

From Flex to Phase-Out

Technical Report of the Coal Transition
Commission Assessing the Role of Coal Flexibility
in Accelerating Coal-to-Clean Transitions in
Emerging Markets and Developing Economies

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Foreword

Tackling coal emissions is critical to reach the temperature goal of the Paris Agreement. It is also a key opportunity for building modern, secure, and competitive energy systems, ensuring sustainable growth, energy security and sovereignty. This is the mandate given to the Coal Transition Commission: a unique initiative chaired by France and Indonesia to discuss one of the most challenging questions of the climate and energy agenda.

Delivering this transition in emerging markets is a complex challenge, which involves rewiring energy systems while expanding access, meeting fast growing energy demand, and minimising the impact on workers and communities. Energy systems are complex, very different from one country to another, and there is no “one size fits all” solution. Each country’s pathway must be nationally driven, just and aligned with socio-economic development goals

As set out in the Pact for Prosperity, People and the Planet, no country should have to choose between fighting poverty and addressing climate change. We need to find practical solutions, and this is exactly what the Coal Transition Commission has been doing over the last two years.

In 2025, the Coal Transition Commission has focused on generating solutions to two real challenges of transition, building on the first report published at COP29: how to scale up the pipeline of coal retirement projects, and how to quickly build the flexibility modern energy systems require.

This report focuses on the second question, bringing together key learnings about the steps that can be taken to build the flexibility and reliability that power systems need as they integrate variable renewables. It highlights the role that operating coal plants flexibly could play within broader coal-to-clean transition plans in certain circumstances, but also the challenges and risks and the need for strong guardrails.

This nuanced message reflects well the ethos of our joint endeavour through the Coal Transition Commission, but also the added value of international cooperation. We know that solutions for the real world are complicated and involve careful weighing of risks and opportunities but we are committed to show that there is a pathway forwards.

We must now move to implementation. We stand ready to work with governments and utilities who are willing to take advantage of the opportunities that have been demonstrated and to support them to build country- and context-driven roadmaps, to address technical challenges and fiscal constraints and to build international support mechanisms.

The Coal Transition Commission’s members together constitute a remarkable reservoir of experience, expertise and resources that can be harnessed to help design and help deliver practical roadmaps for transition, tailored to the varied challenges coal-dependent economies face. Together we can accelerate progress towards cleaner, more secure and affordable energy systems. As we celebrate the 10th anniversary of the Paris Agreement, this fits perfectly with the collective ambition to make COP30 an “implementation COP”.



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We would like to express our sincere thanks to TransitionZero for conducting the technical analysis that underpins this report and for gathering and organising the experiences and reflections of those who took part in the consultations. The lead author of this report is Isabella Suarez (TransitionZero), with support from Binu Jeyakumar (Powering Past Coal Alliance). Technical modelling and research were conducted by Thu Vu, Daniel Welsby, Abhishek Shivakumar, and Handriyanti Diah Puspitarini.

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While the authors and the Secretariat of the CTC have done their best to reflect the valuable insights provided by these organisations, we recognise that our efforts have been at best partial. The final text of the report has been prepared by the Secretariat of the CTC and should not be taken as representing the views of any of the above organisations.

Executive Summary

In November 2024, the Coal Transition Commission, co-chaired by France and Indonesia, published a report, 'Accelerating Coal-to-Clean Energy Transitions,' which set out the key steps that can be taken to enable an accelerated and just transition from coal to clean power. In the report, analysis by the International Energy Agency (IEA) suggested that early retirement of coal assets is the most critical long-term lever to reduce coal power emissions over time, and that there is also a significant role for repurposing of coal power plants for flexibility especially in emerging economies in the near term. It therefore recommended further study of coal flexibility, which is less well understood.

This technical report uses emerging experience and analyses to examine the role that flexible operation of coal power plants can play in the broader coal-to-clean transition. It concludes that coal flexibility can play a useful near-term transitional role in scaling up renewables and supporting the long-term phase-out of unabated coal power in certain circumstances if deployed with robust guardrails. It is especially relevant in coal-dependent emerging economies facing challenges with capacity constraints alongside rapid demand growth and limited near-term alternatives for flexibility. However, there are limitations and barriers to coal flexibility, especially in contexts where long-term power purchase agreements incentivise high levels of utilisation of coal-fired power plants. There may also be significant costs associated with implementation and, if appropriate guardrails are not in place, there are risks of unduly extending the life of coal power plants or diverting resources from more impactful investments in clean energy. As such coal flexibility is likely not a fleet-wide strategy and should be considered carefully on an asset-by-asset basis within a holistic transition plan deploying a broader set of levers.

Accelerating the transition from coal to clean energy is critical to avoiding the worst impacts of climate change, unlocking economic development, and delivering energy security. A growing number of emerging market and developing economies (EMDEs) are exploring how to accelerate their transitions from coal to clean energy sources and engaging with technical and financing partners on tools that can be deployed.

The Coal Transition Commission's 2024 report identified two primary ways to reduce emissions from coal-fired power plants: early retirement and repurposing for flexibility. Based on analysis by the IEA, the 2024 report indicated that while early retirement is the most important lever for reducing emissions in line with a 1.5°C aligned pathway, there is also a role for repurposing coal power plants to operate more flexibly, especially in the near term in EMDEs. The benefits, challenges and costs of the early retirement of coal-fired power stations and replacement with clean energy have been well explored; the use cases for coal flexibility are much less well understood. This technical report was therefore undertaken to explore the issue of coal flexibility in greater depth.

Increasing power system flexibility is a key element of delivering a successful transition. The variability of wind and solar places new demands on power systems as they strive to balance supply and demand in real time by absorbing surpluses and responding rapidly to shortfalls. Without sufficient flexibility, there is the risk that the system is unable to absorb the energy generated by renewables at times when total supply exceeds total demand, resulting in higher curtailment of wind and solar resources and higher system costs. Flexibility can come from various sources, including dispatchable power such as geothermal that can ramp power production up or down, energy

storage such as batteries and pumped storage hydro, demand-side management, and cross-border transmission. While coal has some flexibility to dispatch, coal power plants can also be adapted operationally or through retrofits to more easily increase and decrease generation rapidly, providing flexibility rather than traditional baseload generation.

In emerging economies which are heavily coal dependent for generation, reduced and flexible operation of some coal plants could support a more rapid transition to alternative clean sources of energy. While operating coal plants flexibly is less reliable and much higher emitting than using clean alternatives such as storage and cross-border transmission in the long term, it can play a near-term role in the transition. It may be an option to consider particularly for systems with significant near-term growth of wind and solar, with temporary grid congestion, with high demand growth or without other alternatives for flexibility currently available.

However, there are significant challenges and risks with implementing coal flexibility. In many emerging market economies, coal plants operate as baseload and are often covered by long-term Power Purchase Agreements (PPAs), which are structured to incentivise high or constant use. Addressing this to enable flexibility requires engagement with coal plant owners and operators to develop new contractual arrangements and operational protocols. Such renegotiations may require some refinancing or alternative compensation schemes to compensate for loss of revenue, and additional investments may be needed for retrofitting and other costs associated with coal flexibility. The financing required may be challenging to secure because many financing partners are seeking to reduce exposure to high emitting sectors like coal, and a plant that can be operated flexibly presents an uncertain emissions profile. The investment in coal flexibility may risk prolonging the operation of coal capacity or diverting resources and investment away from clean energy solutions that can provide more sustainable and reliable flexibility.

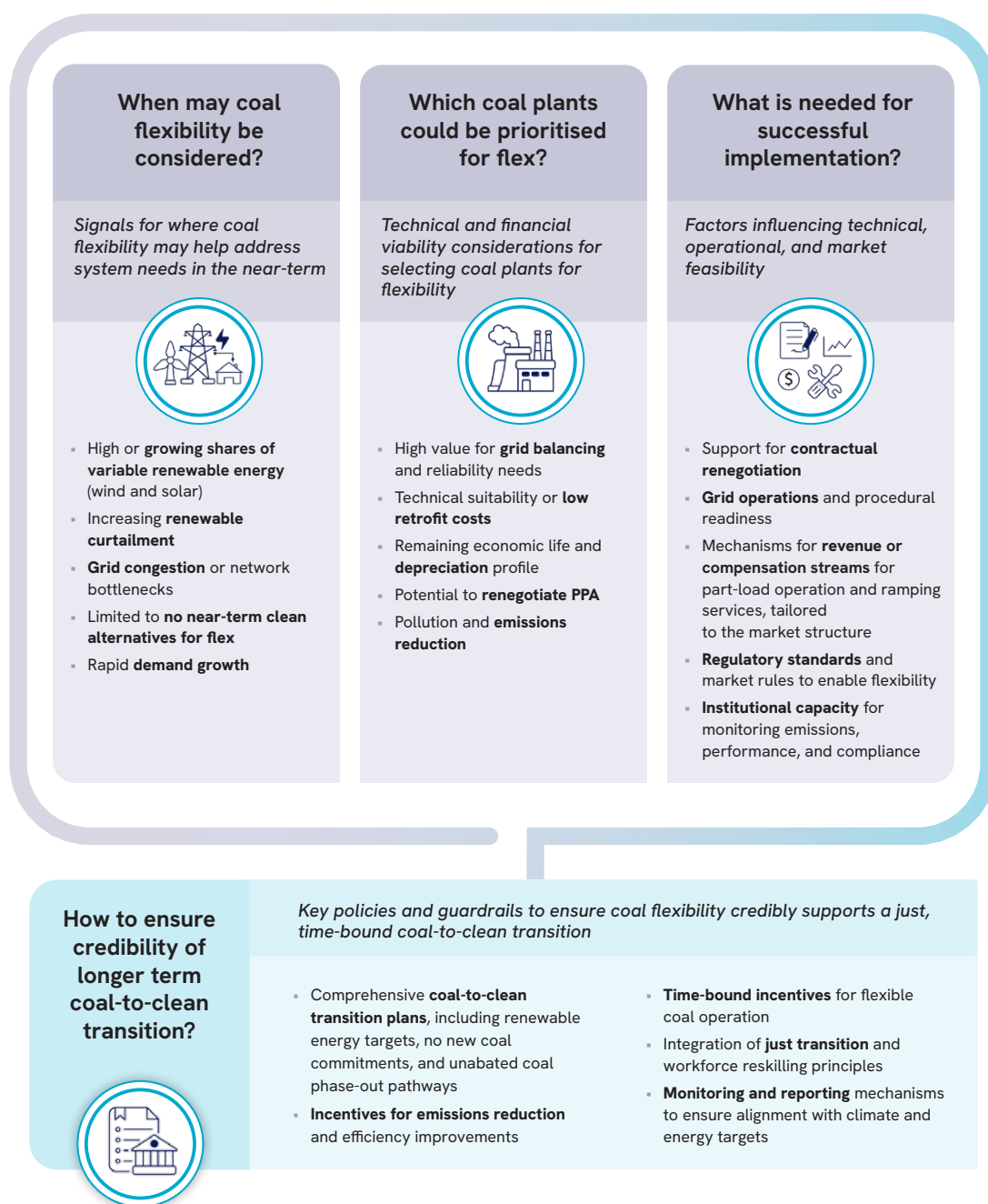
More broadly, there are practical operational measures and technical interventions that system operators need to pursue. These are likely to differ at country level, but may include updating grid codes to establish specific ramp rates, minimum load thresholds and start-up time standards to institutionalise flexibility expectations. System operators may also develop dedicated ancillary services to procure load-following, frequency regulation and reserve capacity from plants that meet defined operational and emissions standards. This will first require more sophisticated, country-specific modelling to assess the full system costs and benefits of coal flexibility. Many of these measures are needed to facilitate flexibility in general, regardless of the technology pathway being used for flexibility.

