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| RESEARCH ARTICLE

Carbon Capture in Coal-Fired Power Plant for Cleaner Energy Management in Indonesia

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| ABSTRACT

Indonesia faces a significant challenge in transforming its power sector to meet the national target of achieving Net Zero Emissions (NZE) by 2060. The country's heavy reliance on coal for base-load electricity generation primarily due to its low cost and domestic availability represents a significant barrier to achieving decarbonization goals. Although global energy trends are shifting toward renewable and low-carbon sources, coal remains a dominant part of Indonesia's energy mix. In this context, the adoption of transitional energy management such as Carbon Capture and Storage (CCS), particularly Post-Combustion Carbon Capture (PCC), is essential for reducing carbon dioxide (CO_2) emissions while ensuring energy reliability and economic stability throughout the transition period. This study examines the technical and economic feasibility of applying PCC technology at a subcritical coal-fired power plant (CFPP) by integrating the flue gas streams from two 315 MW units in Banten, Indonesia. Each unit emits flue gas containing approximately 14.3% CO_2, with a target capture efficiency of 90%. The research methodology includes literature review, case study analysis, and process simulation using Aspen HYSYS V12. Technical and economic data are drawn from relevant literature and previous PCC implementation cases in CFPPs. The simulation evaluates the integration of a single PCC unit for two combined flue gas sources and calculates both operational and capital costs. The simulation results indicate that the integrated PCC configuration reduces total capital expenditure (CAPEX) from USD 365 million to USD 334 million when compared to the combined cost of individual CCS installations. It also achieves a significantly lower Levelized Cost of Electricity (LCOE), at approximately USD 88.6/MWh, compared to USD 103.6–105.2/MWh in individual unit configurations. In order to attain an IRR target 11%, the integrated system requires a carbon tax of USD 57/tCO_2, which is lower than the USD 73/tCO_2 needed for the single-unit CCS scenario. These outcomes indicate the economic benefits of integrated CCS implementation in advancing Indonesia's transition toward a low-carbon power generation sector.

| KEYWORDS

Emission management, carbon tax, coal-fired power plant, decarbonization, emission cap, levelized cost of electricity, net zero emission, post-combustion carbon capture.

| ARTICLE INFORMATION

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1. Introduction

The use of fossil fuels, particularly coal, remains one of the primary contributors to the rising concentration of greenhouse gases (GHG) in the atmosphere. Carbon dioxide (CO_2) emissions from coal combustion significantly drive global warming, climate change, and the increasing frequency of extreme weather events. In response, countries around the world are striving to develop and implement clean and low-emission energy technologies.

As one of the largest coal producers globally, Indonesia has declared its commitment to addressing climate change by joining the Paris Agreement with a target of achieving Net Zero Emissions (NZE) by 2060. This commitment was further reinforced by the signing of the Global Coal to Clean Power Transition Statement at COP26. However, this transition poses major challenges due to Indonesia's heavy reliance on coal-fired power plants (CFPPs), which account for approximately 62% of the national electricity mix and contribute around 80% of emissions from the energy sector (PT PLN (Persero), 2021; IESR, 2023).

Based on data Energy & Economic Statistics of Indonesia, 2022, Indonesia's verified coal reserves, totalling 33.3 billion tons (ESDM, 2022), and rising domestic consumption highlight the country's continued dependence on coal. Thus, an immediate shift to renewable energy is constrained by high investment costs. The 2021–2030 Electricity Supply Business Plan (RUPTL) emphasizes the development of power plants based on the *least-cost* principle, while maintaining supply reliability and sustainability (PT PLN (Persero), 2021).

In response to the plan, PT PLN (Persero), the state-owned electricity company, has demonstrated its commitment to deliver clean and affordable electricity. Efforts include technological transformation and digitalization, strengthening the electric vehicle ecosystem, biomass cofiring, and promoting low-emission technologies such as Carbon Capture and Storage (CCS) or Carbon Capture, Utilization, and Storage (CCUS). One of the strategic approaches to reduce CO_2 emissions from CFPPs is the application of carbon capture technology.

The CCS consists of three main components: CO_2 capture, transportation, and storage processes (Bui et al, 2018). Most CCS technologies are designed to reduce at least 90% of CO_2 emissions, a target considered technically achievable and economically justified according to Morris et al. (2021) and Paltsev et al. (2021). Therefore, CCS stands out as a key technological solution to support Indonesia's transition toward low-carbon power generation.

Preliminary findings suggest that the integrated CCS configuration offers significant cost advantages, reducing both LCOE and capture costs compared to individual unit applications. Moreover, the integration approach aligns with Indonesia's least-cost planning principle and provides a more flexible and scalable pathway for meeting its carbon reduction targets. Thus, strategically deploying CCS particularly through integrated solutions can bridge the gap between continued reliance on coal and the long-term goal of a decarbonized power sector.

