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ASEAN Coal Transition Technologies: Study Report on Coal Transition Financing Guidelines

Economic Research Institute for ASEAN and East Asia

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List of Abbreviations

ADB	Asian Development Bank
AEO8	8th ASEAN Energy Outlook
ASEAN	Association of Southeast Asian Nations
AMS	ASEAN Member State
BESS	battery energy storage system
CAPEX	capital expenditure
CCS	carbon capture and storage
CCT	clean coal technology
CCUS	carbon capture, utilisation, and storage
CFPP	coal-fired power plant
CO_2	carbon dioxide
DFI	development finance institution
ETM	Energy Transition Mechanism
GW	gigawatts
HELE	high-efficiency, low-emissions
IFB	international financial body
IRB	integrated resource planning
MDB	multilateral development bank
MEMR	Ministry of Energy and Mineral Resources
Mtoe	million tonnes of oil equivalent
MW	megawatt
OPEX	operational expenditure
PPA	power purchase agreements
PLN	Perusahaan Listrik Negara
SO_2	sulfur dioxide
US	United States
USC	ultra-supercritical
WACC	weighted average cost of capital

Chapter 1

Introduction

Coal Supply and Demand in ASEAN

Coal continues to be a fundamental pillar in the energy strategies of Association of Southeast Asian Nation (ASEAN) Member States (AMS). As the region navigates the challenges of energy security and affordability, coal remains a reliable and accessible resource, especially for countries balancing rapid economic growth with expanding energy demands. As the region navigates the challenges of energy security and affordability, coal remains a reliable and accessible resource, particularly for countries balancing rapid economic growth with surging energy needs.

ASEAN's gross domestic product, which contracted by about 3.0% in 2020 due to the coronavirus (COVID-19) pandemic, rebounded strongly to 5.3% in 2022, surpassing its pre-pandemic growth rate of 5.0% in 2019, supported by extensive fiscal stimulus measures. This economic rebound was mirrored in energy consumption, which after consecutive declines of 7.6% in 2020 and 0.2% in 2021, demand spiked by 15.2% in 2022 to reach 432 million tonnes of oil equivalent (Mtoe), well above pre-pandemic levels (ACE, 2024a).

Such figures highlight the tight linkage between economic performance and energy demand in ASEAN, and underscore why coal, with its affordability and established infrastructure, continues to underpin the region's growth trajectory. To that end, most AMS have taken deliberate steps to secure coal through a combination of domestic production and strategic imports, with each country following a pathway shaped by its unique resource endowment and policy priorities.

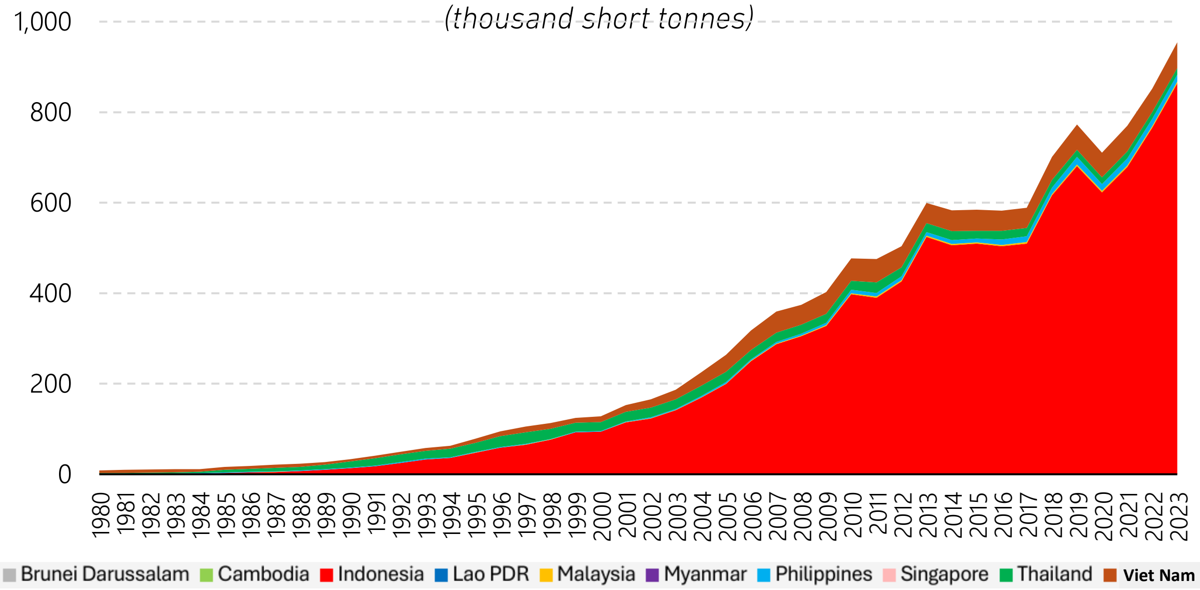
Indonesia, the region's dominant coal producer, has long underpinned ASEAN's coal market. By 2023, Indonesia's annual coal production had climbed to about 775 million tonnes, marking a strong growth from earlier benchmarks of around 600 million in 2018 (Saha, Mittal, and Basu Roy, 2024)Click or tap here to enter text.. Despite facing global and domestic headwinds during the 2020 economic downturn, Indonesia maintained robust output, reinforcing its position as a key exporter and supplier, not only to ASEAN but to global markets (Boyle, 2020).

Alongside production, Indonesia's coal reserve estimates have fluctuated significantly. Reserves surged from 25 billion to 44 billion short tonnes between 2017 and 2018, before tapering to around 38 billion by 2020. This sharp increase was largely driven by production dynamics, as total coal output exceeded the plan approved by the Ministry of

Energy and Mineral Resources (MEMR), primarily due to overproduction by numerous holders of provincial mining business permits (IUPs).[1]

In aggregate, they produced almost twice their initial allocations, a situation that was difficult for provincial governments to monitor given the large number of licensees. Higher international coal prices also incentivised companies to ramp up output to maximise profits. At the same time, the government raised the national coal production cap in 2018 by 100 million tonnes to help ease the trade deficit, further fuelling reserve adjustments (Tumiwa, 2019). After tapering in 2020, reserves stabilised at around 31–35 billion short tonnes in 2023 (Indonesia Business Post, 2024).

Figure 1.1. Coal Production by Member States in ASEAN, 1980–2023



Source: US Energy Information Administration (EIA, 2024).

Beyond Indonesia, other AMS show mixed trajectories. Viet Nam and the Lao People's Democratic Republic (Lao PDR) have consistently scaled up both coal production and consumption. Lao PDR, driven by a need to offset seasonal hydropower shortfalls and reduce power imports, increased production dramatically, from under 1 million short tonnes in 2012 to 18 million short tonnes in 2023. Similarly, Viet Nam has pursued coal aggressively to fuel its industrial growth, while also witnessing a steady uptick in consumption averaging 11.4% annually between 2010 and 2023.

Meanwhile, the Philippines and the Republic of the Union of Myanmar have maintained modest but growing production capacities. The Philippines, in particular, has shown a 6% average annual increase in production, complemented by rising consumption that has

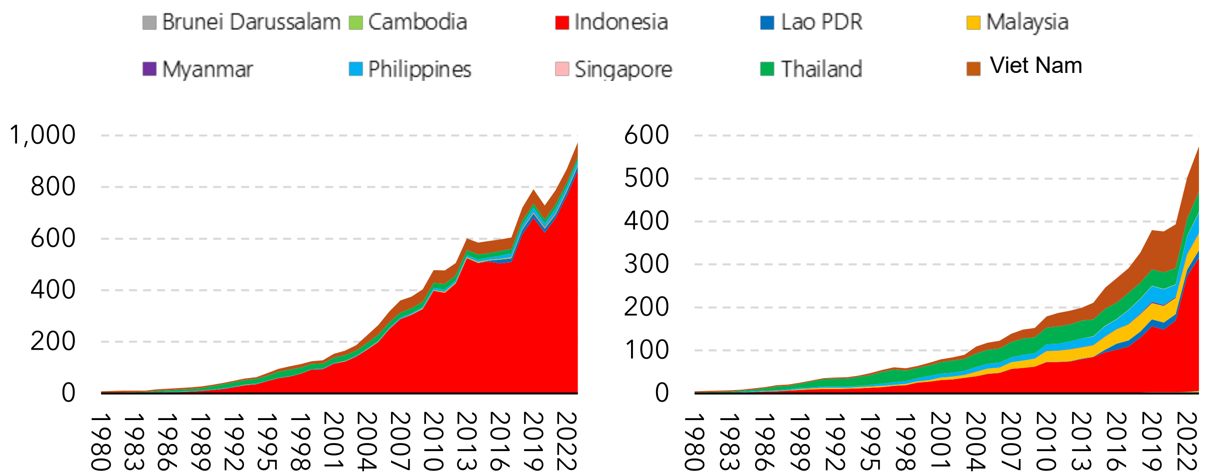
[1] An IUP is an official permit issued by the central or regional government authorising companies, co-operatives, or individuals to conduct mineral and coal exploration or production operation activities within the territory of Indonesia, which is mandatory for stages ranging from investigation to sales.

outpaced domestic supply, pushing the country further into import dependence. Cambodia's entry into coal production, marked by the opening of the Han Seng Coal Mine in 2021, indicates new trends in regional supply diversification. Conversely, countries like Thailand have seen a gradual reduction in domestic output, signalling resource depletion and shifting energy preferences, while Singapore and Brunei Darussalam remain non-producers due to geological constraints (US Energy Information Administration (EIA), n.d.; ACE, 2024a).

ASEAN's coal demand patterns reveal a clear and growing reliance on imports amongst several AMS. Indonesia has remained a net exporter, leveraging its high production volumes to anchor regional and global markets. In contrast, Viet Nam has transitioned from a coal exporter to a net importer, reflecting rising domestic demand and the increasing cost-effectiveness of imported coal. Similar dynamics have emerged in Malaysia and the Philippines. In Malaysia, rising natural gas prices in 2017 incentivised coal imports, resulting in a 42% surge in net coal purchases in that year alone. Thailand, on the other hand, has maintained relatively stable import levels, with modest annual increases of around 4% over the past decade (EIA, n.d.; ACE, 2024a).

Figure 1.2. Coal Production (Left) and Consumption (Right) by ASEAN Member States, 1980–2022

(million short tonnes)



Lao PDR = Lao People's Democratic Republic; Myanmar = Republic of the Union of Myanmar.
Source: US Energy Information Administration (EIA, 2024).

Despite evolving national strategies and global pressure to decarbonise, the reality remains that coal continues to play a central role in Southeast Asia's power generation mix. Since the 1980s, countries like Malaysia, Thailand, and the Philippines have depended on coal to sustain their electricity supply. While the region is increasingly aware of the environmental costs and long-term limitations of coal, the path away from it is neither immediate nor straightforward.

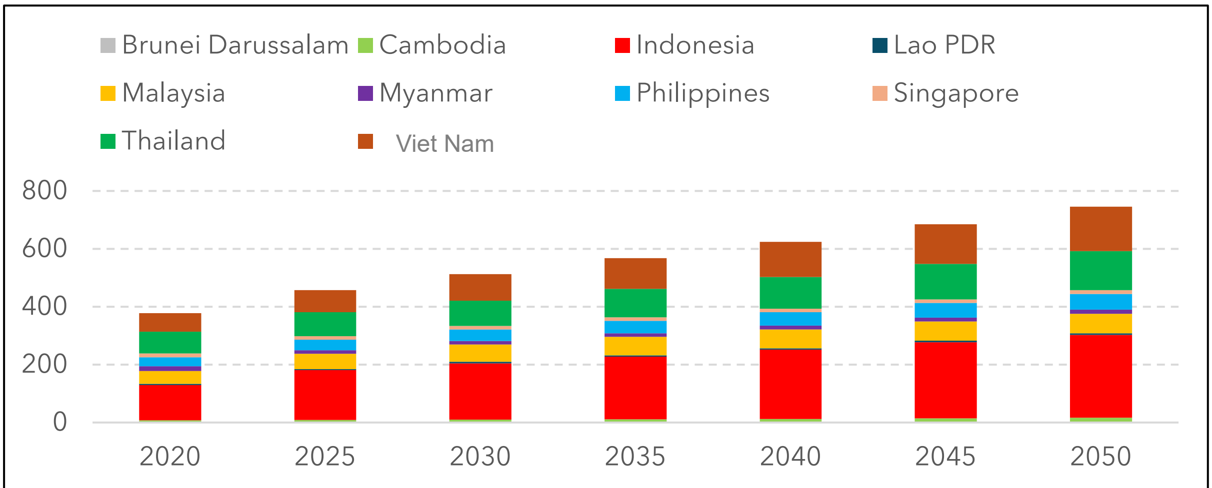
This report, therefore, is not premised on an abrupt exit from coal, but rather on a pragmatic exploration of how ASEAN can transition responsibly. It recognises coal's continued relevance and proposes financing solutions that can enable cleaner use in the short to medium term. In doing so, the report also seeks to chart a course toward a future where coal's role is gradually diminished, without compromising energy security, affordability, or economic resilience.

ASEAN's Coal Dependency in the Context of the Region's Energy Outlook

The continued relevance of coal within Southeast Asia's energy structure becomes even more apparent when examined through the region's official energy planning outlook. According to the 8th ASEAN Energy Outlook, specifically the AMS Target Scenario,[2] energy demand in the region is anticipated to grow considerably, by 36% by 2030 and 73% by 2050 relative to 2020 levels. This increase is underpinned by an average annual demand growth rate of 2.3%, with certain AMS such as Cambodia, Indonesia, and Viet Nam leading the trend with rates exceeding 2.9% per year (ACE, 2024a; Saha, Mittal, and Basu Roy, 2024).

Figure 1.3. Total Energy Demand Projections by ASEAN Member States, 2020–2050

(million tonnes of oil equivalent)



Lao PDR = Lao People's Democratic Republic; Myanmar = Republic of the Union of Myanmar.
Source: ASEAN Centre for Energy (ACE) (2024a).

Despite efforts to promote renewable energy and bioenergy, fossil fuels, especially coal, are projected to maintain a substantial foothold in the region's energy consumption. Coal demand is set to surge from 47.71 Mtoe in 2020 to 145.83 Mtoe by 2050, reflecting a 128.0% cumulative increase, or roughly 3.8% annual growth. By 2030, coal is forecast to

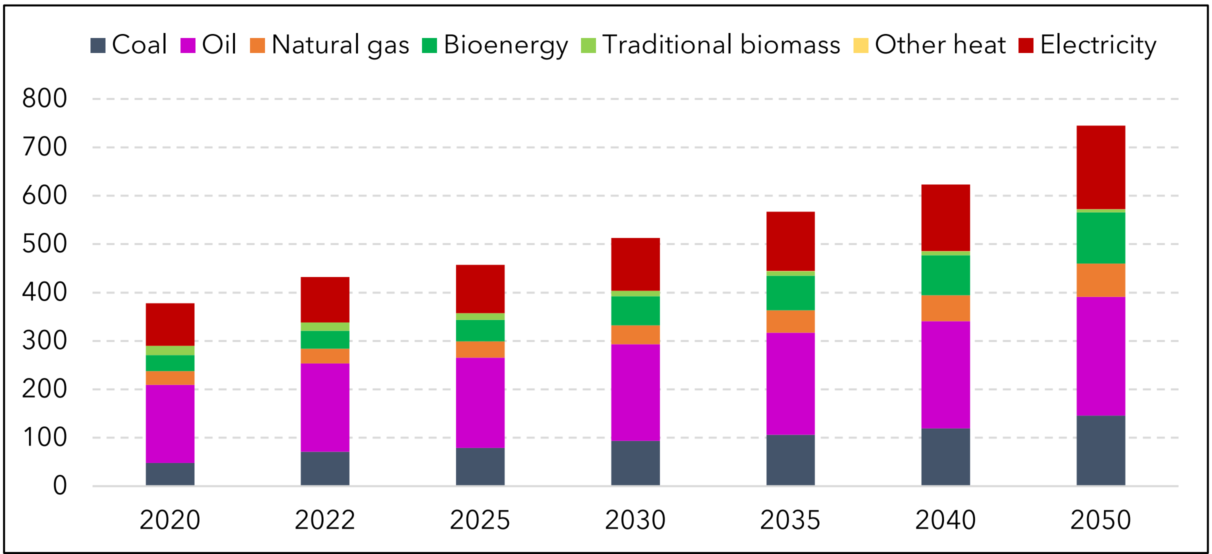
[2] Target Scenario is based on an assessment of the impact of current national policies and measures from official documents on the Power Development Plan, energy efficiency, and renewable energy.

account for 18.0% of ASEAN's total energy demand, rising slightly to 19.2% in 2040 and 19.6% in 2050 year (ACE, 2024a; Saha, Mittal, and Basu Roy, 2024).

A closer look at sectoral usage reveals a clear transformation in how coal is utilised. While its role in power generation is expected to diminish significantly, falling by around 63% over the 2020–2050 period, coal use in the industrial sector will expand dramatically, driven by the need for industrial heat and transformation processes (Figure 1.4).

Figure 1.4. ASEAN's Total Energy Demand Projections by Fuel in Mtoe

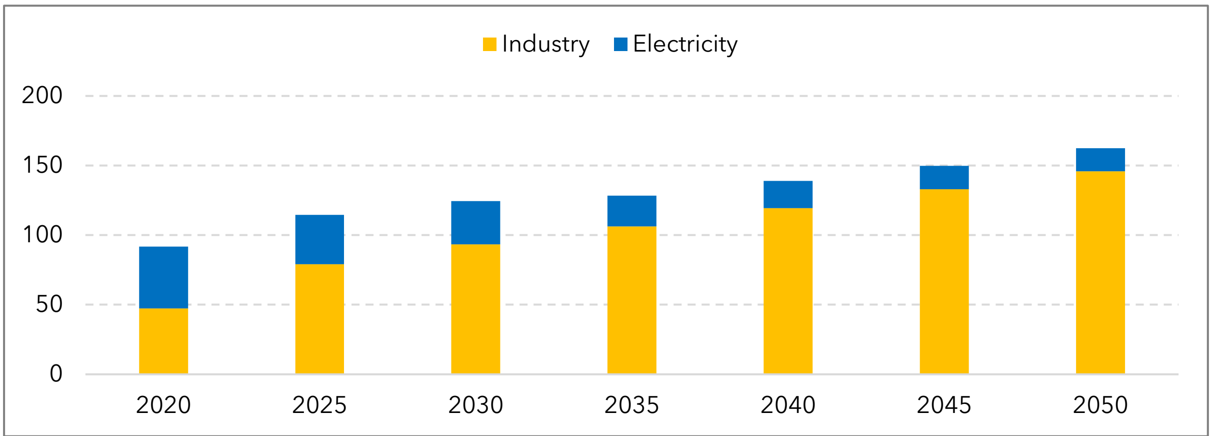
(million short tonnes)



Source: ACE (2024a).

