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Capitalizing on Coal: Early Retirement Options for China-backed Coal Plants in SE Asia and Beyond

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ABSTRACT

The International Energy Agency's (IEA) Net Zero Emissions by 2050 Scenario (NZE 2050) pathway to economy-wide net zero emissions requires unabated coal power to be phased out of the global electricity system by 2040. To remain below the 1.5ºC threshold of the Paris Agreement, the Intergovernmental Panel on Climate Change (IPCC) estimates total coal-fired power generation will have to fall by 70 percent by 2030, and 96 percent by 2050 on average. Although China is not alone in directing public financing to new coal-fired power across the globe, China's development finance institutions have played a role in financing over 39GW of currently operating overseas coal power plants, largely in South and Southeast Asia and commissioned within the past two decades. Assuming these plants have operating lifetimes of 30 years would take many of them beyond the 2040 IEA phase-out target. Early retirement of plants still in existence beyond 2040 will very likely be necessary for host countries and China alike to realize their climate ambitions and limit the social costs of climate change.

This working paper analyzes early retirement options for representative subcritical and supercritical coal power plants located outside China and financed by Chinese entities. The paper focuses on the implications for India and three other countries—Pakistan, Indonesia and Vietnam—where Chinese finance has enabled a significant amount and/or proportion of currently operating coal plants, power markets remain highly regulated and where electricity demand is rising rapidly. We calculate that at \$100/tCO_2 avoided, the economic benefits of retiring Chinese overseas coal plants ten years early could be \$200 billion. Our analysis of an illustrative subcritical plant with representative characteristics suggests that an interest rate/equity return requirement subsidy approach allows the plant to be retired 20 years early for \$151 million, 20 percent less than the cost of a full buyout at \$184 million. Further, the price on avoided emissions required to fully fund a subsidy for retiring the plant 20 years early is just \$12.5/tCO_2, falling to \$2.8/tCO_2 if retired ten years early. These findings suggest that subsidizing investor returns may be a more effective use of concessional funding than full buyouts in securing early retirement, especially in the context of countries with growing electricity demand and relatively early-stage renewable energy buildout. Providing an interest rate subsidy sufficient to allow early retirement, but for a long enough period of time to allow the host country to invest in replacement capacity, may be a workable solution to pursue. Early retirement of Belt and Road Initiative (BRI) coal plants may require more active engagement by Chinese lenders and equity holders in renegotiating outstanding debts, lowering the cost of borrowing where appropriate and subsidizing interest payments where possible; or agreeing to the transfer of debt and equity ownership to other institutions.

Keywords: coal, climate change, development finance, China, Belt and Road Initiative

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INTRODUCTION

To remain aligned with a development pathway consistent with 1.5ºC in average global temperature rise over historical averages, the use of unabated coal-fired power generation will have to decline dramatically. The International Energy Agency (2021) finds in its NZE 2050 Scenario that reaching this goal requires a complete phase-out of unabated coal-fired power generation by 2040. Median estimates in below-1.5ºC scenarios reviewed by the IPCC see annual electricity generation from coal, including any plants equipped with CCS technology, fall 70 percent by 2030 and 96 percent by 2050 (Rogelj et al 2018, Table 2.7). Even if the required measure to meet the 1.5ºC target are not taken, a growing share of the global economy by emissions have committed to achieving net zero between 2050 and 2060—a feat that would also require, at a minimum, the elimination of unabated coal power and its replacement with zero-carbon energy sources.

Chinese leader Xi Jinping committed in 2021 to end new public financing for coal power overseas. This does not resolve the problem of existing China-financed coal-fired power plants past 2040. China's development finance institutions (DFIs) have been the dominant public financiers of coal power expansion in developing economies in recent years, particularly in South and Southeast Asia. Between them, the China Development Bank (CDB) and Export-Import Bank of China (CHEXIM) accounted for 50 percent of global public finance commitments to overseas coal-fired power plants closed from 2013-2018, or 40 percent of total publicly financed generation capacity, with Japan and South Korea accounting for 30 percent and 11 percent respectively (Ma and Gallagher 2021).[1] Most of the coal plants backed by Chinese public entities were commissioned and built within the last decade. This takes their expected operating lifetimes up to 2040 and beyond and suggests that to remain consistent with 1.5-degree pathways, the plants will have to be retired early.

Early retirement reduces the committed greenhouse gas emissions associated with a coal plant, but can result in unanticipated costs for investors, workers and surrounding communities and electricity consumers. This is particularly true of the economies in which China-backed coal power features most heavily. To varying degrees, they are characterized by a significant state presence in the power sector, highly regulated or subsidized electricity markets, high projected energy demand growth and limited capacity of state-owned enterprises (SOEs) or national budgets to absorb significant stranded infrastructure costs.

Phasing out China's overseas coal plants may prove particularly difficult, given that a significant share of currently operating capacity is less than ten years old and the financial cost of retiring early may be high, particularly where the plants are profitable. The first part of this study quantifies these costs. We analyze the relationship between concessional finance and early retirement of a representative subcritical and supercritical coal plant financed by Chinese DFIs from a financial perspective. We then analyze the relationship between carbon finance and early retirement. We further link carbon pricing to early retirement to assess the implications for the financial costs of early retirement, as envisaged in the Just Transition Transaction (JTT) model described in Table 2 below.

The second part of the study applies these results to the political economy context in the countries in which Chinese financing and suppliers have enabled the largest new coal power capacity additions in recent years: Pakistan, Vietnam and Indonesia. All these countries are members of China's ambitious Belt and Road Initiative (BRI) at, or since, the time of financing. In all of these cases, power markets remain highly regulated and electricity demand is rising. We ask what might be required in each context for early retirement mechanisms to succeed, and what specific and general conclusions might be drawn from assessing their applicability in each context. In doing so, we contribute to an understanding of existing policy options for appropriate retirement mechanisms for coal plants in these countries by identifying the costs and benefits of using concessional/carbon funds for this purpose, as well as identifying specific barriers to implementation and practical routes for implementation.

[1] While China's development finance institutions and commercial banks (state-owned and private) are the largest financiers of overseas coal plants, financing 69GW of new capacity between 2013 and mid-2019, their share of total financing for overseas coal power from all sources is much smaller than previously estimated, accounting for just 17 percent of new additions and 11 percent of capacity under construction and planning. Independent research by Urgewald (2021) finds that institutional investors and banks based in the United States, Japan and United Kingdom were the largest investors in, and lenders to, the coal industry globally.

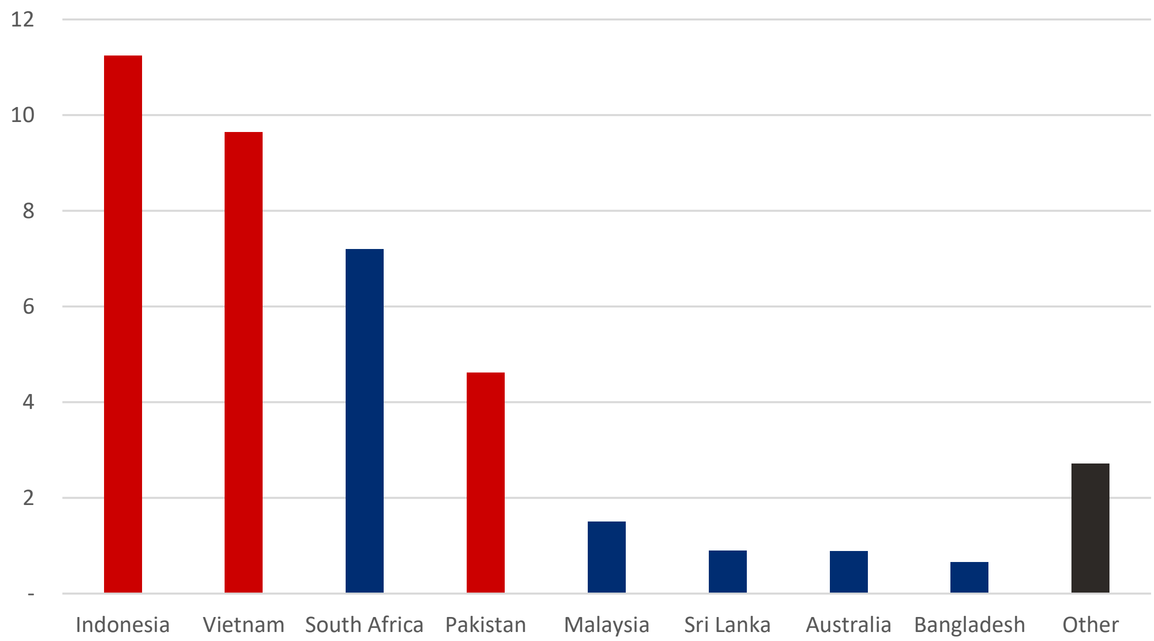
BRI Coal: Overview Of China's International Coal Capacity Footprint

China's role as a leading source of finance for overseas coal projects has expanded as it has sought to internationalize the activities of its SOEs and find markets for spare industrial capacity to mitigate domestic oversupply, as host countries have sought to fill their energy needs with coal fired power (Li et al. 2022). The dominant players in facilitating this expansion (in some cases lending directly, in other cases underwriting) have historically been the CDB, China's national development finance institution and CHEXIM, its export credit agency.

As the BRI evolves, the environmental framework behind BRI-linked projects has become more clearly defined. The 2022 edition of joint guidelines issued by China's Ministries of Ecology and Environment (MEE) and Ministry of Commerce (MOFCOM) to overseas development finance institutions charges them with "the sustainable development of foreign investment," "the construction of a green Belt and Road" and "the construction of a new ecological development pattern" (MEE 2022). While CDB has committed to a number of voluntary standards including the Global Reporting Initiative, UNEP Finance Initiative, and UN Global Compact, as well as being the largest member of the International Development Finance Club (IDFC), it does not disclose the details of its investments.

Chinese investors and lenders (including DFIs) are involved in the cross-border financing of 39GW of currently-operating coal power capacity, spread across 109 power generating units globally outside China (Figure 1), and a further 14GW and 4.5GW under construction and in the planning stages, respectively. Of the 109 operating units, 69 feature CDB, CHEXIM or both, as a lender. Two-thirds of the associated operating capacity (nearly 26GW) is located in just three countries—Vietnam, Indonesia and Pakistan—and 75 percent of operating capacity is located in South and Southeast Asia. These three countries together also account for 40 percent of capacity under construction and nearly 80 percent of capacity in the planning stages. South Africa is the only other country featuring significant China-backed operating capacity, while Bangladesh, Turkey and Zimbabwe are the only other countries with significant capacity in the construction and planning stages. Prior research has also shown that a significant amount of coal-fired generating capacity in India has received support from Chinese engineering, procurement and construction (EPC) contractors (Springer et al. 2021).

Figure 1: Overseas Coal Capacity Financed by Chinese Investors and Lenders (GW)



Source: China's Global Power (CGP) Database (2022), Boston University Global Development Policy Center.

While some, if not many, of the coal projects that have received financing from China predate the BRI, at least some of them may since have been reclassified as formal components of the initiative. For simplicity, China-financed coal plants discussed in this study are referred to henceforth as "BRI plants". On average, and in every country except Brazil, Singapore and Australia, all operating BRI coal plants were commissioned in the last ten years. In the three case study countries, all have average BRI plant ages of less than ten years, with Pakistan having one of the youngest BRI coal fleets at under four years on average, and Indonesia and Vietnam seven and eight years, respectively (Table 1). Assuming these plants have operating lifetimes of thirty years would take many of them beyond the 2040 phase-out target.

Table 1: Average Age of Currently Operating BRI Coal Plants by Country, Ranked from Newest to Oldest

Country	Region	Years since commissioning, average
Bangladesh	South Asia	2
Brunei Darussalam	Southeast Asia	3
Kyrgyz Republic	Central Asia	3
South Africa	Africa	4
Pakistan	South Asia	4
Mongolia	Central Asia	5
Morocco	Africa	5
Malaysia	Southeast Asia	6
Uzbekistan	Central Asia	6
Cambodia	Southeast Asia	7
Indonesia	Southeast Asia	7
Tajikistan	Central Asia	7
Vietnam	Southeast Asia	8
Sri Lanka	South Asia	9
Brazil	Americas	11
Singapore	Southeast Asia	14
Australia	Oceania	18

Source: China's Global Power (CGP) Database (2022), Boston University Global Development Policy Center.
Note: Excludes countries with <100mw commissioned capacity.

Across Pakistan, Indonesia and Vietnam approximately half of the coal plants that have entered operation in the last eight years use less efficient subcritical technology, with a further 10-15 percent using supercritical or ultra-supercritical technology and a third for which technology type information is unknown.

The currently-operating 39GW BRI plant fleet is estimated to generate 198 million tons of carbon dioxide emissions (MTCO2) annually (Boston University Global Development Policy Center 2022b). Assuming a constant load factor and a thirty-year operating lifetime, the total estimated remaining committed-emissions across the entire fleet is approximately 4.75 billion tons in CO_2 emissions (GTCO2). Every five-year reduction in the average lifetime of the fleet would result in around 1 GTCO2 avoided emissions, a figure that can be substantially higher or lower depending on the actual trajectory of plant load factors and differences in individual plants' sizes, efficiencies and fuel sources. Retiring the fleet ten years early would avoid almost 2 GTCO2, and so on. If a value were to be placed on these avoided carbon emissions, a $10-$100/tCO2 price on carbon would generate approximately $10-$100 billion in nominal carbon revenues (if a market price) or benefits (if a social price) if the plants were retired five years early, or twice as much $20-$200 billion if retired ten years early. The present value of these revenues, from a financial point of view, would depend on when the revenues would be realized and the discount rate applied.

Early retirement of plants still in existence beyond 2040 may be necessary for host countries and China alike to realize their climate ambitions but will also preemptively manage asset stranding risks before they materialize and can be designed to maximize the incentivize to invest freed-up capital into low-carbon energy sources, a process from which both parties will ultimately benefit. Host countries will see reduced carbon lock-in, less air and water pollution, and lower-cost energy; while China may expect both reputational benefits and the opportunity to further expand existing export markets for its low-carbon technologies and products.

Mechanisms for Early Retirement of Coal-Fired Power Plants

Mechanisms for early retirement targeting coal power are already in various stages of design and deployment. In the United States and European Union, regulatory measures and financial innovation have both been used to accelerate the retirement of ageing coal plants, including auctions for capacity closures, carbon price floors, concessional financing and ratepayer-based securitization. More recently, efforts have been made to design platforms more suited to the challenges of developing country contexts with more limited options for financial engineering, younger coal fleets and more limited state capacity. Several concrete mechanisms for financing early retirement have been proposed, and in some cases adopted.

The Just Energy Transition Partnership (JETP) framework for supporting developing country governments to transition away from fossil fuels has been backed by the United States, United Kingdom, Germany, France and the EU. It has been deployed in different forms in South Africa, Indonesia and Vietnam. The general approach that the JETP model promotes combines concessional international financing (provided to accelerate the replacement of these countries' coal assets with clean alternatives) with a country-specific suite of proposed policy reforms and investments in physical and financial infrastructure for renewable energy and energy efficiency. While the details of the JETP programs announced to date are yet to be fully defined, the overarching JETP approach of simultaneously retiring existing coal plants and replacing them with a self-sustaining renewable sector may yet be successful, although it is of limited direct applicability to Chinese overseas coal.

