Coal in Net Zero Transitions

Strategies for rapid, secure and people-centred change

International Energy Agency

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World Energy Outlook Special Report

INTERNATIONAL ENERGY AGENCY

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As the energy sector's single largest source of carbon dioxide emissions, coal is at the heart of the global conversation on energy and climate. All scenarios modelled by the International Energy Agency (IEA) for the future of energy supply and demand that are consistent with international climate goals feature a rapid decline in global coal emissions. Without such a decline, it will be impossible to avoid severe impacts from a changing climate.

As our new analysis in this World Energy Outlook Special Report makes clear, more than 95% of today's global coal consumption occurs in countries that have pledged to achieve net zero emissions. At the same time, however, the data show that the world is far from heading decisively in that direction. Global coal use and emissions have essentially plateaued at a high level, with no definitive signs of an imminent reduction. In fact, coal use in some countries has seen a modest uptick as a result of the current global energy crisis. Even if this is temporary, as our analysis suggests, it is a worrying sign of how far off track the world is in its efforts to put emissions into decline towards net zero – especially the narrow-but-achievable goal of doing so by 2050.

The current situation in energy markets underscores the huge challenges of reducing emissions while maintaining energy security. Renewable energy options such as solar and wind are the most cost-effective new sources of electricity generation in most markets, but despite their impressively rapid growth in recent years, they have not yet brought about a decline in coal's global emissions. Reducing global coal emissions while ensuring reliable and affordable energy supplies and tackling the social consequences of this change will require a dedicated and determined policy effort by governments. Multiple challenges remain. In many countries, the way in which markets and contracts have been designed mean that coal plants are effectively shielded from competition. In the industrial sector, accelerated innovation is crucial to bring to market the technologies needed to drive down coal emissions in key areas such as steel and cement.

Building up clean energy assets to replace coal is absolutely essential to reach environmental goals and support economic growth while safeguarding energy security. At the same time, carefully designed policies and government coordination with other stakeholders such as industry and labour organisations are fundamental to enable workers and communities to adjust to changes affecting the coal industry, which has deep links to jobs and economic development in coal-producing regions. These challenges are especially significant in developing economies where electricity demand is growing rapidly, coal is often the incumbent fuel for electricity generation, and industrial uses of coal are on the rise. This is one of the reasons why, if the international community fails to manage coal transitions appropriately, I see a real risk of fractures emerging between some advanced and developing economies, which could lead to damaging geopolitical rifts globally. There are some encouraging signs of international collaboration in the discussions on Just Energy Transition Partnerships with South Africa, Indonesia and other major emerging economies. But there's much more to be done to match funding with needs and to make progress on implementation.

This Special Report is designed to provide pragmatic, real-world guidance on how policy makers can achieve a reduction in coal emissions without harming their economies or energy security. Its analysis covers a range of policy and technology areas, including the potential for carbon capture, utilisation and storage. And it offers recommendations to improve financing for the phasing down of coal and to address the social and employment aspects of this transition. The report makes it clear that there is no one single approach to putting coal emissions into decline but a range of approaches tailored to national circumstances.

The report benefitted not only from the IEA's unparalleled energy data and modelling capabilities but also the input of a High-Level Advisory Group of global energy, climate and finance leaders that I convened earlier this year. This advisory group was chaired by Michael R. Bloomberg, the UN Secretary-General's Special Envoy for Climate Ambition and Solutions, and co-chaired by Arifin Tasrif, Minister of Energy and Mineral Resources of Indonesia, which currently holds the G20 Presidency, and Teresa Ribera Rodríguez, Deputy Prime Minister and Minister for the Ecological Transition and the Demographic Challenge of Spain. I would like to thank the chair, co-chairs and all the members of the advisory group for the important perspectives and strategic insights they provided for the report.

The IEA is deeply committed to supporting governments around the world as they navigate the current global energy crisis and seek to tackle climate change. I believe this report will be a valuable tool in efforts to design policies that support secure, affordable and fair transitions to clean energy. In particular, the social and employment aspects of these transitions is an important and expanding area of work for the IEA, as reflected by our Global Commission on People-Centred Clean Energy Transitions, our Clean Energy Labour Council and our World Energy Employment report.

I'm very grateful for the dedication and expertise of the IEA team who produced this Special Report under the exemplary leadership of my colleagues Laura Cozzi and Tim Gould. I strongly thank and commend them for this vital contribution to the international energy and climate conversation at such a pivotal moment.

Dr Fatih Birol
Executive Director
International Energy Agency

This study was prepared by the Directorate of Sustainability, Technology and Outlooks in co-operation with other directorates and offices of the International Energy Agency (IEA). The study was designed and directed by **Laura Cozzi**, Chief Energy Modeller and Head of Division for Energy Demand Outlook, and **Tim Gould**, Chief Energy Economist and Head of Division for Energy Supply and Investment Outlooks.

Principal IEA authors of the report include: **Thomas Spencer** (coal transitions), **Carlos Fernández Alvarez** (coal), **Brent Wanner** (power), **Paul Hugues** (industry), **Peter Levi** (industry), **Christophe McGlade** (supply), **Peter Zeniewski** (investment) and **Tanguy de Bienassis** (investment).

Main IEA contributors include: **Yasmine Arsalane** (power), **Blandine Barreau** (just transition policies), **Simon Bennett** (hydrogen, energy technologies), **Justina Bodláková** (historical coal transitions), **Olivia Chen** (employment), **Yunyou Chen** (power), **Leonardo Collina** (industry), **Daniel Crow** (air pollution), **Davide D'Ambrosio** (data science, power), **Amrita Dasgupta** (critical minerals), **Tomás de Oliveira Bredariol** (critical minerals, methane), **Darlain Edeme** (geospatial analysis), **Eric Fabozzi** (power), **Mathilde Fajardy** (geospatial analysis), **Pablo González** (investment and finance), **Emma Gordon** (investment and finance), **Alexandre Gouy** (industry), **Louis Hennequin** (just transition policies), **Pablo Hevia-Koch** (investment and finance), **Bruno Idini** (project management), **George Kamiya** (critical minerals), **Hyeji Kim** (affordability), **Martin Kueppers** (industry), **Rachael Moore** (carbon capture utilisation and storage), **Faidon Papadimoulis** (industry), **Ryszard Pospiech** (coal supply modelling), **Diana Perez Sanchez** (industry), **Nasim Pour** (carbon capture utilisation and storage), **Max Schoenfisch** (power), **Tiffany Vass** (industry), and **Wonjik Yang** (data visualisation). Other contributors include: **Caleigh Andrews**, **Michael Drtil**, **Leonie Staas** and **Anthony Vautrin.**

Edmund Hosker carried editorial responsibility.

Debra Justus was the copy-editor.

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High Level Advisory Group

The High Level Advisory Group provided strategic guidance for this report. The opinions and judgements expressed in this report are solely those of the IEA, but we benefited greatly from the time and expertise of the distinguished Group members:

Chair: Michael R. Bloomberg	UN Special Envoy for Climate Ambitions and Solutions and Founder of Bloomberg LP and Bloomberg Philanthropies
Vice-chair: Arifin Tasrif	Minister of Energy and Mineral Resources, Indonesia, current holder of G20 Presidency
Vice-chair: Teresa Ribera Rodríguez	Deputy Prime Minister and Minister for the Ecological Transition and the Demographic Challenge of Spain
Patrick Graichen	State Secretary for Economic Affairs and Climate Action, Germany
Jonathan Wilkinson	Minister of Natural Resources, Canada
Kadri Simson	Commissioner for Energy, European Union
Daniel Mminele	Head of the Presidential Climate Finance Task Team, South Africa
Ahmed Saeed	Vice President of the Asian Development Bank
Mafalda Duarte	CEO of the Climate Investment Funds
Aditya Mittal	CEO of Arcelor Mittal
Gary Nagle	CEO of Glencore
Gurdeep Singh	Chairman and Managing Director of NTPC
Lei Zhang	CEO of Envision Group

Peer reviewers

Many senior government officials and international experts provided input and reviewed preliminary drafts of the report. Their comments and suggestions were of great value. They include:

Rafayil Abbasov	Asian Development Bank
Saleh Abdurrahman	Ministry of Energy and Mineral Resources, Indonesia
Doug Arent	Canada
Florian Ausfelder	DECHEMA
Varun Bhargava	Arcelor Mittal
Abhishek Bhaskar	Climate Investment Funds
Mick Buffier	Glencore
Koben Calhoun	Rocky Mountain Institute

Xavier Chen	Envison Energy and Beijing Energy Club
Rebecca Collyer	European Climate Foundation
Russell Conklin	United States Department of Energy
David Elzinga	Asian Development Bank
Andrew Fikkers	Global Cement and Concrete Association
Cody Finke	Brimstone Energy
Nikki Fisher	Thungela
Lauren Flanagan	Envision Group
David Fritsch	Energy information Administration, United States
Michael Hackethal	German Federal Ministry for Economic Affairs and Energy
Yuya Hasegawa	Ministry of Economy, Trade and Industry, Japan
Lilly Höhn	Federal Ministry of Finance, Germany
Li Jiangtao	State Grid Energy Research Institute, China
Shiva Prashanth Kasina	NTPC
Francisco Laveron	Iberdrola
Peter Morris	Minerals Council of Australia
Isabel Murray	Department of Natural Resources, Canada
Lauri Myllyvirta	Centre for Research on Energy and Clean Air
Andi Novianto	Coordinating Ministry for Economic Affairs of the Republic of Indonesia
Yongduk Pak	Korea Energy Economics Institute
Andrew Purvis	Glencore
Mauricio Riveros	The Carbon Trust
Justine Roche	World Economic Forum
Ana Belén Sánchez	Institute for the Just Transition, Spain
Hans Wilhem Schiffer	RWE
Jesse Scott	Agora Energiewende
Christine Shearer	Global Energy Monitor
Chris Stephens	The Carbon Trust
Rahul Tongia	Centre for Social and Economic Progess
Adair Turner	Energy Transitions Commission
Willem Tom Van Ierland	Directorate-General for Climate Action, European Commission
Michael Waldron	Independent Consultant
Ailun Yang	Bloomberg Philanthropies

The individuals and organisations that contributed to this study are not responsible for any opinions or judgements it contains. All errors and omissions are solely the responsibility of the IEA.

Comments and questions are welcome and should be addressed to:

Laura Cozzi and Tim Gould

Directorate of Sustainability, Technology and Outlooks
International Energy Agency
9, rue de la Fédération
75739 Paris Cedex 15
France

E-mail: weo@iea.org

Web: www.iea.org

Annexes

A steep decline in coal emissions is essential to reach our climate goals

Every pathway that avoids severe impacts from climate change involves early and significant reductions in coal-related emissions. Coal is both the largest emitter of energy-related global carbon dioxide (CO_2) – 15 gigatonnes (Gt) in 2021 – and the largest source of electricity generation, accounting for 36% in 2021, and a significant fuel for industrial use. Comprehensive, integrated policies addressing emissions from all sources are essential for climate action, but reducing emissions from coal needs to be a first-order priority.

Coal transitions require a special focus because of coal's high emissions intensity, growing competition from cost-effective clean energy technologies like renewables, and deep links to jobs and development in coal-producing regions. Coal is second only to oil in the global energy mix, and coal demand – far from declining – has been hovering at near-record highs for the past decade. Today's global energy crisis has led to modest increases in coal consumption in a number of countries, at least temporarily, mainly in response to sky-high prices for natural gas. Continued high coal use is one of the most visible symbols of the challenge of aligning the world's actions with its climate ambitions: more than 95% of current global coal consumption occurs in countries that have pledged to achieve net zero emissions. This *World Energy Outlook Special Report* maps out how to achieve a rapid reduction in emissions from coal while maintaining affordable and secure energy supplies, and tackling the resulting consequences for workers and communities.

The new *IEA Coal Transition Exposure Index* highlights countries where coal dependency is high and transitions are likely to be most challenging: Indonesia, Mongolia, China, Viet Nam, India and South Africa stand out. A range of approaches, tailored to national circumstances, is essential for the power sector, where almost two-thirds of global coal is consumed, and in the industry sector, which accounts for another 30%. The social implications are often concentrated in specific regions: coal mining typically accounts directly for less than 1% of national employment, but around 5-8% in coal-intensive regions such as Shanxi in China, East Kalimantan in Indonesia, and Mpumalanga in South Africa.

The geographical concentration of coal use marks it out from other globally-used fuels: China accounts for over half of global coal demand and the share of all emerging market and developing economies exceeds 80%, up from half in 2000. China's power sector, on its own, accounts for one-third of global coal demand. China produces more than half of the world's steel and cement, and so also plays a dominant role in coal use in industry. During this decade, emerging market and developing economies' share of historical emissions from coal-fired power generation will overtake that of advanced economies.

Achieving clean energy transitions on the scale and speed required by national climate goals and the global 1.5 °C target has dramatic implications for coal. Our analysis considers *how* the necessary changes can be achieved, using two key scenarios from the *World Energy Outlook 2022*. The **Announced Pledges Scenario** (APS) assumes that all net zero pledges announced by governments are met on time and in full. In the APS, global coal demand drops by 70% by mid-century, alongside declines in oil and gas of around 40%. The **Net Zero Emissions by 2050** (NZE) **Scenario** illustrates a path to achieve the goal of 1.5 °C stabilisation in the rise in global average temperatures. In the NZE Scenario global coal use falls by 90% by 2050, and the global power sector is completely decarbonised in advanced economies by 2035, and worldwide by 2040.

If nothing is done, emissions from existing coal assets – on their own – would tip the world across the 1.5 °C limit.

If operated for typical lifetimes and utilisation rates, the existing worldwide coal-fired fleet would emit 330 Gt of CO_2 – more than the historical emissions to date of all coal plants that have ever operated. There are around 9 000 coal-fired power plants around the world, representing 2 185 gigawatts (GW) of capacity; around three-quarters of this is in emerging market and developing economies. Coal transitions are complicated by the relatively young age of coal plants across much of the Asia Pacific region: plants in developing economies in Asia are on average less than 15 years old compared with more than 40 years in North America.

Industrial facilities using coal are similarly long lived: for coal-dependent heavy industries such as steel and cement, the year 2050 is just one investment cycle away. Average lifetimes for emissions-intensive industry sector assets such as blast furnaces and cement kilns are around 40 years, but plants often undergo a major refurbishment after about 25 years of operation. Around 60% of steel production facilities globally and half of cement kilns will undergo investment decisions this decade, which to a large degree will shape the outlook for coal use in heavy industry. Without any modification to their current mode of operation, these existing assets would generate 66 Gt of CO_2 emissions through their remaining lifetime.

A rapid scale up of clean electricity generation and infrastructure is the essential condition for coal transitions in the power sector

A massive scale up of clean sources of power generation, accompanied by system-wide improvements in energy efficiency, is key to reducing coal use for power and cutting emissions from existing assets. In the APS, global output from existing unabated coal-fired plants is reduced by nearly 2 500 terawatt-hours from 2021 to 2030 to get on track for national climate pledges, and 75% of this is replaced by solar PV and wind. Many of the transitions away from coal observed so far have been driven by rapid uptake of solar PV and wind; however, these have typically been in countries where electricity demand was flat or in decline. A key challenge ahead is to achieve such transitions in fast-growing emerging market and developing economies such as India and Indonesia, where demand for electricity causes generation from coal to increase until the early 2030s in the APS even with a speedy deployment of renewables.

In the APS, around USD 6 trillion in investment is required to 2050 to reduce emissions from coal-fired power in line with national climate targets. Around 90% of this sum is spent on low-emissions generation, mainly renewables but also nuclear power, with the remainder for energy storage and expanding and modernising electricity grids**.** Governments need to set the right policy and regulatory frameworks while the private sector can provide much of the necessary investment. In the NZE Scenario, the cumulative investment required for coal transitions in the electricity sector reaches USD 9.5 trillion to 2050.

Innovative financial strategies can open the door to faster transitions

Governments and international institutions need to remove roadblocks that can prevent more cost-effective and cleaner options from entering the energy system. Favourable economics for renewables, on their own, will often not be enough to secure rapid coal transitions. There is more than USD 1 trillion of capital yet to be recovered from today's coal plants, which creates a potentially powerful constituency in favour of their continued operation. Moreover, many coal plants are shielded from market competition, in some cases because they are owned by incumbent utilities, in others because private owners are protected by inflexible power purchase agreements. In Viet Nam, for example, such agreements govern the operation of around half the fleet. Innovative financing mechanisms have an important role in accelerating the pace of change. Outside China, where low-cost financing is the norm, the weighted average cost of capital for coal plant owners and operators is around 7%. Bringing this down by 3 percentage points through refinancing would accelerate the point at which owners recoup their initial investment, clearing a path for one-third of the global coal fleet to be retired or repurposed within ten years.

International support is vital to accelerate coal transitions in emerging market and developing economies

Over the period to 2030, emerging market and developing economies outside China require about USD 500 billion in investment to put them on a path to transition securely away from unabated coal in the APS and well over a trillion dollars in the NZE Scenario. The majority of this spending needs to take place in the electricity sector, where clean energy technologies are proven and often competitive. Nonetheless, emerging market and developing economies will require international capital to cover around one-third of total investment in coal transitions. Public international actors, such as multilateral development banks, can play a vital catalytic role in raising domestic sources of finance and encouraging domestic public investment in clean energy. The transition also requires investment in the coal sector to repurpose or retrofit coal assets and to support coal-dependent regions; financial channels need to be open to support credible transition plans. Packaging together different elements of coal transitions, as with the Just Energy Transition Partnerships in Indonesia, South Africa and other countries, can be an effective way to gain momentum, mobilise international support, and ensure overall policy coherence.

Reducing coal power sector emissions in line with the 1.5-degree goal means no new development of unabated coal-fired power plants

An important condition to reduce coal emissions is to stop approving new unabated coal-fired power plants. New project announcements have slowed in the last few years, although there are still around 175 GW of capacity under construction. An immediate halt to approvals for new unabated coal-fired power plants is a key milestone in the NZE Scenario, but there is a risk that today's energy crisis fosters a new readiness to move ahead with such projects. Around half of the 100 financial institutions that have supported coal-related projects since 2010 have not made any commitments to restrict such financing, and a further 20% have made only relatively weak pledges. Stepping up policy and financial support for cost-competitive clean sources of generation, including international climate finance, is essential to close off avenues for continued growth in coal-fired capacity.

Giving governments confidence that they can forego new investments in coal-fired plants, and retire old plants, will require scaling up replacements not only for the electricity that coal plants produce, but also the system services they provide. A portfolio of options is required to deliver the flexibility that power systems increasingly need to ensure electricity security, and which today is provided in part by coal-fired power plants. During the transition, coal plants that have been repurposed to run less but more flexibly, or retrofitted to co-fire biomass or ammonia, can provide important peak capacity and load-balancing services. Repurposing existing coal plants to operate less accounts for 60% of the CO_2 emissions savings achieved in the APS; early retirements account for a further 33%.

Carbon Capture, Utilisation and Storage (CCUS) technologies open important potential to mitigate emissions from coal use in both power and industry; there are only five coal-based CCUS projects in operation, but another 23 are currently under development. If all of these projects are developed, they would capture around an additional 35 million tonnes (Mt) CO_2 each year by 2030 on top of the 5 Mt captured by existing projects. This would move deployment towards the levels anticipated for 2030 in the APS, although still far below the amounts in the NZE Scenario.

Comprehensive energy transitions can ensure affordability for consumers. The upfront investments associated with coal transitions are offset over time by lower overall system costs, because of large savings on fuel and electricity bills, alongside huge environmental gains. In the APS, total household energy bills in major coal-consuming countries remain roughly constant as a share of disposable income, thanks to the benefits of efficiency and electrification. Replacing coal-fired power plants with cost-competitive renewable technologies allows average system costs per unit of electricity to fall from 2021 to 2050 in the APS, both in advanced economies and in emerging market and developing economies.

Solutions are available to drive near-term emissions reductions in industry and these are needed alongside immediate efforts to boost innovation

Unlike the power sector, clean alternatives to coal in some key industrial applications such as steel and cement are not yet readily available. In the short term, efficient use of materials and energy, alongside with some fuel switching, are the best ways to reduce emissions in the industry sector. But it is crucial to use the coming decade to drive the development and commercial deployment of innovative new clean energy technologies. Progress depends to a large extent on public finance to accelerate technology demonstration and diffusion.

Advanced economies need to take the lead: the commitment taken at the Global Clean Energy Action Forum in September 2022 to mobilise USD 94 billion for clean energy demonstration projects is a welcome step.

Industrial materials and products are traded in global markets and producer margins tend to be thin; switching to zero or near-zero emissions technologies could lead to a loss of competitiveness without mechanisms to compensate for the increased risks and costs. Some USD 6 trillion is required to reduce coal emissions from industry in the APS to 2050 by rolling out near-zero emissions technologies and infrastructure, for example, to transport CO_2 or low-emissions hydrogen. Government co-ordination and support is essential, for example via carbon contracts for difference or through policies – such as sustainable procurement – that can create demand for industrial products with a substantially lower emissions footprint.

Comprehensive policies for people-centred transitions

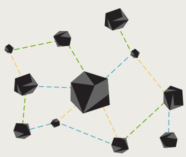
Around 8.4 million people work worldwide in coal value chains, including 6.3 million in mining, processing and transportation; and 2.1 million in power generation. In the APS, total coal employment declines to 6.1 million in 2030, but around half of this reduction is due to continued improvements in labour productivity. Some, but not all, of these job losses can be absorbed by natural retirements. Schemes to compensate and support existing coal workers who may need assistance and retraining will be vital. However, of the 21 most coal-dependent countries, only five (representing less than 5% of total coal sector workers) have announced or implemented comprehensive just transition policies.

The energy transition creates millions of new clean energy jobs, but they may not be in the same places or require the same skills as the coal jobs that are lost. In the APS, clean energy employment increases from around 32 million in 2019 to 54 million in 2030. New detailed geospatial analysis undertaken by the IEA indicates that around 40% of coal miners worldwide today live less than 200 kilometres from a critical mineral mine or deposit, and that more than 99% of coal miners live in countries with a critical mineral mine or deposit. While unlikely to absorb all of the employment lost in the coal sector, critical mineral mining can provide new industrial opportunities and revenue sources for coal-dependent companies and communities. In the APS, revenue from critical minerals exceed those from coal by 2040.

Integrated approaches for coal transitions

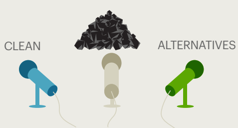
International co-operation, public financial support and well-designed integrated approaches that incorporate the need for people-centred transitions will be essential in the move away from unabated coal. Coal transitions are not just about coal: they are about building the clean alternatives that can provide the same energy services affordably and securely, but without the emissions. They are also fundamentally about people, and making sure that the promise of a more secure and sustainable energy sector does not leave coal-dependent communities behind. This is a global effort, and there is no more important task in energy transitions than to get coal transitions right.

High level policy messages



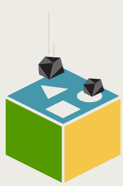
Coal transitions need integrated policy visions

Coal is the largest source of global emissions - well-defined strategies, aligned with net zero ambitions, tailored to country specifics and accompanied by clear interim targets are essential to bring these emissions down quickly.



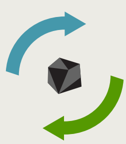
Coal transitions are not just about coal

They are about building up the clean energy alternatives that can provide the same energy services affordably and securely, but without the emissions.



Different aspects of coal use need different sets of solutions

The technologies that can reduce coal use for electricity generation are mature, but innovation is needed for some industrial sectors, especially steel and cement.



Repurposing coal to run less is a central strategy, alongside retirements and retrofits

Repurposing coal plants to run less can lower emissions while ensuring electricity security; coal plants can also be retired early or retrofit with co-firing or carbon capture technologies.

Coal transitions are about people

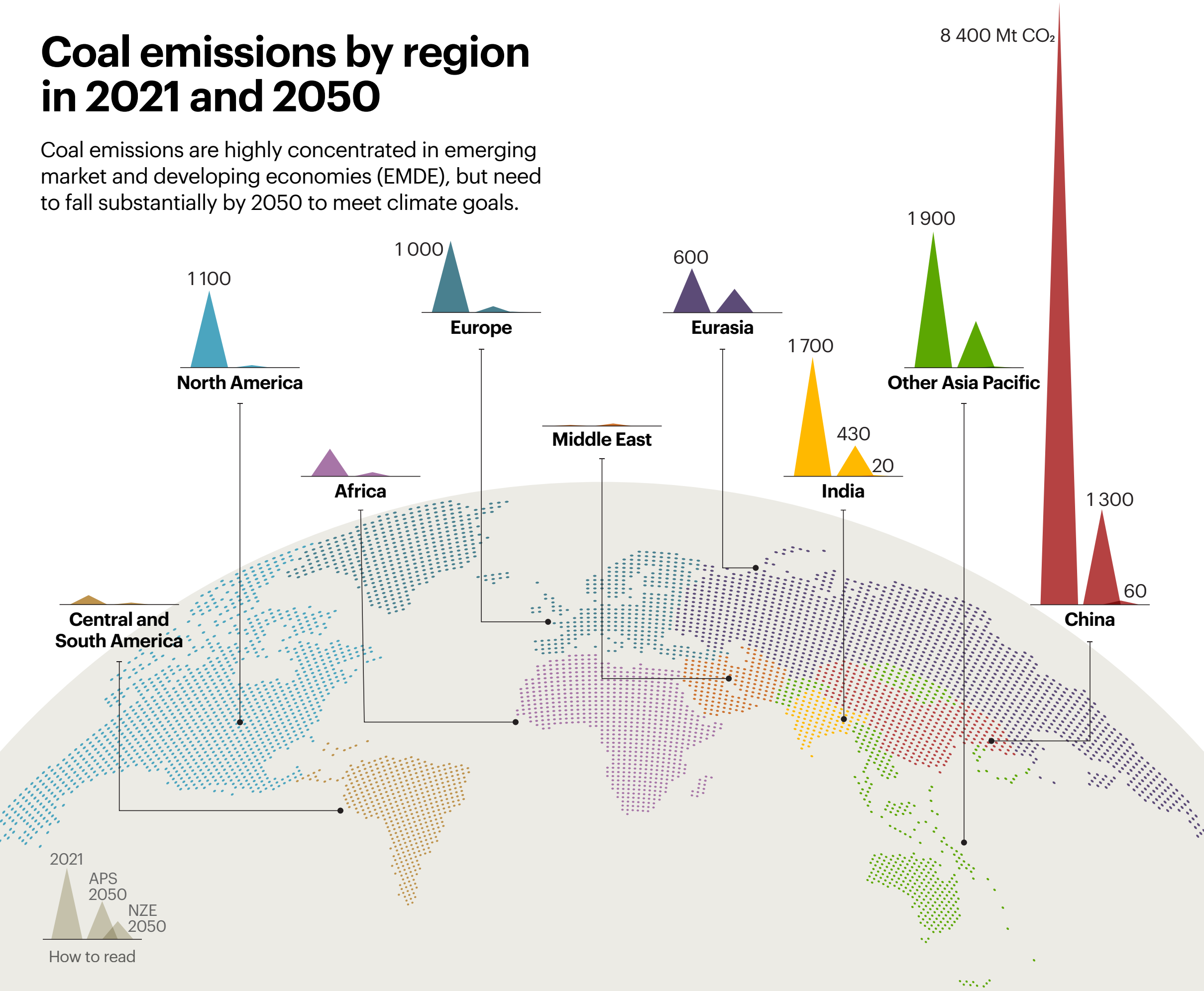
Millions of people are employed around the world in coal; the effects of coal transitions are concentrated in specific regions and communities, which may not be where clean energy jobs are created: governments need to address the social consequences of change.

International support is essential

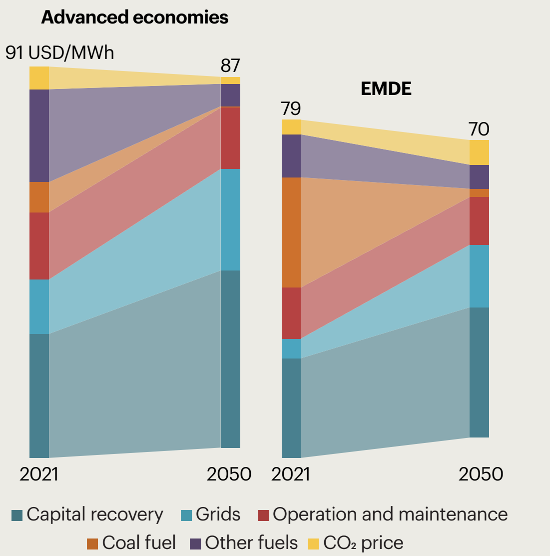
Packaging together all the different elements of ambitious national coal transitions can be a very effective mechanism for international support and investments.

Coal emissions by region in 2021 and 2050

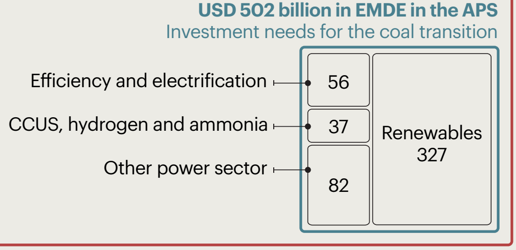
Coal emissions are highly concentrated in emerging market and developing economies (EMDE), but need to fall substantially by 2050 to meet climate goals.



The coal transition does not raise electricity supply costs



How much does the coal transition cost to 2030?



USD 4.7 trillion in EMDE in the APS
Total clean energy investment needs

Coal in clean energy transitions

A new context for coal in net zero emissions energy systems

SUMMARY

- Today's global energy crisis puts a premium on finding ways to enhance energy security that are consistent with the need to reduce global greenhouse gas (GHG) emissions. Coal is inevitably central to this effort. Unabated coal accounts for one-quarter of global GHG emissions, which is more than any other source of energy. Despite recurrent narratives of imminent decline or renaissance, global coal demand has been broadly stable for the last decade at its highest ever level – on average around 5 500 million tonnes of coal equivalent (Mtce) per year.
- Emerging market and developing economies account for 80% of global coal use today, with the People's Republic of China (hereinafter China) alone responsible for more than half of global coal use. Globally, around 65% of coal is consumed in the power sector and 30% is used in industry. Coal is the least traded of all fossil fuels, with international trade accounting for 20% of consumption (40% for oil). Coal produced domestically meets more than half of total energy demand in China, 20% in other emerging market and developing economies, and 15% in advanced economies.
- Reducing emissions from coal is central to reducing CO_2 emissions, although parallel actions to reduce oil and natural gas emissions are needed to achieve climate goals. There are a number of low-emissions alternatives to the use of coal in the power sector. Carbon capture, utilisation and storage (CCUS) has a potentially important part to play, but the existing pipeline of projects is limited: if all 23 projects being developed are combined with operating CCUS projects they would capture around 35 million tonnes (Mt) CO_2 per year by 2030.
- Recent energy market turmoil and heighted energy security concerns look set to lead to a near-term increase in coal use. But each of our scenarios project a decline in coal demand in this decade, largely as a result of rising shares of renewables in the electricity generation mix, increasing electrification of end-uses and efficiency gains. The speed of the decline depends on the stringency of climate and other energy policies and the efficacy of their implementation. By 2050, coal use drops by 30% in the Stated Policies Scenario (STEPS), by 70% in the Announced Pledges Scenario, and by 90% in the Net Zero Emissions by 2050 (NZE) Scenario. Almost 90% of coal used in the NZE Scenario in 2050 is consumed in plants equipped with CCUS.
- Some countries face particular difficulties in moving away from the use of coal because mining provides around 2-8% of total employment and up to 20-35% of GDP in areas where coal mining is an important part of the economy. We have developed a new index – the Coal Transition Exposure Index – to assess countries exposure to coal transitions. The Index shows that Indonesia, Mongolia, China, Viet Nam, India and South Africa are particularly exposed to a shift away from coal.

1.1 Why focus on coal emissions?

Reaching net zero emissions requires reductions in emissions from all fuels, including from oil and gas. However, a rapid decline in unabated coal use is inevitably a central feature of all pathways to a more sustainable energy system.[1] Coal is the most carbon-intensive fossil fuel and is responsible for a larger share of global GHG emissions than any other source of energy – 15 gigatonnes (Gt) CO_2 in 2021. At the same time, its role is increasingly under threat: it faces strong competition from cleaner alternatives for power generation, and nearly 75 countries – representing 95% of current global coal consumption – have made net zero emissions pledges.

Despite these challenges, in 2021 global coal demand rebound strongly to 5 650 million tonnes of coal equivalent (Mtce) as economies recovered from the Covid pandemic and coal-fired power generation reached a historic high. Moreover, the global energy crisis in 2022 has reinforced the focus on energy security, with several countries announcing plans to extend the use of coal in response to concerns about the availability and price of natural gas in the wake of the Russian Federation's (hereinafter Russia) invasion of Ukraine. A transition away from coal has to be grounded in an understanding of the factors underpinning the current high levels of coal consumption. In this context, it makes sense to consider what lessons can be learned from countries that have successfully reduced reliance on coal. It is vital to find ways to align near-term energy security imperatives with longer term energy transition goals.

Although its price in global markets recently has risen sharply, for a long time coal has been viewed as a relatively cheap fuel in many markets, and its position in the electricity sector is often shielded from market competition by long-term power purchase agreements. Its past price advantage is one of the reasons that the global fleet of coal power plants has expanded so rapidly in the last two decades. A number of emerging market and developing economies now have very young fleets of coal-fired power generation, and large amounts of capital investment have yet to be recovered from their operations. For example, the average coal plant in China is only 13 years old, in Indonesia it is 13 years, and in Viet Nam it is 8 years. An estimated 8.4 million people are now employed in coal production, processing, transport and power generation around the world. Many of these jobs are very localised with the coal sector deeply embedded in the local economies.

The persistence of coal in the global energy mix is driven by a complex array of structural factors. Achieving a transition away from coal at the scale and speed required by climate goals requires a comprehensive policy approach which takes account of these structural factors, and that means addressing the energy, economic, financial and social implications of

[1] Unabated coal is coal used in a facility that is not equipped with CCUS. Co-firing coal with biomass or ammonia reduces emissions by substituting for unabated coal, but the remaining coal that is combusted is considered to be unabated.

the transition. This report aims to inform a comprehensive assessment. It addresses these key questions:

- How can the transition away from unabated coal be made consistent with maintaining energy security and affordability at a time of high and volatile energy prices?
- Does the current period of global energy market turmoil and a possible return to coal threaten the achievement of climate change goals?
- What is needed to ensure a just transition while assisting emerging market and developing economies in the shift from unabated coal?

This chapter provides an overview for the full report by setting out the context for net zero emissions transitions, analysing the nature of coal dependence at national and sub-national levels, and highlighting the overarching trends for coal in our scenarios.

Chapter 2 examines options to accelerate reducing emissions from coal in the electricity sector, while preserving security and affordability.

Chapter 3 picks up the challenge of reducing emissions from coal in the industry sector.

Chapter 4 looks at issues related to financing reductions in emissions from unabated coal, with a particular focus on emerging market and developing economies.

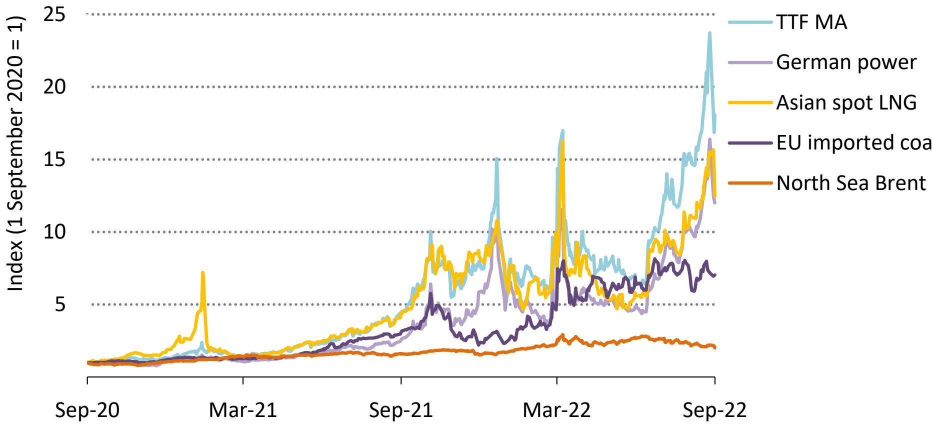
Chapter 5 considers the lessons from past transitions for coal-dependent countries, the implications of net zero emissions transitions for people working in mining and their local communities, and the strategies that could help ensure people-centred change.

1.2 A new context for the net zero emissions transition

1.2.1 Coal and energy security

As a result of market imbalances and supply chain disruptions related to the Covid-19 pandemic and dramatically exacerbated by Russia's invasion of Ukraine, global markets are experiencing record prices for energy commodities. Spot natural gas prices in Europe have regularly been above USD 40 per million British thermal units (MBtu), more than double the oil price on an energy-equivalent basis. This has raised concerns about impacts on the role of coal-to-gas switching in energy transitions, although even scenarios developed prior to the energy crisis were not clear-cut on the role of this emissions reduction strategy (Box 1.1). International coal prices have seen unprecedented high levels – above USD 300/tonne – more than tripling the average price of the 2010s. In turn, tight natural gas and coal markets led to exceptionally high electricity prices in many markets (Figure 1.1). The global energy crisis is hurting households, industries and entire economies – most severely in the developing world where people can least afford it.

Figure 1.1 ▷ Energy prices in global markets, 2020-2022



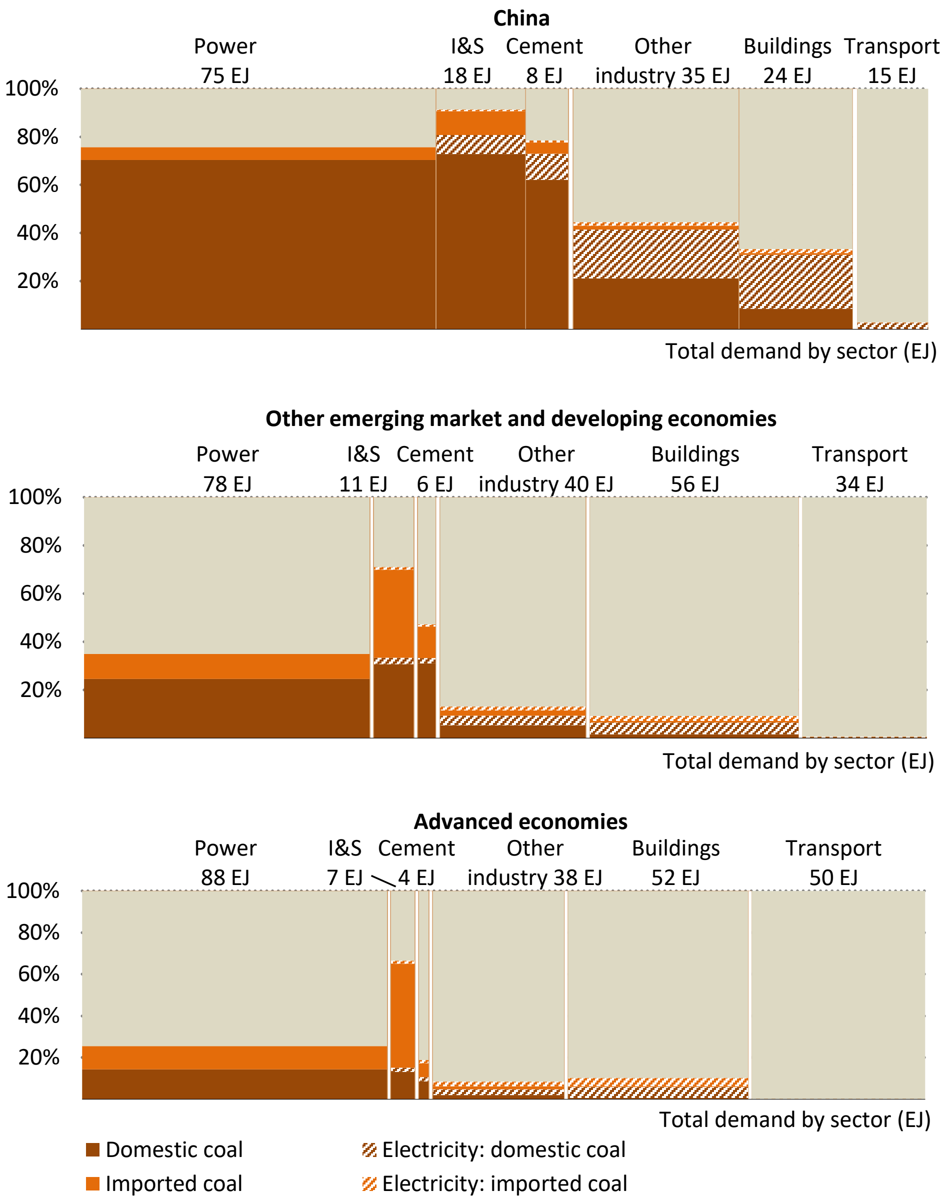
Russia's invasion of Ukraine exacerbated the pre-existing tightness in world energy markets into a full-blown global energy crisis

Notes: LNG = liquefied natural gas; EU = European Union. TTF MA = Title Transfer Facility month-ahead prices, i.e. benchmark European Union natural gas price. German power = spot electricity price in Germany. Brent = Brent crude oil price benchmark.

Coal is the most abundant of fossil fuels. Reserves would be adequate to satisfy more than 100 years of current levels of consumption worldwide. The United States is estimated to have the largest coal reserves in the world – over 200 gigatonnes (Gt) – followed by Russia, China, Australia and India, all with reserves of more than 100 Gt. This relative abundance, together with its low energy density compared to other fuels, explains why coal is the least traded among fossil fuels. International trade accounts for less than 20% of total coal consumption, compared with around 40% for oil. Today importing countries face extremely high prices, but the aggregate costs of coal to the energy system have not increased as much: in countries that use domestic coal, prices are often lower than in international markets. Price rises in international markets have had the most impact in countries that import almost all of their coal needs such as Korea and Japan.

The low energy density of coal means that its direct use is overwhelmingly concentrated in the electricity and industry sectors, and that much of the coal used comes from domestic production. China, for example, meets more than half of its total energy demand with domestic coal (Figure 1.2). For other emerging market and developing economies, domestic coal accounts for around 15% of total energy demand, and in advanced economies for about 10%.

Figure 1.2 ▻ **Domestic and imported coal demand by sector and region, 2021**



Domestic coal meets more than half of total energy demand in China, 15% in other emerging market and developing economies and 10% in advanced economies

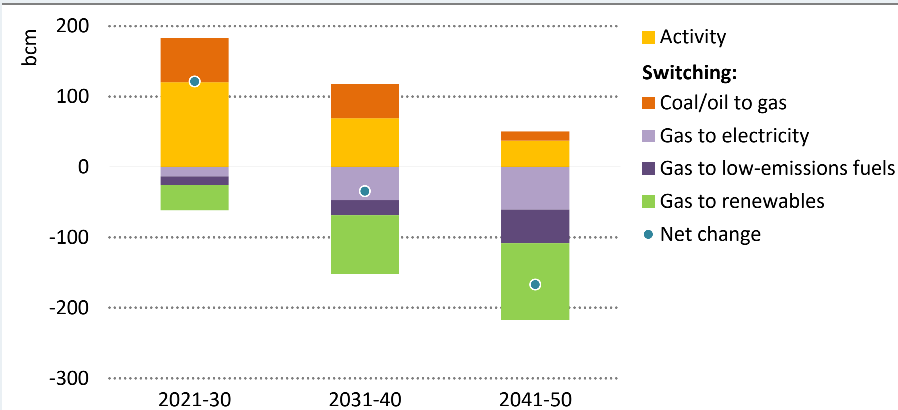
Notes: EJ = exajoule; I&S = iron and steel. Other industry includes all other industry sectors except iron and steel and cement.

Box 1.1 ▹ The complex narrative of natural gas as a transition fuel

Natural gas has sometimes been proposed as a transition fuel that could replace coal to help coal-intensive countries and regions reduce emissions, and to avoid coal dependence in countries with growing energy needs. This is not a straightforward matter, and it has become more complex as a result of the global energy crisis.

Coal-to-gas switching, spurred largely by low natural gas prices, has been a major element in curbing emissions growth in recent years, alongside strong growth in renewables and improvements in energy efficiency (IEA, 2019). However, one of the effects of Russia's invasion of Ukraine and the high prices that followed is to draw the era of rapid growth in global natural gas demand to a close. In the STEPS, the scenario that sees the highest gas consumption, global demand rises by less than 5% between 2021 and 2030 and then remains flat. The outlook for gas is dampened not only by higher near-term prices, but also by more rapid deployment of heat pumps and other efficiency measures; higher renewables deployment and a faster uptake of other flexibility options in the power sector; and, in some cases, reliance on coal for slightly longer.

Figure 1.3 ▹ Drivers of change in natural gas demand in emerging and developing markets in Asia in the APS



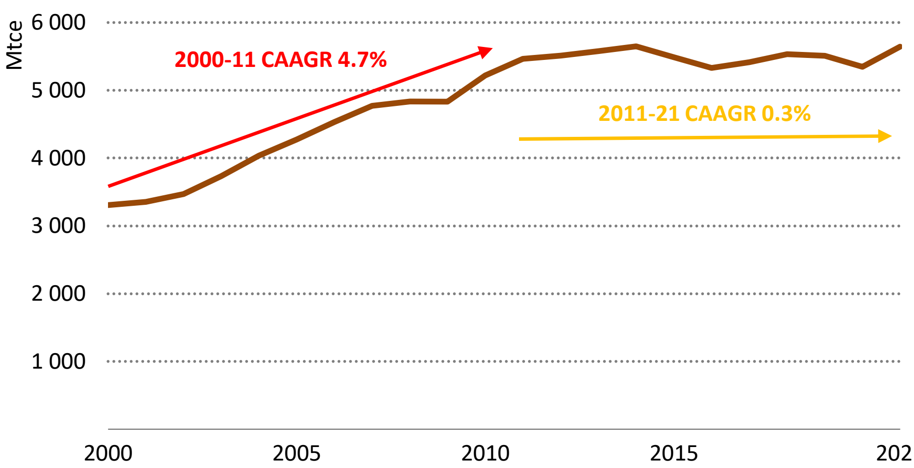
Population and economic growth increase gas demand for a while, but renewables, low-emissions fuels and electrification diminish gas demand in the long-term

New supply brings prices down by the mid-2020s, and LNG becomes even more important to overall gas security. As prices come down, emerging market and developing economies see continued growth in natural gas demand this decade in both the STEPS and the APS, prompting continued coal-to-gas switching, and this helps countries meet their emissions reduction goals (see section 1.4 for scenario definitions). But momentum behind natural gas growth in developing economies is slower than in previous editions of the *World Energy Outlook*, notably in South and Southeast Asia, putting a dent in the credentials of gas as a transition fuel. By the 2030s in the APS, natural gas demand in emerging and developing economies already starts to fall back (Figure 1.3).

1.2.2 Global coal demand has been stable for a decade

Today coal accounts for around a quarter of the world's total energy supply, the second-largest energy source after oil. Energy supply from coal has been between 5 500 Mtce (155 exajoules [EJ]) and 5 650 Mtce (165 EJ) each year since 2011, oscillating by a maximum of 3% around an average amount of 5 500 Mtce depending on annual variations in economic growth, weather and energy markets (Figure 1.4). This stable level is surprising in a decade that has seen so many changes in the global economy and energy sector. Contrary to some accounts of the imminent end of coal or of a coal renaissance, the data actually show that coal demand has plateaued for a decade at or close to its highest ever level.

Figure 1.4 ▷ Total energy supply from coal, 2000-2021



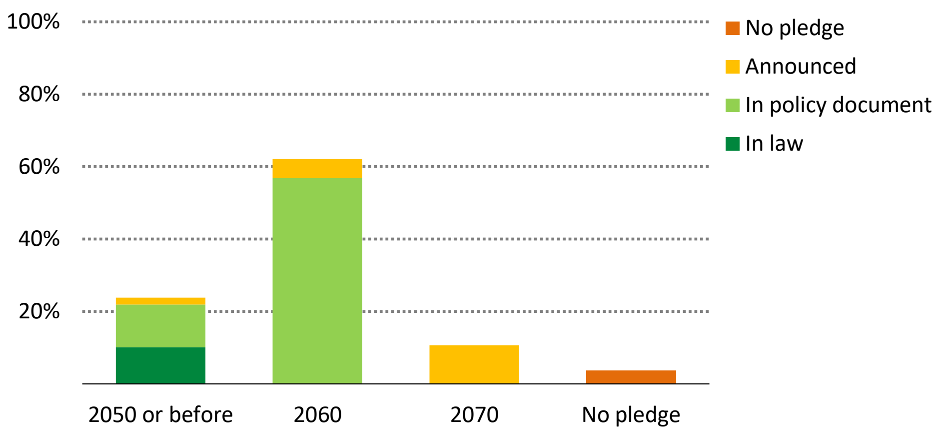
Global coal use has remained broadly unchanged for a decade

Note: Mtce = million tonnes of coal equivalent; CAAGR = compound average annual growth rate.

Nonetheless, coal has been increasingly in the spotlight for policy makers, investors and activists. This is not surprising given that more than 95% of global coal consumption occurs in countries that have net zero emissions pledges, albeit on different timescales and varying levels of legal status (Figure 1.5). In addition to aggregate net zero emissions pledges, countries, sub-national regions and companies have made specific commitments to phase down or out the use of unabated coal. In the Glasgow Climate Pact adopted at the 26th Conference of the Parties to the United Nations Framework Convention on Climate

Change in 2021, countries called for "accelerating efforts towards the phasedown of unabated coal power". And yet, despite all these commitments, so far, unabated coal demand has not entered into structural decline.

Figure 1.5 ▷ Share of global coal consumption covered by net zero emissions pledges by status and target date



More than 95% of global coal is consumed in countries that have some sort of net zero emissions pledge

Note: Status of pledges indicated in the figure are current as of October 2022.

1.2.3 Emerging market and developing economies dominate coal use

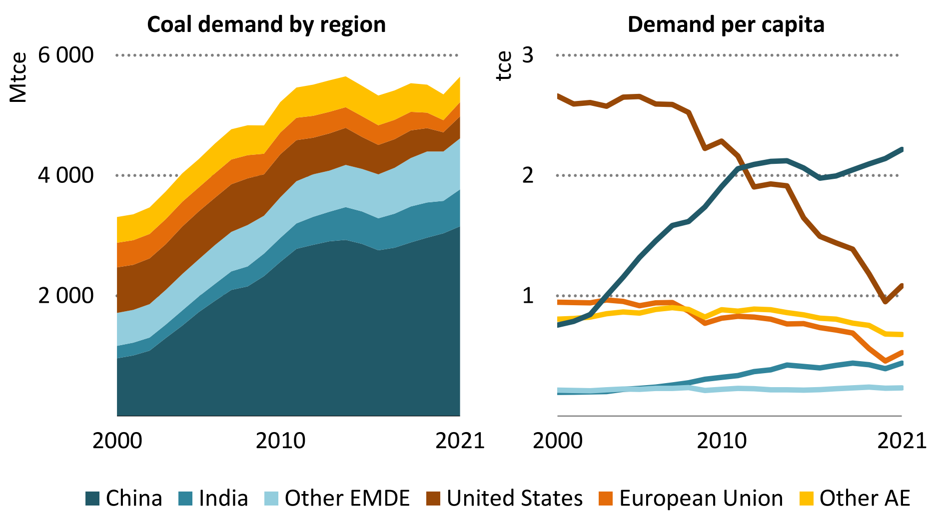
Coal is unique among fuels in the unparalleled dominance of one country – China alone accounts for over 55% of world coal demand (Figure 1.6). Indeed, by itself China's electricity sector is responsible for one-third of global coal demand. China is the largest coal producer by far, mining more than half of global output, and is the largest coal importer. While China has seen impressive deployment of clean energy technologies, in 2021, coal still accounted for around 60% of its energy supply and almost two-thirds of electricity generation.

India is next in line in terms of coal consumption, accounting for over 10% of world coal demand. Like China, India has a population of around 1.4 billion people, but its per capita energy demand is four-times lower, reflecting a lower gross domestic product (GDP) per capita and a less energy intensive economic structure. Coal is the cornerstone of electricity generation in India, accounting for around three-quarters of total generation (compared with almost two-thirds in China). Overall, at around 45% the coal share in the total energy supply mix in India is lower than in China (around 60%) in 2021, which reflects the lower level of coal-intensive industrial energy demand in India.

Together, China and India account for two-thirds of global coal demand. Other emerging market and developing economies account for a further 15%, resulting in a total share for emerging market and developing economies that exceeded 80% in 2021, up from half in 2000. Coal demand in advanced economies has declined by about one-third over the same period. In absolute terms, this decline in advanced economies is equivalent to total current coal demand of India, but less than 20% of total coal demand in China. In 2021, the United States accounted for around 6% of global coal demand and the European Union for around 4%.

The picture in per capita terms is slightly different, and has undergone significant changes in recent decades. In the early 2000s, the United States consumed more than 2.5 tonnes of coal equivalent (tce), or around 80 gigajoules (GJ) of coal per capita. As a result of a modest decline in total energy demand, and a substantial switch to natural gas and renewables, total coal demand per capita in the United States has more than halved over the last two decades. This shift, together with China's rapid industrial growth, means that the United States per capita consumption of coal is now well below the level in China. However, it is still much larger than in India with per capita coal consumption of around 0.45 tce (13 GJ), less than half the level of the United States. In the European Union, coal consumption has declined in recent decades and the per capita level is only slightly higher than that of India today (around 0.5 tce or 15 GJ).

Figure 1.6 ▷ Coal demand by region and per capita, 2000-2021



Together emerging market and developing economies account for over 80% of global coal demand, of which China and India account for two-thirds

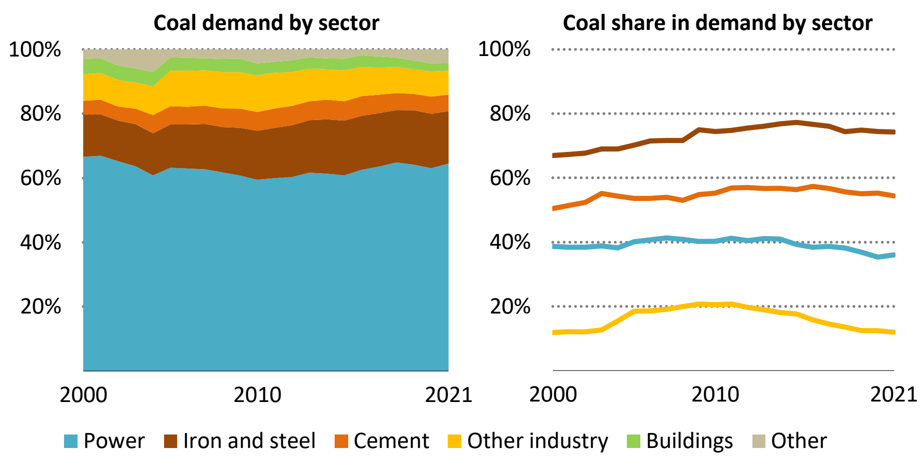
Notes: Mtce = million tonnes of oil equivalent; tce = tonne of coal equivalent. Other EMDE = emerging market and developing economies excluding China and India; Other AE = advanced economies excluding the United States and the European Union.

Per capita consumption of coal needs to be seen in the context of consumption of fossil fuels as a whole. Advanced economies have a much larger per capita consumption of oil and natural gas than emerging market and developing economies in the aggregate. For example, in 2021 the United States consumed around 95 GJ of oil per capita (down from around 125 GJ in 2000), which is nearly seven-times the average for the emerging market and developing economies. Per capita natural gas consumption in the United States was around 90 GJ in 2021, up from 80 GJ in 2000. The European Union consumed around 40 GJ of oil per capita, about twice as much as China in 2021.

1.2.4 Coal use is deeply embedded in a few sectors

Power generation remains the biggest driver of coal demand and accounts for two-thirds of total global coal demand (Figure 1.7).[2] Although low-emissions sources of electricity generation as a group have recently overtaken it, coal meets 36% of total electricity generation needs and remains the single largest source of electricity generation. The share of coal in the generation mix has been slowly declining as the share of electricity in total energy has been steadily increasing: since 1980, global total energy supply increased by less than 2% per year on average whereas electricity demand increased by more than 3% per year.

Figure 1.7 ▹ Global coal demand and coal share in energy demand by sector, 2000-2021



IEA. CC BY 4.0.

Power generation accounts for two-thirds of total coal demand; coal is the dominant energy source for steel and cement production

Notes: For end-use sectors, the right figure shows the share of coal in total final energy consumption in the sector. For the power sector it shows the share of coal-fired electricity in total generation.

[2] This includes electricity generation, combined heat and power, and district heat production.

The decline in the share of coal in electricity generation has been slower than the increase in electricity generation, so the output of coal-fired electricity has continued to increase. In addition, the global fleet of coal-fired power plants is relatively young, particularly in developing Asia, following a surge of capacity additions (Box 1.2).

Industry is the only other sector that uses large amounts of coal, and accounts for almost one-third of global coal demand. In particular, coal is the dominant source of energy used to make products that are essential to modern civilisation: iron and steel, and cement. The iron and steel sub-sector has the highest share with coal accounting for nearly three-quarters of its energy consumption and around 16% of total coal demand. Indeed, almost all primary steel production is coal-based today. The cement sub-sector accounts for 5% of total coal demand and coal accounts for around 55% of its energy consumption. Other industry sub-sectors account for about 8% of total coal demand. Although plastics are mostly produced from oil products and ammonia-based fertilisers from natural gas, a significant proportion of plastics are produced from coal gasification in China, often using methanol as an intermediate material, and ammonia production capacity in China and a few other countries mostly uses coal.

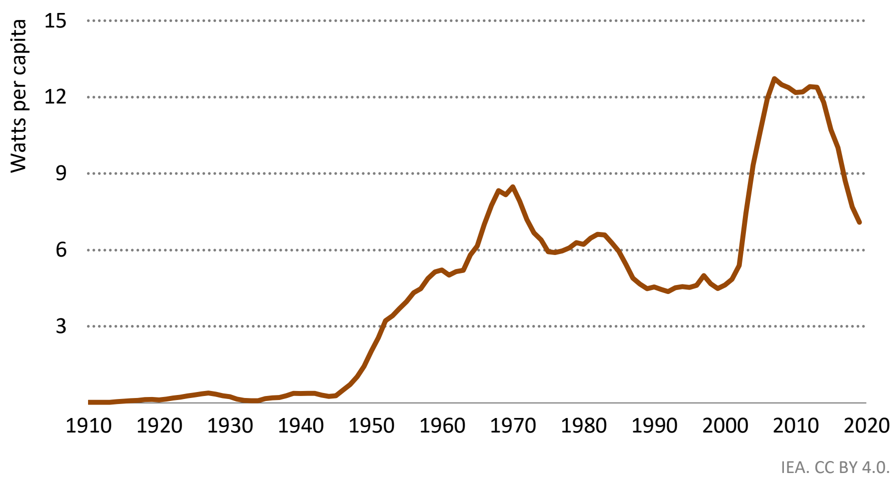
Box 1.2 ▷ Unprecedented surge in coal-fired capacity additions since 2000

Between 2000 and 2021, the total installed capacity of coal-fired generation doubled from about 1 100 gigawatts (GW) to just under 2 200 GW. Even accounting for growth in the global population, this expansion represents the fastest increase in the global installed capacity of coal-fired generation since the origin of the technology at the end of the 19th century (Figure 1.8).

Installed coal-fired generation capacity reached new heights in the early 1970s on the heels of several decades of rapid economic growth and rising electricity demand in advanced economies. Much of this demand was met by coal with 40% of total electricity generation from coal in advanced economies in 1971. Many of the coal-fired plants built in advanced economies during this surge in capacity additions in the 1960s and 1970s have been retired or are now reaching the end of their technical lifetimes.

As rapid economic and electricity demand growth extended to emerging market and developing countries in the 2000s, those with favourable resource endowments – particularly in the Asia Pacific region and especially in China – added huge amounts of coal-fired generation capacity. From 2005 to 2015, the annual increase in the installed capacity of coal-fired electricity generation, normalised per capita, was 50% larger than during the previous peak in the 1960s and early 1970s. This leaves the world with a huge stock of young coal-fired power plants, which must be made compatible with the pathway to net zero emissions.

Figure 1.8 ▷ Global installed coal-fired generation capacity annual net change, normalised per capita, 1910-2020



Annual growth in coal-fired generation capacity was 50% higher in the period 2005-2015 than the previous surge, even normalised for population

1.3 Coal-dependent countries and regions

1.3.1 Countries

Impacts of clean energy transitions relative to coal are country-specific. They depend on resource endowments, the level of coal in the energy mix, and economic structure and labour markets. In order to help assess the challenges that countries may face in the transition away from coal, we have developed a typology of major coal producing and consuming country exposure to the global clean energy transition – the Coal Transition Exposure Index (CTEI). The typology is designed to be simple and transparent while including all the key indicators. The CTEI typology is structured in four categories and employs two indicators for each category.

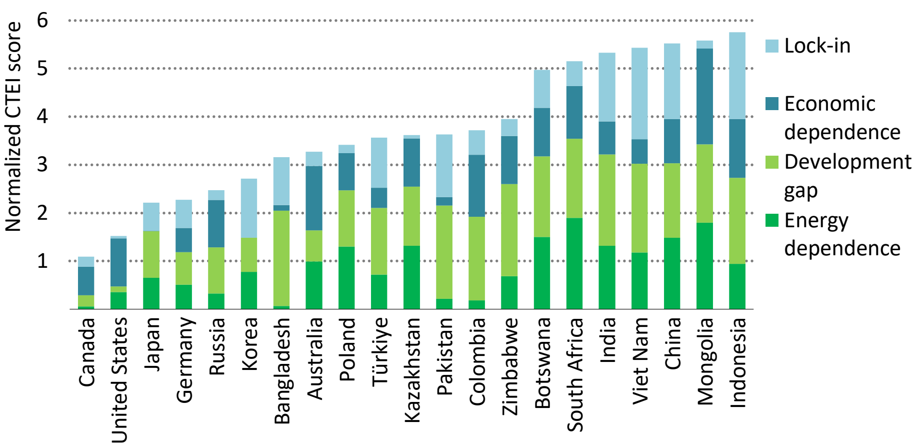
- **Energy dependence** on coal is quantified by its share in total energy supply and in electricity generation. This measure is straightforward and gives an approximate idea of what it will take for a country to reduce its use of coal.
- **Development gap** is quantified by GDP per capita measured at purchasing power parity and total final energy consumption per capita. These indicators provide proxies for a country's future rate of energy demand growth and its financial and technological capacities. In countries where energy demand is stable, the generation of 1 megawatt-hour (MWh) of clean energy will replace 1 MWh of fossil fuel electricity: if demand is declining, it will replace more than 1 MWh. However, in a country with rapidly rising

energy demand, clean energy supply needs to expand as fast as demand in order to avoid increased coal use, and even faster than demand growth to cut into existing coal use.

- **Economic dependence** is measured by the share of coal in total goods exports and the share of coal produced domestically compared with total coal consumption. Domestic production of a sizeable share of coal demand is likely to see coal playing a larger role in the economy than for a country that imports coal.
- **Lock-in** aims to quantify the challenge of potential early retirement of assets that have not been fully depreciated. To assess potential lock-in risks we evaluate the capacity-weighted age of a country's integrated steel mills and its coal-fired power plants.

To generate the index, the raw data for each of the eight indicators was normalised in order to assign a total score. For each indicator, the country with the highest value was allocated a one, and the country with the lowest value received zero. For example, Mongolia has the highest share of coal in its goods exports and therefore received the highest normalised score of one for this indicator. Normalised scores were added together to give an aggregate score (Figure 1.9).

Figure 1.9 ▷ Coal Transitions Exposure Index scores



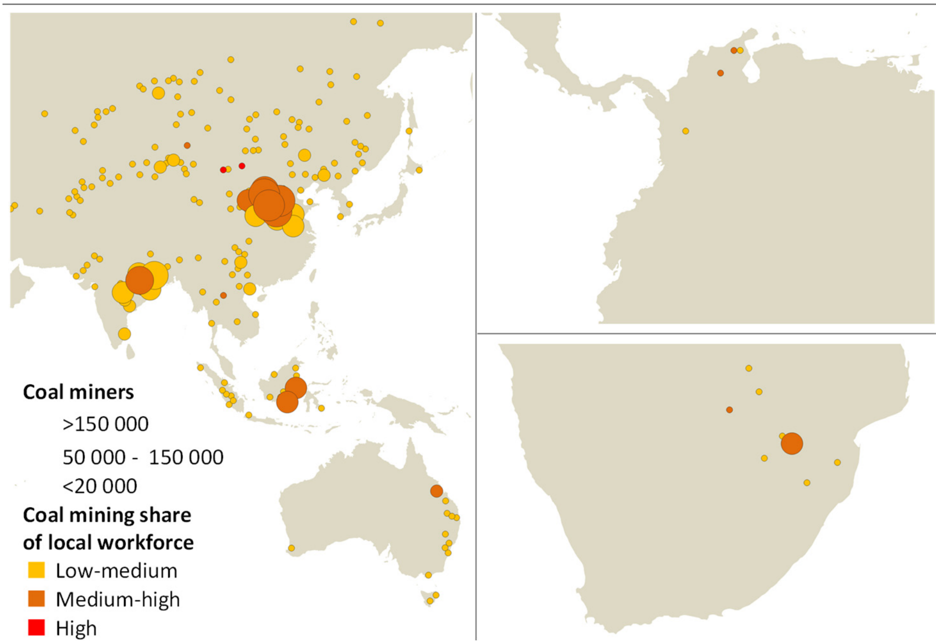
Botswana, South Africa, India, Viet Nam, China, Mongolia and Indonesia have a particularly heavy and multi-faceted dependence on coal

Scores have been calculated for a selection of countries that represent more than 90% of global coal production and consumption. The 15 largest coal producers and 15 largest coal consumers are included, as are countries with particularly large energy needs and potential for growth in coal demand, e.g. Pakistan and Bangladesh, together with countries with very large coal reserves, a high level of domestic dependency and low level of coal exports, e.g. Botswana and Zimbabwe. This leaves a sample of 21 countries for which we calculate the CTEI.