Figure 1.5. Projections for Coal Transformation and Final Demand by Sector in ASEAN

(million tonnes of oil equivalent)



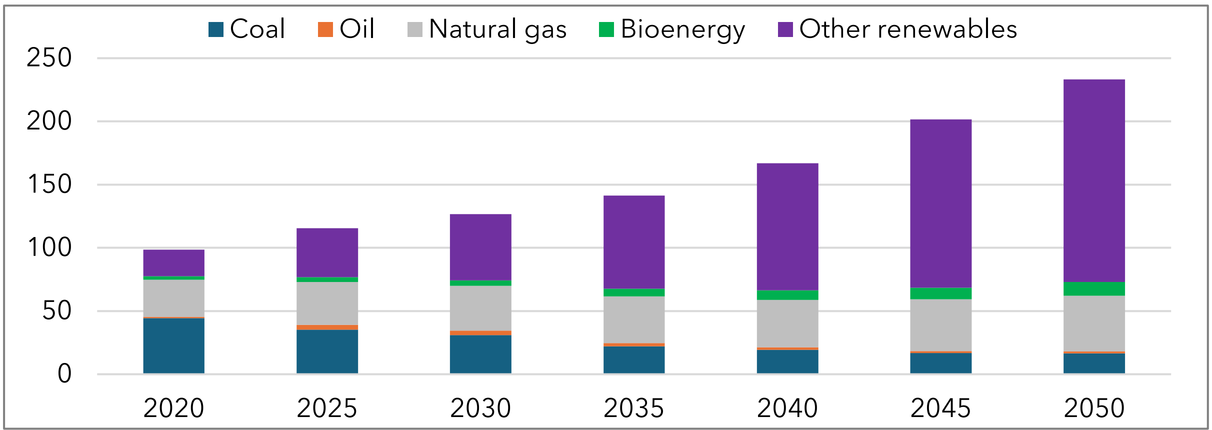
Source: ACE (2024a).

Industrial coal demand alone is projected to increase by over 200% during the same time frame. This divergence suggests that, although coal's share in electricity production will be eroded by the growth of natural gas and renewables, it will continue to be indispensable in fuelling heavy industries.

In terms of electricity generation, the region's total energy consumption is anticipated to grow by 137.0% by 2050, with coal still comprising a substantial part of the mix in the short and medium terms. Specifically, coal will account for 30.6% of energy used for power generation in 2025 and 15.7% by 2035. It is only by 2050 that its contribution is expected to decline significantly to around 7.0% (ACE, 2024a; Saha, Mittal, and Basu Roy, 2024).

Figure 1.6. Projections of Net Energy Consumption for Energy Transformation in ASEAN

(million tonnes of oil equivalent)



Source: ACE (2024a).

This forward-looking perspective reinforces the central thesis of this report, where coal, while gradually giving way to cleaner energy sources, will remain a critical part of ASEAN's energy landscape in the coming decades. Therefore, it is imperative for the region to identify and adopt pathways that enable cleaner and more efficient use of coal in the near term, while steadily paving the way for a coal-free future aligned with long-term decarbonisation targets.

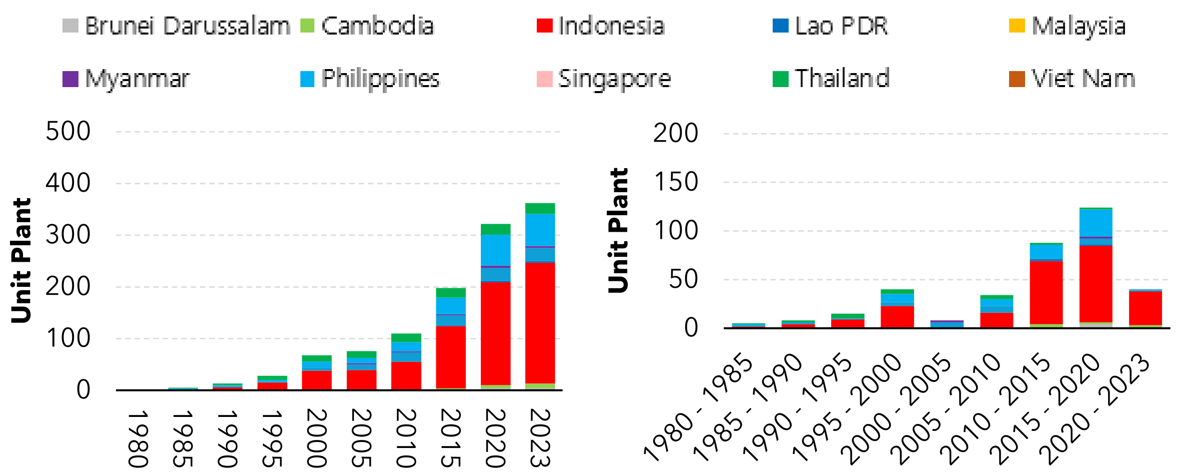
The State of ASEAN's Coal-Fired Power Plants

Despite increasing global momentum toward coal phase-out, coal-fired power plants (CFPPs) remain central to ASEAN's electricity systems. Amongst AMS, Indonesia, Malaysia, the Philippines, and Viet Nam stand out, collectively accounting for nearly 92% of the region's total coal-based electricity generation. These four countries also dominate the region's CFPP fleet in terms of both capacity and technological diversity.

The majority of CFPPs in ASEAN are still relatively young (ACE, 2024b; Boyle, 2020). As of 2024, over 57% of installed capacity has been in operation for less than a decade, with an average plant age in the region of 14.3 years, considerably younger than the United States (US) (40 years) or the European Union (35 years). Although several of the oldest CFPPs date back to the 1980s, most of the region's fleet still has decades of technical life remaining, assuming regular maintenance. This signals a continued reliance on coal infrastructure in the near to medium term, due to both sunk capital costs and the baseload reliability CFPPs provide.

Indonesia continues to lead the region in both total capacity and new developments. Between 2015 and 2023 alone, the country added 114 new coal units, raising its CFPP fleet to 234 plants and increasing its installed capacity from 8.2 gigawatts (GW) in 2000 to 45.2 GW in 2023, equivalent to an average of 1.6 GW of new capacity added each year. The Philippines and Viet Nam also recorded significant growth, particularly from 2010 onward. Viet Nam's coal capacity rose nearly tenfold between 2010 and 2023, from 2.6 GW to 25.8 GW, while the Philippines added 5.8 GW between 2015 and 2023. In contrast, Malaysia and Thailand have added only minimal new CFPP capacity in the past decade, signalling a more cautious stance on further coal investment.

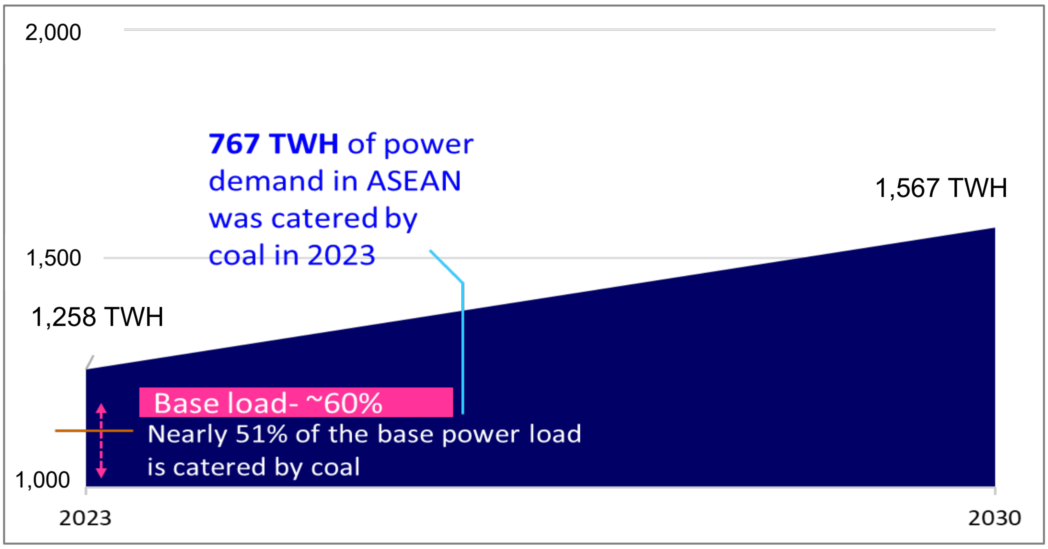
Figure 1.7. Total Number (Left) and Additions (Right) of Coal-Fired Power Plants in ASEAN Member States



Lao PDR = Lao People's Democratic Republic, Myanmar = Republic of the Union of Myanmar.
Source: Global Energy Monitor (GEM) (n.d.).

Current estimates, as illustrated in Figure 1.8, show that coal still plays a crucial role in ensuring regional electricity reliability. In 2023, coal supplied approximately 767 terrawatt-hours of electricity across ASEAN, much of it fulfilling base load needs – about 60% of total electricity demand – with coal contributing nearly 51% of this base load supply. This reveals not only the extent of coal's entrenchment but also the challenges that any transition effort must overcome.

Figure 1.8. Coal Dominance in Catering for Electricity Demand in ASEAN, 2023 and 2030 (Projection)

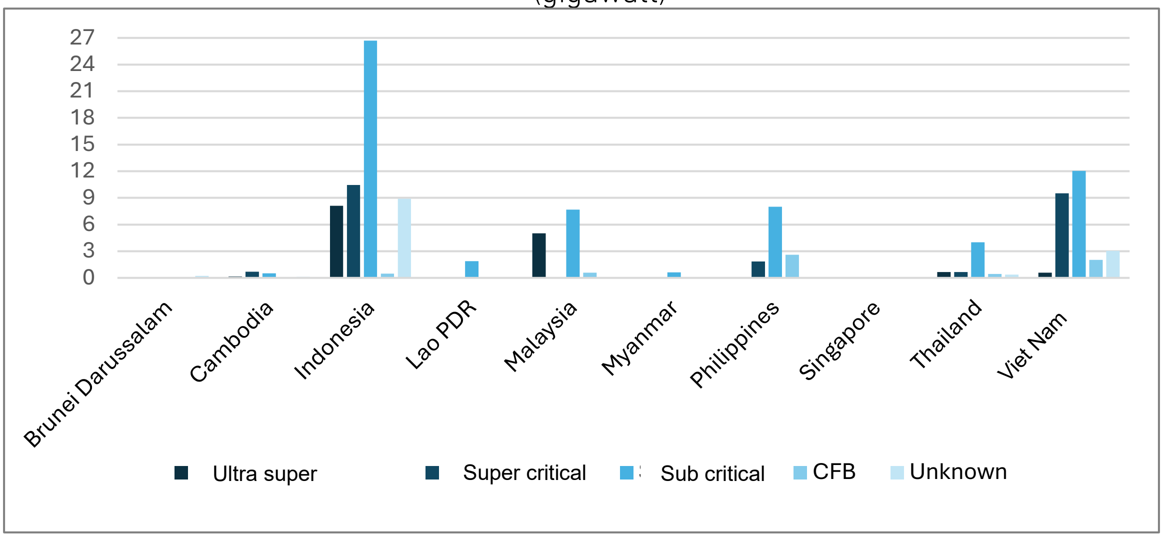


ASEAN = Association of Southeast Asian Nations, TWh = terrawatt-hour
Source: Eninrac Consulting (2025).

In terms of technology, ASEAN's CFPP fleet is a mix of legacy and more efficient systems, as depicted in Figure 1.9. Out of the region's approximately 116.9 GW installed capacity in 2024, around 14.5 GW is based on ultra-supercritical (USC) technology, 23.2 GW on supercritical, and 61.4 GW on subcritical systems, the latter still making up the bulk of operational plants. Indonesia again leads in all categories, hosting the largest share of advanced technology deployments (GEM, (n.d.), Tumiwa, 2019).

Figure 1.9 Breakdown of the Capacity of Coal-Fired Power Plants Based on Technology across ASEAN Member States, 2024

(gigawatt)

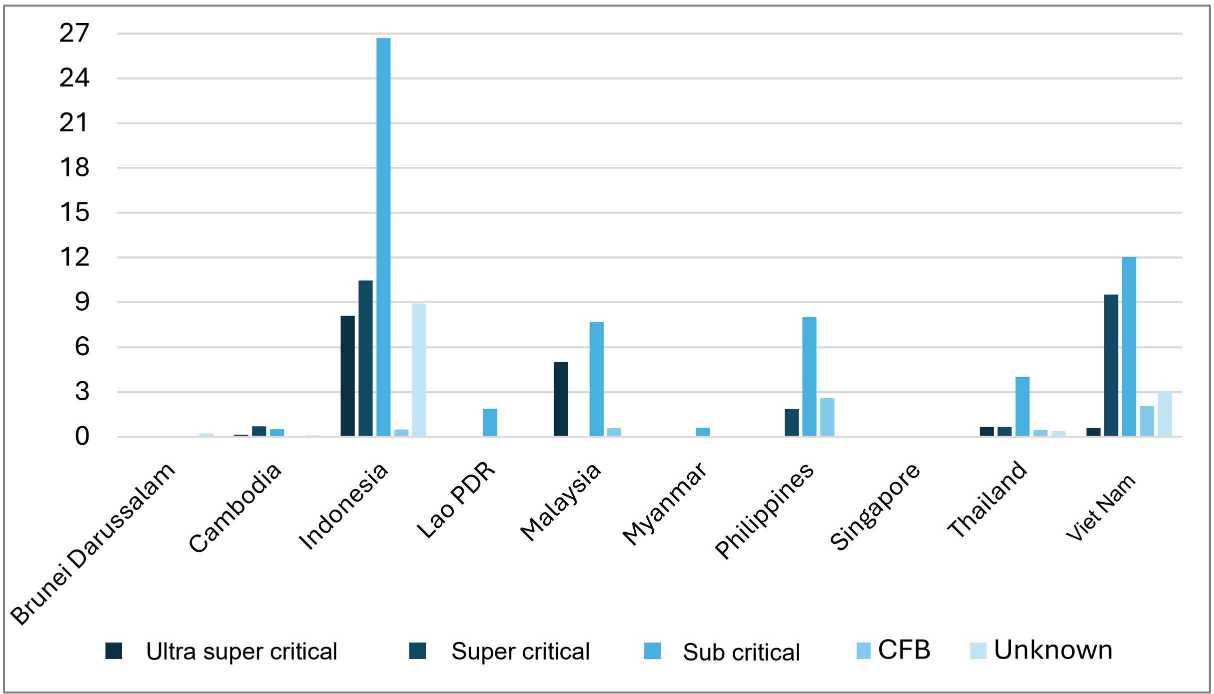


ASEAN = Association of Southeast Asian Nations, CFB = Circulating fluidised bed, Lao PDR = Lao People's Democratic Republic, Myanmar = Republic of the Union of Myanmar.
Source: Eninrac Consulting (2025), GEM (n.d.).

While many governments have announced moratoria on new coal power developments, substantial pipeline capacity remains. As of 2024, ASEAN has nearly 39 GW of additional CFPP capacity either under construction (26.2 GW), permitted, or announced. Indonesia alone accounts for more than half of this pipeline, with 13 GW already under construction. Lao PDR, the Philippines, and Viet Nam also show significant new capacity additions in progress.

On the other side of the spectrum, some AMS have begun charting early retirement plans. In Thailand, three units of the Mae Moh Power Plant (Units 5, 6, and 7), with a combined capacity of 450 megawatts (MW), were decommissioned in 2019. However, these units were replaced by new ones, meaning the country did not necessarily reduce its overall coal fleet. In Indonesia, only one facility was retired during this period – the 55 MW Kalimantan Cement Works Power Plant – after its owner, PT Indocement Tunggal Prakarsa Tbk, switched to sourcing power from Perusahaan Listrik Negara (PLN) and later installed solar panels at its Tarjun factory in 2023. In the Philippines, the 40 MW Unit 2 of Toledo City's Power Station was decommissioned in December 2023, as it no longer appeared on the Department of Energy's list of operating units. Looking ahead, Malaysia has outlined the most detailed plan in the region, aiming to halve its coal power capacity in the coming years and retire all remaining coal plants by 2044 (GEM, n.d.; Tumiwa, 2019).

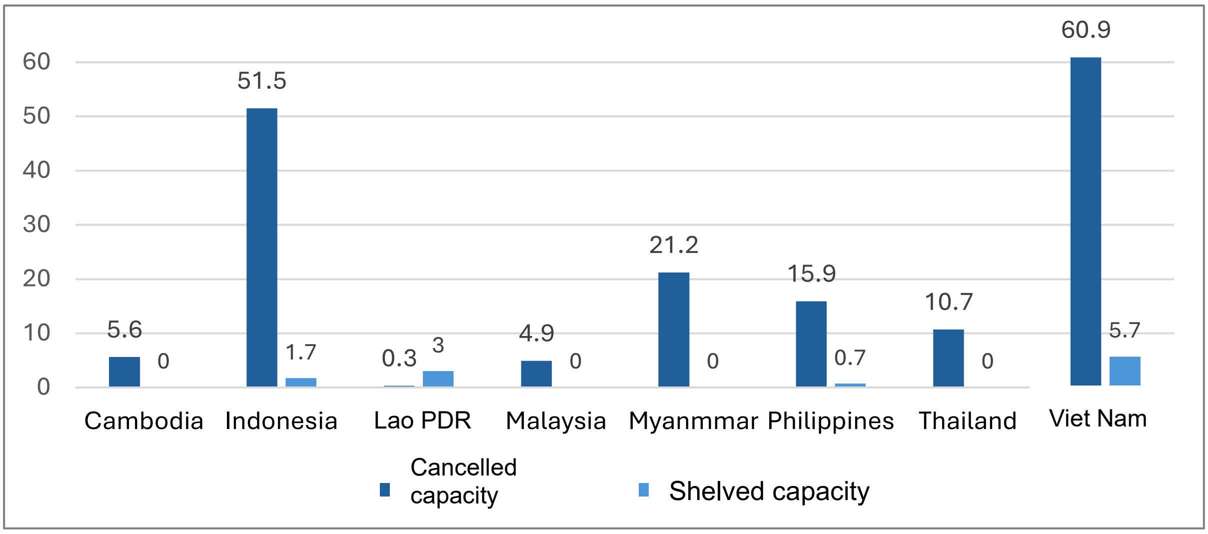
Figure 1.10. Status of Potential Coal-Fired Power Plants Capacity to be Commissioned in ASEAN
(gigawatt)



ASEAN = Association of Southeast Asian Nations, CFB = Circulating fluidised bed Lao PDR = Lao People's Democratic Republic, Myanmar = Republic of the Union of Myanmar.
Source: Eninrac Consulting (2025), GEM (n.d.).

Figure 1.11. Cancelled and Shelved Coal-Fired Power Plant Capacity ASEAN

(gigawatt)



ASEAN = Association of Southeast Asian Nations, Lao PDR = Lao People's Democratic Republic, Myanmar = Republic of the Union of Myanmar

Source: GEM (n.d.).

Importantly, the growing scale of cancelled or shelved coal projects reflects a broader shift in strategic energy planning. Viet Nam has cancelled over 60.0 GW of planned capacity, while Indonesia has dropped 51.5 GW. Several other countries, including the Republic of the Union of Myanmar, the Philippines, and Thailand, as charted in Figure 1.11, have similarly walked back large-scale developments, indicating a pivot away from coal's long-term expansion, even if short- to mid-term dependence remains (GEM, n.d.; Tumiwa, 2019).

Hence, ASEAN's CFPP landscape is defined by a mix of youth, embedded dependency, and cautious transition. This presents both a challenge and an opportunity. While the relative youth of the coal fleet complicate immediate phase-out plans, it also enables repurposing potential. Newer and more efficient plants are often better suited for retrofits, emissions control upgrades, or co-firing with cleaner fuels.