This study focuses on the use of concessional and carbon financing to facilitate early retirement. Of the early retirement mechanisms articulated to date (Table 2), two most closely resemble this model and are feasible for South and Southeast Asian country contexts. One is the Energy Transition Mechanism (ETM), under development by the Asian Development Bank (ADB). The ETM proposes using a blended finance structure to help coal plant owners commit to early retirement schedules by using concessional lending to support commercial returns to private investors. However, applicability to Chinese-financed coal in South and Southeast Asia, the regions it is targeting for initial applications, is still somewhat limited by the lack of available financial instruments and public funds (in host countries) for capitalizing retirement-focused vehicles and the presence of coal and power market controls. The other is the Just Transition Transaction (JTT) model first developed for application in South Africa. It proposes concessional financing delivered in several tranches linked to actual emissions reductions at a pre-agreed price on avoided carbon.

Table 2: Overview of Mechanisms for Early Coal Power Retirement

Description	Geography	Source of funds	Mechanism	Status	Applicability to South and Southeast Asia
Securitization	United States	Bond markets	Ratepayer-backed bonds on regulated utilities' coal assets are securitized and issued to support coal refinancing and reinvestment in renewables, backed by surcharges on ratepayers' energy bills (Bodnar et al 2020; Fong and Mardell 2021).	Implementation	Unclear. Unlikely to succeed in securitized bond form given underdeveloped bond markets. Could have traction as hard currency-denominated transition bonds (likely RMB) issued at entity level, especially where renewable energy is already cheaper than coal fuel costs.
Just Transition Transaction (JTT)	South Africa	Local public finance	Blended finance facility to purchase debt from electric utility (Eskom), with a sustainability-linked credit enhancement provided by government in exchange for Eskom delivering aggregate CO2 reduction at an implied price of $7/tCO2. Concessional finance provision is tied to performance (Steyn, Tyler, Roff, Renaud and Mgoduso 2021).	Under development	Feasible. PLN (Indonesia), and EVN (Vietnam) could use a blended finance facility with concessionality, conditional on decarbonizing at the system level. May require further modification to be financially viable depending on whether PLN (M. Brown 2020), and EVN (Vu 2021) can meet costs of decarbonizing power mix without additional capital injections.
Energy Transition Mechanism (ETM)	Southeast Asia	Global climate finance, private finance	A blended finance facility backed by Asian Development Bank, focused on reducing emissions, on the basis on concessional finance and carbon credits for avoided emissions (M. Brown and Hauber 2021; Carbon Trust, Asia Group Advisors and Climate Smart Ventures 2021).	Feasibility study	Feasible. Created specifically to facilitate early retirements in Southeast Asia, albeit not for Chinese-financed plants.
Coal Phase-Out Act	Germany	Local public finance	Competitive auctions to use public finance to compensate coal plant owners affected by the early retirement of plants, supported by other policy and financial measures (Calhoun et al 2021).	Implementation	Unlikely. Limited availability of public finance, focused on merchants, and insufficient competition in power markets for auctions to be viable.
Engie Energía Chile	Chile	Blended finance, private finance	Monetizing emissions reductions from coal plant retirement and guaranteeing future revenues from avoided carbon emissions, conditional on new investment in wind energy. Funded by IDB Invest, Climate Investment Funds, Engie Energía (Calhoun et al 2021).	Implementation	Feasible. Similar to ETM and JTT. Difficulties arise if avoided carbon revenues are not available, or the guarantees provided by government to pay for them are not credible.
Just Transition Mechanism (JTM)	European Union	Local public finance	Three-part fund that supports the just transition, by providing funding for economic diversification, investment in new infrastructure assets, and repurposing of existing assets (Calhoun et al 2021).	Capitalization	Unlikely. Limited availability of public finance.

Accelerating Coal Transition (ACT)	Global	Climate Investment Funds	Concessional financing to support the reclaiming and repurposing of coal assets, support laid-off workers, and guide the governance of the coal transition (Calhoun et al 2021).	Pre-launch	Feasible. This mechanism is funding the initial development of the ETM. The ACT can be used as a source of concessional finance for the ETM.

Source: Authors' elaboration

METHODOLOGY

A discounted cash flow (DCF) project finance model is used to generate the results discussed in this study. DCF analysis is frequently used by project developers to assess project value over a period of time. Academic studies have applied DCF models to valuation of electric power projects under different scenarios, including varying capital structure between lender and borrower (B. Chen and Liou 2017), carbon price scenarios (Rohlfs and Madlener 2014) and damages from physical climate risk (Espinoza et al 2020).

This working paper models the debt and equity cashflows associated with a coal plant with an assumed operating lifetime of 30 years[2], and evaluates future cashflows on the basis of the net present value of the cashflows at a given point in time. Since technical specifications and financing conditions for each of the individual coal plants on which this study focuses are not generally available, we elected to run the model for two archetypal plants—one subcritical and one supercritical—based chiefly on inputs from the Vietnamese and Indonesian contexts. The results should therefore be treated as approximations, rather than point estimates. The authors would be eager to input more precise plant-based figures if they were made available. Future refinement will entail sensitivity analyses to understand whether and how our results are being driven by key assumptions.

Subcritical and supercritical plants are modelled separately because of differences in plant efficiency, size, age, financing costs and capital costs. The results for the subcritical plant are those presented in this study, since they are most representative of the plants targeted by this study. Differences in some of the more important inputs are summarized in Table 3.

Table 3: Key Unit-Level Assumptions

Input	Unit	Subcritical	Supercritical
Capacity	MW	500	600
Utilization rate (a)	%	65%	70%
Capital cost (b)	USD/MW	950,000	1,150,000
Operations & Maintenance cost	% of capital cost	4.0%	3.5%
Debt ratio	%	75%	75%
Loan interest rate (c)	%/year	10%	10%
Loan term	years	15	15
Corporate tax rate	%	30%	20%
Regulated return on equity (d)	%/year	16%	12%
Heat rate (e)	Kcal/kWh	2200	2050
Coal energy content (f)	Kcal/kg	4000	5000
CO_2 emissions factor (g)	tCO2/MWh	0.925	0.825
Government cost of capital (h)	%/year	8.0%	8.0%

Source: (a) Based on averages for plants under 20 years old in (Carbon Trust et al., 2021); (b) Based on averages for Vietnam and Indonesia in (Carbon Trust et al., 2021); (c) Research by M. Chen (2020) suggests that in the mid-2010s, some CHEXIM loans were made at subsidized rates of 2-3 percent, while CDB loans averaged 3-6 percent. Internal analysis by Boston University Global Development Policy Center (2022a) suggests that CHEXIM loans in the power sector for which data is available average 2 percent, while CDB power sector loans average 8 percent. The China's Global Power Database shows CHEXIM to be the main lender for power projects in Indonesia and Vietnam, although the origin of a significant proportion of the loans remains unknown. An estimated average underling interest rate of 5 percent is therefore assumed (Boston University Global Development Policy Center 2022b). However, since CDB and CHEXIM transactions are typically carried out in Chinese currency, the total effective interest rate is assumed to be 10 percent, after accounting for the cost of currency hedging; (d) Based on averages for Vietnam and Indonesia in (Carbon Trust et al 2021); (e) See Global Energy Monitor (2022); (f) Based on averages for Vietnam and Indonesia in (Carbon Trust et al 2021); (g) See Eggleston, Buendia,

[2] This is distinct from the regulatory lifetime of a coal asset, which may define, among other things, depreciation schedules and the duration of guaranteed returns on equity.

Miwa, Ngara, and Tanabe (2006); (h) Based on averages for Vietnam, Indonesia and Pakistan in World Government Bonds (2022).

Four primary variants of early retirement scenarios are modelled here. In each of the "concessional finance" cases, the model provides results for every possible combination of *refinancing year* (the year in which the plant's debt and/or equity is either refinanced at a lower rate or transferred to a new entity, which might be a blended finance fund, state bank or other entity dedicated to accelerating coal retirement); and *retirement year* (the year in which the plant ceases operations). Where a subsidy is involved, the associated costs are discounted at the rate applicable to the institution providing the subsidy—which is likely to be a government or other public sector body. The four variants are as follows, with all costs evaluated at the point of refinancing (e.g., if a plant is refinanced in year 5, the net present value of costs in each scenario is evaluated as of year 5):

1. **Cash buyout**, in which the refinancing entity entirely buys out the remaining debt and equity cashflows for the coal plant at the point of refinancing and retires it immediately. This is most similar to other approaches in the literature that have attempted to quantify the costs of early retirement.
2. **Concessional finance**, in which a subsidy is paid to the holders of debt and/or equity respectively that allows the refinancing entity to achieve its desired return while also retiring the plant early. The subsidy is calculated on the basis of the cashflows that would be foregone in the case of early retirement.
3. **Carbon buyout**, which calculates the price on future avoided emissions that is required to allow debt and/or equity holders to retire the coal plant early. This "debt-for-carbon" swap is roughly analogous to a "debt-for-nature" swap, in which liabilities owed by one party to another (typically governments) are restructured or written off in exchange for not exploiting a resource with negative externalities, in this case carbon-emitting coal combustion.
4. **Concessional carbon finance**, which calculates the value that needs to be placed on future avoided emissions to fund the costs of the concessional finance subsidy. This is a second variant of a debt-for-carbon swap.

This approach is designed to evaluate the costs of more or less ambitious approaches to coal retirement in contexts where compensating plant owners for the full remaining lifetime of the plants (often in excess of 20 years) would likely be prohibitively expensive, and in which markets for avoided carbon emissions largely do not exist.

It is important to note than in many of the countries in which BRI plants are present, the power sector is controlled to a significant extent by SOEs and embedded in a specific political and economic context. This means that the costs of early retirement are more likely to ultimately fall to the sovereign, either in the form of being the implicit guarantor for SOEs or as the entity providing ongoing capital support in the form of government transfers, regulated electricity prices or other forms of explicit or implicit subsidy. In the cases of interest to this study, where Chinese firms typically hold debt and equity positions, and/or EPC contracts, for the plants, early retirement would result in net transfers to the Chinese lenders unless debt or equity returns were renegotiated.

Thus, while the quantitative results are a useful guide for the range of costs associated with retiring BRI coal, the ultimate goal of this working paper is integrating these results into a comparative assessment of the political economy regimes in which the plants are situated in reality (see Section 4).

RESULTS

The results of the financial analysis are presented here in detail for subcritical plants, given that this is the dominant type of plant among those of interest to this study. Table 4 shows a summary of the results under each of the four core scenarios. All values are expressed in millions of US dollars. We find that the cost of using concessional finance to subsidize early retirement by allowing debt and equity holders to meet their return requirements is 20 percent cheaper than a full buyout if implemented in year five of operation for retirement in year 10 (20 years early), about 50 percent cheaper for retirement in year 15 (15 years early), or two-thirds cheaper in year 20 (10 years early). We also find that the prices on avoided emissions required to fund either a full buyout or to pay for the cost of subsidies is very low, at below \$20/tCO2 in all these cases. The required carbon price also falls the later the plant is retired, as the foregone revenue it is required to fund falls faster in net present value terms than the emissions available to be monetized.

Table 4: Summary of Costs of Early Retirement under Each Core Scenario, Assuming (for Scenarios 3 and 4) Implementation in Year Five of Plant Operation

Scenario	Retirement year		
	Year 10 (20 years early)	Year 15 (15 years early)	Year 20 (10 years early)
Cost ($m)			
Cash buyout	184	81	33
Concessional finance	151	46	11
Required carbon price ($/tCO2)			
Carbon finance	12.5	5.9	2.8
Concessional carbon finance	14.8	5.9	2.8

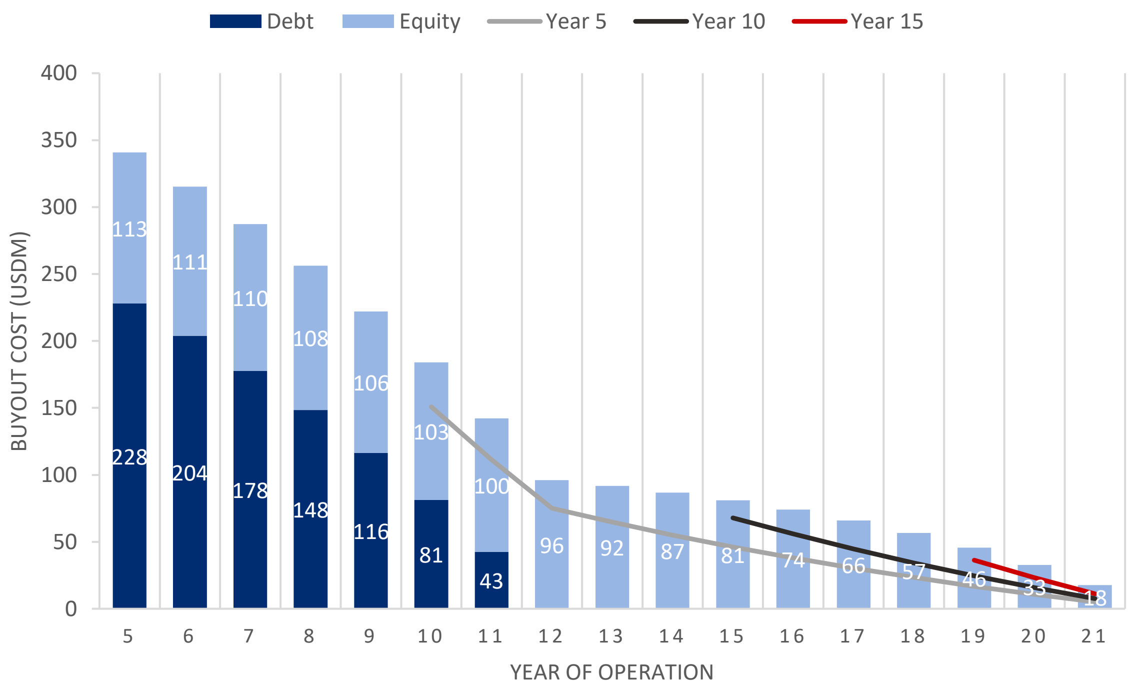
Source: Authors' elaboration.

CASH BUYOUT AND CONCESSIONAL FINANCE

In a full buyout scenario, the original owners of the coal plant's equity and debt sell their stakes, valued on the basis of remaining expected cashflows, to a new buyer, who immediately closes the plant. The remaining value of future cashflows at the point of the buyout declines over time as the remaining cashflows fall. For our illustrative subcritical plant (Figure 2), the present costs of full buyout and immediate retirement (bars) start at $341 million if retired after five years of operation with 25 years remaining (of which two thirds is to pay off the debt holder), falling to $184 million if retired after ten years (45 percent debt), or $81 million if retired after fifteen years (100 percent equity, since the debt holder has been fully paid off).

