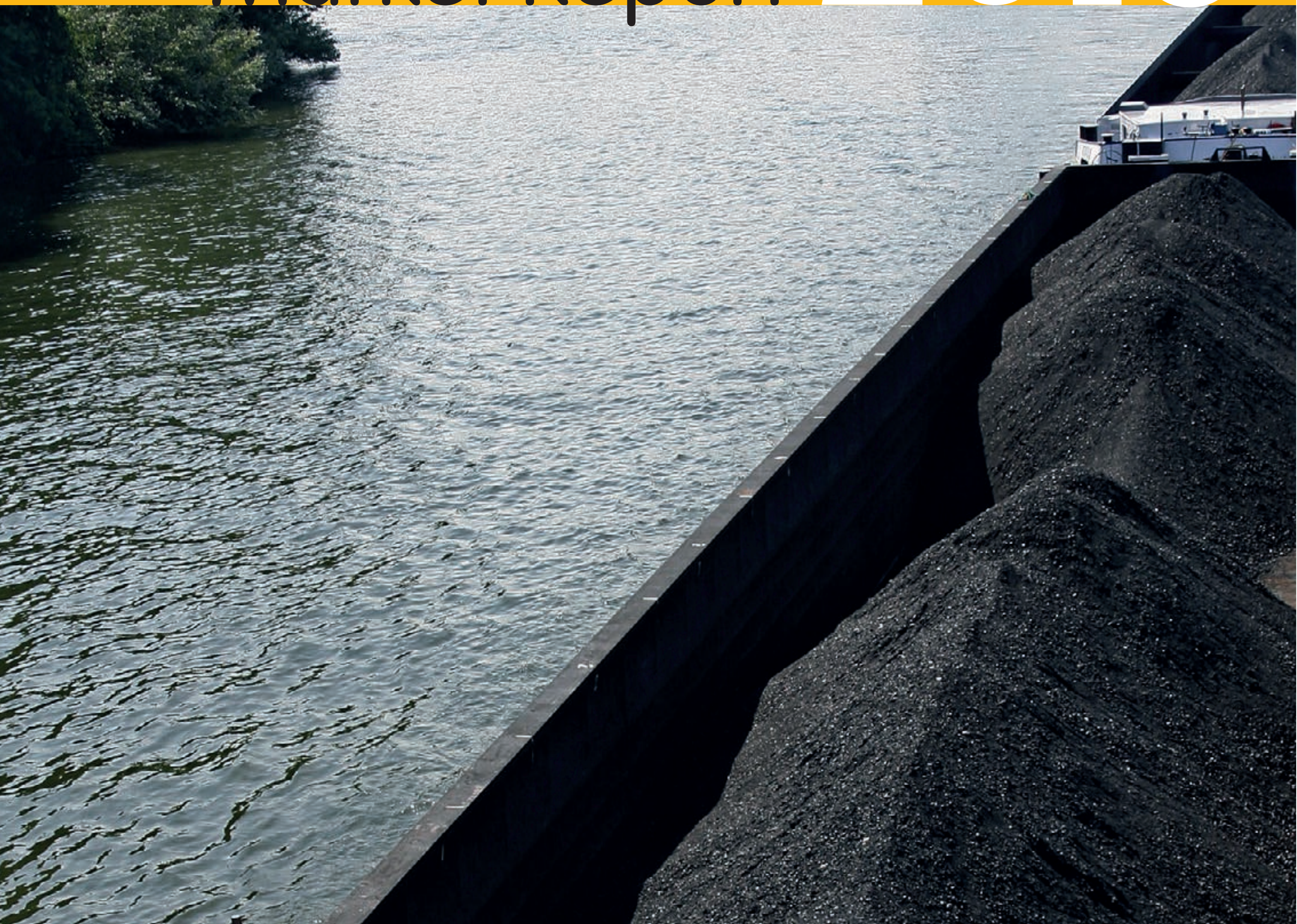
COAL
Medium-Term Market Report 2015



Market Analysis and Forecasts to 2020

International Energy Agency
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FOREWORD

The publication of the *Medium-Term Coal Market Report 2015* is perfectly timed to appear just as COP21 finishes. During the two weeks of COP21 discussions in Paris, and after many months of preparation, the world has been looking for ways to reduce CO_2 emissions. Now it is time to share how the IEA sees coal supply, demand and trade in the coming five years.

Given the difficult conditions that the coal industry currently faces, five years will seem too long for some. The short-term concerns of market participants are how long – and how many – coal producers can survive at current prices; how quickly oversupply can be balanced and how different this bust cycle is from past ones, given the stronger climate policies in place; and the increasing competition from other sources, i.e. wind and solar photovoltaics.

In large part, the answers to those questions depend on the People's Republic of China. Uncertainty regarding China is not new. Coal is the marginal supplier of the Chinese energy system, and coal consumption is sensitive to any variation in the evolution of several circumstances: higher/lower rain – and hydro production; mild/harsh weather conditions – and the subsequent demand for heating and air conditioning; and stronger/weaker economic growth conditions. In addition, since the 2014 data are only preliminary, we are also dealing with some statistical uncertainties.

China has definitively entered a new era in which its economic growth is slowing down, the energy-intensity of that growth is declining, and coal dependency is lessening, largely driven by environmental considerations such as air pollution and CO_2 curtailment. Taken together, these three factors mean that the past era of strong coal growth is over. Preliminary data suggest that coal use in China in 2015 was lower than 2013 levels. The immediate question is whether Chinese coal use peaked in 2013, a scenario that now looks feasible. It is for this reason that we have modelled a sensitivity case called "The Chinese Peak Case" with which to analyse the drivers for this to happen and the main consequences if this does happen.

I will present the 2015 IEA *Medium-Term Coal Market Report* in Singapore. It is the first time that the *Coal Market Report* will be launched outside of Paris, and the decision to go to Southeast Asia for the launch was not a casual one. Asia plays a critical role in global energy markets. The IEA has prioritised its relations with many countries in the region, especially China, Indonesia and Thailand, which recently formalised ties with the IEA. The IEA's vocation is to be the global reference for energy and especially for clean energy. In this regard, coal itself offers the biggest potential – through making cuts in polluting emissions, through better efficiency in generation, and through carbon capture and storage (CCS) development.

This report covers only a five-year outlook, and unfortunately, forecasters do not have much work to do in CCS given such a horizon since progress is terribly slow. This is bad news for the environment, but it is much worse news for the coal industry. With increasing energy-related CO_2 emissions, the window of opportunity for high-carbon sources is closing; but with increasing carbon prices, decreasing costs of renewable power generation, and the more ambitious climate policies that are coming, the business case for unabated coal use diminishes.

The IEA pursues the transformation of the global energy system that is needed to cut greenhouse gas emissions while we maintain energy security and give universal energy access across the world. We acknowledge that coal is an important part of this system and, hence, has to be an important part of this transformation.

Dr. Fatih Birol
Executive Director
International Energy Agency

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EXECUTIVE SUMMARY

Some sudden changes emerge in 2014

For the first time since the 1990s, global coal demand growth halted in 2014. This was the result of a combination of some structural and temporal factors, mostly in China, where half of global coal is used. In 2014, Chinese gross domestic product (GDP) grew 7.4%, while power demand grew 3.8% after a decade of an almost one-to-one relationship between GDP and electricity demand in China. The lower electricity intensity reflected the rebalancing of the Chinese economy, although whether such a low elasticity is sustainable remains to be seen. The diversification of the power sector away from coal has been going on for a number of years. More than 55 gigawatts (GW) of capacity in hydro, wind, solar and nuclear power were added in 2014, which also saw an unusually high level of rainfall that brought hydro generation to around 100 terawatt hours (TWh) higher than production with average precipitation. Growth in coal-intensive industries like steel and cement plummeted after two-digit growth on average since the beginning of this century. Preliminary data in the first ten months suggest the acceleration of these trends in 2015. Due to the combination of ageing coal capacity, weak power demand, and strong renewable and climate policies, OECD coal demand had a relentless decline of 47 million tonnes (Mt) in 2014. India and the Association of Southeast Asian Nations (ASEAN) region, the two remaining centres of significant coal growth, increased 112 Mt in 2014. Given the economic rebalancing in China and ongoing structural decline in OECD countries, even with the continuation of growth in India and ASEAN countries, a downward trend in global coal consumption in 2015 is likely.

Oil prices plummeted. In principle, oil and coal do not compete in the same markets. The main use of coal is power generation followed by steel production. Oil is used predominantly for transportation and chemicals. However, prices of gas, the main competitor of coal in power generation, are often linked to oil prices; hence, low oil prices mean that coal faces stronger competition from gas, which can lead to gas regaining market share from coal in some countries, like the United Kingdom. It is also important to note that oil is an important component of coal mining (through explosives and diesel, especially in open-pit mining) and transportation costs; thus, lower oil prices have an impact on coal prices.

Environmental pressure is mounting

Carbon dioxide (CO_2) reduction is imperative. When this report went to the printers, COP21 was taking place in Paris. Climate policy is more influential in longer-term coal demand than in the five-year outlook of this report. Coal is the most carbon-intensive fuel, and coal burning is the largest contributor to CO_2 emissions: current unabated burning is incompatible with climate stabilisation. While decisions regarding investment and decommissioning of coal power plants are affected by other factors as well, climate policy has emerged as a major driver for the future of coal in large parts of the world. Coal-based electrification provides low-cost energy access in the developing world, while, at the same time, it can conflict with CO_2 emissions reduction targets.

Air pollution also matters. Whereas modern coal-fired power plants can be fitted with environmental controls to tackle SO_2, NO_x, mercury and particulate emissions, this often does not take place. In addition, coal burning in the industrial and residential sectors, which rarely are equipped with emission control equipment, is a major contributor to the local air pollution in some countries. Smog and acid rain have therefore emerged as key policy concerns shaping regulatory decisions, especially, but not only, in China. The Environmental Protection Agency (EPA) rules in the United States and the Large Combustion Plant Directive in Europe have led to a wave of decommissioning coal plants, some of which would have continued to operate with existing climate policies. Local communities have also resisted coal plant investments, which led to project cancellations in several countries.

Coal restricting policies are increasingly adopted worldwide. Renewable feed-in-tariffs, CO_2 pricing, coal taxes and other measures to reduce emissions together with the increasing competitiveness of renewables are causing coal to struggle to maintain its place in the power mix. In addition, some multilateral development banks, export credit agencies in some countries, and other international financial institutions have set policies that make financing coal plants overseas very difficult. Other institutions are discussing the possibility of imposing similar policies. Pension funds and others are also divesting from coal or from fossil fuels more broadly. Nevertheless, lack of access to financing has not yet emerged as a major constraint for coal investments.

The golden age of coal in China seems to be over

We revise our global demand forecast downward by over 500 million tonnes of coal-equivalent (Mtce). Coal demand will grow to 5814 Mtce through 2020, which is 0.8% per year on average. Half of the growth, 149 Mtce, will occur in India. The ASEAN region represents over one-quarter, i.e. 79 Mtce, with lower growth in other regions such as Other Asia. On the contrary, we expect a decline of 75 Mtce in the United States and a decline of 22 Mtce in OECD Europe. Coal power generation will drive demand growth, with global capacity growing over 200 GW by 2020. However, because power demand will grow even faster, the share of coal in power generation will fall from the current 41% to 37%. This forecast makes cautious assumptions on the rebalancing of the Chinese economy. As a result of the global slowdown, the share of coal – after two decades of increasing in the world's energy mix – is now declining. We estimate that from 2014 to 2020 China's share of coal will fall from 29% to 27% of total primary energy. If a deep restructuring in China leads to the peak coal case, there would be an even steeper decline to 26%.

With cautious assumptions on the rebalancing of its economy, Chinese coal demand levels off through 2020. This is driven by three factors: first, the economic growth forecast is weaker than last year. Second, structural reforms are also gathering momentum. Projections of energy-intensive industries reliant on coal, like steel and cement, have been revised downward and, in some cases, to a decline. Given that gas and oil power generation is very limited in China, coal competes with low variable-cost nuclear and renewables; consequently, lower electricity demand projections primarily affect coal demand. In addition, lower expected production of steel and cement is reflected in industrial coal use. Low oil and gas prices add to the well-known issues related to water and CO_2 emissions, making coal conversion, especially coal-to-gas, lose momentum in China. These three factors, together with China's ongoing efforts to diversify away from coal to achieve a more energy-efficient economy and to address local pollution, lead to a levelling out of coal use. China is the largest renewable investor in the world economy; however, without structural change to cut the energy intensity of Chinese GDP growth, even large-scale renewable investments would succeed only in the slowing down of Chinese coal.

Accelerated structural reform and clean energy policies could lead to a downward trend in Chinese coal demand. For the first time since the *Medium-Term Coal Market Report* was first produced in 2011, a "peak coal scenario" in China is probable. The drivers of this peak would be an even stronger rebalancing of the economy, with stagnating housing and infrastructure construction and lower-than-expected power demand, mainly from declining electricity use in heavy industry. A further acceleration of renewable investment is possible, but the key uncertainty is the macroeconomic structure. Whether consumed directly or through electricity, around one-third of the coal used in China is related to infrastructure and real estate. A stronger rebalancing, coupled with ongoing renewable and energy efficiency investments, can conceivably cut Chinese coal demand – a drop of 200 Mtce below 2013 levels. Chinese coal production declines less than demand, which cuts import needs. In fact, China turns into a net exporter of thermal seaborne coal. Despite this, thermal coal prices are only a few USD/t lower than in our forecast; a significant proportion of global mining capacity is already failing to recover its costs, so a further decline in demand will lead to mine closures. In this case, coal's share in power generation globally would fall to 36%.

Coal in advanced economies: The long sunset

The decline in US coal demand is inevitable. Despite rejection of the mercury regulations by the US Supreme Court, we do not see upside risks in our demand forecast for the United States since existing coal capacity will be retired and no new coal plants are expected other than those few under construction. The share of coal in power generation will dip below 35% by 2020, the lowest share since the International Energy Agency (IEA) was created over 40 years ago. Abundant shale gas, increasing renewable generation and EPA environmental rules put pressure on coal, especially in the context of sluggish power demand and with the Clean Power Plan on the horizon.

Slow and structural coal decline in Europe. In Europe, existing coal plants remain competitive on a marginal cost basis despite the low Emissions Trading System (ETS)'s carbon price. However, as power demand stagnates or declines while renewables continue to grow, the forecast for coal is steady decline. In the European Union, we expect coal power generation to decline on average over 1.5% per year through 2020. With spare coal capacity, the main upside risks could come from higher-than-expected power demand or unexpected nuclear closures. On the other hand, gas generation costs have moved closer to coal, which poses some downside risks.

India and ASEAN: the two remaining growth engines

India is the only major economy with strong coal growth. The Indian government has ambitious plans to provide full electricity access to the 240 million people still without it and to expand the manufacturing sector, where coal is the lowest-cost base load option. While India has an ambitious and accelerating renewable investment programme, the scale of the electricity need is such that new coal investments and further growth in coal consumption are inevitable. Key ASEAN countries are in a very similar position: energy access and poverty reduction ambitions drive coal investments in Indonesia, Viet Nam and the Philippines.

But India is not the new China. As forecast in former editions of this report, India will become the second-largest coal consumer in the world, bypassing the United States, and the largest importer of thermal coal. However, India and China have different governance and growth models, with energy-intensive heavy industry playing a considerably smaller role in India. Indonesia and Viet Nam, while expected to significantly increase their coal power generation, are on a different scale than India. Malaysia, Philippines, and even Sri Lanka, will require increasing imports for coal generation. Growth in India and ASEAN countries will not compensate for the new trajectory of Chinese coal demand.

Australia recovers the throne among coal exporters. Persistent low prices, dwindling Chinese imports, and growing domestic demand are affecting Indonesian exports, which will feel the bite much more than Australia, again the largest coal exporter. Most of the thermal trade growth comes from India, and this brings a great uncertainty because demand for imports is closely interlinked with the performance of Coal India, which has been successful in increasing output recently. Nevertheless, quality, location and low prices also play a role in determining import levels. Despite the export of increasingly high ash volumes, Australian exports are mostly coking and high-quality thermal coal mined in the traditional basins. Colombia increases exports over the period, based on its low cost.

End of commodity super-cycle or the start of a low coal price era?

Coal prices are now at their lowest since the financial crisis. Boom and bust cycles are common for commodities, but the series of factors pushing coal prices down has been astonishing: oversupply in China at the same time that main exporters expanded capacities; the increasing gas production in the United States; major cost reduction in the industry, sometimes by gaining scale and increasing production; take-or-pay infrastructure contracts in major exporters; currency depreciation of exporting countries; low oil prices; and, finally, the Chinese halt. These factors explain trends to the present, but given the dramatic fall in the cost of solar and wind generation and the stronger climate policies that are anticipated, the question is whether coal prices will ever recover. While a price forecast is not the aim of this publication, it is apparent that the continuous pressure from shale gas in the United States, stronger climate policies, and especially, the overcapacity and slowdown in China all contribute to the oversupply. This glut will be even more acute if a peak coal demand in China becomes real.

Mining and infrastructure investments are discouraged by low prices. In the current persistent low coking and thermal price environment, most investment decisions on mining and infrastructure capacity will be delayed or postponed and – if prices do not recover – eventually cancelled, meaning that coal will stay underground. On the other hand, such persistent low prices make coal very attractive for power generators. The current 1 900 GW of installed coal capacity globally will be expanded as capacity under development in Asia exceeds the likely retirements in Europe and the United States. While improving renewable technology can make new coal plant investments unattractive, once a coal power plant is constructed and operating, given low fuel generation costs, it is likely to run for a long time, especially in places with power shortages. Therefore, based only on variable costs, the utilisation of the existing coal fleet can be constrained only by very cheap gas, a sizeable CO_2 price, or a policy-driven renewable deployment that exceeds demand growth.

Technology is improving but there is a long way to go. Two-thirds of coal is used in power generation, so both future demand prospects as well as the environmental impact of coal are heavily influenced by the power sector. Some positive signs are emerging. The shift from inefficient subcritical to high-efficiency super or ultra-supercritical plants (SC/USC) is happening. More than two-thirds of coal capacity under construction is SC/USC, led by China, with India and the ASEAN region lagging behind. There is also progress on reducing air pollutant emissions from coal power plants. OECD countries have already been tackling this for a long time, and now China leads the efforts to reduce emissions from coal-fired plants. Other countries must progress dramatically in this regard. Last, but not least, carbon capture and storage (CCS) is no longer a theoretical possibility, with several CCS commercial-scale projects started or under construction in North America, Australia and possibly in China. Nevertheless, CCS deployment is still largely off track and needs to be accelerated by strong policies in order for coal to contribute to a carbon-constrained energy system.

1. RECENT TRENDS IN DEMAND AND SUPPLY

Summary

- **Coal maintained its position as the second-largest primary energy source in the world behind oil in 2014**. Roughly 30% of global primary energy consumption derives from coal.

- **Global coal consumption declined for the first time in this century**.[1] Total demand decreased by 0.9% from 7 991 million tonnes (Mt) in 2013 to 7 920 Mt in 2014. The decline was caused by falling steam coal[2] consumption (-1.0%) while metallurgical (met) coal use increased (+1.3%).

- **Coal consumption fell in Organisation for Economic Co-operation and Development (OECD) countries as well as OECD non-member economies**. However, the decline was more pronounced in the OECD (-2.2%) than in the rest of the world (-0.4%).

- **Chinese coal demand decreased for the first time since 1999**. Coal consumption in China fell by 116 Mt (-2.9%) to a total of 3 920 Mt in 2014. Despite the decline, China still accounted for 50% of global coal demand.

- **India overtook the United States (US) as the second-largest coal consumer in the world by mass.** Indian coal demand grew 12.8% in 2014, which is very high compared with the ten-year average of 7.4%. US demand is still higher on an energy basis.

- **Demand for coal fell in OECD Americas (-0.3%), OECD Asia Oceania (-2.0%) and OECD Europe (-4.5%)**. The decrease was strongest in OECD Europe, where climate policies and renewable energies put pressure on coal usage.

- **Global production of coal fell also for the first time in this century in 2014**. Production decreased in China (-2.6%) and Indonesia (-3.5%), while India (+9.6%), Australia (+7.0%) and the United States (+1.4%) ramped up.

Demand

With a share of approximately 30%, coal remained the second-largest primary energy source in the world behind oil in 2014. Yet at an estimated 7 920 Mt, global coal demand decreased by 0.9% (-71 Mt) in comparison with 2013, which is the first decline of coal demand in this century. This result in 2014 therefore contrasts with the average growth rate of 4.2% over the past ten years. The main reason for this decline is a decrease of coal demand in China, which fell by 2.9% (-116 Mt) in 2014. This development was partially offset by a very strong demand growth of 12.8% (+103 Mt) in India. Nevertheless, aggregated coal demand declined in OECD countries (-47 Mt) as well as in OECD non-member economies (-24 Mt).

[1] Chinese historical statistics have been reviewed in October 2015. This report includes this revision. However, data on consumption in China in 2014 are preliminary and subject to revision, as are conclusions drawn from them.

[2] Definitions of coal types and other technical terms can be found in Box 1 of IEA (2011) and Box 1 of IEA (2012).

Table 1.1 Coal demand overview

	Total coal demand (Mt) 2013	Total coal demand (Mt) 2014*	Absolute growth (Mt) 2013-14	Relative growth (%) 2013-14	CAGR (% per year) 2004-13	Share (%) 2014
China	4 035	3 920	-116	-2.9%	8.8%	49.5%
India	804	907	103	12.8%	7.4%	11.4%
United States	840	835	-5	-0.5%	-1.5%	10.5%
Germany	245	236	-9	-3.7%	0.0%	3.0%
Russia	210	201	-9	-4.3%	-0.6%	2.5%
European Union	734	691	-43	-5.9%	-1.2%	8.7%
OECD	2 136	2 089	-47	-2.2%	-0.6%	26.4%
Non-OECD	5 855	5 831	-24	-0.4%	6.9%	73.6%
World	**7 991**	**7 920**	**-71**	**-0.9%**	**4.2%**	**100.0%**

* Estimate
Notes: CAGR = compound annual growth rate. Differences in totals are due to rounding.
Source: IEA (2015a), *Coal Information 2015*, www.iea.org/statistics/.

Despite decreased coal consumption, China remains by far the largest coal market in the world, accounting for almost 50% of global coal demand. With an average growth rate of 8.8% over the last ten years, China was the main driver for the global rise in coal consumption in this century (Box 1.1). A declining coal demand in China could therefore substantially change global coal markets. This decrease could indicate a new era for coal in China; nevertheless, it is still unclear if it means a turnaround for Chinese coal consumption, given that the picture is complex, with year-to-year changes driven by weather conditions and different industrial output (see "Demand focus on China" in this chapter and Chapter 3 for detailed analyses).

Box 1.1 Coal in the 21st century: 15 years on

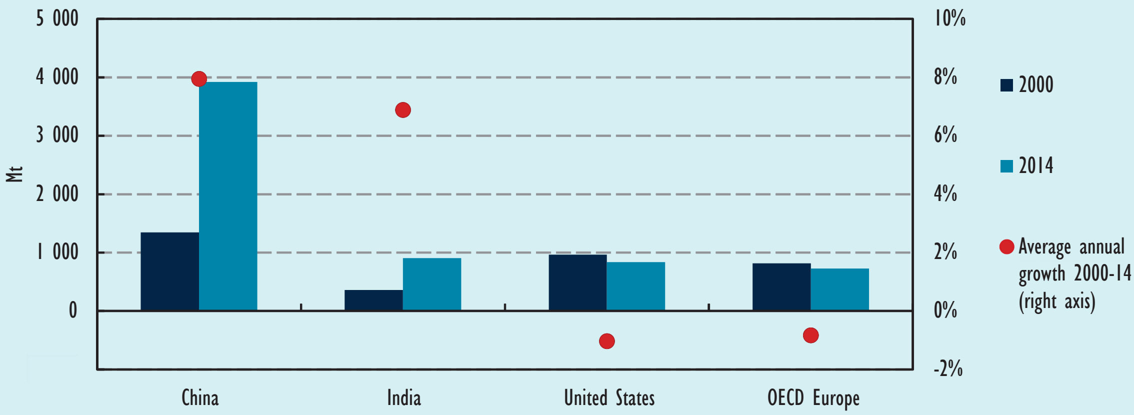
From 2000 to 2013,* annual coal use grew more than 3 billion tonnes, supplying 45% of the additional primary energy worldwide. Consumption trends were not evenly distributed across the globe, with China leading the growth and the United States leading the decline. While coal has proved to be a secure low-cost source of power generation, coal burning is the main contributor to greenhouse gas emissions. The balance between climate policies and coal competitiveness compared with other energy sources defines the trends of every region.

For the last 15 years, China, the United States, India and the European Union have been developing different policies concerning the use and supply of coal, following different paths, some of them stimulating the production and consumption of coal to foster economic development and growth, others intensifying policies to mitigate the environmental impact. Together these four major consumers accounted for over 80% of the global demand in 2014, an increase of 7 percentage points compared with their share in the global consumption in 2000.

Given the high importance of China, India, the United States and OECD Europe in accounting for coal consumption, an analysis of the four regions largely explains the global trends.

Box 1.1 Coal in the 21st century: 15 years on (continued)

Figure 1.1 The four major consumers of coal, 2000-14



Source: IEA (2015a), *Coal Information 2015*, www.iea.org/statistics/.

China

China's coal demand has tripled since 2000, rising from 1 344 Mt to 3 920 Mt in 2014, reaching roughly 50% of the total global demand. In this time, coal power generation capacity has almost quadrupled from 220 gigawatts (GW) to almost 850 GW. Coal has been the dominant fuel of choice, playing a strategic role in China's economic growth and industrial development as well as its energy security. To meet the internal demand of mainly the power and industrial sectors, one of the strategic targets of the Chinese government has been to increase and accelerate the production of coal. Consequently, between 2000 and 2014, domestic coal production also almost tripled, going from 1 354 Mt to 3 650 Mt.

The development of Chinese coal consumption in this century was shaped by a period of strong growth from 2003 to 2006, when demand grew at double-digit rates. Growth of coal consumption slowed down during the financial crisis as the global economy struggled, but picked up annual growth rates of roughly 10% again from 2009 to 2011. After 2011, China entered a period of more moderate growth rates of coal demand as the economy increasingly matured and gross domestic product (GDP) growth started to slow down. Additionally, China started to put more emphasis on nuclear energy and renewable energies as well as environmental issues.

India

India has experienced high growth rates in coal consumption in the 21st century; between 2000 and 2014, coal demand grew by a factor of 2.5, from 357 Mt to 907 Mt. Indian demand growth has been mainly driven by increased coal use in power generation. Electricity consumption in India has grown rapidly because of economic growth as well as increased electrification of the country, and coal was the most important energy source to supply this additional electricity. As a result, the installed capacity of coal-fired power plants in India almost tripled from 61 GW in 2000 to 168 GW in July 2015. Growth of Indian coal demand since 2000 could have been even higher given that an estimated 240 million people still live without access to electricity. However, further demand increases have been curtailed by substantial problems in increasing domestic coal production in India, bottlenecks in coal transportation, and issues in the regulation of the power sector, as well as lack of payments to generators for additional power due to under-collection of power sales by the Indian distribution companies.

Box 1.1 Coal in the 21st century: 15 years on (continued)

United States

Coal consumption in the United States fell from 966 Mt in 2000 to 835 Mt in 2014. The share of the United States in total global coal demand decreased from 20% to 10% over the same time period. From 2000 until 2005, coal consumption in the United States grew at low rates. In 2005 coal demand peaked at 796 million tonnes of coal-equivalent (Mtce) (in physical tonnes, the peak was in 2007 at 1 030 Mt) and entered a phase of decline afterwards.

The decline in coal demand in the United States was mainly caused by increasing competition from natural gas. Because of the increasing production of unconventional gas in the United States, gas prices decreased significantly, which led to substantial fuel switching from coal to gas, especially in the power sector. To a lesser extent, coal consumption was negatively influenced by weak power demand, increasing public opposition, and environmental concerns. In recent years, for example, the US Environmental Protection Agency (EPA) initiated a series of actions to reduce pollution that put so much pressure on coal-fired electricity generation that the term "war on coal" was coined to describe it.

OECD Europe

With a drop of 11% between 2000 and 2014, OECD Europe has seen a decline in coal consumption in the 21st century. In the time period from 2000 to 2008, coal demand in Europe grew slightly by roughly 1% per year on average. After the financial crisis, however, coal consumption decreased rapidly and is now 14% below the levels of 2007. This decrease of European coal consumption was interrupted by a short period of growing demand after the Fukushima Daiichi accident, when the shutdown of nuclear power plants led to a spike in Japanese gas consumption and consequently to high gas prices at the same time that coal prices went down, which favoured coal-fired electricity generation. The overall share of OECD Europe in global coal demand decreased from 17% in 2000 to 9% in 2014.

The continued decrease of European coal consumption in the 21st century can be attributed mainly to two factors. First, Europe has experienced only relatively low economic growth since 2000 and faced a fierce recession after the financial crisis, which dampened energy consumption. Additionally, European countries have increasingly been pushing towards usage of renewable energy sources and have introduced significant environmental and climate policy measures. The most prominent example is the introduction of the EU Emissions Trading Scheme (EU-ETS) in 2005, which puts a price on carbon dioxide (CO_2) emissions across the European Union. However, the Large Combustion Plant Directive (LCP Directive) limiting emissions of sulphur dioxide (SO_2), nitrogen oxides (NO_x) and dust probably had a higher impact on curtailing coal consumption.

Table 1.2 summarizes the major drivers for the development of coal consumption in the 21st century for the four described regions.

Table 1.2 Factors impacting coal consumption in the 21st century

	Climate policy	Economic growth	Gas competition
China	🟢	🟢	🟢
United States	🔴	🟡	🔴
India	🟢	🟢	🟢
OECD Europe	🔴	🟡	🟢

🟢 Positive factor for coal consumption 🔴 Negative factor 🟡 Neutral

* The last year for which the IEA has complete energy balances.

The strong growth in Indian coal demand over the last ten years continued in 2014 with an increase of 12.8% compared with a ten-year average growth rate of 7.4%. This means that coal consumption in India has more than doubled since 2004, making India the second-largest consumer of coal in terms of physical tonnes for the first time in history.

In the United States, now the third-largest coal consumer on a tonnage basis (accounting for roughly 10% of the global market), coal consumption has been declining by an average 1.5% annually for the last ten years. This decline continued in 2014 with a negative growth rate of 0.5%. Hence coal demand in the United States continued to suffer as a result of low gas prices, which are mainly due to cheap domestic shale gas production.

Coal demand in the European Union (EU) declined by 5.9% in 2014. This decrease can be explained by continued pressure on coal-fired power generation due to environmental policies on the national and supranational levels. As a result, total coal consumption in the European Union dropped to the lowest level in this century. Germany maintained its position as the largest coal consumer within the European Union and fourth-largest coal consumer in the world despite a 3.7% drop in consumption. However, approximately 75% of Germany's coal consumption consists of very low calorific lignite. As a result, Russian coal demand is higher on an energy basis.

Developments in the Russian Federation (hereafter "Russia") in 2014 were driven by the economic situation after the oil price drop, Western sanctions, and a mild winter – the warmest in the history of weather monitoring in the country. Consequently, Russian coal consumption declined by 4.3% in 2014. Despite this decrease, Russia is still the fifth-largest coal consumer in the world ahead of Japan.

Total global consumption of hard coal decreased by 46 Mt to an estimated 7 115 Mt in 2014. This corresponds to a growth rate of -0.6%, which is in sharp contrast to the ten-year average growth of 4%. The two main drivers for the development of hard coal consumption were again strong demand growth in India (+99 Mt) and declining demand in China (-116 Mt).[3] Additionally, demand in OECD countries declined by 2.1% (-34 Mt).

Global demand for steam coal fell in 2014 by 1.0% (-59 Mt) to an estimated 6 093 Mt. Again this result is mainly driven by growing demand in India (+95 Mt) in combination with declining demand in China (-119 Mt) and the OECD countries (-34 Mt).Total consumption of met coal grew slightly by 1.3% (+12.5 Mt). This increase in demand was caused by growing demand in India (+4.9 Mt) and China (+3.4 Mt), while demand in OECD countries remained almost unchanged (+0.7 Mt).

Total global lignite consumption in 2014 decreased by 3.1% (-25.5 Mt). Lignite demand fell in OECD member countries (-13.1 Mt) as well as in OECD non-member economies (-12.3 Mt). The share of lignite in total coal consumption, measured in weight, was 10% in 2014. This share is almost half in energy units since lignite has relatively high moisture content and therefore a low calorific value compared with hard coal.

[3] In China, lignite is not reported, and total coal consumption, except for met coal, is counted as thermal coal. This needs to be taken into account throughout the entire report. Likewise for Indonesia: there is no differentiation between lignite and thermal coal, with all counted as thermal.

OECD demand trends

Demand for hard coal amounted to approximately 1 545 Mt in OECD countries in 2014, a decrease of 2.1% (-34 Mt) compared with 2013. The total share of OECD countries in global 2014 hard coal demand continued its decline over the last ten years and accounted for 21.7%.

The largest decrease in 2014 OECD hard coal consumption took place in OECD Europe, where demand fell by 6.9% (-24 Mt). This is a consequence of EU climate policy, which has resulted in continued pressure on coal, and promotion of renewable energy sources in the European market (22 GW of new renewable generation capacity was added in 2014). Apart from OECD Europe, coal consumption also declined slightly in OECD Asia Oceania (-7 Mt) and in OECD Americas (-3 Mt). In terms of coal type, the decrease in hard coal consumption was driven by declining demand for thermal coal, whereas demand for met coal remained stable.

Table 1.3 Hard coal and lignite consumption in selected OECD member countries (Mt)

Country	Hard coal		Lignite	
	2013	2014*	2013	2014*
Australia	58.3	54.9	62.8	60.7
Austria	3.6	3.2	0.0	0.0
Belgium	5.0	4.5	0.0	0.0
Canada	29.9	34.0	8.9	8.4
Chile	11.3	11.9	0.0	0.0
Czech Republic	7.1	7.5	38.9	38.7
Denmark	5.3	4.4	0.0	0.0
Finland	5.8	5.1	0.0	0.0
France	18.3	13.2	0.1	0.2
Germany	62.7	59.1	182.5	177.0
Greece	0.3	0.2	54.4	47.1
Hungary	1.6	1.5	9.7	9.2
Ireland	2.1	2.0	0.0	0.0
Israel**	11.7	11.0	0.0	0.0
Italy	21.1	20.1	0.0	0.0
Japan	195.6	187.7	0.0	0.0
Korea	127.9	133.1	0.0	0.0
Mexico	23.8	21.5	1.0	0.6
Netherlands	13.0	14.6	0.0	0.0
New Zealand	2.8	2.5	0.3	0.3
Poland	78.8	73.2	65.9	63.8
Portugal	4.4	4.5	0.0	0.0
Slovak Republic	3.9	3.8	2.7	2.5
Spain	20.6	21.9	0.0	0.0
Turkey	28.9	32.3	55.3	61.5
United Kingdom	60.4	48.1	0.0	0.0
United States	770.2	765.3	69.7	70.1

* Estimate.

** The statistical data for Israel are supplied by and under the responsibility of the relevant Israeli authorities. The use of such data by the OECD and/or the International Energy Agency (IEA) is without prejudice to the status of the Golan Heights, East Jerusalem and Israeli settlements in the West Bank under the terms of international law.

Source: IEA (2015a), *Coal Information 2015*, www.iea.org/statistics/.

At country level, the United States remained by far the largest hard coal consumer in the OECD, followed by Japan and Korea. Hard coal demand fell in the United States (-5 Mt) and in Japan (-8 Mt), whereas Korea had the largest increase in hard coal consumption in 2014 in OECD countries (+5 Mt). The increase in Korean demand for hard coal was a result of additional electricity generation in coal-fired power plants. Japan and Korea are the largest consumers of met coal in the OECD. Korean demand for met coal rose by 12% in 2014 because of higher steel production, whereas demand in Japan slightly declined.

2014 lignite demand fell slightly by 2.4% to 543 Mt in the OECD countries, which still make up 68% of total global lignite consumption. The largest decrease took place in OECD Europe, particularly in Greece (-7 Mt), where the economic crisis put pressure on energy demand, and Germany (-6 Mt), where electricity generation in lignite-fired power plants declined.

Power sector

Total 2014 coal-fired power generation in OECD member countries was estimated at 3 435 terawatt hours (TWh), down 2.1% from 3 508 TWh in 2013. This is the lowest value for coal-based electricity generation in the OECD in the last decade. The share of coal-fired power generation in the electricity mix of all OECD member countries fell only slightly from 32.5% to 32.1%, as total electricity generation decreased from 10 796 TWh to 10 711 TWh.

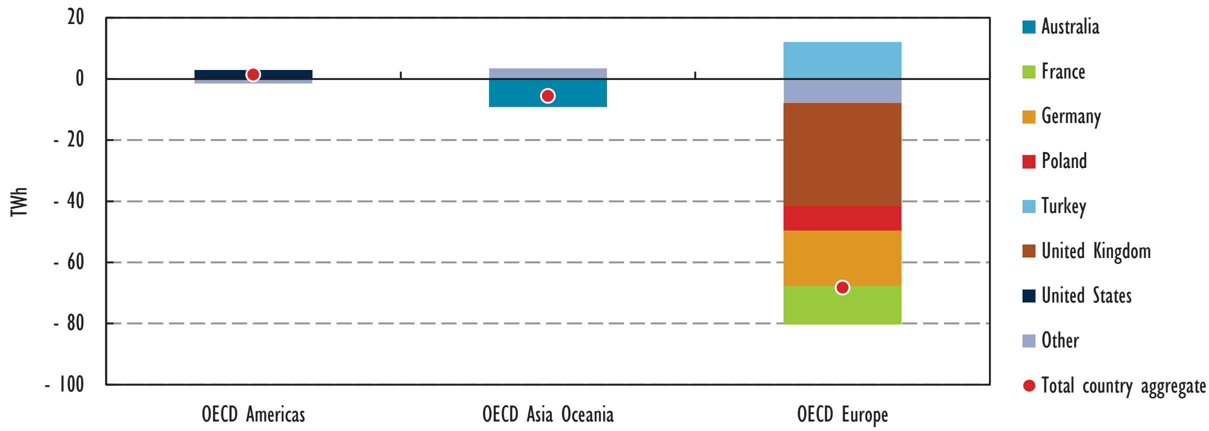
Decreasing coal-fired power generation in OECD countries was mainly driven by developments in OECD Europe, where coal-based electricity generation in 2014 fell by 68 TWh, declining 7.5% compared with 2013 (see Figure 1.2). The largest contributor to this decline was the United Kingdom, with a decrease of 34 TWh, which corresponds to a drop of 25% from 2013. One reason for this sharp decline is 11 TWh of higher renewable generation in 2014, with biomass as the largest source of incremental generation (≈4 TWh), followed by wind (≈3.5 TWh) and solar (≈2 TWh). In addition, the closure of two 490 megawatt (MW) units at Ferrybridge Power Station at the end of March 2014 due to the LCP Directive also contributed. Additionally there is pressure on coal-fired electricity generation due to the carbon price floor (CPF), which was introduced by the UK government in 2013.[4] In April 2014, the CPF was almost doubled from GBP 4.94 per tonne of CO_2 (tCO_2) to GBP 9.55/tCO_2, which led to a significant loss of competitiveness for coal-fired power plants in favour of gas-fired electricity generation pushed by cheaper LNG. In combination with lower electricity demand and higher infeed from renewable energy sources, this led to a decline of the share of coal-based electricity generation in the United Kingdom, from 37% in 2013 to 30% in 2014.

In Germany, coal-fired electricity generation decreased by 18 TWh due to lower electricity demand and higher electricity generation from renewable energy sources, which has lower variable costs and, ultimately, unlimited priority feed-in and therefore pushes electricity generation from hard coal out of the market. Electricity generation based on lignite fell only slightly because of power plant revisions. Despite these developments, coal remained by far the most important energy source in the German electricity sector with a 45% share in total electricity generation. In France, coal-fired power generation declined by 12 TWh, a 50% drop compared with 2013, because of lower electricity demand and decommissioning of coal-fired power plants. In Poland, electricity generation based on coal declined by 8 TWh also because of lower electricity demand compared with 2013. The European

[4] The CPF sets a minimum price on CO_2 emissions in the United Kingdom to encourage investments in low-carbon technologies and to reduce risk for investors against the backdrop of consistently low prices for emissions certificates in the EU-ETS.

OECD member country with the largest increase in coal-fired power generation was Turkey, where electricity generation based on coal went up by 12 TWh. This was due to higher electricity demand in combination with a decline in hydropower generation, which was caused by drought. In the Netherlands, coal-based electricity generation went up by 6 TWh, increasing 20% from 2013, because of three new hard coal power plants (over 3 GW) that came online at the end of 2013 and the beginning of 2014. However, these power plants were not yet in full commercial operation in 2014.

Figure 1.2 Net change in coal-based electricity generation in OECD countries, 2013-14



Source: IEA (2015a), *Coal Information 2015*, www.iea.org/statistics/.

Compared with 2013, coal-fired power generation in OECD Americas remained roughly flat in 2014 at an estimated 1 841 TWh. In the United States, coal-based generation increased slightly by 3 TWh and maintained its share in total electricity generation of 40%. This can be attributed to a slightly higher electricity demand amid record cold temperatures during the polar vortex in the beginning of 2014, which led to comparatively high gas prices despite the continuing growth in domestic gas supply. It can be concluded that the increase in coal-fired power generation in 2014 in the United States was only a temporary development that will not continue, as competition from gas continues to be strong. Consequently, monthly data on electricity generation showed that gas overtook coal as the main source of power generation in the United States for the first time in history in April 2015.

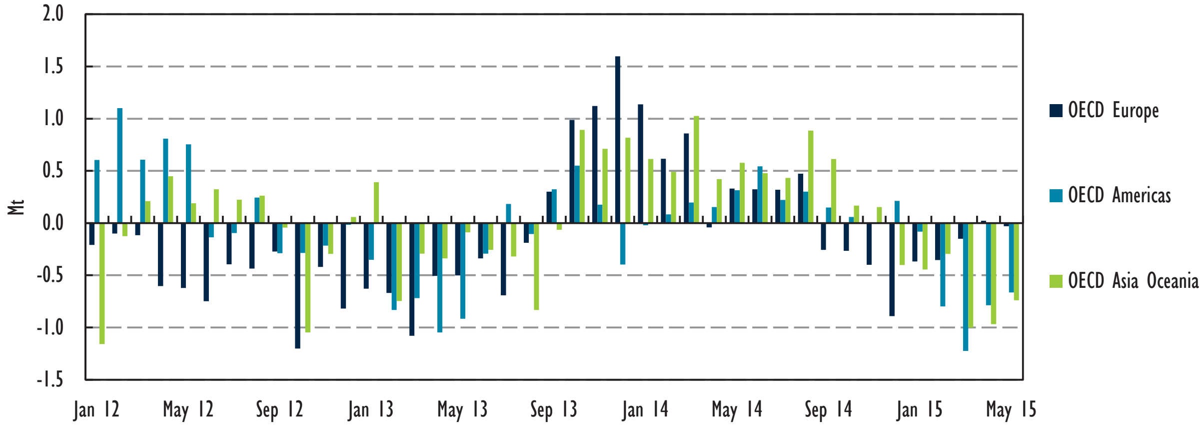
In OECD Asia Oceania, coal-based power generation decreased slightly by 6 TWh, mainly due to developments in Australia, where electricity generation from coal-fired power plants went down 9 TWh or 6% compared to 2013. This drop in conventional power generation was mainly offset by higher generation from renewable energy sources. Three nuclear power plants in Korea that were shut down in 2013 because of some legal issues came back on line in the beginning of 2014. The additional power generation of these plants pushed mainly gas-fired power plants out of the market. In combination with higher electricity demand, this led to a 5 TWh increase in coal-fired electricity generation in 2014. In Japan, coal-based power generation remained roughly unchanged in comparison with 2013. This seems surprising at first, given that the two new coal-fired power plants, Hirono 6 and Hitchinaka 2, with an aggregated capacity of 1.6 GW, started commercial operation in December 2013. However, these two units had been in trial operations from April 2013. Therefore the increase in coal-fired generation produced by the two plants was already reflected in the calendar year 2013.

Non-power sector

Total 2014 coal consumption in the non-power sector in the OECD is estimated at 282 Mtce, a decrease of 1% from 2013. The largest non-power coal consuming sector is the iron and steel industry, with an annual consumption of 159 Mtce in 2014, followed by the cement industry, which accounted for 30 Mtce of non-power coal consumption.

Met coal consumption in the OECD in 2014 remained roughly unchanged compared with 2013 (+0.7 Mt). Steel production, however, increased by 2% in 2014, indicating slightly higher efficiency in the production process. The first months of 2015 showed a declining trend in steel production in OECD member countries (Figure 1.3).

Figure 1.3 Monthly year-on-year differences in crude steel production in OECD member countries, 2012-15



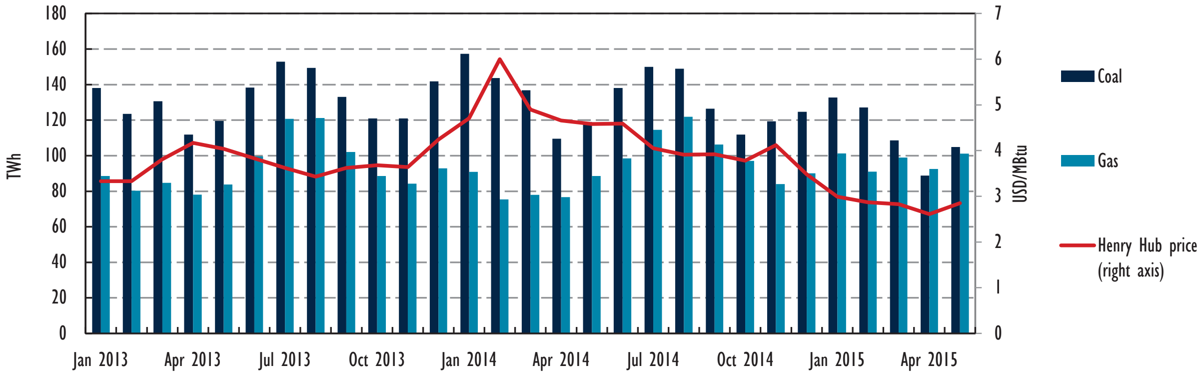
Source: World Steel Association (various years), *Crude Steel Production*, www.worldsteel.org/statistics/crude-steel-production.org.

Regional focus: United States

The United States is the third-largest coal consumer in the world in terms of physical tonnes, and second-largest in energy units. Coal consumption, however, has been declining in recent years: over the period from 2004-13, coal consumption in the United States declined by 1.5% per year on average, from 1 010 Mt to 840 Mt. In 2014, US consumption further decreased, but by a comparably moderate -0.5% to 835 Mt. Demand for all coal types stayed mostly flat: steam coal demand, which accounts for roughly 90% of US coal consumption, stood at 747 Mt, down by 4 Mt compared with 2013. Coking coal remained at roughly 2% of coal consumption in the United States and close to 2013 levels at 19 Mt. Lignite makes up the balance of 70 Mt and was almost unchanged from 2013.

Power generation accounts for over 90% of US coal consumption. Coal's share in US power generation has been declining, from over 50% in 2000 to only 40% in 2014. The reasons for this trend are threefold. First, electricity demand growth has been weak in spite of a recent uptick in economic growth. Second, coal generation is affected by competition from other fuels, in particular gas. Gas prices, with the exception of the spike of USD 6 per million British thermal units (MBtu) during the polar vortex in February 2014, have remained at low levels. In April 2015, at USD 2.6/MBtu and many coal plants off for annual maintenance, gas-fired power generation in the United States was for the first time higher than coal-fired power generation. Coal-fired power generation overtook gas again in May, but clearly gas has become increasingly competitive with coal in the United States (Figure 1.4). Third, US coal-fired power capacity declined in recent years, by around 4 GW alone in 2014.[5] Recently enacted regulations as well as economic considerations led to plants retirements. The EPA's Mercury and Air Toxics Standards (MATS) rule also led to some early coal plant retirements after 2012, and despite the rejection of MATS by the Supreme Court in June 2015, these retirement decisions will not be reversed. Ohio and Pennsylvania were the states with the largest retirements in 2014, each accounting for retirements of roughly 0.8 GW. In 2014, practically no new coal-fired capacity was installed. Potentially higher load factors of the remaining fleet did not substantially change the picture of a declining coal share in overall generation.

Figure 1.4 Development of coal- and gas-fired power generation in the United States and natural gas prices, 2013-15



Source: EIA (2015a), *Electricity Data Browser*, www.eia.gov/electricity/data/browser; EIA (2015b), *Henry Hub Natural Gas Spot Price*, www.eia.gov/dnav/ng/hist/rngwhhdm.htm.

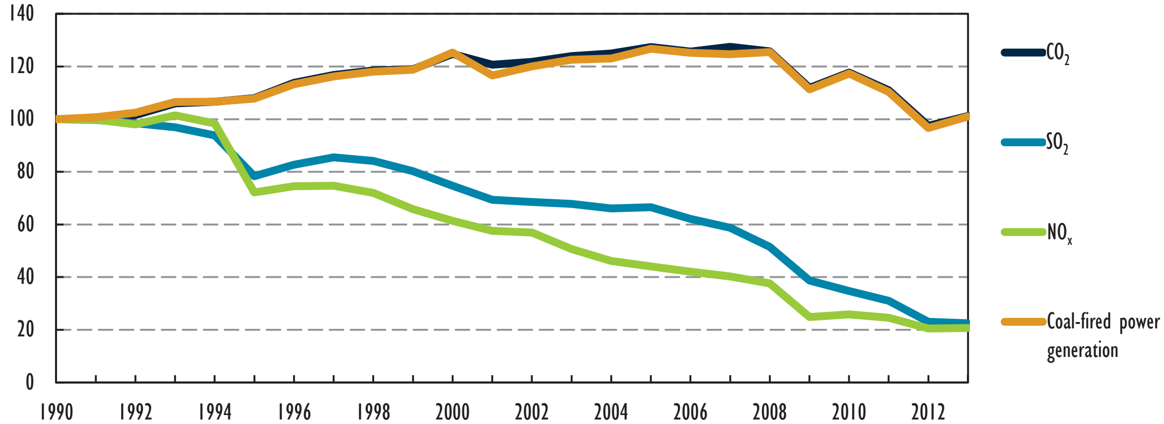
However, coal in the United States is a regionally more diverse story. In some states, in particular in parts of the Midwest like Ohio the share of coal fell more dramatically (-31% in coal-fired power generation compared with 2008, the biggest absolute decrease of all states); the smaller coal-use states in the Northeast with high delivered coal cost like Connecticut saw even bigger declines (-81% compared with 2008), Delaware (-84%), Massachusetts (-73%), New Jersey (-72%) and New York (-76%); and in Southern states with high delivered coal cost like Alabama (-37%) and Georgia (-47%), the availability of cheap gas, due to the ongoing shale gas revolution in the United States, is cutting strongly into coal's share in power generation, and coal is finding it hard to compete. Domestic coal can, however, still compete with gas in some areas. For instance, coal supplied from Illinois can stay competitive with gas at USD 4/MBtu at a distance of only a few hundred kilometres (km). For power plants supplied by Powder River Basin (PRB) coal, the lowest-cost coal in the United States, the distance is significantly higher at around 2 000 km, meaning that PRB coal in large parts of the American Midwest can still compete with gas.

Another important aspect driving present and future coal-fired power generation is public and regulatory concerns about local air pollution and CO_2 emissions, which led to a tightening of regulations regarding emissions from power generation. The United States has reduced local air pollution from coal-fired power generation significantly over the last two decades. One reason is the decrease in coal-fired power generation since 2008. But the most important reason is that the

[5] Capacity in this paragraph refers to net summer capacity, which differs from a plant's nameplate capacity.

United States has installed emissions controls over the last 25 years so that while coal generation continues at a similar level today as in 1990, emissions (SO_2, NO_x and particulates) have declined over 75% during that period (see Figure 1.5). Regulations such as the Clean Air Act Amendments, the Acid Rain Programs and the Clean Air Interstate Rule, which were initiated as a result of acid rain and poor air quality, were a main driver behind these developments. CO_2 emissions still stand at levels close to those of 1990 as the average plant efficiency increased only slightly between 1990 and 2014, and carbon capture and storage is not yet deployed at levels that have a significant effect on reducing overall CO_2 emissions.

Figure 1.5 Coal-fired power generation and related CO_2, SO_2 and NO_x emissions in the United States (indexed), 1990-2013



Source: EIA (2015a), *Electricity Data Browser*, www.eia.gov/electricity/data/browser/.

Regional focus: Poland

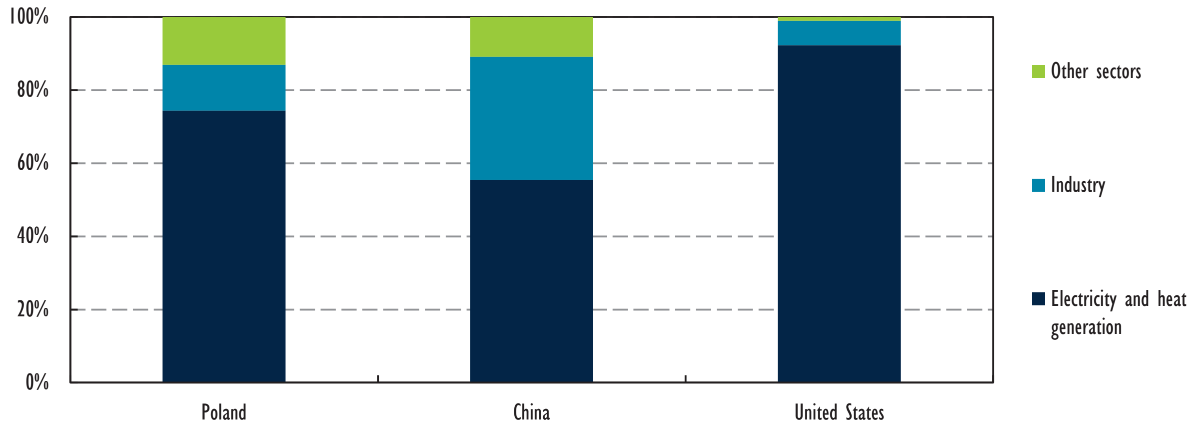
Until 2009, the dynamics of domestic coal consumption in Poland followed economic growth. A significant decrease in its utilisation was caused by the economic slowdown as well as relatively mild winters. Yet Poland is the tenth-largest coal consumer in the world and the second-largest in the European Union, after Germany.

Total consumption of hard coal in 2014 was an estimated 72 Mt, with the largest share coming from power plant and thermal electric power plant consumption (38 Mt), followed by the industry and buildings sectors including steel production (16 Mt), the small consumers sector including households and agriculture (12 Mt), commercial heat engineering power plants (0.2 Mt), and others.

The small consumers sector includes consumption by households (10 Mt), agriculture (1.5 Mt) and other customers (0.9 Mt), the first of which is a vitally important market in Poland (although geographically dispersed). Household consumption covers household heating, from both individual and local boiler plants. The share of coal consumption outside the industry and the power sectors is bigger in Poland than China, a fact that underlines the relatively high importance of coal in residential heating (see Figure 1.6). Lignite coal production is almost entirely consumed by domestic power plants. Total Polish lignite consumption amounted to an estimated 64 Mt in 2014.

As of 31 December 2014, the electric capacity of Poland (installed capacity) was 39 353 MW. Hard coal power plants account for approximately 52% (20 291 MW), and lignite power plants account for 23% (9 220 MW). Big hydro power plants contribute 6% (2 207 MW), and small hydro power plants and other renewable resources contribute 11% (4 187 MW) of total installed electric capacity. As of 2014, over 80% of Poland's electricity generation was powered by hard coal and lignite, yet solid fuels are gradually being pushed out by a growing share of renewables in the energy mix, accounting for a 12% share. Big hydro and natural gas-based electricity production remains flat.

Figure 1.6 Structure of Polish coal demand in comparison with the United States and China (2013)



Source: IEA (2015a), *Coal Information 2015*, www.iea.org/statistics/.

Coking coal consumption is included in the industry and buildings sector. The vast majority of coking coal produced in Poland (12.3 Mt) is consumed domestically by coke plants, with coking coal exports estimated at 2.4 Mt and the imports levelling out at 2.0 Mt. Until 2006, domestic production of coking coal was sufficient to cover demand; since then, Poland has had to import some volumes of that fuel for reasons of quality and seasonality. In its coking plants, the JSW Group processes approximately 50% of the coking coal it produces.

OECD non-member demand trends

With an aggregated consumption of 5 569 Mt in 2014, OECD non-member economies accounted for 78% of global hard coal demand. Compared with 2013, total hard coal consumption fell slightly by 12 Mt in 2014, a decline of 0.2%. It is the first decrease in hard coal demand of OECD non-member economies in this century. Over the last ten years, coal demand in OECD non-member economies grew strongly with an average growth rate of 7.4%.

The main contributor to the global decrease in hard coal demand was China, where 2014 hard coal consumption fell by 2.9% (-116 Mt) to 3 920 Mt. Despite the decrease, China is still by far the largest hard coal consumer in the world and accounts for over 70% of the demand in OECD non-member economies. The decrease in China was partly offset by a strong increase of hard coal consumption in India. Compared with 2013, Indian hard coal demand rose by 13.1% (+99 Mt) to 859 Mt. Apart from the developments in China and India, there was also a strong decrease in Ukrainian hard coal consumption – by 20.3% (-15 Mt) – because of the ongoing political crisis.

In terms of coal type, the decrease in 2014 hard coal demand in OECD non-member economies was driven by a lower consumption of thermal coal, which went down by 0.5% (-24 Mt). Again this development was mainly a result of declining thermal coal demand in China (-119 Mt) and increasing thermal coal demand in India (+95 Mt). Met coal consumption in OECD non-member economies rose slightly by 1.5% (+12 Mt). India was the largest contributor to this growth with an increase of 10.9% (+5 Mt) in comparison with 2013.