Chapter 2

Readiness and Challenges in Coal Fired Power Plant Transitioning

2.1. The Role of Clean Coal Technologies in ASEAN's Energy Landscape

For decades, coal has underpinned energy security and affordability across AMS. Its abundance, affordability, and ability to provide reliable baseload power have made it central to national energy strategies. While global momentum is shifting towards cleaner energy systems, coal remains an integral part of ASEAN's short- to medium-term energy outlook. In this context, clean coal technologies (CCT) are emerging as a strategic tool, offering a pathway to reconcile continued coal use with the region's sustainable development and climate objectives.

CCT encompass a series of technological advancements that improve the efficiency of coal combustion while significantly reducing harmful emissions such as sulfur dioxide (SO_2) and nitrogen oxides (NMA, 2016; Indonesia Business Post, 2024). By enabling higher energy output per unit of coal and lowering pollutant intensity, CCT represent an important bridge solution for AMS seeking to decarbonise without jeopardising energy security.

The strategic importance of CCT in the region is reflected in ASEAN's institutional energy framework. The Coal and Clean Coal Technology (CCT) Programme Area under the ASEAN Plan of Action for Energy Cooperation Phase II: 2021–2025 aims to strengthen regional co-operation in the coal sector, promote intra-ASEAN coal trade, disseminate best practices, and accelerate CCT deployment. The explicit inclusion of CCT in ASEAN's energy blueprint underscores their role in balancing the dual imperatives of maintaining coal's contribution to energy security and meeting environmental sustainability targets.

As the region navigates the complex challenges of climate change, growing energy demand, and industrial competitiveness, CCT adoption will serve as both a transitional measure and a foundation for future pathways, such as co-firing with biomass, integration with carbon capture technologies, or eventual plant repurposing. This positions CCT not merely as a technical option, but as a strategic enabler in ASEAN's broader energy transition journey.

2.2. Current Adoption of Clean Coal Technologies ASEAN

Despite growing interest in CCT, their practical application in ASEAN's CFPPs remains limited. At present, only two CCT measures are in actual operation across the region's CFPP ecosystem – boiler technology upgrades and biomass co-firing.

Boiler technologies play a central role in improving CFPP performance, with high-efficiency, low-emissions (HELE) systems representing a major step forward. This category includes supercritical, USC, and advanced ultra-supercritical boilers, designed to operate at higher temperatures and pressures, thereby improving thermal efficiency and lowering specific fuel consumption. Amongst these, advanced USC boilers can achieve efficiencies of up to 50%, significantly reducing greenhouse gas emissions per unit of electricity generated. For AMS, where coal remains a cornerstone of the energy mix, HELE deployment can deliver immediate emissions reductions while maintaining reliable baseload power (ACE, 2025a; EIA, n.d.).

Biomass co-firing, on the other hand, represents a more direct pathway to lowering the carbon intensity of coal generation. By substituting a portion of coal feedstock with biomass, such as agricultural residues, wood pellets, or organic waste, plants can achieve meaningful reductions in net emissions. Several AMS, including Indonesia and Malaysia, are advancing co-firing initiatives, leveraging domestic biomass availability to scale up adoption (ACE, 2025a; EIA, n.d.).

While carbon capture and storage (CCS) has been identified as a future cornerstone for deep decarbonisation of CFPPs, no operational coal plants in ASEAN currently deploy this technology. Indonesia and Malaysia have initiated CCS project development, and the recent study by the ASEAN Centre for Energy has explored its integration with biomass co-firing. However, such approaches remain at the conceptual or pilot stage, with commercial-scale deployment still years away (ACE, 2025b; ACE, 2024b).

Given these realities, this section focuses on HELE boiler upgrades and biomass co-firing as ASEAN's most actionable CCT pathways today, offering immediate efficiency and emissions benefits while laying the groundwork for more advanced technologies in the future.

2.2.1. Boiler Technology Upgrades

Boiler technology upgrades are amongst the most impactful and widely applicable CCT measures available in ASEAN today. These upgrades, particularly through the adoption of HELE systems allow CFPPs to achieve higher efficiency and lower emissions without fundamentally altering their role in the grid.

Indonesia is home to the largest CFPP complex overall, the Paiton Power Station in Probolinggo, East Java, with a combined capacity of 4,825 MW across eight units. Notably, Paiton Unit 3 (815 MW) holds the distinction of being Indonesia's first supercritical coal-fired unit, marking a major step in the country's shift toward more efficient CFPP designs (ACE, 2025a; EIA, n.d.).

Elsewhere in ASEAN, Malaysia has been at the forefront of USC deployment. The Manjung Unit 4 power plant in Perak, commissioned in April 2015, was the first USC unit in Southeast Asia, delivering 1,000 MW of high-efficiency baseload power. This development paved the way for larger USC installations, including Malaysia's Manjung Units 4 and 5 and Indonesia's Batang Power Plant in Central Java, both of which represent the largest USC coal-fired plants in the region, each with a combined capacity of 2,000 MW from two 1,000 MW units (ACE, 2025a; EIA, n.d.).

These examples illustrate that, while subcritical units still dominate ASEAN's CFPP fleet, the region has begun incorporating higher-efficiency boiler technologies into its generation mix. Such upgrades offer a clear pathway to lower emissions per unit of electricity generated, making them a critical bridge solution for balancing energy security, affordability, and environmental performance during the energy transition.

2.2.2. Biomass Co-Firing

Biomass co-firing has emerged as one of the most practical CCT applications currently available to AMS. By blending alternative fuels – most commonly biomass – with coal in existing CFPPs, operators can reduce coal consumption, lower greenhouse gas emissions, and diversify their fuel mix without major structural changes to existing plants. Beyond emissions benefits, biomass co-firing can support circular economy principles by repurposing agricultural residues, forestry by-products, and wood waste, thus improving the environmental footprint of existing infrastructure while advancing toward more sustainable power generation.

The readiness of biomass co-firing adoption in ASEAN can be assessed across several key parameters, including estimated cost range, technological maturity, and policy/regulatory frameworks. A snapshot of selected policies provides further context (Table 2.1).

Table 2.1. Biomass as an Abatement Measure for Coal-Fired Power Plants in ASEAN

Abatement Measure	Estimated Cost Range (US$/$tCO_2$ avoided)	Technological Maturity (ASEAN context)	Policy & Regulatory Readiness	Key Dependencies & Risks	Practical Viability (overall assessment)
Biomass co-firing (20%)	20–40	Medium	Medium	Fuel supply-chain stability, price volatility, and sustainability of sourcing.	Medium
Ammonia co-firing (e.g., 20% blue/green)	159–191	Low	Low	Extreme fuel cost, unproven technology at scale, import dependency, and NOx emissions.	Low
CCUS retrofit (full chain)	141–271	Low	Low-Medium	Extreme CAPEX, long-term storage liability, lack of carbon price, and public acceptance.	Low (except for targeted industrial pilots)
Early retirement of subcritical plant	41–140	N/A	Low	Massive international financing needs, political will, and managing stranded assets.	Low (without major international finance)

US$ = United States dollar, ASEAN = Association of Southeast Asian Nations, CAPEX = capital expenditure, CCUS = carbon capture, utilisation, and storage, N/A = not applicable, NOx = nitrous oxide, tCO_2.= tonne of carbon dioxide.
Source: ACE, (2025b); ACE (2024b).

Biomass co-firing, which typically substitutes up to 20% of coal with biomass, offers one of the most cost-effective pathways for carbon abatement, with estimates ranging from US$20 to US$40 per tonne of carbon dioxide (CO_2) avoided. The technology is considered moderately mature, with a growing degree of regulatory support across the region. However, challenges remain, particularly around feedstock supply-chain stability and broader sustainability concerns. When applied carefully, especially with safeguards against land-use change emissions, as highlighted in recent studies, biomass co-firing is viewed as a reasonably practical and scalable option for ASEAN.

In practice, biomass feedstocks must be processed, often into pellets or briquettes, to meet the technical and combustion requirements of power plant systems. Across ASEAN, potential feedstock sources include rice husks, palm kernel shells, coconut shells, sugarcane bagasse, forestry residues, and sawdust. While biomass is often promoted as a carbon-neutral fuel, its environmental credentials depend heavily on sustainable sourcing and careful consideration of the carbon cycle, land-use changes, and possible competition with food production. This makes robust sustainability criteria and supply-chain planning critical for large-scale adoption (Table 2.2).

Table 2.2. The Potential of Biomass Resources in ASEAN

Member State	Annual biomass Production	Biomass Energy Potential	Key Biomass Resources
Brunei Darussalam	N/A	278 MW (annually)	Coconut shells, coconut and corn fibres, rice husks, sawdust
Cambodia	N/A	1,000 MW	Rubber, rice, maize, cassava stalk, sugarcane, groundnut, coconut, jatropha, oil palm
Indonesia	146.7 million tonnes	32,600 MW	Palm oil and sugarcane residues, rice husks and straw, corn cobs
Lao PDR	N/A	938 MW	Firewood, charcoal, agricultural residues
Malaysia	100 million dry tonnes	2,300 MW	Palm oil, sugarcane and coconut residues
Myanmar	20 million tonnes	6,900 MW	Paddy residues, firewood, agricultural residues
Philippines	N/A	210 MW	Agricultural residues, bagasse, rice husks, coconut shells
Singapore	N/A	92.34 MW (annually)	Horticultural waste, wood waste
Thailand	N/A	18,000 MW	Rice husks, bagasse, corn cobs, palm kernel shell
Viet Nam	N/A	7,000 MW	Rice husks and straw, forest residues, cassava

ASEAN = Association of Southeast Asian Nations, Lao PDR = Lao People's Democratic Republic, MW = megawatt, Myanmar = Republic of the Union of Myanmar, N/A = not applicable.
Source: ACE, (2025b); ACE (2024b).

A leading example of biomass co-firing in the region is Paiton 1–2 CFPP in Indonesia, which stands as Southeast Asia's largest biomass co-firing facility. By November 2023, the plant had consumed 126,000 tonnes of biomass, primarily sourced from wood sawdust, to generate 134,530 megawatt-hours of green energy. This initiative has avoided approximately 128,229 tonnes of CO_2 emissions, with biomass making up 3.25% of the plant's total fuel mix (ACE, 2024b and Boyle, 2020).

Another standout example is the Hotelkamp Power Plant in Papua, Indonesia, which holds the highest co-firing rate in Southeast Asia at 7.14%. By consuming 1,118 tonnes of biomass, the plant has produced 1,807 megawatt-hours of renewable electricity while achieving a CO_2 emissions reduction of 3,274 tonnes [10] [6]. These cases demonstrate that, even with modest co-firing rates, the emissions and sustainability gains can be substantial. Scaling up biomass co-firing across the region, however, will require key challenges to be overcome, particularly sustainable feedstock availability, logistics, and cost competitiveness, to ensure it becomes a mainstream component of ASEAN's CCT portfolio.

2.3. Key Enablers and Barriers to Clean Coal Technology Deployment in the Region

2.3.1. Enablers

The ASEAN region's readiness to adopt CCT is shaped by a mix of policy commitments, sector-specific regulations, and emerging frameworks for complementary technologies such as biomass co-firing and carbon capture. Across AMS, the policy landscape reveals diverse approaches, reflecting a delicate balance between meeting rising energy demand, sustaining economic growth, and addressing climate imperatives.

AMS are progressing along different pathways towards coal phase-down, signalling a region in transition. Indonesia's coal policy has evolved through a complex interplay of decarbonisation pledges, industrial demands, and financial constraints, resulting in selective restrictions, continued captive coal expansion, and a transition strategy increasingly reliant on international support. Malaysia's transition reflects a steadily intensifying commitment to carbon neutrality by 2050, anchored by a clear moratorium on new coal projects and a phased retirement strategy that culminates in a full coal exit by 2044.

The Philippines, in turn, has adopted a conditional moratorium on new greenfield CFPPs, though exemptions remain for pre-approved projects. Its strategy increasingly centres on early retirements and a pragmatic balancing of supply security with climate goals. Viet Nam's coal trajectory is framed by a justice-driven narrative that emphasises fairness in global climate responsibility, balancing its rapid industrialisation with a gradual decline in coal capacity.

Co-firing with biomass is emerging as one of the most widely promoted CCT options in the region, supported by clear policy frameworks in several AMS (ACE, 2025a; EIA, n.d.).

- Indonesia has issued two key regulations: the Minister of Energy and Mineral Resources Regulation No. 12/2023, which governs biomass supply, pricing, safety, and incentives; and PLN's Director Regulation No. 004/DIR/2022, which sets technical and monitoring standards for co-firing, aligning the practice with renewable energy targets.

- Malaysia's Renewable Energy Roadmap positions bioenergy as a core strategic pillar, calling for the development of equitable and feasible support mechanisms for biomass co-firing.
- Thailand's Alternative Energy Development Plan 2018 targets a 30% renewable share by 2037, with community-based biomass projects forming part of the expansion strategy.
- Viet Nam's Power Development Plan VIII outlines a staged transition for existing coal plants, introducing biomass co-firing after 20 years of operation, with a gradual increase to 100% biomass fuel by 2050, at which point coal-fired generation will be phased out entirely.

While CCS/carbon capture, utilisation, and storage (CCUS) remains at an early stage in ASEAN, pioneering regulations are beginning to take shape.

- Malaysia's CCUS Act 2025 establishes a comprehensive regulatory framework covering the full CCUS value chain, capture, transport, utilisation, and permanent storage, applicable to all industrial facilities, including CFPPs, without explicitly singling them out (Baker McKenzie, 2025; GEM, n.d.).
- Indonesia has enacted Presidential Regulation No. 16/2024 and MEMR Regulation No. 16/2024, providing a general legal basis for CCS deployment across sectors (Draps and Ibnuaji, 2025; NMA, 2016).
- Other AMS, such as Thailand, Viet Nam, and the Philippines, have acknowledged CCS in their energy transition frameworks but remain in the conceptual or early development stage without dedicated regulations.

These enabling factors, ranging from coal transition pledges to technology-specific policy instruments, form the foundation for scaling up CCT adoption. They provide not only the regulatory certainty needed to attract investment but also a roadmap for integrating cleaner coal use into national energy transition strategies.

2.3.2. Barriers

While the ASEAN region possesses the technical potential and policy entry points for CCT adoption, multiple structural, financial, and logistical barriers continue to slow deployment. These challenges are interconnected, reflecting both regional realities and broader global trends in coal financing and policy.

High capital expenditure costs. Advanced boilers require significant upfront investment compared to conventional subcritical units. For instance, the International Energy Agency estimates that upgrading a subcritical plant to USC technology can cost between US$500–

US$1,000 per kilowatt or around 25%–50% increment[3], while integrating CCS/CCUS can increase capital costs by 50%–100% depending on scale and technology maturity (Burnard, et al.; ACE, 2025a). In ASEAN markets, where electricity tariffs are often regulated and low, these additional costs present a major barrier, especially when the perceived payback period is extended. Without dedicated financing mechanisms, operators are hesitant to commit to such high-cost retrofits, even if they offer long-term efficiency and emissions benefits.

Lack of clear regulatory incentives. In many AMS, regulatory frameworks do not yet provide the long-term certainty needed to justify large investments in CCT. While renewable energy benefits from feed-in tariffs, tax incentives, and clear targets in some countries, CCT often fall into a policy grey area, acknowledged as a transition technology but without explicit, enforceable support measures. For example, while Indonesia and Malaysia have begun integrating biomass co-firing and CCS into national plans, there are still no widespread fiscal tools such as carbon pricing, production tax credits, or accelerated depreciation schemes to make these investments competitive. Without stable, technology-specific incentives, project developers face uncertainty that discourages adoption.

Limited domestic and international financing. The global financial landscape for coal has shifted dramatically over the past decade, with many international lenders, multilateral banks, and export credit agencies adopting strict coal exit policies. According to the Institute for Energy Economics and Financial Analysis, over 200 major financial institutions worldwide have announced restrictions on coal financing, particularly for unabated projects (Trivedi and Srivastava, 2023; ACE, 2025b). This trend extends to transitional coal investments, including retrofits with CCT, which are sometimes viewed as prolonging coal's operational life rather than accelerating its phase-down. As a result, AMS face a financing bottleneck, domestic banks have limited appetite for high capital expenditure (CAPEX) power sector upgrades, and international funds are increasingly conditioned on strict emissions-reduction timelines.

Biomass supply-chain constraints and sustainability risks. Biomass has emerged as a leading candidate for co-firing in ASEAN's coal fleet, supported by the region's vast agricultural sector. Yet, despite abundant feedstock potential, biomass deployment in CFPPs is hindered by persistent supply-chain challenges. Biomass feedstocks require consistent quality, moisture control, and specific processing to maintain combustion efficiency. This adds logistical and cost burdens, especially for plants located far from major agricultural hubs (ACE, 2024b). Even in Indonesia, which boasts substantial agricultural output, securing a stable year-round biomass supply has proven challenging.

Moreover, biomass sourcing must navigate sustainability risks, including land-use competition with food production, biodiversity loss, deforestation, peatland degradation,

[3] Based on a reasonable midpoint baseline of the capital cost in creating a new subcritical CFPP at US$2,000 per kilowatt.

and potential social conflicts over resource allocation. These concerns are increasingly scrutinised by investors and international markets, meaning that without robust certification schemes and traceability systems, biomass co-firing could face both reputational and policy pushback.

Financial hurdles in retrofitting coal-fired power plants for co-firing and carbon capture and storage/carbon capture, utilisation, and storage. Retrofitting existing coal plants to integrate biomass co-firing or CCS/CCUS is recognised by the International Energy Agency as a pragmatic step towards emissions reduction while maintaining grid stability (IEA, n.d.; Baker McKenzie, 2025). However, these retrofits require substantial investment not only in plant modification but also in associated infrastructure such as biomass handling systems or CO_2 transport and storage facilities. Despite the technical feasibility, these projects have yet to secure strong backing from either domestic or international financial institutions. This is partly due to the perceived high risk of stranded assets, particularly if policy shifts accelerate coal phase-out schedules. Without targeted financial instruments, such as concessional loans, blended finance mechanisms, or guarantees, these promising retrofit pathways may remain underutilised in the region.

Hence, while ASEAN's policy commitments, regulatory initiatives, and early project deployments demonstrate that the region has a clear entry point for CCT adoption, the previously mentioned enablers cannot be fully leveraged without addressing the systemic barriers outlined above. High-CAPEX requirements, uncertain regulatory incentives, and limited financing create a challenging investment environment, while biomass supply-chain issues and sustainability risks add further complexity.

The gap between political ambition and on-the-ground implementation underscores the need for targeted interventions that can de-risk projects and accelerate adoption. Without these measures, CCT deployment risks remaining a series of isolated pilot initiatives rather than a region-wide transition pathway, limiting ASEAN's ability to meet its energy security and climate goals in tandem.

2.4. Strategic Connection to Transition Pathways

CCT and CFPP repurposing are often perceived as separate strategies, one seeking to extend the operational life of coal assets in a cleaner way, the other aiming to transition those assets away from coal entirely. In reality, the two approaches are not mutually exclusive, rather, they form part of a continuum of transition pathways that AMS can deploy to balance energy security, climate objectives, and economic considerations.

In the short to medium term, CCT deployment, through measures such as boiler efficiency upgrades, biomass co-firing, and, in the near future, CCS, can deliver immediate emissions reductions while maintaining the baseload stability that coal currently provides. These interim solutions help to 'buy time' for the region to scale up renewable energy capacity and grid flexibility. For newer CFPPs, particularly those with decades of operational life remaining, integrating CCT can also preserve asset value and reduce the stranded asset risk that abrupt phase-outs might entail (Table 2.3).

