



Financing the Modernisation of Power Systems Beyond Coal

The role of transition credits in
Southeast Asia

International
Energy Agency



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Abstract

Coal is a central component of power systems in Southeast Asia, even as governments have committed to reducing coal-related emissions. Rapid electricity demand growth, alongside coal's role in system adequacy, reliability and energy security, complicates efforts to accelerate coal transitions. Recent volatility in international gas markets has reinforced the short-term economic and security value of existing coal assets, adding complexity to national transition strategies. The region's young coal fleet also implies substantial long-term emissions if plants continue operating at current utilisation rates.

Against this backdrop, new approaches are being explored to support coal transitions while maintaining secure and reliable power systems. This report examines the potential role of transition credits as a market-based instrument to support coal transitions in Southeast Asia. It analyses the scale of emissions from existing coal fleets, options to reduce emissions from operating plants, and considers the investment and power system planning challenges of replacing coal generation while maintaining essential system services. It also reviews project-based and emerging jurisdictional approaches to transition credits, focusing on methodologies for the early retirement of grid-connected coal plants and their replacement with clean energy.

By examining these issues from a power system, investment and carbon markets perspective, the report aims to provide a clearer understanding of coal transition strategies and outlines recommendations for countries that may choose to explore transition credits as an option to reduce the role of coal in their electricity mix.

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Executive summary

The role of coal in power systems is evolving

This report assesses the potential applications, limitations and relevance of transition credits in Southeast Asia. Coal is the largest source of power generation worldwide and the largest source of energy-related carbon dioxide emissions. All Southeast Asian countries with coal in their power generation mix have adopted commitments to reduce coal-fired generation or emissions targets that imply a significant decline in coal consumption in the coming decades. To meet these targets, the International Energy Agency (IEA) has long emphasised that a range of strategies can be deployed to reduce coal emissions. The global energy crisis of the first half of 2022 has added a layer of complexity to coal transition and energy security strategies: heightened volatility in gas markets, driven in large part by conflict in the Middle East, has increased the short-term economic value of existing coal assets. At the same time, interest has grown in new financing mechanisms that could help accelerate coal transitions. Transition credits are one such option that have received increasing attention in the energy and carbon markets community in Southeast Asia. This report examines how transition credits could be designed to accelerate a coal transition for those countries seeking to do so, while maintaining energy security and grid reliability. This report focuses primarily on Southeast Asia, where coal remains an integral part of the electricity mix and where many of the current discussions and pilot initiatives for transition credits are concentrated.

Despite rapid growth in renewables, coal remains critical to meet growing electricity demand and fulfil key power system needs. Coal use is in structural decline in advanced economies, but it continues to play a central role in some emerging market and developing economies. Southeast Asia illustrates this dynamic, as one of the world's fastest-growing regions for electricity demand, driven by population growth, urbanisation, industrialisation and electrification. Although the share of coal in electricity generation in the region is expected to decline over the coming decade as renewables expand rapidly, coal-fired power generation is anticipated to remain important for system adequacy, reliability and energy security. Recent disruptions in gas markets have reinforced this role, with governments in Southeast Asia increasing coal-fired power generation to maintain electricity supply and manage fuel supply risks.

If operated for typical lifetimes and utilisation rates, the existing worldwide coal fleet would emit 330 gigatonnes (Gt) of carbon dioxide (CO₂) to 2100 – more than the historical emissions to date of all coal-fired power plants that

have ever operated. Countries across developing Asia have added over 1 450 gigawatts (GW) of coal power since 2000. In 2024, the region accounted for nearly three-quarters of global coal-fired power capacity, with around 80% of plants under 20 years old. At current utilisation rates and standard lifetimes, existing coal plants in developing Asia would emit over 280 Gt CO₂ to 2100, over 85% of the projected global coal-related emissions, and equivalent to over 20 times the People's Republic of China's current annual energy-related CO₂ emissions, or nearly 90 times India's. The young coal fleet in Southeast Asia adds to the risk of long-term coal emissions.

Achieving coal transitions at the speed and scale required by government policies, national climate goals and international commitments has large implications for coal fleets. While many of these policies include caveats that constrain their practical application, such as partial coverage across the coal fleet, meeting stated targets would still require substantial and co-ordinated changes in generation, investment and system operation across Southeast Asia.

Managing coal transitions requires maintaining secure, reliable and affordable electricity supply

Four strategies to reduce emissions from operating coal-fired power plants could cut cumulative global emissions by 140 Gt CO₂ to 2050. In the Announced Pledges Scenario (APS), which reflects governments' announced energy and climate commitments, repurposing coal plants to focus on system adequacy or flexibility services accounts for half of global CO₂ emissions savings achieved, while retiring coal plants ahead of the end of their technical lifetimes delivers another 45%. Retrofitting coal plants with carbon capture, utilisation and storage (CCUS) and co-firing with lower-emissions fuels such as biomass and ammonia can also reduce emissions while keeping assets operational. Repurposing and retrofitting enable coal plants to continue providing important peak capacity and load balancing services. The choice of which emissions reduction strategies to deploy depends on the specific circumstances of the country and the nature of the existing coal fleet.

Coal transitions in Southeast Asia require scaling up replacements not only for the electricity that coal plants produce, but also the system services they provide. Coal-fired power plants are dispatchable and can contribute close to their nameplate capacity to meeting peak demand, giving them an important role in system adequacy. In the APS, low-emissions electricity sources meet all demand growth and progressively displace coal, with more than three-quarters of the displaced coal-fired generation in Southeast Asia replaced by solar photovoltaic (PV) and wind. Because coal plants in the region typically operate at a moderate to high capacity factor, replacing the electricity generated by 1 GW of coal in the region requires 1.5 GW to 2 GW of onshore wind or around 3 GW to 4 GW of

solar PV, unless complemented by storage or other firm resources. The contribution of unabated coal capacity to system adequacy in Southeast Asia declines by over 2 GW per year to 2050 in the APS and is offset through a diversified mix of technologies, led by battery storage and supported by demand-side response and stronger regional grids.

Coal transitions require large investment, while policy and finance shape affordability

In Southeast Asia, around USD 20 billion in investment per year is required in the APS to 2050 to reduce emissions from coal-fired power. Of the USD 20 billion, 70% of investment is directed towards replacing the use of unabated coal power with solar PV and wind. Mobilising this investment will require supportive regulatory and market frameworks, complemented by international public finance to help accelerate coal asset retirement and unlock private investment.

Accelerated coal transitions are compatible with keeping electricity prices affordable, but their socio-economic impacts need to be addressed in a people-centred and just manner. In the APS, where coal plays a smaller role in 2035 than today, an 80% decline in coal fuel costs in the next decade delivers substantial cost savings. In Southeast Asia, these savings more than offset rising capital recovery costs associated with investment in new infrastructure, leading to an overall reduction in total electricity system costs. Lower electricity system costs do not necessarily translate into lower household electricity bills, though, as retail prices are driven by a range of regulatory, fiscal and structural factors beyond generation costs, underscoring the continued value of targeted policy support to protect affordability. Moreover, early closure of coal-fired power plants will have economic consequences for coal-dependent communities, requiring development strategies that offer alternative sources of employment.

Transition credits can support early coal retirement and clean energy replacement, provided energy security considerations are integrated in their design

Transition credits can support the modernisation of power systems and facilitate a secure move beyond coal. Transition credits are a type of carbon credits issued from verified emissions reductions in the power sector, through either emissions reductions for individual plants or through system-level reductions in emissions intensity. By providing a complementary market-based revenue stream linked to emissions outcomes, transition credits can improve the

economic viability of coal transition strategies and accelerate change where national strategies, power system planning and clean energy investment are already aligned.

Most transition credit approaches today are focused on individual projects for the early retirement of grid-connected coal-fired power plants and their replacement with clean energy, addressing one of the four coal-transition strategies. Several carbon market methodologies for project-based transition credits are publicly available or under development. Among them, Verra's VM0052 methodology is being applied as a pilot to the South Luzon Thermal Energy Corporation plant in the Philippines, where transition credits could generate significant revenue between 2031 and 2040 from the plant's early retirement and its replacement with clean energy.

Alignment among transition credit approaches, national transition pathways and power system planning is essential to ensure energy security. The implementation of transition credits does not occur in isolation and should consider country-specific power system conditions, market structures and planning priorities. Decisions on the scale, location, timing and modality of clean energy replacement should be guided by power system plans and close co-ordination between transition credit proponents and system planners. Robust and flexible planning is critical to ensure that transition credit projects preserve reliability and energy security while delivering credible emissions reductions.

Managing carbon leakage is critical to the integrity of transition credits. Emissions reductions from coal retirement may be undermined if lost generation is replaced by fossil fuel sources elsewhere in the system, if there is new coal investment or if there are shifts in international coal trade. The rate of clean energy replacement is a central safeguard against carbon leakage in transition credit projects. The more coal generation is directly replaced by new clean energy, the lower the risk that emissions are merely displaced rather than reduced. Residual leakage should also be explicitly accounted for by quantifying and deducting any additional fossil fuel emissions elsewhere in the system.

Additionality is central to the environmental integrity of transition credits, requiring evidence that early coal plant retirement would not occur on the same timeline without carbon credit revenues. This is particularly relevant in Southeast Asia, where coal phase-down commitments are emerging but early retirement is often not yet mandated by law, leaving open the possibility for transition credits to accelerate change beyond existing policy trajectories. However, falling renewable energy costs are narrowing the case for financial additionality in some markets, raising the risk that credits could subsidise closures that would have occurred anyway.

Transition credit demand is limited, but compliance markets could become a significant source of future demand. Carbon markets face headwinds from reputational concerns and evolving standards that have increased uncertainty around the use of carbon credits in corporate climate claims. At the same time, price uncertainty, limited post-2030 visibility and policy reversal risks constrain willingness to pay higher prices. Compliance carbon markets offer the strongest potential source of demand for transition credits, particularly where governments allow their use for meeting regulatory obligations. This source of demand could be complemented by long-term agreements under Article 6.2 of the Paris Agreement and pooling of buyers into coalitions.

Realising the full value of transition credits requires coherent policy, system planning and financing

Recommendations:

Embed coal transition pathways in credible national policy frameworks.

While long-term government strategies provide high-level direction, clear and co-ordinated policy frameworks are needed to translate high-level targets into implementable coal transition pathways. Such frameworks improve policy predictability, enabling market actors to plan viable emissions reduction strategies with greater confidence. In parallel, coherent guidance on carbon market governance is critical to safeguard environmental integrity, provide consistent investment signals and ensure that transition credits operate coherently alongside other policy instruments.

Integrate coal transition pathways and transition credits into power systems planning. Coal continues to play a central role in energy security across Southeast Asia even as governments pursue long-term coal transition goals. Reducing emissions from coal power while maintaining reliable, affordable and secure electricity supply requires co-ordination between coal transition initiatives and power system planning for replacement capacity, grid infrastructure, flexibility resources and energy efficiency measures. This helps ensure that transition credit projects are consistent with power system needs and deliver credible, durable emissions reductions. Embedding transition credits within power system planning can also improve project feasibility and predictability, by clarifying how and when coal capacity is replaced and reducing risks to reliability and investment outcomes.

Further develop transition credit methodologies to better integrate energy security considerations and reflect local power systems priorities. Current transition credit methodologies are largely designed for pilot projects and focus primarily on early coal plant retirement. As these methodologies evolve, there is scope to strengthen alignment with power system planning to ensure that

transition credit projects are consistent with host-country energy security objectives. Continued attention to safeguards against emissions and market leakage, together with regular updates to baselines and additionality assumptions, will be important to maintain credibility as power systems evolve. Allowing for more context-specific application could, over time, enable methodologies to support a wider range of coal transition pathways and facilitate scaling beyond pilot projects.

Consider transition credits as a complementary performance-based revenue stream, contingent on stronger demand-side signals. Achieving coal transitions at the scale required under national targets will require substantially more favourable clean energy economics. Within this context, transition credits can provide a performance-based revenue stream that improves the risk-adjusted returns of transition projects, complementary to other financing instruments and public support mechanisms. Strengthening demand-side signals, alongside durable policy commitments and risk mitigation instruments, is critical to enable transition credits to complement broader financing packages and support coal transitions more effectively.

Chapter 1. The role of coal in power systems

Overview

[Coal](#) is the largest source of power generation worldwide and the largest source of energy-related carbon dioxide (CO₂) emissions. In 2025, global coal demand for power generation plateaued at historically high levels. Despite [rapid growth in renewables](#), coal continues to underpin power systems in many emerging market and developing economies (EMDE) where it provides both firm electricity supply and system services such as flexibility. This is particularly evident in Southeast Asia, where electricity demand is rising rapidly and coal-fired power plant fleets are relatively young, usually supported by long-term financial, contractual and regulatory arrangements. At the same time, many countries, including in Southeast Asia, have coal phase-down or emissions reduction targets which imply significant reductions in coal consumption over the coming decades.

The International Energy Agency (IEA) has long emphasised that there is no single pathway for reducing coal emissions and that achieving emissions goals will require addressing all sources of emissions, not just those from coal. A range of coal transitions strategies is available and can be adapted to national circumstances. As outlined in the [2022 IEA Coal in Net Zero Transitions](#) report, these include 1) repurposing coal plants by reducing operations to focus on system adequacy or flexibility services; 2) retrofitting coal plants with carbon capture, utilisation and storage (CCUS); 3) co-firing low-emissions ammonia or biomass; and 4) retiring coal plants before they reach the end of their technical lifetime. These strategies have different implications for emissions reductions, energy security, costs and social outcomes, and their suitability varies across countries. External developments can also shape supply considerations and transition choices: recent volatility in gas markets, driven in large part by conflict in the Middle East, has increased the short-term economic value of existing coal assets, influencing the pacing and choice of coal transition pathways.

Financing is central to coal transition strategies. While a range of public and private financing instruments already exist and are expected to provide the bulk of investment required for a coal transition, interest has grown in new mechanisms that could help accelerate this process. Transition credits have emerged as one such option. This report defines transition credits as carbon credits issued for emissions reductions in the power sector by 1) accelerating the retirement and repurposing of fossil fuel power assets (here focusing on coal) and replacing their

capacity or output with cleaner alternatives; or 2) lowering the emissions intensity of electricity supplied at the system level. They are designed to complement existing financing mechanisms by helping to close financial gaps and improve the economics of early coal retirement or system-level emissions reductions. While the concept is still nascent, it can become part of a broader toolkit for managing coal transitions.

This report assesses the potential applications, limitations and relevance of transition credits in Southeast Asia, where coal remains an integral part of the electricity mix and where many of the current discussions and pilot initiatives for transition credits are concentrated. The report also provides recommendations for policy makers and project developers in countries that are considering whether transition credits could support a reduced reliance on coal.

The projections of coal use and emissions in this report are based on the [Announced Pledges Scenario](#) (APS) developed for the *World Energy Outlook* (WEO). The APS assumes that all announced national energy and climate targets, including net zero commitments, are met in full and on time. It provides a scenario-based framework to assess how coal transitions can unfold in line with existing commitments, while maintaining electricity security, affordability and system reliability across regions. By focusing on announced targets and policies, it enables an assessment of how coal phase-down pathways interact with power system planning, investment needs and operational requirements across regions. This perspective helps clarify the scale, timing and composition of measures needed to replace coal's role in electricity systems while maintaining adequacy, flexibility and reliability. The APS therefore serves as a policy-relevant benchmark for analysing how coal transitions may unfold under current commitments and supporting secure and orderly implementation.

In this report:

- **Chapter 1** sets the stage by examining coal use and power demand trends, highlighting the scale of the challenge to reduce emissions from coal and introducing the potential role for transition credits in this context.
- **Chapter 2** explores various elements of coal transitions, including the emissions impacts of different coal transition levers, the impacts of using different technologies for coal replacement and strategies to finance coal transitions.
- **Chapter 3** outlines the main opportunities and challenges of using transition credits as an instrument to accelerate a coal transition while maintaining the host country's energy security and grid reliability.
- **Chapter 4** concludes with recommendations on how transition credits could be used most effectively as part of a broader coal transition strategy for countries choosing to pursue this option.

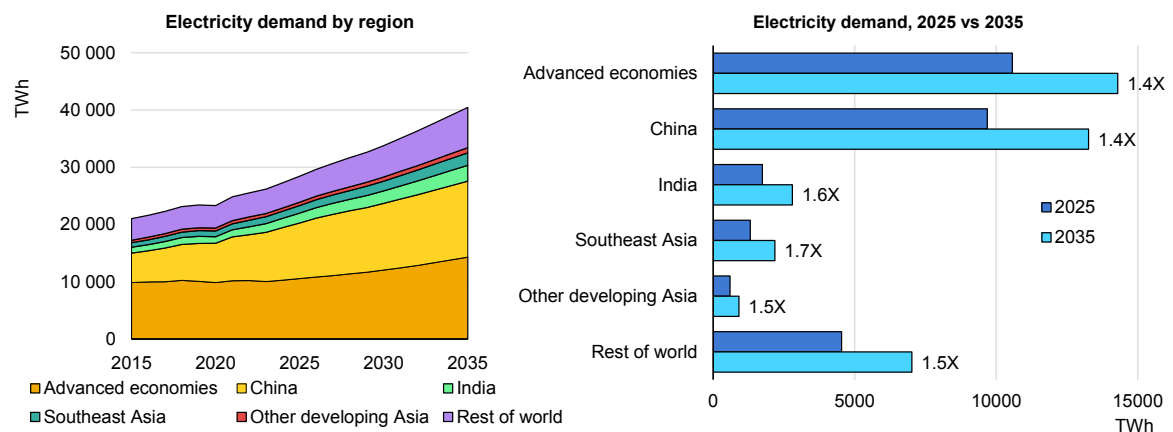
Context

While coal remains critical for energy security in Asia, transitions are under way across the energy system

Strong electricity demand growth heralds the Age of Electricity

The world is entering the [Age of Electricity](#). Globally, demand for electricity has risen by 35% in the last decade, more than twice as fast as total energy demand. Advanced economies accounted for nearly 40% of global electricity demand in 2025. Their electricity consumption has remained largely stable in the last decade, though there has been a rise recently due to drivers such as data centres and electrification of end uses. By contrast, the People’s Republic of China (hereafter, “China”) has vastly grown its electricity demand, with an annual average growth of 6% in the last decade.

