	2018	3	CC	LA
Australia	Bundi	MetroCoal	N	2020	5	TC	LA
Australia	Byerwen Coal Project	Qcoal/JFE Steel	N	2018	10	CC, TC	MA
Australia	Bylong Coal Project	Kepco	N	2020	6.5	TC	LA
Australia	Carmichael Coal Project	Adani	N	2021	10	TC	MA
Australia	Caval Ridge Expansion	BHP Billiton / Mitsubishi Alliance	E	2019	7.2	CC	MA
Australia	China First (Galilee Coal project)	Waratah Coal	N	2022	40	TC	LA
Australia	China Stone	MacMines Austasia	N	2024	38	TC	LA
Australia	Clifford	Stanmore Coal	N	..	5	TC	LA
Australia	Clyde Park Project	Clyde Park Coal Pty Ltd	N	..	1.8	TC	LA
Australia	Codrilla	Peabody	N	2022	3.2	PCI	LA
Australia	Colton	New Hope Group	N	2023+	0.5	CC	LA
Australia	Columboola Project	SincoCoal And MetroMining	N	2023+	5	TC	LA

Country	Project	Company	Type	Earliest proposed start-up	Estimated capacity (Mtpa)	Resource	Status
Australia	Comet Ridge	Acacia Coal	N	2016	0.4	TC, CC	LA
Australia	Curragh Extension	Wesfarmers	E	2018	10	CC, PCI	LA
Australia	Dawson West	Civil & Mining Resources	N	..	1.6	TC	LA
Australia	Dysart East	Dysart Coal	N	..	1.4	CC	LA
Australia	Eagle Downs	Aquila Resources / Vale	N	2023+	4.5	CC	MA
Australia	Eaglefield	Peabody Energy	E	..	5	CC	LA
Australia	Elimatta	New Hope	N	2023+	5	TC	LA
Australia	Ellensfield	Ellensfield Coal Management	N	2023+	4.7	TC	LA
Australia	Wilton-Fairhill	Wilton Coking Coal	N	..	..	CC	LA
Australia	Grosvenor West	Carabella Resources	N	..	3.5	TC, CC	LA
Australia	Kevin's Corner	GVK	N	2019	30	TC	LA
Australia	Moranbah South	Anglo American / Exxaro	N	2021	18	CC	LA
Australia	Moorlands	Cuesta Coal	N	2018	1.6	TC	LA
Australia	New Acland (Stage 3)	New Hope Coal	E	2019	7.5	TC	LA
Australia	New Lenton	New Hope Coal	N	..	2	CC	LA
Australia	North Galilee Project	FTB and Orion Mining	N	2022	7	TC	LA
Australia	Okay Creek (Phase 2)	Glencore, Sumisho, Itochu, Icra OC	E	2018	20.9	CC	LA
Australia	Olive Downs	Nippon Steel and Sumitomo Metal	N	2023+	14	TC, CC	LA
Australia	Red Hill Mining	BHP Billiton / Mitsubishi Alliance	N	2023+	14.5	TC, CC	LA
Australia	Rolleston Expansion Project	Glencore, Sumisho, IRCA	E	..	19	TC	LA
Australia	Sarum	Glencore, Itochu, Sumisho	N	..	4.2	CC	LA