Table 2.3. Strategic Transition Timeline through Clean Coal Technology Adoption and Coal-Fired Power Plant Repurposing

<table>
<tr><th colspan="3">Clean Coal Technology Adoption → Coal-Fired Power Plant Repurposing</th></tr>
<tr><th>Immediate term
(2025–2030)</th><th>Medium term
(2030–2040)</th><th>Long term
(2040–2050)</th></tr>
<tr><td>• Deploy readily available CCT: boiler efficiency upgrades, biomass co-firing (5%–20% blends), and plant efficiency optimisation.
• Strengthen policy and regulatory frameworks for CCT adoption, including incentives for biomass supply chains.
• Begin CCUS-readiness integration into plant design for new builds and retrofits.
• Pilot integration of renewable energy (e.g., solar photovoltaics) and BESS at CFPP sites to complement plant operations and provide grid services.</td><td>• Scale biomass co-firing ratios to 50%–100%, with parallel biomass supply-chain expansion.
• Introduce hydrogen and ammonia co-firing, building on pilot projects to gradually substitute coal with cleaner fuels and prepare plants for deeper decarbonisation.
• Deploy first commercial CCUS projects in CFPPs where technically and economically viable.
• Implement large-scale retrofits and hybridisation of CFPP sites, transforming them into renewable–storage hubs with significant renewable energy and BESS capacity.</td><td>• Full or majority repurposing of CFPPs to non-coal uses:
  ◦ 100% biomass or green hydrogen/ammonia firing
  ◦ Conversion to renewable-powered industrial hubs
  ◦ Use as backup/peaking plants with storage integration
• Decommissioning of residual coal units based on remaining economic life and grid needs.</td></tr>
<tr><td>Objective: Reduce emissions intensity while maintaining baseload power; preserve asset value of newer CFPPs.</td><td>Objective: Gradual fuel shift, reduced coal dependency, and operational flexibility for repurposing.</td><td>Objective: Achieve net-zero compatible power sector with repurposed assets contributing to energy security.</td></tr>
</table>

BESS = battery energy storage system, CCT = clean coal technology, CCUS = carbon capture, utilisation, and storage, CFPP = coal-fired power station.
Source: ACE, (2024b).

At the same time, early adoption of CCT can serve as a stepping stone towards full or partial repurposing. For example:

- Boiler upgrades not only enhance efficiency during coal operations but can be adapted for future co-firing with higher biomass ratios or other low-carbon fuels.
- Biomass co-firing can gradually increase renewable input into CFPPs, paving the way for complete conversion to 100% biomass or other sustainable fuels.

- CCUS-readiness in plant design can ensure that, when capture technologies become commercially viable in the region, retrofitting is technically and economically feasible.

From a policy and financing perspective, linking CCT adoption with repurposing strategies creates stronger investment cases for development finance institutions (DFIs) and private investors. This 'dual-purpose' framing, where current CCT investments are structured to enable future repurposing, can attract concessional finance and blended capital, especially from climate-aligned funding sources. For AMS with younger coal fleets, this integrated approach is particularly strategic, as it avoids locking in high-emission pathways while keeping the door open for deep decarbonisation measures.

Ultimately, ASEAN's readiness for CCT adoption should not be seen as an end state but as an enabling phase in a longer-term transition roadmap. By designing CCT interventions with repurposing compatibility in mind, AMS can ensure that today's investments serve both immediate emissions reduction needs and the structural transformation of the power sector. This forward-looking alignment will be critical to meeting the region's twin imperatives, sustaining energy security in the near term and achieving net-zero targets in the decades ahead.

Chapter 3

Strategic Mechanism to Finance Coal-Fired Power Plants Transition in ASEAN

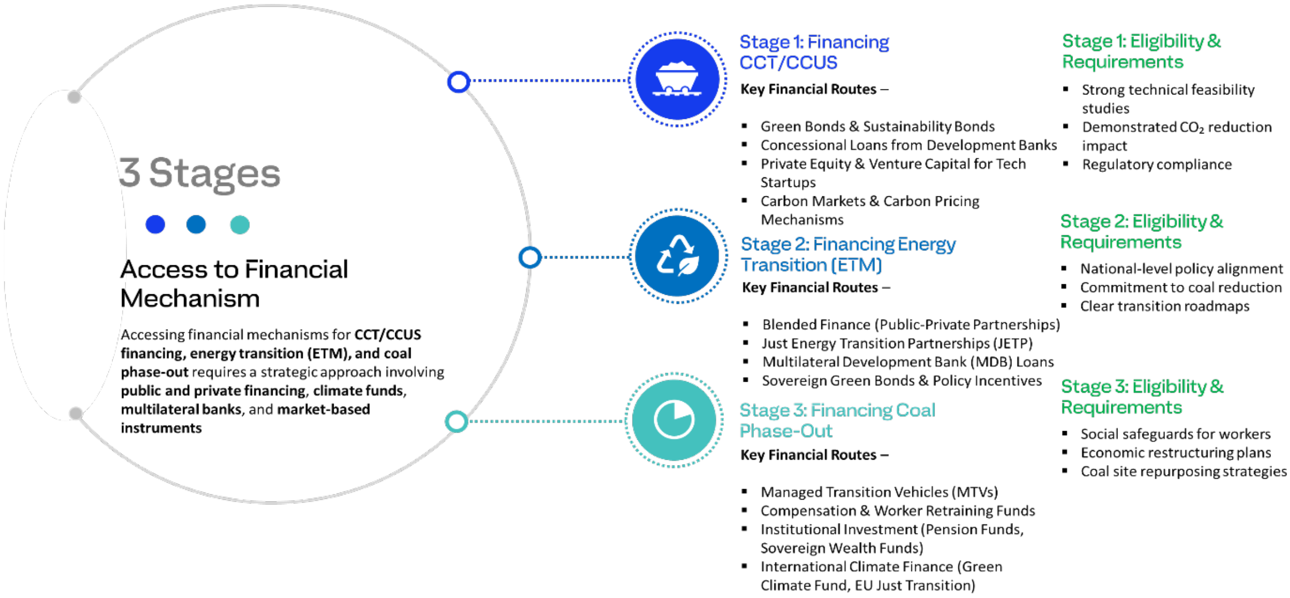
3.1. Stages of Innovative Financing Mechanism for the Transition

The urgency of transitioning CFPPs toward cleaner energy pathways is growing, particularly in ASEAN, where coal remains a dominant part of the energy mix but is increasingly under pressure from climate commitments and market shifts. In the region, a structured approach that begins with deploying CCT, progresses toward plant repurposing, and ultimately facilitates phase-out, provides a realistic and politically feasible transition pathway. Innovative financing solutions are central to enabling each stage of this progression, as they can address the unique technical, economic, and policy barriers faced along the way.

In the first stage, financing mechanisms focus on accelerating CCT deployment to enhance plant efficiency, reduce emissions, and prepare CFPPs for future integration with low-carbon systems. This may involve concessional loans, blended finance structures, or green bonds earmarked for technology upgrades such as HELE boilers, biomass co-firing systems, or pilot-scale CCS facilities. Such instruments can lower the cost of capital for upgrades and attract both domestic and international investors willing to support transitional climate actions.

The second stage shifts toward repurposing CFPPs for cleaner operations. Financing in this stage supports structural retrofits and integration of renewable generation or storage technologies, such as adding biomass co-firing at higher blending rates, integrating solar photovoltaics, or deploying battery energy storage systems (BESS). Mechanisms here often combine concessional finance from multilateral development banks (MDBs) with commercial lending, supported by policy incentives, capacity-building grants, and regulatory reforms that improve the bankability of repurposing projects (Figure 3.1).

Figure 3.1. Pathways to Access Financing Mechanisms across Stages of Coal Transition in ASEAN



ASEAN = Association of Southeast Asian Nations, CCT = clean coal technology, CCUS = carbon capture, utilisation, and storage, CO_2 = carbon dioxide, EU = European Union.
Source: Eninrac Consulting (2025).

In the final stage, financing solutions enable managed phase-out of CFPPs. This stage relies on more complex instruments such as transition credits, refinancing packages to lower weighted average cost of capital (WACC), or re-gearing approaches to release equity value early. These mechanisms are often complemented by just transition financing to address workforce reskilling, community redevelopment, and environmental remediation. international initiatives such as the Energy Transition Mechanism (ETM) by the Asian Development Bank (ADB) or similar coal retirement facilities demonstrate how blended finance and policy alignment can shorten plant lifespans without imposing undue financial losses on asset owners.

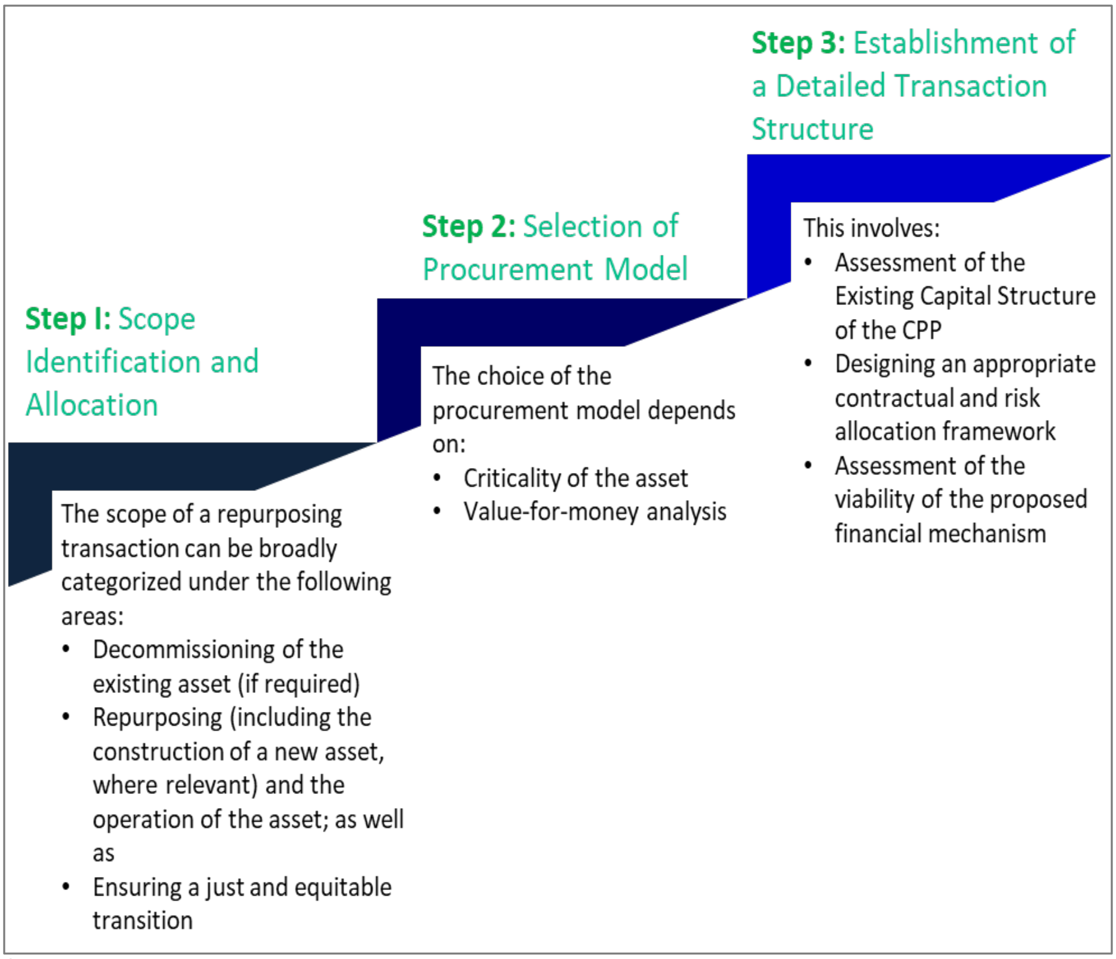
This staged approach also ensures that existing infrastructure is optimised before retirement, avoiding stranded assets, supporting economic resilience, and delivering measurable emission reductions along the way.

3.2. Key Principles for Designing Financial Mechanism

Designing financial mechanisms for CFPP transitioning requires careful consideration of both economic and social dimensions to ensure long-term viability, as depicted in Figure 3.2. The first principle is ensuring financial sustainability. Mechanisms must be structured with a full understanding of their implications for all stakeholders, particularly current asset owners. The feasibility of a repurposing solution depends on factors such as the existing plant's cash flows, the chosen repurposing pathway, and the financial structure itself.

For plants operating under long-term take-or-pay power purchase agreements (PPAs) and secured coal supply contracts, cash flows tend to be stable and predictable. In such cases, owners are more likely to participate in repurposing initiatives if deal structures can guarantee continued financial certainty, such as long-term renewable energy PPAs that provide comparable stability when a coal unit is converted to solar or another clean energy use.

Figure 3.2. Essential Steps for Designing a Financial Framework for Coal-Fired Power Plants Repurposing Transactions



CPP = coal power plant.
Source: Eninrac Consulting (2025).

The second principle is scalability. Financial mechanisms should be designed not merely as bespoke solutions for individual assets but as frameworks that can be replicated across multiple plants and geographies. Leveraging public funds to crowd in private sector investment is central to achieving this scale, ensuring that mechanisms can deliver the level of transformation required to meet the Paris Agreement's 1.5°C climate target. Standardised, replicable templates can lower transaction costs, streamline implementation, and enhance investor confidence, making them essential to building scalable solutions.

The third principle is maximising impact through strategic allocation of scarce financial resources. In coal-dependent economies, achieving significant emission reductions will require large-scale repurposing programmes. Given the finite pool of concessional and public finance available, it is critical that funding is directed towards plants that would otherwise continue to operate under business-as-usual scenarios, rather than subsidising capacity already nearing natural retirement. By focusing only on plants with a high likelihood of continued operation, financing mechanisms can ensure that every dollar mobilised delivers additional decarbonisation impact, thereby accelerating progress towards global climate goals.

Finally, transitioning CFPPs must be grounded in the principle of a just, equitable, and sustainable transition. Coal remains strategically significant in many countries, supporting not only plant owners but also workers, coal miners, freight operators, and local communities. Repurposing therefore risks disrupting entire value chains and livelihoods.

Financial mechanisms must explicitly address these challenges by embedding social equity measures such as worker retraining programmes, community-led renewable energy initiatives, and economic diversification strategies in coal-dependent regions. By ensuring that the transition is inclusive and equitable, financing frameworks can help build resilient, sustainable economies that benefit all stakeholders while minimising the social costs of decarbonisation.

3.3. Designing a Financial Framework for Coal-Fired Power Plants Transitioning

3.3.1. Immediate Term (2026–2030)

Financing efforts for CFPP transitioning will need to focus on readily available CCT such as boiler efficiency upgrades, modest biomass co-firing, and pilot integration of renewable energy and battery storage at plant sites. These projects are often small in scale, relatively high in perceived risk, and require public intervention to attract private participation.

Blended finance and project preparation facilities can play a catalytic role by providing concessional loans, grants, or guarantees that de-risk early investments, while public subsidies and regulated price support, such as Indonesia's government-mandated biomass price ceilings, help ensure predictable cash flows for utilities and suppliers. Public–private partnerships (PPPs) are also essential at this stage, with governments and state utilities providing policy frameworks and seed funding, and private actors delivering technology and capital where risk is mitigated.

Leadership in this phase is therefore best shared between governments, DFIs, and the private sector. Governments must set the enabling policy environment, create fiscal incentives, and mobilise international climate funds, while private companies bring operational expertise and innovation.

However, several challenges must be addressed. For boiler efficiency upgrades and optimisation measures, the main risks lie in securing financing for projects with relatively modest returns and in ensuring consistent technical performance. For co-firing, reliable biomass supply chains remain a key bottleneck, with feedstock availability, logistics, and price competitiveness all posing risks. Meanwhile, early integration of renewables and battery storage faces challenges related to grid compatibility, project bankability, and technology costs.

Across all options, policy uncertainty and slow permitting processes remain cross-cutting barriers, highlighting the importance of clear, stable regulations and streamlined approval procedures. If effectively managed, financing mechanisms in this phase can support emissions reductions, preserve the value of existing CFPPs, and build the foundation for larger-scale repurposing in the following decades.

Medium Term (2030–2040)

The medium term marks a shift from incremental efficiency improvements toward more comprehensive repurposing of CFPPs. During this phase, financing mechanisms are expected to evolve from government-led initiatives to mixed public–private frameworks. These will support deeper decarbonisation strategies, including high-ratio biomass or ammonia co-firing, partial CCS retrofits, and integration of renewable energy and BESS to hybridise generation assets. As plants age and amortise their initial debt, refinancing and re-gearing instruments become more attractive, providing opportunities to unlock equity value for reinvestment in clean technologies.

At this stage, financing is likely to rely on a combination of concessional capital, commercial lending, and transition finance instruments, designed to bridge the gap between climate objectives and market risk appetites. Public funds, through green or transition bonds, multilateral climate facilities, and sovereign guarantees, continue to play a catalytic role in crowding in private investors. However, as technologies mature and regulatory frameworks stabilise, the share of private capital grows substantially. Instruments such as sustainability-linked loans, carbon contracts for difference, and green securitisation can offer bankable pathways for investors seeking predictable returns tied to verified emission reductions.

The medium term also introduces greater emphasis on market-based mechanisms. Carbon pricing, emissions trading schemes, and the monetisation of verified carbon credits can strengthen financial viability for plant repurposing and partial CCS integration. Countries with stronger institutional capacity, such as Indonesia, Malaysia, and Viet Nam could begin piloting CFPP transition auctions or performance-based subsidies to drive competition amongst project developers and financiers. Meanwhile, regional facilities, such as the ASEAN Catalytic Green Finance Facility and Just Energy Transition

Partnerships, could be scaled up to support project aggregation and reduce transaction costs across multiple jurisdictions.

Despite the growing maturity of financing structures, several challenges will persist. The high capital intensity of CCS retrofits and the logistical complexity of ammonia and biomass co-firing require stable, long-term policy commitments and transparent pricing mechanisms. Financial institutions will demand clear standards for 'transition-aligned' investments to avoid reputational and regulatory risks associated with greenwashing. In addition, ensuring equitable access to finance across ASEAN's diverse economies remains crucial, as smaller or less creditworthy markets may still require concessional support to maintain momentum toward decarbonisation.

Long Term (2040–2050)

The long term represents the culmination of ASEAN's coal transition, where the focus shifts decisively from incremental decarbonisation to complete transformation or retirement of coal assets. By this stage, most existing CFPPs will have reached or exceeded their technical lifespans, and their economic competitiveness, relative to renewables and storage, will have significantly eroded. Financing mechanisms thus evolve toward supporting large-scale clean energy deployment, decommissioning programmes, and site repurposing, marking the final phase in the region's power sector decarbonisation pathway.

In this period, market maturity and policy alignment become defining features. Power market liberalisation in several AMS is expected to allow for open competition between renewable and storage technologies, supported by digitalised grids and regional interconnections under the ASEAN Power Grid framework. Financing flows will be driven predominantly by private capital, guided by robust carbon markets, regional taxonomy harmonisation, and stable renewable energy standards.

Instruments such as green asset-backed securities, carbon credit derivatives, and climate-aligned infrastructure funds will mobilise long-term institutional investment from pension funds, insurance companies, and sovereign wealth funds seeking predictable, low-carbon returns.