Figure 1.1 Electricity demand in the Announced Pledges Scenario, 2015-2035



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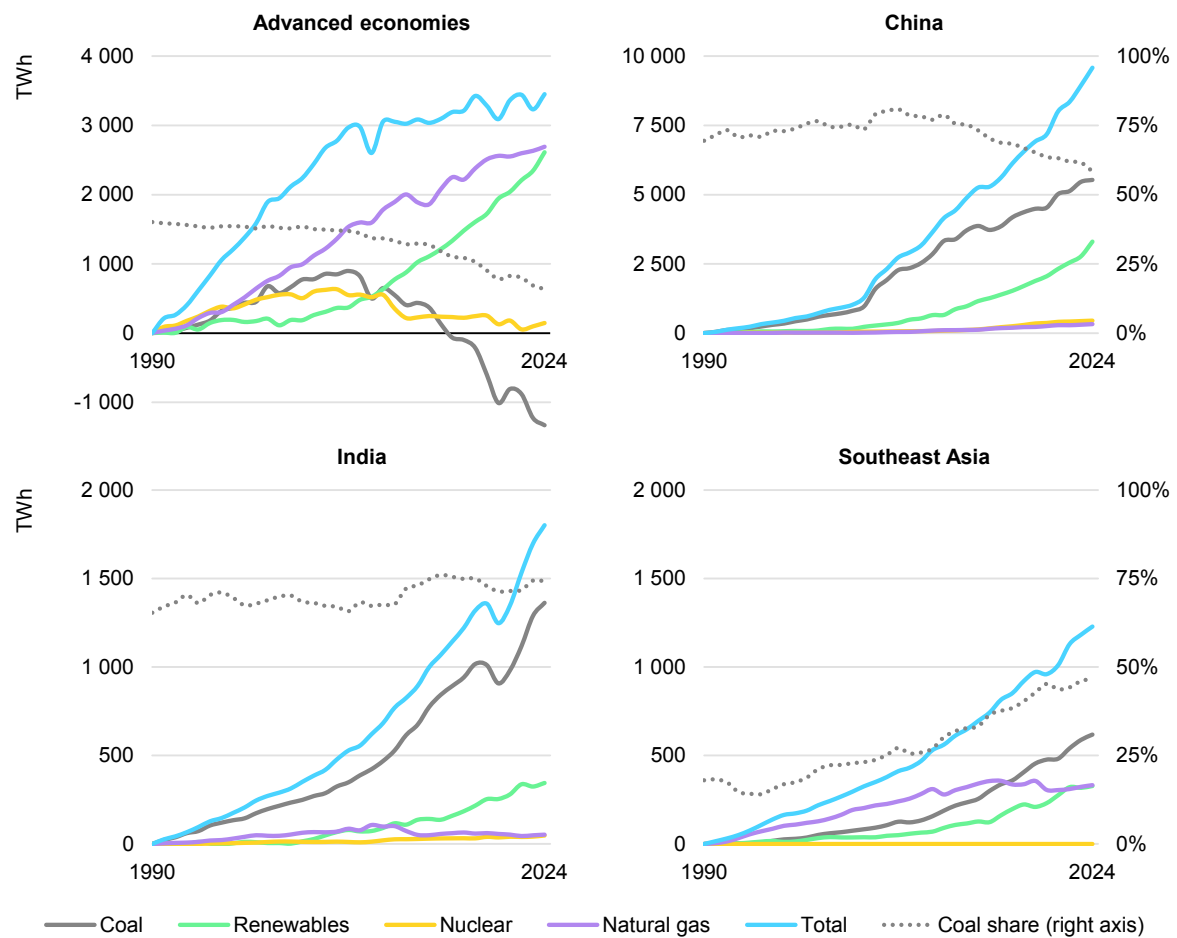
Notes: TWh = terawatt-hours. “Other developing Asia” = Bangladesh, Democratic People’s Republic of Korea (North Korea), Mongolia, Nepal, Pakistan, Sri Lanka, Chinese Taipei.

In the next decade, China’s electricity demand growth is expected to moderate to 3% per year, but it remains the world’s largest consumer of electricity. Electricity demand growth is instead shifting to other EMDE, led by India and Southeast Asia. In the [APS](#), electricity demand between 2026 and 2035 in India grows by around 50% and in Southeast Asia grows by around 60%. This reflects growing populations and economies as well as rising urbanisation, industrialisation and electrification of end uses.

Amid rapid renewables growth, coal remains critical to meet electricity demand and system flexibility needs across Asia

Coal has historically dominated electricity generation globally, supporting electrification and economic development in many regions. In 2025, it remained the largest source of global electricity generation, accounting for 34% of total generation. However, its role is evolving along distinct regional trajectories.

Figure 1.2 Change in electricity generation by fuel and evolution of coal share in power systems by region, 1990-2024



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In advanced economies, coal use in power is in structural decline. At the same time, low-cost natural gas and renewables, supported by robust policy frameworks – including carbon pricing, emissions and pollution regulations, renewable support schemes, and climate targets – have been sufficient to meet new demand and displace coal from power systems in line with coal transition commitments. In the United States, coal's share of electricity generation fell from over 50% in the early

2000s to below 20% in recent years. In the European Union, coal declined from around 40% in 1990 to 10% in 2024, now concentrated in a small number of member states.

Looking forward, coal in advanced economies continues to decline in the APS as plants reach the end of their lifetimes and renewables and other low-carbon sources gain share. Between today and 2035, coal in electricity generation in advanced economies drops by over 85%.

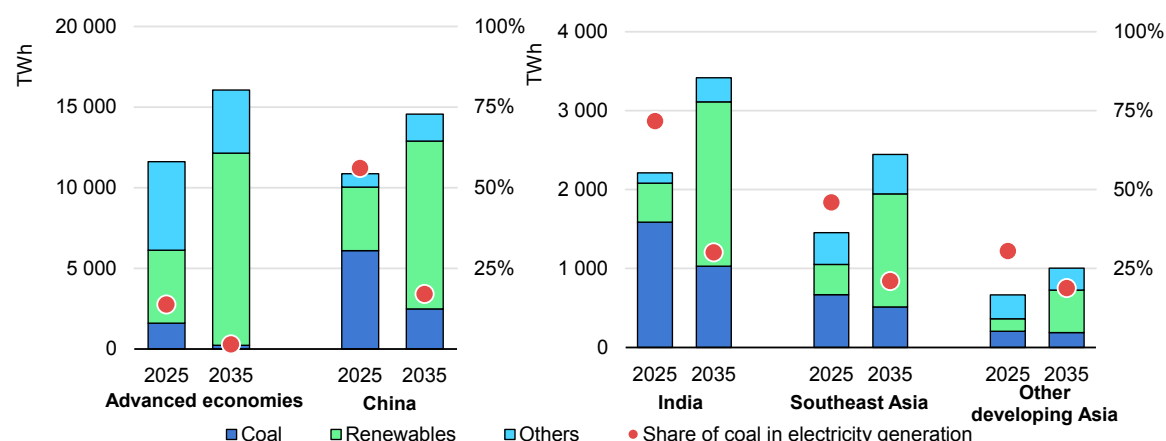
China remains by far the world's largest coal power producer. While coal remains the largest source of electricity generation in absolute terms, faster growth in renewables and other low-emissions sources has steadily eroded coal's share of generation, from around 70% a decade ago to closer to 60% today.

In China, electricity generated from coal drops by 60% in the next decade in the APS, but coal remains important for system flexibility. In 2024, the National Development and Reform Commission released a [guiding policy](#) requiring accelerated flexibility retrofits of coal-fired power plants by 2027, complemented by [reforms](#) and an [implementation plan](#) for capital mobilisation.

By contrast, in many other EMDE, rapidly rising electricity demand means coal-fired generation continues to play a central role in balancing power systems, even with record renewable additions and the rising use of natural gas. In India, electricity demand grew nearly eight-fold between 1990 and 2024, with coal generation expanding broadly in line. Southeast Asia is also seeing one of the fastest increases in coal use globally, with coal approaching half of regional electricity generation. Abundant domestic coal has underpinned [Indonesia's](#) continued reliance on coal, reaching roughly 70% of electricity generation in recent years. Coal use was negligible in both Viet Nam and the Philippines in 2000, but has since risen to around 45% of electricity generation in Viet Nam and about 60% in the Philippines.

In Southeast Asia, electricity generation from coal in the APS continues to rise until the end of this decade, driven by strong economic growth and surging electricity demand. It then declines in the 2030s with growing renewables penetration. The share of coal in electricity generation was nearly 50% in 2025, and declines to 20% in 2035 in Southeast Asia.

Figure 1.3 Electricity generation by source in the APS in selected regions



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Notes: “Others” = Natural gas, oil, nuclear, hydrogen, ammonia and non-renewable waste. “Other developing Asia” = Bangladesh, Democratic People’s Republic of Korea (North Korea), Mongolia, Nepal, Pakistan, Sri Lanka, Chinese Taipei.

Coal’s central role in Southeast Asia is driven by policy, market structures, industrial demand and energy security concerns

Policy and market structures have reinforced coal’s persistence where it is often seen as affordable, dispatchable power. In Southeast Asia, similar to many other regions, energy security and industrial considerations give coal a privileged role. Furthermore, long-term contracts and regulated tariffs, including capacity-based power purchase agreements, have historically guaranteed offtake for coal plants and prioritised them in dispatch. Beyond grid-connected coal, [captive power coal plants](#) account for over 10% of global fossil fuel power capacity. These plants provide dedicated on-site generation for energy-intensive industries with high reliability needs and grid access constraints, such as metal processing, cement and petrochemicals.

Recent supply disruptions in gas markets could, however, lead to a temporary increase in coal demand in parts of Asia. The 2026 conflict in the Middle East, which nearly halted shipping traffic through the Strait of Hormuz, triggered the largest supply disruption in the history of the global oil market and may have significant implications for global gas flows. [About 80% of oil and gas products transiting the Strait](#) in 2025 were destined for Asia. In March 2026, the Asian liquefied natural gas (LNG) market faced extreme volatility with spot prices [reaching a three-year high](#). This pushed some buyers, particularly in more price-sensitive economies, to turn to coal to support energy security. [The Philippines](#) declared a [state of energy emergency](#) in March 2026 and is ramping up coal-fired power generation while slashing LNG-fired output. [Thailand](#) is also boosting dispatch from its largest coal plant in response to rising LNG costs. Indonesia, the world’s largest coal exporter, is [considering a coal export tax](#) in response to the

crisis. Southeast Asia other than Indonesia is a net coal-importing region, importing over 3 500 petajoules in 2024, representing over 15% of total energy supply, exposing many countries to global price volatility and supply risks.

The risk of high emissions from the existing coal fleet is particularly acute for Asia

At the global level, the existing coal-fired power plant fleet represents a substantial source of potential long-term carbon dioxide emissions, particularly where plants are relatively young and have long remaining operating lifetimes. In 2024, 2 260 gigawatts (GW) of coal-fired capacity was in operation worldwide, with an average age of approximately 20 years. If these plants were to continue operating at historical utilisation rates over typical technical lifetimes, they would cumulatively emit around 330 gigatonnes (Gt) CO₂ from 2025 through 2100. The distribution of these potential emissions across regions is highly uneven, reflecting stark differences in fleet scale and age patterns.

Table 1.1 Existing coal-fired power plants installed capacity and average age in 2024 and emissions to 2100 at current utilisation rates and standard lifetime by selected region/country

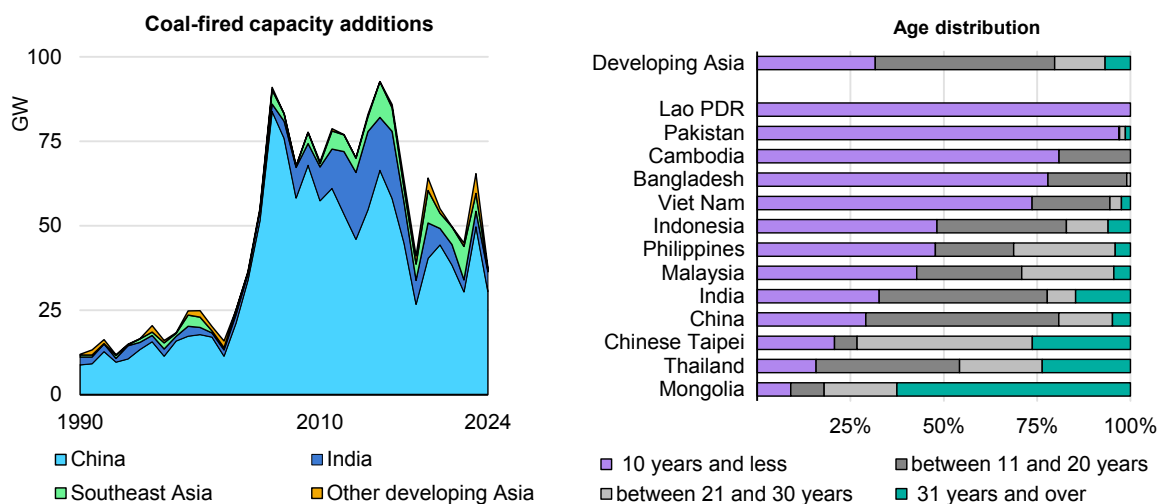
	2024		2025-2100 cumulative CO ₂ emissions	
	Capacity (GW)	Average age (years)	Gt CO ₂	Share
Developing Asia, of which	1 651	15	281	86%
China	1 244	15	208	63%
India	255	16	43	13%
Indonesia	49	12	10	3%
Viet Nam	28	9	7	2%
Chinese Taipei	20	24	2	1%
Malaysia	13	15	3	1%
Philippines	13	15	3	1%
Pakistan	8	6	2	1%
Bangladesh	7	6	1	0%
Thailand	6	21	1	0%
North America	195	43	8	3%
Europe	164	36	11	3%
Other Asia Pacific	124	24	17	5%
Eurasia	59	41	4	1%
Africa	52	31	5	2%
Central and South America	13	19	2	1%
Middle East	1	43	0	0%
World	2 259	20	329	100%

Coal fleets in advanced economies are generally older, with average ages exceeding 35 years in North America and Europe, and nearly 300 GW have been retired over the past two decades. As a result, these regions account for a relatively small share of projected emissions, together contributing around 6% of the global total.

By contrast, countries across developing Asia added over 1 450 GW since 2000. As a result, developing Asia accounted for nearly three-quarters of global coal plant capacity in 2024, 80% of which is under 20 years old. In several Southeast Asian countries, including Indonesia and Viet Nam, coal fleets are younger still, reflecting rapid build-out since the mid-2010s. Overall, the young age profile implies long remaining technical lifetimes and underscores the importance of how this capacity is operated and embedded within energy systems.

Part of this young coal capacity is accounted for by captive plants serving energy-intensive industries, which follow different investment and operating drivers from grid-connected generation. Around [22 GW](#) of captive coal is in operation in Southeast Asia, accounting for 18% of total coal capacity. Captive coal is [particularly prominent in Indonesia](#), primarily for critical minerals processing, where nearly 20 GW of captive coal was in operation in 2024 (see Chapter 3).

Figure 1.4 Coal-fired capacity additions 1990-2024 and age distribution of existing coal-fired power plants in 2024 in developing Asia



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Notes: Lao PDR = Lao People's Democratic Republic. "Other developing Asia" = Bangladesh, Democratic People's Republic of Korea (North Korea), Mongolia, Nepal, Pakistan, Sri Lanka, Chinese Taipei.

At current utilisation rates and standard lifetimes, existing coal plants in developing Asia alone would emit more than 280 Gt CO₂ to 2100 – equivalent to over 20 times China's current annual energy-related CO₂ emissions, or nearly 90 times India's. Under these assumptions, China dominates this picture by a wide margin, with cumulative emissions roughly five times those of India, the second-largest

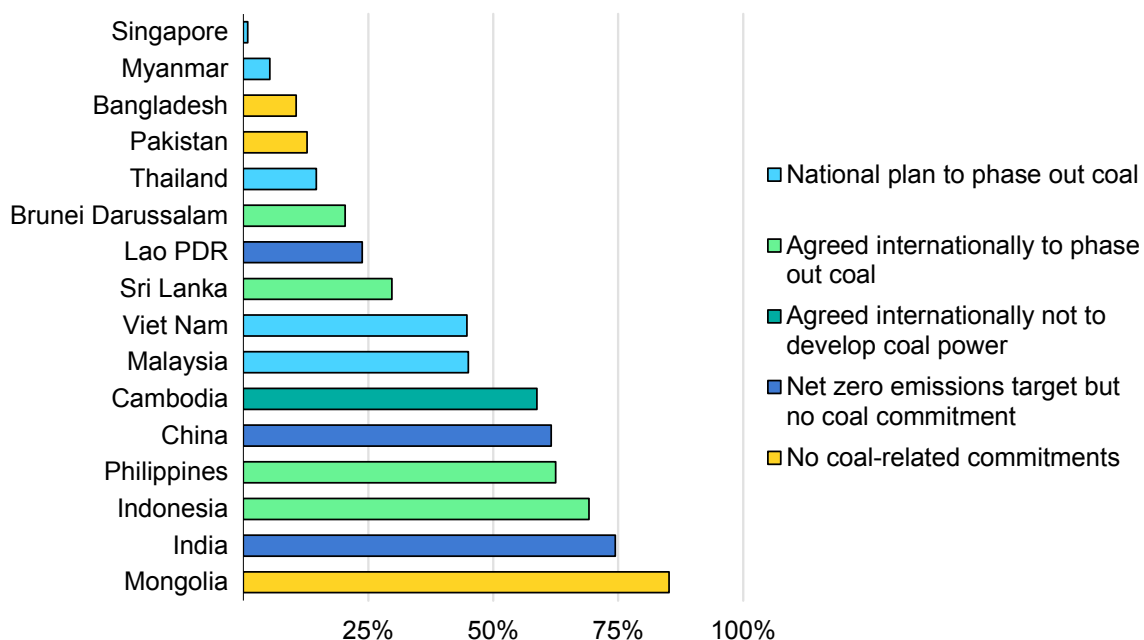
contributor. Beyond these two systems, a growing number of coal-dependent power systems in Southeast and South Asia, such as Indonesia and Viet Nam, add materially to regional risks of increased coal-based emissions.

