Scientific Contributions Oil & Gas, Vol. 48. No. 3, October: 53 - 66

SCIENTIFIC CONTRIBUTIONS OIL AND GAS
Testing Center for Oil and Gas
LEMIGAS

Journal Homepage:http://www.journal.lemigas.esdm.go.id
ISSN: 2089-3361, e-ISSN: 2541-0520

A Techno-Economic Approach to Optimizing CCS Fiscal Parameters in Indonesia: A Case Study of Integrated Oil and Gas Development in CO_2-Rich Areas

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Manuscript received: June 13th, 2025; Revised: June 30th, 2025
Approved: July 08th, 2025; Available online: October 08th, 2025; Published: October 08th, 2025.

ABSTRACT - This study introduces a techno-economic approach to optimizing storage fees for CCS integrated with oil and gas development, where both operations are managed by the same entity. The analysis adopts the production sharing contract cost recovery model in accordance with the implementation of Ministerial Regulation of Energy and Mineral Resources No. 16 of 2024, which addresses CCS-related parameters. Technical evaluation confirms reservoir suitability for long-term CO_2 injection through 5 injection wells, while oil and gas development is supported by 10 oil wells and 8 gas wells. The project's economic viability under baseline conditions shows an IRR of 10.14% and POT of 15.73 years. Sensitivity analysis across fiscal parameters, such as investment credit, FTP, contractor split, CCS service fee and storage fee, CAPEX, royalty, and tax, identifies the storage fee as the most influential factor for viability. To achieve a commercially viable IRR of 15%, the project requires a minimum CCS service fee of 55 US$/MT and a storage fee of at least 35 US$/MT. The study underscores the need for clear regulations on fiscal incentives, CO_2 pricing, storage fees, and PSC integration to enhance CCS economic viability, while also offering a replicable framework for CO_2 assessments under dynamic fiscal regimes.

Keywords: net zero emission, carbon capture and storage, CO_2 injection, production sharing contract, storage fee.

How to cite this article:

Najeela Faza Ramadhani, Dedy Irawan, Sudono, Prasandi Abdul Aziz, 2025, A Techno-Economic Approach to Optimizing CCS Fiscal Parameters in Indonesia: A Case Study of Integrated Oil and Gas Development in CO_2-Rich Areas, Scientific Contributions Oil and Gas, 48 (3) pp. 53-66. DOI org/10.29017/scog.v48i3.1809.

INTRODUCTION

Climate change, primarily driven by the rapid increase in greenhouse gas emissions from fossil fuel combustion and industrial activities, reached a record global CO_2 emission of 36.8 gigatons in 2022 and continued to rise throughout the year (IEA, 2023). The responding transition toward a low-carbon economy has intensified the need for effective carbon mitigation strategies. Among the available options, carbon capture and storage has emerged as a pivotal technology capable of significantly reducing CO_2 emissions from major point sources, particularly in the oil and gas sector (IPCC, 2022). As countries commit to ambitious decarbonization targets under frameworks like the Paris Agreement, the deployment of CCS is becoming increasingly vital to achieving net zero emissions while maintaining global energy security (Global CCS Institute, 2023).

Indonesia, a regional leader in decarbonization efforts within ASEAN, holds an estimated CO_2 storage potential of up to 700 gigatons (Global CCS Institute, 2023). More recent basin scale assessment by ERIA in 2024, estimate Indonesia's technically feasible CO_2 storage capacity at approximately 572 gigatons. To achieve its net zero emission target by 2060, Indonesia integrated CCS into its list of National Strategic Projects to drive industrial demand while contributing to national emission reduction goals. This urgency is underscored by the fact that Indonesia possesses substantial natural gas reserves, many of which contain high concentrations of CO_2, making CCS not only a decarbonization tool but also a technical necessity for gas utilization and commercialization (Global CCS Institute, 2023). However, despite its vast potential, the technical and economic feasibility of CCS remains a significant challenge. The robust technology needs and costs related to CO_2 capture, transportation, and storage continue to hinder large-scale deployment (Zakkour & Cook, 2020).

In recent years, techno-economic assessment (TEA) methodology has evolved to better integrate technical performance with fiscal and regulatory contexts. Studies such as Mardiana et al. (2024) have applied TEA frameworks to offshore CCS-integrated oil and gas projects in Southeast Asia, while Prasandi et al. (2023) have demonstrated optimization approaches for CCS economics in CO_2-rich gas fields in Indonesia. These assessments highlight the importance of aligning reservoir engineering design, capital efficiency, and fiscal instruments to improve project viability. From a business model perspective, the integration of CCS into oil and gas developments can follow different structures, ranging from fully integrated "full-chain CCS" operated by a single entity to models where transport and storage are provided by specialized third-party service providers (Global CCS Institute, 2023). Furthermore, comparative assessments of international CCS tax regimes indicate substantial variation across jurisdictions, with fiscal treatments playing a decisive role in shaping project viability. In the United Kingdom, the Department for Energy Security and Net Zero (DESNZ, 2023) has introduced Dispatchable Power Agreements and Industrial Carbon Capture Contracts to guarantee revenue stability for CCS operators. In the United States, a fiscal incentive approach to carbon management, the Section 45Q Tax Credit, offers a reduction in income tax liabilities for facilities that capture, permanently store, or utilize carbon dioxide by rewarding companies financially for each ton of CO_2 mitigated (Carbon Capture Coalition, 2025). In Norway, under the Norwegian Ministry of Petroleum and Energy, Meld. St. 33 (2019–2020) for Longship project, the government covers 75% of carbon capture costs and 80% of CO2 storage investment. In addition, the general carbon tax in Norway is NOK 544 per ton of CO2 in 2020 ensuring the viability of the full CCS chain. These international practices illustrate how fiscal incentives can be tailored to different CCS business models, influencing the balance between public support and private investment.