For comparison, a study of the costs of decommissioning coal plants, including remaining capital and operational expenditures, found the mean decommissioning cost of coal plants in India was $58 million per GW, relative to the plant operating for another ten years. For a developed country, the authors estimated a higher average cost at $117 million per GW in a U.S. context (Jindal & Shrimali, 2022).

Figure 2: Net Present Costs for Immediate Retirement (Bars) and Concessional Financing for Early Retirement (Lines), at Point of Purchase



Source: Authors' elaboration.

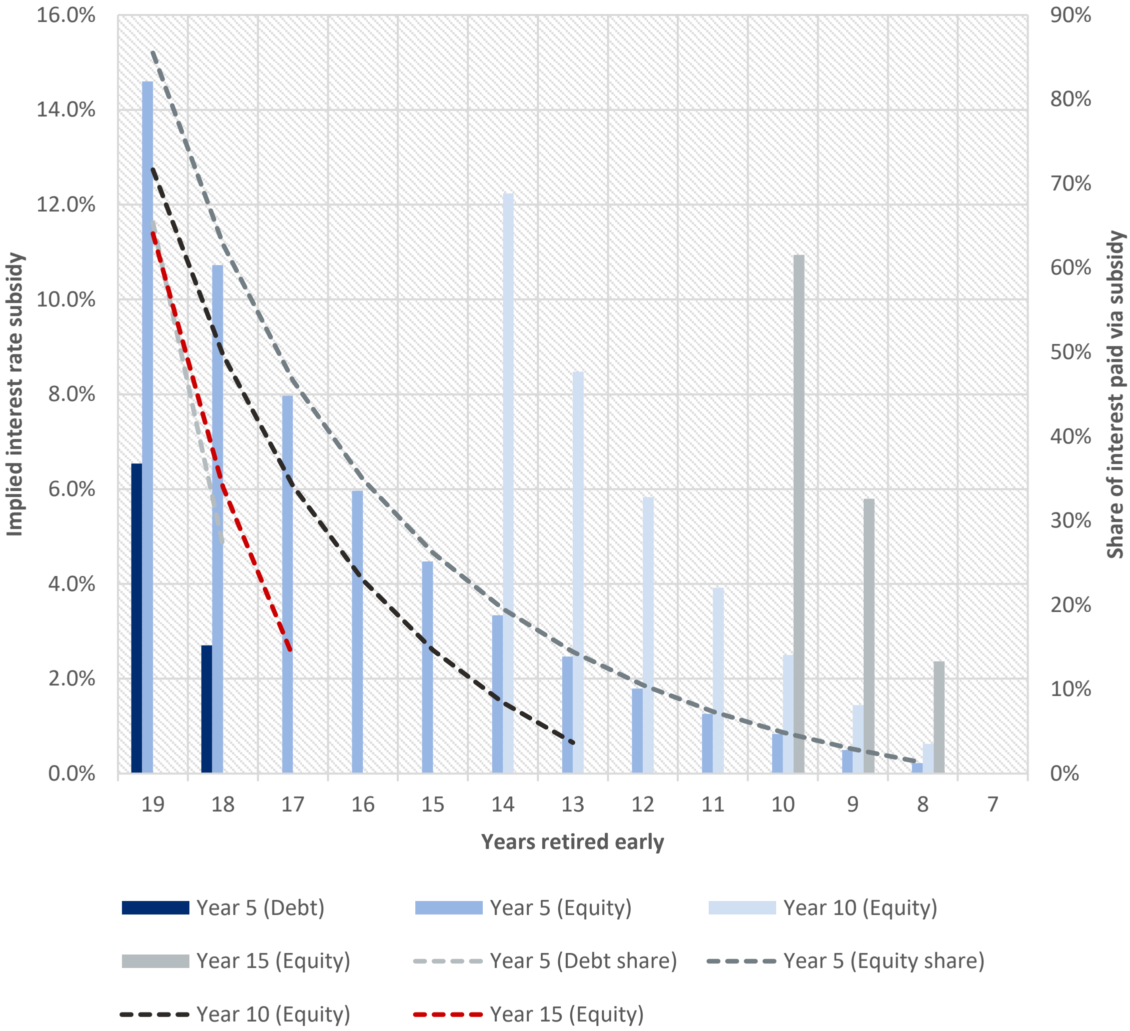
In a concessional finance scenario (lines), the plant is refinanced at a given point in time but not retired immediately, with a public finance provider providing a subsidy sufficient to ensure that the refinancing entity (which may have an equal or lower return requirement than the original lender) does not lose money. This subsidy can either be provided in the form of a direct grant (in which the subsidy provider pays to the refinancing entity all cashflows foregone as a result of early retirement), or by paying a portion of the interest (for debt) or equity returns (for equity) remitted to the refinancing entity. These are equivalent options from the point of view of the debt and equity holder, as long as they deliver an equivalent net present value to each of them.

Since the subsidy provider's cost of capital is lower than the commercial rate, it is able to demand a much lower return on capital. We assume that the retirement year is in a year after the refinancing year. In this scenario, the cost to the subsidy provider for covering cashflows after retirement is lower than a cash buyout. The cost to the subsidy provider of guaranteeing the immediate retirement of a plant by committing to paying post-retirement cashflows on the original debt and equity are higher than a cash buyout due to the lower discount rate for concessional finance raising the present cost of foregone future cashflows. However, for a capital-constrained government with power generation sectors and coal cashflows under pressure, where some share of the plant is owned by a foreign entity (e.g., CDB) but that nonetheless needs to take short-term action to secure the future retirement of existing plants, the same approach could be used to shorten the life of a plant, at lower cost than retiring it immediately.

If, for example, the plant is refinanced in year five and the subsidy provider pays enough of the interest on the remaining loan to ensure that the plant can be retired at the end of year ten (i.e., 20 years early), this could be achieved at a cost to the subsidy provider of $151 million ($33 million less than a full buyout in the same year), most of which is destined for equity providers. Allowing the plant to operate for a further five years (closing it 15 years early) would reduce the total cost to $46 million (compared to the $81 million cost of a full buyout achieving the same result), all of which would be used to pay off equity holders. If the plant is refinanced in year ten and retired in year 15, achieving the same result would cost less (at the point of refinancing) than it would have had it committed to the subsidy mechanism five years later. Refinancing in year 15 and retiring in the same year would cost $81 million in subsidies.

If post-retirement cashflows are foregone, the subsidy (paid each year between refinancing and retirement) that would be required to replace those cashflows can also be expressed as a subsidy to the interest rate paid on the principal (or, analogously, equity cashflows) outstanding at the point of refinancing. The implied percentage point interest rate subsidy is given in Figure 3, with the dotted lines and right-hand axis representing the share of total interest paid by the subsidy. An interest rate subsidy is only an option for years in which the required subsidy is less than the interest on the loan (or, for equity, returns on equity paid to shareholders). In the case modelled here, interest rate/equity return subsidies can be used to retire the plant up to 20 years early if the subsidy is introduced in year five of operation, 14 years early if introduced in year ten and up to 11 years early if introduced in year 15. Retiring the plant earlier would require complementing the "concessional" subsidy with an additional grant component. The debt is paid off after 13 years of operation, so subsidies after that point are directed entirely to equity returns. After 22 years of operation, both debt and required equity returns are fully paid off, such that no subsidy is required.

Figure 3. Interest Rate / Return Subsidies at Point of Refinancing (in Years Five, Ten and 15 of Operation)



Source: Authors' elaboration
Note: Bars are the interest rate subsidy (in percentage points) and dotted lines are the share of total interest this represents.

CARBON BUYOUT AND CONCESSIONAL CARBON FINANCE

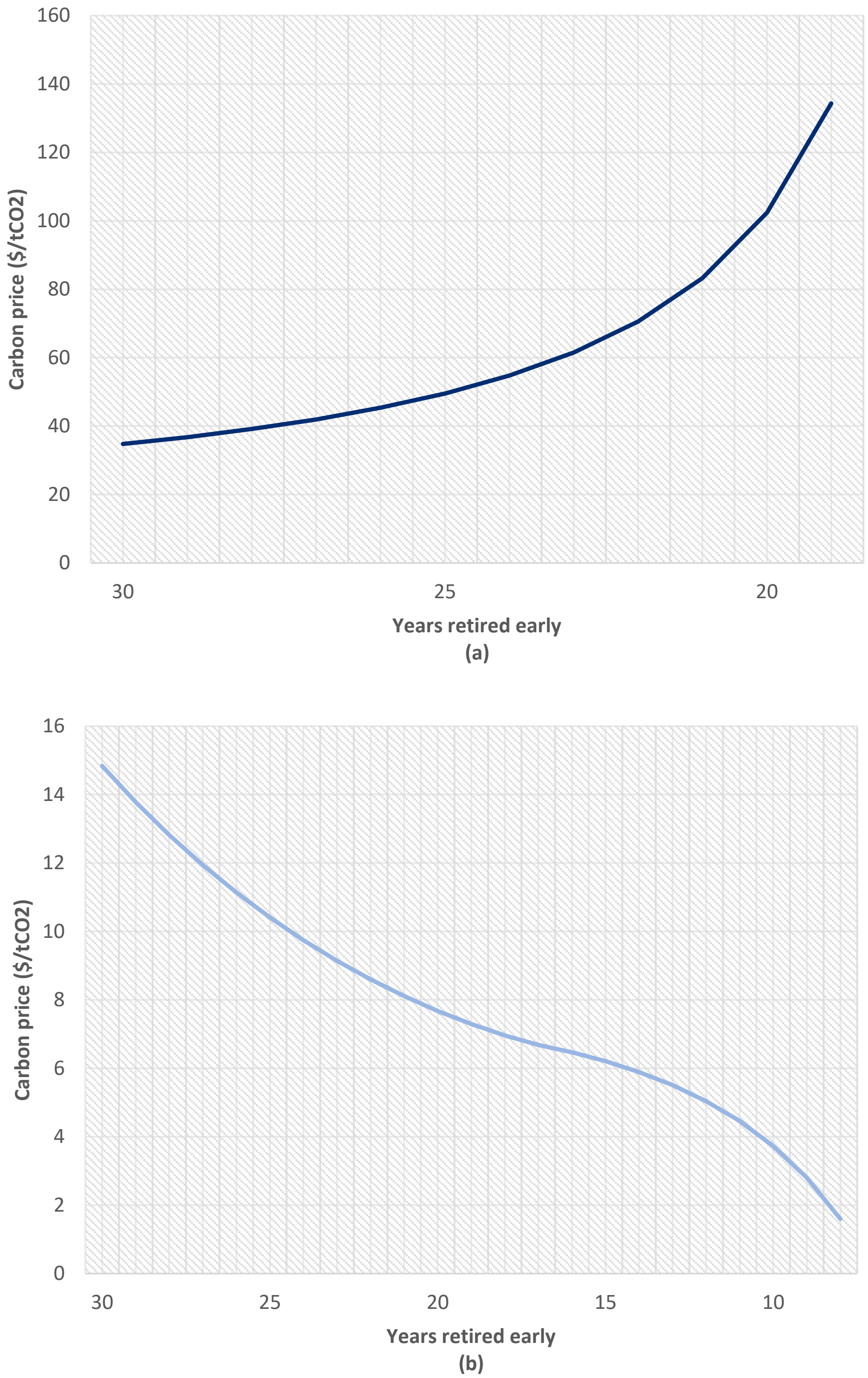
Given the avoided emissions associated with the early retirement of a coal plant, there will be a price on avoided emissions at which both debt and equity holders would be able to cover the value of all future cashflows, assuming that these avoided emissions are converted into revenue at the point at which they would have been emitted (i.e., in post-retirement years). At this price on avoided emissions, the debt and equity holders could immediately retire the plant without sacrificing any net present value.

The price required to fully compensate debt holders is much higher than that required to compensate equity holders and it rises the later that the plant retires. In both cases, waiting longer to retire the plant means that there are fewer years in which avoided emissions can be monetized to pay for foregone cashflows (increasing the price), but also fewer foregone cashflows to pay for (decreasing the price). Since avoided emissions are attributed to debt and equity holders according to their share in the remaining project and the debt principal is paid down over time, the rate at which emissions associated with debt holders are available to be monetized falls is higher than the rate at which the value of foregone cashflows falls. The net effect is an increasing carbon price. Moreover, the rate at which debt-linked avoided emissions falls accelerates relative to the rate at which the value of foregone cashflows falls, as the loan reaches maturity declines. The required carbon price therefore also rises at an increasing rate with later retirement (

Figure 4a).

In the case of equity holders, their share of avoided emissions rises as debt is paid down, such that the net present value of avoided emissions attributed to equity holders rises for later retirement years, peaking for 17 years' early retirement (visible as an inflection point in Figure 4b). Since the value of avoided emissions is higher than for debt and rises as the value of foregone cashflows falls, the carbon price is low than for debt and declining with later retirement. The rate of decline slows as the rate of increase in the value of avoided emissions also slows. From 18 years' early retirement onwards, the present value of avoided emissions begins to fall at an increasing rate. In combination with the declining present value of foregone cashflows, the net effect is an accelerating rate of decline in the required carbon price if the plant is retired less than 18 years early.

Figure 4: Carbon Price on Future Avoided Emissions Required to Justify Early Retirement, NPV Basis

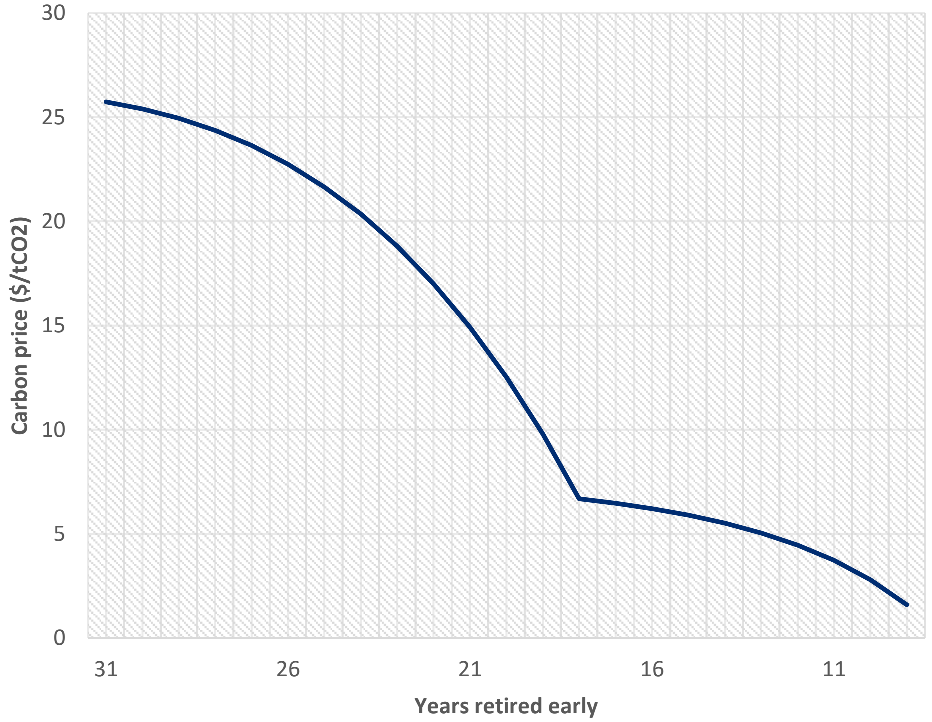


Source: Authors' elaboration.
Note: (a) is the price required to pay off debt holders and (b) equity holders.

