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Analysis of CCS implementation in Indonesia's coal fired power plants, economic optimization, and potential impact on Java-Bali grid for future decarbonization

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ABSTRACT

This study aims to evaluate impact of retrofitting carbon capture and storage (CCS) technology on coal fired power plants (CFPP) in Indonesia. Using a representative 3×330 MW CFPP, the integration of CCS increases the levelized cost of electricity (LCoE) to 124 USD/MWh. Key cost components include CO_2 capture (21.7%), energy penalty from steam extraction (18.5%), and CO_2 transport and injection (16.7%). Sensitivity analysis indicates that CCS becomes financially viable under a high carbon cap (0.9 tCO_2/MWh) and a carbon tax of 76 USD/tCO_2. Meanwhile, International carbon markets offer a potential revenue at 75 USD/tCO_2 can fully offset CCS costs. Additionally, CAPEX grants can reduce LCoE to 12.4%, serving to mitigate upfront investment for CCS deployment. Within the Java–Bali grid, CFPP account for 58.8% of the generation mix with 41% aged 10–20 years using predominantly subcritical technology while 28% are over 20 years old and follow natural retirement being replaced by renewable energy. CCS retrofitting is more economically and technically viable for mid aged plants with newer technologies and lower emission intensities, supporting grid stability with limited renewable base load availability. This strategy also serves as a transitional pathway toward long term renewable integration until the LCoE of PV+BESS falls below 50 USD/MWh.

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1. INTRODUCTION

Over the past few decades, Indonesia has been gone through significant economic growth, primarily driven by purchasing power parity adjustments. This economic transformation has been closely linked to the development of the energy sector, particularly the electricity sector, which has served as the backbone supporting the growth of industry, transportation, and household consumption [1]. In 2014, Indonesia's electricity consumption per capita was recorded at 812 kWh, representing only 26% of the global average. This number continued to rise, reaching 1,021 kWh per capita in 2017, and by 2022, electricity consumption per capita had increased to 1,172 kWh. This trend reflects a significant surge in electricity demand, driven by ongoing urbanization and industrialization processes across the country [2].

On the other hand, Indonesia's energy sector faces significant challenges due to its heavy reliance on fossil fuels such as coal. A substantial portion of the power plants has been developed named the fast track program (FTP) Phases 1 and 2. These 35,000 MW projects are still dominated by coal fired power plants

(CFPP) [3]. Based on the last RUPTL (Electricity Supply Business Plan) the total installed power generation capacity in Indonesia amounts to 62.4 GW, comprising 43.7 GW from PLN-owned plants, 17.3 GW from individual power producers (IPP), and 1.4 GW from rent. The capacity distribution by power generation type consists of 51% from CFPP serving as baseload generators, 29% from gas-fired and combined cycle plants (NGCC), 7% from diesel power plants, 8% from hydroelectric and micro-hydro plants, 5% from geothermal power plants, and its remain from renewable energy sources [4]. This dependency not only poses a risk to long-term energy security but also significantly contributes to the increase of greenhouse gas (GHG) emissions.

The projection outlined in RUKN (National Electricity General Plan) 2023–2060 indicates that national electricity demand will increase nearly sevenfold by 2060, with the industrial sector being the largest energy consumer. This condition will require an additional power generation capacity of approximately 17 GW per year, resulting in a total installed capacity of around 722 GW by 2060. However, if this capacity continually grow to predominantly rely on fossil fuels, it is projected that carbon dioxide emissions could increase up to four times the 2010 emission levels [5]. Greenhouse gas emissions specifically carbon dioxide, have become concern due to their significant role in driving global climate change. Global warming caused by these emissions heightens the risk of natural disasters such as coastal flooding from sea level rise and other hydro geo meteorological events. As part of its global commitment, Indonesia has been ratified the Paris Agreement through Law No. 16 of 2016, aiming to limit the increase of global temperature to below 2 °C above pre-industrial levels. One of the key strategies adopted involves reducing emissions from the energy sector through the development of renewable energy and the implementation of carbon capture and storage (CCS) technologies [6].

In the context of the energy transition towards achieving Net Zero Emissions (NZE) by 2060, continued reliance on coal without accelerating the development of renewable energy (RE) or effective emission reduction technologies will become a major obstacle to reach this target. In the RUKN (National Electricity General Plan) 2025, Indonesia government has outlined the implementation of CCS as part of the strategic plan to achieve Net Zero Emissions 2060. Strategic measures have been undertaken to reduce CO_2 emissions from the power generation sector, one of which includes feasibility studies on the application of post-combustion CO_2 capture technology at CFPP in Indonesia. In the study [7] regarding to the application of CCS at coal CFPP in Indonesia, it was found that the energy penalty increased by 30–40% relative to the baseline CFPP, resulting in a rise in the levelized cost of electricity (LCoE) to approximately 0.11–0.12 USD/kWh, or about two to three times the LCoE baseline. Consequently, the implementation of CCS in power plants remains economically uncompetitive. This study aims to address these challenges through a comprehensive analysis and evaluation of CCS implementation in CFPP. Furthermore, the potential for economic optimization is assessed by optimizing carbon cap, tax schemes, grant options, and the role of international carbon markets in improving the economic viability of CCS in the power sector. The study also evaluates the potential impacts on the Java–Bali power system, particularly in terms of energy mix distribution, system stability and reliability, in supporting future decarbonization efforts.

2. METHOD

Process modeling was performed using Aspen HYSYS V14 with acid gas package consisting of up to 79 reactions modelled as kinetics and equilibrium reactions using default factors from Aspen. Economic analysis included capital expenditure (CAPEX), operational expenditure (OPEX), LCoE, and sensitivity to carbon cap, tax, credits, grants, and financing incentives. A system level overview of the Java-Bali grid was also conducted to compare decarbonization pathways business as usual (BaU), early retirement with renewables, and CCS retrofit.

2.1. Base case

The baseline scheme was established by implementing CCS on a CFPP without any optimization. Operational parameters of the CFPP were obtained from the mass and energy balance of power plant. CFPP consists of three units, each unit with a gross capacity of 330 MW. Design of a shared CCS facility for the three flue gas streams will be carried out. This study also includes a techno-economic comparison between dedicated and shared CCS infrastructure applied to three CFPP units. SO_x treatment will be enhanced by installing a flue gas desulphurization (FGD) system. The flue gas entering the absorber column has a pressure of 1.2 bar and a temperature of 40 °C, coming from the output of the flue gas blower. The existing CFPP has an operational efficiency of 38.4%, with an emission intensity recorded at 1.02 tCO_2/MWh [8]. The initial step involved modeling the carbon capture process using Aspen HYSYS V14, where the design parameters for the absorber and regenerator were adopted from established literature references [9], [10] in Table 1.