1.3.2 Regions

There are big differences in the extent of exposure to coal between various provinces, states, and regions within countries. Coal mining is often a highly regionalised activity. For example, the provinces of Kalimantan account for 6% of Indonesia's population, but around 90% of its coal production. Similar levels of regional concentration characterise other major coal producing countries (Figure 1.10).

Figure 1.10 ▷ Coal miners in the Asia Pacific region, Colombia and South Africa, 2022



In major coal producing countries, coal mines and associated employment are concentrated in specific regions that need to be the focus of just transition policies

Source: IEA analysis based on data from Global Energy Monitor (2022).

Coal value chains, and coal mining in particular, are very concentrated spatially. Coal mining typically accounts for 1-3% of national GDP and seldom exceeds this even in the largest coal mining countries such as Indonesia or China (Table 1.1). However, at the sub-national level of states or provinces, coal mining can account for over one-third of GDP, for example, as it does in Cesar or La Guajira in Colombia. Care needs to be taken with this metric. Not all of the wealth embodied in regional GDP remains in the region. Some accrues to holders of capital, which are not necessarily local, and some accrues to central governments as fiscal revenues. Moreover, the extent of the benefits that flow from regional GDP benefits may vary widely from one region to another. Nevertheless, it represents a good starting point for analysis.

Because workers are likely to spend their income locally, the share of coal mining in local employment is also a meaningful metric to assess the role of coal in regional economies. Coal mining typically accounts for less than 1% of national employment, but can account for around 5-8% of employment in coal-intensive sub-national regions such as Shanxi, China; East Kalimantan, Indonesia; or Mpumalanga, South Africa. It is interesting to note that improvements in labour productivity mean that this is an order of magnitude lower than the levels seen in the past in sub-national regions in the United Kingdom or United States, when coal mining was much more labour intensive. For example, at its peak in the United Kingdom, coal mining accounted for 7% of national employment and much more in coal producing regions (see Chapter 5).

Coal mining is a relatively well-paid job. The wage premium [3] for coal miners over employment in other production sectors, i.e. manufacturing, construction and utilities, ranges from 1.05-1.50 in countries with the lowest wage premium, such as China, Indonesia and South Africa, to as high as 4-7.5 in countries with higher wage premiums, such as India and Colombia. Wages for informal workers, however, are much lower than for formal workers.

The overall development level of coal mining regions also needs to be considered. In the United Kingdom, coal mining regions tended to experience a high level of industrial development on the back of the comparative advantage brought by local coal deposits. Even as coal mining jobs were being lost in Wales in the 1950s and 1960s, non-coal industrial employment was increasing. Non-coal mining industrial employment peaked at around 40% of total employment in the early 1970s, and at nearly 50% in the East Midlands. In other words, the coal employment transition was cushioned, and indeed often dwarfed, by a trend of very strong industrialisation up to the mid-1970s in countries such as United Kingdom, United States and Germany. Subsequently it was exacerbated by a rapid trend of deindustrialisation that substantially deteriorated labour market opportunities for blue-collar workers (see Chapter 5).

Today, many coal mining intensive regions in emerging market and developing economies face a situation of generalised underdevelopment in the form of low levels of industrialisation, urbanisation and productive job creation. Manufacturing employment accounts for around 8% of total employment in Jharkhand and around 5% in Chhattisgarh in India, for example, while agriculture accounts for nearly 40% and 60% respectively of total employment in these states. At the district level in Korba, the most coal-intensive district in Chhattisgarh, coal mining accounts for about 15% of employment, while manufacturing accounts for less than 4%. Total industry employment, i.e. mining, manufacturing, construction and utilities, accounts for one-quarter of employment in Korba, while agriculture accounts for more than one-third. The challenge for just transition policies in these areas is not only to cushion sectoral transitions but also to support development broadly for coal and non-coal workers alike.

[3] Wage premium is the ratio of coal miner wages over the average of wages in the manufacturing, construction and utilities sectors.

Table 1.1 ▹ Key metrics of coal value chains and employment by region

	Annual coal production (Mt)	Share of GDP from coal	Share of employment in coal	Unemployment rate	Labour force participation rate	Wage premium for coal workers
China	**4 071**	**0.6%**	**0.4%**	**4.8%**	**68%**	**n.a.**
Shanxi	1 193	12%	4.4%	2.3%	n.a.	1.26*
Inner Mongolia	1 039	8%*	1.4%	3.8%	n.a.	1.52*
Colombia	**52**	**1%**	**1.0%**	**14.3%**	**65%**	**3.11***
Cesar	35	35%	4.7%	14.5%	52%	4.32*
La Guajira	23	36%	3.9%	12.6%	58%	3.83*
India	**716**	**n.a.**	**0.4%***	**6.3%**	**50%**	**4.44**
Chhattisgarh	158	n.a.	1.6%	2.8%	63%	5.07
Jharkhand	119	10%*	1.8%	5.6%	47%	7.62
Indonesia	**491**	**2%**	**1.1%**	**4.4%**	**68%**	**n.a.**
East Kalimantan	238	35%	8.6%	6.6%	n.a.	1.05
South Kalimantan	166	17%	3.9%	4.5%	n.a.	1.03
Poland	**107**	**1%**	**0.5%**	**3.2%**	**56%**	**1.31**
Łódź	44	n.a.	0.5%*	3.1%	57%	n.a.
Silesia	59	8%	4.2%	2.7%	53%	1.47*
South Africa	**306**	**2%**	**0.5%**	**38.2%**	**47%**	**1.19**
Mpumalanga	275	19%	5.3%	43.3%	49%	1.19

* Indicates that data is for the mining and quarrying sector as a whole, not specific to coal mining. Notes: n.a. = not available. Wage premium is calculated as the ratio of the average wage of coal workers to the average wage of workers across mining, manufacturing, construction and utility sectors. Data are the most recent available.

Sources: EURACOAL (2020); European Commission (2020); World Bank (2020); Statistics Poland (2021); DANE (2021); Shanxi Provincial Bureau of Statistics (2021); Energy Foundation China (2021); ILO (2021); Renshetong (2021); China, Inner Mongolia Autonomous Region Statistics Bureau (2021a); China, Inner Mongolia Autonomous Region Statistics Bureau (2021b); India, Ministry of Coal (2022); India, Ministry of Statistics and Programme Implementation (2021); Global Energy Monitor (2022); IEA (2022a); SEI (2019); BPS (2019); Statistics South Africa (2019); China, National Development and Reform Commission (2021); China, National Bureau of Statistics (2021); UPME (2022).

1.4 Outlook for coal demand and emissions

This report uses the scenarios developed for the *World Energy Outlook 2022 (WEO-2022)*, based on the IEA Global Energy and Climate Model (IEA, 2022b). The *WEO-2022* includes detailed analysis of the implications of each scenario for energy transitions. Here we focus on the implications for coal markets, emissions and carbon capture, utilisation and storage.

The three scenarios are:

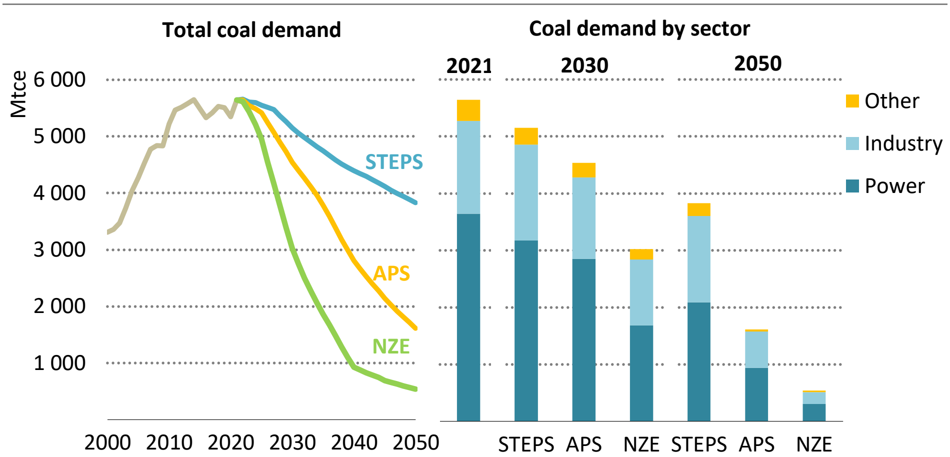
- **Announced Pledges Scenario** (APS): Assumes that all climate commitments made by governments around the world, including as stated in Nationally Determined Contributions and long-term net zero emissions pledges, will be met in full and on time, regardless of whether the pledges are currently underpinned by detailed implementing laws, policies and regulations.

- **Net Zero Emissions by 2050** (NZE) **Scenario:** Sets out a narrow but achievable pathway for the global energy sector to achieve net zero CO_2 emissions by 2050. In this scenario, advanced economies take the lead, but all regions achieve very rapid reductions in energy sector CO_2 emissions in order for the global energy sector to reach net zero emissions by 2050.
- **Stated Policies Scenario** (STEPS): Takes a more conservative and granular approach, integrating sector-by-sector analysis of the impacts of established and announced policies and regulations. It does not assume that net zero emissions pledges are met in full and on time.

1.4.1 Coal demand

Coal demand dropped in 2020, though this was more than offset by a strong rebound in 2021, taking coal demand very close to an all-time high. Global coal demand is set to rise slightly in 2022 driven by switching to coal in some markets in the face of high natural gas prices. Nonetheless, each scenario sees a structural decline in coal demand in the current decade, though the pace of this decline depends on the stringency and effectiveness of climate policies.

Figure 1.11 ▷ Coal demand by scenario and sector, 2010-2050



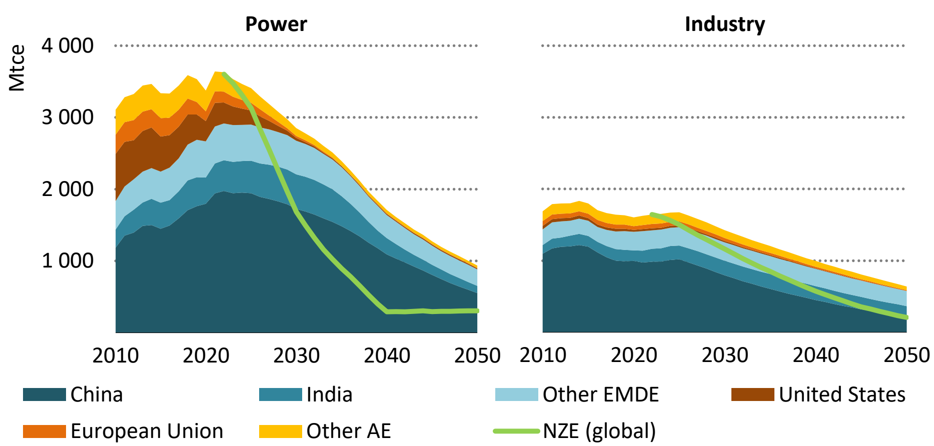
Coal use falls in each scenario to 2050 – by 70% in the APS and 90% in the NZE – reflecting the stringency of climate policy

Notes: Other includes the small amounts of coal consumed in the buildings and transport sectors, and in other energy transformation. Power includes both electricity and heat production.

In the STEPS, global coal demand falls by just under 10% to 2030 and by 30% to 2050 (Figure 1.11). The reduction to 2030 occurs in the power sector and in advanced economies and China, while coal demand in industry and in other emerging market and developing economies increases modestly.

In the APS, total coal demand falls by around 20% to 2030 and by more than 70% to 2050. Demand reductions over the rest of this decade are most pronounced in the electricity sector, where renewables and other low-emissions sources expand and displace coal. Total coal use over the period to 2030 falls by slightly over 2% per year, which is slower than the rate of increase in global coal demand between 2000 and 2010. After 2030, the annual rate of decline in global coal demand accelerates to more than 5% per year, which is faster than the rate at which advanced economies decreased their coal demand over the past decade.

Figure 1.12 ▷ Coal demand in power and industry sectors by region in the APS, 2010-2050



Both the power and industry sectors see declining coal demand in the APS, initially led by advanced economies; cuts in coal demand are much steeper in the NZE Scenario

Notes: EMDE = emerging market and developing economies; AE = advanced economies.

In the power sector, coal use worldwide falls by 20% to 2030 and by 75% to 2050 in the APS. Declines are steepest in advanced economies, where demand falls by more than 75% to 2030 as progress is made towards net zero emissions pledges for 2050 and as electricity demand increases by a relatively modest 1.8% per year (Figure 1.12). In emerging market and developing economies, electricity demand growth is higher – it averages almost 3.2% per year to 2030 – and many countries have net zero emissions pledges for 2060 or 2070 (rather than for 2050). As a result, use of coal in the power sector declines by less than 10% between 2021 and 2030, a much smaller decline than in advanced economies. This net reduction includes very different results in individual countries. For example, demand declines by 10% in China and increases by more than 15% in India. These divergent trends are a consequence of their different levels of economic development, with China's maturing economy seeing GDP and energy demand increase less than in India. More rapid progress is made after 2030, and coal use in the power sectors of emerging market and developing economies falls by two-thirds between 2030 and 2050.

In industry, options to substitute coal are at a lower level of technological maturity than in electricity generation. In the APS, global coal use in industry falls by more than 10% to 2030 and by more than 60% to 2050. Coal demand in industry in advanced economies declines by around 20% to 2030, largely as a result of energy and materials efficiency measures. Coal consumption in industry in China falls by almost 20% to 2030 as demand for primary materials such as steel starts to saturate. In other emerging market and developing economies, coal demand in the industry sector increases by around 5% to 2030 as steel and cement production continues to expand. After 2030, new low-emissions technologies become more mature and less expensive, and, together with additional efficiency measures, this leads to faster declines in coal use in industry worldwide (see Chapter 3).

In the NZE Scenario, global coal demand falls by 45% to 2030 and by 90% to 2050, reaching 540 Mtce. Declines are led by the electricity sector, where global coal use is reduced by nearly 55% between 2021 and 2030 as low-emissions sources of generation ramp up significantly. By 2040, there is no use of unabated coal for electricity generation anywhere in the world. Reductions in coal use in industry (30% to 2030) are slower than in the electricity sector because of the lower level of maturity of low-emissions alternatives. Nonetheless, energy and materials efficiency gains help reduce consumption considerably. Fuel switching plays a part too, including a shift to the use of biomass for cement production.

1.4.2 Coal with CCUS

Coal facilities equipped with carbon capture, utilisation and storage (CCUS) are able to produce low-emissions electricity, hydrogen and hydrogen-based fuels, and industrial products. CCUS provides an opportunity for countries that have large coal reserves to continue to use coal as a domestic source of energy while reducing emissions, preserving some existing strategic assets, and cushioning transitions for coal-dependent communities.

So far, the development of coal-related CCUS applications has been limited. Five coal-related CCUS projects operate today and account for the capture of around 5 million tonnes of carbon dioxide (Mt CO_2) per year. China has three operating projects in coal-based power, chemical and fertiliser applications, while the United States has the largest single CCUS facility (Table 1.2).

There are 23 coal-related CCUS projects currently under development: fifteen in the power sector, four in industry and four for fuel supply. China is developing seven projects, the United States is developing five, and the remainder are in Australia, Bahrain, India, Indonesia, Japan, Korea, Norway and Russia. If these 23 projects are fully developed, they would capture around 35 Mt CO_2 per year by 2030.

Table 1.2 ▷ Operating commercial-scale CCUS facilities related to coal and their applications

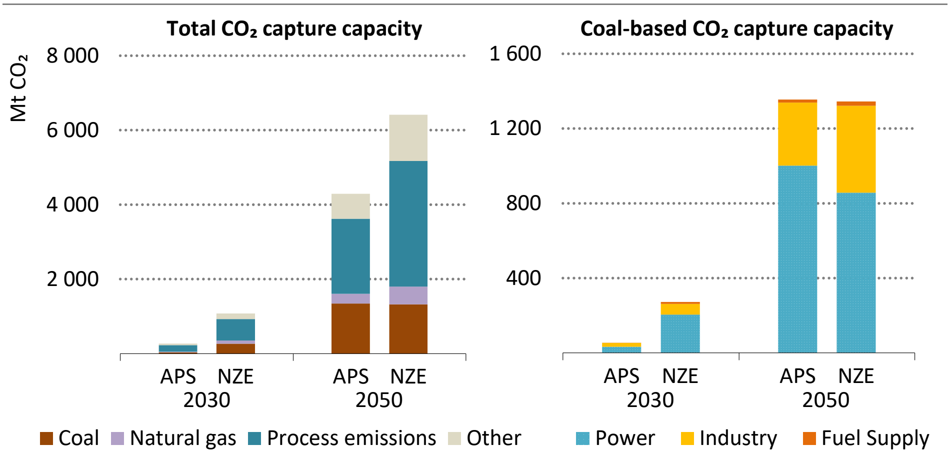
Country	Project	Project developer	Application	Capacity (Mt/year)
China	Nanjing Chemical Industries CCUS	Sinopec	Chemicals	0.2
	Qilu Petrochemical Plant	Sinopec	Chemicals	1
	Guohua Power Jinjie	China Energy	Power	0.15
Canada	Boundary Dam CCS	Saskpower	Power	1
United States	Great Plains Synfuel Plant	Dakota Gas	Fuel supply	3

Notes: CCS = carbon capture and storage. Projects are considered commercial-scale if they have an annual capture capacity of 0.1 Mt CO_2 or larger. The Nanjing Chemical Industries CCUS project and Qilu Petrochemical Plant use coal as primary feedstock.

Sources: IEA analysis based on Cai, Lin and Ma (2020) and corporate communications.

In the APS, more than 50 Mt CO_2 are projected to be captured from coal facilities in 2030 and 1 350 Mt CO_2 in 2050 (Figure 1.13). Around 30% of coal consumption in 2050 is used in facilities equipped with CCUS in the APS. In the power sector, coal plants are retrofitted with CCUS which allows continued operation and lower emissions. This is especially significant in Asian economies which have a very large fleet of young coal-fired power plants. In the industry sector, coal use with CCUS is mainly focussed on steel and cement production and is concentrated in emerging markets and developing economies including China and India.

Figure 1.13 ▷ CO_2 capture capacity by fuel, sector and scenario



Coal use with CCUS grows rapidly in both the APS and the NZE Scenario. In the APS, 30% of coal used globally in 2050 is in facilities equipped with CCUS and 90% in the NZE Scenario

In the NZE Scenario, there is a much faster uptake of CCUS with coal in the period to 2030, by when 270 Mt CO_2 are projected to be captured from coal-fired power plants each year, but the volumes of CO_2 captured in 2050 are slightly lower than in the APS. This is because the NZE Scenario sees more fuel switching away from coal, faster retirement of coal-fired assets, and a much bigger role for renewables in power generation. Just under 90% of the coal consumed in 2050 in the NZE Scenario is used in facilities equipped with CCUS.

If they all are developed, the current pipeline of CCUS projects under construction and proposed would provide 60% of the CO_2 captured from CCUS with coal in 2030 in the APS and 10% of that in the NZE Scenario. Making up the difference will require strong policy support for the development and use of CCUS (Box 1.3).

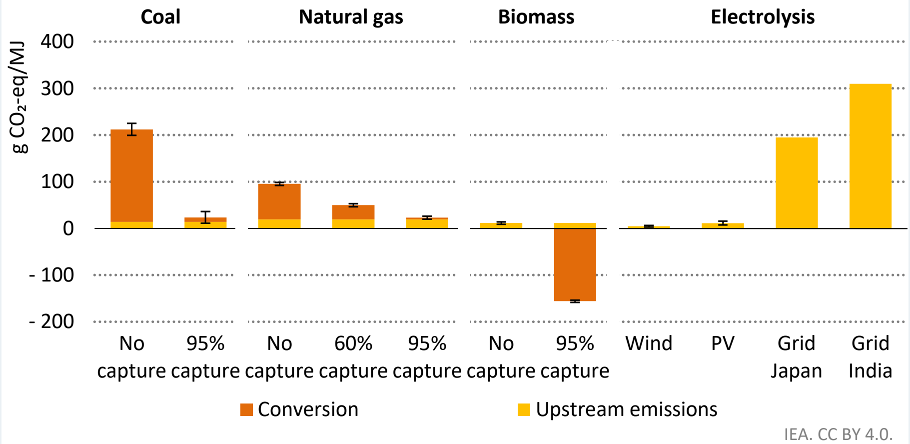
Box 1.3 ▹ Accelerating deployment of CCUS with coal

It is not a simple task for coal facilities equipped with CCUS to contribute in a meaningful way to emissions reduction goals. Projects need to capture more than 90% of the CO_2 emissions arising from coal combustion or conversion, GHG emissions associated with the extraction, processing and transport of the coal need to be kept to a minimum, and the end product needs to have a lower emissions intensity than the product it is replacing.[4] Coal producing regions can use CCUS to reduce emissions from existing assets through retrofits and to be low-emissions sources to produce hydrogen, hydrogen-based fuels and chemicals. Producing hydrogen from coal with CCUS can have a similar emissions intensity profile as its production from natural gas fitted with CCUS (Figure 1.14).

Appropriate legal and regulatory frameworks need to be in place to support deployment of CCUS with coal. Support is needed to assess CO_2 storage potential. Countries should also consider what they can do to promote the development of shared CO_2 transport and storage infrastructure, given its potential to boost economies of scale and lead to lower per-tonne transport and storage costs. Shared infrastructure has been operational in Canada since 2020 as part of the Alberta Carbon Trunk Line Project and is being developed in other countries including China, Europe and United States. In turn, the development of shared CO_2 transport and storage infrastructure would benefit from coal-based CCUS deployments. Coal with CCUS facilities produce large volumes of centralised CO_2 emissions which can serve as an anchor to support the development of wider CO_2 transport networks and storage hubs.

[4] For example, dimethyl ether (DME) can be produced from coal and can be used as a direct replacement for liquefied petroleum gas (LPG). However, producing DME from coal with CCUS facilities is unlikely to achieve lower emissions than LPG even with very high capture rates.

Figure 1.14 ▷ Emissions from hydrogen production by various routes



Emissions from hydrogen production would be similar for both coal and natural gas if they are equipped with CCUS with a 95% capture rate

Notes: g CO_2-eq/MJ = grammes of carbon-dioxide equivalent per megajoule at lower heating value. Upstream emissions are those related to the production and transport of fossil fuels and bioenergy, and from the construction of renewable energy technologies. Grid emissions are based on values in 2019.

Source: IEA (2021b).

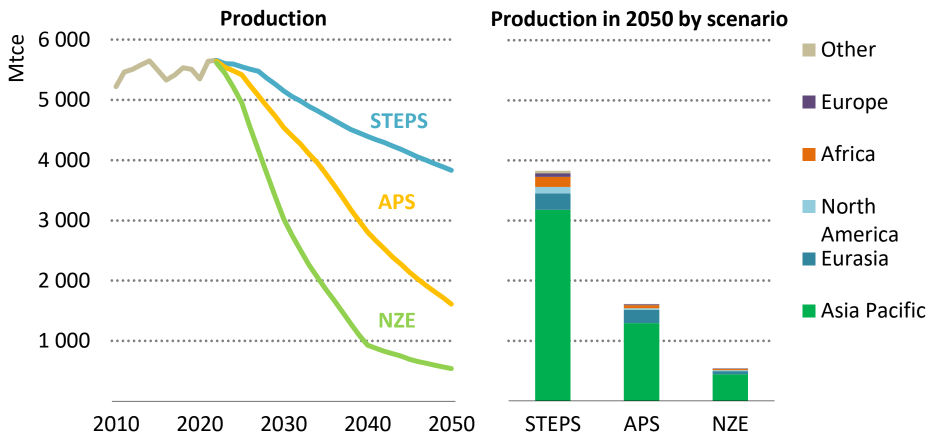
1.4.3 Coal supply and trade

Supply

In the context of the current energy crisis, coal suppliers are under pressure to increase production. Coal production failed to keep pace with rebounding coal demand in 2021, especially during the first-half of the year, which led to lower stock levels and higher prices. In 2022, the European Union banned coal imports from Russia in retaliation for its invasion of Ukraine, which further tightened coal markets. The main coal exporting countries were prevented from fully taking advantage of high prices by supply chain disruptions and events such as flooding in Indonesian mines. Some countries, led by China and India, responded to these conditions with policies to ramp up domestic coal production to meet demand and reduce coal shortages. In other countries, most additional production in 2021 came from existing mines or reopened mines that had been idled during periods of low prices, as investment in new mines has been limited in recent years (see Chapter 4).

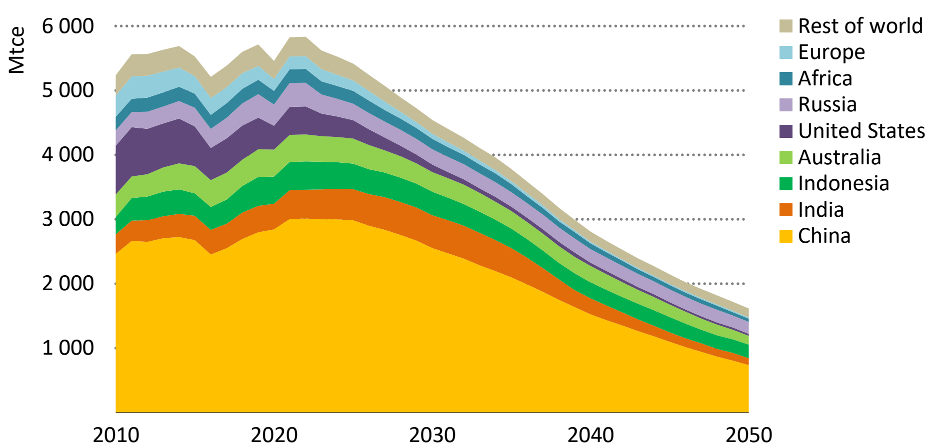
In the APS, the coal industry needs to balance the current rise in demand against declining long-term prospects (Figure 1.15). No new coal mines are needed in aggregate to meet demand, although existing mines need to be carefully managed to ensure timely supply. In advanced economies, unabated coal use is rapidly phased down in the power and industry sectors, with aggregate demand dropping by around two-thirds in the period to 2030. Supply falls in parallel as existing mines reach the end of their economic lifetime. In China – the world's largest coal producer and consumer – production plateaus in the near term in response to current market conditions, but then falls over the longer term as domestic demand for industrial goods slows and as clean energy technologies are more widely deployed. In India, coal production increases by nearly 15% between 2021 and 2030 but then drops by around 80% between 2030 and 2050. Globally, coal production falls by around 20% between 2021 and 2030, and the decline then picks up pace: by 2050, coal production is over 70% lower than it was in 2021 (Figure 1.16).

Figure 1.15 ▷ Coal production by scenario and region, 2010-2050



Coal demand declines rapidly in the APS and NZE Scenario with no new coal mines needed

Figure 1.16 ▷ Coal production by region in the APS, 2021-2050



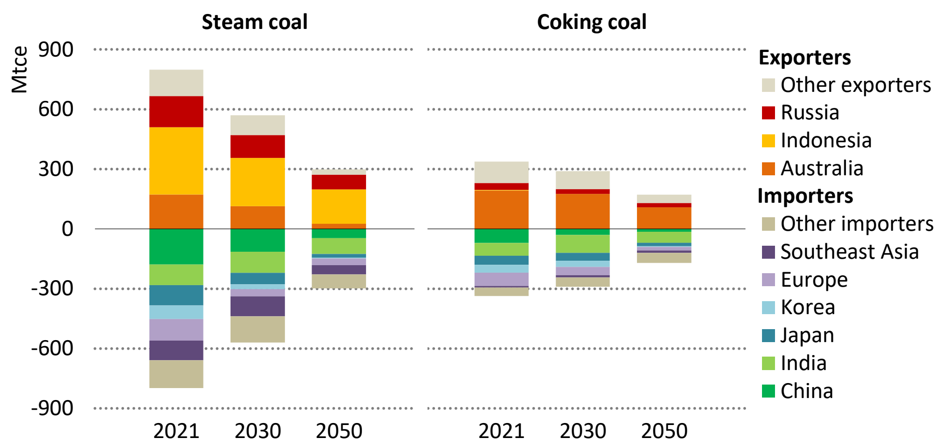
China dominates coal production today, but its production declines significantly after 2030

In the NZE Scenario, demand falls by 90% to 2050 and there is no need for new coal mines or mine lifetime extensions. Investment in coal supply falls by around three-quarters from 2021 to 2030 with the remaining coal-related investment focussed on maintaining production at existing mines as they wind down and on reducing their emissions intensity as much as possible, for example through reducing coal mine methane emissions.

Trade

Coal trade is limited by the widespread availability of coal and by its low energy density. Nonetheless, coal imports are important for a number of countries. For instance, long distances between production and consumption hubs within a particular country can mean that overseas imports can be more cost effective, and the same situation can arise when there are differences in coal quality between what is available domestically and what is required for particular end-uses.

Figure 1.17 ▷ Coal exporters and importers in the APS, 2021-2050



Declining global coal demand leads to a 60% drop in coal imports to 2050; steam coal trade declines further and faster than coking coal trade

Over 1 100 Mtce of coal was traded worldwide in 2021, and more than 75% of global coal imports went to countries in the Asia Pacific region (Figure 1.17). China and India were the largest importers: China imported around 250 Mtce and India imported about 165 Mtce. Australia was the world's largest coal exporter in terms of energy and economic value, and the dominant global supplier of coking coal, providing over half of global exports in 2021, while Indonesia was the largest exporter by weight. Australia and Indonesia accounted for 60% of coal exports in 2021, benefiting from their proximity to major coal markets in East and Southeast Asia. Russia was the third-largest coal exporter in 2021, accounting for over 15% of global coal exports. Around 40% of Russia's exports were to Europe, but it also served markets in the Asia Pacific region, Africa and countries in Eurasia. In April 2022, as part of the fifth package of economic sanctions against Russia, the European Union banned all coal imports from Russia effective as of August 2022.

In the APS, global coal trade declines by 25% to 2030. Steam coal trade falls by one-third and coking coal trade by around 10%. Imports to China decline by around 40% to 2030 and by 75% to 2050 as it reduces demand as part of the implementation of its net zero emissions pledge. India has reaffirmed its intention to ramp up domestic coal production and reduce imports as much as possible, but rising demand means its coal imports increase by over 15% to 2030 before declining thereafter as it approaches its net zero emissions target date. Indonesian exports drop by around 30% to 2030 as its main export markets for steam coal shrink. Australia fares better, but its exports nevertheless decline by about 20% to 2030: they fall further and faster after 2030 as significant reductions in coking coal demand from major importers start to add to the rapid decline in steam coal. Australia's exports in 2050 are almost 65% lower than in 2021. On the other side of the world, coal trade between the European Union and Russia comes to an end, and Europe's total coal imports drop from 2021 levels by around 55% to 2030 and by over 70% to 2050.

In the NZE Scenario, coal trade declines to about half its current level by 2030 and in 2050 it is nearly 90% lower than in 2021. Most of the remaining coal trade is related to power plants and industries equipped with CCUS in the Asia Pacific region. Coking coal accounts for well over half of total coal imports in 2050 (up from 30% today).

1.4.4 Greenhouse gas emissions and air pollution

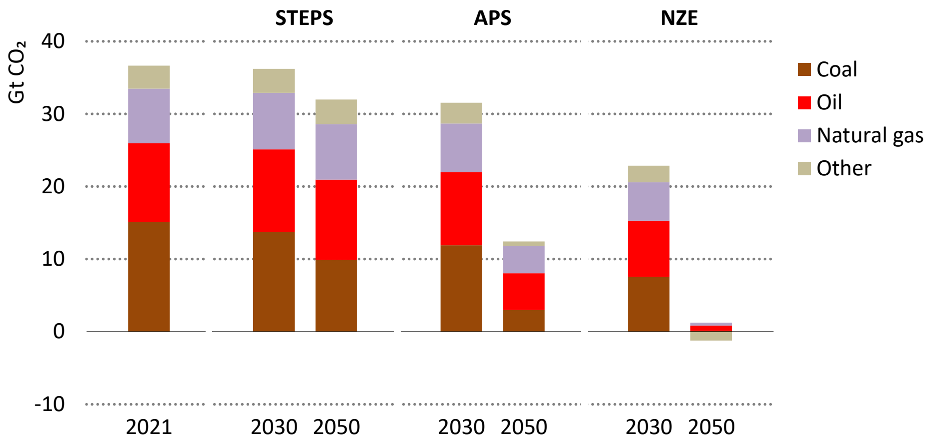
CO_2 emissions

Coal accounted for around 40% (15 Gt CO_2) of global energy-related CO_2 emissions in 2021. China and India accounted for two-thirds of these emissions, with the United States, the European Union, Russia, Japan, Indonesia, South Africa and Korea responsible for the majority of the remainder.

In the STEPS, annual emissions from coal decline by around 1.5 Gt CO_2 between 2021 and 2030, more than offsetting modest increases in industrial process CO_2 emissions and in combustion emissions from oil and gas (Figure 1.18). After 2030, coal emissions continue to decline, falling by nearly 4 Gt CO_2 to 2050. Emissions from oil and gas decline between 2030 and 2050, but at a much slower rate than for coal in the STEPS.

In the APS, emissions from all fossil fuels decline to 2030, but coal leads the way. There is a 20% reduction in emissions from coal to 2030 and this drop is roughly half as large as the reductions in emissions from oil, natural gas and industrial processes combined. Between 2021 and 2030, coal emissions decline by 3% per year (compared with a 1% decline in the STEPS) and between 2030 and 2050 this increases to 7% per year. By 2050, emissions from coal are 80% lower than in 2021.

Figure 1.18 ▷ CO_2 emissions by source and scenario



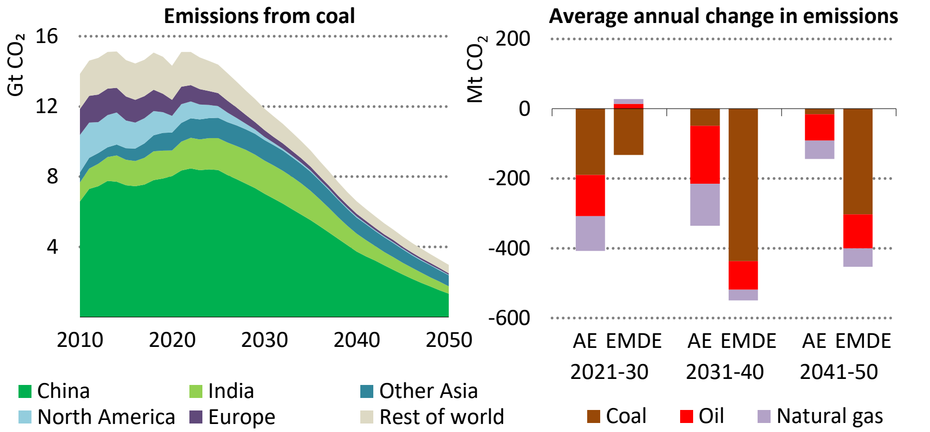
All scenarios see a peak followed by decline in CO_2 emissions, coal contributes most to the decline

In the period to 2030, emissions reductions from coal account for nearly two-thirds of total emissions reductions from the energy sector in the APS. This reflects the importance of reducing coal consumption if countries are to achieve their net zero emissions goals as well as broadening the availability of cost-effective alternatives to coal in the power sector, which accounts for the bulk of coal use. Emissions reductions to 2030 are fastest in advanced economies, driven by the rapid transition of their electricity sectors to clean energy technologies, notably solar photovoltaics (PV) and wind. Advanced economies reduce annual emissions from coal by almost 2 Gt CO_2 between 2021 and 2030 (nearly 70% reduction) (Figure 1.19). North America halved emissions from coal between 2010 and 2021 and it cuts emissions by another 80% to 2030, mainly due to the rapid pace of change in the electricity sector. Annual coal emissions from emerging market and developing economies decline by 1.3 Gt CO_2 between 2021 and 2030 (10% reduction).

After 2030, coal emissions continue to fall sharply in the APS, as the rapid growth of low-emissions sources of generation to 2030 lays the foundation for a much stronger reduction in emissions from coal thereafter. Annual emissions from coal fall by nearly 9 Gt CO_2 between 2030 and 2050. Nonetheless, the share of emissions reduction from coal falls to just over half of total emissions reductions between 2030 and 2050 as oil consumption undergoes a rapid decline.

In the NZE Scenario, emissions from all fossil fuels decline substantially by 2030. Coal leads the way, given its high emissions intensity and the competitiveness of low-emissions alternatives in the electricity sector. Emissions from coal drop by half from 2021 to 2030, driven by the rapid rise of low-emissions sources of electricity generation, and emissions from oil and natural gas both fall by around one-third over this period.

Figure 1.19 ▷ CO_2 emissions from coal by region, and average annual changes in emissions by fuel in the APS



Emissions reductions from coal account for nearly two-thirds of total emissions reductions to 2030 in the APS, led by declines in advanced economies

Note: AE = advanced economies; EMDE = emerging market and developing economies.

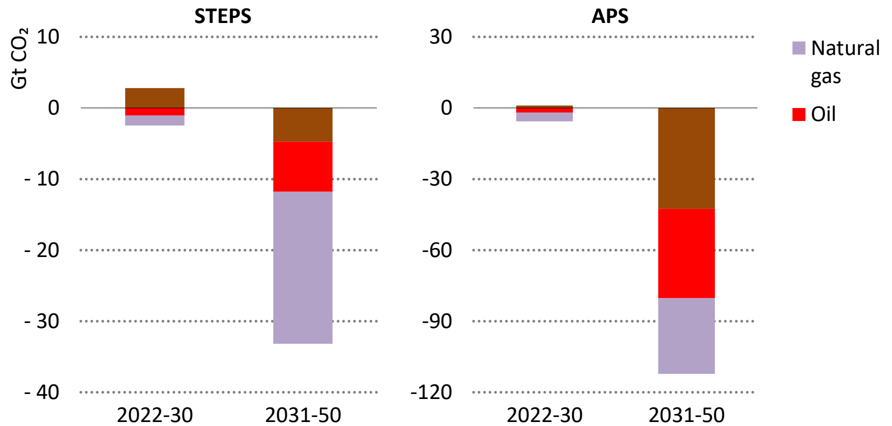
SPOTLIGHT

Does the current energy market turmoil threaten a return to coal?

In response to the current energy crisis, a number of European countries have announced temporary energy security measures, including life extensions or return to service of some coal plants. Notable as these measures are, the countries that have announced them account for less than 2% of global coal consumption. The big question for coal markets concerns the likely response of large coal consuming countries such as China and India to the energy crisis and the likely effect on emissions of their responses. To help address this question, we compare emissions in the STEPS and APS from the *WEO-2022* and the *WEO-2021* (Figure 1.20).

The STEPS in the *WEO-2022* projects higher near-term coal use than in the previous year's *Outlook*, resulting in around 3 Gt CO_2 additional cumulative emissions between 2021 and 2030. This increase is partly offset by lower emissions from oil and natural gas as current high prices and stronger policies accelerate the transition to clean energy in sectors dominated by these fuels, notably transport and buildings. However, the *WEO-2022* version of the STEPS sees total fossil fuel use peak and then start to decline after 2030 – the first time that this has been projected in this scenario. As a result, cumulative emissions between 2030 and 2050 are nearly 30 Gt CO_2 lower than in the *WEO-2021* STEPS, with the largest reductions seen in natural gas.

Figure 1.20 ▷ Differences in cumulative CO_2 emissions by scenario in the *WEO-2022* and the *WEO-2021*



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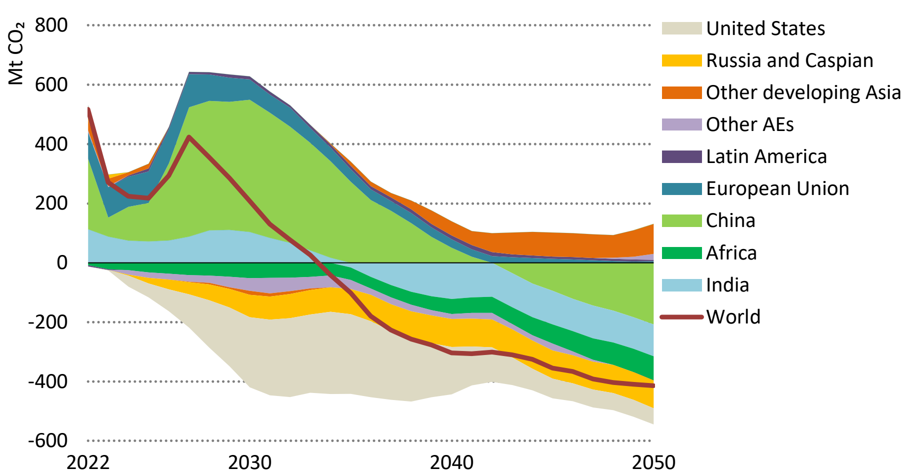
CO_2 emissions to 2030 are higher in the WEO-2022 STEPS relative to the WEO-2021, but emissions from all fuels are lower over the longer term

Note: *WEO-2022* = 2022 edition of the *World Energy Outlook* (IEA, 2022b); *WEO-2021* = 2021 edition of the *World Energy Outlook* (IEA, 2021a).

Figure 1.21 ▷ Change in CO_2 emissions by region in the *WEO-2022* STEPS relative to the *WEO-2021*, 2022-2050



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CO_2 emissions in the WEO-2022 STEPS projections are higher to the mid-2030s with particularly large increases in China, but long-term emissions are significantly lower

Due to the energy crisis, the STEPS in the *WEO-2022* projects an increase of around 430 Mt CO_2 additional annual emissions from coal use in the late 2020s in China, compared with last year's version of the STEPS, and around 100 Mt of additional emissions in both the European Union and India (Figure 1.21). In the longer term, however, China and India see a faster transition away from coal use in the *WEO-2022* STEPS, while new policies adopted in the United States accelerate the deployment of renewables in its power sector and a decline in coal emissions throughout the period to 2050.

In the APS, temporary energy security measures mean that coal use in the near term is slightly higher in the *WEO-2022* than was projected in the *WEO-2021*. However, the new net zero emissions pledges included in the *WEO-2022* APS, including from India and Indonesia, mean that coal use in the longer term is much lower than it was in the 2021 version of the APS.

Coal mine methane emissions

Methane emissions are responsible for around 30% of the current rise in global average temperatures; rapid and sustained reductions are key to limiting near-term global warming. Coal mine operations released around 43 Mt of methane into the atmosphere in 2021, close to one-third of total energy-related methane emissions. This is equivalent to around 1.3 Gt CO_2-eq,[5] more than all the CO_2 emissions from Europe's power sector.

Coal seams naturally contain methane (referred to as coal mine methane), which can be released during or after mining operations in a number of ways. These include through: seepage from coal seams exposed in surface or open pit mines; ventilation in which methane is extracted from underground coal mines as a safety measure; post-mining activities such as processing, storage and transport when methane still trapped in the matrix of the coal seeps out; and from abandoned mines where methane escapes to the atmosphere. Deeper coal seams tend to contain more methane than shallower ones, and older seams tend to have higher methane content than more recent ones.

Absent mitigation measures, methane emissions tend to be higher for underground mines than for surface mines. Underground mines, which accounted for about 60% of total coal production in 2021, were responsible for around 80% of total coal mine methane emissions. There are more options for mitigating methane emissions from underground mines than from surface mines. We estimate that it is technically possible to avoid around half of global methane emissions from coal operations today, and more than 90% of abatement potential is associated with underground coal mines.

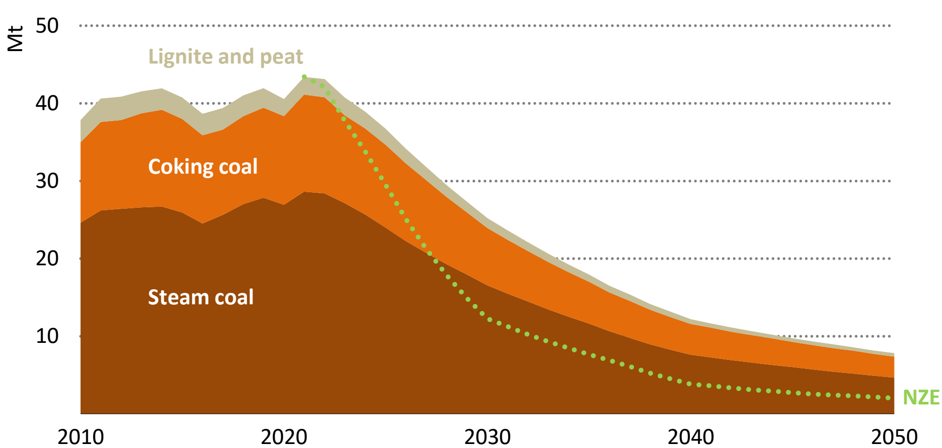
[5] Methane is converted to CO_2-equivalents based on the 100-year global warming potentials reported by the Intergovernmental Panel on Climate Change Sixth Assessment Report (IPCC, 2021), with one tonne of methane equivalent to 30 tonnes of CO_2.

In mines that have yet to start operations, high concentration sources of methane can often be captured if effective measures are taken. Degasification wells and drainage boreholes can capture methane in coal reserves to reduce the potential for leaks during production. The captured methane can be used for small-scale power generation or, if concentrations are high enough, injected into a local gas grid. Where concentrations are low and there is no nearby demand for methane, it can be combusted to reduce its climate impacts, either through open flares or enclosed combustion systems.

For operating mines, ventilation air methane can be directed to processes such as blending or oxidation to make it usable as an energy source, for instance to heat mine facilities or to dry coal. Thermal or catalytic oxidation technologies can be used even with low methane concentrations (between 0.25% and 1.25%) and reduce over 50% of associated emissions, although it is critical to ensure that these are designed to ensure safety.

In the APS, annual coal mine methane emissions fall by 18 Mt (42% reduction) between 2021 and 2030 (Figure 1.22). Declines in steam coal production reduce coal mine methane emissions by 6 Mt, and declines in the production of coking coal, peat and lignite reduce emissions by a further 3 Mt. Targeted efforts to abate coal mine methane emissions account for the remaining 9 Mt. Reductions continue after 2030, helped by declining demand for coal, and total coal mine methane emissions in 2050 are less than 20% of current levels. In the NZE Scenario, coal mine methane emissions decline about 70% from 2021 levels by 2030 and about 95% by 2050. Most of this reduction comes from a steep drop in coal use, but technical efforts to mitigate emissions from coal mines are also very important, particularly up to 2030.

Figure 1.22 ▷ Coal mine methane emissions in the APS and NZE Scenario



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Methane emissions decline by over 40% to 2030 and more than 80% to 2050 in the APS, while declines are steeper in the NZE Scenario

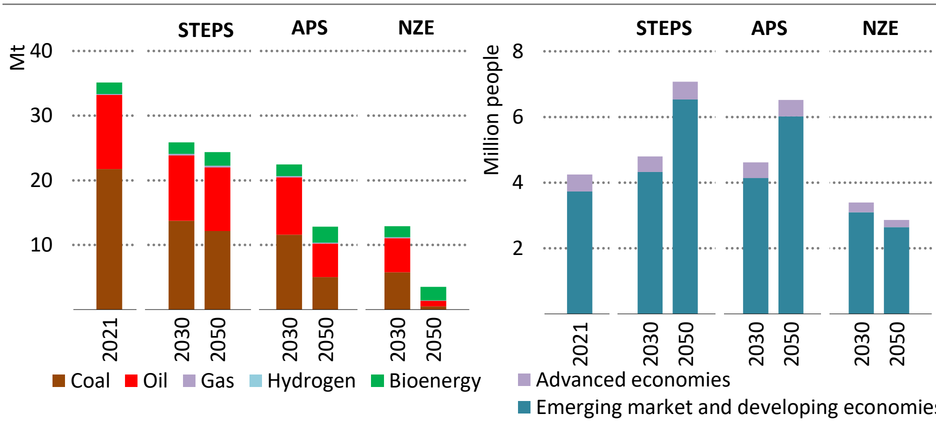
These estimates do not include methane leaks from closed or abandoned coal mines, and some have suggested that these could be a major cause of methane emissions (Kholod et al., 2020). Mine flooding is the most effective way to reduce methane emissions from these mines as it stabilises the hydrostatic pressure on the coal seams. In cases where this is not technically feasible, mines can be sealed and drainage systems put in place to ensure that emerging gas is captured. These measures are not widely deployed at present, and new policies and regulations dealing with emissions from legacy sites are needed to ensure their future deployment, given the importance of minimising methane emissions.

Air pollution

Polluted air causes serious diseases, damages natural habitats, and reduces the health and yield of farmed crops. In 2021, air pollution from outdoor sources (ambient air pollution) caused more than 4 million premature deaths, 85% of which were in emerging market and developing economies, mainly in Asia. In addition, household air pollution – mostly from the traditional use of biomass for cooking – caused around 3.6 million premature deaths in 2021, mainly in Africa, India and China. In addition to its human cost, air pollution places a burden on public healthcare systems and constrains economic growth. Mortality and morbidity caused by exposure to fine particulate matter air pollution alone costs around 6% of global GDP and in excess of 10% in some countries, including India and China.

Various fuels are responsible for different types of air pollutant emissions. In 2021, coal was responsible for over 60% of sulphur dioxide (SO_2) emissions, oil caused around 60% of nitrogen oxide (NO_X) emissions and biomass caused around one-half of fine particulate matter ($PM_{2.5}$) emissions.

Figure 1.23 ⊳ Emissions of sulphur dioxide by fuel and premature deaths from air pollution by scenario, 2021-2050



SO_2 emissions moderate in the APS, but the number of premature deaths continues to rise; in the NZE Scenario, emissions are mitigated significantly

Note: SO_2 = sulphur dioxide; NO_X = nitrogen oxides; $PM_{2.5}$ = fine particulate matter.

In the STEPS, demand for oil and natural gas increases to 2030 and coal use drops only marginally. The number of premature deaths caused from ambient air pollution increases significantly, especially after 2030 (Figure 1.23).

In the APS, air pollution emissions drop quickly. By 2030, the accelerated phase-out of coal use for electricity generation and in industry helps cut SO_2 emissions by one-quarter from 2021 levels, while increases in electric cars and less use of traditional biomass for cooking and heating drive reductions in NO_X and $PM_{2.5}$ emissions. However, despite these reductions, the combination of larger, older and more urban population in many regions means that there are around 360 000 more premature deaths from ambient air pollution in 2030 than in 2021 worldwide, with all of the increase occurring in emerging market and developing economies.

In the NZE Scenario, steeper reductions in coal use than in the APS, as well as less use of oil in road transport mean that SO_2 emissions in 2030 are less than half of their 2021 levels. There are also rapid reductions in emissions of NO_X and $PM_{2.5}$. As a result, there are about 860 000 fewer premature deaths from ambient air pollution in 2030 than in 2021, with over 70% of this reduction in emerging market and developing economies.

Coal in electricity generation

The elephant in the room?

SUMMARY

- Coal-fired power plants provided 36% of global electricity generation in 2021, accounting for 65% of global coal consumption, and emitted 10.5 gigatonnes of carbon dioxide (Gt CO_2), or 29% of energy-related CO_2 emissions. However, a growing number of countries – 75 as of July 2022 – have specific plans to phase out unabated coal or not develop new plants, and 16 more countries have made net zero emissions pledges, combined they cover nearly 100% of current global coal-fired generation.
- In the Announced Pledges Scenario (APS), coal-fired power output and CO_2 emissions drop 20% from 2021 to 2030. The recent uptick in coal use in advanced economies is short-lived, with a 75% fall by 2030. Emerging market and developing economies see coal power and emissions peak in 2025 and then decline. By 2050, global unabated coal power and emissions fall by 85% in the APS. The Net Zero Emissions by 2050 (NZE) Scenario calls for a 55% cut by 2030 and full phase out of unabated coal by 2040.
- Ending approvals for constructing new unabated coal plants is a primary milestone on the path to net zero emissions by 2050. As each new unabated coal plant could emit CO_2 for 50 years or more, it is critical to minimise new builds beyond the 175 gigawatts (GW) under construction at the start of 2022. Yet, in countries without commitments, an extra 150 GW of new unabated coal capacity is built by 2050 in the APS.
- Unless action is taken, operating the current fleet of coal plants as in the past would emit 330 Gt of CO_2 emissions from 2022 to 2100, more than all historical emissions from coal plants and two-thirds of the remaining budget to limit warming to 1.5 °C. In the APS, emissions from existing coal plants are cut to 155 Gt, with 60% of reductions from repurposing plants to focus on flexible operations, 33% from early retirements and 7% from carbon capture retrofits and co-firing with low-emissions fuels.
- Replacing coal requires the scaling up of alternative sources of electricity. In the APS, 2 500 terawatt-hours (TWh) of unabated coal generation is replaced by 2030, mostly by renewables (about 90%) and nuclear (8%). Replacing system services provided by coal plants is critical to electricity security: batteries cover nearly half of these needs in the APS, with significant contributions from hydro, other renewables and nuclear. Converting sites of retired coal plants can expand low-emissions or flexibility options.
- Transitioning from unabated coal, if designed and executed well, can be achieved without significantly raising costs to consumers. After modest increases to 2030, total system costs per unit of electricity are 10% lower in 2050 than today in the APS. Investment of USD 6 trillion is needed to replace coal, but these costs are outweighed by lower fuel bills. Both advanced economies and emerging market and developing economies benefit, with lower electricity costs in 2050 in the APS than today.

2.1 Introduction

It is essential to move away from the use of unabated coal in power plants in order to reduce CO_2 emissions and help address the challenge of global climate change, but achieving this will not be easy. Coal has been and continues to be a fundamental part of electricity generation. In 2021, coal-fired power plants provided 36% of global electricity generation, accounted for 65% of global coal consumption and emitted 10.5 gigatonnes of carbon dioxide (Gt CO_2) emissions, or 29% of global energy-related CO_2 emissions. Of total coal consumption in the power sector in 2021, more than 90% was for electricity generation and the rest for heat production. Global trends are mostly driven by emerging market and developing economies, where demand for electricity continues to grow strongly: three-quarters of the 2 185 gigawatt (GW) capacity of the global coal power plant fleet today is based in these countries, and more than half of it is in China.

Recent trends underscore the challenge to shift away from coal in the power sector. After falling by 5% in 2020 as the Covid-19 crisis reduced demand for electricity, unabated coal-fired generation jumped by 7% in 2021 to 10 200 terawatt-hours (TWh), its highest ever level. Coal met about half of electricity demand growth in 2021. Strong economic recovery was the main driver of this growth in China (+9%) and India (+13%), whereas record high natural gas prices were the main driver in the European Union (+20%) and United States (+16%).

Estimates for the first-half of 2022 show global coal generation remaining stable, with slightly declining output in China (-3%) and the United States (-6%) being offset by rising generation in India (+10%) and the European Union (about 15%). The large percentage rise in generation in the European Union reflects that coal is preferred over natural gas as concerns arose about its price and availability in the wake of Russia's invasion of Ukraine. There are indications that global coal generation is likely to rise in the second-half of 2022, so it is possible that 2022 may establish a new record for unabated coal-fired power generation.

This chapter draws mainly on the Announced Pledges Scenario (APS), which reflects a future energy world where all announced pledges and targets are implemented on time and in full. It also draws on the updated Net Zero Emissions by 2050 (NZE) Scenario, which describes a cost-effective pathway to achieve net zero emissions by mid-century in the energy sector that also limits cumulative emissions in line with a 50% chance of limiting the global average temperature increase to 1.5 °C by 2100, and occasionally for comparison it uses the Stated Policies Scenario (STEPS), which reflects the policies and measures in place now.

Section 2.2 provides an overview of the transition away from unabated coal-fired electricity generation and the associated CO_2 emissions reductions.

Section 2.3 highlights recent policy developments related to coal use in the power sector.

Section 2.4 looks at the issue of ending construction of new unabated coal power plants.

Section 2.5 presents an assessment of the risks of locking in CO_2 emissions from coal-fired power plants around the world.

Section 2.6 presents the IEA multi-pronged strategy to tackle emissions from coal plants in operation today and highlights the assessment of its impact in the APS.

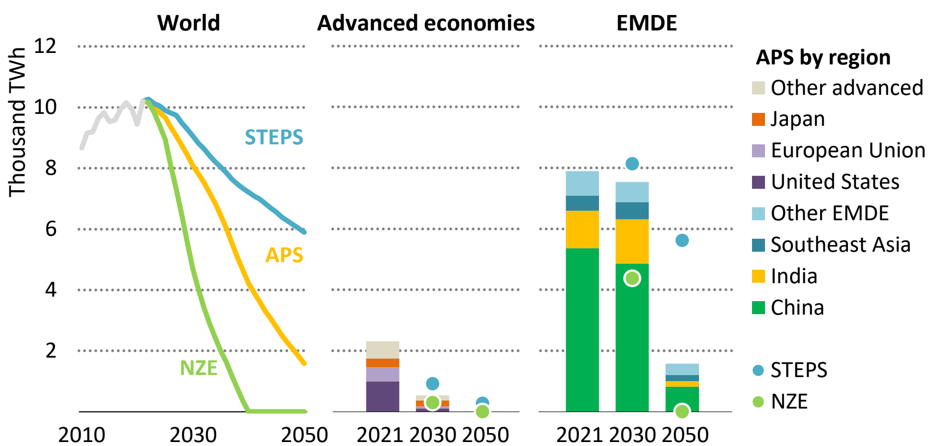
Sections 2.7 and 2.8 assesses how coal can be replaced in the electricity sector, both in terms of electricity generation and overall contributions to power systems.

Section 2.9 looks at the overall affordability of the transition away from unabated coal-fired power through an assessment of global power system costs by component.

2.2 Overview

In the Announced Pledges Scenario, the assumed fulfilment of national pledges brings about a 20% decrease in unabated coal-fired generation in the period to 2030 (Figure 2.1). This 2 100 TWh reduction marks a significant break from the trend over the past decade, especially against a background of continuing growth in electricity demand. The size of the global reduction in unabated coal-fired generation to 2030 is larger than today's combined power systems of Japan and Korea.

Figure 2.1 ▷ Unabated coal-fired electricity generation by region and scenario, 2010-2050



Today's return to coal is short-lived; unabated coal generation falls by 20% by 2030 in the APS, compared with over 50% in the NZE Scenario and just 10% in the STEPS

Notes: TWh = terawatt-hours. EMDE = emerging market and developing economies. APS = Announced Pledges Scenario; STEPS = Stated Policies Scenario; NZE = Net Zero Emissions by 2050 Scenario.

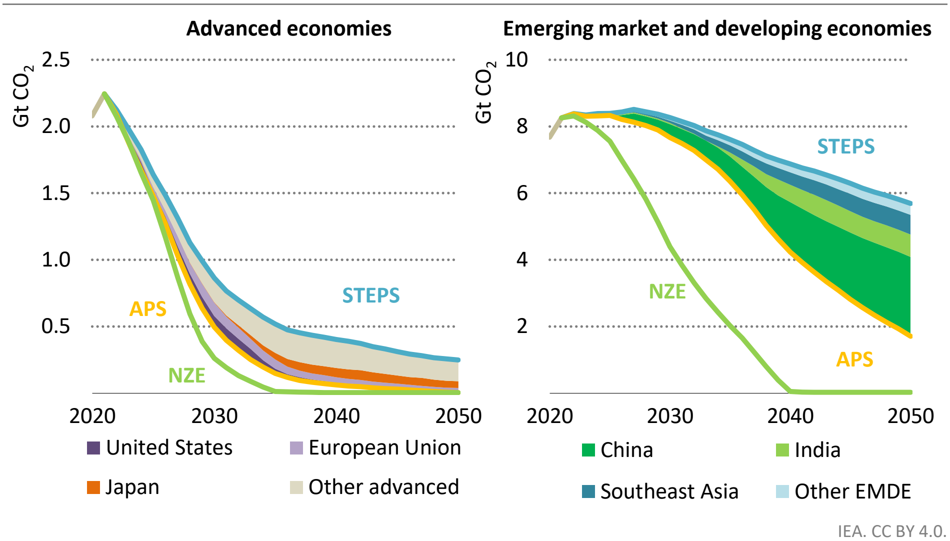
The rapid CO_2 emissions reductions required in the NZE Scenario deliver about a 55% reduction in unabated coal generation by 2030. By contrast, accounting only for the policies in place today, unabated coal-fired generation is reduced by just 10% in the STEPS by 2030.

By 2050, unabated coal-fired electricity generation is 40% below current levels in the STEPS, 85% below current levels in the APS, and is fully phased out by 2040 in the NZE Scenario.

Spurred by the global energy crisis, the boost in coal use in power generation is temporary. Advanced economies collectively cut unabated coal generation by about 75% by 2030 and over 95% by 2040 in the APS compared with 2021 levels, with the largest reduction in the United States. This marks an acceleration of the downward trend that has already brought a 45% reduction since unabated coal generation peaked in advanced economies in 2007.

In emerging market and developing economies, unabated coal generation peaks in 2025 in the APS and then falls slightly to 2030 but by nearly 50% to 2040. This reduction reflects targets in China for coal use to be reduced from 2025 to 2030 and in India to scale up renewables to meet rising demand. With capacity factors declining, the role of the remaining coal fleet increasingly shifts to provide flexibility services rather than baseload electricity. The NZE Scenario calls for cutting unabated coal generation in emerging market and developing economies by 45% by 2030 and 100% by 2040.

Figure 2.2 ▷ CO_2 emissions from coal-fired plants by scenario and reductions by region, 2020-2050



Global cumulative emissions from coal plants to 2050 are 60 Gt lower in the APS relative to the STEPS, of which 80% is in emerging market and developing economies in Asia

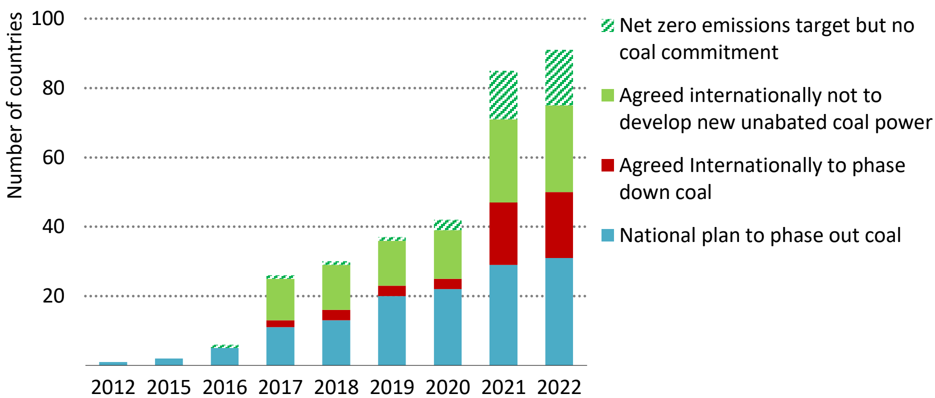
Note: Gt CO_2 = gigatonnes of carbon dioxide.

CO_2 emissions from electricity and heat sectors are set to decline by over 20% from 2021 to 2030 in the APS, largely due to the 2.3 Gt reduction in emissions from coal-fired power plants worldwide over this period. By 2050, emissions from coal-fired power plants fall to 1.7 Gt, nearly 85% below the level in 2021. In advanced economies, CO_2 emissions from coal plants fall to below 0.5 Gt by 2030 and to nearly zero by 2050: cumulative emissions over the period are about 10 Gt lower than in the STEPS (Figure 2.2). In emerging market and developing economies, CO_2 emissions from coal-fired power plants decline sharply after 2035 in the APS, in line with long-term net zero emissions pledges, and fall below 2 Gt by 2050, with cumulative emissions over the period about 50 Gt lower than in the STEPS.

2.3 Recent policy developments and commitments

An increasing number of countries have made net zero emissions pledges or adopted policies to reduce coal use in the power sector. As of July 2022, 75 countries had agreed to phase out coal or to not to develop new unabated coal power plants, collectively accounting for 20% of current coal-fired generation (Figure 2.3). In addition, 16 countries have announced net zero emissions targets without any coal-specific targets, and many will need to phase out unabated coal by the date of their net zero emissions target. Together these 91 countries account for almost 100% of coal-fired generation today, including the top-five in the world: China, India, the United States, Japan and South Africa.