Country	Project	Company	Type	Earliest proposed start-up	Estimated capacity (Mtpa)	Resource	Status
Australia	Saraji East	BHP and Mitsubishi	N	2023+	7	CC	LA
Australia	South Burnett	MRV Tarong Basin Coal	N	2019	12.5	TC	LA
Australia	South Galilee	Alpha Coal Management	N	2023+	17.5	TC	LA
Australia	Springsure Creek	Adamelia Resources	N	2023+	7	TC	LA
Australia	Spur Hill	Malabar Coal	N	2023+	6	TC, CC	LA
Australia	Styx	Waratah Coal, Queensland Nickel	N	..	1.5	TC, PCI	LA
Australia	Talwood	Baosteel Resources Australia	N	2023+	3.6	TC, PCI, CC	LA
Australia	Taroborah	Shenhua Energy	N	2018	5.7	TC	LA
Australia	Teresa	United Mining Group	N	..	6	PCI, TC	LA
Australia	The Hume Coal Project	POSCO	N	2020	3.4	TC	LA
Australia	The Range Project	Stanmore Coal	N	2023+	5	TC	LA
Australia	Togara North	Glencore	N	..	6	TC	LA
Australia	Vickery	Whitehaven	N	2021	4.5	TC	LA
Australia	Karin	Vitrinite / Itochu Corporation	N	..	0	CC	LA
Australia	Wallarah 2 Coal Project	Kores	N	2024+	5	TC	LA
Australia	Wandoan (Phase 1)	Glencore, ICRA, Wandoan, Sumisho	N	2024+	22	TC	LA
Australia	Wards Well	BHP Billiton / Mitsubishi Alliance	N	2017	5	CC	LA
Australia	Washpool	Aquila Resources	N	2023+	2.9	CC	LA
Australia	Watermark	Shenhua Energy	N	2023+	6.2	TC	LA
Canada	Carbon Creek	Cardero Coal	N	2022	4.1	CC	LA
Canada	EB Wolverine (Perry Creek)	Walter Energy	E	2020	1.5	CC	LA
Canada	Crown Mountain	Jameson Resources	N	2019	1.7	CC	LA
Canada	Central South	Glencore	0	2023	2.1	CC	LA
Canada	Roman Mountain	Anglo American	N	2022	2.8	CC	LA

Country	Project	Company	Type	Earliest proposed start-up	Estimated capacity (Mtpa)	Resource	Status
Canada	Donkin	Kameron Collieries ULC	E	2021	2.8	CC	MA
Canada	Elko	Pacific American Coal	N	..	0	0	LA
Canada	Tent Hill	Montem	N	..	1.5	CC	LA
Canada	Echo Hill	Hillsborough Resources	N	..	1	TC	LA
Canada	Grand Cache	Sonicfield Global	E	2018	2.3	CC	MA
Canada	Grassy Mountain	Riversdale Resources	N	2021	3.9	CC	LA
Canada	Groundhog	Atrum Coal	N	..	0.9	A	LA
Canada	Murray River	HD Mining	N	2018	6	CC	LA
Canada	Quintette	Teck Resources	N	2022	3.5	CC	LA
Canada	Tenas	Allegiance Coal / Itochu	0	..	0.8	CC	LA
Canada	Willow Creek	Walter Energy	E	2018	1.7	CC, PCI	MA
Canada	Sukunka	Glencore	N	..	3	CC	LA
Colombia	Canaverales	Yildirim Holding	N	2019	2.5	TC	LA
Colombia	Cerrejon P40	Cerrejon	E	2018	8	TC	MA
Colombia	El Descanso	Drummond	E	..	12	TC	LA
Colombia	Papayal	Yildirim Holding	N	2017	2.5	TC	LA
Colombia	San Juan	Yildirim Holding	N	2019	16	TC	LA
Indonesia	Bumi Barito Mineral	Cokal	N	2018	2	CC, PCI	MA
Indonesia	East Kutai Coal Project	Churchill Mining / Ridlatama Group	N	..	30	TC	LA
Indonesia	Adaro MetCoal Companies (AMC) Concessions	Adaro	N	..	20	CC	LA
Indonesia	Mitra Energi Agung	Indika	N	..	0	TC	LA
Indonesia	Mustika Indah Permai	Adaro	N	..	0	TC	LA
Indonesia	Arni Bersaudara	PT Arni Bersaudara	N	2023	1	TC	LA
Indonesia	Pakar North	Kangaroo Resources	N	2020	9	TC	LA
Indonesia	Pakar South	Kangaroo Resources	N	..	0	TC	LA