The CO_2 capture process simulation was conducted using the Shell Cansolv Solvent (MDEA + PZ), with the acid gas chemical solvent fluid package applied for the simulation. A capture rate of 90% was targeted with a reboiler temperature set at 120 °C as illustrated in Figure 1. The flue gas temperature from the existing CFPP is 141.1 °C and the gas composition consists of 13.8% CO_2, 2.16% O_2, 70.1% N_2, and 13.3% H_2O, with SO_x and NO_x emission concentrations measured at 844 mg/Nm³ and 164 mg/Nm³.

Modelling of the CFPP system was conducted based on data derived from the mass and energy balance [11]. As part of the integration with the carbon capture system, some potential tapping points for steam extraction were identified and evaluated in Table 2. A technical assessment was subsequently performed to compare the required steam mass flow to supply the reboiler and resulting energy penalty associated with each tapping option. This evaluation served as the basis for selecting the optimal tapping point that minimizes performance degradation of the existing CFPP. Based on the baseline modelling results, CAPEX, OPEX, and LCoE were calculated and subsequently validated against data from previous CCS retrofit studies. LCoE comparison between a shared CCS system serving three CFPP and three separate CCS systems with one installed for each power plant unit will be studied.

Table 1. Post combustion capture parameters

Unit	Parameter	
Absorber	Type	: Bubble Cap Tray
	Number of stage	: 40 stages
	Diameter	: 22 m
	Absorber pressure	: 1.2 bar
	Flue gas temperature	: 40 °C
Regenerator	Type	: Bubble Cap Tray
	Number of stage	: 20 stages
	Diameter	: 15.8 m
	Regenerator pressure	: 1.8 bar
	Regenerator temperature	: 120 °C
Heat exchanger	ΔT_{min}	: 10 °C
Duty	Regenerator duty	: $2.9x10^9$ kJ/h

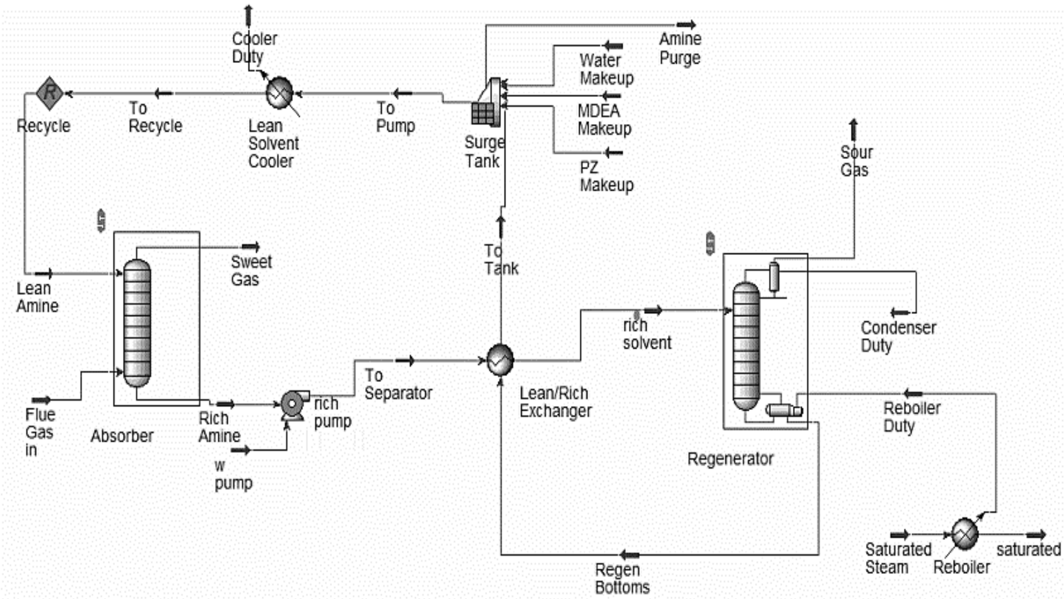


Figure 1. Carbon capture modelling on Aspen Hysys

Table 2. Steam tapping options

Tapping	Pressure (bar)	Temperature (°C)	Mass flow (ton/h)
LP/IP crossover	5.04	261	731
Cold reheat	43.5	339	880
Main steam	177	540	969
Aux steam	10.6	353	43.3

2.2. Economic analysis

The economic assessment of CFPP CCS retrofitting was carried out by calculating LCoE. In general, LCoE represents the cost required for a power plant to generate one kilowatt-hour (kWh) of electricity. The LCoE is influenced by several components, including the CAPEX and OPEX of the existing CFPP. The CAPEX and OPEX associated with the capture system including the addition of a flue gas desulfurization (FGD) unit, CO_2 transportation and injection costs, and the energy penalty costs arising from steam consumption to supply the CCS regenerator, as described in (1).

$$\text{LCoE} = \frac{PV\ \Sigma\ CAPEX\ cap + OPEX\ cap + Carbon\ Penalty}{PV\ \Sigma\ Electricity\ (MWh)} \tag{1}$$

The cost calculation for the existing CFPP was based on the basic cost of electricity production in 2024, with a detailed breakdown into CAPEX and OPEX components, including fuel cost, fixed O&M cost, and variable O&M cost. For the capture cost calculation, data were obtained from the equipment cost results generated by ASPEN Process Economic Analyzer V14. The CAPEX for CCS was determined as the total module costs, which comprise direct expenses, indirect expenses, contingency, and fees. Most equipment costs were estimated using Aspen Process Economic Analyzer (APEA), while the FGD unit and flue gas blower costs were taken from the literature, with all costs converted to a 2022 basis using the CEPCI ratio and Guthrie multiplier factor. The OPEX for CCS was calculated based on three components: direct cost, fixed cost, and general expense. Capture OPEX estimation was carried out following the methodology proposed by Turton. LCoE was calculated using the NPV method with an 10% discount rate to convert future cash flows to present value. In general, the capture cost represents the required expenditure to capture one ton of CO_2, as expressed in (2).

$$\text{Capture cost} = \frac{LCoE\ after - LCoE\ before}{CEI\ before - CEI\ after} \tag{2}$$

2.3. Economics sensitivity

This study evaluates the impact of carbon cap and tax policies by Ministry of Energy and Mineral Resources Regulation No. 16 of 2022, on the economic viability of carbon capture implementation. The potential of carbon credit revenues from international markets will be assessed to improve LCoE. As well as incentives aimed at reducing the CAPEX burden of the capture system, in relation to changes in the plant's LCoE. The carbon credit schemes obtained, grant support, and the available incentive options are illustrated in Figure 2.