Although Indonesia has demonstrated its commitment to decarbonization through the development of regulations related to CCS, several regulatory gaps continue to impede the full implementation of CCS technology. In the context of integrated oil and gas development projects that include CCS activities, there is currently no formal incorporation of CCS into existing production sharing contract (PSC) frameworks, whether under the cost recovery or gross split schemes, as conventional PSCs are not designed to accommodate the financial risks associated with CCS investments. The lack of financial incentives has been a primary barrier to CCS implementation in Indonesia, which is often perceived as economically unappealing (Prasandi et al., 2023). The current regulation, Ministerial Regulation of Energy and Mineral

Resources No. 16 of 2024, introduces several parameters related to CCS, including CCS service fee, storage fee, and responsibilities for monitoring and reporting. However, the current regulation lacks detailed operational guidelines and clarity on essential components such as royalty obligations, revenue sharing schemes, and the legal ownership of the stored CO_2 or long-term liability framework following storage operations. These regulatory ambiguities and absence of concrete economic and fiscal support give a significant risk for operators and investors. Without such mechanisms, the attractiveness of CCS remains limited.

The integration of PSCs as legal and fiscal infrastructure, alongside storage fees as key financial instruments, forms the foundation for the long-term viability and sustainability of Indonesian CCS projects. In response to these challenges, this study aims to evaluate and optimize the application of CCS in Indonesia by addressing both technical and economic feasibility, with a special focus on integrated oil and gas developments in remote CO_2-rich areas. Specifically, the study seeks to identify and enhance fiscal incentives that support CCS deployment, including investment credit (IC), first tranche petroleum (FTP), CCS service fee and storage fee, contractor split, capital expenditures (CAPEX), royalty, and tax. Using this approach, the study is expected to offer a replicable framework for CO_2 assessments under dynamic fiscal regimes.

METHODOLOGY

This study applies a techno-economic modeling approach to estimate and optimize the storage fee for developing CCS in a CO_2-rich structure. The methodology consists of two main stages.

Technical evaluation

The technical evaluation is focused on assessing the feasibility of CO_2 storage in a CO_2-rich oil and gas structure. This stage is essential for designing a viable CCS project that aligns with reservoir behavior and operational safety requirements.

Reservoir description and co_2 storage potential

Structure X is a carbonate platform located in the Natuna Sea, in Terumbu Formation, characterized by substantial hydrocarbon reserves and a high CO_2 content of 45%. The geological characteristics, such as porosity, permeability, and caprock integrity, support both hydrocarbon production and long-term CO_2 storage.

To manage the high CO_2 content and align with emission reduction objectives, the project integrates carbon capture and storage (CCS) through CO_2 reinjection into the same geological formation. Injection modeling is performed using simulation with residual trapping as the primary storage mechanism due to its effectiveness and long-term stability. As supported by Khanal and Shahriar (2022), this mechanism offers a promising recovery factor and ensures that the CO_2 plume remains localized within the injection zone.

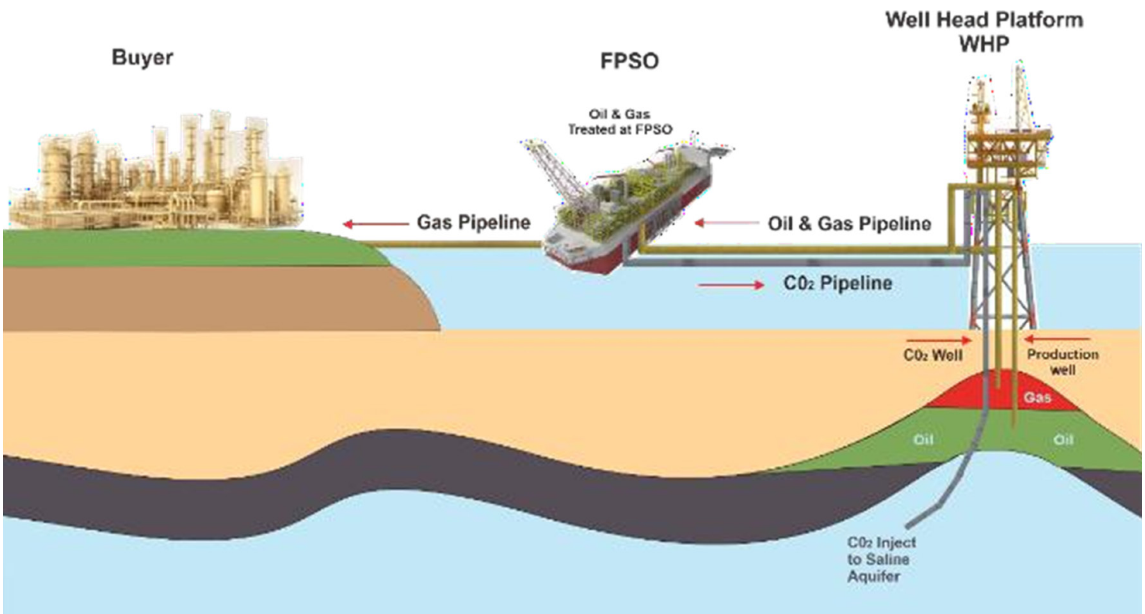

Figure 1. Facility layout.

CO_2 facility

The offshore CO_2 handling facility in this study is designed to manage gas with a high CO_2 content of approximately 45%, requiring robust separation and compression systems. The separated CO_2 from the acid gas removal unit (AGRU) undergoes further processing in desulfurization and dehydration units to meet injection specifications. It is then compressed under supercritical conditions, reaching a pressure of around 3,500 psi, using a combination of booster and injection compressors. The compressed CO_2 is transported via a 3-kilometer carbon steel pipeline to the wellhead platform for injection into the reservoir. This facility layout was evaluated for its capability to support integrated CCS operations while maintaining compliance with technical integrity and safety standards as illustrated in Figure 1. Meanwhile, the separated hydrocarbon gas is delivered to the buyer, and the oil produced is processed and stored through a floating production storage and offloading (FPSO) facility, which functions as the central hub for processing, storage, and crude oil export.