2. Methodology

This research was carried out in four main stages: process modelling, data validation, economic calculation, and sensitivity analysis. The process modelling was performed using Aspen HYSYS V12 to simulate and evaluate the performance of Post-Combustion Carbon Capture (PCC) systems under two different configurations. The simulation used the Acid Gas–Chemical Solvents property package, which is widely applied for modelling amine-based CO_2 absorption systems due to its suitability for post-combustion gas conditions. The primary technical data was derived from subcritical coal-fired power plants 2 x 315 MW in Banten, Indonesia. And additional data were obtained through a literature review of relevant scientific sources and case study analysis.

Two carbon capture scenarios were developed: (1) Individual CCS units, in which two CFPP unit operates a separate capture system and (2) Integrated CCS configuration, where the flue gas streams from two 315 MW units are combined and processed through a single PCC system. The simulation results were used to generate key process performance indicators, which served as the basis for calculating Capital Expenditures (CAPEX), Annual Operational Expenditures (OPEX), and the Levelized Cost of Electricity (LCOE). Additionally, the economic evaluation incorporated carbon tax implications by estimating carbon penalties based on emission intensity levels and the regulatory benchmark of PTBAE (Power Plant Emission Cap in Indonesia). A comparative analysis of the two scenarios was conducted to identify the most technically and economically viable approach for CCS deployment in coal-fired power plants.

2.1. Process Modeling

The scope of the PCC unit designed for the CFPP in this study includes several key components: flue gas blower, CO_2 absorber, rich amine pump, rich/lean heat exchanger, regenerator, lean amine cooler, CO_2 compressor, and CO_2 dehydration unit. This configuration is based on the designs presented in previous studies by (Kheirinik et al. (2021), Madejski et al. (2022), and Park et al. (2024), with the schematic diagram illustrated in Figure 1.

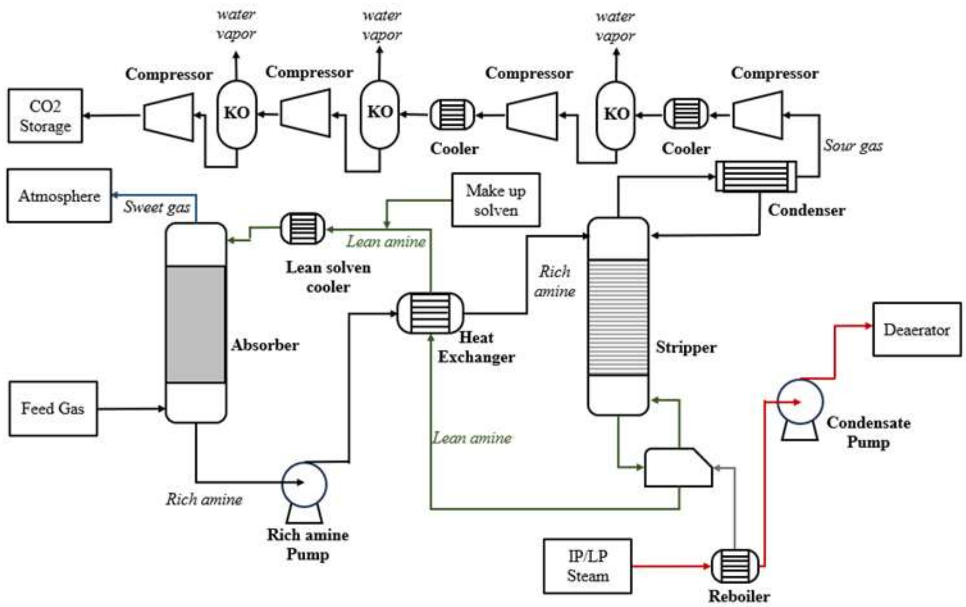


Figure 1. Overall post-combustion CO_2 capture schematic process

The post-combustion CO_2 capture technology applied in this study involves an absorption process using 40% *methyldiethanolamine* (MDEA) solution and 10% *piperazine* (PZ). The system is designed to capture 90% CO_2 content from the flue gas. If there is a problem with the CO_2 capture system, the flue gas can be bypassed directly to the stack without any disturbances to the power generation. The steam required for the CO_2 capture reboiler is extracted from the intermediate-to-low pressure (IP-LP) cross-over section of the steam turbine. The chemical reactions involved in CO_2 absorption and solvent regeneration are automatically defined in Aspen HYSYS and consist of three types of reaction models: equilibrium, kinetic, and dissociation. The reaction between MDEA-PZ and CO_2 are shown in Table 1 in equations 1-8.