Policy and regulatory guardrails can help policymakers and system operators address some of the risks and challenges associated with coal flexibility. Where coal flexibility is found to be a relevant lever for the overall transition, governments need to ensure that coal flexibility accelerates, rather than delays, the coal-to-clean transition. International finance also needs sufficient certainty of the emissions reduction, which can only be provided by effective guardrails. These guardrails may include robust eligibility criteria to ensure coal flexibility is used only when less-emitting, cost-effective alternatives are not available; incentives to reduce emissions; binding sunset timelines for coal flexibility; firm commitments to no new coal and full phase-out of unabated coal; and transparent systems for monitoring and reporting. Support and consideration for the just transition of workers and affected communities must also be incorporated in the development of these guardrails.

Summary of recommendations

This report makes a series of recommendations to help policymakers assess the applicability of repurposing coal power plants for flexibility in emerging markets, to facilitate its viability, and to use it where it can be a tool to deliver accelerated transitions away from unabated coal power. The figure below outlines the key considerations for decision-makers assessing and implementing coal flexibility in the context of broader transition efforts.

Considerations for assessing and implementing coal flexibility in a coal-to-clean transition



Recommendation one: National governments can implement measures to ensure that the market and system architecture supports flexibility in the power sector from a variety of sources. This may include reforms to grid codes, creation of compensation mechanisms or markets for additional services to the grid beyond generation of energy (e.g. frequency regulation that helps with grid reliability), and integration of financing mechanisms (e.g. carefully designed capacity payments that reward availability without providing overcompensation) to sustain investment in flexible capacity. Such measures can be implemented in a technology-agnostic manner while prioritising cost-effectiveness, and can then support not only coal flexibility but also the deployment of other solutions such as energy storage.

Recommendation two: National governments or utilities planning to use coal flexibility within broader coal-to-clean transition plans should link flexibility interventions to plans for no new coal and coal phase-out, emission reduction guardrails and just transition measures. To mitigate the risks of extending the life of coal power plants and crowding out clean alternatives, measures to support coal flexibility should be paired with a commitment to no new unabated coal power, a clear emissions reduction trajectory or binding retirement year for the plants, and a broader plan for phasing out unabated coal power. This ensures that flexibility is a transitional tool, not an operational status quo. Retirement schedules should be publicly disclosed, monitored and subjected to independent review. Transparent reporting and monitoring, along with broad engagement on the prioritisation plans with regulators, system operators, asset owners, finance and civil society is essential for credibility and accountability. Support for coal flexibility should be linked to emissions performance, and should decline as the clean solutions for flexibility ramp up. In addition, linking these plans and measures to just transition also helps mitigate the impacts of reduced use of coal while preparing workers and communities for the broader coal-to-clean transition.

Recommendation three: National governments or utilities planning to use coal flexibility within broader coal-to-clean transition plans should consider focusing flexibility retrofits only on coal plants that offer the greatest system value at lowest costs. For example, plants located near renewable generation, with contracts that are amenable to renegotiation, requiring minimal modification to operate flexibly are good candidates. This approach helps avoid locking in high-emitting assets and prevents crowding out clean alternatives such as renewables and storage. For the targeted plants, the governments may consider directly supporting contract renegotiations where needed and in a cost-effective manner.

Recommendation four: Investors seeking climate impact could consider investing in repurposing for flexibility, but only where very robust guardrails are in place. Analysis in this report suggests that repurposing coal power plants for flexibility can play an important role in accelerating coal-to-clean transitions where extensive conditions are met (including those provided in recommendations one and two above). However, very robust guardrails would be essential. At the national level, these may include no new coal commitments, unabated coal phase-out plans, and credible energy transition pathways. More specifically, guardrails should address the selection of plants, link to retirement dates, and quantify baselines and emissions pathways to help manage associated risks.

Recommendation five: Commission participants might consider further work through the Coal Transition Commission to facilitate the development of repurposing coal plants for flexibility as an effective tool to accelerate coal-to-clean transitions. Specific activities the CTC could consider over the next two years might include:

- Collaborate with interested governments to conduct further analysis on the role that coal flexibility can play in coal transition plans, its impacts on costs and emissions, and the context-dependent financing strategies that can be deployed.
- Share lessons learnt from existing pilot projects on the technical, regulatory, financial and just transition measures employed to implement coal flexibility and support the identification of additional pilot projects.
- Work with national governments and financing partners to further develop guidance on guardrails and best practices for policy and regulatory solutions which will enable coal flexibility while ensuring that the pathway from “flex” to “phase-out” is viable, credible, irreversible and compatible with both national energy plans and international climate commitments.

CHAPTER 1

Background

Across the globe, the power sector is undergoing a fundamental shift. Falling costs of solar, wind and storage technologies, combined with rising electrification, and the imperative to reduce emissions, are transforming how electricity is produced and consumed. For many countries this shift involves not only modernisation of the power sector but also a transition away from unabated coal towards clean energy sources. A well-planned coal-to-clean transition offers multiple dividends: significant emissions reductions, improved public health outcomes, enhanced access to electricity, and more affordable and reliable power over time.

Recognising the important role of the emissions reduction from the coal-to-clean transition in achieving the Paris Agreement goal of limiting global temperature rise to 1.5°C, the Coal Transition Commission (CTC) published its first report in November 2024, *Accelerating Coal-to-Clean Energy Transitions*. The report set out practical recommendations to accelerate global coal transitions and identified two key measures to reduce emissions from coal-fired power plants: the early retirement of coal plants and their repurposing for flexibility.

Early retirement is the most important long-term lever, representing two-thirds of the necessary emissions reductions in a 1.5°C-consistent pathway. However, considering the limited experience and clarity regarding the applicability and viability of coal flexibility, the Commission issued the following recommendation in its 2024 report:

“Recommendation one: *Further work should be undertaken by the IEA and other relevant technical bodies to provide guidance—and develop practical experience—on how and when to most effectively deploy the different policy levers available to reduce emissions from existing coal power plants.*”

This report responds to that recommendation by examining the potential role of coal flexibility in emerging markets and developing economies (EMDEs), with a particular focus on Southeast Asia. It assesses when and where coal flexibility may be appropriate, the enabling conditions required for its implementation, and how its use can be aligned with broader coal-to-clean transition and just transition objectives.

1.1 The growing need for flexibility in the energy transition

To deliver accelerated coal-to-clean transitions, countries face the dual challenge of reducing emissions from coal power plants and rapidly scaling up supply from alternative sources to meet rising demand while maintaining energy security. But as the share of renewable power from variable sources such as wind and solar grows, so does the complexity of managing supply and demand. That, in turn, requires new forms of flexibility, which is the ability of power systems to balance supply and

demand through the day and across seasons. The IEA has highlighted the rising need for flexibility as renewable penetration increases, especially once wind and solar exceed around 30% of generation.¹

A portfolio of tools and technologies can deliver this flexibility, including energy storage, transmission, distributed energy resources, demand-side management and dispatchable generation, i.e. generation that can be called on to ramp up or down as needed such as geothermal and hydropower. Countries that have completed or are at advanced stages of coal phase-out – such as the UK, China, Chile and France – have used such tools to maintain security of energy supply while reducing emissions and air pollution. In many cases, this portfolio approach that looks at the whole system has also delivered cost savings, underscoring that no single solution is sufficient but that a mix of measures can successfully replace coal while keeping power secure and affordable.

In emerging economies, the need to ramp up renewables rapidly – and the flexibility that they require – is especially pressing as their electricity demand is rising more rapidly than in the rest of the world, driven by industrialisation, population growth, residential cooling and electrification. By 2027, emerging economies will account for 85% of global growth in electricity demand, according to the IEA.²

However, the full portfolio of solutions for flexibility may not be readily available in the near-term in many EMDEs. For example, EMDEs will need around US\$300 billion/year in investment for transmission and distribution, accounting for half the global investment need,³ as a result of higher-voltage lines being constructed for the first time in many cases. Similarly, significant changes to regulations and upgrades to system operation and distribution infrastructure, such as metering devices, are still needed to unlock some of the demand-side measures. At the same time as grid infrastructure investment, regulatory changes and other steps are taken to unlock these solutions, there may be a near-term role for using existing coal plants for flexibility to enable renewables integration and the broader transition from coal to clean.

1.2 Understanding coal flexibility

Coal flexibility is defined as the ability of coal-fired power plants (CFPPs) to operate reliably at varying load levels and to respond dynamically to system requirements. Unlike traditional baseload operation, where plants run continuously at or near full capacity, flexible operation allows coal plants to increase or decrease generation output more quickly in response to fluctuations in grid demand and variable renewable energy (VRE) output across hours in the day and seasons in the year. Coal flexibility measures do not necessarily constitute as abatement, unless they are explicitly combined with abatement technologies such as carbon capture utilisation and storage (CCUS).

¹ International Energy Agency, Integrating Solar and Wind, 2024

² International Energy Agency, Electricity 2025: Analysis and Forecast to 2027, 2025

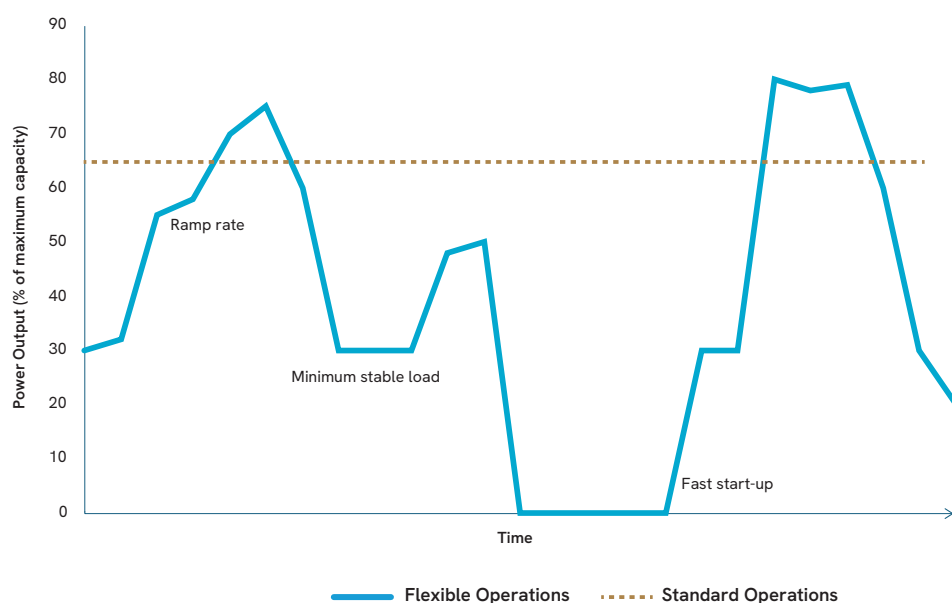
³ International Energy Agency, Electricity Grids and Secure Energy Transitions, 2023

Intra-day flexibility

Most coal plants have some degree of operational flexibility, though their capabilities vary depending on design, age and maintenance. There are three technical parameters that determine how flexibly a CFPP can operate within daily system needs:

- i. **Minimum load** is the lowest output level at which the coal unit can operate stably. Lower minimum loads allow units to remain online while allowing renewables to provide more energy and to ramp up faster compared to a cold start when needed.
- ii. **Ramp rate** is the speed at which a unit can increase or decrease its output, usually measured as a percentage of nominal load per minute. Faster ramping improves the unit's ability to respond to variabilities in renewable energy generation.
- iii. **Start-up time** is the time required to bring a unit from shutdown to part load. This varies depending on whether the plant is starting cold (shutdown for more than 48 hours) or hot (shutdown for less than 8 hours). The shorter the start-up time, the easier it would be for the coal unit to cover sudden VRE shortfalls.

Figure 1. Illustration of technical parameters for coal flexibility



Source: Adapted from Grzeszczak, Jan & Grela, Łukasz & Achter, Thomas. (2017). Environmentally Friendly Replacement of Mature 200 MW Coal-Fired Power Blocks with 2 Boilers Working on One 500 MW Class Steam Turbine Generator (2on1 Unit Concept). Archives of Thermodynamics. 38. 10.1515/aoter-2017-0030.