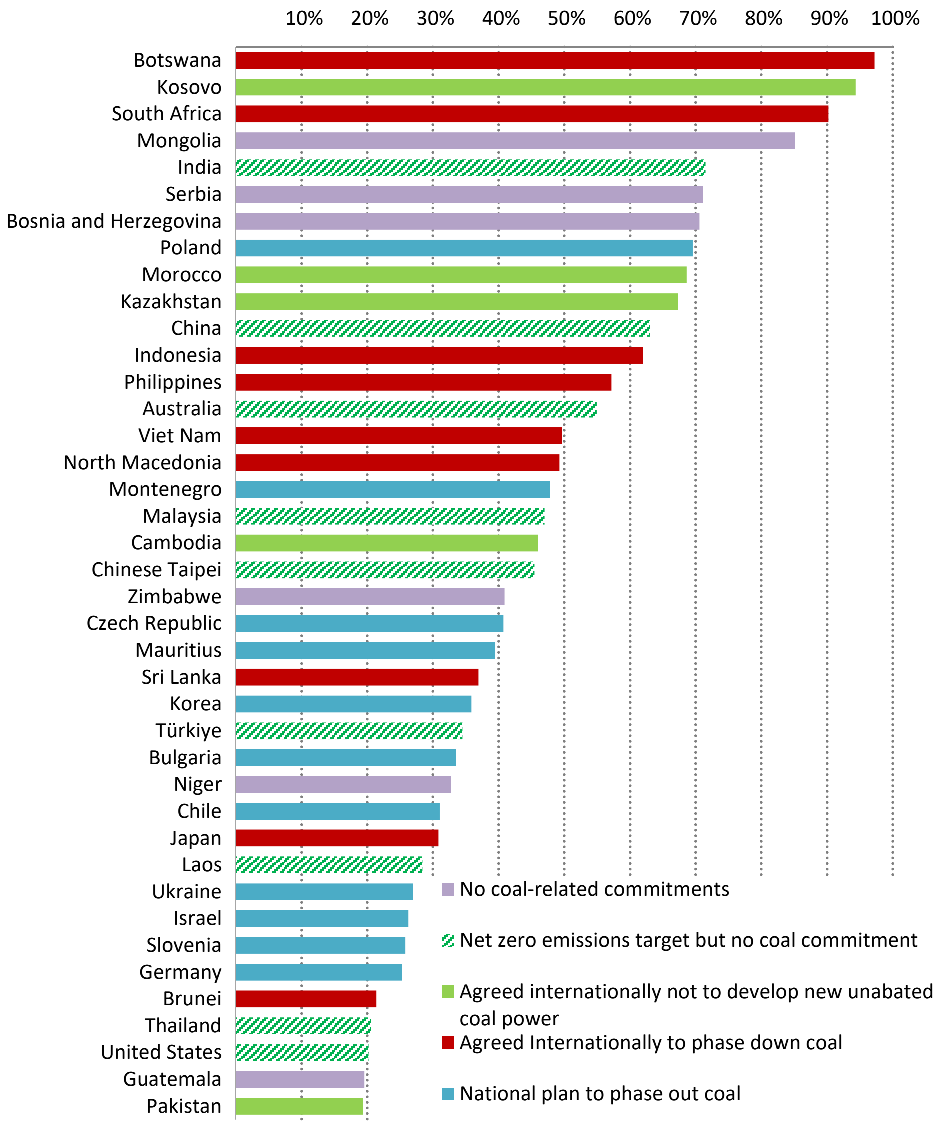
Figure 2.3 ▷ Number of countries with plans to phase down coal use and net zero emission pledges



After years of growth, there are now 75 countries with direct plans to phase out coal and another 16 countries that aim to reach net zero emissions

Pledges to phase out coal use in power have taken the form of announcements, national plans and international initiatives. In 2017, Canada and the United Kingdom made the first move to encourage the phase-out of coal in power generation by creating the Powering Past Coal Alliance (PPCA). Before its establishment, only five countries – Austria, Belgium, Finland, France and United Kingdom – had pledged to phase out coal. Luxembourg had achieved such a phase-out in 1980.

Figure 2.4 ⊳ Share of coal in electricity generation and coal policies



12 of the 15 countries most reliant on coal-fired power for electricity have a national plan to phase it out, have agreed internationally to do so or have a net zero emissions target

Note: The top 40 countries with the highest share of coal in electricity generation are shown. Other countries that use coal-fired power today are Romania, Russia, Dominican Republic, Greece, Zambia, Madagascar, Colombia, Myanmar, Hungary, Denmark, Korea, Croatia, Kyrgyzstan, Tajikistan, Netherlands, Slovak Republic, Canada, Panama, Mexico, Italy, New Zealand, Portugal, Finland, Uzbekistan, Austria, Namibia, Brazil, Bangladesh, Senegal, Spain, Belgium, Ireland, United Kingdom, Argentina, Singapore and France.

Since then, the number of countries making commitments to phase out coal has continued to increase to reach 71 by the end of 2021. Most of these commitments are reflected in the Nationally Determined Contributions required by the Paris Agreement. The PPCA has steadily attracted new members. Countries also signed onto, in whole or in part, to the Global Coal to Clean Power Transition Statement (GCCPTS) at COP 26 in November 2021. South Africa and Japan are not part of these initiatives but have made announcements to accelerate the phase-down of unabated coal power. The PPCA encourages all members of the Organisation for Economic Co-operation and Development and the European Union to phase out coal by 2030, and all other countries to do so by no later than 2050. The GCCPTS calls for major economies to phase out coal in the 2030s (or as soon as possible thereafter) and for all other countries to do so in the 2040s (or as soon as possible thereafter), as well as to cease new permits for unabated coal plants and to strengthen financial, technical and social support for affected communities. Countries that have made unabated coal phase-out commitments or have net zero emissions targets include those that have a high share of coal in power generation today, such as Botswana (97%), India (72%), China (63%), Australia (55%), Philippines (57%) and Viet Nam (50%) (Figure 2.4).

By June 2022, 31 countries had incorporated coal phase-out targets with specified dates in national plans, most are in Europe and 80% are advanced economies. They include countries with a high degree of reliance on coal-fired power such as Poland, the Czech Republic and Montenegro. They also include Germany, where the government has signed an agreement to bring forward the end-date for the phase-out from 2038 to 2030. By the end of 2021, four countries – Austria, Belgium, Portugal and Sweden – had succeeded to phase out the use of coal in power generation, although Austria is considering restarting one coal-fired plant temporarily in the light of the current energy crisis triggered by Russia's invasion of Ukraine.

Global efforts have already altered coal use in electricity generation in the past years. Countries with national plans to phase out coal or those having agreed internationally to do so are seeing a 12% reduction in coal-fired generation from 2012 to 2019. In the rest of the world, coal-fired generation increased by 15% over the same period. In 2022, the global energy crisis prompted many countries to a temporary return to coal-fired power generation, though a return to strong declines is expected when market disruptions subside.

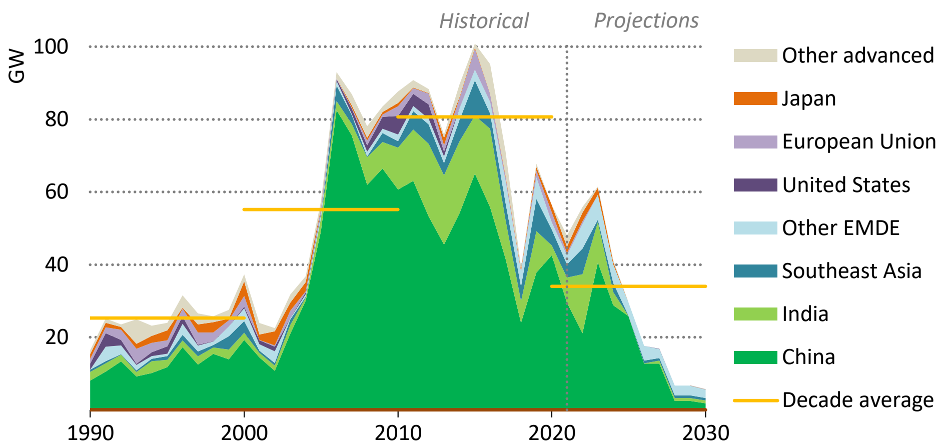
2.4 Cease construction of unabated coal plants

Reaching net zero emissions requires a comprehensive strategy that addresses all sectors and all fuels. Among the more than 400 milestones identified in the *Net Zero by 2050: A Roadmap of the Global Energy Sector* (IEA, 2021a), ending the construction of new unabated coal-fired plans was identified as one of the primary actions to be taken. With technical lifetimes of around 40-50 years for new coal-fired power plants, any new construction poses a risk of decades of emissions of CO_2 and other pollutants. At the start of 2022, about 175 GW of unabated coal-fired power capacity was under construction worldwide, of which nearly 100 GW was in China. Further additions beyond these would run entirely counter to the aim of achieving net zero emissions by 2050, and so the first milestone in the NZE Scenario is for no new unabated coal to be approved for development from now forward.

In the APS, construction of unabated coal plants slows but does not stop. The amount of new unabated coal capacity added each year declines dramatically from 48 GW in 2021 to just 6 GW by 2030, by which time it is substantially lower than at any time in the last 50 years (Figure 2.5). Average annual capacity additions from 2022 to 2030 in the APS are below 30 GW, a similar level to that in the 1990s but well below the average annual capacity additions of 55 GW in the 2000s and 80 GW in the 2010s.

Beyond 2030, an average of 4 GW of new unabated coal plant capacity continues to be built each year to 2050 in the APS in countries that have not committed to phase out its use, mainly to replace coal plants that reach the end of their lives. Over the period from 2022 to 2050, a total of 150 GW of unabated coal-fired power capacity that is not yet under construction is completed in the APS. In the NZE Scenario, the plants currently under construction are completed, but there are no further additions.

Figure 2.5 ▷ Coal-fired capacity additions in the APS, 1990-2030



From a record high in the 2010s, construction of unabated coal plants slows dramatically in the late 2020s in the APS; it comes to a complete halt in the NZE Scenario

Note: GW = gigawatt.

The majority of new coal plants have been constructed in emerging market and developing economies in recent years. This continues to be the case in the APS. Emerging market and developing economies, as they are categorised in 2022, accounted for more than half of new coal capacity in 1987 and have done so every year since 1994. In the last ten years, emerging market and developing economies accounted for over 90% of all new unabated coal capacity additions.

China has been the largest market for new coal plants by far, accounting for over half of the total built since 1970 and more than 60% of the worldwide total in the last ten years. China has announced that it will limit coal consumption growth to 2025 and then reduce it in the period to 2030, and that it intends to raise the share of non-fossil fuels in the electricity mix and to reach net zero emissions by 2060. Accordingly, new coal capacity additions in China are set to slow dramatically to 2030 in the APS. India has been the second-largest market for new coal capacity, accounting for almost 20% of the global total over the last ten years. But India too is set to reduce new unabated coal plant construction sharply this decade as it pursues a goal of reaching net zero emissions by 2070. Other countries in Africa, Latin America and Southeast Asia, including Indonesia, are also planning to cut coal power plant construction dramatically by 2030 to pursue announced targets.

Coal capacity additions in advanced economies have long been heading downwards and are set to reach zero by 2030 in the APS. Average coal capacity additions have declined since the 1970s in advanced economies, as they are categorised in 2022, falling from 21 GW per year in the 1970s to 16 GW in the 1980s, 8 GW in the 1990s and 6 GW in the 2000s. During the 2010s, however, the figure increased slightly to an average of 7 GW per year, with construction of new capacity taking place primarily in the European Union, Korea and the United States. Looking forward, net zero emissions targets across advanced economies point to a rapid shift away from unabated coal and to no new unabated coal except for those plants that are already under construction.

2.5 Risks of locked-in CO_2 emissions from existing coal plants

Unless remedial action is taken, the current fleet of relatively young, coal-fired power plants risks locking in CO_2 emissions for decades to come. To measure the risks, we developed a plant-by-plant assessment of the remaining technical lifetime of coal-fired power plants in operation at the start of 2022.[1] In parallel we analysed the potential associated emissions at recent levels of operation through to the year 2100 (Table 2.1). Historical emissions for all existing and previously retired coal-fired power plants have been estimated back to 1900.

Total coal-fired power plant capacity today stands at a little under 2 185 GW and is made up of around 9 000 units with an average age of 20 years per unit. Around a quarter of this capacity is in advanced economies and three-quarters in emerging market and developing economies. While the coal-fired fleet is relatively old on average in North America (41 years), Eurasia (40 years), Europe (34 years), Africa (29 years) and the Middle East (27 years), combined they account for only around only 25% of total coal-fired capacity today. The Asia Pacific region accounts for almost three-quarters of current global coal-fired capacity, which has an average age of 14 years. China alone accounts for over half of global coal-fired power capacity, which has an average age of only 13 years. Coal-fired units in Malaysia, Indonesia and Philippines have an average age of only 13 years while units in Viet Nam's fleet are only 8 years on average. Among advanced economies, Korea has one of the youngest fleet at 15 years on average.

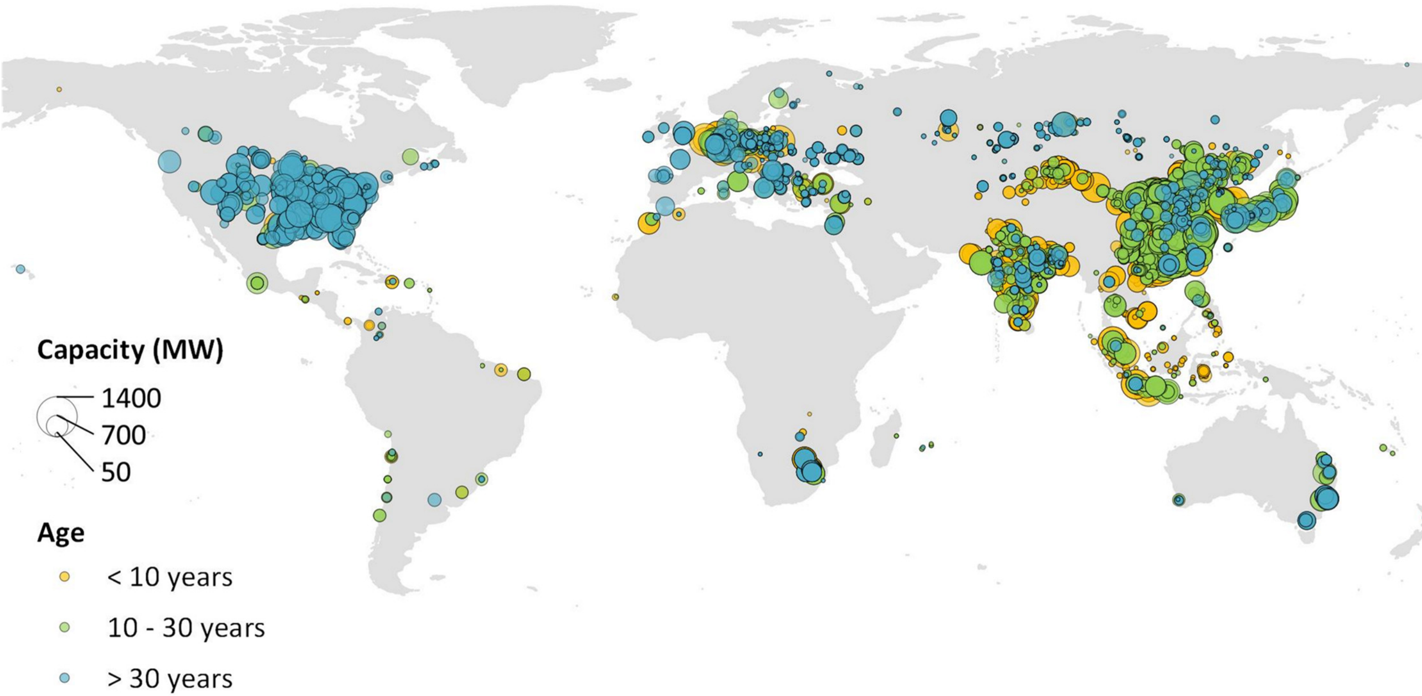
[1] For the purpose of this analysis, we assume a technical lifetime of 50 years for all plants.

Table 2.1 ▹ Historical and potential locked-in emissions from existing coal-fired power plants by region and average age

	Existing coal-fired power plants		Cumulative CO_2 emissions from existing plants			
	Capacity in 2021 (GW)	Average age today (Years)	1900-2021		2022-2100	
			Gt CO_2	Share (%)	Gt CO_2	Share (%)
North America	244	41	88	27%	12	3%
United States	233	41	83	26%	10	3%
Central and South America	13	17	2	1%	3	1%
Europe	184	34	65	20%	14	4%
European Union	122	32	46	14%	9	3%
Germany	39	30	15	5%	2	1%
Poland	31	33	8	3%	2	1%
Czech Republic	10	35	3	1%	1	0.2%
Italy	9	32	3	1%	1	0.3%
Ukraine	24	50	5	2%	0.6	0.2%
Türkiye	17	17	2	1%	3	1%
Africa	51	29	10	3%	6	2%
South Africa	44	31	9	3%	5	1%
Middle East	0.3	27	0.05	0.01%	0.1	0.03%
Eurasia	66	40	16	5%	6	2%
Russia	50	41	12	4%	4	1%
Kazakhstan	12	41	3	1%	1	0%
Asia Pacific	1 625	14	140	44%	290	88%
China	1 141	13	87	27%	203	62%
India	240	14	21	7%	42	13%
Japan	55	25	9	3%	8	2%
Korea	41	15	5	2%	9	3%
Indonesia	35	13	2	1%	7	2%
Australia	25	35	7	2%	2	1%
Viet Nam	23	8	1	0.3%	6	2%
Chinese Taipei	18	20	3	1%	3	1%
Malaysia	14	13	1	0%	3	1%
Philippines	11	13	1	0%	3	1%
World	**2 185**	**20**	**321**	**100%**	**330**	**100%**

Note: Cumulative emissions for the 1900-2021 period also include those from coal-fired power plants that were retired during the period.

Figure 2.6 ⊳ **Existing coal-fired power plants by age and size**

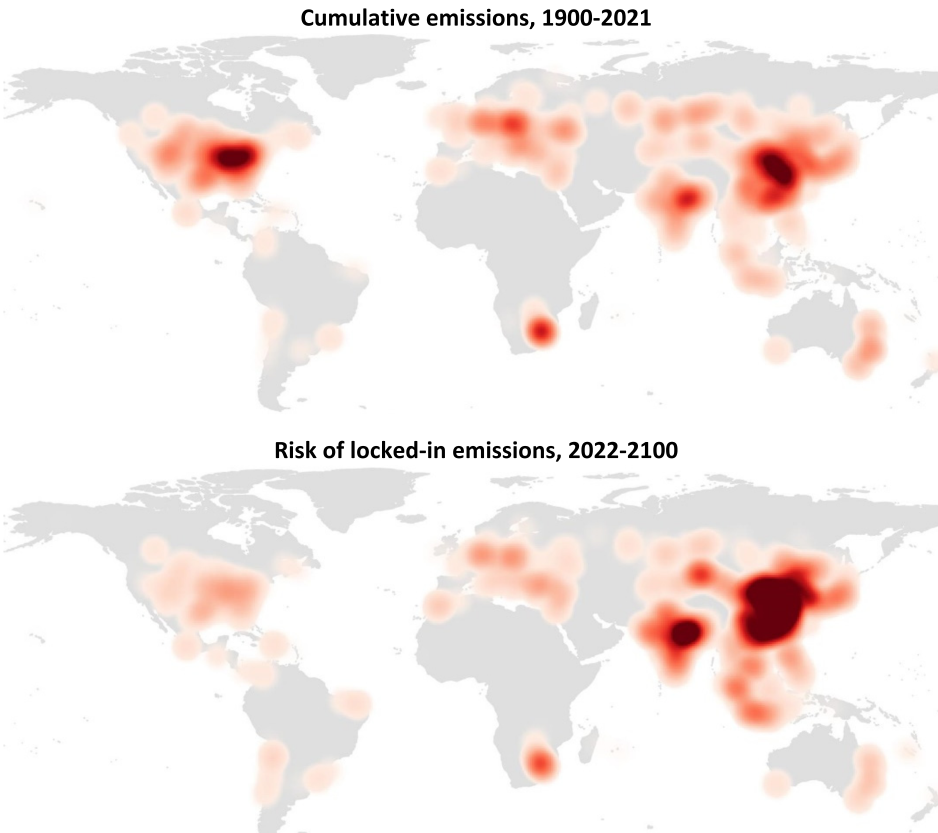


Coal-fired plants are spread around the world, with ageing plants mainly in the United States and Europe, and younger ones mostly in Asia

Sources: IEA analysis based on S&P Global (2021); Global Energy Monitor (2022); China Electricity Council (2022).

There is a strong regional imbalance in terms of the age and location of existing coal-fired power plants (Figure 2.6). The vast majority of plants that have operated for ten years or less are in emerging market and developing economies, most prominently in Asia, while the bulk of plants older than 30 years are in North America, Europe and Eurasia. Many of these older plants are potential candidates for retirement or conversion to alternative uses as they near the end of their economic lives (see section 2.6).

Figure 2.7 ▻ Emissions from existing coal-fired power plants



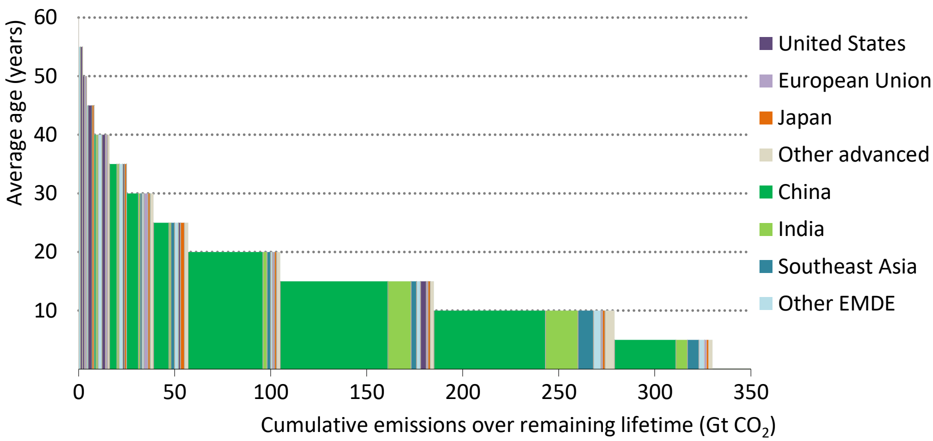
IEA. CC BY 4.0.

There are risks that emissions from the current fleet of coal-fired power plants could exceed the level of historical emissions from all coal plants since 1900

Given the relatively young age of most of today's coal-fired power plant fleet, there is a strong risk of future CO_2 emissions exceeding historical emissions, unless suitable action is taken. If existing plants continue to operate at current levels and without carbon capture, utilisation and storage (CCUS) retrofits or co-firing with low-emissions fuels over the rest of their technical lifetime, 330 Gt CO_2 emissions could be emitted from 2022 to 2100, with the

Asia Pacific region contributing almost 90% (Figure 2.7). China and India matter most in this context: their contributions to locked-in emissions on the basis set out here would be over 60% and about 15% respectively (Figure 2.8). Among advanced economies, major contributors at risk to lock in CO_2 emissions from coal-fired power generation include Europe (4%), the United States (3%), Korea (3%) and Japan (2%). The 330 Gt of emissions would account for two-third of the remaining cumulative emissions budget of 500 Gt consistent with a 50% chance of limiting average global temperature warming to below 1.5 °C. Emissions for the period from 2022 to 2030 alone could be as high as 90 Gt, and, if unchecked, cumulative emissions to 2060 from the existing coal plant fleet could exceed all coal plant emissions to date.

Figure 2.8 ▻ Cumulative emissions from existing coal-fired power plants at current use by age and region, 2022-2100



If left unchecked, the existing fleet of coal plants could emit 330 Gt of CO_2 emissions over the period to 2100 – two-thirds of the remaining budget for limiting warming to 1.5 °C

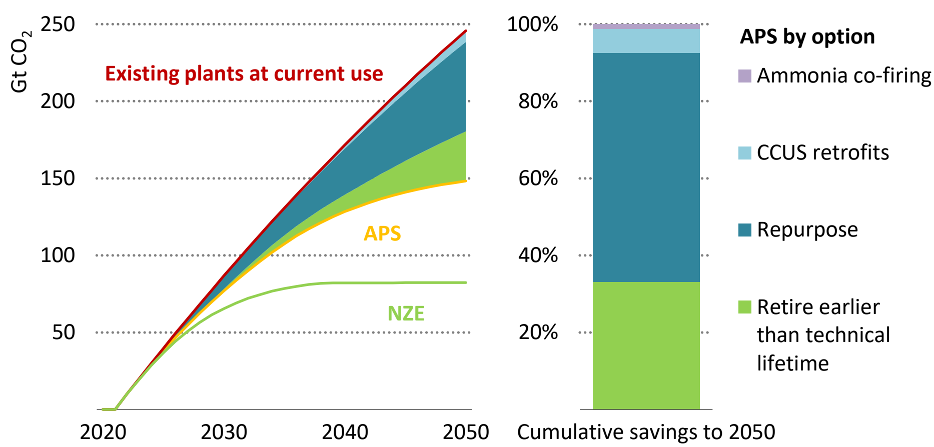
Note: Cumulative emissions over the remaining lifetime of a plant assume continued operations at historical levels. Individual plants are reported in five-year age groups.

Advanced economies account for 55% of the 320 Gt of historical cumulative coal-fired power CO_2 emissions worldwide stretching back to 1900. Developing economies in Asia made up most of the remainder, with China alone accounting for around one-quarter of the global total. Cumulative emissions from coal plants in advanced economies will be overtaken by those in emerging market and developing economies this decade. If all the potential locked-in emissions were to materialise, and if the total were to be added to historical emissions, advanced economies would be responsible for around one-third of total CO_2 emissions and emerging market and developing economies for around two-thirds. On a per capita basis, however, cumulative emissions from coal-fired power plants in the emerging market and developing economies would still be lower than those of advanced economies.

2.6 Tackle emissions from the existing coal fleet

A variety of existing technologies offer options to reduce emissions from existing coal-fired power plants in ways that best fit the particular circumstances. They include: repurpose coal plants to focus on flexibility; retrofit with CCUS technology; retrofit to co-fire with low-emissions fuels such as ammonia or biomass; and retire them early. Against a baseline of coal plants continuing to operate as they have in the recent past, the cumulative CO_2 emissions savings to 2050 in the APS is close to 100 Gt (Figure 2.9). Repurposing accounts for 60% of these reductions, with early retirements the second-largest contributor to cutting emissions (33% of the total), followed by CCUS retrofits and co-firing with other fuels.

Figure 2.9 ▷ Cumulative CO_2 emissions from existing coal-fired power plants



The fleet of existing coal-fired power plants could emit 250 Gt CO_2 by 2050, but there are several options to curb their emissions and keep the door open to 1.5 °C

2.6.1 Repurpose for flexibility

Repurposing coal-fired power plants – reducing operations to focus on system adequacy or flexibility services – is one option to cut emissions while continuing to operate. It means that an unabated coal plant produces less electricity over a certain period, but remains available at times when the system needs are highest, contributing to the reliability of power systems, and is available to ramp up and down to meet flexibility needs. Since most coal-fired power plants are currently operated in a stable 'baseload' mode, this is an option that is available for a large part of the coal plant fleet in many countries, notably in emerging market and developing economies, including China, India and Indonesia.

Repurposing coal plants for flexibility is widely adopted in the APS because it enables the existing coal fleet to support and facilitate the integration of increasing shares of variable renewables. As a result, the average annual capacity factor[2] of the global unabated coal plant fleet declines from 53% in 2021 to about 45% by 2030, 30% by 2040 and 20% by 2050 in the APS. While the average capacity factor of unabated coal in emerging market and developing economies only declines slightly to 2030 and then begins to fall thereafter, it drops much faster in advanced economies, where it declines from 51% in 2021 to under 30% by 2030, 14% by 2040 and drops to zero by 2050. These reductions in operations unlock significant emissions savings, though they could create financial difficulties that will need to be overcome along the way, depending on market design or the structure of contracts in place (see Chapter 4, section 4.4.2). In the NZE Scenario, unabated coal is phased down more quickly in advanced economies and in emerging market and developing economies, reducing the global capacity factor to below 40% by 2030, under 30% by 2035 and zero by 2040.

Repurposing coal plants for flexibility may require minor equipment upgrades, changes to market designs and plant operations, and updates to contracts. As well as ramping down to zero or up to maximum output, coal plants can generally run at partial load, i.e. produce a fraction of their maximum rated output, and can adjust their output within minutes or a few hours. Technically, coal-fired power plants often have far more flexibility than is currently being used. Adjusting control systems that shift the operational boundaries of the plant may be enough to unlock that flexibility.

The main hurdles are often operational practices and contract structures. Flexibility requires more regular activity to adjust the output of plants, calling for new or more active roles for onsite staff. Contract structures based on total output over a period as long as an entire year tend to favour relatively constant output that minimises wear-and-tear on equipment rather than incentivising flexibility. Incentives are likely to be improved where system flexibility needs are translated into economic signals to which coal and other power plants can respond.

Targeted investments can further enhance flexibility: for example, retrofitting alternative boilers can lower a coal plant's stable minimum load, while upgrades to control systems and plant components can increase ramping speeds and allow plants to be operated at levels higher than their rated capacity for brief periods of time. Other retrofit options, such as coupling the plant with battery energy storage, can further boost flexibility in terms of the grid. They can at the same time allow the plant to provide ancillary services such as fast frequency response or spinning reserves without burning additional fuel. Heat storage can be added to make coal co-generation plants more flexible.

Repurposing coal plants for flexibility has several appealing characteristics for coal plant owners, the surrounding communities, broader electricity consumers and policy makers. For coal plant owners, the financial impacts of repurposing for flexibility are modest in the short term, with limited investment requirements and progressive changes to operations as renewables scale up, though the details inevitably depend on the structure of any contracts in place. (A more in-depth look at the financial aspects of adapting coal plants to clean energy

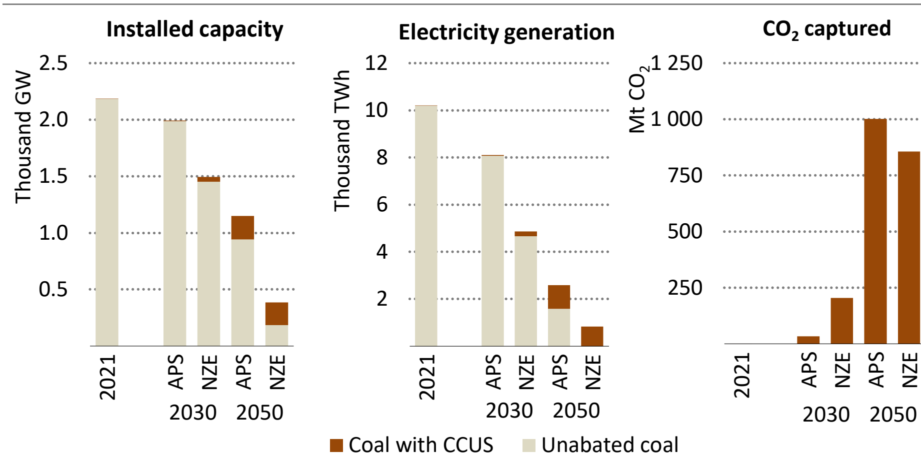
[2] Capacity factor is calculated as the gross electricity generation divided by the gross installed capacity.

transitions is provided in Chapter 4.) For surrounding communities, employment remains broadly unchanged. For electricity consumers, repurposing coal plants helps maintain affordability throughout clean energy transitions by making good use of existing assets. For policy makers, repurposing coal plants for flexibility also reduces the potential need for other investments in fossil fuel power plants that could be inconsistent with clean energy transitions.

2.6.2 Retrofit with carbon capture

Retrofitting coal plants with carbon capture, utilisation and storage provides a means to preserve existing assets, provide dispatchable electricity, help maintain grid stability and offer energy storage in the form of coal. In some cases, CCUS may be an attractive option to keep plants close to active coal mines in operation, maintain mining jobs and support mining communities. Where newer plants are concerned, retrofitting with CCUS may often be a reasonable compromise to avoid the closure and near full write-off of a plant. If the capture system allows energy to be stored, the retrofit can boost the flexibility of the system and support high levels of variable renewables. Available CCUS technologies for coal power plants include pre-combustion, oxy-combustion and post-combustion.

Figure 2.10 ▷ Global coal-fired power plants unabated and equipped with CCUS in the APS and NZE Scenario



IEA. CC BY 4.0.

Coal capacity equipped with CCUS reaches nearly 210 GW in 2050 in the APS, generates over 1 000 TWh of electricity and captures close to 1 Gt CO2 emissions

The total capacity of coal power plants with CCUS in the APS increases marginally over the next five years and expands rapidly afterwards. By 2030, coal plants with CCUS provide 6 GW of capacity and generate around 35 TWh while capturing 33 million tonnes of carbon dioxide (Mt CO_2) per year (Figure 2.10). By 2050 in the APS, there is nearly 210 GW of coal plants with CCUS – of which almost 75% is in China – that generate over 1 000 TWh and capture 1 Gt CO_2. In the NZE Scenario, the deployment is faster with around 45 GW of coal plants equipped with CCUS by 2030, generating close to 200 TWh and capturing over 200 Mt CO_2. By 2050, over 200 GW of coal-fired capacity is equipped with CCUS, generating almost 830 TWh by 2050, capturing around 850 Mt CO_2. These long-term contributions are slightly lower than in the APS due to a much shorter window of opportunity to deploy CCUS retrofits as the electricity sector is fully decarbonised by 2040 in the NZE Scenario.

Today only two commercial coal-fired power plants have been retrofitted with CCUS: the Petra Nova project in Texas, United States, and the Boundary Dam project in Saskatchewan, Canada. The Boundary Dam CCUS project has been operating since 2014 and has a capture capacity of around 1 Mt CO_2 per year. The Petra Nova facility, which operated from December 2016 to May 2020, had the largest post-combustion carbon capture system (1.4 Mt CO_2 annually) installed on a coal-fired power plant. Captured CO_2 was used for CO_2 enhanced oil recovery, but capture operations were suspended in May 2020 as a result of the low oil prices associated with the economic impact of the Covid-19 pandemic. In addition to these two plants, in January 2021, China Energy completed construction of a CO_2 capture demonstration at the Guohua Jinjie Power Plant. The demonstration project will capture 0.15 Mt CO_2 annually and is a significant step forward for coal-fired power with CCUS in China.

Despite limited progress in adding CCUS to coal-fired power plants, there are signs of growing interest with plans for around 15 new projects in development around the world. This momentum is driven by net zero emissions goals and an improved investment environment, particularly in the United States, where tax credits provide up to USD 85 per tonne of CO_2 (t CO_2) stored. If all planned projects proceed, the potential capture CO_2 capacity from the coal power plant fleet would be around 28 Mt CO_2 in 2030. All but one of these projects are retrofits of existing coal-fired power plants, of which almost three-quarters are located in China or the United States.

Considerations for retrofitting coal-fired power plants

CCUS retrofits can be applied to the whole facility or to part of a plant. The simplest form of retrofit involves re-routing the flue gas from a unit boiler through a CO_2 capture facility. More extensive modifications include conversion of the boiler to oxy-fuel combustion or the construction of an external heat source, such as a natural gas-fired combined heat and power plant. The reduction in net electricity output of a coal-fired power plant unit retrofitted with CO_2 capture is around 20%.

Coal plants retrofitted with CCUS can support power system transitions in several ways. As well as supplying low-emissions power from existing coal assets, they can provide stability services such as inertia, ramping flexibility and firm capacity at peak times. At the same time, they use transmission infrastructure that is already in place, and they allow current plants to be operated so that investments can be recouped while reducing their carbon footprint. This is particularly important for emerging economies in Asia, where the average age of coal-fired power plants is only 13 years and new plants continue to be built.

There are various criteria that could be used to assess the suitability of coal plants for retrofits (Table 2.2). Key points include:

- In general, younger plants are less costly to retrofit per megawatt (MW) than older ones. They also have a longer remaining lifetime in which to pay off the capital costs of CCUS retrofits.
- Larger units offer economies of scale. The unit cost of CO_2 capture, transport and storage generally decreases as capacity increases.
- Supercritical and ultra-supercritical power plants are better candidates for retrofits than other plant types because the CCUS-equipped facilities will have higher efficiencies and therefore lower marginal costs. Plants with design efficiency of over 45% could achieve efficiency of 37% when equipped with CO_2 capture, which is about equal to the current average global operational efficiency of coal-fired power plants without CCUS.

Table 2.2 ▷ Retrofit-readiness criteria for coal-fired power plants

Technical	• Age • Capacity • Efficiency • Cooling type • Steam turbine design • Pollution controls
Logistic	• Proximity to potential storage sites • Access to CO_2 transport • Location of fuel source • Onsite space for carbon capture equipment
Strategic	• Regulatory frameworks • Emissions targets • Capacity factor • Public acceptance
Commercial	• Attractiveness of available alternatives to CCUS • Access to funding • Power market design

Costs of retrofitting coal-fired plants with CCUS

Capital costs are an important component of CCUS projects and make up the vast majority of additional costs for the first-generation CCUS retrofit plants in operation. The projected capital cost for retrofit projects is in the range of USD 1 000-3 000 per kilowatt in 2030, yielding a levelised cost of electricity (LCOE) generally below USD 100 per megawatt-hour (MWh) (when combining the capital cost with fuel costs, CO_2 prices and maintenance costs and dividing by output). At this cost level, coal plants with CCUS would be an attractive option compared with other dispatchable low-emissions sources in many markets (see section 2.9).

The main components in terms of capital expenditure are the costs of purchasing the capture unit, upgrading the boiler or turbine and installing pollution control equipment, e.g. flue gas desulphurisation. Operating costs at coal plants retrofitted with CCUS are typically higher than those at unabated plants due to a reduction in efficiency caused by the energy requirements of CO_2 capture. The efficiency penalty will depend on the type of CO_2 capture technology used and the scale of technological advances. Further operating expenses relate to the use of solvents, chemical reagents and catalysts, the disposal of waste products and the additional staff needed to run the CCUS facilities.

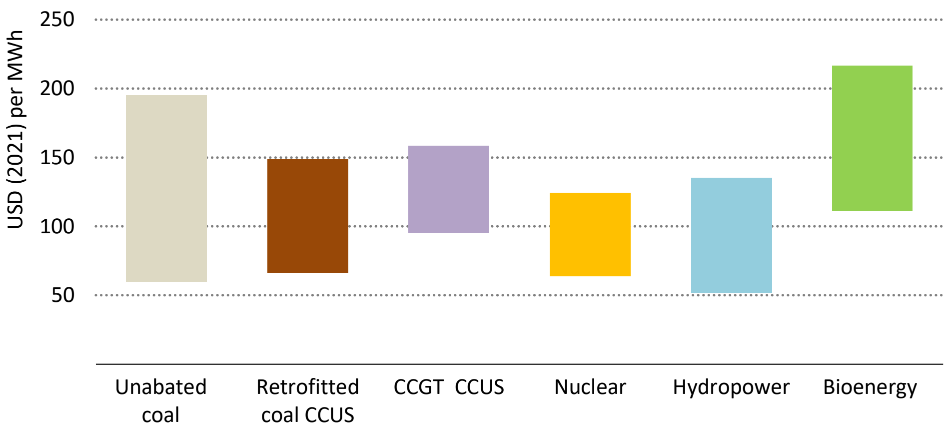
A feasibility study by the International CCS Knowledge Centre in Canada, based on Boundary Dam project data and costs, suggests that a second-generation capture facility could be built with 67% lower capital costs at a cost of USD 45 per t CO_2 captured and a CO_2 capture rate of up to 95% (International CCS Knoweldge Center, 2018). Lessons learned from Boundary Dam could support deployment of post-combustion CCUS at other coal-fired power plants, while also providing a foundation to retrofit existing facilities for CO_2 capture for a variety of purposes, including cement production.

Carbon pricing could make retrofitting a coal-fired power plant a more attractive proposition. From a financial perspective, CO_2 prices of USD 50-100/t CO_2 would cross the breakeven point for many unabated coal plants and incentivise them to consider CCUS retrofits (see Chapter 4, section 4.4.3). Retrofitting coal plants with CCUS could be an attractive option compared with other dispatchable low-emissions sources of electricity, including nuclear power, hydropower, bioenergy and natural gas with CCUS. All these sources provide comparable value to power systems through a full set of services, including to system stability, flexibility and adequacy. Direct comparison of LCOEs provide a useful indicator of competitiveness. In the APS, the LCOE of coal plants retrofitted with CCUS is projected to be in the range of USD 70-150/MWh by 2030, having benefited from significant cost reductions this decade. In this cost range, coal plants retrofitted with CCUS are on par with most new nuclear reactors, hydropower projects, natural gas with CCUS and lower cost bioenergy projects (Figure 2.11).

To assess the competitiveness of coal CCUS retrofits with variable sources of electricity, mainly solar photovoltaics (PV) and wind power, requires additional information about the contributions that each makes to system value. In our analysis, this assessment is embodied in the value-adjusted LCOE that combines the LCOE with estimated value contributions by technologies to system flexibility, capacity adequacy and flexibility. The variable nature of solar PV and wind means that their system value tends to be lower than for dispatchable sources and it tends to decline as their share of total generation increases.

In the APS, the estimated system value for new solar PV and wind in 2030 is USD 10-40/MWh less than it is for coal CCUS retrofits and comparable dispatchable technologies. When this is factored in, coal CCUS retrofits are significantly more competitive with solar PV and wind than a comparison of LCOEs alone would indicate. However, as the LCOE of new solar PV and wind is USD 50/MWh or less in most cases in 2030 in the APS, the value adjustment is not large enough to enable coal with CCUS to bridge the cost gap. Beyond 2030, the difference in system value between solar PV and wind and dispatchable sources continues to increase, though battery storage can be paired onsite with them to provide a competitive source of low-emissions electricity that contributes to all system services.

Figure 2.11 ▹ Levelised cost of electricity for selected dispatchable low-emissions electricity generation in the APS, 2030



Retrofitting coal plants with CCUS puts them roughly on a par with other dispatchable low-emissions sources of electricity in terms of cost

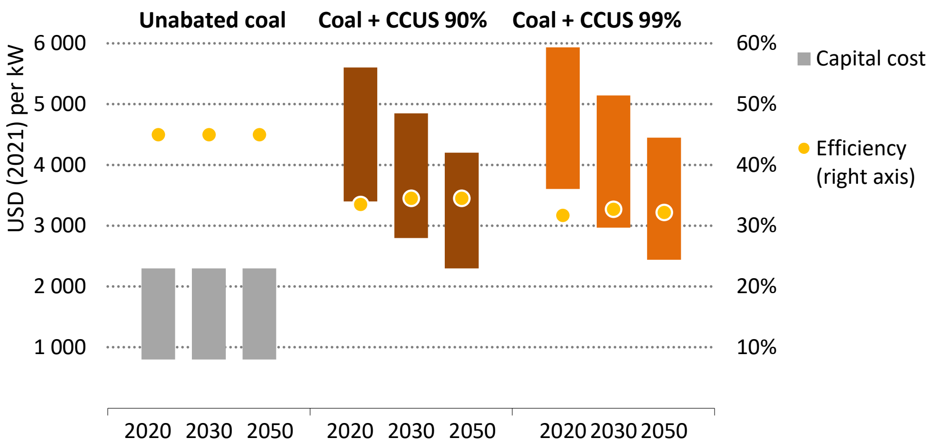
Notes: CCGT = combined-cycle gas turbine. Technology costs include the cost of emissions, with CO_2 prices in the Announced Pledges Scenario reaching up to USD 135 per tonne CO_2 in 2030. Retrofitted coal CCUS includes the costs, including capital costs, of the unabated coal plant and the CCUS retrofit.

High capture rates are essential in a net zero emissions power system

Higher CO_2 capture rates will become increasingly important in the transition to a net zero emissions energy system. CCUS power plants operating today capture around 90% of the CO_2 from flue gas, but future plants could be designed to capture 99% or more. While there are no technical barriers to increase capture rates beyond 90% for most mature capture technologies, a better understanding of the modifications and associated costs is needed.

According to a study by the IEAGHG, CO_2 capture rates as high as 99% can be achieved at a relatively low additional marginal cost compared with 90% capture (IEAGHG, 2019). The findings indicate that increasing the capture rate from 90 to 99% would result in 6-7% higher capital costs and a 2% energy efficiency drop for coal plants (Figure 2.12). On this basis, CO_2 prices higher than USD 75/t CO_2 would make the LCOE of coal plants with a 99% capture rate lower than that of plants with a 90% capture rate.

Figure 2.12 ▹ Capital cost of unabated coal plants relative to coal plants with CCUS at 90% and 99% capture rate



Additional costs needed to achieve a 99% capture rate in CCUS are modest compared with a 90% capture rate

Note: kW = kilowatt; CCUS = carbon capture, utilisation and storage. For unabated coal, capital costs and efficiencies are provided for ultra-supercritical designs.

Source: IEA analysis based on IEAGHG (2019).

2.6.3 Retrofit to co-fire with ammonia or biomass

Co-firing low-emissions ammonia or biomass is another option to cut CO_2 emissions while continuing to operate coal-fired power plants. Co-firing also offers valuable system benefits. As the share of variable renewables in the electricity generation mix increases, dispatchable generation becomes ever more important for grid stability. In the APS, ammonia and biomass co-firing in coal power plants play an important role to ensure that grid stability is maintained while also enabling emissions reductions targets to be met.

Traditional coal-fired power plants generally use a single type of coal or have been co-fired with biomass, but new advancements in fuel mixing allow for the blending of ammonia as an alternative secondary fuel. As with biomass, co-firing with ammonia reduces the CO_2 emissions intensity of the electricity produced. The blending level is set at the combustion end of the power plant, where ammonia and coal mix together. While the effect is similar to co-firing biomass with coal, ammonia has different technical characteristics, is at an earlier stage of development and presents unique opportunities to cut emissions from existing coal power plants, provided that the ammonia comes from low-emissions production methods.

Following the success of a demonstration project at the Mizushima Power Plant in Japan that established the viability of 1% blending of ammonia in a commercial plant, Jera Company and IHI Corporation are working towards a 2023 start date for a 1 GW large-scale demonstration with 20% blending. For low volume blends of up to 20% ammonia, the retrofits required are relatively modest in terms of both scope and capital investment. Combustion retrofits include modification and potential replacement of burners. Additional infrastructure to support higher volumes of ammonia is required, including onsite ammonia storage tanks, vaporisers and injection systems. Plants selected for ammonia co-firing need to have additional space available for onsite ammonia equipment, access to a reliable supply of ammonia and good transport links. The costs of transporting ammonia mean that plants located near import terminals or inland transportation hubs are ideal. At the plant level, these changes do not affect the majority of onsite equipment, allowing most of the operations at the plant to continue as before the retrofit.

Biomass co-firing, which has been around for decades, is a similar process. A portion of the coal is substituted with biomass, thereby reducing emissions. Unlike ammonia co-firing, this is a mature technology that is in use on a commercial scale in several regions, notably in India, the United Kingdom and United States. Biomass co-firing is already able to reach much higher percentage blends than ammonia: in some cases biomass accounts for more than 50% of the mix. The share of biomass blended with coal in power plants today is mainly dependent on price and availability of sustainable biomass supply. Agricultural and forestry residues that otherwise would be burned without any benefit offer a pragmatic solution (IEA, 2021a), but the size of a typical coal plant means that it can be difficult to find sufficient quantities of sustainable biomass nearby for high blending rates or full conversion to biomass. Sustainability is as important as availability: accountability, traceability, emissions in the supply chain (collection, processing and transport) and indirect land-use change are all issues that need to be addressed in this context.

The future level of co-firing with ammonia and biomass will inevitably depend to a large extent on their prevailing costs. The higher fuel cost of ammonia relative to coal means that coal-fired plants are likely to vary blend rates according to carbon pricing, fuel costs and retrofit costs for higher percentage blends. The combination of low upfront costs and a high level of uncertainty about future fuel costs may also create financing challenges (see Chapter 4, section 4.4.3). In the APS, decarbonisation targets point towards the reduction of traditional coal-fired power generation, but co-firing with ammonia and biomass helps to avoid stranded assets by enabling some coal-fired plants to continue operation while avoiding former levels of emissions.

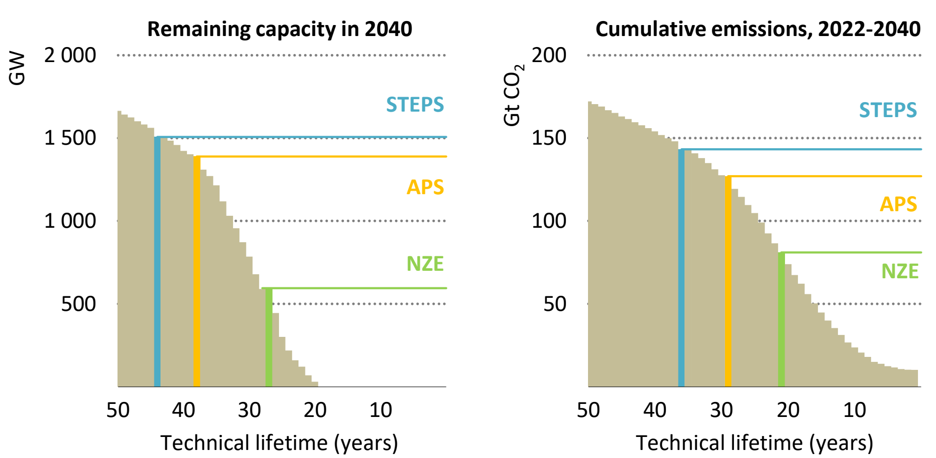
Aside from reducing CO_2 emissions, research efforts to date have focused on increasing ammonia use without increasing nitrogen oxides (NO_X) emissions or decreasing plant generation performance. While the ability to achieve this has been proven at low blending shares, it has yet to be proven at higher shares. NO_X is one of the most damaging man-made sources of air pollutant emissions, so the level of NO_X emissions is crucially important. Higher N0x emissions could come from multiple sources during co-firing with ammonia, including from increased fuel-NO_X due to the higher nitrogen content of ammonia relative to coal, thermal-NO_X resulting from the combustion process, and un-combusted ammonia itself that is exhausted.

2.6.4 Retire coal-fired power plants early and convert sites

Another option to cut emissions from unabated coal-fired power plants is to retire them before they reach the end of their technical lifetimes, and potentially convert the site to another use. While the technical lifetime of a coal plant is generally 40-50 years, its economic lifetime is generally 20-30 years, and this is the timescale over which capital invested is usually recovered. As coal plants age, asset owners often face decisions about whether to invest in refurbishments, and these will invariably depend on the financial prospects for the plant. These decision-making points offer major opportunities for policy makers and financial institutions to exert influence and facilitate early retirements (see Chapter 4, section 4.4.1).

Of the total existing coal plant fleet today, only one-quarter or around 520 GW will have reached 50 years of operations by 2040. Continuing operations at current levels and with current technology, i.e. no retrofits or co-firing, means cumulative emissions from the existing fleet to 2040 would be 35% higher than in the APS. If lifetimes were shortened to 40 years, then another 240 GW of capacity would be up for retirement by 2040, 80% of which is in Asia Pacific. That would mean roughly one-third of the existing fleet would be retired by then, which is similar to the amount in the APS following phase outs and early retirements of uneconomic units (Figure 2.13). If all coal plants were shut after 25 years of operations, then about 85% of the existing fleet would be retired by 2040, leaving just over 300 GW in operation in 2040. That is 50% less than in the NZE Scenario at that time: however, without changes in operations and retrofits with CCUS or to co-fire with ammonia or biomass, the related CO_2 emissions to 2040 would still be almost 30% higher than in the NZE Scenario.

Figure 2.13 ▷ Remaining capacity and cumulative CO_2 emissions from existing coal-fired power plants by assumed lifetime, 2040



Shortening the lifetime of coal plants to 40 years or less would significantly reduce the size and emissions of the coal fleet by 2040

In many advanced economies, where coal plants tend to be older, early retirement is often likely to be the pragmatic solution for plants as they near the end of their economic or technical lifetimes. Since 2010, coal power plant retirements have averaged around 25 GW each year, largely as a result of the closure of ageing plants in Europe and the United States. Declining competitiveness, increased regulation in the form of pollution limits and carbon taxes, and increased competition from renewable energy sources and natural gas have all played a part in bringing about these early retirements.

A coal power plant contains a variety of useful assets such as the boiler, the water/steam system, the cooling system and the turbine/generator, as well as equipment for handling materials. The land on which the plant is located and its grid connection are also valuable assets, as are a skilled workforce, auxiliary industry and services developed around the plant, the licence to operate and the support of the local community. These assets make coal plant sites an attractive option for a variety of electricity-related or industrial applications.

Increasing levels of variable renewables will increase demand for flexibility tools such as energy storage and ancillary services. One way to provide additional energy storage would be to replace existing coal boilers with thermal energy storage. When variable electricity supply is plentiful, and there is surplus in the system, electricity can be absorbed by a thermal storage plant and used to heat a material that will store the energy. At times of shortage in the system, the stored can then be transferred to the water in the steam generators, thereby enabling the steam turbine and generator to provide ancillary services as necessary to support grid stability.

Coal power plants can also be transformed into synchronous condensers, which provide ancillary services that help network operators maintain a reliable electricity system. Thermal generators have traditionally provided these vital services as required by the system operator, mostly as by-products of the turbines and generators of conventional thermal plants rotating in synchrony. These ancillary services include inertia to stabilise frequency, reactive power to control voltage, and system strength to manage faults and maintain voltage stability. In many cases, specific remuneration for these services was not needed because they were by-products of other activities and in abundant supply due to the prevalence of fossil fuel plants and hydropower. As clean energy transitions accelerate, these services need to be provided differently and remunerated accordingly.

Another option post retirement is to reuse the former coal plant site as a brownfield site for alternative electricity generating technologies. In Ontario, Canada, for example, a 44 MW solar facility was built on the grounds of the retired Nanticoke coal plant, making use of the existing transmission switch yard to establish the grid connection. Similar developments have taken place in other countries as well, involving renewables, battery storage or natural gas. It may also be possible for former coal plant sites to host nuclear power plants based on small modular reactor technology. A number of small reactors can be built on the site of retired coal-fired unit, allowing for the potential reuse of much of the existing infrastructure for grid connections.[3] Another alternative is to convert a coal power plant to 100% biomass. Since 2013, four-of-six units of the Drax power plant (4 GW), which was the United Kingdom's biggest coal plant and the second-largest in Europe, have been converted to run on biomass. The two remaining units will be converted in the coming years. If a 100% biomass plant were to be combined with CCUS, this could produce negative emissions.

Conversion to biomass is not without challenges. Unless the original fuel is lignite, one major change is that a larger volume of fuel is required as wood has a lower energy density than coal and its moisture content is higher, and the mass of biomass fuel needed is approximately double that of coal. Burning biomass also produces more particulate matter than burning coal. If, as in the case of Drax, wood pellets are imported, the complex logistics of importing, transporting and storing the pellets provide an additional challenge. As highlighted, it is essential that the biomass used is sustainable: among other things, i.e. addressing emissions in the supply chain and from land-use change.

As well as displacing plant workers and coal miners, the closure of coal plants damages the prospects of workers in supporting sectors and the fabric of entire communities in coal-dependent regions. Many coal-producing countries lack the resources needed to protect workers and communities, remediate impacted lands and capitalise on the economic opportunities a transition away from coal makes possible. Managing closures appropriately and successfully depends on planning for the impacts on affected workers and communities, and on repurposing and reclamation of affected land, including mines. This is likely to entail long-term engagement by various parts of government, as well as local businesses.

There is not a single blueprint for managing the retirement of coal-fired generation because a great deal inevitably depends on local circumstances and priorities. The possibility of converting coal-fired power plants to other uses should be assessed before any decision to close. Conversion enables the plant owner to retain some of the value of the existing assets while maintaining a source of jobs in the community. Conversion also contributes to the operation of the electricity system. Transitions require a range of financial mechanisms that are tailored to coal plants of different types and age, as well as to the varied market structures within which they operate (IEA, 2021b).

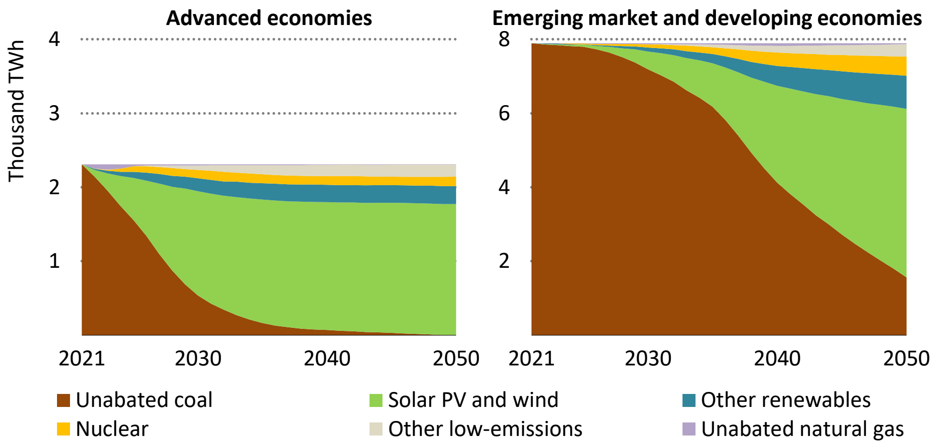
2.7 Scale up alternative sources of electricity

Replacing unabated coal-fired generation requires alternative sources of electricity to be scaled up rapidly. In the APS, global output from existing unabated coal-fired power plants is nearly 2 500 TWh lower in 2030 than in 2021, with over three-quarters of this drop in generation replaced by solar PV and wind, 11% by hydropower and other renewables, 8% by nuclear power and 1-2% each of unabated natural gas, CCUS technologies and hydrogen and ammonia (Figure 2.14). The limited role of unabated natural gas reflects the changing

[3] More information on the opportunities and challenges for nuclear power and small modular reactors in the transition to a clean energy system is provided in *Nuclear Power and Secure Energy Transitions* (IEA, 2022a).

perceptions of that fuel in light of recent market volatility and supply concerns linked to Russia's invasion of Ukraine. By 2050, generation from existing unabated coal-fired power plants is 8 600 TWh lower than in in 2021, with other technologies replacing it in roughly the same proportions as in 2030, except that CCUS makes up almost 5% of the total, having had more time to develop.

Figure 2.14 ▷ Replacing electricity generation from existing unabated coal power plants in the APS, 2021-2050

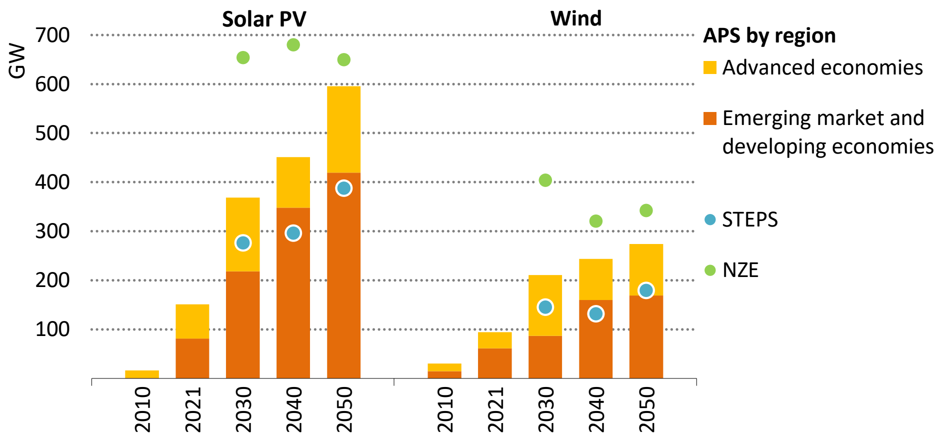


Solar PV and wind are the primary replacements for unabated coal-fired generation, complemented by a host of other low-emissions options and unabated natural gas

While the paths for the transition away from unabated coal vary between advanced economies and emerging market and developing economies, they share many elements. In advanced economies, unabated coal declines rapidly to 2030 in the APS: it is primarily replaced by wind and solar PV, with a host of other sources also playing an important role. In emerging market and developing economies, the decline of unabated coal takes several years longer to take hold: solar PV and wind play the central role in replacing it, with hydropower, nuclear power, other low-emissions sources and a small amount of unabated natural gas each also making a contribution.

Solar PV and wind power dominate the replacement of unabated coal-fired electricity generation because of their low costs and widespread availability and because of the strong policy backing they enjoy, with supportive measures in place in 156 countries as of 2021 (REN21, 2022). Building on the rapid growth of the past decade, global annual capacity additions of solar PV rises nearly 2.5-fold from 2021 to 2030 in the APS, reaching 370 GW, while in the same period wind deployment more than doubles to 210 GW (Figure 2.15). Emerging market and developing economies continue to account for the majority of solar PV and wind capacity additions, led by China, though technology leadership for offshore wind is well established in Europe.

Figure 2.15 ▷ Annual capacity additions of solar PV and wind by scenario, 2010-2050



Solar PV and wind capacity additions more than double to 2030 in the APS to replace unabated coal and meet rising electricity demand

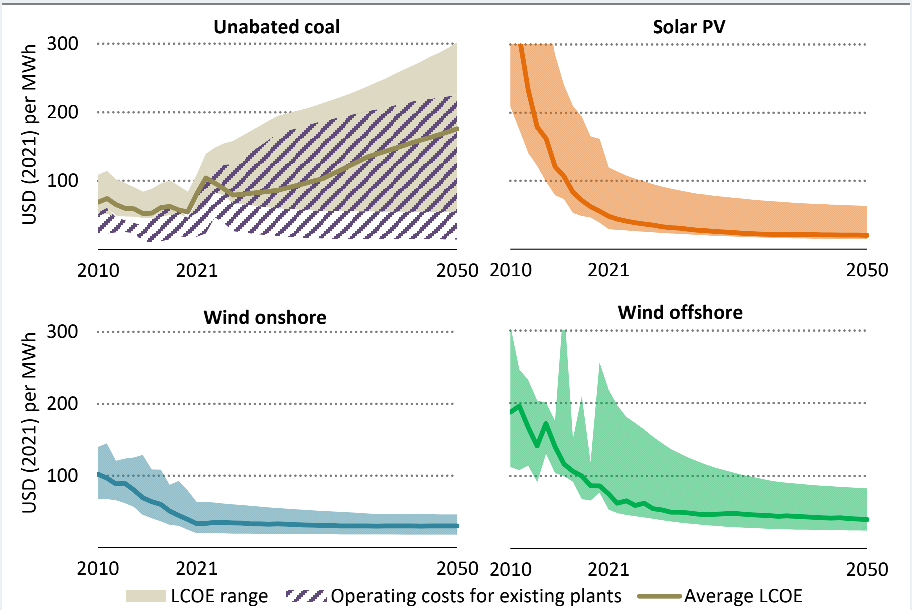
Beyond 2030, solar PV and wind markets continue to scale up in the APS, reaching 595 GW and 275 GW respectively in 2050. The NZE Scenario calls for a much faster scaling up by 2030, passing 650 GW for solar PV additions and 400 GW for wind power additions. To achieve the strong expansion of solar PV and wind in each scenario requires attention to developing robust supply chains with a diversity of market players at each stage (IEA, 2022b). In the STEPS, solar PV and wind markets continue to expand, but it takes until 2050 to reach the deployments reached by 2030 in the APS.

We estimate that the total investment required in the APS to transition away from unabated coal-fired power worldwide is about USD 6 trillion over the period to 2050, representing about half of the total investment needed to shift away from all unabated uses of coal (see Chapter 4, section 4.3). About half of the investment is in emerging market and developing economies, though this is much smaller than their share of unabated coal-fired generation because solar PV and wind projects in these countries cost about 40% less than those in advanced economies on an LCOE basis. The low costs of solar PV and wind mean that, while significant investment is needed in the APS to transition away from unabated coal, a significant portion of the necessary deployment can take place without adding to costs for electricity consumers (Box 2.1).

Box 2.1 ▷ Cheap solar PV and wind power offer opportunities to reduce coal-fired power without raising costs to consumers

Solar PV and wind are the cheapest new sources of electricity in most markets today, despite supply chain issues and temporary increases in equipment costs. The global average LCOE of utility-scale solar PV was below USD 50/MWh for projects completed in 2021, which is almost 90% below the costs in 2010 (IRENA, 2022). Onshore wind projects had an average LCOE of just USD 33/MWh in 2021 and offshore wind had an average LCOE of USD 75/MWh: both are 60-70% below their 2010 levels. Recent supply chain bottlenecks, higher commodity prices and tight financing conditions have raised the cost of new solar PV and onshore wind projects. Nevertheless, benchmark projects remain below USD 50/MWh in 2022 (IEA, 2022b), and this offers opportunities for expansion without raising power system costs.

Figure 2.16 ▷ Levelised cost of electricity for solar PV and wind compared with existing and new unabated coal-fired power in the APS, 2010-2050



Solar PV and wind power costs are lower than those of new unabated coal in nearly all cases and on a par with the operating costs of existing coal plants in many regions

Note: LCOE = levelised cost of electricity.