Lignite consumption in OECD non-member economies fell for the third year in a row to an estimated 261 Mt, which corresponds to a decrease of 4.5% (-12 Mt) from 2013. Demand decreases were most notable in Serbia and Russia.

Table 1.4 Hard coal and lignite consumption in selected OECD non-member economies (Mt)

Country	Hard coal		Lignite	
	2013	2014*	2013	2014*
Bosnia and Herzegovina	7.1	7.4	5.5	6.1
Brazil	26.1	27.7	0.0	0.0
Bulgaria	1.8	1.7	28.7	31.2
Chinese Taipei	65.9	67.1	0.0	0.0
Colombia	7.0	7.3	0.0	0.0
DPR of Korea	19.7	19.9	0.0	0.0
India	759.9	859.4	43.9	47.2
Indonesia**	59.9	61.7	0.0	0.0
Kazakhstan	79.7	82.1	4.6	4.6
Kosovo	0.0	0.0	8.3	8.2
Malaysia	24.3	26.3	0.0	0.0
Mongolia	2.4	2.7	6.2	6.3
China	4 035.4	3 920.6	0.0	0.0
Philippines	18.7	19.5	0.0	0.0
Romania	0.9	0.7	25.0	23.9
Russia	137.1	132.1	73.3	69.3
Serbia	0.1	0.1	40.3	30.2
South Africa	181.9	177.9	0.0	0.0
Thailand	18.5	20.9	19.1	18.0
Ukraine	71.3	56.8	0.0	0.0
Viet Nam	28.1	30.7	0.0	0.0

* Estimate.

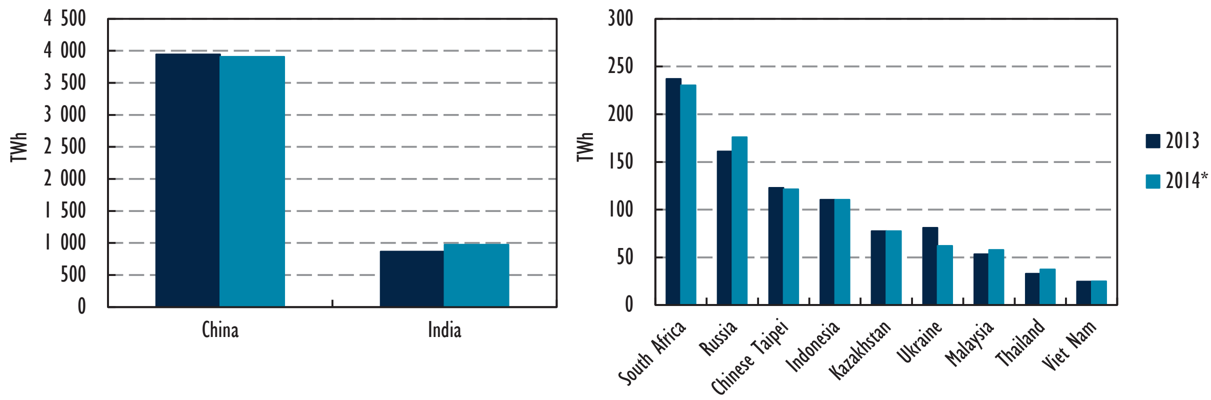
** The Indonesian Ministry of Energy and Mineral Resources estimates total hard coal demand in 2014 to be 95.6 Mt.

Source: IEA (2015a), *Coal Information 2015*, www.iea.org/statistics/.

Power sector

China is by far the largest producer of coal-fired power in the world. The estimated total electricity generation in Chinese coal-based power plants was 3 908 TWh in 2014, which is a decline of 40 TWh or 1% compared with 2013 (see Figure 1.7). After years of strong growth in Chinese coal-fired electricity generation, it is the first decrease in this decade. The reason for declining electricity generation of coal-fired plants in China is low growth of power demand combined with higher generation based on hydro, nuclear energy, and wind and solar power. Chinese hydro generation was exceptionally high because of significant precipitation and substantial new hydro capacity additions in 2014 (see also regional focus on China).

Figure 1.7 Coal-based electricity generation in selected OECD non-member economies



* Estimate.

Source: IEA (2015a), *Coal Information 2015*, www.iea.org/statistics/.

Indian power generation based on coal is estimated at 974 TWh for 2014, an increase of 12.1% compared with 869 TWh in 2013. The strong role of coal-fired electricity generation can be explained by rising electricity demand and new coal-fired power plants as well as lower hydroelectricity because of a lighter-than-usual monsoon season in 2014.

In South Africa, estimated 2014 coal-based power generation decreased slightly by 7 TWh or 2.9% from 2013. This can be explained by slightly lower total electricity generation and the collapse of a coal storage silo at the Majuba power plant in November 2014, which lowered the available generation capacity and forced South African utility Eskom to introduce scheduled rolling blackouts known as load shedding.

Box 1.2 Flexible coal plants

Electricity is hard to store in an economical way. Batteries, pumped storage and some other technologies offer some possibilities, but they are limited as to the amount of electricity to be stored and by the price of storage. Currently, for the most part, electricity must be produced and consumed at the same time. In the past, power plants covered variability of demand, which was largely determined by day and night, weekends and workdays, and seasonal differences. Flexibility in the power supply driven by demand variability is nothing new. However, recently, increasing amounts of variable renewable energy sources (VRE), i.e. wind and solar, now add fluctuations to the supply side; thus, conventional plants need to increase their flexibility even more. For example, there is no correlation between wind production and power demand, so sometimes demand for electricity increases at the same time that the feed-in from wind plants dramatically decreases. In such cases, load adjustment by power plants is critical. In a longer perspective, variability, although it can be forecast up to four days in advance, is significant. In Germany, for example, in 2013, conventional generation ranged from 14 405 MW on 24 March to 74 335 MW on 24 January. (In 2014, the range was similar, from 12 GW to 70 GW.) This has technical and economic implications for conventional generators.

Box 1.2 Flexible coal plants (continued)

Most European countries are interconnected in the European synchronous zone, an area that spreads from Norway and Finland to Spain and Portugal. Electricity exports help to reduce the problem since wind variability declines when larger areas are considered. However, this only marginally limits the variability, especially when interconnection capacity is not sufficient and considering that consumer behaviour across borders is not similar. Currently, variability of power demand and VRE supply are largely managed by flexibility of conventional plants at a country level. For example, in Germany during Easter 2014, if isolated, variability of conventional power would have been 45.4 GW in three days. Exports reduced it to 36.2 GW.

Nuclear and coal plants were designed as base-load generators with gas turbines and hydro generating electricity during peak demand. This scheme, from times when highly planned and regulated power markets existed, was based on the wrong notion that only hydro and gas turbines can provide systems with flexibility. However, in places such as Germany where VRE capacity is large, there are very few dedicated base-load plants that do not allow for flexible operation. Table 1.5 compares combined-cycle gas turbines (CCGT) (two gas turbines with one steam turbine) with state-of-the-art new hard coal and lignite, and with hard coal as optimised to make plants flexible. Values are approximate since load change rate depends on the operating regime. New lignite plants could operate at 25% but have not been implemented yet, and, as of today, 40% is the minimum load.

With increasing feed-in of variable renewables into the grid, flexibility has a greater value. This needs to be considered when designing and operating grids.

Table 1.5 Comparison of technical parameters of modern gas-fired and coal-fired power plants

Parameter	Unit	Natural gas (new, CCGT)	Hard coal (new)	Lignite (new)	Hard coal (existing, optimised)
Capacity	MW	800	800	1100	300
Minimum load/rated load	%	~60	~25-40	~25-40	~20
Mean load change rate	%/min	~3.5	~3	~3	~3

Among other OECD non-member economies, Russia, Malaysia and Thailand stepped up coal-fired power generation according to the estimates for 2014. Coal-based generation in Indonesia, Chinese Taipei, Kazakhstan and Viet Nam remained roughly unchanged compared with 2013, whereas Ukrainian electricity generation in coal-fired power plants fell sharply because of the ongoing political crisis.

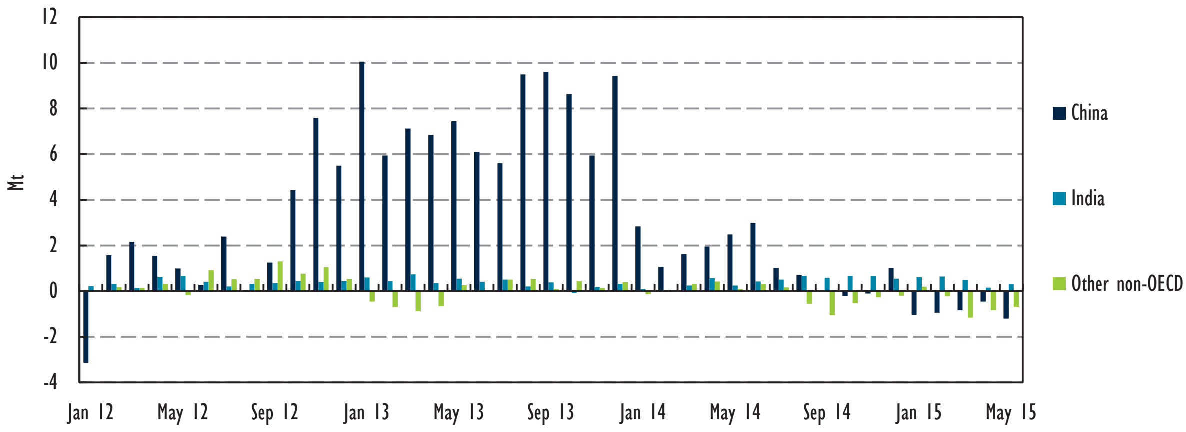
Non-power sector

In OECD non-member economies, non-power coal consumption in 2014 was an estimated 1 893 Mtce, accounting for 45% of total coal consumption, which is more than double the share that non-power coal consumption accounts for within the OECD. Compared with 2013, non-power coal consumption of OECD non-member economies grew by 1% (+11 Mtce). The largest consumer was the steel industry, accounting for an estimated 681 Mtce of consumed coal in 2014, which was 36% of total non-power coal consumption outside the OECD. The cement industry was the second-largest sector with an estimated 277 Mtce of coal consumption, equivalent to a 15% share, in 2014.

China, with an estimated 1 471 Mtce in 2014, accounted for approximately 75% of non-power coal consumption of OECD non-member economies, and was both the largest steel producer and the largest cement producer in the world. In comparison with 2013, consumption remained roughly unchanged (+5 Mtce). The Chinese steel sector consumed an estimated 486 Mtce of coal to produce 823 Mt of steel, which is roughly the same output as in 2013. However, production statistics for the first half of 2015 indicate decreasing Chinese steel production (Figure 1.8). Cement production in China consumed an estimated 206 Mtce of coal in 2014 and had an output of approximately 2.5 billion tonnes of cement.

In India, coal consumption by the non-power sector grew by 6% (+10 Mtce) in 2014 to an estimated total of 179 Mtce. Growth was driven mainly by the steel sector, which expanded production by 7% to 87 Mt. Consequently, coal consumption of the Indian steel sector increased to an estimated 83 Mtce. The Indian cement sector's coal consumption in 2014 remained roughly unchanged at 26 Mtce, which was used to produce 280 Mt of cement.

Figure 1.8 Monthly year-on-year differences in crude steel production in OECD non-member economies, 2012-15



Source: World Steel Association (various years), *Crude Steel Production*, www.worldsteel.org/statistics/crude-steel-production.org.

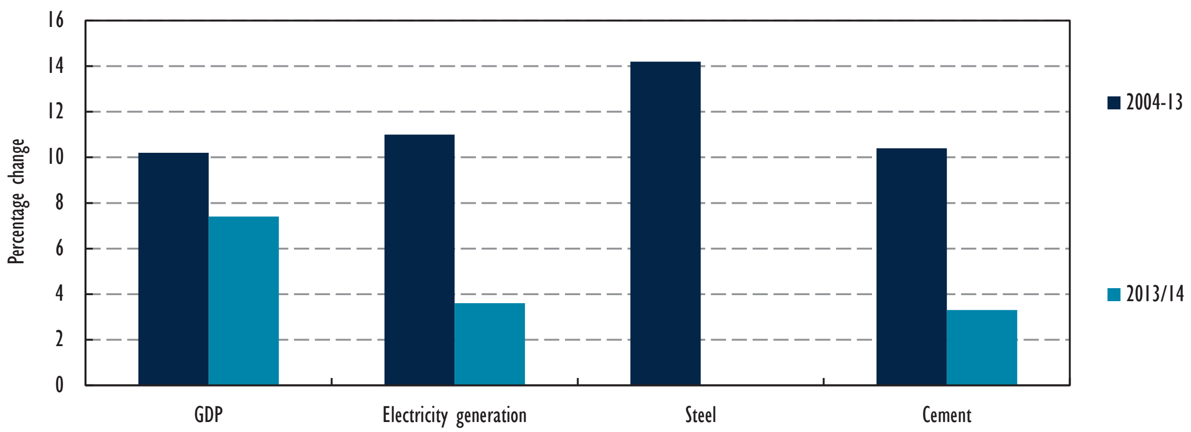
Regional focus: China

China has been the growth engine of world energy and coal demand over the last ten years: primary energy demand in China increased by roughly 8.4% per year over the time period 2004-13, making up 55% of world energy demand growth over the period. This development has largely been powered by coal. Coal accounted for roughly 72% of primary energy demand growth in China over the period. Coal consumption from 2004-13 increased by 8.8% per year on average, and China's share of world coal consumption increased from just 35% in 2004 to over 50% in 2013. However, both primary energy demand and coal consumption growth in China stalled in 2014. Coal demand in China even decreased for the first time since 1999. Demand for steam coal in China decreased by 3.5% (-119 Mt) to a total of 3 248 Mt. Met coal demand in contrast slightly increased by 0.5% to 671 Mt, but that was still much lower than the ten-year average growth rate of over 10%.

What were the drivers behind the slowdown in coal demand in China? Taking a look at the broad economic development in China, GDP grew by 7.4% in 2014. This is markedly lower than the ten-year average of 10.2%, so explains some of the slowdown in coal demand growth. A further potential contributing factor is the anticipated "rebalancing" of the Chinese economy, a term that is used to describe a potential structural change in the economy, away from heavy energy-intensive industries to a more service sector-based economy. Overall Chinese energy intensity is a good indicator of the rebalancing process. A drop in energy intensity year-by-year of roughly -4% shows that the development in China in 2014 was not unique. This indicates that there is margin for further intensity drops, driven by the rebalancing of the Chinese economy.

For a further investigation of coal consumption developments in China, we need to take a look at its particular consumption pattern, as it is quite distinct from developed Western countries. Steel and cement have a share of over 26% of coal demand in China. This compares to around 4% in the United States and some 13% in the European Union. In this respect, a part of the slowdown in Chinese coal consumption can be explained by slower growth in these sectors in 2014 (Figure 1.9): steel consumption stayed roughly flat compared with a ten-year average growth of 14.2%. Cement grew by 3.3% compared with 10.4% on average over the last decade. Steel and cement production are to a large extent dependent on infrastructure expansions in China, so coal consumption is also linked through these sectors to infrastructure developments (see Chapter 3 for a more detailed overview).

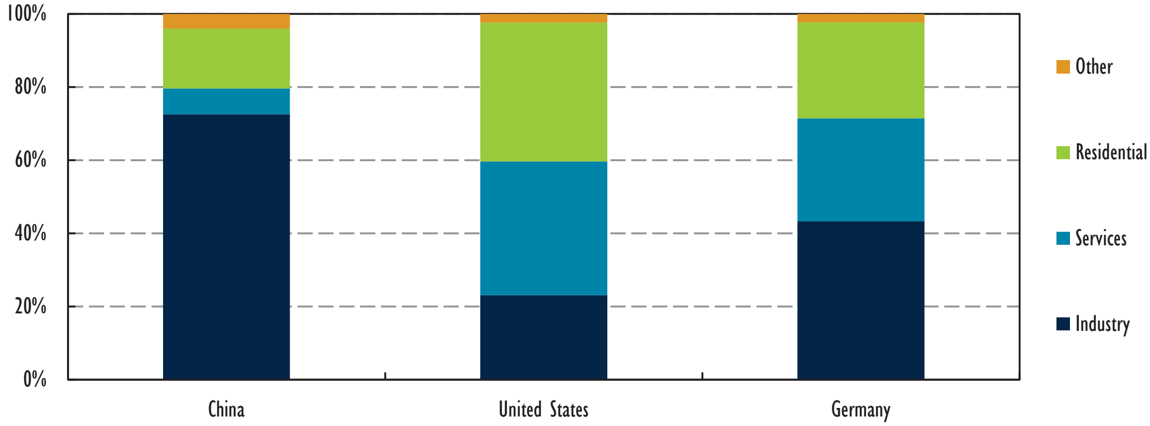
Figure 1.9 Economic growth in China, CAAGR and 2013/14



Note: CAAGR = compounded average annual growth rate.

Electricity generation accounts for the majority of coal demand – roughly 60% – in China. Electricity generation grew by around 3.6% in 2014, markedly slower than in the ten years before. Additionally, its growth was significantly lower than GDP growth in 2014. This is in sharp contrast to the developments from 2010 to 2013 because electricity generation and GDP grew at about the same rates in recent years. Like electricity generation, growth in electricity consumption was also weak in 2014 at 3.8%. The main drivers were developments in the industrial sector. It accounts for the bulk of electricity consumption in China, in contrast to regions such as the European Union or North America, where the bulk of electricity consumption is in the service and residential sectors. Even compared with an industrial country like Germany, the share of the industry sector in total electricity consumption is significantly higher in China (Figure 1.10). Growth in the industrial sector almost halved in 2014, down from 7% to around 3.7% in 2014. Consumption growth in the service sector also slowed, down from 10.3% in 2013 to 6.4%.

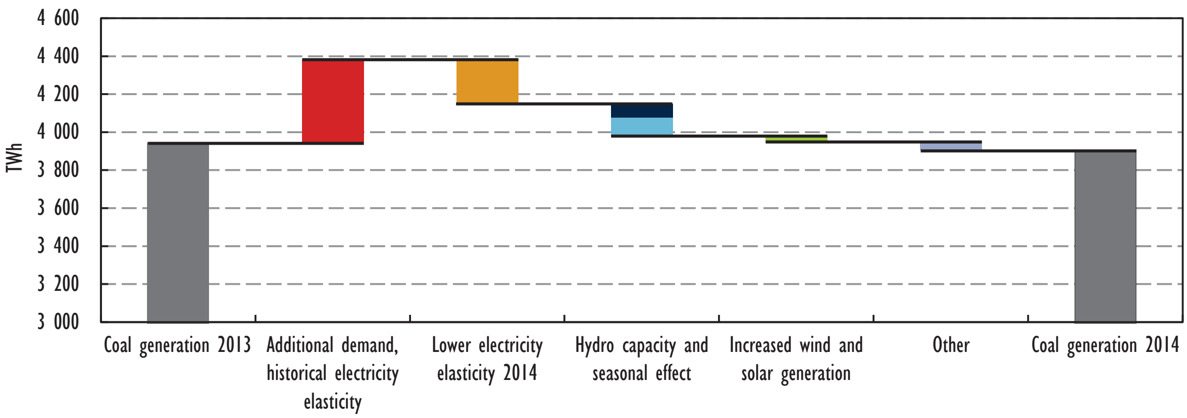
Figure 1.10 Power consumption in China by sector compared with the United States and Germany, 2013



Source: IEA (2015b), *World Energy Statistics and Balances 2015*, www.iea.org/statistics/.

In addition to the slow growth in electricity generation, coal's share within generation decreased in 2014 from 74% in 2013 to 70% in 2014. This development can mainly be attributed to increased hydropower generation. Strong hydropower generation typically leads to lower thermal power generation, and 2014 was a particularly strong hydro year in China. As a result, full-load hours of hydropower grew by over 290 hours from 2013 to a total of around 3 650 hours. Second, new-build hydro of around 22 GW came on line in 2014. Despite being lower than the 30 GW installed in 2013, China almost reached its five-year plan target of a total of 284 GW hydro capacity by the end of 2014, one year ahead of time. The biggest additions came in southwest China, in remote areas of the provinces of Sichuan and Yunnan, posing additional challenges to grid integration. The combined effect of the strong hydro year, new hydro capacity additions, increased generation from renewables and nuclear energy, and slow growth of electricity generation led to a reduction in coal-fired power generation from roughly 3 947 TWh in 2013 to 3 908 TWh in 2014. Full-load hours of coal-fired power plants in total China decreased from around 5 000 hours to 4 700 hours in 2014.

Figure 1.11 Drivers for the decrease in Chinese coal-fired power generation in 2014



It can be assumed that coal-fired electricity generation would have been significantly higher if the GDP elasticity of electricity demand had been at levels of the past years. If the exceptionally high hydro generation had not occurred, there would have been additional growth in coal-fired power generation as well. As indicated in Figure 1.11, the combined negative effect of the increased hydro generation and the reduced GDP elasticity of electricity demand on coal-fired generation adds up to more than 300 TWh.

Supply

Global coal supply in 2014 decreased by 55 Mt or 0.7%, from 7 980 Mt to an estimated 7 925 Mt. This represents the first decline in global coal supply since 1999. The ten-year average growth rate over the last decade was 4.3%. The decreased global coal supply in 2014 was caused mainly by declining supply in China (-2.6%) and Indonesia (-3.5%). For both countries this is a significant change, as supply in China and Indonesia grew strongly over the last decade with average growth rates of 7.5% in China and 15.3% in Indonesia. In contrast, the United States, the second-largest coal producer in the world, increased its coal production by 1.3% (+13 Mt) after two years of declining output and an average growth rate of -0.7% over the last decade. India and Australia both increased their coal production in 2014. India's production went up by 9.6% (+58 Mt) in 2014 to 668 Mt, which is a strong increase in comparison to the ten-year average growth rate of 4.7%. Australia expanded its coal production by 7% (+32 Mt) in 2014 and became once again the fourth-largest coal producer in the world, a position that it lost to Indonesia in 2013.

Table 1.6 Coal supply overview

	Total coal supply (Mt) 2013	Total coal supply (Mt) 2014*	Absolute growth (Mt) 2013-14	Relative growth (%) 2013-14	CAGR (% per year) 2004-13	Share (%) 2014
China	3 749	3 650	-99	-2.6%	7.5%	46.1%
United States	904	916	13	1.4%	-0.7%	11.6%
India	610	668	58	9.6%	4.7%	8.4%
Australia	459	491	32	7.0%	3.0%	6.2%
Indonesia	488	471	-17	-3.5%	15.3%	5.9%
OECD	1 989	2 016	27	1.3%	-0.2%	25.4%
Non-OECD	5 992	5 909	-82	-1.4%	6.4%	74.6%
World	**7 980**	**7 925**	**-55**	**-0.7%**	**4.4%**	**100.0%**

* Estimate.
Note: Differences in totals are due to rounding.
Source: IEA (2015a), *Coal Information 2015*, www.iea.org/statistics/.

Thermal coal accounted for 77% of total 2014 coal supply, while met coal accounted for 13% and lignite for the remaining 10%. The decline in total coal supply is a result of decreasing production of thermal coal (-59 Mt) and lignite (-24 Mt), while the global met coal production increased (+28 Mt). With shares of roughly 80% and 70%, the vast majority of 2014 global steam and met coal was mined in OECD non-member economies, while OECD member countries produced 67% of the global lignite supply.

OECD supply trends

Coal production in OECD member countries increased by 1.3% (+27 Mt) to an estimated 2 016 Mt in 2014. The growing coal supply in the OECD can be attributed to an increase in 2014 hard coal production, which was expanded by 2.7% (+39 Mt) compared with 2013. This increase consists of 1.7% (+19 Mt) additional steam coal production and 6.7% (+20 Mt) additional met coal production in 2014. Production of lignite on the other hand decreased by 2.2% (-12 Mt).

Table 1.7 Hard coal and lignite production among selected OECD member countries (Mt)

Country	Hard coal		Lignite	
	2013	2014*	2013	2014*
Australia	396	431	63	61
Canada	60	61	9	9
Czech Republic	9	9	40	38
Germany	8	8	183	178
Greece	0	0	54	48
Hungary	0	0	10	10
Korea	2	2	0	0
Mexico	15	14	1	1
New Zealand	4	4	0	0
Norway	2	2	0	0
Poland	77	73	66	64
Slovak Republic	0	0	2	2
Spain	4	4	0	0
Turkey	3	3	58	62
United Kingdom	13	12	0	0
United States	834	844	70	72

* Estimate.
Source: IEA (2015a), *Coal* Information *2015*, www.iea.org/statistics/.

The additional hard coal production in 2014 stems in large part from supply expansions in OECD Asia Oceania, where Australia's hard coal output increased by 8.7% (+34 Mt). Australia thereby managed to increase its market share in a difficult global market environment by continuing the path of relentless cost cutting and productivity improvements. The increase in Australian hard coal supply consists of higher steam coal production (+9 Mt) as well as higher met coal production (+25 Mt) in 2014 compared with 2013.

Hard coal production in OECD Americas also increased as the United States expanded output by 1.3% (+11 Mt) in 2014. Accordingly coal supply in the United States recovered compared with the weak 2013 output, but it is still sharply below historical levels. The additional coal supply in 2014 stems mainly from higher production in PRB and Northern Appalachia, which both raised production by roughly 10 Mt. Additionally, production in the Illinois Basin grew by approximately 5 Mt. This increase in coal output was partly offset by lower production in Central Appalachia and several smaller mining regions.

Production of hard coal in OECD Europe declined by 5.1% (-6 Mt) compared with 2013. The largest decrease took place in Poland, where supply was down 4.9% (-4 Mt), as decreasing demand from power and co-generation[6] plants lowered domestic production (see also regional focus on Poland). Apart from that, production declined in the United Kingdom by 10.2% (-1 Mt).

[6] Co-generation refers to the combined production of heat and power.

The decrease in 2014 lignite production in the OECD is due in large part to lower production levels in OECD Europe (-11 Mt), whereas lignite supply in OECD Americas (+1 Mt) and OECD Asia Oceania (-2 Mt) changed only slightly. Lignite production in Germany, the largest lignite producer in the world, declined by 2.5% (-5 Mt) because of lower electricity production in lignite-fired power plants.

Regional focus: Poland

Poland is the second-largest coal mining country in Europe after Germany and the largest European hard coal producer by far as well as the ninth-largest coal producer in the world and a key supplier of coal to its domestic market. Coal production in Poland has been systematically declining since 1990, a result of a restructuring of the domestic coal sector. Given current coal prices, legitimate doubts exist about the economic viability of a portion of the Polish mines, which could require further restructuring in the future.

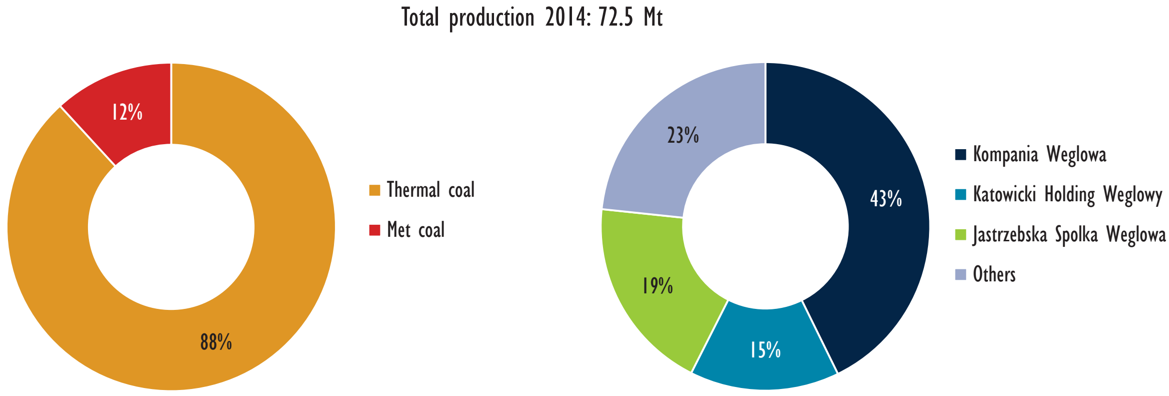
The anticipated economic resources of hard coal totaled 51 960 Mt (as of 2014). Thermal coals represent almost 75% of the resources, and coking coals roughly 25%. Hard coal deposits occur in Poland in three regions: the Upper Silesian Coal Basin, the Lublin Coal Basin and the Lower Silesian Coal Basin. Currently, coal-mining operations are performed in only two of those regions: in the Silesia Basin, which traditionally has always been the main source of Polish coal and where most of the mines are situated, and in the Lublin Basin. (The third region, the Lower Silesian, has a historical significance only.) Poland's anticipated economic resources of lignite amounted to 23 510 Mt as of the end of 2014. Lignite is mined at opencast mines in four principal mining areas located in central and western Poland (Adamow, Belchatow, Konin and Turow).

The number of mines in operation decreased from 70 in 1988 to 42 in 2000, and reached 29 in 2014, with possible further closures looming large. In 2014, the state treasury owned 100% stake in 19 mines belonging to two major Polish coal companies – Kompania Weglowa (14 mines) and Katowicki Holding Weglowy (4 mines). One mine is owned directly by Spolka Restrukturyzacji Kopaln, a restructuring company. Two companies are listed on the Polish stock exchange: Jastrzebska Spolka Weglowa (five mines with 55.16% share of the state treasury) and LW Bogdanka (a private company; one mine with 1% share of the state treasury). One mine is owned by Tauron Wydobycie, a subsidiary of Tauron Polska Energia, the largest electricity distributor and second-largest electricity generator in Poland. Two private small-scale mines with Polish capital belong to ZG Siltech and EKO-Plus (one each), and PG Silesia is owned by the Czech company EPH. There are also coal trading companies – Weglokoks and Spolka Restrukturyzacji Kopaln, owned by the state treasury, responsible for the closure of non-productive mines and managing other aspects of the government's restructuring programme. Two vertically integrated power utilities use lignite to produce electricity: PGE and ZE PAK.

Poland has a highly skilled coal-mining workforce. In 1988, the number of employees in the mining sector reached 428 200, but since then it has continually declined (159 600 in 2000, 100 000 in 2014). The number of employees fell below 100 000 in 2015.

In 2012, hard coal production in Poland reached 79.2 Mt., but then it declined from 76.5 Mt in 2013 to 72.5 Mt in 2014, down by 5% year-on-year (see Figure 1.12). Steam coal production contracted by 4.2 Mt (6%) year-on-year, whereas coking coal production increased by 0.2 Mt (1%) year-on-year. After a moderate growth in 2011-13, lignite production in 2014 equaled 63.8 Mt, down by 2 Mt year-on-year (65.8 Mt in 2013).

Figure 1.12 Structure of Polish hard coal production in 2014



Hard coal stocks at mines at the end of 2014 hit record volumes (8.2 Mt), increasing by 1.5 Mt year-on-year. In 2014, thermal coal stocks went up by 1.5 Mt to reach 7.8 Mt, while coking coal inventories fell only by a tiny fraction reaching 0.4 Mt. Moreover, overall coal stocks are actually much higher, considering that power production companies possess their own coal stocks. However, 2015 saw a substantial decline in coal stocks due to the pricing policies of coal companies. Lignite coal stocks are negligible.

Coal sales increased by 7% from 71.9 Mt in 2012 to 77.5 Mt in 2013; since then, however, they have dropped sharply by 7.2 Mt (9% year-on-year) to reach 70.3 Mt in 2014. In 2014, a vast majority of Polish coal (62.0 Mt) was sold on the domestic market, but the total volume of domestic sales went down by 7% (4.9 Mt) in comparison with the previous year (66.9 Mt). In 2013, domestic coal sales for electricity generation grew by 6%, yet there was a decline in sales to all other sectors involved (including other commercial power industry, electrical power and heating plants, coking plants, etc.). Virtually the entire production of lignite is sold on the domestic market.

OECD non-member supply trends

Total 2014 coal production in OECD non-member economies was an estimated 5 909 Mt, which corresponds to a decrease of 1.4% (-82 Mt) from 2013. Hard coal supply fell by 1.2% (-70 Mt) due to a 1.6% (-78 Mt) decrease in steam coal production, which was partly offset by a slight increase in met coal production of 1.1% (+8.3 Mt). Total production of lignite in OECD non-member economies fell by 4.4% (-12 Mt) in 2014.

The decline in 2014 hard coal production in OECD non-member economies is mainly a result of declining coal production in China, by far the largest coal producer in the world. Chinese hard coal supply went down by 2.7% (-99 Mt) compared with 2013 to an estimated 3 650 Mt in 2014. The country's decrease in 2014 thermal coal production was even more pronounced, with supply falling by 3.4% (-107 Mt), while coking coal supply increased slightly by 1.5% (+9 Mt) in comparison with 2013. After several years of oversupply, high stocks and low prices, the lower coal demand in 2014 put further pressure on coal producers in China. Additionally, the Chinese government continued to shut down small mines. In total roughly 1 500 mines, mainly in the southwestern provinces of Sichuan, Yannan, Guizhou, Hunan and Chongqing, were closed in 2014 because of low safety standards and high risks of gas explosions.

Table 1.8 Hard coal and lignite production among selected OECD non-member economies (Mt)

Country	Hard coal		Lignite	
	2013	2014*	2013	2014*
Bulgaria	0.0	0.0	28.6	31.2
China	3 748.5	3 649.9	0.0	0.0
Colombia	85.5	88.6	0.0	0.0
India	565.8	621.2	44.3	47.2
Indonesia**	487.7	470.8	0.0	0.0
Kazakhstan	112.9	108.8	6.7	6.6
Romania	0.0	0.0	24.7	23.6
Russia	252.3	264.5	73.7	69.6
Serbia	0.0	0.0	40.3	29.9
South Africa	256.3	253.2	0.0	0.0
Ukraine	68.8	44.7	0.0	0.0
Viet Nam	41.0	35.8	0.0	0.0

* Estimate.
** Lignite makes up a portion of coal production in Indonesia.
Source: IEA (2015a), *Coal Information 2015*, www.iea.org/statistics/.

In contrast to China, hard coal production in India increased significantly by 8.9% (+55 Mt) in 2014. This increase is due to rising thermal coal supply since met coal production remained stable in comparison with 2013. Coal India Limited (CIL), the largest coal mining company in the world, was able to increase production levels by 7% to a total of 494 Mt in the fiscal year from April 2014 to March 2015. Despite the increased output, CIL has once again missed the production targets set by the Indian government.

Supply of hard coal in Indonesia declined by 3.6% (-17 Mt), as the Indonesian government tried to limit production in order to stabilise prices in the oversupplied international coal market. The government also stepped up measures to cut down illegal mining activities.

Ukrainian hard coal production plummeted in 2014 by 54% (-24 Mt) because of the ongoing political crisis. A large number of coal mines have been damaged as the most-affected regions, Donetsk and Luhansk in the southeastern part of Ukraine, account for roughly 75% of domestic coal mining activity. Hard coal production in 2014 in Russia increased by 4.6% (+12 Mt) mainly due to rising exports. South Africa, on the other hand, lowered output slightly in 2014 by 1% (-2.3 Mt) because of lower electricity production in coal-fired power plants.

Lignite production in 2014 decreased by 4.4% (-12 Mt) in the OECD non-member economies. The largest decline in lignite supply in 2014 took place in Serbia, where production fell by over 25% (-10 Mt) compared with 2013. This sharp decrease resulted from extensive damages in the Kolubara Basin due to flooding. Lignite output also decreased in Russia with a decline of 5.6% (4 Mt) from 2013.

Regional focus: Indonesia

The Indonesian coal supply increased by over 15% on average per year over the period 2004-13. Most of this supply growth served the export market, with only about 8% of the growth destined for domestic consumption. The reasons for this impressive growth are to be found in the availability of low-cost mines close to the ports as well as in Indonesia's advantageous geographic location to serve the coal demand centres of the last ten years, namely China and India. These two countries absorbed over 70% of additional coal supplies from Indonesia over the period. However, in 2014, Indonesian coal supply strongly declined (-3.5%) for the first time since the financial crisis in 2008. The reasons for this development are again to be found in the export market, more specifically in lower exports to China as well as new regulations in China and Indonesia regarding coal quality and exports (see Chapter 2 for a detailed description).

Indonesian coal reserves are currently estimated at 14 gigatonnes, making Indonesia the ninth-largest reserve holder in the world. The largest reserves are located in East Kalimantan and South Sumatra. East Kalimantan, with its mining regions of Kutai and Tarakan, is today the main coal production region of the country. Together with Barito and Asam Asam in South Kalimantan as well as production from mines in Central Kalimantan, the island of Kalimantan accounts for around 90% of Indonesian coal production. Around 8% of Indonesian coal is mined in South Sumatra, and the rest in smaller mining areas such as Jambi on Sumatra. New Indonesian mining regions that are developed include the region of Aceh on Sumatra due to its shipping advantage of roughly five days to India compared with other Indonesian regions.

Indonesian coal production is bituminous and sub-bituminous coal, and lignite although lignite is not reported in the statistics. It is generally low ash (5-7%) and low sulphur (<1%) but also has a high moisture content (up to 20-30% on a gross as received [GAR] basis) and a low calorific value, generally lower than 5 000 kilocalories per kilogramme.

The five largest producers In Indonesia are PT Adaro Indonesia, PT Kaltim Prima Coal (Bumi), PT Kideco Jaya Agung, PT Arutmin Indonesia (Bumi) and PT Indo Tambangraya Megah (Banpu) (see Table 1.9). Together they account for roughly 40% of Indonesian production. In line with general production increases in Indonesia, these companies generally increased production strongly in the years to 2013. Strip ratios for the companies compare to an overall Indonesian average strip ratio of around 8. Coal characteristics as well as production costs vary significantly among the companies, illustrating the differences among producers as well as the potential blending opportunities among different coal types.

Table 1.9 Profile of major Indonesian coal producers

Company	Moisture	Ash	Sulphur	Strip ratio	Production cost	Production 2013 (Mt)	Production 2014 (Mt)
PT Adaro Indonesia	-	2.0-3.5%	0.1-0.3%	5.8	33.0	52.3	56.2
PT Kaltim Prima Coal (Bumi)	11-23%	2.5-4.5%	0.3-0.9%	9.6	42.8*	53.5	52.4
PT Kideco Jaya Agung	27-35%	2.5-3.5%	0.1%	-	-	37.0	40.0
PT Arutmin Indonesia (Bumi)	9-35%	3.9-12.0%	0.2-1.4%	2.3	21.8*	28.8	32.2
PT Indo Tambangraya Megah (Banpu)	-	-	0.3-1.8%	8.6-11.0	40.4	28.6	20.5

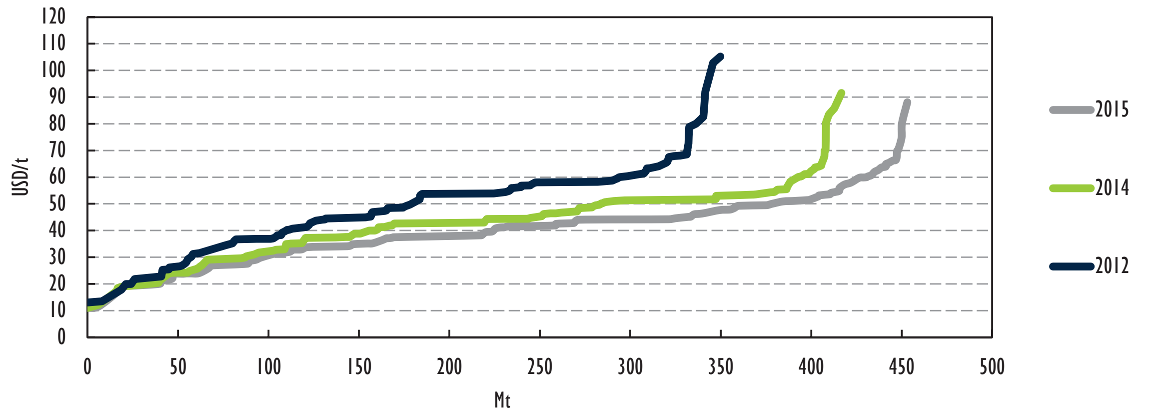
* First half of 2014.

Source: Company annual reports.

Free-on-board (FOB) costs have decreased by approximately 17% over the past three years in Indonesia, from a weighted average of USD 47.9/tonne (t) in 2012 to USD 39.8/t in 2015, making

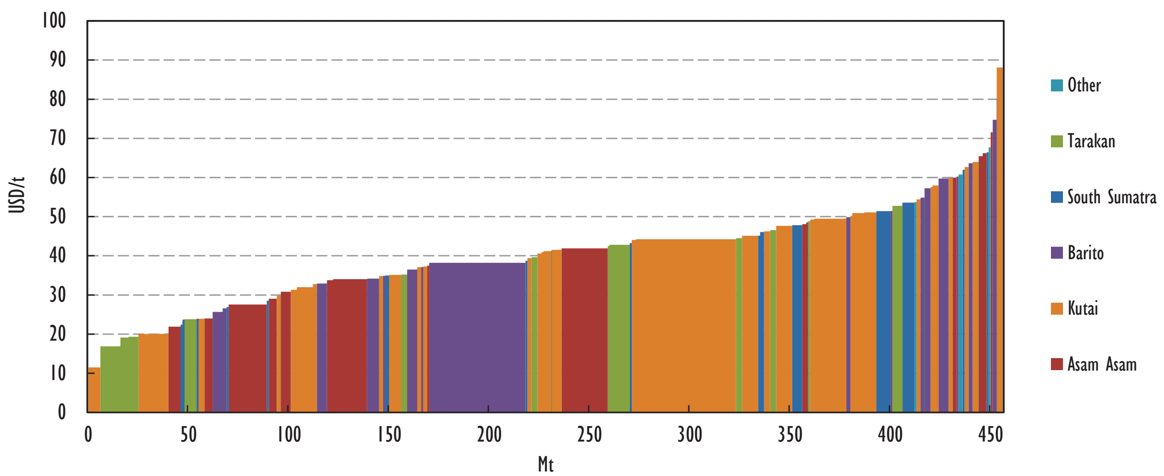
Indonesia one of the lowest-cost coal producers. However, costs vary substantially among Indonesian basins and also within basins. The lowest-cost coal in Indonesia is mined in Tarakan (East Kalimantan) at average costs below USD 33/t. Mining costs in Kutai (East Kalimantan) and Barito (South Sumatra) in contrast average at around USD 42/t. Surface mines using truck and shovel mining methods are prevalent in Indonesia. Mining costs, which form the main part of FOB costs in Indonesia, are therefore strongly dependent on oil price movements. The decline in oil prices since July 2014 has contributed to mining and FOB cost decreases. As illustrated in Figure 1.13, not only average costs have decreased in Indonesia, but also the supply curve in general has flattened over the last three years due to the closures of most high-cost mines in the current low-price environment and cost-cutting efforts of producers, including aiming for higher efficiencies and reducing strip ratios. However, the decline in coal prices has been higher than cost reductions, so the situation of coal producers has further deteriorated despite cost reductions. Figure 1.14 shows additionally the Indonesian supply curve differentiated by the major coal basins in Indonesia.

Figure 1.13 FOB cash costs for Indonesia: 2012, 2014 and 2015



Source: IEA analysis based on Wood MacKenzie (2015), *Coal* (private database), accessed April 2015.

Figure 1.14 Indicative FOB cash costs for Indonesia, 2015



Source: IEA analysis based on Wood MacKenzie (2015), *Coal* (private database), accessed April 2015.

The increase in domestic coal demand is helping to balance the market oversupply, but the effect is limited, given the size of Indonesian domestic markets compared with the international or the Chinese market. The Indonesian government has announced an ambitious plan to build 35 GW of new power generation capacity, roughly 20 GW of which will be coal-fired (see Chapter 3 for more). Through the domestic market obligation (DMO) in Indonesia, producers are required to allocate a minimum percentage of their production to the domestic market. The DMO, currently less than 18%, is expected to rise to more than 25% in a couple of years due to more domestic coal needs, thereby potentially limiting coal exports. Similar demand and export patterns have been observed in other resource exporting countries, e.g. Egypt and Oman for gas. Though not completely comparable due to the different sizes and structures of the economies, domestic demand picked up in both countries and led to imports of gas in Egypt and lower exports in Oman.

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2. RECENT TRENDS IN INTERNATIONAL COAL TRADING

Summary

- **After four years of strong growth, international coal trade grew only slightly by 0.6% in 2014.** The total trade volume amounted to 1 384 million tonnes (Mt), which is 23% of global coal demand. Roughly 90% of the total coal trade was seaborne.

- **The slowdown in total trade growth was caused by the first decline in steam coal trade (-1.7%) after the recession in 2008.** Metallurgical (met) coal trade increased 8.8% in 2014. Total trade amounted to 1 054 Mt of steam coal, 322 Mt of met coal and small quantities of lignite.

- **Chinese imports declined for the first time since 2008.** Despite the strong decrease of 10.5%, China remained the largest coal importer in the world and accounted for 21% of total global imports.

- **Coal exports from Indonesia fell because of the lower demand for coal imports in China.** As a result, Indonesia maintained its position as the largest coal exporter in the world in terms of physical tonnes, but was overtaken by Australia in terms of energy content.

- **International prices for steam coal and met coal continued to decline throughout 2014 and 2015.** Lower global coal demand and oversupplies put substantial downward pressure on prices. In 2015, import prices for thermal coal fell below USD 60 per tonne (t) in Europe and Asia.

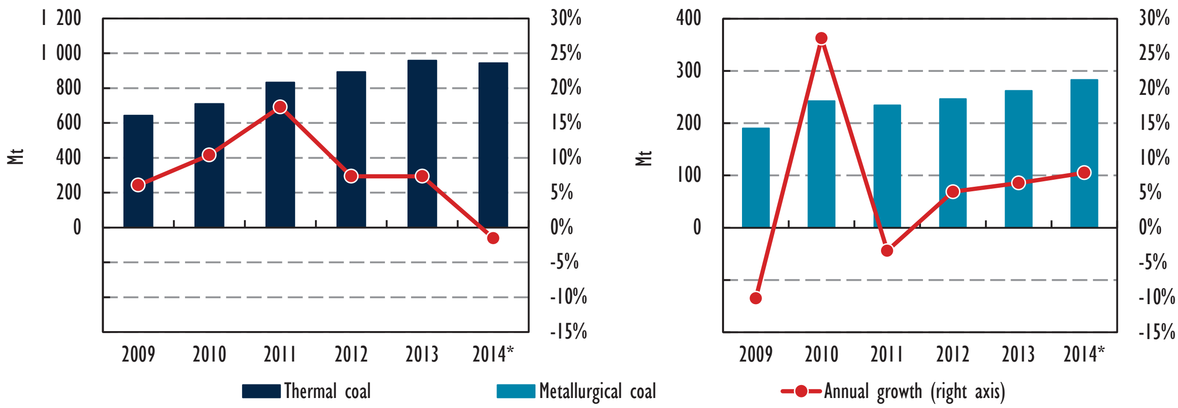
- **Currency depreciation in exporting countries, low oil prices and efficiency gains helped coal producers to reduce supply costs.** Despite these developments, many producers continue to produce at a loss in the current low-price environment.

The international coal market

After four years of strong growth, trading volume in the international coal market increased only slightly by 0.6% (+9 Mt) in 2014. The traded volume amounted to 1 384 Mt, with thermal coal accounting for 76% (1 054 Mt) of total trade. Another 23% (322 Mt) of the volume consisted of met coal, and small quantities of lignite accounted for the balance. In comparison with 2013, the traded volumes of steam coal declined by 1.7% (-18 Mt) while global trade of met coal increased significantly by 8.8% (+26 Mt).

With a share of roughly 90%, the vast majority of international trade was seaborne. Like the absolute trading volumes, the growth rate of seaborne trade in 2014 was small and amounted to 0.7% (+8.5 Mt). Again this can be attributed to a decline in seaborne thermal coal trade, even though seaborne met coal trade volumes increased. The total quantity of seaborne traded coal in 2014 amounted to 1 232 Mt. This amount consisted of 945 Mt thermal coal, 283 Mt met coal and small quantities of lignite.

Figure 2.1 Development of the seaborne thermal (left) and met (right) coal markets, 2000-14



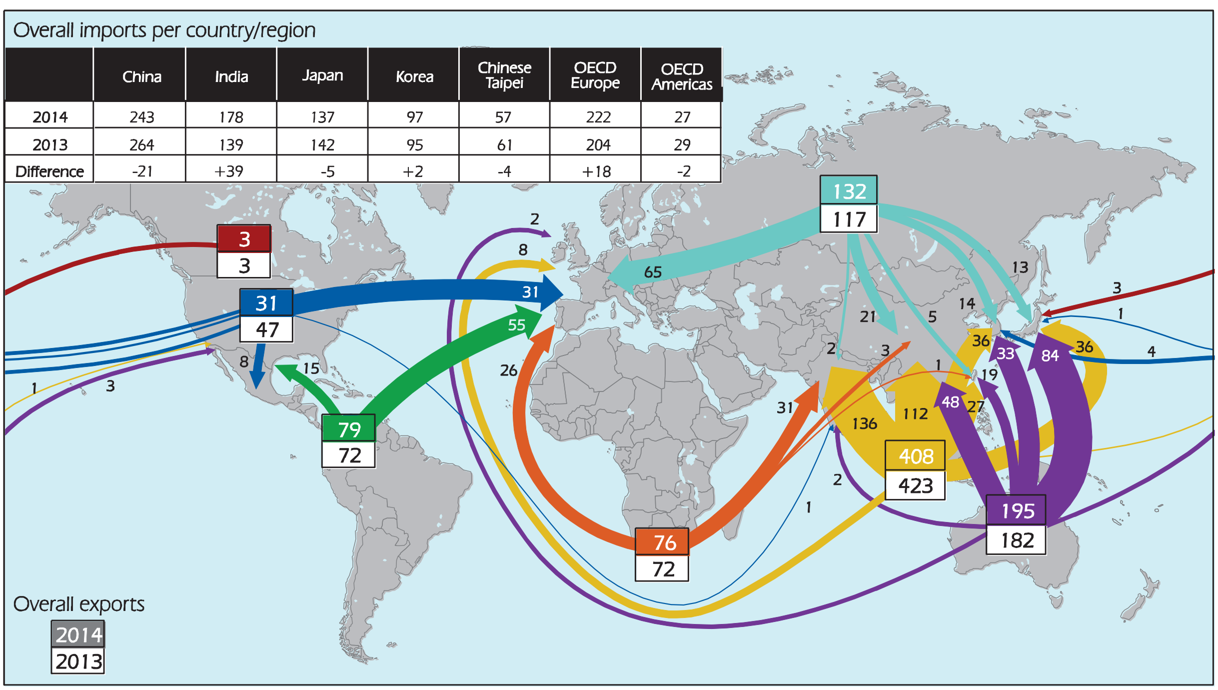
* Estimate.

Source: IEA (2015), *Coal Information 2015*, www.iea.org/statistics/.

International thermal coal trade

Despite the strong growth of thermal coal trade over the last years, the majority of thermal coal demand is produced domestically and only 17% is traded on the international market. Roughly 90% of international thermal coal trade is seaborne.

Map 2.1 Major trade flows in the thermal coal market, 2014



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

Note: Given that minor flows have not been represented in the map, and some statistical differences, imports and exports flows do not match exactly. This figure must therefore be regarded as indicative.

Source: IEA (2015), *Coal Information 2015*, www.iea.org/statistics/.

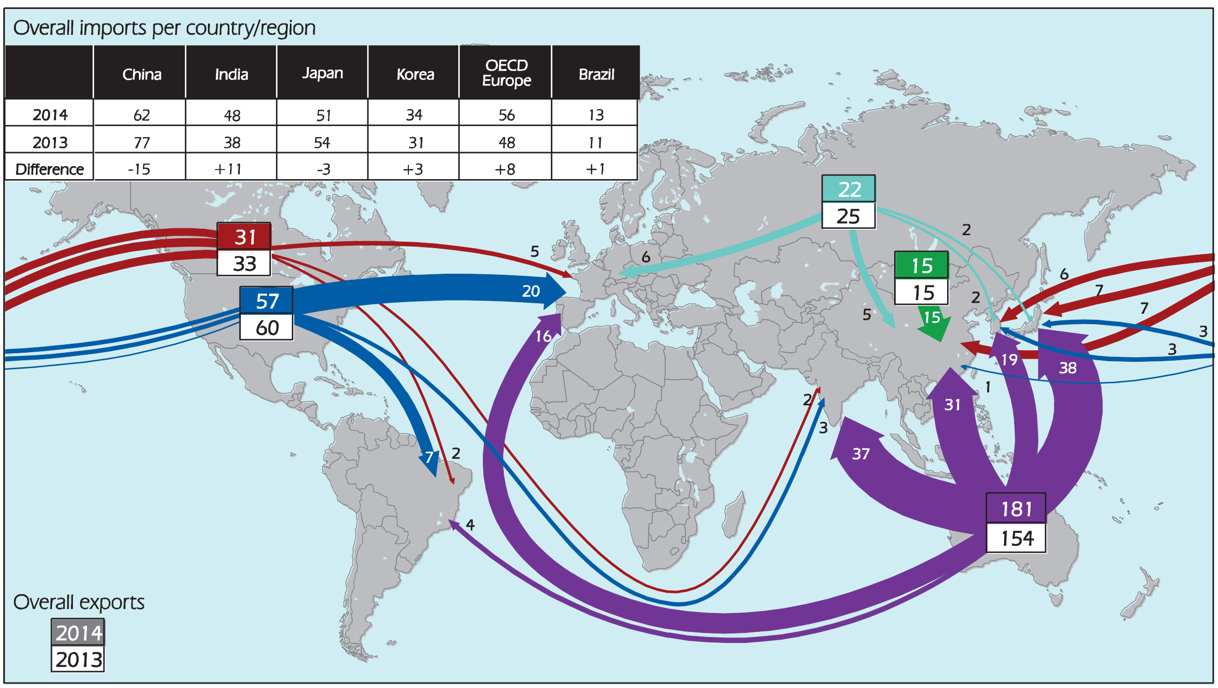
The major thermal coal trade flows from the largest producing countries to the primary demand centres are depicted in Map 2.1. It can be seen that the Pacific Basin, where the largest exporters and importers are located, dominates international trade of thermal coal. In terms of weight of exported coal, Indonesia was again the world's largest exporter of thermal coal, followed by Australia and the Russian Federation (hereafter "Russia"). The largest importer of thermal coal was China, ahead of India and Japan. Significant volumes of thermal coal are also imported by the Organisation for Economic Co-operation and Development's (OECD) Europe country group.

International met coal trade

The international trade of met coal accounted for 33% of 2014 met coal consumption, while the remaining 67% was produced and consumed domestically. Seaborne trade dominates the international met coal market with a share of 88% in total traded volumes.

The most important exporters and importers of met coal with the corresponding trade flows are illustrated in Map 2.2. It is evident that the international market for met coal is concentrated, because the largest exporters, Australia, the United States (US) and Canada, accounted for more than 80% of the total met coal trading volumes in 2014. The most important importers of met coal are China, Japan and India. The aggregated imports of OECD Europe also have a significant share in international met coal trade.

Map 2.2 Major trade flows in the met coal market, 2014



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

Note: Given that minor flows have not been represented in the map, and some statistical differences, imports and exports flows do not match exactly. This figure must therefore be regarded as indicative.

Source: IEA (2015), *Coal Information 2015*, www.iea.org/statistics/.

Regional analysis

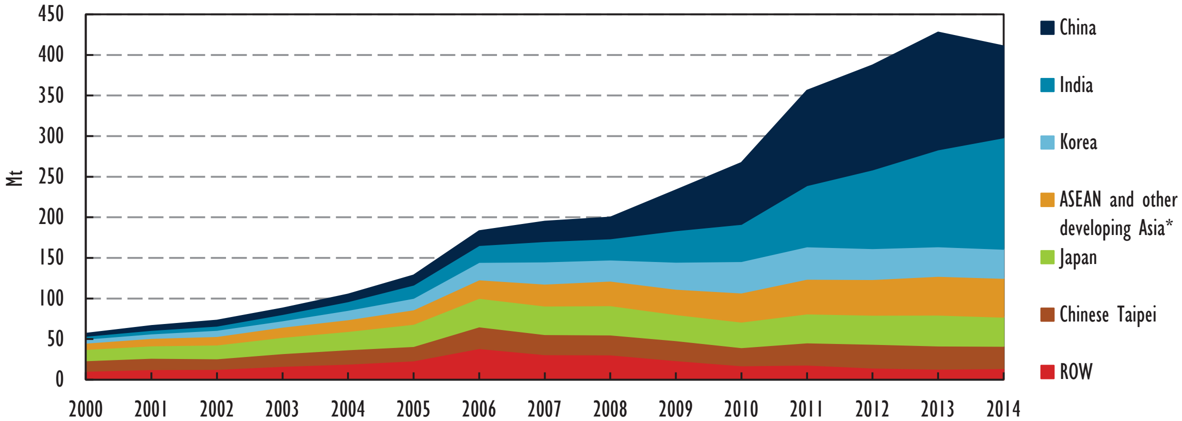
The following section focuses on recent trends in international coal trade and gives a short overview of important developments in the main exporting and importing countries.

Exporters

Indonesia

Indonesian coal exports have been growing impressively since the beginning of the 21st century, making Indonesia the largest coal exporter in the world. In 2014, however, coal exports from Indonesia decreased for the first time since the beginning of the strong Indonesian export growth in the 1990s. As a result, Indonesia maintained its position as largest coal exporter only in terms of tonnage and is now the second-largest exporter in terms of energy content behind Australia. Indonesian coal exports fell by 4% (-17 Mt) in comparison with 2013 to an absolute amount of 411 Mt. Consequently, 87% of Indonesian coal production in 2014 was exported, with Indonesian exports accounting for roughly 30% of the global coal trade. Indonesian exports consist almost entirely of steam coal, as Indonesian coal typically has a high moisture content and therefore does not meet the quality requirements for met coal.

Figure 2.2 Development of Indonesian export destinations, 2000-14



*Excludes Chinese Taipei.
Notes: ASEAN = Association of Southeast Asian Nations; ROW = rest of world.
Source: IHS Energy (2015), *Coal McCloskey Price and Statistical Data*, https://connect.ihs.com/industry/coal.