Retrofitting to improve these parameters usually focuses on lowering the minimum load, enhancing ramp rates and shortening start-up times.⁴ These improvements enable CFPPs to provide load-following support, contribute to grid balancing, and reduce solar and wind curtailment.

However, it is not a long-term solution for a transition to clean energy, as keeping units on “hot standby” – that is, running at low output to remain online and ready to ramp up quickly – still requires burning fuel and therefore produces emissions. Moreover, the inherent technical limitations of unabated coal units prevent them from achieving the rapid ramping rates needed to reliably serve as peaking power in response to immediate or unanticipated demand.

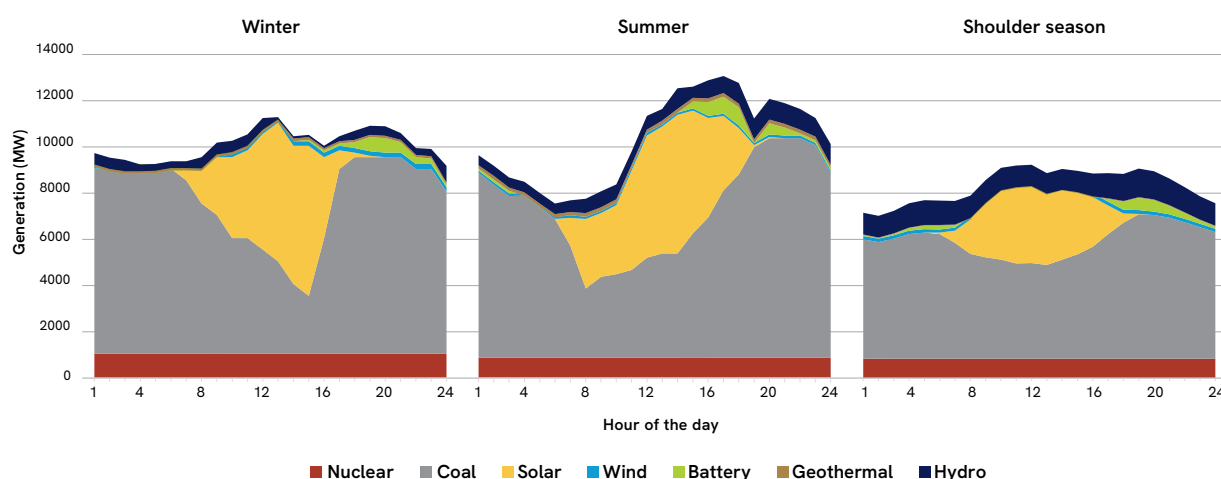
Seasonal coal flexibility

Adjusting coal power output to match seasonal variations in energy demand and the supply of renewable sources like wind and solar across the year can also be considered another mode of flexibility. This can mean running plants more during dry seasons when hydro output is low, and less during windy monsoon months, when wind power is abundant.

Unlike intra-day flexibility, such operations generally do not require retrofits or modifications to existing plants. In some cases, existing plants already operate in this way. However, it may have significant implications on plants with power purchase agreements (PPAs) or contracts, as this would entail lowering capacity factors or utilisation, which many compensation mechanisms are tied to.

A consistently low capacity factor may be an indication of an uneconomical plant or one that is not needed, except possibly for peak demand. Where plant operations can dip with new renewables, this type of flexibility might be a prelude to retirement.

Figure 2. Illustration of intra-day and seasonal coal flexibility



Source: Data for illustrative purposes only.

⁴ Common retrofit options to improve the operational flexibility of coal-fired power plants include modifications to the boiler, turbine, and control systems. Specific measures comprise (i) mill and burner upgrades to allow faster load changes and stable combustion at lower loads; (ii) turbine bypass or sliding pressure operation to widen the load range; (iii) enhanced control systems for coordinated boiler-turbine response; and (iv) improved air and flue gas handling to mitigate corrosion risks during low-load operation. Modeling studies of 200–225 MWe drum-type units demonstrate that such retrofits can enable load reductions from the typical 60% technical minimum to around 40% of rated capacity, though this is accompanied by a 1–2 percentage point efficiency loss and increased thermal stress on components.

1.3 System and plant conditions where coal flexibility contributes to reliability and renewables integration

Given the grid services that flexible coal plants can provide, coal flexibility can help maintain a reliable power supply while supporting the integration of renewable energy. An in-depth assessment and review of related literature and case studies found that the relevance of coal flexibility varies by context, depending on the structure and needs of the power system. It is generally relevant in power systems that exhibit a combination of the following characteristics:

- i. **Significant or growing shares of variable renewables such as wind and solar:** In systems where variable renewable energy (VRE) from wind and solar is substantial – or where credible near-term expansion plans exist – greater system flexibility may be needed to integrate VRE effectively. At lower levels of renewable penetration, existing grid flexibility is likely sufficient. However, where VRE has increased to the point of being frequently curtailed due to inflexible generation, operating coal plants flexibly can help the grid absorb more renewables and reduce energy losses.
- ii. **Grid congestion and curtailment:** Curtailment occurs when electricity cannot be delivered from where it is generated to where it is needed, often due to transmission constraints or inflexible generation on the system. This can lead to the underuse of available capacity – whether from renewables, thermal power or other sources. In such cases, additional system flexibility is required to optimise resource use and avoid unnecessary losses. Coal flexibility can provide interim balancing while grid and infrastructure upgrades are under way to connect new and existing capacity, provided there is a credible plan and timeline for resolving these constraints.
- iii. **Limited alternative sources of flexibility:** In systems with little or no dispatchable power generation, limited hydropower, underdeveloped demand-side response, and minimal transmission or interconnection capacity, coal plants may be one of the very few near-term flexibility resources available.
- iv. **High demand growth with near-term capacity gaps:** When the demand for electricity is expected to grow rapidly – as it is in most emerging economies – there is an urgent need to make sure there is enough generation capacity on the grid. In cases where the immediate development of new generation sources is slow, there may be a near-term option to operate a few coal plants flexibly to meet the increasing demand while allowing renewables to generate, provided there are credible plans to develop the alternative sources promptly.
- v. **Coal plants with technical potential and limited retrofitting needs:** In some countries, coal fleets include units with the technical capabilities for flexible operation – such as low minimum loads, fast ramp rates and short start-up times. If minimal investment is needed to retrofit or reconfigure these assets, coal flexibility may offer a cost-effective, short-term option. In other cases, plants may be run flexibly without significant retrofitting costs or limited upgrades. This will need to be considered at the asset-level, rather than as a fleet-wide application. Whether it is technically feasible and economically viable will vary by plant. These options are further explored in Chapter 2: Economic and Financial Considerations in Implementing Coal Plant Flexibility.

Case Study: Chile's experience in coal plant minimum load and the implementation pathway to achieve it

Chile's energy transition has been driven by a combination of technological innovation, policy frameworks and diversified energy sources, among which the flexibilisation of coal-fired power plants has also played a role. The country has progressively reduced the minimum load of its coal fleet from 30–60% down to 20–35% of nominal capacity, placing its plants among the most flexible worldwide. This adjustment has allowed coal units to provide grid services⁵ while generating less energy during periods of high wind and solar output, reducing renewable curtailment, system costs and system-wide emissions.

These reductions were achieved independently by private operators, without dedicated policy incentives for flexibilisation. The shift was largely driven by operational pressures: higher cycling from increased renewable penetration was raising maintenance costs and failure rates. Lowering minimum loads (MLs) allowed operators to mitigate these issues while improving the competitiveness of their plants compared to less flexible thermal units.

To further assess potential of coal flexibility in Chile, a techno-economic modelling study was carried out to assess the impact of further reducing the minimum load of coal and gas units. The study identified that under an aggressive flexibility scenario the

overall thermal generation was expected to decrease by around 5%, including a 42% drop in out-of-merit coal power dispatch. This translated into savings of about US\$63 million in side-payments in 2027, renewable curtailment reductions of over 600 GWh and CO₂ emissions lowered by nearly 2%. Notably, the changes would be marginal compared to the current MLs of some units. As a result, while the system benefits from lower MLs, the overall impact is limited. The reduction in the ML of coal- and gas-fired power plants would lead to a 1–5% decrease in thermal generation by 2027.

The estimated cost of implementation is US\$6–24 million for the entire Chilean coal fleet – well below the projected savings. Coal power flexibilisation emerges as a cost-effective transitional tool, where it has been designed to enhance renewable integration, reduce curtailment, and deliver lower emissions and consumer benefits under clear policy and regulatory oversight.

The results of the study can be found in a case study by GIZ.⁶

Coal flexibility has been effective in Chile because the country's power system combines high renewable penetration with a diversified generation mix, market mechanisms that reward flexible operation, and prior investments that lowered coal plants' minimum loads – creating an enabling environment for managing variability while maintaining system reliability and affordability. Any flexibilisation strategy should be carefully tailored to the specific context to most effectively support renewable energy integration and enable cost reduction.

⁵ Grid services can include inertia, voltage control, and frequency regulation, as variable renewable sources already deployed were not yet fully capable of delivering these services.

⁶ GIZ and Inodú, Impact of Thermal Flexibility on the Operational Performance of Chile's Power System, 2025.

1.4 Risks introduced with the use of coal flexibility

While coal flexibility can be a useful strategy under the conditions outlined above, its usage – if not accompanied by mitigating measures – can create additional risks, both at the plant level and at the system level.

Reliability and outage risk

Cycling coal plants more frequently increases the probability of forced outages. Repeated thermal stress from ramping and low-load operations accelerates component fatigue – especially in boilers, turbines and steam piping – raising the likelihood of sudden failures. Coal plants often represent sizeable capacity, so unexpected downtime can have a disproportionate impact on reserve margins and system reliability. For system operators, this means higher uncertainty around availability, requiring additional reserves or backup resources to maintain reliability. This is a particularly acute issue in India, where the large, relatively young coal units dominate capacity and outages can sharply reduce reserve margins.^{7,8} In the United States, analysis by NREL found that cycling coal plants led to cost increases of \$0.50–\$4.00 per MWh, higher forced outage rates and shortened component lifespans.⁹

Efficiency trade-off

Operating coal plants flexibly reduces thermodynamic efficiency, leading to higher emissions per unit of electricity generated. A study of a 225 MW unit in Poland found that lowering output from 60% to 40% reduced gross efficiency by more than three percentage points, while also lowering steam temperatures and altering flue-gas conditions in ways that heighten corrosion risk. These impacts to equipment can also reduce the long-term efficiency of the unit. Such declines in efficiency not only raise fuel costs but also increase emissions intensity, i.e. emissions measured per unit of energy generated.

Uncertain emissions impact

The climate benefits of coal flexibility are not guaranteed. A coal plant operating flexibly continues to generate an unpredictable level of emissions, unlike one that has been fully retired. At the plant level, coal flexibility only results in emission reductions if usage meaningfully declines. The extent of reduction required depends on the plant's technology and efficiency, and the technology that comes in to replace it. This underscores the need for technical assessments to evaluate when and where flex is incorporated as a solution in transition plans. It is also important to ensure that the total system emissions can be credibly reduced, not merely shifted in timing or location. The broader impact on the electricity system will hinge on replacement generation sources and the market and operational incentives in place. Without sufficient renewable energy integration, flexible operation may simply be substituted by other coal or fossil fuel plants.