A significant share of capital in this period will also be directed toward asset retirement and repurposing, ensuring that stranded CFPPs can be transformed into economically productive assets. Decommissioned sites can host solar photovoltaics, BESS, or green hydrogen facilities, leveraging existing grid interconnections, water infrastructure, and transmission assets.

Financing models such as public decommissioning funds, asset recycling programmes, and land-use transition schemes can be employed to manage the financial and social costs of plant closure. Multilateral institutions, working with governments and utilities, may provide concessional capital or results-based payments to support social protection measures, workforce retraining, and community revitalisation.

However, the long-term transition will not be without challenges. The management of residual emissions, particularly from partially decarbonised or flexibly operated coal plants, may still require limited CCS application or carbon offsetting. There will also be political and fiscal pressures to ensure that energy security, affordability, and employment remain balanced as the region transitions away from coal. Strong institutional co-ordination, across energy, finance, and labour ministries, will be essential to maintain social licence and investor confidence throughout the process.

Ultimately, by 2050, ASEAN's financing landscape for coal transition will have evolved from publicly driven mitigation efforts to a mature, market-integrated clean energy economy, underpinned by regional co-operation, carbon market convergence, and sustainable infrastructure investment. The long-term phase thus represents not only the end of the coal era, but the beginning of a new cycle of low-carbon industrialisation and regional energy integration.

Table 3.1. Financing Mechanism by Term and Leadership

Term	Key Financing Mechanism and Tools	Likely Leadership/Actors	Rationale and Relevance with ASEAN
Immediate term (2026–2030)	• Blended finance/project preparation facilities: small-scale grants, concessional loans, public guarantees to de-risk early projects like biomass co-firing, solar photovoltaics and BESS pilot integrations. • Public subsidies/regulated price supports: biomass price ceilings; feed-in tariffs (or similar) to guarantee revenue flows. • Public–Private Partnerships: Where utilities partner with private technology providers/contractors to implement pilot retrofit or renewable energy and storage projects. • Government grants/tax incentives: for investments in CCT (advanced boilers, efficiency upgrades), renewable energy/BESS deployment.	• A mixed model: strong government backing, with private sector as implementing partner. • Government sets regulatory frameworks, provides public funds or concessional financing; private sector brings capital, technical expertise. • Relevant public bodies (energy ministries, state utilities), development finance institutions, possibly international climate funds.	• PLN in Indonesia expanding biomass co-firing, using government regulation to set biomass price ceilings and securing supply contracts via SOEs and communities [17]. • ASEAN Centre for Energy paper highlights using blended finance and project preparation facilities to bypass early-stage barriers [18].
Medium term (2030–2040)	• Commercial CCUS financing instruments: hybrid contracts for difference, 'payment for low-carbon generation' models, public support for CO_2 transport & storage infrastructure. • Green bonds/sustainability-linked debt: for larger-scale hybrid/retrofit/hybrid renewable energy and storage installations, to mobilise private capital.	• Mixed, leaning more toward private sector with strong government/public sector support. • Governments to enable via regulation, PPAs, subsidy regimes, and infrastructure investment; private capital for CAPEX, operations.	• UK's CCUS business model propositions: regulated Transport & Storage networks, low-carbon generation payments [19]. • ASEAN's discussions on ETM and blended finance to drive CFPP retirement/repurposing. • Indonesia's biomass / co-firing scale-ups with government

Term	Key Financing Mechanism and Tools	Likely Leadership/Actors	Rationale and Relevance with ASEAN
	• Repurposing/hybridisation financing via long-term PPAs/revenue guarantees: to ensure stable returns when converting CFPPs. • Risk sharing mechanisms: guarantees, insurance, public funds to de-risk private investment in new technologies (hydrogen/ammonia co-firing, large biomass co-firing). • Regional or multilateral funds/JETPs/Just Energy Transition funding: to support larger transitions, policy reform, capacity building.	• Development banks, international climate finance, institutional investors (pension funds, green investment funds) would play a bigger role.	regulations combined with community-based biomass supply and private supplier contracts [20].
Long term (2040–2050)	• Asset retirement/buy-out funds/early retirement mechanisms: financial instruments to compensate owners of coal plants for retiring assets ahead of full economic life. • Large-scale green infrastructure funds/sovereign green investment banks: to finance full repurposing, renewable energy and storage hubs, transmission enhancement, cross-border grids. • Market incentives/carbon pricing/clean energy certificates/CfDs & capacity markets: To make clean energy and storage economically competitive as coal declines. • Private equity/institutional investment in clean energy/energy storage infrastructure: once technologies, markets, regulatory frameworks are matured. • Just transition financing: social funds, retraining programmes, community	• More government-led and public sector in setting up enabling frameworks; private & institutional capital to deploy and operate large clean energy/storage assets. • Governments, state utilities, regulators to define market structures; international climate finance, institutional investors, pension funds to commit large funds. • Possible involvement of green banks or state investment banks.	• UK's plans for CCUS, capacity markets, regulated asset base style funding for CO_2 transport and storage infrastructure. • Use of large sovereign/quasi-public green investment banks in places like Malaysia, Australia, and the UK to mobilise private capital at scale. (green banks concept) [21]. • JETP/ETM in Indonesia and Viet Nam: donor public + and private investment over longer-term horizons [22].

Term	Key Financing Mechanism and Tools	Likely Leadership/Actors	Rationale and Relevance with ASEAN
	development financed through public sources, possibly via climate funds or donor/multilateral programmes.		

ASEAN = Association of Southeast Asian Nations, BESS = battery energy storage systems, CAPEX = capital expenditure, CCT = clean coal technology, CCUS = carbon capture, utilisation, and storage, CFD = contracts for difference, CFPP = coal-fired power station, CO_2 = carbon dioxide, ETM = energy transition mechanism, JETP = Just Energy Transition Partnership, PLN = Perusahaan Listrik Negara, PPA = power purchase agreement, SOE = State-Owned Enterprise, UK = United Kingdom.

Source: ACE, (2024).

Hence, designing a robust financial framework for CFPP transitioning ultimately hinges on balancing risk, policy certainty, and social equity. Mobilising private capital in the early phases requires governments to reduce perceived regulatory, fuel supply, and technological risks through clear and consistent policy signals. Addressing supply-chain vulnerabilities, such as ensuring the reliability of biomass or renewable inputs, is equally important to provide investors with confidence in revenue stability and input costs.

Streamlined permitting and reduced transaction costs further strengthen the enabling environment, helping early projects reach bankability. As the transition progresses, attracting institutional investors such as pension and sovereign wealth funds will depend on achieving sufficient scale, stable returns, and low risk, conditions typically found in the medium to long term.

Finally, ensuring a just and inclusive transition remains essential. Financial mechanisms should integrate dedicated provisions for worker retraining, community development, and social safeguards, recognising that maintaining political and social legitimacy is as critical as achieving financial and environmental sustainability.

Chapter 4

Cost Assessment for Transition Pathways

4.1. Overview of Financial Requirements for Coal-Fired Power Plant Transitioning

Transitioning CFPPs in ASEAN presents significant financial and systemic challenges. Most CFPPs are built with an expected operational lifespan of around 25 years, and the financing structures behind these assets are designed accordingly (Kutani, Namba, and Phoumin, 2023; Draps and Ibnuaji, 2025). Accelerating the retirement of these plants before the end of their planned lifetime could result in substantial financial losses for plant owners, investors, and utility companies, who may be left with stranded assets and underperforming portfolios. Meanwhile, CFPPs that operate beyond their amortisation period often face shrinking profitability and increased policy scrutiny due to their environmental footprint, creating a different set of challenges.

Compounding the financial risk is a shifting investment landscape. Financial institutions globally are tightening restrictions on coal-related lending. ADB, for instance, has announced that it will no longer finance upgrades or modernisation of existing coal infrastructure, a position echoed by major Malaysian banks such as Maybank and CIMB, both of which have committed to phasing out coal financing (E3G, n.d.; Reuters, 2020; Reuters, 2021; Burnard, et al., 2014; Trivedi and Srivastava, 2023; IEA, n.d.).

Meanwhile, international financial institutions in countries like Japan, China, and the Republic of Korea continue to provide support for Southeast Asia's coal sector. However, pressure is growing, both from civil society and international climate accords, for stronger commitments to phase out coal and adopt responsible lending practices (CEED, 2025; Argus, 2024).

Amid these dynamics, Indonesia has emerged as a policy front-runner by establishing a formal roadmap through the MEMR Regulation No. 10 of 2025 (Nurmansyah et al., 2025; Maulana et al., 2023). This regulation sets out a framework for early retirement of CFPPs and outlines how financial sector participation will be mobilised in support of the transition. This development, supported by ADB, signifies the importance of aligning regulatory, financial, and investment tools to manage the early phase-out process effectively. Other countries in the region are also beginning to explore similar strategies, though progress varies widely.

Beyond financing, the question of what happens post-retirement is becoming increasingly urgent. As CFPPs are taken offline, nations must consider how to repurpose or decommission these assets. Repurposing for renewable energy integration or storage can reduce economic losses and contribute to decarbonisation goals. However, decommissioning also implies the need for massive infrastructure rollouts to fill the energy supply gap, particularly through renewable energy and BESS.

This technical transition introduces new cost burdens. Many AMS have already faced challenges with grid instability and power intermittency due to the variable nature of renewable energy, and addressing these issues demands investment in grid modernisation, smart grid technologies, and flexible power generation such as natural gas peakers. Technologies like pumped-storage hydropower and compressed-air energy storage are also crucial, but they require long lead times and substantial capital.

Data from regional studies, including the 8th ASEAN Energy Outlook and the 2nd ASEAN Renewable Energy Outlook, highlight how investment needs to sharply increase in scenarios with deeper decarbonisation pathways (ACE, 2024a; IRENA and ACE, 2022; Saha, Mittal, and Basu Roy, 2024; King, Ferrier, and Campbell, 2024). For instance, a pathway aligned with the 1.5°C climate target would necessitate achieving a 90% share of renewable energy in power generation and a 52% share of electricity in final energy consumption. Under such a scenario, power sector investments would need to be five to six times higher than those estimated under the Carbon Neutrality Scenario, underscoring the magnitude of the financial transformation required.

The financial requirements for transitioning CFPPs in ASEAN follow a staged pathway that begins with the deployment of CCT and evolves towards repurposing or phasing down coal assets over time. In the near term, capital will be required for investments such as boiler upgrades, biomass co-firing infrastructure, and pilot-scale carbon capture projects. These initiatives aim to improve plant efficiency, reduce emissions intensity, and extend the operational viability of existing assets while preparing them for eventual repurposing. In the medium to long term, financing needs will shift towards large-scale fuel switching, integration of CCUS, and the conversion of CFPP sites to non-coal uses, such as renewable generation hubs, industrial facilities, or grid-support services.

Multiple cost drivers influence this transition. These include the investment required for CCT retrofits, the premature retirement or conversion of relatively young coal plants, stranded asset risks, decommissioning costs, and the high CAPEX for alternative generation and storage technologies. Additional expenses arise from upgrading grid infrastructure to accommodate a changing power mix, as well as uncertainties around coal project refinancing, evolving regulations, and increasing expectations for climate-aligned investments.

The economic gap, defined as the difference between capital available under current conditions and what is required to achieve a low-carbon, CCT-enabled, and repurposing-ready power sector, remains wide. Bridging this gap will demand not only significant capital mobilisation but also the deployment of de-risking mechanisms, concessional finance, and credible national transition strategies. These strategies must demonstrate a clear, bankable pathway from immediate-term CCT adoption to medium- and long-term

CFPP repurposing, thereby attracting a diverse set of public, private, and multilateral funding sources.

4.2. Cost Assessment for Transition Pathways

Cost Assessment for Retrofitting Existing Coal-Fired Power Plants with Clean Coal Technologies

Retrofitting existing subcritical CFPPs with CCT represents a critical transitional step for decarbonising ASEAN's power sector while maintaining energy reliability. However, the CAPEX required for such retrofits varies considerably across regions, depending on factors such as plant age, design efficiency, and local cost structures.

Global benchmarks provide a useful reference point. In the US, retrofitting a 200 MW subcritical thermal power plant is estimated to cost approximately US$55.87 million, translating to around US$279,000 per MW. For larger 500 MW subcritical units, the per MW cost decreases to US$177,600, or US$88.8 million in total, reflecting economies of scale (Venkataraman et al., 2013; Mitsubishi Power, 2022).

Similarly, Germany's retrofit costs are estimated to range between US$132,000 and US$405,000 per MW, depending on the plant's condition and the complexity of the upgrade. In contrast, India demonstrates significantly lower retrofit costs, between US$2,400 and US$5,400 per MW, primarily due to lower labour and material costs, as well as standardised, domestic retrofit technologies (Wiranegara, 2022; Pradnyaswari, Batrisyia, and Rakhiemah, 2024).

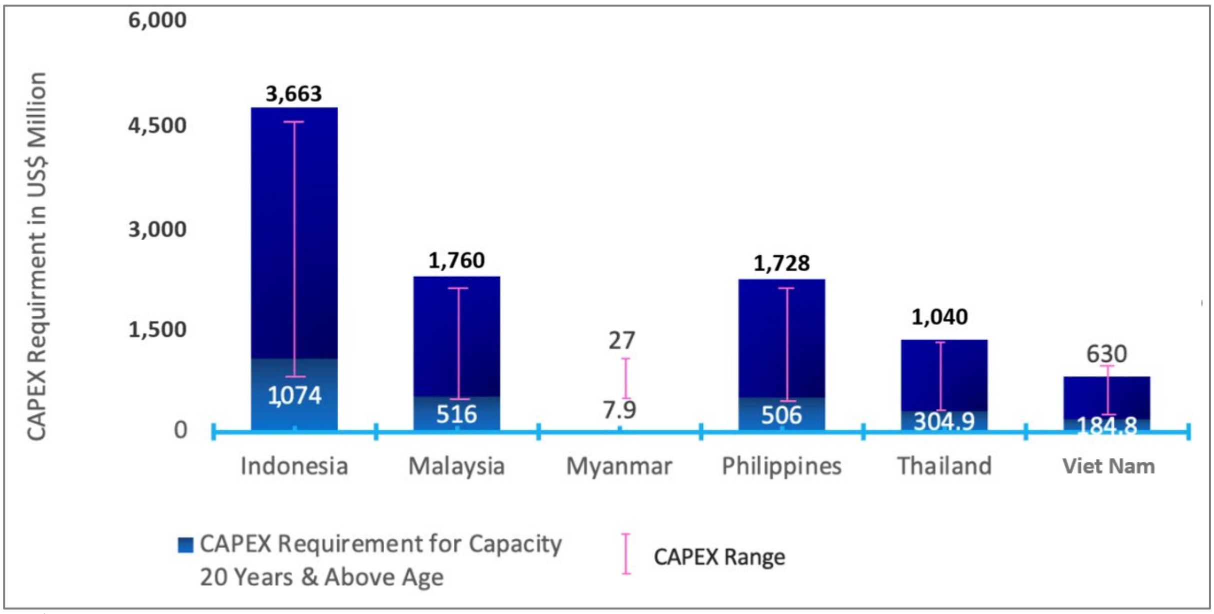
For ASEAN, a dual benchmark approach has been applied based on plant age to estimate retrofit costs more accurately. For older CFPPs (over 20 years), German benchmarks have been used due to their relevance in ageing infrastructure retrofits. Conversely, Indian benchmarks are used for younger CFPPs (4 to 10 years old), as these plants are relatively modern and require less extensive upgrades. This tailored methodology ensures a more context-sensitive estimate for each national fleet.

Within the ASEAN region, approximately 16.84 GW of subcritical CFPP capacity is under 10 years old. Given their recent commissioning, these younger plants typically do not require major structural or environmental upgrades. Instead, retrofitting efforts focus on startup optimisation, condition monitoring, and emissions control enhancements, which are comparatively cost-effective. The estimated CAPEX for this younger fleet lies between US$40.4 million and US$90.9 million, depending on site-specific factors and technology choices.

In contrast, ASEAN hosts about 19.1 GW of subcritical CFPP capacity that is more than 20 years old. These ageing assets require far more extensive intervention, ranging from boiler and turbine refurbishments to flue gas desulphurisation and digital retrofits. As a result, the estimated CAPEX for this older fleet ranges significantly higher, from $2.5 billion to US$8.6 billion. These figures reflect the broader scope of work required to bring older units in line with efficiency and emissions standards aligned with modern CCT benchmarks.

Figure 4.1. Capital Expenditure Requirements for Modernising Subcritical Coal-Fired Power Plant Capacity Aged 20 Years and above in ASEAN Member States

(US$ million)



US$ = United States dollar, ASEAN = Association of Southeast Asian Nations, CAPEX = capital expenditure. Myanmar = Republic of the Union of Myanmar.
Source: Eninrac Consulting (2025).

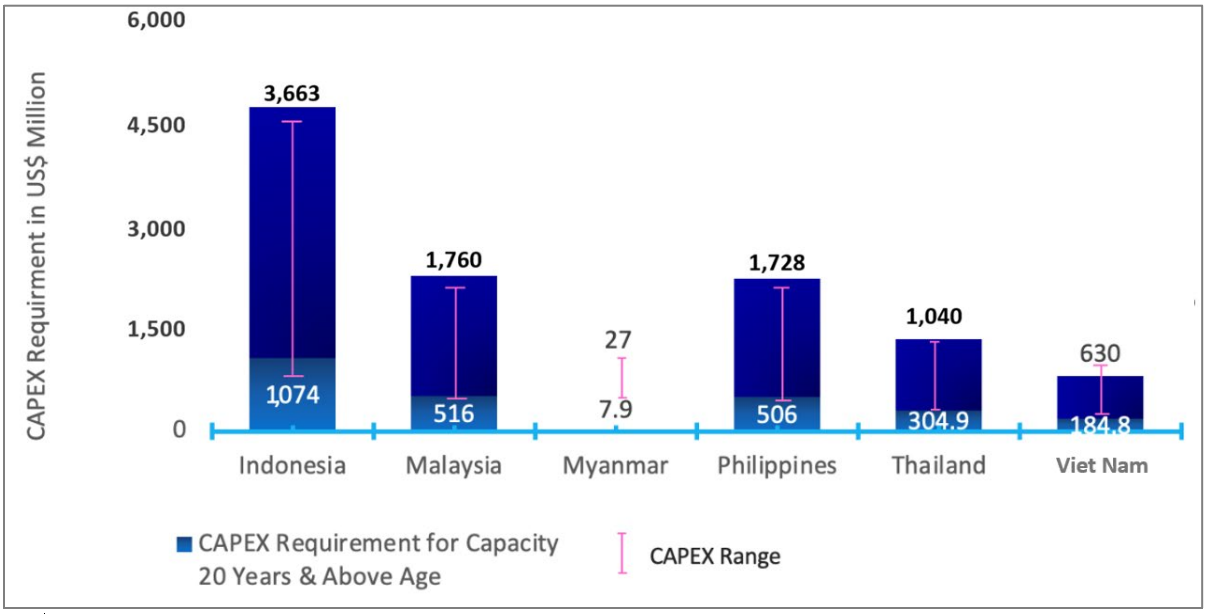
Modernising older CFPPs comes with substantial financial implications due to the extensive rejuvenation needed to meet contemporary efficiency and environmental standards, as depicted in Figure 3.1. Indonesia stands out with the highest CAPEX requirement, estimated at US$1.07 billion, with an upper bound reaching US$3.66 billion, reflecting the country's large ageing coal fleet. Malaysia and the Philippines follow closely, with base CAPEX estimates of US$516 million (Malaysia) and US$506 million (the Philippines). Their upper bounds are similarly high, at US$1.76 billion for Malaysia and US$1.73 billion for the Philippines. Thailand's requirement is also notable, amounting to US$305 million with a maximum of US$1.04 billion.