The main reason for the decline in 2014 Indonesian exports is the lower coal demand in China, as exports to China dropped by 22%. This decrease was only partly offset by higher exports to India, which grew by 15%, making India the most important buyer of Indonesian coal with a share of 32% in total exports, followed by China with a share of 26%. Exports to more distant destinations such as Japan, Korea and Chinese Taipei remained roughly unchanged in 2014.

Indonesia largely benefited from the rapid growth of energy use in China over the last decade and is now affected by the slower economic growth and stronger environmental efforts in China. Apart from that, Indonesian coal exports in 2014 were also affected by new regulations that came into effect in October and require companies to be registered as official exporters in order to reduce exports from illegal mining activities.

Australia

Coal exports from Australia grew substantially by 11.6% (+39 Mt) in 2014 to a total of 375 Mt to become the largest coal exporter on an energy basis. The growth in exports in 2014 stemmed from growing steam coal exports, which increased by 7% (+12 Mt), as well as from met coal exports, which grew by 17% (+27 Mt). Met coal exports totalled 180 Mt in 2014, so Australia strengthened its position as the largest met coal exporter in the world by far, and even surpassed the record high in Australian met coal exports from 2010 (157 Mt).

The primary export destinations for Australian coal in 2014 remained Japan, with 31% of total exports, and China, with 24%. Shipments to Japan decreased by 1.2% compared with 2013 to a total of 116 Mt, while exports to China increased strongly by 10% to 91 Mt. India accounted for 12% of total Australian exports in 2014. Total exports to India amounted to 39 Mt, which is an increase of 16% compared with 2013. As a result, Australia could extend its market share in the seaborne coal market despite the stagnating global market environment of 2014 because of the high quality of Australian coal as well as the cost-effectiveness of Australian mines. Although export quantities increased, revenue from exported coal in the fiscal year 2013/14 (July to June) decreased slightly in comparison with the previous fiscal year because of lower market prices. Total revenues generated by Australian coal exports were USD 37 billion, of which roughly 60% stemmed from met coal.

Russia

Russia, the world's third-largest coal exporter, increased its exports by 10.5% (+15 Mt) to a total of 156 Mt in 2014. The exported Russian coal consisted primarily of steam coal, at 132 Mt, and it accounted for the incremental exports in 2014. Met coal exports remained roughly unchanged at 21 Mt with small amounts of lignite accounting for the balance. In total, 47% of Russian coal production in 2014 was exported.

At 71 Mt, almost half of Russian coal exports in 2014 were destined for OECD Europe, shipped through ports in the Baltic Sea (Riga or Ventspils in Latvia or Ust-Luga in Russia), the Black Sea (Tuapse) or the Barents Sea (Murmansk). However, exports to Europe slightly decreased in 2014 because of the lower 2014 coal demand in OECD Europe. Instead Russia increased exports to the Asian markets; Russia's Pacific ports (Vostochny and Nakhodka) saw growth rates of roughly 25% in export volumes, indicating an increasing shift of Russian exports to the Asia-Pacific markets.

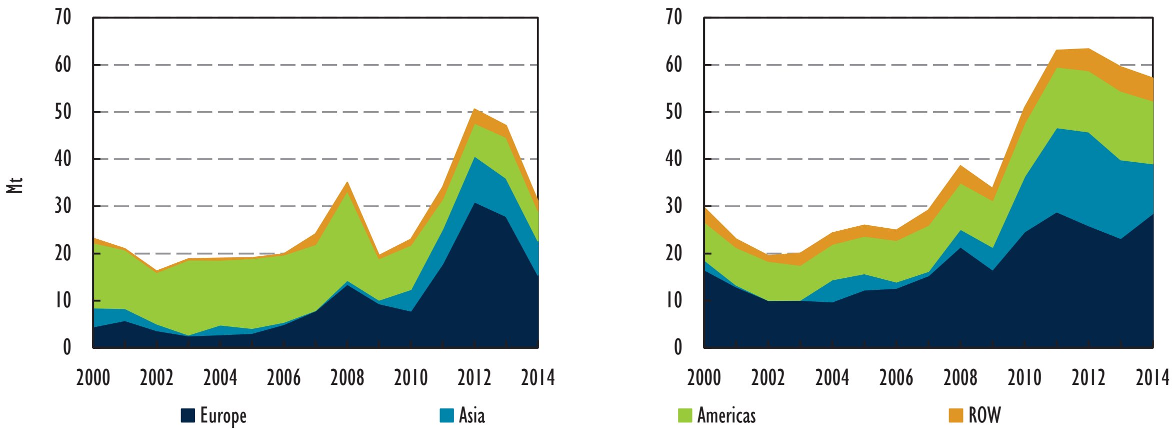
Generally the strong increases of Russian coal exports in 2014 were caused by lower domestic demand and the sharp drop of the ruble against the US dollar, which strengthened competitiveness of Russian producers in the international market. The falling ruble made cash revenues for Russian thermal coal in nominal value at the start of 2015 similar to those obtained in 2011, when coal prices in northwest Europe were around USD 120/t. That is about twice the coal price in the first half of 2015.

United States

Exports from the United States decreased sharply by 17.3% (-18 Mt) in 2014, totalling 88 Mt. The decline was mainly caused by a drop of thermal coal exports of 34% (-16 Mt) to 31 Mt, while the decline in met coal exports was less pronounced at 4% (-2 Mt) to 57 Mt. Because both export volume and market prices decreased in 2014, revenue from US coal exports declined significantly from USD 11.2 billion in 2013 to USD 8.5 billion in 2014; 71% of total revenue was generated by met coal exports.

The most important export destination for coal exported from the United States remains Europe. In 2014, exports of thermal coal to Europe declined substantially because of decreasing coal demand there and competition from other exporting countries such as Russia and Colombia, which benefit from the strong dollar. Similarly, met coal exports to Asia decreased in 2014 because of weakened competitiveness of US producers in comparison with other countries, whose currency depreciated against the dollar.

Figure 2.3 Development of United States exports of thermal (left) and met coal (right), 2000-14

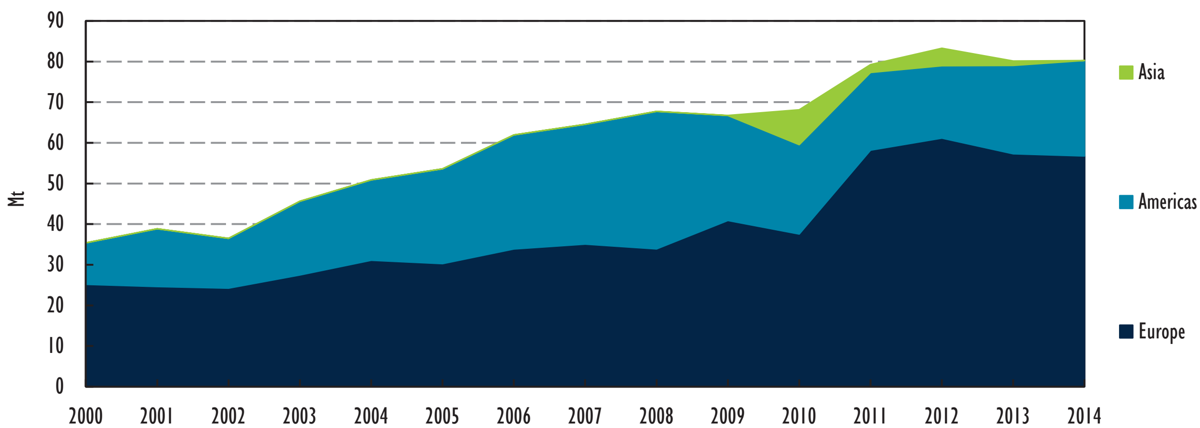


Source: IHS Energy (2015), *Coal McCloskey Price and Statistical Data*, https://connect.ihs.com/industry/coal.

Colombia

Colombian exports in 2014 remained unchanged at 80 Mt compared with 2013, making it the fifth-largest coal exporter in the world. At 79 Mt, thermal coal makes up almost all of the exported Colombian coal, while met coal makes up only a very small proportion. Additionally, almost all of the coal produced in Colombia –over 90%- is exported. The main export destinations for Colombian coal are Europe and the Americas; the small quantities exported to Asia in the last years vanished in 2014.

Figure 2.4 Development of Colombian export destinations, 2000-14



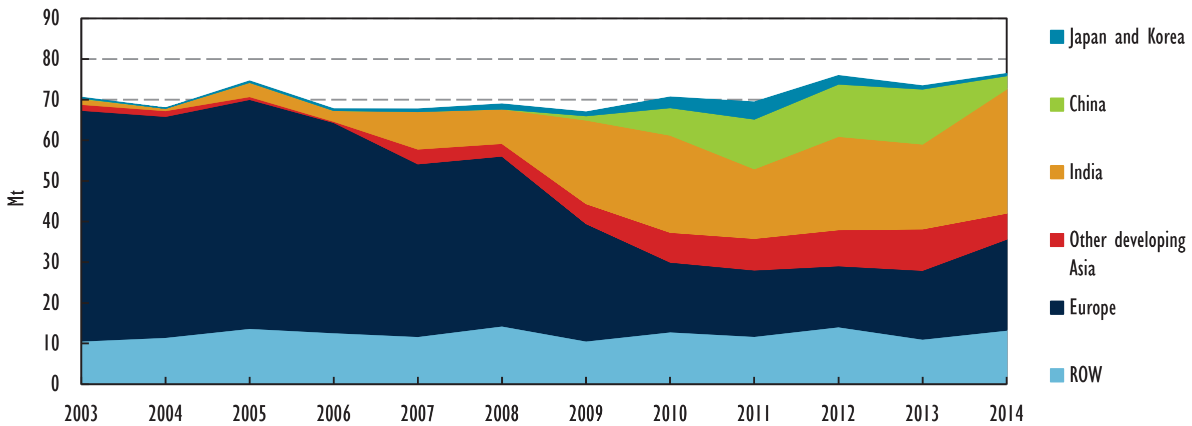
Source: IHS Energy (2015), *Coal McCloskey Price and Statistical Data*, https://connect.ihs.com/industry/coal.

Exports from Colombia in 2014 were generally lower than expected because of a new regulation that requires companies to use a less-polluting method of loading coal on ships. The US-based mining company Drummond was forced to halt exports in the first quarter of 2014 because it was not able to comply with this regulation. Colombia Natural Resources failed to export any coal at all in 2014 for the same reason.

South Africa

South African coal exports grew slightly by 2.4% (+1.8 Mt) to 76 Mt, which is a record high level. Almost all of the exported coal from South Africa is steam coal and is shipped through the Richards Bay Coal Terminal. The annual capacity of the Richards Bay Coal Terminal of 91 Mt would allow for higher amounts of exported coal; however, there are constraints in the capacity of the rail infrastructure that limited South African exports to values of 70 Mt to 75 Mt in the past years. In total 30% of South African coal production was exported in 2014; the remainder of domestic production usually has lower energy content compared with the exported coal.

Figure 2.5 Development of South African export destinations, 2003-14



Source: IHS Energy (2015), *Coal McCloskey Price and Statistical Data*, https://connect.ihs.com/industry/coal.

The majority of South African coal exports are shipped to Asia, with India being the largest customer. But due to its geographic location, South Africa also exports coal competitively to Europe. Figure 2.5 shows that the structure of South African coal exports has changed entirely over the last decade. In 2003, Europe was by far the most important market for South African exports. Due to surging Asian coal demand, particularly in India and China, as well as increasing competition in the European market from Colombia, the United States and Russia, South African coal exports shifted to Asia. In 2014, however, exports to Europe increased substantially as shipments to China dried up because of lower domestic coal demand in China and competition from Australian exports. At the same time, coal exports to India grew strongly, which can be explained by the strong growth in Indian coal demand. Preliminary data for the first half of 2015 show that exports to Turkey, Morocco and the United Arab Emirates increased substantially compared with the same time period in 2014 as shipments to China further decreased.

Canada

Coal exports from Canada decreased by 12% (-5 Mt) in 2014 and totalled 34 Mt. At 31 Mt, the vast majority of Canadian coal exports were met coal, making Canada the world's third-largest met coal exporter. The main export destinations for Canadian coal are located in Asia, with Japan and China being the largest buyers, each accounting for roughly 7 Mt of 2014 Canadian coal exports. Another 6 Mt was exported to Democratic People's Republic of Korea. Shipping to Asia is handled by coal terminals on the Canadian west coast, for example Westshore, Ridley and Neptune Bulk.

Poland

Poland is the largest coal exporter in OECD Europe. After 1991, Polish coal exports reached a peak in 1995, and since then it has been on the decline (with the exception of 2011). For the last few years, coal exports from Poland have been falling as result of the decrease in output combined with the increase in demand on the domestic market. Moreover, geographic factors contributed to the decrease in export volumes, namely the growing costs of rail transport of coal from mines located in Upper Silesia to Polish ports. Exports of coal fell by 21% (-2.2 Mt) from 10.5 Mt in 2013 to 8.3 Mt in 2014, partly due to unfavourable pricing conditions. Hard coal exports accounted for 76% of the overall Polish coal exports (6.3 Mt), whereas coking coal amounted to 2.0 Mt (24%). In 2014, the biggest importers of Polish coal in the European Union were the Czech Republic (2.5 Mt in 2014) and Germany (2.2 Mt in 2014), followed by Austria (0.8 Mt), Slovakia (0.4 Mt) and Denmark (0.3 Mt). Morocco was the biggest importer of Polish coal outside the European Union (0.5 Mt). Some 0.2 Mt of Polish coal was imported by Ukraine.

Other countries

Exports from **Mongolia** increased slightly from 18 Mt in 2013 to 19 Mt in 2014, of which 10 Mt were met coal. Mongolian coal exports are primarily destined for China. Because of insufficient railway infrastructure, exports to China have to be trucked to the Chinese border. However, in 2014, the government announced investments into a large expansion project of the Mongolian railway system.

Viet Nam exported 10 Mt coal in 2014, a 22.9% (-3 Mt) decrease from 2013. Vietnamese exports went mainly to China, while small quantities were also shipped to Japan and Democratic People's Republic of Korea, and consisted almost entirely of anthracite[1]. Coal exports from Viet Nam have been decreasing since 2009 because of increasing domestic coal demand.

Mozambique, where one of the world's largest remaining undeveloped coal regions can be found, exported 4.6 Mt in 2014, up roughly 1 Mt from 2013. On 30th November 2015, Vale completed the first trial shipment of coal from the new deepwater port at Nacala.

Importers

China

After years of tremendous growth, Chinese coal imports in 2014 declined for the first time since 2008. Compared with 2013, imports to China fell by 10.2% (-35 Mt) to 305 Mt. Despite this decrease, China remained the largest coal importer in the world, accounting for 21% of total global coal imports. Roughly 80% of Chinese coal imports in 2014 consisted of steam coal. Imports of steam coal declined substantially by 8% (-22 Mt), and imports of met coal dropped by 17% (-13 Mt).

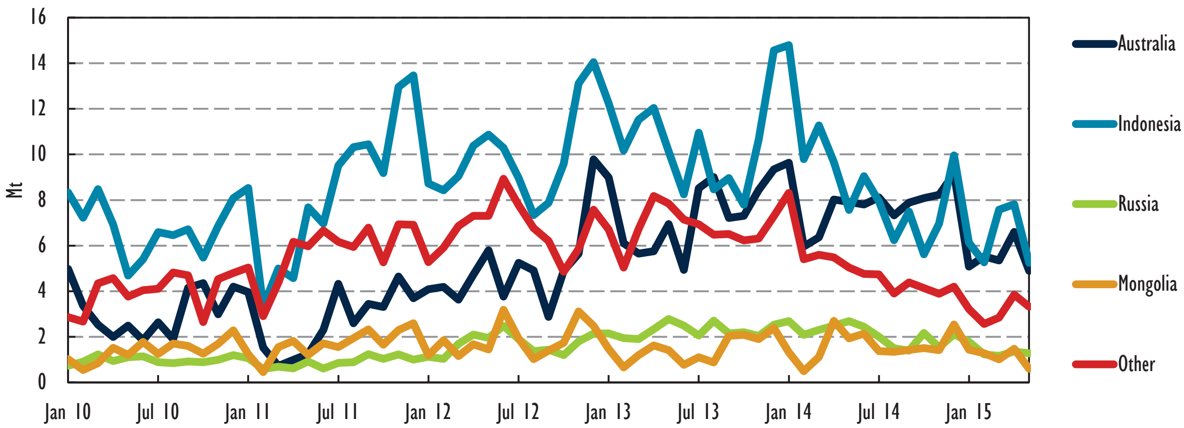
The primary supplier of Chinese coal imports in 2014 remained Indonesia; it was the origin of roughly 40% (119 Mt) of total Chinese imports. However, imports from Indonesia declined by 14% in 2014

[1] Anthracite is classified as steam (or thermal) coal in this Report.

while Australian imports continued to gain in importance and accounted for over 30% of coal imported to China. Compared with 2013, imports from Australia grew by 7% to a total of 95 Mt. Australia is also the primary supplier of Chinese met coal imports, followed by Mongolia.

The decline in Chinese coal imports can be explained by three developments. First, lower domestic demand dampened the need for imported coal. Second, the Chinese government reintroduced import taxes, which include for example a 6% tax on thermal coal imports from Russia and South Africa. And third, China imposed a limit on coal imports by the power sector in order to reduce oversupply in the domestic coal market. The regulatory pressure put on Chinese coal imports by the government continued in 2015 as a new quality control for coal was introduced in January. According to the new law, imported coal has to meet certain minimum quality standards in terms of ash, sulphur content, and especially trace elements such as chlorine, mercury and arsenic. There are controversies, as only Chinese quality tests are accepted and it is not completely clear if the same limits are also applied to domestic coal.

Figure 2.6 Evolution of monthly Chinese coal imports, 2010-15



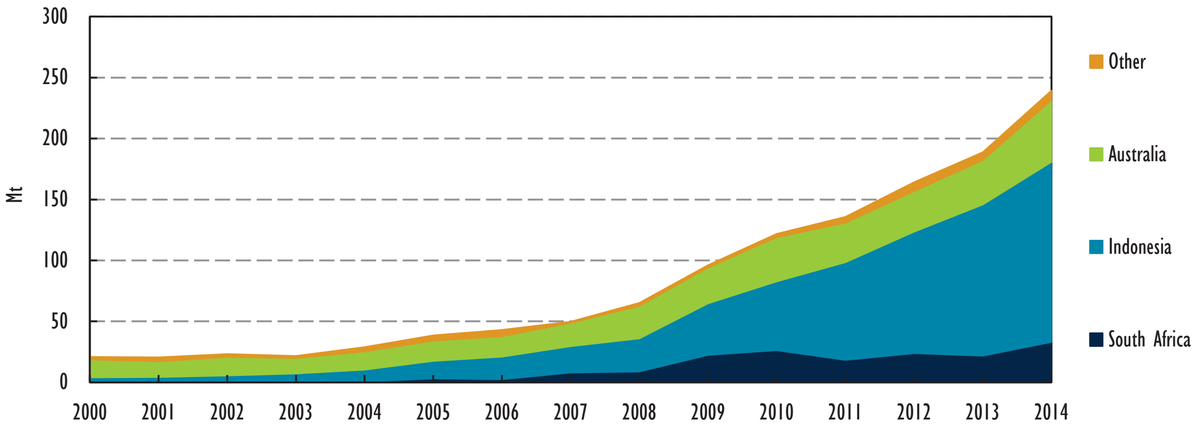
Source: IHS Energy (2015), *Coal McCloskey Price and Statistical Data*, https://connect.ihs.com/industry/coal.

India

Coal imports to India increased massively by 26.8% (+51 Mt) in 2014. With a total quantity of 239 Mt of imported coal, India thereby surpassed Japan as the second-largest coal importer in the world for the first time. The strong growth can be attributed to thermal coal imports, which increased by 28.5% (+42 Mt) and account for almost 80% of total 2014 Indian imports, as well as to met coal imports, which grew by 21% (+9 Mt).

With a share of 66% (184 Mt) in total imports, the largest share of Indian coal imports by far was provided by Indonesia. However, relative growth in 2014 was stronger for coal imports from South Africa, with a gain of 52% (11 Mt), and Australia, up by 39% (+14 Mt). This indicates that Indian buyers shifted their focus increasingly to the higher calorific value coal provided by these two countries. Coal imports from South Africa consisted entirely of steam coal, while Australia provided primarily met coal. Generally the strong increase in 2014 Indian coal imports was a result of higher domestic coal demand in combination with legal and logistical constraints that limit growth of domestic coal production.

Figure 2.7 Evolution of yearly Indian coal imports, 2010-15



Source: IHS Energy (2015), *Coal McCloskey Price and Statistical Data*, https://connect.ihs.com/industry/coal.

Japan

Japan does not have significant domestic economical coal resources and is therefore dependent on imports to meet coal demand. In 2014, Japanese coal imports totalled 188 Mt, a slight decrease of 4% (-8 Mt) compared with 2013, making Japan the third-largest coal importer in the world. Imports of thermal coal declined by 3.4% (-5 Mt) and imports of met coal fell by 5.9% (-3 Mt) in 2014.

Australia is by far Japan's largest coal supplier with a share of 63% in total Japanese imports. Indonesia follows with a share of 19%, and Russia is next with 8%. Japanese power plants typically use high calorific value coal and therefore prefer Australian coal over imports from Indonesia. Additionally, Japanese importers value the price stability of long-term contracts and the quality consistency provided by Australian exporters. On the other hand, in order to diversify procurement sources, they are also purchasing Indonesian coal. There have been discussions for a long time about renovating old plants to facilitate usage of lower-rank coal in order to lower average coal purchasing costs.

Korea

Korea has only minimal domestic coal reserves and therefore relies on imports. In 2014, Korean coal imports increased slightly by 3.5% (+4 Mt) to 131 Mt. This growth stemmed mainly from increases in met coal imports by 12% (+4 Mt) to a total amount of 34 Mt. The largest supplier of Korean coal imports is Australia, accounting for 42% of total imports, followed by Indonesia and Russia.

In July 2014, the Korean government introduced an import tax on coal, which favours coal with higher calorific values. One year later the import tax was raised. However, the impact on Korean coal imports has been limited until now, as some of the Korean power plants are suitable for using coal with a low calorific value.

Poland

Imports of coal to Poland were 10.3 Mt, falling by 0.2 Mt year-on-year. Coking coal accounts for 77% of overall import volume (7.9 Mt), whereas the remaining 23% is hard coal (2.4 Mt). The biggest exporter of coal to Poland is Russia (6.5 Mt), followed by Australia (1.2 Mt), the Czech Republic (1.4 Mt), the United States (0.4 Mt), Ukraine (0.3 Mt), Chile (0.1 Mt), Colombia (0.1 Mt) and others

(0.3 Mt). Coal supplies to Poland from the neighbouring Czech Republic are explained mainly by quality issues (coking coal) and seasonality. Coal is transported into Poland by land (mainly by rail through the Braniewo-Mamonowo Poland-Russia cross-border rail link; the Terespol-Brest Poland-Belarus border crossing; the Hrubieszów-Izow Poland-Ukraine border crossing; and the Poland-Czech Republic border crossings), as well as by sea (dry bulk/coal terminals in Gdańsk, Gdynia, Szczecin and Świnoujście).

Poland's coal imports have been a salient feature of the domestic market for some time. Before its accession to the European Union in 2004, Poland managed to impose quotas on coal imports coming from Russia and the Czech Republic, resorting to duties and border taxes. In the following years, as domestic demand for energy coal increased (with binding coal export agreements in place), the demand gap on the market was filled by imports from abroad. Consequently, Poland became a net importer of coal in 2008 for the first time in history. A large increase of domestic coal stocks in 2012-13 to the tune of 7-8 Mt (this time, stemming from oversupply of Polish coal) reduced the volume of imports, though it still averaged well above 10 Mt. The first half of 2015 saw a steady drop in domestic coal stocks due to the pricing policy of mining companies, which pushed some volumes of coal imports out of the market. Polish coal exports diminished, partly due to the oversupply on the global market and the unprofitability of seaborne export of coal.

OECD Europe

Aggregated coal imports by OECD Europe increased slightly by 1.4% (+4 Mt) to a total quantity of 281 Mt in 2014. Imports of met coal grew strongly by 15.8% (+8 Mt) in OECD Europe, while steam coal imports declined slightly by 2.1% (-5 Mt). Small quantities of additional lignite imports account for the balance.

Germany maintained its position as the largest coal importer in OECD Europe with 57 Mt of total 2014 imports, up 4.9% (3 Mt) compared with 2013. The primary suppliers of German coal imports were Russia with 13 Mt, the United States with 11 Mt and Colombia with 7 Mt. Significant amounts of steam coal were also imported from South Africa (5 Mt) and Poland (2 Mt). Roughly 0.5 Mt of steam coal were imported from Norway. The largest suppliers of met coal were Australia and the United States.

Coal imports of the **United Kingdom** declined by 17.7% (-9 Mt) in 2014 to 41 Mt in total. This sharp decline was mainly driven by lower electricity generation in coal-fired power plants. The largest suppliers of imports to the United Kingdom were Russia (16 Mt), the United States (10 Mt) and Colombia (9 Mt).

Turkey imported 30 Mt of coal in 2014, an increase of 12% (3 Mt) over 2013. The increase consisted primarily of steam coal imports, which grew by 13% (3 Mt) to a total of 24 Mt. Important suppliers of coal to Turkey are Russia and Colombia, which each account for roughly 9 Mt of imports, as well as South Africa and the United States with shipments of roughly 4 Mt each.

Italian coal imports remained unchanged at 20 Mt in 2014. Coal imports in **Spain** grew by 20% (+3 Mt) to 16 Mt. Spanish steam coal imports grew more strongly by 32.6% (+4 Mt), while met coal imports declined slightly (-1 Mt).

Other countries

Chinese Taipei increased coal imports slightly by 1.7% (+1 Mt) to 67 Mt and was the world's fifth-largest coal importer in 2014. At 60 Mt, the bulk of these imports came from steam coal, while met coal imports accounted for 7 Mt. The main import sources are Australia, which supplies 44% of total coal imports to Chinese Taipei, and Indonesia, which supplies 41%.

Russia imported 25 Mt of coal in 2014, a decrease of 13.9% (-4 Mt) compared with 2013. The imported coal comes overland from Kazakhstan, a legacy of the former Soviet Union, which built some power plants near the border designed for Kazakh coal.

Malaysian coal imports in 2014 increased by 7% (+2 Mt) to a total amount of 24 Mt. The imported coal consisted entirely of thermal coal and was supplied mainly by Indonesia, Australia and South Africa.

Brazil increased coal imports by 12.8% (+2 Mt) to 20 Mt in 2014. More than half of the imports are met coal, making Brazil the world's fifth-largest met coal importer. The main suppliers for Brazilian coal imports were the United States, Colombia and Australia.

Coal trading

Although there were no significant changes in trade patterns during the last 12 months, there are a few developments to be noted.

In the United States, despite the increased utilisation of spot purchases, these are still a minority, with long-term contracts (more than three years) making up approximately 10% and short-term contracts (quarterly to less than three years) about 75% of total trade volumes. It is important to note that this is how contracts are designated in the United States. In other places, "long-term" is any contract over one year. Domestic coal sales are generally not linked to international indices.

In China, not only the largest but also the fastest-evolving market in the world, a major development was the introduction of new legislation on coal quality in 2014 entering into effect 1 January 2015. The new legislation set limits for heating value, as well as content of ash, sulphur, phosphorus, chlorine, arsenic and mercury. Different limits are set for coal depending on whether it is used for power, metallurgy or chemicals and also depending on whether it will be moved more or less than 600 kilometres. Regardless of how stringent the limits are, the analyses have often delayed deliveries, and discrepancies between the results of analyses from Chinese and non-Chinese labs have been frequent.

The import thermal market is dominated by spot transactions, and coastal South China is still the clearing market, i.e. the main place where price is formed, in the Pacific Basin, especially for low calorific coal. Imports mainly from Indonesia and Australia compete with domestic seaborne trade, and are sold at the prevailing spot price for the day when the deal was done or even at the prevailing spot price for the day that coal arrives at the port.

Imported coking coal in China is mostly bought on a spot basis, most of the times with volumes agreed when the deal is done and prices determined when the coal arrives at its destination. There are cases, however, in which prices are determined when the deal is done, and even some long-term contracts longer than a year, but this is not frequent, and even in these cases, prices are fixed at the prevailing spot price when coal arrives at the destination port.

Regarding domestic coal trading, a major move occurred during the first quarter of 2015, when the large miners, i.e. Shenhua and others, moved to quarterly pricing, with price mainly determined based on the Bohai index, which is still the main price reference, together with the regional China Coal Price Index (CCPI) published by China National Coal Association and China Coal Transport and Distribution Association. Other common indices are the China-Taiyuan Coal Transaction Price Index (CTPI) produced by the China-Taiyuan Coal Transaction Centre for coal in Shanxi, and the Ordos Steam Coal Price Index (OSPI), published by the Inner Mongolia Coal Exchange Centre for coal in Inner Mongolia.

In India, the Coal Mines Act was amended in mid-March 2015. The amendment includes the opportunity for commercial mining by the private and state sectors. Until now, commercial coal trading has been the monopoly of the central government, exercised through Coal India Limited. Under the new act, the state governments and private players could mine and sell directly to end users. This would invigorate the Indian coal market, but actual implementation must be monitored to analyse how it is done and the possible consequences.

API 2[2], price index for coal of 6 000 kcal/kg of net calorific value arriving at Amsterdam, Antwerp Rotterdam ports, and the most popular coal index worldwide, will be assessed changing the time window from 90 days to two months ahead.

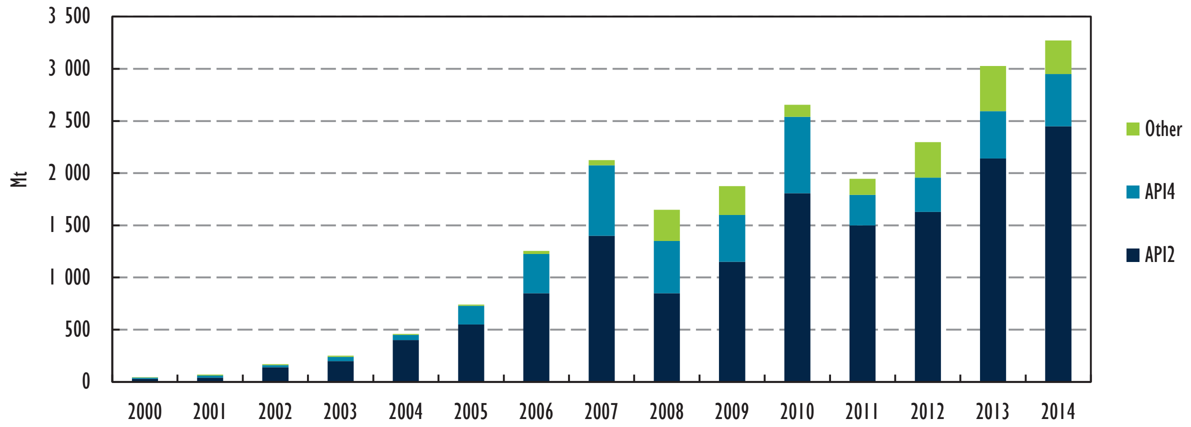
Coal derivatives

Since falling in 2011, the volume of coal derivatives has not stopped growing. In 2014, the volume was close to 3.5 billion, with the majority of it being around 2.5 billion API 2-based derivatives. The market is maturing, and whereas when the International Energy Agency (IEA) published the *Medium-Term Coal Market Report 2011* (IEA 2011), cleared coal derivatives accounted for only around one-third of the total, now they are more than 95% of the volume of derivatives. Another change is in the use of different instruments, with option volumes growing steadily, and currently representing more than 15% of the derivative volume. GlobalCoal, the trading coal platform, announced the launch of Atlantic Coal Futures in 2015, the first coal futures contract with physical settlement, which is 6 000 kilocalories per kilogramme (kcal/kg) coal in Rotterdam. With new financial instruments, the players have more tools to hedge and arbitrage, providing wider opportunities and encouraging greater liquidity.

In China, after the launch of the first domestic thermal coal swaps in summer 2014, the take-off is going slowly, even with a few of the big miners turning to this market for hedging risks. The increasing number of available price indices for different regions and coal types, the development of derivative markets and the creation of new tools for arbitrage and hedging will further develop the coal market in China, with future prices exerting a bigger influence as their trade volume increases.

[2] Published through Argus/McCloskey's Coal Price Index services, API 2 is the benchmark price reference for coal imported into northwest Europe.

Figure 2.8 Development of trade volumes for coal derivatives, 2000-14



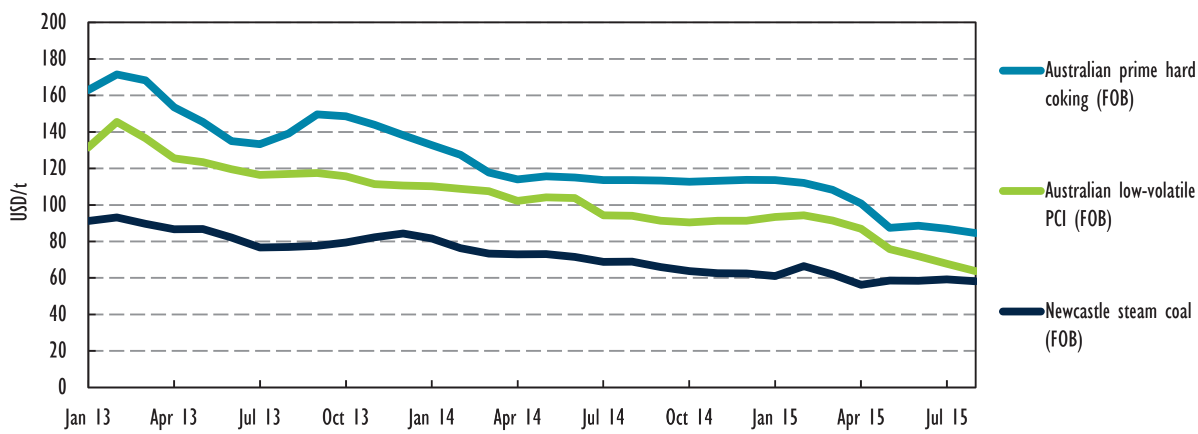
Note: The API 4 index is the benchmark price reference for coal exported out of South Africa's Richards Bay terminal and is used in physical and over-the-counter (OTC) contracts. Published through Argus/McCloskey's Coal Price Index service.

Source: IHS Energy (2015), *Coal McCloskey Price and Statistical Data*, https://connect.ihs.com/industry/coal.

Prices

Coal is a heterogeneous product that is traded in a variety of different types and classifications. Coal prices therefore differ not only among regions but also in terms of coal quality. Figure 2.9 illustrates this by comparing the price development of three price markers for different coal types exported from Australia: prime hard coking coal, low-volatile pulverised coal injection (PCI) and steam coal. All price curves show a general downward trend between 2013 and 2015 as the market has been oversupplied regardless of the coal type. However, the specific price development is different because market dynamics vary among coal types. The price decline over the depicted time period was for example less pronounced for Australian steam coal with a drop of 36% compared with prime hard coking coal, which decreased by 38%, and low-volatile PCI, down by 42%. This difference can be explained by lower-than-expected Chinese steel production growth, which pushed down prices for PCI and coking coal in Australia.

Figure 2.9 Development of coal marker prices for different types of coal, 2013-15



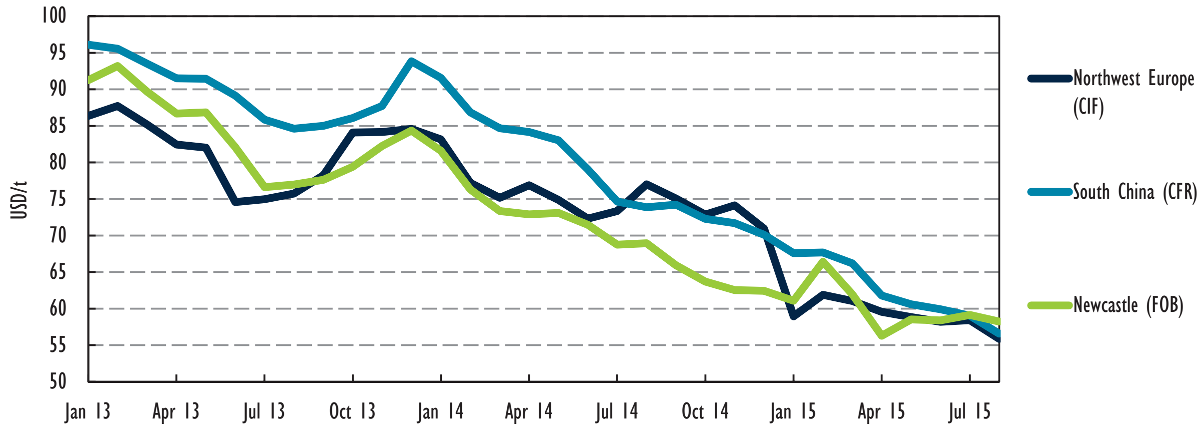
Note: FOB = free on board.

Source: IHS Energy (2015), *Coal McCloskey Price and Statistical Data*, https://connect.ihs.com/industry/coal.

Seaborne thermal coal prices and regional arbitrage

International prices for seaborne traded thermal coal in the European, Asian and Australian markets continued to decline in 2014 and 2015, following the general downward trend that started in 2011 (see also Box 2.1).

Figure 2.10 Thermal coal price markers in Europe, China and Australia, 2013-15



Source: IHS Energy (2015), *Coal McCloskey Price and Statistical Data*, https://connect.ihs.com/industry/coal.

As shown in Figure 2.10, European thermal coal prices, as indicated by the Amsterdam Rotterdam Antwerp (ARA) cost, insurance and freight (CIF) price index, dropped from USD 83/t in January 2014 to USD 56/t in August 2015, a decrease of 33%. The development of Chinese and Australian thermal coal price markers was similar as the Newcastle FOB index declined from USD 81/t to USD 58/t, or by 29%, and the cost and freight (CFR) price index for South China fell from USD 92/t to USD 57/t, or by 38%, over the same time period. International coal price levels were thereby even lower than the prices during the financial crisis in 2009.

Box 2.1 Why do coal price declines last so long?

The price of thermal coal is at its lowest level since the 2008 recession after five years of an almost continuous decline. Simplistic theories fail to explain this long decline, as there have been many diverse circumstances pushing prices down during this period. A price spike began in December 2010 (Figure 2.11) when severe rains and floods in Australia affected mines and ports and halted coal shipping from Queensland's ports, the origin of half of coking coal exports in the world and also a notable thermal exporter, for three months. Unsurprisingly, coking prices jumped, and the effect carried over to thermal coal.

The Arab Spring, the Great East Japan Earthquake and the subsequent phase-out of German nuclear plants were other events that occurred in early 2011, which although less important, were also bullish for coal prices. So when prices started to go down in 2011, it looked like a normal correction after three unexpected bullish events. No one seemed to hear the news coming from China about the large-scale oversupply there, resulting from the coal rush during the first decade of this century. To summarise this rush in one figure, investment in coal mining capacity during the 11th Chinese five-year plan (2006-10) was 2.5 times higher than it had been throughout the entire history of the People's Republic of China. At the same time, driven by high prices and strong demand and expectations of ongoing urbanisation and industrialisation, (i.e. larger imports, in China), expansions took place in the main exporting countries as no producer wanted to miss the Chinese surge.

Box 2.1 Why do coal price declines last so long? (continued)

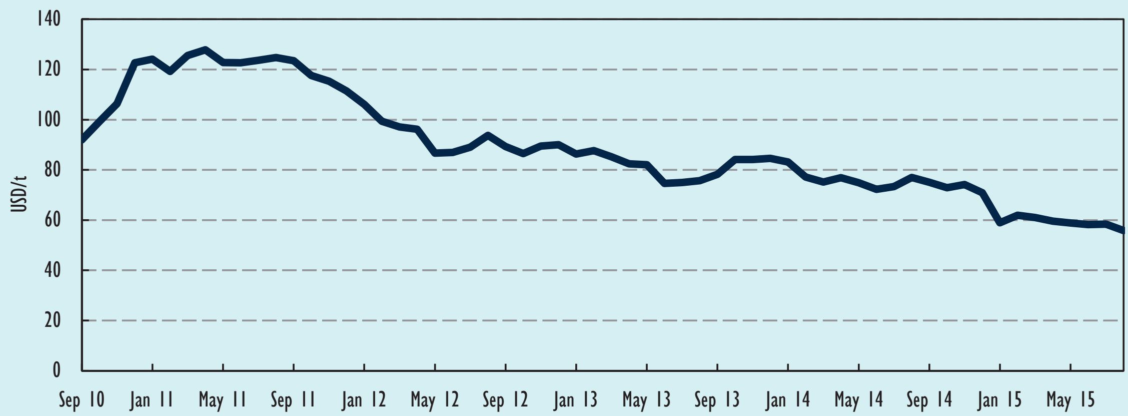
On top of that, in 2012, US coal generation declined by more than 200 terawatt hours compared with 2011. The mildest winter in decades together with the sustained increasing shale gas production brought gas prices below USD 2 per million British thermal units (Henry Hub), pushing coal out of the domestic market, and sending some tens of millions of tonnes of coal to look for a place in the foreign markets.

At that time, many producers were facing losses, but the expected supply discipline, i.e. production cuts, did not occur. In Australia, producers had signed long-term take-or-pay contracts to ensure the availability of rails and ports services to export. These companies needed to produce to minimise losses. They also needed to honour export contracts entered into with Asian customers. In other places, financial liabilities required some producers to have cash to avoid bankruptcy. Therefore, there was no price recovery, but just the opposite.

The companies started cost cutting, so the cash cost curve was pushed downward, and sometimes the cost reduction was made through increasing production to reduce unit cost. This meant more coal in the market and higher oversupply. There were also persistent low freight rates and important debottlenecking in the Chinese rail system, which did not help a price recovery either.

When most analysts thought prices were on the floor, the currency of the main coal exporters depreciated versus the US dollar, pushing prices further down. Unexpected low oil prices, an important component of mining and transportation costs of coal, lowered the price floor again. If the Chinese economy cools down further, coal markets could become even more depressed. In the meantime, the very few bullish events, such as a few disruptions in Colombia – strikes and problems with coal loading in ports – the recent surge in Indian imports and Glencore's attempt to hold back production, are unlikely to offset the chain of bearish events.

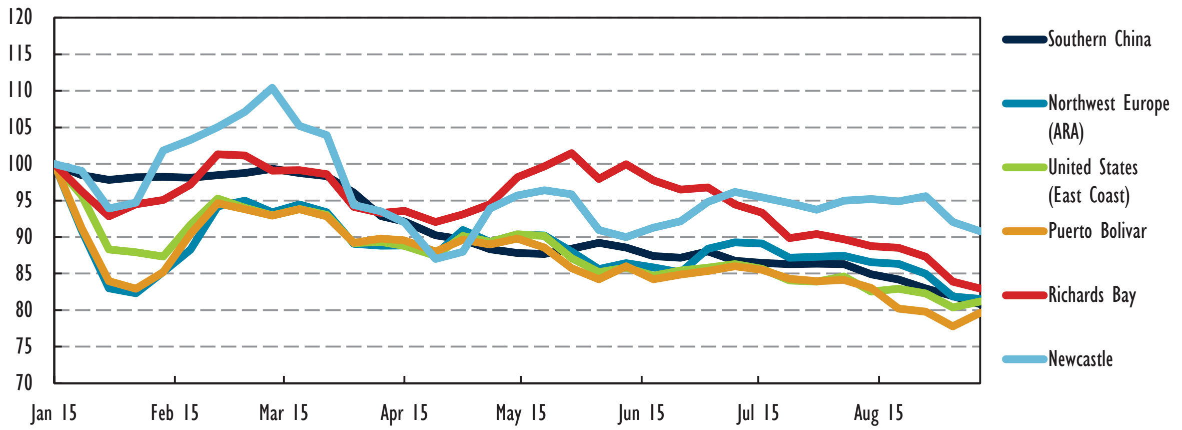
Figure 2.11 Decline of thermal coal prices in northwest Europe (ARA CIF), 2010-15



Source: IHS Energy (2015), *Coal McCloskey Price and Statistical Data*, https://connect.ihs.com/industry/coal.

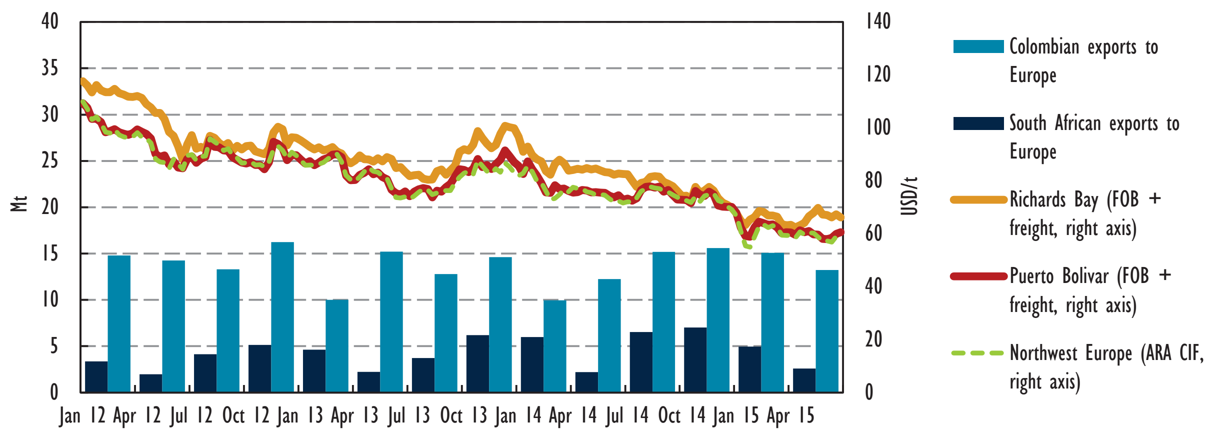
Traditionally, international steam coal markets consisted of two broad geographical sites: the Atlantic Basin and the Pacific Basin, with Russia and South Africa supply both depending on prices. More recently, lower freight rates, increased demand in Asia, and increasing exports from Colombia and the United States coupled with weak European demand all have strengthened links between the Atlantic and Pacific Basins, allowing coal traders to benefit from regional arbitrage. Additionally, coal consumers have arbitrage opportunities by buying either domestic coal or imported coal based on current price levels. As a result, price movements are similar in international coal markets because regional price differences are quickly balanced by changes in trade flows. Figure 2.12 illustrates this by comparing the indexed price development of thermal coal price markers in South Africa, Southern China, Australia, Europe, US East Coast and Colombia in 2015. The graph shows that price divergence among the markets happens but is usually followed by a period of price convergence as arbitrage activity balances the international markets unless structural changes occur.

Figure 2.12 Indexed price development of thermal coal price markers in different markets in 2015



Source: IHS Energy (2015), *Coal McCloskey Price and Statistical Data*, https://connect.ihs.com/industry/coal.

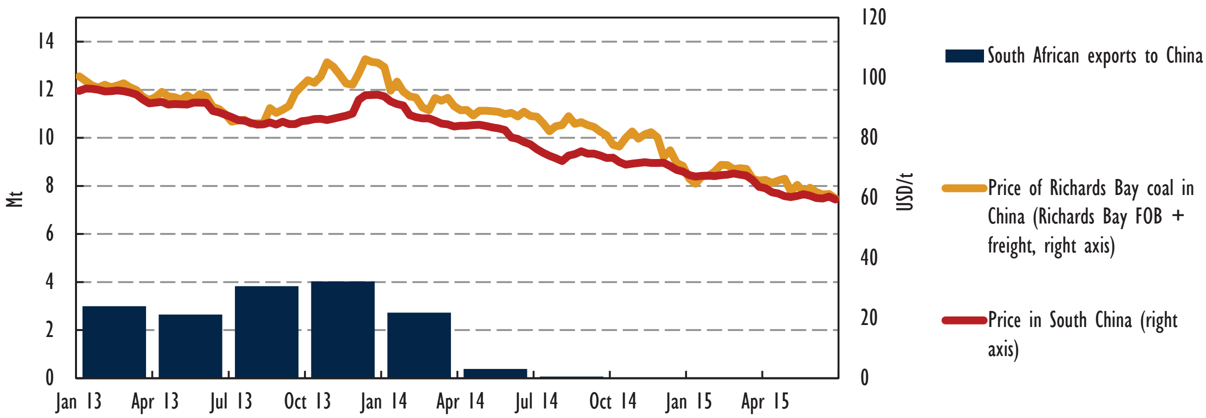
Figure 2.13 Quarterly Colombian and South African exports to Europe and thermal coal prices in Europe compared with Colombian and South African supply costs in Europe, 2012-15



Source: IHS Energy (2015), *Coal McCloskey Price and Statistical Data*, https://connect.ihs.com/industry/coal.

Countries such as South Africa and Russia, swing suppliers whose geographical location allows them to export coal to the Asian and European markets, play an important role in international coal trade because they connect the Atlantic Basin with the Pacific Basin. Figure 2.13 shows the quarterly export volumes from Colombia and South Africa to Europe as well as steam coal prices in the relevant markets in order to further analyse regional arbitrage in international coal markets. The graph shows that European coal prices are mainly determined by the sum of the price in Colombia and the freight costs to Europe, because Colombia is the main supplier of thermal coal in Europe. Additionally, the price curves indicate that South African coal exporters start to ship additional coal to Europe when spreads between the European prices and the South African supply costs to Europe, determined by the prices in Richards Bay and freight costs to Europe, are low. If spreads are high, South African exporters prefer other destinations in the Asian coal market.

Figure 2.14 Quarterly exports from South Africa to China and thermal coal prices in China compared with South African supply costs in China, 2013-15



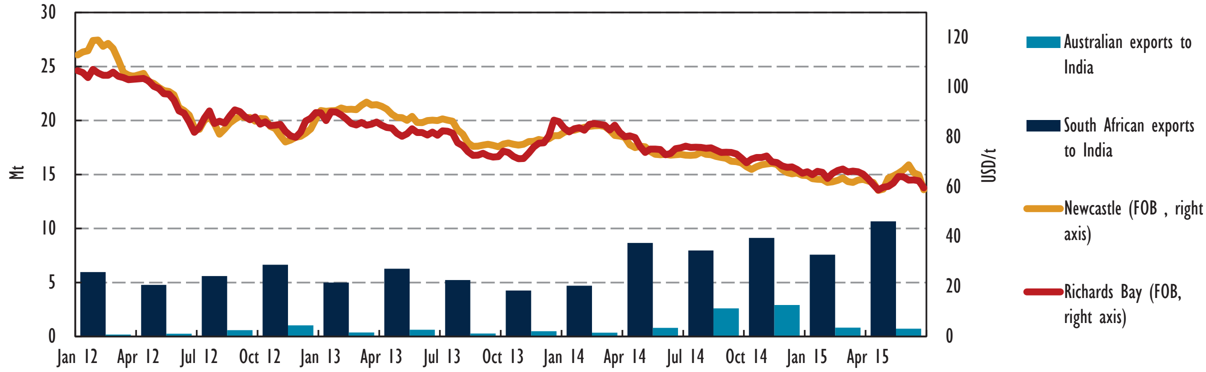
Source: IHS Energy (2015), *Coal McCloskey Price and Statistical Data*, https://connect.ihs.com/industry/coal.

Figure 2.14 additionally shows the development of thermal coal exports from South Africa to China as well as coal prices in China and prices of South African coal in China.

Chinese coal prices were aligned to South African coal prices in the first half of 2013. Starting in the second half of 2013, prices in South Africa increased compared with China. After this price spread emerged, South African exporters started to reduce coal shipments to China and stopped exporting to China completely after a time period of some months. Figure 2.14 therefore shows how market participants react to price changes. The time gap between price divergence and adjustment of trade flows can be explained by coal deliveries that had already been contracted before the change in prices occurred.

The drop in South African exports to China shown in Figure 2.14 raises the question of which other export destination attracted coal-exporting companies in South Africa. This question can be answered with Figure 2.15, which shows exports from South Africa and Australia to India as well as thermal coal prices in South Africa and Australia. It is evident that when South African exports to China stopped in the second quarter of 2014, exports to India increased. Apparently South African coal exporters could sell their product at a higher price to India, where the strong growth in coal consumption led to higher import needs. Additionally, Figure 2.15 shows that despite the great distance, Australian exports to India start to rise when prices in Newcastle are lower than prices in Richards Bay. Indeed, prices reflect market dynamics, so this story can be perceived as Australia exporting to India when India's demand for coal increased and China's fell.

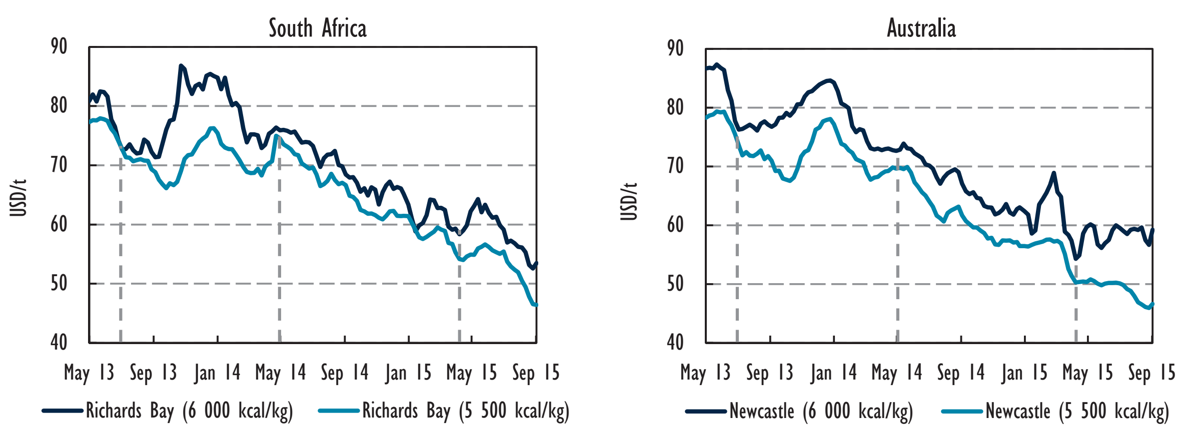
Figure 2.15 Quarterly exports from South Africa and Australia to India and thermal coal prices in South Africa and Australia, 2012-15



Source: IHS Energy (2015), *Coal McCloskey Price and Statistical Data*, https://connect.ihs.com/industry/coal.

The decrease of thermal coal prices in 2014 and 2015 can be observed irrespective of the coal quality. Figure 2.16 illustrates this by comparing prices for different coal qualities in South Africa and Australia. Prices have been standardised to an energy content of 6 000 kcal/kg. Besides the price decline, it can be seen that despite the standardisation, prices for coal with higher calorific values are higher because buyers are willing to pay a premium for coal with higher energy content. The graph also shows that the spreads between the different coal qualities follow similar patterns in South Africa and Australia. This demonstrates again that international coal markets are very competitive, because arbitrage does not only happen between locations but also between different coal qualities. Quality arbitrage can be achieved by blending different types of coal to get a product that meets the quality requirements of the consumer. However, there are limitations to quality arbitrage, because the blending process creates additional costs and can lead to problems in the operation of boilers. There are also additional costs of storing different coal qualities on stockpiles.

Figure 2.16 Price markers of different thermal coal qualities in South Africa and Australia, standardised to an energy content of 6 000 kcal/kg, 2013-15

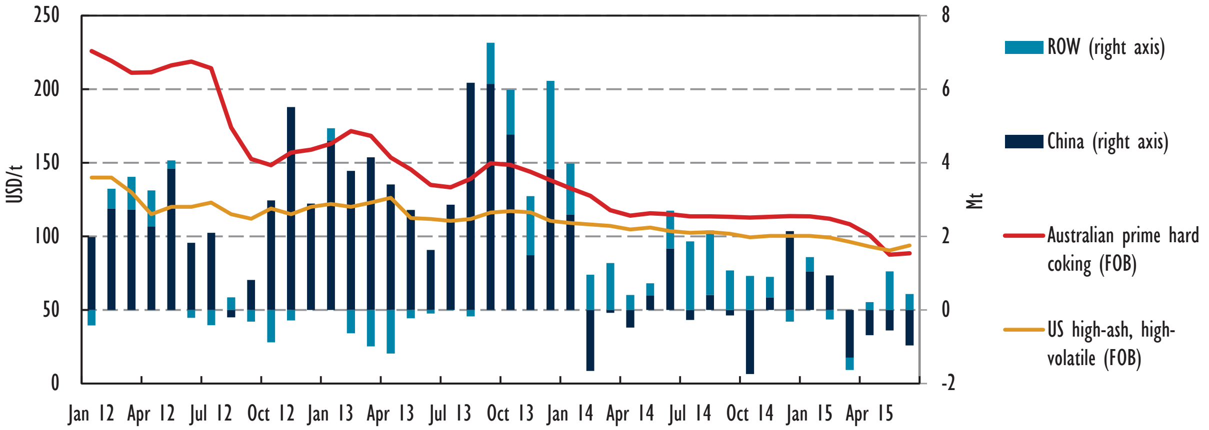


Source: IHS Energy (2015), *Coal McCloskey Price and Statistical Data*, https://connect.ihs.com/industry/coal.

Seaborne met coal prices

The trend of decreasing met coal prices continued in 2014 and the first half of 2015. In 2015, prices of Australian prime hard coking coal and US high-ash, high-volatile coking coal fell below USD 100/t, which is a very sharp decline compared with the record high levels above USD 300/t in 2011 (see Figure 2.17).

Figure 2.17 Development of met coal prices and monthly year-on-year differences in BFI production, 2012-15



Note: BFI = blast furnace iron.

Source: World Steel Association (2012-2015), *Crude Steel Production*, www.worldsteel.org/statistics/BFI-production.html; IHS Energy (2015), *Coal McCloskey Price and Statistical Data*, https://connect.ihs.com/industry/coal.