⁷ USAID, Grid Integration of Renewable Energy in India: Lessons Learned and Best Practices, 2020

⁸ Brookings India, Coal Power and the Grid in India: Flexible Operation and Future Outlook, 2020

⁹ National Renewable Energy Laboratory, Power Plant Cycling Costs, 2012

Moreover, flexibly operated coal units remain a significant source of air pollutants such as particulate matter, sulphur dioxide and nitrogen oxides. Release of these pollutants increases at lower loads, due to less efficient combustion and degraded performance of control equipment like flue gas desulphurisation units and electrostatic precipitators.¹⁰

Coal power plant lifetime extension and risk to energy transition

Positioning coal flexibility as an integral system solution may inadvertently prolong the economic life of coal assets. Furthermore, the required flexibility retrofits and associated costs could potentially strengthen the case for extending plant operation beyond original retirement schedules. Prolonging coal asset lifetimes risks delaying investment and grid space for clean alternatives, as continued coal operations can crowd out renewables in dispatch and divert financial, technical and policy resources away from developing low-carbon flexibility solutions. Without clear policy and regulatory frameworks tying flexibility measures to phase-out timelines, coal flexibility could undermine long-term transition objectives.

Crowding out clean energy and balancing solutions

Keeping coal plants online for too long risks displacing the generation capacity that would otherwise be filled by clean energy sources. Additional investment in coal flexibility can also divert capital away from more sustainable long-term solutions – such as storage, interconnections, demand-side resources or other low-carbon flexibility options.

This risk underscores the importance of clear long-term planning: without it, short-term reliance on coal flexibility may inadvertently slow the scale-up of the very solutions needed to secure a resilient, low-carbon power system.

Diminishing returns of coal flex

Coal flexibility could deliver its greatest value at the margin – the first few units made flexible might provide valuable system balancing benefits by accommodating VRE variability. However, once enough flexible capacity is online, the incremental value of additional flexible CFPPs declines sharply. Beyond a certain point, keeping more units on standby mode adds limited operational benefit while still imposing efficiency penalties, higher costs and emissions risks.

The above risks underscore the importance of approaching coal flexibility as a carefully bounded transitional measure. Without guardrails, there is the risk of undermining reliability, straining system reserves and diluting the emissions benefits of renewable energy integration. Successful implementation must be paired with strengthened maintenance regimes, clear retirement timelines and parallel investment in clean forms of flexibility – such as storage, demand response and grid interconnection.

To understand what successful implementation of coal flexibility entails, the following chapter explores the economic and financial considerations that are necessary to enable coal flexibility.

¹⁰ International Energy Agency, Status of Power System Transformation, 2018

Case Study: Coal flexibility simulation in Malaysia

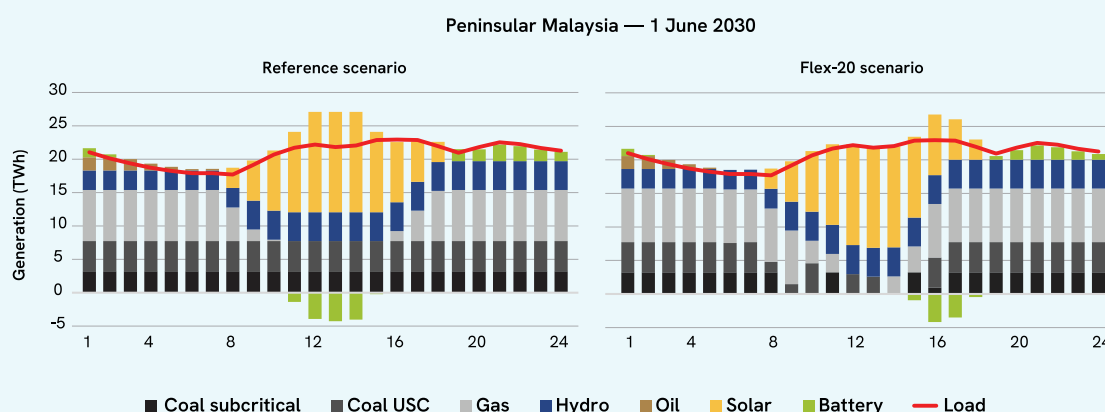
With 13.3 GW of installed capacity, Malaysia's coal fleet has reached its peak, with no further greenfield developments in the pipeline in accordance with national policies. The government's coal phase-out roadmap targets full retirement of the fleet by 2044, with half of the capacity scheduled for retirement by 2035 as their PPAs expire.

Dispatch model simulations conducted by TransitionZero suggest that coal flexibility may have limited impact in driving a coal-to-clean transition in Peninsular Malaysia, given rapid electricity demand growth and the fossil fuel-heavy structure of the supply mix. Specifically, by 2030, the Peninsular grid is expected to remain dominated by coal and gas generators, with solar as the only renewable option available for significant scale-up. In the absence of additional clean resources – through either accelerated domestic deployment or imports – curtailing coal units alone will not trigger meaningful coal-to-clean switching. Instead, reduced

coal output is likely to be offset by higher gas dispatch.

As illustrated in Figure 3, under the Reference Scenario, the coal fleet operates as baseload, maintaining constant generation throughout the day on the sampling day of 1 June 2030. In the Flex-20 Scenario – where annual coal generation is curtailed by 20% relative to the Reference Scenario – gas output increases by 30% to compensate. Solar generation remains unchanged across both scenarios, as it is already fully utilised, though shifts in battery charging and discharging hours are observed due to reduced coal availability during solar peak hours. In both cases, solar build-out reaches the maximum modelled limit of nearly 26 GW installed capacity. This underscores solar power's cost-effectiveness and technical feasibility for solar integration. However, it also reveals a critical policy gap – the modelled solar capacity far exceeds Malaysia's current target of 7 GW by 2030. Without more ambitious renewable deployment, coal ramp-down risks driving deeper reliance on gas.

Figure 3. Sample hourly dispatch under Reference and Flex-20 scenarios in Peninsular Malaysia



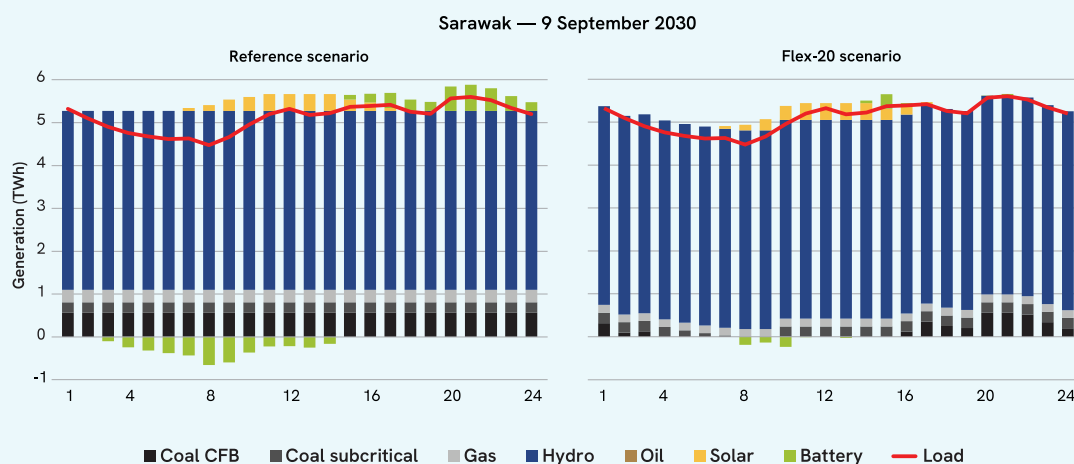
Source: Preliminary modelling results by TransitionZero (2025)

By contrast, simulations for Sarawak show far greater energy transition potential. By 2030, the region's coal capacity declines to 894 MW following the scheduled retirement of the Sejingkat coal station in 2028. Owing to the limited role of coal in the power mix – accounting for less than 10% of total installed capacity in the simulation – and the availability of clean alternatives at scale such as hydropower and solar, coal flexibility enables more direct coal-to-clean substitution. For instance, on the sampling day of 9 September 2030, under the Flex-20 Scenario, as coal generation is curtailed by 56% compared to the Reference Scenario, the system draws almost entirely on its abundant hydropower to replace the shortfall.

The study underscores that the effectiveness of coal flexibility in enabling a clean

transition heavily depends on the power system at stake, its broader supply mix and availability of clean alternatives. In Peninsular Malaysia, a credible coal-to-clean pathway will require coal ramp-down to be paired with robust emissions constraints and renewable obligations. Without such policy signals, cost-based system optimisation will simply substitute curtailed coal with other thermal sources, delivering limited emissions reductions while failing to incentivise clean energy adoption. Policy tools such as emissions caps, carbon pricing or mandatory clean energy replacement will be critical. Malaysia's planned introduction of a carbon tax in 2026 could help drive this transition, though further simulations are needed to determine the optimal tax range to effectively discourage "emissions leakages" through coal-to-gas switching.

Figure 4. Sample hourly dispatch under Reference and Flex-20 scenarios in Sarawak Malaysia



Source: Preliminary modelling results by TransitionZero (2025)

CHAPTER 2

Economic and Financial Considerations in Implementing Coal Plant Flexibility

The role of coal flexibility in coal-to-clean transitions depends not only on its technical feasibility and system need, but also on its economic and financial costs. Retrofitting plants, renegotiating contracts, adjusting dispatch practices and ensuring operational readiness all involve costs and risks. These must be weighed against both the near-term benefits of facilitating renewable energy integration and the longer-term contribution to each country's energy transition pathway.

As discussed in Chapter 1, CFPPs were designed for steady baseload operation. Repurposing them to deliver flexible services comes with significant trade-offs. These include direct costs such as capital expenditure for retrofits and higher operations and maintenance (O&M) requirements, as well as indirect costs such as forgone revenues from reduced generation hours or the complexities of contractual renegotiation.

This chapter explores the economic, contractual and financial dimensions of coal flexibility: the scale and nature of known costs; the implications for plant owners and system operators; the role of regulatory and market design; and the financing sources and instruments that governments, regulators and system operators might consider if they choose to pursue coal flexibility as a transitional tool.

2.1 Direct costs of flexible operations

The costs of coal flexibility extend beyond the initial outlay. The most immediate are the direct costs: operational expenses, which accrue over the remaining life of a plant, and investment costs, which arise when technical retrofits are required. In addition, there are indirect costs that can be equally significant. These include efficiency losses and higher fuel consumption when operating at part load, accelerated wear and tear leading to more frequent maintenance, and heightened risks of corrosion, leakage and pollution-control system failures.

The following subsections examine each of these categories in turn, highlighting both the technical underpinnings and the financial risks associated with flexible operation.

Retrofit and control system costs

Boiler and turbine retrofits are among the main measures used to improve the flexibility of CFPPs. Adaptation requires investment in advanced control systems, real-time sensors, fuel-flow monitoring and predictive-maintenance software. In some cases, dual firing – such as co-firing with biomass or trials with ammonia – is being considered to cut emissions while improving flexibility. However, these are costly interventions that deliver limited emissions reductions compared to a more decisive early retirement of coal assets.

Retrofitting plants for flexibility can be costly. For a typical 600 MW unit, reducing the minimum load may cost around US\$1.9 million, while improving ramping speed can cost between US\$160,000 to US\$425,000.¹¹ Vietnam Electricity (EVN), for example, launched pilot projects at the 1,200 MW Vinh Tan 4 plant to test digital upgrades and mill-modulation systems designed to improve ramp rates. Early results show improved responsiveness, though the retrofit costs several million US dollars per unit.

The age of a plant is a key factor in determining retrofit feasibility and cost: older units may require more extensive and costly modifications to operate flexibly, while newer plants can typically adapt more easily. For example, modelling of an almost 40-year-old 225 MWe unit in Poland found that operating below 60% load caused steep efficiency losses and corrosion risks, making deep retrofits uneconomic compared with early retirement.

Table 1 provides indicative costs per unit. Many items – such as digital automation systems – fall within a similar cost range across plants regardless of unit size, since software can be standardised even if larger units require additional sensors. This suggests that while the scale of retrofits may differ, much of the cost structure is transferable across different plants and contexts.

Increased operational costs and equipment stress

While Chapter 1 demonstrates that CFPPs can be operated more flexibly within defined technical limits, doing so inevitably entails higher O&M costs.