Country	Project	Company	Type	Earliest proposed start-up	Estimated capacity (Mtpa)	Resource	Status
Indonesia	Graha Panca Karsa	Kangaroo Resources	N	..	0	TC	LA
Indonesia	Bukit Enim Energi	Adaro	N	..	0	TC	LA
Indonesia	Tekno Orbit Persada	MEC Coal	N	..	17	TC	LA
Mozambique	Benga Extension	ICVL	E	2021	15	CC	LA
Mozambique	Midwest	Beacon Hill Resources	N	..	7	TC	LA
Mozambique	Moatize	Vale/Mitsui	E	2017	8	TC, CC	MA
Mozambique	Ncondezi	Ncondezi Energy	N	2018	7	TC	LA
Mozambique	Revuboe	Nippon Steel and Sumitomo Metal	N	..	7	TC, CC	LA
Mozambique	Zambeze	ICVL	N	..	..	CC	LA
Russia	Amaam	Tiger Realm Coal	E	2022	2	CC	MA
Russia	Denisovskaya East	Kolmar	N	2018	4	CC	MA
Russia	Elegest	OPK	N	2020	1.3	CC	LA
Russia	Elga	Mechel	E	2018	11.7	TC, CC	MA
Russia	Inaglinsky-1	Kolmar	N	2017	4	CC	MA
Russia	Inaglinsky-2	Kolmar	N	..	8	CC	LA
Russia	Karakansky (Stage III)	Karakan Invest	N	2019	3	TC	LA
Russia	Yubileynaya	Topprom	E	2021	2	CC	LA
Russia	Sibirskaya	Sibuglemet	N	2023	0.5	TC	LA
Russia	Usinsky-3	NLMK	N	2018	4.3	CC	LA
Russia	Zhernovskoye-1	NLMK	N	2018	5.7	CC	LA
Russia	Zhernovski Gluboki	NLMK	N	..	0	CC	LA
Russia	Solntsevsky	Solntsevsky Coal Mine LLC	E	2020	10	TC	LA
Russia	Butovskaya	Industrial Metallurgical Holding	E	..	0.9	CC	MA
Russia	Tikhova	Industrial Metallurgical Holding	N	2018	3.4	CC	MA
South Africa	Argent	Glencore/Shanduka	N	2018	1.2	TC	LA
South Africa	Belfast	Exxaro	N	2019	2.7	TC	MA

Country	Project	Company	Type	Earliest proposed start-up	Estimated capacity (Mtpa)	Resource	Status
South Africa	Boikarabelo	Resource Generation	N	2020	6	TC	MA
South Africa	Brakfontein	Universal Coal	N	..	1.2	TC	LA
South Africa	De Wittekrans	Canyon Coal	N	2018	0.4	TC	MA
South Africa	Grootegluk 6 Phase 2	Exxaro Resources	N	2020	1.7	TC	MA
South Africa	Impumelelo	Sasol Mining	N	2019	8.5	TC	MA
South Africa	Kangala	Universal Coal	E	..	3.3	TC	MA
South Africa	Leeuwpan	Exxaro	E	2018	2.7	TC, CC	MA
South Africa	Klipfontein	Genet South Africa	N	..	1	TC	LA
South Africa	Koornfontein OC	Glencore/Optimum	E	..	3.3	TC	..
South Africa	Mafube	Exxaro/Anglo American	E	2019	3.1	TC	MA
South Africa	Makhado	Coal of Africa	E	2020	1.7	TC, CC	MA
South Africa	Moabsvelden	Wescoal	N	2018	1.1	TC	MA
South Africa	New Largo	Seriti/Coalzar/IDC	N	..	12	TC	LA
South Africa	Optimum Coal Mine	Tegeta	E	..	12	TC	MA
South Africa	Shondoni	Sasol Mining	N	2018	9.2	TC	MA
South Africa	Thabametsi	Exxaro	N	2020	3.9	TC	MA
South Africa	Vele	Coal of Africa	E	2019	3.4	TC, CC	MA
Mongolia	Erdenebulag	Aspire Mining	N	..	0	TC	..
Mongolia	Nuurstei	Aspire Mining	N	2019	1	CC	LA
Mongolia	Shinejinst	Gobi Coal and Energy	N	2018	1.4	CC	MA
Mongolia	Tavan Tolgoi Extension	Erdenes Tavan Tolgoi	E	2019	19	CC	LA
Mongolia	Ovoot	Aspire Mining	N	2020	10	CC	LA
United States	Blue Creek Number 1	Warrior Met Coal	E	2020	6.7	CC	LA
United States	Berwind	Ramaco Resources, Inc.	N	2018	0.9	CC	MA
United States	Knox Creek	Ramaco Resources, Inc.	N	2017	0.1	CC	MA
United States	RAM Mining (PA)	Ramaco Resources, Inc.	N	2019	0.5	CC	LA
United States	Whigville	B&N Coal Co. Inc.	N	2017	0.2	TC	MA

Country	Project	Company	Type	Earliest proposed start-up	Estimated capacity (Mtpa)	Resource	Status
United States	Poplar Grove Mine	Paringa Resources Ltd.	N	2018	3.5	TC	MA
United States	Panther Eagle	Alpha Natural Resources	N	2017	0.6	CC	MA
United States	Cypress Mine	Paringa Resources Ltd.	N	2021	4.7	TC	LA

Notes: The table lists currently discussed mining projects according to publicly available information but has no claim to completeness. Data on the start-up data is according to public information but does not necessarily represent our view concerning expected export capacity additions. Data on the estimated capacity represents the targeted capacity, which is often not available in the year of start-up.
Type: N = New project, E = Expansion
Resource: TC = thermal coal, CC = coking coal, AN = anthracite, PCI = pulverised coal injection
Status: MA = More advanced, LA = Less advanced
Mtpa = million tonnes per annum.