Economic evaluation

Commercialization

The commercialization of Structure X will be carried out through phased hydrocarbon development, beginning with oil production in the 10th year and followed by continued gas production in the 11th year. Considering the offshore location of the field, the development plan includes the installation of a wellhead platform (WHP) that will be tied back to a floating production storage and offloading (FPSO) unit. The FPSO will serve as the central processing hub. To comply with sales gas specifications and ensure environmental responsibility, CO_2 will be separated from the produced gas stream at the FPSO before gas delivery to the buyer via pipeline. The extracted CO_2 will then be reinjected into the deep saline aquifer of Structure X, supporting both hydrocarbon commercialization and long-term carbon storage objectives.

Economic model

The economic evaluation was conducted using the production sharing contract (PSC) cost recovery model and implements the new Ministerial Regulation of Energy and Mineral Resources No. 16 of 2024. This regulation explicitly addresses CCS-related expenditures and integrates all cost components associated with CCS deployment, including CO_2 transportation and injection facilities. The economic feasibility of the project for the contractor was assessed based on economic indicators such as net present value (NPV), internal rate of return

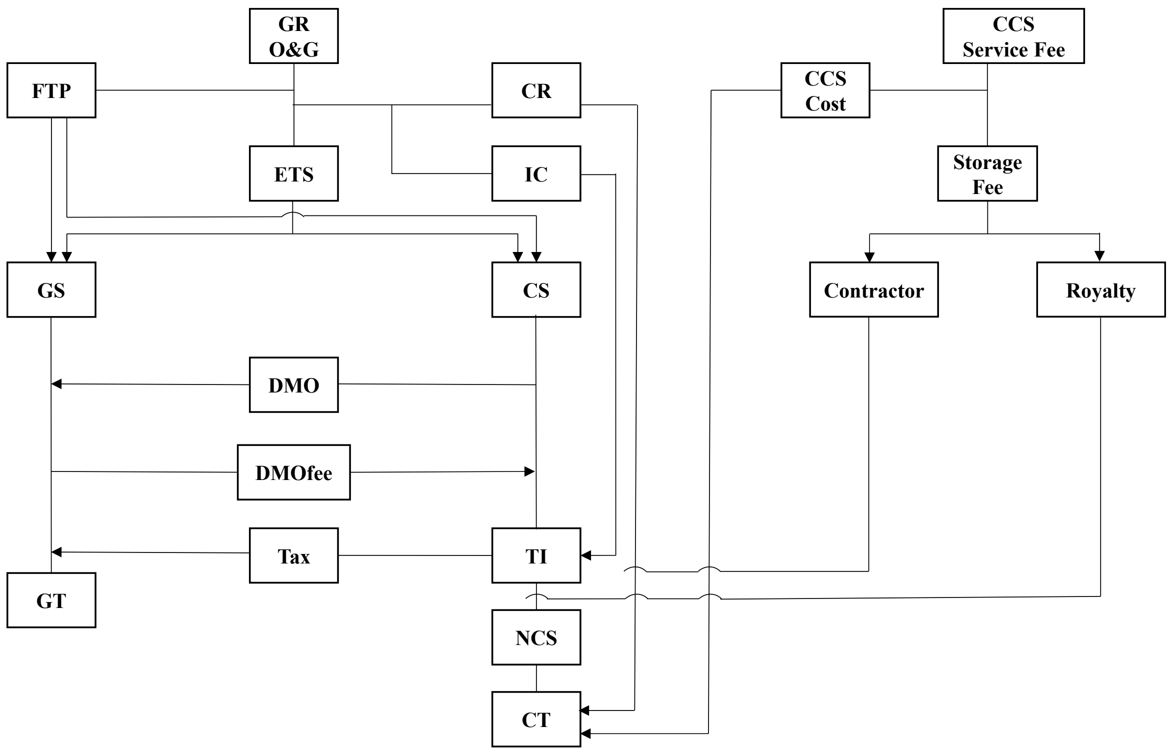

Figure 2. Economic model of CCS integrated oil and gas development.

 | DOI org/10.29017/scog.v48i3.1809

(IRR), and payout time (POT), while feasibility for the government is based on government take. Furthermore, this stage includes a comprehensive analysis of the storage fee and its correlation with fiscal parameters such as investment credit, split, CO_2 price, royalty, and tax. In this case study, the CO_2 is obtained from Structure X itself, and the storage operator is the same party as the CO_2 producer.

An illustration of the economic model can be seen in Figure 2. In accordance with Ministerial Regulation of Energy and Mineral Resources No. 16 of 2024, four CCS-related fiscal parameters are incorporated into this study: CCS service fee, CCS cost, storage fee, and royalty. The CCS service fee represents the total cost per ton of CO_2 required by the CO_2 storage operator to conduct the entire injection operation. Based on MEMR Regulation No. 16 of 2024, the storage fee is the agreed carbon storage service price between the licensed CO_2 storage operator and the CO_2 emitter, calculated after deducting the CO_2 injection operating costs or CCS cost. The CCS cost encompasses the total expenditure for executing CCS injection operations. Therefore, the storage fee serves as a negotiable component in business-to-business agreements and to maintain transparency and competitiveness, the storage fee is benchmarked against carbon prices in compliance markets or the level of national carbon taxes. On the other hand, royalty constitutes a non-tax state revenue payable to the government.

Sensitivity Analysis

A sensitivity analysis was conducted to examine how PSC fiscal parameters influence the project's economic viability, as these factors have a significant effect on project economics (Partowidagdo 2001). Various fiscal instruments have been found to enhance project attractiveness (Lubiantara 2012; Partowidagdo 2002). This analysis facilitated the identification of optimal fiscal terms to support the successful implementation of CCS. The results are illustrated through a spider chart, providing a comprehensive visualization of each variable's relative influence.

RESULT AND DISCUSSION

Technical evaluation

Reservoir description and CO_2 storage potential

The reservoir simulation results confirm that Structure X has the technical capability to support both hydrocarbon recovery and long-term CO_2 storage. Oil and gas production profiles show the production rate capability over the 30-year project life. For CCS operations, CO_2 injection requires 5 injection wells to maintain pressure balance and ensure effective CO_2 containment.