Table 1. Reaction between MDEA-PZ and CO_2 (Zhan, Wang dan Zhang, 2020)

Reaction	
$CO_2 + MDEA \leftrightarrow MDEA - CO_2$	(1)
$MDEA - CO_2 + H_2O \leftrightarrow MDEAH^+ + HCO_3{}^-$	(2)
$CO_2 + PZ \leftrightarrow PZ - CO_2$	(3)
$PZ - CO_2 + H_2O \leftrightarrow PZCOO^- - H^+$	(4)
$MDEA + PZCOO^- + H_3O^+ \leftrightarrow PZ + MDEAH^+ + HCO_3{}^-$	(5)
$PZCOO^- + H^+ \leftrightarrow PZH^+COO^-$	(6)
$PZCOO^- + H^+ \leftrightarrow PZ(COO^-)_2$	(7)
$2H_2O \leftrightarrow H_3O^+OH^-$	(8)

The reaction between CO_2 and piperazine (PZ) occurs in parallel with the reaction between CO_2 and MDEA. Additionally, due to its high reaction rate, PZ also functions as a catalyst in the absorption process.

The selection of the process scheme and fluid package refers to *AspenTech's* recommendations for acid gas removal processes and is further supported by the study conducted by Qamar et al. (2020). Table 2 presents the overall parameters used for the post-combustion capture process simulation. The specifications and operating parameters for the absorber column, regenerator, heat exchanger, pump, and compressor are based on relevant literature used as references in this study.

Table 2. Data parameter of CO_2 capture simulation

Unit	Parameter	Reference
Absorber	• Column Type: Packed column • Number of stages: 20 • Operating Pressure: 1,2 bar	Sultan et al., (2021) Gervasi et al., (2014)
Regenerator	• Column Type: packed column • Number of stages: 20 • Operating Pressure: 2,3 bar	Sultan et al., (2021) Gervasi et al., (2014)
Lean/Rich Heat Exchanger	• ΔT minimum approach = 10 °C	Khan et al., (2020) Gervasi et al., (2014)
Compressor	• CO_2 final pressure: 100 bar • Temperature: above 30°C • Compression ratio: 1 – 3 • Compression stages: 4 • Compression efficiency: 0,85	Øi et al., (2016) Coquelet et al., (2017)

The simulation consists of three main components: CO_2 capture, CO_2 compression, and steam supply from the IP-LP crossover for the reboiler. The visual representation of integrated CCS system simulation setup is shown in Figure 2.

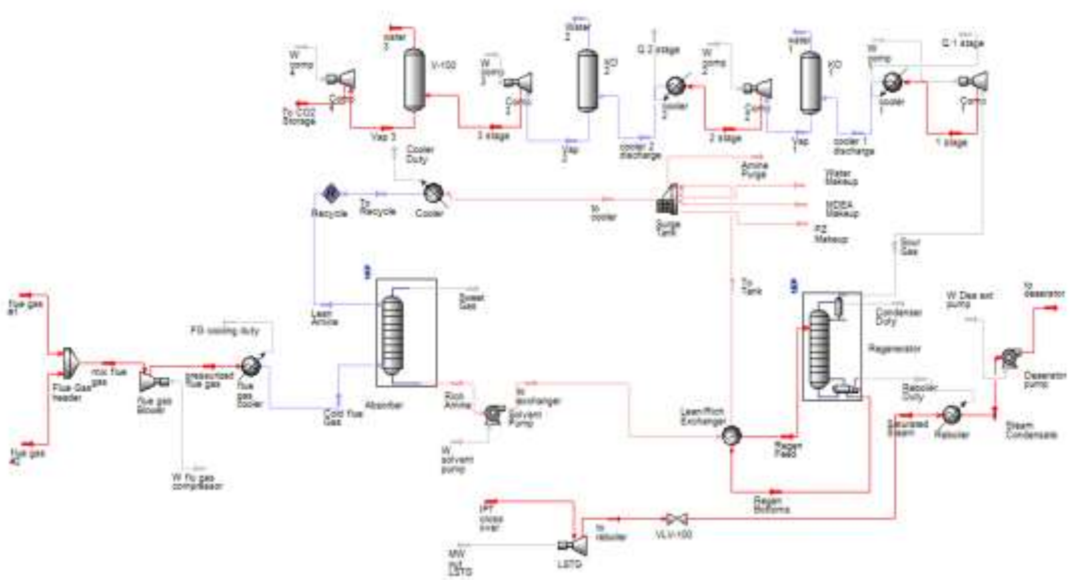


Figure 2. Combine flue gas integrated post-combustion carbon capture simulation

2.2. Data Validation

Model validation in Aspen HYSYS was carried out by comparing the results of the baseline model with existing literature references, as presented in Table 3.

