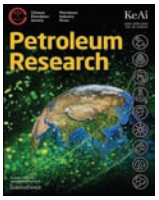
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Full Length Article

Economic and environmental impact assessment of carbon storage in Malaysia

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ABSTRACT

The global carbon emissions resulting from the combustion of fossil fuels have had a negative impact on the environment. This research presents an in-depth analysis of the economic and environmental impacts associated with carbon storage initiatives in Malaysia. It also explores the distributional effects of carbon pricing and the perception of its regressive nature as a significant challenge. Urgent and thorough measures are necessary to reduce carbon emissions from oil and gas, thereby mitigating the catastrophic consequences of climate change and facilitating a transition towards a more sustainable and environmentally responsible energy system. A comprehensive assessment of the potential impacts of Malaysia's carbon pricing policy on the Organization's economy and environment. Four cases were analyzed: (1) New Field Development, (2) New Field Development with Carbon Tax, (3) New Field Development with CCS and Carbon Tax, and (4) New Field Development with CCS, Carbon Tax, and Subsidy. The results show Internal Rates of Return (IRR) of approximately 16.5%, 14.5%, 12.8%, and 15.0–15.5% respectively. These findings highlight that a combined policy mix (carbon tax + CCS + subsidies) substantially improves economic viability, aligning with global best practices and offering a strong policy pathway for Malaysia.

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1. Introduction

Over the past 150 years, hydrocarbons have been the driving force behind economic expansion; however, their emissions significantly contribute to the phenomenon of climate change. The fossil fuel industry is subject to criticism due to its adverse environmental effects. Immediate measures are required to transition towards achieving a state where there are no net greenhouse gas emissions to tackle climate-related threats effectively. Operators are adjusting their strategies by making strategic investments in innovation. Notwithstanding the existence of advanced technology, air pollution resulting from petroleum production continues to endure. This study examines the obstacles hindering progress and proposes a bold transition in the oil and gas sector towards a low-carbon future, to restrict global temperature increases to 1.5 °C (Degryse et al., 2023; Gargett et al., 2019; Zhao et al., 2023).

Organizations worldwide are incorporating climate science into their plans, with a specific emphasis on technological progress, laws and incentives, research and development, and financing. The Paris Agreement establishes emission targets aimed at restricting the increase in global temperatures. Countries, such as Malaysia, commit to achieving net-zero carbon emissions. The Intergovernmental Panel on Climate Change (IPCC) states that to prevent the most severe consequences of climate change, such as the increased occurrence of extreme weather events like hurricanes, heatwaves, floods, and droughts, it is crucial to limit average global warming to 1.5 °C above pre-industrial levels (Fan et al., 2021; Gao et al., 2017; IPCC, 2018). According to the International Energy Agency's Net Zero Emissions (NZE) by 2050 scenario, even in the most ambitious situation, where energy demand levels off after 2030, oil and gas will still be included in the global energy mix, but in very small quantities (Wang et al., 2023). The next step for both governments and businesses is contingent upon the composition of energy sources, policy frameworks, the surrounding environment, and available resources. Future sustainability relies heavily on decarbonization efforts and investments in alternative energy sources. The oil and gas business is obligated to make significant additional investments to support global climate

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targets. Companies are enhancing their skills to adopt low-carbon strategies, implementing technology such as carbon capture utilization and storage (CCUS), methane detection, green hydrogen, biofuels, and renewable energy sources (Greig and Uden, 2021). Attaining net zero by 2050 requires implementing cost-effective and robust strategies, with a focus on digitalization, streamlining processes, and reducing costs. PETRONAS is committed to achieving carbon neutrality by 2050, according to the Paris Agreement and the International Energy Agency's scenarios for NZE and announced pledges scenario (APS). This commitment will guide PETRONAS in making strategic decisions.