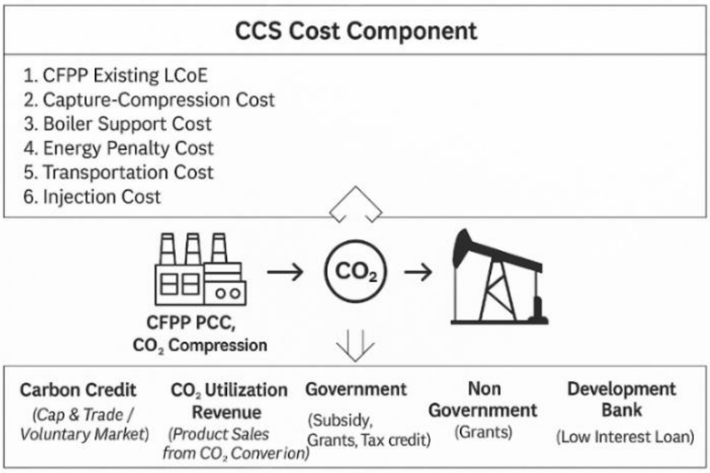


Figure 2. Economic sensitivity options

2.4. Comparison of business as usual (BAU), early retirement, and CCS retrofit scenario

This section compares the economic and financing aspects of three scenarios: business as usual (BAU), early retirement of CFPP replaced by renewable energy (RE), and coal plant retrofitting with CCS. In addition to comparing LCoE across these scenarios, an analysis of the initial CAPEX burden is also conducted. In the early retirement scenario, several financial considerations must be addressed, including the value of stranded assets, decommissioning costs, and the investment required for the replacement renewable energy capacity. According to reference [12], decommissioning costs is 117.4 mUSD/1000MW. The calculation of stranded assets can be performed based on the formula provided in reference, which considers the overnight capital cost (OCC, USD/kW), the installed capacity of the power plant (K), the expected economic lifetime (L), and the age at early retirement (R). This formula estimates the unrecovered capital investment at the point of early retirement by proportionally allocating the OCC over the remaining lifetime of the plant. Specifically, the stranded asset value is given by (3).

$$\text{Stranded assets} = OCC * K * (L - R) * L \quad (3)$$

In the case of early retirement of CFPP it is important to review both the capacity being retired and the replacement power system. As shown in (4), when CFPP are replaced with renewable energy sources, such as solar or wind, the required renewable energy capacity must be calculated based on the difference in capacity factors. This ensures the new system can produce the same amount of electricity each year [13].

$$\text{Replacement RE capacity (MW)} = \frac{Annual\ Coal\ generation\ (MWh)}{8760 * RE\ Capacity\ factor\ (\%)} \quad (4)$$

3. RESULTS AND DISCUSSION

3.1. Base case result

The result from the base case simulation with 90% CO_2 capture showed a reboiler energy requirement of 2.9×10^9 kJ/h, corresponding to a specific reboiler duty of 3.46 MJ/kg CO_2. The model was validated using reboiler duty data from previous studies [14]. This reboiler energy demand must be compensated by utilizing steam from the existing CFPP, with the potential tapping point options summarized in Table 3. The highest steam mass flow requirement is observed at the LP-IP crossover tapping, amounting to 414 t/h per CFPP unit. However, it also yields the lowest energy penalty at 33.7%. This tapping point significantly influences the net power output, where the LP-IP crossover achieves the highest net output of 216 MW. In addition to minimizing the energy penalty, selecting the LP-IP crossover tapping has minimal impact on the operation of the existing CFPP compared to other tapping options. For instance, tapping at the cold reheat line poses a risk of tube overheating in the reheater boiler, tapping at the IP extraction point could disrupt deaerator operations, and tapping from the existing LP extraction line would be insufficient to meet the steam mass flow requirements of the CCS system [15]. A detailed breakdown of the energy penalties associated with each tapping point is summarized in Figure 3.

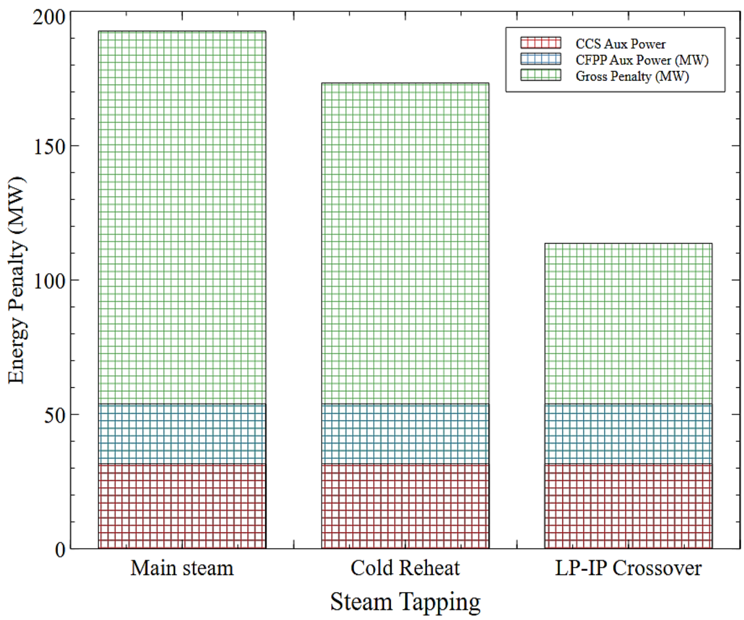


Figure 3. Energy penalty comparison

Table 3. Steam tapping analysis result

Tapping	Steam req (ton/h)	Gross out (MW)	Energy penalty (%)	Net power (MW)	Efficiency (%)
Main steam	355.7	191.3	57.9	137.4	18.5
Cold reheat	399.0	210.6	52.0	156.7	21.4
LPIP crossover	414.3	270.2	33.7	216.3	27.4

3.2. Economic analysis

The LCoE cost breakdown for CCS retrofitting on a CFPP consists of several major components, following Figure 4: the baseline LCoE of the CFPP 57.2 USD/MWh, the cost of the capture system including boiler retrofits such as FGD and SCR 28.71 USD/MWh, the energy penalty due to steam extraction 23.8 USD/MWh, and CO_2 transport and injection costs 2.5 and 19.0 USD/MWh respectively. Quantitatively, the energy penalty accounts for approximately 17.0% of the total LCoE, while the capture system contributes 26.0%, and CO_2 handling transport + injection comprises 16.0%. The largest share remains with the original CFPP operation, which represents 41.0% of total costs. To reduce the burden of the energy penalty, process modification strategies such as steam extraction optimization and heat integration are essential and have been discussed in preceding sections.