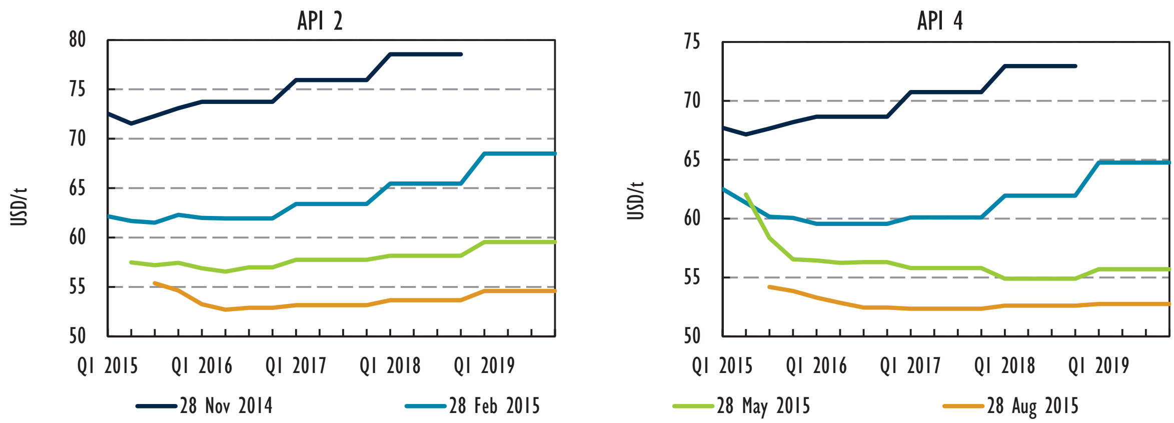
The price decrease was particularly pronounced for Australian met coal, with a decline of 14% in 2014 and another 24% between January and July 2015. Met coal prices in the United States, on the other hand, decreased by only 8% in 2014 and 14% in the first half of 2015. As a result, the price premium for Australian prime hard coal over US high-ash, high-volatile coal disappeared in 2015.

The continued decline of met coal prices in 2014 and 2015 can be explained by a substantial slowdown in China in growth of BFI production, which is the primary end use of metallurgical coal. Chinese BFI production grew by only 0.4% in 2014, which is significantly lower in comparison with the growth rate of 6.9% in 2013. Production data for 2015 indicate a continued stagnation in BFI production growth in China. In the rest of the world, BFI production grew by 2.5% in 2014. In addition to slow growth on the demand side, the global met coal market continues to be oversupplied, because the record high prices in 2011 triggered substantial investments into new mining capacity. These new mines came online over the last years and led to a substantial intensification of competition among met coal exporters. The strong decline in prices of Australian prime hard coking coal suggests that oversupply is particularly pronounced for high-quality coal.

Coal forward prices

With exception of a small backwardation at the end of 2013 and beginning of 2014 due to issues related to Colombian supply, coal price forward curves have been in contango since the *Medium-Term Coal Market Report 2011* (IEA 2011). However, as shown in Figure 2.18, backwardation is the new normal for API 4, and even API 2 has been in backwardation from May 2015 onward. Weak expectations driven by exogenous variables, such as lower economic growth in some of the key consumers, or endogenous variables, such as coal output increase in Coal India Limited and hence, less need for Indian imports, is probably underpinning this trend. Chinese currency depreciation in August 2015 drove future prices further down. In order to give the magnitude of the drop, in May 2014, the API 4 call for 2018 was traded at USD 87/t. As seen in Figure 2.18, in August 2015, just over a year later, the API 4 call for 2018 was traded at USD 52/t.

Figure 2.18 Forward curves of API 2 (left) and API 4 (right), 2013-15



Source: IHS Energy (2015), *Coal McCloskey Price and Statistical Data*, https://connect.ihs.com/industry/coal.

Coal supply costs

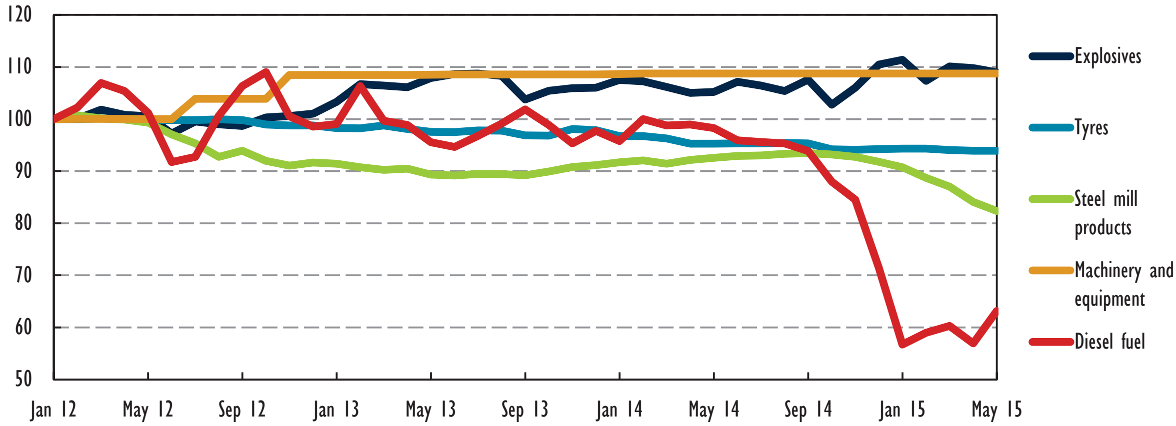
Supply costs for internationally traded coal include mining costs as well as costs for inland transport, port fees, seaborne transport, taxes and royalties. In contrast to the cost structure of oil and gas extraction, a significant part of the full costs of coal mining consists of variable costs, as coal production is less capital-intensive. Additionally, currency prices on the foreign exchange market are an important factor for the competitiveness of coal exporters participating in the international markets.

Development of input factor prices

Mining costs account for the largest proportion of total coal supply costs in most coal-exporting countries in the world. Variable mining costs, also called mining cash costs, include input factors such as materials and labour costs as well as other costs such as royalties and outside services. The detailed composition of these costs varies vastly among countries and mines, as geological conditions and the applied mining methods are different for every region and mine. However, material costs generally account for more than half of the cash costs of a coal mine. This share can be even larger when a coal-exporting country has comparatively low labour costs, which is the case for example in South Africa or Indonesia. The development of large parts of material costs in coal mining follows global price trends, as input factors such as diesel fuel, steel mill products, explosives, tyres and machinery are internationally traded. Other inputs such as electricity and water depend on national price movements.

The indexed price development of different internationally traded inputs in coal mining is depicted in Figure 2.19. It can be seen that prices for diesel fuel declined sharply in the second half of 2014, following the global price trend for crude oil. This decrease lowers mining costs, especially in opencast mines, which need a large number of vehicles running on diesel fuel to operate. Transportation costs are also affected by lower prices for oil. Prices for steel mill products also decreased significantly, by more than ten index points in the same time period. Prices of the remaining coal-mining inputs shown in Figure 2.19 remained roughly unchanged in 2014 and changed only slightly, by less than ten index points, over the depicted time period.

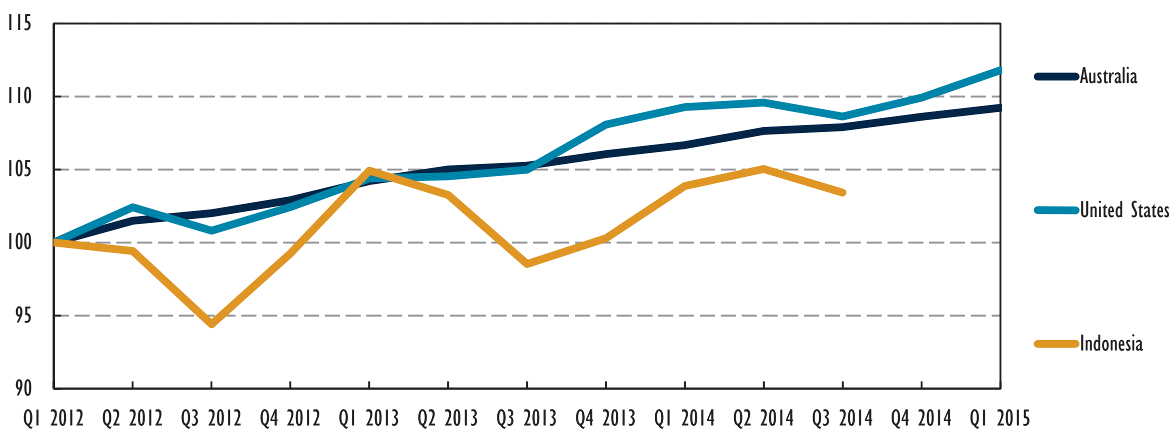
Figure 2.19 Indexed nominal price development of select commodities used in coal mining



Source: US Bureau of Labor Statistics (2015a), *Producer Price Data Commodity and Industry*, www.bls.gov/data/.

Besides materials, labour costs are an important determinant for the development of total coal-mining costs. Depending on country and mining method, labour costs typically account for 20% to 50% of mining cash cost. In highly developed countries such as the United States, Australia and Canada this share is usually significantly higher compared with coal production in emerging countries such as South Africa, Colombia and Indonesia. However, this difference is partly offset by higher labour productivity in the developed countries. Figure 2.20 shows the development of indexed real labour costs in local currencies for selected countries. The graph shows that labour costs in Australia and the United States increased by roughly 10% between 2012 and the beginning of 2015. In Indonesia the rise of labour costs was less pronounced, with a 3% increase until the end of 2014. Additionally it can be seen that labour costs tend to be far more volatile in Indonesia in comparison with Australia and the United States.

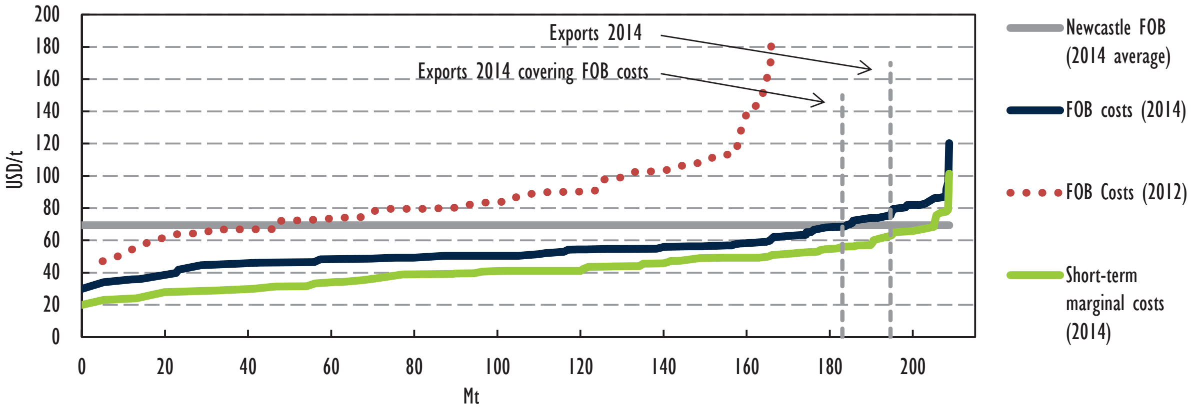
Figure 2.20 Indexed real labour cost development (in local currency) in select countries



Sources: Australian Bureau of Statistics (2015), *6345.0 Wage Price Index*, Australia, June 2014, www.abs.gov.au/ausstats/abs@.nsf/mf/6345.0/; BPS-Statistics Indonesia (2015), *Nominal Wage and Real Wage Index of Production Workers in Mining Below Supervisory Level*, www.bps.go.id/index.php/linkTabelStatis/1446; US Bureau of Labor Statistics (2015b), *Employment, Hours, and Earnings from the Current Employment Statistics Survey (National), Industry: Coal Mining (Average Hourly Earnings of all Employees)*, www.bls.gov/data/.

Australian coal producers have been rigorously cutting costs in recent years in order to adjust to declining market prices and to avoid mine closures. In 2014 this trend continued with further efforts by Australian producers to increase productivity and improve capital efficiency, which led to substantial cost savings. Figure 2.21 underlines this by showing that the majority of Australian steam coal producers in 2012 would not have been able to be profitable At the average price level of 2014. Figure 2.21 also suggests that despite the cost cuts, approximately 12 Mt of the 195 Mt steam coal exported from Australia in 2014 was sold at a loss, as supply costs were higher than the average 2014 FOB price for steam coal in Newcastle. One possible explanation for these unprofitable exports is take-or-pay contracts, which incentivise coal companies to keep producing as long as short-term marginal costs, indicated by the green line in Figure 2.21, are covered. However, it must be also stated that Figure 2.21 shows a simplified model of reality, as variations of FOB prices over the year, differences in coal qualities and contractual details are not accounted for. Additionally, not every coal producer is bound by take-or-pay contracts, and other cost components such as labour and machinery do not necessarily need to be counted as short-term marginal costs.

Figure 2.21 Development of Australian steam coal supply cost curves 2012-14 compared to export volumes and price levels 2014



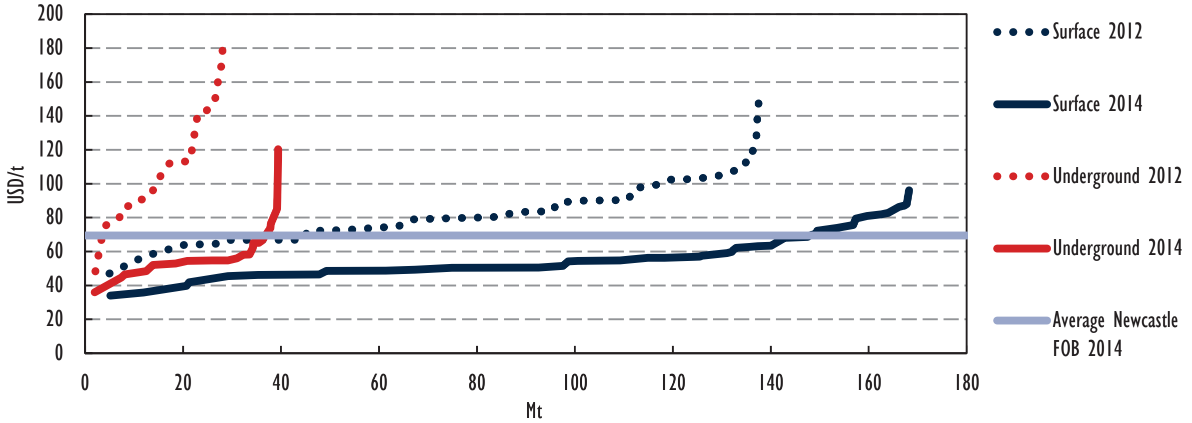
Note: Coal volumes, prices and costs are based upon a calorific value of 6 000 kcal/kg. Short-term marginal costs comprise variable production costs, processing, overburden removal and royalties. For simplification, this analysis assumes that port usage and inland transportation are based solely on long-term contracts and are therefore not part of the short-term marginal costs. FOB costs comprise short-term marginal costs and the costs of inland transportation and port usage. Royalties are assumed to increase proportionally with the production output.

Source: IEA analysis from Wood MacKenzie (2015), *Coal* (private database), accessed April 2015; IHS Energy (2015), *Coal McCloskey Price and Statistical Data*, https://connect.ihs.com/industry/coal.

The development of supply costs for Australian steam coal is further analysed in Figure 2.22. The graph shows that the decline in supply costs between 2012 and 2014 was strong for both underground and surface mining.

The difference of supply costs between underground and surface mines, however, is less pronounced in 2014. Most of the underground and surface mines would not be able to produce profitably at current coal price levels with the supply costs of 2012. It can also be seen that the continued pressure to lower production costs over the last years led to a flattening of the supply curve. This can be explained by the higher incentive that high-cost mines have to reduce costs or halt operations. It must be noted that the cost curves of 2014 do not fully reflect the sharp decline of oil prices in the recent months. It can therefore be assumed that further cost reductions are more pronounced for surface mining because of its higher sensitivity to oil prices.

Figure 2.22 Comparison of Australian steam coal supply cost curves for surface and underground mines in 2012 and 2014



Note: coal volumes, prices and costs are based upon a calorific value of 6 000 kcal/kg.

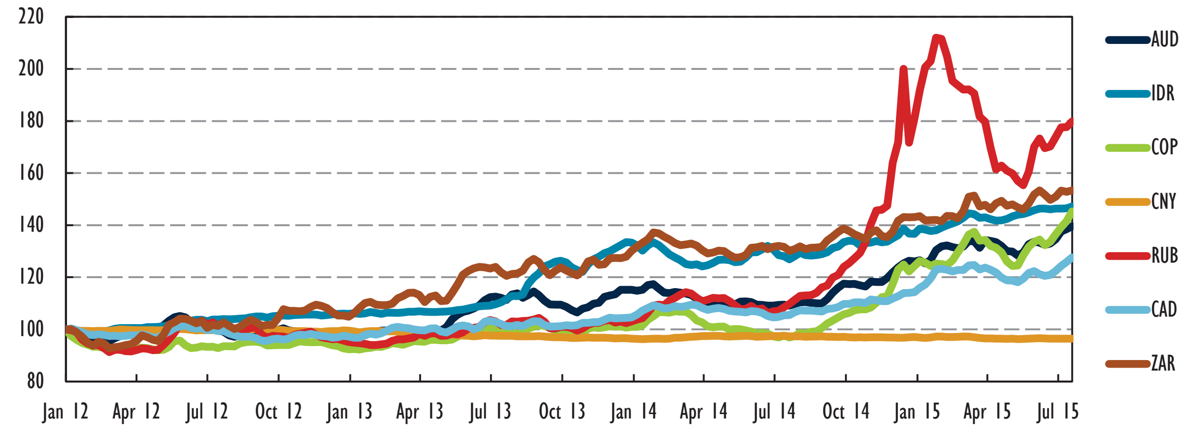
Source: IEA analysis from Wood MacKenzie (2015), *Coal* (private database), accessed April 2015; IHS Energy (2015), *Coal McCloskey Price and Statistical Data*, https://connect.ihs.com/industry/coal.

Currency exchange rates

Coal exporters mainly generate revenue streams in US dollars, as international coal trades are usually settled in US currency. However, many of the production costs such as labour costs, railway tariffs, port charges and royalties are paid in local currency. As a result, changes in currency exchange rates have a direct impact on the competitiveness of coal suppliers in the international coal market. A depreciation of the local currency against the US dollar translates into an implicit decrease in supply costs for domestic producers, while an appreciation is an implicit increase in supply costs. The effect is only partial, as imported inputs, such as fuel and tyres, go up in price with local depreciation. Analogously, currency fluctuations affect coal buyers as for example a depreciated local currency leads to higher procurement costs in US dollars. To mitigate the risks of exchange rate fluctuations for coal suppliers and buyers, there is a wide variety of financial hedging instruments available.

Figure 2.23 shows the indexed development of the US dollar against currencies of selected countries from 2012 to mid-2015. It can be seen that the US dollar had a strong year in 2014, as all depicted currencies depreciated against it. The Russian ruble (RUB) and the Colombian peso (COP) in particular depreciated sharply, as the economies in these countries are highly dependent on oil exports and therefore suffered severely from the oil price collapse in 2014, and Russia also suffered from Western sanctions. The largest exporters, Indonesia and Australia, also saw domestic currency depreciation versus the US dollar. As a result, the depicted development of currency exchange rates at least partly offset the continued decline of international US dollar-based coal prices for coal producers in 2014.

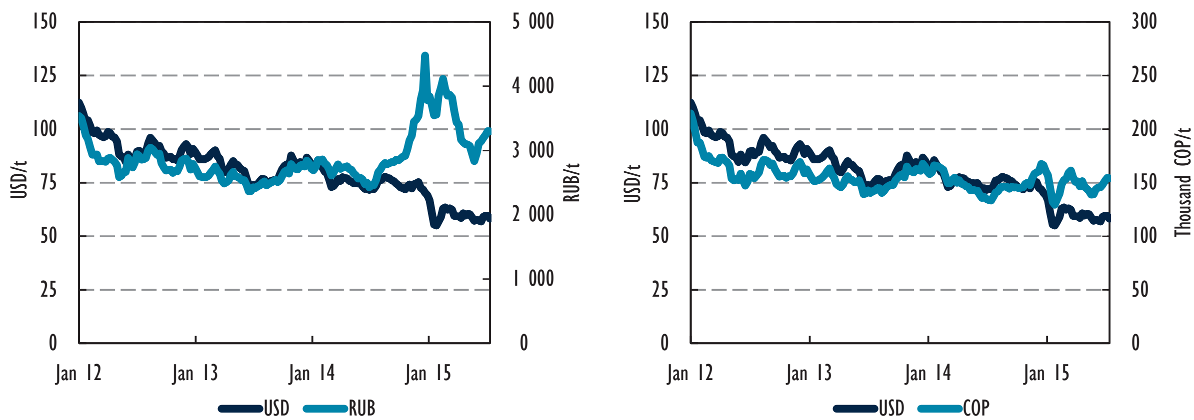
Figure 2.23 Indexed development of the USD against selected currencies



Notes: AUD = Australian dollar; IDR = Indonesian rupiah; CNY = Chinese Yuan renminbi; CAD = Canadian dollar; ZAR = South African rand. The graph shows the indexed (Jan 2012 = 100) development of the US dollar against selected currencies, expressed as USD/domestic currency (for example USD/AUD). Therefore a devaluation of the US dollar (USD 1 buys fewer units of another currency) results in a decline in the index.

The described effect is illustrated in Figure 2.24. The left chart shows the ARA CIF price denoted in US dollars and rubles. It can be seen that the ARA CIF price marker has declined by more than USD 15/t since the beginning of 2014. When expressed in rubles, however, the same price marker shows a sharp increase in 2014 followed by a decline in 2015. This development increased competitiveness of Russian exporters significantly, as costs for inland railway transportation, which make up a large part of total coal supply costs in Russia, are paid in rubles. As a result, Russian exports increased substantially in 2014. The right chart in Figure 2.24 shows an equivalent graph for Colombia with ARA CIF prices expressed in US dollars and Colombia pesos. It can be seen that the effect of currency fluctuations in Colombia was similar to Russia, but less pronounced. When expressed in Colombian pesos, the ARA CIF price marker remained roughly constant in 2014, because currency depreciation offset the decline in coal prices. Also, inland transport is far less important for production costs of Colombian coal suppliers, which dampens the effect of currency fluctuations compared with Russia.

Figure 2.24 FOB steam coal prices in USD and local currency



Note: RUB/t = Russian per tonne; COP/t = Colombian peso per tonne.

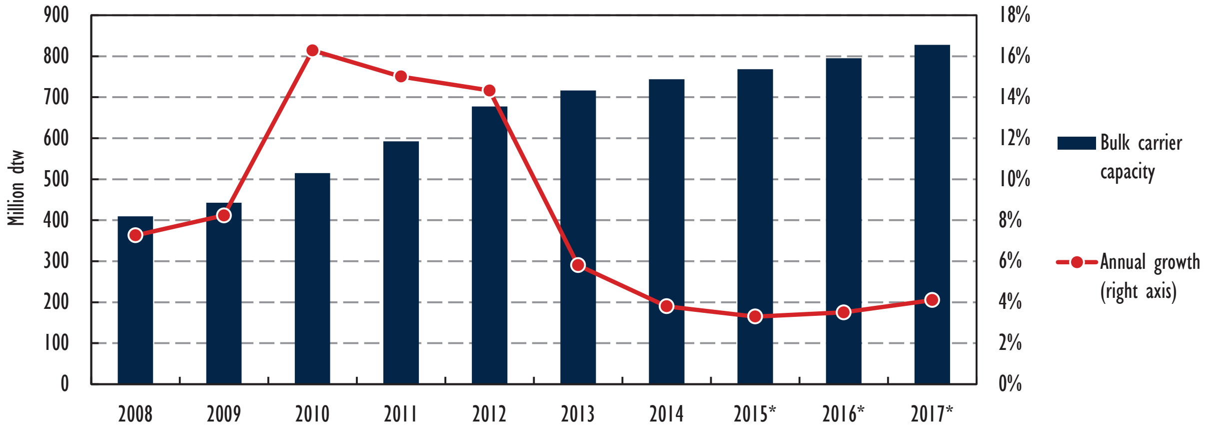
Source: IHS Energy (2015), *Coal McCloskey Price and Statistical Data*, https://connect.ihs.com/industry/coal.

Dry bulk shipping market

Roughly 90% of internationally traded coal is transported by ship. Therefore the seaborne dry bulk shipping market is an important part of the international coal supply chain. The shipping is handled by dry bulk freight vessels, which are categorised based on the weight they can carry measured in deadweight tonnage[3] (dwt). Thereby the four main vessel types are Handysize (10 000 dwt to 60 000 dwt), Handymax/Supramax (35 000 dwt to 60 000 dwt), Panamax (60 000 dwt to 80 000 dwt) and Capesize (over 80 000 dwt).

The most important dry bulk goods are iron ore, coal and grain, with coal accounting for roughly 30% of total seaborne dry bulk trade. The common vessel types in international coal trade are Panamax and Capesize. The supply of dry bulk carrier capacity is inflexible, as lead times between the placement of orders and the delivery of new carriers are typically one to two years. The number of assembly docks is also limited, which limits production capacity. This rigidity leads to a cyclical and volatile behaviour of the dry bulk shipping industry and its shipping rates.

Figure 2.25 Development of the bulk carrier fleet, 2008-17



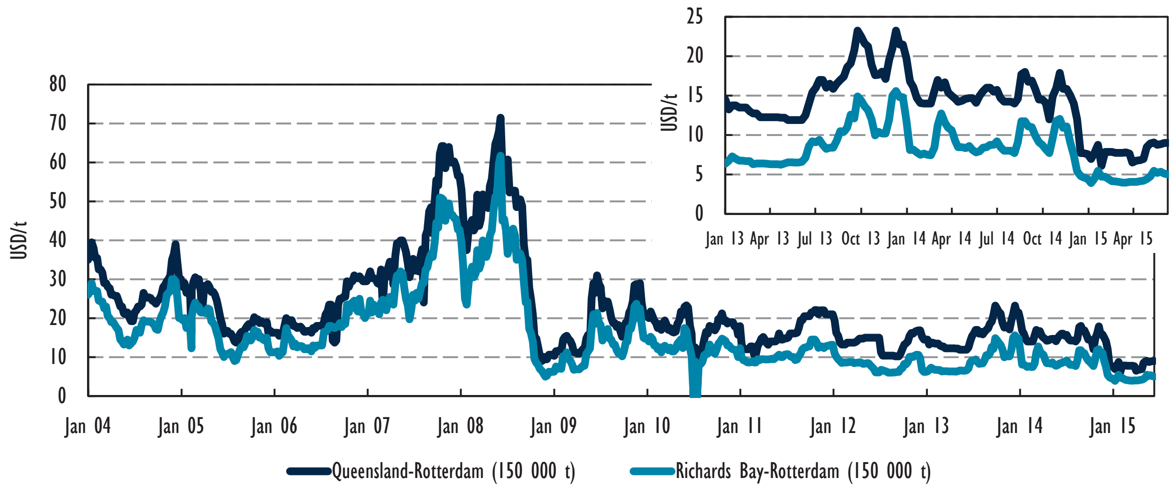
* Estimate.

Figure 2.25 shows the development of the global dry bulk carrier fleet. It can be seen that growth rates were around 15% between 2010 and 2012, leading to a fast expansion of the dry bulk capacity in that time period. The reason for this strong growth can be seen in Figure 2.26. Freight rates were exceptionally high in 2008, which led to high investments in dry bulk carrier capacity. Because of the lead times in construction, the ordered ships were ready for the market after the global economic crisis in 2009 had slowed down global trade. As a result, the dry bulk market has been vastly oversupplied since 2009, and growth of the dry bulk carrier fleet has dropped sharply.

Sea freight rates decreased sharply in the end of 2014 as the dry bulk market was still oversupplied. Freight rates from Richards Bay to Rotterdam declined from USD 15/t in December 2013 to USD 5/t in December 2014. Freight rates from Queensland to Rotterdam fell from USD 22/t to USD 8/t in the same period. In 2015, freight rates remained at low levels because of weak coal imports in China. In the coming two to three years, the dry bulk market is likely to remain oversupplied despite high scrapping of old ships in the first half of 2015.

[3] Deadweight tonnage is the mass that the ship can safely carry. It does not include the ship weight, but includes fuel, water, crew and, of course, cargo.

Figure 2.26 Development of selected freight rates, 2003-15



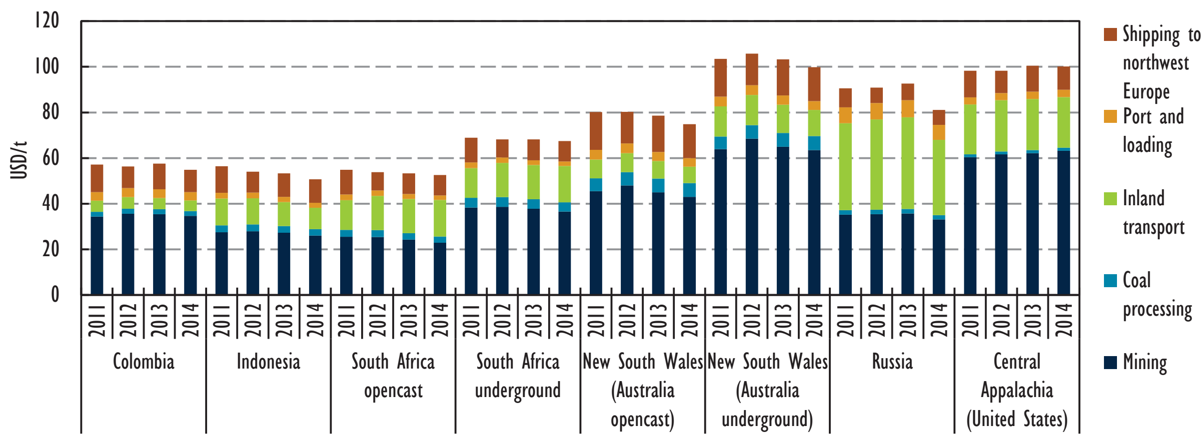
Source: IHS Energy (2015), *Coal McCloskey Price and Statistical Data*, https://connect.ihs.com/industry/coal.

Development of coal supply costs

In 2014, coal supply costs continued to decrease in most coal-producing countries, which can be explained by several main developments. First, the US dollar was strong in 2014 and appreciated against most currencies. Second, several input factor prices for coal mining decreased or stagnated. Prices for diesel fuel in particular declined sharply because of the drop in oil prices. Third, freight rates to Europe were lower in 2014 compared with 2013. Finally, companies continued their efforts to reduce mining costs in the face of continued low coal prices in the international market, including closure of unprofitable high-cost mining assets. Labour costs, on the other hand, continued to increase in various exporting countries.

The described developments are illustrated in Figure 2.27, which shows indicative steam coal supply costs to northwest Europe (ARA ports) for selected countries. Royalties and taxes are not included in the figure to improve comparability among different coal exporters and regions.

Figure 2.27 Indicative steam coal supply costs to northwest Europe by supply chain component and by country, 2011-14

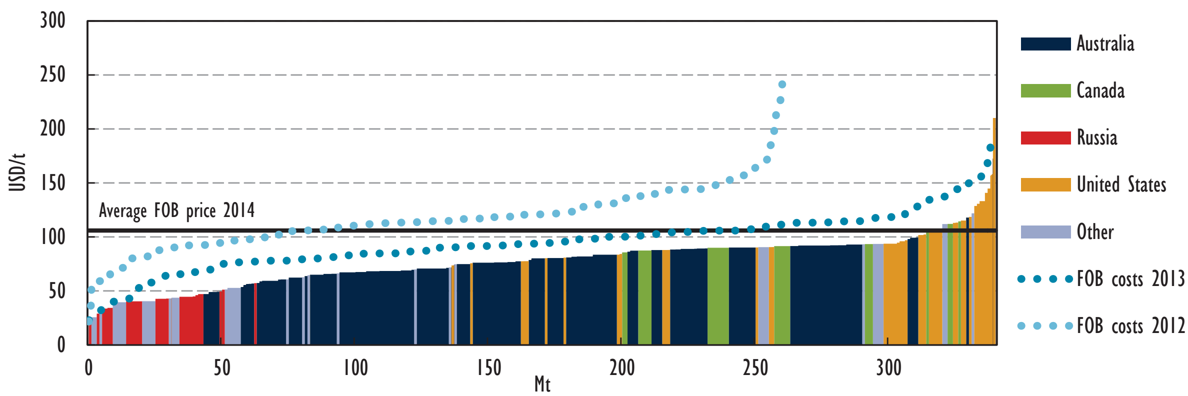


Note: indicative supply costs shown in this figure do not include taxes and royalties.

The country with the strongest decrease in coal supply costs in 2014 was Russia. The reason for this decline was the sharp depreciation of the ruble against the US dollar, which led to lower costs for ruble-denominated expenses relative to the revenue stream from coal sales in US dollars. In particular, costs for rail-based inland transportation, which account for a large share of total Russian supply costs because of high average transportation distances, declined significantly. Australian supply costs also declined substantially in 2014 as producers continued to implement strong measures to reduce mining and labour costs. These measures include reduced labour, better utilisation of mining equipment, reduction of overhead costs and renegotiations of service contracts to improve overall efficiency. The only analysed country where coal production costs remained roughly constant in 2014 was the United States, as the strong dollar worsened relative competitiveness for US producers.

Supply costs of met coal also decreased in 2014 for the reasons described above. Producers were thereby partly released from the pressure caused by the continued decline of met coal prices in 2014. In January 2014, met coal FOB prices ranged from USD 110/t to USD 135/t, depending on coal quality. Through December 2014 these prices declined to a range of USD 90/t to USD 115/t. As a result, the market remains oversupplied despite the various cost reduction efforts, and several met coal producers are not able to operate profitably as depicted in Figure 2.28. Because of the appreciation of the dollar, US producers particularly lost relative competitiveness and moved right to the upper end of the supply curve. As mentioned before, Russian producers on the other hand benefited from the ruble crash and gained competitiveness in the international met coal market.

Figure 2.28 Indicative met coal FOB cost curve and FOB price levels, 2012-14



Notes: FOB price levels are monthly averages derived from different price indices, such as Australian prime hard coking coal; Australian low-volatile PCI; US high-ash, high-volatile; and US low-volatile. Price levels of certain met coal types can deviate from these indicative figures. FOB costs comprise variable production costs, processing, overburden removal, royalties, port usage and inland transportation.

Source: IEA analysis from Wood MacKenzie (2015), *Coal* (private database), accessed April 2015; IHS Energy (2015), *Coal McCloskey Price and Statistical Data*, https://connect.ihs.com/industry/coal.

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3. MEDIUM-TERM FORECAST OF DEMAND AND SUPPLY

Summary

- **Global coal demand is forecast to grow by 0.8% per year on average over the outlook period.** In total, coal demand is expected to increase by 275 million tonnes of coal-equivalent (Mtce) to 5 814 Mtce by 2020.

- **Coal demand increases by 1.5% per year in non-member economies of the Organisation for Economic Co-operation and Development (OECD) while demand in OECD countries declines by 1.3% per year.** As a result, non-OECD economies account for over 75% of total global coal demand in 2020.

- **Coal demand in China is forecast to level off over the medium term.** Total Chinese coal consumption in 2020 will amount to 2 945 Mtce, which is similar to the consumption level of 2013.

- **Coal demand grows strongly in OECD non-member economies in Asia other than China.** Relative growth is strongest in the Association of Southeast Asian Nations (ASEAN) country group with a growth rate of 7.8% per year, followed by India, where coal demand grows by 4.1%.

- **In OECD member countries, coal demand decreases across all regions.** The decline is most pronounced in OECD Americas (-2.2% per year), followed by OECD Europe (-0.9%). Coal use in OECD Asia Oceania declines only slightly (-0.1%).

- **Global demand for metallurgical (met) coal remains unchanged, but Chinese demand decreases.** Lower consumption in China is driven by a slowing infrastructure investment and rebalancing of the Chinese economy.

- **The additional global coal demand is supplied by coal producers in the Pacific basin.** Coal production increases in China, India and Australia. Production in OECD Europe, OECD Americas and the ASEAN country group declines.

- **Given the recent slowdown in power and coal demand growth in China, a Chinese Peak Case Scenario (CPCS) has been modelled in which energy-intensive industry slows further down.** In the CPCS, Chinese coal demand declines by 203 Mtce over the outlook period and global demand remains flat.

Methodology

In this section, coal demand is forecast for different coal types. The forecast is subdivided into thermal coal and lignite demand and met coal demand. This market-oriented approach reflects that met coal is priced and traded differently than thermal coal and lignite. As with the previous editions of this report, the International Energy Agency (IEA) provides forecasts for both OECD member countries and OECD non-members.

Coal usage is driven by factors such as the relative prices of coal and its substitutes (particularly for power generation and industry), economic and population growth, and electrification rates. However, similar growth rates of the gross domestic product (GDP) in two countries may result in different growth rates for coal demand, depending on factors such as the country's average per capita income (used as a measure of its development level), resource endowment or energy policies. To account for the diverse influences, demand forecasts in the *Medium-Term Coal Market Report* are based upon country-specific econometric estimations, for example the elasticity of non-power thermal coal demand to GDP or population growth. Using assumptions about various relevant parameters (such as GDP and population growth forecasts provided by the International Monetary Fund [IMF], fuel prices, and development of average efficiency of coal-fired power plants in the various countries) allows for demand projections specific to the country and coal type. Drawing on the broad expertise of the IEA on primary energy markets enables consistent demand estimates that account for development in the other primary energy markets, such as natural gas, renewable energies or crude oil.

Given the recent developments of coal demand in China and its enormous importance in international coal markets, the *Medium-Term Coal Market Report 2015* provides a sensitivity analysis in addition to the forecast. In this additional scenario CPCS, it is assumed that Chinese coal demand already peaked in 2013 and will decline in the future. This allows us to analyse fundamental drivers for peaking coal demand in China as well as to capture effects of possible future declining coal demand in China on the international coal markets. This case does not imply a different GDP growth in China over the outlook period. Given the extraordinary energy and coal intensity of the infrastructure development (one-third of coal use in China is infrastructure-related), we assume a different breakdown of the components of the GDP growth, with more participation from the tertiary sector, i.e. services, and less from energy-intensive industries. The CPCS also assumes slower developments of coal conversion projects.

Assumptions

One of the most important drivers for global coal use is GDP growth. The demand forecast as well as the CPCS is based on the April 2015 GDP forecast of the IMF (IMF, 2015). In the IMF forecast the global economy grows on average by 3.8% per year in the period 2015-20. A comparison of the April 2015 IMF forecast with the April 2014 forecast used in last year's *Medium-Term Coal Market Report* (IEA, 2014) shows that the IMF revised its projection for the period 2014-19 slightly downward by 0.1 percentage points. Growth will be stronger in OECD non-member economies with average annual growth rates of 5.0% in the period 2015-20, while economies in OECD member countries grow only 2.2% on average in the same time frame, according to the IMF forecast.

Economic growth in OECD Europe will be 2.0% per year on average from 2015 to 2020. The average forecast growth rate for OECD Americas is 2.6% per year, mainly influenced by economic development in the United States (US). GDP in OECD Asia Oceania will grow by 1.9% on average, according to the IMF forecast. Korea is the fastest-growing economy in OECD Asia Oceania, while growth in Japan is projected to be below 1% on average over the outlook period.

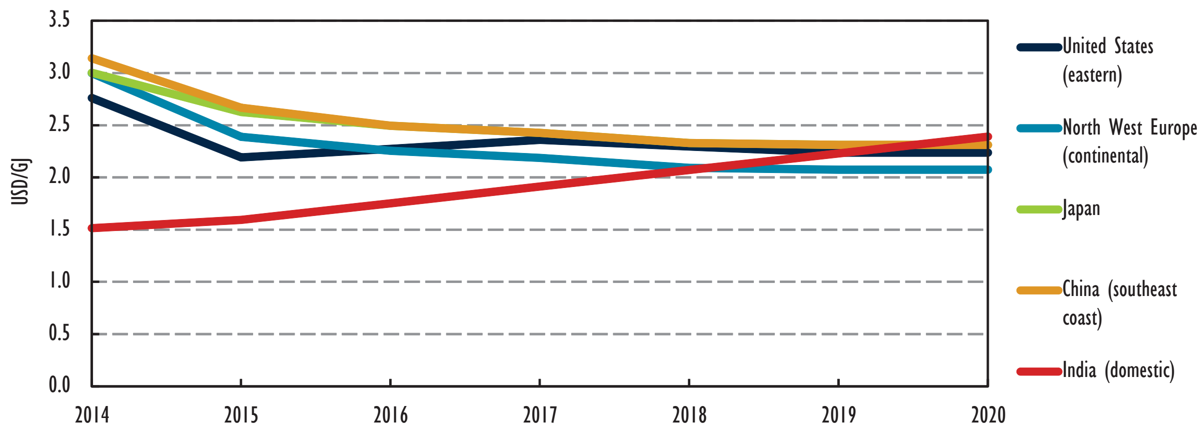
Economies of OECD non-members in Asia will continue to grow, with substantially higher growth rates than economies in OECD member countries. However, forecast average growth for China has been revised downward to 6.3% per year over 2015-20 from 7% per year over 2014-19, which was the assumption for last year's *Medium-Term Coal Market Report*. In contrast, GDP growth in India is seen more optimistically at 7.6% in the April 2015 IMF forecast, an upward revision of more than one percentage point compared with the April 2014 projection. Other developing economies in Asia are expected to grow 5.2% on average, largely influenced by average GDP growth of 5.9% in Indonesia.

Average economic growth in African economies is revised slightly downward to 4.9% per year. GDP in Latin America is assumed to grow by 2.0% per year and GDP in the Middle East by 3.3% per year on average. Growth for non-OECD Europe/Eurasia is projected to be 1.5% per year, which is a strong downward revision compared with the forecast of April 2014, mainly because of recession in the Russian Federation.

Another important factor that influences future coal demand is the evolution of fuel prices. The assumed price paths for oil, gas and coal are consistent with other *Medium-Term Reports* published by the IEA (2015a; 2015b; and 2015c). As these assumptions are derived from forward curves, however, they cannot be interpreted as official IEA forecasts.

Nominal IEA average oil import prices are assumed to increase from current price levels to USD 68 per barrel in 2020. Oil markets are therefore assumed to recover from 2016 onward with a steady and gradual increase. However, prices will stabilise at levels that are substantially below the highs of recent years. In the natural gas market, a persistence of price divergence among the United States, Europe and Asia is assumed because seaborne transportation costs, infrastructure constraints and long-term contracts that are indexed to oil prices continue to prevent full inter-regional arbitrage. Average Henry Hub gas prices are expected to increase to price levels around USD 3.5 per million British thermal units (MBtu) by 2020. Gas prices in continental Europe will continue to be based on a mix of spot and oil indexation over the outlook period with an average expected price level of USD 6.9/MBtu. Gas prices in OECD Asia Oceania (represented by Japan) will remain above gas prices in the United States and Europe. By 2020, an increase of Asian gas prices to USD 9.6/MBtu is assumed. Prices for carbon dioxide (CO_2) emission certificates in Europe are assumed to slightly increase to roughly EUR 8 per tonne (t) by 2020.

Figure 3.1 Regional (real) steam coal price assumptions, 2014-20

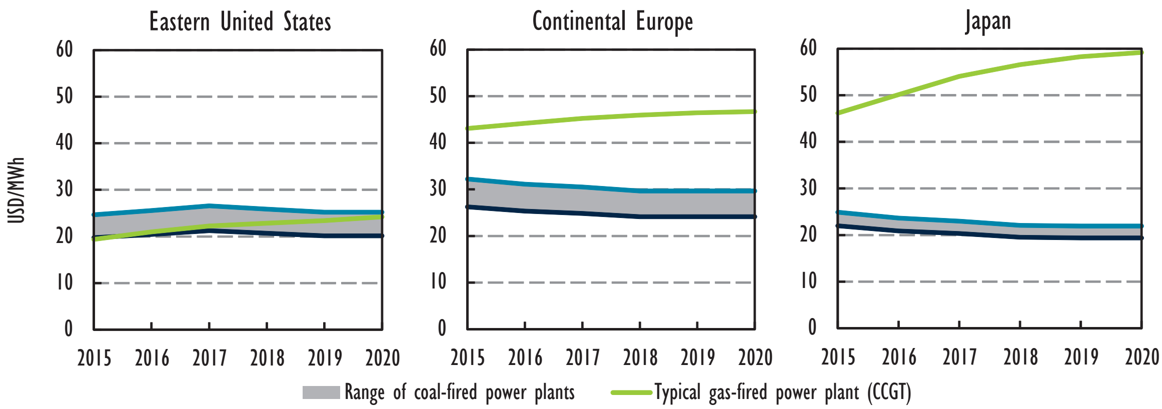


Note: GJ = gigajoule.

Assumptions for regional coal prices in this report are based on forward curves subject to individual adjustment to account for e.g. transport and handling costs (Figure 3.1). Prices in the United States (eastern), North West Europe (continental), Japan and China (southeast coast) are assumed to slightly decline or stay roughly flat on the low levels of 2015 over the outlook period. Coal prices in India are assumed to rise significantly from USD 1.5/GJ in 2014 to USD 2.4/GJ in 2020. Generally, international coal prices in different markets around the world are assumed to converge over the outlook period.

The described price assumptions have strong implications for the competitiveness of coal with other energy sources, especially natural gas. Figure 3.2 compares the marginal costs of electricity generation of coal-fired and gas-fired power plants in the United States, continental Europe and Japan based on the assumed commodity prices. As the efficiency of coal-fired power plants can vary substantially depending on age and technology of the plant, the charts show a range of generation costs between high-efficiency and low-efficiency coal-based power plants in the different regions. Generation costs for gas-fired power plants are given for combined-cycle gas turbine (CCGT) plants, which typically compete with coal-fired electricity generation in the merit order of electricity markets.

Figure 3.2 Implied marginal costs of electricity generation for coal-fired and gas-fired power plants in different regions, 2015-20



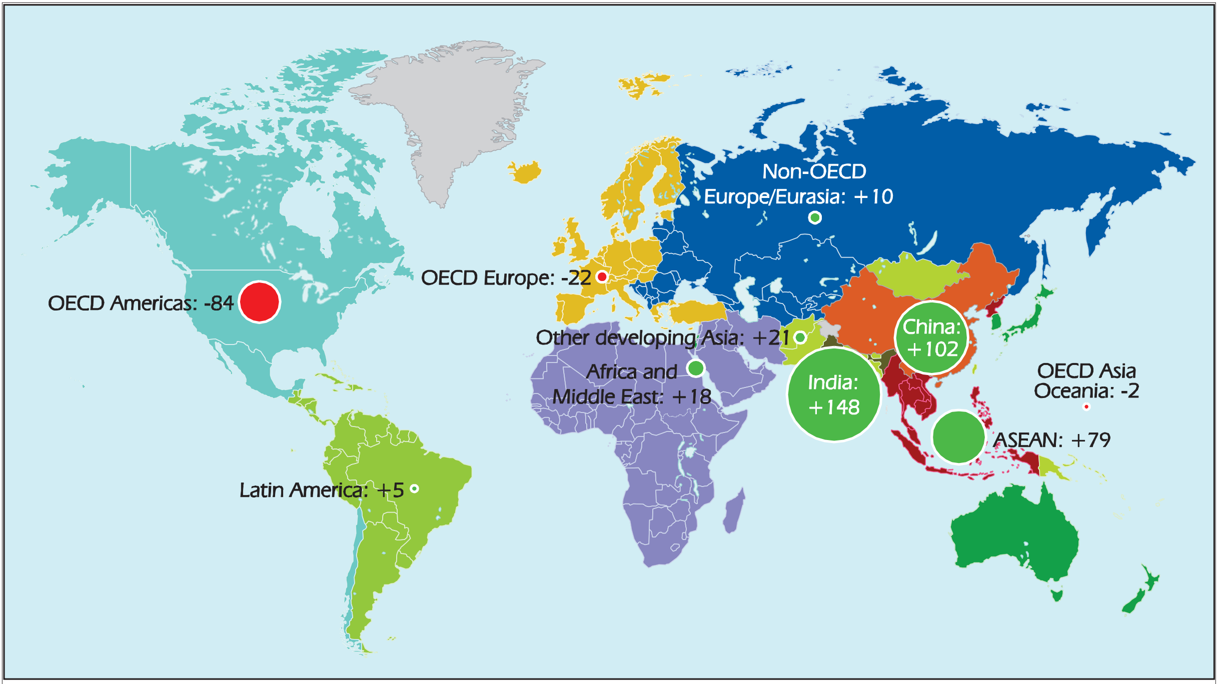
Note: MWh = megawatt hour.

Figure 3.2 shows that over the outlook period, gas-fired power plants will be competitive with coal-fired generation in the United States, where cheap shale gas production will continue to keep natural gas prices low. In continental Europe, gas prices are significantly higher compared with the United States, which leads to strong competitive advantages of coal-fired generation over the outlook period. The situation is different in the United Kingdom, where the carbon price floor significantly improves the competitiveness of gas-fired electricity generation. In Japan, the advantage of coal-based power plants is even more pronounced compared with continental Europe because of higher gas import prices and the absence of an emissions trading system. The situation is similar in other developed Asian economies such as Korea. Generally, commodity prices favour coal-fired electricity generation in most countries over the outlook period. However, it must be noted that gas and coal prices can vary substantially among different locations. Particularly in the United States, several gas hubs with different prices exist. Additionally, coal prices at the power plant differ depending on transportation costs and availability of domestic coal close to the plant. Figure 3.2 can therefore give only a rough overview of the market situation, as a detailed analysis of coal-to-gas competition in electricity generation must include the described local and regional particularities.

Global coal demand forecast

Global coal demand is forecast to grow by 275 Mtce, from 5 539 Mtce in 2014 to 5 814 Mtce in 2020, which corresponds to an average annual growth rate of 0.8%. Therefore, compared with the average annual growth rate over the last decade of 4.2%, growth of coal demand is projected to slow down substantially in the outlook period. Considering IEA forecast for other energy sources, the share of coal in total primary energy consumption declines from 29% to 27% over the outlook period. Economies in OECD non-members will drive global coal use in the coming years with an average annual growth rate of 1.5%. However, demand growth in China, the largest coal consumer in the world by far, will level off in the outlook period. Total Chinese coal consumption in 2020 will be comparable to the historic levels of 2013. The largest incremental growth of coal demand over the outlook period will take place in India (+148 Mtce). China accounts for the second-largest absolute increase (+102 Mtce). However, this has to be put into the context of the scale of coal in China (roughly 3 000 Mtce) and the strong decrease estimated in 2014. In relative terms, growth of coal demand will be strongest in the ASEAN country group (7.8% average annual growth), followed by India (4.1%) and other developing countries in Asia (3.4%). In total, OECD non-members will account for 77% of total coal demand in 2020.

Map 3.1 Forecast of incremental global coal demand 2014-20 (Mtce)



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.

In contrast to the expected demand growth in OECD non-members, coal use in OECD economies will decline over the outlook period by 1.3% per year on average. In absolute terms, coal demand will decrease by 108 Mtce from 1 430 Mtce in 2014 to 1 322 Mtce in 2020. The strongest decline in coal use is projected for OECD Americas, with demand decreasing by 2.2% per year over the outlook period. The bulk of this decline can be attributed to the United States, where coal demand is forecast to be 75 Mtce lower in 2020 than in 2014. In OECD Europe,[1] coal use is projected to decline by 0.9% per year. Coal consumption in OECD Asia Oceania remains roughly unchanged over the outlook period and amounts to 353 Mtce in 2020. The absolute development of coal demand in the different regions of the world is depicted in Map 3.1.

[1] Numbers for OECD Europe differ slightly from other IEA publications as Israel is not included in the forecast. Also, oil shale and oil sands in Estonia as well as peat in Ireland and Finland are not accounted for.

Box 3.1 Potential upcoming players in coal markets

Currently South Africa consumes over 90% of the coal used on the whole African continent. Only Morocco and Zimbabwe have surpassed the 1% threshold of global Africa consumption, and together with Botswana, are the only countries consuming over 1 million tonnes (Mt) of coal per year. But this situation might change in the future, as some countries have announced plans to build their first coal power plants. The list of potential new entrants includes Egypt, Malawi, Kenya, Zambia, Congo, Ghana, Guinea, Senegal and Mozambique. It could also include Tanzania, where only the Kiwira mine power plant (6 megawatts [MW]) is operating, and Nigeria, where Oji River (30 MW) has worked in the past.

Due to the scale of the proposed developments, Egypt deserves special consideration. In 2014 the government of Egypt approved the use of coal in power and industry. The decision, largely driven by the scarcity of gas for industry, gave rise to a swift switch from gas to coal in cement kilns. In addition, this was expected to lead to construction of new coal power plants. Egypt, the largest oil and gas consumer in Africa, has problems with power shortages, and coal seems to be part of the solution, together with nuclear and renewables. Since the government adopted the new policy, a few large coal power plants have been announced. Tharwa Investments announced the construction of the largest coal power plant in the world (6 gigawatts [GW]), Al Nowais has proposed a 4 GW coal plant, Orascom plans a 3 GW coal plant, and Safaga power has been announced as a 1 950 MW plant. Whether the plants are eventually built or not will largely depend on the signature of a satisfactory power purchase agreement backed up somehow by the Egyptian government. However, the discovery of a huge offshore gas field, potentially one of the largest in the world, in 2015 could ease the Egyptian energy problems and therefore soften the need for coal-fired power generation, even if no gas production from that field is expected before 2020.

Nigeria has also announced important developments of 1 000 MW or so in three different sites, accounting for 3.4 GW of new capacity in order to reduce excessive dependency on gas. Mozambique is also the site of large potential developments. There, exporting the higher priced coking coal and burning thermal coal, including rejection from coking coal washing, domestically, especially mine mouth, makes a lot of economic sense. ACWA Power International announced the start of construction of a 300 MW plant. Another country with significant capacity announced is Malawi, over 2 GW, but how likely this is to materialise is a different story.

Tanzania is also endowed with significant coal reserves, but this does not mean things are easier. On the contrary, investments needed to access the coal add to those needed to build the power plants, which can be an issue given troubles raising funds in Tanzania.

Ghana, Kenya and Zambia make up a group with over 1 GW of coal-fired power plants announced, but there are big uncertainties about their development. Guinea, Congo and Senegal announced small capacities, some of them captive plants for energy-intensive industries.

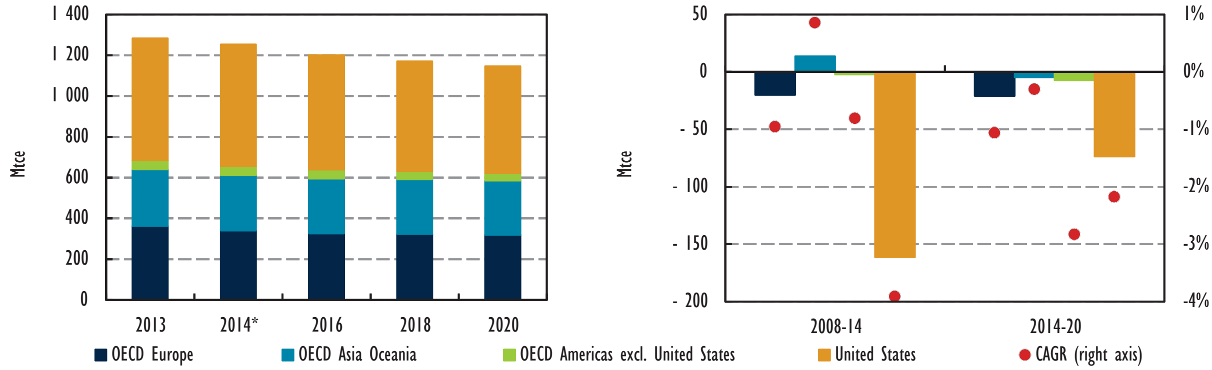
A few caveats should be mentioned. First, as developments generally require some time and delays are frequent, hardly any of the capacity eventually built will come into operation in the outlook period of this publication. Moreover, the experience over the world shows that only a fraction of the announced projects is finally built, so many of the above-mentioned plants will be halted, suspended or cancelled, especially considering the financial, regulatory, technological and human resource constraints existing in some of those countries. Finally, despite the importance of these plants at country level, the scale of the development is not that significant at a global scale. Retirements in the United States or new plants in India will be much larger by far than all the projects to be developed in these countries in the outlook period.

OECD coal demand forecast, 2015-20

Thermal coal and lignite

Thermal coal and lignite account for over 85% of total coal consumption in the OECD. By 2020, consumption of thermal coal and lignite is forecast to decline from 1 253 Mtce in 2014 to 1 146 Mtce, which is equivalent to an average annual decline of 1.5%. Given that in the OECD, 90% of thermal coal and lignite is used in the power sector, this development is largely driven by electricity generation in coal-fired power plants.