Reservoir parameters indicate that the reservoir is capable of CO_2 injection, meeting the injection criteria based on the Economic model of CCS integrated oil and gas development (IEA 2022) CCUS Handbook, with an effective permeability of more than 10 mD and an effective porosity of more than 10%. Furthermore, the reservoir is a carbonate buildup with shale as a structural barrier, and there are no indications of active faults. The injected CO_2 remains trapped via residual mechanisms, with plume migration remaining localized. Simulation results depicted the reservoir's ability to hold CO_2 as lasting for more than 100 years. The injection pressure

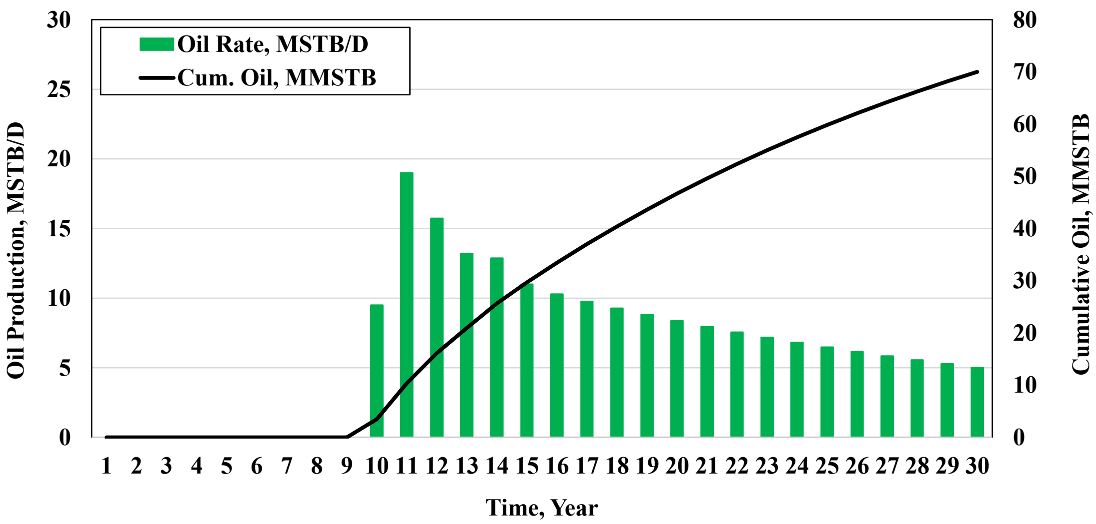

Figure 3. Oil production forecast for structure X.

used remains within safe limits of the reservoir's fracture gradient, confirming operational feasibility. Aligned with MEMR Regulation No. 16 2024 and international MMV frameworks (International Energy Agency 2022; Intergovernmental Panel on Climate Change 2022) a layered MMV and contingency plan is implemented across pre-injection, operational, and post-closure phases, incorporating seismic and well integrity surveys, pressure monitoring, and predefined thresholds with corrective actions to ensure long-term storage security.

The development plan for Structure X includes the drilling of 10 oil production wells, 8 gas production wells, and 5 injection wells. The project is designed for a 30 year lifespan, in accordance with the length of the PSC contract. Estimated oil, gas, and CO_2 production and performance are presented in Figures 3 to 5 and Table 1.

CO_2 facility

The facility configuration demonstrates the feasibility of integrating CO_2 separation and storage with ongoing hydrocarbon production. The designed system successfully manages the high CO_2 content, enabling effective gas separation, treatment, and compression for injection. The 3-kilometer carbon steel pipeline offers reliable and efficient transportation from the processing unit to the injection wellhead. In parallel, the configuration ensures uninterrupted hydrocarbon operations, with separated gas routed to buyers and crude oil processed and exported via the FPSO. The FPSO not only serves as a processing and storage center but also enhances operational flexibility in an offshore environment. Overall, the integrated design supports the dual objective of maximizing hydrocarbon recovery while facilitating CO_2 injection, all in alignment with international standards for safety, reliability, and environmental performance.

Economic evaluation

Parameters and assumptions

The parameters and assumptions used in the economic evaluation are as follows: 1). Exploration wells cost 31.36 MMUS$ per well in the 4th year and 34.99 MMUS$ per well in the 5th year; 2). Development wells cost 26.24 MMUS$ per well in the 10th year; 3). Production facility costs (excluding transportation and injection costs of CO_2) are 1,012 MMUS$; 4). Transportation and injection costs of CO_2 are 334 MMUS$; 5). Oil variable cost is 35 US$/bbl; 6). Gas variable cost is 0.5 US$/MSCF; 7). CO_2 variable cost is 0.3 US$/MSCF; 8). Oil price is 70 US$/bbl; 9). Gas price is 8.4 US$/MMBTU; 10). Gross heating value (GHV) is 1,000 MMBTU/MMSCF; 11). Base CCS service fee is 0 US$/MT.

Fiscal terms

The economic evaluation of the Structure X development, including integrated CCS, was conducted using the PSC cost recovery model in accordance with the Indonesian upstream fiscal framework as stipulated in MEMR Regulation No. 16/2024 on Carbon Capture and Storage (CCS) Implementation, along with SKK Migas PTK-070 Rev. 2 (2018) as the technical guideline for Plan of Development (POD) economic assessment. Several fiscal terms are used as base case assumptions which