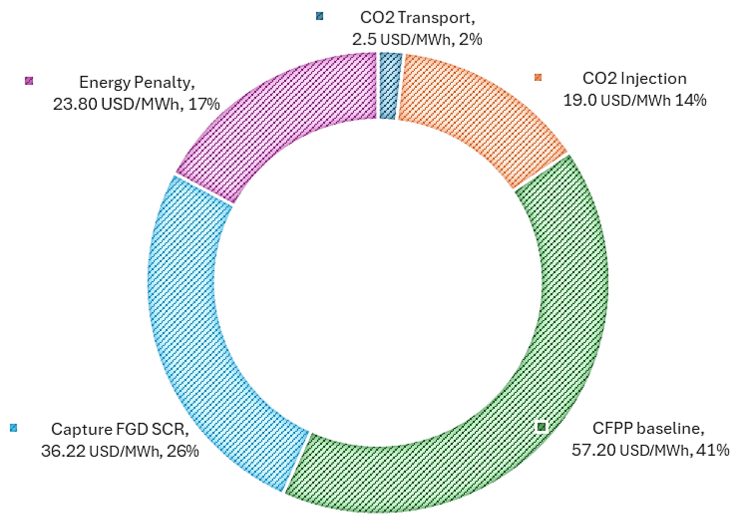


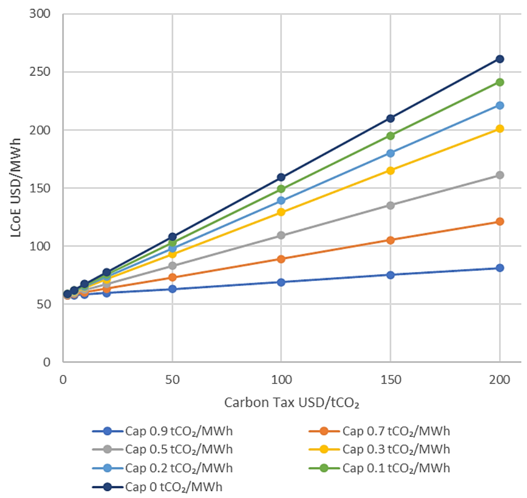
Figure 4. CCS cost components

The impact of CAPEX and OPEX between dedicated CCS and shared CCS designs for three CFPP units. It was found that, both in terms of CAPEX and OPEX, the shared CCS design resulted in lower costs compared to the dedicated CCS system. Consequently, LCoE for the shared CCS system was 124 USD/MWh, while the dedicated CCS system resulted the LCoE of 139 USD/MWh.

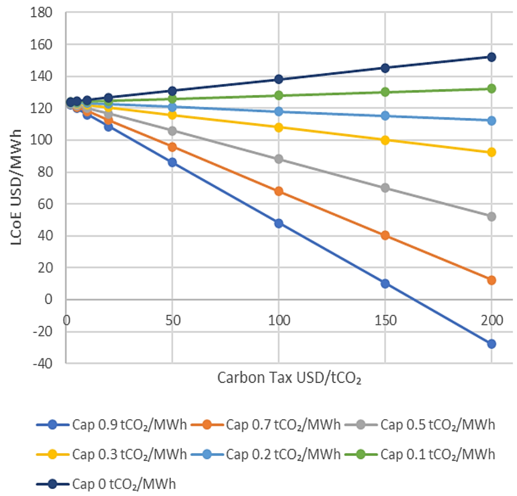
3.3. Economic sensitivity

3.3.1. Carbon cap and tax sensitivity

In the first part, a sensitivity analysis was conducted on the impact of carbon cap and tax values in the Ministry of Energy and Mineral Resources Regulation No. 16 of 2022 [16]. If the CFPP is not retrofitted with CCS, and different carbon cap and tax values are implemented, a comparison with the CCS-retrofitted CFPP can be observed in Figure 5. In Figure 5(a), LCoE increases with higher carbon tax rates when the emission cap is set below the actual emission intensity of the power plant. The baseline LCoE for the CFPP without CCS is 57 USD/MWh. Under condition of low cap (approaching 0 tCO_2/MWh) and high carbon tax (up to 200 USD/tCO_2), the LCoE reaches a maximum value of 210 USD/MWh. Meanwhile, Figure 5(b) shows that the baseline LCoE for the CFPP with CCS retrofit is 124 USD/MWh. LCoE declines with increasing carbon tax rates if the actual emissions of a power plant equipped with CCS are lower than the emission cap, as the plant benefits from selling carbon credits. An analysis of the values in Figures 5(a) and 5(b) was conducted to determine the breakeven point for LCoE. At an emission cap of 0.9 tCO_2/MWh, the breakeven occurs at a carbon tax of USD 76/tCO_2, resulting in an LCoE of USD 66/MWh. In contrast, with a lower emission cap of 0.1 tCO_2/MWh, the required carbon tax rises to USD 83/tCO_2, and the LCoE increases to USD 127/MWh. These results indicate that stricter emission cap leads to higher LCoE and carbon tax values. The application of CCS during the energy transition becomes more competitive when the carbon cap is high, such as 0.9 tCO_2/MWh, combined with a carbon price of 76 USD/tCO_2, resulting in an LCoE equivalent to the pre-retrofit condition. Gradually tightening emission caps alongside moderate increases in carbon tax rates offers a pragmatic pathway to improve the cost competitiveness of CCS, while minimizing disruptions to electricity prices during the transition period.



(a)



(b)

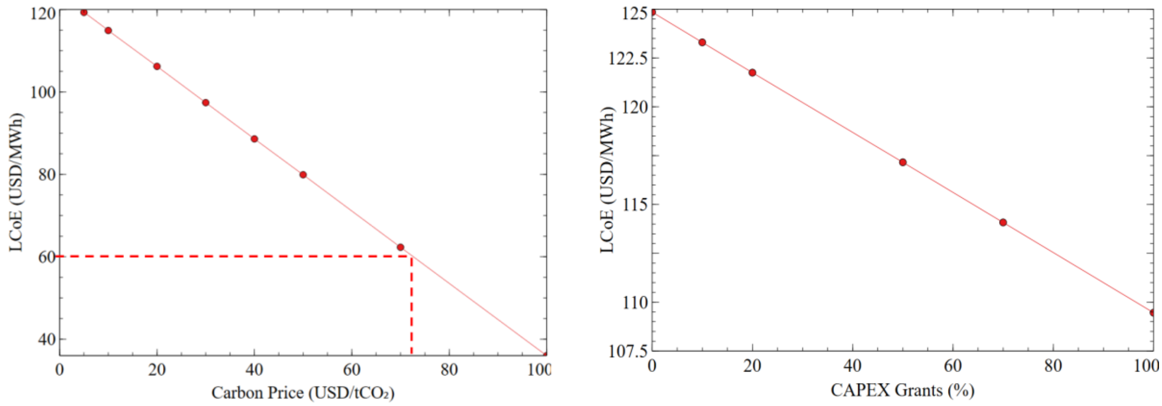
Figure 5. LCoE comparison: (a) CFPP without CCS and (b) CFPP with CCS