Despite coal’s large share in the current electricity mix, many EMDE in Asia have committed to a phase-down or -out of unabated coal in line with international climate agreements

Today many countries in Asia are looking to reduce their reliance on coal. The [outcomes of the first Global Stocktake](#), concluded at the 28th Conference of the Parties (COP28) in Dubai in 2023 sets out ambitious global goals for energy sector emissions to align with a 1.5 °C pathway. The Stocktake calls upon countries to contribute to these collective goals with supportive national policies and to integrate them into the next round of nationally determined contributions. One of the [calls](#) in the first Global Stocktake decision is to accelerate “efforts towards the phase-down of unabated coal power”.

As of April 2026, ten EMDE in Asia have announced plans to phase out coal, phase down coal or not develop new unabated coal power plants. In addition, China, India and Lao PDR have announced net zero emissions targets that imply a need to significantly phase down unabated coal without stating it explicitly.

Figure 1.5 Coal transition policies (as of April 2026) and share of coal in electricity generation in EMDE in Asia



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Notes: Lao PDR = Lao People’s Democratic Republic; data on the share of coal in electricity generation is from 2023; Timor-Leste has not been included as its [share of coal in electricity generation is zero](#).

National coal transition policies across Asia are nuanced, reflecting diverse power system needs and the long-standing role of coal for energy security. While several countries have pledged to avoid developing new unabated coal power, some of these commitments come with clarifications, exceptions or caveats that narrow their scope or limit their practical effect. For instance, [Indonesia](#)'s pledge to stop building new coal power plants does not apply to captive coal plants serving industrial zones, to projects categorised as national strategic projects, or to those already included in existing electricity plans. The Philippines has introduced similar caveats. Although the Department of Energy implemented a [coal moratorium](#) for new coal plants in 2021, a 2025 [clarification](#) exempted coal plants in off-grid areas and allowed coal for mining and processing of critical minerals as well as for industrial own-use.

Overall, Southeast Asian countries with coal in their electricity mix all have either commitments to reduce emissions from coal or to reduce coal dependency, or net zero emissions targets. The remainder of the report explores coal transition strategies and where transition credits may be an option for countries in the region interested in pursuing them as part of a broader coal reduction or emissions reduction strategy.

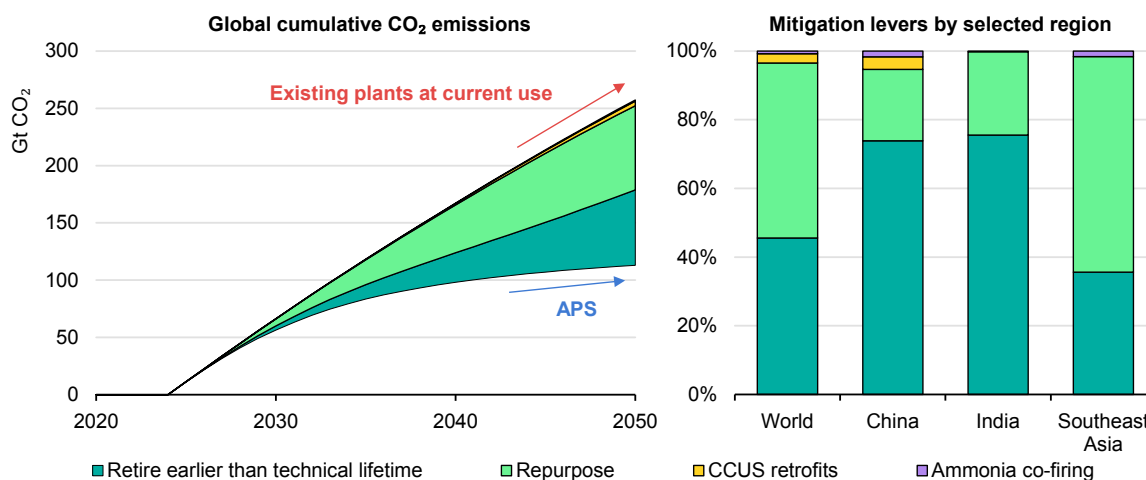
Chapter 2. Coal transition strategies

Managing coal transitions requires approaches that reduce emissions while maintaining reliable and affordable electricity supply. This chapter examines the strategies available to accelerate the transition away from unabated coal, focusing primarily on the power sector in Southeast Asia and other parts of developing Asia where coal use remains significant. Building on the assessment of the risk of high emissions from the existing coal fleet set out in Chapter 1, the analysis highlights how these emissions can be managed through a combination of reduced utilisation, early retirements and targeted retrofits, alongside a rapid scale-up of alternative sources of electricity. In Southeast Asia, these strategies need to be carefully sequenced with investments in grids, storage and flexibility to ensure that reducing emissions from coal supports, rather than constrains, economic growth and energy security.

Levers for reducing emissions from existing coal plants

As set out in Chapter 1, the expectation of future emissions from the existing coal-fired power plant fleet reflects structural risks rather than an unavoidable outcome. These risks can be mitigated through policy choices and changes in plant operation, investment and system planning. Over the past decade, a growing number of governments have adopted policies to limit coal use in power generation, reflecting both climate objectives and air quality concerns. While local air pollution from coal can be substantially reduced through emissions control technologies, addressing coal-related carbon dioxide (CO₂) emissions is essential to avoid severe climate impacts. These commitments are reflected in the Announced Pledges Scenario (APS), which assumes all national energy and climate targets, including net zero goals, are met in full and on time. In the APS, a range of options to reduce emissions from operating coal-fired power plants could collectively cut cumulative emissions by around 140 gigatonnes (Gt) CO₂ to 2050, relative to a continuation of recent operating patterns.

Figure 2.1 CO₂ emissions from existing coal-fired power plants and mitigation levers in the Announced Pledges Scenario



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Note: CCUS = carbon capture, utilisation and storage.

- Repurposing coal plants to focus on system adequacy or flexibility services** is the largest contributor to these reductions – especially in Southeast Asia – representing half of global savings in the APS. Under this approach, plants generate less electricity but remain available during periods of high demand, supporting system reliability and, in some cases, facilitating the integration of higher shares of variable renewables. Most coal plants can be used more flexibly, with operational changes and, where needed, targeted equipment upgrades enabling lower minimum loads, more frequent ramping and part-load operation. [China](#) and [India](#) have issued guidelines to improve coal plant flexibility, while similar operating patterns are already common in Europe. In parts of Southeast Asia, [including Thailand](#), coal plants already provide a degree of operational flexibility, but further progress will depend on reforms to contracts and market frameworks to adequately reward flexibility, for example through capacity or ancillary service payments. Experience in India illustrates the importance of such incentives, as [recent delays in implementation](#) reflect economic trade-offs linked to higher fixed costs and efficiency losses from flexible coal operations.
- Retiring coal plants early, ahead of the end of their technical lifetimes**, contributes around 45% of long-term emissions savings in the APS. Decisions around refurbishments create natural inflection points, but policy interventions and targeted financial mechanisms, such as transition credits, can also incentivise earlier closures. Early retirement also requires careful consideration of impacts on workers, communities and the local environment. In Southeast Asia, retiring relatively young plants remains challenging but is increasingly part of policy discussions. International initiatives such as Just Energy Transition Partnerships (JETPs) aim to accelerate coal retirements

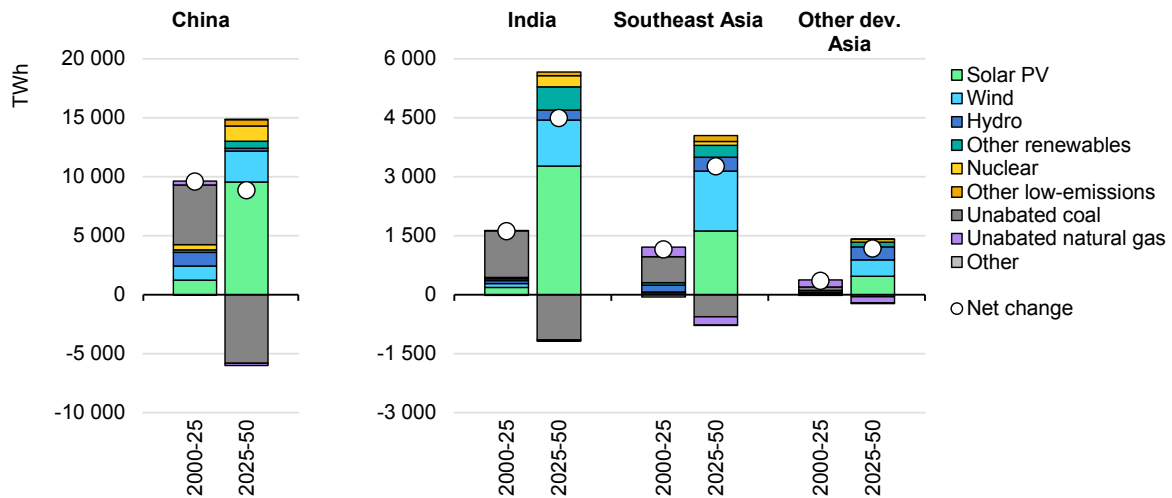
while supporting system reliability and impacted communities, although implementation to date has proceeded more gradually than initially anticipated. Examples include Indonesia's [USD 20 billion](#) JETP and Viet Nam's [USD 15.5 billion](#) package, which combine public and private finance with policy support and hinge on timely deployment of replacement capacity.

- **Retrofitting coal-fired power plants with carbon capture, utilisation and storage (CCUS)** contributes to about 3% of global emissions reductions while preserving existing assets, in particular young and large units. Deployment remains constrained by high costs, limited CO₂ transport and storage infrastructure, and the need for stronger policy support to improve project economics. China is actively exploring CCUS for coal power, with several pilot projects in operation and plans for larger-scale demonstrations. In Southeast Asia, Indonesia has established the region's [first CCUS regulatory framework](#), marking an important initial step, although it does not provide a clear pathway for application to coal power, despite [interest from the state-owned utility PT PLN](#).
- **Retrofitting coal-fired power plants to co-fire with lower-emissions fuels** can also reduce emissions while keeping assets operational. Biomass co-firing is a mature option but depends on sustainable feedstock availability and cost. Ammonia co-firing is less mature but requires limited upfront modifications at low blending shares, although high fuel costs and nitrogen oxides emissions present challenges. In Asia, biomass co-firing has gained traction in India, while large-scale ammonia co-firing is seeing demonstrations being led by Japan and is being [explored](#) in some Southeast Asian countries such as Malaysia and Indonesia. The [Asia Zero Emission Community](#) is a platform including most Southeast Asian countries which supports the use of hydrogen and ammonia to reduce emissions from coal.

Scaling up alternative sources of electricity

Over the past 25 years, growth in low-emissions electricity generation in Southeast Asia has not kept pace with rapidly rising demand. Since 2000, electricity generation from low-emissions sources, including renewable energy, nuclear power, fossil fuels with carbon capture, hydrogen and ammonia, increased by around 300 terawatt-hours (TWh) across the region. Over the same period, total electricity generation rose by more than 1 100 TWh. Most of the gap was filled by coal-fired generation, which increased by over 600 TWh, alongside an expansion in gas-fired output of over 200 TWh, while electricity generation from oil declined.

Figure 2.2 Change in electricity generation by source and country/region in the Announced Pledges Scenario, 2000-2050



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Notes: "Other dev. Asia" = Bangladesh, Democratic People's Republic of Korea (North Korea), Mongolia, Nepal, Pakistan, Sri Lanka, Chinese Taipei. PV = photovoltaic.

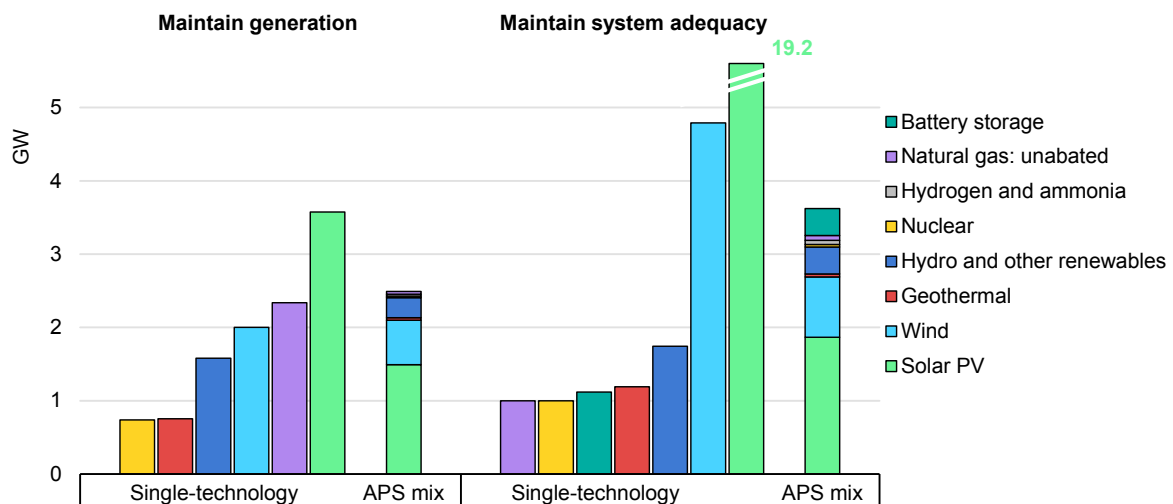
Full implementation of announced pledges over the next 25 years, as envisaged in the APS, implies a decisive shift in these dynamics. Many Southeast Asian nations have made strong commitments to enhancing the share of renewable energy, reducing energy intensity and lowering emissions. As a region, the Association of Southeast Asian Nations (ASEAN) [Plan for Action on Energy Cooperation](#) 2026-2030 states the goal of a 45% share of renewable energy in installed power capacity by 2030 (up [from 33.5% in 2023](#)). Faster deployment of renewable energy, combined with stronger action on energy efficiency, allows low-emissions electricity sources to meet all demand growth and to progressively displace existing fossil fuel generation. Coal-fired output falls by more than 170 TWh by 2035, equivalent to around one-fourth of current levels, and by over 500 TWh by 2050.

A typical coal plant in Southeast Asia operates at a moderate to high capacity factor, so replacing the electricity generated by 1 GW of coal requires roughly 1.5 GW to 2 GW of onshore wind or around 3 GW to 4 GW of solar PV, depending on local resource conditions. These ratios reflect differences in average utilisation rather than reliability considerations and help explain why renewable capacity additions need to significantly exceed coal capacity retirements when measured in gigawatts.

Coal transitions in the power sector are not just a matter of replacing their electricity output, but also the replacement of the system adequacy services provided. Coal plants are dispatchable and can contribute close to their nameplate capacity to meeting peak demand, subject to outages. In contrast, the contribution of wind and solar to adequacy depends on their availability at times of system stress, which is typically much lower than their installed capacity. In Southeast Asia, where peak

demand often coincides with evening hours and periods of high cooling load, the firm capacity contribution of solar PV is limited, while wind provides a higher but still partial contribution depending on location. As a result, replacing the adequacy contribution of 1 GW of coal requires several gigawatts of variable renewables, unless complemented by storage, demand response or other firm resources. These differences are captured using capacity credit or effective load-carrying capability metrics, which are increasingly central to system planning frameworks.

Figure 2.3 Capacity required relative to 1 GW of coal to maintain electricity generation and system adequacy in Southeast Asia, by technology and in the Announced Pledges Scenario



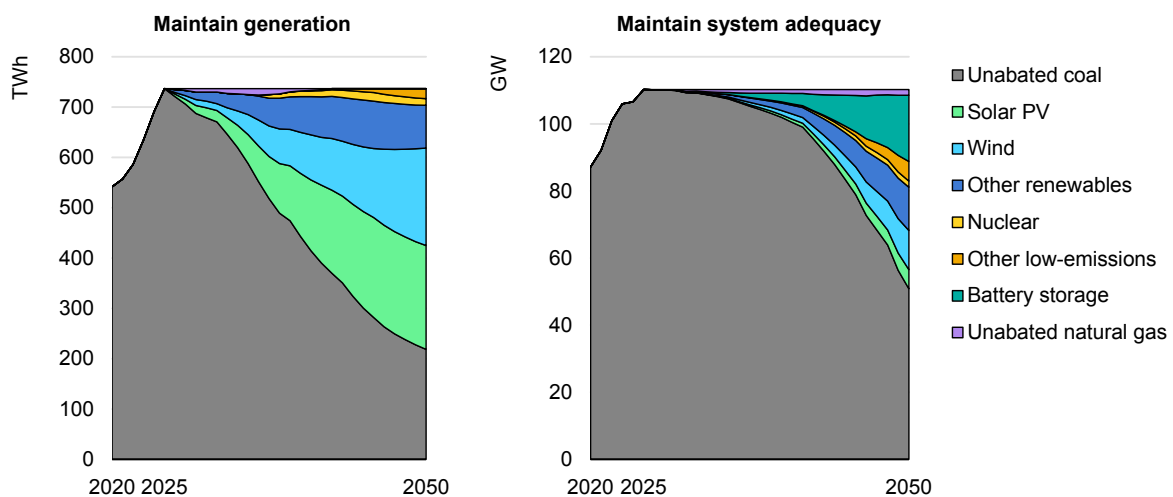
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Addressing this gap does not imply that coal must be replaced one-for-one by other conventional dispatchable plants. Instead, it points to the importance of system solutions that combine multiple technologies to jointly deliver energy, adequacy and flexibility. Recent analysis shows that appropriately designed portfolios of wind, solar PV and battery storage can meet a large share of coal-like demand profiles at competitive cost, even for applications requiring high availability.