Evidence from the U.S. National Renewable Energy Laboratory (NREL) shows that frequent cycling can raise maintenance costs by a factor of two to three compared to steady-state operation. Similar risks are already evident in Southeast Asia, where operators report more unplanned outages linked to boiler-tube failures, seal leakage and other stress-induced damage. These additional costs and risks stem primarily from thermal fatigue, accelerated mechanical wear, and reduced lifetimes of high-temperature components such as superheaters, reheaters and steam turbines.

These can be mitigated through careful planning and targeted maintenance, for example, by expanding the number of scheduled maintenance intervals and deploying advanced monitoring tools such as cameras and sensors to improve predictive accuracy. Yet even these mitigation strategies carry their own costs, as they increase downtime, require additional skilled labour and necessitate new investment in digital systems.

In addition, the efficiency losses outlined in Section 1.5 also contribute to higher cost of fuel for every unit of energy generated.

Insurance costs

Operating outside design specifications not only jeopardises technical performance but may invalidate insurance coverage or raise premiums. Insurers view off-design cycling regimes as elevating risk profiles due to higher likelihoods of forced outages and failures.

Table 1 illustrates that while flexibility is technically achievable, its full cost stack must be weighed carefully against the expected continued duration of plant operation.

¹¹ Danish Energy Agency, Technology Data for the Indonesian Power Sector, 2024

Table 1. Indicative direct cost ranges for coal plant flexibility retrofits and associated expenditures

Retrofit/cost category	Description	Indicative cost range (US\$ million per unit)	Investment cost category
Digital control & automation	Upgrade control systems, sensors and analytics for faster ramping and better cycling.	1-5	Retrofit cost
Mill modulation	Modify coal mills/feeders for finer load control and quicker fuel response.	2-6	Retrofit cost
Low-load boiler optimisation	Adjust burners, air/fuel mix and heat surfaces for stable low-load operation.	1.5-4	Retrofit cost
Turbine bypass/steam cycle changes	Add or upgrade bypass systems and condensate equipment for rapid ramping.	2-7	Retrofit cost
Hybrid package	Combine digital, mill, boiler and turbine upgrades.	4-10	Retrofit cost
Balance-of-plant upgrades	Improve cooling, pumps, electrical systems or auxiliary boilers.	0.5-3	Retrofit cost
O&M cost increases	Higher wear, outages and part replacements from cycling.	2-3 x annual O&M	Operational cost
Efficiency penalties	Lower output efficiency and higher fuel use at low loads.	Market-specific	Operational cost
Insurance/warranty impacts	Higher premiums or reduced coverage for off-design operation.	Market-specific	Insurance cost
Grid compliance	Metering, SCADA and code compliance upgrades.	0.3 - 1.5	Retrofit cost

Sources: NREL (2012), *Power Plant Cycling Costs*; International Energy Agency (2024), *Coal in Net Zero Transitions*; Agora Energiewende (2017), *Flexibility in Thermal Power Plants*; Żyrkowski, M. and Żymetka, P. (2019), 'Modelling of flexible boiler operation in coal fired power plant', *IOP Conference Series: Earth and Environmental Science*, 214, 012074. doi:10.1088/1755-1315/214/1/012074; Central Electricity Authority (2023), *Operational Flexibility in Thermal Power Plants*; German Federal Ministry for Economic Affairs and Energy (2015), *Flexibility in Conventional Power Plants*; Electric Power Research Institute (2017), *Low-Load Boiler Operation Impacts*; NTPC Limited (2018), *Flexible Operation of Coal-Based Power Plants in India*; U.S. Department of Energy (2016), *Improving Ramp Rates in Fossil Steam Plants*; European Network of Transmission System Operators for Electricity (2020), *Ancillary Services and Flexibility Requirements*; ADB (2022), *Technical Guidelines for Flexible Operation of Thermal Power Plants*; NEA China (2019), *Ancillary Services Market Implementation Report*; Lloyd's Market Association (2019), *Operational Risk in Power Generation Insurance*; World Bank (2021), *Managing Operational Risks in Power Generation*; Philippines DOE (2022), *Ancillary Services Procurement Plan*.

2.2 Indirect costs: Forgone revenue, contractual barriers and compensation mechanisms

The indirect costs of coal plant flexibility extend beyond physical retrofits or higher wear-and-tear. They emerge from the financial and legal structures that underpin CFPPs. Flexible operation undermines the revenue assumptions of PPAs and fuel contracts originally designed for high usage, and may require costly renegotiations or compensation. These indirect costs can be as material as the direct investment costs, and in many cases will determine whether flexibility is financially and politically feasible.

Forgone revenues from reduced baseload generation

Flexible operation of CFPPs reduces total energy output compared with traditional baseload generation. This can erode expected revenues, particularly where PPAs are based on energy payments linked to dispatched output. Under contracts without take-or-pay clauses, plant operators are incentivised to run at higher capacity factors to maximise income and recover capital investments. By contrast, in PPAs with take-or-pay clauses, they shift the incentive to the system operator, who may choose to dispatch the plant even when not strictly necessary, since energy payments are owed regardless of actual generation.

In cases without PPAs, the impact depends on the underlying market structure. In vertically integrated systems, reduced operation primarily affects internal cost recovery within the utility rather than direct revenue loss, often requiring tariff or regulatory adjustments to maintain fiscal balance. In partially liberalised markets, where generators are exposed to a mix of contracted and merchant sales, flexible operation may lead to lower dispatch and forgone revenues unless supported by ancillary or capacity payments. In fully competitive markets, flexible operation exposes plants to price volatility – revenues from reduced baseload generation may be partly offset by opportunities to generate during high-price periods, but overall income becomes less predictable.

Moving to part-load operation or increasing cycling (frequent start-stop sequences) lowers dispatchable output, diminishing earnings under energy-linked PPAs and increasing financial risk in uncontracted or competitive markets. Where fixed-payment contracts remain in place, these dynamics may also raise system costs, as payments are triggered despite reduced usage.

Costs of contractual changes

In addition to lost revenue from reduced generation, there are structural costs associated with modifying contracts to support flexible operation. If a plant is bound by a long-term PPA or fuel supply agreement, enabling greater operational flexibility may require contractual amendments – each carrying its own cost.

Fuel supply contracts might impose penalties for early termination or reduced offtake, while changes to PPAs may require compensating plant owners for accepting a different operational profile. Such compensation could be paid upfront to offset future revenue losses. These depend not only on the structure of the original contracts, but also on local market rules and regulatory oversight, which determine whether and how renegotiations are permitted or recoverable through tariffs.

Moreover, amendments agreed for one plant may set precedents for similar claims from other generators, potentially increasing the complexity of negotiations and creating additional administrative burden for regulators and system operators. Clear and consistent frameworks are therefore essential to manage these transaction costs while avoiding unintended system-wide implications – highlighting the importance of establishing clear guardrails around any policies or pilots for implementing coal flexibility.

In short, enabling flexibility is not merely a technical or operational matter; it often involves navigating market structures and complex legal arrangements whose revision can entail significant financial consequences, and which are discussed in Section 2.3.

2.3 Contractual risks

The 2024 CTC report highlighted distinct market archetypes, each with varying readiness for coal-to-clean transitions, which suggest that the potential for implementing coal flexibility differs significantly across market types.

In deregulated markets, price signals can nudge coal generators to adjust output in response to variable renewable generation. Thus here, the main challenge for coal flexibility in such markets is economic viability. In mature competitive markets with higher renewable share and established ancillary services, coal plants can face higher costs, weaker compensation and stronger competition from clean flexibility options, making coal flexibility a marginal strategy. In emerging or less mature markets, where renewable and storage capacity remain limited, deregulation may not yet result in meaningful competitive pressure, and coal plants can continue to provide balancing services, albeit at increasing financial and environmental cost over time.

On the other hand, single-buyer or vertically integrated markets present a greater challenge. These systems lack real-time market signals and rely heavily on physical, long-term offtake arrangements in the form of PPAs, requiring more targeted interventions to introduce flexibility.

This makes the type of market critical to understanding contractual risks: in competitive markets, PPAs may coexist with spot trading opportunities that offer some room for adjustment, while in single-buyer systems, rigid PPAs often determine a large share of the revenue stream. These differences shape how costly and politically sensitive it is to introduce flexibility into existing agreements.

Coal PPAs were often designed to attract investment by insulating generators from market and operational risks, but in doing so they embedded rigidities that now constrain system operation. Policymakers may be reluctant to revisit these agreements given concerns about investor confidence and legal exposure, yet without carefully designed reforms, coal plants remain locked into inflexible baseload operation. These concerns are legitimate. Any attempt to revise contractual terms should proceed with caution and ensure that reductions in investor security are matched by appropriate compensation as necessary.

Elements of the coal PPAs

Legacy PPAs and their rigid terms remain a key barrier to introducing coal flexibility. Many of these contracts were signed before the onset of the energy transition, and their provisions are often ill-suited to the demands of a modern, renewables-integrated grid. System operators may be incentivised to dispatch coal plants at high loads, even when doing so undermines integration of VRE.

Although details vary by market and counterparty, coal PPAs exhibit several common characteristics:

PPAs as a principal source of plant revenue. CFPPs typically depend on PPAs that do not incentivise flexible operation. Wholesale and spot electricity markets are either unavailable or insufficient. Even where nascent markets exist, PPAs offer little incentive or flexibility for generators to engage outside their contractual terms. In Vietnam, for example, a spot market has been established, but existing PPAs have prevented Independent Power Producers (IPPs) from participating in the development of the market. This contributes to the perception of coal assets as low-risk, insulated investments.

Long-term contract duration. Most PPAs are signed for 25 to 30 years, often extending beyond their debt servicing period which typically spans 10 to 20 years in project-finance structures. While the PPA provides long-term revenue certainty for asset owners, it also locks offtakers into legacy terms that are difficult to renegotiate.

Two-part tariff structure. Coal PPAs often feature a two-part tariff: a capacity payment and an energy payment. Capacity payments usually cover capital recovery, fixed operating and maintenance costs, and a reasonable return on investment. These payments are availability-based and made irrespective of actual generation. Energy payments, on the other hand, compensate for variable costs such as fuel, occasionally with pass-through arrangements —where fuel-price fluctuations are borne by the offtaker.

In some cases, capacity payments are minimal or absent, with high energy payments structured to recover fixed costs, which can be combined with take-or-pay clauses that require the offtaker to pay for minimum volume of energy regardless of the actual generation. In other cases, capacity payments are set particularly high, resulting in very low marginal energy costs. This can distort dispatch incentives for the utilities or single buyers, who may opt to keep such plants running, as most of the cost is already sunk.

In both models, utilisation tends to remain high. Where energy payments are dominant, they are often paired with guaranteed run-rate clauses, further reinforcing inflexible operation. These dynamics overlap with must-run provisions, which can further restrict the system's ability to accommodate clean or cheaper alternatives.

Must-run and guaranteed offtake. Some PPAs incorporate must-run provisions or guaranteed dispatch quotas, obliging the offtaker to purchase a minimum volume of electricity from the plant. While such clauses de-risk cash flows for coal generators, they constrain system flexibility and result in the curtailment of clean or cheaper generation sources.