3.3.2. Carbon credit scheme

In this scheme, the international carbon market is utilized to monetize CO_2 emission reductions from the post-combustion capture process. Currently, the carbon tax value in developing countries such as Indonesia is uncompetitive for implementing a high tax rate, due to various considerations regarding its potential domino effects on the national economy. The international carbon market offers an alternative mechanism to compensate for the increase in the LCoE. Carbon price in the international market is varied between USD 5/tCO_2 and USD 100/tCO_2. The following section presents a sensitivity analysis of carbon pricing in the market and its impact on LCoE. The result shows that the LCoE can decrease to approximately USD 58/MWh, similar to the baseline level of a CFPP if the international carbon price approaches USD 75/tCO_2, following Figure 6(a). The analysis confirms that increasing carbon prices significantly enhances the economic feasibility of CCS implementation by reducing the final LCoE. At carbon price levels above USD 70–80 per ton of CO_2, the LCoE becomes comparable to, or even lower than, that of conventional power generation. This finding is consistent with projections by [17], [18], which indicate that a global carbon price in the range of USD 75–100/tCO_2 is required to accelerate investment in low-carbon technologies, particularly in hard-to-abate sectors such as power sector. Moreover, within the framework of Article 6 of the Paris Agreement and the evolving voluntary carbon markets (VCM) [19], monetizing captured CO_2 through international crediting mechanisms presents a viable pathway to further support CCS economics. Therefore, establishing a transparent and predictable carbon pricing policy, combined with access to international carbon markets, is essential for making CCS deployment financially viable while contributing to national decarbonization targets. This sensitivity analysis can also be applied to assess the potential value of CO_2 feedstock sales. The selling price of CO_2 as an industrial feedstock influences the LCoE in power plants equipped with CCS technology. When CO_2 is used in downstream industries, such as urea production, synthetic fuels, or construction materials, Indonesia has significant geological potential for the implementation of CCUS, particularly through enhanced oil recovery (EOR) or enhanced gas recovery (EGR) [20]. This utilization potential is expected to generate revenue and help offset the cost of CO_2 capture.

3.3.3. CCS CAPEX grants

One of the major cost components contributing to the increase in the plant's LCoE is the capture cost. The capture cost includes the CAPEX and OPEX of the capture system, along with the additional equipment required for flue gas treatment prior to entering the absorption column is 22% of the total retrofitted LCoE. The detailed breakdown shows that the CAPEX for the capture system amounts to 606 million USD, while the OPEX capture cost is approximately 75 million USD per year. In the CAPEX grants scheme, variations between 0% and 100% incentives were evaluated, while a full 100% CAPEX funding incentive led to a 12.4% reduction in LCoE, following Figure 6(b). The use of CAPEX grants has proven to be a critical instrument in lowering initial investment barriers for CCS, particularly for large-scale and high-risk projects. Several countries, including Canada, Norway, and the United States, have adopted capital grant schemes to support the deployment of CCS projects. These countries consistently integrate direct grant support into their national CCS strategies, complemented by additional policy instruments such as carbon pricing, tax incentives, and public sector involvement. This integrated approach aims to reduce upfront investment risks and enhance the financial viability of large-scale carbon capture initiatives.



(a) (b)

Figure 6. Impact of policy incentives on LCoE: (a) effect carbon price on LCoE and (b) LCoE reduction with CAPEX grants

3.4. CCS retrofit impact on Java-Bali grid

3.4.1. CFPP retrofit in the Java-Bali interconnection system

In 2023, Indonesia's total installed electricity generation capacity is 91 GW, with approximately 56.1% located in the Java-Bali grid. CFPP accounts for 58.8% of the total installed capacity within this system. The distribution of CFPP in the Java-Bali grid system can be seen in Figure 7. In the Java-Bali grid, more than 54.5% of the installed capacity consists of subcritical CFPP, as shown in Figure 8(a). Therefore, subcritical CFPP produces the highest accumulated emission per year, as illustrated in Figure 8(b). The majority (53.1%) of subcritical CFPP are 10 to 20 years old, as illustrated in Figure 8(c). The capacity of subcritical CFPP is shown in Figure 8(d). This study examines the broader application of CCS on CFPP that contribute most significantly to the electricity generation within the Java-Bali interconnection system.

CCS modelling in this study is based on reference cases from previous literature. The analysis is carried out by considering both the economic aspects and technical performance outcomes of CCS implementation across CFPP technologies and capacities. The analysis shows that larger and more efficient units, such as the 1,000 MW USC plant, achieve the lowest energy penalty (30.5%), and lowest LCoE (0.111 USD/kWh). In contrast, subcritical units face higher emissions and costs. As shown in Table 4, this highlights that CCS retrofitting is more cost-effective when applied to high-efficiency power plants. The design for CCS implementation within the Java-Bali grid system produced the following results: the net dependable capacity of CFPP is projected to decrease by approximately 33% across the system.

The implementation of CCS is also highly influenced by the remaining operational lifespan of power plants. The age distribution of CFPP is shown in Figure 9. CFPP with a short remaining lifespan are generally considered uneconomical for CCS retrofitting due to their outdated technology, high emission intensity, and low energy efficiency [21]. From an economic perspective, CFPP must cover the CAPEX within a short period, making retrofitting less feasible for units with a short remaining lifespan. Retrofitting CCS on newly constructed CFPP is generally discouraged in prior studies, primarily due to the considerable capital requirements it imposes. This approach substantially increases the combined investment costs of both the power plant and the CCS infrastructure. Additionally, such retrofits often coincide with the early-stage debt repayment period, during which financial flexibility is limited, thereby reducing the economic attractiveness of implementing CCS at an early operational phase [22]. Compared to their typical operational lifespan, these plants have an estimated remaining service life of around 20 years.