Tabel 3. Simulation result validation

Parameter	Unit	Simulation result	Data Comparison	
			Value	Reference
Reboiler duty	MJ/kgCO_2	3.6	(2.5 – 3.6)	Bui et al. (2018)
Crossover IP-LP steam flow	%	59	(40 – 60)	Stöver et al. (2011)
Energy Penalty	%	29.9	(30)	Ciferno and Fout, (2009)

2.3. Economic Calculations

This analysis examines several critical economic parameters, including capital expenditures (CAPEX), annual operational expenditures (OPEX) for both the coal-fired power plant and the carbon capture system (CCS), the levelized cost of electricity (LCOE), and the cost of CO_2 capture. CAPEX and OPEX for the power plant are estimated based on empirical constants derived from U.S. Department of Energy (DOE/NETL) data and further supported by information from PLN's RUPTL. The capital cost of the CCS system is defined as the total module cost, comprising three main components: direct costs, indirect costs, and contingency allowances. CCS operational costs are classified into direct, fixed, and general categories and are used to calculate annual cash flow, excluding depreciation. A summary of all cost components is presented in Table 4.

Table 4. Economic calculation formula

Parameter	**Calculation method**	**Reference**
CAPEX CCS	APEA simulation and Guthrie method (1969)	-
OPEX CCS	Turton Method (2018)	Turton, (2012)
Levelized cost of electricity (LCOE)	$LCOE = \frac{(TCC\ x\ FCF) + Opex + Carbon\ penalty}{Net\ power\ output\ x\ cf\ x\ 8760} \$.MW^{-1}$	Rubin, (2015); Yun *et al.*, (2021)
Fixed Charged Factor (FCF)	$FCF = \frac{r(1+r)^T}{(1+r)^T - 1}$	Rubin *et al.*, (2013)
Carbon penalty	$Carbon\ Penalty\ (USD/h) = (CEI - EC) \times Capacity\ plant \times Carbon\ tax$	Rubin *et al.*, (2013)
CO_2 capture cost	$Capture\ cost\ \left(\frac{USD}{tCO_2}\right) = \frac{LCOE_{after\ CCS} - LCOE_{before\ CCS}}{(tCO_2/MWh)_{captured}}$	Yun *et al.*, (2021)

3. Results and Discussion

The simulation variations in this study involved combining flue gas streams from two sources within the plant and processing them through a single, integrated CCS system. In this configuration, Aspen HYSYS calculated the combined flow rate and gas composition.

3.1. Process Modeling Results

The integrated CCS setup for the two flue gas streams demonstrates that 90% CO_2 capture led to an overall increase in equipment duty requirements. This scenario also resulted in higher solvent circulation rates, corresponding to the increased cumulative CO_2 flow. The implementation of a CCS system in coal-fired power plants led to an estimated 30% reduction in net power output to the grid, primarily due to energy penalties associated with the capture process. The main results from the simulation and calculations are summarized in Table 5.

Table 5. Data result comparison from two scenario simulations

Parameter	Unit #1	Unit #2	Integration PCC unit #1 & #2
Plant capacity before CCS (MW)	315	315	630
Plant capacity after CCS (MW)	220.7	217.4	436
Emission intensity (tCO_2/MW)	1.052	1.09	1.07
Emission intensity after CCS (tCO_2/MW)	0.143	0.149	0.145
CO_2 flowrate (ton/h)	315.5	327.1	642.6
CO_2 after CCS (ton/h)	31.47	32.42	63.54
Solvent circulation (ton/h)	3,284.9	3,416.8	7,054.9
Reboiler duty (MJ/ton CO_2)	3.32	3.32	3.37
Reboiler duty (MW)	62.09	64.27	128.39
Compressor duty (MW)	21.7	22.51	44.24
Blower duty (MW)	10.16	10.53	20.69
Pump duty (MW)	0.31	0.32	0.65
Total energy Penalty (MW)	94.27	97.63	193.9
	29.9 %	30.9 %	30.8 %

3.2. Economic Analysis

The economic analysis focuses on key economic factors such as capital expenditures (CAPEX), annual operational expenditures (OPEX) for both the coal-fired power plant and the carbon capture system (CCS), as well as the LCOE and CO_2 capture costs. CAPEX and OPEX estimates were based on data from the U.S. Department of Energy/NETL and supported by PLN's RUPTL. The total capital cost of CCS includes direct, indirect, and contingency cost (Turton, 2012). Operational costs were divided into direct, fixed, and general expenses, and are used to estimate yearly cash flows, excluding depreciation. CAPEX and OPEX for the CCS unit were calculated to get the unit cost for each scenario. These expenses were then used to calculate the incremental CCS LCOE, which accounts for the increase in energy production costs required to cover the extra costs associated with setting up the CCS system. Economic calculation results are shown in Table 6.