A single price on future avoided emissions can be calculated such that debt and equity holders are both paid off (

Figure 5). That is, the carbon price is such that revenue from avoided emissions equal the outstanding present value of debt and equity cashflows in the refinancing year (i.e., the year in which the plant owner replaces the original post-retirement cashflows with carbon revenues). This price is higher the sooner the plant retires, and also declines at an increasing rate the later retirement occurs. This is because, despite the debt-linked price rising, the share of debt payments in the present value of future cashflows falls and the upward pressure on the overall price exerted by the higher debt price falls. The rate of decline slows once the debt is paid off 17 years from the original retirement date (represented by the kink in Figure 5, after which point the carbon price is simply the equity price in Figure 4b).

Figure 5: Carbon Price on Future Avoided Emissions Required for Excess Payout to Equity Holders to Fully Compensate Debt Holders, NPV Basis

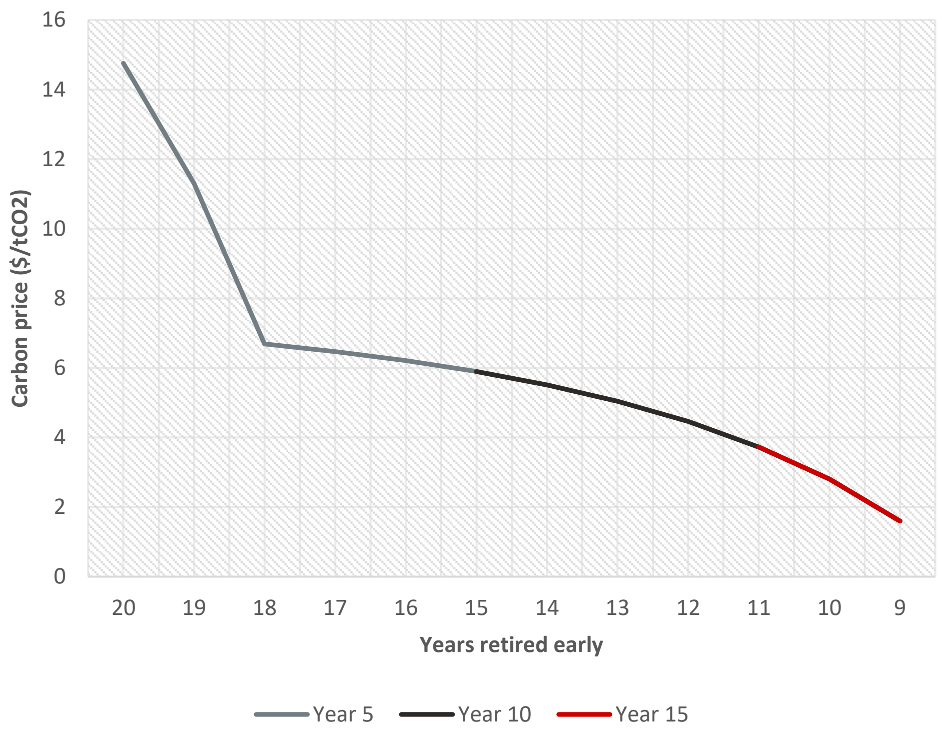


Source: Authors' elaboration.

It is also possible to find the carbon price on avoided emissions that would be required to fully replace the subsidy amounts required in a concessional finance scenario (

Figure 6). This can only be calculated for combinations of years in which both an interest rate and equity return subsidy can also be calculated. As with Figure 5, it also declines over time as the required subsidy falls, rebounding slightly after the debt is paid off before declining at a slower rate at the same value as the carbon price required to pay off equity holders. Importantly, the required carbon price on avoided emissions to fund the subsidy does not depend on the refinancing year, reflecting the fact that avoided emissions are released at the same point in time regardless (i.e., post retirement).

Figure 6: Carbon Price on Future Avoided Emissions Required to Fully Fund Subsidy, NPV Basis (Calculated in Different Years)



Source: Authors' elaboration.

DISCUSSION

The results presented in the modelling analysis for this working paper provide a quantitative basis for discussion of the early retirement structures available for shortening the lifetimes of coal plants that have not paid off their capital costs and which are operating in contexts where immediate retirement is not desirable either from an energy supply perspective or a financial perspective—especially in the case of BRI plants, where the lender and in some cases the sponsor are Chinese. They clearly show that given the option of subsidizing foregone revenues (either as a lump sum or in the form of interest rate subsidies), it is cheaper—given our assumptions—to refinance a plant at the lower interest rate and retire it several years later, still shaving over a decade or more off its original operating lifetime, than to buy out the plant outright.

Coal in National Context

To understand the significance and practical relevance of the quantitative results, we now place them in the context of the political economy regimes of the three countries considered here, all of which have received significant Chinese investment (in the form of lending, equity provision or EPC contract fulfilment) in coal-fired power plants.

INDONESIA

Indonesia, an archipelagic nation of 17,000 islands with highly varied population densities and concentrated centers of economic activity, already accounts for 40 percent of the Association of Southeast Asian Nations (ASEAN) energy use, and expects a tripling of final energy demand between 2014-2030 (IRENA 2017). Its energy supply mix remains dominated by coal and oil, with domestic coal contributing roughly 60 percent of total generation (Christina and Nangoy 2021). Oil and gas consumption has more than doubled since 1990, but despite rapidly increasing oil imports (IEA 2021b), Indonesia's coal export industry means it is still a net energy exporter (ADB 2020). Indonesia's abundant domestic coal resources have contributed to political endorsement of expansionist coal power policies, backed by political and economic elites (both individual oligarchs and energy sector SOEs).

It is also the world's largest producer of biofuels (IEA, 2021b). Non-bioenergy generation in 2020 was dominated by hydropower (19.5 TWh) and geothermal (15.6 TWh), with wind and solar combined producing just 0.9 TWh. Investment in renewable energy in 2021 totaled $1.5 billion, just 20 percent of the annual requirement from 2021-2025 to reach even short-term renewable targets (IISD 2022) and far short of the levels required to compensate for accelerated coal retirement.

China's role in growing the Indonesian coal sector expanded sharply in the late 2010s, across debt financing, equity investment and construction contracts. As royalties from coal mining to serve these domestic plants has become an ever-larger component of local and national public budgets, self-reinforcing incentives for the public sector to sustain the coal industry have also emerged (Ordonez, Jakob, Steckel and Fünfgeld 2021). With SOEs acting as a powerful additional locus of political patronage, the state-directed development model remains a core component of Indonesian energy policy and a major constraint on accelerated coal phase-out. Legal reforms enshrined in the Autonomy Act of 1999 devolved energy sector planning and regulatory functions to provincial authorities, but institutional barriers, inconsistent policy incentives and the de facto blurring of developmental versus commercial objectives have served to stifle provincial stakeholders' capacity to catalyze a restructuring of the coal sector (Sekaringtias, Verrier and Cronin 2023). Early decommissioning of existing Indonesian coal capacity is also directly constrained by international investor-state dispute settlement (ISDS) protection for 90 percent of foreign-owned coal plants. The China-ASEAN treaty further explicitly protects 12 more relatively new Indonesian coal plants, largely subcritical, from stranded costs estimated at $6.8-7.9 billion if Indonesia meets its Paris targets (Tienhaara and Cotula 2017).

PAKISTAN

Pakistan has experienced regular energy crises for over two decades and is projecting electricity demand to rise by a quarter from 154TWh in 2019-2020 to 192TWh in 2024-2025 (IEA 2021c). The country's generation mix has historically been dominated by hydro, gas and oil, but a rapid shift towards meeting marginal demand with new coal plants financed by Chinese entities has been observed more recently. The plants, developed through the China-Pakistan Economic Corridor (CPEC), attracted Chinese investment on the basis of costly concessions: very high returns on equity, reimbursement of fees levied by China Export and Credit Insurance Corporation (Sinosure) for political risk insurance and a relatively short debt repayment period of ten years (Ali 2020; Khan and Liu 2019).

These arrangements have led directly to rapidly rising debt liabilities (some $1.4 billion in the form of sovereign guarantees) and coal import costs for the Pakistani government (Ebrahim 2019). In 2019, gas was still providing almost half of generation, followed by hydro and coal at 20 percent and 12 percent, respectively. An insubstantial domestic mining industry combined with rapid growth in coal capacity have led to increasing coal import dependency. Hydropower generation is growing, but slowly (EIA 2022), while bioenergy's share has fallen steadily to approximately one-third in 2019. The country's natural wind corridors are well-suited to onshore wind installations, but despite this potential (partly realized with the conclusion of several successful projects), installed solar and wind capacity in Pakistan remains low at 1.5GW in 2020, contributing just 3-4 percent of total generation. In 2020, Pakistan announced the intended cancellation and replacement of two coal-based projects with new hydropower (The Express Tribune 2020). Meanwhile, estimated asset stranding costs for the existing coal power industry have been placed at $18 billion, with another $20-$30 billion required to replace coal with sufficient renewable capacity replacement and additional grid capacity to meet demand. Pakistan's unstable economic outlook, combined with the absence of carbon markets, extremely generous regulated equity returns and capacity payments for existing coal plants, financially stressed utility companies, and lack of structural incentives for renewable energy development, are making it challenging to attract new investment in utility-scale renewable projects (Bhandary and Gallaghe, 2022; Nedophil Wang, Springer, Volz and Yue, 2022; Solangi, Longsheng and Shah 2021). This combination of factors makes it exceptionally challenging to retire Pakistan's coal capacity ahead of its originally intended schedule without external support.

VIETNAM

Vietnam's energy demand is still growing by 10 percent annually (Breu, Castellano, Deffarges and Nguyen 2021). Vietnam's generation mix was dominated by hydropower until 2010, but by 2021 was seeing 60 percent of generation from coal, gas and oil (Pham 2022; VinaCapital 2022). Coal has doubled its generation share since 2010 to nearly 50 percent, its rise accelerated by the abandonment of nuclear power development plans

(Murray 2021) and demand for coal is expected to double by 2030 (Phu 2022). Vietnam has since gone from a net coal exporter to importer (Samuel 2022).

While solar capacity has risen from near zero in 2015 to 16.5GW in 2021 (Tachev 2022b), wind deployment has faltered (Merdekawati, Supendi and Vu 2022). Vietnam's 8th PDP (Power Development Plan), running from 2021-2030, articulates a longer-term vision for 2045. It plans to expand wind power to 64 percent of generation, supported by 15GW of gas, 45GW of LNG and slower growth in coal capacity. Nevertheless, Vietnam's existing coal plants are already struggling with high fuel costs (Dat 2022) and most plants operate with load factors of 60-70 percent, with some periodically shutting down in response to coal shortages (Vietnam Investment Review 2022) and further expansion increasingly subject to political opposition (Pham 2022). With the withdrawal of significant financing partners from international coal investments, several high-profile pre-investment coal projects face uncertain futures (Tachev 2022a). Options under consideration for accelerating the retirement of the existing coal power plant fleets include buying and replacing them earlier than planned with clean energy sources under the ADB's ETM (Hoang 2021) and fuel-switching to ammonia (The Investor, 2022).

Political Economy and Retirement Mechanisms

The three contexts considered here share key characteristics with respect to the future of coal and the feasibility of retiring existing capacity. First is double-digit expected electricity demand growth in the medium term, requiring an expansion of power supply. Second is the centrality of coal to the existing generation mix. In Indonesia, coal has long held this central position, while Pakistan and Vietnam have pivoted heavily to coal power, and coal imports, much more recently. Third, is the weak financial outlook for inflexible coal assets, driven by competition from renewables, high costs and load factors declining towards 60 percent (in Indonesia’s case reflecting short-term overcapacity). Finally, each country has clearly articulated long-term decarbonization goals and a need to attract significant new private investment to achieve them without risking energy supply security.

Contextual circumstances present in each country also differ in several notable respects. First, Vietnam has invested heavily in solar expansion, and increasingly wind, while Indonesia and Pakistan have failed to do so at scale, in part due to a lack of supporting domestic policies and an uncertain regulatory environment for renewables, and in part to poor system planning and external shocks leading to an excess in short-term capacity (with further expansion likely to further deteriorate existing coal plants’ financial circumstances). Second, Vietnam is relatively more advanced in developing a policy framework for the early decommissioning of coal assets and the integration of these measures into long-term planning. Pakistan and Indonesia, with limited alternative investment options and heavy financial burdens associated with existing coal fleets, are at the earliest stages of a structured approach to coal phase-out.

Given the range of methodological frameworks available for parsing this information, we opt for the ‘Actors, Objectives, Context’ (AOC) approach. This simple but heuristic model for identifying and analyzing political-economic relationships balances parsimony, rigor and policy relevance well, and has been applied to a range of studies considering the obstacles to coal power phase-out across diverse jurisdictions (Heerma van Voss and Rafaty 2022; Jakob and Steckel 2022; Jakob et al. 2020; Ohlendorf, Jakob and Steckel 2022). While this study does not undertake primary research, it draws heavily on this existing work—itself built on a combination of expert surveys, in-depth national case studies and comparative policy formation analysis—to situate the modelling findings in context and attempt to draw general conclusions on the common factors determining the available policy options for coal retirement in the countries studied.

The principal **actors** in coal retirement decisions can be broadly separated into primarily political and primarily economic constituencies. The most influential political actors in each case are the head of state, ruling party, electricity regulators and the cabinet ministries responsible for energy development. The equivalent economic actors are electric utilities and coal mining companies, which tend to be either state-owned or under a degree of oligarchic control, in both cases acting as patrons for the key political actors. By comparison, the political-economic role of civil society is meagre. Power is concentrated among elite political figures and brokers whose political fortunes are closely tied to their ability to attract foreign capital to domestic infrastructure projects, especially those well-placed to benefit principal economic actors—i.e., energy supply, high-growth sectors and export-oriented industries.

The overarching **objectives** of coal policy, shared among the principal actors, are concentrated on three priorities: (i) economic growth, (ii) electricity supply security and (iii) electricity affordability. Proponents of, and investors in, coal projects refer to these objectives almost exclusively in the literature reviewed on the three country contexts. By contrast, there is little mention, among non-marginal political and economic actors, of policies designed to capitalize on early coal retirement.

The historical and structural **context** in which the principal actors and their major objectives sit is derived chiefly from the design of domestic power markets and the modalities available for infrastructure financing. Existing literature notes how the structural features of power markets, especially ownership and control over power assets, and transmission and distribution infrastructure, limit actors' influence over coal policy decisions from investment through to underwriting, construction, commissioning, operation, refinancing and retirement. Since this represents a more or less binding constraint absent major power sector reform, infrastructure financing is more relevant to identifying the available options for plant retirement. Perhaps the most salient contextual factors across all countries studied is a move towards financial liberalization in the energy sector, even where foreign capital is channeled through domestic institutions, as in Indonesia's case.