In the APS, coal phase-down in Southeast Asia is realised through a system-level transformation rather than one-for-one replacement by individual technologies. More than three-quarters of the reduction in coal-fired electricity generation across the region is replaced by solar PV and wind, reflecting their scale, cost-competitiveness and speed of deployment. Hydropower and other renewables account for a further 17%, while nuclear power contributes less than 5%. Unabated natural gas, CCUS-equipped plants, and hydrogen and ammonia together account for less than 1% of replacement generation, underscoring the central role of renewables in meeting incremental electricity needs. At the same time, maintaining electricity security requires complementary investments to

replace coal’s contribution to system adequacy. In the APS, the contribution of unabated coal capacity to adequacy in Southeast Asia declines by over 2 GW per year to 2050 and is offset by a diversified mix of technologies. Battery storage provides around 40% of the replacement adequacy capacity, supported by other dispatchable sources, notably hydropower and nuclear power. These changes are underpinned by stronger and more interconnected power grids, with initiatives such as the [ASEAN Power Grid](#) helping to support the APS trajectory by integrating higher shares of renewables through regional balancing, enhanced flexibility and lower system costs.

Figure 2.4 Replacing electricity generation and the contribution to system adequacy of existing unabated coal power plants in Southeast Asia in the Announced Pledges Scenario, 2025-2050



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

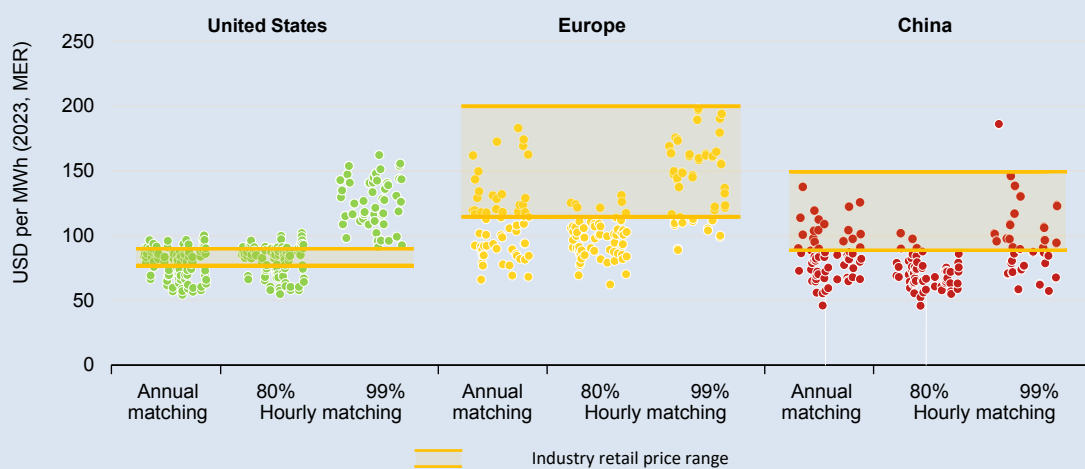
Box 2.1 Cost-competitive system portfolios for replacing coal

Coal-fired power plants are often described as providing “baseload” supply, implying that coal output is inherently constant and difficult to replace. In practice, while certain technologies have characteristics that have historically favoured continuous operation, whether and how coal serves baseload demand depends on system operation, market design and contractual arrangements. Many coal units have historically operated at high utilisation because they offered low variable costs, benefited from long-term offtake agreements and delivered a bundle of system services alongside energy. However, coal plants are not technically bound to generate a constant level of output. In many systems they already ramp over the day, cycle more frequently, or shift into reserve and peak roles as system conditions

and economics evolve. This distinction matters for transition planning because the challenge is to replace coal’s full energy contribution while maintaining reliability outcomes for the power system.

Insights from recent analysis of [hourly matching portfolios](#) designed to supply electricity to data centres and artificial intelligence (AI) workloads help to reframe this question. These applications are characterised by near continuous demand and high reliability requirements, often cited as justifications for conventional dispatchable generation. The analysis shows that firm supply does not necessarily always require thermal power. Portfolios combining wind, solar PV and battery storage can closely follow a flat demand profile on an hourly basis, with batteries smoothing intraday variability and hybrid wind-solar configurations reducing exposure to single-resource patterns. Across more than 1 000 use cases in European countries, US states and Chinese provinces, such portfolios were optimised to minimise costs while meeting specific hourly matching targets. The results indicate that portfolios achieving around 80% hourly matching can meet roughly 80% of a baseload type demand profile at an average cost competitive with prevailing industry retail electricity prices in the United States, Europe and China.

Figure 2.5 Total cost of electricity per unit consumed for hybrid options of wind, solar PV and battery in the United States, Europe and China



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Notes: MWh = megawatt-hours; MER = market exchange rate. Annual matching = portfolio of wind and solar PV optimised to meet annual volume demand target; 80% hourly matching = portfolio of wind, solar PV and batteries to reach at least 80% hourly matching with demand; 99% hourly matching = to reach at least 99% hourly matching with demand. Each dot represents a different use case based on the renewable potential of various locations in the United States, Europe and China. Total costs include grid-supplied electricity, priced using historical retail price ranges for the relevant locations over 2014-2023.

This evidence helps reframe how coal replacement is assessed and can be useful to Southeast Asian countries looking to phase down coal generation. Rather than assuming that coal generation must be substituted one-for-one by other 24/7 generators, a large share of the energy associated with baseload operation can be

supplied by hybrid renewables and storage, with the remainder met by the grid and other resources, at competitive cost. In the underlying analysis, unmet demand is supplied by grid electricity priced at average industry retail levels, and is fully included in the total cost. Moving from annual volume matching towards higher levels of hourly matching reduces reliance on the grid during many hours, lowering exposure to price volatility and cutting emissions where marginal supply is fossil based.

Achieving near-complete hourly matching is technically feasible, but it entails a material cost premium because it requires additional overbuild of generation and storage capacity. For example, delivering 100 megawatts (MW) of firm capacity might involve around 600 MW of solar PV combined with 400 MW of battery capacity and around 1 600 MWh of storage behind a shared inverter. Such systems produce significant volumes of surplus electricity above the firm output level, which may be curtailed or, where grid access exists, used for other purposes. Even with this oversizing, the resulting value-adjusted levelised cost of electricity can be broadly comparable with that of some dispatchable sources, reaching around USD 75/MWh in China, USD 135/MWh in the United States and USD 180/MWh in the European Union. Incorporating onshore wind into these portfolios can lower costs by 10-45%, depending on local resource conditions, making such systems [competitive with coal, gas and nuclear generation](#) and broadly aligned with average generation costs projected for the mid-2030s. At these cost and availability levels, solar PV plus storage and hybrid projects become increasingly attractive options not only for the grid, but also for consumers requiring high reliability electricity supply, including industrial installations and data centres.

Coal transitions demand large-scale investment

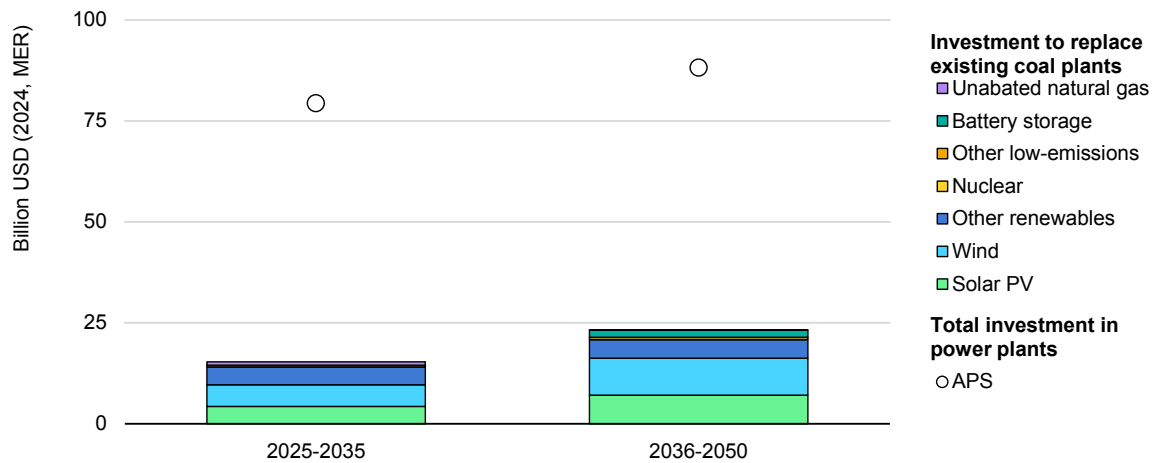
In Southeast Asia, reducing emissions from coal plants requires USD 20 billion per year to 2050

Maintaining the existing energy system and meeting the growing demand for energy services requires substantial investment. To achieve these goals while reducing emissions in line with existing coal phase-down or net zero targets would require also a rapid scale-up of low-emissions energy sources, efficiency measures, and grids and storage investments.

In Southeast Asia, about USD 80 billion is spent on power plants on average each year in the APS between 2025 and 2050, to build or refurbish all types of power plants and deploy battery storage. Most of this investment, around USD 60 billion,

supports demand growth and the replacement or refurbishment of non-coal capacity, while around USD 20 billion of this amount goes towards reducing emissions from existing coal plants. Of this, nearly 70% goes towards investment in solar PV and wind to replace unabated coal generation.

Figure 2.6 Breakdown of annual average energy investment in power plants in the Announced Pledges Scenario, 2025-2050



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Note: The remainder includes capital spent to meet electricity demand growth and replace or refurbish non-coal power plants reaching the end of their operational lifetime.

The new capital investment needed to transition away from unabated coal-fired electricity generation is only one part of the story. Another obstacle is the unrecovered capital in the current coal power plant fleet. As of 2025, 1 700 GW of operating coal plants, nearly 80% of the global fleet, have yet to recoup about USD 1.3 trillion in capital, including USD 135 billion in Southeast Asia.¹

Not all capital invested in coal plants tends to be recovered before closure. Regulatory mandates, climate policies, and market competition from cheaper alternatives such as renewables and natural gas [frequently drive retirements earlier](#) than economic or technical lifetimes. The total capital yet to be recovered represents the financial exposure that investors and utilities face when plants close earlier than expected.

¹ The capital yet to be recovered pertains to coal-fired power plants that have already been constructed by 2025 but not projects that are in construction or are in the pipeline.

Mobilising finance towards a just coal transition hinges on robust policies that complement financial mechanisms and market-based measures

There are a variety of actions that can be taken to mobilise the investment to reduce emissions from coal-fired power generation and accelerate investment in clean energy.

First, governments can apply direct regulation such as mandating plant closures, limiting operating hours or implementing pollution controls. Second, market-based measures that favour clean energy sources such as priority dispatch, carbon pricing or reverse auctions can reduce the economic attractiveness of continued unabated operation of thermal power plants. Moreover, the public acceptability and socio-economic outcomes of coal transitions depend on policy measures, supported by financial mechanisms that also address impacts on affordability and employment.

Third, financial mechanisms typically provide incentives for owners to retire assets early or limit their operations by offering a financing package conditional on the sale or retirement of a plant or on emissions reduction outcomes. Some examples to encourage the early retirement of coal plants include results-based finance,² ratepayer-backed securitisation³ and equity buy-outs, where a coal plant is purchased at a lower cost of equity, enabling a reduction in the plant's economic lifetime.⁴ The use of these mechanisms in practice remains uncommon, with only a handful of cases globally where each measure tends to be tailored to specific asset characteristics.

Box 2.2 Affordability and employment towards a just transition

Ensuring that electricity remains affordable and that consumers feel they are paying a reasonable and fair price is a key concern when considering coal transitions. While a large amount of capital investment is required for a coal transition, including in power generation capacity and grid infrastructure, these costs are offset by significant fuel cost savings that come from reduced coal demand. A drop in fuel

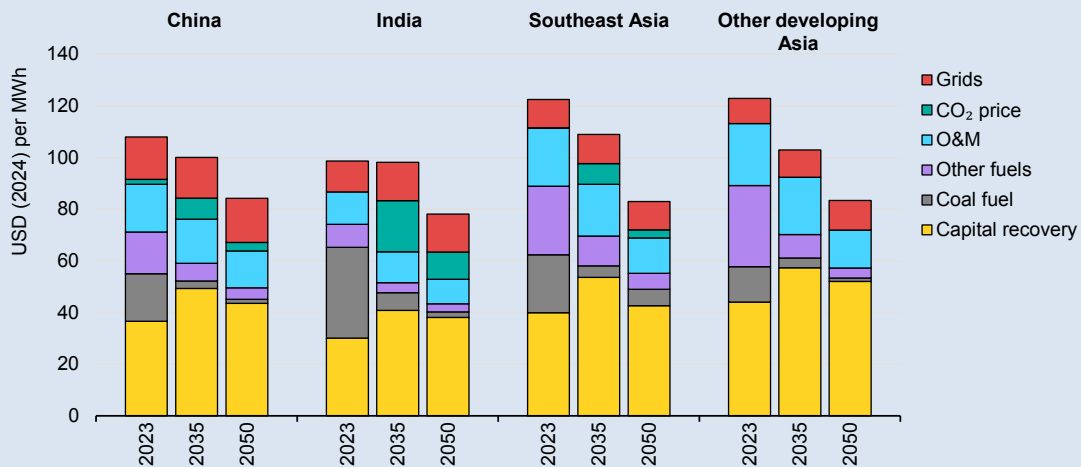
² An example of debt restructuring is the Tocopilla coal plant in Chile. IDB Invest [accelerated](#) retirement and its replacement with a wind power plant through a blended finance structure that tied the interest rate of the concessional tranche to the volume of emissions reduction achieved through early retirement.

³ Ratepayer-backed securitisation was applied to the Asbury Power Plant in Missouri, United States, where over [USD 300 million](#) was securitised through the sale of bonds for transition costs, backed by future ratepayer surcharges, which lowers the cost of debt to fund the retirement and transition costs of coal assets.

⁴ An example of an equity buyout is the ACEN [Corporation's South Luzon Thermal Energy Corporation](#) plant. ACEN sold 100% of its equity to a special purpose vehicle. The transaction required early closure of the coal plant in 2040, versus its technical lifetime of 2055.

costs in China, India, Southeast Asia and other developing Asia between today and 2035 contribute to a reduction in electricity system costs, despite an increase in capital recovery costs across the board.

Figure 2.7 Total electricity system costs by component and by country/region in the Announced Pledges Scenario, 2023-2050



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Notes: "Other developing Asia" = Bangladesh, Democratic People's Republic of Korea (North Korea), Mongolia, Nepal, Pakistan, Sri Lanka, Chinese Taipei. O&M = operations and maintenance.

While an analysis of system costs suggests that coal transitions are likely to have limited adverse consequences for household electricity affordability, the actual effects on electricity bills are more complicated than that, in part due to energy subsidies. Electricity prices differ significantly between countries and consumer groups, depending on local regulations, tariff structures, taxes, weather conditions and geopolitical events. Many governments, including in Southeast Asia, [intervene](#) to keep regulated electricity prices low, such as through fossil fuel subsidies, which are already putting significant strain on their public balance sheets, though are politically difficult to phase out. Singapore and the Philippines are the only countries in Southeast Asia with liberalised electricity markets.

Beyond the impacts on affordability, governments need to address the social consequences of a coal transition. In 2024, around [6.1 million people](#) worked in coal supply jobs globally and 2.2 million worked in coal-fired power generation. Close to 80% of these jobs are in China and India. Coal-related activities represent about 10% of total energy sector employment globally, but in regions with coal mines such as Indonesia, the shares of coal employment could be much higher; moreover, local communities could be almost entirely dependent on income generated from coal production and related industries. In the APS, global coal supply employment is set to decline, although retrofitting of existing plants with CCUS technologies helps offset some losses through job creation. Although the transition from coal to renewables creates new jobs, they may not be in the same places or require the

same skills as the coal jobs that are lost. A just coal transition depends on effective policy measures to address a loss in jobs in coal-related activities. The International Energy Agency (IEA) 2024 report [Accelerating Just Transitions for the Coal Sector](#) details policy strategies supporting a people-centred and just transition.

Large amounts of capital tied up in existing coal plants, high cost of capital, contractual obligations and concerns over power system reliability make coal transition strategies financially unattractive in many emerging market and developing economies. In this context, a significant share of the funding for coal transitions may come from international sources. Multilateral initiatives such as the JETPs aim to bridge financing gaps by mobilising large-scale blended finance packages, with partnerships under way in Indonesia and Viet Nam. Another example is the Asian Development Bank's [Energy Transition Mechanism](#), which pools concessional capital in blended refinancing structures to support early retirement or repurposing of coal-fired power plants. However, work under these initiatives is still under way.

The IEA's Coal in Net Zero Transitions [special report](#) provides an overview of the financing options available to support the investment required for a coal transition. The effectiveness of any instrument varies by context, influenced by factors such as plant technology and age, power market structures, capital market maturity, government regulation and political priorities. There is thus no one single type of intervention which will work for all countries and contexts. The remainder of this report discusses the potential for transition credits as an accelerator for coal transitions.

Chapter 3. Transition credits

How transition credits translate emissions reductions into performance-based revenues

Transition credits are a market-based instrument to incentivise technology switching from unabated coal

Coal transitions face financial and structural barriers, even where cleaner alternatives are available and cost-competitive. As discussed in the previous chapter, a range of policy, regulatory and financing levers can help reduce coal emissions, but in many cases, these measures alone are insufficient to unlock coal transitions at scale. Public budgets in emerging market and developing economies are also constrained, with governments facing competing demands to fund clean energy investment, especially at a time when international public financial flows are declining.

In this context, innovative financing instruments are emerging. Transition credits are intended to complement existing financing structures by strengthening the economics of coal transition strategies. While public finance, concessional capital and private investment are already being deployed, these instruments often do not fully address the revenue and value gaps associated with early transition decisions, including forgone operating revenues by asset owners. Transition credits can address part of this gap by converting emissions reductions from coal transitions into an additional, market-based revenue stream. Credits are issued and sold only once emissions reductions are achieved and verified. By improving expected project economics and lowering the opportunity cost of coal transitions, these credits can facilitate a secure move from coal where national strategies, power systems planning and clean energy investment are already aligned.