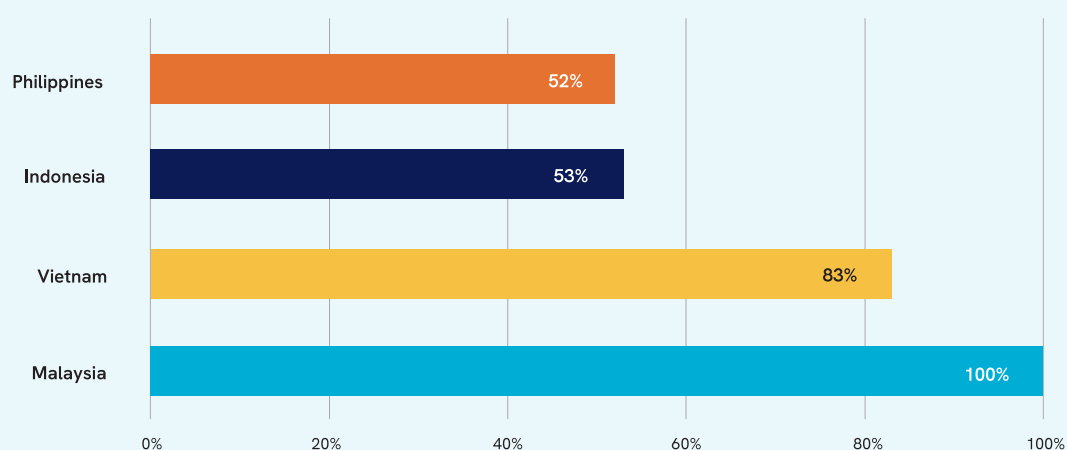
In Southeast Asia, minimum offtake levels are sometimes set to reflect the technical constraints of plant operation – for instance, a coal unit may not be able to run reliably below a certain capacity factor. Such clauses do not necessarily require baseload operation, but they can still dampen the incentive to reduce output during periods of lower demand. In Thailand, for example, the IEA reports that must-run obligations during peak hours can reach 100%, limiting the ability of the system operator to dispatch alternative resources.

Fuel supply commitment. Coal PPAs often integrate long-term fuel supply contracts, which are often linked to domestic mines or state-controlled fuel suppliers. These arrangements ensure fuel availability and price stability but also reinforce operational inflexibility. Plants are typically obligated to consume contracted volumes of coal, which limits their ability to respond to evolving market signals or to reduce output during periods of low demand. In some cases, fuel supply commitments are further supported by implicit or explicit subsidies – such as regulated coal prices, transport incentives or priority dispatch – that reduce the financial pressure and market signals.

Case Study: PPA barriers in Southeast Asia

Across Southeast Asia, CFPPs are tied to long-term PPAs that will remain in force for many years. The average remaining lifespan of coal PPAs is estimated at approximately 17.5 years in Indonesia, 14.1 years in Vietnam (excludes assets owned by EVN parent company), 9.2 years in the Philippines, and 8.8 years in Malaysia.¹² While these figures point to an eventual phase-out horizon, the sheer volume of contracted capacity means PPAs will continue to influence dispatch and constrain flexibility well into the 2030s and beyond. Even a marginal reduction in the load factors of plants could allow the system space for renewables to increase their share of the generation mix.

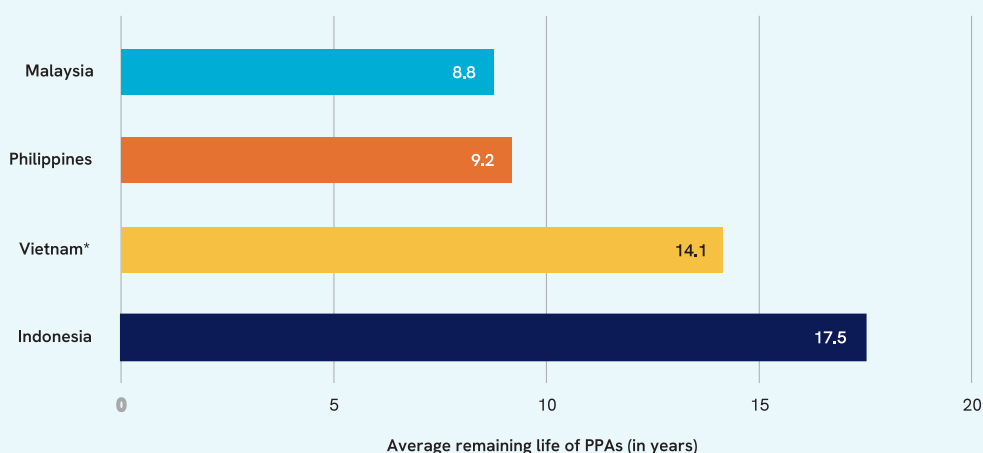
Figure 5. Share of coal capacity in Southeast Asia covered by PPAs



¹² TransitionZero, Coal Asset Transition (CAT), 2025

Coal assets in the region have already demonstrated some degree of medium-term flexibility. System operators have adjusted annual dispatch in response to demand trends and relative fuel costs. For example, a CFPP in Peninsular Malaysia has seen its annual capacity factor vary from 75% to 86%, reflecting modest responsiveness to changing system conditions. However, integrating higher shares of solar and wind will require not just annual or monthly flexibility, but daily and even intra-day responsiveness—something current PPAs are rarely designed to accommodate.

Figure 6. Average remaining life of PPAs in select ASEAN countries



* Excludes assets owned by EVN parent company

Table 2. Summary of PPA barriers for coal flexibility

PPA feature	Barrier
Contract duration	Creates a lock-in effect until the end of the PPA
Tariff structure	Incentivises high utilisation rates when the capacity payment component is large, as most fixed costs are recovered through availability or take-or-pay provisions. For IPPs it can also discourage operational changes that increase performance and maintenance risks or reduce capacity payments
Must run	Requires system operators to dispatch irrespective of the economic incentive
Fuel supply	Incentivises high utilisation rate as fuel will be a sunk cost
Termination or amendment clauses	Penalties or fees for early termination, amendment or deviation from contracted dispatch profiles can increase transaction costs

Risk and operations burden

The shift from a coal-dominated, baseload dispatch model to one that supports dynamic, grid-responsive operations is constrained on both sides of the PPA.

For plant owners, the primary concern is revenue certainty. Existing PPAs provide predictable cash-flows and shield investors from market volatility. Introducing more flexible dispatch – whether through market reforms or contractual amendments – could reduce revenues and increase financial risk. In such cases, it would run counter to the fiduciary duties of asset owners to accept a new structure without appropriate compensation.

For utilities, renegotiating PPAs presents legal, institutional and political hurdles. Many coal contracts, particularly those involving foreign investors, include regulatory-change protection clauses. These provisions render even minor contract revisions time-consuming, costly and politically sensitive. If greater flexibility is to be introduced, asset owners would want to be compensated for the perceived or real loss of value. Whether this compensation takes the form of lump-sum payments or alternative financial incentives, the burden ultimately falls on the utility. Even where no explicit compensation is paid, utilities often remain obligated to cover capacity payments for plants generating less electricity. As a result, the average cost of electricity from these assets increases.

Given these constraints, introducing flexibility may require the same sort of loss-absorption mechanisms used in early retirement transactions. Without them, both sides face asymmetrical costs and risks, making reform politically and commercially unpalatable.

Even in cases where PPAs are not the primary barrier, many national utilities lack the institutional and operational infrastructure to support dynamic dispatch. Realising flexibility will require more than just contractual reform. It will demand comprehensive changes to market design, control centre procedures, scheduling protocols and grid codes. This, in turn, calls for regulatory clarity, technical capacity-building and sustained institutional commitment.

Crucially, these mechanisms cannot be designed in ways that shift costs to the offtaker or consumers, as this would raise concerns about the affordability of retrofits and undermine just transition objectives.

2.4 Sources of finance

Cost recovery remains a central barrier to mainstreaming coal flexibility. As discussed in Sections 2.1 and 2.2, several categories of costs must be covered: upfront investment for retrofits, higher operational expenses, and, in many cases, the contractual costs of altering PPAs. Unlike early retirement, where permanent emission reductions make financing more straightforward, coal flexibility presents challenges because the emissions benefits are temporary, uncertain and contingent on system-level outcomes. This may prove to be a challenge on the financing front.

Financing may require a mix of **public intervention, concessional instruments and regulatory reform**, with private and public capital only participating where clear transition guardrails are in place.

Government support mechanisms

Governments can provide targeted support through capacity payments, performance-based subsidies or grid service contracts. However, this requires fiscal space, regulatory changes and political support. These all pose independent challenges.

India's pilot National Flexibility Scheme offers a cautionary example. Select CFPPs in Tamil Nadu and Gujarat were permitted to participate in day-ahead ancillary service markets, but results were mixed due to mismatches in cost recovery and lack of institutional clarity. This highlights the difficulty of mobilising public funds for coal flexibility without strong frameworks. Moreover, it would mark a step change for governments in many EMDEs to dedicate fiscal resources towards coal transitions. Allocating public funds to reduce the use of coal assets may prove to be a particular political challenge.

Debt-based finance from investors seeking climate impact

Coal flexibility poses significant reputational and financial risks to investors seeking climate impact. Under current policy frameworks and institutional mandates, it is harder to finance than early retirement, as it lacks the emissions reduction certainty, permanence and additionality typically required to justify debt-based or concessional finance. The 2023 GFANZ guidance on managed coal phase-out confirms that only activities tied to clear retirement timelines and permanent reductions are financeable.¹³ This approach is reflected in the Asian Development Bank's Energy Transition Mechanism, which supports early retirement but excludes mid-life flexibility upgrades.

Financial sector policies on coal are evolving. Only recently has coal retirement been recognised as an eligible activity under "no coal" financing policies, and even now governments must confirm that retirement transactions can be considered transition aligned. Early retirement qualifies because the emissions reduction compared to business-as-usual is clear and permanent. By contrast, the emissions outcome of flexibility remains uncertain, making it difficult for financial institutions with transition plans to justify. Penalty mechanisms for under-performance are unlikely to be sufficient to address this concern.

As such, flexibility may only attract international finance if paired with a firm retirement commitment. Otherwise, support will likely need to come from domestic fiscal budgets.

Equity investment

Equity holders in coal plants typically operate under highly favourable conditions. Long-term, take-or-pay PPAs, fixed capacity payments, fuel pass-through clauses, and in some cases direct or indirect subsidies for coal supply and infrastructure insulate them from market risk. These arrangements provide predictable cash flows and, in principle, the financial capacity to reinvest in operational upgrades that improve flexibility and grid integration.

¹³ Glasgow Financial Alliance for Net Zero (GFANZ), Financing the Managed Phaseout of Coal-Fired Power Plants in Asia-Pacific, 2023.

For IPPs, however, fiduciary responsibilities to shareholders act as a limiting factor. Any reinvestment must deliver returns at least equal to the cost of equity. Since flexibility upgrades seldom generate direct revenue under current contractual frameworks, they are unlikely to meet return expectations. The very insulation from market risk that underpins IPP profitability removes incentives to invest in flexibility. Without regulatory requirements, compensation mechanisms or external financing support, equity-backed flexibility investments from IPPs remain improbable.

In some jurisdictions, State-Owned Enterprises (SoEs) face an additional layer of constraint tied to the preservation of state value. Declining use of coal plants may require asset write-downs, which – if done to enable renewable IPPs to supply more electricity – can be perceived as a loss of public value or fiscal exposure. Such write-downs have legal, regulatory and political implications. As a result, SoEs may resist actions that lower the book value of their assets unless explicit accounting solutions or government regulations provide cover.

Similar challenges arise in regulated and privately owned utilities; impairments can affect balance sheets, credit ratings or tariff recovery. As a result, asset owners may resist measures that diminish asset value unless clear accounting guidance, compensation mechanisms or regulatory cover are in place to manage these transition risks. Taken together, these dynamics mean that while equity holders are financially secure, neither IPPs nor SoEs face incentives aligned with investing in flexibility. IPPs are constrained by shareholder return requirements, while SoEs are bound by state value considerations. Unlocking equity participation in flexibility improvements will therefore require regulatory reforms, market-based compensation or government-led solutions that address both sets of barriers.

Carbon credits

For early retirement, carbon credits were identified as a source of revenue replacement. Carbon credits require additional and permanent emission reductions that avoid the risk of fossil fuel lock-in. Achieving this is particularly challenging in a growing economy that already plans to reduce electricity sector emissions, and especially where legacy coal plants remain in operation with no definitive plant retirement schedule. As such, carbon credits face the same difficulties as debt financing in terms of the stringent guardrails needed, and at the moment there are no carbon credit methodologies under development which could be used to finance a coal flexibility transaction.