The oil and gas industry makes a substantial contribution to climate change by releasing carbon dioxide (CO_2) into the atmosphere. This study investigates the implementation of carbon capture and storage (CCS) technology in the oil and gas business in Asia, with a specific focus on Malaysia. The study considers the urgent need to decrease the levels of CO_2 in the atmosphere, as highlighted by the IPCC in 2020. Petroleum, primarily consisting of carbon (85%) and hydrogen (13%), releases CO_2 upon combustion (Turgeon and Morse, 2025). CCS technology sequesters and stores CO_2 underground, thereby reducing the impact of climate change (Skiba, 2020). Offshore CCS, which originally started as a continuation of onshore initiatives, has experienced significant growth in the last 10 years. The oil and gas industry, which accounts for 15% of energy-related global greenhouse gas (GHG) emissions, is in a favorable position to take the lead in the development of CCS technology (F1F9, 2020; IEA, 2023). CCS deployment entails the process of capturing CO_2 at emission sources, such as power plants (Gonzales et al., 2020; Kim et al., 2023). Thorough surveillance guarantees the preservation of storage quality in the geosphere, biosphere, and atmosphere. Nations that have pledged to reduce carbon emissions as part of the 2015 Paris Agreement must tackle significant amounts of greenhouse gas emissions, particularly methane (Ignatius, 2022; Lee et al., 2023). Efforts to decrease emissions in the oil and gas industry encompass measures such as limiting flaring, enhancing energy efficiency, implementing CCS technologies, and adopting alternate ways of power generation (Voldsund et al., 2023).

The IPCC Guidelines require the measurement and disclosure of emissions from the extraction and production of oil and gas, including both onshore and offshore activities. Activities must document the presence of gases, including CO_2, methane (CH_4), N_2O, HFCs, SF_6, Nitrogen Oxides (NO_x), Carbon mono-oxide (CO), non-methane volatile organic compounds (VOCs), and SO_2 (Watson, 2020). The average age of oil and gas fields generally ranges from 15 to 30 years; however, larger reserves can sustain production for 50 years or beyond (OilNOW, 2017; Planete Energies, 2015). The expenses associated with offshore plants, which include discovery, development, operation, and abandonment, are subject to variation depending on factors such as the plant's size, complexity, location, design, regulations, and market circumstances. The costs associated with development can vary from hundreds of millions to several billion US dollars, particularly for intricate and deep-water platforms, which tend to result in larger expenditures. The installation of an offshore oil rig typically requires a duration of 2–3 years and incurs an average expenditure of around $650 million (English, 2020).

Exploration and delineation drilling in Canadian offshore Newfoundland averaged $26,494 per meter and $90.9 million per well from 1998 to 2019. In the same timeframe, mobile offshore drilling equipment costs $91.1 million for a development well with a producing well and $68.8 million for an injector well. Regional production costs averaged $23.4 per barrel from 2006 to 2019. The prices at Hibernia were $16.8 and Terra Nova and White Rose were above $35 (Kaiser, 2021).

In 2023, the Organization for Economic Co-operation and Development (OECD) reported that huge, manned platforms and subsea tiebacks had an average unit operating cost (UOC) of over £8 in 2018 (ICAP, 2023). In 2020, the International Association of Oil & Gas Producers (IOGP) predicted that over 200 Southeast Asian offshore fields would stop producing oil by 2030. These programs are projected to cost $30–100 billion to decommission (IOGP, 2020).

Significant obstacles and additional factors make the widespread deployment of CCS difficult. CCS costs can be estimated using several measures, depending on the technology and analysis that depend on the process plant, capture method, and storage solution. CCS is particularly important in power generation, refineries, iron & steel, and cement production. Capture methods include post-combustion separation, oxy-combustion, and chemical looping combustion, which cost $20–100 per ton of CO_2. The most expensive approach is post-combustion with amine separation, while EOR/EGS storage is cheaper. Each metric ton of CO_2 transported 250 km cost $1.3 to $15.1 in 2015. Each metric ton of CO_2 costs $1.6 to $31.4 in 2015 USD to store. For a 250-km pipeline, Budinis estimates that CCS costs 22.9 to 156.5 $ per metric ton of CO_2 to capture, transport, and store. The running and abandonment costs of CCS facilities are similar to industrial units (Budinis et al., 2018).