Table 6. Summary of the economic calculation results for 2 x 315 MW CFPP

Parameter	Unit #1	Unit #2	Integration PCC unit #1, #2
$CAPEX_{CCS}$ (Million USD)	180.9	184	334.4
$OPEX_{CCS}$ (Million USD)	59.9	59.6	79.5

LCOE $_{after\ CCS}$ (USD/MWh)	103.6	105.2	88.6
LCOE $_{Increment}$ (USD/MWh)	48.9	49.6	35.5
CO_2 capture cost (USD/ton CO_2)	66.9	65.9	51.8

Table 6 presents a comparative analysis of the economic feasibility between individual and integrated post-combustion CCS configurations. The incremental LCOE resulting from CCS implementation reflects the added cost from capital expenditures and operational expenditures relative to the reduction in net electricity output due to energy penalties. While both CAPEX and OPEX increase with the scale of integration, the results clearly indicate that integrating multiple units into a single CCS system offers greater economic efficiency.

Specifically, the incremental LCOE for individual CCS installations ranges between USD 48–49/MWh, whereas integrating two units reduces this value to USD 35.5/MWh a decrease of over 25%. Similarly, CO_2 capture costs show a significant reduction, declining from USD 66.9/tCO_2 and USD 65.9/tCO_2 for individual units to USD 51.8/tCO_2 for the integrated configuration. This demonstrates that integration not only improves cost-effectiveness but also enhances scalability for large power plants. The reduction in both incremental LCOE and CO_2 capture cost in the integrated system suggests a more practical approach for carbon capture technology deployment, especially in countries like Indonesia, where coal-fired power plants remain dominant. The graph comparation of economic parameters are presented in Figure 3.

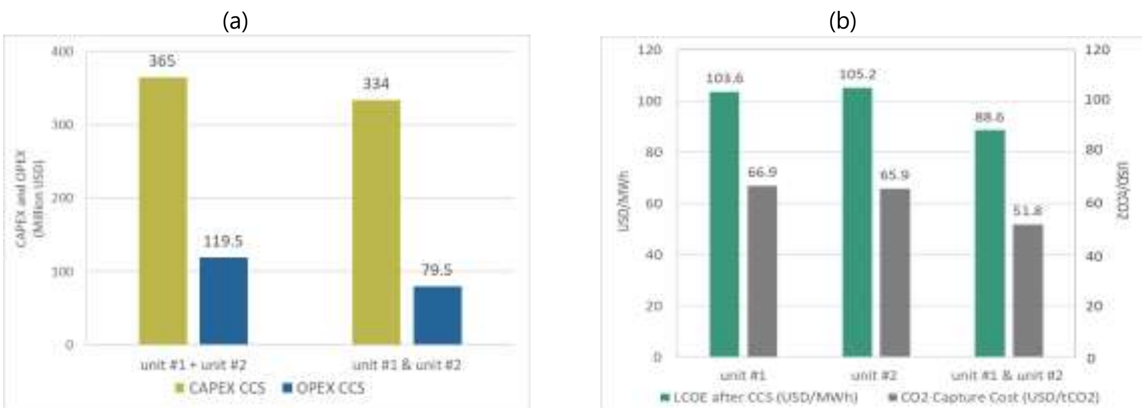


Figure 3. Economic result comparison (a) CAPEX and OPEX (b) LCOE and capture cost

Figure 3(a) compares the capital and operational expenditures of individual and integrated CCS configurations at the CFPP, specifically units 1 and 2. The data clearly show that both capital expenditures (CAPEX) and operational expenditures (OPEX) are significantly higher when CCS is implemented separately on each unit. The total CAPEX for the individual CCS configurations reaches approximately USD 365 million, while the integrated configuration where both units share a single CCS system requires only USD 334 million, reflecting a cost reduction of about 8.5%. Operational expenses show even greater savings; OPEX decreases from USD 119.5 million for the separate systems to USD 79.5 million for the integrated setup, yielding an operational cost reduction of approximately 33.5%.

Figure 3(b) further supports the economic advantage of integration, illustrating that both the LCOE after CCS and the CO_2 capture cost are lower in the integrated configuration. The LCOE for the integrated scenario is USD 88.6/MWh, compared to USD 103.6/MWh and USD 105.2/MWh for Units 1 and 2, respectively, in the individual configurations. Similarly, the CO_2 capture cost decreases significantly from approximately USD 65.9–66.9/tCO_2 in the separate systems to USD 51.8/tCO_2 in the integrated setup.

These findings highlight the cost-saving potential of integrated CCS systems, particularly in retrofitting scenarios where multiple units are co-located. The integration not only reduces upfront investment and ongoing operational costs but also improves economic performance metrics such as LCOE and capture cost key indicators for financial feasibility in large-scale CCS deployment. This suggests that adopting an integrated carbon capture approach can be a more efficient and scalable strategy, particularly for utility companies seeking to meet emission reduction targets under tightening climate regulations.