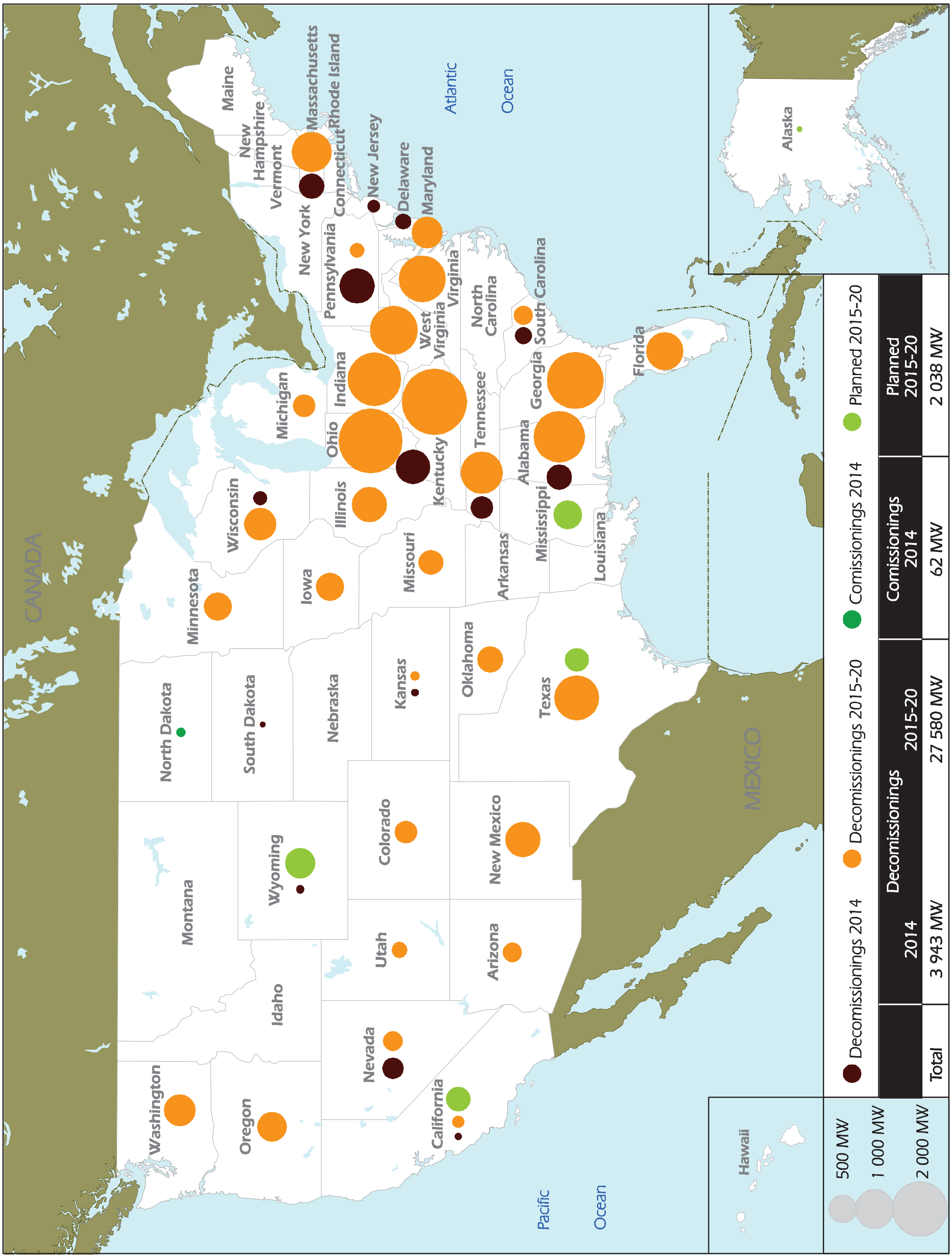
Figure 3.3 Forecast of thermal coal and lignite demand for OECD member countries



* Estimate.
Note: CAGR = compound annual growth rate.

The United States accounts for over 45% of total thermal coal and lignite consumption in OECD member countries throughout the outlook period. However, to 2020 the amount of thermal coal and lignite consumed by the United States will fall from 597 Mtce in 2014 to 523 Mtce, a decrease of 2.2% per year. The decline in US consumption stems mainly from lower electricity generation in coal-fired power plants. As gas prices in the United States are expected to stay low over the outlook period, strong coal-to-gas competition will remain. Additionally, the regulatory environment will continue to put pressure on coal-fired power generation despite the Supreme Court's rejection of the Mercury and Air Toxics Standards (MATS) of the US Environmental Protection Agency (EPA) in June 2015. The decision against MATS will have only limited impact because most of the affected power plants have already been either retired or retrofitted; nevertheless, it is expected that some of the existing coal-fired power plants will stay on line because of the Supreme Court's decision. Total retirements of coal-based plants in the United States over the outlook period are projected to be between 40 GW and 45 GW. Currently, retirements with a total capacity of 28 GW have been already announced. As shown in Map 3.2, the retirements are most pronounced in the Midwest and Northeastern United States.

Map 3.2 Coal-fired power plant projects and decommissionings in the United States



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Planned coal capacity additions amount to roughly 2 GW until 2020. The majority of these projects are plants equipped with carbon capture and storage (CCS), as for example the Texas Clean Energy Project (TCEP), Kemper (Mississippi), Petra Nova (Texas) and HECA (California). The projects in Wyoming are conventional coal-fired power plants, however it is currently unclear if these projects will actually be built. Additional large-scale investments in new coal-fired generation capacities in the United States are highly unlikely, especially since the United States plans to reduce carbon emissions by 32% below 2005 levels by 2030 according to the Clean Power Plan.

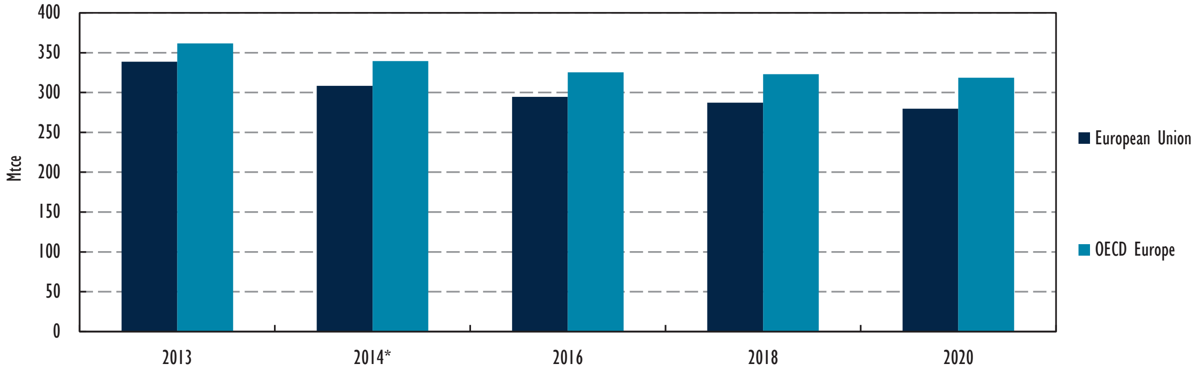
In other OECD Americas countries, coal demand is also expected to decrease over the outlook period. Total thermal coal and lignite demand in OECD Americas is projected to fall by 81 Mtce to 562 Mtce in 2020, which is a yearly decline of 2.2% on average.

Demand for thermal coal and lignite in OECD Europe is projected to decline from 340 Mtce in 2014 to 319 Mtce in 2020, a decrease of 21 Mtce or 1.1% per year. The decline in coal consumption is caused by moderate economic growth in combination with increasing electricity generation from renewable energy sources and lower electricity demand due to continuing efforts to raise energy efficiency. In addition, Germany decided to mothball 2.7 GW of lignite-fired power plants in 2015 in order to reduce national carbon emissions. These plants will not be allowed to sell power in the normal market but will instead be put into a power-capacity reserve that gets activated in case of power shortages. However, there are doubts about the compatibility of the proposed capacity reserve with state aids rules of the European Union (EU), as it might be considered as unjustified state aid. An increasing effect on coal-fired electricity generation in Germany is expected to occur because of the shutdown of nuclear power plants in the coming years. In conjunction with the German nuclear phase-out, the power reactor Gundremmingen B (1.3 GW) will be shut down by 2017, and Philippsburg 2 (1.5 GW) is scheduled to close by 2019. The Grafenrheinfeld nuclear power plant (1.3 GW) stopped operations in June 2015. In the current market environment with low prices for coal and CO_2 emission certificates, a substantial part of the nuclear energy will be replaced by coal-fired electricity generation and coal decline will slow down compared with what could be otherwise expected.

Generally, coal-fired electricity generation in the European Union is affected by high political and regulatory risks as the European Union as well as individual member states plan to implement additional measures to cut carbon emissions, such as the market stability reserve, which will be implemented in 2019 and will increase scarcity in the EU Emissions Trading System (EU-ETS) by controlling the number of surplus allowances that circulate in the market. As a result, no substantial new investments in coal-fired power plants are expected over the outlook period in the European Union, despite the current low prices for carbon emissions allowances and the favourable gas-to-coal spread for coal-based electricity generation. An exception to this is Greece, which is building a 660 MW lignite-fired power plant in Ptolemaida by 2018. Additionally, two coal-fired power plants started commercial operation in Germany in 2015, and there will be one coal-fired power plant commissioned in the Netherlands in 2016. Investment decisions for these projects were made before 2008. Poland also has plans for new coal plants (see section on Poland in this chapter).

In the European Union, the demand of thermal coal and lignite will decline by 1.6% per year, compared with 1.1% in OECD Europe (Figure 3.4). This difference is mainly Turkey, where coal will be part of the solution to growing energy needs, and it plans to massively extend its coal-fired power plant fleet.

Figure 3.4 Thermal coal and lignite demand forecast for OECD Europe and the European Union



* Estimate.

Consumption of thermal coal and lignite in OECD Asia Oceania is projected to decrease slightly by 0.3% per year on average from 271 Mtce in 2014 to 266 Mtce in 2020. In Korea, the increasing power demand led to large-scale investments in coal-fired power generation. Over the outlook period, more than 10 GW of new coal-based power plants are expected to come online. In Japan, the retail and generation markets for electricity will be liberalised in 2016, and many utilities and potential new market entrants are planning to invest in coal-fired power plants because of the competitiveness of coal-based electricity generation. New coal-fired power plants are also built to lower costs of electricity generation, as old and low-efficiency plants had to run at full capacity over the past years because of the shutdown of all Japanese nuclear power plants after the nuclear accident in Fukushima. Despite plans for large coal power generating capacity of around 10 GW, coal demand will not grow. Part of the proposed plants will be delayed after 2020 or not built. The new coal-fired plants will mainly replace less-efficient old plants, which results in less coal consumption to produce the same electricity output. Coal consumption will be further dampened by the restart of substantial amounts of nuclear generation capacity in Japan and increasing photovoltaics (PV). At Sendai power station, two nuclear reactors restarted commercial operation in 2015; more restarts are expected in the near future.

Met coal

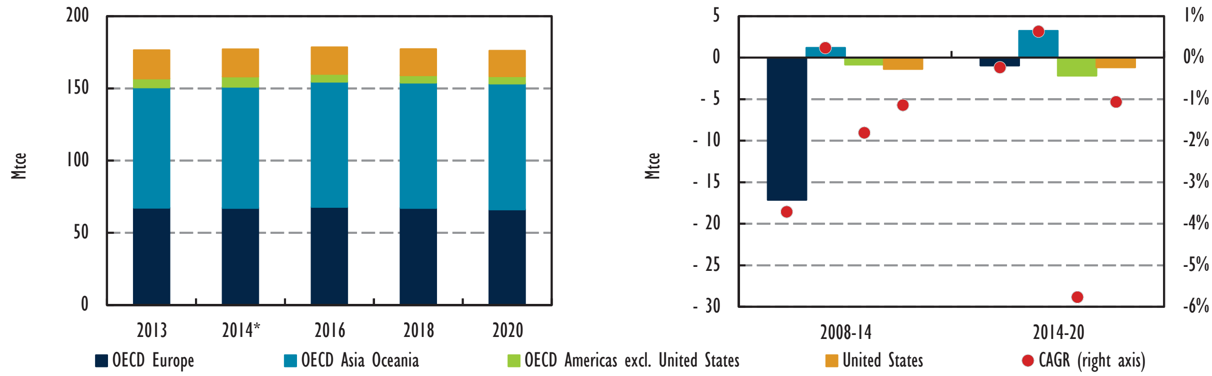
Demand for met coal in OECD member countries will remain flat over the outlook period, with 177 Mtce met coal consumption in 2014 and 176 Mtce in 2020. Demand in OECD Americas is projected to decrease, OECD Europe's met coal consumption will remain flat, and consumption in OECD Asia Oceania will slightly increase.

In OECD Americas, met coal demand will decrease by 2.0% per year from 26 Mtce in 2014 to 23 Mtce in 2020. In the United States, the decline in met coal consumption is less pronounced at -1.1% per year on average, to a total of 18 Mtce in 2020.

Met coal consumption in OECD Europe will remain roughly unchanged over the outlook period, totalling 67 Mtce in 2014 and 66 Mtce in 2020. The flat demand stems from a combination of decreasing met coal consumption in mature economies such as Germany, and the United Kingdom where steel capacity has been closed recently, and increasing consumption in economies with growing energy demand such as Turkey.

OECD Asia Oceania is projected to increase met coal demand from 84 Mtce in 2014 to 87 Mtce in 2020, which is equivalent to an average annual growth of 0.6%. This development is driven by growing demand in Korea, where the steel industry will benefit from stable economic growth over the outlook period.

Figure 3.5 Forecast of met coal demand for OECD member countries



* Estimate.

Poland

The Polish economy is projected to grow by 3.5% per year on average over the outlook period according to the GDP forecast of the IMF. This will make Poland the fastest-growing economy among OECD Europe countries until 2020. Coal, which currently supplies more than 50% of Polish total primary energy consumption and over 80% of the electricity, will be an important energy source to cover this additional demand.

The main driver for coal demand is the power sector; it is by far the most important coal-consuming sector in Poland, accounting for roughly three-quarters of Polish coal demand (see the regional focus on Poland in Chapter 1). Power demand is projected to grow by 2.5% on average over the outlook period as a result of the strong economic growth. The share of coal in the Polish electricity mix, however, decreases from 83% in 2014 to 80% in 2020. This decline is a result of additional electricity generation based on renewable energy sources, which are projected to supply approximately an additional 10 terawatt hours (TWh) by 2020. Gas-fired electricity generation on the other hand will remain stable, as there are no plans to substantially extend the gas-fired power plant fleet in Poland over the outlook period, and coal generation costs are lower than gas costs. Despite the decreasing share, total coal-based electricity generation is projected to grow from 132 TWh in 2014 to 146 TWh in 2020, which corresponds to an annual average growth rate of 1.7%.

The current coal-fired power plant fleet has enough capacity to supply the additional generation, so no substantial capacity additions are required until 2020. However, four investment projects in coal-fired generation that will replace older plants are expected to come online over the outlook period. At the Kozienice power plant, a new ultra-supercritical (USC) coal-fired unit with a capacity of 1 075 MW and design net efficiency of 45.6% is projected to come online by 2017. Additional USC coal-fired units are projected to be operational by 2019: two units at the Opole power plant (1 800 MW and design net efficiency of 45.5%) and one unit at the Jaworzno power plant with a capacity of 910 MW and design net efficiency of 45.9%. Finally, a new supercritical lignite-fired unit with a capacity of 450 MW and efficiency of 42% will come online at Turow power plant. With the start of operations at these projects, older units at the same locations will be shut down. Consequently the efficiency of the Polish thermal power plant fleet will increase from approximately 34% currently to 36% by 2020. As a result, coal consumption in the Polish power sector is forecast to grow from 47 Mtce in 2014 to 51 Mtce in 2020. The share of lignite in total coal consumption of the power sector will remain constant at roughly 40%.

Box 3.2 Is Poland on track for the 2030 emission target?

Poland is the fifth-largest CO_2 emitter in the European Union. It managed to reduce greenhouse gas (GHG) emissions substantially in the past. The level of CO_2 emissions dropped from 564 Mt of CO_2 in 1988 to 400 Mt of CO_2 in 2012, a 30% drop. But even though the country has managed to reduce substantially its energy intensity since 1990, it is still over the average of EU economies. As European leaders struck a broad climate change pact obliging the European Union as a whole to cut GHG by at least 40% by 2030, concessions were granted to Poland to allow for the modernisation of coal-fired power plants. In 2015, the Polish government presented two sets of official documents regarding future Polish energy policies, including possible low-emission policy solutions. The national Programme for Low-Emission Economy Development (presented by the Ministry of Economy in August 2015) highlights the dominant role of fossil fuel-related emissions in the Polish economy: industry (cement production), agriculture and waste/by-products sectors (methane). Electricity and heat generation from coal is the largest sectoral contributor to emissions in Poland (over 40% of total emissions in 2011). This is caused both by the dominance of hard coal and lignite in the energy mix as well as by the relatively low efficiency of power plants.

Due to the inherent limits of hydroelectricity generation in Poland and the lead time of nuclear energy development programmes, low-emissions power generation capacity will remain marginal. According to the document, in the next three decades, replacement of current electricity production energy units is necessary, in order to make possible the enhancement and improvement of the efficiency of coal use (and to increase the share of low-emissions technologies in the sector). The main goal of the programme is the development of a low-emissions economy to ensure sustainable development of the country. In this context, the Polish government is searching for a less resource-intensive model of development through the creation of a circular economy aiming to reduce consumption of primary fuels. In line with the concept of a circular economy, its global goal will be achieved by specific objectives such as low-emissions electricity production and the improvement in the use and consumption of fuels. According to the macroeconomic model applied, the implementation of objectives will translate into a gradual decrease in CO_2 emissions. Today’s homogenous electricity generation mix in Poland (83% of electricity is produced from coal) is the result of the history of the domestic power generation mix as well as a consequence of impediments to renewable and nuclear energy development projects. Within the framework of the EU Directive on Industrial Emissions (effective 2016), Poland will be obliged to shut down energy units with a capacity of 6 600 MW by 2020 (and an additional 10 000 MW by 2028). Four additional coal-fired power units, owned by three biggest state-owned power and electricity companies – PGE, Tauron and Enea – will start operation in 2017-19 (one lignite-fired power unit and three hard coal-fired power units), which will add some 4 200 MW power capacity. Replacement power generation capacity will absorb a vital part of the sector’s investment capital, but it can also create an opportunity to restore power capacity based on the application of low-emissions technologies. The replacement of obsolete, low-efficient coal-fired power plants with highly efficient ones (45% efficiency) will contribute to a reduction of CO_2 emissions. The programme identifies areas of improvement paving the way to the transition to the low-emissions economy that include the application of capital investment and regulatory/environment policies. The objective is to increase the share of renewable energy in the current energy mix. (Decreasing transmission and distribution losses and deploying clean-coal technologies are also on the agenda.)

Box 3.2 Is Poland on track for the 2030 emission target? (continued)

Poland will be able to comply with the European GHG reduction targets for 2030 if the necessary policy measures are taken. The reductions will be mainly achieved by an increase of electricity generation based on renewable energy sources and a modernisation of the coal-fired power plant fleet, which will raise efficiency of the conventional power plant fleet and lower coal consumption. Therefore, coal will remain an important part of the Polish energy system and the main energy source in electricity generation while reduction targets are achieved.

Coal consumption in the Polish non-power sector is forecast to remain roughly unchanged over the outlook period. This is a result of slow demand growth in the industry, as steel and cement production are expected to increase only slightly despite the strong economic growth. Additionally, coal use in residential heating is expected to decrease as environmental concerns and pollution problems in Polish cities will lead to increasing pressure to replace old coal-fired boilers in residential buildings.

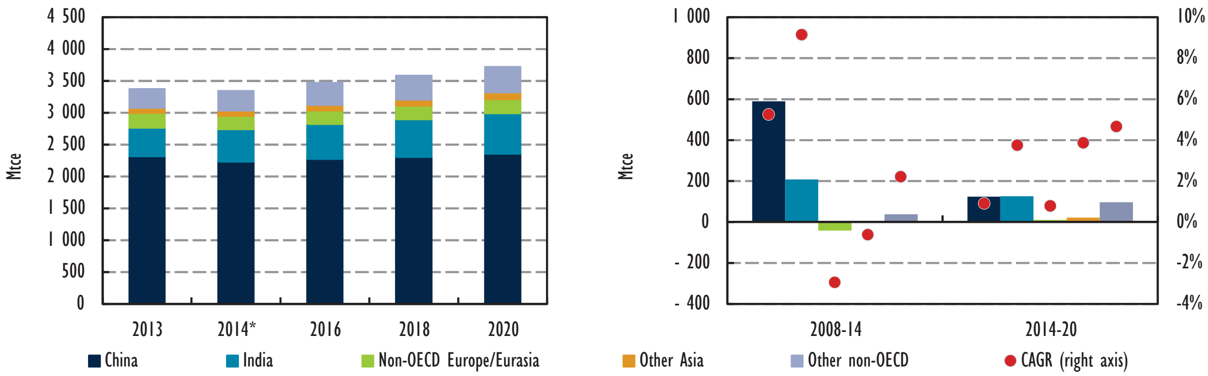
In total, Polish coal demand is forecast to grow from 78 Mtce in 2014 to 83 Mtce in 2020. This is equivalent to an average annual growth rate of 1.0%. It must be noted, however, that the projection for Polish coal demand is highly dependent on future economic growth. As a coal-dependent economy, if economic growth is different than expected, coal demand should be revised accordingly.

OECD non-member coal demand forecast, 2015-20

Thermal coal and lignite

Thermal coal and lignite demand in OECD non-member economies will increase by 1.8% per year over the outlook period. In absolute terms, consumption will grow to 3 722 Mtce in 2020, compared with 3 344 Mtce in 2014.

Figure 3.6 Forecast of thermal coal and lignite demand for OECD non-member economies



* Estimate.

Incremental growth over the outlook period in OECD non-member economies is equal to 30% of total 2014 thermal coal and lignite consumption in the OECD. With a share of 67% in incremental growth, the power sector in OECD non-member economies will continue to drive consumption of thermal coal and lignite. The share of the power sector in total thermal coal and lignite consumption in OECD non-member economies is 62%.

China

China remains by far the largest consumer of thermal coal and lignite in OECD non-member economies and the world over the outlook horizon. However, Chinese demand is projected to grow only by 0.9% per year from 2 231 Mtce in 2014 to 2 355 Mtce in 2020. Compared with historical growth rates, this is a significant slowdown of growth in Chinese demand for thermal coal and lignite. Consequently, the share of Chinese consumption in total thermal coal and lignite demand of OECD non-member economies declines over the outlook period from 67% to 63% as relative growth of demand in other Asian countries such as India and the members of ASEAN is stronger.

There are three reasons that explain the slowing demand for thermal coal and lignite in China. First, growth of the Chinese economy is slowing down, with a projected growth rate of 6.3% per year over the outlook period. Second, the rebalancing of the Chinese economy and the subsequent shift to a more service-based growth model has recently accelerated, dampening the increase of coal consumption. Third, Chinese energy policy continues to push for a diversification of the Chinese energy mix as well as for a more efficient and environmentally friendly use of energy. One example for these efforts is the clean-coal action plan that was released by China's National Energy Administration in May 2015. According to this plan, China will substantially expand the use of clean-coal technologies over the period from 2015-20. Existing coal-fired power plants and industrial boilers will continue to be retrofitted in order to improve overall efficiency of the Chinese power plant fleet and to reduce emissions of particulates, sulphur dioxide (SO_2) and nitrogen oxides (NO_x) (Box 3.3). Bans on usage of coal in residential heating will be expanded, and scattered small-scale heat and power engines fuelled by low-quality coal are planned to be replaced by systems that are based on natural gas or renewable energies. Additionally, coal washing will be further developed in order to remove ash and improve coal quality. The clean-coal action plan sets a target of 80% of raw coal to be washed by 2020.

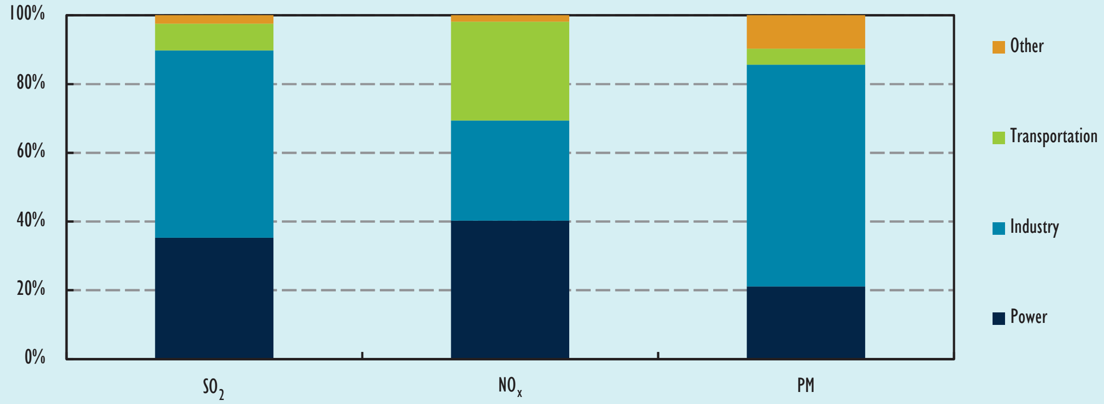
Box 3.3 Cleaning Chinese skies

Air pollution in the cities has become one of the biggest issues for Chinese people, and hence one of the highest political priorities for the government, which has officially declared a war against pollution. The air pollution is related to the concentration of harmful components directly emitted by the sources or generated through subsequent reactions. The most important pollutants to be considered are fine particles ($PM_{2.5}$), inhalable coarse particles (PM_{10}), NO_x and SO_2, although there are a few others such as ozone, mercury and carbon monoxide. Figure 3.7 shows the share of emissions in China in 2013 from the power sector, industry, transport and others, i.e. fertilisers, pesticides, forestry, etc.* From Figure 3.7 it is clear that coal will be the main target to tackle the air pollution issue, considering that coal is the main energy source for power and industry and considering the much higher emissions rates of coal compared with other sources. The question now is, will this have an impact on coal consumption? The answer is yes, but probably in a different way from what could be in principle expected.

Box 3.3 Cleaning Chinese skies (continued)

In power generation, the main measures against pollution will include enhancing the ongoing retrofitting of coal power plants with emissions-control cleaning equipment and the development of alternative sources of power generation.

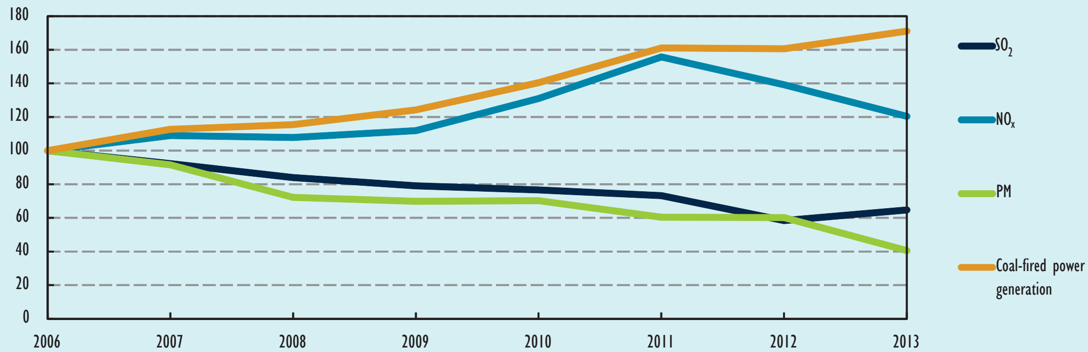
Figure 3.7 Sectoral breakdown of SO_2, NO_x and particulate matter (PM) emissions in China in 2013



Note: Industry comprises all industrial uses except power generation.

Emissions standards for coal power plants in China have been improved since the 1990s, and currently the legal emissions levels in force are comparable with standards in place in Europe and United States. In addition, power from plants with scrubbers to reduce sulfur and NO_x emissions receives an extra tariff. The regulatory and incentive schemes will result in declining emissions rates in coal power plants in China. Figure 3.8 shows how the increase in coal power generation since 2006 has come with a strong decline of SO_2 and particulate emissions during this time, from over 5 grammes (g) of SO_2 per kilowatt hour (kWh) in 2006 down to 2.1 g/kWh in 2013, and from 1.5 g of PM/kWh in 2006 down to 0.35 g/kWh in 2013. Regarding NO_x, Figure 3.8 shows that NO_x control equipment was installed only after 2011, and it went from 3 g of NO_x/kWh in 2006 down to 2.1 g/kWh in 2013. China has added NO_x and PM controls on more than 200 GW of coal plants both of the last two years. With continued efforts from the government, overall emissions reduction is expected in China over the next five years.

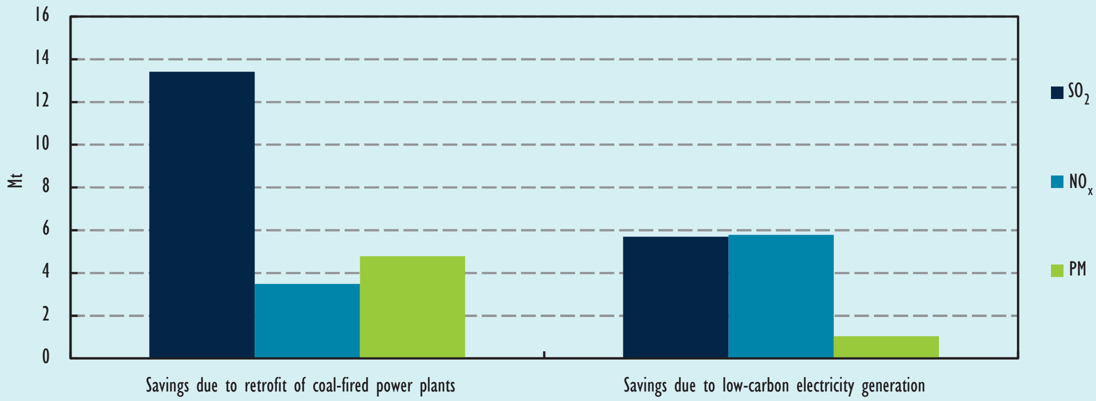
Figure 3.8 Evolution of emissions from coal-fired power plants



Box 3.3 Cleaning Chinese skies (continued)

In the case of power generation, China's development of nuclear, hydro, wind and solar is unmatched in the world. In 2014, for example, nuclear additions totalled more than 5 GW, hydro more than 20 GW, wind more than 20 GW and PV more than 10 GW. This policy, while beneficial for the air quality, has been adopted also for other reasons, such as diversification, to extend the life of domestic coal reserves and to reduce the carbon footprint. Figure 3.9 compares how many emissions were avoided in 2013 by the better performance of coal power plants as explained in the paragraph above (2013 versus 2006 rates) and how many were avoided by nuclear, hydro, wind and solar additions (considering zero emissions of these sources versus the same electricity generated from coal at average 2013 rates). As mentioned above, NO_x were only abated from coal power plants after 2011, so emissions avoidance from non-coal production is higher, but for SO_2 and PM, the emissions reduction from coal retrofits is significantly higher.

Figure 3.9 Emissions reduction between 2006 and 2013 due to better performance of coal-fired power plants versus switching to other energy sources

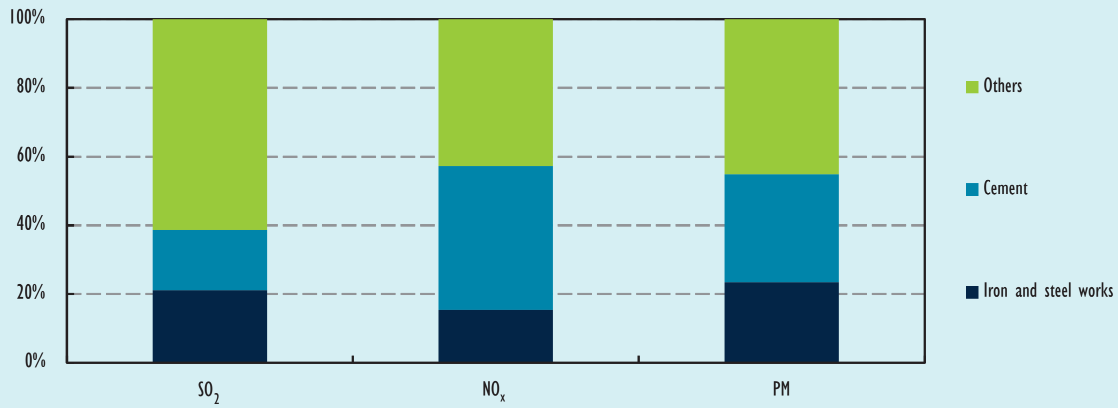


As shown in Figure 3.7, emissions from industry are the main source of air pollution in China. Figure 3.10 shows the breakdown among the three main sources of pollution: coke plants and steel works, cement plants, and others, largely coming from small unabated industrial boilers. Whereas emissions from steel and cement plants are significant, consolidation and retrofitting of these plants can make big steps towards reducing pollution. The biggest challenge is posed by small coal boilers. In China, around 700 Mt of coal are consumed every year in half a million boilers for residential and dispersed industrial sectors (excluding power, iron and steel, and cement). These boilers, often small, polluting and difficult to be retrofitted, are a significant factor in local pollution. Natural gas and, to a lesser extent, electric boilers should be in principle the replacement for most of those boilers, but supplying the gas required to replace that coal may be an issue. In 2014, gas consumption in China was 150 billion cubic metres (bcm), and growth was around 20 bcm. Under conservative assumptions, 1 bcm of gas can replace 2 Mt of coal, and hence, a part of the cleaner air needs to be achieved by replacing coal with cleaner coal. Big centralised co-generation** and district heating coal plants together with centralised large coal boilers with emissions-control equipment, much more efficient and much cleaner than small boilers, will also replace a big part of them.

Box 3.3 Cleaning Chinese skies (continued)

In addition, the improvement of air quality in the cities will imply a migration of coal consumption, and therefore emissions, towards the north and west, largely underpinned by three developments. The construction of ultra-high voltage lines to transmit electricity to the coastal regions will move hydropower from the south, mainly Sichuan and Yunnan, as well as solar power from Qinghai. But a big part of them will transmit wind and especially coal electricity from Inner Mongolia and Xinjiang. Likewise, coal conversion projects producing chemicals, liquids and synthetic natural gas will be built mostly in Xinjiang and Inner Mongolia. At the same time, restrictions on coal use in coastal regions will move part of the heavy industries, and hence coal consumption, to the west and north.

Figure 3.10 Breakdown of industrial emissions in 2013



Note: *Others* refer to industries others than power, iron and steel works and cement.

In summary, the fight against pollution is already happening and will be enhanced in the future, with significant impact on coal demand, both in volumes and in the geographical distribution. But not all the policies fighting air pollution will mean a reduction in coal use, as an important emissions reduction will come from better use of coal together with migration to mine-mouth consumption, rather than from coal use reduction. The conclusion is that, whereas reducing emissions from the power sector is relatively straightforward and is on track, the small boilers pose a more difficult challenge although the government has been promoting their shutdown for a few years.

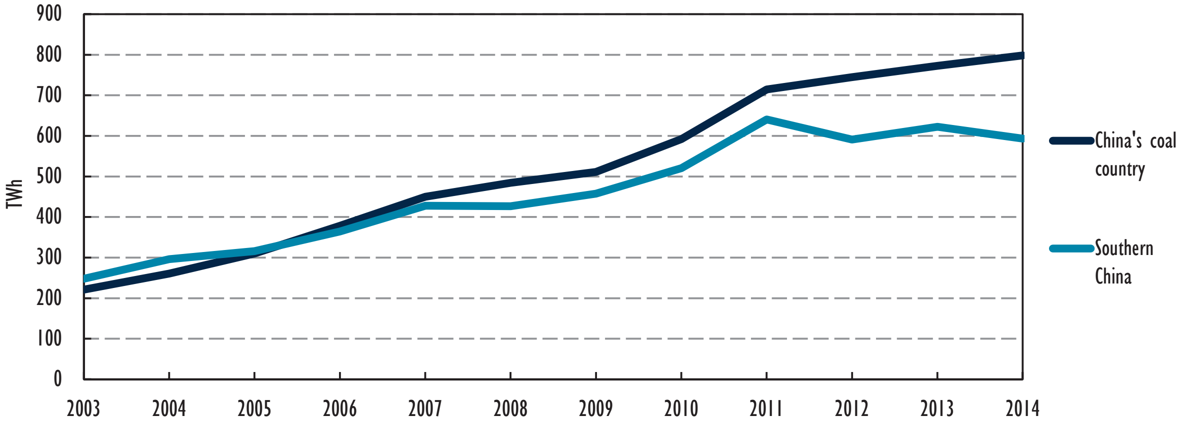
* The emissions figures do not come from official IEA statistics, but they are estimates from different sources, the main one being the Ministry of Environmental Protection of China.

** *Co-generation* refers to the combined production of heat and power.

Uncertainty remains on the future development of coal conversion, a series of processes that transform coal into gas, liquid fuels or chemicals. Currently there are around 104 coal conversion projects planned in China, which would increase Chinese coal consumption. However, it is unlikely that a significant proportion of these projects will be realised over the outlook period. Coal-to-liquids and coal-to-gas processes in particular are hardly profitable with the current low oil and gas prices. Additionally, the Chinese government plans to introduce tougher environmental regulations for coal conversion. Strict water-supply rules will be imposed, and all projects in regions that had environmental problems in the past five years will be banned, according to a draft of the National Energy Administration. Also, minimum requirements for energy efficiency will be set for coal conversion plants. As a result, it is expected that only limited large-scale development of coal conversion will happen in China until 2020. The estimated growth of coal demand for coal conversion over the outlook period is therefore revised downward in comparison with last year's *Medium-Term Coal Market Report* to a total quantity of roughly 125 Mt.

Besides the absolute changes in coal consumption, a geographical shift of Chinese coal demand from the southern provinces to the Chinese inland is expected to continue over the outlook period. To illustrate this, Figure 3.11 shows the development of coal-fired electricity generation, the main driver of thermal coal consumption, in the Chinese south and in the main coal-producing provinces of China, namely Inner Mongolia, Shanxi, Shaanxi and Ningxia. It is evident that coal-fired electricity generation in southern China peaked in 2011 and declined by 7% through 2014. Coal-based power generation in the main coal-mining provinces on the other hand continued to grow after 2011. The development shows that coal-fired electricity generation in China started to shift geographically towards the inland, especially to the coal-mining areas.

Figure 3.11 Electricity generation in coal-fired power plants in southern China and China's coal country, 2003-14



Note: Provinces considered as southern China: Fujian, Guangdong, Guangxi, Hainan, Zhejiang; provinces considered as China's coal country: Inner Mongolia, Shanxi, Shaanxi, Ningxia.

This depicted trend is expected to continue as greater environmental awareness and tighter regulations limit the potential for coal-fired power generation near the densely populated areas of coastal China. Beijing, for example, announced that the last of four coal-fired power plants in the city will be closed in 2016 and will be replaced by gas-fired generation. Additionally, China invests heavily in power transmission lines, which allow large-scale electricity generation far away from the demand centres and subsequent transportation of the electrical energy to the populated areas with low losses. The geographical shift of coal demand will be driven not only by the electricity sector, as Chinese industry is also affected by increasing environmental regulation and therefore will increasingly move to the Chinese north and west, too. Additionally, all major coal conversion projects are planned in the Chinese inland, which will add to the described shift. Generally, it can be stated that Chinese coal demand will increasingly be shaped by diverging trends in different areas of the country.

India

In India, the power sector will remain the key driver for thermal coal and lignite demand until 2020. With strong annual GDP growth of 7.6% and increasing rural electrification over the outlook period, power demand in India will rise substantially. Coal-fired electricity generation, which currently accounts for roughly 70% of total Indian electricity generation, will be one of the main sources to supply the additional Indian electricity demand. The target of the 12th Five-Year Plan of the Indian government was to add almost 70 GW of coal-fired generation capacity. Currently, there are coal-fired power plants with a total capacity of more than 80 GW already under construction, and around 50 GW of them are expected to come on line during the outlook period. More than half of these plants are based on supercritical technology, which is highly efficient and will therefore improve fuel efficiency of the Indian electricity system. In addition, old and inefficient power plants are increasingly renovated and modernised or shut down. One major contributor to achieving the electrification targets of the Indian government is the Ultra Mega Power Projects Programme, an initiative that aims to build 16 supercritical coal-fired power plants with capacities of approximately 4 GW each. However, until now only two of the planned power plants have been commissioned since the start of the programme in 2006.

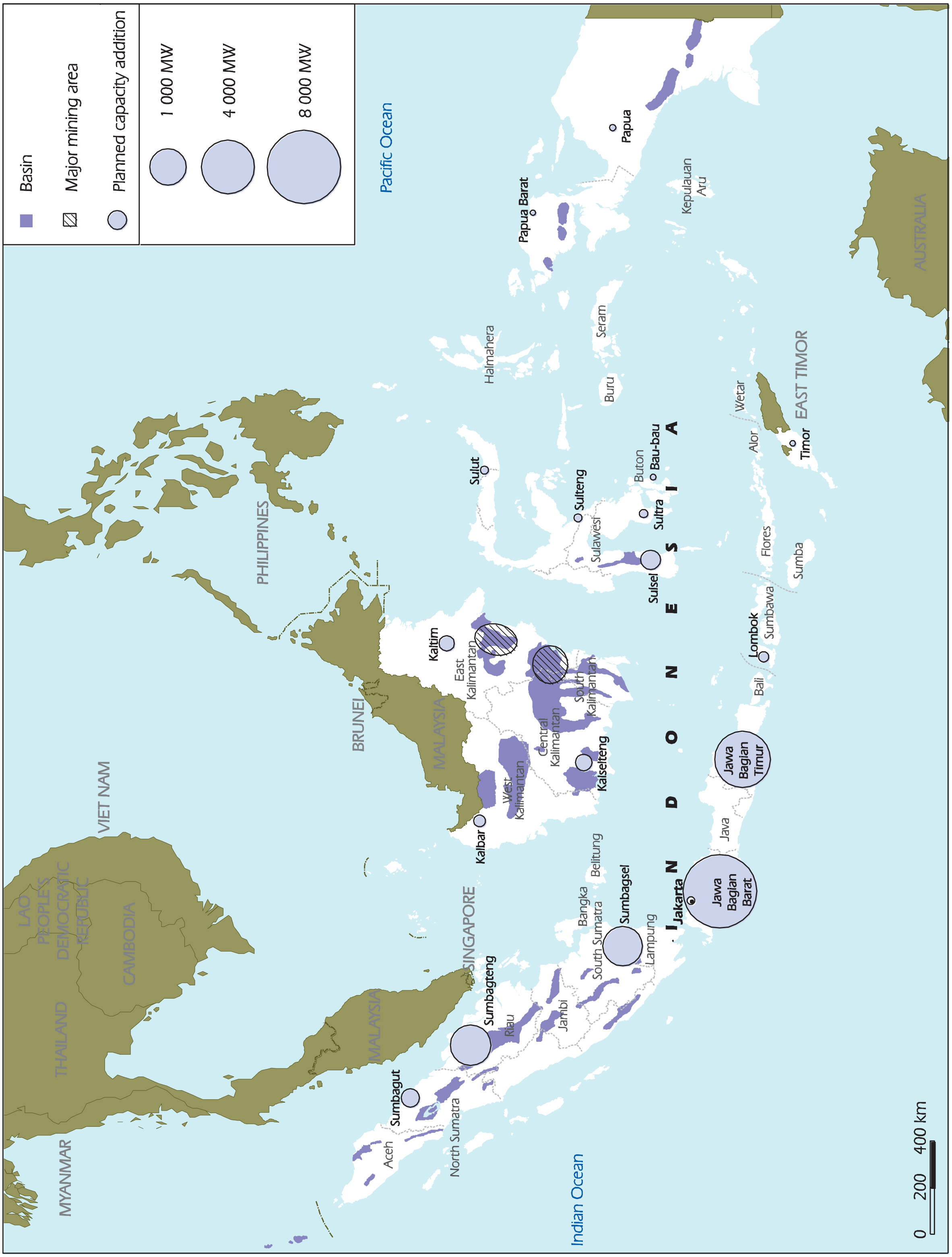
Taking into account the described developments, Indian demand for thermal coal and lignite is projected to grow from 510 Mtce in 2014 to 636 Mtce in 2020, which is equivalent to 3.7% average annual growth. Consumption of thermal coal and lignite in the power sector will grow from 360 Mtce to 451 Mtce over the outlook period, maintaining its share of approximately 70% of total consumption of thermal coal and lignite. With the projected growth rates, India will surpass the United States as the world's second-largest consumer of thermal coal and lignite in energy units by 2018. In terms of physical tonnes, India already surpassed the United States in 2014.

Other Asia including ASEAN

Demand for thermal coal and lignite in ASEAN countries is forecast to grow by 7.7% per year from 137 Mtce in 2014 to 214 Mtce in 2020, making it the fastest-growing country group in the outlook period. The main driver for the strong growth of coal demand in ASEAN countries is the electricity sector, because strong economic growth in combination with increasing electrification will lead to rising demand for electricity. Coal-fired power plants will be a major contributor to supply this additional demand, as several ASEAN countries plan to significantly extend their coal-fired power plant fleet over the outlook period.

In Indonesia, the administration under President Joko Widodo has initiated an ambitious plan to add 35 GW of installed capacity to the current grid capacity of 46 GW within the next five years in order to speed up electrification and provide a basis for economic growth in the coming decade. It is expected that coal-fired power plants are the major contributor to reach the 35 GW target with a share of roughly 55%, equivalent to 20 GW of coal-based generation capacity. The Indonesian government pushes coal-fired electricity generation because it increasingly wants to use the abundant domestic coal reserves as cheap fuel in the electricity sector. In addition to the 35 GW plan, the government launched the second so-called Fast-Track Programme (FTP-2) in 2010, which aims to add 10 GW of generation capacity to the Indonesian power plant fleet. However there have been substantial delays in construction, and the initial deadline of 2016 had to be postponed. In total there is 28 GW of coal capacity in the pipeline for commissioning in the outlook period, of which roughly half is already committed or under construction. The additional power plants from the 35 GW plan will also impact infrastructure needs for coal transport, as the new power plant projects are in general farther away from mining areas (Map 3.3).

Map 3.3 Planned capacity additions of coal-fired power plants in the Indonesian 35 GW plan



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.

Given the delays that the Fast Track Programmes experienced in the past, it is not expected that these power plants will be on line in time. Nevertheless, Indonesian coal-fired electricity generation will rise substantially over the outlook period. Additionally, coal consumption in fertilizer production is expected to increase. Demand for steam coal and lignite is therefore forecast to rise from 64 Mtce in 2014 to 100 Mtce in 2020.

Viet Nam also plans to build a substantial number of additional coal-fired power plants in the outlook period in order to reduce power shortages and keep up with rising electricity demand. In total roughly 19 GW of coal-fired capacity is intended to be commissioned by 2020 (Table 3.1), though less than half of that is expected to start in the outlook period, given the difficulties which such projects face. Malaysia and the Philippines also plan to extend their coal-fired power plant fleet significantly until 2020 and are therefore expected to have a growing demand for steam coal and lignite. Demand in other non-ASEAN developing Asian markets will also grow over the outlook period. However, with an average growth rate of 3.7%, the increase will be far lower than in the ASEAN country group.

Table 3.1 Planned commissioning of coal-fired power plants in Viet Nam

Plant	Company	Capacity (MW)	Commissioning
Duyen Hai 3	EVN	1 244	2016
Nghi Son 2	Kepco, Marubeni, EVN	1 200	2018
Thai Binh 1	EVN	600	2018
Thai Binh 2	PVN	1 200	2018
Vung Ang 2	PVN	1 200	2018
Vinh Tan 1	CPI, Vinacomin	1 200	2018
Vinh Tan 3	EVN, One Energy, Pacific Group	1 980	2018
Vinh Tan 4	EVN	1 200	2018
Thang Long	Thang Long-Gelexemco Thermal Power	600	2016
Song Hau 1	PVN	1 200	2019
Long Phu 1	PVN	1 200	2019
Long Phu 2	Tata Power	1 320	2019
Duyen Hai 2	Janakuasa	1 200	2020
Quang Trach 1	PVN	1 200	2020
Quynh Lap 1	Vinacomin	1 200	2020
Total		**17 744**	

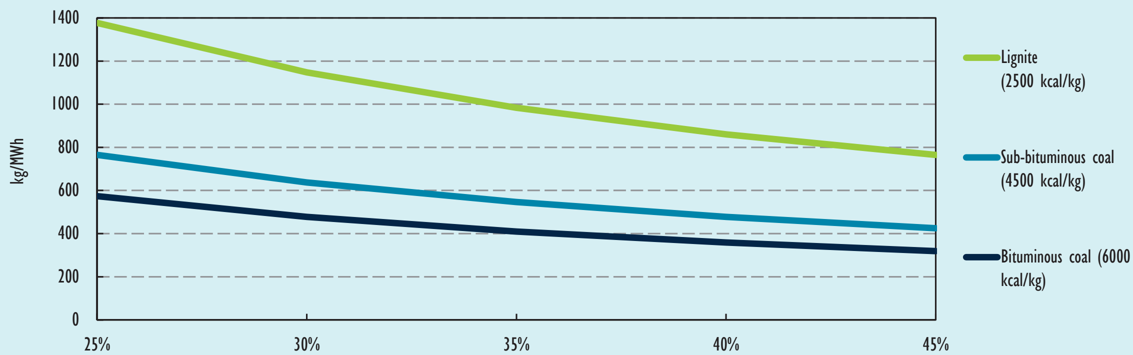
Other non-OECD

Demand for thermal coal and lignite in Africa and the Middle East will grow by 1.9% per year, equivalent to an increase of 17 Mtce. In South Africa, a combined 9.6 GW of coal-fired generation capacity will be added to the country's generation portfolio once the Kusile and Medupi power stations are on line. Despite the heavy delays in the construction schedule it is expected that Medupi will be fully operational within the outlook period. The first unit of the Kusile power plant is expected to come on line in 2017. Safi, in Morocco, will be the first USC coal power plant in Africa. Additionally, in Zambia, the 300 MW Maamba power plant nears completion and will presumably start commercial operations in 2016. Growth of demand for thermal coal and lignite in non-OECD Europe/Eurasia is forecast to grow slightly from 210 Mtce in 2014 to 220 Mtce in 2020, an increase of 0.8% per year. Demand in Latin America is expected to grow by 2.6% per year to 26 Mtce in 2020.

Box 3.4 Shifting to higher efficiency in coal power generation

The coal demand forecast for the power sector expressed in tonnes is defined by three parameters: coal power generation (MWh), efficiency of the coal plants (%) and calorific value of coal (kcal/kg). Figure 3.12 shows how much coal is needed to produce 1 MWh of electricity depending on these parameters. Obvious consequences of higher efficiencies are lower variable costs for the same electricity output: lower fuel costs, lower O&M costs and lower CO_2 emissions, which is also a cost where carbon price is in place. As a rule of thumb 1% point of increased efficiency reduce CO_2 emissions 2% points CO_2 (actually, the CO_2 reduction is a little bit higher).

Figure 3.12 Effect of efficiency and calorific value on coal consumption in power generation



The efficiency of a coal plant depends on many design and operating parameters, but the main factor defining plant efficiency is steam conditions (the higher pressure and temperature, the higher efficiency). Other important factors are cooling temperature (the lower temperature, or the lower condenser pressure, the higher efficiency), plant size (the larger, the higher efficiency) and coal quality (bituminous gets better efficiency than lignite, with sub-bituminous in between; the lower ash, the higher efficiency, etc.)

Subcritical plants are those in which steam is below the critical point of water (374°C and 221 bar). As mentioned, efficiencies depend on many parameters, but to give an order of magnitude, with typical steam conditions of 540°C and 175 bar and 6 000 kcal/kg bituminous coal, efficiency can be in the range of 35-40%* referred to Lower Heating Value. In Supercritical plants (SC), steam is above the critical point and therefore steam is not either a liquid or gas. With typical conditions of 250 bar and 540/565°C, efficiency can be 3-4% higher than for the mentioned subcritical conditions. In order to distinguish even higher steam conditions, the Ultra-supercritical plants (USC) concept has been defined (usually refers to steam at pressure higher than 250 bar and temperatures of 600°C). In a USC plant, efficiency can be 2-3% higher than in a SC plant.

Box 3.4 Shifting to higher efficiency in coal power generation (continued)

Higher steam conditions require special alloys and thicker walls, which means that SC and USC plants are more expensive than subcritical plants. Therefore, the decision to build subcritical vs SC/USC is a trade-off between higher capex and lower opex of US/USC. Low coal price, low or no price for CO_2 emissions, high interest rate and low load factor are all factors favouring subcritical plants over SC/USC plants. Given larger size required for SC (>300 MW) and USC plants (>600 MW), the lack of enough financial resources or the existence of small grid, for example in small islands, can also be a factor determining the construction of subcritical plants. Stringent emission standards favour SC/USC. In case of air pollutants, given the losses associated to the emission control equipment, adoption of stringent emission standards may foster the construction of SC/USC rather than subcritical. In case of CO_2, emission standards of 800 g/kWh mean that at least SC technology must be applied. Standards can be imposed by the government, but very often the lenders, either commercial banks or International Financial Institutions, set those standards as a principle.

Around 70% of the operational coal plants in the world are subcritical. In OECD countries, with an average age of the fleet over 30 years, most of the plants are subcritical. Exceptions are Korea and Japan, where most of the fleet is SC/USC. China has the largest SC/USC fleet in the world, over 300 GW, almost 40% of its coal power plants. In India, however, less than 15% of the fleet is SC, and none USC. Indonesia commissioned its first SC unit in 2011. Therefore, the shift from subcritical to SC/USC is happening and this trend will accelerate in the coming years. In China, most of the new plants will adopt SC/USC technologies. In India, the government announced in March 2015 that out of 87 GW of coal power plants under construction, 48 GW will be SC. Indonesia announced four new USC units due to be commissioned before 2020, although still subcritical is being built. In South Africa, the two new coal plants under construction (9.6 GW) will use SC technology. Safi (Morocco) will be the first USC plant in Africa. Overall, around two thirds of the plants under construction in the world are SC/USC plants, with more SC than USC.

The IEA has recommended that a good strategy to move forward is to phase out or retrofit the old and inefficient subcritical coal power plants and build only USC plants unless grid size or another limitation is in place. But this is a medium term policy; in the longer term, large-scale CCS is the only way for coal to move forward.

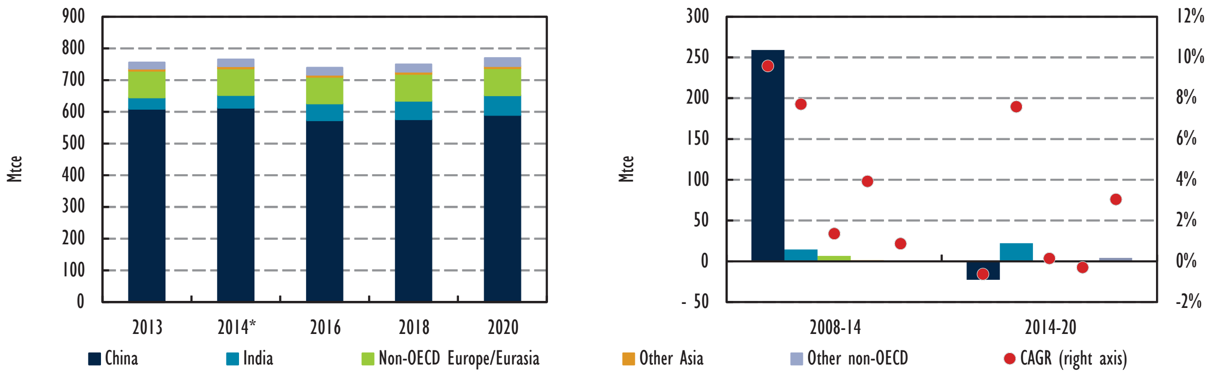
* As mentioned, this value can be only a very rough approximate, as efficiency depend on local weather, design, fuel quality, operation conditions, maintenance, etc. Average efficiency is lower than this for a variety of reasons: poor coal, bad maintenance, intermittent operation, lower steam conditions, etc.

Met coal

Met coal demand in OECD non-member economies remains roughly unchanged over the outlook period and amounts to 769 Mtce in 2020. In the short term, met coal consumption in OECD non-members will slightly decline but will recover after 2016. The share of OECD non-members in total global met coal demand remains constant at 81%.

In China, which is by far the largest met coal consumer in world, met coal demand is forecast to fall by 23 Mtce over the outlook period from 613 Mtce in 2014 to 590 Mtce in 2020, which equals an annual decline of 0.6%. This is a significant change for global met coal markets, as Chinese met coal demand grew strongly by roughly 10% on average over the last five years. In the short term, met coal consumption in China is expected to decline even stronger but will recover after 2016. This development is driven mainly by a slowdown in China's infrastructure investment and construction activity that affects demand for steel, cement and other building material that relies on coal in the production process. The slowdown is caused by lower growth of urbanisation and a greater emphasis on services and consumption in the Chinese economy. Additionally, the demographic structure in China changes, and the average age of the population increases. This affects for example construction activity in the residential housing sector. Another factor that negatively affects Chinese met coal consumption is the expected increase in scrap-based steel production. Because of the lower domestic steel consumption, the Chinese industry will increase exports of coke and steel, which in the short term will partly offset the negative impact of the developments described above on Chinese met coal demand. These exports will be mainly destined for other emerging markets, as Chinese companies intend to increase investment activity in foreign markets. Despite its own decline in demand, China accounts for 77% of met coal demand in OECD non-member economies and 62% of global met coal demand in 2020.

Figure 3.13 Forecast of met coal demand for OECD non-member economies



* Estimate.

Demand for met coal in India is projected to grow by 7.6% per year on average over the outlook period. In absolute terms, demand will grow from 40 Mtce in 2014 to 62 Mtce in 2020, which is the largest increase over the outlook period. The increase in Indian met coal demand is driven by economic growth and heavy infrastructure investments, which will lead to increasing steel production.

Non-OECD Europe/Eurasia is the second-largest met coal-consuming region among OECD non-members. Over the outlook period, demand remains roughly unchanged in this country group with a total of 84 Mtce in 2014 and 85 Mtce in 2020. Demand in Africa and the Middle East does not change substantially through 2020. In Latin America, consumption of met coal will grow slightly by 1 Mtce or 1.3% per year over the outlook period. In the ASEAN country group, demand for met coal doubles from 2 Mtce in 2014 to 4 Mtce in 2020, mainly because of additional Indonesian steel production. Met coal demand in other developing Asian economies remains unchanged over the outlook period.

Global coal demand forecast in the CPCS

Global coal demand has been heavily influenced by the strong growth of Chinese coal consumption over the last decade. However in 2014, according to official data, Chinese coal demand could have declined for the first time in 15 years (see Chapter 1). And preliminary figures for 2015 indicate that Chinese coal consumption might further decline in 2015. China's National Energy Administration announced in its coal statistics for the first half of 2015 that coal consumption fell by 5%, while electricity consumption increased by 1.3%. Additionally, Chinese coal imports from January to July fell 33.9% in 2015 compared with the same time period in 2014. Total coal production in China declined by 7.2% from January to July 2015. All these figures have to be interpreted with caution, as 2014 data are preliminary and could be revised. Nevertheless, a structural decline of Chinese coal consumption has to be considered at least as a feasible scenario, and if economic growth is much weaker than expected, it is even likely.