In contrast, the Republic of the Union of Myanmar and Viet Nam show lower base estimates – US$7.9 million and US$184.8 million, respectively – though the Republic of the Union of Myanmar has a relatively large CAPEX range reaching US$27 million, suggesting potential cost volatility or data uncertainty. These variations reflect both the size and condition of the respective ageing coal fleets, as well as differences in retrofit scope.

In contrast, as shown in Figure 3.2, retrofitting younger CFPPs is comparatively less capital-intensive, primarily involving efficiency enhancements and minor technological upgrades rather than full-scale overhauls. Viet Nam and Indonesia again top the list, with base CAPEX requirements of US$14.6 million (for Viet Nam) and US$14 million (for Indonesia). Their upper-bound estimates rise sharply to US$33 million for Viet Nam and US$32 million for Indonesia, indicating a significant cost spectrum due to plant size differences and varying retrofit strategies.

Figure 4.2. Capital Expenditure Requirements to Retrofit Subcritical Coal-Fired Power Plant Capacity Aged under 10 Years in ASEAN Member States

(US$ million)



US$ = United States dollar, ASEAN = Association of Southeast Asian Nations, CAPEX = capital expenditure, Myanmar = Republic of the Union of Myanmar.
Source: Eninrac Consulting (2025).

The Philippines, with a CAPEX requirement of US$6 million, also shows a wide range of up to US$14 million. Smaller ASEAN economies such as Brunei Darussalam, Cambodia, Lao PDR, and the Republic of the Union of Myanmar show minimal financial needs, each requiring well under US$10 million. For instance, Cambodia and Lao PDR require only US$0.64 million (Cambodia) and US$4.5 million (Lao PDR). These smaller figures reflect the limited size of newer subcritical coal fleets in these countries.

Comparing both charts reveals a stark contrast in financial scale. Retrofitting older CFPPs in ASEAN demands billions of dollars in investment, while younger plants only require tens of millions, highlighting a key strategic consideration. Governments and utilities may prioritise lower-cost, high-efficiency retrofits for younger fleets to achieve near-term gains, while longer-term decisions about older plants may lean toward retirement or repurposing, given the higher costs and emissions intensity.

These charts collectively show the uneven financial landscape for CFPP transition in ASEAN, both in terms of country-specific requirements and fleet age. Policymakers will need to adopt differentiated financing strategies, targeting cost-effective retrofits for young plants, while carefully evaluating whether older assets warrant retrofit investment, full repowering, or decommissioning under just transition frameworks.

Investment Requirements for Coal-Fired Power Plants with Biomass, Hydrogen, and Ammonia Co-Firing

Retrofitting existing CFPPs for biomass co-firing represents one of the most practical and cost-efficient decarbonisation pathways available to AMS in the near term. Based on international benchmarks and regional cost data, the CAPEX required for such retrofits typically ranges between US$50 and US$250 per kilowatt of installed capacity (Tavoulareas, 2024). This range reflects differences in plant design, boiler technology, and the extent of physical modifications required, ranging from relatively simple burner and fuel-handling adjustments at the lower end to more complex upgrades involving boiler reinforcements, advanced control systems, and additional storage infrastructure at the upper end.

When applied to a 300 MW subcritical unit, this translates to a retrofit cost of approximately US$15 million– US$75 million, while a 600 MW unit would require around US$30 million– US$150 million, and a 1,000 MW plant US$50 million– US$250 million. These costs are modest when compared with the multibillion-dollar investments required for CCS retrofits or full plant replacements with renewable capacity. At the regional level, the estimated CAPEX for ASEAN's younger subcritical fleet (around 16.84 GW) lies between US$0.8 billion and US$4.2 billion, whereas the older subcritical fleet (about 19.1 GW) would require US$1 billion– US$4.8 billion, depending on the site-specific scope and level of technological integration (Reza et al., 2025).

The overall cost rises with higher co-firing ratios, as greater shares of biomass require additional fuel preprocessing, storage, and boiler adaptation. For instance, increasing co-firing from a low blend of 5%–20% to a medium range of 30%–50% may raise retrofit costs by around 50%, while a high-blend scenario (≥50%) can potentially double the CAPEX requirement. Even so, co-firing remains far more financially accessible than most other decarbonisation measures and can be implemented incrementally, allowing utilities to scale investment alongside supply-chain maturity (Reza et al., 2025).

However, these retrofit figures reflect only the plant-side capital costs and exclude broader supply-chain investments that are often critical to project feasibility. Establishing reliable biomass feedstock systems, encompassing crop cultivation, collection, preprocessing (pelletisation or torrefaction), transportation, and storage, can significantly increase total costs. In regions where agricultural residues are dispersed or underutilised, the logistics component may become a dominant factor, sometimes exceeding the retrofit CAPEX itself. These considerations underscore the need for co-ordinated policy measures that support biomass aggregation hubs, logistics optimisation, and fuel price stability to complement plant-level investment.

From a financing perspective, the comparatively small scale of these retrofit investments makes them attractive to commercial lenders and public–private partnerships, particularly if revenue certainty is ensured through PPAs or co-firing mandates. Yet, predictable biomass supply and consistent policy support remain prerequisites for bankability. Without assurance of stable feedstock availability or clear regulatory frameworks, investors may perceive elevated risks, which could drive up financing costs and delay project implementation.

Beyond biomass, other emerging retrofit pathways under consideration for existing CFPPs include ammonia and hydrogen co-firing. These options are technologically more complex but offer a similar rationale, enabling partial substitution of coal with low-carbon fuels while maintaining the existing generation asset. From a CAPEX perspective, retrofit requirements for co-firing are relatively modest compared with full replacement or CCS installation. Evidence from Japan's ongoing programme suggests that enabling coal boilers to co-fire with ammonia may require a CAPEX increment of roughly 10%–15% of new-build costs, covering modifications to burners, combustion control systems, fuel storage, and safety infrastructure (Cordier, 2025).

These retrofit costs, though material, are small relative to the dominant cost driver, the production and delivery of low-carbon ammonia. Likewise, hydrogen co-firing retrofits show similar capital intensity for gas-turbine units, where manufacturers have begun supplying hydrogen-ready equipment or offering upgrade packages to allow blending of 10%–30% hydrogen by volume. For conventional coal boilers, the scope of modification is broader, encompassing adjustments to flame characteristics, nitrogen oxide control systems, and in some cases, heat-exchange optimisation, which can raise CAPEX but remains substantially below the cost of carbon capture or new-build low-carbon generation (Freitag et al., 2024).

Operationally, ammonia and hydrogen co-firing offer measurable emission benefits proportional to the blending ratio. Ammonia contains no carbon and hydrogen combustion produces only water, allowing direct reductions in CO_2 emissions from the fuel mix (Japan Beyond Coal, 2024). Pilot projects, notably Japan's JERA 20% ammonia co-firing trials, demonstrate the technical feasibility of these systems with limited impact on plant performance, provided that proper control measures are in place to manage flame temperature, nitrous oxide emissions, and ammonia slip (AEA, 2024).

Beyond emissions, these retrofits can help extend system reliability and preserve dispatchable capacity during the transition period, while gradually integrating low-carbon fuels into the generation mix. They also strengthen fuel-flexibility and energy-security prospects for countries investing in domestic hydrogen and ammonia production.

However, the overall economics remain challenging. While retrofit CAPEX itself is manageable, the levelised cost of electricity from co-firing is dominated by fuel costs, which are currently high for both green ammonia and green hydrogen. Unless supply chains mature and production costs fall significantly, co-firing remains costlier than biomass co-firing or conventional coal generation (Tao, 2022; Oshiro and Fujimori, 2024).

Investment Requirements for Coal-Fired Power Plants with Carbon Capture and Storage Retrofit

Retrofitting CFPPs with CCS technology entails significant capital investments, particularly for the capture component, which remains the most technically demanding and cost-intensive part of the CCS value chain. According to global benchmarks, the cost of constructing a new USC coal plant equipped with 95% carbon capture capacity ranges from approximately US$7.4 million per MW in the US, to US$3.5 million– US$6 million per MW in Norway, and US$2 million– US$3.5 million per MW in India (EIA, 2024; Global CCS Institute, 2023; Malyan and Chaturvedi, 2021; Giwangkara, 2023; Kutani, Namba, and Phoumin, 2023; E3G, n.d.). For AMS, cost estimates are expected to fall within a similar bracket. The addition of CCS can increase the capital cost of a base coal plant by more than 50%, highlighting the need for strategic financial planning and potential public–private collaboration to support such retrofits.

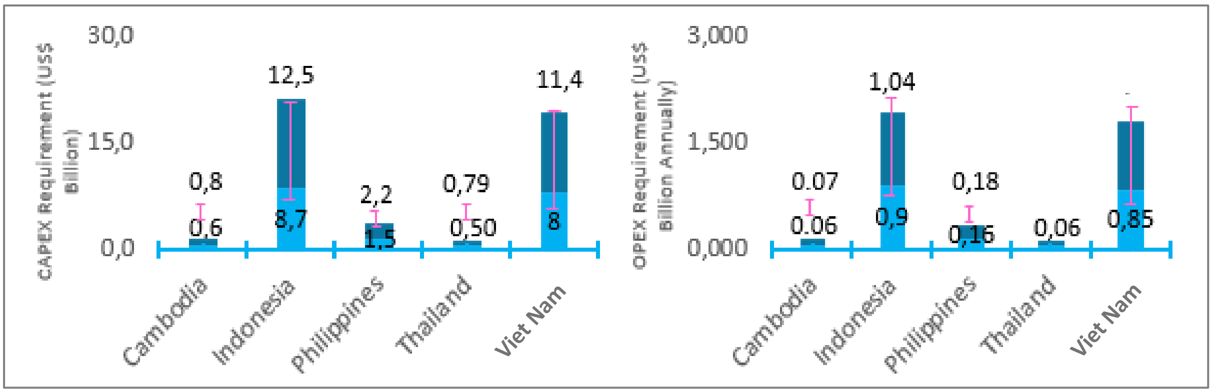
A World Bank study on CCS readiness in Indonesia offers further insight into project-level cost dynamics (World Bank, 2015; Reuters, 2020). The study evaluated two potential retrofit scenarios: the West Java power plant (2×1,000 MW) and the South Sumatra power plant (1×600 MW). For West Java, retrofitting with a 90% CO_2 capture rate would require an incremental capital investment of around US$1.68 billion and an annual operating cost of approximately US$182 million. For the smaller South Sumatra facility, the additional capital investment is estimated at US$743 million, with annual operating costs reaching US$65 million.

The capital and operational expenditure required to retrofit existing supercritical CFPPs with carbon capture technology in AMS reveals substantial variation. Indonesia leads the region with the highest capital requirement, amounting to US$12.5 billion, followed closely by Viet Nam at US$11.4 billion. These figures reflect the scale of their existing supercritical capacity.

In contrast, countries such as the Philippines (US$2.2 billion), Thailand (US$0.8 billion), and Cambodia (US$0.8 billion) show more modest capital needs due to their smaller supercritical fleets. Operational expenditures (OPEX) follow a similar pattern. Indonesia again records the highest annual OPEX at US$1.04 billion, with Viet Nam trailing slightly at US$0.95 billion. The Philippines requires US$0.18 billion annually, while Thailand and Cambodia have relatively low OPEX burdens, each around US$0.06 to US$0.07 billion per year.

Figure 4.3. Capital Expenditure and Operational Expenditure Requirements for Retrofitting Existing Supercritical Capacity with Carbon Capture Technology in ASEAN Member States

(US$ billion)



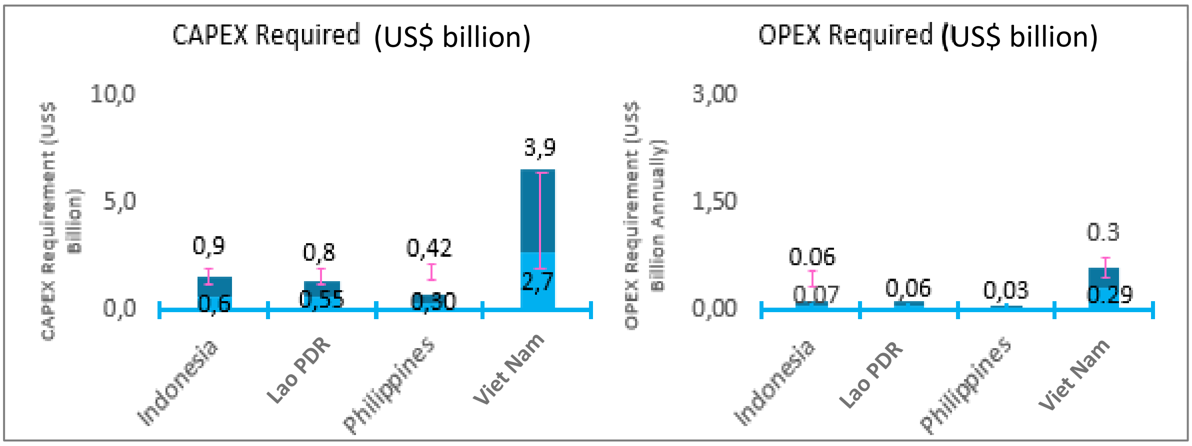
US$ = United States dollar, ASEAN = Association of Southeast Asian Nations, CAPEX = capital expenditure, OPEX = operational expenditure.

Source: Eninrac Consulting (2025), based on World Bank (2015).

When it comes to retrofitting under-construction CFPPs with carbon capture, the financial requirements are noticeably lower, highlighting the cost efficiency of early integration. Viet Nam continues to top the list, with a capital need of US$3.9 billion, roughly one-third of what is required for its existing supercritical units. Indonesia's capital requirement drops significantly from US$12.5 billion to just US$0.9 billion when the retrofitting is planned during the construction phase. Lao PDR and the Philippines also show relatively modest CAPEX, at US$0.8 billion (Lao PDR) and US$0.4 billion (Philippines). Annual operational costs are similarly reduced across all countries. Viet Nam still accounts for the highest OPEX at US$0.3 billion per year, while Indonesia, Lao PDR, and the Philippines each range between US$0.06 and US$0.07 billion per year (Figure 4.4).

Figure 4.4. Capital Expenditure and Operational Expenditure Requirements for under-Construction Supercritical Capacity with Carbon Capture Technology in ASEAN Member States

(US$ billion)

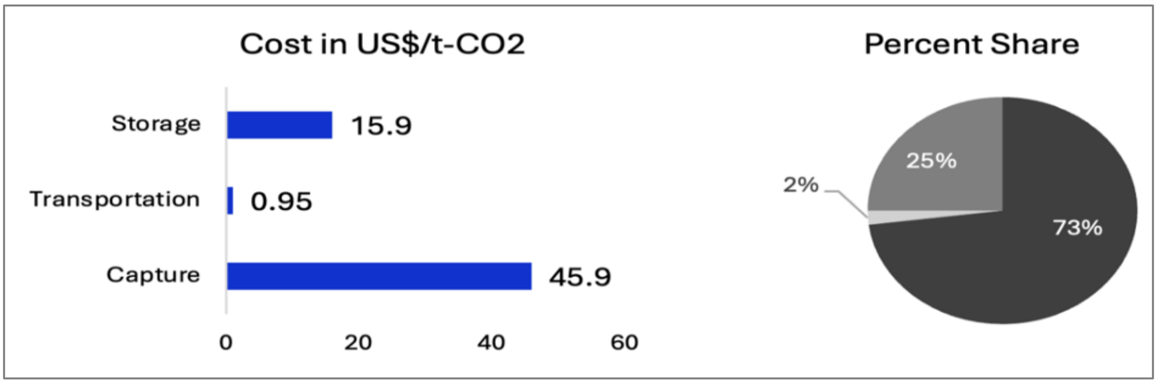


US$ = United States dollar, ASEAN = Association of Southeast Asian Nations, CAPEX = capital expenditure, Lao PDR = Lao People's Democratic Republic, OPEX = operational expenditure.
Source: Eninrac Consulting (2025), based on World Bank (2015) and ERIA (2023).

Further disaggregation of CCS costs, illustrated in Figure 3.5, shows that carbon capture itself dominates the cost structure, accounting for roughly 73% of the total cost, or about US$45.9 per tonne of CO_2 captured (Kimura et al., 2022; Reuters, 2021). This reflects the energy-intensive and technologically complex process of separating CO_2 from flue gas, especially in CFPPs, where flue streams are typically dilute and require advanced chemical absorption or membrane separation technologies. Storage costs rank second, at US$15.9 per tonne (25% of the total), which includes costs related to geological surveys, site development, injection systems, and long-term monitoring for safety and containment. Transportation is the least costly element, at US$0.95 per tonne (2%), largely involving pipeline systems or marine shipping between capture and storage locations.

Figure 4.5. Cost Breakdown for Utilisation and Transport of Carbon Capture and Storage in ASEAN

(US$/t-$CO_2$)



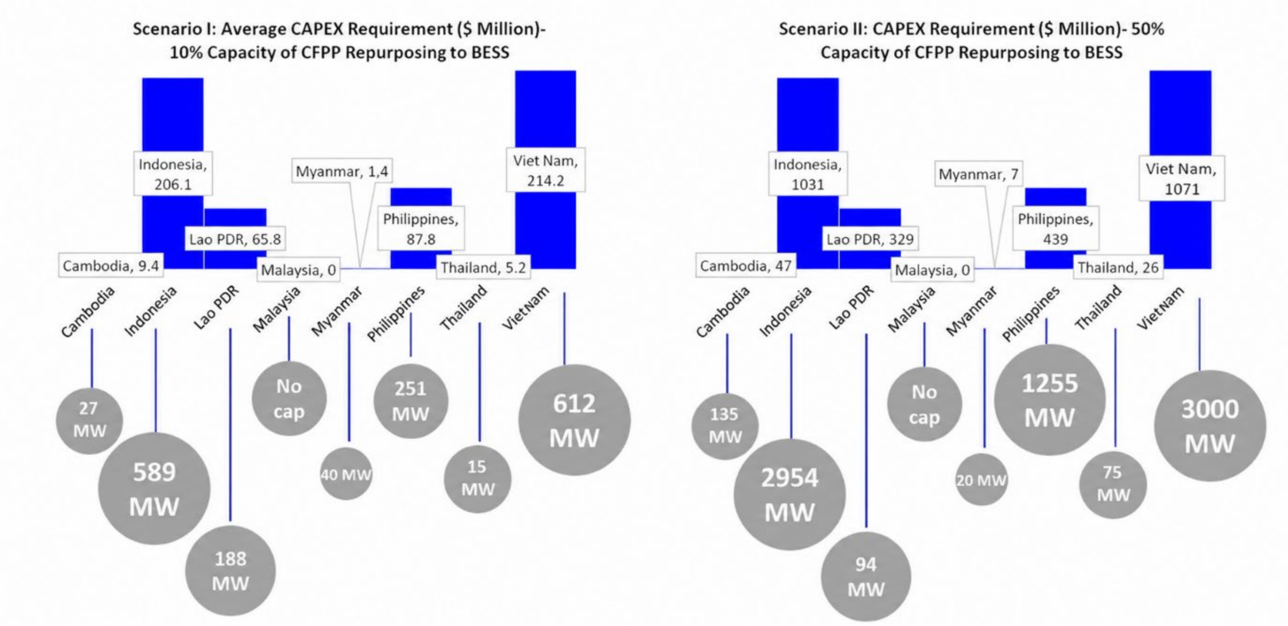
US$ = United States dollar, ASEAN = Association of Southeast Asian Nations, t-CO_2 = tonne of carbon dioxide.
Source: Kutani, Namba, and Phoumin (2023).