Carbon taxes are specifically aimed at firms that release carbon dioxide during their operations, to reduce environmental pollution and the generation of greenhouse gases. The initiative enforces financial penalties, specifically targeting higher polluters. Several nations, including Singapore, have adopted carbon pricing to achieve their NZE 2050 targets. The present carbon tax rate in Singapore stands at $5 per tCO_2e, and there are plans to gradually increase it to $25, $45, and $50-$80 per tCO_2e by 2030 (SLA, 2022). Malaysia, a significant contributor of CO_2 emissions in the ASEAN region, has pledged to achieve a 45% decrease in carbon intensity by the year 2030. The 12th Malaysian Plan includes a carbon price, however specific proposals about its form, tax base, rate, administration, and revenue allocation have not been put forward yet (CNA, 2021).

Gas flaring and venting, which have been used in oil exploration for more than a century, have been utilized to meet operational, financial, and safety requirements. In recent times, increased consciousness about the environment has raised worries regarding the long-term viability of these practices. Flaring and venting on oil and gas facilities are regulated procedures that are crucial for ensuring safety and managing emergencies, as well as for cases where it is not feasible to use, export, or reinject gas (Abdulrahman et al., 2015). Flaring releases methane, black carbon, and nitrous oxide. Flaring has a lower negative impact on the environment compared to venting. Since 2012, there has been a noticeable increase in oil production in Malaysia, which peaked in 2016 before sharply declining to a historically low level in 2021. Due to a greater decrease in oil output compared to gas flaring in 2021, the intensity of oil production did not accurately represent the decline. A total of 56 locations were identified in the 2019 flare count (GGFR, 2022). In 2016, Malaysia agreed to the terms of the Paris Agreement and the Kyoto Protocol and presented its initial Nationally Determined Contribution (NDC). This contribution was later revised in 2021. The revised NDC pledges a 45% decrease in carbon intensity relative to the levels recorded in 2005. Although the NDC acknowledges the importance of the oil and gas sector to its economy, it fails to address the issue of flaring and venting. Malaysia has historically tackled energy concerns by implementing strategic plans since 1975. Petronas, the state-owned oil company, publicly pledges to reach a state where the amount of carbon emissions it produces is balanced by the amount it removes

from the atmosphere by the year 2050. This commitment primarily involves efforts to decrease the release of gas through flaring and venting, absorbing methane emissions, and improving production methods (GGFR, 2022). Flaring transforms methane-containing gas to CO_2, while venting releases methane and other pollutants into the environment (Soltanieh et al., 2016).

Gas flaring has both environmental and economic impacts, as it not only causes harm to the environment but also results in substantial financial losses for governments by giving up potential income. The environmental ramifications encompass global warming, climate change, regional air pollution, and health concerns, with more than 250 known pollutants released during flaring (Awulu, 2022). Nigerian oil companies incur an approximate annual loss of $2.5 billion as a result of the combustion of 2.5 billion cubic feet of gas daily (Collins and Oshodi, 2010). In 2021, Malaysia's per capita CO_2 emissions from fossil fuels and industry amounted to 7.63 tons (Ritchie and Roser, 2024).

The 12th Malaysian Plan (2021–25) includes the implementation of carbon pricing, highlighting the Malaysian Prime Minister's dedication to addressing climate change (RMK12, 2021). The carbon component of fossil fuels will be subject to a set fee, forcing energy and fuel suppliers to raise costs. The administration hasn't yet made the foundation for the carbon tax announcement. The tax base, tax rate, tax administration, and utilization of revenue are all poorly understood. The new tax policy also calls into question the best way to impose a carbon tax during the Covid-19 economic crisis, to both cut greenhouse gas emissions and help the economy recover. The research's main goal is to thoroughly analyze the viability and impact of carbon storage solutions to analyze the cost of carbon storage systems for different scenarios such as development with and without CCS, to evaluate the cost-benefit of carbon storage systems using carbon tax for both scenarios and to estimate the environmental impact of the carbon storage system.

Carbon capture, utilization, and storage (CCUS) is increasingly acknowledged as an essential strategy for attaining net-zero emissions, particularly in challenging sectors such as oil and gas. This study focuses on CCUS due to its capacity to facilitate substantial reductions in CO_2 emissions, especially in scenarios where electrification is impractical. Research from the IPCC and other international entities indicates that the prompt implementation of CCUS technologies can substantially modify national decarbonization trajectories. Furthermore, the current oil and gas infrastructure in Malaysia offers a cost-efficient potential for the early implementation of CCUS. Recent studies (e.g., Fan et al., 2021; Zhao et al., 2023) underscore the significance of CCS incentives and their incorporation into national energy strategies for the attainment of climate objectives.