Figure 7. Distribution of CFPP across the Java-Bali interconnected grid

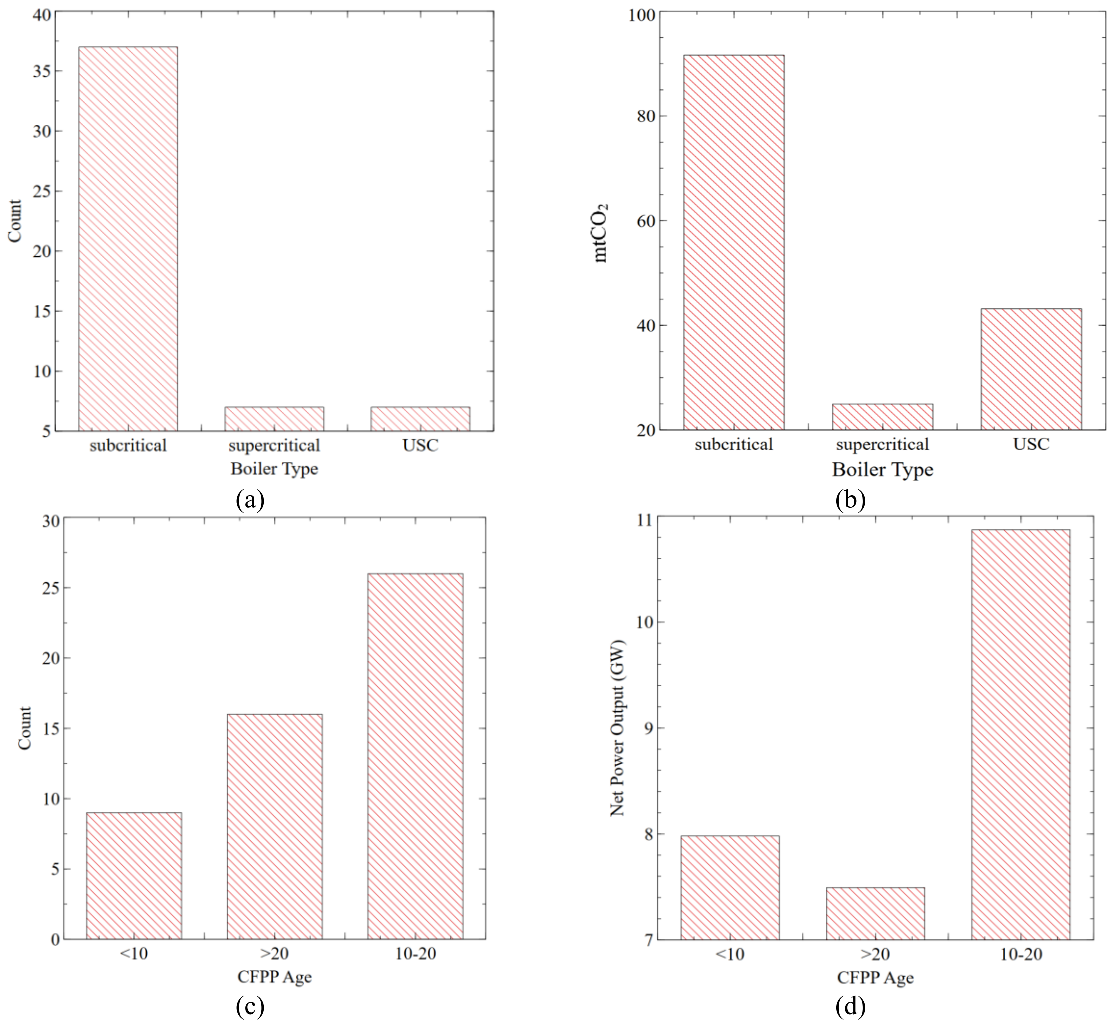


Figure 8. Characteristics of CFPP in the Java-Bali interconnection system: (a) installed CFPP by boiler technology, (b) Java-Bali CFPP annual emission distribution, (c) distribution of power plant age, and (d) net power output of CFPP by age

Table 4. CCS retrofit performance based on power plant type and capacity

Parameter	300 MW supercritical	660 MW subcritical	600 MW subcritical	1,000 MW USC
Energy penalty (%)	33.5%	32.4%	35.7%	30.5%
CEI before (tCO_2/MWh)	0.933	0.935	0.937	0.838
CEI after CCS (tCO_2/MWh)	0.131	0.16	0.137	0.118
Reboiler duty (GJ/tCO_2)	2.96	2.92	2.93	3.01
CCS CAPEX (M USD)	231	477	479	558
CCS OPEX (M USD)	33.7	69.4	68.9	83.9
LCoE after CCS (USD/kWh)	0.144	0.133	0.127	0.111