The costs of unabated coal-fired power plants vary widely across regions. China and India are the most significant countries in terms of new construction, and they have delivered projects with costs as low as around USD 60/MWh, with operating costs of USD 30-45/MWh (Figure 2.16). Recent market turmoil has raised market prices for imported coal and that could have an impact on future costs.

The contributions that plants make to system value are critical to evaluating both the competitiveness of a technology and its impact on overall power system costs. The LCOE does not attempt to measure these contributions, but the value-adjusted LCOE is a metric in the IEA Global Energy and Climate Model that incorporates simulated value for contributions to energy, capacity and flexibility services for each technology. This enables a more complete view to be taken of the cost effectiveness of a given technology in a specific region, year and scenario. In the APS, the value-adjusted LCOE in 2030 indicates that new solar PV and wind are able to outcompete new unabated coal-fired generation, and to compete on broadly level terms in many regions with unabated coal-fired power plants which only have to consider operating costs.

Based on projected technology costs and fuel prices, the majority of global solar PV and wind deployment in the APS to 2050 could be carried out at no additional cost to consumers compared with 2021 electricity prices. After recovering from current market disturbances, the APS sees solar PV and wind returning to year-on-year cost reductions, and coal and natural gas prices coming down from their current high levels. In this environment, new solar PV and wind (along with the grid extensions to connect them and associated grid reinforcement costs) are able to undercut the operating costs of unabated coal in several markets and to reduce costs to consumers. The case is particularly clear where CO_2 prices are in place and increasing, though less so where coal prices are set at low levels or subsidised.

Nuclear power plays a significant role in replacing unabated coal-fired electricity generation. In the APS it expands in over 30 countries that remain open to the technology. Global nuclear capacity additions average 18 GW each year from 2026 to 2030, triple the recent average of 6 GW from 2017 to 2021. China is currently the market leader for nuclear deployment, and it accounts for almost 40% of all new nuclear capacity to 2030. However, many other countries have recently announced support for nuclear or plans to invest in new nuclear projects, including France, India, Poland, United Kingdom and United States (IEA, 2022a). Beyond 2030, an average of 20 GW of nuclear capacity is added each year through to 2050 in the APS. These capacity additions include small modular reactors, which have been the subject of increasing recent interest: their smaller design, lower upfront costs and inherent safety and waste management attributes could open new opportunities for the nuclear industry, including at retired coal plant sites.

2.8 Ensure electricity security

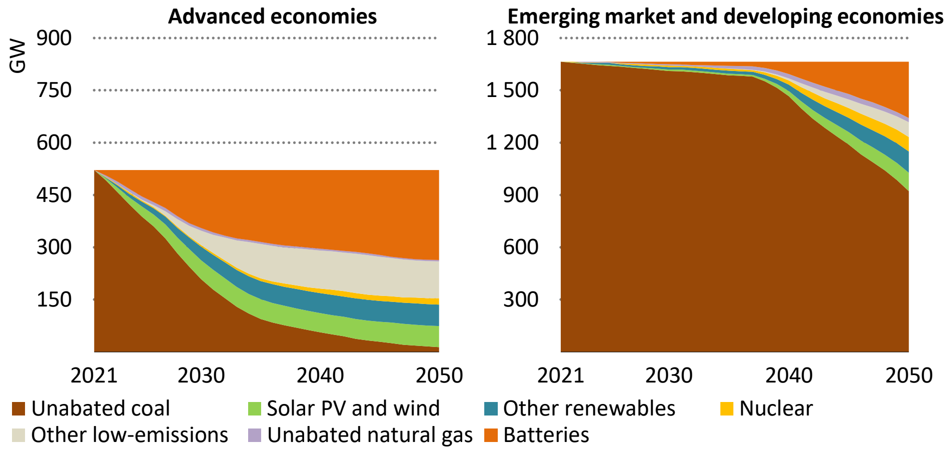
To ensure electricity security throughout transitions away from unabated coal, it is critical to replace their system services as well as their electricity output. Coal-fired power plants contribute to the adequacy of power systems by supporting the ability of available electricity supply to meet demand in all hours of a year. They also contribute to system flexibility by adjusting output in many markets in minutes or hours to match supply and demand. In addition, they support grid stability by providing inertia continuously when operating their large spinning turbines.

In the APS, the global contribution of unabated coal-fired capacity to system adequacy declines by over 40 GW per year to 2050 and is replaced by contributions from a broad suite of technologies. As the line between electricity demand and supply blurs over time, demand response becomes increasingly important in all scenarios to provide system flexibility and to reduce peak demands, thereby limiting system adequacy needs. To then meet those needs, battery storage is the primary replacement for coal, making up 45% of the total, followed by hydropower and other dispatchable renewables (15%), solar PV and wind (just below 15%), nuclear, fossil fuels with CCUS and hydrogen and ammonia (7-8% each and new unabated natural gas-fired capacity (4%). Solar PV and wind, with variable output dependent on weather patterns, contribute less to replacing coal in terms of system adequacy (as well as other system services) than to replacing electricity output from coal. Battery storage, often paired with solar PV and wind, is able to make a significant contribution to all three of the main system services. Contributions from nuclear power to electricity security are another reason for it gaining momentum; Belgium and Korea are scaling back plans to phase out existing nuclear and the United Kingdom includes plans for eight new reactors in its Energy Security Strategy.

Both advanced economies and emerging market and developing economies rely heavily on batteries to replace coal's contributions to system adequacy (Figure 2.17). In advanced economies, batteries are deployed extensively by 2030 as the unabated coal fleet is rapidly phased down, whereas emerging market and developing economies look to batteries to partially compensate for accelerating retirements of coal only by 2040. At the global level, battery storage deployment grows more than ten-fold by 2030 to 70 GW in the APS. The market for batteries continues to expand after 2030: it exceeds 160 GW in 2040 (including replacements) and 200 GW in 2050. In the NZE, battery storage expands even faster to help replace system services from coal, reaching annual capacity additions of 140 GW in 2030 and nearing 300 GW by 2040, a level broadly maintained through to 2050.

The relative importance of other dispatchable technologies to replace coal varies between advanced economies and emerging market and developing economies. Advanced economies rely more on blending hydrogen in gas-fired power plants, particularly in the United States, Japan and the European Union while emerging market and developing economies blend more ammonia in coal plants and develop more hydropower and other renewable sources. CCUS retrofits of coal-fired power plants also play a significant role in emerging market and developing economies, notably in China, and unabated natural gas is used more often to replace coal capacity and services in emerging market and developing economies than in advanced economies.

Figure 2.17 ▷ Replacing the contribution of unabated coal-fired capacity to system adequacy in the APS, 2021-2050



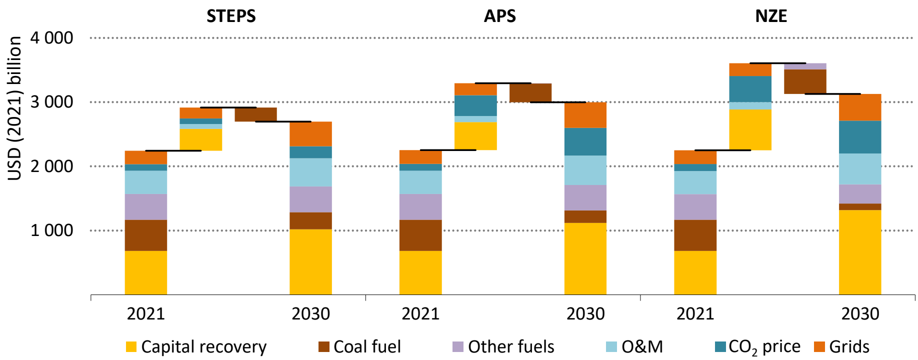
Battery storage is the primary replacement for coal's contributions to system adequacy, flexibility and grid stability, complemented by other dispatchable technologies

Note: GW (gigawatt) refers to the capacity credit associated with each technology or de-rated capacity.

2.9 Maintain electricity affordability

The transition away from unabated coal-fired power can be achieved without significant increases to costs for consumers. To meet a nearly 30% increase in electricity demand to 2030 in the APS, total electricity system costs increase by about 35%, from an estimated USD 2.2 trillion in 2021 to USD 3 trillion (Figure 2.18). A huge amount of investment is required to replace coal-fired generation, the system services from coal and the grid construction needed to support the expansion of alternative sources. These are partially offset by massive fuel cost savings that come from reduced demand for coal – the bill for coal is USD 290 billion lower in 2030 than 2021 in the APS – while other fuel costs for electricity are broadly stable. A major effort to implement energy efficiency measures also helps to moderate system costs by making the most of existing and new power plants and grid infrastructure. By 2050, total electricity system costs are double the level in 2021, though electricity demand more than doubles in the APS.

Figure 2.18 ▷ Global electricity system costs by component and scenario, 2021-2030



Electricity system costs rise in parallel with growing electricity demand, increasing by 20-40% by 2030 across the scenarios from USD 2.2 trillion in 2021

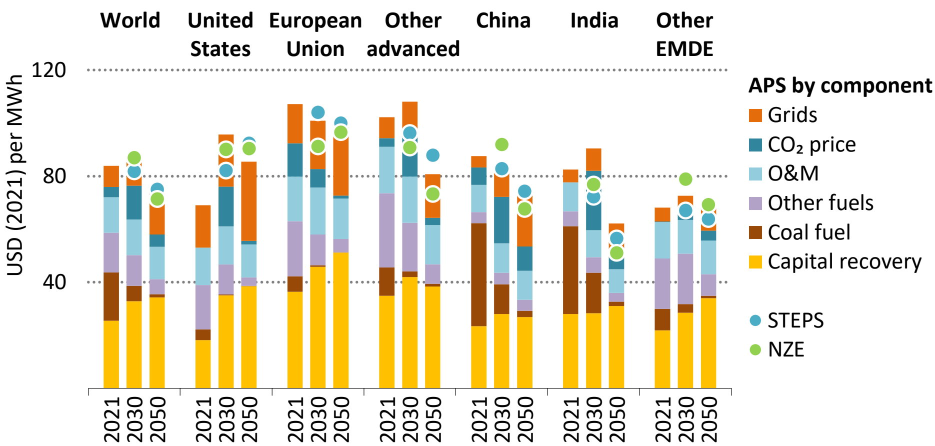
Note: O&M = operation and maintenance.

The average system cost per unit of electricity, including grids, rises from USD 85/MWh in 2021 to about USD 90/MWh in 2030 in APS, before falling to USD 75/MWh by 2050 (Figure 2.19). The cost of coal used in power plants accounts for over 20% of electricity system costs today, but this falls to less than 10% by 2030 and just 2% in 2050. Electricity systems become more capital intensive over time, with capital recovery for power plants, storage and grids rising from under 40% of system costs to 50% in 2030 and 70% in 2050 in the APS.

Compared with the other scenarios, the APS has very similar costs per unit of electricity to the STEPS through to 2050, but slightly higher than in the NZE Scenario. The APS sees more investment in low-emissions sources of electricity and grids than in the STEPS, though these are offset fully by lower fuel costs. Compared with the NZE Scenario, the slower transitions in the APS have less investment in renewables, nuclear, storage and grids, but these are offset by higher coal and other fuel costs per unit of electricity in 2030. By 2050, higher fuel and CO_2 costs per unit of electricity outweigh lower capital recovery costs, making electricity costs per unit slightly higher in the APS than the more ambitious NZE Scenario.

In the APS, total electricity system costs per unit decline from 2021 to 2050 by a few percentage points in advanced economies and about 10% in emerging market and developing economies. In the latter, coal fuel costs per unit of electricity are cut substantially by 2030, particularly in China and India, though higher investment and CO_2 costs mean that average costs per unit only start to decline after 2030. In advanced economies, the reduction of the natural gas fuel bill that is brought about by investment in low-emissions sources of electricity is the primary reason that unit costs decline, although the reduction of coal fuel costs also makes a significant contribution. In advanced economies collectively, electricity costs per unit in 2050 are the highest in the STEPS, failing to take full advantage of cheap renewables. In emerging market and developing economies, the APS is slightly more expensive than the STEPS pathway, though an increase in total electricity system costs of about USD 5/MWh in 2030 and just USD 3/MWh in 2050 needs to be weighed against all the benefits of reducing CO_2 emissions, mitigating the impacts of global climate change and enhancing energy security. Faster transitions in the NZE Scenario would cost USD 5/MWh more than the APS to 2030, but deliver the least expensive electricity in emerging market and developing economies by 2050.

Figure 2.19 ▷ Electricity system costs per unit by component, region and scenario, 2021-2050



Electricity system costs per unit of generation are set to decrease in the APS by about 10% from 2021 to 2050, with rising capital recovery costs more than offset by lower fuel costs

Notes: O&M = operation and maintenance.

Coal in industry

Between a rock and a hard-to-abate place

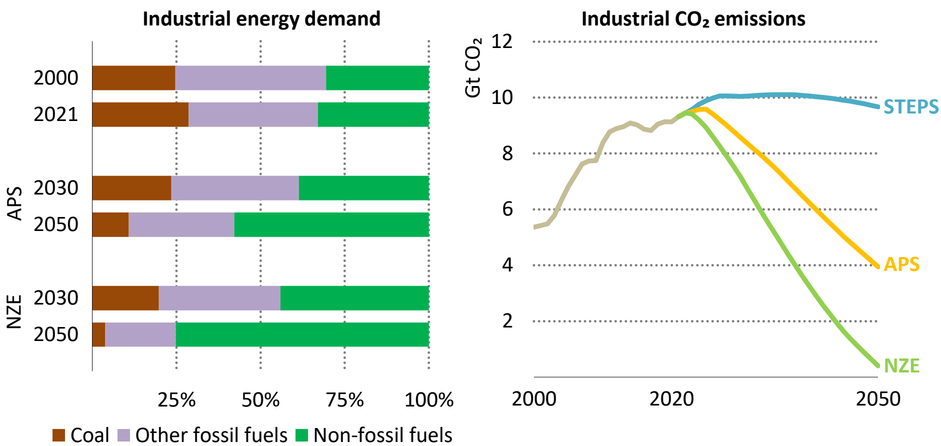
SUMMARY

- Coal use in the industry sector is old as industry itself, increasing throughout the 20th century. Coal demand in industry doubled between 2000 and 2021 to 1 630 million tonnes of coal equivalent (Mtce); China's rapid industrialisation drove this dramatic increase. Since the 1980s, industries in the United States and the European Union have reduced coal use by switching processes and fuels. Today, three-quarters of global coal demand in the industry sector is in China, India and Russia.
- Coal is the largest single source of CO_2 emissions in the industry sector at 4 gigatonnes (Gt) CO_2 in 2021. In the Announced Pledges Scenario (APS), coal emissions in industry peak this decade at below 4.2 Gt CO_2, reversing a century-old upward trend. CO_2 emissions fall 15% below their current level by 2030, and 70% below by 2050. This reflects materials and energy efficiency gains, the substitution of coal by clean energy sources and the use of carbon capture, utilisation and storage (CCUS).
- The steel and cement sub-sectors account for 70% of industrial coal consumption. If they were to continue to operate as today, existing steel plants would produce cumulative CO_2 emissions from coal of over 40 Gt by 2050, and existing cement kilns would produce 15 Gt from coal by 2050, totalling more than 10% of the global remaining carbon budget for keeping the temperature rise in 2100 below 1.5 °C. Around 60% of the steel production facilities and half of cement kilns will undergo investment decisions this decade. If all these decisions were to lead to the deployment of low-emissions technologies, this would avoid more than 35 Gt CO_2 of cumulative emissions by 2050 and minimise stranded assets.
- In the short term, materials and energy efficiency strategies are the best ways to reduce industrial emissions: in the APS, they account for 90% of CO_2 savings by 2030. Nonetheless, it is crucial to use the coming decade to develop at commercial scale the technologies that will increasingly be needed after 2030. In the APS, 21% of coal use in industry is equipped with CCUS by 2050, and some 21 million tonnes of hydrogen displace 180 Mtce of coking coal for steel production. In the Net Zero Emissions by 2050 Scenario, over half of the emissions reductions from heavy industries depend on technologies that are not yet available at scale on the market.
- An effective policy approach depends on having clear long-term goals supported by stable policy frameworks. In addition to cross-cutting measures like CO_2 prices and minimum energy performance standards, it is likely to include "push" measures to alleviate the risks of investing in near zero emissions technologies and materials together with "pull" measures to create early and secure markets for them. International co-operation is important to ensure a level playing field for low-emissions materials production in a competitive international market.

3.1 Introduction

The industry sector accounted for almost 40%, or 167 exajoules (EJ), of global total final energy consumption in 2021, and around one-quarter, or 9 gigatonnes of carbon dioxide (Gt CO_2) emissions from the energy sector (Figure 3.1).[1] Industry is the second-largest source of energy-related CO_2 emissions after the power sector, and the second-largest consumer of coal. In 2021, industry consumed 1 630 million tonnes of coal equivalent (Mtce), equivalent to 30% of world coal demand, and emitted 4 Gt CO_2. This makes coal the single-largest contributor to emissions from industry (44%), followed by industrial processes (28%), natural gas (16%), oil (11%) and non-renewable waste (1%).

Figure 3.1 ▷ Energy demand by fuel and scenario and CO_2 emissions in the industry sector, 2000-2050



Industrial coal demand must fall dramatically to meet energy and climate goals

Note: STEPS = Stated Policies Scenario; APS = Announced Pledges Scenario; NZE = Net Zero Emissions by 2050 Scenario.

Emerging market and developing economies are the primary driver of recent growth in industrial coal demand. As a country industrialises, its per capita consumption of steel, cement and other coal-intensive goods increases. Few alternatives to coal are available today to produce steel, cement and other industrial products. In cases where there may be alternative means such as the use of natural gas, they tend to be more expensive than coal in most regions. Many emerging market and developing countries are far from reaching the saturation levels of the outputs such as steel and cement that have been observed in advanced economies, so their demand for coal is projected to continue to rise rapidly.

[1] The industry sector includes final energy consumption in industry, non-energy use for chemical feedstock and energy use in blast furnaces and coke ovens. Industry CO_2 emissions include industrial process emissions.

Today, coal demand in industry is relatively concentrated among a handful of applications and countries. Two materials – steel and cement – account for 70% of industrial coal demand. Three countries – China, India and Russia – account for 75% of coal demand in industry largely owing to their substantial shares of global steel and cement production. Advanced economies, such as the United States and the European Union have seen significant declines in industrial coal use over the past half-century. This is partly due to structural shifts, for example, more steel production from scrap as opposed to iron ore, more use of natural gas, and imports in place of domestic production.

Over the past two decades, trends in coal use in industry have diverged in the major coal-consuming regions of the world. The share of coal in industry demand has decreased in North America and Europe. Only modest increases in the share of coal in industry demand are noted in Central and South America, and Africa. In contrast, coal demand in industry has been increasing rapidly in the Asia Pacific, Eurasia and the Middle East regions. China and India – current two largest coal consumers in industry – have seen significant demand increases to support their rapidly expanding industrial sectors.

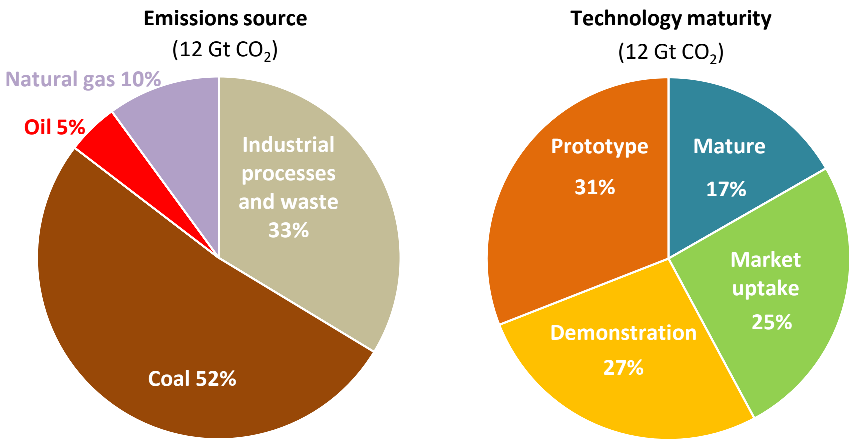
If climate goals are to be achieved, conventional technologies that use coal and other fossil fuels must transition to clean energy technologies. In our scenarios, coal is increasingly displaced with innovative technologies that significantly lower the emissions intensity of production. In addition, emissions reductions are achieved through materials and energy efficiency, fuel switching and repurposing existing assets.

In the Announced Pledges Scenario (APS), coal demand in the industry sector falls by more than 10% by 2030 and 60% by 2050, and coal-related emissions from industry fall by nearly 15% by 2030 and 70% by 2050. This primarily reflects more use of electricity and low-emissions fuels. Structural shifts in the way heavy industries – steel, cement and chemicals – produce their outputs also contributes as do improvements in materials and energy efficiency that reduce demand for all fuels.

In the Net Zero Emissions by 2050 (NZE) Scenario, CO_2 emissions from coal are virtually zero by 2050 (0.1 Gt CO_2). In the NZE Scenario, emissions fall over the next two decades as rapidly as they rose during China's ascent to become an industrial superpower in the previous two decades. Industrial carbon capture, utilisation and storage (CCUS) technologies are critical to address certain sources of industrial CO_2 emissions, with 7 Gt of cumulative emissions captured from coal combustion in the NZE Scenario by 2050.

The industry sector, in particular heavy industries, faces considerable challenges to cut emissions. Chief among them is that substantial reductions in industrial emissions from coal require technologies that are likely only to reach markets at commercial scale in the mid-to-late 2020s (Figure 3.2). While it is important to make progress to cut emissions from coal before 2030 through fuel switching and efficiency gains, it is also essential in the near term to lay the groundwork for the rapid and widespread deployment of new innovative technologies thereafter.

Figure 3.2 ▻ Emissions reductions in heavy industries by source and technology maturity in the NZE Scenario, 2021-2050



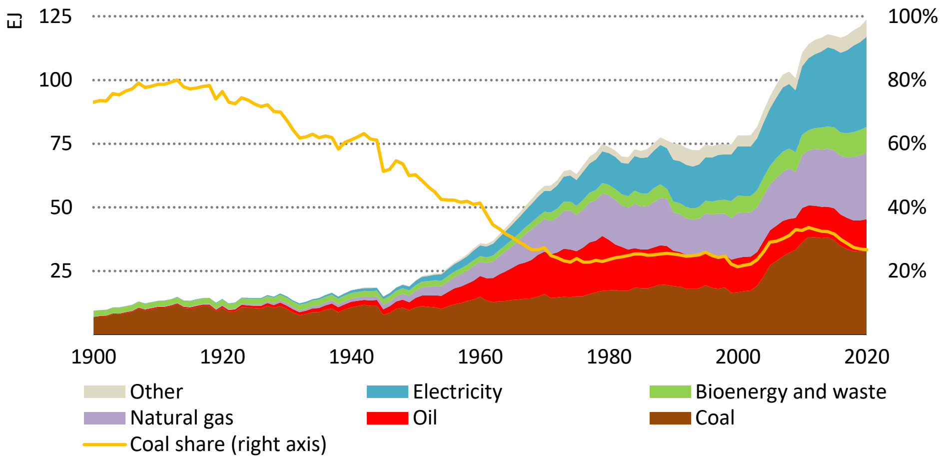
More than half the projected emissions reductions stem from technologies that are not available on the market today

In addition to economy-wide policies, such as carbon pricing, minimum energy performance standards and measures that target inefficient over-capacity, a successful approach is likely to involve measures oriented towards the supply of innovative technologies together with demand-side incentives, i.e. both push and pull measures as well as efforts to accelerate international co-operation and to enhance competitiveness. This policy toolbox is at the heart of the analysis requested by the German presidency of the G7 and presented in *Achieving Net Zero Heavy Industry Sectors in G7 Members* (IEA, 2022a).

3.2 Coal use in industry today

Industrial coal use is as old as industry itself (Figure 3.3). The first large-scale industrial uses of coal date to 18th century England and the industrial revolution, when steam engines and iron making processes began to use coal in place of wood, charcoal, work animals and human labour to provide motive power and heat. While coal was used to forge iron during the time of the Roman Empire and even earlier in ancient China, it was not until the mid-19th century and the arrival of some major industrial innovations that global coal demand began to accelerate dramatically. Henry Bessemer patented the first cost-effective industrial steel making process in 1865; Thomas Crampton did the same for Portland cement in 1877, and Charles Hall for aluminium in 1886. Coal, and later coke, were key enablers of these early industrial applications, providing an abundant supply of affordable fuel that was capable of providing the required high temperatures.

Figure 3.3 ⊳ Final energy consumption in industry, 1900-2020



Coal has been an important part of the energy mix in industry for more than a century and remains so today despite increasing shares of natural gas, oil and electricity

Notes: EJ = exajoules. Industry final energy consumption in this figure excludes energy use in blast furnaces and coke ovens, and non-energy use for chemical feedstock due to data unavailability prior to 1971.

Sources: IEA (2022b) and IIASA (2022).

Coal use in industry pre-dates its widespread use for electricity generation, which is its leading use today. While the use of coal in transport was largely displaced by oil during the 20th century, many of the same industrial commodities and processes commercialised two-three centuries ago, albeit substantially modified, drive industrial coal demand today. While the inception of the modern chemical industry in the early 1900s led to dramatic growth in natural gas, oil and electricity use, no wholesale substitutions for industrial coal use have emerged, particularly in key applications such as iron and steel production. The rise of emerging market and developing economies, particularly since the turn of the millennium, has increased industrial demand for energy, and led to an increase in the share of coal in final energy consumption in the industry sector from a century low point of 25% in 2000 to almost 30% in 2021. These factors, combined with its low cost and wide availability underpin the continuing role of coal in the industrial energy mix.

3.2.1 Regional trends

Worldwide coal demand in the industry sector doubled (+770 Mtce) over the past two decades, outpacing the increase in overall industrial energy demand.

China alone accounts for 80%, over 600 Mtce, of the increase in coal demand in industry since the turn of the millennium – its current level of demand eclipses that of all other countries combined. On average between 2001 and 2010, China installed more than three average-size steel plants and over thirteen cement factories per month. Never before in history has a country added so much industrial capacity in such a short period of time. China today produces 53% of the world's steel and 55% of cement, up from 15% and 36% respectively in 2000. While a portion of China's production serves export markets, the vast majority of its steel and cement production is for domestic consumption (Table 3.1). Although India's industrial coal demand is only one-sixth of China's, it is the world's second-largest consumer of coal in industry.

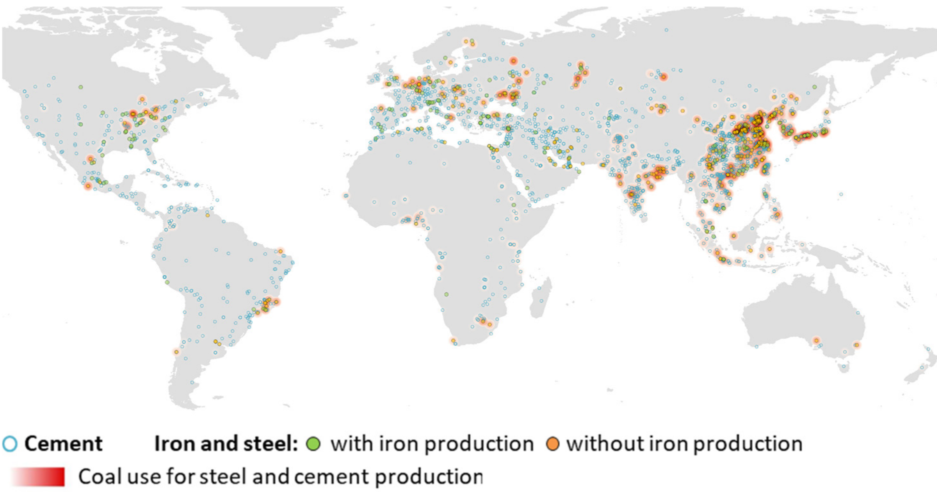
Table 3.1 ▷ Key indicators of coal consumption in industry by region

	Coal demand in industry (Mtce)		Coal share of industrial energy demand		Crude steel production (Mt)		Cement production (Mt)	
	2000	2021	2000	2021	2000	2021	2000	2021
World	**845**	**1 629**	**25%**	**29%**	**849**	**1 952**	**1 662**	**4 270**
North America	71	40	10%	6%	134	117	135	156
United States	62	30	11%	6%	102	86	90	92
Central and South America	20	22	11%	9%	40	46	89	150
Brazil	14	15	14%	11%	28	36	39	65
Europe	147	94	20%	15%	244	230	293	301
European Union	90	55	17%	12%	178	153	222	177
Africa	19	23	21%	17%	13	21	73	212
South Africa	14	14	43%	41%	8	5	8	15
Middle East	2	5	2%	2%	10	46	69	188
Eurasia	44	82	16%	25%	64	81	39	90
Russia	35	73	15%	26%	59	76	32	56
Asia Pacific	542	1 362	41%	42%	342	1 411	964	3 174
China	349	975	63%	48%	128	1 034	598	2 365
India	47	166	30%	39%	27	118	95	330
Japan	63	54	28%	31%	106	96	81	52
Southeast Asia	18	84	14%	29%	10	50	92	265

Note: Mtce = million tonnes of coal equivalent; Mt = million tonnes.

The use of coal in industry is highly concentrated in the main steel and cement producing economies. Steel production takes place in virtually all the world's major economies, but just a handful of countries account for the vast majority of the coal-intensive steel producing assets. China, India, Japan, Russia, and Korea together account for more than 80% of global pig iron production, an intermediary product produced almost exclusively using coal (Figure 3.4). Some countries, for example the United States and Italy, produce large amounts of their steel from scrap, typically in electric furnaces. These facilities are much less coal-intensive than those that produce steel from iron ore, and also tend to be smaller and more geographically dispersed. Facilities that produce steel from iron ore tend to be large and located around supply hubs for their main material inputs (coking coal and iron ore). Nearly all the facilities in China and India, for example, are of this type. A single modern blast furnace produces 2-3 million tonnes (Mt) of pig iron per year, and many sites have multiple blast furnaces (IEA, 2022a). The POSCO Gwangyang steel plant in Korea is the largest facility in the world with a total crude steel production capacity of around 23 Mt (1% of the global total).

Figure 3.4 ▷ Global distribution of coal-intensive industrial plants



Coal-intensive industrial capacity is heavily concentrated in Asia, Europe, Russia and North America; China produces almost 55% of the world's steel and cement combined

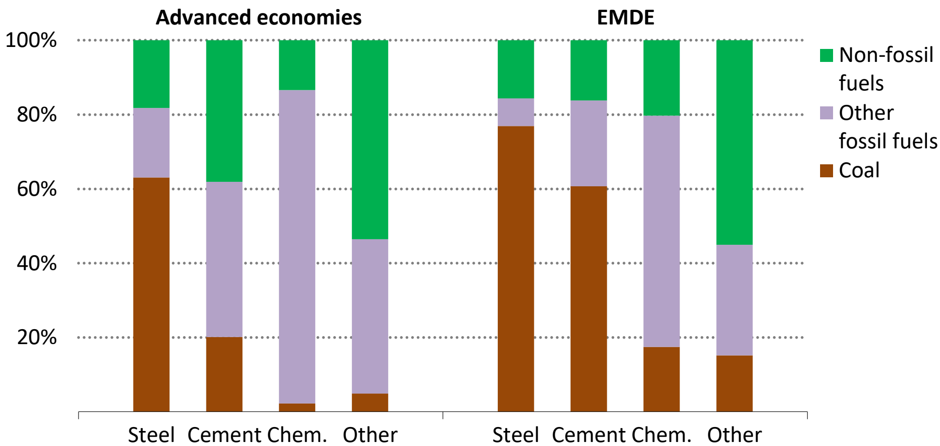
Sources: Global Energy Monitor (2022) and Global Cement (2022).

Around 4.3 billion tonnes of cement were produced in 2021. Large volumes are required for its main applications for building construction and infrastructure, and transportation costs are relatively high compared with production costs. Cement plants tend to be located close to the point of use, often in cities and near big infrastructure projects, or close to limestone quarries where the main material input is extracted. They also tend to be relatively small: global clinker production capacity totals around 3 700 Mt, and a single cement kiln typically produces anywhere between 0.1 and 3 Mt of clinker per year. As a result, there are many more cement plants that use coal, or have the potential to, than steel plants. The United States is an instructive example, where cement plants are widely distributed across the country, while coal-based steel production is highly concentrated in the Midwest and Northeast regions.

3.2.2 Coal-intensive industrial applications

Steel and cement together account for 70% of global coal demand in the industry sector. Coal accounts for three-quarters of energy inputs to the iron and steel sub-sector, and 55% of those to the cement sub-sector (Figure 3.5). Both steel and cement can be made using other fuels, but generally coal is used in most countries because it is abundant, easy to use and comparatively cheap.

Figure 3.5 ▻ Coal use in industry by sub-sector, 2021



Industrial coal use is heavily concentrated in the steel and cement sub-sectors, and in emerging market and developing economies

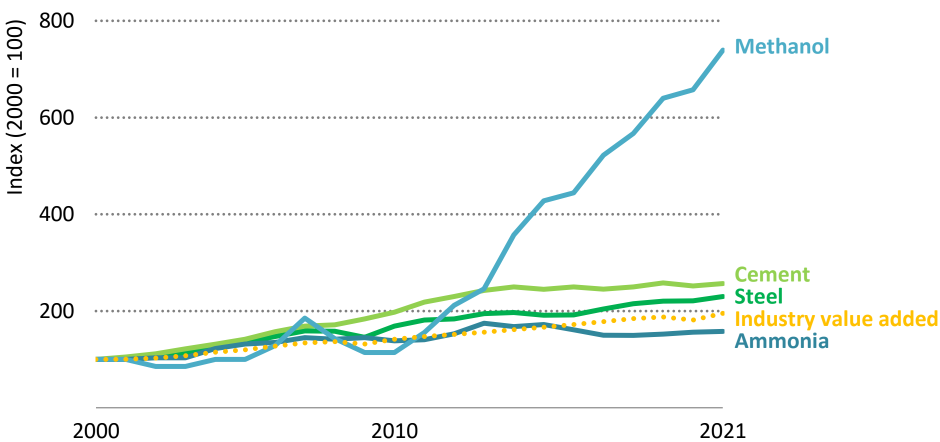
Note: EMDE = emerging market and developing economies; Chem. = chemicals.

Steel can be produced from scrap, or a mixture of iron ore and scrap. When steel is produced solely from scrap, very small quantities of coal and coke are used, mainly to regulate the carbon content of the steel product and assist with slag forming in electric furnaces. When it is produced mainly from iron ore, the ore needs to be chemically reduced before the iron it contains can be used for steel making, and coal and coke are the main sources of the carbon required. Around 70% of global steel production makes use of iron made in blast furnaces, and the vast majority of these use coal. In countries with low cost natural gas, such as Russia, United States and countries in the Middle East, blast furnaces are injected with natural gas instead, although some coke made from coal is still needed. Around 8% of global steel production uses direct reduced iron (DRI) instead of iron from blast furnaces. DRI can be produced in furnaces fuelled by natural gas or coal, depending on the furnace design. The Middle East accounts for the largest share of DRI production globally (26%), and virtually all is based on natural gas. India accounts for 25% of steel production from DRI and the majority of its plants use coal.

Demand for steel has more than doubled since the turn of the millennium (Figure 3.6). Most of this growth is from emerging market and developing economies for buildings and infrastructure – the two prominent end-uses for steel. In 2020, the Covid-19 pandemic caused significant disruption to global steel production, with plants in India, Japan and United States seeing particularly sharp reductions in output. Russia's invasion of Ukraine in early 2022 led to a fall in crude steel production in Ukraine of around 85%. Turbulence in global energy and commodity markets as a result of the invasion has led to soaring prices, including for metallurgical coal (Box 3.1). This is supressing global demand as end-use consumers, including governments, put off purchases and projects. Monthly global crude steel production in the first-half of 2022 was 6% lower than in the first-half of 2021.

Cement is produced in kilns, most of which are designed to use coal to provide heat. Portland cement is made using limestone which is ground and heated along with a mix of silicon, aluminium and iron to around 1 500 °C. Coal, natural gas, oil, bioenergy and waste are the main fuels used to produce this heat, but coal accounts for the largest share (62%) worldwide. While individual cement kilns can be adapted to consume a wide range of fuels, they generally cannot switch quickly between solid, liquid and gaseous fuels. Kilns set up to use solid fuels typically have a wider range of fuels available due to the varying composition of waste streams and bioenergy. As with steel, natural gas tends to be used for cement production in regions where it is available at low cost. Demand for cement has risen two-and-a-half-times since the turn of the millennium, with demand growth mostly for buildings and infrastructure in emerging market and developing economies.

Figure 3.6 ▷ Drivers of coal demand in industry, 2000-2021



Steel, cement and coal-based chemicals are the key drivers of industrial coal demand

Note: Ammonia and methanol include only coal-based production of these two materials.

Ammonia and **methanol** – two of the most energy-intensive large volume outputs of the chemical industry – are produced using coal, which serves both as raw material input or feedstock and as a source of the heat required to transform the feedstock. Ammonia is the starting point for all mineral nitrogen fertilisers, which account for around 70% of total demand for ammonia. The remaining 30% is for a wide range of industrial applications, including explosives, synthetic fibres and specialty materials. Methanol is used mainly as an intermediary product to make other chemicals. Its largest derivative by volume is formaldehyde, which is in turn used to produce a number of resins used by the construction, automotive and consumer goods industries. Several fuel applications also use methanol directly or after conversion to another compound, for example methyl-tert-butyl ether.

The use of coal for ammonia and methanol production is highly concentrated in China, which accounts for 95% of global coal-based ammonia and 99% of global coal-based methanol production. Coal is used in China as an alternative to conventional oil-based routes, i.e. steam cracking of naphtha and ethane, in the production of methanol, which serves as an intermediate product to make high value chemicals (key chemical precursors for producing plastics). The ability to produce these chemical products from coal forms an important component of China's strategy to increase industrial output without adding further to oil imports, and coal is therefore viewed as an important commodity in terms of energy security. Coal-based ammonia production in China has increased by 60% since 2000, and that of coal-based methanol has increased 35-times. The increase in the use of coal to produce these two commodities in China since 2000 is equivalent to the total current coal consumption of Latin America.

Other energy-intensive and **light industries**[2] also use coal. In these sub-sectors, coal is mainly used in furnaces, boilers and reactors for heating, drying and raising steam, where it often competes directly with natural gas, and to a lesser extent oil products, bioenergy and electricity. Countries that are coal-intensive overall tend to see higher shares of coal use in these applications where multiple fuel options exist (see Chapter 1).

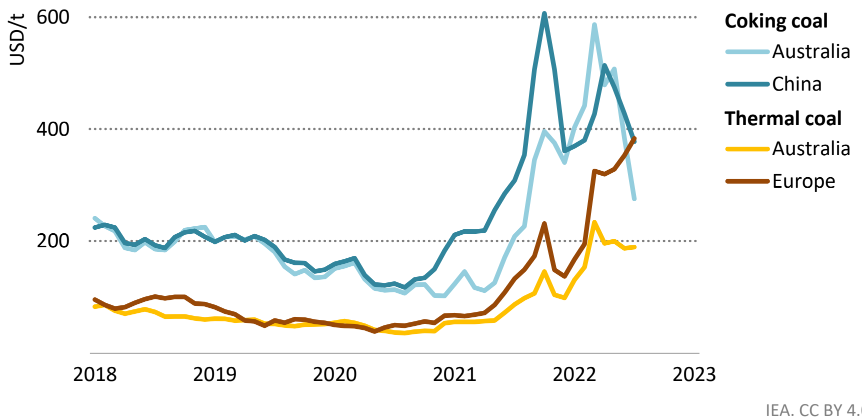
Box 3.1 ▷ Inverted markets for thermal and coking coal

Coking coal, which is mostly used to produce coke for the steel industry, typically commands a higher price per tonne than thermal coal, which is mainly used to produce heat (Figure 3.7). Before the recent turmoil in global energy markets caused by Russia's invasion of Ukraine, a buyer could typically expect to pay more than twice as much for coking coal as for thermal coal. This is because coking coal must meet higher quality specifications, including in terms of calorific value, and is less widely available around the world than thermal coal.

[2] Other energy-intensive industries include aluminium and paper production. Light industries include the construction, mining and quarrying, food and tobacco, transport equipment, machinery, wood and wood products, textiles and leather sub-sectors.

Coking coal prices fell in the first-half of 2022, due in part to weak demand in China, where steel demand is around 6% lower than in 2021. Demand for thermal coal meanwhile rose sharply as a conjunction of switching from natural gas to coal in reaction to concerns about high prices and the outlook for natural gas, suspension of coal exports in Indonesia and European sanctions on Russia. This led to an unprecedented inversion of international prices for coking coal and thermal coal in June 2022. Adjusting for the difference in energy content, coking coal was discounted by 30%, meaning a thermal coal user could potentially get more energy for their money by buying coking coal. It is expected that this price inversion is a temporary phenomenon and will correct itself in the coming months.

Figure 3.7 ▷ International coking and thermal coal monthly prices



In June 2022, prices for thermal coal rose above those of coking coal for the first time

Notes: Coking coal benchmarks: Australia refers to Metallurgical Coal API C1 index (premium hard, low-volatile) free on board. China refers to Metallurgical Coal API C8 index (premium hard, low-volatile) cost and freight. Thermal coal benchmarks: Australia refers to Coal API 5 index free on board. Europe refers to Coal API 2 index cost insurance and freight.

3.3 Key measures to address coal emissions from industry

Emissions from coal and other sources in industry will need to fall dramatically if the world is to achieve the climate change goals of the Paris Agreement. The world will continue to need vast quantities of industrial commodities like steel and cement. Moreover, these materials will play an important role to enable the transition of other parts of the energy system, for example by providing steel for wind turbines. It is therefore vital to find ways to reduce emissions from their production.

Fortunately, an array of measures are available to mitigate emissions from the industry sector, most of which apply not just to coal but to all sources of CO_2 emissions. While many of these strategies and technologies have elements that are specific to each sector, they can be considered in three broad categories:

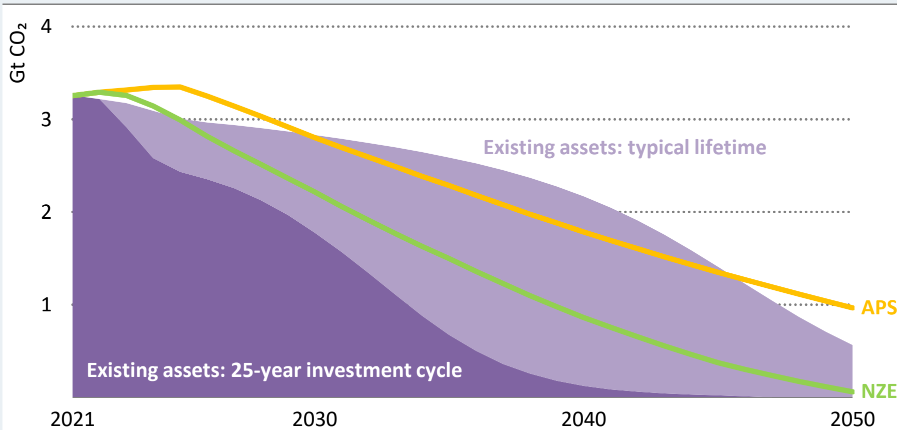
- **Cross-cutting measures** that apply across all timeframes and geographies, such as materials efficiency strategies.
- **Measures to tackle emissions from existing assets** using currently available technologies, including incremental energy efficiency measures and various kinds of fuel switching.
- **Innovative technologies** not yet available on the market that need to be developed and deployed in both new and existing industrial facilities.

The timing of investment cycles is an important factor in weighing the latter two categories of mitigation options.

Box 3.2 ▹ Investment cycles in heavy industries

For heavy industries, the year 2050 is just one investment cycle away. Average lifetimes for emissions-intensive industry sector assets such as blast furnaces and cement kilns are around 40 years. After about 25 years of operation, plants often undergo a major refurbishment to extend their viability.

Figure 3.8 ▹ CO_2 emissions from coal use in heavy industries from existing assets, 2021-2050



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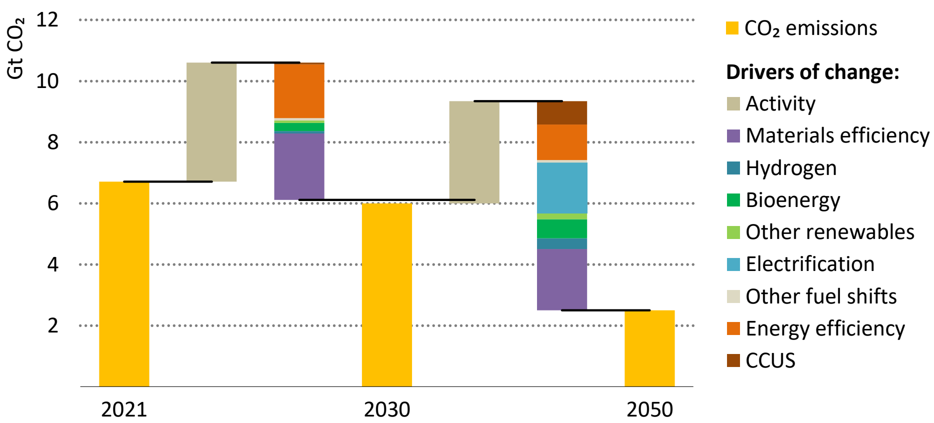
Intervening at the end of the 25-year investment cycle could help unlock over 36 Gt CO_2 emissions from coal, over 55% of emissions from current heavy industry assets

The challenge is to ensure that innovative near zero emissions industrial technologies that are at the large prototype and demonstration stage today reach markets within the next decade. That is when around 60% of steel plants and 50% of cement plants worldwide will have reached 25 years of age and thus face investment decisions. If these innovative technologies are not ready to be deployed rapidly at commercial scale within the next decade, the existing assets in question will continue to produce emissions at around their current level until the end of their working life or they will at some stage become stranded assets. Conversely, if they are ready, and if existing plants are retrofitted with them or replaced by them at the 25-year investment decision point, this could reduce projected cumulative emissions to 2050 from existing heavy industry assets by more than 55% (Figure 3.8). The critical window of opportunity from now to 2030 should not be missed.

3

Materials efficiency strategies are no-regret options that offer the prospect of meaningful progress to reduce industrial emissions to 2030. Some materials efficiency strategies reduce the amount of material required without affecting the quality of the product involved or the service it provides. These strategies include light weighting, life extensions of buildings and infrastructure, modular designs to facilitate disassembly, yield improvements and direct reuse of materials without remanufacturing. Other materials efficiency strategies require adjustments to the way materials are produced. These strategies include increases in secondary material production, e.g. steel, aluminium and plastics, and decreases in the clinker to cement ratio. Virtually all of these strategies can be implemented using conventional technologies, meaning that action can be taken now. In the APS, materials efficiency strategies account for almost half of the emissions reductions to 2030 and 30% of reductions from 2030 to 2050 (Figure 3.9).

Figure 3.9 ▷ Emissions reductions in industry by mitigation lever in the APS



Materials and energy efficiency account for 90% of emissions reductions to 2030

The **adoption of best available technology** can help reduce coal and other industrial energy consumption and associated emissions. Waste heat recovery, increased process integration, predictive monitoring and maintenance processes are all examples of technologies widely available today that can improve energy performance, increase reliability and reduce emissions. It is important to acknowledge the trade-off between investments in equipment that deliver incremental energy efficiency improvements and those in technologies that can achieve substantial cuts in emissions intensity. It may be strategic to extend the lifetime of existing assets by a few years through efficiency measures with a short payback period, especially while innovative technologies are still developing, but it is also important to give careful consideration to the case for investments in the technologies required post-2030, weighing the emissions savings against longer payback periods. In the APS, energy efficiency improvements account for 40% of the emissions reductions from now to 2030, and less than 20% from 2030 to 2050.

Fuel shifts can yield reductions in emissions using conventional technologies. These shifts include switching from coal to electricity, bioenergy and other renewables and in some circumstances to natural gas. Some fuel shifts can be implemented with little or no need for modifications to a given piece of process equipment, for example, firing biomass in a cement kiln to displace coal. In other instances, a change of process unit and/or input material is required, for example, using an electric furnace to produce steel from scrap as opposed to a blast furnace and basic oxygen furnace fuelled with coal and fed with iron ore. Combined, these fuel shifts account for 10% of the emissions reductions in the APS from now to 2030, and almost 40% from 2030 to 2050.

The use of **hydrogen** and **CCUS technologies** account for the remainder of the emissions reductions from industry in the APS. These technology portfolios offer applications for industry that range from the use of electrolytic hydrogen for ammonia, methanol and DRI production to pre- and post-combustion carbon capture arrangements for cement kilns and steel making furnaces. Most of these technologies are still at relatively early stages of development, which explains the modest role of hydrogen and CCUS in delivering emissions mitigation to 2030: together they account for less than 5% of the reductions in the APS by 2030. But the importance of these technologies is underscored by their growing role in later years: they account for over 15% of the reductions between 2030 and 2050, when many of the other mitigation options have limited scope to deliver further reductions. The pace of deployment of innovative technologies is the main factor that differentiates the NZE Scenario from the APS, with 13% of emissions reductions between now and 2050 attributed to hydrogen and CCUS in the NZE Scenario compared with 11% in the APS.

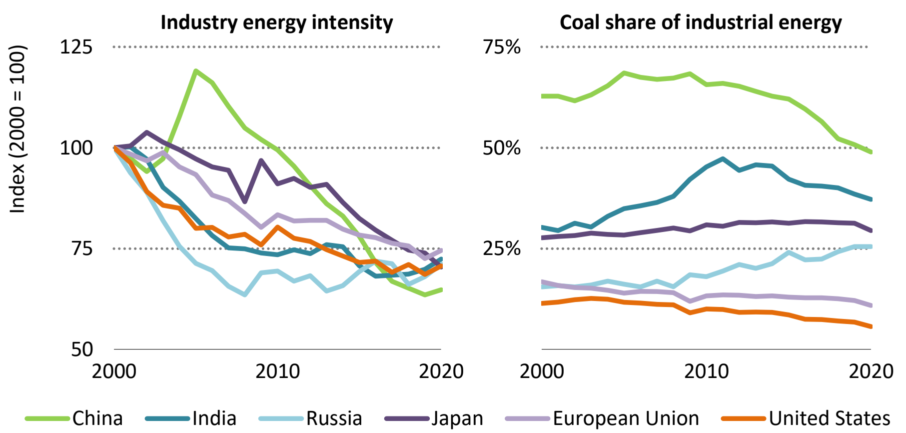
SPOTLIGHT

How much has energy efficiency and fuel switching tempered demand for coal in industry?

Increases in energy efficiency over time in the industry sector have tempered rising demand for coal and other fuels. While detailed data on the performance of individual classes of equipment are limited, macro-level indicators indicate significant efficiency gains in the major coal-intensive industrial economies. The global energy productivity of industrial value added improved from USD 4.5 per megajoule (MJ) in 2000 to USD 4.0/MJ in 2020.

China's industrial boom initially produced a sharp rise in the energy intensity of industrial value added, but since 2005 it has fallen dramatically (with the exception of 2020). In absolute terms, China's industrial sector is still one of the most energy-intensive among countries with major industrial sectors because it accounts for a high proportion of the global production of energy-intensive commodities.

Figure 3.10 ▷ Energy intensity of industry and coal share of industrial energy consumption by region, 2000-2020



Substantial efficiency gains in all major industrial coal-consuming countries have been offset by increases in the rising share of coal use and growth in industrial output

Notes: Industry energy intensity is final energy consumption in the industry sector divided by gross value added by industry in purchasing power parity terms.

A number of other major industrial coal consumers – European Union, India, Japan and United States – have seen similar efficiency improvements over the past two decades, with the energy intensity of industry value added falling by 26-30% between 2000 and 2020 (Figure 3.10). Russia is an exception: its industrial energy efficiency improved in the early 2000s, but the past 10-15 years have seen efficiency improvements in Russia stagnate, and the energy intensity of industrial value added actually rose slightly during this period.

Alongside improvements in efficiency, the industry sector has seen significant shifts in coal use. The share of coal in global industrial energy rose from 25% in 2000 to 35% in 2011 before falling to 29% by 2020 (Table 3.2). The European Union and the United States have undergone a progressive shift away from coal use in industry, with their shares of the global total falling by 35% and 50% respectively over the past two decades. This is due in part to larger shares of industrial value added being generated over time from less coal-intensive industries such as chemicals and light industries, and in part to a shift to the use of electric furnaces fed with scrap for steel making. By contrast, Japan's share of coal in industrial energy consumption has risen, largely due its continued reliance on the blast furnace - basic oxygen furnace method of steel production, and further coal use in the chemical and pulp and paper sub-sectors. China and India still have the most coal-intensive industrial sectors in the world today, but have started to diversify their fuel inputs over the past decade as their portfolio of industrial assets evolves and matures.

Table 3.2 ▷ Key metrics for the coal intensity of steel and cement production

	Electric furnace share of crude steel production		Coal share of cement sector energy inputs	
	2000	2020	2000	2020
World	**34%**	**26%**	**50%**	**55%**
Advanced economies	38%	44%	32%	20%
United States	45%	71%	33%	22%
European Union	39%	43%	17%	7%
Japan	27%	25%	43%	45%
Emerging market and developing economies	27%	20%	59%	61%
China	18%	10%	79%	73%
India	39%	55%	68%	54%
Southeast Asia	84%	50%	64%	75%

Sources: Steel process route shares from World Steel (2022); coal share of cement sector energy inputs from IEA (2022b) and Global Cement and Concrete Association (2022).

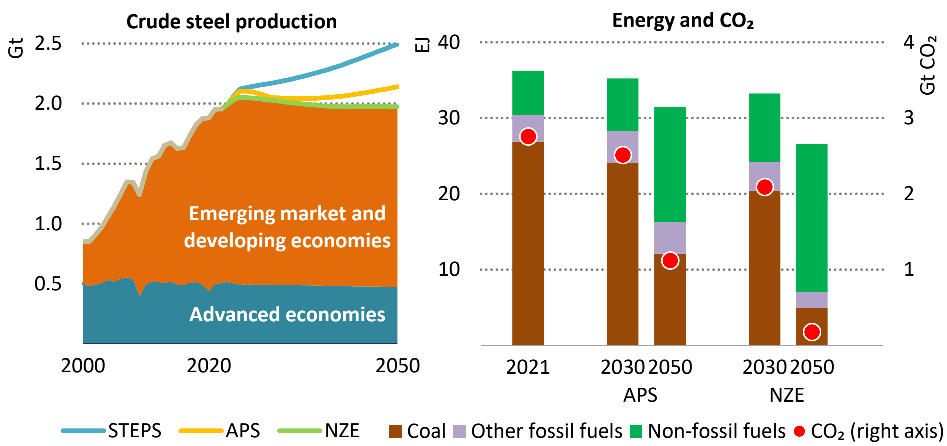
3.3.1 Reduce coal-related emissions in the iron and steel industry

This section explores the various abatement options in the iron and steel industry. The main options are measures to: reduce demand; cut emissions from existing assets; and to use innovative technologies to reduce or avoid CO_2 emissions.

The steel industry accounts for 6% of global energy demand and contributes almost 8% of total energy system CO_2 emissions. It is the single-largest user of coal in industry, accounting for 16% of global coal demand and for more than 90% of coking coal demand. Coal and coke are used primarily as chemical reduction agents to separate the oxygen from the iron oxides that make up iron ore. While steel produced from scrap in an electric furnace can almost eliminate the need for coal and coke, all steel production from iron ore today requires some form of carbon as a reduction agent, whether sourced from coal (the vast majority), natural gas or charcoal.

In the STEPS, total energy consumption in steel production peaks before 2030 and is still around 5% higher than today by 2050. Coal demand peaks as well but is 10% lower in 2050 than it is today: the reduction in demand to 2050 reflects an increase in the availability of scrap and a rise in steel production that uses scrap in electric furnaces. CO_2 emissions from iron and steel climb from 2.7 Gt today to around 3 Gt in the second-half of the 2020s and then slowly decline, with CO_2 emissions 4% lower than today by 2050 (Figure 3.11).

Figure 3.11 ▹ Steel production by region and scenario, and energy demand and CO_2 emissions by scenario



Rapid deployment of clean energy technologies facilitates a shift away from coal in the APS, with iron and steel CO_2 emissions falling by 60% by 2050

In the APS, the combined effect of materials and energy efficiency gains, fuel switching, rapid deployment of innovative technologies and increased use of scrap in electric furnaces for steel making results in a fall in coal demand in the iron and steel sub-sector from 920 Mtce today to 820 Mtce in 2030 and 410 Mtce in 2050. Iron and steel-related CO_2 emissions fall almost 10% from current levels by 2030 and 60% by 2050.

In the NZE Scenario, the pace of innovative technology deployment is more than twice as fast as in the APS. This leads to a reduction in current emissions from iron and steel production of more than 20% by 2030 and more than 90% by 2050.

Materials efficiency and increased scrap use

Demand for steel can be broadly divided into four end-uses: construction, vehicles, machinery and consumer goods. The largest share of demand tends to be from the construction sector, which includes buildings and infrastructure such as bridges, power plants, pipelines and sanitation systems. Construction accounts for about half of total end-use demand globally and nearly 70% of the steel actually in use: the difference between the demand and in-use figures arises because buildings and infrastructure tend to have longer lifetimes than other products made from steel. Although difficult to estimate accurately, the amount of steel in use today is thought to be around 4.5 tonnes per capita. In advanced economies this figure tends to level off at around 10-15 tonnes per capita (Pauliuk, Wang and Müller, 2013). In the world's poorest countries, the figure is less than 0.5 tonnes per capita today.

Demand for steel is expected to continue to rise in the years ahead, particularly in emerging market and developing economies. During the early stages of economic development, countries typically require large amounts of steel to build infrastructure. As the in-use stock of steel accumulates in buildings, vehicles and so on, demand gradually shifts from the acquisition of new goods containing steel to the maintenance of the installed inventory of steel products, or in-use stock. In the STEPS, crude steel production rises 10% by 2030 and 30% by 2050. Emerging market and developing economies account for almost 90% of the growth in production between 2021 and 2030, though output is projected to fall significantly in China in the coming decades following its rapid industrialisation over the past two decades.

Much can be done to reduce this projected demand increase, thereby easing pressure on clean technology deployment. In the APS, steel production in 2050 is nearly 15% lower than in the STEPS, and only 10% higher than in 2021. These reductions are driven by a variety of materials efficiency strategies and shifts in demand at different stages along the steel value chain. The key elements are lifetime extensions in end-uses such as buildings and vehicles, direct reuse of steel products without remelting, improved design to enable lighter products that can be disassembled more easily for reuse or recycling, improved manufacturing yields, reduced end-use demand due to behavioural changes, such as car sharing or cycling. These make a real difference in the medium term: lifetime extensions of buildings alone save 50 Mt of steel by 2030 compared to the STEPS. In the NZE Scenario, a further reduction in demand for steel of almost 10% by 2050 stems from the universal adoption of materials efficiency strategies in all regions, not just those with net zero emissions pledges.

Increasing the use of scrap in steel making is of critical importance to reduce emissions with existing technology. Scrap can be used without any major alteration to the equipment in integrated facilities – both blast furnace and DRI facilities – and in fully scrap-based electric furnaces. However, the use of scrap faces practical limits, given the need to maintain sufficiently high temperatures in each process unit, particularly in basic oxygen furnaces. In the APS, the share of scrap in total metallic inputs to steel making rises from around 30% today to 35% in 2030 and 45% in 2050. These relatively modest increases reflect the fact that, although the availability of scrap is projected to increase, scrap is finite and already among the most recycled materials in the world. They also reflect a reduction in overall demand for steel as a result of the impact of materials efficiency strategies.

It is difficult to isolate the impact of materials efficiency strategies and increased scrap use on coal demand and emissions, given the interlinkages and interdependencies of the various processing steps. However, the facts are that one tonne of steel consumes around ten-times more energy if made mainly from iron ore (21.4 gigajoules on average) than if made from scrap, using the best available technology. On average, switching a tonne of iron ore-based production to scrap-based production saves almost 480 kilogrammes (kg) of coal equivalent and around 0.6 tonnes of CO_2. Reducing steel demand by one tonne by adopting materials efficiency savings cuts slightly more energy and emissions.

Coal use in existing iron and steel industry assets

The iron and steel industry is characterised by a very large fleet of capital-intensive, long-lived assets. Iron making is the most coal-intensive step in steel production, and the process units involved (blast and DRI furnaces) are often the assets that guide investment decisions about the steel production facility as a whole. The global stock of steel plants is relatively young. An estimated 90% of steel making production capacity in the European Union is more than 20 years old, and the equivalent figure for the United States is around 80%. However, plants in Asia are much younger, with China's stock – which comprises around half of global steel production capacity – at just 16 years old on average. If operated until the end of a typical lifetime for these facilities, around 40 years on average, the current global fleet would give rise to more than 40 Gt CO_2 emissions cumulatively over its lifetime. The next investment cycle constitutes an important opportunity to intervene and reduce emissions without locking in another wave of capacity investments (Box 3.2). But there are various strategies and technologies that could mitigate emissions from existing assets before they are retrofitted or replaced – a change that takes place from the late 2020s in the APS and the NZE Scenario. There is scope to increase energy efficiency across a number of process units in the iron and steel industry, although it will be important to ensure that the payback period required does not delay more substantial emissions reductions being achieved by switching to innovative technologies. Cross-cutting examples include the application of waste heat recovery to steel production furnaces, increased process integration to reduce demand for fuel for pre-heating, and predictive process control and monitoring to reduce unscheduled (and inefficient) downtime. Coke dry quenching can recover the latent heat from the hot coke output of coke ovens and use it to generate electricity, while also reducing total coke oven fuel consumption. Similarly, blast furnaces can be installed with top-pressure recovery turbines that use the pressure and heat of the blast furnace gas for electricity generation. In the APS, the adoption of these and other best available technologies leads to a decrease in overall energy intensity in the iron and steel sub-sector of 7% by 2030.

There is also scope to achieve emissions reductions through fuel switching and other operational changes. The core process units of the iron and steel industry have some scope to use low-emissions fuels in place of coal without major modifications to existing equipment. Partial substitution with natural gas is another possible option in coal-based coke ovens and blast furnaces – indeed this has been standard practice in several regions for decades – though only modest reductions in emissions intensity are achievable. Blast furnaces can also utilise bioenergy in the form of charcoal (small blast furnaces in Brazil operate with charcoal today) or so-called biocoal, a type of torrefied biomass. Hydrogen blending in blast furnaces is currently being tested, and substitution of around 30% of total coal input is thought to be possible with minor modifications. DRI furnaces are more flexible: 30% hydrogen blends are already achievable with most natural gas-based units, and the two main licensors for commercial DRI furnaces, Midrex and Energiro, are offering units that claim to be 100% hydrogen-ready. No such units have yet been demonstrated at full commercial scale, but one facility run by HBIS in China is planning to introduce a 70% hydrogen blend in a small commercial-scale furnace in the near term. In the APS, 1.3 Mt of hydrogen are blended in iron making furnaces by 2030, this scales up after 2030 as hydrogen supply becomes cheaper and more widely available.

Increased materials and energy efficiency can help to reduce emissions from the iron and steel industry to 2030 and beyond, and so can changes to the operation of existing assets. But innovative technologies are needed to achieve the more substantial reductions in emissions intensity required in the APS, and even more so in the NZE Scenario. Some meaningful progress is already being made in developing these technologies in the iron and steel industry (Table 3.3).

Innovative technologies currently under development for steel production can be broadly categorised as either CO_2 management or CO_2 avoidance technologies. The management category includes CCUS and bioenergy technologies such as ArcelorMittal's Torero and Carbalyst projects, which aim to co-fire torrefied pellets or biochar in blast furnaces. The CO_2 avoidance category includes hydrogen and other technologies that use non-carbon reduction agents.

There are three main sub-groups of technologies in the CCUS family. First are DRI furnaces equipped with CCUS, of which one natural gas-based plant is operating at commercial scale in the United Arab Emirates and has an annual CO_2 capture capacity of 800 kilotonnes (kt). Second are blast furnaces equipped with CCUS, of which multiple small-scale demonstration projects are being pursued. Third is a different iron making process called smelting reduction which produces a more concentrated stream of CO_2 which is more amenable to capture than the CO_2 produced by the other two categories. Tata Steel planned to demonstrate this new process at full-scale in the Netherlands in 2027, but it has been delayed. Smelting reduction requires new plant for its operation, whereas the other two technology categories can be used via retrofitting existing plants as well as in new plants.

Hydrogen-based steel making has picked up significant momentum. Several new project announcements have been made since the release of *Net Zero by 2050: A Roadmap for the Global Energy Sector* (IEA, 2021). Hydrogen process technologies for steel production are of two types: one that produces steel from DRI pellets and the other that uses iron ore fines. In the DRI pellet category, the Hybrit project in Sweden aims for a full-scale demonstration plant by 2025, with commercial-scale production beginning in 2030. Several newly announced projects in Europe and North America aim to be ready to produce hydrogen-based steel at commercial scale in the 2026-30 period, and have made varying degrees of progress to secure a sustainable supply of hydrogen. These projects include: H2GS in Sweden; ArcelorMittal in Spain, Canada and Germany; ThyssenKrupp, Voestalpine and Salzgitter in Austria. In the iron ore fines category, new technologies are being developed in which metal is reduced by direct electrolysis, such as Boston Metal molten oxide electrolysis, Electra, Metso Outotec or ArcelorMittal Siderwin.