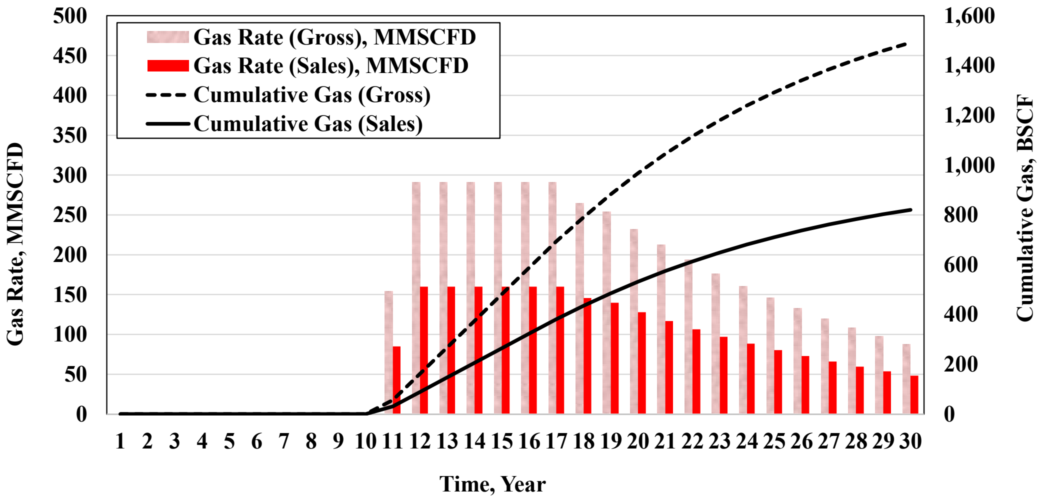

Figure 4. Gas production forecast for structure X

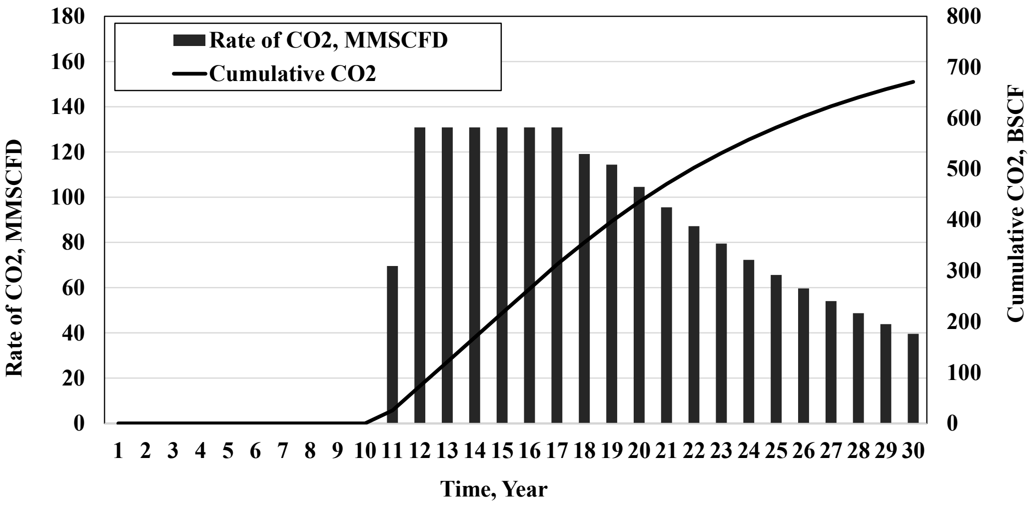

Figure 5. CO_2 production forecast for structure X

Table 1. Production result for structure X

Parameter	Value	Unit
Peak oil rate	19,000	MSTBD
Cumulative oil	70	MMSTB
Peak gas rate	290	MMSCFD
Cumulative gas	1,492	BSCF
Cumulative gas sales	820	BSCF
CO_2 content	45	%
CO_2 peak injection rate	131	MMSCFD
Cumulative CO_2	671	BSCF
Injected	34.99	Million Ton

are: 1). FTP shared is 10%; 2). Contractor split after tax is 45% for oil (72.1154% before tax) and 50% for gas (80.1282% before tax); 3). DMO for oil and gas is 25% and DMO fee is 100%; 4). Government tax is 37.60%; 5). Royalty is 10%; 6). Depreciation used double declining balance (DDB) method, 25%, 5 years; 7). Discount factor is 10%.

Economic results

Based on the production estimates, cost parameters and assumptions, and fiscal terms above, the economic evaluation with this model produces the following economic indicators: 1). Net present value (NPV) is 7.73 MMUS$ at 10% discount factor; 2). Internal rate of return (IRR) is 10.14%; 3). Payout time (POT) is 15.73 years from start of project or 5.73 years from start of production.

The economic viability of oil and gas operations integrated with CCS may be perceived as less attractive due to elevated operating costs, based on company assumption of a minimum attractive rate of return (MARR) of 15%. Notably, this evaluation excludes the CCS service fee component. The result is also compared with project's economic viability if it is developed without the integrated CCS component, which are: 1). Net present value (NPV) is 265 MMUS$ at 10% discount factor; 2). Internal rate of return (IRR) is 15.39%; 3). Payout time (POT) is 13.85 years from start of project or 3.85 years from start of production.

Without the integrated CCS component, the project's economic viability would be significantly stronger, as capital and operating expenditures related to CCS are removed.The results demonstrate that without adequate fiscal incentives to achieve MARR of 15%, the integration of CCS diminishes the project's viability. Consequently, government intervention through supportive fiscal mechanisms is essential to bridge the economic gap and make CCS deployment commercially attractive while aligning with national decarbonization goals. The CCS service fee and storage fee were calculated in accordance with Ministerial Regulation of Energy and Mineral Resources No. 16 of 2024 and the price is agreed upon between the licensed storage operator and the carbon emitter or delivering party after deducting transportation and operational costs incurred by the storage license holder. In this case, since the CO_2 emitter and the CO_2 injector are the same entity, the economic evaluation was conducted by integrating the results of the PSC cost recovery based upstream project with the economic performance of the CCS activities. This combined economic assessment enables a more holistic analysis of the project's overall viability from the contractor's perspective. The storage fee serves as a fundamental basis for business-to-business (B2B) negotiations between CO_2 storage operators and emitters. Furthermore, CO_2 price and storage fee are inherently interconnected, as the prevailing CO_2 price often serves as a key reference point in determining an acceptable and competitive storage fee. Therefore, an additional CCS service fee using the minimum CO_2 price in Indonesia of 2 US$/ton (Law Number 7 of 2021 concerning Harmonization of Tax Regulations) was added to the economic calculation. However, the addition of the CCS service fee did not provide attractive results for the project economics.