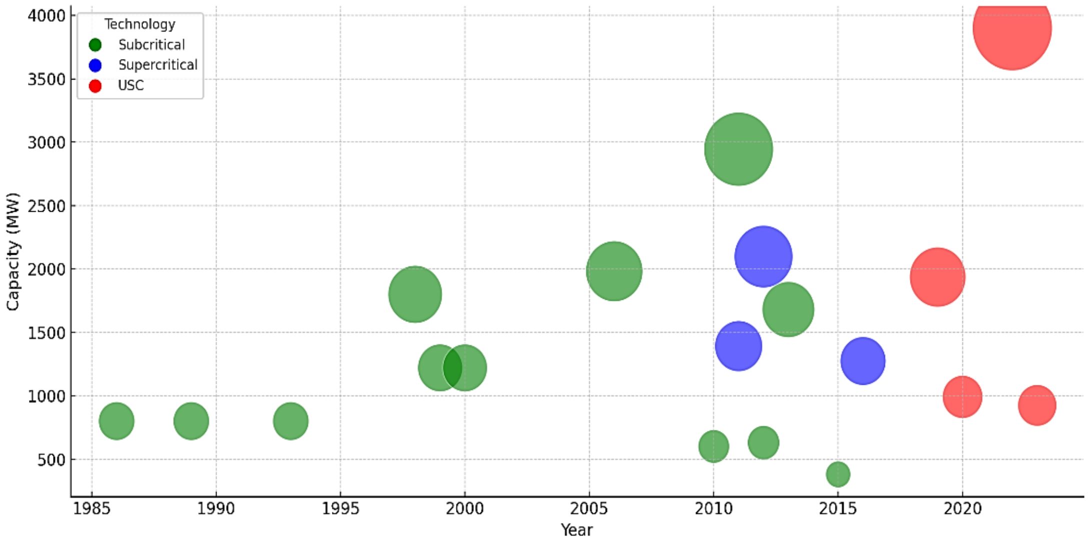


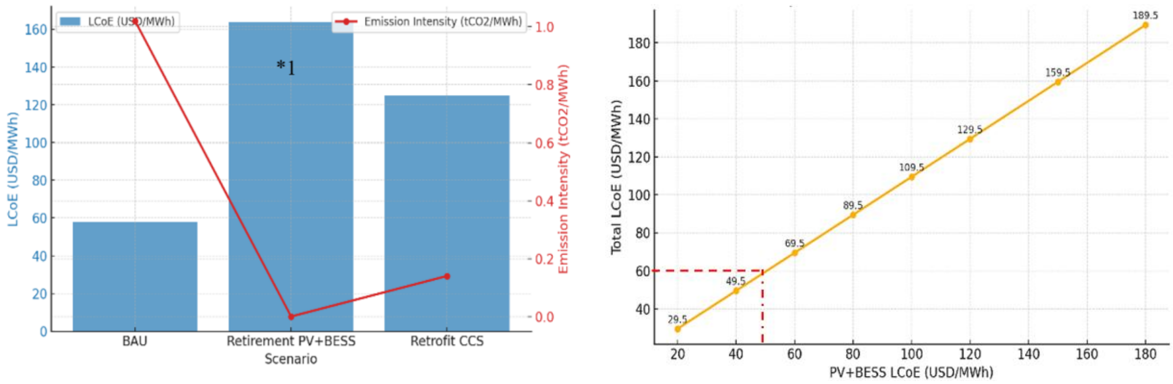
Figure 9. Power plant capacity by year and technology

From a grid perspective, it is also important to assess the capacity factor, which is linked to the plant dispatch pattern. Currently, dispatch priority is typically given to the lowest-cost power generator, which affects the capacity factor of each plant. Under retrofit or retirement schemes, the dispatch order should be adjusted to prioritize cleaner plants, because a lower capacity factor will make CCS retrofit schemes less competitive.

3.4.2. Business-as-usual (BAU), early retirement, and CCS retrofit schemes

In this study, a comparative model was developed to assess the business-as-usual (BAU) scenario against early retirement with replacement by PV+BESS, as well as the CCS retrofit scenario. Under the BAU scenario, the emissions generated by the 3×330 MW CFPP are estimated at 7.2 million tCO_2/year, with a corresponding LCoE of USD 58/MWh. In the early retirement scenario, the capacity lost from the decommissioned coal power plant must be replaced by new renewable energy plants with an annual capacity at least equivalent to that of the retired unit. The LCoE of the PV+BESS system is reported in previous study to be approximately USD 158/MWh [23]. Another study from [24], the PV and BESS hybrid configuration without diesel generators in East Kalimantan achieved a LCoE of 168 USD/MWh with Homer Pro Software. In the CCS retrofit scenario, the modelling incorporates previously evaluated economic parameters such as LCoE, CAPEX, and OPEX, and achieves an annual CO_2 capture rate of 90%. A comparative summary of the results across these scenarios is presented in Figure 10(a). Figure 10(b) illustrates that the LCoE of the retirement scenario is strongly influenced by the LCoE of the PV+BESS system.

The sensitivity analysis shows that the retirement scenario becomes most economically favorable when the LCoE of PV and BESS reaches around USD 50/MWh. In the study [25], the early retirement of CFPP is recommended primarily for older units, which are typically characterized by outdated technologies, lower thermal efficiency, and higher emission intensity. Plant aging leads to increased CO_2 emissions and outage rates due to declining thermal efficiency, making age a key factor in retrofit or retirement decisions. In the case of early retirement, the government must account for the stranded asset value of CFPP based on their remaining operational life as well as the high upfront capital investment required for deploying renewable energy to achieve equivalent electricity capacity. Given that the capacity factor of utility-scale solar PV on Cirata Power Plant in Indonesia [26] ranges between 17% and 20% substantially lower than that of coal power plants, which typically operate at 80% to 90%. The installed PV capacity must be increased by a factor of four to five to achieve comparable annual energy production. Consequently, the initial CAPEX is assessed based on the equivalent electricity generation capacity. These dual challenges financial losses from underutilized assets and substantial CAPEX for replacement infrastructure highlight the urgency of well-structured financing mechanisms. International financial support, including concessional funding, grants, and global climate finance instruments, will be essential to bridge the economic gap and ensure a just and viable transition.



(a) (b)

Figure 10. Comparative economic analysis of CFPP transition scenarios: (a) LCoE comparison business as usual (BaU), CFPP retirement (Yuan *et al*. [23]), and CCS retrofit; and (b) relation PV+BESS LCoE and total accumulated LCoE

The penetration of variable renewable energy (VRE) sources can serve as a replacement for the normal retirement of aging CFPP units, particularly those utilizing outdated technologies with high emission factors. Meanwhile, CFPP that are within the optimal age range for retrofit and equipped with more modern systems are better suited for CCS retrofitting, making them a one of effective option for emission reduction and system stability. In Figure 11 [27], 58.8% of the baseload generation is supplied by CFPP. To accommodate the saturated penetration of VRE in the grid, generation sources with sufficient system inertia are still required to maintain grid stability. Several baseload generation options need to be further considered, including renewable-based plants or retrofitted CFPP with CCS. Based on the renewable energy resource potential published by the National Energy Council (DEN) [28], the capacity of renewable sources such as hydropower and geothermal remain insufficient to fully replace the current CFPP baseload in the existing power grid. Another alternative involves integrating renewable energy from rich resource regions such as Sumatra and Kalimantan, particularly through large-scale hydropower. This would require the development of a Java–Sumatra-Kalimantan super grid, enabling stable and reliable baseload support for the Java electricity network. The penetration of VRE sources such as photovoltaic (PV) and wind turbines must be carefully planned to maintain power system stability. High penetration of VRE poses critical operational risks to power systems, particularly due to the reduction in system inertia [29]. A previous study [30] highlights that replacing conventional thermal units with inverter-based resources decreases the system's rotational inertia, weakening its ability to maintain frequency stability under sudden disturbances. This low-inertia condition increases the risk of cascading failures and underscores the need for transitional dispatchable sources or advanced control strategies to preserve grid resilience during the energy transition. According to previous studies, the maximum saturation level of VRE in the grid without compromising stability is approximately 30-40%. Beyond this threshold [31], the system requires support from dispatchable power plants, including base load units, follower units, or other power generators that can tolerate frequency disturbances. In the Java-Bali grid system, CFPP still dominate the generation mix, accounting for around 58% of the total installed capacity. Under these conditions, a normal retirement scheme may be applied to aging coal units, which can be replaced by more economically competitive VRE technologies. CFPP older than 20 years account for approximately 15% of the total power generation fleet, while CFPP represent 58.9% of the overall installed capacity. For CFPP with mid to relatively low operating age, retrofitting with CCS remains a viable option. While the retrofit process imposes an energy penalty of around 25%. There is a potential capacity gap of 18% that could be filled by adding variable renewable energy power plants.