3

Table 3.3 ▷ Key innovative technologies under development in the iron and steel industry

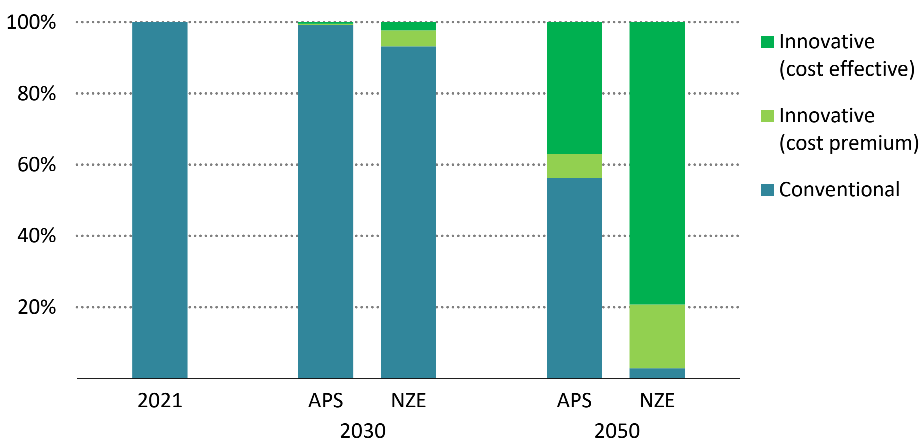
Technology category	Technology maturity	Key projects under development
CO_2 management		
Application of carbon capture or utilisation of CO_2	Demonstration/ market uptake	• ADNOC, United Arab Emirates, DRI NG w/CCUS, 5 Mt CO_2 capture, 2030. • ArcelorMittal (3D project), France, BF w/CCUS, 4 kt CO_2 capture, 2022. • ArcelorMittal and LanzaTech (Steelanol), Belgium, BF w/CCUS, 125 kt CO_2, 2022.
CO_2 avoidance		
Replacing fossil fuels with other means of chemical reduction	R&D stage / prototype/ demonstration	• SSAB, LKAB and Vattenfall (Hybrit), Sweden, H_2 DRI, 2021. • Metso: Outotec, Finland, H_2 DRI, 2023. • H2GreenSteel, Sweden, H_2 DRI, 2024. • HBIS, China, H_2 DRI, 2025. • ArcelorMittal, Canada / Spain / Germany, H_2 DRI, 2025-2030. • Salzgitter AG, Germany, H_2 DRI, 2025-2026. • Boston Metal, United States, MOE, 2024-2025. • Electra, United States, low-temperature iron ore electrolysis, 2023. • ArcelorMittal (Siderwin), France, Electrowinning, 2022-2025.

Notes: DRI = direct reduced iron; NG = natural gas; CCUS = carbon capture, utilisation and storage; BF = blast furnace; H_2 = hydrogen. MOE = molten oxide electrolysis (direct electrolysis of iron ore to metallic iron that is of crude steel quality). Dates refer to the actual or announced first year of operation. Technology maturity categories are: market uptake = technologies that are being deployed in a number of markets; demonstration = technologies where the first examples of a new technology are being introduced at the size of a full-scale commercial unit; prototype = technology types for which prototypes are being developed at a considerable size, as in pilot plants. See *Energy Technology Perspectives: Clean Energy Technology Guide* (IEA, 2022c) for further information.

Currently announced projects and policy plans using these innovative technologies are projected to capture 1% of primary production by 2030. Despite their higher maturity, CO_2 management technologies account for the minority, and CO_2 avoidance technologies – the project pipeline for which is growing more rapidly – scale up quickly as they become more mature. By 2050, hydrogen-based steel making and direct electrolysis account for around 60% of the growth in innovative primary production and replace CCUS technologies as the primary innovative solution. This is a higher percentage than in the model results published in the *Net Zero by 2050: A Roadmap for the Global Energy Sector* in 2021. The change reflects the tripling of the number of hydrogen DRI projects announced within the last year (IEA, 2022d). It also reflects the way that hydrogen-based solutions are favoured in various national and regional targets or policies, such as the European Union's REPowerEU Plan. However, technology shares are likely to vary significantly by region depending on their potential to produce or import low-emissions hydrogen, the nature of policies and targets, the availability of demonstration projects and the existing or planned CO_2 infrastructure.

While projects under development today require additional funding, around half of the innovative projects realised in the APS are expected to be cost effective by 2030. The equivalent figure in the NZE Scenario is one-third: it is lower because this scenario envisages technologies with a lower maturity being used in more projects at an earlier date than in the APS. The levelised cost of production of innovative technologies starts to be attractive from 2030, and more than 80% of projects using innovative technologies are cost competitive by 2050 in both scenarios (Figure 3.12).

Figure 3.12 ▷ Cost-competitive primary steel production by scenario



An effective CO_2 price is needed to tilt the balance in favour of innovative technologies, and leads to almost 80% of primary steel production in 2050 in the NZE being cost effective

Decreasing costs for components, effective CO_2 prices, the level of fuel prices and the availability of low cost capital are all important factors in determining the cost effectiveness of innovative technologies compared to conventional blast furnace-based production. Up to 2030, the cost competitiveness of innovative technologies mainly depends on reductions in the costs of components, high fossil fuel prices and a CO2 price for the iron and steel industry, of around USD 75 per tonne of CO_2 to compensate for additional investments in capture units and CO_2 infrastructure. In the long term, low electricity prices are the critical factor, especially for CO_2 avoidance technologies.

In the APS, an increasing number of regions introduce CO_2 prices, and this leads to levies peaking between 2030 and 2035. These levies raise more than enough to finance the additional premiums for innovative steel production. The cumulative revenues to 2050 from CO_2 prices for coal alone are five-times higher than the cumulative cost premium for innovative technologies. Even with the accelerated expansion seen in the NZE Scenario, the revenues from CO_2 prices are twice the amount of the premium. Governments or regulators could use the surplus to finance hydrogen and CO_2 infrastructure or additional renewables capacity. International co-ordination is needed to avoid the problems that differing carbon prices across jurisdictions would bring, and to prevent the possible introduction of carbon border adjustment mechanisms.

3.3.2 Reduce coal-related emissions in the cement industry

This section describes the potential to reduce the use of both cement and clinker and the short-term opportunities to reduce coal consumption in existing cement production facilities through energy efficiency and fuel switching. It concludes by exploring the scope for the use of innovative technologies to reduce emissions from coal, oil and natural gas along with process emissions.

Cement production is the third-largest coal-consuming sector after electricity generation and steel making. It used more than 230 Mtce of coal in 2021 (4% of global coal energy supply) in combination with other fuels to provide the very high-temperature levels required to produce clinker[3] in cement kilns. Cement production differs from steel making in that coal does not have a reagent role in clinker or cement production and can therefore be fully substituted by alternative fuels. Low-grade coals, such as bituminous coal, can be used in kilns.

Coal's predominant role in the cement industry, accounting for half of thermal energy used in kilns today, reflects its comparatively low cost and that the top cement producers are in coal-rich countries. China accounts for more than half of global cement production, followed by India (8%), Viet Nam (2%) and United States (2%). These four countries are all significant coal producers with ample proven reserves (Figure 3.13).

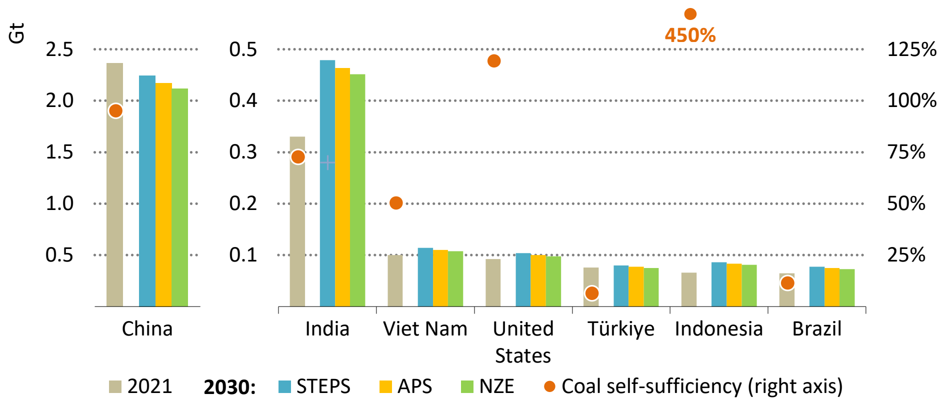
Coal use in the cement industry accounts for over 0.6 Gt CO_2 emissions today, equivalent to the total CO_2 emissions of Germany. However, coal is responsible for only a quarter of the 2.5 Gt emissions of the cement industry with the vast majority are process emissions from the decarbonisation of lime.

Cement is mostly used as a binder in concrete, which is the basic material for many buildings, bridges, dams and ports. In the STEPS, annual cement production continues to increase in the next two decades before plateauing just below 5 Gt, up from 4.3 Gt today. China continues to account for the lion's share of production, but its share of the global total declines as industrial and infrastructure growth slow. Demand for cement in the coming

[3] Clinker is mainly produced from the calcination of calcium carbonate-rich materials, such as limestone. The calcination process accounts for the majority of the energy required to produce cement.

years is driven by population and economic growth and urbanisation in other emerging market and developing economies, especially India. In advanced economies, cement is used mainly for maintaining the existing building stock and infrastructure.

Figure 3.13 ▷ Cement production in top producing countries in 2030, and current level of coal self-sufficiency



Most major cement producing countries are also major coal producers

Note: Country coal self-sufficiency indicator is domestic coal production divided by total coal demand.

There are a number of ways to reduce coal-related emissions in the cement industry by reducing demand. These include extending the life of existing buildings and infrastructure, using cement more efficiently in the production of concrete, or light weighting new buildings and infrastructure so that they need less concrete. Compared with the STEPS, materials efficiency measures save 3% of cement production by 2030 in the APS (9% in the NZE Scenario), and 6% by 2050 (19%).

Clinker production is by far the most energy-intensive step in the cement production process. On average, 720 kg of clinker are required to produce one tonne of cement. Reducing the clinker to cement ratio by 0.01 would save around 3 Mtce of coal consumption, almost 10 Mt of coal-based CO_2 emissions and more than 20 Mt of process emissions globally each year. Companies therefore are increasingly turning to alternatives that enable reduced use of clinker without compromising the mechanical properties of cement. Examples include calcined clay, volcanic stones (pozzolana), blast furnace slag[4] (a by-product of steel production) and fly ash (a by-product of coal-fired power plants). New low clinker cements (with clinker to cement ratios as low as the theoretical minimum of 0.5 for most applications) and associated standards are being developed.

[4] Availability of blast furnace slag, a by-product of conventional primary steel making, declines over time with the deployment of low-emissions technologies.

Unlike steel or aluminium, cement is difficult to recycle as the crushed rubble does not have the physical characteristics required for Portland cement specifications. However, this is an active field of research. For example, Cambridge Electric Cement has proposed an indirect recycling route where crushed concrete, after a microwave separation, is used as an alternative to lime in electric arc furnaces, which in turn produces a slag meeting the specifications of clinker used for Portland cement.

Coal use in existing cement kilns

Given its heavy nature and relatively low price, cement is generally produced close to places where its raw materials are found or places where large quantities are going to be used. This explains why there are around 2 500 cement plants spread across the world. Cement plants are long-lived assets, and more than half of current production capacity has been added in the last fifteen years. If all existing cement factories were to continue to be operated in the way they are today until the end of their lifetime, their cumulative emissions from coal combustion between now and 2050 would total 15 Gt CO_2.

There is scope for savings from the use of best available technologies. On average, the production of one tonne of clinker requires 3.5 gigajoule (GJ) of thermal energy today, and the production of one tonne of cement requires around 100 kilowatt-hours (kWh) of electricity. These energy requirements span cement and raw material grinding, cement kiln heating, fuel grinding and cement packaging and loading. There are potential savings at each step of the process, and best available technologies can push requirements down to 2.9 GJ per tonne of clinker and 70 kWh of electricity per tonne of cement. If all kilns were best-in-class, this would reduce coal use by 39 Mtce per year, or almost 20%. But they are not, and kilns are expensive and long-lived assets, so savings are likely to materialise only gradually as the stock turns over.

There are policies in place in a number of countries to foster energy efficiency and these may accelerate adoption of best available technologies, among other measures. In China, for example, large enterprises are required to undertake measures to achieve specified energy savings targets, which include establishing energy management systems. In India, the Perform, Achieve, Trade (PAT) Scheme sets sectoral energy efficiency targets and uses market-based regulation to ensure that action is taken. The global average thermal intensity of conventional kilns decreases by 2% in the STEPS, by 3% in the APS and by 5% in the NZE Scenario.

There is also some scope for savings from the use of different fuels. Cement production does not require stringent fuel specifications and the range of alternatives to coal is large. Switching to natural gas can avoid some CO_2 emissions in the short term but does not lead to low-emissions cement production: the main reason for such a switch is usually to reduce air pollution. Multi-channel combustion technology allows the use of solid, liquid or gaseous biofuels and renewable wastes, such as animal fat or bone meal. If a kiln is equipped with combustion emissions CCUS technology, bioenergy use enables carbon removal from the atmosphere (BECCS). Non-renewable wastes, such as tyres or mineral grease, can also be used in place of coal, but they have widely varying emissions intensities and, in many cases, do not provide any reduction in emissions. In the STEPS, the share of natural gas in thermal energy use remains around 19-21% in the period to 2030, and the share of bioenergy and renewable waste remains around 4-5%. With countries moving towards net zero emissions targets, the share of bioenergy and renewable waste in thermal energy rises to 10% in the APS in 2030, and to 16% in the NZE Scenario.

Innovative technologies

A wide range of technologies are being developed to reduce the CO_2 footprint of cement and concrete production: some focus on the management of CO_2 once emitted, while others aim to avoid CO_2 emissions with the use of alternative raw and binding materials and alternatives to fossil fuels (Table 3.4).

Table 3.4 ▹ Key innovative technologies under development in the cement industry

Technology category	Technology maturity	Key projects under development
CO_2 management		
Application of carbon capture or utilisation of CO_2	Prototype/ market uptake	• Norcem, Norway, CCUS by chemical absorption, 400 kt CO_2 per year, 2024. • HeidelbergCement, Germany, CCUS by direct separation, 100 kt CO_2 per year, 2025. • Holcim, United States, CCUS by physical adsorption, 2 Mt CO_2 per year, 2025.
CO_2 avoidance		
Alternatives to fossil fuels	Prototype	• SOLPART project, France, partial concentrated solar, 2025. • HELIOGEN, United States, concentrated solar, 2025. • VTT, Finland, electric kiln, n.a. • Cementa, Sweden, electric kiln, n.a. • Norcem, Norway, electric kiln, n.a. • Hanson Project, United Kingdom, partial use of hydrogen, n.a.
Alternative raw materials	Concept/ market uptake	• Various companies, Brazil, calcined clay, 2015. • Solidia, United States/Hungary, wollastonite, 2019. • Brimstone, United States, calcium silicate, n.a.

Notes: CCUS = carbon capture, utilisation and storage; kt = kilotonnes; n.a. = not announced. Dates refer to the actual or announced first year of operation. Technology maturity categories are: market uptake = technologies that are being deployed in a number of markets; demonstration = technologies where the first examples of a new technology are being introduced at the size of a full-scale commercial unit; prototype = technology types for which prototypes are being developed at a considerable size, as in pilot plants. See *Energy Technology Perspectives: Clean Energy Technology Guide* (IEA, 2022c) for further information.

There are several examples of CCUS technologies and projects in the cement sector. US-based Skyonic has operated a 75 kt capture capacity unit in a Capitol Aggregates cement plant since 2014, capturing 15% of CO_2 emissions and using them to produce sodium bicarbonate via physical adsorption. In China, Conch groups operates a 50 kt capacity unit to produce food grade, industrial grade and dry ice CO_2 through post-combustion chemical absorption. The same capture technology in a 400 kt unit is being installed in one of Norcem's kilns in Norway and will capture half of its emissions and an indirect limestone heating technology (direct separation) is being demonstrated in Germany; both are scheduled to start operation in 2024-25.

Next steps for CCUS are to scale up its use and to maximise the capture rate. The Holcim Colorado project, which is due to start operating at the end of 2025, provides an example. It is using a post-combustion solid adsorption technology and aims for a 2 Mt capture capacity with a 95% capture rate. The high upfront costs of transport and storage of CO_2, mean that these technologies are initially likely to be deployed at scale in industrial clusters. For instance, the Edmonton Lehigh Cement CCUS project in Canada is intended to form part of Enbridge's open access carbon hub in the Wabamun area: this hub aims to support the decarbonisation of multiple industries, including power generation, oil and gas and cement.

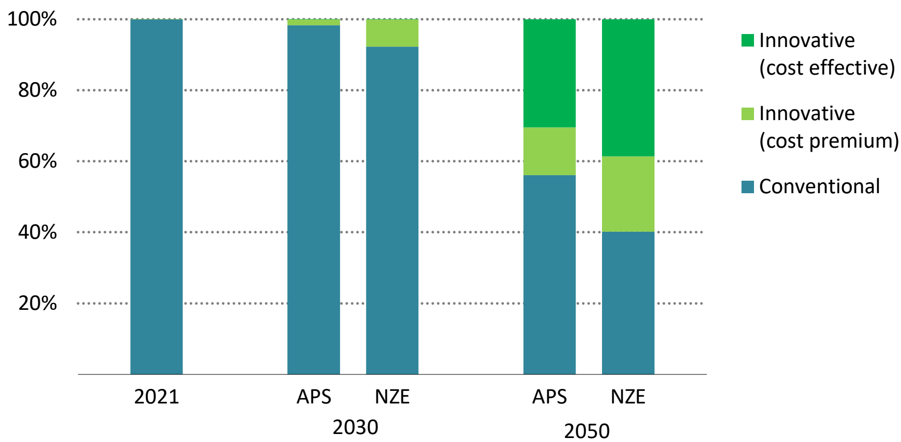
The use of alternatives to fossil fuels is still under development, with the exception of bioenergy. Indirect heating provided by alternative fuels requires significant adaptations to existing kilns or completely new designs for concentrated solar-based kilns or electric kilns, for example. Two projects, SOLPART in France and HELIOGEN in the United States, are developing concentrated solar heat to produce the 1 450 °C temperature required, while VTT Decarbonate is operating pilot electric kilns with almost 1 kt/year capacity. Another project has reported a successful trial using 20% hydrogen with 70% biomass and 10% electrical plasma energy.

One way of reducing process emissions from cement is to use raw materials that do not generate process emissions in the way that calcium carbonates do. There is interest, for example, in using calcium or magnesium silicates to produce clinker or alternative binding agents. Their potential use is at an early stage of development, but the start-up company Brimstone announced plans in 2022 to build a demonstration plant in the United States to produce Portland cement from calcium silicate rocks: this would not produce process emissions and could even result in negative emissions through the use of a magnesium-based waste product that can absorb and mineralise fuel combustion emissions.

Cement factories would need to use a combination of these options and technologies to deliver significant reductions in both CO_2 combustion and process emissions. The NZE Scenario details what a high level of ambition might deliver; low-emissions innovative kilns account for 92% of cement production in 2050; electricity, hydrogen and solar thermal contribute almost 20% of thermal demand; and more than 1.3 Gt CO_2 is captured and stored.

As cement production is a mature industrial process, innovative near zero emissions technologies struggle to compete with conventional routes. By 2030, innovative processes require subsidies to enter in the market both in APS and NZE (Figure 3.14). After 2030, higher CO_2 prices and economies of scale help to close the gap with innovative routes, which are strongly penalised by the volumes of unabated process emissions on top of those from fuel combustion. In 2050, 30% of cement production is cost effective in the APS and 40% in the NZE Scenario.

Figure 3.14 ⊳ Cost-competitive cement production by scenario



IEA. CC BY 4.0.

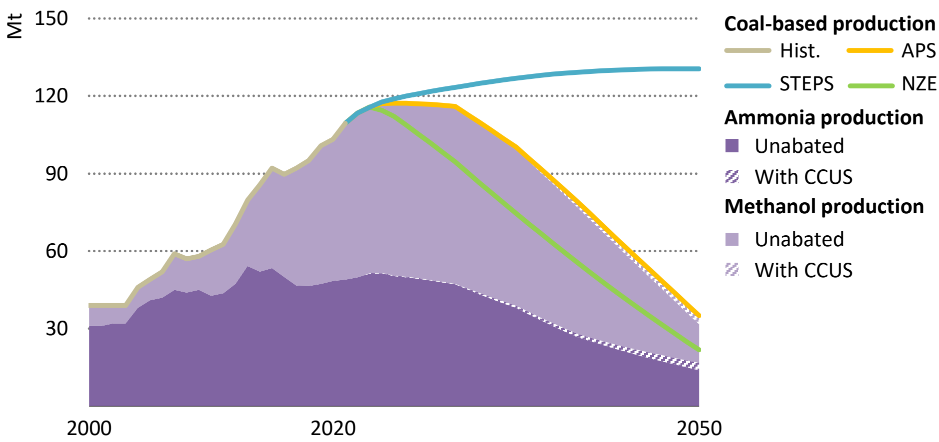
Conventional cement remains the cheapest option to 2030, but adequate policy framework and economies of scale allow innovative routes to compete after 2030

3.3.3 Reduce coal-related emissions in the other industrial sectors

By far, steel and cement are the largest sources of coal-related emissions in the industry sector, together accounting for over 70% of the total. Most of the remaining coal-related emissions in industry are from its use to generate heat to manufacture chemicals (8%), other non-metallic minerals such as lime, glass or ceramics (4%), light industrial goods (4%) and non-ferrous metals including aluminium (3%). These emissions have been declining in advanced economies since 2000 and this continues in the APS. They begin to decline in China too from the mid-2020s, and in other emerging market and developing economies from 2030.

The production of two chemicals – coal-based ammonia and methanol – accounts for more than 80% of the coal-related emissions from the chemicals sub-sector (7% of total industry emissions from coal) (Figure 3.15). Around 110 Mt of ammonia and methanol are produced from coal today (36% of global production), leading to almost 0.3 Gt of industrial CO_2 emissions. Coal-based ammonia is twice as emissions intensive as production using natural gas, and coal-based methanol is three-and-a-half-times as intensive. The vast majority of coal-based ammonia and methanol production is in China, where the use of coal is favoured to reduce the need to import natural gas. In the APS, production in China using coal peaks in the mid-2020s before declining sharply, by 2050, it is 70% below its level in 2021. The share of global ammonia and methanol production produced using coal drops from 36% today to less than a quarter in 2040 and below 10% in 2050.

Figure 3.15 ▷ Coal-based ammonia and methanol production by scenario



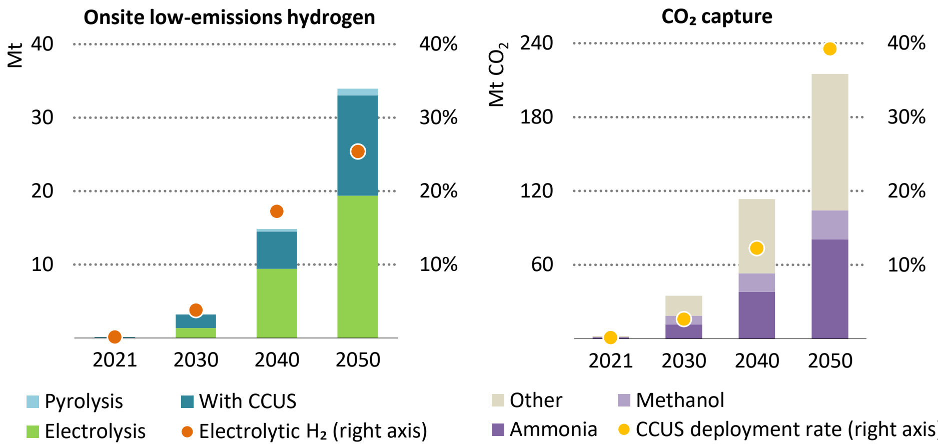
Natural gas, modern bioenergy and electricity rapidly replace coal in the production of ammonia and methanol in the APS

Note: Hist. = historical.

This reduction in coal use for chemicals production is achieved through a combination of efficiency gains, which mean that demand for ammonia and methanol is lower than it otherwise would be, and the rapid roll-out of clean technologies, which provides alternative fuel options. Electrolysis is chief among the latter, though CCUS equipped production via natural gas also plays an important role in regions with access to low cost resources. In the APS, low-emissions hydrogen production in the chemicals sub-sector increases from less than 0.1 Mt today to 3 Mt in 2030 and 34 Mt in 2050, with around 60% being produced via electrolysis. CO_2 capture in chemicals manufacturing also increases from around 2 Mt CO_2 today to 35 Mt in 2030 and 215 Mt in 2050 (Figure 3.16). Pyrolysis – a process that uses natural gas as a feedstock and produces carbon black[5] as a by-product – plays a minor additional role, but the limited number of markets for this carbon by-product hobbles its further growth.

[5] Carbon black is mainly used to strengthen rubber in tyres, but can also act as a pigment, UV stabiliser, and conductive or insulating agent in a variety of rubber, plastic, ink and coating applications.

Figure 3.16 ▷ Onsite low-emissions hydrogen use, and CO_2 capture in the chemicals sub-sector in the APS



Electrolytic hydrogen and carbon capture are two important levers for reducing emissions from primary chemicals production in the APS

Note: CCUS = carbon capture, utilisation and storage; H_2 = hydrogen.

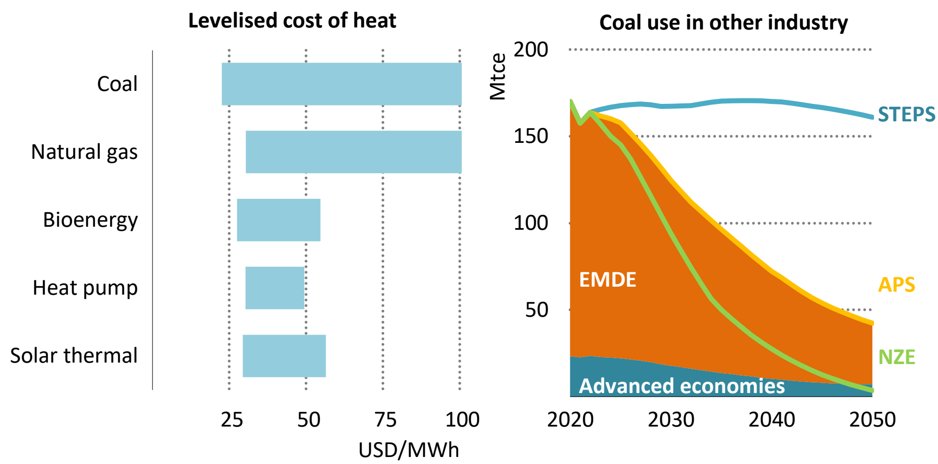
Most of the rest of the coal consumed in the industry sector is primarily used to generate heat for the production of downstream chemicals, non-ferrous metals, other non-metallic minerals besides cement and light industrial goods. The furnaces, boilers and other heating equipment needed are typically more expensive that the natural gas-based equivalents, but the low cost of coal more than compensates for this. In the APS, lower energy prices combined with CO_2 prices of USD 135 per tonne in advanced economies tilt the balance in favour of natural gas in those economies: it becomes up to 50% cheaper by 2030 to produce heat from natural gas than from coal. Although the levelised cost of coal-based heat varies widely in the APS, coal remains the least expensive option in 2030 in regions with cheap coal and relatively low CO_2 prices, such as India or Indonesia (Figure 3.17).

Required temperature is also a key consideration in decisions about which technology to use to generate heat in industrial applications. Industrial heat pumps are expensive today, but they are likely to get significantly less expensive as deployment increases, and have been demonstrated at temperatures up to over 150 °C with efficiencies far exceeding any that are achievable using combustion technology.[6] High-temperature heat can also be generated using bioenergy, electric resistance heaters, concentrated solar thermal heaters, and electromagnetic heating technologies, although large-scale applications of the latter are still at early stages of development. While not as efficient as heat pumps, these alternative low-emissions technologies after further development are likely to constitute competitive

[6] See the forthcoming IEA report *The Future of Heat Pumps* to be released in November 2022, www.iea.org.

alternatives to coal and other fossil fuels for heat at all temperature levels, provided that they are able to make use of low cost electricity (or geothermal/solar thermal resources). In the APS, low-emissions heating technologies are projected to be available in a range of USD 27-56 per megawatt-hour (MWh) in 2030, and to be cheaper than their fossil fuel counterparts in advanced economies.

Figure 3.17 ▷ Levelised cost of heat by technology in the APS in 2030, and coal use in other industry by scenario



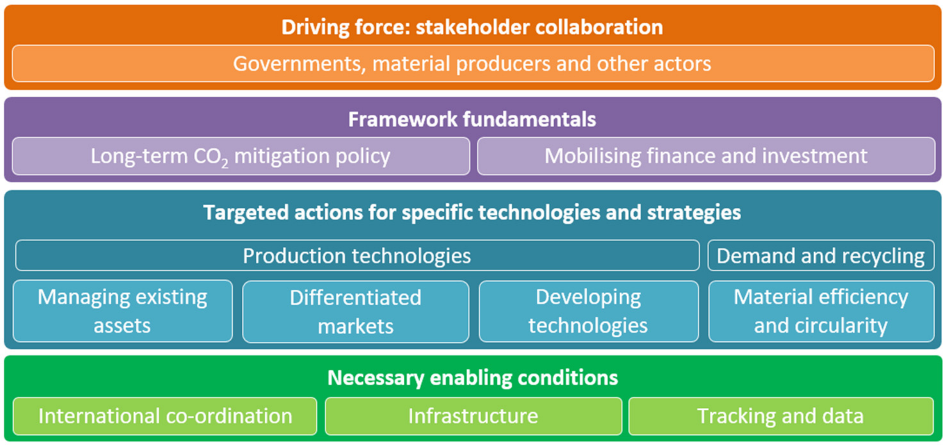
Cost reductions and policy support for clean technologies lead to significant reductions in the use of coal in other industry in the APS

Notes: MWh = megawatt-hour; Mtce = million tonnes of coal equivalent; EMDE = emerging market and developing economies. Other industry includes construction, food and tobacco, machinery, mining and quarrying, transportation equipment, textile and leather, wood and wood products, and non-specified industry.

3.4 Key actions for policy makers to 2030

Governments have a vital role to bring about a net zero emissions transition for the industry sector. While policy mixes and designs may vary, one key factor is common across all jurisdictions: the transitions will not happen at the required pace and scale without a big push from government policy. Drawing on the findings of the IEA recent report *Achieving Net Zero Heavy Industry Sectors in G7 Members* (IEA, 2022a), this section presents a policy framework that governments may find helpful in considering how to accelerate the transition to net zero emissions. The framework is relevant for all countries, with the G7 identified as the basis for a potential group of first movers, together with other willing countries.

Figure 3.18 ▷ Key components of a policy toolbox to accelerate the net zero emissions transitions in industry



Net zero emissions transitions in industry require a tailored policy approach along with economy-wide CO_2 mitigation policies

Ambitious, stable and well-designed policy frameworks play a vital part in creating the conditions for a rapid net zero emissions transition for the industry sector: the key components are summarised in Figure 3.18. There is no silver bullet, each country needs to produce its own robust portfolio of measures. From a policy standpoint, there should be nothing unique about industrial emissions from coal, relative to those from other sources. Effective policies will target substantial and sustained emissions reductions in industry wherever they can be achieved. The measures described here therefore apply to all sources of industrial emissions.

The essential first requirement is to set out long-term plans and establish a clear, strong, predictable long-term policy framework that is consistent with those plans. This needs to be sufficiently attractive and convincing to provide the confidence that investors need to make long-term commitments. It should be accompanied by the provision of access to financing mechanisms that facilitate the investments required to shift away from conventional process technologies and towards – initially higher cost and higher risk – innovative technologies (see Chapter 4).

Policies targeted to particular technology areas and strategies will be needed to complement and reinforce broad CO_2 reduction policies. Such policies should include the creation of differentiated markets for products produced with substantially lower emissions, support for technology innovation and incentives for materials efficiency strategies. The need for targeted policies is not confined to new technologies. For example, addressing excess capacity – particularly in the coal-intensive steel and cement sectors – will be essential.

Box 3.3 ▷ Transforming industries in coal-rich areas: a case study from China

Mitigating emissions from industry is particularly challenging in areas with abundant domestic coal resources. Changing mentalities and transforming conventional processes require policy makers and industrial stakeholders to plan well in advance and communicate effectively between each other. In recent years, several global initiatives have been launched to accelerate and foster the deployment of low-emissions technologies for hard-to-abate industrial processes; to showcase technical feasibility and economic advantages of transitioning to low-emissions industries.

One example comes from the city of Ordos, in China's province of Inner Mongolia, which is home to a coal deposit of 210 billion tonnes – one-sixth of China's total coal resources. In this region, around 330 coal mines are in operation, totalling production capacity of 650 million tonnes per year. In 2021, about 70% of local GDP came from coal-related businesses, such as extraction, conversion, power generation and export to other provinces in the country. In order to meet China's target of reaching a peak in emissions by 2030 and achieving net zero emissions by 2060, the city's 14th Five-Year Development Program (2021-2025) focuses on innovative technologies, such as electric vehicle production and low-emissions materials manufacturing.

The city and prominent industrial players, such as the Envision Group, which specialises in the development of low-emissions technologies, have joined forces to build an industrial innovation cluster spanning over 70 km^2 and aiming to attain carbon neutral operations along the entire supply chain for all its activities. Three plants are already under construction. First, a storage battery manufacturing unit, built and operated by Envision, with the first phase of 10 GWh in operation as of April 2022. Second, an electric heavy truck manufacturing unit to be built by Shanghai Automobile Company with a production capacity of 50 000 trucks per year, and another 50 000 electric cars per year by Feichi Technology. Third, a solar PV silicon wafer cell manufacturing unit, which is financed by the Longi Group, a leading solar PV company based in China.

Renewable electricity from wind and solar PV will power the operations of these industries, tapping into the impressive renewable energy potential of the Kubuqi Desert. Such investments are made viable thanks to favourable local policies along with reliable existing infrastructure of the provincial power grid. Envision will invest in the development of wind power in the Desert, with 50 MW of wind turbines already having been installed. In addition, the cluster will be equipped with renewables-based electricity storage, utilising the flexibility offered by both batteries and electrolytic hydrogen. The carbon footprint of the cluster's manufacturing activities will also be monitored in real-time, and a carbon emissions report will be provided on a digital platform developed by Envision for every product manufactured there.

CO_2 emissions reduction of more than 10 Mt per year as well as a creation of 100 000 direct and 200 000 indirect jobs are envisaged as an outcome of this initiative.

Policies also need to create market conditions that facilitate change both at home and internationally. Such policies should include support for national and international infrastructure development, for example, CO_2 transport and storage, and low-emissions hydrogen and electricity production and distribution, creation of transparent tracking and data collection frameworks, and efforts to reach global agreement on CO_2 prices.

Many governments are already implementing policies to help advance the net zero emissions transition in the industrial sector. For example, the member states of the European Union and five other countries – Canada, China, Korea, Indonesia and United Kingdom – have in place, or under development, CO_2 pricing policies that cover important elements of the industry sector. Others have policies in place to support innovation and are developing policies that create demand for low-emissions materials. Material producers, manufacturers and their representative bodies are also taking important steps to facilitate net zero emissions transitions. However, large gaps remain between rhetoric and action, and faster progress is needed.

3.4.1 Policies to stimulate prompt reductions in emissions

Much as we might wish otherwise, the industry net zero emissions transition cannot take place overnight. Yet there is no time to waste in moving it forward. The present decade to 2030 is a critical window of opportunity to lay the groundwork for long-term success. Policies that target increased energy efficiency, materials efficiency and fuel switching will yield the largest emissions reductions before 2030, and together account for virtually all of the emissions reductions to 2030 in the APS. This is because the underlying technologies and strategies are generally proven at commercial scale, and the relevant policies can be implemented without delay.

Energy efficiency policies can incentivise industrial plants to improve their operational performance and invest in best available technology to obtain further energy savings without fundamental changes to existing process equipment. Advanced process control systems that better predict maintenance intervals can reduce unscheduled and inefficient downtime; waste heat recovery and process integration can make use of latent heat that would otherwise be lost; upgraded boilers and process heaters can reduce thermal energy needs. The list of potential measures is a long one, and many options will have relatively short payback periods. A balance needs to be struck, however, between investing in incremental improvements in high-emitting conventional plants in the near term, and the need to shift to technology with substantially lower emissions intensities in the medium to long term. Governments might consider differentiated energy and emissions performance requirements for existing and new plants to ease the financial burden for companies that demonstrate commitment to medium- to long-term near zero emissions technology shifts. Several countries already have well-established policies in place to promote energy efficiency. India's PAT Scheme is a major industrial energy efficiency initiative, and an amendment made this year to India's Energy Conservation Act aims to establish carbon markets. Japan has a suite of measures to promote energy efficiency, including its Energy

Conservation Law, which sets a target for companies to reduce energy consumption by 1% per year. The law includes a benchmark system that requires companies to report energy consumption in order to ascertain which companies have performed the best in each category. China has a top energy-consuming enterprises programme, and Indonesia has an energy conservation regulation, both of which promote energy savings among industrial producers.

Materials efficiency strategies offer another important way of reducing industry emissions. As with energy efficiency, progress can be made immediately with existing technologies. Policy initiatives could help overcome various barriers related to cost, delivery times, co-ordination and the regulatory regime. Regulations that consider life cycle emissions would help incentivise savings in materials along value chains and promote durable end-use products. Modifying design regulations, building codes, and public procurement policies to focus on performance rather than prescriptive requirements would facilitate leaner construction and manufacturing, and encourage the use of less emissions-intensive materials. Demolition fees and building refurbishment incentives would help to maximise the lifetimes of structures and products. Governments could also help co-ordinate improved channels for end-of-life material collection, sorting, reuse and recycling.

Existing policies promoting materials efficiency include circular economy strategies, such as those of the European Union, France, Germany, Italy, Japan and China. Some jurisdictions are also introducing more targeted policies. For example, the European Union is developing the Sustainable Products Initiative, a revision of its Ecodesign Directive, with the aim of promoting more durable, reusable, repairable and recyclable products, while France has developed embodied carbon targets in its RE2020 buildings regulation to help promote efficient use of materials in buildings construction. Yet, there is scope for more to be done to incentivise the full suite of materials efficiency strategies.

Shifting to established lower emissions fuels can also bring important short-term benefits. Examples include deploying large-scale heat pumps for low- to medium-temperature heat in light manufacturing industries, increasing renewable wastes and bioenergy blending in cement kilns, and deploying natural gas DRI plants equipped with CCUS or that are able to transition to hydrogen instead of new coal-based blast furnaces in the steel sub-sector. Implementing CO_2 prices at sufficiently high levels may be one of the most effective policies to incentivise these types of changes. Other more targeted policies might include low interest loans or tax breaks for heat pump installations, programmes to improve collection and sorting to increase the availability of scrap and renewable wastes, and regulations on tradeable emissions performance standards. While carbon prices covering industry are becoming increasingly common, there is scope for more to be done to support fuel switching.

3.4.2 Lay the groundwork for rapid deployment of innovative technologies

In addition to making efforts to accelerate emissions reductions through materials and energy efficiency measures, it is vital that governments lay the groundwork before 2030 for the rapid deployment of innovative technologies in subsequent years. Both the APS and the

NZE Scenario depend heavily on these technologies between 2030 and 2050, and yet very few of them are close to being available on the market today.

We suggest three kinds of measures that will be integral to any successful approach by governments to make near zero emissions production of these materials a reality and subsequently the norm:

- *Push policies* that address the supply side of near zero emissions technology development.
- *Pull policies* that address the demand side.
- Measures to cultivate *international co-operation* and competitiveness.

Push policies can alleviate some of the risks faced by first mover companies that produce and supply near zero emissions materials. Technology R&D and demonstration require large investments that involve considerable risk, given the inherent uncertainty about the performance of technologies that are still under development and for which premium markets have yet to be clearly established. Early commercial deployment of near zero emissions technologies also involve considerable risk, and the infrastructure they need, for example for the transport and storage of CO_2 and low-emissions hydrogen, is likely to be used subsequently by many other companies and industries. The massive amount of capital investment required and the need for co-ordination between multiple stakeholders could easily result in a slow roll-out without government planning and support. Push mechanisms such as carbon contracts for difference would help overcome these barriers.

Pull policies can help create certainty in markets for near zero emissions materials once the relevant technologies reach commercial scale. Such policies might aim at differentiating products with a substantially lower emissions footprint and creating premiums to help bridge the gap in costs with those produced using established and higher emissions technologies. Mechanisms that may be useful include public and private sector sustainable procurement agreements, near zero emissions materials mandates and life cycle-based product emissions standards.

Clear definitions of what constitutes near zero emissions production – together with recognition for interim measures on the way to achieving this standard – are vital to the implementation of both push and pull mechanisms. Industry and investors alike need definitions that are developed or endorsed by governments to guide their planning and decision making. As part of the analysis for the German presidency of the G7 in 2022, the IEA proposed near zero emissions production definitions for steel and cement (IEA, 2022a), which were included in the G7 Climate and Energy Ministers' communiqué (G7, 2022).

International competitiveness and collaboration are two sides of the same coin for the industry net zero emissions transitions. Industrial materials and products are traded in highly competitive global markets, and producer margins tend to be thin. In many cases, using lower emissions technologies raises production costs, exacerbating the competitiveness challenge in conventional markets. When emissions reduction policies differ significantly between countries, producers sometimes relocate to one of the least restrictive jurisdictions. This is damaging to countries with stricter regulations and risks weakening domestic support for emissions reductions policies. It also undermines policy effectiveness, since the emissions simply move elsewhere.

Governments should address these issues by seeking to create a level playing field for low-emissions materials production within competitive international markets. Co-operation would facilitate more ambitious global policies while reducing the competitiveness challenge posed by policy asymmetry. Fruitful areas for governments to explore together include international carbon markets with common price floors, sectoral agreements between countries, carbon-based border adjustments, harmonised consumption-based taxation policies, international finance and technology co-operation for developing economies, and co-ordinated efforts on the push and pull policy areas described.

Coal-intensive industries tend to be dominated by a small number of very large corporations which dominate local markets and create regional monopolies served by enormous plants. This makes it particularly difficult for new companies with zero emissions technologies to enter the market. Governments should look at adopting policies which have worked in other sectors, such as purchase agreements and emissions standards. A clean cement purchase agreement, for example, could guarantee that a government department would buy cement from any company which could produce it at a given emissions level and price. Similarly, a low-emissions cement standard could create a declining cap and trade scheme which would only allow participants in the scheme to buy from other companies in that industry: a conventional cement player would then need to install CCUS or buy credits from a company which makes low-emissions cement.

While a focus on heavy industries is understandable in view of the challenges they face, governments should not overlook the need for measures to spur the immediate deployment of already available near zero emissions technologies in light industries. Adopting a carbon price and then increasing the price over time – through carbon taxes or emissions trading systems for larger manufacturers – may be the simplest way to achieve that objective. Other regulatory measures such as tradeable low-emissions fuel and emissions standards could yield the same outcome, but might well involve more administrative complexity. Technology mandates such as minimum energy performance standards for new motors and boilers are likely to be needed to maximise energy efficiency savings. Tailored programmes and incentives for small and medium enterprises could also play a helpful role.

Financing the coal transition

Investing for the future

S U M M A R Y

- The coal transition requires USD 12 trillion of investment in the Announced Pledges Scenario (APS) to 2050. Of this, half is for the power sector and half is for the industry sector. Around 75% of the total spending in the APS takes place in emerging market and developing economies, which need support from the international financial community to move away from unabated coal while also investing in clean energy.
- In many industrial applications, zero-emissions alternatives to coal are not yet mature, and a near-term focus on innovation and demonstration projects is essential to bring costs down. These initial investments in industry have a different risk profile than those in the power sector, and progress depends on a much larger role for public finance and support than is necessary in the power sector.
- In the power sector, three-quarters of the USD 6 trillion investment to transition away from coal is for renewables, networks and energy storage. International collaboration, public financial support and well-designed integrated approaches that encompass just transitions will be essential in the move away from unabated coal. Governments need to set the right framework, but the private sector can drive the necessary investment.
- There is more than USD 1 trillion of unrecovered capital in today's fleet of coal-fired power plants, meaning that their owners – often state-owned enterprises – have a strong stake in their continued operation. Emissions from the plants may be locked in by inflexible power purchase agreements, which remunerate plants regardless of their operation. In Viet Nam, for example, such contracts govern the operation of around half the fleet. In the APS, up to USD 270 billion of capital invested in coal-fired power plants is at risk of being unrecovered.
- In practice, most coal-fired power plants are shielded from market competition, so other means are needed to replace them with low-emissions sources in the generation mix. A range of options that are open to governments to break this logjam are assessed, including direct regulation, market-based measures and financial mechanisms. The common denominator is that they alter the incentives facing coal plant owners so that the plants operate more flexibly, are equipped with carbon capture, utilisation and storage (CCUS), co-fire with low-emissions fuels or are retired.
- There is considerable scope for innovative financing to help bring down the total cost of the coal transition. Outside China, where low-cost financing is the norm, the weighted average cost of capital of coal plant owners and operators is around 7%. Refinancing to bring this down to 4% would accelerate the point at which owners recoup their initial investment, clearing the path towards retirement for up to one-third of the global coal-fired power plant fleet within ten years.

4.1 Introduction

Financing the coal transition on the net zero emissions pathway lies at the intersection of a number of energy and development challenges. A key message is that integrated approaches are essential. There are a number of interlocking elements that must be co-ordinated and sequenced; the challenge is not just to reduce emissions from existing coal-fired assets, but also to ensure that the energy services or other outputs that these assets provide are effectively provided by other means, and that the social implications of change are addressed.

Many of the key clean energy technologies that can replace coal are very cost competitive, but an accelerated move away from the most polluting assets will not happen at the required pace without a strong policy push and adequate financing. The starting point for this discussion is in some respects discouraging, given the headwinds of volatility, inflation, rising borrowing costs and global supply chain dislocations that the world is facing today. These factors hamper the ability of companies, especially in developing economies, to raise debt and attract the financing required to invest in clean energy, pay for retrofits or retire coal assets early. The near-term commodity price squeeze has starved large-scale users of coal, such as steel and cement industries, of some of the financial resources to make new investments in more efficient equipment, although it has at the same time endowed others, such as oil and gas exporters, with additional resources that could be invested.

There is an indispensable role for public policy, public finance and international collaboration to catalyse the necessary processes of change. Some of the financing tools are tried and tested, especially those that build clean energy infrastructure. But other elements are new, notably the engagement that is required with the owners of emissions-intensive assets to change the way that they operate, or to retire them early. There are difficult judgement calls to be made about how this support is structured and implemented so as to secure additional reductions in emissions without unduly compensating entities for their investment in polluting technologies. But these difficult issues cannot be avoided if the world is to achieve its climate goals in an equitable and secure way.

This chapter reviews the current state of play related to coal investment and financing, and quantifies the investments required to transition away from coal in the World Energy Outlook scenarios. Further it discusses the financial solutions that might be applied to existing and planned coal infrastructure in different parts of the world, drawing on asset-level analysis and case studies to highlight the costs, benefits and uncertainties of each. This chapter also assesses the extent to which different financing approaches can help to ensure consistency between the need to reduce emissions and the need to maintain energy security and affordability.

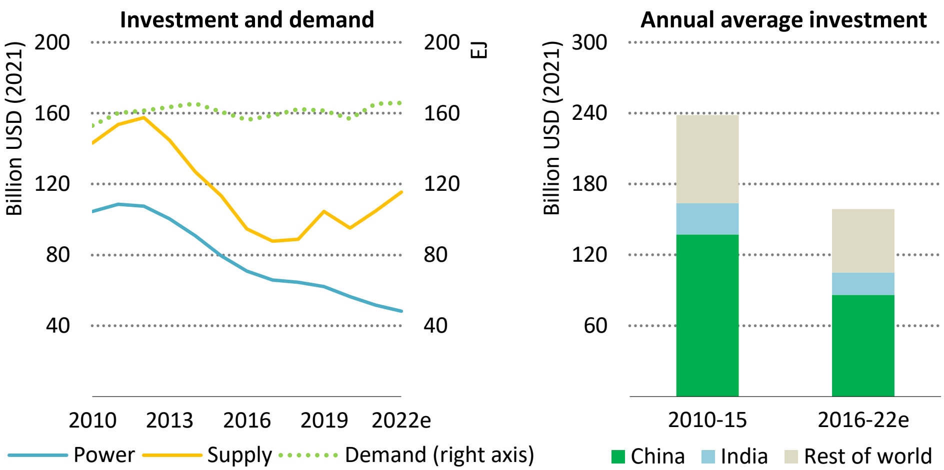
4.2 Coal investment and financing: state of play

Financing for coal investment has been increasingly constrained in recent years. The financial community has been moving to reduce or halt financing for new coal-related investments and to sell coal assets, but less attention has been paid to financing emissions reductions among the large stock of existing assets.

4.2.1 Trends in coal investment

The allocation of investment in unabated coal along the value chain is very different to that of other fossil fuels. Most capital investments in oil and natural gas are concentrated in the upstream (exploration and extraction) and in the midstream (transport). In contrast, capital investment related to exploration and extraction for coal is relatively modest: the variable costs of production, such as labour costs, and fuel and power for mining machinery, account for most of the expenditure required to get coal to market. The need to invest in coal transport varies widely according to the location of the deposit, but the amounts involved can be significant if new dedicated rail or port infrastructure are required. A significant share of coal-related investment takes place in the power sector. A 1-gigawatt (GW) plant requires between USD 700 million and USD 2.5 billion of capital investment, depending on where it is built and the type of technology; the mine to fuel the plant typically costs ten-times less.

Figure 4.1 ⊳ Coal demand and investment, 2010-2022



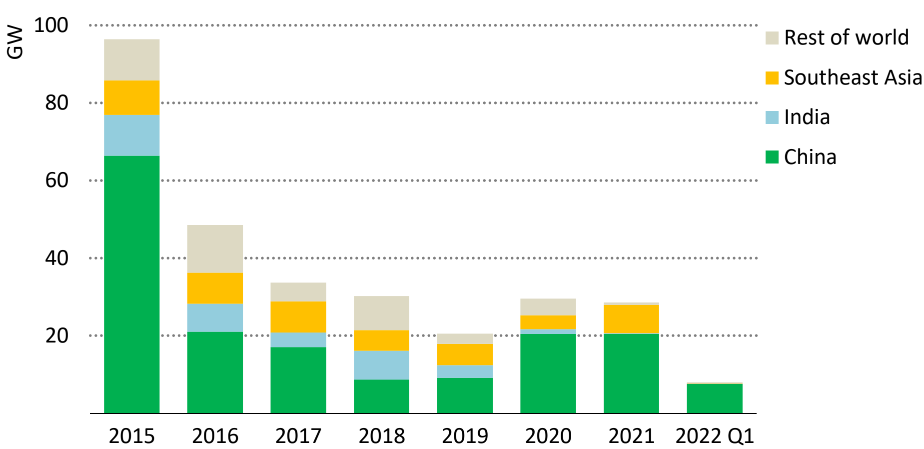
Global demand for coal has been stable, but investment has fallen and is now increasingly concentrated in emerging Asian economies, especially China and India

Notes: e = estimated for 2022 data. Investment relates to spending for unabated coal supply and power generation.

Demand for coal remained high throughout the 2010s, but total investment in coal supply and in coal-fired power plants has fallen from around an annual average of USD 240 billion between 2010 and 2015 to USD 160 billion since 2016 (Figure 4.1). This reduction reflects a lower level of spending on coal-fired plants caused by tighter financing conditions, expansion of renewables and the overhang of coal capacity in some key markets from an investment boom in 2005-10 (see Chapter 1, Box 1.2). It also reflects a decline in spending on coal supply, though there has been a slight rebound since 2018 in response to rising coal prices and increases in seaborne coal trade. Today investment in both coal-fired power plants and coal supply are dominated by China and India, which together account for around 70% of all investment spending and two-thirds of coal demand.

Final investment decisions for new coal-fired power plants have declined dramatically since 2015, but have stabilised at around 30 GW of approved capacity per year (Figure 4.2). In 2021, new coal plants received the green light in Viet Nam and Indonesia, but most new approvals are in China, especially since the presidential announcement that China would no longer support the building of coal-fired power plants abroad. Data for the early months of 2022 suggest that more than 20 GW of new coal-fired capacity was approved in China. The National Energy Administration announced that USD 5 billion was spent on new thermal power plants in the first-half of 2022, a 70% increase from the previous year. Almost 180 GW of coal-fired power capacity is currently in various stages of construction across the world (see Chapter 2).

Figure 4.2 ▷ Final investment decisions for new coal-fired plants, 2015-2021

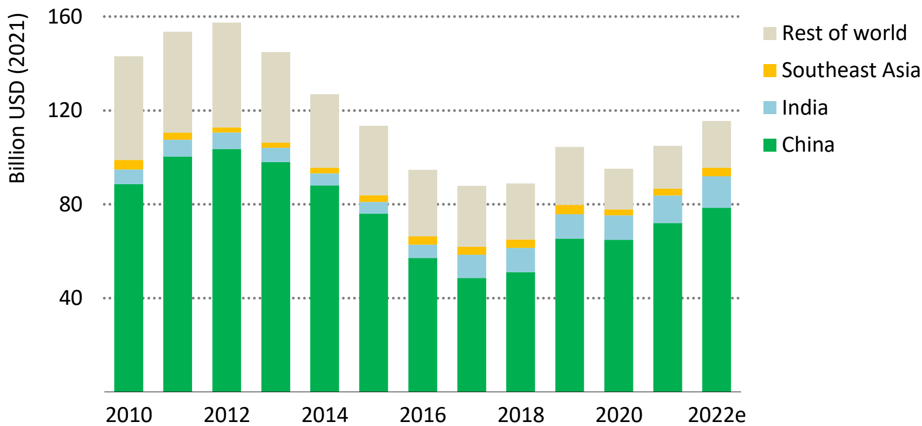


Final investment decisions for new coal power plants are far below where they were in the early 2010s, but have stabilised in recent years at around 30 GW per year

Note: GW = gigawatt; Q1 = first quarter.

Today investment in coal supply is driven largely by China and India (Figure 4.3). China's pledge to reach carbon neutrality by 2060 set in motion a nationwide effort to reformulate mid- and long-term policy frameworks for decarbonisation. China is also focussed on energy security, and coal supply difficulties led to many provinces experiencing power outages and a spike in energy prices during the second-half of 2021. As a result, previous restrictions on domestic coal output were eased, and coal-producing provinces were encouraged to ramp up production. This has been a major factor in rising investment in coal supply globally since 2017. Authorities in India are also looking to ramp up domestic production to reduce the use of more expensive imported coal. Coal India Limited is responsible for more than 80% of national output and it has put in place an ambitious production target. Elsewhere in the world, investment has generally been slower to respond to high prices, not least because of the political, financial and regulatory environment in many countries which have become increasingly hostile to additional investment in coal supply. Overall investment remains well below levels seen in the early 2010s.

Figure 4.3 ▷ Global investment in coal supply, 2010-2022



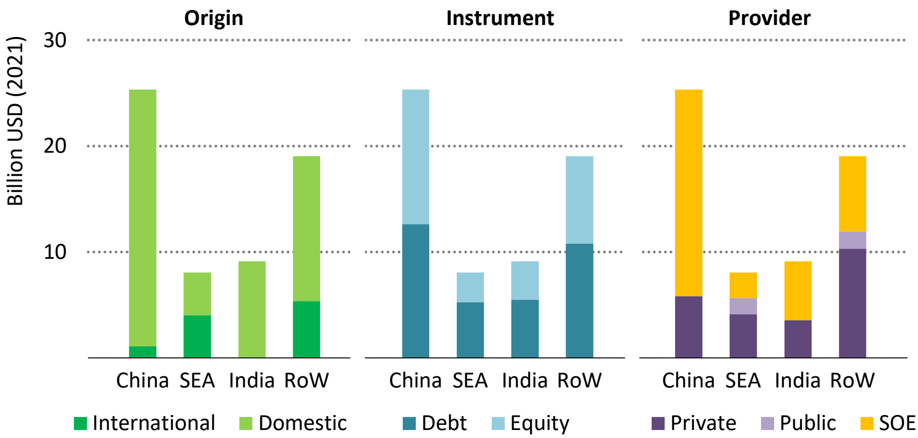
Investment in coal supply has edged higher since 2020 as a result of the post-pandemic economic recovery and a near-term focus on energy security in China

Note: 2022e = estimated data for 2022.

4.2.2 Sources of finance

Various approaches have been used to finance coal plants. Until recently, financing was typically made on a utility balance sheet with a higher proportion of equity, but it now tends to rely more on project finance deals carried out off-balance sheet with higher level of debt. In aggregate, nearly 60% of coal investments over the past seven years have been debt financed. Whatever the precise method used, the majority of coal-fired power generation in recent years share a common factor, which is that it has been primarily financed through domestic sources, with state-owned enterprises playing a large role (Figure 4.4). In most cases, capital is recovered through regulated tariffs contractually charged to an off-taker on a long-term basis.

Figure 4.4 ▷ Annual average financing for coal-fired power plants by origin, instrument and provider, 2015-2022



Financing of coal-fired power plants typically has relied heavily on domestic financial sources and state-owned enterprises, especially in China and India

Note: SEA = Southeast Asia; RoW = rest of world; SOE = state-owned enterprise.

International capital has been a key conduit to unlock investment in coal in many developing economies. These financial flows have involved foreign project developers, international commercial banks and public finance institutions, and have originated from a small number of countries. Institutions from China, India and Japan have been the primary financiers of roughly 75% of coal projects over the last five years (Global Energy Monitor, 2022). Similarly, financial organisations domiciled in six countries including China, India and United States were responsible for 86% of overall bank financing and 80% of institutional investments in the coal industry between 2019 and 2021 (Urgewald et al., 2022).

Opposition to coal is not new, but in recent years an increasing number of governments and financial institutions have announced policies to restrict or prohibit financing for coal projects and investments. Many major economies have developed sustainable finance guidelines, though not all preclude domestic financing of coal (Table 4.1). Almost all of the multilateral development banks and export credit agencies have also announced restrictive lending criteria or outright prohibitions on coal-related projects.

Further momentum to restrict financing for coal comes from the financial community, where many institutional investors, pension funds, banks, insurance companies and others have committed to reduce or end their involvement in coal. For example, many large institutional investors have signed the Powering Past Coal Alliance Finance Principles, which consists of a series of restrictions aimed at phasing out coal in the Organisation for Economic Co-operation and Development (OECD) member countries and the European Union members by 2030 and no later than 2050 in the rest of the world. For banks, commitments to reduce their involvement in coal primarily take the form of lending restrictions together with broader efforts to decarbonise their loan books and increase the portion allocated to "green" assets.

Table 4.1 ⊳ National-level restrictions on coal financing in key countries

Country	Coal power-related targets	Sustainable finance regulations and initiatives
Canada	Phase out coal power by 2030.	In October 2021, Canada, along with other OECD nations agreed to end export credits for unabated coal-fired power plants. A draft voluntary transition finance taxonomy overseen by the Canadian Standards Association has been delayed.
China	No financing for new overseas coal plants from 2021.	End of financing for coal-fired power plants abroad from September 2021. The latest version of the Green Bond Endorsed Project Catalogue (often referred to as China's green bond taxonomy) recently removed investment in clean coal, i.e. supercritical coal technology. Green credit guidelines do not include coal.
India	Renewables to make up half of total energy requirements by 2030.	The government is currently working on a sustainable taxonomy. Indian financial institutions often report their carbon emissions and increasingly their carbon risks, but coal is rarely excluded from funding.
Japan	Phase out inefficient thermal coal plants.	Japan agreed to end new direct government support for unabated international thermal coal power generation by the end of 2021 and proposed a phase-out plan for inefficient thermal coal power plants in the period to 2030. The energy ministry published guidance about climate transition finance in 2021. It also published Green Bond Guidelines in 2017 which include a non-exhaustive list of bond uses.
Korea	Phase out coal in electricity generation by 2050.	Public banks, including the Exim bank, must abide by government plans to phase out coal by 2050, but currently there are no fixed coal financing restrictions in place. The environment ministry published a national green taxonomy guideline in December 2021, but it is not legally binding.
United Kingdom	Phase out coal power plants by 2025.	The government proposed a series of regulations similar to those agreed in the European Union, including on sustainability disclosure and a green taxonomy. The United Kingdom agreed to stop providing export credits for unabated coal-fired power plants in October 2021.
United States	Reduce greenhouse gas emissions 50-52% from 2005 levels by 2030.	The approach to coal financing varies by state. At the federal level, the government ended export credits for unabated coal-fired power plants in October 2021. In April 2022, the Securities and Exchange Commission published proposed regulations related to environment, social and governance disclosures and product labelling but these fell short of including specifics on financing for fossil fuels.

In bond markets, many capital providers have opted for sustainable issuances as they seek to reduce fossil fuel lending unless it is associated with achieving sustainability targets. This is particularly the case in Europe, where sustainable finance regulations are most advanced.

In equity markets, some institutional investors have tended either to divest their stakes or to use their ownership to engage with the company and seek strategy changes. Divestment is popular with activists and environmentally conscious consumers, but there are still many organisations willing to acquire coal assets and to provide them with capital. Moreover, the purchaser of the asset may have a less robust carbon reduction strategy than the seller, or indeed none at all, and may also be less amenable to pressure to change. A strategy of engagement also has limitations, particularly if it is not time bound. In practice, a combination of both active stakeholder engagement and selected divestment may prove most effective, along with a series of other coal phase-out financing mechanisms (see section 4.4).

These developments in bond and equity markets however are unlikely to impact coal projects that are underpinned by domestic finance. State-owned enterprises (SOEs) account for almost 60% of coal investments globally and nearly 80% in China. Institutional investors are generally only involved with SOEs through either international bonds issued by the companies or sovereign bonds. Applying restrictions on bond purchases that are linked to fossil fuel use may reduce available capital or push up the cost of capital to SOEs, but otherwise financial institutions and institutional investors have limited ability to influence the strategy of SOEs.

S P O T L I G H T

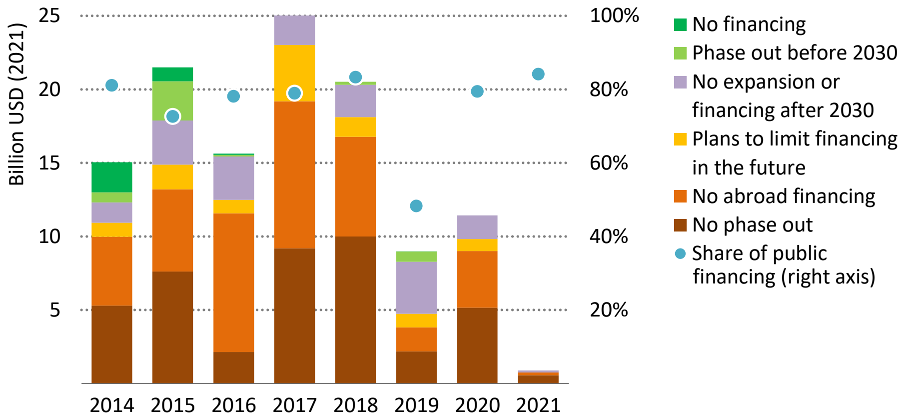
How has the sustainable finance movement affected the top-100 coal financiers?

There has been a proliferation of sustainable finance regulations and industry-led alliances in recent years. Regulations and initiatives have focussed on two areas: improving climate-related risk management, often using the framework laid out in by the Task Force on Climate Related Financial Disclosures, and increasing the flow of finance to sustainable activities, including through the use of taxonomies and transition finance (TCFD, 2022).

How is this network of initiatives and obligations affecting banks and financial institutions that finance coal-fired power projects worldwide? To answer this question, we examined each of the top-100 financial institutions that have financed coal power worldwide between 2010 and 2020 to see what sort of commitments they have made to restrict lending to coal-related projects (Figure 4.5). These include 54 public or governmental institutions and 46 private companies.

We found that half of the 100 institutions that finance coal have not made any commitments to restrict coal-related financing and a further 20% have made only relatively weak pledges. These 70 institutions account for a total of USD 135 billion in funding for coal power since 2010, and their share in the total finance provided by this group has risen from 70% in 2010 to 85% today. Over the same period, around 30 institutions have taken on more far-reaching obligations to stop funding new projects or to phase out coal entirely.