Economic sensitivity

Sensitivity analysis is essential in understanding the economic robustness of a project by identifying the key parameters that influence its overall feasibility. By examining how changes in these parameters affect economic outcomes, sensitivity analysis not only highlights the most critical risk factors but also serves as a valuable tool for guiding economic optimization strategies. Similar studies have emphasized the importance of using fiscal incentives to improve project IRR in offshore contexts by performing such an analysis (Mardiana et al., 2024). Other insights were highlighted by Iskandar and Musu (2025), who adopting an NPV

Table 2. Investment

Investment	Gas MMUS$	Oil MMUS$	CO_2 MMUS$
Capital			
- CAPEX Tangible			
Drilling (20% tangible)	115	127	87
Facility (100% tangible)	811	189	62
Non-Capital			
- CAPEX Intangible			
Exploration (100% intangible)	5	5	0
Drilling (80% intangible)	462	507	349
Studies (100% intangible	27	25	0
- OPEX (fixed, variable, ASR, etc.)			
ASR (100% intangible)	83	21	0
OPEX (100% intangible)	746	2011	200
Total	**2249**	**2855**	**698**

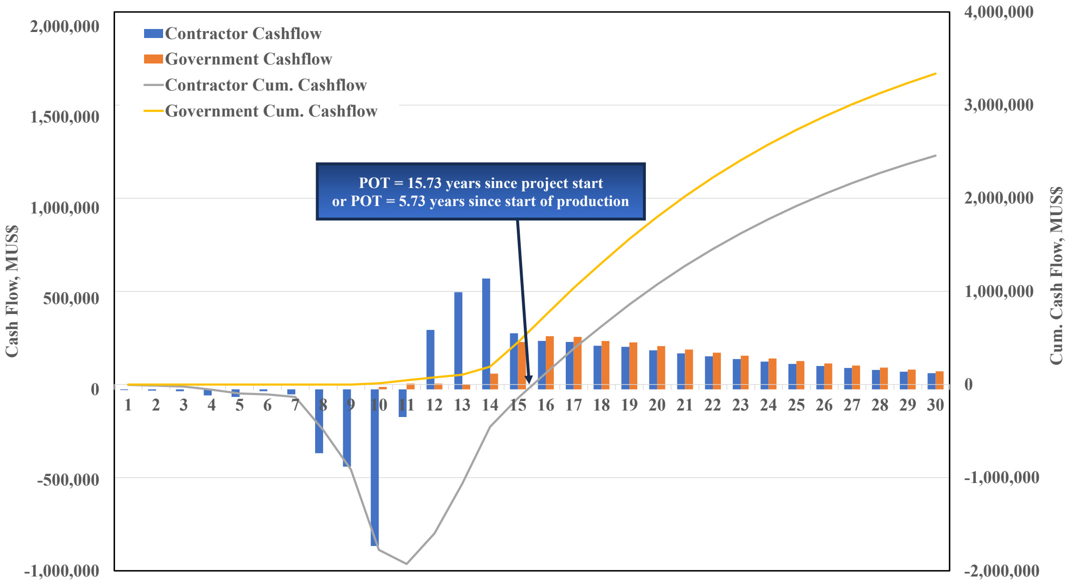

Figure 6. Economic cashflow for structure X

based optimization framework strengthens the economic assessment of CCUS projects, offering relevant insights for CCS analysis. This process enables stakeholders to prioritize efforts toward cost efficiency or contract structuring to enhance project viability under different scenarios.

Economic sensitivity analysis for integrated oil and gas production combined with CCS activities was conducted by sequentially varying key fiscal parameters, structured according to their institutional authority and implement ability: 1). Investment credit (IC); 2). First tranche petroleum; 3). Contractor split; 4). CCS service fee and storage fee; 5). Capital expenditures (CAPEX); 6). Royalty; 7). Tax.

The analysis began with investment credit (IC), which falls under the authority of SKK Migas and offers relatively straightforward application as a fiscal incentive. Next, first tranche petroleum (FTP) and the contractor split were tested, both of which are under the jurisdiction of the Ministry of Energy and Mineral Resources. These components directly influence the revenue-sharing structure and contractor take. Further analysis was performed on the CCS service fee and storage fee, which are also under ESDM authority. Capital expenditure (CAPEX) efficiency was then considered, this may be improved through incentives such as import duty exemptions or tax relief, subject to approval by the Ministry of Finance. Finally, the analysis was extended to royalty and corporate income tax, both of which are fiscally significant but fall solely under the control of the Ministry of Finance.

Investment credit (IC)

The sensitivity analysis of the investment credit (IC) incentive reveals that its impact on overall project economics is relatively limited. The application of 15% investment credit results in a slight improvement, raising the IRR by 1.07%. This is primarily because the project's cost structure is dominated by high operating expenditure (OPEX). Since the IC incentive directly affects capital expenditure (CAPEX), its influence becomes less significant in scenarios where OPEX constitutes the major share of total costs.

First tranche petroleum (FTP)

The sensitivity analysis of first tranche petroleum (FTP) shows little attractiveness, since reducing FTP yields minimal improvement in project economics. Even when the FTP is reduced to zero, the project's IRR increases by only 0.22%. This outcome suggests that FTP does not play a massive role in determining economic feasibility. As FTP represents an upfront share of production allocated to the government before cost recovery, its adjustment is closely tied to state revenue. However, it offers minimal flexibility for improving contractor economics, since this fiscal component falls under the jurisdiction of the Ministry of Finance.

Contractor split

TThe contractor split, which determines the share of production allocated to the contractor after cost recovery, plays a crucial role in shaping project profitability. Adjustments to contractor split were made without considering CCS service fee and storage fee in the economic cashflow. Several variations of contractor split for oil split and gas split were performed, but these still did not yield attractive economic results.