3.3. Carbon Tax Sensitivity Analysis

Carbon tax is an economic policy designed to reduce emissions in the power generation sector. For coal-fired power plants (CFPPs), this tax affects the LCOE, both for conventional systems and those with CCS. To evaluate the impact, a sensitivity analysis was carried out by varying carbon tax rates (USD/tCO_2) across different emission intensity levels (tCO_2/MWh). Emissions are taxed when they exceed a set limit called the emission cap. In Indonesia, the cap for CFPPs (100–400 MW) is 1.01 tCO_2/MWh (KLHK, 2019), with a carbon tax of USD 2/tCO_2. If emissions are below the cap, the difference can be sold as carbon credits, providing extra income for the plant.

The sensitivity analysis was applied to CFPP Unit #1 before and after CCS, and compared with an integrated CCS setup using flue gas from two units. Before CCS, emission intensity was 1.052 tCO_2/MWh, and after CCS, it dropped to 0.143 tCO_2/MWh. Emission caps were varied between 0.1 and 1.01 tCO_2/MWh, and tax rates ranged from USD 2/tCO_2 to USD 100/tCO_2. The analysis results are shown in Figures 4, 5, and 6.

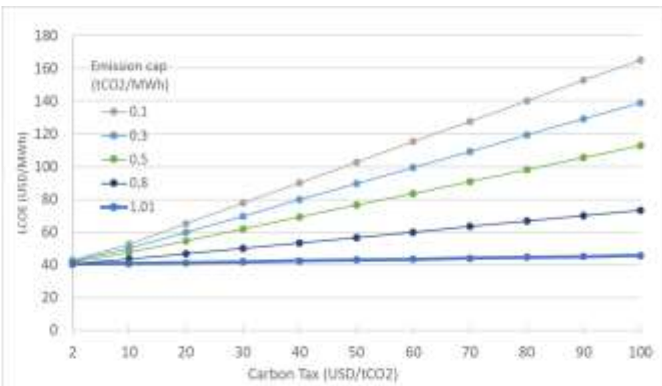


Figure 4. Carbon tax effect on LCOE CFPP Unit #1 without CCS

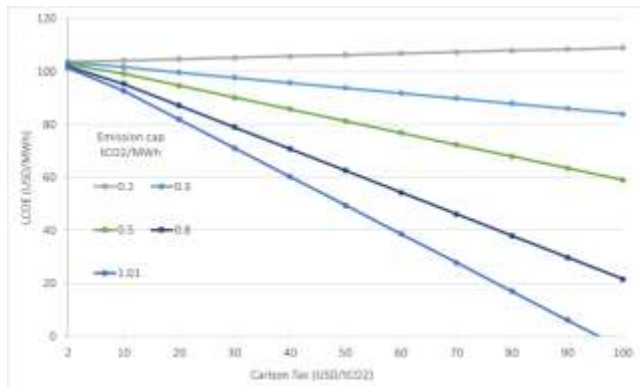


Figure 5. Carbon tax effect on LCOE CFPP Unit #1 with CCS *(individual)*

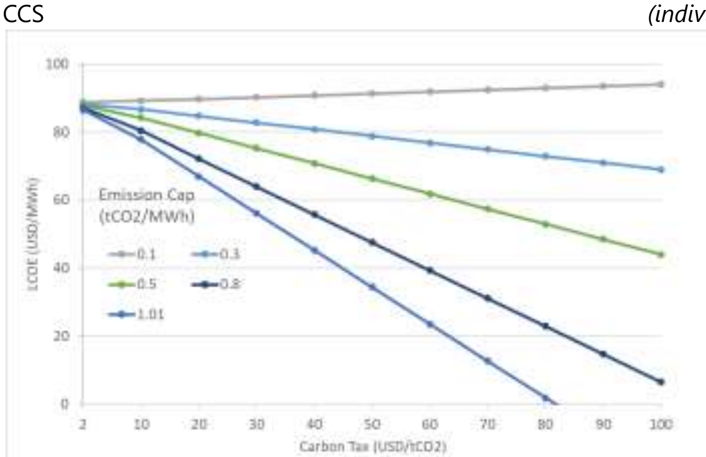
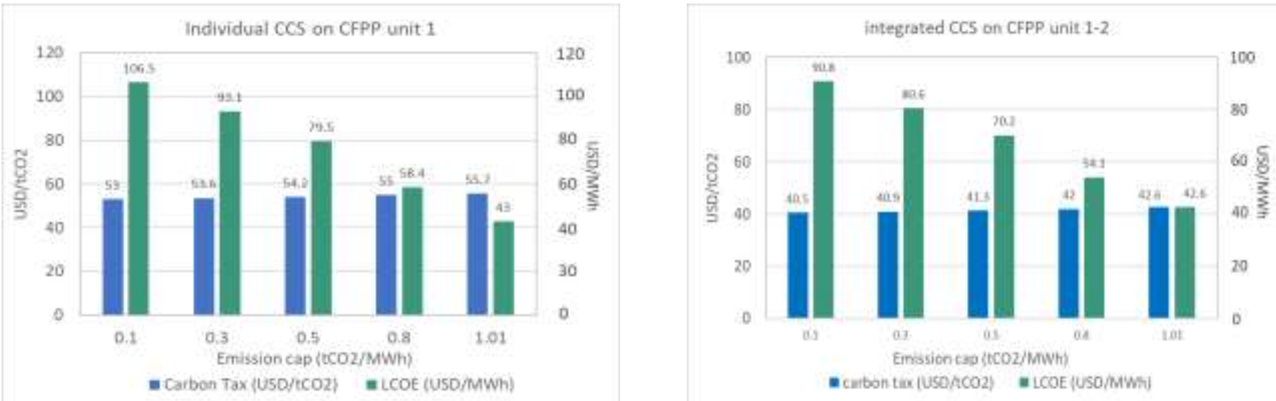