Market mechanisms

If coal flexibility is to play a transitional role, it will require deliberate market design and public sector intervention as discussed in previous chapters. Possible measures include: establishing ancillary service markets that explicitly value ramping and reserve capacity; introducing payment schemes that compensate generators for operating below their minimum stable load and clarifying in regulations that asset devaluation from flexibility (e.g., for SOEs) does not constitute state loss. In China, ancillary service markets are the primary revenue source for flexible operations. For example, North-east China's load regulation market, launched in 2014, rewards thermal units with deeper ramping abilities, with payments based on real-time load regulation and competitive bidding.¹⁴

Without such interventions, coal flexibility may remain technically feasible but financially unattractive.

¹⁴ Northeast China Power Grid, Flexibility Retrofit Achievements and Impacts on Renewable Energy Curtailment, 2019.

Table 3. Compatibility of existing financing mechanisms with coal flexibility

Financing pathway	Compatibility with coal flexibility	Primary barriers
Long-term PPAs	Not aligned	Fixed schedules, no ramping pay
Government support mechanisms	Limited	Political will, fiscal space
Debt-based finance	Difficult to align with FI policies	No emissions permanence
Equity investment	High risk, low returns mean it is likely not compatible with equity investment thresholds	No revenue certainty
Carbon credits	No current methodologies under development	No emissions permanence
Grid services market	Not yet widely available	Revenue uncertainty and market immaturity

2.5 Broader economic considerations and a just transition for workers and communities

Coal flexibility does not fully shield workers and communities from the impacts they would face with early coal retirement, but if planned well it can provide opportunities for implementing just transition efforts earlier and a smoother runway for the transition. There is significant experience now in the opportunities and challenges of the coal-to-clean transition for the economy and for impacted workers and local communities. However, there is not as much experience in this field for coal flexibility.

The actual impact of flexible operation of coal plants on workers and communities in comparison with coal retirement depends on how the coal plant is used. For example, in Germany, some lignite coal plants were placed on safety standby (i.e. not producing power but being maintained so that they may be brought online when needed) and many of the plant workers were laid off. On the other hand, if the plant is operated flexibly but producing power every day, the impact on the plant workers might be minimal. If coal is sourced domestically, a reduction in power generation at a coal plant – and thus in coal consumption – will have only a limited effect on overall demand until a certain threshold is reached. As a result, the impact on coal mining employment is likely to be minimal. Were the usage to drop very low and across several plants, there would be measurable impact on coal workers.

Regardless of the magnitude of impact, even if a government adopts coal flexibility in the interim for some plants as opposed to coal retirement, the same principles of just transition apply as for coal retirement. Measures such as early planning, worker and community engagement, securing finance etc. are all equally critical.

There are also certain just transition risks and considerations specific to coal flexibility that governments will have to navigate with workers and communities:

- **Income instability:** Unlike outright coal retirement, coal flexibility can result in gradual but uncertain job closures. This can manifest as reduced hours, redeployment or casualisations which require different forms of support such as wage subsidies and income smoothing.
- **Dual skilling:** The training opportunities related to operations and maintenance skills for flexible coal plants can be combined with retraining for clean energy.
- **Supply chain thresholds:** Governments should consider monitoring metrics such as coal demand reductions and trigger support when they drop below a set threshold (e.g. 30% decline in tonnage).
- **Community effects:** Slower, less visible declines can undermine local small and medium enterprises and the municipal tax revenues. Ongoing monitoring and phased support by governments for local businesses and community investment would be needed.
- **Psychological and social impacts:** Flexibility creates uncertainty rather than a clear stop in operations, requiring transparent communication, trust-building and mental health support.

Case Study: Lessons on coal flexibility from select markets

The following case studies illustrate how coal flexibility has been applied in both developed and developing contexts, driven by different system needs and policy priorities, and using different approaches to enable or incentivise coal flexibility.

In developed economies, coal flexibility was initially adopted to extend the operational lifetime of ageing coal units while alternative energy sources were deployed. **Germany's** experience demonstrated that technical retrofits, including turbine upgrades, control system improvements and boiler modifications, can significantly improve the flexibility of older CFPPs. By the early 2000s, retrofitted plants achieved minimum loads as low as 10–12% of rated capacity and ramp rates up to 6% of nominal load per minute.¹⁵ By comparison, conventional subcritical

units typically operate at minimum loads of 40–60% and ramp at 1–2% per minute, depending on boiler design. Achieving 10–12% minimum load requires significant upgrades, particularly to address thermal stress, slagging and combustion stability. This came at a hefty price tag, ranging from €70 to €215 million per plant.

More recently, coal flexibility gained prominence in developing Asian markets as a critical enabler of ambitious national renewable energy deployment. This has generally been done by government policy mandates. Since 2016, **China's** Government has set flexibility retrofit targets for its coal fleet to support solar and wind penetration. By 2023, approximately 300GW of coal capacity – 26% of the country's coal fleet – had been retrofitted.¹⁶ In wind-rich Northeast China, government data suggests that minimum load levels were reduced from 58% to 50%, contributing to a sharp decline in

¹⁵ Agora Energiewende, Flexibility in Thermal Power Plants: With a Focus on Existing Coal-Fired Power Plants, 2017

¹⁶ International Energy Agency (IEA), Meeting Power System Flexibility Needs in China by 2030, 2024

renewable curtailment from 17% to just 3%.¹⁷ State mandates have been instrumental in this trend in China. A February 2024 order directed all retrofittable units (collectively 500-700GW) to make modifications for flexible operation by 2027.¹⁸

In **India**, efforts to enhance coal flexibility began in 2018, targeting its relatively young subcritical and supercritical fleet. Pilot tests at selected plants demonstrated stable operation at 40% minimum load, with ramp rates of around 2% per minute.¹⁹ This marks a substantial improvement over traditional Indian coal fleet operation, where plants often run at 70-85% load with limited cycling capability and ramp rates closer to 1% per minute. Without major capital investment, tests showed some plants could operate down to 55% minimum load. As a result, the Central Electricity Authority updated its grid regulations in 2023, requiring all existing and new CFPPs to operate at 55% minimum load by January 2024, with a future target of 40%. Additionally, plants operating above 70% load are now required to meet ramp rates of at least 3% per minute. The government is reportedly considering using incentives and compensation for coal plant owners to meet the future 40% minimum load target.²⁰

What of the tangible impacts of flex on emission reductions thus far? At a national scale in India and China, data are scarce on emissions changes directly attributable to programmes for operating coal flexibly. Modelling for China suggests that using coal for flex “significantly alleviates the pressure for early retirement” of coal power

compared to a scenario of baseload coal, cutting average lifespan loss of plants by ~12 years. It is unclear, however, what impact this would have on emissions, given it is also modelled to prevent the installation of over 500GW gas power capacity long-term, again compared to a scenario in which coal is continually used for baseload.²¹

Early experience with flexible coal operation in India offers several insights for countries exploring similar pathways. Pilot projects undertaken by the Central Electricity Authority and NTPC have demonstrated the technical feasibility of deeper load changes on subcritical units, but they have also highlighted the importance of market readiness and institutional coordination. The ancillary service market remains at a relatively early stage of development, with limited participation and few pricing mechanisms that adequately compensate generators for providing flexibility. As a result, the economic signals to operate flexibly are still weak, and coal units have continued to operate largely under baseload scheduling patterns. Furthermore, system operators face challenges in integrating flexible operation into existing dispatch and reliability frameworks. These experiences suggest that for flexibility measures to meaningfully support renewable integration, they must be accompanied by robust ancillary service markets, clear operational standards and alignment with long-term decarbonisation objectives, ensuring that flexibility serves as a transitional enabler.

¹⁷ Electricity Sector & Industry Group (ESIG), CHP as a Flexibility Resource in a Coal-plant Intensive Power System: North-east China’s Experience with Renewable Energy Integration, 2019

¹⁸ International Energy Agency, Meeting Power System Flexibility Needs in China by 2030, 2024

¹⁹ Central Electricity Authority, Flexibilisation of Coal-Fired Power Plants, 2023

²⁰ PSU Watch, Government weighs incentives for thermal plants to run at 40 % load to aid RE integration, 2025

²¹ Kangxin An, Xinzhu Zheng, Jianxiang Shen, Canyang Xie, Can Wang, Wenjia Cai & Chujie Bu, Repositioning coal power to accelerate net-zero transition of China’s power system, , 2025

CHAPTER 3

Guardrails to Support a Credible Coal-to-Clean Transition and Unlock Finance

To ensure that coal flexibility enables – rather than delays – the coal-to-clean transition in EMDEs, it is essential that national programmes and pilots be guided by clear principles and guardrails. These safeguards serve two purposes: first, to ensure alignment with national decarbonisation and no new coal pathways; and second, to provide the certainty international financiers require to justify temporary support for coal flexibility. Without them, coal flexibility risks prolonging asset lifetimes, diverting scarce capital from clean energy, and delaying renewable deployment – undermining the very transition it is meant to facilitate. Guardrails should therefore define the limited scope of coal flexibility, embed enforceable retirement deadlines and set declining emissions trajectories, particularly in contexts where public funds, policy incentives or transition finance are involved.

The following guardrails are important enabling factors for consideration in policy, market design and contractual frameworks from the outset:

Eligibility criteria: Strictly limiting participation to plants that meet a defined set of technical, locational and cost-effectiveness benchmarks set by national governments and system planners will ensure resources for coal flexibility are deployed judiciously and only where they provide value to the system. The benchmarks or criteria may include technical suitability (based on age, technology etc.) and efficiency at part-load operation; proximity to renewable generation and grid balancing needs; remaining economic life and depreciation profile; projected emissions and air-quality impacts; and alignment with the country's coal phase-out and just transition plans. Such a framework ensures that flexibility is applied only where it supports renewable integration, without locking in additional emissions or prolonging coal dependence. For example, some newer and higher-efficiency units can operate flexibly with minimal retrofit cost and operational risk. At the same time, older plants may be run flexibly – with certain limitations – at much lower efficiency and with greater damage to equipment, but the plant owners may accept the shortened operating life. Plants located in or near renewable energy zones – particularly with a high penetration of renewables – with existing transmission can have an impact on enabling greater integration of renewables. Applying these criteria avoids diverting resources toward inefficient, high-emitting units or those in locations where flexibility provides little system value. The criteria would need to be consulted with financiers to ensure alignment with their due diligence and disclosure requirements, thereby strengthening the credibility, transparency and bankability of flexibility initiatives.

Screening should be transparent and periodically reviewed to reflect system changes, such as the commissioning of new renewables or grid reinforcements.

Coal-to-clean transition planning and policy certainty: All flexibility arrangements must include fixed, legally enforceable expiry dates that take into consideration timelines for coal-to-clean transition as backed by climate science, and ideally earlier if aligned with national or regional decarbonisation goals. These sunset dates should be written into PPAs, market participation agreements or

regulatory mandates, and linked directly to a plant's decommissioning schedule. If international capital is needed, the sunset dates may even need to be combined with early retirement to ensure integrity of the transaction.

The retirement year should not be negotiable once agreed, except to bring it forward. Embedding a retirement date in binding contracts sends a clear signal to investors, operators and communities that flexibility arrangements are transitional, not open-ended. This helps avoid the "perpetual pilot" problem observed in some jurisdictions where temporary flexibility programmes were designed outside of decarbonisation pathways. Linking flexibility agreements to a binding and enforceable retirement date ensures that short-term flexibility contributes to long-term transition goals.

To ensure emissions reductions, the utility should have a commitment to not build any new coal capacity and a plan to phase-out unabated coal power. Considerations should be made around whether the country also has "no new coal" commitments and broader plans to phase-out unabated coal power to avoid the risk of leakage and maintain policy credibility.