Most transition credit methodologies today focus on the early retirement of individual grid-connected coal plants

The use of carbon credits to reduce emissions from fossil fuel power generation is not new. Two decades ago, under the Kyoto Protocol, projects were registered under the Clean Development Mechanism and Joint Implementation which involved fuel switching (coal-to-gas or coal-to-biomass), coal plant efficiency improvements,⁵ and the development of new renewable capacity.

⁵ The Clean Development Mechanism methodology was subject to intense scrutiny and was [suspended](#) in 2012 due to [concerns](#) over baseline setting and additionality

Today, the scope for carbon crediting has expanded beyond improving the efficiency of existing fossil fuel assets to also support the replacement of fossil fuels with cleaner energy technologies. In this context, transition credits have emerged as a specific application, with market initiatives, such as the Monetary Authority of Singapore's [Transition Credits Coalition \(TRACTION\)](#), the [Coal to Clean Credit Initiative \(CCCI\)](#) and the [Kinetic Coalition](#), having largely converged on applying transition credits to the early retirement of grid-connected coal plants and their replacement with clean energy through a project-based approach or reducing the grid emissions factor through a jurisdictional (or policy-based) approach. More recently, the application of transition credits has broadened to cover a wider range of fossil fuel generation assets. In late March 2026, Gold Standard approved a [methodology](#) for the replacement of fossil fuel-based generators such as diesel gensets with new renewable energy systems.

Most transition credit approaches rely on project-based methodologies, where emissions reductions are quantified at the level of an individual power plant and the replacement through cleaner energy technology. Project-based approaches compare a counterfactual scenario in which the coal plant (or another fossil fuel-based generator) continues operating under business-as-usual assumptions and a project scenario in which the plant is retired earlier than planned. The difference in cumulative emissions between these scenarios forms the basis for issuing transition credits, with one credit representing one tonne of carbon dioxide equivalent (CO₂-eq) reduced against the counterfactual scenario.

The term “transition credits” has also been used in jurisdictional (or sectoral) methodologies where carbon credits are issued based on improvements in [grid-level or sub-grid-level emissions factors](#), rather than on discrete plant-level interventions.

To capture all these nuances, this report defines transition credits as carbon credits issued for emissions reductions in the power sector achieved by 1) accelerating the retirement or repurposing of fossil fuel power assets and replacing their capacity or output with cleaner alternatives; or 2) lowering the emissions intensity of electricity supplied at the system (grid or sub-grid) level. This report, unless specified otherwise, uses “transition credits” to refer to the issuance of carbon credits from the early retirement of coal plants and their replacement with clean energy, and “methodologies” to refer to project-based methodologies. This reflects the fact that project-based methodologies for early retirement of coal plants are currently the only approach with standard-approved methodological guidance and pilot transactions already under way as of April 2026.

Several transition credit methodologies are now publicly available or under development.

Table 3.1 List of transition credits crediting methodologies, status and scope, as of April 2026

Methodology	Status	Scope	Developers/ Carbon credit standard
Methodology for Early Retirement of Coal-Fired Power Plants using a Just Transition	Finalised and published (a public consultation for revision is open as of April 2026)	Project-based: Grid-connected coal plants with long-term PPA contracts	CCCI (Rockefeller Foundation and a consortium of technical partners)/ Verra
Joined-Up Sustainable Transition (JUST): Coal Decommissioning	Finalised and published	Project-based: Grid-connected coal plants	Gold Standard
Joined-Up Sustainable Transition (JUST): Fossil Fuel Generators	Finalised and published	Project-based: Generation system where fossil fuels provide >80% of the total energy input	Gold Standard
Methodology for Early Phaseout of CFPP with Just Transition by Replacing with Clean Energy Sources	Draft (under public consultation since August 2024)	Project-based: Grid-connected coal plants in a regulated electricity market	Sustainability Economics/Asia Carbon Institute
Paris Agreement Crediting Mechanism (PACM) methodology to support transition credits for coal-to-clean power projects	Under development	Project-based: Grid-connected coal plants	The Rockefeller Foundation, World Bank, Asian Development Bank, Inter-American Development Bank
Standard for the Transformation of the Electric Power Sector (STEPS)	Draft (under public consultation from 30 April until 1 July 2026)	Jurisdictional: power-sector-wide emissions from all power plants, captive plants, and distributed renewables, with imports and exports treated through emissions-rate adjustments	Winrock International/ Environmental Resources Trust

Note: PPA = power purchase agreement; CFPP = coal-fired power plant.

Among these, the project-based [VM0052 methodology](#) registered under Verra is the most advanced as of April 2026. It is currently being applied to a pilot project in the Philippines, with first credit issuance expected in 2031. As of April 2026, the

methodologies being developed by the 1) Asia Carbon Institute; 2) the Rockefeller Foundation, the World Bank, the Asian Development Bank and the Inter-American Development Bank; and 3) Environmental Resource Trust remain at the drafting stage and not all of them are publicly accessible.

Box 3.1 Piloting the application of transition credits in the South Luzon Thermal Energy Corporation coal plant

The Philippines has approximately 12 gigawatts (GW) of installed coal capacity, supplying around 60% of its generation needs. At the end of 2021, the government announced a [moratorium](#) on new coal plants, although already approved projects were [allowed](#) to proceed. The [Philippine Energy Plan 2023-2050](#) does not include a coal retirement schedule. While the share of coal is projected to decline, coal generation in absolute terms is expected to increase to 2030 to meet growing demand, supported in part by [over 1.8 GW](#) of new coal approved before the end of 2021 anticipated to come online by 2028.

The South Luzon Thermal Energy Corporation (SLTEC) plant is a 246 megawatt (MW) coal-fired power station in Calaca, Batangas, previously owned by ACEN Corporation. In November 2022, ACEN successfully implemented an Energy Transition Mechanism (ETM) transaction, involving the divestment of the plant alongside a commitment to retire the facility by 2040 – effectively halving its 50-year technical life – and transition to renewable energy. The transaction, modelled under the Asian Development Bank's ETM, was supported by debt financing from Philippine banks, including BPI and RCBC, and equity investments from institutional investors such as GSIS and Insular Life.

In 2023, ACEN [announced a partnership](#) with the Rockefeller Foundation and the Monetary Authority of Singapore to pilot the use of transition credits to accelerate the retirement of SLTEC to as early as 2030. If realised, the earlier shutdown could generate up to 19 million tonnes (Mt) CO₂-eq of emissions reductions, on top of the 50 Mt CO₂-eq avoided by closing the plant in 2040. ACEN plans to replace the 246 MW coal baseload capacity, which generates around 1.8 TWh annually, with a combined 400 MW mid-merit clean energy facility comprising of around 1 400 MWh of solar and 1 600 MWh of battery energy storage (BESS). The facility is expected to produce over 1.8 TWh of annual output, enabling a 1:1 pairing between foregone coal generation and clean energy replacement.

ACEN estimates that USD 1.5 billion in extra financing is needed to bring forward the retirement date to 2030, including for SLTEC's decommissioning, its replacement with renewable energy sources and associated just transition measures. Transition credits are an essential component of its financing strategy, helping to bridge the gap between required investment and future revenues while keeping electricity prices affordable. The earlier shutdown would result in

USD 48 million to USD 75 million per year in forgone cash flows post-2030. Moreover, the [levelised cost of electricity \(LCOE\)](#) for the proposed renewable and storage system, estimated at USD 0.11 per kilowatt-hour (kWh), is around 22% higher than SLTEC's current LCOE. ACEN expects that up to USD 800 million can be generated by transition credit revenue between 2031 and 2040, if the coal plant closes in 2030. The project intends to apply Verra's VM0052 methodology, with first credit issuance projected for 2031, following the early retirement of SLTEC's plant.

Source: IEA analysis, based on stakeholder consultations

Jurisdictional and nested approaches could broaden transition credits beyond individual projects, but face unresolved design challenges

While current transition credit methodologies have largely been applied at a project level, efforts are under way to develop jurisdictional (or sectoral) approaches, where emissions reductions are credited at the scale of the national or sub-national electricity system, benchmarked against a predefined performance emission standard.

Compared with project-based methodologies, such approaches would cover a broader set of interventions. Any quantifiable regulatory, policy, investment, subsidy, tax or other measure that accelerates the power sector's decarbonisation trajectory that fits within proper accounting frameworks could contribute to credit generation. Under these proposals, host country governments or their delegated authorities would own transition credits and would assume responsibility for monitoring, reporting and distributing the proceeds.

In principle, a jurisdictional approach minimises the risk of emissions leakage within the same jurisdiction, and avoids some of the challenges inherent to project-based methodologies, particularly the need to evaluate asset characteristics against counterfactuals. It is also a market-based mechanism directly linked to sector-level policy ambition.

Nevertheless, significant questions [remain](#).⁶ As with asset-level methodologies, there is a key question and challenge regarding how to set benchmarks, such as projected baselines and associated emissions reductions, against which to measure additional power sector emissions reductions and issue credits. A

⁶ The Standard for the Transformation of the Electric Power Sector (STEPS) was published for [public consultation](#) on 30 April 2026. Owing to the timing of its release, this report discusses jurisdictional approaches in general terms and does not assess STEPS specifically; references to jurisdictional methodologies therefore do not reflect subsequent developments.

jurisdictional approach will need to balance general applicability while also being sensitive to the unique characteristics of each country's power system. Moreover, the approach and assumed emissions trajectories would need to evolve to accommodate economic and technological changes over time. At the same time, the approach would need to assess additionality at the level of policies or sector-wide interventions, rather than individual activities, to avoid crediting mitigation that would have occurred in the absence of the mechanism. Finally, the approach would need to clarify how power sector crediting aligns with broader mitigation efforts, including consistency with the host country's nationally determined contribution, and how this is reported under the Paris Agreement. If these elements are not addressed robustly in a jurisdictional approach, there is a risk of over-crediting, double counting, and broader challenges for national and international accounting and reporting.

A second challenge is the complexity in setting up and monitoring jurisdictional programmes. These can take significant time and cost to establish and may lead to inconsistent delivery. Finally, there remain open questions about how crediting can be managed amid political and implementation risks such as changes in government, and how revenues from transition credits sales could be distributed fairly among market participants.

There is not yet a publicly available jurisdictional methodology applicable for transition credits. Environmental Resources Trust, a non-profit subsidiary of Winrock International, is leading the development of a methodology that could issue transition credits through improved emissions performance relative to jurisdictional baselines. As of April 2026, the draft methodology proposes two crediting options: one for improved emissions intensity performance and another for absolute emissions reductions. While the concept is still at a high level, Winrock International is proposing a pilot in the Dominican Republic with credit issuance possible as early as 2027. A draft methodology is set to be released for public comment in 2026.

Nested approaches are also being considered. A nested approach links project-based activities to a jurisdictional or national accounting framework, allowing emissions reductions generated at the project level to be integrated within jurisdiction-wide baselines and targets. Under this approach, project-level credits are issued and accounted for in a way that is consistent with jurisdictional accounting, helping to avoid double counting and misalignment. Nesting therefore enables project-based finance while supporting a transition towards jurisdictional

or national-level crediting and oversight. To date, however, there are no concrete applications or developments using the nested approach to transition credits.⁷

While the current focus is on grid-connected coal-fired power plants, transition credits can be applied to other project types

Most existing project-based methodologies for transition credits are focused on grid-connected coal plants. However, transition credits are being explored for a broader set of coal plants and transition pathways, including:

- **Phased shutdown:** TRACTION suggests that existing methodologies could be adapted to support transition credit issuance for the [sequenced decommissioning of coal plant boiler units](#). Gradually phasing down operations can enable earlier credit generation while mitigating grid reliability risks, provided the shutdown schedule is aligned with the pace of renewable energy deployment.
- **Captive coal:** Captive power – dedicated on-site generation for use by industries or businesses – plays a key role in energy-intensive industries with high reliability needs and grid access constraints, such as metal processing, cement and petrochemicals. Verra is currently developing additional modules under its VM0052 methodology to apply transition credits to captive coal facilities.
- **Other fossil fuels applications:** Beyond coal, transition credits could apply to other types of fossil fuels, such as diesel, kerosene or natural gas. Gold Standard [published](#) a methodology on the use of transition credits to replace fossil fuel-based electricity generators with new renewable energy systems.

Case study: Potential application of transition credits to captive coal assets in Indonesia

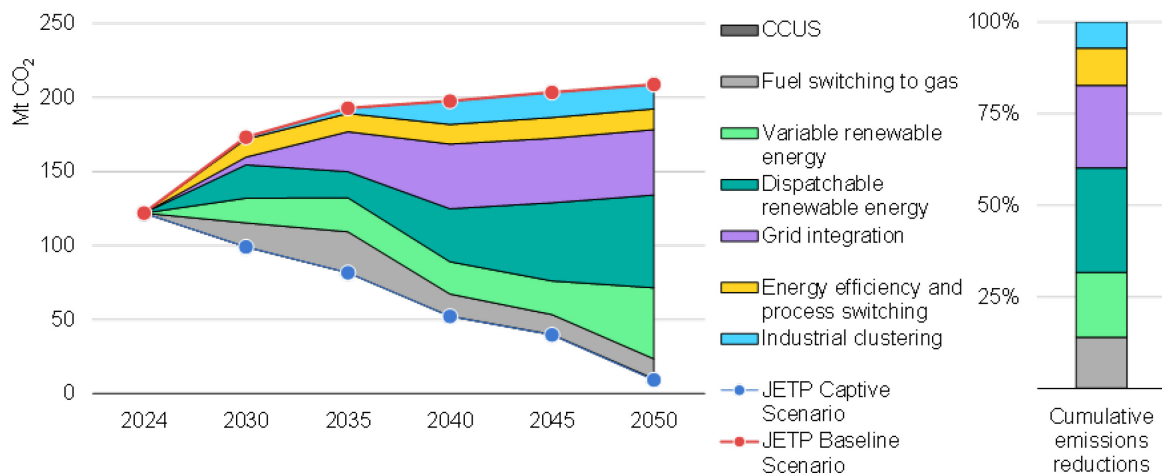
According to the Just Energy Transition Partnership (JETP) thematic report on captive power, captive power in Indonesia rose rapidly from 12.9 GW in 2019 to 25.9 GW (net) in 2024, to make up [25% of total power capacity](#). Growth has stemmed mostly from critical minerals processing. Over 75% of operating captive power is coal-based (19.7 GW), and with 8.6 GW under development, captive coal may top 28 GW without effort to avoid new assets and transition existing ones.

Recent work points to potential strategies and pathways for transitioning Indonesia's captive coal power sites. The JETP study demonstrates strong potential for on-site renewable power – solar PV, bioenergy (including co-firing), hydropower – but levels vary by site and distance to resource. JETP system

⁷ The [TRACTION Final Report](#) discussed scenario archetypes for the co-existence of project-based and jurisdictional approaches.

modelling finds that Indonesia can cost-effectively increase its share of renewables-based captive generation to 40% by 2035, from 9% in 2024, with 58% lower emissions compared with a baseline, and reach net zero emissions by 2050. The JETP Captive Scenario relies on multiple energy measures, site-specific firm power solutions, incentives to address investment and electricity cost gaps, and policy commitment to limit new captive coal and cap emissions for existing assets.

Figure 3.1 Projected captive power CO₂ emissions in Indonesia by JETP Scenario



IEA. CC BY 4.0.

Note: CCUS = carbon capture, utilisation and storage.

Source: JETP Indonesia (2025), [Captive Power Study: Deep Dive into Indonesia's Industrial Power Landscape and Green Energy Transition Opportunities](#).

A government roadmap for the nickel industry sets out a pathway to [reduce CO₂ emissions over 80% by 2045](#), prioritising smelter efficiency, transmission connection to on-grid power and renewables-based hydrogen for remaining captive assets. Government electricity planning sees captive power reaching net zero emissions by 2060, but [more gradually](#).

Challenges include accessing land and transmission in remote areas; integrating on-site renewables with high reliability; and managing impacts from shutting or operating captive coal at lower utilisation. Still, transitions for captive coal plants present an opportunity to enhance competitiveness in light of market interest in clean industrial products.

In Indonesia, transition credits could help cover funding gaps for renewables and costs from early shutdowns of captive coal. The Gold Standard methodology on the replacement of fossil fuel-based electricity generators with renewable energy technologies, published in late March 2026, applies to the replacement of captive fossil fuel generators, but there have not yet been any applied projects. Enabling

these credits will depend on addressing integrity and practical issues in methodologies and transactions that are still evolving.

Existing integrity principles can guide determination of the preliminary addressable capacity for transition credits. Based on applying selection criteria from [TRACTION](#) to the JETP Captive Power Database, the potential addressable captive coal capacity for transition credits in Indonesia is around 15 GW.⁸ These criteria exclude 8.6 GW of future captive coal identified by the JETP Captive Power Study as in construction or planning, as well as operating capacity with ownership involved in developing the new capacity.

Unlocking this potential depends on alignment of technical plans and strategies with carbon market integrity criteria. [Presidential Regulation 112/2022](#), which sets out Indonesia's ambition to accelerate coal phase-out, allows new captive coal serving strategic industries, but requires emissions reductions of at least 35% by asset owners in the first ten years and operations to cease by 2050. The [Indonesia Taxonomy for Sustainable Finance](#) allows captive coal investment to be classified as "transition" when aligned with the conditions set out in Presidential Regulation 112/2022. Transition crediting that supports emissions reductions beyond those required by regulation (regulatory additionality) could come from crediting that accelerates retirement plans, but should also consider uncertainty over lifetimes of metals smelters, which can vary with market conditions.

Transition pathways above suggest asset owners may need to invest in complex hybrid measures – integrating efficiency, renewables, storage, gas and industrial clustering with centralised energy management and shared infrastructure – while operating captive coal at lower rates to ensure stable power and process heat, where relevant. While this phase-down approach can include retirements of coal boiler units and renewables replacements that align with crediting criteria, project feasibility will depend on site- and industry-specific factors. Moreover, grid integration may often represent the most optimal solution from a system planning and decarbonisation perspective, but crediting for grid connections would require further exploration. At present, the focus of transition crediting on renewables replacement for individual assets risks excluding a wider range of transition measures required to phase down captive coal in Indonesia. By planning interventions and measuring emissions impacts against performance standards at industrial cluster level, transition credits may be able to support a broader suite of measures and better align with the government industrial strategy.