Figure 4.5 ▷ Coal finance allocated by the top-100 financiers relative to their phase-out policies, 2014-2021



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Coal continues to be mostly financed by government-owned or public institutions that have few plans to proactively restrict coal financing in the near future

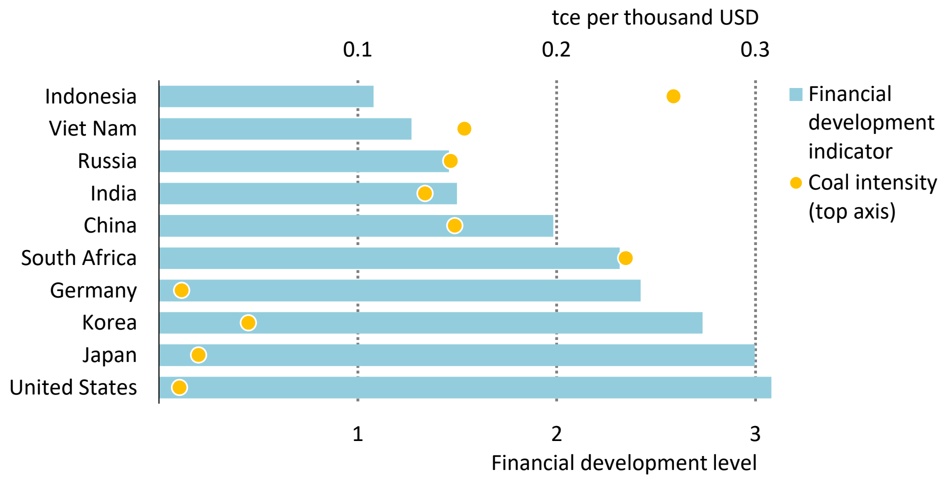
Note: Amounts shown represent the financing allocated to coal-fired power plants and coal supply by the financiers during the given year.

4.2.3 Challenges and hurdles facing investors in the coal transition

Developing economies that are most in need of transition financing tend to have a high cost of capital and underdeveloped banking and financial sectors compared to advanced economies (Figure 4.6). Perceptions of exchange rate volatility risk are also an impediment to attracting foreign capital. Currency markets are immature in a number of countries where coal plays an outsized role in the economy, and foreign exchange movements can create mismatches between obligations priced in dollars and revenues denominated in local currency. As a result of these various factors, institutional investors still play a relatively small part in financing clean energy transitions in most emerging market and developing economies.

One of the major hurdles to addressing emissions from coal-fired power plants is the fact that most of the operations are shielded from market competition. Around 60% of current coal power plants in emerging market and developing economies were financed by state-owned utilities, and a large share of the rest were built based on a single buyer model, where independent power producers (IPPs) transact with a single utility on the basis of regulated pricing. Very little coal-fired generation in emerging market and developing economies is produced on a pure merchant basis, whereas in Europe, and North and South America, generators compete to sell power in wholesale markets.

Figure 4.6 ▷ Financial development indicator and coal use per unit of GDP in the ten-largest coal-consuming countries



Emerging market and developing economies where coal is deeply embedded tend to have relatively underdeveloped banking and financial sectors

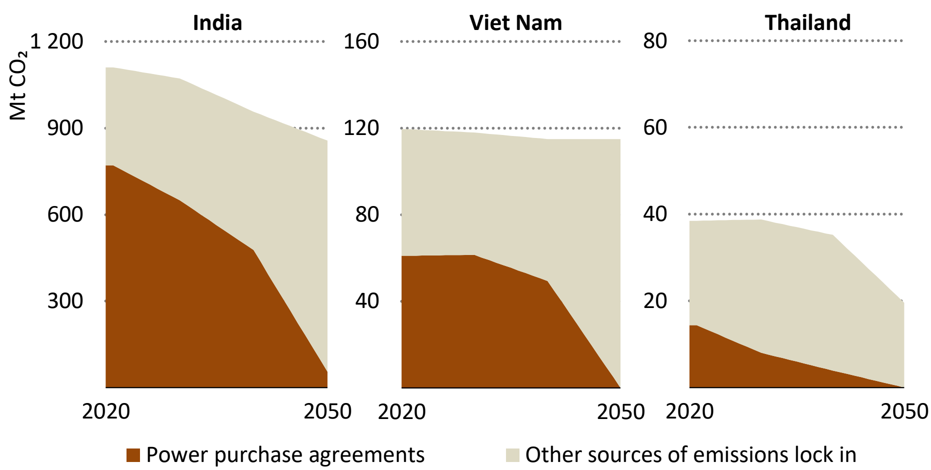
Notes: tce = tonne of coal equivalent. The financial development indicator consists of an equal weighting of private sector credit to GDP ratio and the stock market capitalisation to GDP, with higher values indicating a higher level of financial sector development. Coal use refers to production and exports. Data are averages from 2016-2020.

A key feature of the single buyer model is the power purchase agreement (PPA). These are contracts that set the terms of sale of power between two entities over a defined period, usually years or decades, and help to underpin the financing required for a power generation project. PPAs typically contain a capacity charge which covers the capital costs of building the plant, including a return on equity for the project sponsors, as well as the fixed operating and maintenance costs of the plant. This capacity charge applies to the available plant capacity regardless of whether it is used or not. While there are many different PPA models and variations, they have been widely used as a way of enabling IPPs to use debt to finance coal plants. They ensure that investors are paid back regardless of the operation of the plant and that the counterparty – usually a state-owned utility or central off-taker – shoulders the risk. PPAs are also often underpinned by sovereign guarantees and may contain clauses that adjust for currency risks for foreign lenders.

Some PPAs have provisions that allow the seller to source power from different sources as long as demand is met at the agreed volumes and price. This allows different assets to operate flexibly to meet the obligations of the PPA, and would permit the replacement of electricity produced by an unabated coal power plant with electricity from renewables or other low-emissions sources. However, some PPAs have clauses that define minimum levels of generation from a specific plant, and these agreements pose a risk of contractually locking in emissions from the current coal power plant fleet.

We have undertaken a detailed review of publicly available data and conducted a series of interviews with experts in the field to derive estimates of the contract duration of coal PPAs and their share of emissions. This review covered a sample of emerging market and developing economies, which provides the baseline for the assessment of the potential for locked-in emissions over the remaining technical lifetime of coal-fired power plants (see Chapter 3). The results are illustrated in Figure 4.7. It shows that PPAs risk locking in a significant share of coal-fired generation. In India, for example, around half of the coal generation fleet is owned by IPPs and the majority of plants have PPAs in place; India's state-owned utility, NTPC, also has PPAs in place with distribution companies. In Viet Nam, PPAs govern the operation of around half of its coal-fired generation fleet and so potentially lock in an equivalent level of emissions. However, it also shows that, important as coal PPAs are in terms of locking in emissions, they constitute only part of the problem. The majority of the remaining emissions that are at risk of being locked are in state-owned utilities, which are also shielded from market competition.

Figure 4.7 ⊳ CO_2 emissions from coal-fired generation that is contractually tied to power purchase agreements in selected countries



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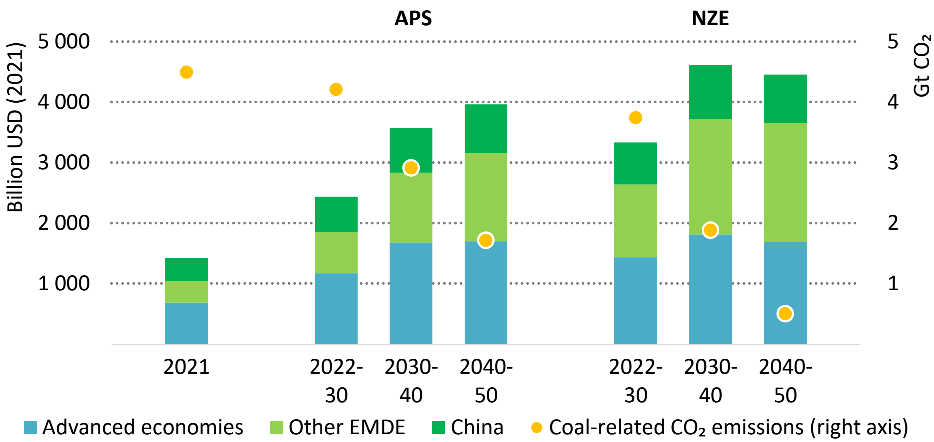
A large share of emissions from coal-fired power generation are at risk of contractual lock in by PPAs, which guarantee a minimum off-take for several years

4.3 Coal transition investment outlook

A step-change in investment is required in all regions to deliver on the climate goals in the Paris Agreement, but especially in emerging market and developing economies (Figure 4.8). The required investment will need to meet rising demand for energy services in a sustainable way while at the same time reducing emissions from the existing capital stock. Doing both in parallel will be challenging. In this section we quantify the amount of investment in clean energy that is required to reduce emissions from coal in the Net Zero Emissions by 2050 (NZE) Scenario and the APS, and the amount of capital that is at risk of being unrecovered in coal-fired power plants in the APS.

Figure 4.8 ▷ Annual average clean energy investment by region in the APS and NZE Scenario



Annual investments in clean energy transitions need to double this decade to achieve climate pledges, and triple to get on track for net zero emissions by 2050

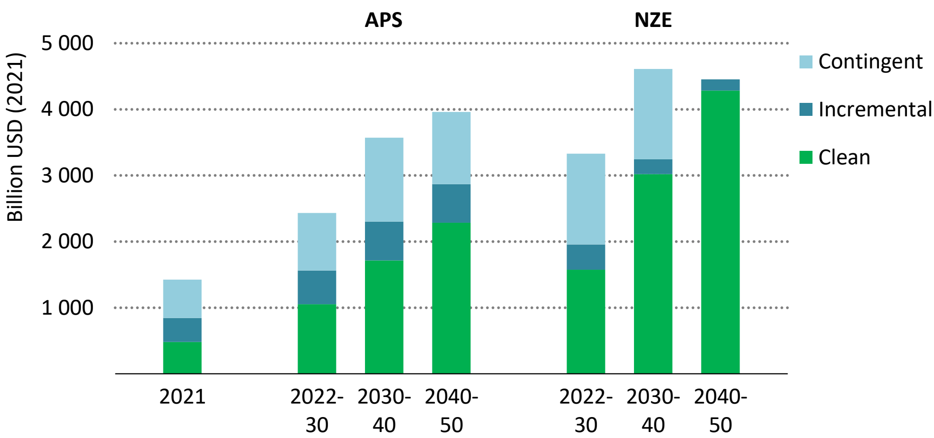
Note: APS = Announced Pledges Scenario; NZE = Net Zero Emissions by 2050 Scenario; Other EMDE = emerging market and developing economies excluding China.

4.3.1 Clean energy investment

A large part of the investment required for the coal transition is to replace a polluting source of energy with a clean one, for example investing in solar photovoltaics (PV) to enable the retirement of coal-fired power plants. But not all transition-related investments that are necessary to reduce coal emissions can immediately deliver zero-emissions energy or energy services. For example, investments in electricity grids or storage are key to enable the transition but is only truly clean when electricity generation is zero-emissions: these are considered "contingent transition investments", or investments that enable emissions reductions only with changes elsewhere in the energy system. In other cases, zero-emissions technologies are not immediately available and an intermediate solution is required that reduces emissions but does not immediately bring them down to zero: these are considered "incremental transition investments", or investments leading to incremental emissions reductions over time. Examples include co-firing coal plants with low-emissions fuels such as biomass, low-emissions hydrogen or ammonia, and measures that reduce methane emissions from coal mining operations.

To enable coal transitions, clean investments need to be scaled up to bring more zero-emissions energy into the system as rapidly as possible. In the APS, investment in technologies that immediately deliver zero-emissions energy averages more than USD 1 000 billion between 2022 and 2030, which is around half of total energy investment over this period. The other half consists of contingent and incremental investment, the bulk of which is in grid infrastructure (Figure 4.9). This underscores the importance of designing sustainable finance frameworks and taxonomies that support all aspects of emissions reductions and not just those areas that immediately deliver zero-emissions energy.

Figure 4.9 ▹ Annual average clean energy investment by type of transition finance needed in the APS and NZE Scenario

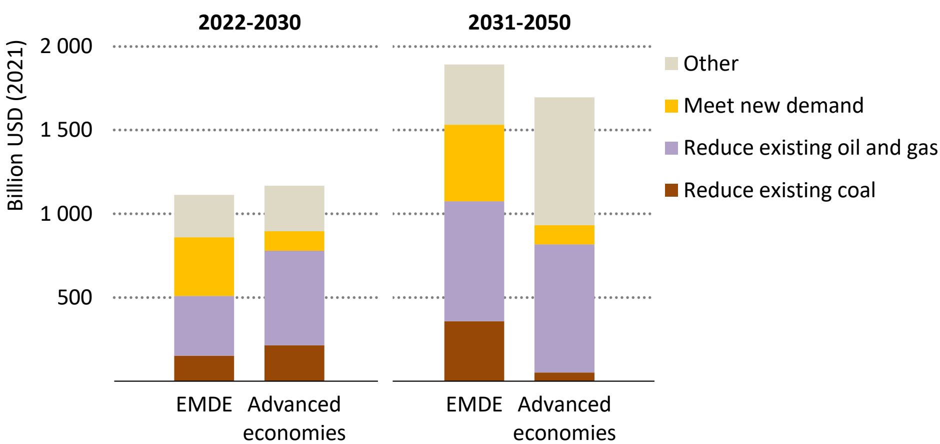


Half of the investments that bring down emissions to 2030 in the APS and NZE Scenario do not immediately bring zero-emissions energy services

Another consideration for sustainable financial frameworks is to determine whether energy transition investments reduce the use of existing coal assets (or other unabated fossil fuel infrastructure), or whether they meet new demand for energy services which might otherwise have been met by fossil fuels. This distinction is particularly important in emerging market and developing economies, which undergo rapid economic growth in each scenario and so need to finance new energy infrastructure in order to meet the needs of an expanding and more affluent population. To better understand the portion of total investment in the scenarios which reduces emissions from coal (as opposed to meeting new demand for energy services or maintaining the existing energy system through spending on grid infrastructure), we have undertaken a detailed sectoral decomposition of investment. This enables us to attribute the level of investment spending in clean energy to a corresponding reduction in the use of existing unabated coal assets.

Between 2022 and 2030, roughly USD 2 300 billion is spent on clean energy on average each year in the APS. Around USD 380 billion of this amount goes towards reducing emissions from coal, and this is split fairly evenly between advanced economies and emerging market and developing economies (Figure 4.10). Between 2031 and 2050, most of the remaining emissions from coal are in emerging market and developing economies: spending on coal transitions in those regions averages USD 380 billion per year, or around 20% of total clean energy investment (compared to less than 5% in advanced economies). Around 25% of total clean energy spending in emerging market and developing economies goes towards meeting rising energy service demand, compared to around 7% in advanced economies.

Figure 4.10 ▷ Breakdown of annual average clean energy investment in the APS, 2022-2050



Emerging market and developing economies face the task of attracting finance to reduce coal use while also investing in clean energy to meet rising demand

Notes: EMDE = emerging market and developing economies. Other includes capital spent to maintain transmission and distribution networks and investments in electrification and energy efficiency that are unrelated to fossil fuel transitions.

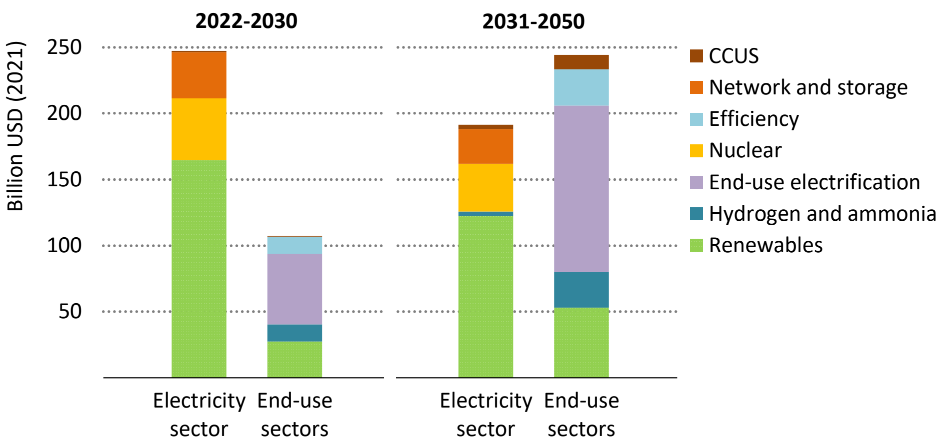
Globally, emissions from coal fall from 15 gigatonnes of carbon dioxide (Gt CO_2) in 2021 to 12 Gt CO_2 in 2030. This means that each tonne of CO_2 reduction from the use of coal equates to USD 12 in terms of investment, making this one of the cheapest ways to bring down emissions in the energy sector. Global emissions from coal fall further to 3 Gt CO_2 in

2050, with each tonne CO_2 reduction costing USD 4. This is lower than for the period to 2030 as unit investment costs of solar PV, wind and other renewables continue to decline, and the costs of clean energy technologies that reduce emissions from coal in the industry sector – such as electrification, hydrogen and CCUS – are lower as they move to full commercialisation.

In the period to 2030, around USD 250 billion, about 70% of global investment in the coal transition, is spent in the power sector to replace the use of unabated coal with low emissions sources, primarily wind and solar PV. This includes investment in transmission and distribution networks and battery storage. A further USD 120 billion per year is spent to reduce coal emissions in total final consumption (90% of which is in industry) by around 1 Gt CO_2. After 2030, annual investment levels that aim to further reduce emissions from coal-fired power generation are lower as scale and technological learning effects cut the costs of adding solar PV and wind and deploying flexibility tools such as storage to balance power grids (Figure 4.11).

4

Figure 4.11 ▷ Average annual investment required to transition from unabated coal to clean energy in the APS, 2022-2050



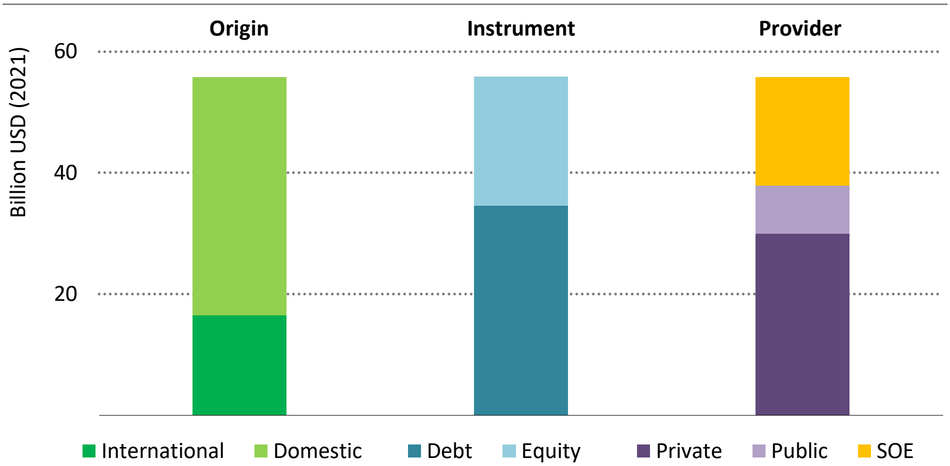
USD 12 trillion of capital is channelled towards the coal transition mainly via renewables in the power sector; after 2030 electrification of end-uses plays a strong role.

In the period to 2030, 90% of investment in the end-use sectors, dominated by coal use in industry, is directed towards electrification, renewables deployment and efficiency improvements. Electrification accounts for the largest amounts of capital, as investments are made in secondary production processes, in particular for steel, aluminium and plastics, and industrial heat pumps for processes with low-temperature heat requirements. Solar thermal, geothermal and bioenergy heating technologies are also employed. Bioenergy blending is a relatively cost-efficient route to lower unabated coal use in the cement sector. Investments in efficiency are made by adopting best available technologies and enhanced process controls for energy-intensive processes.

Compared with the decade ahead, the amounts invested in CCUS and hydrogen double in the period after 2030. Many of these technologies, and those used to satisfy high-temperature heating needs with electricity, are largely in the research and demonstration phase and are expected to reach commercial maturity from the late 2020s (see Chapter 3). These technologies are typically more expensive than incumbent routes today, with levelised cost premiums generally in the 10-120% range. However, the main pieces of equipment (electrolysers, carbon capture) that are additional to the core production equipment, do not constitute a significant boost in capital investment. For example, electrolysers deployed in the industry sector constitute USD 100 billion of cumulative investment in the APS, or an average of USD 5 billion per year after commercial-scale deployment begins. Similar dynamics can be observed for carbon capture technologies in the APS, albeit with smaller cost declines over time.

While the average annual investment for the coal transition in the industry sector increases substantially in the 2031-50 period, it is moderated over time by increased materials efficiency along the full value chain of industrial products. Without this moderating impact, the transition would cost substantially more, with the marginal increases in production having to be met by hydrogen, CCUS and electrification technologies if emissions were not to increase.

Figure 4.12 ▷ Annual investment in coal transition in EMDE by origin, instrument and provider in the APS, 2022-2030



Emerging market and developing economies require significant financial resources – with a crucial catalytic role played by public actors and international sources of capital

Note: SOE = state-owned enterprise.

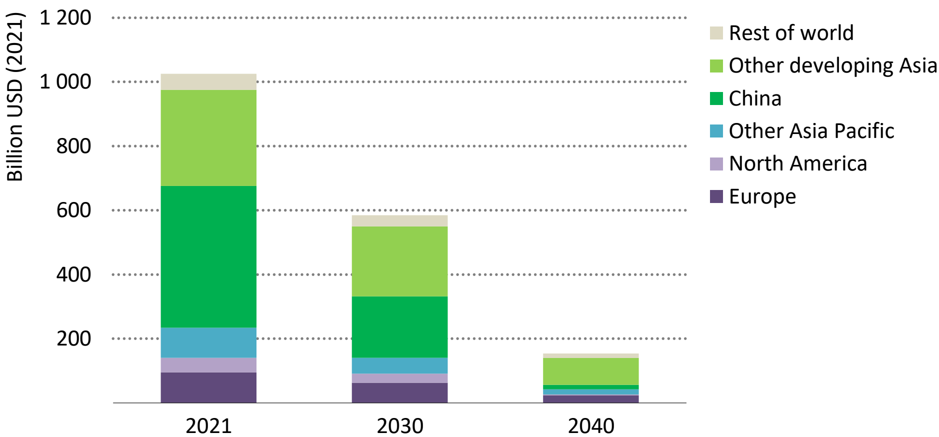
In the Announced Pledges Scenario, emerging market and developing economies require nearly USD 60 billion per year to support the transition away from unabated coal over the period between 2022 and 2030 (Figure 4.12). This includes the clean energy investments required to replace coal in both the power and industry sectors. Almost one-third of the capital required comes from international sources, including foreign project developers, international commercial banks and public finance, including multilateral development banks. This share – amounting to almost USD 20 billion per year – may in fact underestimate the importance of international support, as much of the domestic capital raised would rely on the catalytic role of foreign investment. There is also a significant role played by public institutions and state-owned enterprises, which account for nearly half of the spending required over the period from 2022 to 2030. This is a higher public share than the global average for all energy spending in the APS, partly because investment in grids and energy storage form a large part of the public capital outlay to support the transition from coal to renewables in the power sector, and partly because the solutions in coal-intensive heavy industries are not yet commercially mature and so require significant government support in the early stages of deployment. A relatively large share of the capital spending is also financed through raising debt; with debt-to-GDP levels and interest rates on the rise along with an unfavourable macroeconomic backdrop, this increases the importance of ensuring that clean energy projects are based on strong fundamentals and can monetise, where possible, avoided emissions from unabated coal.

4.3.2 Unrecovered capital risks for coal-fired power plants

The total capital investment required to transition from unabated coal to clean energy is only part of the story. There is also a significant amount of sunk capital in the current coal-consuming assets that has yet to be recovered and, in practice, could be a key barrier to transition away from unabated coal use, especially in emerging market and developing economies. In the power sector alone, investors in over 1 400 GW worth of plants, accounting for close to 70% of the world's coal-fired power fleet, have yet to recoup more than USD 1 trillion of invested capital (Figure 4.13). Given that many governments have pledged to reach net zero emissions and have committed to phase out their use of unabated coal, there is a risk that some of this capital may not be recovered.

Whether a coal asset is retired before the end of its economic lifetime is a key factor to determine the amount of capital that is at risk of ultimately ending up unrecovered (Box 4.1) The majority of the 1 300 GW of coal capacity that are retired between 2022 and 2050 in the APS will have operated for at least 30 years, which is the typical period to recover the initial capital investment. In advanced economies, only around 25 GW of capacity is retired before reaching 20 years of operation, and another 50 GW are retired after operating for less than 30 years. In emerging market and developing economies, there are more retirements of coal capacity overall, but nearly all are after 30 years or more of operations.

Figure 4.13 ▻ Capital yet to be recovered from global coal power plant fleet with traditional rates of depreciation



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There is more than USD 1 trillion of capital yet to be recovered in the world's coal-fired power plants. Some of this capital may not be recovered in rapid transitions

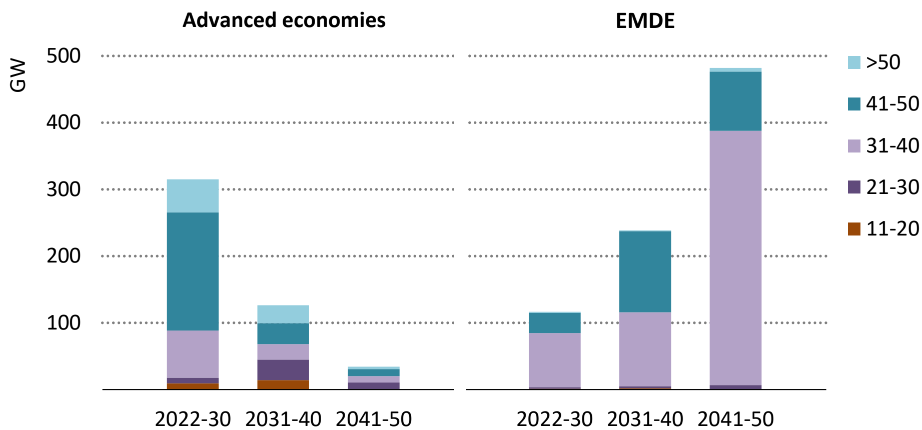
Box 4.1 ▻ What is the economic lifetime of a coal-fired power plant?

Coal plants typically operate for around 50 years. This can be considered the technical lifetime of a plant, reflecting the intended design life from an engineering and operational perspective. Coal plants also have an economic lifetime, which – from a financial planning perspective – covers the period over which plant owners or investors may expect to receive income from the operation of the plant in the form of cash flows or dividend payments that cover the initial invested capital and an expected return (based on the asset-level or firm-level weighted average cost of capital). If projects are partly or fully financed using debt, their economic lifetimes usually exceed the loan maturity period (which can last as short as 3-5 years but typically do not exceed 20 years). Economic lifetimes also overlap with a depreciation schedule, a pre-defined period over which an asset value on a company balance sheet is steadily reduced over time. Economic lifetimes hinge on the annual rate of capital recovery, which can vary depending on plant utilisation rates and profitability; the degree of exposure to competitive market pressures may also differ depending on market design and contractual structures.

There is no consensus about what marks the end of economic lifetime; it may be viewed as the period from when an asset earns less than what it costs to keep it running, or it could be marked as the point at which the asset is fully depreciated (or otherwise reaches its salvage value as defined at the outset). Moreover, the technical and economic lifespans of coal assets are dynamic and interrelated: some assets might undergo refurbishment or otherwise require large-scale investments over the course of their technical lifetime, which can prolong their economic lifetime. Considering both the technical and economic maturity of a coal asset is an essential part of developing financial interventions for the coal transition, but it is only one of a range of factors that need to be considered. In our analysis, economic lifetime refers to the typical period to fully recover the initial capital investment, generally spanning 30 years.

Because most coal plants in the APS are retired after their economic lifetimes (Figure 4.14), our assessment of the risk of total unrecovered capital in this scenario represents a modest 4-8% of the total remaining capital to be recovered as of today (or between USD 40-90 billion). By 2050, this range rises to USD 130-270 billion in 2050. To represent financing and contractual uncertainties, two parameters were varied: the weighted average cost of capital from 5% to 10% in real terms and the degree of capital recovery at different levels of operations for coal plants, with higher levels of utilisation linked to a higher rate of capital recovered in a given year (and vice versa).

Figure 4.14 ▷ Coal-fired power plant retirements by regional grouping and age at retirement in the APS, 2022-2050



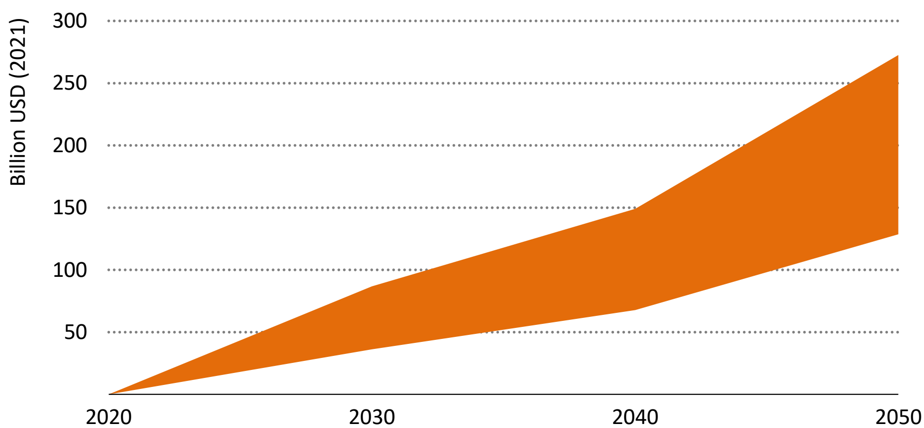
About 20% of all coal-fired power plants are retired by 2030 and another 40% by 2050 in the APS, though most operate for more than 30 years before closing

Note: EMDE = emerging market and developing economies.

In emerging market and developing economies, unrecovered capital in coal-fired power plants at retirement is estimated at USD 5-10 billion in 2030 and USD 70-140 billion in 2050. The emerging market and developing economies have many young coal plants and they represent over three-quarters of the total unrecovered capital in coal plants, yet a number of factors limit the extent of their exposure to unrecovered capital risks in the APS. These include lower initial investment costs, transitions that take time to build momentum consistent with their post-2050 net zero emissions pledges, and market designs and power purchase agreements (PPAs) that preserve revenues for coal plants (and can reward them for contributions to system services).

Unrecovered capital risk from coal power plants in advanced economies in the APS is estimated at USD 35-80 billion in 2030 and USD 60-130 billion in 2050. These totals are relatively high compared with their share of total outstanding capital yet to be recovered for two main reasons. Along with retiring a significant number of coal plants before reaching 30 years of operations, rapid transitions in the APS drive down capacity factors for unabated coal plants over the next decade from an average of 51% in 2021 to below 30% in 2030, and below 15% in the 2040s. These lower levels of operation would significantly reduce the ability to recover capital over the remaining lifetime of these assets (Figure 4.15).

Figure 4.15 ▷ Unrecovered capital risk from coal-fired power plants in the APS



Potential unrecovered capital in coal-fired power plants is in the range of USD 40-90 billion in 2030 and USD 130-270 billion in 2050

4.4 Secure the needed investment outcomes

Public and private actors involved in the coal transition face the twin challenge of accelerating investments in clean energy while minimising the risk of unnecessary stranding coal assets as far as possible, without undermining emissions reductions targets. This section explores some of the possible options that could help to move away from the use of unabated coal. Broadly, there are three types of interventions:

- **Direct regulation** involves the forced closure of a plant or reduced operations. This approach is prevalent in countries such as China, which have broad powers to impose sweeping changes, as demonstrated by the drive in the 2010s to retire old units and build new, more efficient coal plants. Regulations can also curb the activities of coal plants indirectly by tackling externalities, for example through strict air quality regulations.

- **Financial measures** provide incentives for owners to relinquish the asset or make changes to its operation by offering a financing package that is conditional on the sale or retirement of a plant or on emissions reductions. Financial measures typically involve low cost government debt such as securitised loans, debt purchases or loan guarantees. They are usually asset-specific and hinge on two points: first, the extent to which the asset is already depreciated; second, whether the cost of investing in an alternative clean energy technology yields a net financial benefit over the cost of continuing to operate the coal assets under existing market conditions and contractual arrangements. The most attractive targets are assets with some remaining capital to recover but for which replacement by a renewable energy alternative would immediately generate savings for consumers. In these cases, the savings can be used to pay back the upfront costs to government, lowering the burden on the taxpayer.
- **Market-based measures** are those that reduce the economic incentives of the owner to continue high levels of unabated operation. They include carbon pricing schemes and measures that reduce revenues available beyond a limited number of operating hours through taxes, tenders or market rules. If designed well, auction-based capacity mechanisms could incentivise plant owners to reduce their operations in exchange for payments to remain online in case they are required by the system operator, with net benefits for emissions outcomes.

Most current policies rely on financial or market-based measures that affect the incentives of asset owners.[1] Several jurisdictions and lenders are working on new solutions that use market-based measures. Effective policy mixes will vary among countries depending on factors that include the prevalence of coal-related installations, ownership structures, electricity market rules, maturity of capital markets, and interactions with other policies and political priorities. Ultimately, all three types of intervention can help bring about the outcomes highlighted in Chapter 2: retire coal assets early; repurpose coal plants from baseload operation to provide power system services; retrofit with CCUS to lower emissions or co-firing with biomass or low-emissions hydrogen-based fuels.

While each type of outcome is important, the associated upfront costs and monetary transfers are not all easily aligned with taxonomies intended to unlock more clean investment. Payments that facilitate retirements, for example, may not fall within the scope of defined investments. Repurposing may require contingent investments that rely on developments elsewhere in the system. Enabling retrofits might require a mixture of incremental, contingent and clean investments over time. In cases where there are grey areas, institutional frameworks that help segregate problematic assets in order to manage

[1] Asset owner is used here as shorthand for any actors with decision-making responsibility for the operation of a coal-producing or coal-using installation, including owners, operators and creditors. It can also be extended to include prospective owners.

their transition may be needed, akin to the "bad banks" model used to isolate distressed assets during the 2008 financial crisis.

4.4.1 Facilitate early retirement of coal power plants

Most coal-fired power plants have economic lifetimes of around 30 years, meaning they remain on a company balance sheet over that length of time. In the 2021-30 period in the APS, around 400 GW of coal-fired power plants are over the age of 30 when they retire. About 160 GW of coal power plants are retired before the age of 40, of which about 10% are retired before the age of 20 years.

Retirement decisions are typically taken by plant owners when the costs of continued operation outweigh risk-adjusted projected revenues. This often occurs near the end of the plant design life if an owner is deciding whether to undertake a refurbishment and lifetime extension. It can also occur earlier, for example, if renewables generation takes more market share and peak prices do not compensate the coal power plant for reduced operating hours. There are also cases where government intervention, e.g. pollution controls and carbon pricing, can lead to early retirements of otherwise profitable plants. In China, a number of recent policies have mandated the closure of polluting or inefficient power stations and incentivised the construction of more efficient replacements, with the result that the average retirement age of plants in 2021 was 17 years, substantially shorter than the typical 30 year economic life of a coal-fired plant. In contrast, more than half of the coal capacity retired globally between 2014 and 2021 was more than 40 years old, nearly all in Europe and the United States.

Government interventions to encourage plant retirements need to bring forward the date at which the owner calculates it is no longer effective to keep capital tied up in the asset. In the recent years, a number of new financial instruments have been designed by multilateral banks and governments to do exactly this. Approaches vary with local market and technical considerations and also in terms of how they address several critical information asymmetries. For example, governments typically do not know the expected net present value of plants that are not publicly owned. Uncertainties are lower where plants are operated by regulated utility generators, and these plants have received most attention to date. Retirement decisions are influenced by state-owned utility strategies and contracts with plant owners, and by the existence of capacity tariffs that cover capital recovery (see section 4.2.3).

There is not a single blueprint for managing the phase-out of coal-fired generation, but a number of options are available. These can be tailored to coal plants of different types and ages and to the varied market structures in which they operate. Each of the options has strengths and weaknesses. It is important to be aware of these and to mitigate potential adverse outcomes. For example, retiring individual coal assets early may raise the utilisation of the remaining coal fleet, meaning that there is no overall reduction in emissions. Some of these options and their inherent challenges are highlighted in Table 4.2.

Table 4.2 ⊳ Examples of financial options for early retirement of coal-fired power plants

Sector wide	
Mechanism	**Technical assistance/ support**
Description	Toolkits and technical assistance programmes to support asset owners and relevant government authorities.
Typical applicability	Government, asset owners, financial institutions investing in coal phase-out.
Case study	• **Coal Asset Transition Accelerator** led by RMI, Climate Smart Ventures, Carbon Trust and INETT.
Enabling conditions:	Good co-ordination between international initiatives and short lead times.
Mechanism	**Transition support**
Description	Support to organisations such as community development funds or employment retraining programmes with a focus on just transitions.
Typical applicability	Coal communities.
Additional cost/risk	Government.
Case study	• **Just Energy Transition Partnership** between South Africa, France, Germany, United Kingdom, United States and European Union. • **Accelerating Coal Transition** led by Climate Investment Funds with six MDBs (ADB, AfDB, EBRD, IDB, IFC and WB). • European Commission: **EU Just Transition Mechanism.**
Enabling conditions	Clear definition of activities to be supported, donor co-ordination and implementation mechanisms.

Asset level	
Mechanism	**Buy out plants**
Description	Investor (either public or private) buys a coal plant and retires it within a set period. Profits from the plant prior to retirement repay the investor. The original asset owner is incentivised to use profits from the sale to invest in clean power.
Typical applicability	Utilities, IPPs.
Additional cost/risk	Shareholders.
Case study	• Asian Development Bank: **Energy Transition Mechanism.**
Enabling conditions	Mitigate the risk of overpaying for the plants, and ensure that the freed up capital is effectively redeployed to benefit clean energy transitions.
Mechanism	**Monetise emissions reductions**
Description	Creation of a finance mechanism, via blended finance or carbon markets, that values emissions saved by retiring a coal plant early. Asset owner uses funds to retire coal plants and invest in clean power.
Typical applicability	Utilities, IPPs.
Additional cost/risk	Public finance institutions, carbon market.
Case study	• **Engie Energia Chile**, with support from IDB Invest and CIF Clean Technology Fund.
Enabling conditions	Well-functioning and credible mechanism to value emission avoidances, address potential for leakage.

Table 4.2 ▻ Examples of financial options for early retirement of coal-fired power plants (continued)

Asset level (continued)	
Mechanism	**Auctions**
Description	Asset owners submit bids to a government managed fund to compensate owners for early coal plant retirement.
Typical applicability	Utilities, IPPs.
Additional cost/risk	Asset owners.
Case study	• **Reverse Coal Auction** in Germany managed by the Federal Network Agency.
Enabling conditions	Robust regulatory regime (carbon pricing). Avoid overpaying asset owners and the retirement of the wrong plants (either the newest most efficient or the oldest that would be easier to repurpose).
Mechanism	**Ratepayer backed securitisation**
Description	Asset owners raise low cost debt to fund retirement and invest in replacement by renewables capacity. Debt is repaid via a surcharge on customers which is offset by a reduction in cost for electricity.
Typical applicability	Regulated utility.
Additional cost/risk	Ratepayers.
Case study	• **San Juan Generating Station**, operated by Public Service of New Mexico (United States).
Enabling conditions	Lawmakers need to authorise securitisation. Inclination to pass cost of retiring early to customer needs to be addressed.
Mechanism	**Concessional debt or refinancing**
Description	Asset owner accesses lower rate debt in return for targets on emissions reduction or coal plant retirement. The lower rate debt can also be tied to the creation of a just transition support mechanism.
Typical applicability	Utilities, IPPs.
Additional cost/risk	Asset owners.
Case study	• South Africa: Just Transition Transaction. • Vistra Energy Corp in the United States.
Enabling conditions	Debt restructuring for highly indebted utilities.
Mechanism	**Sustainability linked bonds**
Description	Asset owner issues a bond to attract lower cost debt based on achieving key sustainability targets and investing in renewable power.
Typical applicability	Utilities IPPs.
Additional cost/risk	Bond purchasers.
Case study	• **Tauron Polska Energia bond**, co-ordinated by Banco Santander.
Enabling conditions	Establishment of stringent and credible sustainability targets.

Note: MDBs = multilateral development banks; IPP = independent power producers; INETT = International Network of Energy Transition Think Tanks; ADB = Asian Development Bank; AfDB = African Development Bank; EBRD = European Bank for Reconstruction and Development; IDB = Inter-American Development Bank; IFC = International Finance Corporation; WB = World Bank.

Sources: RMI (2022) and WEF (2022).

Sector-wide transition strategies – Just Energy Transition Partnership example

During COP 26 in 2021, the governments of South Africa, France, Germany, United Kingdom and United States, along with the European Union, announced the Just Energy Transition Partnership (JETP) to support decarbonisation efforts in South Africa and the move away from coal. South Africa presents unique challenges as it is highly dependent on coal and its main utility, ESKOM, is highly indebted and unable to dedicate any funding to coal retirement or clean energy transitions. The USD 8.5 billion partnership aims to assist South Africa to achieve the goals it set out in its Nationally Determined Contribution, with a particular focus on reducing emissions in the electricity system, while also continuing to support development and just transition goals.

Electricity in South Africa is produced mainly from a number of large coal plants located in the Mpumalanga province, close to coal mines. Retiring these plants early and rehabilitating and repurposing mines while making sure that energy security and the need for jobs and a just transition are addressed will be the cornerstone of the partnership. The delivery of a JETP Investment Plan is now in process, with the aim of translating the JETP framework into a concrete investment strategy and financing plan. A secretariat has been established, supported and resourced by the Climate Investment Funds, and South Africa has launched the Presidential Climate Finance Task Team.

The contours of the JETP financing package have yet to be articulated, but consultations are underway. The ability of the various JETP funders to effectively leverage and blend private sector financing will be one of the key metrics of success for the partnership. Other emerging market and developing economies are closely following the development of the programme, which could, if successful, become a blueprint for reducing coal emissions elsewhere in the world.

Market-based retirements

Coal plant retirement can be driven purely by market forces when coal generation becomes uncompetitive in deregulated power markets. In the United Kingdom and some parts of the European Union and the United States, the switch to natural gas and nuclear has rendered the use of ageing coal plants obsolete and costly. For example, in a capacity auction held in June 2022 by https://www.bloomberg.com/quote/24195Z:USthe largest grid operator in the United States, a clearing price of USD 34 per megawatt (MW) per day to secure electricity supply in three years was achieved, and coal plants struggled to bid in generation at that price. However, a large share of existing coal-fired generation is protected from market competition, meaning that a purely market-driven approach is unlikely to be the main lever for reducing emissions from coal-fired power generation.

Buy out plants

The Asian Development Bank is piloting a new market-based mechanism to accelerate the transition away from unabated coal in the Asia Pacific region. The Energy Transition Mechanism (ETM) proposes to pool low-cost capital from various concessional and private sources to incentivise the early retirement or to repurpose coal-fired power plants. The ETM would also support new investment in clean energy, networks or storage infrastructure in place of the coal plants. The ETM has two funding vehicles. First is a carbon reduction facility tasked with refinancing or purchasing coal assets. Second is known as the clean energy facility which facilitates investment in clean energy. The potential monetisation of the CO_2 savings resulting from the accelerated closing of a plant through carbon credits may supplement the revenue stream. The ADB has undertaken multiple scoping and feasibility studies with partners in Southeast Asia to ensure that it fully understands the potential environmental and socio-economic impacts of coal asset closures.

An ETM mechanism could help to coalesce multiple pools of finance, but it has yet to be demonstrated at scale. Some uncertainty remains over the willingness of governments and plant owners to transfer ownership of strategic assets to multilateral development banks (MDBs). As in any other transaction, asset owners will naturally seek to maximise concessions from MDBs and international sources of finance, and this will require careful handling. The extent to which freed capital will be transferred from coal to renewables is also uncertain.

Monetise emissions reductions

Carbon pricing incentivises the retirement of coal assets by taxing or setting a cap on emissions, thus making coal-fired generation more expensive. One example is the European Emissions Trading System (ETS), which requires operators of emissions-intensive activities to purchase emission allowances for each tonne of CO_2 released. While it is challenging to single out the exact role of rising ETS prices on the decrease of coal generation in the European Union, the scheme is widely seen as helping to accelerate the adoption of renewables as well as coal-to-gas switching.

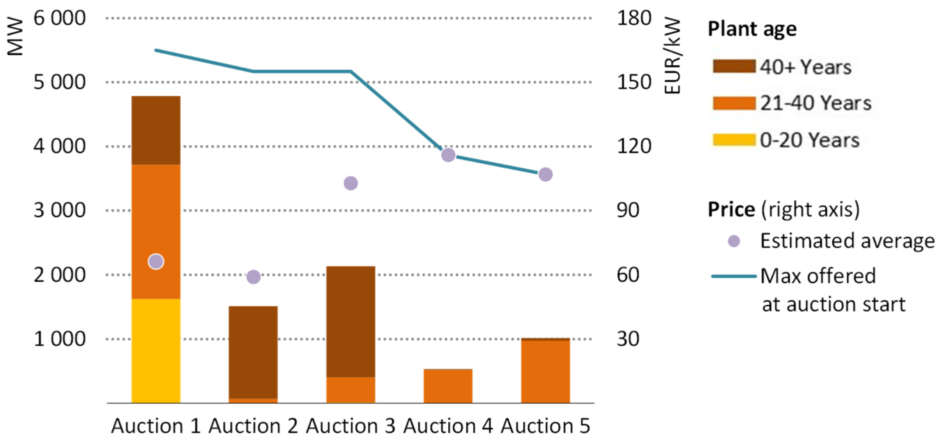
At the international level, several carbon crediting schemes allow the monetisation of emissions reductions that result from a lower share of coal in the power generation mix. Other monetisation mechanisms have been demonstrated, for instance in Chile, where Engie Energia received a USD 125 million loan from the Inter-American Development Bank, the CIF Clean Technology Fund and the Chinese Fund for Co-financing in Latin America and the Caribbean to fund the development of wind generation projects and to close two coal-fired power plants. The deal is structured in a way that carbon emissions reductions resulting from the closure of the coal plants are given a value, and that should a carbon credit market develop in the future, the company will be free to sell them and share the profits with lenders. At the international level, several carbon crediting schemes allow monetisation of emissions reductions resulting from a reduced share of coal power generation, thanks to dedicated fuel switching carbon crediting baselines methodologies in the United Nations Framework Convention in Climate Change Clean Development Mechanism, Verra and Gold Standard.

Auctions

In an effort to accelerate the decommissioning of coal power plants, some countries are studying and piloting the concept of using auction-based compensation mechanisms that allocate funding to plants owners in exchange for early retirement. The objective is to provide funding for the unrecovered capital remaining in the plant to the owner. The competitive nature of the auction mechanism aims to reveal the lowest amount of compensation that plant owners will accept to receive in exchange for early retirement. Auctions are used in various parts of the energy system and, by fostering competition and bringing transparency on prices, they have been instrumental in bringing down the cost of renewables. Some governments have decided to harness the power of auctions to provide incentives for early phase out of coal in a cost-competitive way (World Bank, 2022a).

In Germany, for instance, the Act to Reduce and End Coal-Powered Energy and Amend Other Laws (Coal Phase-Out Act) aims to reduce and eventually end the use of coal-fired electricity generation. Among other things, it established an auction mechanism where a shutdown premium would be awarded to plant operators that agree to take some capacity offline. The most cost-efficient bids are the first ones to be selected, and the bids are awarded in the order in which they are placed in terms of cost efficiency until the tender volume is reached (Federal Network Agency, 2022).

Figure 4.16 ▷ Auctions for coal capacity retirements in Germany



Auctions have shown some initial success to retire coal plants in Germany, but the levels of competition are uncertain

To date five auctions have taken place between September 2020 and March 2022 and 34 coal units have been committed to retirement accounting for almost 10 GW of capacity (Figure 4.16). Plants from across the age spectrum participated in the first auction in September 2020, with a large six-year-old plant operator electing to receive the funding and repurpose the units for green hydrogen production. The first three auctions proved quite competitive, with bids driving down the price per MW retired much lower than the maximum price offered by the facility. While there is no detailed public data available for individual bids, the three last auctions in 2021-2022 accepted bids at the maximum reserve price set by the auctioneer, suggesting a somewhat lower level of competition in these rounds. An upper bound estimation of cost suggests that the auction mechanism is providing an average compensation of EUR 80 per kilowatt (kW) of retired capacity. Our analysis on the unrecovered capital left in coal power plants worldwide suggests that, on average, a much higher price of about 700 EUR/kW would be required to retire coal plants early, recognising that plants have different lifetime and depreciation schedules, and that many coal plants in other countries are newer than those in Germany.

Customer-backed securitisation

Financing the early retirement of coal-fired plants can put a strain on the balance sheets of operators which can be eased if utilities are able to refinance and obtain less expensive green financing products. Securitisation is the process of converting an asset or liability into a marketable security. IPPs in the United States have been piloting securitisation mechanisms where a low rate bond is issued to pay off the remaining debt tied to a coal plant and retire it early. The bond is generally issued by a separately created special purpose vehicle (SPV), and does not add to the general debt burden of the issuer, a key feature for usually highly leveraged utilities. A small increase in the costs paid by energy consumers is allocated to the SPV to match coupon payments on the bond. The increase in costs to consumers can be offset, at least in part, by the savings from switching to less expensive renewables generation.

Securitisation has significant potential to help utilities and customers absorb and reduce the costs of an early transition, though it does depend on the existence of a mature and developed financial market and a sophisticated regulatory regime. In the United States, four utilities are currently working on bond issuances specifically for the purpose of retiring coal plants, and are planning to assign some of the proceeds to just transition aspects. However, to date only one such bond has been issued for coal plant retirement and the ability for utilities to use securitisation is being challenged in courts on several grounds, including that energy consumers should not have to bear the cost of closing coal plants.

Sustainability linked bonds

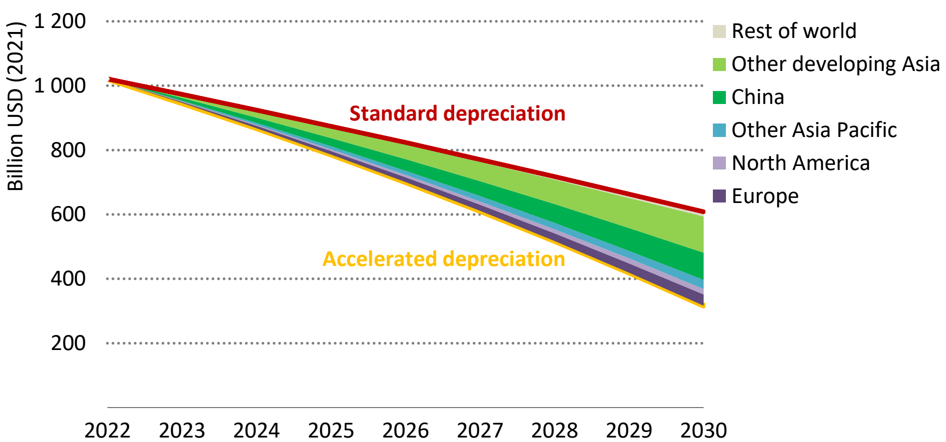
Other forms of company or organisation-wide securitisation could help to bring about the early retirement of coal plants. For example, transition finance in the form of sustainability linked bonds (SLBs) is a type of green debt where the issuer commits to meet certain sustainability targets in exchange for reduced coupon rates (the reduction disappears if they fail to meet the targets). SLBs can be issued by virtually any company and targets can include early retirement of coal plants. However, early feedback on SLBs show that these targets are often weak and the bond structure can allow for early repayments before the penalty actually kicks in. Green taxonomies, environmental, social and governance frameworks and public opinion might also hinder investor willingness to participate in financial transactions involving coal, even when the objective is to retire capacity early.

If implemented properly, transition finance has the potential to allow utilities to harness the power of global capital markets and raise lower cost financing for coal retirements. This could be especially useful in emerging market and developing economies, where the issuance of green debt has been lagging behind the levels seen in advanced economies. One possibility could be for emerging market and developing economies to package ambitious commitments on coal phase out into a green financing product to raise international funding, although it is uncertain whether this would gain access to a financing premium (sometimes referred to as a greenium). Another possibility is some form of debt-for-climate swap, whereby a creditor offers to reduce debt obligations in a borrowing country in exchange for commitments to mitigate, although no such swaps have yet been developed and put into practice.

Accelerated depreciation

Several utilities in the United States have gained regulatory approval to accelerate the depreciation schedule of their coal generation assets. This allows plant owners to record higher yearly depreciation charges than initially planned and recoup their initial investment faster by passing the additional cost to their customers. Depreciation allows a utility to completely write off a coal plant quickly while not forgoing any of its future cash flows as would be the case in a securitisation model. For their customers, on the other hand, accelerated depreciation implies higher energy bills with no certainty that they will derive any benefit from the accelerated depreciation, though they might conceivably do so, for example through a faster transition to lower cost renewables.

Figure 4. 17 ▷ Present value of capital remaining in coal-fired generation plants



Accelerated depreciation allows companies to recover their capital faster from coal assets and then redeploy it to renewables, but their customers have to pay

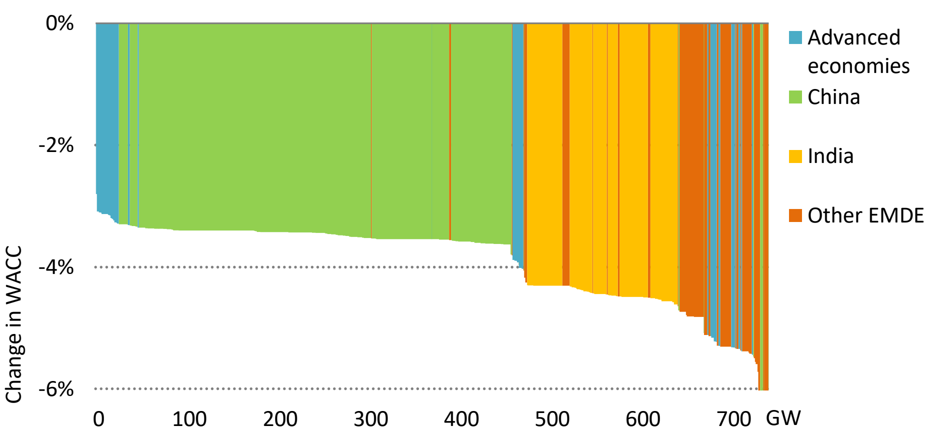
We modelled the impacts of an accelerated depreciation case where coal-fired power plants are allowed to shorten their depreciation schedule from 2022 and to recover the remaining capital left over the next ten years (Figure 4. 17). The results show the depreciation of about

USD 300 billion additional capital by 2030 compared with a business-as-usual scenario, and we estimate that this equates to an additional 820 GW of coal generation capacity has been fully depreciated and can be taken offline at no extra cost.

Concessional debt or refinancing

A detailed assessment of the weighted average cost of capital (WACC) for utilities, IPPs and other owners of coal-fired power plants worldwide was conducted for this analysis. Currently, the weighted average cost of capital of the world's coal plant owners and operators is around 6%, although this varies considerably over time and across different markets: for example, state-owned utilities in China own the vast majority of coal plants and their debt costs broadly correspond to China's sovereign borrowing costs. In Indonesia, the cost of capital is much higher as a result of lower financial credit ratings and higher default and off-taker risk. If China is excluded from the calculation, the average WACC is 7%.

Figure 4.18 ⊳ Reduction in weighted average cost of capital required for plant owner to self-finance a ten-year retirement plan



Financing cost to incentivise early retirement of coal-fired power plants is highest among emerging market and developing economies other than China

Note: WACC = weighted average cost of capital. Other EMDE = emerging market and developing economies excluding China and India.

The reduction in the cost of capital required to enable a sample of companies to retire their coal assets early in line with the trajectory in the APS, without any financial support from the international community is shown in Figure 4.18. This sample was chosen to highlight the range of required refinancing on the basis of a ten-year coal retirement phase-out plan starting in 2025. Its findings are in line with the APS, where the average reduction in the cost of capital needed to incentivise early retirement is 4% in advanced economies and China, and around 6% in other emerging market and developing economies.

It is worth noting that the corporate cost of capital, which should reflect the debt and equity on the entire balance sheet of the firm, may differ from an asset-level cost of capital, which may have been financed under different loan or equity conditions. It may have also been financed many years ago when the corporate cost of capital may have been very different. This has important implications for how assets might be valued or refinanced.

Box 4.2 ▷ Can multilateral development banks take on more risk?

The ability of multilateral development banks (MDBs) to engage more directly in coal retirement will be critical in emerging market and developing economies. Part of the business model of MDBs is to leverage their government provided capital and raise low cost debt on the bond markets to refinance the loans provided to developing countries (Table 4.3).

Table 4.3 ▷ MDBs debt-to-capital, Fitch ratings and average coupon rate

Institution	Debt/ capital (%)	Average coupon (bps)	Fitch rating	Fitch outlook
World Bank	84	153	AAA	Stable
Inter-American Development Bank	76	195	AAA	Stable
African Development Bank	76	162	AAA	Stable
Asian Development Bank	72	165	AAA	Stable
Asian Infrastructure Investment Bank	49	130	AAA	Stable
European Bank for Reconstruction & Development	71	203	AAA	Stable
European Investment Bank	86	163	AAA	Stable
Agence Française de Développement	84	110	AA-	Negative
New Development Bank	21	142	AA-	Negative

Notes: bps = basis points. Average coupon rate is the weighted average coupon rate of all bonds issued by the institution. Fitch ratings and outlooks are prospective evaluations of the credit worthiness of a country or a financial product.

Sources: Bloomberg LB (2022) and Fitch (2022).

MDBs have historically been prudent about the amount of debt they issue, but they are being asked to further tap into capital markets, i.e. issue more bonds, to raise funds to tackle today's multiple crises, including climate change. In this approach, MDBs could establish dedicated investment vehicles, e.g. loans, grants and guarantees, that target coal and refinance them through new bond issuances. MDBs have been quite cautious with their level of gearing, staying well below a 1:1 debt-to-capital ratio that does not take into account the additional callable portion of the capital they can potentially draw upon from their government shareholders in special cases. MDBs also keep a close watch on their issuer ratings, but the average cost of issuing debt, as materialised by the average coupon rate of their bonds, is only marginally impacted by these ratings.

On the other hand, increasing leverage may require MDBs to increase the quality and liquidity of their overall asset portfolio, and that may make them wary about getting involved in riskier investment areas such as the early retirement of coal-fired power plants. The Independent Review of Multilateral Development Bank Capital Adequacy Frameworks, commissioned by the G20 group, provided a few ideas on ways for MDBs to ramp up lending, notably by refining risk tolerance, giving further consideration to callable capital in financial decisions and attracting private sector finance through financial innovation (Kessler, M., 2022).

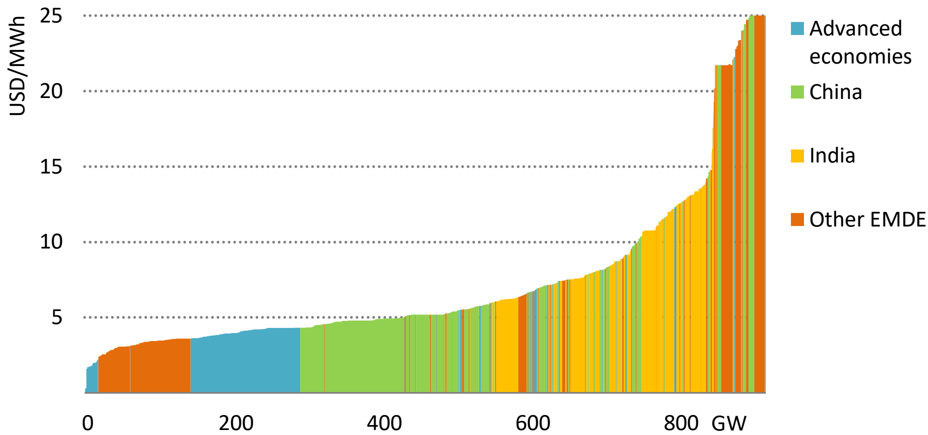
4.4.2 Provide incentives to repurpose coal power plants

The operating purpose of a significant share of current coal-fired capacity is modified in the APS to focus on providing adequacy and flexibility to power systems. Adequacy and flexibility are two services that become more valuable in systems with high shares of variable renewables. Existing dispatchable generators are among the least expensive ways of providing these services, but their owners may be reluctant to provide these services because they face significant uncertainties regarding their future operations. These uncertainties include a lack of knowledge about the market rules and instruments that will remunerate the services, the number of hours during which the capacity will be required and the predictability of dispatch.

As a result, there are risks that a plant could be retired from the system before the need arises for system services that these plants could provide - and yield benefit from. Governments can help manage such risks with instruments that change the incentives of plant owners. The principal way to do this is through a restructuring of the payments received for various services. Providing an adequate level of payment for services such as flexibility or capacity through the creation or improvement of remuneration schemes for capacity and ancillary services could incentivise a more flexible operating profile for many plants while also covering the additional capital costs they incur from reduced operating hours. Our estimate of the investment needed to cover the increased capital recovery costs related to the reduced operating hours in the APS compared to the Stated Policies Scenario is around USD 8 per megawatt-hour (MWh) on average, although there is significant variation in the coal fleet (Figure 4.19). Mechanisms of this kind would improve the cost of flexibility and capacity.

The adoption of carbon pricing would further incentivise coal-fired generation plant operators to consider shifting to the provision of capacity and flexibility services. A carbon pricing scheme together with payments for capacity and flexibility would establish a strong framework to ensure the cost-effective and transparent provision of needed services while reducing the amount of energy and emissions produced by the coal power plants. Revenues obtained from carbon pricing could be used to offset the costs of providing capacity and flexibility payments and to address just transition issues (Box 4.3).

Figure 4.19 ⊳ Increase in capital recovery costs to align the coal fleet with lower plant utilisation rates in the APS



On average, a capital recovery surcharge of USD 8 per MWh would be needed to repurpose coal plants over their remaining lifetime

Notes: MWh = megawatt-hour. Other EMDE = emerging market and developing economies excluding China and India.

In systems where markets are not the main method for recovering fixed costs for generators, which form a very large share of the coal fleet, different financing mechanisms might need to be devised. In this case, reverse auction mechanisms might prove an efficient way forward. Such auctions would in effect require different assets to compete for the level of support necessary for them to modify their operating pattern. The support needed for the winners of reverse auctions could be financed directly by energy users, but governments might also want to consider providing some support through debt forgiveness mechanisms. In some cases, PPAs and other contractual obligations may prove to be an impediment to coal-fired plants making a desired move to the provision of adequacy and flexibility services, and would need to be renegotiated. One option might be to buy them out with the support of climate financing.

Box 4.3 ⊳ Can carbon pricing help to ensure a just transition away from coal?

In recent years, a number of governments have introduced and expanded the coverage of carbon pricing instruments (CPIs) as they attempt to cut emissions in power and energy-intensive sectors. CPIs require those within their remit to pay for their carbon emissions or to cut them. This makes carbon-intensive technologies less economically competitive, triggering investments in lower carbon technologies and fuel switching to less carbon-intensive fuels. CPIs also raise revenue for governments.

If not carefully designed and implemented, CPIs can lead to unintended, regressive social effects such as direct or indirect cost pass through to consumers (which ultimately raises electricity bills) and perceived unfairness. Equality and inclusion should be built into any clean energy policy design, including CPIs, to prevent risks of exacerbating existing inequalities. Against this backdrop, the IEA Global Commission on People-centred Clean Energy Transitions provided action-focussed recommendations that aim to integrate just transition aspects into the policy design process (IEA, 2021).

If designed in line with these recommendations, CPIs can support just transition strategies and help people and communities move away from a reliance on coal. This could be done by earmarking part of CPI revenues and redistributing them among vulnerable groups such as poor households or coal mining communities. An approach of this kind is likely to enhance public support. CPI revenues, which amounted to USD 84 billion in 2021 (World Bank, 2022), could also be used to help governments implement social support or retraining programmes or develop new industries in regions that transition away from coal.

There are already some tangible examples of how carbon pricing can help to ensure a just transition away from coal. For example, the European Modernisation Fund recycles emission trading system revenues to fund the modernisation and decarbonisation of energy systems in coal-dependent regions (European Investment Bank, 2022). The European Union is also working to create a Social Climate Fund, using revenues from carbon pricing in the road transport and buildings sectors. It aims to earmark up to EUR 72 billion for the 2025-32 period to reduce costs through emissions reduction investments and to finance targeted and temporary direct income support for vulnerable households (European Commission,2021). Province-level initiatives in Canada are returning revenues from their CPIs to vulnerable households (World Bank, 2019). In the United States, the California Cap and Trade system requires at least 35% of revenues to be directed towards low income households and disadvantaged communities (ICAP, 2022).