This cost breakdown is consistent with international findings, where capture dominates the economics of CCS deployment, while transportation becomes more cost-effective at scale, particularly when infrastructure is co-located near industrial clusters or coastal regions. For ASEAN, this highlights the importance of prioritising innovation in capture technologies and enhancing energy efficiency to drive down costs. Policy frameworks should also incentivise the development of shared storage infrastructure and transport corridors, as these will be critical enablers of large-scale CCS deployment. Establishing favourable financing mechanisms, carbon pricing signals, and streamlined permitting processes will be essential to de-risk investments and attract private sector participation across the CCS value chain.

Investment Requirements for Coal-Fired Power Plants to Retrofit with Battery Energy Storage Systems

The CAPEX required to retrofit a CFPP with a BESS can vary considerably, depending on factors such as plant size, existing infrastructure, location, and the type of BESS technology deployed. On average, the cost ranges between US$20 million– US$50 million per 100 MW of storage capacity. However, this figure can be significantly lower when key infrastructure, such as grid interconnections, land, and transmission assets, can be retained from the original plant. Figure 4.6 presents the anticipated CAPEX requirements for retrofitting subcritical CFPPs under 10 years of age with BESS across AMS, highlighting the regional variation in retrofit potential and cost intensity.

Figure 4.6. Anticipated Capital Expenditure Requirements for Retrofitting Subcritical Coal-Fired Power Plants with Battery Energy Storage Systems in ASEAN Member States



US$ = United States dollar, ASEAN = Association of Southeast Asian Nations, BESS = battery energy storage system, CAPEX = capital expenditure, CFPP = coal-fired power station, Lao PDR = Lao People's Democratic Republic, MW = megawatt, Myanmar = Republic of the Union of Myanmar.
Source: Eninrac Consulting (2025).

Figure 4.6 presents two scenarios for retrofitting subcritical CFPPs in ASEAN with BESS, one assuming 10% of installed capacity (Scenario I) and the other assuming 50% of installed capacity (Scenario II). These scenarios reflect potential investment paths for decarbonising legacy coal assets while leveraging existing infrastructure for energy storage.

In Scenario I, which assumes a modest retrofitting of 10% of CFPP capacity, the total CAPEX requirements remain relatively low but still demonstrate clear country-level disparities. Viet Nam leads with an anticipated investment of US$214.2 million, retrofitting 612 MW of subcritical CFPP capacity. This is followed by Indonesia at US$206.1 million for 589 MW, and the Philippines with US$87.8 million for 251 MW. Other countries such as Lao PDR, the Republic of the Union of Myanmar, and Thailand show more limited needs, ranging from US$1.4 million to US$65.8 million, linked to smaller available capacity for retrofitting. Malaysia shows no identified capacity in this scenario due to a lack of qualifying subcritical units or prioritisation of other transition pathways.

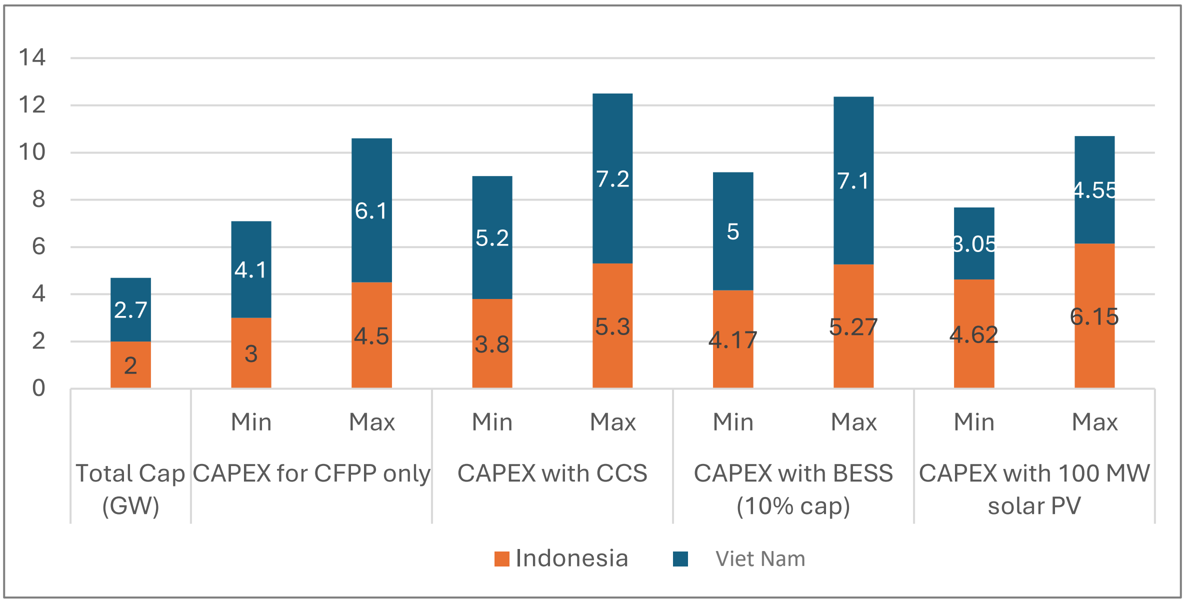
In Scenario II, where 50% of subcritical CFPP capacity is considered for conversion, capital requirements increase significantly. Viet Nam's projected investment surges to US$1.07 billion, targeting 3,000 MW of retrofitted capacity. Indonesia follows closely at US$1.03 billion for 2,954 MW, indicating the scale and opportunity for retrofitting in both countries. The Philippines requires US$439 million for 1,255 MW, while Lao PDR and Cambodia are estimated at US$329 million and US$47 million, respectively. Again, Malaysia registers no investment need under this scenario, and Thailand's projection remains low at US$26 million for just 75 MW, reinforcing a minimal role for BESS conversion within its subcritical fleet.

The divergence in investment requirements and retrofitted capacities reflects each country's existing coal fleet profile, technological readiness, and potential integration plans for energy storage. Notably, Viet Nam and Indonesia stand out not only in scale but in the strategic value of transforming ageing coal assets into grid-supportive infrastructure, essential for intermittent renewables. As costs of lithium-ion storage decline, such repurposing pathways can offer both environmental benefits and grid reliability, particularly if supported by enabling policies and concessional finance mechanisms.

Investment Requirements for under-Construction Coal-Fired Power Plants to be Retrofitted with Carbon Capture and Storage, Battery Energy Storage Systems, and Solar

In the ASEAN region, cumulatively 4,733 MW of CFPP capacity is currently under construction with unit sizes exceeding 600 MW. The average per megawatt CAPEX required for installing this capacity is estimated to range between US$1.5 million to US$2.25 million. Accordingly, the total investment necessary to bring this capacity online would be in the range of US$7 million to US$10.6 billion.

Figure 4.7. Comparative Analysis of the Capital Expenditure Required for under-Construction Coal-Fired Power Plant Capacity (unit size >600 MW)

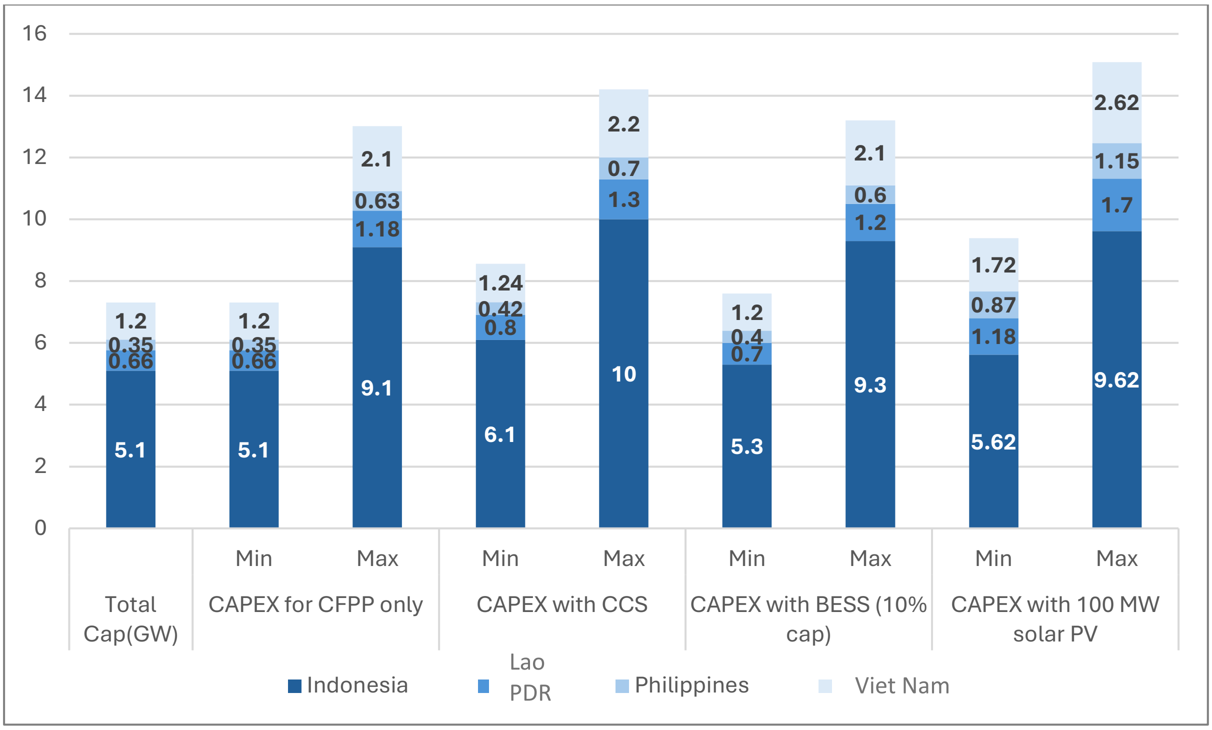


BESS = battery energy storage system, CAPEX = capital expenditure, CFPP = coal-fired power plant, GW = gigawatt, MW = megawatt, PV = photovoltaic.
Source: Eninrac Consulting (2025).

Figure 4.7 provides a comparative breakdown of CAPEX requirements associated with these under-construction large-scale CFPP units in Viet Nam and Indonesia. Viet Nam is building 2.7 GW of capacity, while Indonesia is developing 2.0 GW. The baseline CAPEX requirements for completing these facilities without additional decarbonisation measures are estimated at US$4.1 billion– US$6.1 billion for Viet Nam and US$3.0 billion– US$4.5 billion for Indonesia. However, incorporating CCS technologies significantly escalates the costs. Viet Nam would require US$5.2 billion–7.2 billion, while Indonesia would need US$3.8 billion– US$5.3 billion to retrofit with CCS.

Alternative decarbonisation pathways, such as retrofitting these assets with BESS, also entail significant investments. Retrofitting just 10% of CFPP capacity with BESS would cost US$5.04 billion– US$7.15 billion for Viet Nam and US$5.27 billion for Indonesia. Similarly, if these capacities were to be replaced or augmented with solar photovoltaics (based on 100 MW installations), the CAPEX would range from US$3.05– US$4.55 billion for Viet Nam and US$4.62– US$6.15 billion for Indonesia. These comparisons highlight the relative cost competitiveness and scalability challenges of different decarbonisation options.

Figure 4.8. Comparative Analysis of Capital Expenditure Required for under-Construction Coal-Fired Power Plant Capacity
(unit size 300–600 MW)



BESS = battery energy storage system, CAPEX = capital expenditure, CCS = carbon capture and storage, CFPP = coal-fired power plant, GW = gigawatt, Lao PDR = Lao People's Democratic Republic, Max = maximum, Min = minimum, MW = megawatt, PV = photovoltaic.
Source: Eninrac Consulting (2025).

Figure 4.8 shifts the focus to under-construction CFPP units with capacities between 300–600 MW, predominantly located in Indonesia, Lao PDR, the Philippines, and Viet Nam. Indonesia is developing the bulk of this capacity at 5.1 GW, while Viet Nam (1.2 GW), Lao PDR (0.7 GW), and the Philippines (0.4 GW) follow. The CAPEX requirements for these plants, if completed without CCS, range from US$2.1– US$2.9 billion for Viet Nam, US$0.3–US$0.6 billion for the Philippines, US$1.2 billion for Lao PDR, and a substantial US$5.1–US$9.1 billion for Indonesia.

If CCS were incorporated into these projects, costs would rise further. Indonesia's CAPEX could reach up to US$10 billion, with Viet Nam, Lao PDR, and the Philippines requiring US$1.24 billion (Viet Nam), US$1.3 billion (Lao PDR), and US$0.77 billion (the Philippines) On the other hand, transitioning toward renewables or storage-based alternatives reveals a different cost profile. The CAPEX for 100 MW of solar photovoltaics capacity would range from US$1.72 billion– US$2.62 billion in Viet Nam, US$1.15 billion– US$1.5 billion in the Philippines, US$0.87 billion– US$1.18 billion in Lao PDR, and a high US$5.62– US$9.62 billion in Indonesia. Similarly, BESS deployment across 10% of the coal fleet's capacity would demand US$2 billion– US$2.1 billion in Viet Nam, US$0.4 billion– US$0.6 billion in the Philippines, US$0.7 billion– US$1 billion in Lao PDR, and between US$5.3 billion–US$9.3 billion in Indonesia.

Together, these figures illustrate the high financial stakes involved in ASEAN's power sector decarbonisation. While CCS remains a technologically mature but capital-intensive solution, renewables and BESS offer scalable pathways, albeit with their own cost and integration complexities. The wide variation across countries also highlights the importance of tailored investment strategies, regulatory reforms, and multilateral co-operation in enabling a just and effective energy transition in the region.

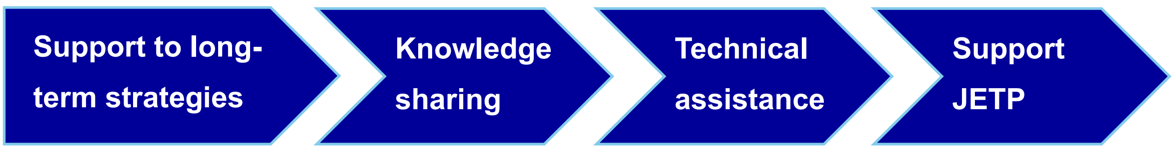
4.3. Financial Stakeholders' Role in Funding Clean Coal Technology Projects

Engaging with National Governments

Public development banks play a pivotal role in facilitating the retrofitting and repurposing of CFPPs, not only by providing financial support but also through targeted technical assistance. While instruments such as policy-based lending and sustainability-linked sovereign bonds are increasingly being used to support policy reform, technical advice and institutional capacity building are essential and often more cost-effective. DFIs can help governments develop the strategic frameworks and competencies necessary to manage complex coal transition projects and ensure that these align with long-term clean energy goals.

Capacity-building efforts can be directed across several key areas. Firstly, long-term power sector strategies can benefit significantly from MDBs and international financial bodies (IFBs) supporting integrated resource planning (IRP) and scenario-based modelling. These tools help governments craft forward-looking, least-cost energy strategies while accounting for socio-economic and climate constraints. Secondly, fostering knowledge exchange is vital. Platforms and structured programmes can be established to equip governments with technical and institutional know-how, drawing from best practices, case studies, and lessons learned globally. This includes support for developing transformation strategies and comprehensive economic and social development plans tailored to the energy transition.

Figure 4.9. Key Segments to Improve the Capacity-Building Initiatives



JETP = Just Energy Transition Partnership.
Source: Shrimali (2022) and Venkataraman et al. (2013).

Another important area is targeted technical assistance to accelerate the staged transition from coal toward cleaner energy. In the early phase, this involves helping governments and utilities integrate CCT, such as boiler upgrades, biomass co-firing, and, where feasible, carbon capture, into existing coal fleets to reduce emissions while maintaining energy security. Technical assistance at this stage can also address coal-related contractual obligations, such as long-term fuel supply or PPAs, that might constrain the adoption of cleaner technologies or later plant repurposing.

As the transition progresses toward partial or full repurposing, development partners can help governments manage the fiscal and macroeconomic implications of reduced coal output, including identifying alternative tax revenues, mitigating risks to supply chains, and ensuring balance-of-payments stability. An essential step is evaluating and prioritising which coal plants are most suitable for staged transformation, starting with CCT deployment and efficiency optimisation, then shifting toward hybrid configurations (integrating renewables and storage) and, eventually, full repurposing for low-carbon energy or industrial uses.

International development institutions are increasingly embedding just transition principles throughout this continuum. The World Bank, for example, supports both technology upgrades and later-stage repurposing, pairing financing with advisory services on social protection, workforce reskilling, and environmental remediation. Similarly, ADB's Just Transition Support Platform assists its members in planning, financing, and managing the socio-economic impacts across the full transition pathway. The European Bank for Reconstruction and Development applies a similar approach through its Just Transition Initiative, combining policy engagement with commercial financing to protect communities and workers affected by the shift toward a green economy.

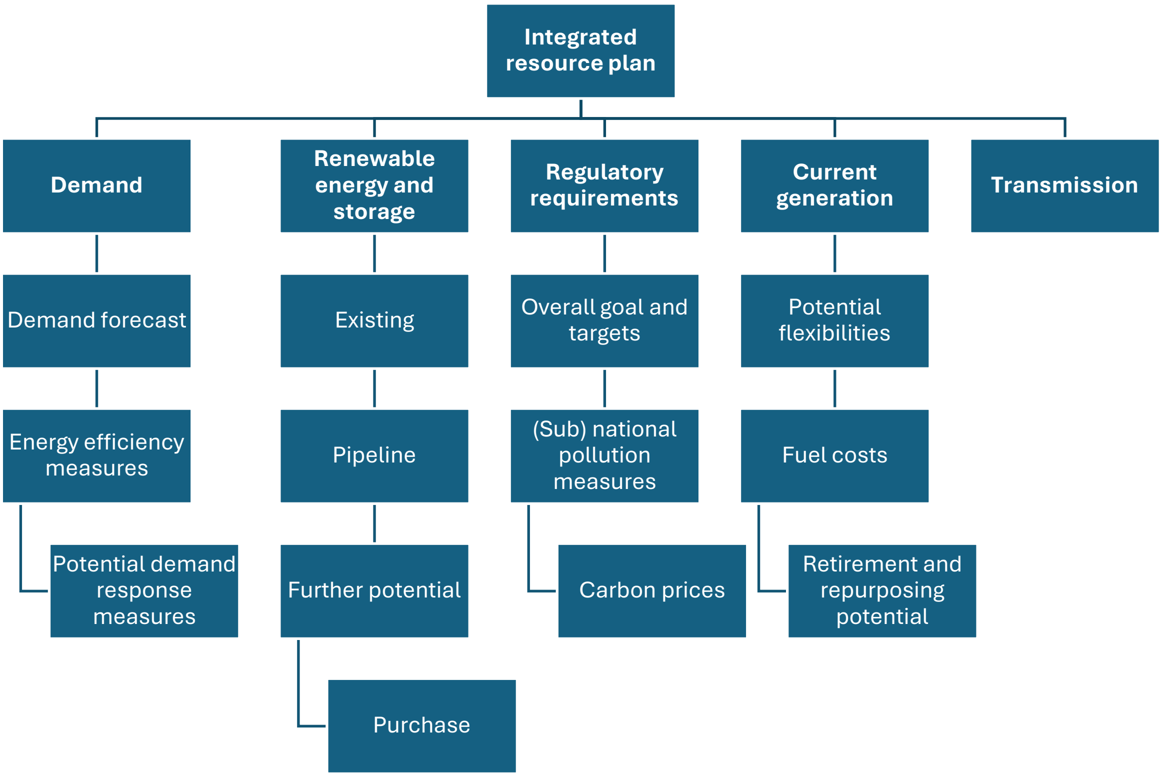
Engaging with Utilities and State-Owned Enterprises

DFIs, such as MDBs and IFBs, play a vital role in helping utilities and state-owned enterprises transition away from coal. A core function of this engagement is mobilising climate finance while simultaneously restricting financial support for fossil fuels. At the project level, MDBs and IFBs can accelerate the closure of existing CFPPs and prevent the development of future coal projects by promoting targeted financial instruments that support renewable energy, battery storage, transmission networks, smart grids, and demand-side management [30]. However, it is equally important to ensure that existing coal exclusion policies do not inadvertently prevent financing for decommissioning, environmental remediation, or site repurposing. Additionally, to close financial loopholes, restrictions should extend to counterparties, preventing indirect coal support through unearmarked capital.