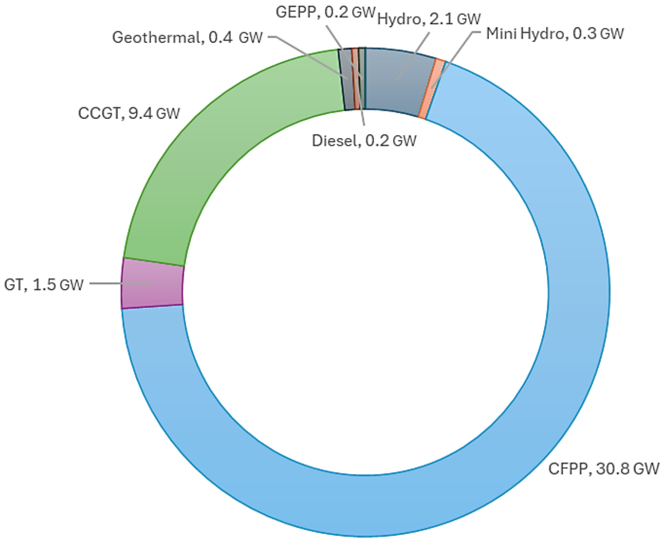


Figure 11. Power plant type and capacity (GW) in Java-Bali grid [27]

In this context, retrofitting CCS can be regarded as one of the viable options to support grid stability in response to the intermittency risks associated with high VRE penetration and potential system disturbances especially when considering baseload alternatives such as hydropower and geothermal, which remain limited in capacity and deployment, as shown in Figure 12. By preserving the operational role of dispatchable baseload power plants, CCS retrofits help ensure reliable electricity supply while enabling emission reductions as shown in Table 5. To achieve Indonesia's net zero emission target by 2060, the short-term adoption of CCS can still be considered one of feasible option when supported by process optimization and access to international carbon markets. CCS has the potential to become economically competitive. However, this approach must be aligned with the characteristics of the existing power grid, particularly the current share of VRE and the availability of dispatchable power to ensure system stability. It is also essential to evaluate the renewable energy potential within each grid region to assess the feasibility of replacing baseload generation. In the long term, government action will be crucial in defining an optimal renewable energy mix and identifying the most effective grid configurations to achieve emission reduction targets while maintaining system reliability and avoiding substantial increases in electricity tariffs.

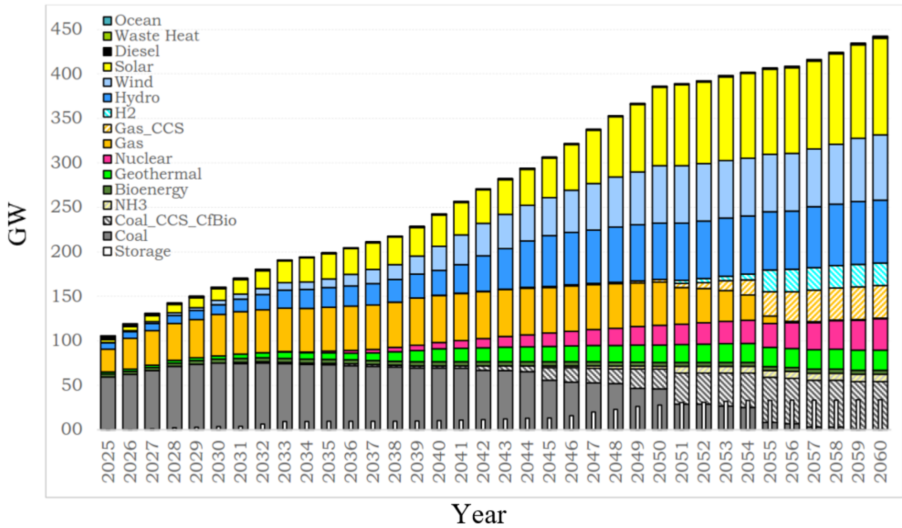


Figure 12. Power generation capacity projection [32]

Table 5. Renewable energy potential in Java-Bali system

Location	PV (GWp)	Hydro (GW)	Wind (GW)	Geothermal (GW)
Banten	51.8	0.1	5.5	0.6
Jakarta	40.4	0.0	0.0	0.0
West Java	155.5	0.4	12.7	4.7
Central Java	185.9	0.1	8.5	1.3
DIY	30.3	0.0	2.1	0.0
East Java	176.4	0.1	10.2	1.3
Bali	21.6	0.0	1.5	0.3

4. CONCLUSION

This study demonstrates that retrofitting a 3×330 MW CFPP with CCS technology increases the LCoE to 124 USD/MWh, approximately 2.2 times higher than the baseline. The cost escalation is primarily driven by CO_2 capture (22%), energy penalty due to steam extraction (18.5%), and CO_2 transport and injection (16.7%). Economic sensitivity analysis indicates that CCS retrofitting during the transition period becomes more financially competitive under a high carbon cap of 0.9 tCO_2/MWh and an optimal carbon tax of 76 USD/tCO_2. In Indonesia's current low-cap and tax landscape, international carbon markets offer a promising revenue stream. With a carbon price of 75 USD/tCO_2, by leveraging carbon credit revenues, the financial burden of CCS can be mitigated, allowing the LCoE to remain competitive with pre-retrofit scenarios. Moreover, CAPEX grants are shown to reduce LCoE by up to 12.4%, improving project viability. CAPEX grants can be proposed as a financial instrument to reduce the high upfront investment associated with CCS infrastructure.

From a system-level perspective, the Java-Bali grid dominated by subcritical CFPP aged between 10 and 20 years presents three strategic pathways: continued operation, early retirement with VRE replacement, or CCS retrofitting. During the transition period, the retirement of aging CFPP and replacing them with VRE is more appropriate from both economic and technical perspectives. In contrast, CCS emerges as one of the viable options for mid-aged units, particularly those with high efficiency and lower emission intensity. Retrofitting CCS offers a technically and economically feasible transition pathway that enables short term emissions reduction while facilitating a smoother shift toward more cost-competitive renewable energy integration, as the LCoE of solar PV and battery energy storage systems (BESS) continues to decline below USD 50/MWh.

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AUTHOR CONTRIBUTIONS STATEMENT

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C : **C**onceptualization
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Fu : **Fu**nding acquisition

CONFLICT OF INTEREST STATEMENT

Authors state no conflict of interest.

DATA AVAILABILITY

The data that support the findings of this study are available from the corresponding author, [AR], upon reasonable request.

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