In addition, ensuring permanence of the retired coal plant (see more details in the section "Alignment with high-integrity principles") will depend on repurposing

⁸ Net capacity. Criteria from TRACTION (2025): plant age up to 25 years, construction start by the end of 2021 (three-year assumption), no phase-out plan before 2030, no new coal commitment (assessed as owners without known expansion plans in Indonesia).

measures to avoid industries maintaining captive coal as reserve power. Avoiding carbon leakage may require strategies for process heat and safeguards against re-export of coal supply. Quantifying emissions will require further study for integrated clusters and for power demand that can evolve with changing market conditions and technical inputs, such as ore quality. Finally, captive industries play a core role in Indonesia's economic development plans – ensuring just transitions for local communities will be essential. Appropriate enabling regulations will be critical to addressing all these considerations.

Aligning transition credits with national transition pathways is difficult but essential

Carbon credit methodologies play an important role by establishing guidelines and rules to ensure that projects align with integrity principles for credibility, quantifiable impact and permanence (see more details in the section “Alignment with high-integrity principles”). Methodologies are designed for a wide range of stakeholders and audiences, including project developers, carbon crediting programmes, verification bodies, potential buyers, and governments and regulators designing national, sub-national and sectoral programmes. A broad geographic scope, often designed for global application, and standardisation are important underpinnings for market adoption. However, the application to specific market contexts, both geographically and over time, requires careful implementation to ensure alignment with the specific needs and priorities of each country and power system. As transition credits mature, it is important for the leaders of a country's carbon market programme to carefully consider processes to align methodologies with existing and future policies, regulations and energy plans.

Proper power system planning is key for moving beyond coal and deliver emissions reductions and grid stability

Ensuring the reliable, cost-effective and sustainable supply of electricity across the system and for all consumers is the priority for system operators, planners and regulators. This happens across multiple timescales and ranging scenarios, including from real-time for grid control and system balancing to multi-year or multi-decade scenario planning aligned with demand projections and climate goals. System planning and operation is growing more complex as electricity systems transition away from a more centralised model largely supported by fossil fuels to one that includes a larger range of technologies providing energy and electricity services. Coal-to-clean transition projects are an example of the added complexity system planners and operators are facing with projects to date often resulting in a single coal asset in one location being replaced by multiple clean projects spread across multiple sites.

The process of identifying and executing the retirement and decommissioning of an operating power asset, along with any proposal for the development of new power projects, must be carefully co-ordinated with power system planners, operators and regulators. Any new power project requires a set of proposals, studies and approvals. This includes grid interconnection and impact studies; compliance with grid and other operational functions; and regulatory, legal and permitting approvals. Coal decommissioning and transition projects will follow a similar process but include additional requirements or recommended steps including environmental and health impact assessments and other safety compliance processes associated with the decommissioning and remediation of the coal power plant and the site, as well as just transition planning and other social impact assessments.

Understanding the likely process for any coal transition project has important implications for assessing the potential risks associated with transition credit projects. Transition credits and the corresponding existing methodologies require replacement of retired coal assets with new clean energy capacity to varying degrees, including 0%, 40% and 100% thresholds. An important concern raised over the current pairing requirements is that having set thresholds may result in suboptimal replacement projects, with impacts on reliability, cost and emissions reductions.

These decisions should be informed first by existing power system plans, with transition credit project proponents then working closely with planners, operators and regulators on detailed proposals for the early transition and replacement of any coal-fired power plant. System planners can support this process by developing more detailed, accessible and regularly updated power system plans and supporting analyses. Detailed planning alongside meaningful co-ordination between project proponents and system planners, and with sufficient flexibility to respond to unexpected system stresses or crises, can result in impactful and optimally designed transition credit projects.

Pairing modalities for clean energy replacement depends on power market structures and ownership models

Pairing early coal plant closures with new and additional cleaner energy is central to the generation of transition credits. The early shutdown of a coal-fired power plant on its own does not automatically generate transition credits. Instead, transition credits are issued when the early retirement of a coal-fired power plant is combined with associated clean energy deployment. This helps demonstrate that the resulting emissions reductions are additional, by showing that coal generation is replaced with cleaner alternatives that would not otherwise have been built.

Transition credits methodologies have outlined various ways in which the retiring coal plants can be “paired” with replacement clean energy. The [TRACTION Final Report](#) has conducted further analysis on the practical considerations for integrity principles, including renewable energy replacement, based on the characteristics of Asian power markets.

Transition credits are likely to incentivise project proponents to lead paired renewable energy project development. Project proponents are usually responsible for developing the project design document and securing approvals from relevant authorities for the coal asset transition and renewables replacement projects. This will likely result in the project proponent leading both coal transition and renewable energy development activities, also because credit volumes and therefore revenues depend directly on the timely delivery and scale of the paired renewable energy. This creates strong incentives for the project proponent to retain control over both the coal transition and replacement projects, in order to manage delivery and revenue risk. However, there remain questions about whether existing coal power asset owners, such as independent power producers and utility companies, or potential third-party coal transition project developers are best positioned to lead renewable energy development in support of coal transition credit projects and how to ensure competitiveness and optimal placement.

Beyond considerations linked to power systems planning, transition credits could face varying degrees of bankability risk in early retirement and clean energy replacement, depending on power market structures and ownership models. As mentioned above, project proponents are likely to prefer to lead the development of and own the replacement renewables generation to manage credit volume and revenue risk. Direct ownership of the replacement projects can provide greater control and certainty over the development process, which are directly connected to the timing and volume of credits generated. However, in markets where replacement renewable energy must be competitively procured, there is no guarantee that the coal plant owner will also become the renewable energy developer. For example, the Philippines has undergone five rounds of Green Energy Auctions, with the Department of Energy promoting [a ten-year Green Energy Auction Programme](#) that will put at least 25 GW of renewable energy capacity to auction between 2027 and 2035, while [Malaysia](#) has adopted competitive bidding for large-scale solar projects.

Separating development and ownership of the coal asset and replacement renewable energy generation results in risk sharing and alignment of interests, resulting in potential additional challenges. In markets where projects are competitively procured, if the independent power producer (IPP) asset owner loses the tender for renewable energy, it becomes fully dependent on a third party to deliver the clean energy that underpins credit issuance, creating delivery risk and revenue risk. Meanwhile, entities with greater system-level control, such as

vertically integrated utilities – which are common in most of Southeast Asia – could have lower project risk thus making projects more bankable.

Policy frameworks can create enabling conditions for transition credit transactions

National policies shape whether transition credit projects can proceed and whether investors view them as credible. All countries in Southeast Asia have adopted policies linked to coal transition planning or net zero emissions targets (see Chapter 1). Moreover, three countries in the region have directly addressed the 28th Conference of the Parties (COP28) call for “accelerating efforts towards the phase-down of unabated coal power” in their new nationally determined contributions (NDCs).

Transition credit methodologies indicate which policies are integral by imposing eligibility criteria based on domestic policy prerequisites. Under the Verra methodology, if the coal plant is owned by a state-owned utility, the host country needs to have a national “no new coal” commitment and a commitment to not increase existing coal plant capacity. Under the Gold Standard methodology, the early phase-out of the coal plant and the renewable energy replacement are not mandated by any existing legal requirement. With current methodologies requiring credits to be issued only after monitoring and verification of project delivery and actual emissions reductions, any backsliding on stated commitments ahead of or during crediting periods would risk credit issuance.

As of April 2026, five countries in Southeast Asia (Malaysia, Myanmar, Singapore, Thailand and Viet Nam) have national plans to phase out unabated coal-fired power; three have agreed internationally to phase out unabated coal-fired power while another has agreed internationally not to develop new coal power.

Beyond methodology-specific eligibility rules, governments must have policy and governance arrangements in place enabling and defining the implementation of carbon markets. These policies, guidelines and established markets are critical to enabling the sale of transition credits. For instance, governments’ participation in Article 6 of the Paris Agreement requires formal procedures, institutions and registries. Furthermore, transition crediting proponents must be aligned with the host government’s strategy and framework for engagement in Article 6 co-operation, which can include limits on the quantity of credits transferred internationally, as well as sectoral eligibility rules.

On a broader scale, policies linking carbon markets to national decarbonisation or sustainable development strategies provide strategic clarity on their role in the trajectory of the power sector, thus supplying investment signals needed for market actors. However, as the transition credit concept is still nascent, countries have not yet integrated these instruments into their national strategies.

Box 3.2 Co-operating under Article 6 of the Paris Agreement

Article 6 of the Paris Agreement provides a framework for countries to voluntarily co-operate in the implementation of their NDCs to allow for higher ambition, including through carbon markets. Under Article 6.2, countries may trade internationally transferred mitigation outcomes (ITMOs) bilaterally, while Article 6.4 establishes the Paris Agreement Crediting Mechanism (PACM), a United Nations-supervised crediting framework.

Transition credits are still at an early stage of development. It remains unclear whether they will be generated exclusively under independent standards or also through the PACM, for which a methodology to support coal-to-clean power transition projects is currently under development. It is also uncertain whether these credits will ultimately be used for voluntary purposes or authorised as ITMOs under Article 6.2. Transition credits authorised as ITMOs can reasonably be expected to command higher prices, reflecting the [opportunity cost](#) to host countries of applying corresponding adjustments against their NDCs, as well as the conditions attached to host country authorisation. Moreover, host countries interested in pursuing Article 6 co-operation must meet a range of [administrative, legal and governance requirements](#) associated with Article 6 participation. To date, 84 countries have begun engaging in co-operation to implement Article 6 measures, including India and most Southeast Asian countries.

Countries must assign a designated national authority (DNA) responsible for authorising the use of emissions reductions or removals through Letters of Authorisation. Countries must also implement clear authorisation procedures to approve mitigation activities and confirm the application of corresponding adjustments.* To date, 126 countries have [formally submitted](#) a DNA to the United Nations Framework Convention on Climate Change (UNFCCC). Countries must also operate a registry capable of tracking the issuance, transfer, holding and retirement of mitigation outcomes. Currently, 27 countries have an active national registry (including Cambodia, Indonesia, Thailand and Viet Nam).

In addition, [56 countries](#) have authorisation arrangements to implement Article 6.2 Guidance that are either in place or in progress. These arrangements provide the legal mandate needed for government authorities to govern market mechanisms, authorise ITMO transfers, ensure transparency and integrity, and embed safeguards for sustainable development and community outcomes. Among others, the governments of Japan, Korea, Norway, Singapore, Sweden and Switzerland have also been actively leading work on Article 6 co-operation.

* A corresponding adjustment is a step to avoid double counting when countries trade ITMOs with each other under Article 6 of the Paris Agreement. For illustrative purposes and in a simplified way, the host country subtracts the amounts of emissions reductions or removals it has transferred abroad from its own emissions inventory, to ensure that the reduction or removal is counted only once in the buyer country's NDC.

Source: IEA analysis

Transition credits should also align with high-integrity carbon markets principles

To provide buyer confidence in transition credits, the credits must correspond as much as possible to the emissions reductions they claim to reduce. A high-integrity supply of transition credits safeguards environmental credibility, strengthens market confidence and ultimately helps mobilise investment. Integrity is established through two pathways: overarching carbon market principles that define high-integrity, and carbon crediting methodologies that set out how individual projects can meet these principles in practice.

Across carbon markets, there are multiple standard-setting initiatives. For corporate buyers, there is increasing convergence around the [Core Carbon Principles](#) (CCP) developed by the [Integrity Council for the Voluntary Carbon Market](#) (ICVCM) as a benchmark for high integrity. Moreover, the United Nations-(UN-)run [PACM](#) provides leadership on integrity for inter-country compliance markets, including through UN-level standards that require robust demonstration of [additionality](#). The [Carbon Offsetting and Reduction Scheme for International Aviation \(CORSA\)](#) applies its own programme-level [eligibility and carbon credit integrity criteria](#) to determine which emissions units can be used for compliance in the aviation sector. Additionally, carbon credit rating agencies exist to provide further assurance by independently assessing carbon credit project integrity at the project level.

No transition credit methodology has yet been officially verified under one of the existing integrity initiatives. Verra has formally submitted its VM0052 methodology for ICVCM assessment and CCP labelling. Moreover, the ICVCM recently led a Continuous Improvement Work Programme (CIWP) to assess integrity principles as they relate to transition credit approaches and identify proposed refinements or added rules to the CCP Assessment Framework. Efforts, such as the ICVCM CIWP on transition credits, can build additional assurance regarding the integrity of approved and labelled methodologies.

Methodology development in carbon markets is an iterative process: standards evolve as new projects are implemented, as integrity review bodies request clarifications or revisions, and as expert input and public discourse contributes to the process. While all aspects of integrity matter, a number of elements have emerged as central to current discussions in transition credits.⁹

⁹ For a more comprehensive review of how transition credit methodologies are addressing integrity principles, see the [TRACTION Interim Report](#).

Carbon leakage

The risk of carbon leakage refers to the possibility that emissions reductions achieved by shutting down a coal plant are offset if other fossil fuel power sources increase their output, either within the same electricity grid or in neighbouring countries. In such cases, overall emissions may not decline because emissions reductions in one location are cancelled out by emissions increases elsewhere. To improve the integrity of transition credits, carbon leakage should therefore either be prevented or be explicitly accounted for. In practice, this is achieved through two complementary approaches: 1) preventing leakage through the pairing of clean energy that replaces coal generation; and 2) accounting for residual leakage by quantifying and deducting any additional fossil fuel emissions that may result from other fossil fuel power sources increasing output elsewhere in the system.

Leakage emissions from replacement electricity

The rate of clean energy capacity replacement (pairing) in transition credit methodologies is one critical safeguard against emissions leakage. The greater the share of clean energy mandated to replace the coal plant, the lower the risk that lost coal generation will be met by other high-emitting sources.

Table 3.2 Selected list of methodologies and clean energy pairing

Methodology	Clean energy pairing	Developers/Carbon credit standard
Methodology for Early Retirement of Coal-Fired Power Plants Using a Just Transition	The approved version includes at least 10% of capacity at the start of the crediting period and 40% of capacity by the end of the initial crediting period. A new draft version open for consultation as of April 2026 includes a proposal for 100% pairing.	CCCI (Rockefeller Foundation and a consortium of technical partners)/Verra
Joined-Up Sustainable Transition (JUST): Coal Decommissioning	Ultimately replace at least the historical annual electricity generation on a 1:1 basis , although the methodology allows for the paired clean energy to be deployed progressively, so that credit issuance may begin before full replacement is achieved.	Gold Standard
Methodology for Early Phaseout of CFPP with Just Transition by Replacing with Clean Energy Sources	At least 50% capacity at start of crediting period to reach 1:1 replacement within three years of shutdown.	Sustainability Economics/ Asia Carbon Institute
Sectoral approach to energy transition credits (name tbd)	Not applicable	Winrock International/ Environmental Resources Trust

Note: CFPP = coal-fired power plant.

As the methodologies outline a range of requirements for renewable energy capacity replacement, in some projects only a small fraction of electricity might be paired with new renewable energy due to physical limitations, such as land availability and renewable energy potential, while the rest will come from other sources connected to the grid. In systems where electricity is fossil fuel based, there is a material risk that increased dispatch from fossil fuel generators will diminish some of the emissions reductions achieved by the coal plant retirement, leading to leakage. This effect is usually captured in the methodologies through emissions quantification and verification processes, and if other fossil fuel generators run more and create extra emissions, these emissions are fully accounted for in the calculation, and therefore in the resulting issuance of transition credits. While accounting approaches are well established in principle and reflected in existing methodologies, their effective application in practice depends on the availability of reliable grid data, robust monitoring systems, and sufficient institutional and technical capacity in host countries.

Methodologies quantify clean energy replacement using different metrics, such as in terms of capacity (Verra) or generation (Gold Standard). For variable renewable technologies such as wind and solar, a 100% capacity replacement does not translate into 100% replacement of annual energy output. As shown in Chapter 2, renewable capacity must typically be scaled by a factor of 1.5 to 4 to match the generation profile of a coal plant. Renewable energy replacement alone may overlook the system services provided by a coal plant, such as dispatchability, inertia, frequency response, reactive power and ramping capabilities. If these services are instead provided by fossil fuel plants, additional leakage would occur and must be accounted for by transition credit methodologies. Analysis in Chapter 2 shows that solar PV and wind capacity would need to be scaled by around a factor of ten to maintain full energy and adequacy in the power system. As highlighted in that chapter, this challenge is addressed through system-level portfolios that combine variable renewables with storage and other flexible resources. Such portfolio-based approaches can also support the provision of certain ancillary services, although maintaining secure system operation continues to require additional, targeted investments and operational measures.

Leakage emissions from national ‘no new coal’ commitments

All publicly available methodologies, draft or approved, include a provision for a prohibition or commitment to no new coal investment. Verra’s [VM0052 methodology](#) requires that the host country have a publicly available commitment to not build new coal plants or increase existing coal plants capacity. This safeguard is designed to prevent a situation in which the capacity of the retired coal plant is replaced by a new coal plant, undermining the emissions reductions claimed by the transition credit project.

However, this requirement applies only to coal plants owned by state-owned utilities. When a coal plant is owned by an IPP, the IPP itself must have a public commitment to not build new coal plants or increase existing capacity. Similarly, the [Gold Standard](#) draft methodology requires the coal plant owner and its related entities to have no plans for or commitments to investment in new assets or extending the capacity of existing assets. These provisions reflect the fact that crediting programmes can impose eligibility requirements only on the project proponent and its related entities, rather than on all actors in the power sector. This leaves open the possibility that another IPP, not bound by the transition credit project requirements, could still develop new coal capacity or expand existing units. In this case, the capacity retired could be offset somewhere else in the system, which creates leakage. A secondary implication of this design gap is that it may reduce the incentive for IPPs to participate in coal retirement transactions. Even if transition credits provide an extra revenue stream, an IPP might be hesitant to retire a coal asset early if competitors retain the ability to add new coal capacity, potentially affecting market share or competitiveness. In practice, this hesitation may be reinforced by regulatory and market uncertainties, such as whether existing permits for new coal capacity are retained, withdrawn or reassigned to competitors. Asset owners may be reluctant to abandon future coal options if doing so risks enabling competitors' capacity additions that could undermine revenues or market position. This dynamic is already emerging in ongoing asset-level decarbonisation discussions.