IRP is another key area where utilities can be supported. Vertically integrated utilities, in particular, possess a broad portfolio of energy resources and are uniquely positioned to adopt a systemic approach to power system optimisation. IRP helps uncover the real costs of maintaining or expanding coal capacity, including both CAPEX and operational inefficiencies, and compares these with more sustainable alternatives [45]. Through IRP and scenario modelling, MDBs and IFBs can help utilities identify least-cost, low-emissions pathways, while leveraging their financing capabilities to encourage ambitious transition strategies.

Many utilities, however, face persistent balance sheet challenges that hinder their ability to invest in clean energy. These include high upfront capital requirements, network inefficiencies such as transmission losses, poor cost recovery due to politically constrained tariffs, and weak financial management practices. MDBs can help address these systemic issues through financial restructuring and technical assistance. They can also help unlock financing mechanisms to support the scaling of renewable energy and the phased closure of coal assets.

Figure 4.10. Integrated Resource Planning to be Supported by Multilateral Development Banks/International Financial Bodies



Source: Eninrac Consulting (2025).

For financially strained utilities, conventional financing may not be viable. In such cases, public development banks can support utility restructuring through innovative instruments. One notable approach is the 'bad bank' or 'managed transition vehicle' model, where legacy coal assets are carved out into a separate entity. These spin-offs are managed with the explicit aim of phasing down coal operations while allocating sufficient funds for decommissioning and environmental remediation. Such mechanisms have been applied in European contexts, including Germany and Poland, where the reputational risk associated with coal holdings made it difficult for utilities to attract new private investment. Any engagement of DFIs in such models must be predicated on a clear, time-bound phase-out plan.

4.4. Financial Solutions to Support Clean Coal Technology Deployment and Repurposing

Scaling Financial Support across the Transition Stages in Emerging Markets and Developing Countries

Deploying CCT and subsequently repurposing CFPPs in emerging markets and developing economies presents significant financial and policy challenges, particularly given the relatively young age of these assets. In the ASEAN region, for instance, 66.98 GW of CFPP capacity is less than 10 years old, while another 30.08 GW falls within the 10–19-year range.

According to GEM, the average age of ASEAN's existing coal fleet by 2040 will be around 28 years, well within the operational lifespan of most plants and below the global average retirement age of 36 years. This youthful fleet means that, without intervention, these assets could continue operating for decades, making it imperative to create financial solutions that enable their technological upgrading and eventual transition to alternative uses.

Table 4.1. Projected Age of the Coal Fleet in ASEAN by 2040

Age in 2040 *(years)*	Plants *(%)*	Capacity *(GW)*
Under 20	17	19.6
20–24	27	30.5
25–29	25	28.3
30+	32	36.6

ASEAN = Association of Southeast Asian Nations, GW = gigawatt.
Source: GEM, (2024).

The central financial challenge lies in bridging the gap between the revenue a plant would earn under a business-as-usual scenario and the adjusted returns from a staged transition pathway, first through CCT adoption, then through partial or full repurposing. For newer plants, this gap is particularly wide, as cost recovery and investment returns are designed over multi-decade operating horizons. Ensuring plant owners can recover value while supporting decarbonisation goals demands innovative financial mechanisms tailored to incremental transition steps.

Two primary strategies are emerging in this context. The first is lowering the cost of capital for CFPPs undergoing CCT upgrades or repurposing. By reducing the WACC, less money is spent on debt servicing, freeing up cash flows that can be redirected toward funding boiler retrofits, biomass co-firing systems, or emissions control installations.

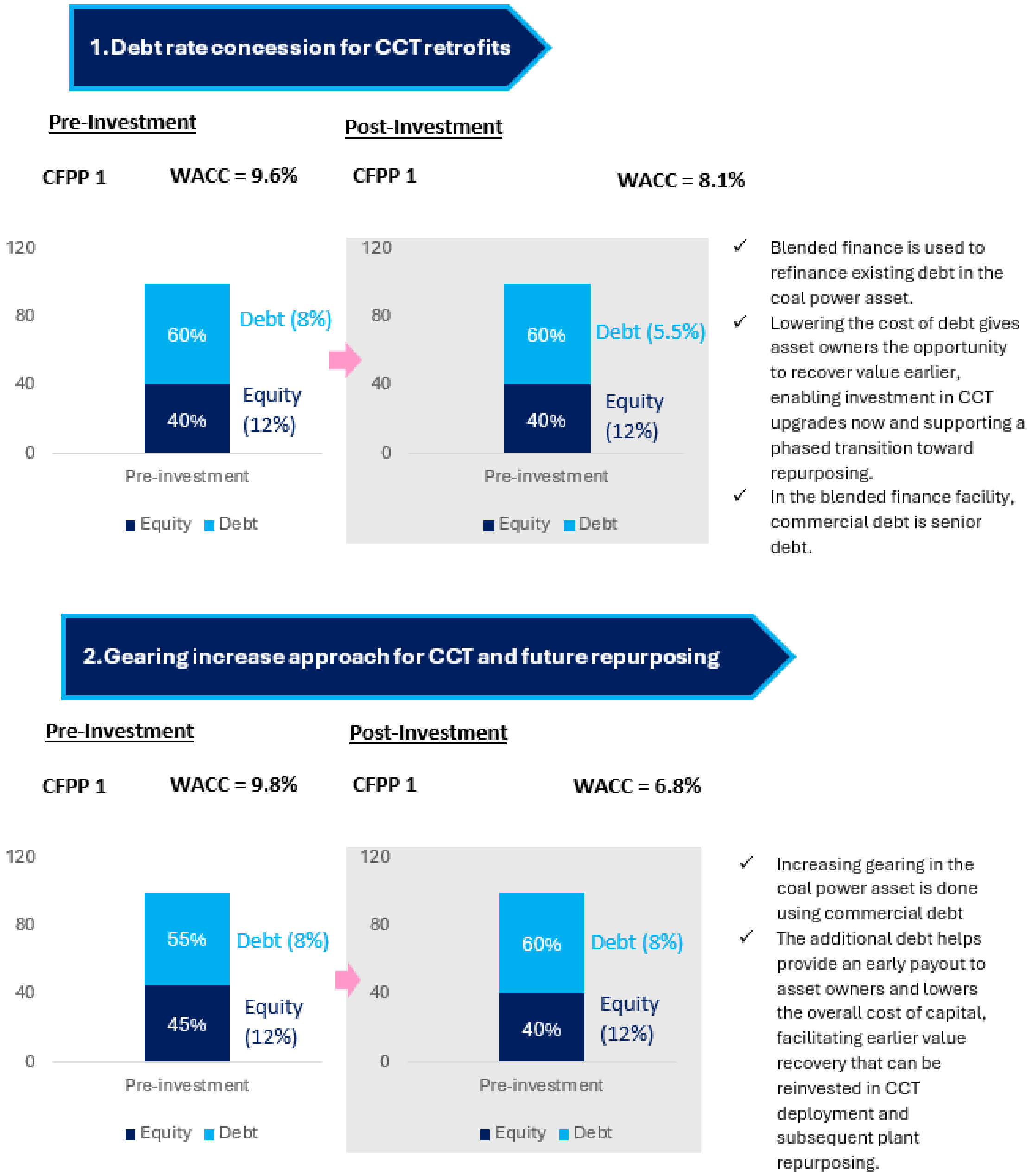
This can be achieved through blended finance structures combining concessional funds from development institutions with commercial debt, thus de-risking investments. Similar financing models, such as those piloted under ADB's ETM, could be adapted to cover CCT deployment as a first-phase intervention, rather than focusing solely on early retirement.

The second strategy involves developing performance-based financial instruments, such as transition credits, to reward incremental emissions reductions from CCT adoption before full coal phase-out. These credits could be linked to measurable performance milestones, such as efficiency improvements or verified co-firing rates, and later extended to reflect the avoided emissions from repurposed facilities. Potential buyers could include corporations seeking voluntary offsets or governments aiming to meet interim climate targets. This approach allows asset owners to monetise environmental performance improvements earlier in the transition timeline, creating a financial bridge from CCT deployment to eventual plant repurposing.

Strategic Use of Concessional Finance to enable Clean Coal Technology Deployment and Prepare for Repurposing

Given the large number of operational CFPPs in ASEAN, relying solely on concessional capital to fund complete plant retirement is neither feasible nor immediately practical. Instead, concessional finance can be strategically deployed to fund near-term CCT upgrades, such as HELE boilers, biomass co-firing systems, and CCS/CCUS-readiness, while laying the groundwork for medium- to long-term plant repurposing. This approach ensures that emissions are reduced in the short term, energy security is maintained, and infrastructure is preserved for future low-carbon use.

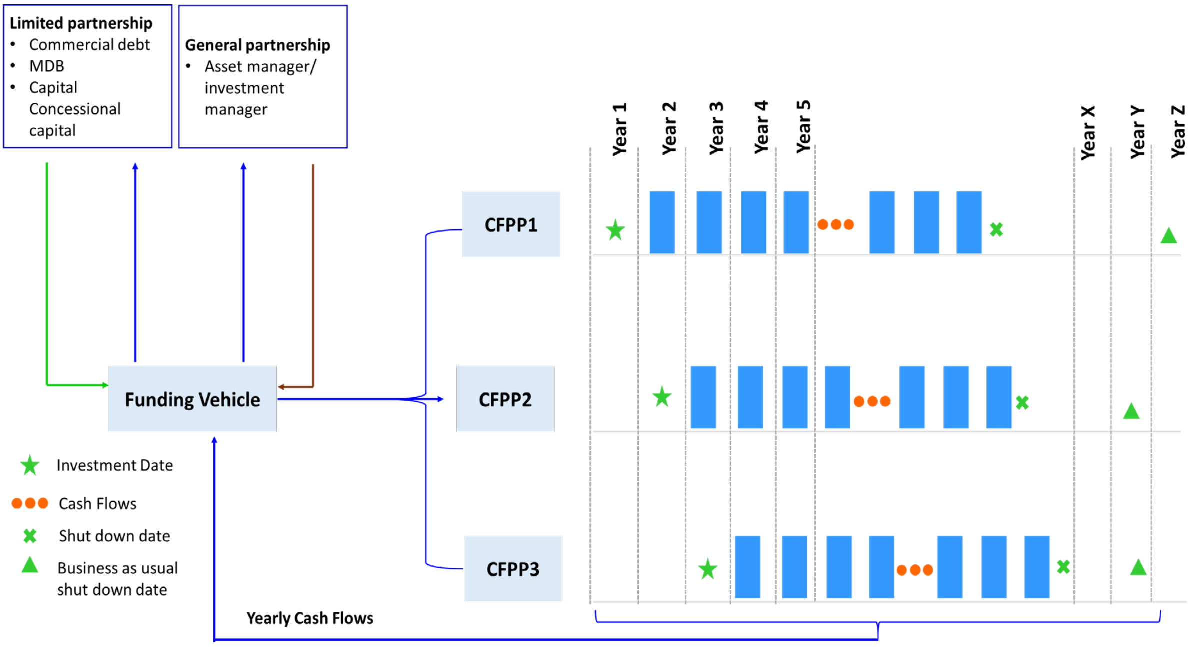
Figure 4.11. Proposed Financial Approaches for Early Retirement of Coal-Fired Power Plants



CCT = clean coal technology, CFPP = coal-fired power plant, WACC = weighted average cost of capital.
Source: World Economic Forum, (2025).

Three concessional financing levers can be adapted to support this pathway, first, through blended financing, combining concessional and commercial capital, asset owners can refinance existing high-cost debt at lower rates, freeing cash flow for immediate investment in CCT deployment. For example, refinancing can unlock capital for installing biomass co-firing systems or upgrading to supercritical/USC boilers. This improved cash flow also positions owners to plan and budget for eventual repurposing projects, such as integrating BESS or renewable generation at CFPP sites.

Figure 4.12. Description of Ongoing Cash Flows for Multiple Plants (Assets to Fund, Fund to Investor)



CFPP = coal-fired power plant, MDB = multilateral development bank,
Source: World Economic Forum, (2025).

Second, replacing more expensive equity with lower-cost concessional debt can lower the overall cost of capital, making large-scale CCT retrofits more viable. In this framework, re-gearing would prioritise financing efficiency improvements, co-firing retrofits, and early-stage CCS infrastructure rather than immediate plant closure. As plants pay down debt and equity proportions rise, further re-gearing can provide the capital needed for repurposing investments, such as grid connection upgrades or renewable plant construction. To manage lender risk, credit enhancements, such as guarantees or political risk insurance, would be critical.

Lastly, extending debt repayment periods can reduce annual debt service, freeing capital for both CCT deployment today and gradual preparation for non-coal uses tomorrow. In practice, this means aligning extended loan tenures with a phased transition plan, first financing the CCT retrofits that deliver immediate emission reductions, then using the financial breathing room to prepare for site conversion. For instance, new debt could mature shortly before a scheduled technology shift, ensuring capital is available when major repurposing works begin.

Chapter 5

Financial Recommendations for ASEAN's Coal-Fired Power Plants Transition

5.1. Establish a Staged and Diversified Financial Framework

A phased approach, moving from CCT deployment to repurposing and eventual retirement, should continue to anchor ASEAN's transition strategy. Each stage requires tailored financing instruments:

- Immediate term (2025–2030): Use blended finance, public guarantees, and project preparation facilities to de-risk small-scale projects such as boiler efficiency upgrades, modest biomass co-firing, and pilot integration of renewables with battery storage. These interventions should remain government-led, supported by concessional capital from development partners and climate funds.
- Medium term (2030–2040): Shift toward mixed public–private financing, expanding the use of transition bonds, sustainability-linked loans, and carbon contracts for difference to enable larger-scale repurposing and partial CCS integration. As regulatory certainty improves, private capital should gradually take the lead.
- Long term (2040–2050): Transition to market-based and private-led investment frameworks supported by carbon markets, green asset-backed securities, and sovereign green investment banks to fund large-scale renewable and storage infrastructure, decommissioning, and just transition programmes.

5.2. Strengthen Government Leadership to Reduce Investment Risks

Mobilising private capital in the early stages of CFPP transition relies heavily on strong policy certainty and regulatory stability. To attract investors, governments must ensure transparent and predictable frameworks governing biomass pricing, renewable energy integration, and carbon pricing, thereby reducing perceived risks related to regulation and fuel supply.

Streamlining permitting and licensing procedures is equally critical to minimise transaction costs and avoid delays that often hinder early-stage projects. In parallel, building institutional capacity through collaboration with MDBs and DFIs can strengthen project preparation, risk assessment, and fiscal planning, ensuring that early investments are both technically sound and financially viable.

5.3. Scale Concessional and Blended Finance to Unlock Private Capital

Given ASEAN's relatively young coal fleet and constrained fiscal space, concessional finance should be deployed strategically to prepare plants for transition rather than fund premature retirements. Blended finance, combining concessional and commercial capital, offers an effective pathway to balance risk and mobilise private investment. Such mechanisms can be used to refinance high-cost debt, therefore lowering the WACC and freeing up cash flows for retrofit projects such as biomass co-firing, supercritical boiler upgrades, or renewable integration.

As technologies mature and investor confidence grows, blended finance can also serve as a bridge toward fully private financing. Instruments like ADB's ETM and the Just Energy Transition Partnerships should therefore be scaled up and adapted to enable project aggregation across multiple plants and countries, ensuring broader impact and efficiency.

5.4. Develop Clear Standards for 'Transition-Aligned' Investments

Financial institutions and institutional investors need clear and transparent standards to distinguish credible transition finance from greenwashing. To build investor confidence and ensure accountability, ASEAN should align its regional sustainable finance taxonomy with established international frameworks.

Establishing robust verification systems that link financing directly to measurable emission reductions, such as verified biomass co-firing rates, CCS performance, or avoided emissions through plant repurposing, will be essential. Additionally, enabling the generation and monetisation of carbon credits from transitional activities can create early revenue streams for asset owners, improving project bankability while reinforcing the credibility of ASEAN's energy transition financing ecosystem.

5.5. Support Just and Inclusive Transition Financing

Ensuring political and social legitimacy in the coal transition requires embedding just transition funding into all financial mechanisms. This should involve dedicated funds to support worker retraining, re-employment, and community redevelopment, ensuring that affected groups are not left behind.

Results-based financing or grants can be directed toward fostering local economic diversification and renewable energy entrepreneurship in coal-dependent regions, creating new and sustainable livelihoods. Moreover, establishing public–private–community partnerships will be crucial to ensure that the benefits of repurposing coal assets are equitably shared and that the long-term sustainability of transition projects is secured through inclusive and participatory development.

5.6. Enhance Regional Financial Co-ordination and Capacity

To overcome fragmented investment environments, ASEAN should strengthen regional co-ordination and financial integration. This includes enhancing regional facilities such as the ASEAN Catalytic Green Finance Facility to enable project aggregation and cross-border knowledge sharing. Joint financial instruments could also be developed to support grid enhancement, renewable energy storage integration, and transmission interconnections under the ASEAN Power Grid, ensuring a cohesive regional energy transition.

Furthermore, fostering peer learning amongst AMS through harmonised financial tools, consistent reporting standards, and structured policy dialogues with MDBs, green banks, and institutional investors will help build a more unified and resilient investment ecosystem across the region.

5.7. Prepare for Long-Term Capital Market Integration

As ASEAN's energy transition advances, financial systems must increasingly align with global sustainable finance markets. Governments and regional institutions can play a pivotal role by developing innovative instruments such as green asset-backed securities and carbon credit derivatives to attract long-term investors, including pension funds and sovereign wealth funds seeking low-carbon opportunities.

Establishing national or regional green investment banks would further help mobilise domestic capital at scale and support large renewable and transition projects. In parallel, promoting carbon pricing and emissions trading systems will enhance the economic competitiveness of clean energy investments, gradually displacing coal and fostering a self-sustaining low-carbon financial ecosystem across ASEAN.

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