Glossary

Definitions

Coal: Coal is a solid, combustible, fossil sedimentary rock. Coals come from buried vegetation transformed by the action of high pressure and temperature over millions of years.

Coal rank: The degree of transformation from the original plant source. It is loosely related to the age of the coal and is mainly determined from random reflectance of the vitrinite, one of coal's organic components. The ranks of coal, in decreasing order of transformation from high to low, are: anthracite, bituminous coal, subbituminous coal, lignite and peat. This report more simply distinguishes between either hard coal (anthracite, bituminous and subbituminous coal) or lignite. Peat is not considered coal in this report.

Coal classifications: Refers to a whole range of ages, compositions and properties. There are many different classifications used around the world. The main parameter used for classifying coal is its rank (from anthracite to lignite), but final destination is also used (thermal coal versus metallurgical coal).

Coal quality: Consists of a large variety of properties exhibited by coal when it is used. Calorific value and impurity content are the main parameters defining the quality of thermal coal, whereas caking properties, resistance and impurity content are the main ones for coking coal.

Thermal (or steam) coal: In this report, refers to hard coal used for purposes other than metallurgy.

Coking coal: High-quality coal used to produce the coke utilised in blast furnaces to produce pig iron. The terms metallurgical coal and coking coal are sometimes used interchangeably.

Semi-soft coal: High-quality steam coal mixed with coking coal to produce coke for blast furnaces.

Pulverised coal injection (PCI) coal: A high-quality steam coal injected into a blast furnace to reduce coke consumption.

Metallurgical coal: In this report, it refers to coking coal, semi-soft coal and pulverised coal Injection (PCI) coal. Although anthracite is often used for metallurgical purposes, in this report it is classified as thermal coal.

Tonne of coal equivalent (tce): A unit of energy widely used internationally in the coal industry, defined as 7 million kilocalories (kcal). Therefore, the relationship between tce and physical tonnes depends on the net calorific value of the coal. One tonne of coal with a net calorific value of 7 000 kilocalories per kilogramme (kcal/kg) represents 1 tce.

Coal mining: A technique used in the removal of coal from a deposit. As coal deposits occur in the Earth's crust at various seam configurations and depths, the condition of the deposit determines the mining method used. Generally, deep deposits are mined by underground mining and shallow deposits are mined by open-cast mining. The strip ratio largely determines whether an open-cast mine is profitable or not.

Strip ratio: The overburden, or waste material (usually expressed in cubic metres [m^3]), to be removed per unit of coal extracted (usually in tonnes). High strip ratios therefore make open-cast mining unprofitable.

Open-cast mining: A mining method whereby the overburden is first drilled, then blasted and finally removed. Once access has been gained, coal is removed in a similar way. For removal, truck and power/electric shovel, and sometimes conveyor belts, may be used as well as some extremely large mining machinery, such as draglines or bucket wheels. Open-cast mining is usually less labour-intensive than underground mining, but has higher consumable costs, e.g. tyres, diesel, explosives. Generally, it implies greater environmental impact than underground mining.

Underground mining: A mining method in which coal seam access is gained through shafts, galleries and tunnels. Although there are many ways to mine a coal deposit underground, coal is usually stripped by automatic shearers or continuous miners using either short/long walls or room-and-pillar exploitations. Underground mining is generally more labour-intensive and requires higher capital investments than open-cast mining.

Coal washing/upgrading: A process in which undesirable constituents (i.e. ash, moisture) are partially removed from raw coal to produce higher-quality coal.

Merry-go-round system: A Merry-go-round system, often abbreviated as MGR, is a closed-circuit dedicated rail transportation system between coal mines and consumption points, e.g. thermal coal plants. The block train of hopper wagons most commonly both loads and unloads its cargo while moving.