Emissions measures and benchmarks: To ensure that flexible operation is consistent with climate objectives, guardrails should impose a declining cap on operational emissions intensity, measured in grams of CO₂ per kWh generated, and implement other disincentives such as carbon pricing in the electricity markets where it may be effective. These benchmarks should tighten over time, reflecting the increasing availability of zero-carbon flexibility options. A phased tightening of benchmarks could also inform a payment schedule that is not front-loaded, thereby rewarding continued emissions reduction and encouraging a gradual shift towards clean flexibility sources as the system evolves. Linking eligibility of plants for retrofits to meeting or beating these benchmarks will ensure that coal flexibility does not displace clean alternatives such as storage, hybrid systems and demand response.

This approach also creates a pathway to align short-term flexibility needs with long-term carbon budgets.

Transparency and reporting from a verified baseline: Robust monitoring, reporting and verification frameworks must be in place to track operational behaviour, performance against flexibility metrics and emissions outcomes. Participating plants should be required to publish annual reports detailing usage rates, ramp rates achieved, minimum stable generation levels reached and emissions intensity. These reports should be independently verified and made publicly available to ensure accountability.

Public transparency will allow regulators, civil society and financiers to verify that flexibility programmes are delivering genuine system benefits rather than serving as a cover for business-as-usual operation.

Phase-down of financial incentives: In the event that flexibility-related payments or subsidies are available, these should be explicitly time-limited and designed to decline over the course of the programme. This could involve a performance-based payment system, where disbursements are linked to the achievement of pre-agreed milestones. This approach, which would require countries to develop and agree on a clear milestone plan, ensures that financial support remains conditional on measurable transition outcomes. Aligning payments with the build-out of renewables, storage and transmission capacity helps avoid long-term dependencies and ensures that scarce public finance is progressively redirected towards permanent clean energy solutions. Where plants fail to meet agreed flexibility or emissions targets, revenue payments should be withheld or clawed back to preserve accountability and credibility.

This performance-linked design reinforces the principle that flexibility is a transitional service, not a new revenue stream. Separate compensation mechanisms should be carefully designed so they do not overcompensate coal plants and should only be introduced in tandem with contract restructuring to ensure incentives remain aligned with energy transition goals.

Enhanced renewable energy targets: To boost credibility and reduce the risk that coal flexibility displaces clean energy, national power plans can set out an indicative link between flexibility from coal and near-term renewable energy targets. As renewables expand, the expectation is that the role for coal in providing flexibility should narrow accordingly. Policymakers could signal this by publishing guidance that flexibility payments are available only for services such as ramping or reserves, and that the scale of support will decline as renewable milestones are met. This provides clarity to asset owners and investors and incentivises flexibility, while keeping the focus on renewables as the main source of power into the future. This approach gives investors and the public confidence that coal flexibility is directly linked to the speed of renewable build-out, prevents “leakage” where coal substitutes for clean energy, and strengthens the credibility of national transition plans.

By integrating these guardrails into the design of contractual amendments, market reforms and financial instruments, policymakers can ensure that coal flexibility remains a temporary, targeted measure. They also provide a governance mechanism for ensuring that the pathway from “flex” to “phase-out” is irreversible, credible and compatible with both national energy plans and international climate commitments.

CHAPTER 4

Recommendations

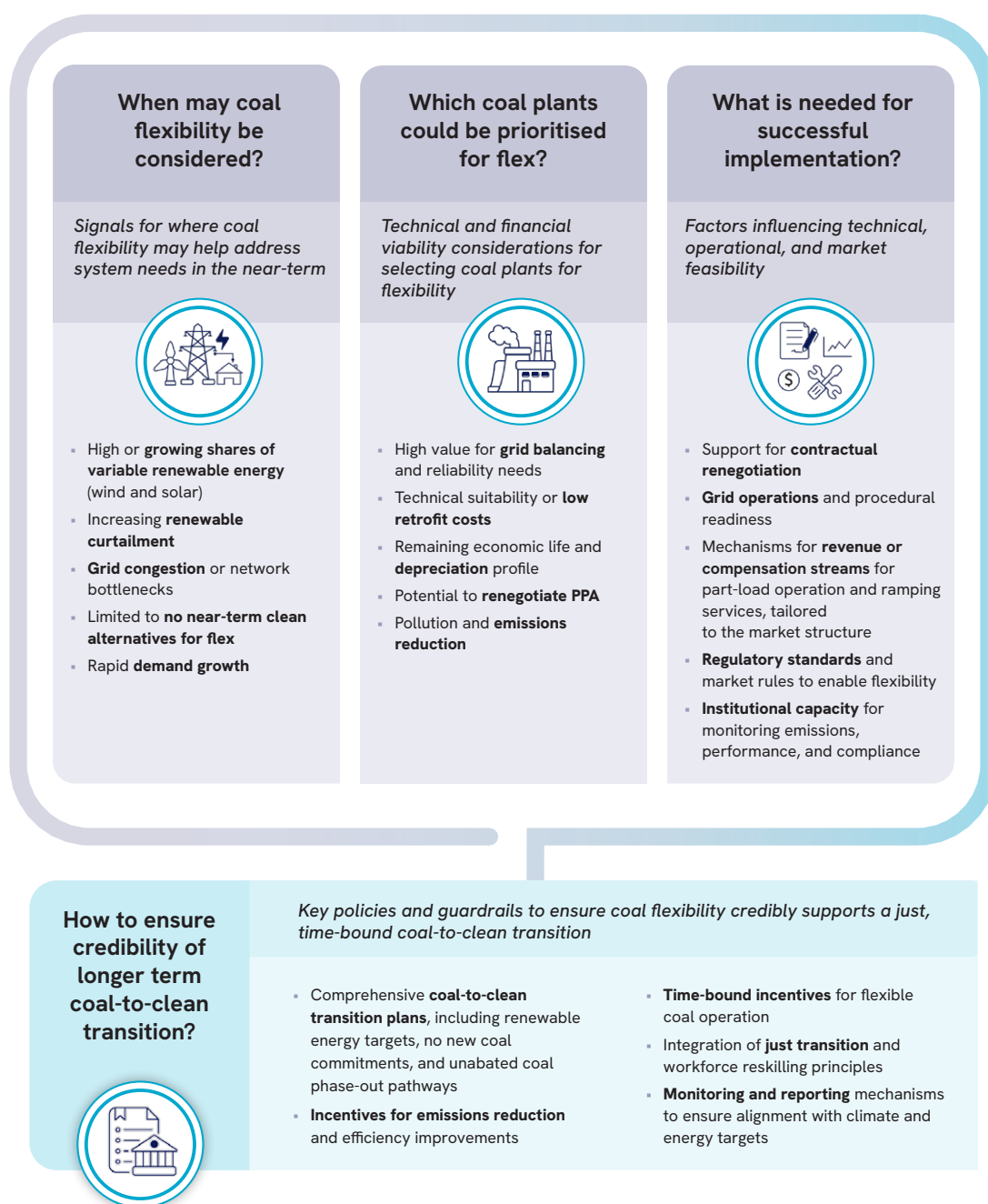
The findings of this report suggest that when paired with appropriate guardrails targeted use of coal flexibility can support near-term renewable energy integration while setting the stage for a full phase-out of coal. This is particularly relevant for countries where coal dominates the generation mix, rapid development of clean and more reliable system flexibility solutions faces substantial obstacles, and early retirement of assets is not yet viable. Coal flexibility should be understood as a bounded, transitional measure, deployed only where it enables faster deployment of clean energy and is paired with credible pathways for retirement. Importantly, any such approach must remain consistent with Paris Agreement objectives and the outcomes of the Global Stocktake, which call for phasing down unabated coal power and aligning energy transitions with pathways that limit warming to 1.5°C.

The recommendations that follow set out how governments, utilities and financial actors can put these principles into practice. These are designed to ensure that flexibility is considered selectively, when it directly supports national decarbonisation strategies while safeguarding against lock-in. They reflect the institutional, financial and technical realities of Southeast Asia's power systems, but are also globally applicable, as identified in the previous chapters. Figure 7 below summarises the key considerations for decision-makers to take into account when they are assessing and implementing coal flexibility in the context of broader transition efforts.

Recommendation one: National governments can implement measures to ensure that the market and system architecture supports flexibility in the power sector from a variety of sources. This may include reforms to grid codes, creation of compensation mechanisms or markets for additional services to the grid beyond generation of energy (e.g. frequency regulation that helps with grid reliability), and integration of financing mechanisms (e.g. carefully designed capacity payments that reward availability without providing overcompensation) to sustain investment in flexible capacity. Such measures can be implemented in a technology-agnostic manner while prioritising cost-effectiveness, and can then support not only coal flexibility but also the deployment of other solutions such as energy storage.

Recommendation two: National governments or utilities planning to use coal flexibility within broader coal-to-clean transition plans should link flexibility interventions to plans for no new coal and coal phase-out, emission reduction guardrails and just transition measures. To mitigate the risks of extending the life of coal power plants and crowding out clean alternatives, measures to support coal flexibility should be paired with a commitment to no new unabated coal power, a clear emissions reduction trajectory or binding retirement year for the plants, and a broader plan for phasing out unabated coal power. This ensures that flexibility is a transitional tool, not an operational status quo. Retirement schedules should be publicly disclosed, monitored and subjected to independent review. Transparent reporting and monitoring, along with broad engagement on the prioritisation plans with regulators, system operators, asset owners, finance and civil society, is essential for credibility and accountability. Support for coal flexibility should be linked to emissions performance, and should decline as the clean solutions for flexibility ramp up. In addition, linking these plans and measures to just transition also helps mitigate the impacts of reduced use of coal while preparing workers and communities for the broader coal-to-clean transition.

Figure 7. Considerations for assessing and implementing coal flexibility in a coal-to-clean transition



Recommendation three: National governments or utilities planning to use coal flexibility within broader coal-to-clean transition plans should consider focusing flexibility retrofits only on coal plants that offer the greatest system value at lowest costs. For example, plants located near renewable generation, with contracts that are amenable to renegotiation, requiring minimal modification to operate flexibly are good candidates. This approach helps avoid locking in high-emitting assets and prevents crowding out clean alternatives such as renewables and storage. For the targeted plants, the governments may consider directly supporting contract renegotiations where needed and in a cost-effective manner.

Recommendation four: Investors seeking climate impact could consider investing in repurposing for flexibility, but only where very robust guardrails are in place. Analysis in this report suggests that repurposing coal power plants for flexibility can play an important role in accelerating coal-to-clean transitions where extensive conditions are met (including those provided in recommendations one and two above). However, very robust guardrails would be essential. At the national level, these may include no new coal commitments, unabated coal phase-out plans and credible energy transition pathways. More specifically, guardrails should address the selection of plants, link to retirement dates and quantify baselines and emissions pathways to help manage associated risks.

Recommendation five: Commission participants might consider further work through the Coal Transition Commission to facilitate the development of repurposing coal plants for flexibility as an effective tool to accelerate coal-to-clean transitions. Specific activities the CTC could consider over the next two years might include:

- Collaborate with interested governments to conduct further analysis on the role that coal flexibility can play in coal transition plans, its impacts on costs and emissions, and the context-dependent financing strategies that can be deployed.
- Share lessons learnt from existing pilot projects on the technical, regulatory, financial and just transition measures employed to implement coal flexibility and support the identification of additional pilot projects.
- Work with national governments and financing partners to further develop guidance on guardrails and best practices for policy and regulatory solutions which will enable coal flexibility while ensuring that the pathway from “flex” to “phase-out” is viable, credible, irreversible and compatible with both national energy plans and international climate commitments.

About the Coal Transition Commission

The Coal Transition Commission brings together governments, financial institutions, industry, international organisations and experts to identify practical solutions to help countries overcome the challenges and access the benefits of the coal-to-clean transition. It is co-chaired by the French and Indonesian Governments and supported by the Powering Past Coal Alliance.

For more information, please visit
[poweringpastcoal.org/strands-of-work/
coal-transition-commission](https://poweringpastcoal.org/strands-of-work/coal-transition-commission)