China accounts for roughly half of global coal consumption, so a sustained decline in Chinese coal consumption would have a significant impact on international coal markets as demand, supply, prices and trade flows would be affected. To address this issue, the CPCS assumes that Chinese coal consumption peaked in 2013 and continues to decline over the outlook period. With an average growth rate of 6.3% over the outlook period, Chinese economic growth is assumed to be the same as in the forecast. Instead, the declining coal consumption in the CPCS is a result of a stronger rebalancing in the Chinese economy and subsequently lower demand in energy-intensive industries, higher decoupling of GDP growth and electricity demand growth, lower coal use in coal conversion processes, and lower activity in the Chinese infrastructure sector.

The infrastructure sector in China is of high importance, as Chinese coal consumption is heavily dependent on infrastructure investments. To illustrate this, Figure 3.14 shows a flow chart of the usage of coal in the Chinese economy in the year 2013. The chart shows that roughly 40% of coal demand in China is used in steel, iron, cement and glass production or the construction sector either by directly consuming coal or by consuming electricity or heat that is generated from coal firing. All the mentioned sectors are mainly driven by infrastructure investments. For example, roughly 70% of Chinese steel consumption is used in housing and infrastructure, which is substantially higher than in other countries; the United States, for example, uses only 40% of the consumed steel for that purpose. In total, roughly one-third of coal consumed in China is infrastructure-related.

Figure 3.14 Flow chart of Chinese coal consumption

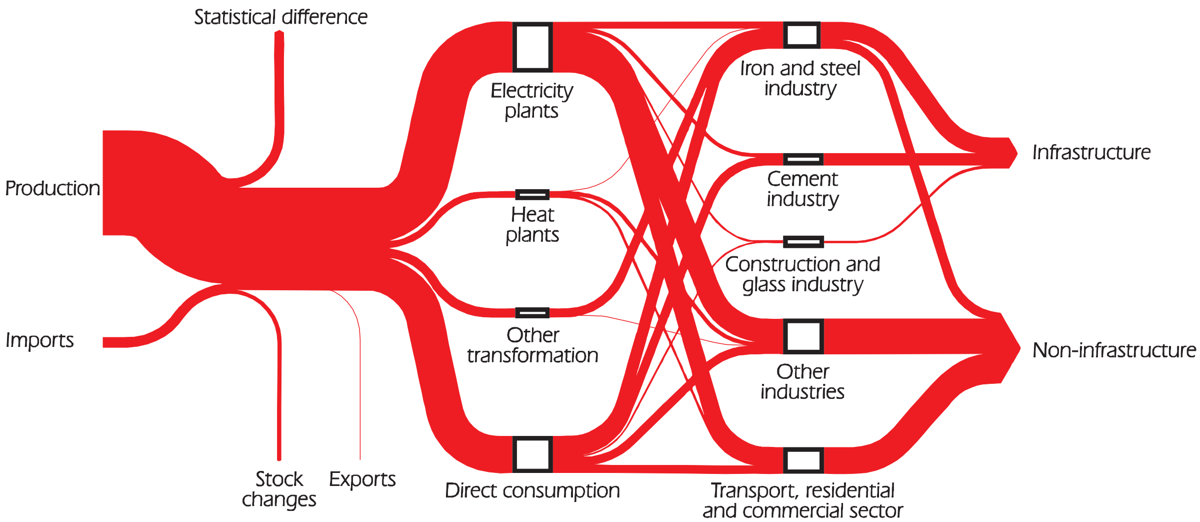
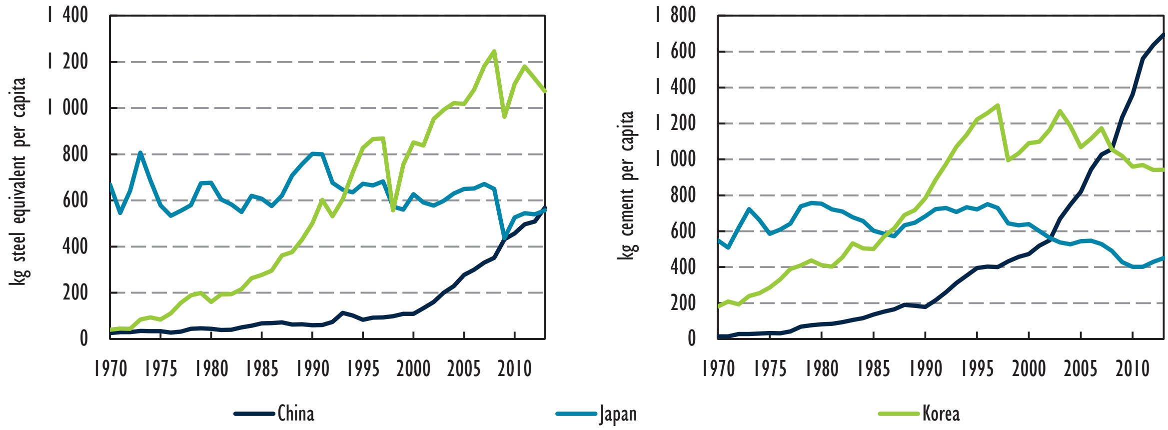


Figure 3.15 shows the historical development of steel and cement consumption per capita in China, Japan, Korea and the United States. It can be seen that consumption of both steel and cement tends to stagnate at a certain point in the development of an economy as economic growth is increasingly driven by domestic consumption and services instead of investment. The Chinese government specifically addressed this issue in its 12th Five-Year Plan, which focuses on sustainable economic growth and a shift from investment, which currently makes up almost half of total Chinese GDP, to consumption. A possible indication that this shift has already started is the recent data on Chinese steel and cement consumption, which show a slowing growth trend for cement and even stagnation for steel in 2014 (see regional focus on China in Chapter 1).

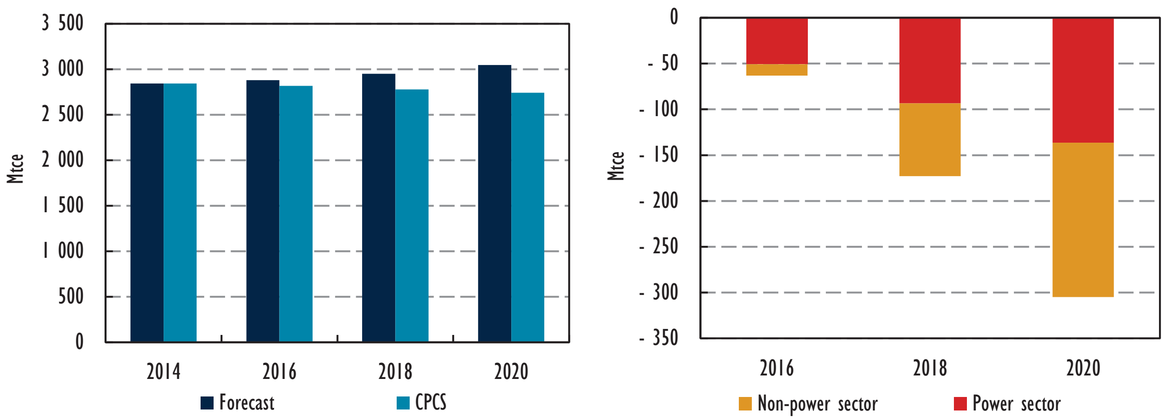
Figure 3.15 Historical steel (left) and cement (right) consumption per capita in selected countries



However, as shown in Figure 3.15, both steel and cement consumption show a volatile as well as cyclical behaviour and are therefore highly dependent on fluctuations in economic output of an economy. The historical data for Asian countries such as Japan and Korea show that steel and cement consumption went into a sideways movement after a strong growth period. Additionally, the first substantial slowdown in steel and cement consumption in Japan and Korea did not necessarily lead to an absolute peak, as consumption continued to grow afterward. If we consider steel stock per capita, China (around 5 kilogrammes [kg] per capita) has less than half of Germany (over 10 kg per capita) and roughly one-third Japan and Korea (around 15 kg per capita). Nevertheless, it is assumed in the CPCS that China will successfully transform towards a more consumption-driven economy in the coming years and consequently will reduce its investment and infrastructure-based use of coal.

The resulting Chinese coal demand in the CPCS in comparison with coal consumption in the forecast is depicted in Figure 3.16. The left chart shows that in absolute terms, coal demand in China declines by 203 Mtce from 2 843 Mtce in 2014 to 2 640 Mtce in 2020 in the CPCS. This decrease is equivalent to an average annual growth rate of -1.2% over the outlook period. The share of coal in total primary energy consumption decreases to 26% compared to 27% in the forecast. The difference between Chinese coal consumption in the forecast and the CPCS amounts to 305 Mtce as shown in the right chart of Figure 3.16. It can also be seen that coal demand is lower in both the power and non-power sectors. In 2020 the difference between coal consumption in the forecast and the CPCS is even higher for the non-power sector (-172 Mtce) compared with the power sector (-136 Mtce). This is a result of the assumed gradual transition of the Chinese economy towards consumption-driven growth, which lowers coal demand in sectors that are mainly influenced by infrastructure investments. In terms of coal type, consumption of thermal coal (-208 Mtce) and met coal (-97 Mtce) is lower in the CPCS. Consequently the decline in met coal consumption is significantly more pronounced in the CPCS compared with the forecast. In the CPCS, demand outside China is hardly affected. The explanation is in the slight impact on price levels, as shown in Chapter 4. Given the large coal-based installed capacity in China in 2020, close to 1 000 GW, and the low load factor implied in the CPCS, the coal peak in China will be a strong disincentive to build other sources of power generation.

Figure 3.16 Chinese coal demand in the CPCS compared to the forecast (left: absolute; right: differences)



Global coal supply forecast

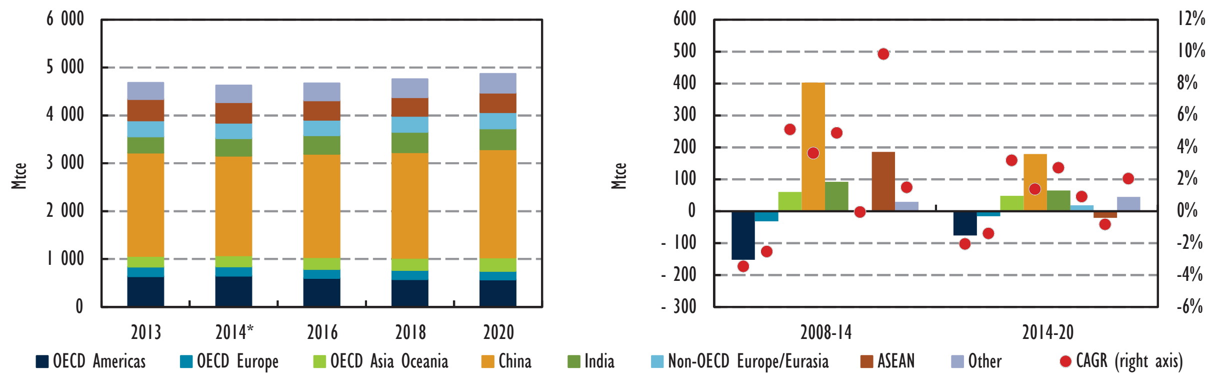
The global coal supply is forecast to amount to 5 814 Mtce in 2020, up from 5 610 Mtce in 2014. The increase of 204 Mtce is equivalent to an average annual growth rate of 0.6% over the outlook period. The incremental growth of coal production stems from OECD non-member economies with an increase of 261 Mtce. Coal production in the OECD declines because of decreasing output in OECD Americas and OECD Europe. The increase in production volumes in OECD Asia Oceania does not offset the falling production in the other OECD regions.

Thermal coal and lignite supply forecast, 2015-20

The global supply of thermal coal and lignite is projected to increase by 0.9% per year from 4 623 Mtce in 2014 to 4 869 Mtce in 2020. The share of thermal coal and lignite in total global coal production will amount to 84% by 2020. The bulk of incremental thermal coal and lignite supply will be produced in OECD non-member economies, where production increases by 287 Mtce or 1.3% per year. Supply in the OECD falls by 43 Mtce over the outlook period, which corresponds to an annual decrease of 0.7%. This development results from declining coal production in OECD Americas and OECD Europe, which is partly offset by growing supply in OECD Asia Oceania.

The supply of thermal coal and lignite in the United States, the largest producer in the OECD, declines by 2.3% per year to 536 Mtce in 2020. US coal production continues to suffer from regulatory pressure regarding environmental permitting and high mining costs in comparison with international market prices. However, mining costs in the United States will continue to differ substantially among regions. The Appalachian Basin is the most costly region with mining costs around USD 80/t. Mining in the Powder River Basin, on the other hand, is substantially cheaper at roughly one-fourth of the costs in Appalachia. In addition to declining production, another trend expected in the United States over the outlook period is a process of consolidation of the coal industry. Four significant bankruptcies have occurred since June 2014: James River Coal, Walters Energy, Patriot Coal and Alpha Natural Resources. They are at different stages of the bankruptcy proceedings, but dissolution of companies is occurring in some cases: Patriot has essentially sold off all its operations. At the same time, other players are acting as consolidators. For example, Murray Energy is growing, acquiring CONSOL assets as well as a large portion of Foresight Energy. Murray has actually become the largest underground coal producer in the United States. Others, such as Bowie Resources and Westmoreland, have both made acquisitions in the United States over the last 18 months. Financial pressure from reduced share prices has also put pressure even on healthier companies such as Peabody and Arch (the two largest US producers), which revised their outstanding shares structure. Production of the second-largest producer in the OECD, Australia, increases by 48 Mtce over the outlook period, as Australian exports to the Asia-Pacific region grow.

Figure 3.17 Forecast of thermal coal and lignite supply



* Estimate.

China, the largest coal producer in the world by far, increases thermal coal and lignite output from 2 081 Mtce in 2014 to 2 261 Mtce in 2020, which is equivalent to growth of 1.4% per year on average. Chinese thermal coal and lignite production thereby accounts for 46% of global output in 2020. Growth of Chinese coal production over the outlook period is caused by falling mining and transportation costs as well as increasing restrictions for imports of low-quality coal, which supports domestic production. A dampening effect on production results from continuing efforts by the Chinese government to close small coal mines, which are usually characterised by low efficiency, high pollution and accident risk for workers. As a result, the total number of Chinese coal mines will fall below 10 000 by the end of 2015 and is expected to decline further over the outlook period.

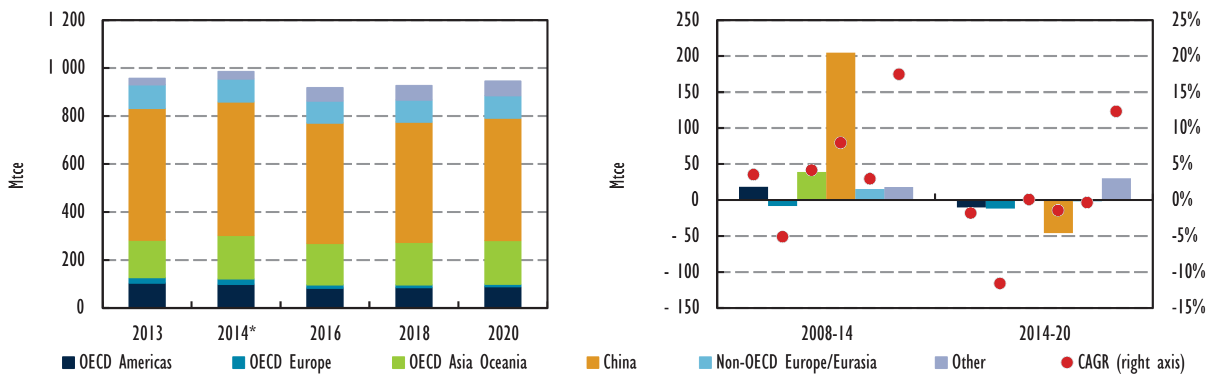
Indian thermal coal and lignite production is projected to grow by 2.7% per year over the outlook period. In absolute terms, Indian output rises from 368 Mtce in 2014 to 432 Mtce in 2020. The incremental growth of roughly 65 Mtce is driven by the government's efforts to increase production. The state-controlled company Coal India Limited (CIL) is the main target of increasing output, but a new bill introduced in March 2015 opens the door to commercial mining and foreign investments. In combination with heavy investments by CIL into the modernisation of Indian mines and mining practices, this allows for improved efficiency and labour productivity. Additionally, improvements in the lacking Indian railway infrastructure enable higher production levels. Compared with the targets of the Indian government to raise total coal production to 1.5 billion tonnes by 2020, of which CIL shall provide 1 billion tonnes, the forecasted increase in Indian coal supply is small. Hence, there is substantial upside potential for coal production in India.

Production of thermal coal and lignite in the ASEAN countries is forecast to decline from 431 Mtce in 2014 to 410 Mtce, a decrease of 0.8% per year on average. This slight decrease is mainly caused by Indonesia, where stronger efforts to cut down on illegal mining as well as higher coal royalties will dampen mining output. Production in Africa and the Middle East will grow by 2.1% per year over the outlook period, as South Africa increases thermal coal supply. Strong production growth is also expected in Latin America with an average yearly increase of 4.6%. This comes mainly from Colombia, which raises mining output as growth in export infrastructure allows for higher Colombian exports. Supply of thermal coal and lignite in non-OECD Europe/Eurasia grows slightly by 0.9% per year to 340 Mtce in 2020.

Met coal supply forecast, 2015-20

Global met coal production is projected to fall from 985 Mtce in 2014 to 945 Mtce in 2020, an average annual decrease of 0.7%. OECD non-member economies account for the vast majority of global met coal production with a share of almost 70% in 2020. The met coal supply in OECD non-members declines from 681 Mtce to 660 Mtce over the outlook period, which is equivalent to an annual decrease of 0.5%. Production in the OECD declines from 304 Mtce in 2014 to 286 Mtce in 2020.

Figure 3.18 Forecast of met coal supply



* Estimate.

In OECD Americas, production of met coal decreases from 100 Mtce to 89 Mtce, mainly driven by developments in the United States. Met coal supply also decreases in OECD Europe, because of relatively high production costs and the phase-out of domestic production in Germany by 2018. Total output in OECD Europe amounts to 11 Mtce in 2020. In OECD Asia Oceania, met coal production remains roughly unchanged over the outlook period at 182 Mtce. Met coal supply in OECD Asia Oceania stems almost entirely from Australia, the second-largest met coal producer and largest met coal exporter in the world.

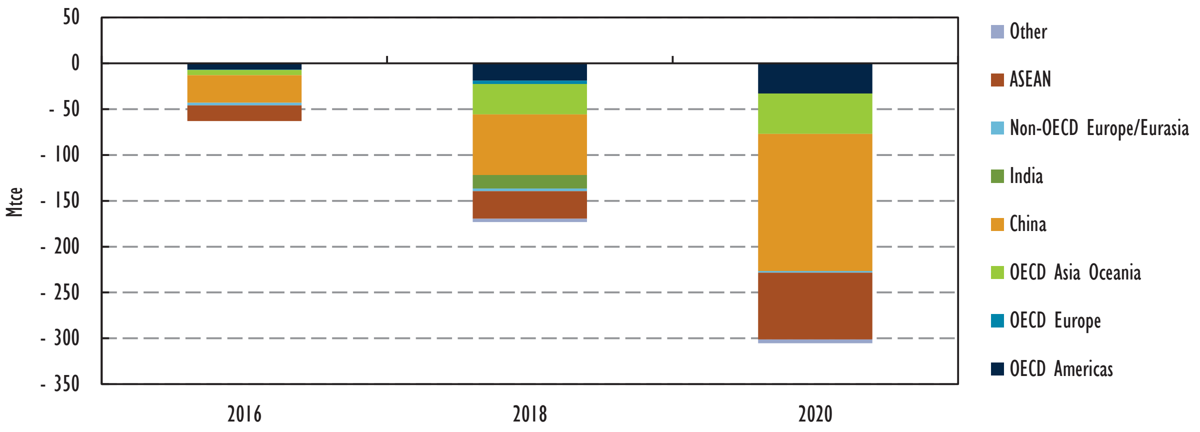
In met coal production, China is again by far the largest producer in the world. Over the outlook period, China decreases its met coal output by 1.4% on average per year to 510 Mtce in 2020. As Chinese met coal supply mostly serves domestic demand, production levels are affected by slowing growth in the Chinese construction and steel sectors and the subsequent decline in met coal consumption.

Relative growth of met coal supply will be strong in ASEAN countries and other developing Asian economies. This development is driven mainly by Mongolia, which increases domestic production and confirms its status as an important met coal supplier to China, supported by improved infrastructure. Met coal production in non-OECD Europe/Eurasia is projected to remain roughly unchanged, amounting to 93 Mtce in 2020. In India, Africa and the Middle East as well as Latin America, met coal supply is forecast to increase slightly but remains at comparably low levels.[2]

Global coal supply forecast in the CPCS

International coal markets are very competitive. Therefore a declining demand for coal in China affects not only coal Chinese coal producers but also suppliers in other countries. Figure 3.19 depicts the difference in coal supply between the CPCS and the forecast for different countries and regions.

Figure 3.19 Differences in total coal supply between the CPCS and the forecast



It can be seen that roughly half of the decline in Chinese coal demand is compensated by lower domestic production and the other half is compensated by lower coal imports. China's 2020 coal production is 150 Mtce lower in the CPCS, mainly because Chinese high-cost mines become unprofitable And lower their output. Additionally, lower coal use in coal conversion processes in the CPCS affects domestic coal production. The most affected coal exporting countries are Indonesia, which lowers its coal output by 73 Mtce; Australia, with a decrease of 44 Mtce; and the United States, which lowers its output by 31 Mtce. Given that a decline in Chinese coal demand has a significant impact on supply in coal-exporting countries, a detailed description of the impacts of declining coal demand in China on international trade volumes is provided in Chapter 4.

[2] Indian met coal statistics are generally difficult to interpret. Not all coals classified as coking coal are suitable to produce coke to be used in metallurgical processes because of quality issues, and are therefore used in steam and heat making.

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4. MEDIUM-TERM FORECAST OF SEABORNE COAL TRADE

Summary

- **International seaborne hard coal trade is forecast to grow by 1.2% per year on average over the outlook period.** Total trade volumes increase by 79 million tonnes of coal equivalent (Mtce) to 1 159 Mtce by 2020. Thermal coal trade grows by 1.3% per year; metallurgical (met) coal trade grows by 0.9% annually.

- **Total coal exports from member countries of the Organisation for Economic Co-operation and Development (OECD) balance imports by 2020.** Coal imports in OECD Europe decline, while exports from Australia and the United States increase. Australia remains the world's largest coal exporter in terms of energy content over the outlook period.

- **The importance of the Pacific Basin in international coal trade continues to rise.** Indian coal imports increase strongly by 6.6% per year. Chinese coal imports decline over the outlook period. As a result, India surpasses China as the largest coal importer in the world.

- **Exports from Indonesia decline by 0.9% per year over the outlook period.** This is a result of growing domestic demand and weak Chinese demand for imports. As Indonesian export volumes decline, Australian exporters step in and raise output.

- **In the China Peak Case Scenario (CPCS), Chinese exports almost offset imports.** Lower domestic consumption leads to a sharp decrease in imports and increasing shipments of Chinese producers into the Asian coal markets.

- **Lower Chinese demand in the CPCS has only a limited effect on coal prices.** Because of the flat supply curve, the price difference between the forecast and the CPCS is less than USD 5/tonne (t). However, the international coal markets will remain oversupplied significantly longer in the CPCS.

Methodology and assumptions

This section gives a medium-term forecast of international thermal and met coal trade based on spatial equilibrium models.[1] These models estimate trade flows between exporting and importing countries until 2020, based on assumptions about the future development of coal demand, transport costs, production costs, mining capacities and infrastructure capacities.

The simulation models include the major coal-mining regions and demand hubs, and feature detailed datasets on mining and transport costs, as well as port, railway and mine capacities. Expansions of mine and infrastructure capacities are derived from detailed project lists. Different coal qualities are distinguished by type (thermal or met coal) and energy content. The evolution of mining costs is projected using assumptions based on the price developments of input factors such as diesel fuel,

[1] For more details, see previous editions of this report. A detailed description of the thermal coal trade model can be found in Paulus and Trüby (2011). For further details on the met coal trade model, please refer to Trüby (2013) or Trüby and Paulus (2012).

steel products and labour force. Productivity gains are assumed to be lower than increases in infrastructure and mining costs due to input price escalations and deteriorating geological conditions. It is further assumed that the main policies regarding coal, such as export quotas, taxes and royalties, stay constant during the outlook period unless changes have been firmly committed.

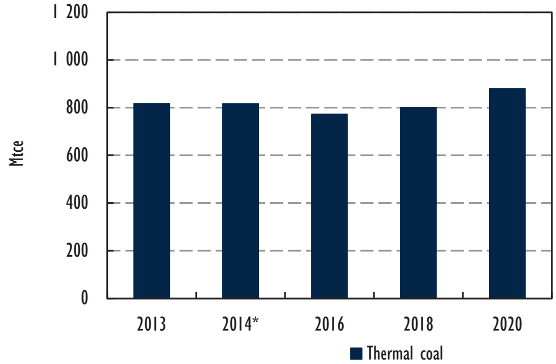
Seaborne coal trade forecast

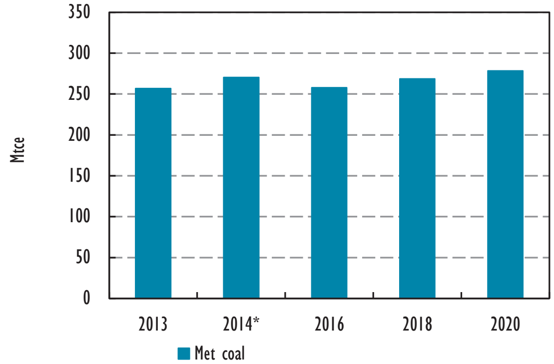
Seaborne hard coal trade is forecast to grow from 1 079 Mtce in 2014 to 1 159 Mtce in 2020, an average increase of 1.2% per year over the outlook period. Most incremental growth comes from thermal coal trade, which increases by 64 Mtce or 1.3% per year. Met coal trade volumes are significantly smaller, accounting for roughly one-quarter of total seaborne hard coal trade. Over the outlook period, met coal trade increases by 8 Mtce, equivalent to average annual growth of 0.5%.

Net imports of the OECD group will continue to decline over the outlook period, and by 2020 the total exports almost offset imports. This development is driven by growing hard coal exports from Australia in combination with decreasing demand in OECD Europe and OECD Americas. Australia will maintain its position as the largest hard coal exporter in the world in terms of energy content and become the largest exporter also by mass over the outlook period.

In OECD non-member economies, India increases net hard coal imports from 178 Mtce in 2014 to 261 Mtce in 2020, a strong average increase of 6.6% per year. At the same time, Chinese imports decline over the outlook period. Therefore India surpasses China as the world's largest importer of hard coal. The Association of Southeast Asian Nations (ASEAN) country group remains a net exporter of hard coal over the outlook period, mainly because of Indonesian exports. However, because of increasing domestic demand for hard coal in the ASEAN countries, net exports will decline from 292 Mtce in 2014 to 198 Mtce in 2020. Net exports of hard coal from Latin America are projected to increase significantly over the outlook period as Colombian exports rise. The development of total export volumes in international seaborne markets for steam and met coal is depicted in Figure 4.1.

Figure 4.1 Forecast of total export volumes in the international seaborne steam (left) and met (right) coal markets





* Estimate.

Seaborne thermal coal trade forecast, 2015-20

Seaborne trade of thermal coal is projected to grow by 1.3% per year on average, from 816 Mtce in 2014 to 880 Mtce in 2020, with this growth occurring from 2018 onwards. The share of seaborne thermal coal trade in total global consumption of thermal coal will remain at 18% over the outlook period. As European and American thermal coal imports decline, Asian countries drive growth of the international seaborne thermal coal trade over the outlook period.

Indian imports of thermal coal increase sharply over the outlook period by 7.7% per year on average. In absolute terms, imports amount to 204 Mtce in 2020, up 73 Mtce compared with 2014. As forecast in previous editions of the *Medium-Term Coal Market Report*, India surpasses China to become the largest importer of thermal coal in the world. The developments in India are driven by a substantial increase in demand (+3.7% per year), which cannot be met by domestic production. Hence, despite increasing efforts by the Indian government to strengthen coal production, for example by accelerating land acquisition and mining approvals and by improving the rail infrastructure, Indian dependency on thermal coal imports will remain over the outlook period.

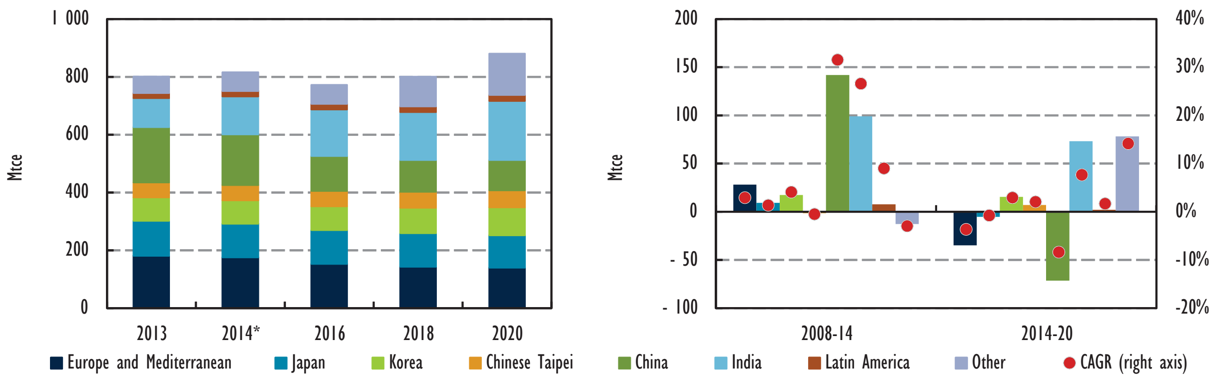
Chinese imports are forecast to decrease from 176 Mtce in 2014 to 104 Mtce in 2020, which is equivalent to an average decline of 8.3% per year. This development can be explained by several reasons. First, growth of Chinese coal demand will slow down, making it easier for domestic suppliers to close the gap between domestic production and consumption. Second, the structure of Chinese coal demand is expected to change over the outlook period with coal demand shifting geographically from the densely populated coastal areas towards inland regions. This shift is caused by sharper environmental regulations around cities in eastern and southern China as well as by improved long-distance power lines that allow for coal-based electricity generation in coal-rich regions, and subsequent transmission of the electrical energy to the demand centres at the coast. Third, domestic coal production is projected to become more competitive because of falling mining and transportation costs that will flatten the cost curve of coal production in China until 2020. Finally, the Chinese government introduced several policy measures to protect the domestic coal sector, such as a quality control for imported coal, a directive for coal-fired power plants to reduce coal imports and to introduce taxes on thermal coal imports. These regulations will improve the competitiveness of domestic thermal coal production in comparison with imports from foreign producers.

In European and Mediterranean countries, declining demand for thermal coal will reduce needs for imports. The effect of lower coal consumption on imports is partly offset by lower domestic coal production in several European countries, for example Germany and the United Kingdom. Additionally, economic growth in Turkey leads to growing coal demand and therefore rising imports. In total, imports of the European and Mediterranean region decline from 175 Mtce in 2014 to 141 Mtce in 2020, or by 3.5% per year on average.

Imports of thermal coal to Japan will decline slightly over the outlook period, totalling 112 Mtce in 2020. Imports to Korea, on the other hand, will rise over the outlook period because of additional coal-fired power plants that increase the need for imported coal. Korean coal imports are expected to increase from 81 Mtce in 2014 to 97 Mtce in 2020, equivalent to average annual growth of 3.0%. Also, in Chinese Taipei, additional use of coal in electricity generation leads to growing thermal coal imports. In 2020, imports are expected to amount to 59 Mtce, up from 52 Mtce in 2014.

Southeast Asian countries, especially Malaysia, Thailand, Viet Nam and the Philippines, are forecast to increase thermal coal imports over the outlook period as all countries plan to build additional coal-fired power plants. Aggregated imports to these countries are expected to increase by more than 75 Mtce over the outlook period. Viet Nam will become a net importer of thermal coal by 2017. In Figure 4.2, which shows the development of seaborne thermal coal imports over the outlook period, the mentioned countries are subsumed under the country group "Other" together with the United States and several small importers.

Figure 4.2 Forecast of seaborne thermal coal imports



* Estimate.

Note: CAGR = compounded annual growth rate.

Box 4.1 Modernising and reforming the coal sector in Indonesia

Coal in Indonesia is not only a secure domestic source of energy but also a source of direct income to central and provincial governments through royalties and taxes as well as a catalyst for the Indonesian economy as a result of the multiplier effect of such a labour- and capital-intensive industry: the impact of the sector's performance goes beyond any society's need for adequate energy supply. On the other hand, the impact of coal production and use on the environment and people is manifold: land is deeply altered by mining; additionally mining, coal washing and power production are water intensive, and there are liquid effluents that must be controlled; coal burning results in local air pollution; and ultimately, carbon dioxide (CO_2) emissions will go into the atmosphere. If best practices are not followed, the environmental impact will be unsustainable and unacceptable. As market players' behaviour is highly dependent on regulations, a good policy on coal will yield significant economic and social benefits, including a reduction of the environmental footprint.

The government of Indonesia is well aware of the role of coal in its energy system, and its coal policy is focused on three key objectives: enhancing energy security, optimising coal resource utilisation and maximising government revenue.

Box 4.1 Modernising and reforming the coal sector in Indonesia (continued)

While pursuing these goals, the government considered or adopted numerous initiatives following the approval of the 2009 Law on Minerals and Coal, including: establishing a production cap at the national level of 400 million tonnes (Mt) (or 425 Mt); a domestic market obligation to sell 25% of production to local consumers; increasing export duties and royalties; banning low-quality coal exports; establishing a new licence for exports; foreign ownership divestment; compulsory processing for coal to be exported; minimal sale price for mine-mouth power project (production cost + 25% margin); and renegotiations of Coal Contracts of Work. Some of these measures, such as the ban on low calorific coal, were discussed for years with many different proposals considered before it was finally decided not to adopt them. While policy needs to be updated and adapted to the changing circumstances and some of the mentioned proposals are well worth a chance, the proliferation of initiatives, regulatory uncertainty and lack of clarity have had a negative impact on investor confidence.

Furthermore, in 2014 the government announced its intention to terminate or renegotiate 63 bilateral investment treaties. These agreements are important as they protect investments against expropriation and nationalisation, and enable foreign investors to seek international arbitration rather than being solely reliant on the domestic courts. While it is logical to modernise the text of the treaties after 40 years in force to reflect the current reality of the country, investors might perceive these measures as an attempt to obstruct their claims or leave new investments unprotected. Indonesia has been able to attract substantial foreign capital, and the economic and demographic reality and prospects of the country make it a very attractive place to invest; the coal sector will continue to need foreign investment to continue its development. If players feel that their investments are not protected, capital flows will decline and existing investments will require a higher country risk premium.

Given the prevalence of low-rank coal reserves in Indonesia, improving the efficiency of this type of coal throughout the whole supply chain is a key issue. This task is not to be underestimated: small and medium-sized enterprises often lack the funding and resources, so the approach has to be flexible and inclusive. While research and development efforts and technology development are important, there are already available technologies that can be used. For example, Neurath F and G in Germany are burning lignite with net efficiency of 43% and very low levels of nitrogen oxides, sulphur dioxide and dust emissions.

The benefits of high-efficient, low-emissions coal power plants are substantial, extending the life of reserves, reducing pollutant emissions by two orders of magnitude, and reducing operating costs given the use of less coal for the same output thus also reducing CO_2 emissions. However, the low cost of coal, lack of a CO_2 price, and difficulties raising capital are the three important factors in favour of subcritical plants compared with supercritical (SC) and ultra-supercritical (USC) units. Therefore, the government needs to reinforce policy measures to promote construction of SC/USC plants rather than subcritical units.

In particular, air pollution from coal burning has to be tackled. This is a matter of principle, given the health issues, but it is also in the interest of the coal industry, as public acceptability depends on it. While replacing wood and dung cooking with electric stoves is beneficial whatever technology is used for power production, clean air should be the top priority. Indonesia will soon burn 100 Mt per year, and if this is not properly controlled, it can become a severe environmental challenge for the country.

Box 4.1 Modernising and reforming the coal sector in Indonesia (continued)

Illegal mining is a recurrent topic on Indonesian coal. Estimates of this activity are around 70 Mt. Given the nature of illegal mining, it is difficult to assess whether this is a good estimate or not, but the imbalance between production figures and Indonesian imports in other countries plus domestic consumption suggests that it is in the range of 50-100 Mt. Illegal mining does not pay royalties or taxes, causes greater environmental degradation, and does not protect workers' health and safety. It also can damage the credibility of the entire country. Moreover, in the current low coal price environment, illegal mining contributes to the oversupply and low prices, which is negative for Indonesia as one of the major producing countries. Efforts and progress on this matter made by the government need to be acknowledged, but this practice should be eradicated as soon as possible. In addition, better enforcement of laws and regulations on the ground is required, for which trained personnel are needed.

Indonesian coal producers had an impressive decade, quadrupling exports during the period from 2005 to 2014. Small producers were instrumental in this remarkable performance due to their flexibility to promptly ramp up production in response to high demand and prices. However, the current state of affairs suggests that industry consolidation may be positive. Companies with greater financial and human resource capabilities tend to perform better in terms of environmental protection, health and safety at work, and better respond to the challenge posed by low coal prices.

The government has identified its priorities, and the goals have been correctly established. But it needs targets and the capability to measure the progress towards their achievement. This requires an improvement of statistics and data accuracy. Without reliable information, analysis is impaired and conclusions are rendered meaningless. Indonesian statistics are considered not as accurate as they should be. The IEA has been working with a number of countries in order to collect, manage, gather and disseminate reliable statistical information, and offers its full co-operation and experience in order to improve Indonesian statistics.

In conclusion, whereas Indonesia faced few hurdles in attracting foreign investment in the past, that should not be assumed going forward. The proliferation of contradictory proposals, policies and regulations could deter foreign direct investment. Stability, transparency, predictability and effective communication of policy formulation always pay back in the long term, and will bring Indonesia the investment and technology it needs to further develop its coal sector.

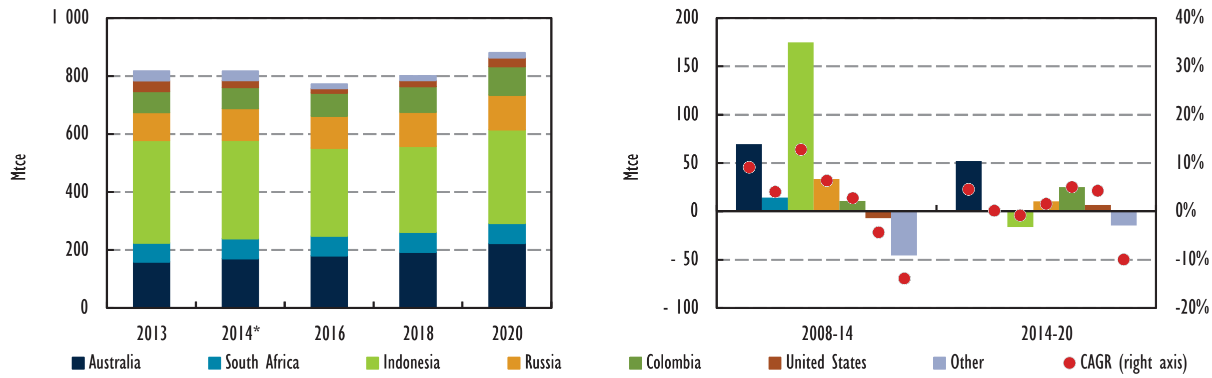
Indonesia will maintain its status as by far the world's largest exporter of thermal coal over the outlook period. The amount of thermal coal exported from Indonesia will however decline from 340 Mtce in 2014 to 323 Mtce in 2020, a decrease of 0.9% per year. Consequently, the market share of Indonesia in total international trade of thermal coal declines from 42% to 35%. The fall in Indonesian exports can be attributed mainly to the decline of Chinese coal imports, rising domestic demand and increasing regulatory constraints. Domestic coal demand will increase over the outlook period as Indonesia plans to substantially extend its coal-fired power plant fleet. Additionally, the Indonesian government is expected to continue its efforts to secure coal supply for domestic demand, to raise non-tax mining revenue and to cut illegal mining. Policy measures that have been introduced to enforce these targets include for example increased coal-mining royalties, an obligation for coal producers to sell a certain portion of their output to the domestic market and the introduction of official export licences that are required for producers to be allowed to export coal. Apart from the mentioned policy measures and the higher domestic demand for thermal coal, Australian miners continue to be strong competitors, which dampens the export possibilities for Indonesia.

Exports of thermal coal from Australia will grow on average by 4.5% per year over the outlook period. Total Australian exports will therefore amount to 223 Mtce in 2020 compared with 171 Mtce in 2014, increasing the market share of Australian exports in total seaborne thermal coal trade from 21% to 25%. The increase is driven mainly by demand growth in Asia, where India as well as traditional export destinations for Australian coal such as Korea and Chinese Taipei will increase their demand for thermal coal until 2020. Australian coal producers will also benefit from the extensive cost cuts they achieved in recent years, which will make Australian coal very competitive in the international market over the outlook period. Additionally, several new infrastructure developments will increase Australian export capacities.

Exports from the Russian Federation (hereafter "Russia") are forecast to grow from 109 Mtce in 2014 to 120 Mtce in 2020, an average annual increase of 1.6%. In the face of declining European coal markets and increasing competition from Colombian and US coal producers in Europe, the focus of Russia will increasingly shift to Asia. However, exports to Asia are constrained by infrastructure bottlenecks. So despite increasing infrastructure development and investment into port and railway capacity in the Russian east, growth of coal exports to Asia will be limited. In the medium term, Russia also plans to develop new coal deposits in the eastern Russian districts Sakha, Tuva Republic and Zabaykalsky Krai, which will allow for lower-cost thermal coal exports to Asia.

Thermal coal exports from Colombia benefit from low production costs and infrastructure developments that will increase export capacities and lower costs for inland transportation. Infrastructure improvements include new ports on the Caribbean coast (Puerto Brisa) as well as dredging of the Magdalena River, which would allow coal to be transported by barge from deposits located in the inland to the coast, and expansions of rail capacities that decrease dependency on trucking. Whereas the dredging of the Magdalena River is facing some challenges, the rehabilitation of Colombia's Central Railway System presents better perspectives. If accomplished by 2016 as expected, coal shippers from interior regions could save up to 30% of costs compared with trucking. As a result, Colombian exports are projected to grow from 73 Mtce in 2014 to 98 Mtce in 2020, which is equivalent to an increase of 5.0% per year. Major export destinations for Colombian coal will continue to be Europe and Latin America, as transportation costs to Asia are considerably higher, and spreads between European and Asian prices rarely justify shipments to markets in Asia.

Figure 4.3 Forecast of seaborne thermal coal exports



* Estimate.

Thermal coal exports from South Africa will remain almost flat over the outlook period at the 69 Mtce exported in 2014. Given the lower thermal coal demand in the Atlantic Basin, South African coal shipments will slightly shift to Asia, specifically the growing Indian market. However, exports to India are dampened by competition from Indonesian coal producers.

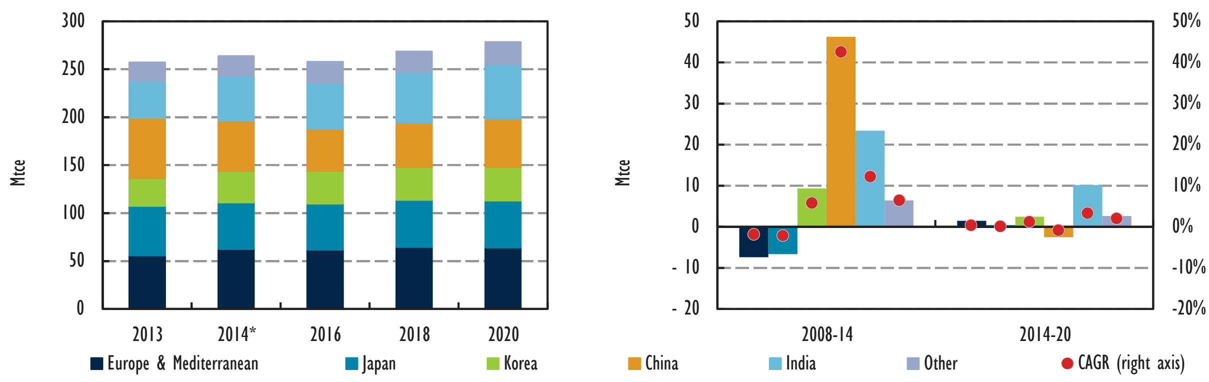
Exports of thermal coal from the United States are projected to fall and recover by the end of the outlook period, totalling 30 Mtce in 2020. The major driver for this increase in export activity is the falling domestic coal consumption in the United States, which will make coal producers look for the export market. However, US exporters are generally high-cost producers, and hence the most likely to reduce exports in the case that thermal coal imports do not reach the projected volumes or any major exporting country manages to increase exports.

Seaborne met coal trade forecast, 2015-20

Seaborne met coal trade is forecast to increase by 1% per year over the outlook period, totalling 278 Mtce in 2020. Import demand will rise mainly in Asian countries, while imports in the Atlantic Basin remain roughly constant. The share of seaborne met coal trade in total global met coal demand increases slightly from 28% to 29% over the outlook period.

China, the largest importer and consumer of met coal in the world, reduces its seaborne met coal imports by 1% per year from 53 Mtce in 2014 to a total of 50 Mtce in 2020. In addition to the seaborne imports, China will continue to import substantial amounts of met coal from Mongolia. Total imports from Mongolia, which reach China by overland transport, are projected to grow substantially from 10 Mtce in 2014 to 30 Mtce in 2020. The strong increase of met coal imports from Mongolia will be enabled by infrastructure improvements, especially expansions of the Mongolian railway system. There are for example plans to build a 265 kilometre railway from Tavan Tolgoi, the largest met coal deposit in Mongolia, to the Chinese border. Mongolian coal is already very competitive in China and will be even more competitive once the planned infrastructure improvements are finished. In total, Chinese met coal imports will amount to 80 Mtce in 2020.

Figure 4.4 Forecast of seaborne met coal imports



* Estimate.

Seaborne met coal imports to India are expected to increase from 47 Mtce in 2014 to 57 Mtce in 2020. The annual growth rate for Indian met coal imports over the outlook period is 3.3%. As India has no significant high-quality met coal production, it has to rely on imports to meet rising demand from the Indian steel sector. The main supplier for met coal imports to India is Australia.

Japan and Korea do not have any domestic met coal production and are therefore dependent on imports. Demand in both countries is mainly driven by the steel sector, whose output is positively correlated with economic growth. The International Monetary Fund expects only slow average annual growth in Japan, which leads to constant met coal imports of 49 Mtce over the outlook period. For Korea, higher economic growth is projected. Consequently, Korean met coal imports grow by 1.0% per year from 33 Mtce in 2014 to 35 Mtce in 2020.

In Europe and the Mediterranean region, met coal imports remain roughly unchanged over the outlook period, totalling 64 Mtce in 2020. This development is a result of increasing demand in growing economies such as Turkey and stagnating or decreasing met coal demand in mature economies. In addition, domestic coal production in European countries is expected to decline over the outlook period.

Met coal supply in international seaborne trade is highly concentrated, with Australia alone accounting for 65% of the market in 2014. The three biggest exporters, Australia, the United States and Canada, account for almost the entire global seaborne met coal market with a share of 91% in 2014. Over the outlook period this share is projected to slightly decrease to 89%. This high concentration leaves the international market vulnerable to supply disruptions caused, for example, by bad weather conditions or strikes.

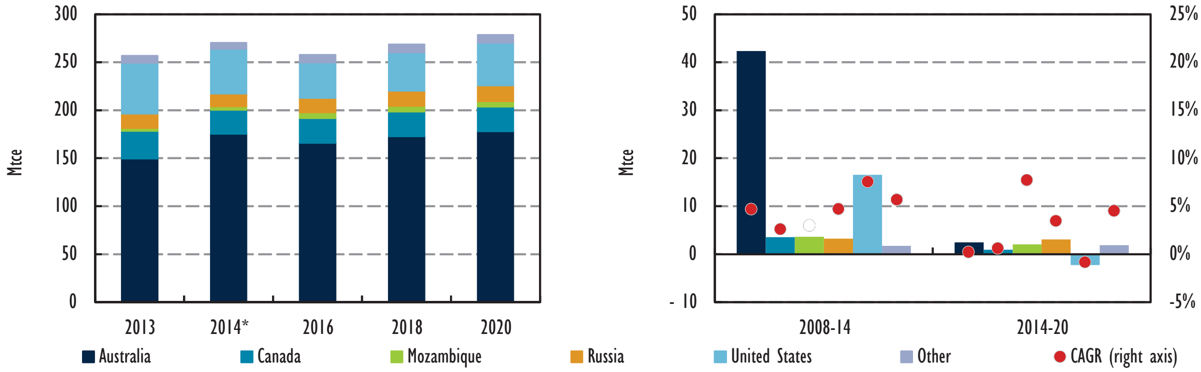
Met coal exports from Australia are forecast to amount to 178 Mtce in 2020, which is only a slight increase of 0.2% per year in comparison with 2014. Australian mining companies have cut production costs and increased productivity substantially over the last years. However, against the backdrop of recent developments of met coal prices, which hit the lowest level in a decade in 2015, some producers will have to close mines or curtail production despite the productivity improvements.

The United States will decrease met coal exports slightly by 3 Mtce to a total of 44 Mtce in 2020. US met coal exports are produced in the Appalachian Basin at comparatively high cost and will be challenged by lower cost exporters, like Australia. In particular, if Mozambique can ramp up production significantly, it will be mainly taking the share of US exporters.

In Canada, met coal exports are projected to amount to 26 Mtce in 2020, increasing 0.6% per year on average. Canadian exports are primarily destined for Asian markets, especially China and Japan, and benefit from good port and railway infrastructure. Russia, the world's fourth-largest met coal exporter, will supply 17 Mtce to the international seaborne met coal market in 2020. Compared with 2014 this is an increase of 3.5% per year. Russian export growth is enabled by infrastructure improvements and additional mining capacity in the eastern parts of Russia that allow for higher export volumes to the Pacific Basin.

Met coal exports in Mozambique are projected to grow faster than in all major exporting countries, with an average of 7.7% per year over the outlook period. In absolute terms, however, exports from Mozambique will remain at low levels and reach 6 Mtce in 2020. Vale, the largest producer, is slowing down ramp-up of coal production because of low met coal price. However, given substantial infrastructure improvements, such as the upgrade of the Sena railway line and the new coal export terminal at the port of Nacala-a-Velha, export forecast may be revised up significantly in the future, replacing mostly US exports.

Figure 4.5 Forecast of seaborne met coal exports



* Estimate.

Poland

Domestic demand for coal in Poland is projected to increase over the outlook period. At the same time it is expected that the Polish hard coal-mining sector will continue to struggle because of low prices and high mining costs imposed by geological conditions in comparison with competitors in Russia and the international seaborne market. According to the recovery programme for the domestic coal-mining sector that was announced by the Polish government in 2015, four unprofitable mines, namely the Brzeszcze, Sośnica-Makoszowy, Bobrek-Centrum and Piekary coal mines, will be transferred to a state-owned restructuring company. After the restructuring process, the mines are planned to be sold to investors or to be transformed into employee companies. Actually, Tauron, the power generator, has signed a preliminary agreement to buy Brzeszcze mine. Despite the efforts of the Polish government, this report assumes that a part of the capacity of the four above-mentioned mines will be shut down over the outlook period, and that the 11 mines expected to be integrated in Nowa Kompania Węglowa will maintain production levels. This includes the following mines: Chwałowice, Rydułtowy-Anna, Marcel, Jankowice, Sośnica Makoszowy Ruch Sośnica, Bolesław Śmiały, Ziemowit, Piast, Bielszowice, Halemba-Wirek and Pokój. Consequently, the IEA assumes a reduction of the domestic production in Poland of roughly 4 Mtce by 2020. To close the gap between rising domestic demand and declining production, Poland will rely on additional imports of roughly 9 Mtce by 2020, provided mainly by Russia via rail and the balance coming from the international seaborne coal market. As a result, Polish coal imports are expected to increase despite efforts to support the domestic mining sector that have been announced by the new Polish government elected in October 2015.

Seaborne trade in the CPCS

In the CPCS it is assumed that Chinese coal consumption decreases over the outlook period and will be 309 Mtce lower compared with the forecast in 2020. This change in Chinese coal consumption has implications not only for the domestic coal market in China, but also for other coal exporting and importing countries, as international coal markets are well interconnected and China is currently the largest coal importer in the world. The total traded hard coal volumes amount to 1 036 Mtce by 2020 in the CPCS, which is 123 Mtce lower compared with the forecast. This implies that the global seaborne hard coal market shrinks over the outlook period in the CPCS, which results from an annual decline in traded met coal by 1.8% on average and a slight decrease of steam coal trade volumes over the outlook period.

The impact of the declining coal demand in China in the CPCS on Chinese hard coal imports is depicted in Figure 4.6. In total, China makes up 129 Mtce of the total difference in coal demand of 309 Mtce by lowering coal imports. The coastal regions of China are especially affected by this change in imports because consumers in the Chinese inland rely typically on domestic coal production, as transport distances to the coast are high. As a result, total seaborne coal imports in China decrease sharply by 31% per year on average over the outlook period and amount to 25 Mtce by 2020 in the CPCS. Chinese overland imports of met coal from Mongolia remain unchanged compared with the forecast.

Figure 4.6 Differences in hard coal imports between the CPCS and the forecast

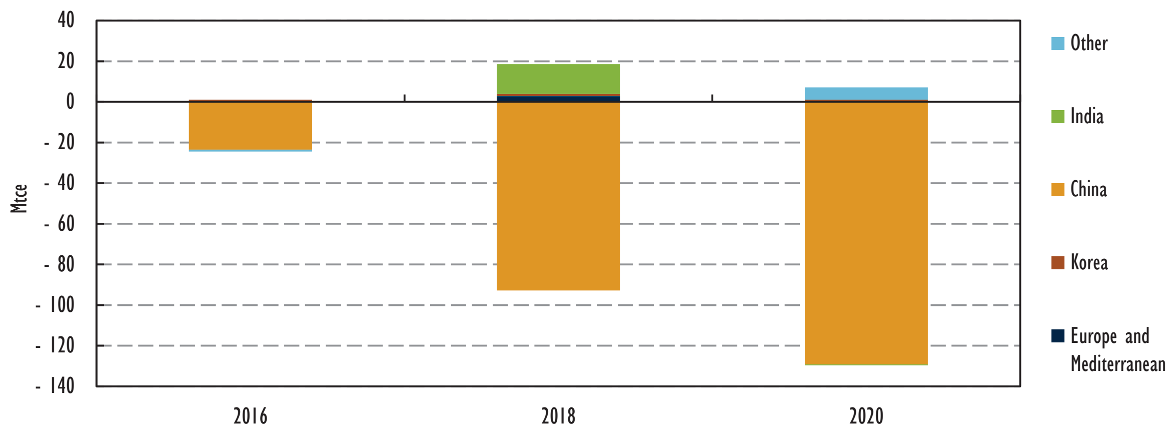
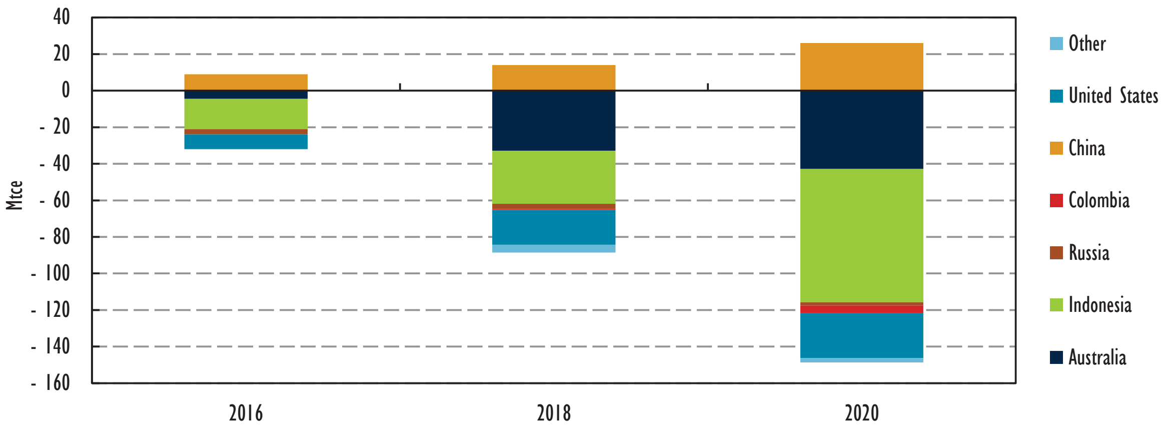


Figure 4.7 depicts the differences in hard coal exports between the CPCS and the forecast for different exporting countries. Indonesian exports are affected the most by peaking coal demand in China, as they are 73 Mtce lower in 2020 compared with the forecast. In particular, smaller Indonesian coal mines with comparatively high production costs are driven out of the market when the export potential to China declines. Coal exports from Australia, the second main supplier of Chinese coal imports besides Indonesia, are 43 Mtce lower in the CPCS by 2020. This decline is mainly a result of lower met coal shipments to China, which are 36 Mtce lower in comparison with the forecast. Australia is the largest exporter of met coal in the world and therefore strongly affected by lower infrastructure investments and steel production in China as they are assumed in the CPCS. The difference of hard coal exports from the United States between the CPCS and the forecast amounts to 25 Mtce in 2020. This is not only a result of lower exports to the Pacific Basin but also of increasing competition in the European markets, which are the traditional destinations for exports from the United States. Swing producers in South Africa and Russia in particular shift their focus to European markets when the export potential to China declines. As a result, production from high-cost mines in the United States is crowded out of the market because South African and Russian producers have cost advantages in Europe. Additionally, the Russian rail chain tends to prefer lower coal prices instead of underutilised rail infrastructure. Colombian coal exports are also only slightly affected by a lower coal demand in China, because Colombian coal is very competitive in the European market. However, against the backdrop of stronger competition in Europe, Colombian producers slightly increase coal exports to North America and therefore put additional pressure on the coal industry in the United States.