Table 3. FTP as a function of IRR

FTP, %	IRR, %
0%	10.36%
2.5%	10.31%
5%	10.26%
7.5%	10.20%
10%	10.14%

Table 4. Contractor split after tax as a function of IRR

Contractor Split (After Tax), %		IRR, %
Oil Split	Gas Split	
45%	50%	10.78%
50%	55%	10.96%
55%	60%	11.84%
60%	62%	12.64%
62%	62%	12.92%

CCS service fee & storage fee

The analysis of CCS service fee and storage fee reveals that they are a key determinant of the economic feasibility of CCS projects, making significant contributions to NPV, IRR, and POT. The evaluation results presented in Table 5 indicate that the project generates no storage fee (i.e., a value of zero) at a CCS service fee price of up to 20 US$/MT. Nevertheless, under this condition (a CCS service fee of 20 US$/MT), the project still achieves an internal rate of return (IRR) of 12.43%. However, to meet the standard investment threshold with a minimum IRR of 15%, the CCS service fee must reach at least 55 USD/MT, while the storage fee must reach a minimum of 35 US$/MT. This finding highlights the critical role of the CCS service fee in bridging the economic gap and ensuring financial viability for the CO_2 injection operator.

Capital Expenditure (CAPEX)

Capital expenditure (CAPEX) is one of the most influential parameters affecting the economic performance of CCS projects. Sensitivity analysis of CAPEX efficiency demonstrates a positive correlation between capital cost reductions and improvements in the contractor's IRR. Therefore, cost efficiency should be a strategic focus in both the planning and operational stages of CCS project development.

A combined sensitivity analysis was conducted by varying CAPEX efficiency levels alongside different values of oil and gas contractor splits. The results indicate that the project becomes economically viable (IRR ≥ 15%) through several strategic combinations of these parameters. Specifically, the project reaches economic feasibility under the following conditions: (i) CAPEX efficiency improves by 15% with both oil and gas contractor splits at 60%; (ii) CAPEX efficiency improves by 20% with oil and gas splits at 55%; (iii) CAPEX efficiency improves by 25% with oil split at 50% and gas split at 55%; and (iv) CAPEX efficiency improves by 30% with oil split at 45% and gas split at 50%. These findings underscore the importance of aligning technical cost-reduction strategies with adjustments in fiscal terms. The combination of CAPEX efficiency and contractor split structures can be a critical pathway for improving project economics.

Royalty

In the initial model, the royalty rate was set at 10%, referencing standard royalty rates commonly applied in the mining sector. Sensitivity analysis was then conducted by varying the royalty rate within a range of 5% to 20%. The results indicate a clear inverse relationship between royalty rates and contractor profitability, as the royalty rate increases, government revenue rises, while the contractor split / contractor take declines. This trade-off highlights the critical role of royalty settings in balancing fiscal returns for the state and economic attractiveness for investors.

Tax

Proposing tax-related incentives within the PSC framework poses a significant challenge, as taxation matters are under the authority of the Ministry of Finance. Unlike components such as investment credit or cost recovery parameters, which can be negotiated within the domain of the Ministry of Energy and Mineral Resources or SKK

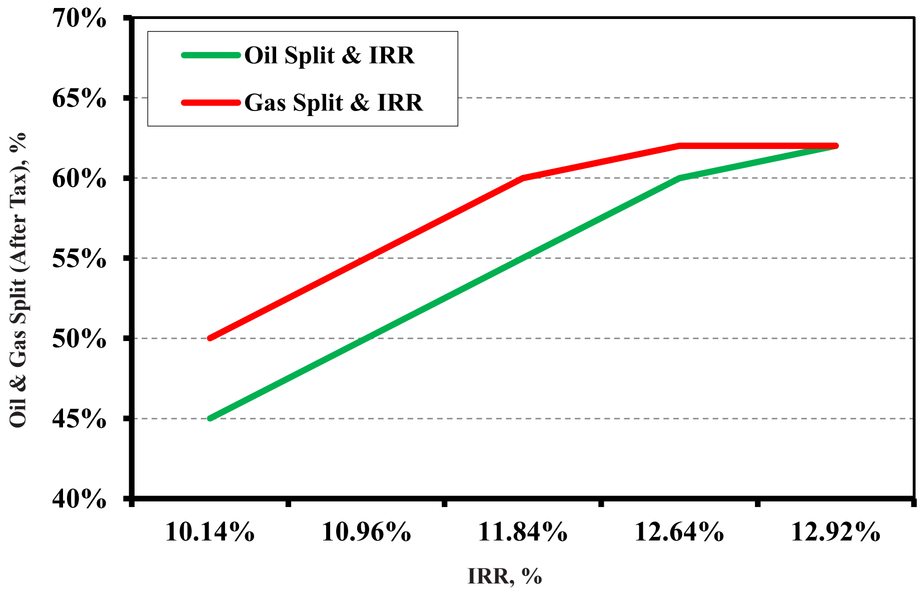

Figure 7. Contractor split after tax as a function of IRR

Table 5. CCS service fee and storage fee as a function of IRR

CCS Service Fee, US$/MT	Storage Fee, US$/MT	IRR, %
0	0	10.14%
5	0	10.74%
10	0	11.32%
15	0	11.88%
20	0	12.43%
25	5	12.89%
30	10	13.29%
35	15	13.66%
40	20	14.01%
45	25	14.35%
50	30	14.68%
55	35	15.00%