Market leakage from international coal trade

Currently, there is no restriction on the type of coal-consuming country to which the methodologies apply. If transition credits are issued from the early retirement of a coal plant in a coal-exporting country, there is a credible risk of market leakage, where coal that would otherwise have been burned domestically is instead exported to meet overseas demand. As a result, emissions reductions credited to early retirement may be partially or fully annulled. [Gold Standard](#) takes market leakage in consideration in its baseline and credits quantification. If market leakage is not appropriately accounted for, transition credits could create a perverse incentive for coal-exporting countries. Finance channelled through transition credits may enable continued profit from coal exports or reduce fiscal expenditures on domestic coal price subsidies, effectively allowing host countries to benefit financially twice from the credited plant closure.

Additionality

Additionality is a key principle of carbon market integrity, where project proponents must prove that a project would not have proceeded on the same timeline without carbon credit revenues. Under transition credit methodologies, this is assessed

against a baseline retirement date based on factors such as regulatory requirements, technical lifetimes, power purchase agreement durations and the date of financially attractive retirement.

Regulatory additionality

The level of existing policy ambition in a host country has important implications for transition credit projects. Under the Verra methodology, project proponents need to demonstrate that the proposed retirement date for the coal plant is earlier than retirement dates imposed by existing regulations or legislation at the national or grid level. Under the Gold Standard methodology, the coal plant needs to be free of any pre-existing legal mandate for early closure.

On one hand, it is in principle desirable for a coal plant host country to implement ambitious policies that favour the retirement of coal and its replacement with clean energy. On the other hand, these policies could complicate the demonstration of regulatory additionality of the projects and thus limit the use case of transition credits. The requirements for regulatory additionality mean that the use case for transition credits is focused on accelerating coal transitions in those countries which are considering a coal transition or have a coal phase-down commitment, but are not yet at the stage of legislating on coal retirement.

Financial additionality

Project proponents need to demonstrate that the early retirement of the coal plant would not have been financially viable in the absence of transition credit revenue. Existing methodologies have outlined conditions such as positive utilisation and positive net cash flow in the last three years, and the financially attractive retirement date is calculated at the year in which cost savings from renewables outweigh the cost of coal plant retirement.

According to International Energy Agency (IEA) tracking of clean energy equipment prices, solar PV prices were [almost 45% lower](#) in 2024 than in 2023 as the cost of panels rapidly decreased. Looking ahead, the installed costs of renewables, specifically solar PV and wind, continue its decline. As renewables become cheaper, the case for financial additionality in retiring the coal plant early weakens, increasing the risk that credits would subsidise closures that would have happened anyway. This is not applicable in markets without economic dispatch and where there are other economic incentives to prioritise the dispatch of coal plants, such as long-term power purchase agreements that include take-or-pay clauses and capacity payments.

Integrating complementary technologies for replacement of the retired coal plant presents a clear case for financial additionality and provides further financial incentive for the coal transition. Battery energy storage systems (BESS) and other technologies that can complement renewable energy in replacing the full system services provided by a coal plant are included in the Gold Standard and Verra methodologies as eligible technologies under the renewable energy plant configuration.¹⁰

Permanence of the retired coal plant

Currently, all the publicly available project-based methodologies allow the issuance of transition credits only after a demonstrated and irreversible retirement of the coal plant. However, there is interest from system planners and operators to support the transition away from coal power production by also focusing on the flexible operation of coal plant in the near term to reduce emissions. [TRACTION](#) has explored the possibility of integrating a phased shutdown approach or asset repurposing. Decommissioning of specific technical components is required to meet methodology requirements, which is aligned with ensuring permanent emissions reductions.

Significant transition credit demand is yet to build up, with the most potential coming from compliance markets

Transition credits could play a role in various carbon market mechanisms, but committed demand is limited

Transition credits could in theory be issued through methodologies registered under independent credit standards or under UN-governed standards such as the PACM. They could be purchased by different stakeholders and used to claim emissions reductions against different targets.¹¹ They could also be used in voluntary co-operation under Article 6.2 of the Paris Agreement.

¹⁰ The technologies eligible under the Verra methodology include wind and solar with or without BESS, hydropower, geothermal, wave, tidal, landfill gas, biogas, waste-to-energy, and biomass-fired power plants; those eligible under the Gold Standard methodology include wind, solar, wave, tidal power and associated energy storage systems.

¹¹ For a more detailed overview of buyer profiles and priorities, see the [TRACTION Interim Report](#).

Table 3.3 Potential sources of transition credit demand

Source of demand	Type of buyer	Description	Latest development on transition credits and examples
Compliance	Governments to allow for higher NDC ambition	Should transition credit methodologies be approved under the PACM or accepted under bilateral agreements, governments could use authorised transition credits (ITMOs) towards NDC achievement.	PACM methodology to support transition credits for coal-to-clean power projects under development. Singapore is prepared to offtake transition credits if it meets Singapore's environmental integrity standards.
	Corporates for compliance under domestic carbon pricing instruments	In some jurisdictions, domestic carbon taxes or emissions trading systems may allow the use of transition credits to partially meet compliance obligations, either as an alternative to paying the carbon tax or in place of surrendering emissions allowances, respectively.	Should Singapore decide to offtake transition credits, these may be made eligible for compliance under its carbon tax.
	Airlines for compliance under CORSIA	Should transition credit methodologies become eligible under CORSIA, airlines could use authorised transition credits (ITMOs) towards CORSIA compliance.	VM0052 is under review for CORSIA eligibility.
Voluntary	Corporates or other organisations to meet voluntary commitments	Corporates or other organisations can use transition credits to meet their voluntary commitments, such as corporate net zero targets.	21 entities signed a Statement of Support from TRACTION; Kinetic Coalition has also formed a Buyers' Alliance

TRACTION and the Kinetic Coalition have engaged in extensive stakeholder engagement and ecosystem-building efforts. However, across all markets, there has thus far been limited committed demand for transition credits.

Governments could use authorised transition credits towards NDC achievement, either through sovereign procurement of transition credits or by allowing their use within domestic carbon pricing instruments. Compliance carbon pricing instruments could become an important source of demand for transition credits. Emissions trading systems, carbon taxes and international schemes such as CORSIA may allow the use of transition credits to complement domestic

abatement, subject to environmental integrity safeguards. For example, Singapore's carbon tax framework already allows liable entities to use high-quality international credits to meet part of their tax obligation, and the government has indicated openness to transition credits provided they meet stringent integrity criteria. Such compliance-based demand could significantly increase market scale if similar provisions are adopted elsewhere.

Unpredictability of credit price and volume could act as a major constraint on demand

Carbon markets have experienced variable fortunes since their conception. Voluntary carbon credit demand remains uncertain amid reputational risk, reversal risk and political risk as key concerns. In voluntary carbon markets, some standard-setters such as the [Science Based Targets initiative](#) have taken a strict stance towards the [use of voluntary credits in corporate claims](#) of emissions reduction contributions. As a result, for many companies that are using such standards, the value to purchase any carbon credits has become limited.

Visibility on demand signals for carbon credits remains largely limited to 2030. Beyond this, there are only few firm commitments or announcements by governments to use international credits towards compliance, and the post-2030 outlook remains highly uncertain. At present, the only sources of longer-term visibility are CORSIA demand through to 2035 (subject to significant regulatory and eligibility uncertainty) and early discussions in the [European Union on the possible use of international credits from 2036 to 2040](#). As a result, compliance demand for transition credits remains fragmented and does not yet provide a sufficiently clear or durable price signal for coal-fired power plant owners to commit to early decommissioning investments in the near term.

The price level of transition credits could also play an important factor in demand creation. Usually, the price of carbon credits depends on several factors, including the type of market the credits are eligible for and the perceived integrity of the credits. For instance, ICVCM CCP-labelled credits are expected to capture a price premium, and so are ITMOs under Article 6 used in compliance regimes. Stakeholder consultations revealed that transition credits could sell at USD 14 per tonne (t) of CO₂-eq to USD 45/t CO₂-eq. This is a higher price than other types of carbon credits, such as clean cooking carbon credits, which cost an average of USD 6.25/t CO₂-eq at retirement in 2025, but is much lower than direct air capture carbon credits, [priced](#) at USD 500/t CO₂-eq.

Another question in early discussions about transition credits in TRACTION was the timing mismatch. In these conversations, many potential corporate buyers showed limited appetite for long-dated commitments, often preferring to purchase credits covering shorter time frames (e.g. three to five years), rather than the full

10-15-year crediting periods proposed by transition credits project developers. In addition, some buyers are reluctant to commit to credits that would be counted against emissions reduction targets in the late 2030s or 2040s, creating a misalignment between project financing needs and demand profiles. While buyer preferences vary and potential solutions exist, notably as governments become a potential source of demand, these demand-side timing issues remain a material constraint for scaling transition credits.

Moreover, stakeholders have highlighted policy reversal risk as one of the most material risks associated with transition credits, particularly in Southeast Asia. Requirements underpinning credit integrity, such as “no new coal” commitments or sustained limits on coal plant operation, could be weakened or reversed in response to changing domestic priorities or political transitions. Regional analyses, including by the [ASEAN Centre for Energy](#), document instances of policy fragmentation and shifting coal phase-down commitments across Southeast Asian countries, underscoring the challenges this poses for the credibility of long-dated crediting frameworks. While some countries, such as [Malaysia](#), have demonstrated relatively more stable coal-phase-out signals compared with other major coal-consuming economies in the region, overall policy support for coal phase-down has not been consistent. Such uncertainty increases the risk of emissions leakage and weakens buyer confidence, particularly for transition credits that rely on forward-looking policy commitments.

Chapter 4. Recommendations

Countries in Southeast Asia with coal in their electricity mix all have either commitments to reduce emissions from coal or reduce coal dependency, or net zero emissions targets. If these commitments are fulfilled, they imply a significant phase-down in coal consumption in the coming decades. Transition credits have emerged as a market-based instrument to facilitate a secure move beyond coal, particularly for the early retirement of grid-connected coal plants, with the first methodologies and pilot projects now being implemented. This chapter outlines recommendations for countries that may choose to explore transition credits as an option to reduce the role of coal in their electricity mix.

Table 4.1 Summary of barriers and recommendations

Area	Target audience	Barriers	Recommendations
Policy formulation	Governments	Policy uncertainty and limited coal transition commitments amid continued coal reliance.	Embed coal transition objectives in policy frameworks that support transition pathways and provide more predictable conditions for carbon market participation.
Power systems planning	Governments, regulators	Complexities in managing coal transitions while maintaining reliable and affordable power systems.	Enhance integrated power system planning to co-ordinate coal transitions with variable renewable energy integration, flexibility investments and energy efficiency measures.
Transition credit methodologies	Carbon credit buyers, carbon credit standards and developers	Trade-offs among environmental integrity requirements, energy security objectives and policy flexibility.	Further develop transition credit methodologies to integrate context-specific system-level planning considerations and leakage safeguards while maintaining robust integrity standards.
Investment	Investors, utilities, operators	Structural financing constraints and elevated risk perceptions limit investment in coal transitions.	Consider transition credits as a complementary, performance-based revenue stream, contingent on stronger demand-side signals.

1. Policy formulation

Provide clear and co-ordinated policy frameworks to mobilise coal transition pathways

A well-defined government strategy is crucial for securing public and private buy-in for coal transitions. While a country's NDC and long-term low-emissions strategy provide high-level direction, they must be supported by implementation strategies that translate targets into actionable plans. Chile offers a strong example: its [Ruta Energética 2018-2022](#) was developed through extensive community and industry participation, resulting in the establishment of a co-ordinated plan to retire or convert all coal units by 2040. Clarifying coal transition policies can provide policy predictability and build market confidence. In emerging market and developing economies (EMDE), this typically requires robust support from the international community. If a country decides to pursue a strategy to accelerate retirement of coal-fired power plants, current project-based methodologies typically require a national commitment to build no new grid-connected coal-fired power plants or units to avoid emissions leakage.

Clear just transition strategies such as providing support for workers impacted by energy transitions and fostering inclusive dialogues among affected sectors, workers and communities is also necessary. Although this report does not examine just transition issues in detail, the International Energy Agency's (IEA) [Accelerating Just Transitions for the Coal Sector report](#) highlights strategies for a people-centred transition.

Policy is also central to the jurisdictional approach to transition credits. Under this approach, policy makers and market participants can more flexibly determine the most effective levers to reduce emissions from the electricity system. Beyond early retirement, which is the focus of most current transition credit methodologies, well-designed jurisdictional approaches could incentivise a wider range of strategies to reduce coal emissions: repurposing for operational flexibility, retrofitting with carbon capture, utilisation and storage (CCUS) and retrofitting for co-firing with other low-emissions fuels. Repurposing, for example, enables half of the emissions that can be reduced in the Announced Pledges Scenario (APS) to 2050 and over 60% of emissions reductions in Southeast Asia.

Clarify carbon market governance to enable credible transition credit implementation

Government policy is essential for the implementation of transition credits on a practical level, beyond the provision of long-term strategies. Where governments are interested in implementing transition credit projects, they could promote the

use of crediting standards that meet international quality benchmarks and, where appropriate, consider authorising transition credits as internationally transferred mitigation outcomes (ITMOs) in line with national priorities and circumstances. More broadly, carbon market implementation frameworks, such as [Cambodia's Article 6 Operations Manual](#), can clarify the parameters for participation in co-operative approaches under Article 6, including institutional governance, ITMO authorisation processes, and alignment with national climate strategies such as nationally determined contributions (NDCs). Additionally, national guidance on voluntary market integrity, such as the [United Kingdom's principles for high-quality credits](#), can enhance buyer confidence. Stable policy signals paired with credible implementation plans increase the confidence of carbon credit buyers.

Policy interactions should also be carefully considered, particularly with other carbon pricing instruments. In countries with existing or planned emissions trading systems, governments can assess how transition credits issued under project-based methodologies would operate alongside these systems. Transition credits should complement the objectives of emissions trading systems, rather than weaken them. A risk arises if revenues from transition credits, not allowance prices, become the primary driver of early coal plant closures. In that case, demand for allowances could fall, carbon prices in emissions trading systems may weaken, and incentives for emissions reductions elsewhere in the power sector could be reduced. In jurisdictions that rely on carbon taxes rather than emissions trading systems, the interaction is different. In these cases, transition credits are less likely to weaken price signals as the carbon tax rate is fixed. However, the impact of the carbon tax on the profitability of coal-fired power plants should be explicitly accounted for in financial additionality assessments to ensure that transition credits do not reward coal plant closures that would have occurred anyway due to the carbon tax.

2. Power systems planning

Coal power continues to underpin energy security in many EMDE across Asia. In the near term, high liquefied natural gas (LNG) prices and volatile supply are prompting several Southeast Asian countries to rely more heavily on coal. Even though many governments have announced long-term coal transition goals in line with their NDCs, coal demand is still projected to rise in parts of Southeast Asia through the end of this decade in the APS.

Reducing emissions from coal-fired power generation and replacing it with cleaner sources, particularly variable renewables, requires investment in the infrastructure needed to deliver system services previously provided by coal. The IEA has undertaken a comprehensive [assessment](#) of the opportunities for Southeast Asia to integrate higher shares of variable renewable energy. This includes investing in grids, storage, flexibility and in parallel, energy efficiency measures to moderate

growing electricity demand. However, given the currently low shares of variable renewable energy in Southeast Asia, these measures do not require significant investment or restructuring of power systems or markets. Countries can implement them progressively, adapting to specific challenges as shares of these technologies increase. Accelerated coal retirement projects using transition credits should be paired with measures that ensure power supply remains reliable, affordable and secure, and should be closely co-ordinated with system planners throughout the project life cycle.

Robust power systems planning also plays an important role in safeguarding just transition outcomes. By clarifying how coal transition projects are sequenced and integrated within the wider power system, planning can help manage impacts on electricity reliability, affordability and access for local communities. Just transition outcomes are often difficult for private project developers to define or demonstrate, given their qualitative, context-specific nature and exposure to external factors. Clear system-level planning could provide a foundation for predictability, helping to delineate responsibilities, manage risks and support investment decisions in transition credit projects.

3. Transition credit methodologies

Current transition credit methodologies are mainly designed for early pilot projects in Southeast Asia, and reflect the assumptions and safeguards typically applied at this stage. As these methodologies are either still being drafted or are subject to revision, there is scope to further develop them to take into account broader issues such as the energy security of the power systems where they could be applied. There is also scope to offer more detailed guidance tailored to specific circumstances. Host countries may hesitate to adopt project-based transition credits as they are currently conceptualised due to concerns over energy security and grid reliability. Hesitation may also arise where methodological requirements assume rapid pairing with clean energy, which may not align with current system readiness in all countries. This highlights a design challenge for methodologies in balancing environmental integrity with practical implementation constraints.

As a result, most transition credit initiatives to date have focused on early retirement as an initial application, reflecting the need to safeguard environmental integrity, particularly permanence and additionality, rather than to signal the relative importance of different coal transition strategies. In systems where coal assets continue to play a role in adequacy, flexibility or system stability, the decision of whether and when to apply transition credits to early retirement rests primarily with national policy and system planning choices, rather than with transition credits methodologies themselves. Transition credits are therefore best understood as one instrument within a broader transition toolkit, to be applied selectively where early retirement aligns with national priorities and system

readiness. One of the main integrity issues is potential carbon leakage, which has already caused scepticism due to past experiences in carbon credit markets. If not addressed properly by methodology developers and project proponents, these concerns could reduce transition credit demand and deter potential investors from supporting projects that include transition credits in their financing. Against this backdrop, several areas emerge where methodological design could be further developed to address these concerns and support effective implementation.