Figure 6. Carbon tax effect on LCOE CFPP Unit #1 and Unit #2 with CCS *(integration)*

Figure 4 shows the relationship between LCOE and carbon tax for CFPP Unit #1 without CCS technology. The figure indicates a linear increase in LCOE as the carbon tax rises. This is due to the high CO_2 emissions from the plant, meaning higher carbon taxes result in greater costs per megawatt-hour (MWh) of electricity. The impact becomes more critical when strict emission caps are applied. As a result, without CCS, LCOE becomes highly sensitive to carbon tax increases, especially under tight emission regulations.

Figures 5 and 6 compare the effects of individual and integrated CCS systems on the LCOE under different carbon tax and emission cap scenarios. For individual CCS (Figure 5), LCOE tends to decrease as carbon tax increases, especially under relaxed emission caps (e.g., 0.5 – 1,01 tCO_2/MWh), since CCS helps reduce emissions and provide carbon credit income. However, under stricter caps, LCOE remains elevated because of the increased expenses associated with carbon taxation. In integrated CCS system that processes flue gas from two units is more economical, as seen in Figure 6. It lowers LCOE more significantly across all emission cap scenarios than individual CCS scenario.

By identifying the intersection points between the graphs in Figures 5 and 6 with Figure 4, it is possible to estimate the minimum carbon tax required to make CCS technology economically viable. In the individual CCS configuration (Figure 7a), the carbon tax needed to equalize the LCOE power plant without CCS is approximately USD 53-55/tCO_2. Whereas, the integrated CCS configuration (Figure 7b) requires a lower carbon tax, estimated at USD 40-43/tCO_2. Overall, the integrated configuration offers more practical option for large-scale carbon reduction in coal power plants.



(a) (b)

Figure 7. Carbon tax intersection points between LCOE of CFPP without CCS and with CCS in (a) individual and (b) integrated configurations

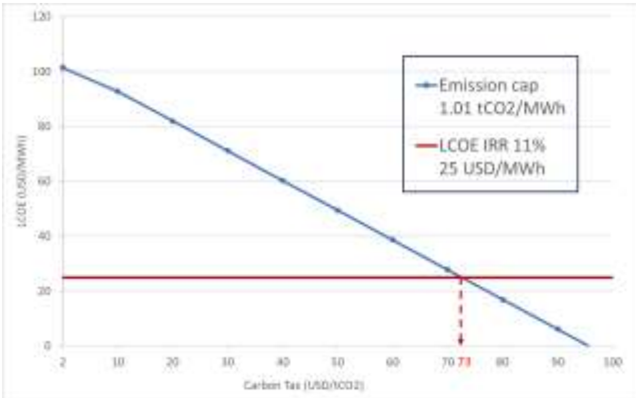
3.4. Economic Feasibility

The internal rate of return (IRR) and net present value (NPV) were determined by adjusting the baseline LCOE CCS value to align with the targeted IRR value. The targeted IRR is set at 11%, which exceeds Indonesia's deposit interest rates 2.3% in US dollars (USD) and 5% in Indonesian Rupiah (IDR) and falls within the fair IRR range of 7% to 11% commonly applied in the energy sector (ESDM, 2018; Naseeb et al., 2022). The calculation was carried out under two investment scenarios, designed to evaluate the economic viability of CCS implementation at the CFPP units: (A) the first scenario involves assessing the total cash flow of standalone CCS system with additional revenue from non-CCS unit. (B) the second scenario considers an integrated CCS system applied to two generating unit. The comparison of IRR values between the two scenarios is presented in Figure 8.