Linking these three components together, the key insight is that the political actors, themselves constrained by domestic economic actors, may see the liberalization, or externalization, of infrastructure financing as a legitimate and politically secure means of stimulating new types of economic activity (e.g., growth in renewables and the phasing out of coal) without risking the destabilization of their rule or necessarily threatening the position of their political patrons (Pond 2018). In the coal context, this means that the most viable pathways for coal retirement will likely involve the use of foreign capital to assume (some of) the costs of retiring coal early. Similarly, it may be unwise to depend on domestic utilities (state-owned or otherwise) to take the initiative to accelerate coal retirement, given the configuration of actors, objectives and contexts in the countries under study.

Our central conclusion, therefore, is that to have a reasonable chance of success—in the short term at least—policy initiatives for early coal retirement will likely require the active engagement of the debt or equity holders, in this case Chinese state-owned financial institutions. Externalizing the capital requirements for early retirement also has the benefit of taking the assets off the balance sheets of host country SOEs and financial institutions, freeing up capital for investment in alternative energy sources that would otherwise be dedicated to funding coal asset retirement. As the modelling approach and results described here suggest, there are several options for achieving this:

(i) Immediate retirement through a full buyout. This comes at a high upfront cost if the debt and equity holders are to be fully compensated and required immediate replacement with alternative power generation.
(ii) Refinancing at a lower cost of capital where possible and/or an interest rate subsidy paid to the debt/equity holders to compensate for cashflows foregone by early retirement. As the modelling results show, this can come at lower cost for an equivalent result and allow sufficient time and predictability to develop substitute power sources.
(iii) Debt-for-carbon swaps either in the form of a full buyout or interest rate subsidy.

In practice, assuming Chinese entities hold debt or equity, the options for implementation might include:

(i) A willingness on the part of these entities—or their shareholder, the Chinese government—to voluntarily renegotiate terms, with debt restructuring to reduce interest rates and/or the Chinese government providing a subsidy, possibly with some of the costs shared with the host country's government.
(ii) The transfer of the coal plant asset to another Chinese entity, such as a government bank charged with winding down the asset at an acceptable cost to the Chinese government.
(iii) The transfer of the coal plant asset to an international blended finance fund comprising a mixture of commercial and concessional capital. This would be conditional on the Chinese entities' willingness to sell the assets, which is perhaps less likely than the first scenario given that the plants generally feature Chinese technology and suppliers and may be considered part of a wider trade and investment partnership with the plant's host country that could be jeopardized by the sale of the asset.

Among the various types of Chinese institutions involved in overseas coal project finance, Chinese DFIs could lead the adoption of the specific mechanisms discussed above. China's DFIs play an important role in coordinating capital allocation across the different actors involved in overseas project finance (Chin and Gallagher 2019). Given their public and quasi-governmental status, China's DFIs are also subject to international pressures for raising the environmental standards of overseas financing to match those of other global DFIs. The JETP model, backed by the G7 and other Western nations, has now resulted in deals being struck with South Africa, Indonesia and Vietnam, and would involve the respective DFIs of these countries as central components of each program. The ADB, also a DFI, is currently developing the ETM model, which may yet feature as a component of the various JETP programs. China has made broad commitments to supporting green and low-carbon energy in developing countries, and increasingly codified these commitments in official guidance, but an increase in financial support since the timing of those commitments has yet to emerge (Springer, Lu and Chi 2022).

Enabling policy frameworks will be necessary to mobilize the finance needed to meet these commitments. While China is unlikely to join the JETP framework or to pursue similar multilateral approaches, Chinese DFIs could still indicate their support for specific energy and emissions goals and provide financial support for achieving those goals in developing countries. The retirement mechanisms discussed above allow for several politically feasible channels through which Chinese DFIs could implement them. First, from the debt perspective, China's DFIs actively engage in debt restructuring negotiations when they are required and have previously issued loans for coal-fired power plants in debt-distressed countries. Other types of debt swaps, such as debt-for-nature and debt-for-climate swaps, are also under discussion in China as possible instruments for foreign financing operations. The implementation options discussed above could be incorporated into any debt swap structures, should Chinese DFIs choose to move forward with them. Second, from the equity perspective, China has already established over two dozen overseas development investment funds that channel equity capital towards stated development goals. Shareholders of these funds include Chinese DFIs, as well as commercial banks and private investors, and some of the funds have also stated green development goals (Moses, Gormley and Springer 2022). These multi-shareholder funds can be used to pool capital for interest rate subsidies and/or serve as an institutional home into which coal plant assets targeted for early retirement can be transferred.

A Chinese-led partnership focused on financing for energy transition need not focus exclusively on coal retirement. Indeed, establishing a policy framework for Chinese DFIs focused on renewable energy may be more politically viable with coal retirement as a supporting mechanism. From a broader perspective, the political viability and environmental efficacy of these options (both for China and host countries) may hinge crucially on concomitant investments in (near-) zero carbon electricity capacity. Given China's substantial comparative advantages and commercial interests in renewable energy equipment manufacturing and export trade, it is conceivable that the case for China-initiated coal retirement would be bolstered by Chinese actors' interests in this burgeoning sector, in addition to the already substantial potential savings from debt restructuring alone described in this study. At the same time, host countries can play an important role in forming these partnerships and could set targets within the agreed-upon framework to support local content or link their level of support for coal retirement to the level of financial support they receive for renewable energy capacity expansion.

CONCLUSION

The starting point for this paper was to address the fleet of currently operating coal plants financed by China overseas, which total approximately 39GW and has an average age of less than ten years. Retiring these plants early can yield greater benefits avoided emissions benefits given their age but is also made more difficult given that most of their debt and equity liabilities have not been paid off and they are operating in regulated markets in which the instruments applied to date to accelerate coal retirement are either not present or too politically disruptive to stand a reasonable chance of implementation or success.

A pro-forma analysis of an illustrative subcritical plant with representative characteristics suggests that an interest rate subsidy approach may be a more effective use of concessional funding than full buyouts in securing early retirement. Not only is the former option a cheaper means of achieving the same avoided emissions outcome (e.g., $151 million for refinancing in year five and retiring in year ten, versus $184 million to retire in year ten), but it is also more practical given that in the three cases that this study has considered, electricity demand growth rates are high and renewable buildout is still at a relatively early stage. Providing an interest rate subsidy sufficient to allow early retirement (in the model, a 3-percentage point subsidy for equity returns paid from year five onwards would allow retirement in year ten), but for a long enough period of time to allow the host country to invest in replacement capacity, may be a workable solution to pursue. Whether or not a market for avoided carbon emissions exists by the time the plant does retire, debt-for-carbon swaps may also be a viable means of financing plant retirement and can fully compensate date or equity holders at a carbon price of less than $20/tCO2 in either scenario.

It is also clear from the political economy analysis conducted here that these solutions are unlikely to arise domestically of their own accord, given limited fiscal space to subsidize interest payments (especially to foreign entities) and powerful pro-coal entrenched interests in the political and economic spheres. If this conclusion is correct, early retirement of BRI coal plants is likely to require the active engagement of Chinese lenders and equity holders in renegotiating outstanding debts, lowering the cost of borrowing where appropriate and subsidizing interest payments where possible or agreeing to the transfer of debt and equity ownership to other institutions, whether these be Chinese government-controlled banks or asset managers, or internationally-capitalized blended finance funds designed to facilitate early coal retirement. While our analysis and results are oriented towards Chinese-financed coal plants in certain countries, the mechanisms and implementation options we identified are relevant for emerging frameworks for coal retirement in developing countries, including JETP and ETM.

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APPENDIX 1: METHODOLOGICAL APPENDIX

Series of Payments

When calculating the implied interest rate *i* of a series of payments, equation (1) is used to calculate a constant *k*, where the net present value of future cashflows (or principal) *A*, the payment per period (annuity) *c* and the number of periods *n* are known. For series with many payments, an algebraic solution is not possible, so an iterative process is used to determine the value for *i*. The iteration method used is the Newton-Raphson method.

$$k = \frac{A}{c} = \frac{(1-(1+i)^{-n})}{i}$$

Where the interest rate (or, for equity cashflows, rate of return) *i* is known, the annuity payment per period on a balance can be calculated (2) by rearranging (1). For equity return calculations (as opposed to loan repayments), the series of cashflows is uneven, that is, the payment per period is variable. In this case, formula (2) can find the equivalent constant annuity such that the net present value of the cashflows using this constant annuity is the same as it would be for the series of uneven cashflows.

$$c = A\frac{i}{(1-(1+i)^{-N})}$$

The interest payments (*In*) over a series of total payments can be calculated using (3), where n is the period in which the payment is made:

$$I_n = -i\left(\frac{c((1+i)^{n-1}-1)}{i} + A(1+i)^{n-1}\right)$$

And the corresponding principal payments (*Pn*) over a series of total payments can then be derived in (4) by subtracting (3) from (2):

$$P_n = c - -i\left(\frac{c((1+i)^{n-1}-1)}{i} + A(1+i)^{n-1}\right)$$

$$= c + i\left(\frac{c((1+i)^{n-1}-1)}{i} + A(1+i)^{n-1}\right) * i$$

Concessional Finance

In this paper, we contemplate a scenario in which a coal plant is refinanced in period *nRF* and retired in period *nRT*, where *nRF* ≤ *nRT* , given a set of original cashflows ending in period *nCF*. In this scenario, any cashflows between *nRT* and *nCF* are foregone, they are assumed not to be paid. *iRF* is the interest rate charged by the refinancing provider, *iRS* is the subsidy provider's discount rate, and *iRT* the implied interest rate (from (1)) on the remaining cashflows accounting for those that are foregone after the plant retires. If the plant retires after the point where cashflows stop (e.g., after the loan term expires), early retirement makes no difference to the cashflows or implied interest rate.

The implied interest rate subsidy is (in percentage points) associated with different combinations of refinancing and retirement years, is calculated in (5) as simply the difference between the refinancing provider's interest rate and the implied interest rate on the remaining cashflows accounting for early retirement. The number of periods used to generate *iRT* is *nRT* – *nRF*, and the present value is *ARF*, which is the principal remaining at the point of refinancing. The interest rate subsidy cannot be higher than the refinancing provider's discount rate, and the interest rate on the remaining cashflows cannot be lower than zero.

$$i_s = i_{RF} - \max(i_{RT}, 0)$$

The hypothetical cost of early retirement to the refinancing provider, if there were no subsidies provided, is the net present value of foregone annuities (NPVRP) for a given retirement year *nRT* at the point of refinancing *nRF* and discount rate *iRF* (6).

$$NPV^{RP} = \sum_{t=n_{RT}}^{n_{CF}} \frac{c_t}{(1 + i_{RF})^{t-n_{RF}}}$$

The present cost of the subsidy that would be needed to ensure that the refinancing provider could still achieve its required return is simply the net present cost—to the subsidy provider—of paying the foregone annuities (NPVSP), at the interest rate *iSP* reflecting the subsidy provider's cost of capital, calculated at the point of refinancing (7).

$$NPV^{SP} = \sum_{t=n_{RT}}^{n_{CF}} \frac{c_t}{(1 + i_{SP})^{t-n_{RF}}}$$

Carbon Finance

The basis of carbon finance calculations is the annual CO_2 emissions *E*. *Et* is found by multiplying the plant's capacity factors *cf* by the plant size *W*, the average hours per year y, and the emissions factor *ef* (in tons of CO2 per MWh). In this analysis, we assume a constant *cf*, such that the CO_2 emissions produced by the plant in a given year *t* are equal across all years (8).

$$E_t = W \times y \times cf_t \times ef$$

Avoided emissions *AE* in a given year are simply annual emissions, if they are not emitted in a given retirement scenario but would have been emitted if the plant had been operational for its full intended lifetime *L*. That is, they are realized only in the years between the early retirement year *RT* and original retirement year (9).

$$AE_t = \begin{cases} 0, & t \leq RT \\ E_t, & t > RT \end{cases} \quad t \in [0, L]$$

The debt-financed share of plant activity in a given year *dt* is defined here as outstanding debt *At* as a fraction of the value of shareholder equity *E*. In turn, shareholder equity is assumed to be the sum of invested shareholder capital and initial debt principal (i.e., the total amount invested in the project at project start). This assumes equity returns are not reinvested in the project (10):

$$d_t = \frac{A_t}{E}$$

Avoided emissions are allocated to debt and equity holders according Debt holder-allocated avoided emissions AE_t^D and those allocated to equity holders AE_t^D are distributed according to the debt ratio dt at the point at which the avoided emissions are realized (11).

$$AE_t^D = AE_t \times d_t$$

$$AE_t^E = AE_t \times (1 - d_t)$$

Carbon revenue in this context refers to revenue generated by avoided carbon emissions if a price is put on these avoided emissions. Revenue from avoided emissions is realized when they are actually avoided, i.e., only after the plant retires. Since these revenues accrue to investors, the (debt- or equity-allocated) avoided emissions used to derive a carbon price need to be valued on a net present basis—i.e., be discounted at the refinancing provider's discount rate *iRF* (12).

$$NPV_{RF,RT}^{AE} = \sum_{t=n_{RT}+1}^{L} \frac{AE_t}{(1+i_{RF})^{t-n_{RF}})}$$

To be able to buy out the plant and retire it immediately based on carbon revenues, the price on (discounted) avoided future emissions must be such that the NPV of remaining cashflows revenues is equal to the NPV of carbon revenues. To calculate the price on avoided carbon *cp* required for the revenue from avoided emissions to justify voluntarily retiring the plant in year *nRT*, one divides the present value of future cashflows to the refinancing provider ARF at the point of refinancing *nRF* (assuming no early retirement) by the present value of avoided emissions given retirement in year *nRT* (13).

$$cp_{RF,RT} = \frac{A_{RF}}{NPV_{RF,RT}^{AE}}$$

This, however, yields different carbon prices for debt and equity holders respectively. There exists a single carbon price *cp** at which excess revenues to debt/equity holders are equal to the shortfall in revenues for equity/debt holders. This is the average of debt and equity cashflow NPV for a given *nRF* and *nRT*, divided by the average of the present value of avoided emissions for debt and equity holders, respectively. Factoring out the divisor yields (14).

$$cp_{RF,RT}^{*} = \frac{1}{2} \times \frac{(A_D + A_E)_{RF}}{(NPV_D^{AE} + NPV_E^{AE})_{RF,RT}}$$

Concessional Carbon Finance

The meaning of concessional carbon finance is the price on avoided emissions that would be required to fund a given share of the foregone revenue calculated in (6). In this analysis, this share is assumed to be 100 percent.