Align transition credit methodologies with system-level integrity and power system planning

Project-based transition credit projects need to be developed and assessed within a power-system framework, rather than treated as isolated asset-level interventions. While methodologies establish common integrity requirements and accounting rules, system alignment is primarily achieved through national planning processes, regulatory approvals and project design documentation, including review by system operators, regulators and off-takers. In this context, host countries may choose to apply market- or jurisdiction-specific requirements on top of existing project-based methodologies, for example by supplementing a standard transition credit methodology with additional adequacy, flexibility or inertia criteria reflecting local system conditions.

Methodologies would benefit from requiring alignment with national or sub-national power system plans, including expected demand growth, reserve margins, and the sequencing of replacement capacity. This can help ensure that credited emissions reductions are durable and system-consistent, while minimising risks to electricity reliability, affordability and security. A transition credit methodology design that recognises the system services provided by coal plants, such as adequacy, inertia and flexibility, can support more credible baselines and safeguards, and reduce the carbon leakage risks within the same power system.

Enhance replicability by contextualising leakage safeguards and through system-level, multi-technology replacement strategies

Project-based transition credit methodologies could be updated to include clearer, more detailed safeguards against leakage, along with measures to mitigate and address it, tailored to the specific circumstances in which they are applied. For example, in terms of preventing emissions leakage, the requirements for replacing coal with clean energy should be refined to reflect the local context more accurately, both in terms of minimum thresholds and in terms of eligible technologies.

The analysis in this report indicates that in Southeast Asia the actual rates at which coal must be replaced to maintain electricity generation and system adequacy are very high for most renewable energy technologies, including solar photovoltaic (PV), wind and hydro, if they are replaced individually. Of the technologies capable of replacing coal at scale, nuclear is explicitly excluded from most carbon standards and transition credits methodologies, as is switching from coal to gas. The transition from coal to gas was previously allowed under the Clean Development Mechanism but it is now less common in carbon markets due to concerns about the lock-in effect, compounded by recent economic and supply chain challenges for gas caused by the conflict in the Middle East. Although geothermal energy is eligible for crediting under some standards and allowed under some transition credit methodologies, its routine development is currently limited to geologically suitable areas, but progress in next-generation geothermal technologies could see deployment across more geographies in the coming decade.

These findings highlight the need to avoid relying on a single replacement technology. Instead, transition credit methodologies should focus on system-level solutions that combine multiple technologies to replace coal power, and where relevant, associated heat supply, ensuring reliable energy supply in line with individual country pathways, system adequacy and flexibility, especially battery energy storage systems and other technologies needed to replace the full system services provided by a coal plant.

Moreover, to enable a more granular treatment of market leakage, the methodologies could consider whether the host country is a net exporter or importer of coal and take into account factors such as whether domestic coal prices are regulated or capped. Clarifying these details in methodologies can help move the concept of transition credits beyond pilot projects, by ensuring more context-specific applications.

Ensure regular updates of grid emissions factors and additionality calculations to minimise the risk of over-crediting

Transition credit methodologies should require frequent and transparent updates of grid emissions factors to reflect changes in generation mixes, dispatch patterns and fossil fuel displacement over time. Using static or outdated factors risks overstating emissions reductions, particularly in rapidly decarbonising power systems. In parallel, additionality assessments should be periodically revisited, rather than fixed at project inception, to ensure that credited activities remain non-business-as-usual and align with evolving policies, market conditions and technologies. These measures can reduce over-crediting risks while maintaining

the environmental integrity and credibility of transition credits, provided that such requirements are applied in a predictable manner to limit revenue uncertainty for project developers and asset owners.

Enable coherence across project-based, jurisdictional and nested approaches

As multiple methodological approaches for issuing transition credits are emerging, including project-based, jurisdictional and nested approaches, methodologies should be designed to allow for coherence and eventual integration across scales. This would help to avoid fragmentation and double counting. Clarity on how baselines are set, how emissions reductions are attributed, and how project-level activities can be reconciled with sector-level targets or accounting frameworks will be essential. Clear guidance on nesting arrangements can help host countries, jurisdictions and asset owners choose approaches that match their institutional capacity and market context, while preserving environmental integrity and facilitating future scale-up.

Build capacity to ensure robust quantifications, monitoring and verification

Credible transition credits depend on strong capacity for emissions quantification, data collection and independent verification across project developers, regulators and verifiers. Targeted investments in monitoring, reporting and verification (MRV) systems, technical guidelines and training can improve the consistency and accuracy of emissions estimates, particularly in complex or data-constrained contexts. Strengthening MRV capacity is especially important for both project-based and jurisdictional (performance-based) transition credits approaches, where verified outcomes underpin credit issuance and market confidence, and are critical to develop at both the national and sub-national levels. Beyond strengthening MRV systems, effective capacity building also requires that carbon credit verifiers (validation and verification bodies), which independently assess project eligibility and verify claimed emissions outcomes, be properly equipped to independently assess project design and verify credited outcomes. This includes the ability to assess legal, financial and system-level aspects of coal transition projects, including ownership structures, investment incentives, replacement options and system adequacy considerations.

Further develop transition crediting approaches for a wider range of countries and emissions reductions strategies

Future iterations of transition credit methodologies could be designed with a wider range of countries and strategies in mind, enabling broader applicability and greater mitigation impact. This could allow more host countries to pursue coal transition strategies that are compatible with their energy security, development and environmental integrity objectives. While Southeast Asia provides a valuable testing ground for piloting transition credits, the largest potential for emissions reductions from coal lies in countries such as the People's Republic of China and India, where coal remains central to power systems and absolute emissions are highest. These markets have distinct characteristics, including scale, ownership structures, regulatory frameworks and financing conditions, that differ very much from those in Southeast Asia and are not fully captured by current methodologies.

Moreover, current project-based transition credit methodologies focus primarily on early retirement of coal plants, which is only one of the coal transition strategies identified by the IEA. In contexts where electricity demand is growing rapidly and concerns around energy security and reliability remain important, the early retirement entry point may constitute a participation barrier for both host countries and asset owners. In principle, the concept of transition credits could be extended to other coal transition strategies, but important methodological, technological or ideological constraints remain. Developing transition credit approaches for repurposing coal assets for flexibility or for co-firing with lower-emissions fuels, including hydrogen and its derivatives, may require effective measurement approaches, as well as reconciliation with project-based methodology requirements on permanence and financial additionality. By contrast, retrofitting coal plants with CCUS may be easier to accommodate under existing carbon crediting methodologies adapted to transition credit frameworks. However, project cancellations, cost overruns and technical challenges have increased scepticism on CCUS technological development and [CCUS remains a niche solution](#). CCUS approaches may also face opposition from civil society organisations. In coal-importing countries, they could risk prolonging dependence on coal.

Sectoral or jurisdictional crediting approaches may offer a pathway to align transition credits with power-system realities, but robust and operational proposals in this space are still under consultation. Although such approaches can, in principle, account for system-level performance, project-based methodologies currently offer a clearer and more immediately operational pathway, supported by established governance structures, well-defined verification processes and stronger buyer familiarity. The choice between these two approaches ultimately involves trade-offs among scalability, precision, institutional readiness and market acceptance.

4. Investment

Explore transition credits as a complementary revenue stream for coal transitions within broader financing packages

In Southeast Asia, about USD 20 billion is spent on average each year to reduce emissions from existing coal plants in the APS between 2025 and 2050, with 70% invested in solar PV and wind to replace unabated coal generation. While renewables are increasingly cost-competitive for new capacity additions, this does not necessarily make the early retirement or reduced operation of existing coal plants economically attractive. Existing coal assets are often financially locked in due to unrecovered capital, contractual barriers, market design features, political hurdles and the continued role of coal in providing system services. Driving coal transitions at the scale required under national targets creates a need for complementary mechanisms that specifically incentivise emissions reductions from coal-fired power generation. These mechanisms typically involve cost-sharing or grant-based support to address project components that cannot be financed, although their scale remains limited.

Projects involving retrofitting may retain the capacity to generate business cash flow and therefore remain eligible for financing. However, many EMDE that are most in need of such financing face high costs of capital and macroeconomic and regulatory constraints that limit access to private capital and international finance.

Given these barriers, international public finance, particularly from multilateral development banks and development finance institutions, can play a catalytic role in mobilising domestic sources of finance and domestic public investment in clean energy. It can also reduce country-level and project-level risks, crowd in domestic investment and enable emissions reductions from coal. Historically, banking exclusion policies and uncertainty over transition pathways have constrained engagement with coal-related assets. Recent transition finance taxonomies and dedicated frameworks, such as the [ASEAN Taxonomy for Sustainable Finance](#) and the [Singapore-Asia Taxonomy for Sustainable Finance](#), have begun to address this by clarifying when and how coal transition activities can be financed. These frameworks improve market participation by reducing policy ambiguity and clarifying eligibility. While lowering risk perception can support a decrease in financing costs, taxonomies alone do not materially reduce structural cost of capital challenges facing many EMDE. Financing coal transitions at scale in EMDE will continue to require blended finance, concessional support and risk-mitigation instruments.

High-integrity transition credits have the potential to create a performance-linked revenue stream associated with accelerated emissions reductions, which can improve the risk-adjusted returns of coal transition projects. However, transition credits are not sufficient revenue streams on their own. Their value lies in their ability to transform cost-sharing payments into investable opportunities through the issuance of carbon credits, thereby improving project bankability. As such, transition credits are most effective when integrated into broader financing structures as an early source of catalytic capital. While methodologies are still being developed, multilateral development banks such as [IDB Invest](#) have used carbon finance in blended arrangements to mobilise private and public capital, offering lessons on structuring, governance and risk sharing that can inform emerging transition credit models. In this context, transition credits can potentially serve as a vehicle through which public or concessional funding can be deployed in a results-based manner, further supporting capital mobilisation.

Address demand-side uncertainties to enable the catalytic role of transition credits

Carbon revenues can cover part of the expenditures associated with a coal transition, their role is not yet sufficiently mature or predictable to enable large-scale financing due to their limited capacity to generate robust cash flows. Transition credit transactions also face structural risks such as governance challenges when coal retirement and renewable replacement assets have different owners. Robust co-ordination on revenue allocation and contractual responsibilities is required, where early engagement with technical experts, insurers and risk advisers can help identify and mitigate these risks during design and structuring.¹² Moreover, political risk is cited by stakeholders as one of the most significant concerns, with uncertainty around policy shifts or reversals potentially affecting credit delivery or validity. While financial backstop instruments such as guarantees and political risk insurance can help mitigate risks that are largely outside investor control, these mechanisms are typically most effective as complements rather than substitutes for strong government policy commitments.

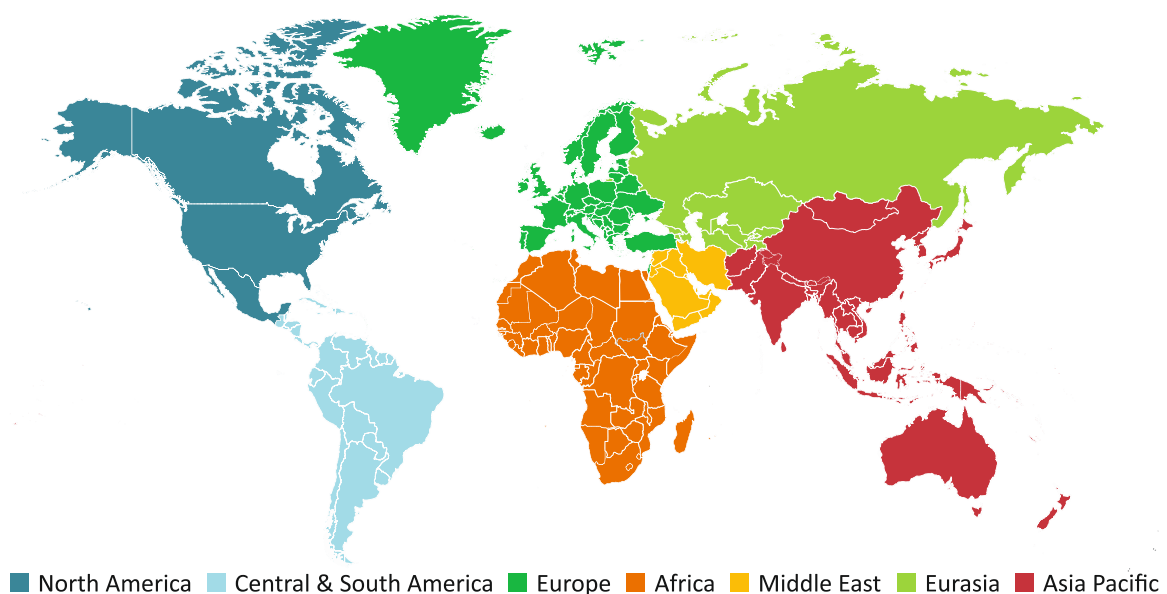
Potential actions to strengthen demand for transition credits include pooling of buyers into coalitions (such as through the efforts of the Kinetic Coalition), expanding eligibility for transition credits within compliance carbon markets and facilitating long-term agreements under Article 6.2 of the Paris Agreement. Strengthening long-term demand signals through these channels will be critical to enable transition credits to play a catalytic role in financing coal transition investments.

¹² The [TRACTION Final Report](#) has detailed the risks faced by different stakeholders across the project life cycle.

Annex

Regional and country groupings

Main country groupings



IEA. CC BY 4.0.

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: Organisation for Economic Co-operation and Development (OECD) 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, The 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), Bolivarian Republic of Venezuela (Venezuela), Brazil, Chile, Colombia, Costa Rica, Cuba, Curaçao, Dominican Republic, Ecuador, El Salvador, Guatemala,

Guyana, Haiti, Honduras, Jamaica, Nicaragua, Panama, Paraguay, Peru, Suriname, Trinidad and Tobago, Uruguay, and other Central and South American countries and territories.⁴

China: Includes (The People's Republic of) China and Hong Kong, China.

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, Gibraltar, Iceland, Israel,⁵ Kosovo,⁶ Montenegro, North Macedonia, Norway, Republic of Moldova, Serbia, Switzerland, 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): Australia, Austria, Belgium, Canada, Czechia, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Ireland, Italy, Japan, Korea, Latvia, Lithuania, Luxembourg, Mexico, New Zealand, Norway, Poland, Portugal, Slovak Republic, Spain, Sweden, Switzerland, The Netherlands, Türkiye, United Kingdom and United States.

Latin America and the Caribbean (LAC): 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): IEA grouping plus Chile, Colombia, Costa Rica, Iceland, Israel, Latvia and Slovenia.

OPEC (Organization of the Petroleum Exporting Countries): Algeria, Angola, Bolivarian Republic of Venezuela (Venezuela), Equatorial Guinea, Gabon, Islamic Republic of Iran (Iran), Iraq, Kuwait, Libya, Nigeria, Republic of the Congo (Congo), Saudi Arabia and United Arab Emirates.

OPEC+: OPEC grouping plus Azerbaijan, Bahrain, Brunei Darussalam, Kazakhstan, Malaysia, Mexico, Oman, Russian Federation, South Sudan and Sudan.

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). Timor-Leste joined ASEAN on 26 October 2025 and is excluded from the grouping for this publication but is included in aggregate within the overarching Asia Pacific group.

Sub-Saharan Africa: Angola, Benin, Botswana, Cameroon, Côte d'Ivoire, Democratic Republic of the Congo (DRC), Equatorial Guinea, Eritrea, Ethiopia, Gabon, Ghana, Kenya, Kingdom of Eswatini, Madagascar, Mauritius, Mozambique, Namibia, Niger, Nigeria, Republic of the Congo (Congo), Rwanda, Senegal, South Africa, South Sudan, Sudan, United Republic of Tanzania (Tanzania), Togo, Uganda, Zambia, Zimbabwe and other African countries and territories.⁷

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, 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, Sint Eustatius and Saba, British Virgin Islands, Cayman Islands, Dominica, Falkland Islands (Malvinas), Grenada, Montserrat, Saint Kitts and Nevis, Saint Lucia, Saint Pierre and Miquelon, Saint Vincent and Grenadines, Saint Maarten (Dutch part), 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 This designation is without prejudice to positions on status, and is in line with United Nations Security Council Resolution 1244/99 and the Advisory Opinion of the International Court of Justice on Kosovo's declaration of independence.

⁷ Individual data are not available and are estimated in aggregate for: Burkina Faso, Burundi, Cabo Verde, Central African Republic, Chad, Comoros, Djibouti, Gambia, Guinea, Guinea-Bissau, Lesotho, Liberia, Malawi, Mali, Mauritania, Sao Tome and Principe, Seychelles, Sierra Leone, and Somalia.

Abbreviations and acronyms

AI	Artificial intelligence
APS	Announced Pledges Scenario
ASEAN	Association of Southeast Asian Nations
BESS	battery energy storage systems
CCCI	Coal-to-Clean Credit Initiative
CCP	Core Carbon Principles
CCUS	carbon capture, utilisation and storage
CFPP	coal-fired power plant
CIWP	Continuous Improvement Work Programme
CO ₂	carbon dioxide
CO ₂ -eq	carbon dioxide equivalent
COP28	28th Conference of the Parties
CORSIA	Carbon Offsetting and Reduction Scheme for International Aviation
DNA	designated national authority
EMDE	emerging market and developing economies
ETM	Energy Transition Mechanism
ICVCM	Integrity Council for the Voluntary Carbon Market
IDB	Inter-American Development Bank
IEA	International Energy Agency
IPP	independent power producer
ITMO	internationally transferred mitigation outcome
JETP	Just Energy Transition Partnership
JUST	Joined-Up Sustainable Transition
LCOE	levelised cost of electricity
LNG	liquefied natural gas
MRV	monitoring, reporting and verification
NDC	nationally determined contribution
PACM	Paris Agreement Crediting Mechanism
PPA	power purchase agreement
PV	photovoltaic
SLTEC	South Luzon Thermal Energy Corporation
STEPS	Standard for the Transformation of the Electric Power Sector
TRACTION	Transition Credits Coalition
UN	United Nations
UNFCCC	United Nations Framework Convention on Climate Change
WEO	World Energy Outlook

International Energy Agency (IEA)

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