Regional and country groupings

North America

Canada, Mexico and the United States.

Central and South America

Argentina, the Plurinational State of Bolivia (Bolivia), Brazil, Chile, Colombia, Costa Rica, Cuba, Curaçao, the Dominican Republic, Ecuador, El Salvador, Guatemala, Haiti, Honduras, Jamaica, Nicaragua, Panama, Paraguay, Peru, Suriname, Trinidad and Tobago, Uruguay, the Bolivarian Republic of Venezuela (Venezuela) and other Central and South American countries and territories.

Europe

Includes the EU regional grouping and Albania, Bosnia and Herzegovina, Iceland, the Republic of North Macedonia, Gibraltar, Kosovo, Montenegro, Norway, Serbia, Switzerland and Turkey.

European Union (EU)

Austria, Belgium, Bulgaria, Croatia, Cyprus, the Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Ireland, Italy, Latvia, Lithuania, Luxembourg, Malta, the Netherlands, Poland, Portugal, Romania, the Slovak Republic, Slovenia, Spain, Sweden and the United Kingdom.

Africa

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

Middle East

Bahrain, the Islamic Republic of Iran (Iran), Iraq, Israel , Jordan, Kuwait, Lebanon, Oman, Qatar, Saudi Arabia, the Syrian Arab Republic (Syria), the United Arab Emirates and Yemen.

Eurasia

Armenia, Azerbaijan, Belarus, Georgia, Kazakhstan, Kyrgyzstan, the Republic of Moldova, the Russian Federation (Russia), Tajikistan, Turkmenistan, Ukraine and Uzbekistan.

Asia Pacific

Includes the Southeast Asia regional grouping and Australia, Bangladesh, the People's Republic of China ("China"), India, Japan, Korea, the Democratic People's Republic of Korea (North Korea), Mongolia, Nepal, New Zealand, Pakistan, Sri Lanka, Chinese Taipei and other countries and territories.

China

Refers to the People's Republic of China, including Hong Kong.

Southeast Asia

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

Abbreviations and acronyms

AAGR	average annual growth rate
ACE	Affordable Clean Energy rule
AKT	Asmin Koalindo Tuhup mining company (Indonesia)
API	Argus/McCloskey's Coal Price Index
ARA	Amsterdam-Rotterdam-Antwerp (price index)
ASEAN	Association of Southeast Asian Nations
B-BBEE	Broad-Based Black Economic Empowerment (South Africa)
BBM	Bumi Barito Mineral coal project
BCCL	Bharat Coking Coal (India)
BFI	blast furnace iron
BLM	Bureau of Land Management (United States)
BMA	BHP Mitsubishi Alliance
BNU	Baruun Noyon Uul mine (Mongolia)
BRI	Belt and Road Initiative
BRM	Black Royalty Minerals
CAGR	Compound average annual growth rate
capex	capital expenses
CCGT	combined cycle gas turbine
CCL	Central Coalfields (India)
CCoW	coal contract of work
CCUS	carbon capture, utilisation and storage
CEIC	China Energy Investment Corporation
CFR	cost and freight
CHP	combined heat and power
CHPP	coal handling and preparation plant
CIF	cost, insurance and freight
CIL	Coal India Limited
CO	carbon monoxide

CO_2	carbon dioxide
CPP	Clean Power Plan
CSN	crucible swelling number
CSR	coke strength after reaction
CRI	coke reactivity index
CV	calorific value
DES	delivered ex ship
DFS	definitive feasibility study
DMIC	Delhi-Mumbai Industrial Corridor
DMO	domestic market obligation
DOE	Department of Energy (United States)
dwt	deadweight tonnage
EBITDA	earnings before interest, tax, depreciation and amortization
ECA	Emission Control Area
ECL	Eastern Coalfields (India)
EIA	Energy Information Administration
EIS	environmental impact statement
EPA	Environmental Protection Agency (United States)
EPC	engineering, procurement and construction
ESDM	Indonesian Ministry of Energy and Mineral Resources
EU	European Union
EU ETS	European Union Emissions Trading System
FEED	Front-End Engineering and Design
FEWA	Federal Electricity and Water Authority (United Arab Emirates)
FID	final investment decision
FOB	free on board
FYP	Five-Year Plan (China)
GAR	gross as received
GDP	gross domestic product