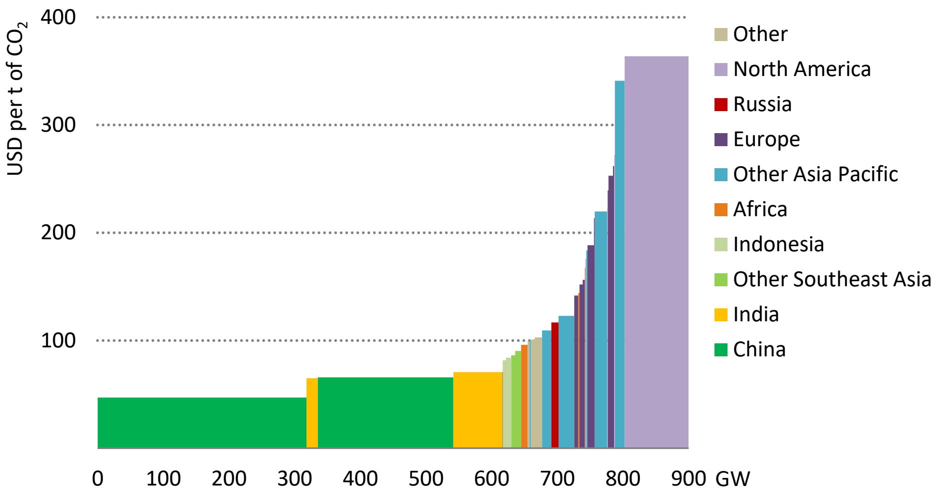
4.4.3 Stimulate investment in coal power plant retrofits

Retrofitting young coal power plants with carbon capture and storage or enabling them to co-fire with low-emissions fuels can be an effective route to CO_2 emissions reductions. So far, investments for these technologies are very limited, except for retrofits with biomass. CCUS has only been applied to three commercial power plants to date, though a number of projects are in the pipeline to equip coal plants with CCUS. Japan has led efforts to co-fire coal with ammonia in existing plants, with demonstrations of less than 10% ammonia co-firing. There are now plans for 20% ammonia co-firing in Japan in 2023 and in Korea and India in the next couple of years. In parallel, China successfully demonstrated 35% ammonia co-firing in 2022. Technical development and demonstration of 50% or more co-firing in Japan is expected by 2028, with plans for single fuel firing to start in the 2040s. Co-firing with biomass is the most widespread and is in use at more than 200 electricity and combined heat and power (CHP) plants. Biomass co-firing with coal was first adopted in northern Europe and North America, and is now in use around the world, including China, India and Indonesia.

The nature of investment in CCUS retrofits and low-emissions co-firing is very different, especially from an investor perspective. The cost of capital and the level of upfront investment vary considerably from one technology to another. Their supply chains vary as do their suitability in different circumstances. CCUS retrofits and low-emissions co-firing should be viewed as alternatives that complement one another rather than as rivals.

Investments in CCUS retrofits involve specific risks. The higher level of energy consumption required to capture and store CO_2 can increase fuel use per unit of output by around 20-30%, making fuel costs an important issue. The capital-intensive nature of CCUS technology also means that financial outcomes for investors largely depend on the level of capital expenditure required, cost of capital and future capacity utilisation rates.

Figure 4.20 ▹ Breakeven CO_2 price at which the levelised cost of electricity of a CCUS retrofit becomes comparable to an unabated coal power plant in the APS



With CO_2 prices of USD 50 per tonne, it would become economic to retrofit up to 300 GW of existing coal plants with CCUS; most of which are in China

Notes: CCUS retrofits are assumed to have a 2025 start date. Assumptions for fuel costs, efficiency, capacity factors, CCUS capital expenditure, operation and maintenance costs, and weighted average cost of capital are from the Announced Pledges Scenario. Transporting and storing CO_2 would cost an additional USD 10-40/t CO_2.

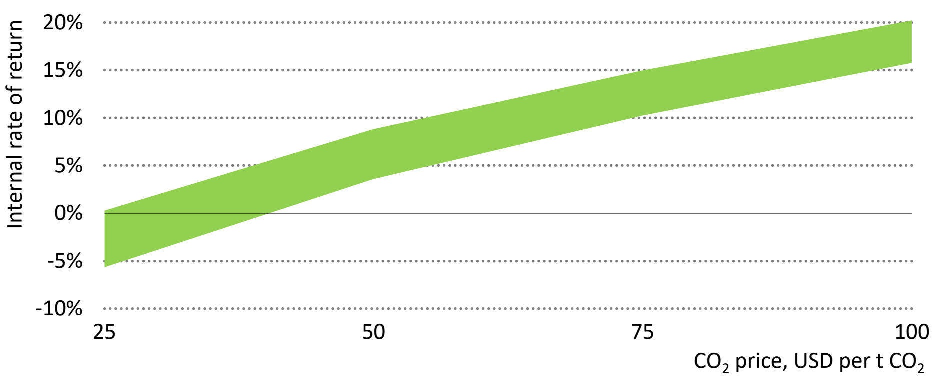
CO_2 prices are perhaps the most important tool for encouraging CCUS retrofits (Figure 4.20). At USD 50 per tonne of CO_2 (t CO_2), around 300 GW of coal power capacity in China would be more competitive, in levelised cost of electricity terms, if retrofitted with CCUS in the APS:

these would mostly be very efficient ultra-supercritical coal power plants with high future capacity utilisation factors. At prices in a range of USD 50-100/t CO_2, another 350 GW of supercritical and ultra-supercritical power plant capacity would become cost competitive in China, India, Indonesia, other countries in Southeast Asia and South Africa. Prices higher than USD 100/t CO_2 would be required in the APS to incentivise CCUS retrofits in Japan, Russia, Europe, Korea and North America, where the high penetration of renewables leads to considerably lower capacity utilisation factors for coal.

Other considerations also need to be taken into account. Some coal-fired power plants do not have the physical space onsite to integrate CCUS, while others have incompatible plant designs. Moreover, some technology types, such as subcritical plants or CHP units, are generally not good candidates for CCUS retrofits. But the most important consideration is that all plants would need to have access to CO_2 transport and storage infrastructure, and that would add between USD 10-40/t CO_2 captured to the breakeven price for the transportation and storage of CO_2.

Current CO_2 prices in the most attractive regions for CCUS retrofits, such as China or India, are still low or non-existent, but international co-operation could potentially help to change this. A notable option is set out in Article 6.2 of the Paris Agreement, which contains provisions for international co-operation between participating countries to achieve and enhance the objectives of their Nationally Determined Contributions by means of Internationally Transferred Mitigation Outcomes (ITMOs). With this mechanism, one mitigation outcome representing one tonne of CO_2 equivalent removed or reduced can be claimed either by the country that achieved it or by the partner country that purchased the ITMO.

Figure 4.21 ▷ Rate of return for a coal CCUS retrofit project in China earning revenue solely by selling CO_2 certificates



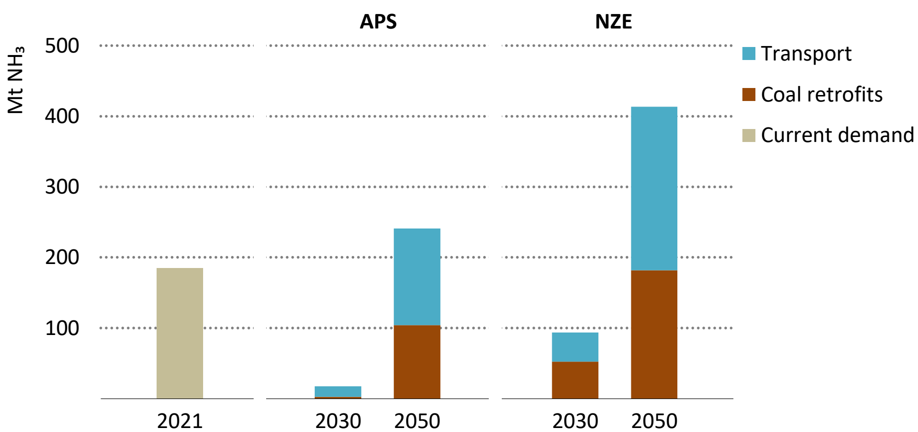
Investments to retrofit coal power plants with CCUS could be profitable if avoided CO_2 emissions are monetised with long-term contracts

Notes: The range includes different efficiencies for supercritical and ultra-supercritical plants. Transporting and storing CO_2 would cost an additional USD 10-40/t CO_2. The internal rate of return is real pre-tax. Plants assumed to operate at similar capacity factors to the current fleet in China.

Emissions reduction purchase agreements involving certificates of CO_2 reductions are another option (Figure 4.21). The seller of the certificate would have the certainty of the necessary cash flow to make the investment to bring about the CO_2 reductions, while the buyer would have a hedge against volatile CO_2 prices. At USD 50/t CO_2, investments to retrofit ultra-supercritical coal power plants in China in the APS would yield a rate of return of around 10%.

Co-firing with low-emissions fuels requires less upfront capital than CCUS retrofits but involves much higher fuel costs than coal combustion alone, meaning that the availability of sustainable finance may depend to a large extent on price, volatility and contract terms for the fuel used for co-firing rather than on the capital structure of the project. A further factor is that the level of emissions reductions depends on co-firing levels: these can vary considerably depending on relative costs and market conditions, which complicates the case for financial interventions that are based on the monetisation of avoided emissions. Co-firing may be best suited to mid-merit or peaking operations in electricity systems, especially those with high shares of renewables, that have frameworks in place that value the contribution of plants delivering low-emissions electricity on demand.

Figure 4.22 ▷ Additional ammonia demand related to co-firing in coal plants, and transport in the APS and NZE Scenario relative to current ammonia demand



Coal retrofits are set to account for over 100 million tonnes of low-emissions ammonia per year in the APS by 2050, and over 180 Mt in the NZE Scenario

Notes: Mt = million tonnes; NH_3 = ammonia. Future demand for current uses of ammonia is not presented in the figure.

Countries that support co-firing initiatives, such as Japan or Korea, do not generally produce low-emissions ammonia domestically and so would need to sign long-term procurement contracts with foreign suppliers. Their ability to do this depends on the development of low-emissions hydrogen and ammonia supply chains. Current ammonia production comes from fossil fuels, and only around 10% of the total demand is shipped. However, there is likely to be plenty of competition for low-emissions ammonia. At present, 90% of ammonia demand is to manufacture fertiliser and chemical products. Companies in these industries are actively seeking to decarbonise their supply chains: they may well be potential competitors for low-emissions ammonia, along with shipping. In the APS, international trade in low-emissions hydrogen and ammonia increases from low levels today to around USD 100 billion by 2050. In the NZE Scenario, this figure rises to around USD 300 billion, representing 30% of total energy trade (Figure 4.22).

4.4.4 Unlock investment for transitions in coal-dependent industries

To move the industry sector away from unabated coal in the APS requires USD 6 trillion of investment, the same amount as needed in the power sector. But, the similarities more or less end there. The emissions reductions that are achieved in the industry sector are about twice more capital intensive than in the power sector. The financing solutions for the power sector discussed here do not all work for the entire industry sector. There are no market-ready equivalents to low cost solar PV and wind power that are affordable and readily available as there are to replace coal-fired power generation. Instead, a shift away from unabated coal in industry largely depends on near zero emissions technologies that are not yet mature.

For the industry sector, bringing near zero emissions technologies to market in the next few years is crucial so that early deployment can begin in the late 2020s and large-scale deployment can take place from 2030 onwards. In the NZE Scenario, more than half of industrial emissions reductions are achieved by technologies that are not commercially available at scale today. Large-scale deployment is heavily dependent on the development of supporting infrastructure, such as CO_2 transport and storage, and hydrogen, and this too needs to be developed rapidly. All this poses a dilemma for financial institutions that like the certainty of consistent returns on established technologies and commercial pathways.

Both supply push and demand pull policy measures can play an important role to overcome these challenges and direct investment towards low-emissions solutions (Table 4.4). There may be opportunities for investors to seek higher risk, higher return, and early-stage investments in clean energy technologies. For example, technology start-ups may be able to raise considerable venture capital: recent examples in the industry sector include the funds raised by Brimstone to develop cement from alternative raw materials, and by Boston Metal and Electra for work on iron ore electrolysis. Though progress is likely to be insufficient without government involvement and financial support, together with international co-operation. It is important that governments hedge their bets by collectively supporting several technology options in parallel, and that they ensure sufficient funding is channelled to large-scale demonstration projects, which tend to carry the highest costs and risks in the process of innovation. Direct grants are likely to play a role, but there is scope too for instruments that minimise the taxpayer burden by leveraging private investment, such as public-private partnerships and low interest loans. Public sector financial support can also help ensure that knowledge is widely shared among various projects across regions.

Table 4.4 ▷ Policy measures to accelerate the transition to near zero emissions technologies in coal-dependent industries

Short-term Develop technologies and deploy innovative plants	**Medium to long term** Large-scale deployment
Supply push	
• R&D and demonstration support (direct funding, public-private partnerships, low interest loans, knowledge sharing platforms). • Retrofit-ready requirements for new construction and major upgrades. • Smart finance incentives to mobilise private finance (tax breaks, low interest loans, subordinate loans, debt guarantees, and early-stage equity investment). • Transition finance mechanisms and guidelines. • Plan to support infrastructure and industrial clusters, include streamlining permitting processes.	• Near zero emissions technology requirements for new construction and major upgrades. • International finance to support deployment in emerging market and developing economies. • Co-ordination and some limited finance to support large-scale deployment of supporting infrastructure.
Demand pull	
• Carbon contracts for difference. • Green public procurement. • Co-ordination and incentives to mobilise private sector buying pools.	• Minimum market share regulations (near zero emissions materials mandates). • Carbon pricing (emissions trading systems or carbon taxes). • Mechanisms to ensure a level playing field internationally (border carbon adjustments, sectoral agreements).

Technical considerations

A key consideration for designing financial support for deployment of near zero emissions industries is industrial facility life cycles. Average lifetimes of emissions-intensive assets such as blast furnaces and cement kilns are around 40 years. After about 25 years of operation, plants often undergo a major refurbishment to extend their lifetimes. This means that 2050, which is also the target year for the NZE Scenario, is only about one investment cycle away for heavy industry. This presents both challenges and opportunities in terms of investments.

Near-term investments in industrial facilities – both greenfield plants to expand capacity and refurbishments of existing facilities to extend their lifetimes – will need to be carefully managed. We estimate that if all existing industrial facilities were to be retrofitted or replaced with near zero emissions technologies at the 25-year investment decision point from now on, this would reduce projected cumulative emissions to 2050 from existing heavy industry assets by over 55%. Governments might use financial incentives such as tax breaks or low interest loans to nudge companies towards retirements or retrofits, though these mechanisms would provide less certainty than direct regulatory requirements.

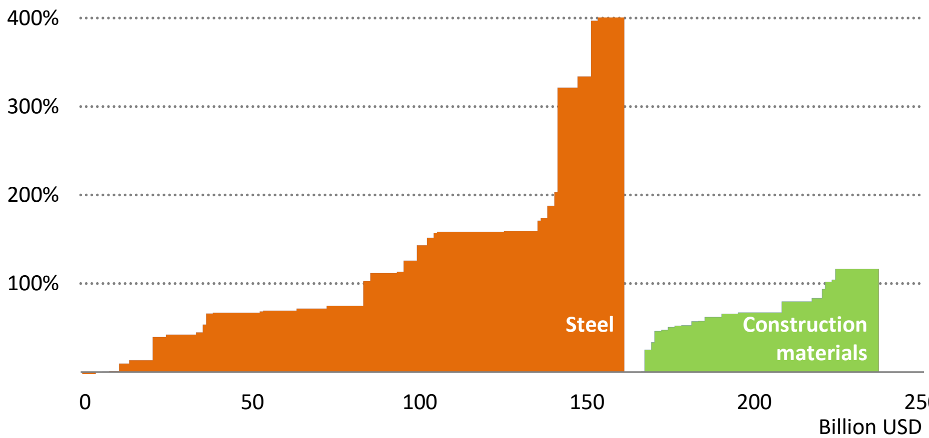
There are also opportunities to make transition investments that partially reduce emissions while near zero emissions technologies are being developed to the point where they are ready to be deployed at scale. Examples include blending hydrogen into blast furnaces or using bioenergy in cement kilns. Such interim solutions are likely to be lower cost and lower risk than a full switch to near zero emissions technologies. Governments could deploy transition finance mechanisms and guidelines to support these interim measures, taking care to ensure as far as possible that investments do not interfere with pathways to near zero emissions production or lead to stranded assets. Investments that are compatible with later near zero emissions production, e.g. hydrogen blending into a direct reduced iron unit that could later be switched to running fully on hydrogen, in most cases may represent the best use of government support. Private sector actors could also issue sustainability linked bonds to finance transitional measures, as has already been done by a number of cement companies, such as Lafarge and Ultra Tech.

Large-scale infrastructure will be necessary for technologies such as near zero emissions hydrogen, and CO_2 transport and storage. Government support and co-ordination will be important here too given the scale of infrastructure needed, the innovative nature of the technologies involved and the likelihood of cross-border projects. Possible models of infrastructure ownership include government-funded public utilities, new companies formed specifically to develop infrastructure, shared ownership among existing industrial companies, and shared public-private partnerships. Where governments do not own the infrastructure in whole or in part, funding through grants and financing support is likely to be needed, at least in the near term.

Commercial considerations

A key challenge for policy to address is that many near zero emissions technologies are expected to result in materials production costs that are roughly 10-50% higher than those of conventional technologies. In some cases this reflects higher operating costs as a result of increased energy costs or expenses for additional services like CO_2 transport and storage, and in others it reflects higher capital costs as a result of the need for new equipment, facilities or infrastructure. For example, the cost of an electrolyser for a typical 2 Mt capacity steel plant employing hydrogen-based direct reduced iron is estimated to be around USD 300 million, equivalent to 20-50% of the capital expenditure for a comparable plant operating on natural gas. The high upfront capital costs of low-emissions technologies pose a challenge for industrial producers given their thin margins, especially if they are largely funded by debt. For example, the debt-equity ratio of a sample of listed steel producers in emerging market and developing economies (other than China) shows an average gearing ratio of nearly 200%, constraining the ability of companies to raise the required debt to finance low-emissions demonstration projects (Figure 4.23).

Figure 4.23 ▷ **Debt-to-equity ratio and annual sales of listed steel and construction materials companies in other emerging market and developing economies**



Some steel companies in emerging market and developing economies have high levels of debt, constraining their ability to raise finance for low-emissions technologies

Note: Other emerging market and developing economies excluding China.

Public financial instruments can help ease the burden of these higher capital costs and at the same time make it easier to leverage private funds. These instruments might include concessional and sub-ordinated loans, debt guarantees, early-stage equity investment and tax incentives. Some industrial stakeholders already factor in assumed government financial support. For example, ArcelorMittal expects that half of the USD 10 billion that it plans to spend on decarbonisation technologies deployment will come from public funding (ArcelorMittal, 2021).

The challenge of capital costs is likely to be particularly acute in emerging market and developing economies where targeted international finance can provide support and help to leverage private finance. While a number of funds that could finance industry sector projects already exist, such as the CIF Industry Decarbonisation programme announced in 2021, a successful global transition will require advanced economies to scale up donor support substantially in order to make a significant impact on transitions in emerging market and developing economies (CIF,2021). There is also a need to improve the co-ordination of the activities of the MDBs, donor countries and recipient countries in order to ensure that funds are put to best use. The Energy Transition Council has pioneered a model for this type of co-ordination for the power sector that could be replicated in other sectors, including industry (ETC, 2022).

Whatever financial support is available, producers also need to feel confident that they will be able to sell near zero emissions materials, despite the higher costs. Here too targeted government support is likely to be needed in the early stages of deployment. Some work is underway on possible options. For example, Germany and France are working towards implementing carbon contracts for difference, which would involve governments agreeing to fund the carbon abatement cost for a guaranteed quantity of production. Green public procurement and private sector buying pools could help with subsequent early deployment, and these mechanisms are being promoted by international initiatives such as the Industrial Deep Decarbonisation Initiative and the First Movers Coalition. The cost premium for final consumers should be relatively small, since materials costs account for a relatively small portion of total product costs. For example, the premium for using near zero emissions cement in a concrete-framed home or near zero emissions steel in a mid-sized car is likely to be less than 1% of the total price. This suggests that mechanisms that help pass on costs to final consumers could be helpful.

In the medium-term, as larger scale deployment of innovative new technologies picks up and both costs and risks fall via technology learning, other mechanisms are likely to be needed to help bridge the remaining cost gap for producers, without causing a large impact on government budgets. Sufficiently high carbon prices might do much of the work here, but minimum market share regulations are another potential option. Mechanisms may also be needed to ensure a level playing field and prevent carbon leakage. If it is not possible to reach international agreements on issues such as carbon prices and materials standards, other options may be needed but should be considered a last resort. These could include carbon border adjustment mechanisms of the kind that the European Union is currently considering. International co-ordination and co-operation would greatly facilitate global industrial decarbonisation and simultaneously reduce the risks of trade friction. Any initiatives that could facilitate that are worth exploring: the climate club proposed by the G7 is one example.

Implications

Strategies for rapid, secure, people-centred change

S U M M A R Y

- Today countries accounting for more than 95% of total coal consumption worldwide have made net zero emissions pledges. In the Announced Pledges Scenario (APS), the implementation of these pledges brings profound changes for the coal industry and its workers, although changes in the next decade owe as much to labour productivity improvements as they do to net zero emissions pledges.
- Worldwide, around 8.4 million people work in the coal value chain that stretches from mining and transport to power generation. Most of these people – about two-thirds – work in coal production. Yet the outlook is for coal-related employment to decrease as mining productivity improves and countries implement their net zero emissions pledges. In the APS, coal value chain employment declines by about 2.3 million people in the period to 2030. Slightly more than half of this decline is caused by falling demand for coal while the rest is due to productivity improvements. Meanwhile, clean energy employment increases from 32 million to 54 million people by 2030.
- We examined the age profile of coal miners in four countries that represent around 90% of coal mining employment worldwide. The analysis suggests that the decline in employment in the coal mining sector projected in the APS would require between 245 000 and 615 000 workers to retire early. The lifetime foregone earnings from this group would be around USD 10-30 billion.
- We examined the coal-related employment situation in the 21 countries that are most exposed in the transition away from coal. The analysis reveals that comprehensive policies are not yet in place to secure just transitions for those who retire early or are otherwise affected by the phasing down of coal. Only five countries, representing 4% of global coal workers, have or are developing policies to equip workers for change, invest in new opportunities, and strengthen coal-dependent communities.
- Emerging best practice on just transition policies suggests that developing long-term plans on the basis of comprehensive stakeholder engagement is a critical first step. This should lead to a suite of measures that combines direct support for workers, measures to foster local cohesion and identity, and measures to stimulate local economic growth and diversification.
- In the APS, revenues from critical minerals exceed those from coal by 2040. An IEA first-of-a-kind analysis shows that 40% of coal miners worldwide today live less than 200 kilometres from a critical mineral mine or deposit, and fewer than 1% of coal miners live in countries without a critical mineral mine or deposit.

5.1 Introduction

At present, countries accounting for more than 95% of global coal demand have announced net zero emissions pledges. Making good on these pledges would bring the world close to achieving the temperature goals of the Paris Agreement (IEA, 2022a), and that is clearly welcome. But the net zero emissions pledges also have less welcome implications for the coal industry, for workers and countries that now depend on coal, even if new opportunities will emerge as the clean energy economy expands.

Against this background, this chapter looks at some of the implications for coal of the clean energy transition. Section 5.2 considers what lessons can be drawn from past coal transitions. Section 5.3 examines the challenge of bringing about people-centred transitions. Section 5.4 looks at the extent to which rapidly rising demand for critical minerals might offer new opportunities for countries and communities that currently depend on coal.

Box 5.1 ▹ Clarifying the terminology of people-centred and just transitions

This report makes frequent use of two terms in discussing the scope of policies necessary to cushion the negative impacts of coal transitions.

- **People-centred transitions**: This is a broad concept promoted by the Global Commission on People-Centred Clean Energy Transitions. It includes the labour market transition associated with transitions to clean energy alongside broad concerns such as energy affordability, energy access, socioeconomic development and an inclusive approach to policy making (IEA, 2021a).
- **Just transitions**: This term, as defined by the International Labour Organization, is primarily focussed on labour market transitions associated with transitions to clean energy, and in particular on seeking to ensure that they include the creation of decent work opportunities, support for workers impacted by energy transitions, effective social dialogue among all groups impacted, and respect for fundamental labour principles and rights (ILO, 2016). We use this term as a sub-set of people-centred transitions.

5.2 Three lessons from previous transitions

Major transitions in the coal sector in a number of countries have played out over the past 60 years. While each experience is unique in context and circumstances, a survey of previous transitions sheds light on potentially valuable lessons for forthcoming transitions. Three points focus this discussion.

5.2.1 Transitions in coal demand have often been relatively quick

A number of countries have already seen a peak in unabated coal in their total energy supply with subsequent decline. Among them, we focus here on the countries that meet the following criteria:

- *Sustained*: The peak in coal demand was sustained during at least ten years, and total unabated coal demand was at least 10% below the peak in the most recent available annual data.
- *Substantial*: Coal accounted for at least 10% of total energy supply in the peak year.
- *Growth compatible*: GDP growth was positive in the ten years immediately following the peak.

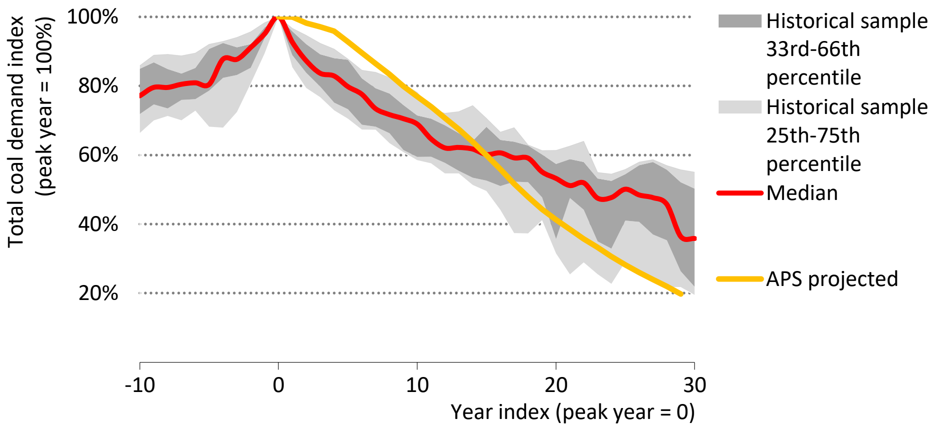
Applying these criteria provided a sample of 22 countries with peaks in coal demand that were sustained, substantial and growth compatible. A number of countries in the former Soviet Union are among those that do not meet these criteria: their coal transitions were driven by a collapse in their GDP after 1990 and do not qualify as growth compatible.

What were the patterns related to the peaks in unabated coal demand?

- The median peak occurred at a GDP per capita level of around USD 21 000 in purchasing power parity (PPP) terms, and GDP grew at a robust 3.3% per year in the ten years following the peak in unabated coal. Today China and India are the biggest consumers of coal: the median peak in our historical sample compares to a GDP per capita in 2021 in PPP terms of USD 19 500 in China and a little less than USD 7 500 in India.
- The coal demand peak, for the median country, occurred at a point when total energy demand was essentially saturated, rising only 0.2% per year in the ten years following the peak. This compares with 0.05% per year in China in the Announced Pledges Scenario (APS) over the next decade and 2.3% per year in India.
- Within ten years of the peak, unabated coal demand in the median country fell by roughly one-third. Within 20 years, unabated coal demand declined by half for the median country. These trends are roughly in line with the speed of the decline in global unabated coal demand after it peaks in the APS (Figure 5.1).

We conducted similar analysis for coal use in the power sector, looking at ten-year episodes where unabated coal generation fell in a manner that was sustained, substantial and growth compatible. The analysis was conducted on the basis of 33 episodes that meet these criteria. Figure 5.2 shows the decline in the use of unabated coal in electricity generation, growth in the main alternative source, and change in total electricity demand, all expressed as a percentage of total generation from all sources at the start of the ten-year transition period. Most coal transitions were driven by increases in wind and solar photovoltaics (PV) and natural gas, although a smaller number were driven by increases in hydropower or nuclear power capacity.

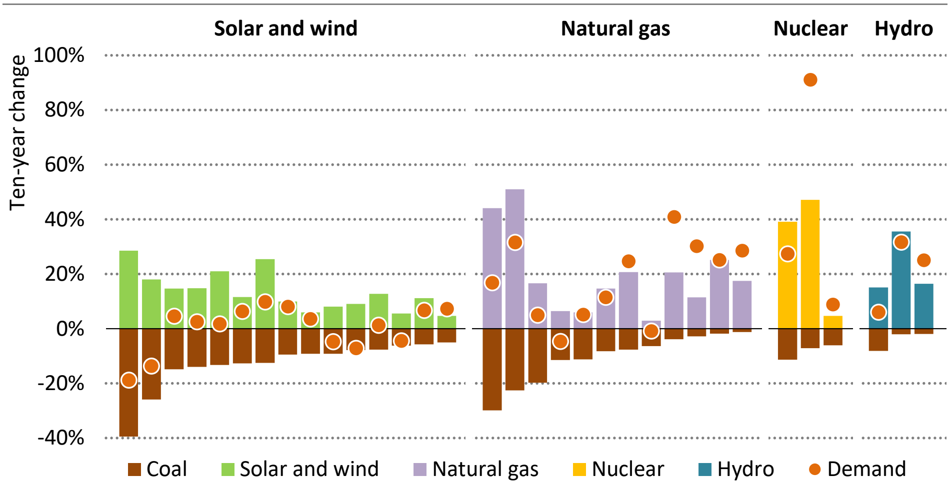
Figure 5.1 ▷ Historical peaks in total coal demand, 1960-2020 relative to the APS, 2020-2050



Historical transitions away from coal have occurred roughly as fast as the global transition seen in the APS

Note: APS = Announced Pledges Scenario.

Figure 5.2 ▷ Ten-year episodes of coal transitions in electricity generation as a percent of total generation in the start year, 1960 - 2019



Transitions in which renewables took a bigger role tended to be in a context of low growth in electricity demand

The largest number of observed transitions away from unabated coal in the electricity sector were driven by the uptake of wind and solar PV. These transitions were in economies where the rate of growth in total electricity generation was often modest or even negative.[1] The median rate of demand growth during the ten years after the peak was 0.2% per year, and the median rate of solar PV and wind growth relative to total generation at the start of the period was 1% per year. This highlights the critical importance of scaling up renewables fast enough to provide an alternative to coal in power generation, particularly in emerging market and developing economies with increasing demand for electricity. It is also worth noting that, although wind and solar PV replaced a larger share of the energy provided by coal than other fuels, they did not provide a substitute for the system services provided by coal-fired power generation (see Chapter 2).

The median rate of electricity demand growth in natural gas driven transitions was higher (1.9% per year) than in the transitions to wind and solar PV (0.2% per year). The median rate of growth of the main substitute fuel source (natural gas) was also higher (1.6% per year).

5.2.2 Economic factors have been the main drivers of transitions in coal employment

Transitions in the United States, United Kingdom and China

Some countries have already experienced very large absolute declines in coal mining employment (Figure 5.3). For example, coal-related jobs in the United States in 2019 were 93% below their peak in 1923. The equivalent figure for the decline from the peak year in the United Kingdom is over 99% and in China it is around 50%.

Previous coal transitions were driven by a combination of factors. These include: declining domestic demand; changes in the relative prices of competing fuels; decreased competitiveness of domestic production; air pollution regulations; and productivity gains. Substantial improvements in coal mining labour productivity have been particularly significant in reducing employment levels in coal mining.

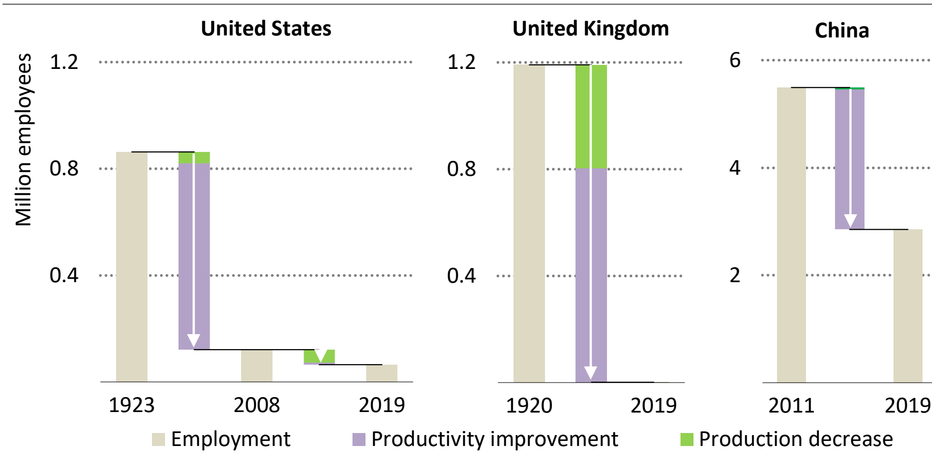
In the **United States**, coal production first peaked in 1918 at around 565 million tonnes (Mt) per year: it then fell as a result of the rise of oil as an alternative fuel. A second peak, at a similar level, occurred in the mid-1940s: production then fell after the end of the Second World War. In 2008, production peaked for a third time at the much higher level of 1 060 Mt: it then fell as the shale revolution made natural gas more competitive than coal and as renewables were increasingly being deployed in electricity generation. Coal production has since fallen steadily.

Coal mining employment peaked well before the peak in production. Jobs in coal mining saw a record high of 863 000 in 1923. The subsequent drop in employment was mainly due to

[1] The sample here includes only episodes where the growth in the main source of generation that substituted for coal was larger than the decline in total generation, if total generation declined during the episode. If total generation declined more than the growth of the main substitute source, the episodes were classified as demand-led and not included.

productivity gains from mechanisation and from structural shifts to less labour-intensive coal basins. From the early 1800s to mid-1960s, around 80% of US coal production came from labour-intensive underground mines in the Appalachian Basin, which spans Ohio, West Virginia, Pennsylvania and other eastern states, and in the Illinois Basin. In the 1970s, a change in coal leasing policies opened vast untapped reserves in the Powder River Basin in Montana and Wyoming. Coal in the Powder River Basin was highly competitive because it came from less labour-intensive open pit mines and had relatively low sulphur content. Productivity as measured by coal output per hour worked has increased at more than 3% per year since 1950 in the United States, which is 60% faster than the growth of labour productivity across the economy as a whole.

Figure 5.3 ▹ Drivers of change from peak coal mining employment in United States, United Kingdom and China to 2019



Productivity improvements spurred historic declines in coal mining employment as production shifted to more competitive mines and processes were mechanised

Notes: Coal sector employment peaked in 1923 in the United States, 1920 in the United Kingdom and 2011 in China. In the United States, coal production reached its most recent peak in 2008, a notable time difference from the employment peak in 1923.

In the **United Kingdom**, coal production peaked around 1913 at a time when the number of jobs in the coal sector exceeded 1 million. Coal industry jobs at this point accounted for around 7% of total national employment, and one-third of total employment at sub-national level in major coal mining areas. Coal exports fell from almost 100 Mt in 1913 – around one-third of total production – to 47 Mt in 1938, primarily because of a decline in competitiveness. After the Great Smog of London (1952), domestic coal consumption peaked in 1956, the same year as the adoption of the UK Clean Air Act.

Over the ten years following the Clean Air Act, coal consumption in the United Kingdom fell by one-fifth, with large reductions in coal use in rail transport, buildings and industry. But coal mining employment started to decline well before the peak in consumption, driven by improvements in labour productivity. It was 35% below its peak by 1938 and 75% below by 1970. By the time of the coal mine strikes in the early 1980s, it was almost 90% below its peak. The miner strikes of 1984-85 were followed by mine closures and coal mining employment fell by a further half within a few years.

In **China**, coal production increased from around 30 Mt in 1950 to around 1 000 Mt in the early 1990s. Then it ramped up significantly in the 2000s, averaging 9% per year over the decade, driven by expansion of heavy industry and electricity demand. Mines are clustered in Shanxi, Inner Mongolia and Shaanxi provinces, all of which are relatively close to industrial centres. Coal production in China has averaged around 3 400 Mt over the last decade, far exceeding the peaks seen in other countries. Production is likely to further increase in 2022 as China strives to replace imports with domestic coal. China remains the world's largest producer and consumer of coal today, but record production has not prevented a significant drop in employment in coal mining (Box 5.2).

Box 5.2 ▷ Decline of coal mining employment in China

Heavy coal use in China led to rising concerns in the 2000s about severe air pollution and its effects on public health. This prompted the government to release the National Air Pollution Control Action Plan in 2013 and to produce the National Energy Development Strategy Action Plan 2014-2020 to cap coal use by 2020 while investing in solar PV, wind, hydropower, nuclear and natural gas as alternatives. The government also launched efforts to close old coal power and mining capacity, close illegal mining operations, consolidate remaining coal mines, and improve the competitiveness of the coal and steel industries. These reforms collectively led to a rapid reduction in coal mining employment from 5.3 million in 2013 to around 2 million in 2021 (Clark and Zhang, 2022).

To help manage the impact of job losses in the coal industry, the Ministry of Finance allocated renminbi (CNY) 100 billion in 2016 to the Industrial Special Fund (about USD 15 billion at 2016 exchange rates). This fund was structured as a bonus payable to provincial governments and state-owned enterprises for capacity cuts. The funds were intended to provide payments to workers in the coal and steel industries that had lost jobs, to help workers that were looking for new jobs, to create new jobs in the public sector and to fund retirement benefits for eligible workers. By the end of 2020, this fund had helped 1 million coal mine workers to find new jobs (China National Coal Association, 2021).

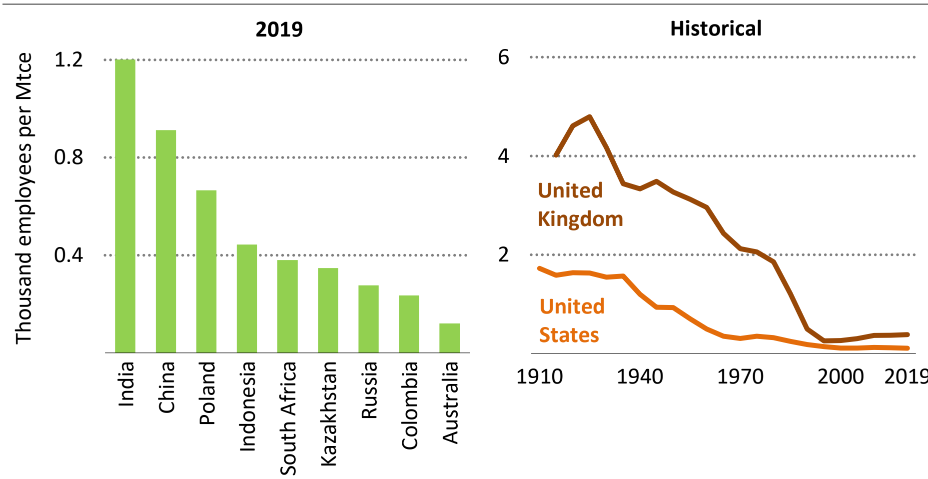
Support provided at national level has been supplemented at sub-national level. Shaanxi, the third biggest coal producing province, cut almost 56 Mt of coal production capacity per year and closed 157 coal mines over the 2016-20 period. It received around CNY 11 100 - 17 500 per coal worker from the Industrial Special Fund to support workers to find new jobs (Shaanxi Provincial Energy Administration, 2021). When the nationwide Industrial Special Fund ended in 2020, Shaanxi Province launched its own programme to allocate support to areas based on the size of their coal capacity cuts.

Based on a calculation of support per worker assisted, the financial support from the Industrial Special Fund represented less than 20% of the average annual wage of public sector employees and around two-fifths of the annual wage of private sector employees in the mining sector in Shaanxi. This is unlikely to have been sufficient to support all coal workers affected by the capacity cuts.

The success of workers to move to new jobs may have had much to do with economic growth in sectors other than coal. Since 2013, for example, Shaanxi has invested in the production of industrial equipment, motor vehicles and electronic components, and in new sectors such as financial services and tourism. However, some major industry developments are still linked to coal: the Yulin City region that produces three-quarters of Shaanxi's coal is being transformed into a chemical industry hub with a – potentially very emissions intensive – coal-to-hydrogen production plant.

Role of labour productivity in driving transitions

Figure 5.4 ▷ Labour intensity of coal mining by selected major producer countries, 1910-2019



Labour intensity varies significantly across regions today, but is consistently well below historical levels

Note: Mtce = million tonnes of coal equivalent.

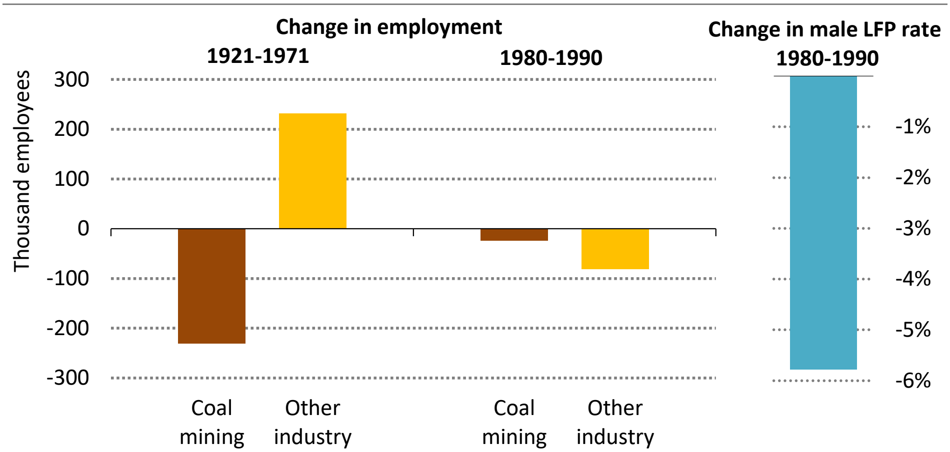
Labour intensity in coal mining varies significantly across regions which reflects differences in geological conditions, mining methods and labour market conditions. Countries such as China and India employ ten-times more workers per tonne of coal produced than Australia or the United States. Yet, in China and India labour intensity in coal mining is around four-times lower than the United Kingdom in 1913 (Figure 5.4). Modern coal mining accounts for a much smaller proportion of total employment in major producer countries today than in the past. Because of huge reductions in labour intensity, direct coal mining jobs do not play the same role in supporting broad-based employment growth and middle-class jobs in major coal mining regions today as they did in the past.

Coal transitions in a broad industry sector context

Coal transitions in advanced economies have often been accompanied by labour market changes that were as large, and often much larger, than changes in the coal industry. This is illustrated by the case of Wales, which at its peak represented over one-fifth of coal production in the United Kingdom. At the peak of coal production in 1913, coal mining accounted for one-quarter of total employment in Wales, and nearly 35% in the counties of Glamorgan (157 000 workers) and Monmouthshire (60 000 workers). The share of coal mining in total employment was an order of magnitude above what we see in major coal mining areas today (see Chapter 1, Table 1.1).

Wales lost around 80% of its coal mining jobs from 1921 to 1971. Although punctuated by the Great Depression, the transition from coal mining was accompanied by increasing industrial employment, which provided a generally favourable labour market context for blue-collar workers leaving the coal industry (Figure 5.5). Wales gained almost exactly as many industrial jobs as those lost in the coal industry over that 50-year period. By 1971, approximately 40% of jobs in Wales were in industry, mostly in manufacturing.

Figure 5.5 ▷ Changes in employment and male labour force participation in Wales, 1921-1971 and 1980-1990



Coal miners that lost jobs in Wales in the 1980s encountered a very unfavourable labour market that lacked alternative opportunities

Notes: LFP = labour force participation. Other industry includes manufacturing and construction.

Sources: IEA analysis based on data from Welsh Government (1985) and Welsh Government (1998).

The context changed in the 1970s and 1980s when a parallel decline in both industrial and coal sector jobs created adverse labour market conditions for male blue-collar workers. The magnitude of job losses in other industry sectors far outweighed job losses in coal: for every job lost in coal, nearly three-and-a-half jobs were lost in manufacturing and other industry sectors. Over the course of one decade, the labour force participation rate among male working-age population decreased by almost six percentage points.

Previous coal transitions in advanced economies were often accompanied by a lack of supportive policies, but in Wales what really mattered in terms of new job opportunities was the broad labour market. In the same way, the challenges of just transition in coal-intensive regions in emerging market and developing economies should be considered in the context of the broad development challenges and labour market transitions that they face.

5.2.3 Previous transitions were largely unanticipated

Policies to manage socioeconomic impacts came too late

Governments have often intervened to sustain domestic coal production, but these interventions have rarely been effective in the long term. For example, Germany provided over EUR 280 billion in subsidies for coal production from 1958 to 2018, but domestic production remained uneconomic and continued to decline (Herpich and Brauers, 2018). Similarly, Poland provided subsidies for coal production of around USD 25 billion from 1990 to 2016 along with almost USD 1.5 billion per year for coal miner pensions (Śniegocki et al., 2022). As in Germany, the subsidies failed to halt a gradual decline in production. In some cases, governments gave companies one-time transfers to make needed upfront investments in mechanisation and productivity improvements, though many operations then slid back into deficit. In other countries, coal production was nationalised or privatised to inject new capital; but these policies could not compensate in the long run for mines with geological conditions that led to high production costs.

Shifts in coal mining have not always been effectively anticipated by policy makers and companies, and played out with inadequate efforts to help those affected in coal-dependent areas. Governments may have provided some compensation to affected workers when coal mining jobs were lost, but initial responses sometimes proved relatively ineffective and were subsequently supplemented by additional measures to support broader community and economic development in response to socioeconomic challenges.

In the United Kingdom, for example, workers who lost their jobs when mines closed in the 1980s were offered redundancy payments and were eligible for unemployment and incapacity (disability) benefits. But it was not until 1997 that government established the Coalfields Task Force and enacted measures to help redevelop coal communities. These included efforts to rehabilitate land at over 100 coal mines for productive use such as housing and industry, and to channel European Union funding to support for local infrastructure, businesses and vocational training. From the outset, the Welsh Development Agency sought to attract investment and create jobs, but new infrastructure projects generally were not located in the areas where coal-related unemployment was the highest (Merill and Kitson, 2017).

In the United States, many coal mining areas in Appalachia took advantage of local grants and investments provided by the Appalachian Regional Commission to develop their own transition strategies focussed on education and economic diversification. For instance, Athens County, Ohio launched a retraining programme to help former coal miners and their families find well-paid jobs in other industries after the closure of the last coal mine in 2002. Some coal mining areas have benefitted from broad infrastructure development support from the Tennessee Valley Authority since the 1930s and later from the Appalachian Development Highway System (Lobao et al., 2021). In 2015, the federal government funded the Partnerships for Opportunity and Workforce, and the Economic Revitalization (POWER+ Plan) to support economic diversification, job creation and employment in the Appalachian region. Funding was also allocated for remediation of abandoned mines, as well as for schools, public health services and cultural amenities to attract investment and diversify local economies. However, this package was designed and implemented long after coal production and employment in Appalachia had begun to decline.

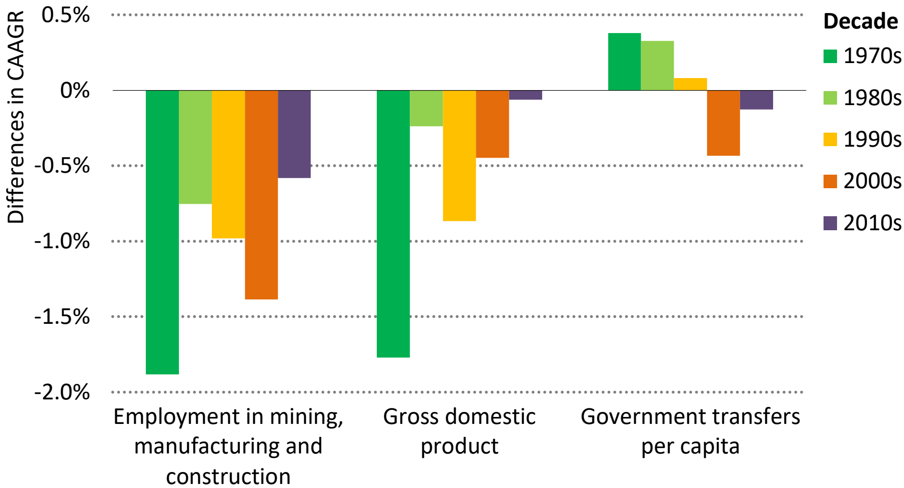
Coal regions were often left with profound and long-lasting socioeconomic scars

Measures taken to support workers and communities in the face of coal mine closures have often not been able to compensate for the associated socioeconomic challenges. Decades after the transitions began, coal mining communities often still lag behind much of the rest of their respective countries.

Across the United Kingdom, for example, every former coal region still has lower employment levels than the nationwide average. In many regions, the employment rate is 5-10% below the level in southeast England (Beatty, Fothergill and Gore, 2019). In Wales, around 15% of working-age males lost their jobs during the 1980s with mine closures and deindustrialization, leading to a rise in poverty and to people moving away from the affected counties. The failure to attract new industry with blue-collar jobs into former coalfields led to many miners being unable to find new jobs (Rising et al., 2021).

In the United States, the loss of jobs in the coal mining industry has had broad socioeconomic impacts. The Appalachian Basin, once the cornerstone of the country's energy supply, has seen coal mining jobs decline from about 500 000 to just 30 000 over the last century. It has struggled for decades with high levels of poverty and public health crises, and its employment and GDP growth lag behind the rest of the country (Figure 5.6). As in other coal regions around the world, access to alternative opportunities was hampered by geographic isolation and lack of infrastructure and training opportunities. As a result, it proved difficult for a large mining workforce to find other blue-collar jobs, especially against the background of a nationwide decline in manufacturing jobs.

Figure 5.6 ▷ Selected socioeconomic indicators for Appalachian Basin counties relative to the rest of the United States, 1970-2020



Following coal mine closures, Appalachia's employment and GDP growth rates have lagged behind the rest of the country for decades

Notes: CAAGR = compound average annual growth rate. Computations are based on county-level data except for gross domestic product for 2000 and before which is available only at the state level.

Source: US Bureau of Economic Analysis (2022).

5.3 People-centred transitions

5.3.1 Employment

Jobs today

In 2019, almost 8.4 million people worked in coal value chains, including 6.3 million in supply (both production and transportation) and 2.1 million in power generation (Figure 5.7). These numbers include our best estimate of informal workers as well as those formally employed. The largest number of coal supply jobs are in mining, the most labour-intensive part of the value chain, but the transportation, washing and processing of coal also provide many jobs. Fewer workers are employed in the manufacturing of specialised mining and conveyance equipment. These data include indirect jobs related to the manufacturing of essential components for coal infrastructure, but they do not include jobs for coke manufacture or jobs in industrial sectors that rely on coal as an input (IEA, 2022b).

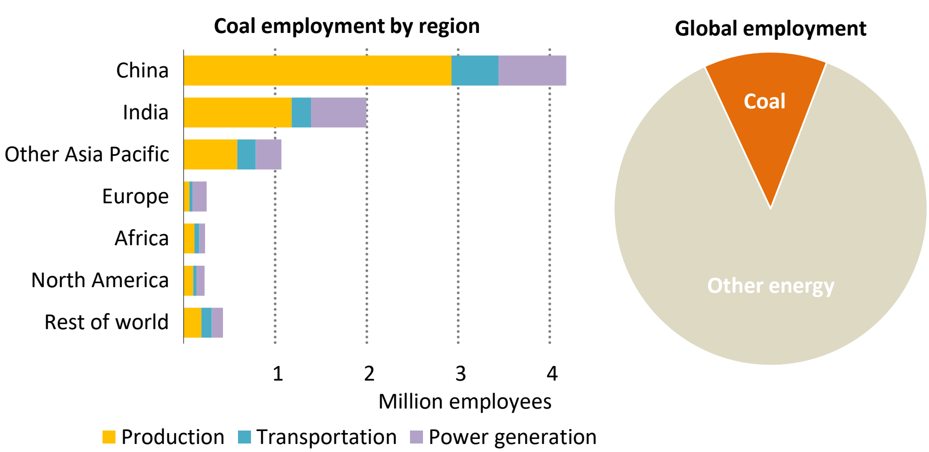
Jobs in coal supply and in coal-fired power generation account for around 0.25% of total global employment, but they tend to be concentrated in areas around coal mines where entire communities may be dependent on income generated in the coal industry (see

Chapter 1). In these regions, coal revenues are critically important for the operation of many other businesses and industries and hence for the jobs they provide.

Today coal supply jobs are concentrated in Asia, with 3.4 million coal workers in China, 1.4 million workers in India, and around 470 000 workers in Indonesia. These three countries, which together account for over 80% of all coal supply jobs, have less mechanised coal industries than in advanced economies, and this is a factor in the overall size of their coal workforces. In recent years, some key coal producers have seen declining employment as labour productivity has improved, in part because of increasing mechanisation. For example, China reduced coal mining employment by almost 2.5 million jobs between 2013 and 2019 while maintaining production volumes.

Coal jobs in power generation involve tasks such as operating and maintaining existing plants, constructing new capacity and manufacturing components such as boilers, turbines and generators. An estimated 740 000 workers were employed in coal-related power sector jobs in China in 2019. This compares with around 150 000 in Europe and over 80 000 in North America, where these jobs have been declining in recent years.

Figure 5.7 ▷ Coal employment by region and share of total global employment in energy, 2019



China has more than 4 million coal workers and India has 2 million, but coal still accounts for less than 1% of the total workforce in each country

Formally employed coal miners around the world tend to be relatively well paid. This stems in part from established labour representation, which has pushed for higher pay and benefits as well as better health and safety standards. In the United States, annual wages average USD 46 000 in coal supply and USD 61 000 in the coal-related power sector, both of which represents a substantial premium over median economy-wide wages. Labour union representation covers 12% of coal supply workers in the United States, compared with a 6%

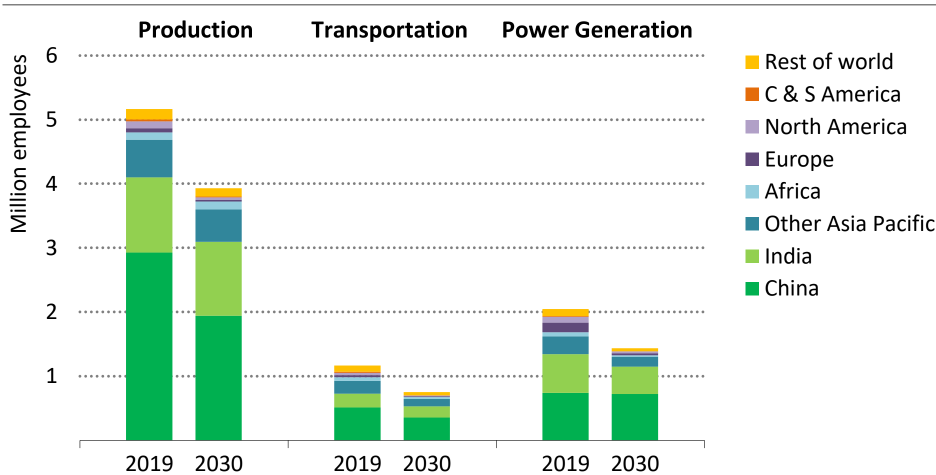
average across the private sector (US DOE, 2022). In India, the average annual wage for workers in coal production is USD 5 000, around 4.5-times the average wage of a worker in production sectors including mining, manufacturing and construction (India, Ministry of Statistics and Programme Implementation, 2021). Coal is the only sector in India with its own pension scheme, which is co-financed by the government and industry.

In the informal sector, both pay and working conditions are often poor. Especially in illegal mining operations, informal coal workers can find themselves facing life-threatening risks in the absence of safety measures and properly maintained mining shafts. Although informal coal miners earn just a small portion of a formal worker salary, the informal coal sector is an important source of livelihoods for many people.

Job changes in the Announced Pledges Scenario

Countries with net zero emissions targets currently account for more than 95% of coal consumption and employment along coal value chains. In the APS, total coal employment declines from 8.4 million in 2019 to 6.1 million in 2030. Some of this decline is due to a fall in coal production and consumption as countries make progress towards their net zero emissions targets. It also reflects improvements in productivity and increased mechanisation; assuming continuation of historic trends, about half of the jobs lost can be attributed to labour productivity gains. Around 1.9 million coal jobs are lost in emerging market and developing economies and 370 000 in advanced economies in the period to 2030. Countries that export coal are among those that experience job losses.

Figure 5.8 ▷ Coal employment by region and value chain segment in 2019 and in the APS in 2030



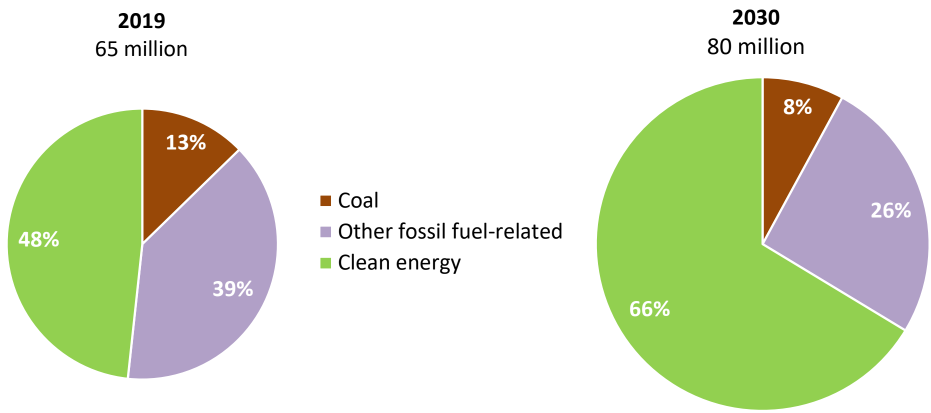
IEA. CC BY 4.0.

Coal employment declines from 8.4 million in 2019 to 6.1 million in 2030 due to increased mechanisation and policies to phase down coal use

Note: C & S America = Central and South America.

The bulk of jobs lost in the APS, around 2.3 million, are in coal supply. Production declines by about 20% worldwide to 2030, but there would be a large reduction in coal mining jobs even if coal production did not fall, as increased mechanisation reduces the need for low skilled labour. In China, for example, around 40% of the 1.1 million jobs lost in coal mining to 2030 are related to improvements in labour productivity (IEA, 2021b). Coal-fired power generation accounts for around 750 000 additional job losses, most of which are associated with the decline in construction of new plants (Figure 5.8).

Figure 5.9 ▷ Energy sector employment in 2019 and in the APS in 2030



Energy sector employment increases by 15 million by 2030, with a pronounced shift to clean energy and away from coal

Notes: Coal includes employment in coal supply and power. Other fossil fuel-related includes employment in oil and natural gas supply and power, and manufacturing of internal combustion engine vehicles.

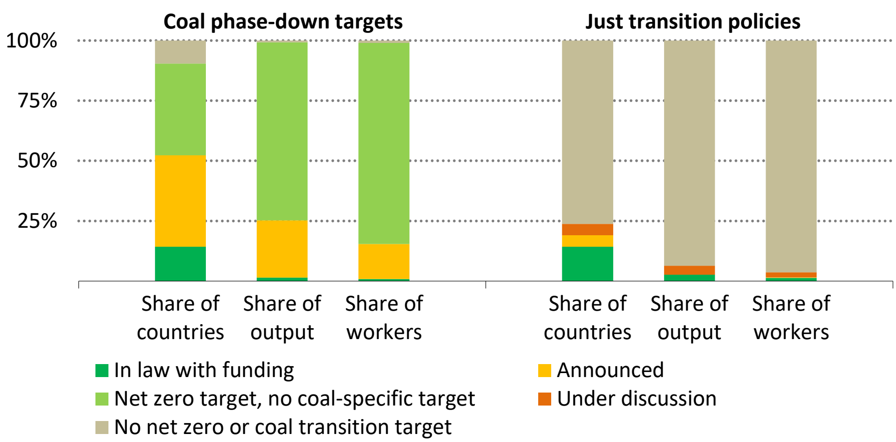
Coal-related jobs account for a declining share of total energy sector employment in the APS (Figure 5.9). Despite an increase in employment at coal plants with carbon capture, utilisation and storage (CCUS), they fall from 13% of the total in 2019 to 8% in 2030. Coal employment sees a sharper decline than either oil or natural gas employment, making it an area of particular concern in terms of just transitions policies. The decline in coal sector jobs forms part of a broader shift in energy sector employment to clean energy, which increases from around 32 million jobs in 2019 to 54 million jobs in 2030, thanks in particular to increasing numbers of jobs focussed on delivering low-emissions power generation and improving end-use efficiency.

5.3.2 Just transition policies

Current status

Of the 21 countries that rank the highest on the IEA Coal Transitions Exposure Index, 17 have established net zero emissions targets in law or made net zero emissions pledges, and 11 have announced or implemented targets to reduce or phase out their use of coal (see Chapter 1, section 3). It is notable that only five countries, which represent a mere 4% of the world's coal workers, have implemented, announced, or initiated discussions on just transition policies for the coal workers and communities affected by transitions away from coal (Figure 5.10). This suggests an urgent need for more countries to consider how best to help the workers and communities that stand to lose coal-related jobs, especially in the most coal-dependent areas.

Figure 5.10 ▷ Coverage of coal phase-down targets and just transition policy in countries high on the Coal Transitions Exposure Index



Half of the most coal-dependent countries have coal phase-out targets, but very few have related just transition policies

Notes: The figure represents the 21 highest-ranked countries in the IEA Coal Transition Exposure Index, which account for over 95% of global coal production and employment. Just transition policies include those designed for coal workers in the context of energy transitions, but not broader labour policies. Announced coal phase-out targets include pledges in the Global Coal to Clean Power Transition Statement (COP 26) and the May 2022 G7 announcement.

A framework for best practice in just transition policies

An important first step is comprehensive stakeholder engagement with the goal of reaching broad consensus around the transition. Mapping existing human resources and infrastructure in affected communities can be useful to identify alternative industries that could make the most of local comparative advantage. Several countries, including Canada, Czech Republic, Germany, Spain and South Africa, have convened national task forces or commissions to estimate the financial implications of socioeconomic challenges and to provide policy recommendations.

Assuming that a timeline has been established for a coal transition, the next step is to agree on a set of just transition policies (Table 5.1). To date, such policies have tended to address three complementary objectives, which together offer tailored support to the people directly affected by job losses and also provide help to sustain local economies and communities.

- Support workers and companies directly affected by the energy transition, including through inclusive policy-making processes.
- Develop alternative industries and stimulate macroeconomic growth in the region to provide additional opportunities for local workers and companies.
- Promote environmental rehabilitation in the affected area to enhance its attractiveness and growth potential, and foster local culture and identity to strengthen social cohesion and improve quality of life.

5

Table 5.1 ▷ Just transition policies in selected countries

	Canada	Germany	Korea	Poland	South Africa
Net zero emissions or carbon neutrality target	2050	2045	2050	2050*	2050
National coal phase-out target	2030	2035	2050	2049**	
Support for workers					
Direct payments and compensation	🟢	🟢	🔵	🔵	🔵
Training, education, career services	🟢	🔵	🔵	🔵	🔵
Support for industry development and economic diversification in coal communities					
Coal decommissioning or retrofits	🟢	🟢		🔵	🔵
Clean energy industries	🟢	🟢	🔵		🔵
Non-energy industries	🟢	🟢	🔵	🔵	🔵
Holistic support for coal communities					
Environmental rehabilitation		🟢			🔵
Community identity and cohesion					🔵

🟢 Policy enacted with funding 🔵 Policy announced or recommended by a just transition commission

* Reflects the European Union objective of carbon neutrality by 2050. **Applies only to hard coal mining.

Notes: Both national and sub-national policies are included. Broader labour market policies are not included.

Many governments have introduced measures to supplement typical labour policies for coal workers in recognition of the reality that accelerated coal transitions generally happen over a short period of time and are concentrated in specific areas. Measures include short-term income support such as severance compensation packages, welfare payments and provisions for early retirement. In Germany, the government provides tax-free income support and a subsidy for health insurance to coal workers made redundant. In Poland, government and trade unions have signed an agreement that allows coal miners to retire early or receive compensation if they take new jobs with lower pay. Some governments offer education and training, career counselling and job search assistance. For example, the Canadian Coal Transition Initiative, established in 2018, provides USD 27 million over five years for economic diversification and skills development, and has established transition centres in coal regions. It is complemented by a related Coal Transition Infrastructure Fund providing another USD 116 million for coal communities through 2025.

Some governments have introduced measures that aim to boost economic development in coal-dependent regions. This is particularly critical in emerging market and developing economies, where many coal mining regions have a high degree of dependence on coal and may be generally underdeveloped. Effective economic development strategies pay careful attention to regional comparative advantages in order to develop realistic plans and projects, and at the same time examine how best to improve connectivity. For example, the European Union Just Transition Fund makes provisions for support for investment that improve connectivity – both digital and physical – on the basis that these will facilitate economic diversification in the long run. While CCUS is unlikely to preserve coal consumption at current levels, it nevertheless can preserve some coal-dependent infrastructure and jobs, while reducing emissions from coal combustion (Box 5.3).