Whereas hard coal exports from the major coal exporting countries are lower in the CPCS, Chinese coal exports are higher compared with the forecast. The difference amounts to 26 Mtce in 2020 and can be explained by the lower domestic coal consumption, which leads to increased shipments of mostly thermal coal into the Asian region by competitive Chinese producers. As Chinese coal imports decline significantly over the outlook period in the CPCS and exports increase, China becomes a net exporter in the seaborne hard coal market in the CPCS by 2020. However, Chinese overland imports of met coal from Mongolia are not affected by peaking coal demand, so total coal imports still exceed exports by a small margin.

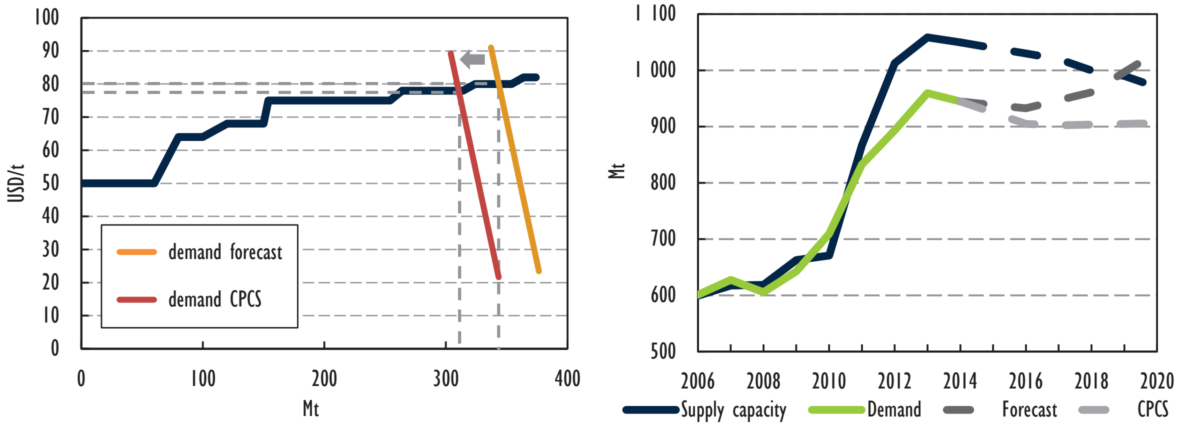
Figure 4.7 Differences in hard coal exports between the CPCS and the forecast



Besides the described effect on trade flows, peaking coal demand in China also affects coal prices in the international market. Surprisingly, coal prices are not significantly lower in the CPCS compared with the forecast. The reason for the expected limited price effect is explained by the left chart in Figure 4.8, which shows indicatively the Chinese steam coal supply curve in the southern coastal provinces Fujian, Guangdong, Guangxi, Hainan and Zhejiang. As these regions do not have significant coal production capacities, large quantities of coal have to be transported to the Chinese south either from the major coal-producing provinces in the north or from other exporting countries, mainly Indonesia and Australia, via seaborne imports. As a result, the majority of Chinese coal imports goes to coastal China, and coal consumers in these regions are able to arbitrage between domestic and imported coal. The impact of lower coal demand in China on coal prices in the international market is therefore mainly influenced by the shift in the supply and demand balance in southern China, as the price effect is determined by changing trade flows between China and its international coal suppliers.

The chart in Figure 4.8 shows that the supply curve in coastal China is relatively flat as producers in China and in coal exporting countries have undertaken substantial efforts to cut production costs in the current low-price market environment. Producers that were not able to cut costs have been driven out of the international hard coal markets during the last years. However, the potential for further production cost reductions is limited because coal mining requires substantial spending for labour and technical equipment that cannot be substituted easily by lower-cost alternatives (see also the discussion of coal supply costs in Chapter 2). If the supply curve is flat, a shift in coal demand as assumed in the CPCS leads only to limited price effects because production costs of the marginal producer in the new market equilibrium are not substantially lower as indicated in Figure 4.8. Similar effects can be observed in other regions due to the combination of low prices and a relatively flat supply curve. As a result, a reduction of international coal prices lower than USD 5/t should be expected in the CPCS.

Figure 4.8 Indicative steam coal supply cost curve in coastal China and the difference between forecast and CPCS (left); balancing of supply and demand in the forecast and CPCS (right)



Despite this relatively small price effect, global coal markets will stay in the current state of oversupply for a longer time period as shown in the right chart in Figure 4.8. It must be noted that the described development is a highly simplified model of the real market mechanism, as, for example, arbitrage between domestic and imported coal in importing countries and between domestic sales and exports in exporting countries are not accounted for. Figure 4.8 can therefore serve only as an illustration of the basic effects. The graph illustrates the historical demand in global thermal coal trade as well as the historical development of global export supply capacity. It can be seen that supply capacity grew substantially stronger than demand over the last years, which led to the current oversupplied market environment. As investment activity is cooling down, it is expected that supply capacity will decrease over the outlook period, because there will be more mine closures compared with new capacity additions. The chart also shows the development of global demand in the seaborne thermal coal trade for the forecast and the CPCS. Because of the different demand trajectory in the CPCS, it will take over three years longer for the market to balance out. Consequently, international coal markets will stay oversupplied significantly longer in the CPCS, and it will take longer for coal prices to recover from low levels.

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5. EXPORT CAPACITY INVESTMENT OUTLOOK

Summary

- **Investment activity in the international coal industry continues to cool down.** Low coal prices make investors reluctant to commit substantial amounts of money. Several mining and infrastructure projects will likely be delayed, postponed or cancelled.

- **Probable new export mining capacities amount to approximately 95 million tonnes per year (Mtpa) by 2020.** This is the lowest value compared with former *Medium-Term Coal Market Reports*.

- **About 35% of the probable additional mining capacity is located in Australia.** Other major mining projects are planned in the Russian Federation (hereafter "Russia"), Colombia and South Africa.

- **Potential additions of export mining capacity amount to roughly 400 Mtpa by 2020.** The majority of the potential new coal mines are located in Australia. However, the realisation of these projects within the outlook period will be difficult.

- **Export capacity of coal terminals is projected to increase by roughly 220 Mtpa over the outlook period.** However, adequate port and railway infrastructure remains a key issue in the realisation of new mining projects.

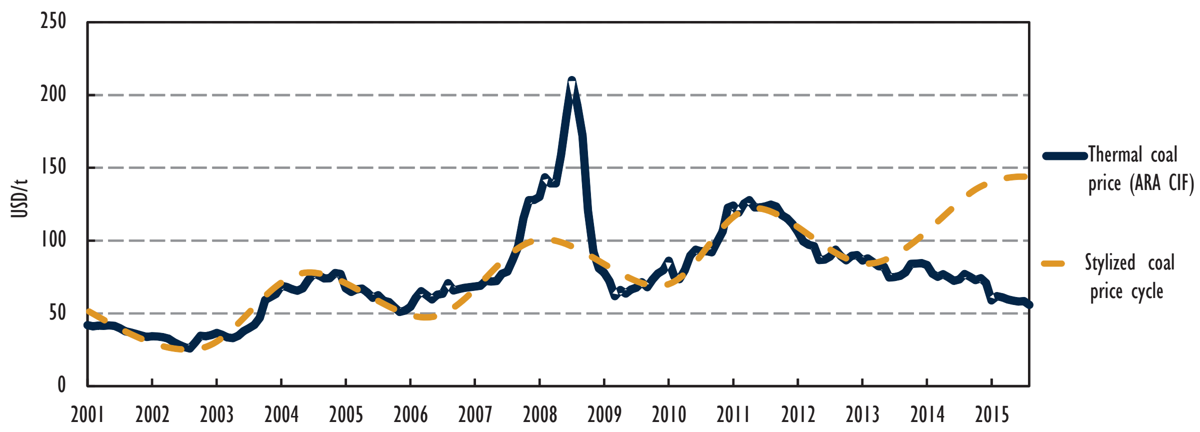
Coal prices and investments

Coal prices and export capacity investment decisions are closely linked, as the coal price determines profitability of an investment project. Consequently, significant export capacity investments in the medium term will by and large not go ahead unless prices recover from their current lows. However, coal prices typically show a cyclical behaviour, as the coal business follows an investment cycle that can generally be found in commodity markets where supply investments have long lead times, which leads to lengthy adjustment processes between changes in demand and supply.

A typical investment cycle in commodity markets moves along several steps: if increasing demand leads to price increases, investment and supply-side market entry become increasingly attractive. Increased investment activity leads to an expansion of the supply side over time, though typically with some delay due to the time required before new supplies become available. Until new supplies become available, prices and demand continue to grow until the switching price, a price level at which alternative resources or generation modes become more attractive. Demand is reduced and/or with additional supply entering the market, prices decrease. As prices decrease, demand starts to pick up again, though not enough to stop the dropping price due to ample supply now available. Prices decrease up to a point at which for some players, prices are lower than marginal costs, which eventually leads to a market exit of these players and to an end of new investments. Increasing demand in combination with market exit of some players leads again to a price increase. This development continues up to a point at which new investment into the market is again incentivised. Clearly this is a simplified illustration of a market, as disruptive technologies or regulation and policies might disrupt the mechanisms described. Further, market-inherent frictions might also lead to time delays in suppliers' or consumers' market reactions. Nonetheless, this simplified illustration serves well in explaining observed commodity price cycles.

Figure 5.1 illustrates the cyclical behaviour of coal prices by showing the historical development of thermal coal prices in North West Europe (Amsterdam Rotterdam Antwerp cost, insurance and freight [ARA CIF]). The chart might suggest that the coal price followed a cyclic trend as described above and that this has only broken recently. However, this would imply that commodity cycles last three to four years when in fact the cycles last for longer periods because capacity additions take time, especially if complementary investments such as ports and rails that need synchronisation with mine developments are required. Such investments are usually triggered after a period of high prices. Additionally, it can be seen in Figure 5.1 that coal prices experienced a strong boom from 2007 to 2008, followed by an even stronger bust after the financial crisis. After 2008, coal prices continued a cyclic trend but entered into an ongoing phase of decline after 2011. The main drivers for this continued price decline are described in Box 2.1. The question arising was whether or not this is a unique cycle driven by factors that will not vanish and may strengthen in the future, such as climate policies (see also discussion in Box 5.1) and competitiveness of renewable energies. While there are reasons underpinning that conjecture, the simple facts are not conclusive.

Figure 5.1 Commodity cycles are much longer than three years

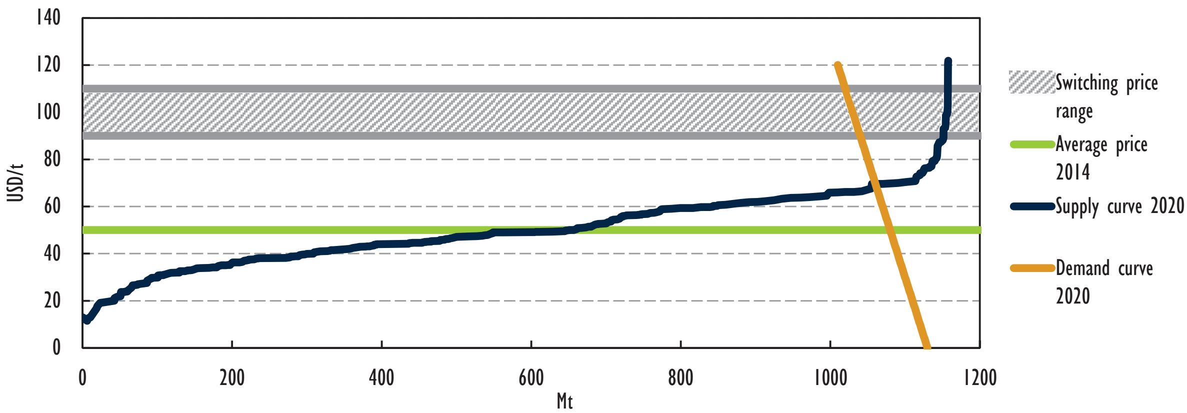


Note: t = tonne.

Source: International Energy Agency (IEA) analysis based on IHS Energy (2015), *Coal McCloskey Price and Statistical Data*, https://connect.ihs.com/industry/coal.

The long-term development of coal prices is further analysed in Figure 5.2. The chart shows an illustrative long-term supply curve for the global seaborne thermal coal trade in 2020. The forecasted demand volumes in 2020 and the corresponding market equilibrium are also depicted in the chart. It can be seen that marginal supply costs in the equilibrium will be well above current market prices as the demand for thermal coal grows and oversupply is reduced. The graph also shows that there is a margin to the ceiling at which switching occurs. This margin is mainly determined in the short term by prices for natural gas and carbon dioxide (CO_2) emission certificates, but in the long term also from costs of renewable energies such as solar and wind power. Whereas in the long term, levelised costs of energy are more appropriate to determine this switching price, in the short term the variable costs are more important. In the short term, low or very low variable cost technologies, such as renewables and nuclear, have a clear advantage over coal, but on the other hand, there is not much room for additional generation from these sources. Another factor to be considered is the lower wholesale prices with higher renewable generation, which is changing the economics of power generators in markets with a high share of variable renewables. Therefore, in the short term, the switching price range is largely defined by gas and CO_2 prices with some caveats. However, as of today, because of the uncertainty about the time and magnitude of the potential recovery, investors will be generally reluctant to invest into risky projects.

Figure 5.2 Illustrative supply curve of global seaborne thermal coal trade in 2020



Box 5.1 Are low coal prices driven by climate policies?

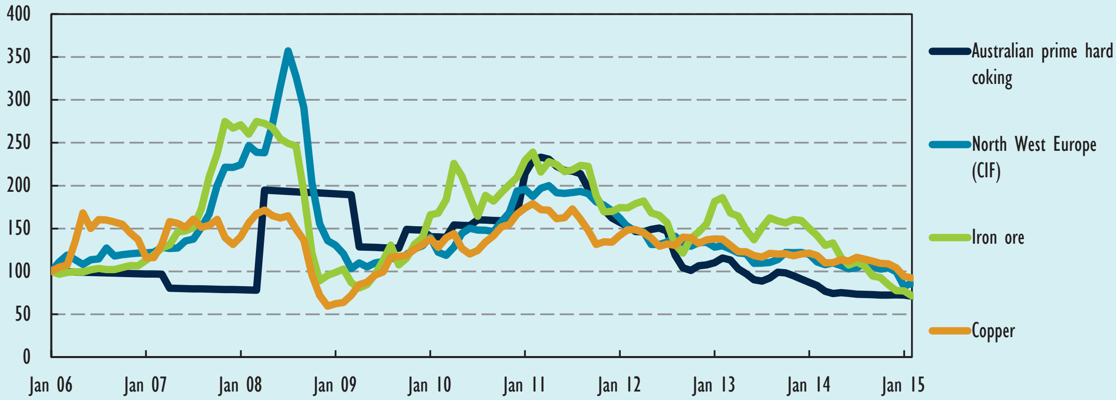
The decline of coal prices during the last few years has been the subject of many analyses and comments. A few of them suggest that climate policies are driving coal prices down and others go even further and think that the (thermal) coal price will never recover from its current lows. Given the disappointing progress in carbon capture and storage, we notice that a cyclical recovery of coal price would require a level of coal demand by 2020 inconsistent with climate stabilisation.

Going back to the main question of this box, a simple exercise is to compare price evolution of different commodities that are unaffected by the two elements: climate change and renewables competitiveness. Looking at copper, iron ore and metallurgical (met) coal, Figure 5.3 shows that all of them follow different trends with a peak and big drop in 2008 after the financial crisis and subsequent economic recession, the recovery of prices pushed by Chinese demand, and the subsequent fall since 2011, driven by oversupply in the markets, especially in the Chinese domestic market given the cooling of Chinese economy. Actually, iron ore and met coal are at lower relative levels than steam coal.

Indeed, while similar patterns exist, every commodity has its own dynamics. For example, a bigger increase is seen in coking coal in 2011, but that was a reaction to the floods in Queensland, origin of half of the exported coking coal worldwide, where ships could not operate for three months.

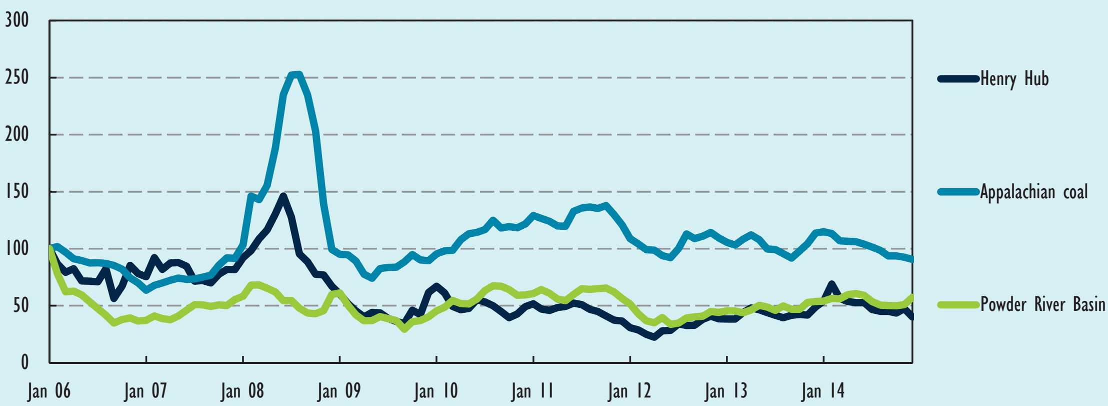
Box 5.1 Are low coal prices driven by climate policies? (continued)

Figure 5.3 Indexed real commodity prices: Copper, iron ore, steam and met coal



The US power market is unique given the lower gas prices compared with other regions. In Figure 5.4, we can see Appalachian coal following a similar pattern to prices in Figure 5.3 while Powder River Basin follows a pattern similar to Henry Hub, the main price index for US gas. A possible explanation is that Appalachian coal is close to the exporting ports of the East Coast, and therefore, more exposed to international prices than Powder River Basin coal, which competes with gas in the domestic power markets, and thus is more exposed to US gas prices.

Figure 5.4 Indexed Henry Hub gas prices in comparison with coal prices in Appalachia and Powder River Basin



Analysis suggests that whereas climate policies, renewables generation and US shale gas are curtailing coal demand to some degree, with evident impact on prices, there is no reason to think that thermal coal is behaving any differently than other commodities or that the cycle this time is in some way unique. The main difference with other cycles may be that the oversupply came with the cooling of the Chinese economy, and Chinese scale is much bigger than anything seen in the past.

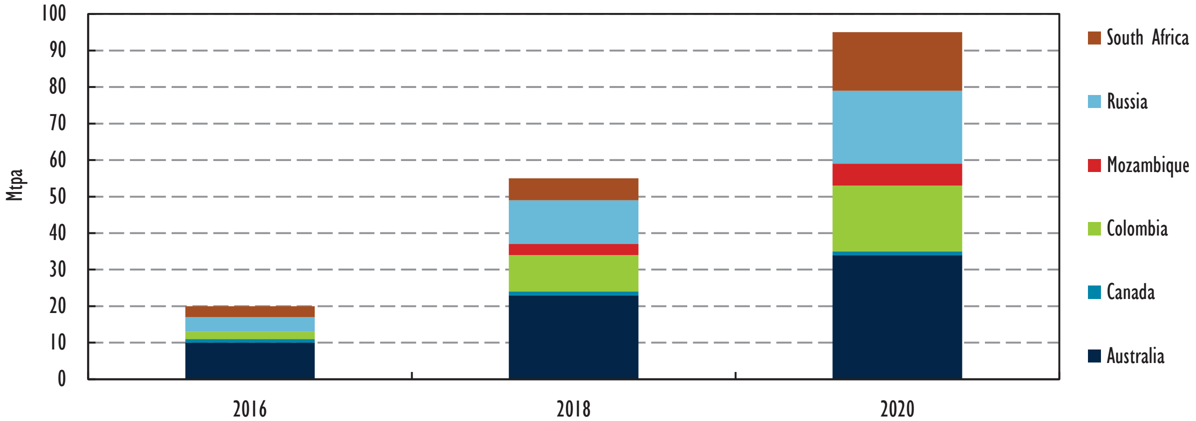
Investment in export mining capacity

Investments in export mining capacity have lead times of several years. Consequently, analysing expansion projects currently under construction allows for an estimate of the development of export mining capacity in the near future. To do this, one must distinguish between probable and potential expansion projects. Projects whose current status is either "approved", "committed" or "under construction" are classified as probable additions. Less advanced projects whose current status is either "feasibility study", "environmental impact study" or "awaiting approval" are classified as potential additions. For countries where detailed project lists are not available, potential additions are based on estimates from various sources.

The realisation of projects classified as potential is uncertain, as for example insufficient funding, environmental constraints or changing market conditions can fundamentally change the expected profitability of a potential investment. Especially against the background of currently oversupplied markets and low prices, delays and cancellations of substantial parts of the potential projects are possible, and they will therefore not come on line over the outlook period. Additionally, for many probable and potential projects, it might take a few years to achieve full capacity, and the targeted mine capacity will therefore not be reached in the start-up year. This issue is addressed by assuming ramp-up times in a range of two to six years depending on the project. Given the high uncertainty regarding the realisation of projects classified as potential, these capacity additions are not included in the model simulations for the supply and trade forecasts in Chapter 3 and Chapter 4.

Generally, the timing and volume of mining capacity entering the market depend on various factors. First, the size of the resource base is a crucial factor in determining project capacity. Second, current and expected demand and price levels, as well as the expected position of a project in the supply cost curve, are decisive to project profitability. Third, export mine projects are highly dependent on the availability of export infrastructure, for example seaports and inland transports. Delays in the construction of expansions of export infrastructure may substantially hamper the realisation of a mining project. Additionally, future regulatory frameworks, public opposition and political risks are key factors that affect investor uncertainty, economic success and consequently the likelihood of a project's realisation. Finally, access to capital can be a critical issue, in particular for greenfield projects that require new infrastructure.

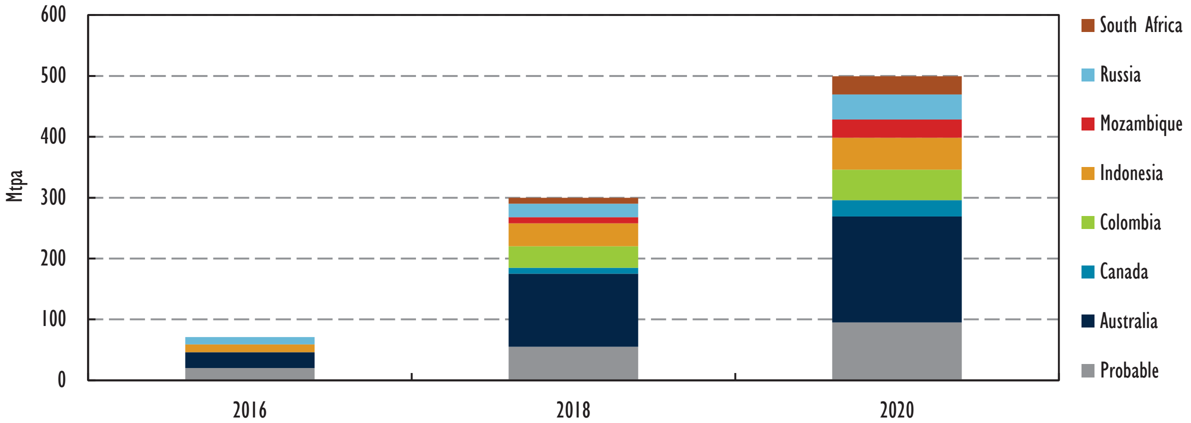
Figure 5.5 Cumulative probable expansion of hard coal export mining capacity, 2016-20



Total additions of export mining capacity classified as "probable" amount to 95 Mtpa over the outlook period. About 35% of total incremental capacity is projected to be located in Australia. The bulk of these new mines will produce met coal; Australia is projected to significantly increase met coal exports by 2020. Other substantial contributors to global export mining capacity additions over the outlook period are Russia and Colombia. Incremental export mining capacities in South Africa and Mozambique require export infrastructure investments and are therefore subject to higher uncertainty despite their classification as "probable". In general, total projected probable capacity additions are lower compared with last year's report, as investors are hesitant in the current low-price market environment.

Potential export mining capacity additions over the outlook period are assumed to amount to roughly 400 Mtpa. Again the majority of the potential new coal mines are located in Australia. Compared with last year's *Medium-Term Coal Market Report* (IEA, 2014), projected potential capacity additions are slightly lower, but still on a high level. Companies therefore seem to stick to early-stage investment projects despite the current difficult market situation. By doing so they can wait for coal prices to recover and avoid writing off large assets on their balance sheets. However, as mentioned above it is expected that the majority of these potential projects will not come on line over the outlook period if the current low international market prices for coal are maintained.

Figure 5.6 Cumulative probable and potential expansion of hard coal export mining capacity, 2016-20



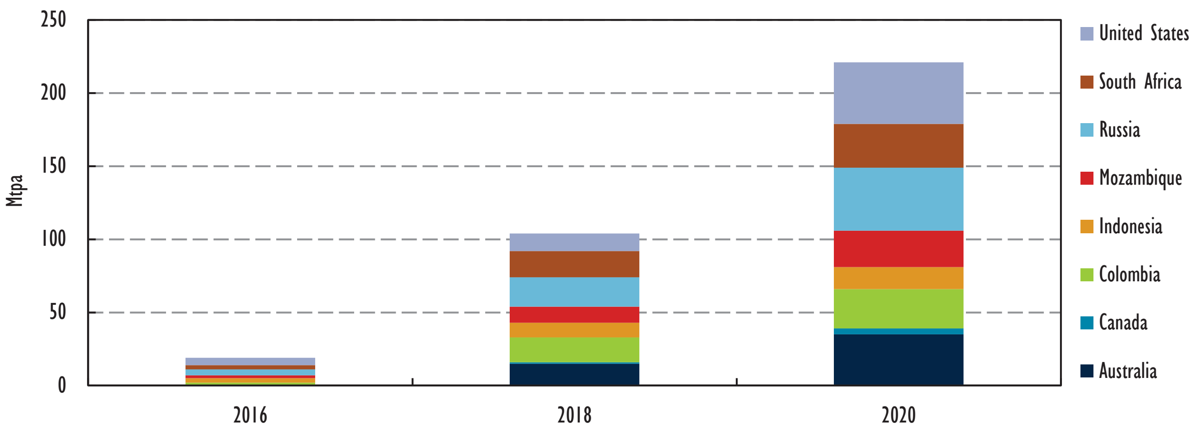
Investment in export infrastructure capacity

Like investments in export mining capacity, export infrastructure investments, for example to build seaports or railways, are associated with lead times of several years. Therefore the development of export infrastructure capacity can be estimated based on the projects that are currently under construction or in the planning stages.

Availability of export infrastructure is a key factor for the success or failure of export mining projects. Often, congested port and railway infrastructure severely hampers newly constructed or expanded mining capacity. Prominent practical examples of countries whose exports suffered from insufficient transport infrastructure in the past are South Africa and Mozambique.

Over the outlook period, several port capacity projects that are currently under construction or in planning stages are projected to come on line. Total global incremental coal terminal capacity is assumed to amount to approximately 220 Mtpa by 2020. Plans for large capacity additions exist in the United States and Russia as some producers in both countries try to extend their potential for coal exports into the Asian markets. South Africa and Mozambique are also trying to extend port capacities in order to ease capacity bottlenecks that significantly constrain possibilities for coal exports. In comparison with *Medium-Term Coal Market Report 2014,* the projected port capacity additions are substantially lower, especially in the short term. This development is a result of the current low-price market environment, which has led to the postponement of several projects as companies wait for improving market conditions before they advance with large-scale investment projects.

Figure 5.7 Projected cumulative additions to coal terminal capacity, 2016-20



Box 5.2 CCS: The technology for coal's future

Carbon Capture and Storage (CCS) is the only technology capable of delivering significant emissions reductions from the use of coal and other fossil fuels, including in industrial processes such as steel and cement production where there are limited or no low-emission alternatives. CCS involves the capture of CO_2 from a large emission source, the transport of the CO_2 to a suitable geological storage site, and the injection and monitoring of the CO_2 to ensure it remains permanently stored. If CO_2 can be used, i.e. for enhanced oil recovery, economics of the process are much better.

The key to reducing emissions from coal

Although not just a coal technology, CCS will be critical in underpinning a future role for coal-fired power generation as the world moves to limit future global temperature increases to 2 degrees. In any long term scenario of climate stabilisation, unabated coal is virtually phased out, with most of coal-fired power generation coming from plants equipped with CCS.

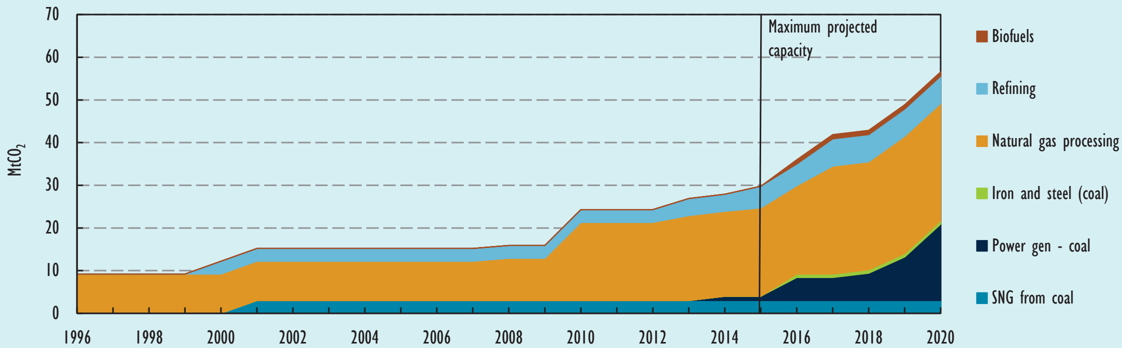
In the near term, CCS offers a protection mechanism – a type of insurance – for power generation and industrial assets which could otherwise become stranded under future climate constraints. The retrofit of existing plants with CCS could be particularly important in countries like China, which has a large (830 GW) and modern fleet of coal-fired power plants. The IEA has assessed that more than 300 GW of China's coal power capacity could be candidates for CCS retrofit, including having access to suitable storage.

Box 5.2 CCS: The technology for coal's future (continued)

CCS is moving forward, in low-gear

2015 has been a year of significant progress for CCS technologies. Two large-scale CCS projects have commenced operation, bringing the total number of large-scale CCS projects operating throughout the world to 15, with a further seven expected to come online by 2018. These projects are capturing up to 27 million tonnes of CO_2 every year.

Figure 5.8 Large-scale CO_2 capture projects



The portfolio of projects applying CCS to coal-fired power generation is growing, albeit slowly and from a small base. The Boundary Dam CCS Project in Saskatchewan, Canada – the first large-scale CCS project applied to an existing coal-fired power plant – has now had more than 12 months of operational experience. Two further coal power projects are expected to be commissioned in the United States in 2016: the Kemper County project in Mississippi and the Petra Nova CCS project in Texas. Kemper County will be the first new-build coal-fired power station with CCS and one of only a small number of Integrated Gasification Combined Cycle (IGCC) power plants in the world, capable of achieving efficiencies well above 45% compared with the current global average of around 33%.

The White Rose CCS project in the United Kingdom, which planned to apply CCS to a new-build coal-fired power station, is unlikely to proceed following the cancellation of the United Kingdom's £1 billion CCS Competition in November 2015.

The portfolio of operating projects is providing valuable practical experience, supporting the refinement of key technologies and contributing to cost reductions. For example, the Boundary Dam project owners believe they could reduce the cost of future plants by 30%. This is important given the relatively high costs of these first of a kind (FOAK) projects – in the case of Boundary Dam around USD 6 000 per kW for the CO_2 capture equipment and around USD 9 500 per kW for Kemper County IGCC.

Continued research, development and demonstration in parallel with greater operational experience ("learning by doing") will be essential to bring these FOAK costs down and pave the way for commercial deployment. IEA modelling suggests that, with technical improvements and increasing carbon constraints, CCS could be competitive with other dispatchable low emission technology options from the mid-2020s. However, this is contingent on a significant acceleration in the current rate of progress, including an increase in the number of large-scale CCS plants operating across both power and industry applications.

Box 5.2 CCS: The technology for coal's future (continued)

Targeted support and real commitment is needed

Efforts by governments and industry to support the development and deployment of CCS have fallen well behind that of other low-emission technologies. CCS will require targeted, transitional support mechanisms to drive early deployment, in much the same way that targeted mechanisms have supported the deployment of renewable energy and driven technology cost reductions for wind and solar.

Industry, including fossil fuel producers, must also be proactive in supporting the development and deployment of CCS. The availability of CCS will be a major determinant of future demand for fossil fuels, and the IEA estimates that revenue streams from coal and gas used in CCS-equipped facilities could be USD 1.3 trillion for coal and gas respectively over the period to 2040. Investment in CCS today should be seen as a necessary investment to secure these future revenue streams.

Regional analysis

The following section analyses current investment projects in both coal mining and export infrastructure over the outlook period.

Australia

Investment in export mining capacity

Since the publication of *Medium-Term Coal Market Report 2014*, several mining projects in Australia have been completed. The Maules Creek project, a new thermal and met coal mine in New South Wales built by Whitehaven Coal, together with Itochu and J-Power, started operation in December 2014 with a capacity of 6 Mtpa. There are plans to extend capacity to a total of 10.8 Mtpa over the next years. The new thermal and semi-soft coking coal Drake mine, which is located in Queensland and run by QCoal, started operation at the end of 2014. Once fully operational, the project represents an estimated investment volume of USD 350 million and a capacity of 6 Mtpa. Other projects that entered the production stage are the 3.6 Mtpa expansion of the Middlemount coking coal mine, jointly operated by Peabody and Yancoal, as well as the 3.5 Mtpa expansion of the Boggabri open-cut thermal coal mine operated by Idemitsu Kosan, Chugoku Electric Power Co., and Nippon Steel & Sumitomo Metal Corporation.

Over the outlook period, additional projects are expected to become operational. Total probable mining additions in Australia amount to 34 Mtpa. The majority of these mine capacities will come on line in Queensland and the remainder in New South Wales. Compared with *Medium-Term Coal Market Report 2014*, probable mining additions in Australia are significantly lower because several projects have been completed in recent years and new project announcements have slowed down as international coal markets continue to be oversupplied given low prices.

Two new coal mines are projected to become operational in Queensland over the outlook period. In late 2016, the USD 1.9 billion underground coking coal mine project in Grosvenor operated by Anglo American will come on line with a capacity of 5 Mtpa. Shipping of small quantities of coal mined in Grosvenor already began in 2015. Baosteel Resources and Vale intend to start operations at the Eagle Downs coking coal mine project in 2017. The project has an investment volume of USD 1.3 billion and an estimated capacity of 4.5 Mtpa. Other probable mining capacity additions are extensions of the Appin Area 9 met coal mine, the Baralaba North met coal mine and the Metropolitan met coal mine.

In addition to the probable capacity additions, there are numerous potential projects with a capacity of up to 174 Mtpa. The largest potential capacity additions are four enormous new mining projects in the Galilee Basin with an aggregated estimated capacity of over 160 Mtpa, which are currently in the feasibility stage. The largest of these proposed projects is the Carmichael coal mine, which is developed by the Indian company Adani Mining. The USD 16.5 billion project is planned to have a total capacity of 60 Mtpa and would be the largest Australian coal mine upon completion, consisting of six open-cut pits and five underground mines. The project faces delays as concerns about the environmental impacts of the project have slowed down the approval process. Nevertheless, the project was approved by the Australian government in October 2015. The other huge mining projects in the Galilee Basin are the China First Coal project (40 Mtpa) by Waratah Coal, the Alpha Coal Project (32 Mtpa) operated by GVK-Hancock Coal, and the Kevin's Corner (30 Mtpa) project by GVK. Additionally, the Project China Stone (55 Mtpa) planned by MacMines Austasia has been announced. All of the projects mentioned are highly dependent on availability of financing and adequate infrastructure. Despite support from Queensland's government, there is also public opposition to the projects, and, hence, the approval process is being challenged, with inevitable delays. In conclusion, it is not likely that the above listed projects will be operational in 2020, if ever.

Investment in export infrastructure capacity

Total coal export capacity of Australian ports amounts to 533 Mtpa. Since the last publication of this report, two projects have been finished and are now operating. The newly built Wiggins Island Coal Terminal started operation in April 2015 and added 27 Mtpa to the Australian port capacity after three years of construction. The terminal is jointly owned and used by eight companies, namely Glencore, Yancoal, Wesfarmers Curragh, New Hope, Cockatoo Coal, Caledon Resources, Aquila Resources and Bandanna Energy. Because of the additional capacity of the Wiggins Island Terminal, coal operations in Barney Point with a capacity of 8 Mtpa will be closed down in 2016 and the port will focus on other dry bulk goods. The second completed project is the phase 3 expansion of the Hay Point Coal Terminal, which extends export capacity from Hay Point by 11 Mtpa to a total of 55 Mtpa and started operation in February 2015.

Currently there are no further port projects under construction. However, there are additional projects at less advanced stages that could potentially increase Australian coal export capacity. The largest potential project is the extension of the Abbot Point Coal Terminal that is currently being assessed by GVK and Adani, two companies that have plans for major mining projects in the Galilee Basin and therefore need suitable export infrastructure. The project was approved by the government of Queensland in October 2015, but the expansion faces opposition mainly related to impact on the Great Barrier Reef. Other major potential port projects are a further expansion of the Hay Point port by 10 Mtpa to 15 Mtpa and an expansion of the just opened Wiggins Island Coal Terminal by a capacity of another 54 Mtpa. Because of the current weakened market situation for coal producers it is unlikely that any of the mentioned potential projects will be operational over the outlook period.

Rail infrastructure has been a bottleneck for Australian coal exports in the past. However, various projects completed in recent years have eased this problem. In 2015, Australian rail infrastructure was further extended by a new rail connection to the Wiggins Island Coal Terminal that started operation in the same year. Additionally, an expansion project of the Goonyella rail system, which will add 11 Mtpa of rail capacity to the connection between the Bowen Basin and the port of Hay Point, is expected to be finished in 2015. Further rail infrastructure investment is proposed to connect coal-mining projects in the Galilee Basin with the Abbot Point Coal Terminal. However, these projects are still at the feasibility stage.

Colombia

Investment in export mining capacity

Colombian export mining capacity is forecast to increase over the outlook period. Probable export mining capacity additions are projected to amount to roughly 18 Mtpa by 2020. The vast majority of those additions will come from thermal coal.

Several current Colombian coal-mining projects are undergoing commercial restructuring. Since 2014, Yildirim Holding has been in the process of acquiring several mine development projects from CCX. These projects include the Cañaverales thermal coal mine, which could be operational by 2019 with a capacity of 5.5 Mtpa; the 2 Mtpa Papayal met coal mine, which could be opened by 2017; and the 16 Mtpa thermal coal mine San Juan, which is projected to start operation by 2019. However the purchase is still pending due to legal issues. In August 2015 Goldman Sachs sold its Colombian mining operation – called Colombia Natural Resource – for less than USD 10 million to Murray Energy, marking the bank's exit from the physical coal business. Among other operations, Colombia Natural Resource contains the Cerro Largo coal deposit. Other mining projects in Colombia include the expansion of Drummond's El Descanso, which is targeted to produce 12 Mtpa. Production capacity at El Cerrejón mine could potentially be increased to 60 Mtpa by 2020, given further investments in new mining equipment. However, it seems unlikely that these investments will be made under current market conditions.

Investment in export infrastructure capacity

Several projects to increase Colombian export capacity have been recently finished or announced. Capacity expansions at Puerto Bolívar continued in 2015 with the opening of a new berth. This was part of the USD 1.3 billion infrastructure expansion programme of Cerrejón, which raises the production capacity of the Cerrejón mine to 40 Mtpa. The new direct loading capesize port Puerto Brisa opened at the end of 2014 with a load capacity of 3 Mtpa. There are also plans to eventually extend the port's capacity to 30 Mtpa in the future. The capacity of Puerto Drummond was doubled by October 2014 to 60 Mtpa with the completion of a second ship loader. The extended capacity allows Drummond not only to export coal from own production but also to offer export services to other Colombian mining companies.

Colombian inland transport infrastructure has been a bottleneck for coal exports in the past. Several infrastructure projects have been announced to improve transport capacity from the inland coal mines to the export terminals at the Caribbean coast. A 325 kilometre (km) railway that connects the recently opened port of Puerto Brisa with the Central Railway System could save coal producers up to 50% on transportation costs compared with trucking coal to the port. Therefore the railway would help Puerto Brisa to become an important export link, especially for coal producers in Colombia's interior departments such as Boyacá, Santander and Cundinamarca. The project is still in the planning phase, but several Chinese and Korean companies have indicated a willingness to provide funding. Another proposed railway project is the Carare line, a 910 km railway that would have the capacity to transport 10 Mtpa of met coal from Boyacá or Cundinamarca to ports at the coast. There are also plans for rehabilitation works at the 228 km railway between Bogotá and Belencito. Besides railway projects, the Colombian government aims to open new transportation routes for inland coal producers by rehabilitating the Magdalena River waterway in order to improve navigability for barges on the river.

South Africa

Investment in export mining capacity

Several mining projects were finished and started production in South Africa in 2014 and 2015. The Kangala thermal coal mine started production with a capacity of 2.4 Mtpa. Mining projects completed in 2015 include the Elandspruit mine, which has a capacity of 2.4 Mtpa and will produce coal for the export market as well as the domestic market. Additionally several small coal mines with a capacity of less than 1 Mtpa were commissioned.

Announcements of new mining projects were scarce in 2014 as there continued to be a paucity of investment in new coal-mining capacity in South Africa. Against the backdrop of low market prices and oversupply, many potential investors hesitate to announce new major investment projects. Additionally, political uncertainties surrounding the amendment to the Mineral and Petroleum Resources Development Act, which was rejected by President Jacob Zuma because of concerns that it might not be compatible with the South African constitution, deter investors. Nevertheless some new mines will be commissioned over the outlook period. Coal production in the Boikarabelo mine in the Waterberg region, which is operated by the company Resource Generation, is projected to start in the first half of 2016. Originally the mine was planned to be operational in 2015, but bankruptcy of the main earthworks contractor delayed the project. Production capacity of the mine will be at 6 Mtpa. Other projects to be completed in 2016 are for example the Impumelelo mine and the Shondoni mine. Both projects are part of efforts of the company Sasol to replace old mines that were built in the 1980s with modern underground mines. Glencore plans to commission the Wonderfontein colliery in Mpumalanga, which will add 2.7 Mtpa of export mining capacity and intends to extend production capacity at the Tweefontein mine within the outlook period.

Box 5.3 Kusile: The dawn has come

Kusile is a word that means "the dawn has come" in the Ndebele language; it is also the name of a coal power plant under construction located in the Nkangala district of Mpumalanga, South Africa, 10 km northwest of Kendal Power Station and around 150 km east of Johannesburg. It consists of six units of 797 megawatts (MW) of pulverised coal working under supercritical (SC) conditions of 24.1 megapascals and 560 °C in the turbine steam. Net efficiency is around 37% on a higher heating value basis.* These data may not be impressive, but Kusile's highlight is not its technical parameters.

Box 5.3 Kusile: The dawn has come (continued)

Kusile and Medupi Power Station, which is being built at the same time in another location, will be the first plants incorporating SC technology in South Africa and, together with Safi, Morocco, the only ones in Africa. Given that the plant will operate in a water-stressed area, air cooling has been adopted. The air-cooled condensers have been installed on a concrete stack that is 60 metres high. Kusile will incorporate fabric filters to reduce particulate emissions below 50 milligrammes per cubic metre and, especially, will be the first plant in South Africa to incorporate flue gas desulphurisation (FGD), thus removing more than 90% of sulphur emissions, which in Kusile is not straightforward. First of all, FGD needs power to operate, around 30 MW or 3% of the output in a country with frequent power shortages. FGD also needs water, and this is piped from Kendal. Nevertheless, water needs are minimised by water recycling and a design for zero liquid effluent discharge. In addition, FGD requires as much as 100 tonnes per hour of limestone, and there is no limestone near Kusile, so this requires bringing it by rail from more than 200 km away. The final product of FGD is gypsum, marketable when there is demand nearby. Unfortunately, this is not the case in Kusile, which means a double burden, first because this is an income reduction and especially because gypsum must be cleanly and safely disposed of at the site.

Once it is built, Kusile, the largest construction site in the southern hemisphere, will be the biggest coal plant in Africa and the fourth-largest in the world. With more than 17 000 workers in the construction site and the six units built at the same time, it still faces a few challenges before electricity production starts. Eskom indicated that synchronisation of the first unit is scheduled by the second half of 2017.

* This is over 39% on the more common lower heating value basis.

Investment in export infrastructure capacity

The vast majority of South African coal exports pass through the Richards Bay Coal Terminal, while only very small quantities are shipped from ports in Maputo and Durban. However, there are plans to extend export capacity in Maputo to 20 Mtpa over the coming years. Additionally, export capacity of Grinrod's Navitrade terminal in Richards Bay is projected to be extended by up to 20 Mtpa by 2017. Other potential projects to extend export capacity such as the construction of a new terminal by the local rail operator Transnet are currently on hold or in the pre-feasibility stage, and therefore not expected to be finished over the outlook period.

Bottlenecks in South African railway infrastructure have limited coal exports in the past. The Richards Bay Coal Terminal has therefore not been able to realise its full export potential of 91 Mtpa over the last years. Despite several projects to extend South African railway capacity, it is expected that scarce railway infrastructure will continue to be a problem for coal exports over the coming years. One major effort to extend railway capacities is the coal link project that connects Mpumalanga with Richards Bay with a capacity of 15 Mtpa by 2017. In addition, the Mpumalanga network is built to connect several coal mines to the coal link main line and coal-fired power plants in the region. Another major project is the Waterberg rail link, which will connect Lephalale and the Central Basin with a capacity of 23 Mtpa. This rail connection is essential for the development of new coalfields in the Waterberg region, which is necessary to substitute old and depleted mines in the Witbank coalfield. The project is still in feasibility stages and not expected to be operational before 2018.

Box 5.4 Divesting from coal

In May 2015, the Parliament of Norway decided to sell off the coal-related assets of the Norwegian sovereign wealth fund, the largest in the world. To be more precise, the decision refers to companies whose involvement in coal extraction, coal power generation, or coal-based conversion represents a significant part of their business. This decision has been presented as the biggest divestment ever, potentially affecting more than 100 companies although the actual effect will depend largely on how the term "significant"* is defined and applied. The impact of that decision goes beyond the direct consequences to the companies whose assets will be sold off; it also sends a powerful signal to others. Some non-governmental organisations, university funds, and other institutions had already divested from fossil fuels – or, in particular, from coal – some time ago; thus, in the run-up to the COP21 in 2015, divestment has very much accelerated.

Motivation for divestment is either declared to be based on ethical issues associated with the activities of coal companies in both mining and power production, or related to risk avoidance – hesitance to invest in assets that are perceived as risky. Others see the divestment campaign as a way to stigmatise coal rather than to impact its financial viability. The United States can be considered the epicentre of this movement, but action can be seen also in many other places, especially Europe, Canada and Australia. Divestment comes together with an increasing number of international financial institutions (i.e. the World Bank Group, European Investment Bank, and European Bank for Reconstruction and Development) and national export credit agencies turning away from coal. At the same time, some banks are tightening lending policies for coal assets, while others are moving away from coal lending.

Whereas the long-term effects are uncertain, in the short-term, under the current circumstances of market oversupply and no need for big investment in coal mining, it is not likely that these policies will have substantial impact on coal producers. But new coal power plants need financial resources to be developed, and in many of the countries in which these plants are proposed there are no proper well-functioning capital markets. Also, there is a lot of available money in the world, so if one investor leaves, another will often step in. But if finance for coal-related assets becomes scarce, their financial costs will increase. Public acceptability may be as important as finance for the future of the coal industry. If coal is not well perceived by public opinion, some stakeholders will sell their coal assets and others will avoid entering the business. And last but not least, if money and people run away from coal, technological development will be also affected, with long-term consequences.

Regarding the effects of insufficient finance, if it becomes true, one thing is certain: geography matters. While in regions like the United States or Europe, new coal plants will be scarce, in many other regions, especially in large populated areas with power shortages in Asia, coal will likely be the backbone of power generation in the coming years. Finance for those projects could be an issue if the institutions from the developed world leave them behind. But it does not necessarily mean the end of the story, as other international financial institutions and other players are open to finance coal investments, and new institutions such as the Asian Infrastructure Investment Bank, the New Development Bank and the Silk Road Fund might take the lead on future investment. This could also have implications on the technology to be built. Lack of enough financial resources will usually lead to investment in inefficient subcritical units, with lower up-front capital requirements than the more efficient SC and ultra-supercritical units.

Whether or not the above-mentioned policies and campaigns will mean a lack of financing for the coal sector in the developing world is unclear for the moment. The effect will be country-specific, defined by a set of conditions such as access to finance, regulation of the power sector, general working of the institutions, and energy resource endowment. The combination of those factors is different from one country to the next.

Box 5.4 Divesting from coal (continued)

For a balanced discussion, some considerations must be made. The first is the value of cheap base-load generation as a pillar of development for places where shortage, load shedding and blackouts are frequent. The second is the opportunity cost, whereby using more expensive alternatives for power generation means that a certain number of schools, hospitals, and so forth could have been built compared with cheaper options. Finally, it is important to remember how different life is for people who have electricity and for those without. While humanity cannot afford to bargain about carbon emissions reduction, it is necessary to consider the different realities of different countries. If, after all, low-carbon alternatives are not suitable and coal plants are to be built, the most efficient and hence least carbon-intensive plants should be promoted.

* Significant in principle means that 30% or more of their activities or incomes come from coal.

Mozambique

Investment in export mining capacity

The huge undeveloped coal deposits in Mozambique's Tete province have attracted the interest of several big international mining companies in the past. However, exploration and transportation turned out to be problematic, which led to substantial write-offs on Mozambican assets. This trend continued in 2015 when Coal India Limited decided to relinquish roughly three-fourths of its licensed coal deposits in Mozambique because of issues with coal quality. Additionally, in the beginning of 2015, the Mozambique-focused met coal-mining company Beacon Hill Resources (BHR) became insolvent after restructuring efforts failed. The future of BHR's Minas Moatize mine is currently unclear.

Despite the continuing problems, there are plans to extend coal production capacity in Mozambique over the outlook period. The India-based company International Coal Ventures (ICVL) intends to increase capacity at its Benga mine from approximately 5 Mtpa to 13 Mtpa over the next five years. Vale intends to ramp up capacity at its Moatize mine to 22 Mtpa. In order to acquire fresh capital for this project, Vale sold 15% of its stake in the Moatize mine to the Japanese trading company Mitsui. Other large-scale projects in Mozambique include the Revuboe mine, majority-owned by Japanese steel company Nippon Steel & Sumitomo Metal Corporation; ICVL's Zambeze project; and the Ncondezi coal mine.

Investment in export infrastructure capacity

Adequate infrastructure is a major problem for coal mining companies in Mozambique, as all coal had to be transported via the Sena rail line and the port of Beira in the past. However, the quality of the Mozambican railway and port infrastructure is about to improve substantially when the new Nacala export corridor becomes operational. The project is executed by Vale and consists of a 912 km railway line from the Moatize basin to the newly constructed Nacala port, which will open up 18 Mtpa of export capacity. The first coal was exported through Nacala in 2015 and the full capacity is expected to be operative by 2017. In addition to the rail line, the Mozambican government plans to transform an approximately 350 km-long narrow and unpaved carriageway into a modern road that crosses the Tete province and ends at the Zambezi River in order to link mining projects with the Nacala rail line.

Another major infrastructure project in Mozambique intends to connect Moatize with the port of Macuse in the Zambézia province via a 530 km railway line. The construction of a 25 Mtpa deep seaport is also included in the project plans. However, the project is under pressure since it has thus far been unable to secure funding.

Russia

Investment in export mining capacity

A substantial share of Russian coal production is targeted for the domestic market, which makes projections of export mining capacity difficult. Therefore, probable thermal and met coal capacity expansions until 2020 are estimated rather conservatively at 20 Mtpa. Another 20 Mtpa of potential mining projects could further increase export mining capacity.

According to the long-term strategy of the coal industry up to 2030, the main new coal deposits to be developed in the medium term are located mainly in the Russian east and include Elginskoye and Denisovsky in Sakha (Yakutia) Republic, Mezhegeyskoye and Elegetskoye in Tuva Republic as well as Apsatskoye in Zabaykalsky Krai. In 2014, North Pacific Coal Company, a subsidiary of the Australian mining company Tigers Realm Coal, was granted the mining licence for Project F at Amaam North. After completion of a USD 61 million fund-raising in March 2014, Project F is expected to start production in 2017 with a capacity of 10 Mtpa. According to a feasibility study, the project could turn out to be one of the lowest operating coking coal mines in the world. Another major Russian greenfield project is Mechel´s Elga coal mine, with an estimated production capacity of 8 Mtpa in 2017 and plans to further extend the capacity to 23 Mtpa by 2021. The project is behind schedule because of commissioning issues. However, Mechel was able to start limited production in 2014 with its first exports of met coal going to Japan. In Ingalinskaya the Russian company Kolmar is building a coking coal mine with a final capacity of 10.5 Mtpa. There are plans to start limited operation with a capacity of 6 Mtpa already in 2015. Additional mining projects are the Elegest mine with a projected production capacity of 15 Mtpa by 2020 and the Karakanskoe thermal coal field, which is expected to have a capacity of 6 Mtpa by 2017. Besides the investment in new coal mines, several existing production pits are expanded. SUEK plans to ramp up 3 Mtpa additional capacity at its Urgal mine located in Khabarovsk Krai by 2016. Capacity at the Solncevskoe deposit will be increased in steps, by 5 Mtpa by 2016 and by another 5 Mtpa by 2020.

Investment in export infrastructure capacity

Russian exporting coal producers have been focusing increasingly on markets in the Pacific Basin in recent years. Consequently, investment activity in export infrastructure is especially strong in Russia's eastern regions. However, there are also plans to expand port capacities in the Black Sea that are necessary for shipments to the Atlantic Basin.

At the Pacific coast, capacity of the Vanino seaport is expected to be extended by 8 Mtpa to a total capacity of 24 Mtpa by 2017. There are also plans to build a new terminal in Vanino by 2020, which would add another 24 Mtpa of export capacity. A large expansion project is also currently being worked on at the Vostochny seaport. With an investment volume of USD 422 million, the project aims at increasing the port's capacity from 17.2 Mtpa to 40 Mtpa by 2020. Smaller port infrastructure projects in the Russian east include the expansion of the Trade Port Posiet and the Maly seaport. The only planned project in the Black Sea is the construction of a new coal terminal at Taman seaport with a projected capacity of 10 Mtpa.

In addition to port capacity, railway capacity is decisive for Russian coal exports. Almost all rail lines in Russia are operated by Russian Railways (RZD) and expanded according to RZD's investment programme. Currently there are no major projects under construction. However, RZD plans to increase capacity of the Trans-Siberian and Baikal-Amur main lines in the eastern part of Russia by 2018. The project has an investment volume of roughly USD 14.5 billion and will increase transport capacity by an estimated 120 Mtpa by 2020. Another project aims to build a new rail line from the Elegest coal mine to Kuragino in order to connect coal deposits in South Siberia with ports at the Pacific coast. However, funding for the project has not been raised yet.

Indonesia

Investment in export mining capacity

Total incremental export mining capacity over the outlook period in Indonesia is estimated at approximately 53 Mtpa. It must be noted that additions of export mining capacity in Indonesia are hard to predict as there are no comprehensive and transparent project lists publicly available. All Indonesian mining additions are therefore classified as potential.

One large coal-mining project in Indonesia is the IndoMet mine complex in Central and East Kalimantan, developed by BHP Billiton and Indonesian company PT Adaro. The project consists of five deposits and could become Indonesia's largest mine in terms of land area. The first step in the IndoMet project is the Haju mine, which will start production in the first half of 2016. Production capacity of the mine will start at 1 Mtpa and will later be ramped up to approximately 5 Mtpa. Another large mining project in Indonesia is the East Kutai Coal Project thermal coal mine, which is jointly owned by Churchill Mining and Ridlatama Group. The mine is projected to produce up to 30 Mtpa when fully developed. However, the project is currently on hold because of legal disputes between Churchill Mining and the Indonesian government. Other Indonesian mining projects include Adaro Energy's Mustika Indah Permai project in South Sumatra and Cokal's Bumi Barito Mineral project in Central Kalimantan.

Investment in export infrastructure capacity

Export port capacity in Indonesia did not change in 2014 and remained at 130 Mtpa. In 2015, a capacity upgrade at PT Bukit Asam's Taharan port in Sumatra as well as a small increase in barge loading capacity at Tanjung Bara in Kalimantan raised export capacity by 13 Mtpa. The Indonesian government announced plans to name 14 ports, which will be the only authorised outlets for coal exports, in order to fight illegal smuggling of coal. The 14 special ports will be located on the routes between Kalimantan and Sumatra Island. The realisation of this plan requires substantial investments over the coming years, which raises questions about the financial feasibility of the project.

Indonesian producers are increasingly moving away from barging coal down the rivers for inland transportation and are instead looking at the construction of railway infrastructure. There are several railway projects that are expected to be operational within the outlook period. Prominent examples are the Pathway Project, which would add 40 Mtpa of railway capacity between Muara Enim and Pulau Baai upon completion, and the East Kalimantan Railway from Kutai Barat to the Balikpapan port with a projected capacity of up to 20 Mtpa. However, many of the Indonesian railway projects face financial, political or technical difficulties.

Canada

Investment in export mining capacity

Canadian coal exports consist primarily of met coal, which is mined mainly in the western Canadian provinces of Alberta and British Columbia. Canada's coal-mining industry suffered significantly in recent years because of the low market prices for met coal and higher operating costs in comparison with global competitors.