GHG	greenhouse gas
HDCTC	Huadong Coal Trading Center
HSFO	high-sulphur fuel oil
ICI	Indonesian Coal Index
ICVL	International Coal Ventures Private Limited
IEA	International Energy Agency
IMF	International Monetary Fund
IMO	International Maritime Organisation
IPO	initial public offering
IPP	independent power producer
IRP	Integrated Resource Plan (South Africa)
JCC	Japanese Crude Cocktail
JSW	Jastrzębska Spółka Węglowa mining company (Poland)
LE-B	Lausitz Energie Bergbau AG mining company (Germany)
LEIP	Limpopo Eco-Industrial Park
LHV	lower heating value
LNG	liquefied natural gas
MCL	Mahanadi Coalfields (India)
met	metallurgical
MGO	marine gasoil
MGR	merry-go-round (train transport system)
MIBRAG	Mitteldeutsche Braunkohlengesellschaft mbH
MOTIE	Ministry of Trade, Industry and Energy (Korea)
MoU	memorandum of understanding
MSR	Market Stability Reserve
NDRC	National Development and Reform Commission (China)
NEA	National Energy Administration (China)
NGO	non-governmental organisation
NLC	Nacala Logistics Corridor (Mozambique)

NSP	National Steel Policy (India)
OECD	Organisation for Economic Co-operation and Development
opex	operating expenses
OTC	over the counter
PCI	pulverised coal injection
PGG	Polska Grupa Górnicza mining company (Poland)
PLN	Perusahaan Listrik Negara corporation (Indonesia)
PM	particulate matter
PNL	Paringa Resources Ltd
PPCA	Powering Past Coal Alliance
PV	photovoltaic
RMCFA	Reinforced Model for Coal Flow Analysis
ROW	rest of world
SAEC	South Africa Energy Coal
SCCL	Singareni Collieries Company Limited (India)
SECL	South Eastern Coalfields
SO_2	sulphur dioxide
SSCI	semi-soft coking coal
SSEG	small-scale embedded generation
SUEK	Siberian Coal Energy Company
TML	Thai Mozambique Logistica
TPES	total primary energy supply
TTF	Title Transfer Facility
UNFCCC	United Nations Framework Convention on Climate Change
US	United States
VGF	Vanggatfontein mine (South Africa)
VLSFO	very-low-sulphur fuel oil
WCL	Western Coalflields (India)
y-o-y	year-on-year

Currency codes

AUD	Australian dollar
CAD	Canadian dollar
CNY	Chinese yuan renminbi
COP	Colombian peso
GBP	Great Britain pound
IDR	Indonesian rupiah
RUB	Russian ruble
USD	United States dollar
ZAR	South African rand

Units of measure

bbl	barrel
bcm	billion cubic metres
Bt	billion metric tonnes
Btce	billion tonnes of coal equivalent
°C	degrees Celsius
dwt	deadweight tonnage
g	gramme
g/kWh	grammes per kilowatt hour
Gt	gigatonne
GW	gigawatt
GWh	gigawatt hour
kb	thousand barrels
kcal	kilocalories
kg	kilogramme
km	kilometre
kWh	kilowatt hours
m	metre
m^3	cubic metre

MBtu	million British thermal units
Mt	million tonnes
Mtce	million tonnes of coal equivalent
$MtCO_2$	million tonnes of carbon dioxide
Mtoe	million tonnes of oil equivalent
Mtpa	million tonnes per annum
MW	megawatt
MWh	megawatt hour
t	tonne
TWh	terawatt hours

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Coal 2019 – Analysis and forecast to 2024

Coal remains a major fuel in global energy systems, accounting for almost 40% of electricity generation and more than 40% of energy-related carbon dioxide emissions.

Coal 2019, the latest annual coal market report by the IEA, analyses recent developments and provides forecasts through 2024 for coal supply, demand and trade. Its findings should be of interest to anyone interested in energy and climate issues.

The report finds that the rebound in global coal demand continued in 2018, driven by growth in coal power generation, which reached an all-time high. Although coal power generation is estimated to have declined in 2019, this appears to have resulted from particular circumstances in some specific regions and is unlikely to be the start of a lasting trend.

Over the next five years, global coal demand is forecast to remain stable, supported by the resilient Chinese market, which accounts for half of global consumption. But the report notes that this stability could be undermined by stronger climate policies from governments, lower natural gas prices or developments in the People’s Republic of China.

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