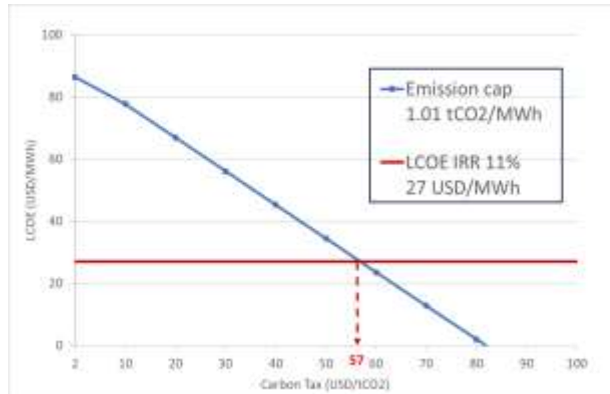
(A) (B)

Figure 8. IRR Value Corresponding to the LCOE of CCS with total revenue of (A) of standalone CCS unit and non-CCS unit, (B) integrated CCS configuration.

In Scenario B, the LCOE required to achieve an IRR of 11% is estimated at USD 27/MWh, indicating a smaller deviation from the baseline LCOE of the integrated CCS configuration for two CFPP units, which is USD 88.6/MWh. Whereas, Scenario A reaches the same IRR at an LCOE of USD 25/MWh, indicating a greater deviation from its corresponding baseline value USD 103.6/MWh. Both LCOE figures associated with an 11% IRR are subsequently evaluated in relation to the carbon tax impact under the current emission cap of 1.01 tCO_2/MWh, as illustrated in Figure 9.



(A)



(B)

Figure 9. Carbon tax contribution Corresponding to the LCOE-IRR of CCS with scenario of (A) of standalone CCS unit and non-CCS unit, (B) integrated CCS configuration

To achieve the targeted LCOE corresponding to an IRR of 11%, the required carbon tax contribution under the integrated CCS configuration for two CFPP units (Scenario B) is relatively lower, at approximately USD 57/tCO_2. In contrast, the configuration involving a single CCS unit combined with revenue from a non-CCS CFPP unit (Scenario A) requires a higher carbon tax rate of approximately USD 73/tCO_2. These results indicate that the integrated configuration provides a more economically advantageous approach for CCS implementation within the framework of a carbon pricing policy. Table 7 shows the summary of feasibility analysis output for CCS implementation in 2 x 315 MW CFPP.

Table 7. Summary of the feasibility analysis in 2 x 315 MW CFPP

Scenario	**Baseline LCOE-CCS**	**LCOE-IRR 11%**	**NPV-IRR 11%**	**Carbon tax contribution**
	(USD/MWh)	(USD/MWh)	(USD Million)	(USD/tCO_2)
(A)	103.6 – 105.2	25	175.3	73
(B)	88.6	27	96.2	57

4. Conclusions

The integration of CCS systems into coal-fired power plants proves to be economically advantageous, particularly when multiple generating units are connected to a single CCS facility. Retrofitting CCS on individual units requires capital expenditures (CAPEX) of approximately USD 180 million and USD 184 million for each unit, respectively. In contrast, an integrated CCS system serving two units incurs a total CAPEX of USD 334.4 million an 8.5% reduction compared to the combined cost of separate installations (USD 365 million). In terms of annual operational expenditures (OPEX), individual units average USD 59 million each, while integration increases total OPEX to USD 79.5 million, reflecting a 33.5% overall savings.

The Levelized Cost of Electricity (LCOE) after CCS installation is approximately USD 103.6–105.2/MWh for the individual configurations, whereas the integrated setup reduces LCOE to USD 88.6/MWh. Similarly, the CO_2 capture cost decreases from USD 66.9/tCO_2 and USD 65.9/tCO_2 for individual units to USD 51.8/tCO_2 in the integrated system a 22% reduction. These findings indicate that a shared CCS infrastructure does not only decrease LCOE and capture costs but also strengthens the economic feasibility of CCS deployment in coal-fired power plants.

As the power sector faces increasing pressure to decarbonize, such integration presents a strategic and scalable pathway toward low-carbon electricity generation. Based on carbon tax sensitivity analysis, the initial implementation of a carbon tax policy should begin with relatively high emission caps (1.01 tCO_2/MWh) and a moderate tax rate in the range of USD 40–60/tCO_2. The integrated configuration not only lowers capital expenditures and Levelized Cost of Electricity (LCOE) but also reduces the carbon tax required to achieve a target Internal Rate of Return (IRR) of 11%. Such an approach allows for a transitional period during which coal-fired power producers can begin preparing for CCS investments while avoiding excessive financial burdens. These results highlight the strategic potential of integrated CCS systems in enhancing the economic feasibility of carbon mitigation in Indonesia's power generation sector, particularly in the context of future carbon pricing mechanisms and the national commitment to achieving Net Zero Emissions by 2060.

Nomenclature

TCC – Total Capital Cost, Total Module Cost
CF – Capacity Factor
CEI – CO_2 Emission Intensity
r – interest rate (0.06)
T – Project life time (20 years)

Declaration of Competing Interest: The authors declare that none of their financial interests or personal connections could have an impact on the results or conclusions presented in this work.

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