As a result, several mines were closed down and investment projects were suspended in 2014. Teck Resources, for example, has delayed the restarting of the Quintette coal mine, which has a potential production capacity of 4 Mtpa export met coal. Other projects that were put on hold in 2014 are Anglo American's Roman project and the Vista coal project. In 2015 the Vista coal project, which has a potential total production capacity of 12 Mtpa and could become Canada's largest coal mine, was bought by US coal producer Cline Group. It is yet unclear when the buyer intends to start production, but the first stage of the mine could be operational by 2017 with an estimated capacity of 6 Mtpa. Additionally Glencore's Sukunka met coal mine project has been suspended. The project's application for environmental assessment has not been approved by the government of British Columbia because there was a lack of detail related to the geological and environmental impacts of the proposed mine.

Despite the difficult market environment and mine closures, several mine development projects are still in progress. The Donkin coal mine in Nova Scotia is expected to start production with a capacity of 1 Mtpa in 2016 and has the potential to produce up to 3 Mtpa when market conditions improve. The Murray River met coal project, which is still in the environmental approval process, is projected to start production with a capacity of 6 Mtpa in 2018. The Crown Mountain project is also still in an early development stage and has yet to pass the environmental assessment. The mine has a projected capacity of up to 2 Mtpa and could enter production in late 2017.

Investment in export infrastructure capacity

Canada's coal export terminals are located mainly on the west coast and have been expanded in recent years in expectation of growing exports from Canada and the Powder River Basin in the United States to the Asian markets. However, the current difficult market situation also affects port operators. Consequently the Ridley terminal suspended a plan to extend export capacity to 25 Mtpa as the company is convinced that the current capacity of 18 Mtpa is enough to handle demand for shipments to Asia until the end of 2019. Plans by Fraser Surrey Docks to build a coal terminal with a capacity of 4 Mtpa to export coal from the Powder River Basin are still intact but in early stages. Despite the current weak investment activity, total export capacity in Canada will not constrain export activity of Canadian coal producers in the near future.

United States

Investment in export mining capacity

The outlook for incremental export mining capacity in the United States remains unchanged in comparison with last year's report. Because of weak domestic coal demand and low international prices, there are no significant additions of export mining capacity expected to come on line over the outlook period.

Investment in export infrastructure capacity

Coal exports from the United States to the Asian markets are currently limited by scarce port capacity at the US West Coast. In particular, coal produced in the Illinois Basin and the Powder River Basin is competitive in the international market, but infrastructure bottlenecks prevent the development of the full export potential. To ease this problem, several projects to extend export capacity in the west are currently on the drawing board. There are plans to build three new export terminals in the US states of Washington and Oregon. The Gateway Pacific project has a planned export capacity of 24-48 Mtpa; the Millennium Bulk Logistics project and the Port Westward project both have a projected capacity of 15-30 Mtpa. All the mentioned projects are currently in the approval process and face strong public opposition because of environmental concerns. It is therefore not expected that the planned export capacities will be operational within the outlook period. In face of the difficult permit process in the Northwest, there are also efforts to increase export capacity of ports located at the Gulf of Mexico. Exports through the Gulf of Mexico will especially benefit from the expansion of the Panama Canal, which will ease shipments to Asia. By 2020, the capacity of current ports at the gulf is planned to be extended by up to 48 Mtpa. Additionally, a new terminal with a capacity of 22 Mtpa is planned but will not be operational by 2020. Despite the efforts to increase export capacity of US ports, it is expected that coal exports from the United States to Asia will continue to be constrained significantly by infrastructure bottlenecks over the outlook period.

US railway infrastructure was significantly congested in 2014 because of surging demand for oil and grain shipping. The two main carriers, Burlington Northern Santa Fe (BNSF) and Union Pacific, responded by agreeing to add capacity. BNSF invested USD 5.5 billion in rail capacity, adding 6 000 workers and 5 000 new railcars in 2014. Union Pacific had fewer delays but also agreed to add some capacity to increase shipments. Building needed rail capacity takes time, but some of the bottlenecks of 2014 already began to improve in 2015.

Poland

Investment in export mining capacity

The Lublin Coal Basin has the potential to host new large-scale coal projects, as it has ideal geological conditions for high productivity. There are some future projects regarding exploitation of Polish hard coal reserves that include foreign private companies' involvement. In February 2014, the German HMS Bergbau AG acquired a Polish company and has since then obtained licences to explore coal reserves in Silesia. Once the mining licence is granted, the Polish subsidiary Silesian Coal can begin the long-term mining in Orzesze region. In July 2015, Prairie Mining announced it had secured the exclusive right to be granted a mining concession for the LCP Project (Lublin Coal Project/Jan Karski Project). The Lublin region has high-quality rail lines connecting it with the countries to the west and with northern ports. Prairie Mining is the first foreign entrant to the basin in 2012. Polish mining and machinery company KOPEX plans to build an underground coal mine in Silesia Region (Przeciszów), through its subsidiary Kopex-Ex-Coal.

Investment in export infrastructure capacity

There are no significant expansions of Polish export infrastructure capacity expected to be operational within the outlook period.

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ANNEX

Table A.1 Coal demand, 2013-20, forecast (million tonnes of coal equivalent [Mtce])

	2013	2014*	2016	2018	2020	CAGR
OECD	1 460	1 430	1 380	1 347	1 322	-1,3%
OECD Americas	670	669	630	602	584	-2,2%
United States	618	616	581	555	541	-2,1%
OECD Europe	429	407	393	390	385	-0,9%
OECD Asia Oceania	361	355	356	355	353	-0,1%
Non-OECD	4 128	4 109	4 208	4 334	4 492	1,5%
China	2 926	2 843	2 847	2 883	2 945	0,6%
India	484	550	603	648	699	4,1%
Africa and Middle East	152	152	170	172	170	1,9%
Eastern Europe/Eurasia	314	295	296	299	305	0,6%
ASEAN	130	139	163	189	218	7,8%
Other developing Asia	89	93	92	102	113	3,4%
Latin America	32	37	37	39	42	2,1%
Total	**5 588**	**5 539**	**5 588**	**5 680**	**5 814**	**0,8%**

* Estimate.

Note: CAGR = compound average growth rate, OECD = Organisation for Economic co-operation and Development

Table A.2 Thermal coal and lignite demand, 2013-20, forecast (Mtce)

	2013	2014*	2016	2018	2020	CAGR
OECD	1 283	1 253	1 201	1 170	1 146	-1,5%
OECD Americas	644	642	607	578	562	-2,2%
United States	599	597	563	537	523	-2,2%
OECD Europe	362	340	326	323	319	-1,1%
OECD Asia Oceania	278	271	269	268	266	-0,3%
Non-OECD	3 373	3 344	3 469	3 584	3 722	1,8%
China	2 317	2 231	2 274	2 306	2 355	0,9%
India	448	510	550	590	636	3,7%
Africa and Middle East	146	148	165	167	165	1,9%
Eastern Europe/Eurasia	230	210	212	215	220	0,8%
ASEAN	130	137	161	186	214	7,7%
Other developing Asia	83	85	85	96	106	3,7%
Latin America	18	22	23	25	26	2,6%
Total	**4 656**	**4 597**	**4 671**	**4 754**	**4 869**	**1,0%**

* Estimate.

Table A.3 Metallurgical (met) coal demand, 2013-20, forecast (Mtce)

	2013	2014*	2016	2018	2020	CAGR
OECD	177	177	179	177	176	-0,1%
OECD Americas	26	26	24	23	23	-2,2%
United States	20	19	18	18	18	-1,1%
OECD Europe	67	67	68	67	66	-0,2%
OECD Asia Oceania	83	84	87	87	87	0,6%
Non-OECD	755	766	739	749	769	0,1%
China	609	613	573	577	590	-0,6%
India	36	40	53	58	62	7,6%
Africa and Middle East	5	5	5	5	5	1,5%
Eastern Europe/Eurasia	84	84	84	85	85	0,1%
ASEAN	0	2	3	3	4	0,0%
Other developing Asia	7	7	7	7	7	-0,7%
Latin America	14	15	14	15	16	1,3%
Total	**932**	**943**	**918**	**926**	**945**	**0,0%**

* Estimate.

Table A.4 Coal production, 2013-20, forecast (Mtce)

	2013	2014*	2016	2018	2020	CAGR
OECD	1 350	1 381	1 313	1 306	1 319	-0,8%
OECD Americas	745	751	689	667	665	-2,0%
United States	682	688	625	605	601	-2,2%
OECD Europe	223	216	201	203	189	-2,2%
OECD Asia Oceania	382	414	421	432	463	1,9%
Non-OECD	4 292	4 229	4 275	4 375	4 495	1,0%
China	2 707	2 638	2 660	2 705	2 771	0,8%
India	340	373	393	430	437	2,7%
Africa and Middle East	219	217	238	239	246	2,1%
Eastern Europe/Eurasia	433	417	412	425	433	0,6%
ASEAN	450	434	408	397	416	-0,7%
Other developing Asia	58	61	60	67	71	2,7%
Latin America	85	91	104	112	120	4,7%
Total	**5 642**	**5 610**	**5 588**	**5 680**	**5 814**	**0,6%**

* Estimate.

Table A.5 Thermal coal and lignite production, 2013-20, forecast (Mtce)

	2013	2014*	2016	2018	2020	CAGR
OECD	1 065	1 076	1 040	1 027	1 034	-0,7%
OECD Americas	640	650	605	582	575	-2,0%
United States	607	615	566	544	536	-2,3%
OECD Europe	200	193	186	192	178	-1,4%
OECD Asia Oceania	225	232	248	254	281	3,2%
Non-OECD	3 617	3 547	3 631	3 727	3 835	1,3%
China	2 159	2 081	2 158	2 204	2 261	1,4%
India	336	368	388	425	432	2,7%
Africa and Middle East	211	210	229	230	237	2,1%
Eastern Europe/Eurasia	333	321	321	333	340	1,0%
ASEAN	447	431	404	392	410	-0,8%
Other developing Asia	51	51	32	36	41	-3,3%
Latin America	81	86	99	107	113	4,6%
Total	**4 682**	**4 623**	**4 671**	**4 754**	**4 869**	**0,9%**

* Estimate.

Table A.6 Met coal production, 2013-20, forecast (Mtce)

	2013	2014*	2016	2018	2020	CAGR
OECD	284	304	273	278	286	-1,0%
OECD Americas	105	100	83	86	89	-1,8%
United States	75	72	58	61	65	-1,6%
OECD Europe	22	23	14	11	11	-11,6%
OECD Asia Oceania	157	182	173	178	182	0,1%
Non-OECD	673	681	645	648	660	-0,5%
China	548	556	502	501	510	-1,4%
India	4	5	5	5	5	0,2%
Africa and Middle East	8	7	9	9	9	3,3%
Eastern Europe/Eurasia	99	95	91	92	93	-0,4%
ASEAN	3	3	4	5	6	14,0%
Other developing Asia	7	10	27	31	30	20,2%
Latin America	4	5	6	6	7	6,4%
Total	**958**	**985**	**918**	**926**	**945**	**-0,7%**

* Estimate.

Table A.7 Hard coal net imports, 2013-20, forecast (Mtce)

	2013	2014*	2016	2018	2020	CAGR
OECD	94	84	67	41	3	-42,6%
OECD Americas	-101	-76	-58	-66	-81	1,0%
United States	-86	-64	-43	-50	-60	-1,2%
OECD Europe	215	222	193	187	196	-2,1%
OECD Asia Oceania	-18	-59	-65	-77	-110	10,7%
Non-OECD	-96	-75	-67	-42	-3	-41,5%
China	257	234	187	178	174	-4,8%
India	139	178	210	218	261	6,6%
Africa and Middle East	-64	-66	-68	-67	-76	2,4%
Eastern Europe/Eurasia	-109	-122	-116	-126	-128	0,8%
ASEAN	-314	-292	-245	-208	-198	-6,3%
Other developing Asia	50	49	32	36	42	-2,6%
Latin America	-57	-55	-67	-73	-78	6,0%

* Estimate.

Table A.8 Seaborne steam coal imports, 2013-20, forecast (Mtce)

	2013	2014*	2016	2018	2020	CAGR
Europe and Mediterranean	182	175	153	143	141	-3,6%
Japan	121	117	117	116	112	-0,7%
Korea	81	81	82	89	97	2,9%
Chinese Taipei	52	52	53	55	59	2,1%
China	191	176	120	110	104	-8,3%
India	100	131	162	165	204	7,7%
Latin America	18	19	19	20	21	1,7%
Other	57	64	65	103	143	14,2%
Total	**802**	**816**	**772**	**801**	**880**	**1,3%**

* Estimate.

Table A.9 Seaborne steam coal exports, 2013-20, forecast (Mtce)

	2013	2014*	2016	2018	2020	CAGR
Australia	160	171	181	193	223	4,6%
South Africa	65	69	68	68	69	0,1%
Indonesia	353	340	303	297	323	-0,8%
Russia	96	109	110	118	120	1,5%
Colombia	73	73	80	88	98	5,0%
China	4	4	4	8	10	14,4%
United States	36	24	15	21	30	4,3%
Other	29	27	11	8	7	-20,6%
Total	**817**	**816**	**772**	**801**	**880**	**1,3%**

* Estimate.

Table A.10 Seaborne met coal imports, 2013-20, forecast (Mtce)

	2013	2014*	2016	2018	2020	CAGR
Europe and Mediterranean	56	63	62	65	64	0,4%
Japan	52	49	48	49	49	0,1%
Korea	29	33	34	35	35	1,2%
China	63	53	44	46	50	-0,8%
India	39	47	48	53	57	3,3%
Other	19	21	22	21	23	2,0%
Total	**257**	**264**	**258**	**269**	**278**	**0,9%**

* Estimate.

Table A.11 Seaborne met coal exports, 2013-20, forecast (Mtce)

	2013	2014*	2016	2018	2020	CAGR
Australia	150	175	166	173	178	0,2%
Canada	29	25	26	26	26	0,6%
Mozambique	3	4	6	6	6	7,7%
Russia	15	14	15	16	17	3,5%
United States	53	47	37	40	44	-0,8%
Other	7	6	8	8	8	4,5%
Total	**257**	**270**	**258**	**269**	**278**	**0,5%**

* Estimate.

Table A.12 Coal demand, 2013-20, forecast (million tonnes [Mt])

	2013	2014*	2016	2018	2020	CAGR
OECD	2 136	2 089	2 021	1 992	1 949	-1,1%
OECD Americas	915	912	849	809	785	-2,5%
United States	840	835	784	748	727	-2,3%
OECD Europe	761	727	718	727	713	-0,3%
OECD Asia Oceania	460	450	454	455	451	0,0%
Non-OECD	5 855	5 831	5 978	6 177	6 438	1,7%
China	4 035	3 920	3 966	4 045	4 147	0,9%
India	804	907	962	1030	1095	3,2%
Africa and Middle East	199	200	218	222	232	2,5%
Eastern Europe/Eurasia	502	474	475	482	503	1,0%
ASEAN	170	179	207	240	284	7,9%
Other developing Asia	107	111	108	115	130	2,7%
Latin America	38	41	42	43	48	2,9%
Total	**7 991**	**7 920**	**7 999**	**8 169**	**8 387**	**1,0%**

* Estimate.

Note: projections have been produced in million tonnes of coal-equivalent. For reference, this Annex also includes coal volumes in million tonnes. We have not analysed the calorific value of coal to be produced; therefore, projections in million tonnes should be consulted with caution.

Table A.13 Thermal coal and lignite demand, 2013-20, forecast (Mt)

	2013	2014*	2016	2018	2020	CAGR
OECD	1 956	1 909	1 840	1 812	1 773	-1,2%
OECD Americas	889	886	829	790	766	-2,4%
United States	821	817	768	733	712	-2,3%
OECD Europe	694	660	653	662	650	-0,3%
OECD Asia Oceania	373	363	357	359	357	-0,3%
Non-OECD	5 026	4 990	5 176	5 366	5 605	2,0%
China	3 368	3 248	3 339	3 414	3 503	1,3%
India	759	857	903	966	1026	3,0%
Africa and Middle East	194	196	213	217	227	2,5%
Eastern Europe/Eurasia	412	382	384	391	412	1,2%
ASEAN	170	177	207	240	284	8,1%
Other developing Asia	100	103	101	108	123	3,0%
Latin America	24	26	29	29	31	3,1%
Total	**6 982**	**6 898**	**7 015**	**7 177**	**7 378**	**1,1%**

* Estimate.

Table A.14 Met coal demand, 2013-20, forecast (Mt)

	2013	2014*	2016	2018	2020	CAGR
OECD	180	180	181	180	176	-0,4%
OECD Americas	26	26	20	19	19	-4,9%
United States	19	19	16	15	15	-3,6%
OECD Europe	67	67	65	65	64	-0,8%
OECD Asia Oceania	87	87	97	96	93	1,1%
Non-OECD	829	841	802	812	833	-0,2%
China	668	671	627	631	644	-0,7%
India	44	49	59	64	69	5,7%
Africa and Middle East	5	5	6	5	5	1,9%
Eastern Europe/Eurasia	91	92	91	91	91	-0,1%
ASEAN	0	2	0	0	0	0,0%
Other developing Asia	7	8	7	7	7	-2,4%
Latin America	15	14	14	14	17	2,5%
Total	**1 008**	**1 021**	**984**	**992**	**1 009**	**-0,2%**

* Estimate.

Table A.15 Coal production, 2013-20, forecast (Mt)

	2013	2014*	2016	2018	2020	CAGR
OECD	1 989	2 016	1 947	1 941	1 952	-0,5%
OECD Americas	991	1 004	930	900	894	-1,9%
United States	904	916	846	819	814	-1,9%
OECD Europe	533	515	508	522	503	-0,4%
OECD Asia Oceania	465	497	510	519	554	1,8%
Non-OECD	5 992	5 909	6 055	6 235	6 443	1,5%
China	3 749	3 650	3 729	3 824	3 947	1,3%
India	610	668	694	750	756	2,1%
Africa and Middle East	269	267	295	297	306	2,3%
Eastern Europe/Eurasia	643	615	614	631	655	1,0%
ASEAN	557	538	533	522	550	0,4%
Other developing Asia	69	72	71	80	88	3,4%
Latin America	95	99	119	130	141	6,1%
Total	**7 980**	**7 925**	**8 002**	**8 176**	**8 395**	**1,0%**

* Estimate.

Table A.16 Thermal coal and lignite production, 2013-20, forecast (Mt)

	2013	2014*	2016	2018	2020	CAGR
OECD	1 692	1 699	1 666	1 656	1 661	-0,4%
OECD Americas	878	896	839	806	796	-2,0%
United States	826	841	785	756	747	-2,0%
OECD Europe	510	492	493	511	493	0,0%
OECD Asia Oceania	304	310	334	340	372	3,1%
Non-OECD	5 256	5 165	5 353	5 530	5 726	1,7%
China	3 148	3 040	3 179	3 275	3 388	1,8%
India	604	662	688	744	750	2,1%
Africa and Middle East	261	260	287	290	299	2,4%
Eastern Europe/Eurasia	536	512	515	530	553	1,3%
ASEAN	553	535	529	517	544	0,3%
Other developing Asia	62	62	43	48	57	-1,4%
Latin America	91	94	113	125	135	6,2%
Total	**6 947**	**6 864**	**7 019**	**7 186**	**7 386**	**1,2%**

* Estimate.

Table A.17 Met coal production, 2013-20, forecast (Mt)

	2013	2014*	2016	2018	2020	CAGR
OECD	297	317	281	285	291	-1,4%
OECD Americas	113	108	91	94	98	-1,5%
United States	78	75	60	63	68	-1,7%
OECD Europe	22	23	14	11	11	-11,6%
OECD Asia Oceania	162	187	176	180	182	-0,4%
Non-OECD	736	744	702	705	718	-0,6%
China	601	610	550	549	559	-1,4%
India	6	6	6	6	6	0,2%
Africa and Middle East	8	7	8	8	8	0,6%
Eastern Europe/Eurasia	106	103	99	101	102	-0,2%
ASEAN	4	3	4	5	6	13,8%
Other developing Asia	7	10	29	32	31	20,2%
Latin America	4	5	5	5	6	3,5%
Total	**1 033**	**1 061**	**983**	**990**	**1 008**	**-0,8%**

* Estimate.

Table A.18 Seaborne steam coal imports, 2013-20, forecast (Mt)

	2013	2014*	2016	2018	2020	CAGR
Europe and Mediterranean	212	205	164	155	161	-3,9%
Japan	145	137	138	138	130	-0,9%
Korea	96	96	94	105	113	2,8%
Chinese Taipei	59	58	59	60	66	2,2%
China	246	219	165	150	128	-8,6%
India	145	175	215	222	277	7,9%
Latin America	20	21	18	20	23	1,6%
Other	65	72	73	113	164	14,6%
Total	**987**	**982**	**926**	**962**	**1 060**	**1,3%**

* Estimate.

Table A.19 Seaborne steam coal exports, 2013-20, forecast (Mt)

	2013	2014*	2016	2018	2020	CAGR
Australia	184	196	209	223	258	4,7%
South Africa	71	74	73	74	74	0,1%
Indonesia	443	421	386	378	412	-0,4%
Russia	112	127	131	140	142	1,8%
Colombia	89	85	93	104	118	5,8%
China	6	6	5	11	13	14,8%
United States	41	26	17	24	34	4,7%
Other	31	29	12	8	7	-20,6%
Total	**976**	**964**	**926**	**962**	**1 059**	**1,6%**

* Estimate.

Table A.20 Seaborne met coal imports, 2013-20, forecast (Mt)

	2013	2014*	2016	2018	2020	CAGR
Europe and Mediterranean	56	63	62	65	64	0,4%
Japan	54	51	51	52	51	0,2%
Korea	30	34	35	36	36	1,2%
China	69	58	49	52	55	-0,7%
India	42	51	53	58	63	3,6%
Other	20	21	22	22	24	1,6%
Total	**270**	**277**	**272**	**284**	**293**	**1,0%**

* Estimate.

Table A.21 Seaborne met coal exports, 2013-20, forecast (Mt)

	2013	2014*	2016	2018	2020	CAGR
Australia	142	173	164	171	175	0,2%
Canada	30	32	33	33	33	0,6%
Mozambique	3	3	5	5	5	7,7%
Russia	16	16	18	20	20	3,7%
United States	59	53	41	45	50	-1,1%
Other	8	8	10	10	10	4,5%
Total	**258**	**285**	**271**	**282**	**293**	**0,5%**

* Estimate.

Table A.22 Coal demand, 2013-20, China Peak Case Scenario (CPCS) (Mtce)

	2013	2014*	2016	2018	2020	CAGR
OECD	1 460	1 430	1 380	1 347	1 322	-1,3%
OECD Americas	670	669	630	602	584	-2,2%
United States	618	616	581	555	541	-2,1%
OECD Europe	429	407	393	390	385	-0,9%
OECD Asia Oceania	361	355	356	355	353	-0,1%
Non-OECD	4 128	4 110	4 145	4 161	4 187	0,3%
China	2 926	2 843	2 784	2 710	2 640	-1,2%
India	484	550	603	648	699	4,1%
Africa and Middle East	152	152	170	172	170	1,9%
Eastern Europe/Eurasia	314	295	296	299	305	0,6%
ASEAN	130	139	163	189	218	7,8%
Other developing Asia	89	93	92	102	113	3,4%
Latin America	32	37	37	39	42	2,1%
Total	**5 588**	**5 540**	**5 525**	**5 508**	**5 509**	**-0,1%**

* Estimate.

Table A.23 Thermal coal and lignite demand, 2013-20, CPCS (Mtce)

	2013	2014*	2016	2018	2020	CAGR
OECD	1 283	1 253	1 201	1 170	1 146	-1,5%
OECD Americas	644	642	607	578	562	-2,2%
United States	599	597	563	537	523	-2,2%
OECD Europe	362	340	326	323	319	-1,1%
OECD Asia Oceania	278	271	269	268	266	-0,3%
Non-OECD	3 373	3 344	3 406	3 455	3 515	0,8%
China	2 317	2 231	2 211	2 177	2 147	-0,6%
India	448	510	550	590	636	3,7%
Africa and Middle East	146	148	165	167	165	1,9%
Eastern Europe/Eurasia	230	210	212	215	220	0,8%
ASEAN	130	137	161	186	214	7,7%
Other developing Asia	83	85	85	96	106	3,7%
Latin America	18	22	23	25	26	2,6%
Total	**4 656**	**4 597**	**4 608**	**4 625**	**4 661**	**0,2%**

* Estimate.

Table A.24 Met coal demand, 2013-20, CPCS (Mtce)

	2013	2014*	2016	2018	2020	CAGR
OECD	177	177	179	177	176	-0,1%
OECD Americas	26	26	24	23	23	-2,2%
United States	20	19	18	18	18	-1,1%
OECD Europe	67	67	68	67	66	-0,2%
OECD Asia Oceania	83	84	87	87	87	0,6%
Non-OECD	755	766	739	706	672	-2,1%
China	609	613	573	533	493	-3,6%
India	36	40	53	58	62	7,6%
Africa and Middle East	5	5	5	5	5	1,5%
Eastern Europe/Eurasia	84	84	84	85	85	0,1%
ASEAN	0	2	3	3	4	0,0%
Other developing Asia	7	7	7	7	7	-0,7%
Latin America	14	15	14	15	16	1,3%
Total	**932**	**943**	**918**	**883**	**848**	**-1,7%**

* Estimate.

Table A.25 Coal production, 2013-20, CPCS (Mtce)

	2013	2014*	2016	2018	2020	CAGR
OECD	1 350	1 381	1 295	1 250	1 242	-1,7%
OECD Americas	745	751	682	648	632	-2,8%
United States	682	688	618	586	570	-3,1%
OECD Europe	223	216	200	200	189	-2,2%
OECD Asia Oceania	382	414	410	399	419	0,2%
Non-OECD	4 292	4 229	4 230	4 258	4 267	0,1%
China	2 707	2 638	2 635	2 639	2 621	-0,1%
India	340	373	393	415	438	2,7%
Africa and Middle East	219	217	238	236	246	2,1%
Eastern Europe/Eurasia	433	417	409	422	431	0,6%
ASEAN	450	434	391	367	343	-3,8%
Other developing Asia	58	61	60	67	71	2,7%
Latin America	85	91	104	112	116	4,2%
Total	**5 642**	**5 610**	**5 525**	**5 507**	**5 509**	**-0,3%**

* Estimate.

Table A.26 Thermal coal and lignite production, 2013-20, CPCS (Mtce)

	2013	2014*	2016	2018	2020	CAGR
OECD	1 065	1 076	1 022	991	998	-1,2%
OECD Americas	640	650	598	565	548	-2,8%
United States	607	615	559	528	509	-3,1%
OECD Europe	200	193	186	188	178	-1,4%
OECD Asia Oceania	225	232	238	237	272	2,7%
Non-OECD	3 617	3 547	3 586	3 634	3 662	0,5%
China	2 159	2 081	2 133	2 163	2 167	0,7%
India	336	368	388	410	432	2,7%
Africa and Middle East	211	210	229	227	237	2,1%
Eastern Europe/Eurasia	333	321	318	329	338	0,9%
ASEAN	447	431	387	362	338	-4,0%
Other developing Asia	51	51	32	36	41	-3,3%
Latin America	81	86	99	106	109	4,0%
Total	**4 682**	**4 623**	**4 608**	**4 625**	**4 661**	**0,1%**

* Estimate.

Table A.27 Met coal production, 2013-20, CPCS (Mtce)

	2013	2014*	2016	2018	2020	CAGR
OECD	284	304	273	259	244	-3,6%
OECD Americas	105	100	84	83	83	-2,9%
United States	75	72	59	58	61	-2,6%
OECD Europe	22	23	14	11	11	-11,6%
OECD Asia Oceania	157	182	172	162	147	-3,5%
Non-OECD	673	681	645	623	604	-2,0%
China	548	556	502	476	454	-3,3%
India	4	5	5	5	6	1,8%
Africa and Middle East	8	7	9	9	9	3,0%
Eastern Europe/Eurasia	99	95	91	92	93	-0,3%
ASEAN	3	3	4	5	6	14,0%
Other developing Asia	7	10	27	31	30	20,2%
Latin America	4	5	6	6	7	6,4%
Total	**958**	**985**	**918**	**883**	**848**	**-2,5%**

* Estimate.

Table A.28 Hard coal net imports, 2013-20, CPCS (Mtce)

	2013	2014*	2016	2018	2020	CAGR
OECD	94	84	84	97	80	-7,5%
OECD Americas	-101	-76	-51	-47	-48	-12,4%
United States	-86	-64	-36	-31	-29	-2,1%
OECD Europe	215	222	193	190	196	1,7%
OECD Asia Oceania	-18	-59	-54	-44	-66	-0,8%
Non-OECD	-96	-75	-85	-97	-80	1,2%
China	257	234	149	71	19	-34,1%
India	139	178	210	233	261	6,6%
Africa and Middle East	-64	-66	-68	-63	-76	2,4%
Eastern Europe/Eurasia	-109	-122	-113	-123	-126	0,6%
ASEAN	-314	-292	-228	-178	-126	-13,1%
Other developing Asia	50	49	32	36	42	-2,6%
Latin America	-57	-55	-67	-73	-74	5,1%

* Estimate.

Table A.29 Seaborne steam coal imports, 2013-20, CPCS (Mtce)

	2013	2014*	2016	2018	2020	CAGR
Europe and Mediterranean	182	175	153	146	141	-3,6%
Japan	121	117	117	116	112	-0,7%
Korea	81	81	83	90	98	3,1%
Chinese Taipei	52	52	53	55	59	2,1%
China	191	176	91	36	16	-32,7%
India	100	131	162	180	204	7,7%
Latin America	18	19	19	20	21	1,7%
Other	57	64	65	103	149	15,0%
Total	**802**	**816**	**744**	**745**	**799**	**-0,3%**

* Estimate.

Table A.30 Seaborne steam coal exports, 2013-20, CPCS (Mtce)

	2013	2014*	2016	2018	2020	CAGR
Australia	160	171	172	177	216	4,0%
South Africa	65	69	68	68	69	0,1%
Indonesia	353	340	286	267	251	-4,9%
Russia	96	109	107	115	118	1,3%
Colombia	73	73	80	87	94	4,3%
China	4	4	13	22	36	41,7%
United States	36	24	7	5	9	-14,4%
Other	29	27	11	4	7	-20,6%
Total	**817**	**816**	**744**	**745**	**799**	**-0,4%**

* Estimate.

Table A.31 Seaborne met coal imports, 2013-20, CPCS (Mtce)

	2013	2014*	2016	2018	2020	CAGR
Europe and Mediterranean	56	63	62	65	64	0,4%
Japan	52	49	48	49	49	0,1%
Korea	29	33	34	35	35	1,2%
China	63	53	44	27	9	-25,7%
India	39	47	48	53	57	3,2%
Other	19	21	22	21	23	2,0%
Total	**257**	**264**	**258**	**250**	**237**	**-1,8%**

* Estimate.

Table A.32 Seaborne met coal exports, 2013-20, CPCS (Mtce)

	2013	2014*	2016	2018	2020	CAGR
Australia	150	175	166	157	142	-3,4%
Canada	29	25	26	26	24	-0,8%
Mozambique	3	4	6	5	5	7,1%
Russia	15	14	15	16	17	3,6%
United States	53	47	37	37	41	-2,3%
Other	7	6	8	8	8	4,5%
Total	**257**	**270**	**258**	**250**	**237**	**-2,2%**

* Estimate.

Table A.33 Coal demand, 2013-20, CPCS (Mt)

	2013	2014*	2016	2018	2020	CAGR
OECD	2 136	2 089	2 025	1 992	1 949	-1,1%
OECD Americas	915	912	850	810	778	-2,6%
United States	840	835	785	748	719	-2,5%
OECD Europe	761	727	722	731	719	-0,2%
OECD Asia Oceania	460	450	452	451	452	0,1%
Non-OECD	5 855	5 831	5 894	5 951	6 051	0,6%
China	4 035	3 920	3 883	3 823	3 754	-0,7%
India	804	907	960	1024	1093	3,2%
Africa and Middle East	199	200	219	219	233	2,5%
Eastern Europe/Eurasia	502	474	475	482	503	1,0%
ASEAN	170	179	206	243	289	8,3%
Other developing Asia	107	111	108	117	130	2,7%
Latin America	38	41	43	44	50	3,6%
Total	**7 991**	**7 920**	**7 918**	**7 943**	**8 000**	**0,2%**

* Estimate.

Note: projections have been produced in million tonnes of coal-equivalent. For reference, this Annex also includes coal volumes in million tonnes. We have not analysed the calorific value of coal to be produced; therefore, projections in million tonnes should be consulted with caution.

Table A.34 Thermal coal and lignite demand, 2013-20, CPCS (Mt)

	2013	2014*	2016	2018	2020	CAGR
OECD	1 956	1 909	1 841	1 811	1 770	-1,3%
OECD Americas	889	886	830	790	758	-2,6%
United States	821	817	769	733	704	-2,4%
OECD Europe	694	660	655	665	653	-0,2%
OECD Asia Oceania	373	363	356	356	358	-0,2%
Non-OECD	5 026	4 990	5 089	5 184	5 321	1,1%
China	3 368	3 248	3 255	3 240	3 216	-0,2%
India	759	857	902	959	1024	3,0%
Africa and Middle East	194	196	213	213	227	2,5%
Eastern Europe/Eurasia	412	382	384	390	412	1,2%
ASEAN	170	177	206	243	289	8,5%
Other developing Asia	100	103	101	109	122	2,9%
Latin America	24	26	29	29	32	3,2%
Total	**6 982**	**6 898**	**6 931**	**6 994**	**7 090**	**0,5%**

* Estimate.

Table A.35 Met coal demand, 2013-20, CPCS (Mt)

	2013	2014*	2016	2018	2020	CAGR
OECD	180	180	183	182	179	-0,1%
OECD Americas	26	26	20	20	20	-4,5%
United States	19	19	16	15	15	-3,6%
OECD Europe	67	67	67	67	66	-0,3%
OECD Asia Oceania	87	87	96	95	94	1,2%
Non-OECD	829	841	804	767	731	-2,3%
China	668	671	628	583	538	-3,6%
India	44	49	58	64	69	5,7%
Africa and Middle East	5	5	6	6	6	3,3%
Eastern Europe/Eurasia	91	92	91	91	91	-0,1%
ASEAN	0	2	0	0	0	0,0%
Other developing Asia	7	8	7	8	8	-0,3%
Latin America	15	14	15	15	19	4,4%
Total	**1008**	**1021**	**988**	**948**	**910**	**-1,9%**

* Estimate.

Table A.36 Coal production, 2013-20, CPCS (Mt)

	2013	2014*	2016	2018	2020	CAGR
OECD	1 989	2 016	1 932	1 884	1 872	-1,2%
OECD Americas	991	1 004	923	879	856	-2,6%
United States	904	916	838	799	779	-2,7%
OECD Europe	533	515	507	517	503	-0,4%
OECD Asia Oceania	465	497	502	488	513	0,5%
Non-OECD	5 992	5 909	5 991	6 072	6 137	0,6%
China	3 749	3 650	3 691	3 733	3 741	0,4%
India	610	668	694	725	756	2,1%
Africa and Middle East	269	267	296	293	306	2,3%
Eastern Europe/Eurasia	643	615	609	627	652	1,0%
ASEAN	557	538	512	484	457	-2,7%
Other developing Asia	69	72	71	80	88	3,4%
Latin America	95	99	119	130	137	5,5%
Total	**7 980**	**7 925**	**7 923**	**7 956**	**8 009**	**0,2%**

* Estimate.

Table A.37 Thermal coal and lignite production, 2013-20, CPCS (Mt)

	2013	2014*	2016	2018	2020	CAGR
OECD	1 692	1 699	1 646	1 613	1 619	-0,8%
OECD Americas	878	896	831	787	764	-2,6%
United States	826	841	777	738	714	-2,7%
OECD Europe	510	492	493	506	493	0,0%
OECD Asia Oceania	304	310	322	320	362	2,6%
Non-OECD	5 256	5 165	5 290	5 395	5 481	1,0%
China	3 148	3 040	3 141	3 211	3 243	1,1%
India	604	662	688	720	750	2,1%
Africa and Middle East	261	260	287	286	299	2,4%
Eastern Europe/Eurasia	536	512	511	527	551	1,2%
ASEAN	553	535	507	479	451	-2,8%
Other developing Asia	62	62	43	48	57	-1,4%
Latin America	91	94	113	124	130	5,6%
Total	**6 947**	**6 864**	**6 935**	**7 008**	**7 100**	**0,6%**

* Estimate.

Table A.38 Met coal production, 2013-20, CPCS (Mt)

	2013	2014*	2016	2018	2020	CAGR
OECD	297	317	286	271	253	-3,7%
OECD Americas	113	108	92	91	92	-2,6%
United States	78	75	61	61	64	-2,6%
OECD Europe	22	23	14	11	11	-11,6%
OECD Asia Oceania	162	187	180	168	151	-3,5%
Non-OECD	736	744	701	678	656	-2,1%
China	601	610	550	522	497	-3,3%
India	6	6	6	6	7	1,8%
Africa and Middle East	8	7	9	8	8	0,9%
Eastern Europe/Eurasia	106	103	98	100	101	-0,4%
ASEAN	4	3	4	5	6	13,8%
Other developing Asia	7	10	29	32	31	20,2%
Latin America	4	5	5	5	6	3,5%
Total	**1 033**	**1 061**	**988**	**948**	**910**	**-2,5%**

* Estimate.

Table A.39 Seaborne steam coal imports, 2013-20, CPCS (Mt)

	2013	2014*	2016	2018	2020	CAGR
Europe and Mediterranean	212	205	166	162	165	-3,6%
Japan	145	137	138	137	130	-0,9%
Korea	96	96	95	104	116	3,2%
Chinese Taipei	59	58	59	61	65	2,0%
China	246	219	131	58	20	-32,8%
India	145	175	214	240	274	7,8%
Latin America	20	21	18	20	23	1,7%
Other	65	72	72	115	169	15,2%
Total	**987**	**982**	**893**	**897**	**961**	**-0,4%**

* Estimate.

Table A.40 Seaborne steam coal exports, 2013-20, CPCS (Mt)

	2013	2014*	2016	2018	2020	CAGR
Australia	184	196	199	205	250	4,1%
South Africa	71	74	73	74	74	0,1%
Indonesia	443	421	364	340	319	-4,5%
Russia	112	127	127	136	140	1,5%
Colombia	89	85	93	104	114	5,0%
China	6	6	17	29	48	42,1%
United States	41	26	8	5	11	-14,0%
Other	31	29	11	4	7	-20,6%
Total	**976**	**964**	**893**	**897**	**961**	**0,0%**

* Estimate.

Table A.41 Seaborne met coal imports, 2013-20, CPCS (Mt)

	2013	2014*	2016	2018	2020	CAGR
Europe and Mediterranean	57	65	64	67	66	0,4%
Japan	54	51	50	51	51	0,1%
Korea	30	34	35	36	37	1,5%
China	68	60	50	32	11	-24,6%
India	42	51	52	58	62	3,5%
Other	23	24	24	24	27	2,2%
Total	**274**	**284**	**276**	**268**	**255**	**-1,8%**

* Estimate.

Table A.42 Seaborne met coal exports, 2013-20, CPCS (Mt)

	2013	2014*	2016	2018	2020	CAGR
Australia	142	173	168	159	144	-3,0%
Canada	30	32	33	33	30	-0,8%
Mozambique	3	3	5	5	5	8,1%
Russia	16	16	17	19	20	3,0%
United States	59	53	43	42	46	-2,3%
Other	8	8	10	10	10	4,5%
Total	**258**	**285**	**276**	**268**	**255**	**-1,8%**

* Estimate.

Table A.43 Current coal mining projects

Country	Project	Company	Type	Estimated start-up	Estimated new capacity (Mtpa)	Resource	Status
Australia	Alpha Coal Project	GVK - Hancock Coal	N	2018	32	TC	F
Australia	Appin Area 9	BHP Billiton	E	2016	3.5	CC	C
Australia	Ashton South East opencut	Yancoal Australia	E	2017	3.6	TC, PCI	F
Australia	Baralaba North expansion	Cockatoo Coal	E	2016	3.5	PCI, TC	C
Australia	Baralaba South Project	Cockatoo Coal	N	2019	3	PCI, TC	F
Australia	Belview	Stanmore Coal	N	2018	..	CC	F
Australia	Bengalla continuation	Rio Tinto / Wesfarmers	E	2018	4.3	TC	F
Australia	Bluff	Carabella Resources	N	2017	1.2	PCI	F
Australia	Broughton Coal Project	U&D Mining Industry	N	2018	1.5	CC	F
Australia	Byerwen Coal Project	Qcoal	N	2016	10	CC	F
Australia	Carmichael Coal Project (mine and rail)	Adani	N	2017	60	TC	F
Australia	Caroona	BHP Billiton	N	2020+	10	TC	F
Australia	China First Coal Project (Galilee Coal Project)	Waratah Coal	N	2018+	40	TC	F
Australia	Clyde Park Project	White Mountain	N	2020	1.75	TC	F
Australia	Codrilla	Peabody Energy	N	2020+	3.2	PCI	F
Australia	Colton	New Hope	N	2018	0.5	CC	F
Australia	Comet Ridge	Acacia Coal	N	2016	0.4	TC, CC	F
Australia	Curragh extension project	Wesfarmers	E	2018	..	CC	F
Australia	Dysart East	Dysart Coal	N	2016	1.4	CC	F
Australia	Eagle Downs (Peak Downs East underground)	Aquila Resources / Vale	N	2017	4.5	CC	C
Australia	Eaglefield	Peabody Energy	E	..	5	CC	F
Australia	Elimatta	New Hope	N	2019	5	TC	F
Australia	Fairhill	Queensland Coal Corporation	N	2017	..	CC	F
Australia	Grosvenor underground	Anglo American	N	2016	5	CC	C
Australia	Grosvenor West	Carabella Resources	N	2020	3.8	TC, CC	F
Australia	Kevin's Corner	GVK	N	2019	30	TC	F
Australia	Metropolitan	Peabody Energy	E	2015	1.5	CC	C
Australia	Minyago	Caledon Resources	N	2017	3	CC	F
Australia	Moolarben (stage 2)	Yancoal Australia	E	2016	5	TC	F

Australia	Moorlands	Cuesta Coal	N	2016	1.9	TC	F
Australia	Mount Pleasant project	Rio Tinto / Mitsubishi	N	2019	10.5	TC	F
Australia	Mt Thorley - Warkworth extension	Rio Tinto	E	n/a	0	TC	F
Australia	New Acland (stage 3)	New Hope Coal	E	2017	2.3	TC	F
Australia	New Lenton	New Hope Coal / MPC	N	2019	2	CC	F
Australia	North Surat - Collingwood Project	New Hope Coal	N	2018	4	TC	F
Australia	North Surat - TaroomProject	New Hope Coal	N	2018	8	TC	F
Australia	North Surat - Woori Project	New Hope Coal	N	2020	2.5	TC	F
Australia	Norhern Galilee Project	Guildford	N	2020	7	TC	F
Australia	Oaky Creek (phase 2)	Glencore, Sumisho, Itochu, ICRA OC	E	n/a	5	CC	F
Australia	Project China Stone	MacMines Austasia	N	2018	55	TC	F
Australia	Rolleston (phase 2)	Glencore, Sumisho, IRCA	E	n/a	3	TC	F
Australia	Russell Vale Colliery	Wollongong coal	E	2015	3	CC	F
Australia	Russell Vale Colliery (preliminary works project)	Wollongong coal	U	2015	nil	CC	C
Australia	Sarum	Glencore / Itochu / Sumisho	N	2017	4.2	CC	F
Australia	South Galilee Epsilon	Alpha Coal Management	N	2018	3.2	TC	F
Australia	Springsure	Springsure Mining	N	2019	1.5	PCI, TC	F
Australia	Spur Hill	Malabar Coal	N	2018	6	TC	F
Australia	Stratford	Yancoal Australia	E	2017	2.6	TC, CC	F
Australia	Styx	Waratah Coal, Queensland Nickel	N	..	1.5	PCI, TC	F
Australia	Talwood	Baosteel Resources	N	2016	3.6	PCI, TC	F
Australia	Taroborah	Shenhuo International	N	2018	5.7	TC	F
Australia	Teresa	New Emerald Coal	N	2016	6	PCI. TC	F
Australia	The Range Project	Stanmore Coal	N	..	5	TC	F
Australia	Togara North	Glencore	N	2017	6	TC	F
Australia	Vermont East/Wilunga	Peabody Energy	N	2015	3	PCI, TC	F
Australia	Vickery	Whitehaven	N	..	4.5	TC, CC	F
Australia	Wallarah underground longwall	Korea Resources Corp / Sojitz Corp	N	..	5	TC	F
Australia	Wards Well	BHP Billiton Mitsubishi Alliance (BMA)	N	2017	5	CC	F

Australia	Washpool coal project	Aquila Resources	N	2018	2.9	CC	F
Australia	Watermark	Shenhua Energy	N	2015	6.15	TC	F
Australia	Wilton Coal project	Queensland Coal Corporation	N	2016	2	TC, CC	F
Canada	Carbon Creek	Cardero Coal	N	..	2.9	CC	F
Canada	Crown Mountain	Jameson Resources	N	2017	2	CC	F
Canada	Donkin	Glencore, Morien Resources	N	2016	1	TC,CC	C
Canada	Echo Hill	Hillsborough Resources	N	..	1.5	TC	F
Canada	Grassy Mountain	Riversdale Resources	N	..	2	CC	F
Canada	Murray River	HD Mining	N	2018	6	CC	F
Canada	Quintette	Teck Resources	N	..	3.5	CC	F
Canada	Sukunka	Glencore Xstrata	N	..	3	CC	F
Canada	Trend	Anglo American	E	2016	1	CC	C
Canada	Vista Coal Project	Coalspur mines	N	2017	6	TC	F
Colombia	Canaverales	Yildirim Holding	N	2019	5.5	TC	F
Colombia	Cerrolargo Sur	Murray Energy	N	..	..	TC	F
Colombia	El Descanso	Drummond	E	..	12	TC	F
Colombia	Papayal	Yildirim Holding	N	2017	2	CC	F
Colombia	San Juan	Yildirim Holding	N	2019	16	TC	F
Indonesia	Bumi Barito Mineral	Cokal	N	2016	2	CC	C
Indonesia	East Kutai Coal Project	Churchill Mining / Ridlatama Group	N	..	..	TC	F
Indonesia	IndoMet Coal Project	BHP Billiton / Adaro	N	..	..	CC	F
Indonesia	Mitra Energi Agung	Indika	N	..	..	TC	F
Indonesia	Mustika Indah Permai	Adaro	N	..	..	TC	F
Indonesia	PT Bukit Enim Energi	Adaro	N	..	..	CC	F
Indonesia	PT Tekno Orbit Persada	MEC Coal	N	..	17	TC	F
Mozambique	Benga	ICVL	E	2020	8	TC	F
Mozambique	Midwest	Beacon Hill	N	..	7	TC	F
Mozambique	Moatize	Vale	E	..	..	TC	F
Mozambique	Ncondezi	Ncondezi Energy	N	2018	7	TC	F
Mozambique	Revuboe	Nippon Steel and Sumitomo Metal	N	2016	7	CC	F
Mozambique	Zambeze	ICVL	N	..	..	CC	F
Russia	Amaam	North Pacific coal company	N	2017	10	CC	F
Russia	Apsatskoe	SUEK	N	2013-19	0.65-2.4	CC	C
Russia	Chulmakanskoe	Kolmar	N	2018	1.25	CC	F
Russia	Denisovskoe	Kolmar	N	2015	2.5	CC	C
Russia	Elegest	TEPK	N	2015	3	CC	F
Russia	Elga	Mechel	N	2017	8	TC,CC	C

Russia	Ingaliskaya	Kolmar	N	2015	6	CC	C
Russia	Karakanskoe field	Karakan Invest	N	2017	6	TC	F
Russia	Kostromovskaya	MMK, (Belon)	E	2017	1-2	CC	F
Russia	Mezhegey	Evraz	N	2015	1.3	CC	F
Russia	Solncevskoe depozit	Sakhalinugol	E	2016	5	TC	F
Russia	Urgal	SUEK	E	2016	3	TC	C
South Africa	Argent	Glencore/ Shanduka	N	2015	1.5	TC	F
South Africa	Belfast	Exxaro	..	..	2.2	TC	x
South Africa	Boikarabelo	Resgen	N	2016	6	TC	C
South Africa	Brakfontein	Goldridge	N	2015	..	TC	C
South Africa	Consbrey	Glencore/Xstrata	N	2016	..	TC	x
South Africa	DeWittekranz	Continental	N	2015	2.6	TC	x
South Africa	Elders Complex	Anglo American	N	..	..	TC	x
South Africa	Eloff	Mbuyelo	N	2016	3.3	TC	C
South Africa	Impumelelo	Sasol	N	2015	8.5	TC	C
South Africa	Klipfontein	Eyethu	N	2015	<1	TC	C
South Africa	Koornfontein OC	Glencore/Optimum	E	2019	3.3	TC	x
South Africa	Kriel	Anglo American	E/N	..	5 – 7	TC	F
South Africa	Leeupoort	Eyethu	N	2015	<1	TC	C
South Africa	Mafube life extension	Anglo American	E	..	3.5	TC	x
South Africa	Matla	Exxaro	E	..	..	TC	x
South Africa	New Largo	Anglo American	N	..	12	TC	F
South Africa	Nooitgedacht	Glencore	N	2016	3	TC	F
South Africa	Smitspan	Sekoko/ Firestone energy	N	..	>1	TC	x
South Africa	Sterkfontein	Keaton Energy	N	..	1	TC	x
South Africa	Thabametsi	Exxaro	N	2016/17	3.8	TC	x
South Africa	Tweefontein Optimisation	Glencore	E	..	2	TC	C
South Africa	Wonderfontein	Glencore/Umcebo	E	..	2.7	TC	C
South Africa	Zonnebloem	Glencore	N	2016	10 ROM	TC	F

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: F = Feasibility, C = Committed

Sources: McCloskey (2014), *McCloskey Coal Reports 2010-2014*, McCloskey's, London, http://cr.mccloskeycoal.com ; BREE (Bureau of Resources and Energy Economics) (2014), *Resources and Energy Major Projects*, Canberra, http://bree.gov.au/sites/default/files/files//publications/remp/remp-2014-04.pdf; CIAB information; various sources.

GLOSSARY

Regional and country groupings

Africa

Algeria, Angola, Benin, Botswana, Cameroon, Congo, Democratic Republic of Congo, Côte d'Ivoire, Egypt, Eritrea, Ethiopia, Gabon, Ghana, Kenya, Libya, Morocco, Mozambique, Namibia, Nigeria, Senegal, South Africa, Sudan, United Republic of Tanzania, Togo, Tunisia, Zambia, Zimbabwe and other African countries (Burkina Faso, Burundi, Cape Verde, Central African Republic, Chad, Comoros, Djibouti, Equatorial Guinea, Gambia, Guinea, Guinea-Bissau, Lesotho, Liberia, Madagascar, Malawi, Mali, Mauritania, Mauritius, Niger, Reunion, Rwanda, Sao Tome and Principe, Seychelles, Sierra Leone, Somalia, Swaziland and Uganda).

ASEAN

Brunei Darussalam, Cambodia, Indonesia, Lao PDR, Malaysia, Myanmar, the Philippines, Singapore, Thailand and Viet Nam.

China

Refers to the People's Republic of China, including Hong Kong.

Europe and Mediterranean

Includes Non-OECD Europe/Eurasia, OECD Europe and North Africa regional groupings.

Latin America

Argentina, Bolivia, Brazil, Chile, Colombia, Costa Rica, Cuba, the Dominican Republic, Ecuador, El Salvador, Guatemala, Haiti, Honduras, Jamaica, Netherlands Antilles, Nicaragua, Panama, Paraguay, Peru, Trinidad and Tobago, Uruguay, Venezuela and other Latin American countries (Antigua and Barbuda, Aruba, Bahamas, Barbados, Belize, Bermudas, British Virgin Islands, Cayman Islands, Dominica, Falkland Islands (Malvinas), French Guyana, Grenada, Guadeloupe, Guyana, Martinique, Montserrat, St. Kitts and Nevis, Saint Lucia, Saint Pierre et Miquelon, St. Vincent and the Grenadines, Suriname and Turks and Caicos Islands).

Non-OECD Europe/Eurasia

Albania, Armenia, Azerbaijan, Belarus, Bosnia and Herzegovina, Bulgaria, Croatia, Georgia, Kazakhstan, Kyrgyz Republic, Latvia, Lithuania, the Former Yugoslav Republic of Macedonia, Moldova, Romania, Russian Federation, Serbia, Tajikistan, Turkmenistan, Ukraine and Uzbekistan.

North Africa

Algeria, Egypt, Libya, Morocco and Tunisia.

OECD

Includes OECD Europe, OECD Americas and OECD Asia Oceania regional groupings.

OECD Americas

Canada, Chile, Mexico and United States.

OECD Asia Oceania

Australia, Japan, Korea and New Zealand. For statistical reasons, this region also includes Israel.[1]

OECD Europe

Austria, Belgium, Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Iceland, Ireland, Italy, Luxembourg, Netherlands, Norway, Poland, Portugal, Slovak Republic, Slovenia, Spain, Sweden, Switzerland, Turkey and United Kingdom.

Other developing Asia

Non-OECD Asia regional grouping excluding China, India and ASEAN countries.

List of acronyms, abbreviations and units of measure

Acronyms and abbreviations

API	Argus McCloskey's Coal Price Index
ARA	Amsterdam Rotterdam Antwerpen
ARTC	Australian Rail Track
ASEAN	Association of Southeast Asian Nations
BFI	blast furnace iron
BHP	Broken Hill Proprietary Company
BMA	BHP Billiton Mitsubishi Alliance
BREE	Bureau of Resources and Energy Economics
BSER	Best System of Emission Reduction
CAGR	compound average growth rate
CAPEX	capital expenditures
CCA	Coal Cooperation Agreement
CCoW	Coal Contracts of Work
CCS	carbon capture and storage
CEA	Central Electricity Authority (India)
CFR	cost freight
CIF	cost insurance freight
CIL	Coal India Limited
CMG	China Merchants Group
CNR	Colombian Natural Resources
CO	carbon monoxide

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

CO_2	carbon dioxide
CPF	carbon price floor
CRCC	China Railway Construction Corporation
EIA	Energy Information Administration
EOR	enhanced oil recovery
EPA	Environmental Protection Agency
ESP	electrostatic precipitator
EU	European Union
EU-ETS	European Union Emissions Trading Scheme
FOB	free-on-board
FSA	Fuel Supply Agreements
FYP	Five-Year Plan
GDP	gross domestic product
GHG	greenhouse gases
HSBC	Hong Kong & Shanghai Banking Corporation Holdings PLC
ICI	Indonesian Coal Index
IEA	International Energy Agency
IMF	International Monetary Fund
IMT	International Marine Terminal
IPP	independent power producers
IUP	Izin Usaha Pertambangan
LHV	lower heating value
LNG	liquefied natural gas
Ltd.	Limited
LCPD	Large Combustion Plant Directive
MATS	Mercury and Air Toxics Standards
Met	metallurgical
MTCMR	Medium-Term Coal Market Report
MoU	memorandum of understanding
NAR	net-as-received
NCIG	Newcastle Coal Infrastructure Group
NO_x	nitrogen oxides
NQBP	North Queensland Bulk Ports
OECD	Organisation for Economic Co-operation and Development
PCI	pulverised coal injection
PJM	Pennsylvania-New Jersey-Maryland Interconnection
PGE	Polska Grupa Energetyczna
PM	particulate matter
PRB	Powder River basin
PV	photovoltaics
PWCS	Port Waratah Coal Services
RBCT	Richard Bay Coal Terminal
RBS	Royal Bank of Scotland
reACT	regenerative activated coke technology
ROM	run-of-mine
ROW	rest of world

RZD	Russian Railways
SCR	selective catalytic reduction
SNG	synthetic natural gas
SO_2	sulphur dioxide
SUEK	Sibirskaja ugolnaja energetitscheskaja kompanija
TNB	Tenaga Nasional Berhad
UHV	ultra high voltage
UK	United Kingdom
UMPP	Ultra Mega Power Projects
UNESCO	United Nations Educational, Scientific and Cultural Organization
US	United States
VAT	value added tax
WICET	Wiggins Island Coal Export Terminal

Currency codes

AUD	Australian dollar
CAD	Canadian dollar
CNY	Chinese yuan renminbi
COP	Colombian peso
IDR	Indonesian rupiah
INR	Indian rupee
RM	Malaysian Ringgit
RUB	Russian ruble
USD	United States dollar
ZAR	South African rand

Units of measure

bbl	barrel
bcm	billion cubic meters
°C	celsius
dwt	deadweight tonnage
GJ	gigajoule
Gt	gigatonne
GW	gigawatt
$GtCO_2$	gigatonne carbon dioxide
h	hour
kg	kilogram
km	kilometre
kcal	kilocalories
kV	kilovolt
m	metre
µg	microgram
mg	milligram
Mbtu	million British thermal units
Mdwt	million deadweight tonnages

mg	milligram
MPa	megapascal
Mt	million tonnes
Mtce	million tonnes of coal-equivalent
$MtCO_2$	million tonnes carbon dioxide
Mtpa	million tonnes per year
MW	megawatt
MWh	megawatt hour
Nm3	normal cubic metre
ppm	parts per million
t	tonne
TWh	terawatt hours

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COAL
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Although it has received less attention than the plunge in oil prices since mid-2014, the drop in coal prices has had a profound impact on global energy markets. Underpinning the weakness in coal prices is the decline in coal consumption in China for the first time this century, while pledges to reduce CO_2 emissions made by dozens of countries ahead of the UN climate negotiations in Paris in December 2015 are also providing negative sentiment for coal producers. Partly offsetting the gloom is demand from a few populous emerging economies in Asia – particularly India – and the high odds that coal will remain China's top energy source for several years to come.

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