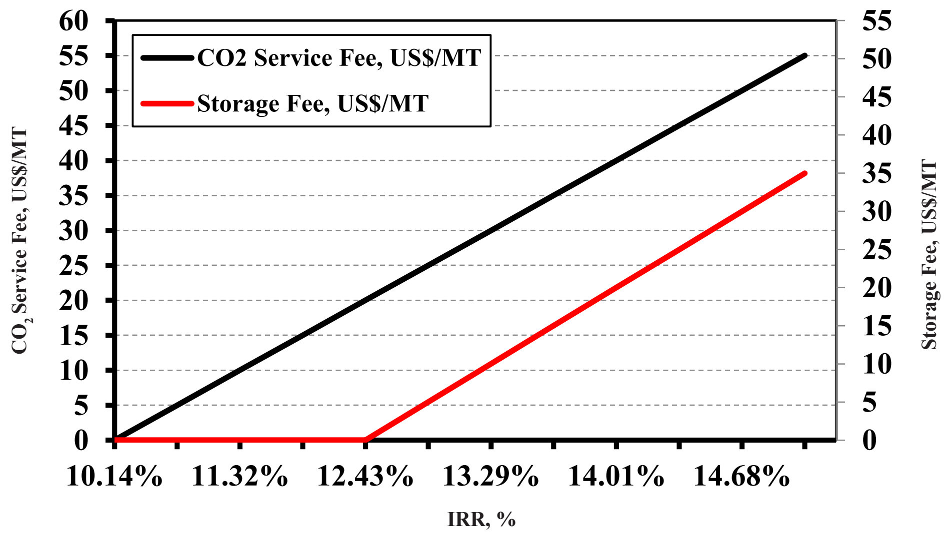

Figure 8. IRR as a function of CO_2 service fee and storage fee.

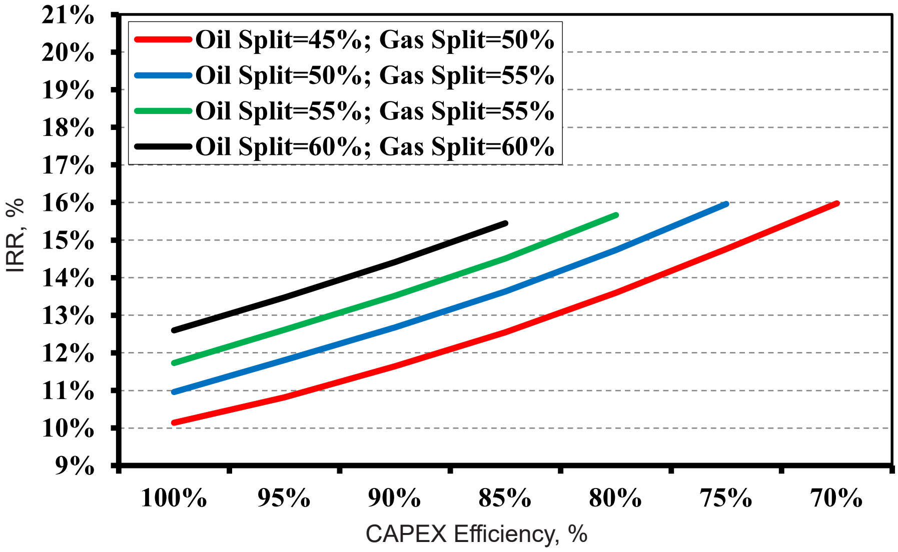

Figure 9. CAPEX efficiency as a function of IRR

Migas, tax incentives involve broader fiscal policy considerations. As a result, any attempt to adjust corporate income tax rates, tax holidays, or other tax relief mechanisms must go through a more complex bureaucratic and legislative process. This limits the flexibility of tax parameters as levers for improving project economics in the short term.

CONCLUSION

This study developed a techno-economic framework for optimizing the CO_2 storage fee in Structure X within an integrated oil and gas development context. The proposed CCS implementation strategy is designed to comply with Indonesia's legal and environmental frameworks, particularly MEMR Regulation No. 16 of 2024 concerning PSC operations. Structure X demonstrates strong technical feasibility for integrated oil and gas production with long-term CO_2 storage, supported by residual trapping mechanisms, safe injection pressures, and a robust offshore facility design.

The base economic scenario under the PSC cost recovery model generates an IRR of 10.14% and a payout time of 15.73 years, below the typical investor thresholds (e.g., MARR ≥ 15%). Sensitivity analysis identifies the CCS storage fee as the most critical factor influencing project viability, requiring a minimum storage fee of 35 US$/MT to achieve a 15% IRR. Other fiscal instruments, such as investment credit, contractor split, and royalty rates, show only limited ability to uplift project economics while the current CO_2 price in Indonesia (~2 US$/MT) is insufficient support commercial-scale CCS. To achieve economic sustainability, fiscal and policy reforms are needed, including carbon price adjustment, subsidy mechanisms, and legal clarity on CO_2 ownership and post-injection liability. With aligned fiscal incentives and contractual innovation, the project could achieve improved cost recovery, optimized revenue sharing, and higher IRR, thereby serving as a scalable model for future CCS-integrated oil and gas developments across Indonesia's upstream sector.

ACKNOWLEDGEMENT

The author would like to express gratitude to the Petroleum Engineering Department at Bandung Institute of Technology, including lecturers, staff, and colleagues. Special thanks are extended to Dr. Ir. Dedy Irawan, S.T., M.T., IPM., Dr. Prasandi Abdul Aziz, S.Si., M.T., and Ir. Sudono, S.T., M.T., IPM., the author's thesis advisors, for their invaluable guidance, continuous support, and encouragement during the completion of this research.

GLOSSARY OF TERMS

Terms	Definition	Unit
AGRU	Acid Gas Removal Unit	-
B2B	Business to Business	-
BOPD	Barrels of Oil Per Day	Barrels/day
BSCF	Billion Standard Cubic Feet	Billion SCF
CAPEX	Capital Expenditure	MMUS$
CCS	Carbon Capture, Storage	-
CO_2	Carbon Dioxide	-
CR	Cost Recovery	-
CS	Contractor Share	-
DMO	Domestic Market Obligation	%
DDB	Double Declining Balance	-
ETS	Equity to be Split	-
FPSO	Floating Production Storage and Offloading	-
FTP	First Tranche Petroleum	%
GHV	Gross Heating Value	MMBTU/ MMSCF
GR	Gross Revenue	-
GS	Government Share	-
GT	Government Take	-
IRR	Internal Rate of Return	%
ISC	Injection Sharing Contract	-
IC	Investment Credit	-
MEMR	Ministry of Energy and Mineral Resources	-
MARR	Minimum Attractive Rate of Return	%
MMBTU	Million British Thermal Units	MMBTU

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