The concessional carbon price *ccp* required to fund a given subsidy amount is the net present value of foregone revenue, divided by the present value of avoided carbon emissions, NPVAE $\neq$ 0. (15).

$$ccp_{RF,RT} = \left(\frac{NPV^{RP}}{NPV^{AE}}\right)_{RF,RT}$$

To find the concessional carbon price *ccp** at which excess revenues to debt/equity holders are equal to the shortfall in revenues for equity/debt holders, the same logic is applied as in (14): finding the average of foregone debt and equity revenue for a given *nRF* and *nRT*, divided by the average of the present value of avoided emissions for debt and equity holders, respectively. Factoring out the divisor yields (16) – note that where NPVRP = 0 for either debt or equity, x = 1; otherwise, x = 2.

$$ccp_{RF,RT}^{*} = \frac{1}{x} \times \left(\frac{NPV_D^{RP} + NPV_E^{RP}}{NPV_D^{AE} + NPV_E^{AE}}\right)_{RF,RT}$$

APPENDIX 2: CASE STUDIES: BACKGROUND AND DESCRIPTIVE DATA

Indonesia

ENERGY SUPPLY MIX: FOSSIL AND RENEWABLE OUTLOOK

Indonesia is a nation made up of several thousand islands, rich in several non-renewable natural resources, most notably coal, gas, bulk metals and a range of mining and agricultural products (Table 5). It also has significant renewable energy capacity potential (Table 6), with its government-estimated geothermal potential considered the largest in the world (ADB, 2020).

Despite its rapidly increasing oil imports (IEA, 2021b), Indonesia is still a net energy exporter. Coal is Indonesia's largest energy export at 11.2 percent by value (ADB, 2020). Most of Indonesia's exported coal is destined for China and India (EIA, 2021). Indonesia is the world's fourth-largest coal producer, the largest gas supplier in the 10-member Association of Southeast Asian Nations (ASEAN), and the world's largest producer of biofuels (IEA, 2021b).

Table 5: Fossil Fuel Reserves and Production in Indonesia (2019)

Resource	Unit	Production	Proven reserves	Potential reserves	R/P ratio
Coal	million tce	616	149,000	37,600	242
Oil	million m3	43.2	394	205	9.1
Gas	million m3	0.078	7.91	4.38	101

Source: ADB, 2020.

Table 6: Non-Fossil and Bioenergy Potential and Generation in Indonesia

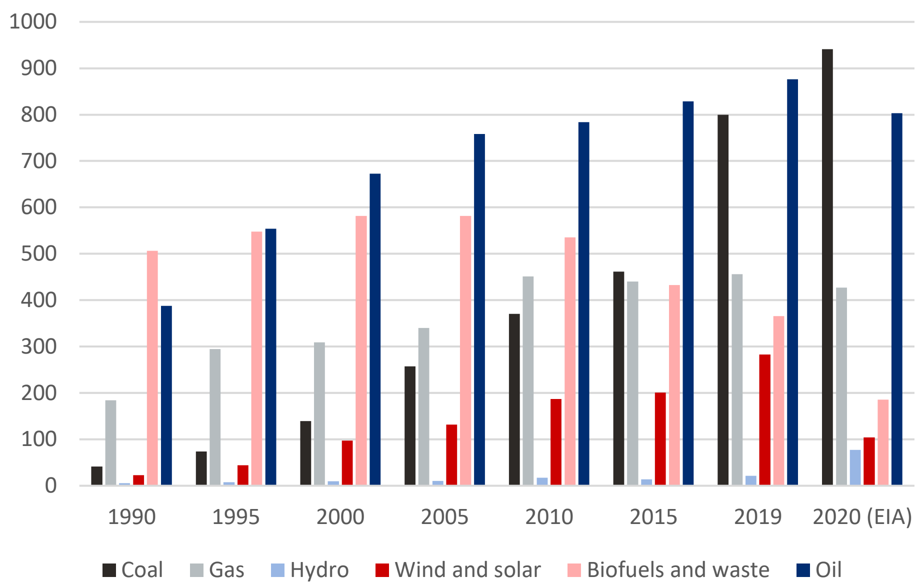
	Capacity potential (ADB, 2020)		Generation (IEA, 2021b)	
Resource	Units	2019	Unit	2020
Geothermal	GW	23.9	TWh	15.56
Hydroelectricity	GW	94	TWh	19.45
Biomass	GW	32.6		
Biogas	million m3	11.63		
Wind	GW	60.6	TWh	0.47
Solar	GW	208	TWh	0.12
Ocean/tidal	GW	17.9		

Source: ADB, 2020.

Domestically, primary energy demand has been increasing at a rate of 3 percent per year since 2010, driven primarily by growth in the transport sector value (ADB, 2020). Between 2000 and 2014, absolute energy consumption in Indonesia increased by early 65 percent. Indonesia now accounts for 40 percent of ASEAN energy use (IRENA, 2017). Indonesia's current energy supply mix is dominated by coal and oil (**Error! Reference source not found.**). While oil's share has remained constant at roughly one-third since 1990, absolute oil-based energy and gas consumption have both more than doubled since then. Energy supplies from coal have risen by a factor of 20 over the same period and more than doubled since 2010. Hydroelectric generation has increased by a factor of four but contributes just 1% of total supply, while wind and solar has risen nearly thirteen times to make up 10 percent of total supply. The use of biofuels and waste has fallen 30 percent in absolute terms since 1990, from nearly half of total energy supply to just 13 percent.

Figure 7: Total Energy Supply by Source (TWh)

[3] Converted from 200,000 barrels/day



Source: IEA World Energy Balances 2020; EIA, 2022

As of 2019, electricity use was dominated by the islands of Bali, Java and Madura (combined demand of 181 TWh), followed by Sumatra (38 TWh) and Kalimantan, Sulawesi, Maluku, and Papua (24 TWh) (ADB, 2020). Indonesia's dispersed geography has made its more remote islands largely dependent on electricity generation from expensive, heavily-subsidized imported diesel that often needs to be transported over long distances and challenging terrain (IRENA 2017). While the electricity system is being expanded in these areas, the electrification rate is still below 90 percent, even as the government is targeting near-full electricity access by 2026 (U.S. Department of Energy 2017).

Indonesia has played a central role in global coal markets since the mid-1990s, being one of the world's largest thermal coal exporters since 1995. Indonesia has exported 80-90 percent of its annual coal production since at least 2008. In 2018, it overtook Australia as the largest coal exporter by weight. In 2019, coal exports grew a further 19 percent year-on-year, depressing prices such that the Indonesian government imposed a production cap of 550 million metric tons in 2020 (EIA 2021).

Domestically produced coal surpassed gas as the cheapest source of energy around 2010, making coal the central feature of Indonesia's electricity supply mix at roughly 60 percent of total generation today (Christina & Nangoy, 2021). In 2020, amid the global coronavirus pandemic, domestic coal use rose sharply to 37% as renewable power generation fell to just 4% and oil and gas consumption fell (EIA 2021).

Biomass has long been Indonesia's largest source of renewable energy. In the form of bioenergy and biofuels, it is produced at a rate of approximately 150 million tons annually. The highest-potential regions include Kalimantan, Sumatra and Sulawesi, although remaining potential is widely distributed across Indonesia's many islands. Installed electricity generation capacity from biomass is, however, still under 2GW (ADB, 2020). Non-bioenergy generation (Table 6) in 2020 was dominated by hydropower (19.5 TWh) and geothermal (15.6 TWh), with wind and solar combined producing just 0.9 TWh. The pace of capacity additions remains slow, with just 17MW of net solar capacity additions in the same year (IRENA 2021).

FUTURE OF ENERGY SUPPLY

Indonesia has set a target of 2060 for reaching net zero greenhouse gas emissions. Its shorter-term National Energy Policy targets 23 percent primary renewable energy supply by 2025 and a reduction in petroleum use to 25 percent of primary energy (IEA 2021b). At the same time, electricity demand is increasing rapidly. IRENA (2017) projected a tripling of demand from 2014-2030, implying over 7 percent annual growth. The government's 2019 Electricity Power Supply Business Plan (RUPTL) projected a slightly lower 6.4 percent annual increase in demand from 2019-28 that nonetheless implies a 75 percent total increase in demand over the course of the decade. The country's state-owned electricity supply monopoly, Perusahaan Listrik Negara (PLN), is charged with implementing electricity expansion plans, but saw its revenue target fall by 15 percent in 2020 as a result of the coronavirus pandemic.

Meeting this demand growth solely with clean energy sources presents a major challenge, both in terms of technical capacity and the supply of appropriate financing and investment. In October 2021, the Minister for Energy announced a new goal of 4.7GW in solar capacity additions by 2030, and a target of making renewables account for over half of total capacity additions. IRENA (2017) estimates solar PV installed capacity by 2030 could be as low at 9GW and as high as 47GW, depending on policy support for renewables. Despite these targets, climate change mitigation remains a relatively low priority versus Indonesia's regional peers, and largely framed around land use, rather than energy.

STRANDED ASSETS AND COAL RETIREMENT

To the extent that Indonesia needs to retire existing coal capacity early, it may face difficulties in doing so unilaterally under international investor-state dispute settlement (ISDS) frameworks. ISDS provisions protect almost 90 percent of Indonesia's foreign-owned coal plants. China's investments (through the Belt and Road Initiative and otherwise) are no exception: the China-ASEAN treaty alone explicitly protects twelve Indonesian coal plants at risk of stranding – at an estimated cost of $6.8-7.9 billion – if Indonesia is to meet Paris Agreement targets (Tienhaara & Cotula, 2017).

High electricity demand growth means that the feasibility of coal retirement also rests on replacement of retired capacity with equivalent renewable capacity, likely with additional storage capacity to handle intermittent generation. Investment in Indonesian renewable energy in 2021 totaled $1.5 billion, just 20 percent of what is needed annually from 2021-25 for the country to reach its short-term renewable targets (IISD, 2022). An inconsistent regulatory environment and a lack of long-term clarity on renewable energy support policies compounds the challenge of reaching the required levels of investment. Indonesia's government will have to leverage both domestic and international resources to raise the required investment financing, both from international capital markets and through its own dedicated public and concessional finance institutions for infrastructure: the Indonesia Infrastructure Guarantee Fund (PT IIGF), Sarana Multi Infrastructure (PT SMI), and Indonesia Infrastructure Finance (PT IIF). One emerging resource for financing Indonesia's energy transition is the recently signed JETP, launched during Indonesia's presidency of the G20.

POLITICAL ECONOMY OF COAL RETIREMENT

Growing domestic demand and abundant domestic coal supplies have driven coal power expansionism, with the endorsement of political and economic elites (individual oligarchs and SOEs alike). As royalties from coal mining to serve domestic plants have become ever larger components of local and national public budgets, self-reinforcing incentives for the public sector to sustain this focus have emerged. Political, and electoral, success for the current Widodo administration has also been explicitly linked to success in developing and deploying public infrastructure (K. Kim 2021; Ordonez, Jakob, Steckel and Fünfgeld 2022). With SOEs acting as a powerful locus of political patronage and a policy process characterized by "backroom deals and political horse-trading" (Salna 2019), this has resulted in the continued subsidization of state-directed development models, and delay of SOE restructuring that has long been called for by international investors and multilateral institutions in favor of a renewed focus on state-led extractivism constrained by oligarchic control of natural resources, and participation by foreign banks, commodity firms, and investors being channeled through domestic financial institutions (K. Kim 2019; K. Kim and Sumner 2021; Winters 2011).

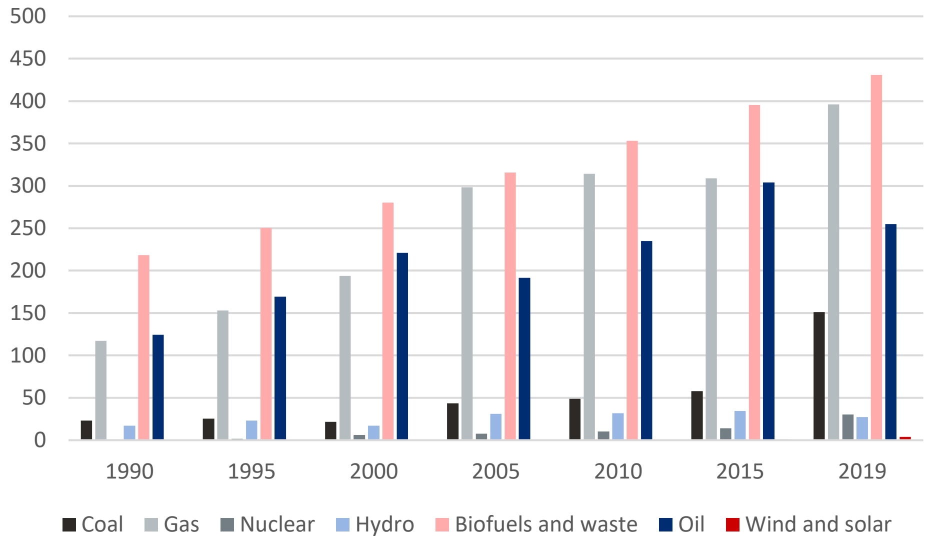
While coal expansion was initially supported by international capital funneled through domestic financial institutions and multilateral lending, however, China's role in growing the Indonesian coal sector expanded sharply in the late 2010s, across debt financing, equity investment and construction contracts. This reflected overcapacity in industrial material production within China, as well as a response to Indonesia's embrace of coal as a tool for promoting economic growth. The majority of Chinese companies active in Indonesian coal power have focused on less efficient subcritical technologies and plant operations have been associated with allegations of illegal labor practices (Tritto 2021). Nevertheless, such is the extent of China's role in facilitating Indonesia's coal expansion that Chinese development banks could conceivably exert sufficient influence to prompt the engagement of the Indonesian political sphere with an accelerated coal phase-out.

Pakistan

ENERGY SUPPLY MIX

In the mid-2010s, Pakistan's energy mix featured little coal. Its contribution to total energy supply only rose above 10 percent in 2019, having risen by a factor of six in the preceding 30 years (**Error! Reference source not found.**). By contrast, natural gas has accounted for roughly 25-35 percent of primary energy supply since 1990, followed by petroleum and other oil-based fuels at 20-30 percent. Most of the remaining energy supply has been comprised of biomass and organic waste for residential use, with much of the population lacking access to reliable electricity (a figure that is still around 40 million today). Bioenergy's share in total supply has, however, fallen significantly from almost half in 1990 to one-third in 2019. Hydropower is the main source of renewable energy, although wind and solar capacity is growing gradually (EIA 2022).