Box 5.3 ▹ Recent developments in CCUS that could support just transitions

Carbon capture, utilisation and storage could support just transitions in coal-dependent areas, especially those countries that top the IEA Coal Transition Exposure Index, e.g. China, Indonesia and India. These countries have a large number of relatively new coal assets, and CCUS retrofits could allow some of them to continue to operate while reducing emissions.

China is playing a leading role in the development and use of CCUS. It has the highest number of operating coal-based CCUS projects in the world. The Administrative Centre for China's Agenda 21 has created a roadmap for CCUS development (ACCA21, 2019). Given the young age of China's coal-fired power plant fleet and its large coal-to-chemicals sector, CCUS retrofits could deliver major emissions reductions while maintaining existing industrial capacity. Both the major coal producing regions in China – Shanxi and Inner Mongolia – are already making some use of CCUS and have plans for further development.

Indonesia has taken a number of steps to enable and encourage the use of CCUS. It has a CCUS Centre of Excellence and has worked with the Asian Development Bank on its development. It is working on draft regulations for CCUS that are expected to be put into law in 2022. There is one coal-based CCUS project currently under consideration in Indonesia in a coal-to-liquids facility to produce dimethyl ether, although this would need to achieve capture rates of higher than 90% to have lower emissions than imported liquefied petroleum gas (LPG).

In India, the Ministry of Coal released a roadmap in 2022 for developing low-emissions hydrogen using coal gasification at mines. Several state-owned enterprises and private sector companies have announced plans to explore CCUS deployment.

There has been limited work on using CCUS in coal-fired power stations to date: this is an area that could offer major future emissions reduction benefits. In South Africa, many coal-fired power stations are due to be decommissioned this decade, but the country has a large coal-to-chemicals sector that could be a prime target for CCUS. South Africa has been working in collaboration with the World Bank to support the deployment of CCUS during its energy transition, and progress has been made on a CCUS legal and regulatory framework, storage assessments and capacity building. There are currently plans to deploy CCUS at the SASOL Secunda coal-to-fuels and chemical plant in Mpumalanga. This would both support emissions reductions at the facility and potentially stimulate employment in the province which has a labour participation rate of less than 50%.

So far, few governments have introduced measures that aim to improve the local quality of life and social cohesion in a holistic approach. Such frameworks can play an important part in increasing job opportunities and attracting investment. Environmental restoration can add a significant element in a social cohesion package. So could policies that seek to foster community culture and identity such as through targeted support for cultural events and education.

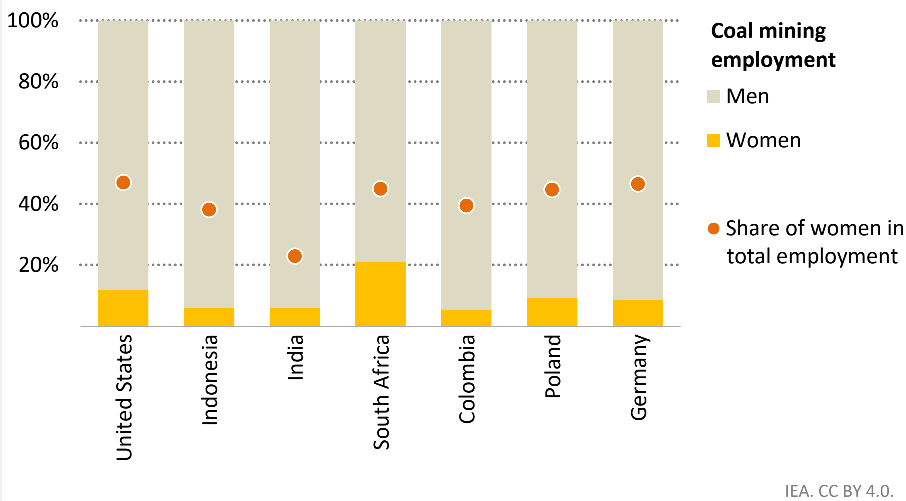
International programmes for just transitions away from coal, in which advanced economies provide support to other countries with limited funds for the transition, are increasingly a topic of discussion (see Chapter 4). International co-operation via the Powering Past Coal Alliance enables lessons learned from previous experiences to be shared between countries.

Just transition policies need to be tailored to the demographics of the affected communities (Box 5.4). Coal miners tend to be older on average than the workforce as whole; the median age of coal miners is 44 years in the United States, 42 in India and 38 years in South Africa. But, overall, the ages span a wide range, so government spending should be divided strategically between enabling early retirements and providing career services and retraining (Spotlight).

Box 5.4 ▹ Gender aspects of just transition policies

Coal miners are predominantly male, but job losses have repercussions for women too (Figure 5.11). Historically, during and after coal transitions, more women have entered the labour market in order to supplement household income, primarily taking up low paying jobs in the services sector (Walk et al., 2021). Interviews also show that men losing jobs in coal mining are reluctant to take up domestic chores, preferring to remain in manual production-oriented work (Braunger and Walk, 2022). In the light of this, there is a case during coal transitions for governments to provide additional childcare services and to extend career services to all members of coal miner households.

Figure 5.11 ▷ Employment in coal mining by gender and country, 2019



Direct female employment in coal mining is low, but coal-related job losses have major repercussions for women in the community

Source: IEA analysis based on data from ILO (2022).

SPOTLIGHT

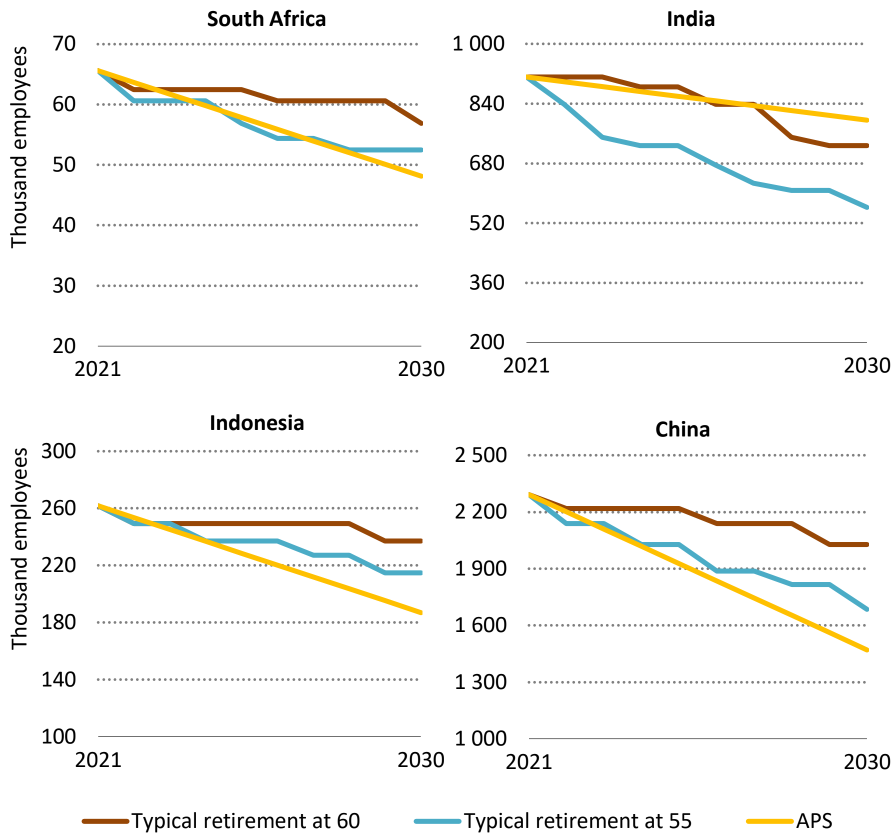
Age profile of coal miners is a critical variable in just transition policies

The age profile of coal miners is important in considering just transition policies because it gives an indication of the natural retirement rate of workers and of the number of those in the workforce that are likely to yet be economically active.

We used labour market surveys to build a model of the age profile of coal miners in Indonesia, South Africa, India and China, which together account for almost 90% of coal mining employment worldwide (Figure 5.12). We modelled a typical retirement schedule for these workers, using a range of retirement ages between 55 and 60 years to take into account differences in retirement ages between countries and between formal and informal workers. We then compared this retirement rate to the level of coal mining employment projected in the APS.

A typical retirement schedule in the four countries would mean that more workers than are projected to be needed in the APS would still be employed in the coal industry in 2030, except in India. With an official retirement age of 60, around 615 000 workers would need to retire early by 2030, 90% of them in China. With a retirement age of 55, this falls to around 245 000.

Figure 5.12 ⊳ Assumed retirement rates for coal miners in selected countries relative to coal mining employment levels in the APS



Coal demand and related employment levels imply that about 615 000 workers would need to retire early by 2030 in four major coal producing countries in the APS

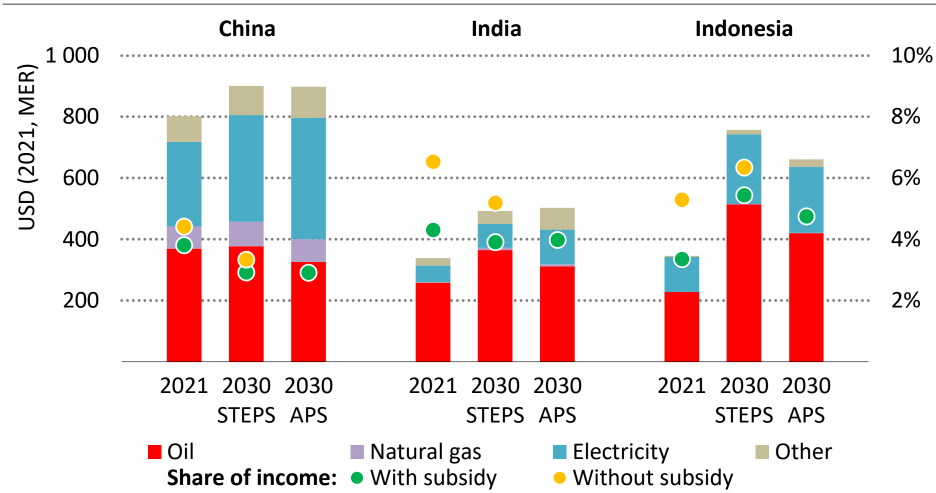
Using country specific coal mining wages, we have estimated the total earnings that would be foregone over the remainder of their active lifetimes by workers if they were to retire early in sufficient numbers to align with the requirements of the APS. These foregone earnings amount to a cumulative USD 10-30 billion, depending on the retirement age assumed. Some portion of this amount could be covered for those miners unable to find alternative employment by government support through just transition policies. To put this in perspective, around USD 380 billion of investment in clean energy is required globally to drive the coal transition each year between 2022 and 2030 in the APS, or USD 3 trillion cumulatively (see Chapter 4).

Our analysis with typical retirement rates indicates that there is no room for new workers to take up careers in coal mining. Many coal regions in emerging market and developing economies have young and dynamic populations that will need to be employed. This point reinforces the need to develop alternative development pathways for coal-dependent regions so as to diversify local economies, while also focussing on the people currently employed in the sector.

5.3.3 Affordability

Households typically spend about 3-5% of their disposable incomes on energy bills (although these percentages are likely to rise as a result of the surge in fossil fuel and electricity prices in 2022). Household energy spending is largely for oil products and electricity, even in the most coal-intensive regions.

Figure 5.13 ▷ Average household energy expenditure by fuel in selected countries in the STEPS and APS, 2021 and 2030



Electricity prices are slightly higher in the APS, but household bills do not rise as a result of the push for electrification and efficiency

Note: MER = market exchange rate.

In the APS, the cost per unit of electricity in both advanced economies and emerging market and developing economies declines by around 5-10% from 2021 to 2050 (see Chapter 2). However, this decline is not as rapid as in the Stated Policies Scenario (STEPS). The APS involves more upfront expenditure to electrify end-uses and to develop low-emissions power supply and grids. However, the APS also involves bigger reductions in energy demand through energy efficiency measures and switching to more efficient fuels. As a consequence, energy bills in the APS are at the same or lower level over time compared to the STEPS, even though the cost per unit of electricity may be slightly higher in the earlier years. In the APS, spending on household energy is similar or lower than in the STEPS by 2030 in major coal-consuming emerging market and developing economies, both in absolute terms and relative to disposable income (Figure 5.13).

Energy subsidies complicate the comparison of household energy spending over time, not least because they can change rapidly. For example, some advanced economies, particularly in Europe, instituted new subsidies in 2022 to cushion households from surging prices. Policies to reduce subsidies are implemented in both the APS and STEPS, and they accelerate after the current energy crisis fades. Electricity and LPG subsidies are phased out by 2030 in most regions in the APS, while they decline much more gradually in the STEPS.

Overall, household energy bills increase in absolute value between 2021 and 2030 in both the APS and STEPS, but they remain roughly constant as a share of disposable income, relative to unsubsidised prices in 2021. A detailed picture inevitably varies from country to country. In emerging market and developing economies such as Indonesia, for example, many consumers switch from non-commercial fuels to modern, commercial energy: this increases energy bills as a share of disposable income but it also brings significant welfare benefits.

5.4 Critical minerals

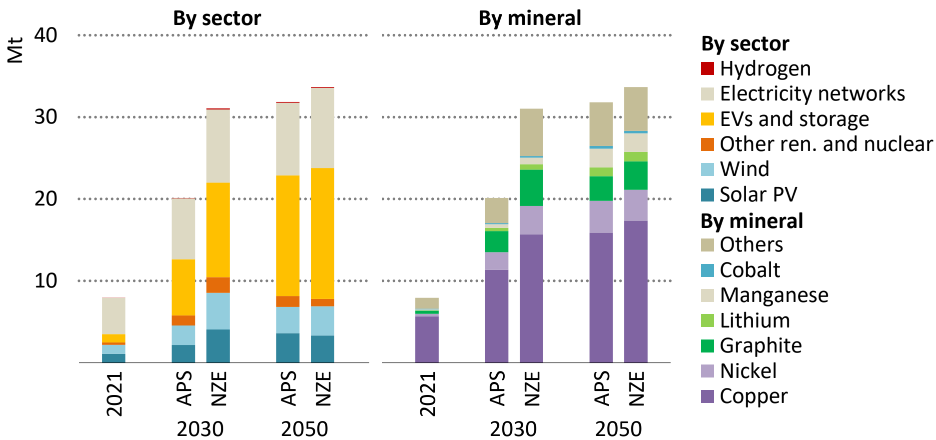
Global clean energy transitions will have far-reaching consequences for extractive industries. The decarbonisation of the energy system is set to curb fossil fuel demand over the coming decades, but rapid deployment of low-emissions technologies are set to boost demand for critical minerals. Although skill requirements and differing locations place some limits on what is realistic, critical minerals could offer a source of jobs and revenue to compensate in part for cuts in the coal sector for both countries and companies.

5.4.1 Critical mineral supply and demand in the APS

Clean energy technologies, including solar PV panels, wind turbines and electric vehicles (EVs), require a variety of critical minerals such as copper, lithium, nickel and rare earth elements. Generally, they require more critical mineral inputs to build than their fossil fuel counterparts. For example, an offshore wind facility requires about six-times more critical minerals by weight to build than a coal-fired power plant. For example, each 8 megawatt (MW) offshore wind turbine requires around 120 tonnes of critical minerals to construct, including over 60 tonnes of copper and nearly 2 tonnes of rare earth elements, plus 1 100 tonnes of steel and 2 000 tonnes of concrete, glass and polymers (IEA, 2021c).

In the APS, demand for critical minerals for clean energy technologies quadruples between today and 2050 (Figure 5.14). Mineral demand for EVs and battery storage increases by 15-times to 2050, while mineral demand for low-emissions power more than triples. Lithium sees the fastest growth among the key minerals, with demand surging by 24-times while demand for cobalt (6-times), nickel (12-times) and graphite (8-times) also increases rapidly. Copper demand registers the largest absolute growth, rising by 10 Mt by 2050.

Figure 5.14 ▷ Critical mineral demand for clean energy technologies by scenario, 2021-2050



In the APS, critical mineral demand for clean energy technologies quadruples by 2050, with particularly high growth for EV-related minerals

Note: NZE = Net Zero Emissions by 2050 Scenario; Other ren. = other renewable; EVs = electric vehicles.

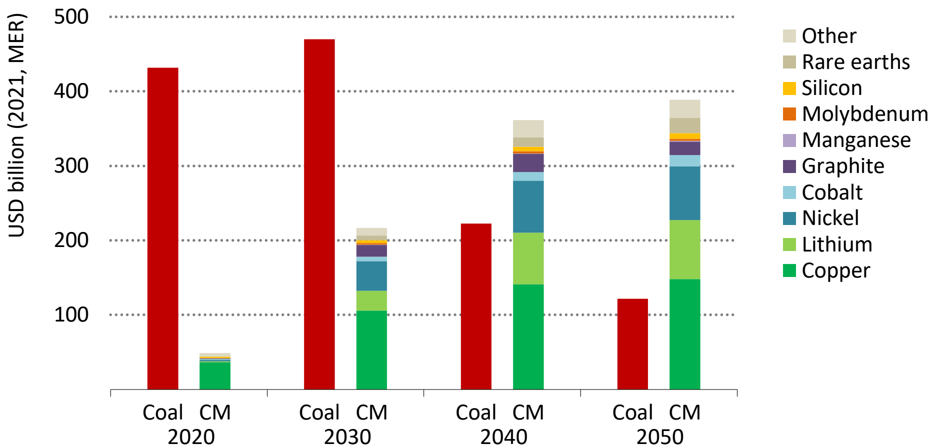
Clean energy technologies are emerging as a major force in mineral markets and a leading source of demand. In the APS, the share of total critical mineral demand attributable to clean energy technologies rises over the next three decades to nearly 50% for copper, 65% for cobalt and nickel and around 90% for lithium. EVs and battery storage have already displaced consumer electronics to become the largest consumer of lithium, and they are set to take over from stainless steel as the largest end-user of nickel by the early-2030s.

Current mineral supply and investment plans fall well short of what is needed to transform the energy sector. This raises the risk of delayed or more expensive energy transitions, especially since the long lead times for scaling up critical minerals mining operations mean that new supply cannot be arranged at short notice. For major mines that came online between 2010 and 2019, it took on average more than 12 years to complete exploration, feasibility studies and permitting processes and 4-5 years for the construction phase. Policy makers can take a range of actions to encourage new supply projects. It is particularly important for them to provide clear signals about their ambitions on clean energy technologies and how their emissions reduction targets will be turned into action.

5.4.2 *Implications for countries and mining companies*

The clean energy transition in the APS offers both opportunities and challenges for mining companies and governments in countries with mineral resources. In the APS, revenues from coal production fall from around USD 430 billion in 2020 to around USD 120 billion in 2050 (Figure 5.15). Over this period, the combined revenues from critical minerals used in clean energy technologies increase from around USD 50 billion in 2020 to nearly USD 400 billion in 2050, overtaking revenues from coal mining in the mid-2030s.

Figure 5.15 ▷ Revenue from coal and critical minerals for clean energy technologies in the APS, 2020-2050



Revenues from critical minerals used in clean energy technologies grow considerably and surpass coal revenues by the mid-2030s

Notes: MER = market exchange rate. CM = critical minerals used in clean energy technologies. 2021 prices are used to calculate the potential revenue for minerals.

Some of the largest coal mining companies today are also active in critical mineral mining, including Anglo American (copper, platinum group metals, nickel and manganese), BHP (nickel and copper), Glencore (copper, cobalt, nickel and zinc) and Teck (copper and zinc). Rio Tinto, which produces aluminium, copper and lithium, recently divested all of its coal mining assets. Other companies such as Vale are heading in a similar direction through the sale of coal assets and reductions in thermal coal production. Although several major coal companies have increased copper production in recent years, most have yet to make a decisive move into critical minerals.

There is some potential in terms of both location and skills for coal mining regions and workers to transition to mining critical minerals. Coal and critical minerals require similar skills during exploration, extraction and transport. In addition, around 40% of coal mining employees worldwide currently work within 200 kilometres (km) of at least one critical mineral mine or deposit. However, the complex and mineral-specific processes that are required for many critical minerals mean that the transferability of skills on the processing side is likely to be much more limited (Spotlight).

Companies looking to boost critical minerals mining will continue to face scrutiny over the environmental, social and governance (ESG) aspects of mining operations. Consumers and investors are increasingly demanding that manufacturers of clean energy technologies should source minerals that are sustainably and responsibly produced. The wide range of environmental issues that could arise in relation to critical minerals mining include local air pollution, water use, water quality, biodiversity and land use, handling of mining waste and greenhouse gas emissions. Unless carefully managed, the direct environmental impacts of critical mineral mining could be worse than those arising from coal mining. Social and governance challenges include the avoidance of poor working conditions, safety hazards, child labour, forced labour, and corruption and bribery. As the volume of critical minerals mining increases, so too will the aggregate impacts on ecosystems and communities. Mining companies will have to ensure high levels of environmental and social performance to position themselves as reliable suppliers for minerals and an essential partner in accelerating global clean energy transitions.

S P O T L I G H T

Can coal workers transfer to employment in critical minerals?

As coal production declines in the coming years, some coal industry workers will need to shift to new jobs. Some will require retraining, learning new skills and relocating. Here we look at the potential for workers to transfer to critical minerals value chains. There are many synergies between the mining and transport of coal and critical minerals, so shifting could offer job opportunities for coal supply workers as well as revenues to sustain local industries dependent on the income from miners.

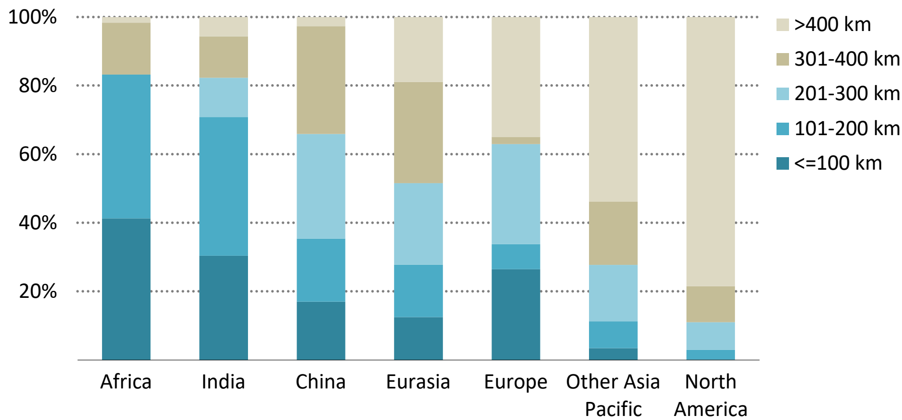
New detailed geospatial analysis undertaken by the IEA indicates that around 40% of coal miners worldwide today live less than 200 km from a critical mineral mine or deposit and around 90% of workers live within 400 km.[2] Distances vary between countries, with more coal workers in Africa and China living near critical mineral deposits than in regions such as North America (Figure 5.16). Fewer than 1% of coal miners live in countries without a critical mineral mine or deposit.

Nevertheless, critical mineral mining produces less by volume than coal mining and requires fewer workers. Furthermore, critical mineral processing facilities and their workers are not necessarily located where coal workers are. There tends to be a low concentration of critical minerals in mined ore and it is usually most cost effective for initial processing to take place onsite. However, concentrates are then shipped to

[2] This analysis only considers mines within the borders of the same country where workers currently live.

secondary processing facilities whose locations are determined by the availability of infrastructure, low cost energy, labour and demand. Today China accounts for the largest share of processing activity for many critical minerals, although large-scale processing capacities are emerging elsewhere, for example in Indonesia and Australia for nickel.

Figure 5.16 ▷ Share of coal mining employees by distance to at least one critical mineral mine or deposit by region, 2022



Around 40% of coal miners worldwide live less than 200 km from at least one critical mineral mine or deposit; around 90% of workers live within 400 km

Sources: IEA analysis based on data from Global Energy Monitor (2022) and S&P Global (2022).

Skills need to be compatible for employment transfers to be feasible. In the exploration and extraction phases, coal and critical minerals require similar skills, including those concerned with the operation of heavy machinery, operations planning, handling of explosives and safety compliance (Table 5.2). Coal transport workers could also transfer to critical minerals with no special need for retraining. However, the transferability of skills in processing is limited. Coal processing – washing, crushing and purification – is a mainly mechanical process with relatively simple steps. In contrast, all critical mineral ores require complex processing specific to the mineral which is carried out by highly skilled workers such as chemical and metallurgical engineers. Significant retraining would be needed for coal processing workers to transfer to these jobs.

Just transition policies could support coal workers shifting to new jobs concerned with critical minerals. However, if former coal miners were to relocate for new jobs, this could bring disruption to their families and communities. This is an issue that governments will need to consider. Where critical mineral and coal mines are near to each other, the risk of disruption is much lower, and the pay and revenues from critical minerals could well allow former coal communities to develop and thrive. Unlike coal, critical mineral reserves also offer the potential for local processing and manufacturing facilities to be developed, for example to incorporate the minerals into batteries and other clean energy technologies. Much depends on the details, but this could provide another source of jobs for former coal miners.

Table 5.2 ▷ Coal and critical minerals jobs by occupation and skill level

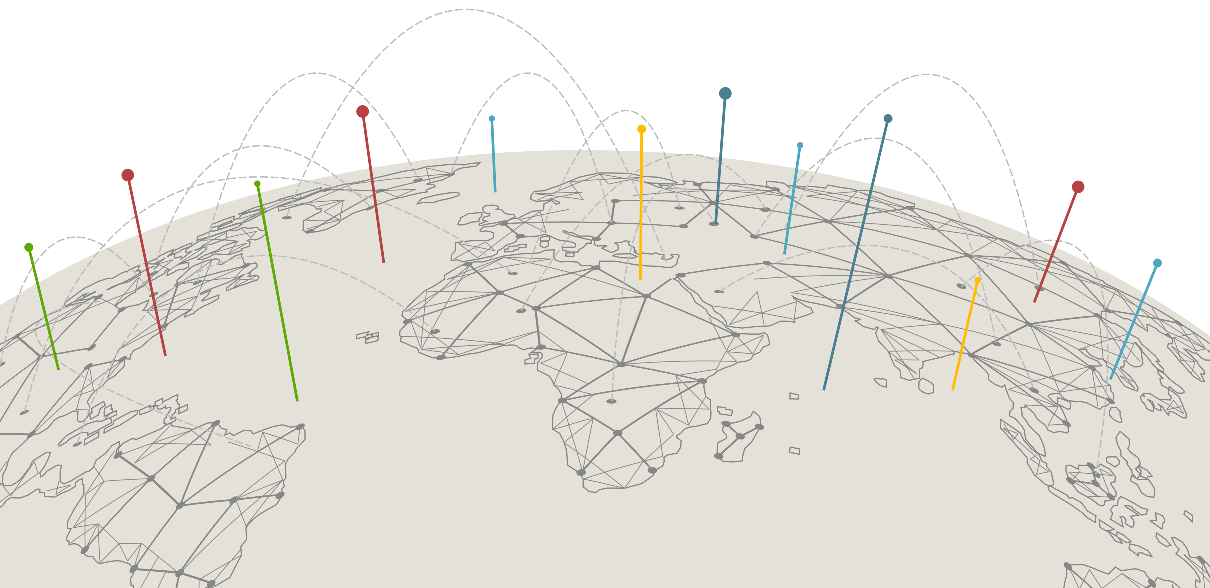
Occupation	Skill level	Coal	Critical minerals
Mining			
Miners and quarriers	Medium	✔	✔
Mining and metallurgical technicians and engineers	High	✔	✔
Geologists and geophysicists	High	✔	✔
Processing			
Mineral and stone processing plant operators	Medium	✔	✔
Metal and chemical processing plant operators	High		✔
Chemical engineers and technicians	High		✔
Transport			
Locomotive engine drivers and related workers	Medium	✔	✔
Ship deck crews and related workers	Medium	✔	✔
Transport and storage labourers	Low	✔	✔

Note: Occupations and skill levels as defined in the International Standard Classification of Occupations.

ANNEXES

Explore the data behind the

World Energy Outlook 2022



Data used for this report comes from the Global Energy and Climate Model. Further data can be found in the latest version of the World Energy Outlook report in the link below:

iea.li/weo22

Definitions

This annex provides general information on terminology used throughout this report including: units and general conversion factors; definitions of fuels, processes and sectors; regional and country groupings; and abbreviations and acronyms.

Units

Area	km^2	square kilometre
	Mha	million hectares
Batteries	Wh/kg	watt hours per kilogramme
Coal	Mtce	million tonnes of coal equivalent (equals 0.7 Mtoe)
Distance	km	kilometre
Emissions	ppm	parts per million (by volume)
	t CO_2	tonnes of carbon dioxide
	Gt CO_2-eq	gigatonnes of carbon-dioxide equivalent (using 100-year global warming potentials for different greenhouse gases)
	kg CO_2-eq	kilogrammes of carbon-dioxide equivalent
	g CO_2/km	grammes of carbon dioxide per kilometre
	g CO_2/kWh	grammes of carbon dioxide per kilowatt-hour
	kg CO_2/kWh	kilogrammes of carbon dioxide per kilowatt-hour
Energy	EJ	exajoule (1 joule x 10^{18})
	PJ	petajoule (1 joule x 10^{15})
	TJ	terajoule (1 joule x 10^{12})
	GJ	gigajoule (1 joule x 10^{9})
	MJ	megajoule (1 joule x 10^{6})
	boe	barrel of oil equivalent
	toe	tonne of oil equivalent
	ktoe	thousand tonnes of oil equivalent
	Mtoe	million tonnes of oil equivalent
	bcme	billion cubic metres of natural gas equivalent
	MBtu	million British thermal units
	kWh	kilowatt-hour
	MWh	megawatt-hour
	GWh	gigawatt-hour
	TWh	terawatt-hour
	Gcal	gigacalorie
Gas	bcm	billion cubic metres
	tcm	trillion cubic metres
Mass	kg	kilogramme
	t	tonne (1 tonne = 1 000 kg)
	kt	kilotonnes (1 tonne x 10^3)
	Mt	million tonnes (1 tonne x 10^6)
	Gt	gigatonnes (1 tonne x 10^9)

Monetary	USD million	1 US dollar x 10^6
	USD billion	1 US dollar x 10^9
	USD trillion	1 US dollar x 10^{12}
	USD/t CO_2	US dollars per tonne of carbon dioxide
Oil	kb/d	thousand barrels per day
	mb/d	million barrels per day
	mboe/d	million barrels of oil equivalent per day
Power	W	watt (1 joule per second)
	kW	kilowatt (1 watt x 10^3)
	MW	megawatt (1 watt x 10^6)
	GW	gigawatt (1 watt x 10^9)
	TW	terawatt (1 watt x 10^{12})

General conversion factors for energy

	Multiplier to convert to:					
Convert from:	**EJ**	**Gcal**	**Mtoe**	**MBtu**	**bcme**	**GWh**
EJ	1	2.388×10^8	23.88	9.478×10^8	27.78	2.778×10^5
Gcal	4.1868×10^{-9}	1	10^{-7}	3.968	1.163×10^{-7}	1.163×10^{-3}
Mtoe	4.1868×10^{-2}	10^7	1	3.968×10^7	1.163	11 630
MBtu	1.0551×10^{-9}	0.252	2.52×10^{-8}	1	2.932×10^{-8}	2.931×10^{-4}
bcme	0.036	8.60×10^6	0.86	3.41×10^7	1	9 999
GWh	3.6×10^{-6}	860	8.6×10^{-5}	3 412	1×10^{-4}	1

Note: There is no generally accepted definition of boe; typically the conversion factors used vary from 7.15 to 7.40 boe per toe. Natural gas is attributed a low heating value of 1 MJ per 44.1 kg. Conversions to and from billion cubic metres of natural gas equivalent (bcme) are given as representative multipliers but may differ from the average values obtained by converting natural gas volumes between IEA balances due to the use of country-specific energy densities. Lower heating values (LHV) are used throughout.

Currency conversions

Exchange rates *(2021 annual average)*	**1 US Dollar (USD) equals:**
British Pound	0.73
Chinese Yuan Renminbi	6.45
Euro	0.84
Indian Rupee	73.92
Indonesian Rupiah	14 308
Japanese Yen	109.75
Russian Ruble	73.65
South African Rand	14.78

Source: OECD National Accounts Statistics (database): purchasing power parities and exchange rates dataset (period-average), https://doi.org/10.1787/data-00004-en, accessed September 2022.

Definitions

Advanced bioenergy: Sustainable fuels produced from non-food crop feedstocks, which are capable of delivering significant life cycle greenhouse gas emissions savings compared with fossil fuel alternatives, and which do not directly compete with food and feed crops for agricultural land or cause adverse sustainability impacts. This definition differs from the one used for "advanced biofuels" in US legislation, which is based on a minimum 50% life cycle greenhouse gas reduction and, therefore, includes sugar cane ethanol.

Agriculture: Includes all energy used on farms, in forestry and for fishing.

Agriculture, forestry and other land use (AFOLU) **emissions:** Includes greenhouse gas emissions from agriculture, forestry and other land use.

Ammonia (NH_3)**:** Is a compound of nitrogen and hydrogen. It can be used as a feedstock in the chemical sector, as a fuel in direct combustion processes and in fuel cells, and as a hydrogen carrier. To be considered a low-emissions fuel, ammonia must be produced from hydrogen in which the electricity used to produce the hydrogen is generated from low-emissions generation sources. Produced in such a way, ammonia is considered a low-emissions hydrogen-based liquid fuel.

Back-up generation capacity: Households and businesses connected to a main power grid may also have a source of back-up power generation capacity that, in the event of disruption, can provide electricity. Back-up generators are typically fuelled with diesel or gasoline. Capacity can be as little as a few kilowatts. Such capacity is distinct from mini-grid and off-grid systems that are not connected to a main power grid.

Billion cubic metres of natural gas equivalent (bcme)**:** An energy unit equal to the energy content of one standard billion cubic metres of natural gas.

Biodiesel: Diesel-equivalent fuel made from the transesterification (a chemical process that converts triglycerides in oils) of vegetable oils and animal fats.

Bioenergy: Energy content in solid, liquid and gaseous products derived from biomass feedstocks and biogas. It includes solid bioenergy, liquid biofuels and biogases.

Biogas: A mixture of methane, CO_2 and small quantities of other gases produced by anaerobic digestion of organic matter in an oxygen-free environment.

Biogases: Include both biogas and biomethane.

Biogasoline: Includes all liquid biofuels (advanced and conventional) used to replace gasoline.

Biomethane: Biomethane is a near-pure source of methane produced either by "upgrading" biogas (a process that removes any carbon dioxide and other contaminants present in the biogas) or through the gasification of solid biomass followed by methanation. It is also known as renewable natural gas.

A

Buildings: The buildings sector includes energy used in residential, commercial and institutional buildings and non-specified other. Building energy use includes space heating and cooling, water heating, lighting, appliances and cooking equipment.

Capacity credit: Proportion of the capacity that can be reliably expected to generate electricity during times of peak demand in the network to which it is connected.

Carbon capture, utilisation and storage (CCUS)**:** The process of capturing carbon dioxide emissions from fuel combustion, industrial processes or directly from the atmosphere. Captured CO_2 emissions can be stored in underground geological formations, onshore or offshore, or used as an input or feedstock in manufacturing.

Carbon dioxide (CO_2)**:** Is a gas consisting of one part carbon and two parts oxygen. It is an important greenhouse (heat-trapping) gas.

Chemical feedstock: Energy vectors used as raw materials to produce chemical products. Examples are crude oil-based ethane or naphtha to produce ethylene in steam crackers.

Clean energy: In *power*, clean energy includes: generation from renewable sources, nuclear and fossil fuels fitted with CCUS; battery storage; and electricity grids. In *efficiency*, clean energy includes energy efficiency in buildings, industry and transport, excluding aviation bunkers and domestic navigation. In *end-use applications*, clean energy includes: direct use of renewables; electric vehicles; electrification in buildings, industry and international marine transport; CCUS in industry and direct air capture. In *fuel supply*, clean energy includes low-emissions fuels.

Clean cooking systems: Cooking solutions that release less harmful pollutants, are more efficient and environmentally sustainable than traditional cooking options that make use of solid biomass (such as a three-stone fire), coal or kerosene. This refers to improved cook stoves, biogas/biodigester systems, electric stoves, liquefied petroleum gas, natural gas or ethanol stoves.

Coal: Includes both primary coal, i.e. lignite, coking and steam coal, and derived fuels, e.g. patent fuel, brown-coal briquettes, coke-oven coke, gas coke, gas works gas, coke-oven gas, blast furnace gas and oxygen steel furnace gas. Peat is also included.

Coal mine methane: Methane released from the coal and surrounding rock strata due to mining activities.

Coalbed methane (CBM)**:** Category of unconventional natural gas that refers to methane found in coal seams.

Coal-to-gas (CTG)**:** Process in which coal is first turned into syngas (a mixture of hydrogen and carbon monoxide) and then into synthetic methane.

Coal-to-liquids (CTL)**:** Transformation of coal into liquid hydrocarbons. One route involves coal gasification into syngas (a mixture of hydrogen and carbon monoxide), which is processed using Fischer-Tropsch or methanol-to-gasoline synthesis. Another route, called direct-coal liquefaction, involves reacting coal directly with hydrogen.

Coking coal: Type of coal that can be used for steel making (as a chemical reductant and a source of heat), where it produces coke capable of supporting a blast furnace charge. Coal of this quality is commonly known as metallurgical coal.

Concentrating solar power (CSP)**:** Thermal power generation technology that collects and concentrates sunlight to produce high temperature heat to generate electricity.

Conventional liquid biofuels: Fuels produced from food crop feedstocks. Commonly referred to as first generation biofuels and include sugar cane ethanol, starch-based ethanol, fatty acid methyl ester (FAME), straight vegetable oil (SVO) and hydrotreated vegetable oil (HVO) produced from palm, rapeseed or soybean oil.

Critical minerals: A wide range of minerals and metals that are essential in clean energy technologies and other modern technologies and have supply chains that are vulnerable to disruption. Although the exact definition and criteria differ among countries, critical minerals for clean energy technologies typically include chromium, cobalt, copper, graphite, lithium, manganese, molybdenum, nickel, platinum group metals, zinc, rare earth elements and other commodities, as listed in the Annex of the IEA special report on the *Role of Critical Minerals in Clean Energy Transitions,* available at: https://www.iea.org/reports/the-role-of-critical-minerals-in-clean-energy-transitions.

Demand-side integration (DSI)**:** Consists of two types of measures: actions that influence load shape such as energy efficiency and electrification; and actions that manage load such as demand-side response measures.

Demand-side response (DSR)**:** Describes actions which can influence the load profile such as shifting the load curve in time without affecting total electricity demand, or load shedding such as interrupting demand for a short duration or adjusting the intensity of demand for a certain amount of time.

Direct air capture (DAC)**:** Technology to capture CO_2 directly from the atmosphere using liquid solvents or solid sorbents. It is generally coupled with permanent storage of the CO_2 in deep geological formations or its use in the production of fuels, chemicals, building materials or other products. When coupled with permanent geological CO_2 storage, DAC is a carbon removal technology.

Dispatchable generation: Refers to technologies whose power output can be readily controlled, i.e. increased to maximum rated capacity or decreased to zero in order to match supply with demand.

Electricity demand: Defined as total gross electricity generation less own use generation, plus net trade (imports less exports), less transmission and distribution losses.

Electricity generation: Defined as the total amount of electricity generated by power only or combined heat and power plants including generation required for own use. This is also referred to as gross generation.

End-use sectors: Include industry, transport, buildings and other, i.e. agriculture and other non-energy use.

Energy-intensive industries: Includes production and manufacturing in the branches of iron and steel, chemicals, non-metallic minerals (including cement), non-ferrous metals (including aluminium), and paper, pulp and printing.

Energy-related and industrial process CO_2 emissions: Carbon dioxide emissions from fuel combustion and from industrial processes. Note that this does not include fugitive emissions from fuels, flaring or CO_2 from transport and storage. Unless otherwise stated, CO_2 emissions in this report refer to energy-related and industrial process CO_2 emissions.

Energy sector greenhouse gas (GHG) emissions: Energy-related and industrial process CO_2 emissions plus fugitive and vented methane (CH_4) and nitrous dioxide (N_2O) emissions from the energy and industry sectors.

Energy services: See useful energy.

Ethanol: Refers to bioethanol only. Ethanol is produced from fermenting any biomass high in carbohydrates. Currently, ethanol is made from starches and sugars, but second-generation technologies will allow it to be made from cellulose and hemicellulose, the fibrous material that makes up the bulk of most plant matter.

Fischer-Tropsch synthesis: Catalytic production process for the production of synthetic fuels, e.g. diesel, kerosene or naphtha, typically from mixtures of carbon monoxide and hydrogen (syngas). The inputs to Fischer-Tropsch synthesis can be from biomass, coal, natural gas, or hydrogen and CO_2.

Fossil fuels: Include coal, natural gas and oil.

Gaseous fuels: Include natural gas, biogases, synthetic methane and hydrogen.

Gases: See gaseous fuels.

Gas-to-liquids (GTL): A process that reacts methane with oxygen or steam to produce syngas (a mixture of hydrogen and carbon monoxide) followed by Fischer-Tropsch synthesis. The process is similar to that used in coal-to-liquids.

Geothermal: Geothermal energy is heat from the sub-surface of the earth. Water and/or steam carry the geothermal energy to the surface. Depending on its characteristics, geothermal energy can be used for heating and cooling purposes or be harnessed to generate clean electricity if the temperature is adequate.

Heat (end-use): Can be obtained from the combustion of fossil or renewable fuels, direct geothermal or solar heat systems, exothermic chemical processes and electricity (through resistance heating or heat pumps which can extract it from ambient air and liquids). This category refers to the wide range of end-uses, including space and water heating, and cooking in buildings, desalination and process applications in industry. It does not include cooling applications.

Heat (supply)**:** Obtained from the combustion of fuels, nuclear reactors, geothermal resources or the capture of sunlight. It may be used for heating or cooling, or converted into mechanical energy for transport or electricity generation. Commercial heat sold is reported under total final consumption with the fuel inputs allocated under power generation.

Heavy-duty vehicles (HDVs)**:** Includes both medium- and heavy-freight trucks.

Heavy industries: Iron and steel, chemicals and cement.

Hydrogen: Hydrogen is used in the energy system as an energy carrier, as an industrial raw material, or is combined with other inputs to produce hydrogen-based fuels. Unless otherwise stated, hydrogen in this report refers to low-emissions hydrogen.

Hydrogen-based fuels: See low-emissions hydrogen-based fuels.

Hydropower: Energy content of the electricity produced in hydropower plants, assuming 100% efficiency. It excludes output from pumped storage and marine (tide and wave) plants.

Industry: The sector includes fuel used within the manufacturing and construction industries. Key industry branches include iron and steel, chemical and petrochemical, cement, aluminium, and pulp and paper. Use by industries for the transformation of energy into another form or for the production of fuels is excluded and reported separately under other energy sector. There is an exception for fuel transformation in blast furnaces and coke ovens, which are reported within iron and steel. Consumption of fuels for the transport of goods is reported as part of the transport sector, while consumption by off-road vehicles is reported under industry.

Improved cook stoves: Intermediate and advanced improved biomass cook stoves (ISO tier > 1). It excludes basic improved stoves (ISO tier 0-1).

Investment: Investment is the capital expenditure in energy supply, infrastructure, end-use and efficiency. Fuel supply investment includes the production, transformation and transport of oil, gas, coal and low-emissions fuels. *Power sector* investment includes new construction and refurbishment of generation, electricity networks (transmission, distribution and public electric vehicle chargers), and battery storage. *Energy efficiency* investment includes efficiency improvements in buildings, industry and transport. *Other end-use* investment includes the purchase of equipment for the direct use of renewables, electric vehicles, electrification in buildings, industry and international marine transport, equipment for the use of low-emissions fuels, and CCUS in industry and direct air capture. Data and projections reflect spending over the lifetime of projects and are presented in real terms in year-2021 US dollars unless otherwise stated. Total investment reported for a year reflects the amount spent in that year.

Levelised cost of electricity (LCOE)**:** The LCOE combines all the cost elements directly associated with a given power technology into a single metric, including construction, financing, fuel, maintenance and costs associated with a carbon price. It does not include network integration or other indirect costs. The LCOE provides a first indicator of competitiveness. For a more complete indicator, see VALCOE.

Light industries: Includes non energy-intensive industries: food and tobacco, machinery, mining and quarrying, transportation equipment, textile, wood harvesting and processing and construction.

Lignite: A type of coal that is used in the power sector mostly in regions near lignite mines due to its low energy content and typically high moisture levels, which generally makes long-distance transport uneconomic. Data on lignite in this report include peat.

Liquid biofuels: Liquid fuels derived from biomass or waste feedstock, e.g. ethanol, biodiesel and biojet fuels. They can be classified as conventional and advanced biofuels according to the combination of feedstock and technologies used to produce them and their respective maturity. Unless otherwise stated, biofuels are expressed in energy-equivalent volumes of gasoline, diesel and kerosene.

Liquid fuels: Include oil, liquid biofuels (expressed in energy-equivalent volumes of gasoline and diesel), synthetic oil and ammonia.

Low-emissions electricity: Includes renewable energy technologies, low-emissions hydrogen-based generation, low-emissions hydrogen-based fuel generation, nuclear power and fossil fuel power plants equipped with carbon capture, utilisation and storage.

Low-emissions fuels: Include modern bioenergy, low-emissions hydrogen and low-emissions hydrogen-based fuels.

Low-emissions hydrogen: Hydrogen that is produced from water using electricity generated by renewables, nuclear, or from fossil fuels with minimal associated methane emissions and processed in facilities equipped to avoid CO_2 emissions, e.g. via CCUS with a high capture rate, or derived from bioenergy.

Low-emissions hydrogen-based fuels: Include ammonia, methanol and other synthetic hydrocarbons (gases and liquids) made from low-emissions hydrogen. Any carbon inputs (e.g. from CO_2) are from non-fossil fuel sources.

Low-emission hydrogen-based liquid fuels: A subset of low-emissions hydrogen-based fuels that includes only ammonia, methanol and synthetic liquid hydrocarbons, such as synthetic kerosene.

Lower heating value: Heat liberated by the complete combustion of a unit of fuel when the water produced is assumed to remain as a vapour and the heat is not recovered.

Middle distillates: Include jet fuel, diesel and heating oil.

Modern gaseous bioenergy: See biogases.

Modern liquid bioenergy: Includes biogasoline, biodiesel, biojet kerosene and other liquid biofuels.

Modern renewables: Include all uses of renewable energy with the exception of traditional use of solid biomass.

Modern solid bioenergy: Includes all solid bioenergy products (see solid bioenergy definition) except the traditional use of biomass. It also includes the use of solid bioenergy in intermediate and advanced improved biomass cook stoves (ISO tier > 1), requiring fuel to be cut in small pieces or often using processed biomass such as pellets.

Natural gas: Includes gas occurring in deposits, whether liquefied or gaseous, consisting mainly of methane. It includes both non-associated gas originating from fields producing hydrocarbons only in gaseous form, and associated gas produced in association with crude oil production as well as methane recovered from coal mines (colliery gas). Natural gas liquids, manufactured gas (produced from municipal or industrial waste, or sewage) and quantities vented or flared are not included. Gas data in cubic metres are expressed on a gross calorific value basis and are measured at 15 °C and at 760 mm Hg (Standard Conditions). Gas data expressed in tonnes of oil equivalent, mainly for comparison reasons with other fuels, are on a net calorific basis. The difference between the net and the gross calorific value is the latent heat of vapourisation of the water vapour produced during combustion of the fuel (for gas the net calorific value is 10% lower than the gross calorific value).

Natural gas liquids (NGLs)**:** Liquid or liquefied hydrocarbons produced in the manufacture, purification and stabilisation of natural gas. NGLs are portions of natural gas recovered as liquids in separators, field facilities or gas processing plants. NGLs include, but are not limited to, ethane (when it is removed from the natural gas stream), propane, butane, pentane, natural gasoline and condensates.

Network gases: Include natural gas, biomethane, synthetic methane and hydrogen blended in a gas network.

Non-energy use: The use of fuels as feedstocks for chemical products that are not used in energy applications. Examples of resulting products are lubricants, paraffin waxes, asphalt, bitumen, coal tars and timber preservative oils.

Non-renewable waste: Non-biogenic waste, such as plastics in municipal or industrial waste.

Nuclear: Refers to the primary energy equivalent of the electricity produced by a nuclear power plant, assuming an average conversion efficiency of 33%.

Off-grid systems: Mini-grids and stand-alone systems for individual households or groups of consumers not connected to a main grid.

Offshore wind: Refers to electricity produced by wind turbines that are installed in open water, usually in the ocean.

Oil: Includes both conventional and unconventional oil production. Petroleum products include refinery gas, ethane, liquid petroleum gas, aviation gasoline, motor gasoline, jet fuels, kerosene, gas/diesel oil, heavy fuel oil, naphtha, white spirits, lubricants, bitumen, paraffin, waxes and petroleum coke.

Other energy sector: Covers the use of energy by transformation industries and the energy losses in converting primary energy into a form that can be used in the final consuming sectors. It includes losses in low-emissions hydrogen and hydrogen-based fuels production, bioenergy processing, gas works, petroleum refineries, coal and gas transformation and liquefaction. It also includes energy own use in coal mines, in oil and gas extraction and in electricity and heat production. Transfers and statistical differences are also included in this category. Fuel transformation in blast furnaces and coke ovens are not accounted for in the other energy sector category.

Other industry: A category of industry branches that includes construction, food processing, machinery, mining, textiles, transport equipment, wood processing and remaining industry.

Peat: Peat is a combustible soft, porous or compressed, fossil sedimentary deposit of plant origin with high water content (up to 90% in the raw state), easily cut, of light to dark brown colour. Milled peat is included in this category. Peat used for non-energy purposes is not included.

Power generation: Refers to fuel use in electricity generation plants, heat plants, and combined heat and power plants. Both main activity producer plants and small plants that produce fuel for their own use (auto-producers) are included.

Process emissions: CO_2 emissions produced from industrial processes which chemically or physically transform materials. A notable example is cement production, in which CO_2 is emitted when calcium carbonate is transformed into lime, which in turn is used to produce clinker.

Productive uses: Energy used towards an economic purpose: agriculture, industry, services and non-energy use. Some energy demand from the transport sector, e.g. freight, could be considered as productive, but is treated separately.

Rare earth elements (REEs)**:** A group of seventeen chemical elements in the periodic table, specifically the fifteen lanthanides plus scandium and yttrium. REEs are key components in some clean energy technologies, including wind turbines, electric vehicle motors and electrolysers.

Renewables: Includes bioenergy, geothermal, hydropower, solar photovoltaics (PV), concentrating solar power (CSP), wind and marine (tide and wave) energy for electricity and heat generation.

Residential: Energy used by households including space heating and cooling, water heating, lighting, appliances, electronic devices and cooking.

Self-sufficiency: Corresponds to indigenous production divided by total primary energy demand.

Services: Energy used in commercial facilities, e.g. offices, shops, hotels, restaurants, and in institutional buildings, e.g. schools, hospitals, public offices. Energy use in services includes space heating and cooling, water heating, lighting, appliances, cooking and desalination.

Shale gas: Natural gas contained within a commonly occurring rock classified as shale. Shale formations are characterised by low permeability, with more limited ability of gas to flow through the rock than is the case within a conventional reservoir. Shale gas is generally produced using hydraulic fracturing.

Solar: Includes solar photovoltaics and concentrating solar power.

Solar photovoltaics (PV)**:** Electricity produced from solar photovoltaic cells.

Solid bioenergy: Includes charcoal, fuelwood, dung, agricultural residues, wood waste and other solid biogenic wastes.

Solid fuels: Include coal, modern solid bioenergy, traditional use of biomass and industrial and municipal wastes.

Steam coal: A type of coal that is mainly used for heat production or steam-raising in power plants and, to a lesser extent, in industry. Typically, steam coal is not of sufficient quality for steel making. Coal of this quality is also commonly known as thermal coal.

Synthetic methane: Methane from sources other than natural gas, including coal-to-gas and low-emissions synthetic methane.

Synthetic oil: Synthetic oil produced through Fischer-Tropsch conversion or methanol synthesis. It includes oil products from CTL and GTL, and low-emissions liquid hydrogen-based fuels.

Tight oil: Oil produced from shale or other very low permeability formations, generally using hydraulic fracturing. This is also sometimes referred to as light tight oil. Tight oil includes tight crude oil and condensate production except for the United States, which includes tight crude oil only (US tight condensate volumes are included in natural gas liquids).

Total energy supply (TES)**:** Represents domestic demand only and is broken down into electricity and heat generation, other energy sector and total final consumption.

Total final consumption (TFC)**:** Is the sum of consumption by the various end-use sectors. TFC is broken down into energy demand in the following sectors: industry (including manufacturing, mining, chemicals production, blast furnaces and coke ovens), transport, buildings (including residential and services) and other (including agriculture and other non-energy use). It excludes international marine and aviation bunkers, except at world level where it is included in the transport sector.

Total final energy consumption (TFEC)**:** Is a variable defined primarily for tracking progress towards target 7.2 of the United Nations Sustainable Development Goals (SDG). It incorporates total final consumption by end-use sectors, but excludes non-energy use. It excludes international marine and aviation bunkers, except at world level. Typically this is used in the context of calculating the renewable energy share in total final energy consumption (indicator SDG 7.2.1), where TFEC is the denominator.

Traditional use of biomass: Refers to the use of solid biomass with basic technologies, such as a three-stone fire or basic improved cook stoves (ISO tier 0-1), often with no or poorly operating chimneys. Forms of biomass used include wood, wood waste, charcoal, agricultural residues and other bio-sourced fuels such as animal dung.

Transport: Fuels and electricity used in the transport of goods or people within the national territory irrespective of the economic sector within which the activity occurs. This includes fuel and electricity delivered to vehicles using public roads or for use in rail vehicles; fuel delivered to vessels for domestic navigation; fuel delivered to aircraft for domestic aviation; and energy consumed in the delivery of fuels through pipelines. Fuel delivered to international marine and aviation bunkers is presented only at the world level and is excluded from the transport sector at a domestic level.

Unabated fossil fuel use: Combustion of fossil fuels in facilities without carbon capture, utilisation and storage.

Useful energy: Refers to the energy that is available to end-users to satisfy their needs. This is also referred to as energy services demand. As result of transformation losses at the point of use, the amount of useful energy is lower than the corresponding final energy demand for most technologies. Equipment using electricity often has higher conversion efficiency than equipment using other fuels, meaning that for a unit of energy consumed, electricity can provide more energy services.

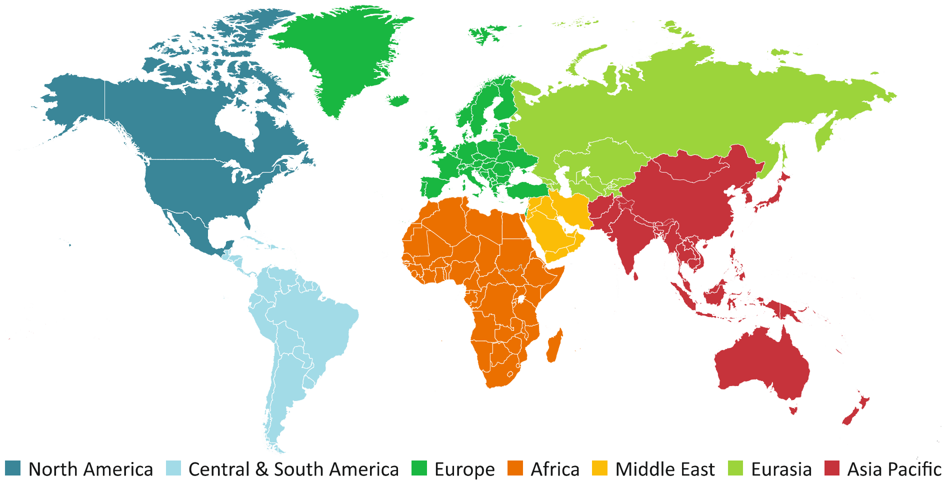
Value-adjusted levelised cost of electricity (VALCOE)**:** Incorporates information on both costs and the value provided to the system. Based on the LCOE, estimates of energy, capacity and flexibility value are incorporated to provide a more complete metric of competitiveness for power generation technologies.

Variable renewable energy (VRE)**:** Refers to technologies whose maximum output at any time depends on the availability of fluctuating renewable energy resources. VRE includes a broad array of technologies such as wind power, solar PV, run-of-river hydro, concentrating solar power (where no thermal storage is included) and marine (tidal and wave).

Zero carbon-ready buildings: A zero carbon-ready building is highly energy efficient and either uses renewable energy directly or an energy supply that can be fully decarbonised, such as electricity or district heat.

Regional and country groupings

Figure C.1 ▷ Main country groupings



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

Advanced economies: OECD regional grouping and Bulgaria, Croatia, Cyprus[1,2], Malta and Romania.

Africa: North Africa and sub-Saharan Africa regional groupings.

Asia Pacific: Southeast Asia regional grouping and Australia, Bangladesh, Democratic People's Republic of Korea (North Korea), India, Japan, Korea, Mongolia, Nepal, New Zealand, Pakistan, People's Republic of China (China), Sri Lanka, Chinese Taipei, and other Asia Pacific countries and territories.[3]

Caspian: Armenia, Azerbaijan, Georgia, Kazakhstan, Kyrgyzstan, Tajikistan, Turkmenistan and Uzbekistan.

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

China: Includes the People's Republic of China and Hong Kong.

Developing Asia: Asia Pacific regional grouping excluding Australia, Japan, Korea and New Zealand.

Emerging market and developing economies: All other countries not included in the advanced economies regional grouping.

Eurasia: Caspian regional grouping and the Russian Federation (Russia).

Europe: European Union regional grouping and Albania, Belarus, Bosnia and Herzegovina, North Macedonia, Gibraltar, Iceland, Israel[5], Kosovo, Montenegro, Norway, Serbia, Switzerland, Republic of Moldova, Türkiye, Ukraine and United Kingdom.

European Union: Austria, Belgium, Bulgaria, Croatia, Cyprus[1,2], Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Ireland, Italy, Latvia, Lithuania, Luxembourg, Malta, Netherlands, Poland, Portugal, Romania, Slovak Republic, Slovenia, Spain and Sweden.

IEA (International Energy Agency)**:** OECD regional grouping excluding Chile, Colombia, Costa Rica, Iceland, Israel, Latvia and Slovenia.

Latin America: Central and South America regional grouping and Mexico.

Middle East: Bahrain, Islamic Republic of Iran (Iran), Iraq, Jordan, Kuwait, Lebanon, Oman, Qatar, Saudi Arabia, Syrian Arab Republic (Syria), United Arab Emirates and Yemen.

Non-OECD: All other countries not included in the OECD regional grouping.

Non-OPEC: All other countries not included in the OPEC regional grouping.

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

North America: Canada, Mexico and United States.

OECD (Organisation for Economic Co-operation and Development)**:** Australia, Austria, Belgium, Canada, Chile, Czech Republic, Colombia, Costa Rica, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Iceland, Ireland, Israel, Italy, Japan, Korea, Latvia, Lithuania, Luxembourg, Mexico, Netherlands, New Zealand, Norway, Poland, Portugal, Slovak Republic, Slovenia, Spain, Sweden, Switzerland, Türkiye, United Kingdom and United States.

OPEC (Organisation of the Petroleum Exporting Countries)**:** Algeria, Angola, Republic of the Congo (Congo), Equatorial Guinea, Gabon, the Islamic Republic of Iran (Iran), Iraq, Kuwait, Libya, Nigeria, Saudi Arabia, United Arab Emirates and Bolivarian Republic of Venezuela (Venezuela).

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

Sub-Saharan Africa: Angola, Benin, Botswana, Cameroon, Republic of the Congo (Congo), Côte d'Ivoire, Democratic Republic of the Congo, Eritrea, Ethiopia, Gabon, Ghana, Kenya, Mauritius, Mozambique, Namibia, Niger, Nigeria, Senegal, South Africa, South Sudan, Sudan, United Republic of Tanzania (Tanzania), Togo, Zambia, Zimbabwe and other African countries and territories.[6]

Country notes

[1] Note by Republic of Türkiye: The information in this document with reference to "Cyprus" relates to the southern part of the island. There is no single authority representing both Turkish and Greek Cypriot people on the island. Türkiye recognises the Turkish Republic of Northern Cyprus (TRNC). Until a lasting and equitable solution is found within the context of the United Nations, Türkiye shall preserve its position concerning the "Cyprus issue".

[2] Note by all the European Union Member States of the OECD and the European Union: The Republic of Cyprus is recognised by all members of the United Nations with the exception of Türkiye. The information in this document relates to the area under the effective control of the Government of the Republic of Cyprus.

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

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

[5] 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.

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

Abbreviations and acronyms

AC	alternating current
APEC	Asia-Pacific Economic Cooperation
APS	Announced Pledges Scenario
ASEAN	Association of Southeast Asian Nations
BECCS	bioenergy equipped with CCUS
CAAGR	compound average annual growth rate
CBM	coalbed methane
CCGT	combined-cycle gas turbine
CCUS	carbon capture, utilisation and storage
CDR	carbon dioxide removal
CEM	Clean Energy Ministerial
CH_4	methane
CHP	combined heat and power; the term co-generation is sometimes used
CNG	compressed natural gas
CO	carbon monoxide
CO_2	carbon dioxide
CO_2-eq	carbon-dioxide equivalent
COP	Conference of Parties (UNFCCC)
CSP	concentrating solar power
CTG	coal-to-gas

A

CTL	coal-to-liquids
DAC	direct air capture
DC	direct current
DER	distributed energy resources
DRI	direct reduced iron
DSI	demand-side integration
DSO	distribution system operator
DSR	demand-side response
EHOB	extra-heavy oil and bitumen
EOR	enhanced oil recovery
EPA	Environmental Protection Agency (United States)
ESG	environmental, social and governance
EU	European Union
EU ETS	European Union Emissions Trading System
FAO	Food and Agriculture Organization of the United Nations
FCEV	fuel cell electric vehicle
FDI	foreign direct investment
FID	Final investment decision
FiT	feed-in tariff
FOB	free on board
GEC	global energy and climate (IEA model)
GDP	gross domestic product
GHG	greenhouse gases
GTL	gas-to-liquids
HEFA	hydrogenated esters and fatty acids
HFO	heavy fuel oil
HVDC	high voltage direct current
IAEA	International Atomic Energy Agency
ICT	information and communication technologies
IEA	International Energy Agency
IGCC	integrated gasification combined-cycle
IIASA	International Institute for Applied Systems Analysis
IMF	International Monetary Fund
IOC	international oil company
IPCC	Intergovernmental Panel on Climate Change
LCOE	levelised cost of electricity
LED	light-emitting diode
LNG	liquefied natural gas
LPG	liquefied petroleum gas
LULUCF	land use, land-use change and forestry
MEPS	minimum energy performance standards
MER	market exchange rate
NDCs	Nationally Determined Contributions
NEA	Nuclear Energy Agency (an agency within the OECD)

NGLs	natural gas liquids
NGV	natural gas vehicle
NOC	national oil company
NPV	net present value
NO_X	nitrogen oxides
N_2O	nitrous dioxide
NZE	Net Zero Emissions by 2050 Scenario
OECD	Organisation for Economic Co-operation and Development
OPEC	Organization of the Petroleum Exporting Countries
PM	particulate matter
$PM_{2.5}$	fine particulate matter
PPA	power purchase agreement
PPP	purchasing power parity
PV	photovoltaics
R&D	research and development
RD&D	research, development and demonstration
SDG	Sustainable Development Goals (United Nations)
SME	small and medium enterprises
SMR	small modular reactor
SO_2	sulphur dioxide
STEPS	Stated Policies Scenario
T&D	transmission and distribution
TES	thermal energy storage
TFC	total final consumption
TFEC	total final energy consumption
TPED	total primary energy demand
TSO	transmission system operator
UAE	United Arab Emirates
UN	United Nations
UNDP	United Nations Development Programme
UNEP	United Nations Environment Programme
UNFCCC	United Nations Framework Convention on Climate Change
US	United States
USGS	United States Geological Survey
VALCOE	value-adjusted levelised cost of electricity
VRE	variable renewable energy
WACC	weighted average cost of capital
WEO	World Energy Outlook
WHO	World Health Organization

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Coal in Net Zero Transition

Coal and its emissions are a critical issue as the world contends with both the global energy crisis and the climate crisis. *Coal in Net Zero Transitions: Strategies for rapid, secure and people-centred change* is a new IEA special report in the *World Energy Outlook* series. It presents pragmatic, real-world guidance on how policymakers can achieve a reduction in carbon dioxide emissions from coal without harming economies or energy security, outlining measures to finance energy transitions and address their social and employment aspects.

All long-term IEA scenarios that meet international climate goals feature a rapid decline in global coal emissions. Without this, it will be impossible to avoid severe impacts from a changing climate. However, the world is currently far from heading decisively in this direction. Renewable energy options are the most cost-effective new sources of electricity generation in most markets, but there are still multiple challenges in reducing emissions from the existing global fleet of coal-fired power plants.

This special report explores the options for the power sector and other parts of the economy where coal plays a notable role. It examines a range of policy and technology areas, including the potential for carbon capture, utilisation and storage. And it addresses investment and financing needs, taking into account the importance of ensuring reliable and affordable energy supplies and of tackling the social consequences of change.