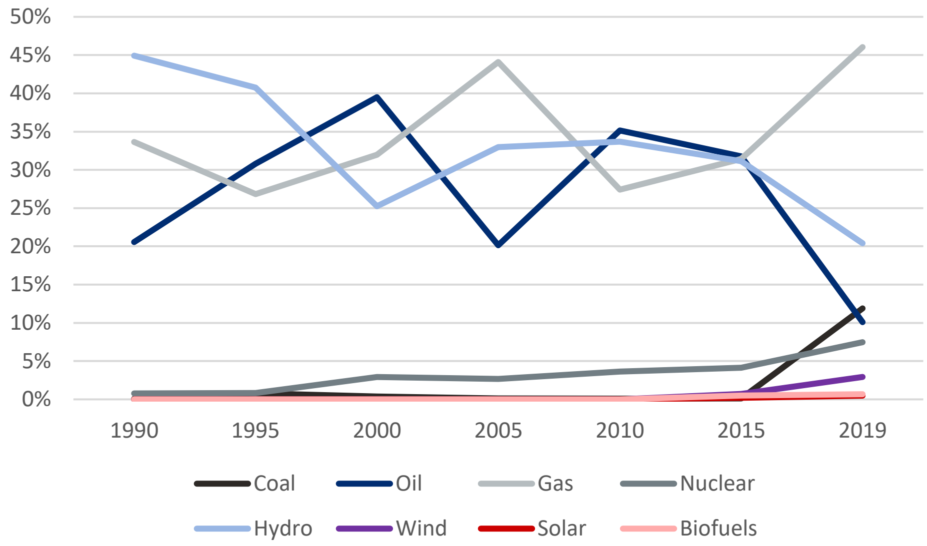
Figure 8: Total Energy Supply by Source, Pakistan (TWh)



Source: International Energy Agency (2019).

Electricity generation, historically dominated by hydro, gas and oil, has shifted towards coal in recent years, with gas largely displacing hydro and oil to comprise almost half of generation in 2019, and hydro declining from a high of 45 percent in 1990 to just 20 percent in 2019 as coal rose from near-zero to 12 percent, surpassing nuclear (**Error! Reference source not found.**). Between them, wind, solar and biofuels provided less than 5 percent of electricity generation in the same year.

Figure 9: Electricity Generation Share by Source (in Percent), Pakistan, 1990-2019



Source: IEA 2022a, 2022b.

Since the early 2000s, Pakistan has been experiencing regular energy crises driven by high expenditure on expensive imported fuel, a highly distressed sovereign debt burden and a lack of adequate transmission and distribution capacity. By the early 2020s, the country had seen significant but uncoordinated investment in electricity distribution that has led to a power surplus, exacerbated by the coronavirus pandemic in the wake of new unneeded capacity additions and lower-than-expected demand growth (Ebrahim 2021). Limited use of standard modelling tools for planning purposes, weak governance and endemic corruption, as well as widespread electricity theft in the residential and commercial sectors, place additional pressure on the electricity market and its ability to sustain efficient operations (Raza et al. 2022; Rehman and Deyuan 2018). With the rapid growth in coal power since 2015 (driven by the Sharif administration's 2013 National Power Policy) and the relative absence of a domestic coal mining industry, Pakistan's coal imports have risen sharply despite the discovery of new domestic resources.

Notwithstanding its heavy dependence on centralized fossil and hydro power generation, Pakistan is very well-endowed with non-hydro renewable energy resources. The World Bank (2020) calculates that using just 0.07 percent of Pakistan's land area for solar power generation would meet the country's current electricity needs. The country has several wind corridors suitable for onshore wind installations, and very high average wind speeds in 10 percent of the windiest areas. Despite this potential, and the conclusion of several successful projects, installed solar and wind capacity in Pakistan remains low at 1.5GW in 2020 – and 3-4 percent of total generation.

FUTURE OF ENERGY SUPPLY

Electricity demand is expected to rise by a quarter from 154TWh in 2019-20, to 192TWh in 2024-25 (IEA 2021c). To meet projected demand in 2030, Pakistan expects to need a 40 percent increase in generation capacity, from 39GW to 57GW, requiring over $30 billion in new investment. Under projections featured in the 2020 Indicative Generation Capacity Expansion Plan, prepared by the National Transmission and Dispatch Company, renewable capacity is expected to reach 6.5GW by 2030 (3.8GW from wind, 1.9GW from solar and 0.75GW from biogas facilities) (Enerdata 2021).

At the 2020 Climate Ambition Summit, Pakistan's then-Prime Minister Imran Khan announced a target of 60 percent clean power generation by 2030, following the cancellation of two coal-based projects with a combined capacity of 2.6GW, and their replacement with hydropower (The Express Tribune 2020). Pakistan's updated Nationally Determined Contribution to the Paris Agreement, submitted in 2021, aims to reduce the country's projected 2030 emissions by 50 percent, banning coal imports in favor of local coal and shifting to electromobility in the process (Government of Pakistan 2021). However, since local coal is of lower quality, this is unlikely to result in lower emissions from the 4GW of capacity targeted for conversion to local supplies (Ebrahim 2019). Additionally, existing regulatory support for renewables is insufficient for attracting major new investment in clean energy. Investors are also wary of policy risks caused by inconsistency across energy and climate policies more broadly (Bhandary and Gallagher 2022).

STRANDED ASSETS AND COAL RETIREMENT

Individual coal plants in Pakistan since 2010 have almost exclusively been backed by Chinese entities as part of the China-Pakistan Economic Corridor (CPEC) initiative, with China the only major international lender still willing to invest in Pakistani coal power in the face of a poor investment climate. The special terms offered by the government to mitigate investment risks included a very high guaranteed return on equity, reimbursement of fees levied by China Export and Credit Insurance Corporation (SINOSURE) for political risk insurance, and a relatively short debt repayment period of ten years.

It is unsurprising, therefore, that several CPEC-financed plants are already facing significant financial challenges. The 1.3GW Sahiwal plant, for example, the first to be launched under CPEC, faced imminent closure on at least one occasion in 2019 when Pakistan's government found itself unable to make a $127 million payment to the project developers. The China- and Qatar-backed Port Qasim plant, faced similar difficulties within a year of opening in the face of rising debt liabilities and imported coal costs (Ebrahim, 2019). A third CPEC plant, a 300MW unit sponsored by the China Communications Construction Company, never reached completion. Originally approved in 2016, the plant may yet be cancelled following a proposal by the Pakistan Power Division to replace it with an equivalent solar plant (Enerdata 2022a).

While Pakistan has expressed interest in the ADB Energy Transition Mechanism in order to evaluate the feasibility early retirement of legacy coal assets, it faces several barriers to possible implementation:

1. Pakistan's coal fleet is very young, with an average age of less than five years. Most of its fleet has not yet paid off its debts, with outstanding debt service cashflows estimated at $665 million to $1.2 billion per plant.
2. These plants are extraordinarily profitable for their owners, enjoying a guaranteed annual return on equity ranging from 27-35 percent.
3. The plants were financed with the backing of sovereign guarantees to reassure sponsors of receiving on-time payments. At present, Pakistan's Central Power Purchasing Agency-Guarantee (CPPA-G) owes $1.4 billion to the existing fleet, representing a major contingent liability to the central government.
4. Power purchase agreements (PPAs) signed for Pakistan's coal plants under the CPEC umbrella are difficult to renegotiate, being embedded within the wider economic relationship with China and linked to a suite of associated government-backed projects. The PPAs underlying Pakistan's coal fleet include large capacity payments in addition to variable fuel costs, disincentivizing the government from investing in additional renewable capacity until demand significantly outstrips supply (which is currently in excess).

Overall, retiring local coal mines and the plants they supply could cost $18 billion, with another $20-30 billion required to replace them with equivalent renewable capacity and built the associated additional grid capacity required to link renewable capacity to major load centers, and to widen the ratepayer base and increase revenue from end users (although whether these costs can be sufficiently offset by additional revenues is uncertain). In the absence of carbon markets or structural incentives for renewable energy development, it may be difficult to assure investors of sufficient revenue streams to attract this additional renewable investment (Nedophil Wang et al. 2022). This combination of factors makes it exceptionally, perhaps uniquely, challenging to retire Pakistan's coal capacity ahead of schedule.

POLITICAL ECONOMY OF COAL RETIREMENT

Notwithstanding the major practical barriers to early coal retirement, the evolution of Pakistan's energy strategy signals a desire to reduce its reliance on expensive coal imports; and to avoid a repeat of the boom-bust cycle of underinvestment and emergency capacity investment that has plagued the electricity sector for several decades.

The 2013 National Power Policy (NPP) was drawn up to address Pakistan's ongoing energy crisis, and to close the supply-demand gap by 2017, moving to a surplus by 2018 and prioritizing low-cost power generation options and reductions in the theft of electricity. This resulted in the rapid expansion of coal and the emergence of a significant oversupply of electricity that Pakistan is nonetheless not well-positioned to take advantage of owing to very limited capacity of government and its financially stressed SOEs to invest in the necessary transmission and distribution infrastructure. This financial strain stems largely, although not exclusively, from weak revenue collection from residential and commercial consumers, which in turn delays fuel purchases, giving rise to blackouts and shortages, which further depress revenue collection—a cycle known as the "circular debt problem". While the 2013 NPP aimed to address these root causes by punishing defaults, limiting power theft, and introducing greater transparency to state-owned power companies' finances, it has had little success in raising the required investment capital, hampered further by sustained political instability in the following years (Bhandary and Gallagher 2022).

CPEC may yet play a significant role in facilitating Pakistan's energy transition. When Pakistan elected to diversify into coal power in the 2010s, it had already experienced a sharp deterioration in the investment environment and, having increasingly turned to China as a "lender of last resort", was willing to pay over the odds in the hope that coal expansion would resolve its chronic energy crisis. With China having ended new financing for coal overseas, incomplete CPEC coal projects may find themselves stranded with no alternative backers. On the other hand, China's own domestic commitments and growing renewable energy industry may provide both countries with incentives to retire and replace existing capacity with new, China-backed renewable capacity (Bhandary and Gallagher 2022).

Vietnam

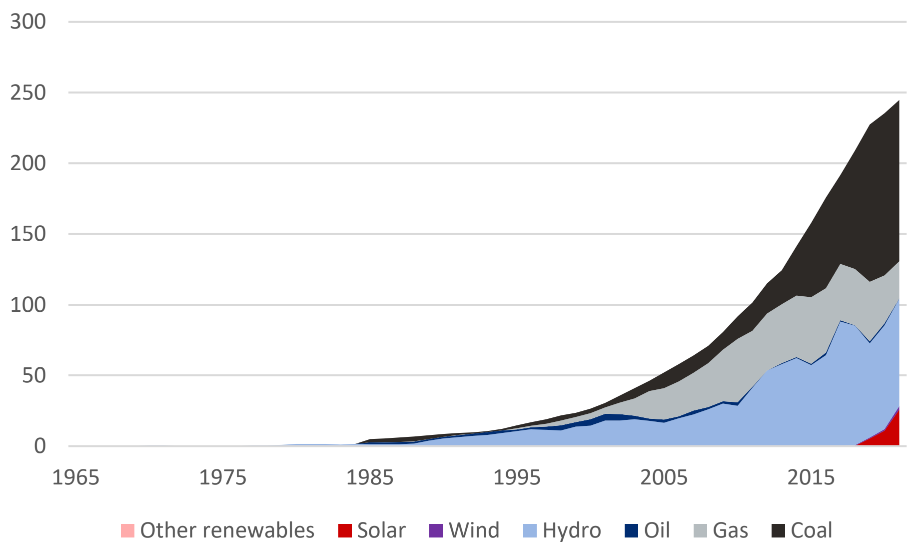
ENERGY SUPPLY MIX

Vietnam has undergone a suite of political and economic reforms since 1986 which have been instrumental in its graduation from one of the world's poorest countries to a lower-middle income country in less than a quarter century (Climate Analytics 2019). The country's energy industry has been the major enabler for growth, supporting urbanization, rapid industrialization in the construction and manufacturing industries, and a high rate of overall economic growth. Energy needs are still growing by nearly 10 percent per year (Breu et al. 2021), and the power sector is expected to grow at 4.5 percent annually from 2022-27 (Mordor Intelligence 2022).

Vietnam's energy resources are relatively diverse; until about 2010 hydropower resources in the north and center of the country were the largest source of power generation (see **Error! Reference source not found.**). The geopolitics of shared water resources, reservoir capacity constraints and increasingly frequent abnormal weather patterns, however, have since driven a rise in the use of fossil fuels to meet incremental demand in recent years (L. D. Nguyen 2022). In the Seventh Power Development Plan (PDP) running from 2011-20, fossil fuels (coal, gas, and oil) consolidated their position at the core of Vietnam's power system, contributing 60 percent of the generation mix in 2021 (Pham 2022; VinaCapital 2022). Based on current extraction rates, Vietnam's domestic coal, gas, and oil reserves are sufficient to provide it with 70, 45 and 18 years of fuel, respectively (Electricity and Renewable Energy Authority in Viet Nam and Danish Energy Agency 2022).

Reliance on coal, which has doubled its share of generation since 2010 to nearly 50 percent, has been accentuated by the abandonment of plans for nuclear power development due to cost and financial constraints (Murray 2021) and the peaking and declining domestic production of oil (since 2010) and biomass production (2015) (Enerdata 2022b). Over the same period, Vietnam's growing appetite for coal has led it to develop new domestic mining capacity, and transformed it from a net coal importer into a net exporter (Samuel 2022).

Figure 10: Electricity Production by Source (Twh)



Source: Our World in Data 2021a.

Since the late 2010s, Vietnam has pursued diversification into renewable energy sources more seriously, with solar capacity rising from near-zero in 2015 to 16.5GW in 2021 (Tachev, 2022b) through a wave of new investment supported by generous feed-in-tariffs, long-term offtake contracts and an above-market price guarantee for developers (J. Nguyen, 2021). Despite Vietnam's coastal wind resources, wind energy has not seen the same level of support or success, reaching just 4GW of total capacity in 2021 and remaining a negligible component of total generation (Merdekawati et al., 2022).

FUTURE OF ENERGY SUPPLY

Vietnam's Eighth Power Development Plan (PDP8) runs from 2021-2030 and, having been through several contrasting variations ranging from aggressive coal expansion to a pivot to renewables in the most recent draft, articulates a longer-term vision for 2045. The Plan, which assumes a 6.6 percent growth rate to 2030, and 5.7 percent to 2045, is nominally intended to align with Vietnam's commitment to net zero emissions by 2050 at the COP26 conference in Glasgow in 2021 and to signal a long-term policy framework focused on decarbonization and renewable energy resources (World Bank Group 2022). It lays out plans to expand renewable (particularly wind) and gas-fired capacity, and limit growth in coal capacity.

The plan envisages 151GW of solar and wind capacity by 2045, with solar comprising 36 percent, onshore wind 28 percent and offshore wind 36 percent of the resulting energy mix (Merdekawati et al. 2022). Wind's envisaged total share of 64 percent is consistent with Vietnam's excellent offshore wind development conditions—long, shallow coastlines and consistent north-easterly winds located close to major demand centers. The World Bank Group (2021) estimates that 25GW of offshore wind capacity would meet up to 12 percent of Vietnam's power needs in 2035. PDP8 also proposes an increase in gas- and LNG-fired installed capacity to 15GW and 45GW respectively by 2045 and a rise in coal capacity to 38GW in 2030 (reflecting plants already under construction), at which point it plateaus until 2045, falling from 31 percent to 13 percent of the national energy mix (GIZ 2022; Reuters 2022). This equates to the cancellation of 14.1GW of planned capacity additions (by SOEs Vietnam Electricity (EVN), PetroVietnam and Vinacomin) on the basis of expected negative financial returns and unfavorable performance in comparison to renewable energy alternatives (D. Brown 2022; Reuters 2022).

STRANDED ASSETS AND COAL RETIREMENT

Despite foregoing any new coal plants beyond those under construction, primary demand for coal will keep rising, from 53 million tons in 2021, to a peak of 125 million tons in 2030. With domestic production expected to remain steady at 40-50 million tons, this implies imports of 50-80 million tons annually from 2025-35 (Phu 2022). Nevertheless, Vietnam's existing coal plants are already struggling, with high fuel costs in 2022 blamed for a sharp fall in both production and profits (Dat 2022), even as total energy supply grew 4 percent year-on-year. Most plants are operating with load factors of 60-70 percent, with some temporarily closing in response to coal shortages (Vietnam Investment Review 2022).

The difficult environment for existing coal capacity is worse for planned capacity. With the withdrawal of major financing partners China, Japan and South Korea, from international coal investments, several high-profile pre-investment projects face uncertain futures (Tachev 2022a). This is compounded by the growing withdrawal of mainstream insurers from coal power in Southeast Asia and their replacement with smaller, less experienced insurance providers (Bosshard 2022). The salient impact of coal power and mining on local communities (increased flooding, soil erosion and the loss of agriculture-based livelihoods) has also given rise to domestic political opposition to further expansion (Pham 2022).

Options under consideration for accelerating the retirement of the existing fleet include buying them out and replacing them earlier than planned with clean energy sources under the ADB's Energy Transition Mechanism (Hoang 2021); and fuel-switching to blue ammonia produced from natural gas with carbon capture and storage in a scheme backed by a South Korean energy firm (The Investor 2022). In December 2022, a JETP agreement was struck between the Vietnamese government and the International Partners Group.

POLITICAL ECONOMY OF COAL RETIREMENT

Despite several waves of economic reform since unification in 1975, Vietnam's electricity market remains under the control of the Communist Party, through the Ministry of Industry and Trade, Committee for Management of State Capital, EVN and its subsidiary the National Power Transmission Corporation (NPT). Under the existing system, the Ministry of Industry and Trade and its provincial partners jointly propose decisions for new power generation unit types and siting for inclusion in decadal PDPs. The rise of coal in Vietnam can be directly linked to this decision-making structure, with the promotion of domestic industries, perceived affordability, environmental sustainability and security of supply (Jakob & Steckel 2022), as well as lobbying by fossil fuel SOEs and the Ministry of Energy (Neefjes & Hoai, 2017), all factoring into coal becoming the government's fuel of choice. Despite environmental concerns becoming more politically salient, siloed decision-making domestically and within international institutions have hampered the emergence of a fully integrated climate strategy.

Early drafts of the eighth PDP signaled a continuation of existing policies, requiring an influx of foreign capital to double domestic coal capacity by 2030 and keep growing the fleet thereafter, while also expressing concern over the destabilizing potential and unreliability of renewable sources (Pham 2022). The proposed final document, however, signals a major change in direction – underscored by Vietnam's 2050 net zero pledge at COP26 – that includes large increases in renewable capacity, reduced coal power generation, greater investment in transmission and the development of LNG import terminals (L. D. Nguyen 2022). While the plan remains a long way from successful implementation, the final text is a strong indication of the government's intent to accelerate power sector decarbonization, including through the cancellation of planning coal capacity, and possible early retirement of existing capacity (Lin 2022).

Supplementary Case Study: India

ENERGY SUPPLY MIX: FOSSIL AND RENEWABLE OUTLOOK

India's economy has grown rapidly in recent years, driven in part by a growing middle class, greater urbanization and expanding industrial activity. Rebounding from the economic shock induced by coronavirus in 2020-21, India's industrial and commercial electricity consumption rebounded by 17.2 percent year-on-year in 2022, having doubled since 2000 (Press Trust of India 2022b). With demand expected to grow 35 percent between 2019 and 2030 (versus pre-coronavirus projections of 50 percent), India will likely become the world's third-largest electricity consumer by the mid-2030s (IEA 2021a).

While India's per capita energy consumption remains less than half the global average and one-tenth that of the United States (Our World in Data 2021b), the country's rapid growth has still required substantial expansion in fossil fuel extraction and use. Incremental energy demand since the 1990s has been met predominantly with coal, oil and biomass, which between them account for over 80 percent of total supply (IEA 2021a). Coal is by far the largest component of the energy mix at around 50 percent of electricity generation (Table 7), and is also the primary source of heat for heavy industries, such as steel production (J. Kim et al. 2022). Installed coal capacity is still growing, with 5GW added between 2020-22, against 30GW—roughly equivalent in terms of generation potential—in non-hydro renewable capacity additions.

Coal demand is expected to grow by up to 63 percent by 2030, to 1.3-1.5 billion tons annually (Livemint 2022). India's coal reserves are found primarily in the central and eastern regions. Proven reserves are sufficient to meet over a century of coal demand at current rates of production, along with 50 years of gas, and 16 years of oil (The Hindu Businessline 2021).

Table 7: Installed Electricity Generation Capacity (2020)

	Installed capacity (GW)			Share of total	
Mode	2020	2022	2020-22	2020	2022
Thermal, of which:	230.9	236.1	+5.2	62%	58%
coal	198.5	204.1	+5.6	54%	50%
lignite	6.6	6.6	0.0	2%	2%
gas	25.0	24.8	-0.2	7%	6%
oil	0.5	0.6	+0.1	0%	0%
Hydro	45.7	46.9	+1.2	12%	11%
Nuclear	6.8	6.8	0.0	2%	2%
Non-hydro Renewable	87.7	118.1	+30.4	24%	29%
Total	371.1	407.8	+36.7		

Source: Central Electricity Authority (2022).

Despite being the world's second-largest coal producer, India's total coal imports have been rising rapidly, tripling from 2011-2021 to reach almost 250 million tons (Policy Circle Bureau 2022). Its domestic reserves are of relatively low quality, with high ash content (45 percent on average) dragging down the energy density of domestic coal. This raises operating, maintenance and transport costs for coal plants and compares unfavorably to the higher-quality, low ash content (10-15 percent) of imported coal (Sahoo 2021). Faced with rising carbon emissions from coal combustion and a largely unutilized stock of annual agricultural waste, in 2021 India mandated 5-7 percent biomass pellet co-firing with coal in order to reduce the emissions intensity of electricity production (Ministry of Power 2022).

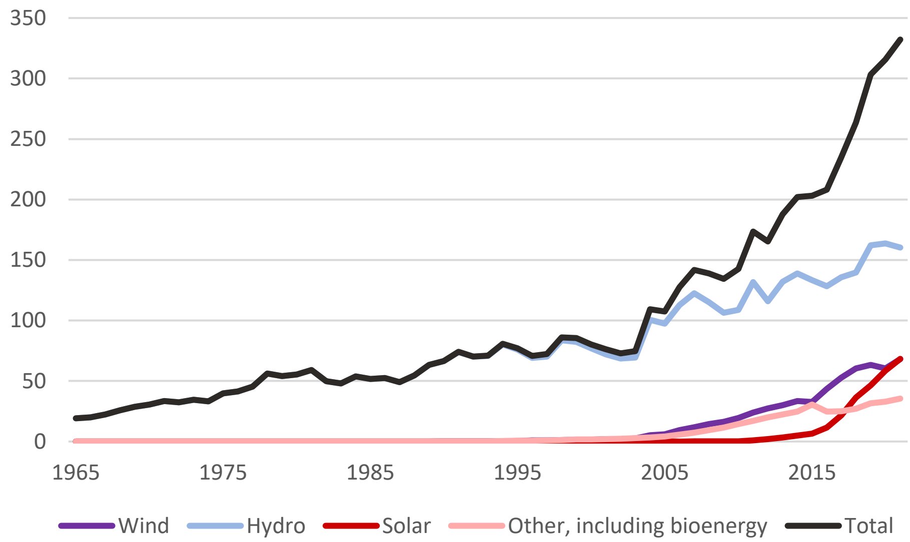
FUTURE OF ENERGY SUPPLY

India faces significant challenges in simultaneously decarbonizing its energy system and ensuring energy security for a population nearing 1.4 billion. Alongside growing coal use, India has expanded its renewable energy capacity at a rapid pace, reaching 155.3 GW in installed capacity in 2022, overachieving targets initially set in 2014 by the Modi government, by over 50 percent. Growth in renewable generation was dominated by steadily increasing hydropower capacity—particularly in the north and northeast—until the early 2000s, and complemented by wind and bioenergy expansion thereafter, with solar growing most rapidly since 2015 (**Error! Reference source not found.**).

While falling module prices and competitive auctioning policies undoubtedly contributed to this success, solar remained more expensive than coal until relatively recently, begging the question of where non-technoeconomic factors came into play in driving this expansion Shidore and Busby (2019) identify domestic politics, international pressure, seeking new investment, and a desire for increased energy independence. In combination, these factors proved an attractive combination to the new Modi administration, keen to be perceived as reformers, promoters of international investment in India, and champions of domestic energy production.

At present, most incremental renewable energy capacity is in the form of wind and solar capacity, propelled by a combination of rapid technological progress, a consistently supportive policy environment, and competitive auctions that have resulted in solar plants providing electricity at a lower cost than coal (IRENA 2022). The ten most renewable-rich of India's states now source 10-30 percent of their electricity from renewable sources. Where hydroelectric plants are able to absorb excess renewable power and ramp up quickly to meet system peaks, they provide complementary support to the grid in terms of stability and balancing services (IEA 2021d; Press Information Bureau 2019).

Figure 11: Renewable Energy Generation, India (Twh)



Source: Ritchie, Roser and Rosado (2022).

STRANDED ASSETS AND COAL RETIREMENT

The impact of climate change, high fuel import costs, and increasingly competitive renewable energy sources have historically been the strongest drivers of policy support and growth in solar, wind and hydropower (Bhattacharjee 2022). Since 2015, the proposed coal capacity pipeline has declined by three-quarters, including 326GW in cancelled plants, and another 250GW in delayed or shelved capacity additions. A total of 32GW of coal power capacity is still under construction (Littlecott et al. 2021). By 2050, the IEA (2020) expects coal to meet less than a quarter of India's power demand, with two-thirds being provided by solar and wind capacity complemented by battery storage.

Alongside the collapse in planned new coal capacity, the future of India's existing coal fleet is uncertain, having been adversely affected by growing renewable capacity and declining revenue. Average plant load factors remain low relative to technical capacity at approximately 65 percent nationally, having fallen from 77 percent in 2009-10. Plants operated by centrally controlled state enterprises have enjoyed much highest load factors over this period, while state-level and private operators see 10-15 percent lower plant utilization on average (* Provisional estimates up to September 2022

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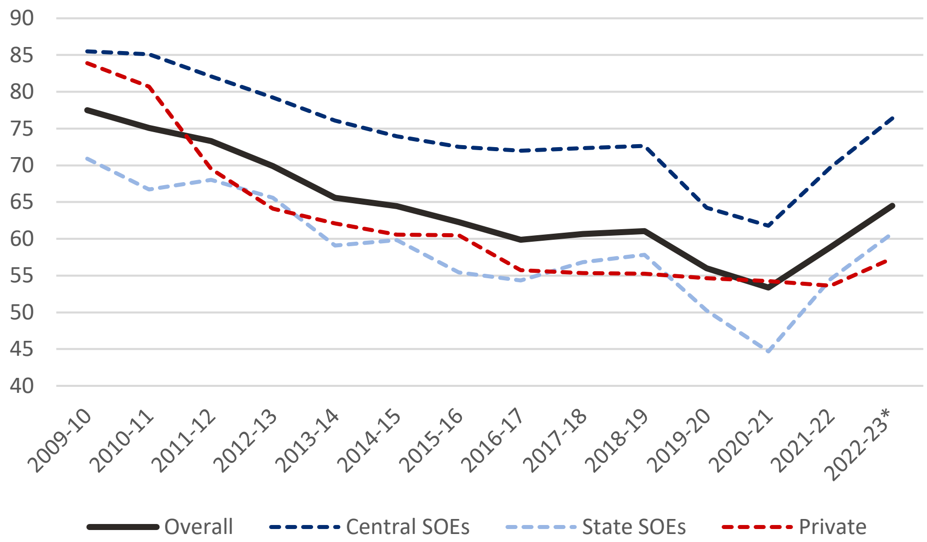
Figure 12: Coal and Lignite Plant Load Factors in India, by Operator Type (in Percent)



* Provisional estimates up to September 2022

Source: Central Electricity Authority 2022.

Lower utilization rates and a consequent rise in the frequency of coal plant cycling have been linked to greater component wear and damage, raising operational and maintenance costs for coal (Debnath, Mittal and Jindal 2022). With solar tariffs being well below the fuel costs of existing coal, the economic future of new inflexible baseload coal capacity is poor, and the case for investment in existing plants to prepare them for greater flexibility is limited at best (IEA 2021d; Shah 2021). Avoiding the need to invest in additional pollution control retrofits for these plants would alone generate estimated savings of $1.37 billion (Chakravarty and Somanathan 2021)

These elements combine to create pressure for the decommissioning of coal plants, particularly older and less efficient subcritical plants that rely on outdated technologies and are both highly emissions-intensive and economically uncompetitive (The Hindu Businessline 2021). Proposals for the accelerated retirement of these plants by 2030 have been put forward, including by prominent government think tank NITI Aayog in the form of a “thermal power plant scrappage policy” targeting 54GW of eligible capacity (Chakravarty and Somanathan 2021).

POLITICAL ECONOMY OF COAL RETIREMENT

While India has not committed to achieving net zero greenhouse gas emissions earlier than 2070, there is significant political momentum behind the decarbonization of electricity in the country. India’s government has provided renewable energy developers with significant state support for some time. With the Paris Agreement in 2015, budget allocation to renewables expansion was increased significantly, with dedicated support for distributed energy sources, distribution companies, and research & development schemes (Sahoo 2021). In 2021, the government announced a target of 500GW in non-fossil energy capacity by 2030, equivalent to half of India’s existing installed capacity (The Economic Times 2021). A year later, it committed to strengthening its targets for emissions intensity reductions and renewable installed capacity to 45 percent and 50 percent, respectively (Singh 2022).

While these goals are ambitious, achieving them relies heavily on the geographical viability of an integrated, high-renewable penetration electricity system, and on resolving entrenched political issues closely linking coal use to wider economic development. Ensuring the alignment of central and state governments in managing state-owned coal resources and introducing appropriate market reforms is essential to the effective execution of any accelerated coal retirement program (Goritz, Schulz and Isoaho 2017). Any declines in coal will have an impact on the financial position of central and state governments through falling tax duties, dividends and royalties and asset revaluations, particularly where plants or coal suppliers are state-owned—as in the case of NTPC and Coal India Ltd (Press Trust of India 2022a). Cross-subsidization of passenger freight on India's railways with revenue from coal freight transport will become another prominent issue to the extent that coal freight volumes fall with the closure of existing and planned plants.