2. Methodology

The research examines the correlation between the capacity of carbon capture storage and its associated cost, employing a quantitative methodology. Projects were subjected to cost-benefit analysis, with a focus on recent improvements and Malaysia's aspiration to become a hub for CCS. An extensive data model, accompanied by explicit assumptions described in later chapters, assessed the cost-effectiveness of carbon capture storage. The model specifically mentions offshore developments located in the South China Sea, in Malaysia.

2.1. Process of economic evaluation

Projections for project cost-benefit analysis are based on economic assumptions, which include variables such as oil prices, production levels, and carbon tax. These characteristics are essential for predicting future income and profitability, and they play a critical role in making decisions before investing. The hurdle rate, which signifies the minimal rate of return that must be met, considers factors such as inflation, risk, and opportunity cost. It functions as a standard for evaluating the profitability of future investments, assisting in the identification of worthwhile projects.

2.1.1. Forecasting key technical and economic parameters

The first step in doing an economic review is acquiring technical data, which includes the following: annual forecast of the oil and gas production, annual forecast of the oil and gas prices, capital expenditure, operating and Maintenance expenditure, and contracting period.

2.1.2. Fiscal system modelling

Oil and gas organizations are required to pay a portion of their profits to various government agencies following a variety of tax laws and/or contractual obligations that are specific to each country. These are referred to as a country's fiscal system when taken all at once. An economic evaluation's ultimate objective is to determine the cash flow since from this a variety of economic indicators that can help with decision-making can be generated. The payment of royalties for oil and gas operations in Malaysia can vary based on several circumstances, including the terms of the production-sharing contracts or agreements between the government and the oil and gas corporations involved.

2.1.3. Economic indicator calculation

The final step in the economic evaluation process is to combine the two steps of future cash flow estimates into several economic indicators that will allow you to decide whether to proceed with the project. The time value of money is a crucial idea on which many economic indicators are built. This indicator is further evaluated using a spider plot and tornado chart to assess the risk of investment from each parameter.

2.2. Quantitative analysis of financial costs and benefits

Oil and gas economic analysis assesses the financial feasibility of energy projects, taking into account expenses, income, and uncertainties. Important performance indicators consist of Net Present Value (NPV), Internal Rate of Return (IRR), and assumptions on Carbon Tax. The gas price, which is of utmost importance for evaluation, is projected to be RM8/MMBtu, with a worldwide standard fluctuating between RM4.5/MMBtu and RM22.5/MMBtu according to a study conducted in September 2021. Cost-benefit analysis applies technical and economic assumptions in a way that is specific to each instance (Smith, 2021). The main determining factor in which case is most preferable is the NPV analysis. NPV is a financial metric used to evaluate the profitability of an investment. A positive NPV indicates that the investment is expected to be profitable, while a negative NPV indicates that the investment is expected to result in a loss. In analysing a longer-term project with multiple cash flows, the formula for the NPV of the project is as follows:

$$NPV = \sum_{t=0}^{n} \frac{R_t}{(1+i)^t} \quad (1)$$

Where, R_t = net cash inflow – outflows during a single period t; i = discount rate of return that could be earned in alternative investment; t = number of time periods. Assumptions are the underlying factors that are used to make predictions of cash inflows and outflows of an investment. These assumptions can include

things like expected revenue, costs, and discount rates. They are used to estimate the future cash flows that will be used to calculate the NPV of an investment. Standardized reporting and industry analysts in the oil and gas industry commonly apply a 10% discount rate on projects' projected cash flow. The discount rate used for this economic analysis is 10% and as a comparison, it is also evaluated at 8% based on the analyzed Weighted Average Cost of Capital (WACC) for seven groups of publicly traded oil and gas companies. The range of discount rates used by the oil and gas industry is illustrated in Fig. 1 (Smith, 2021). Assumptions are an important part of the NPV calculation because they can significantly impact the accuracy of the final result. In this analysis, the discount rate, i for the 30 years of production profile, the industry average was 8–10% based on survey, and industry practices.

The next method used to evaluate the economic viability of each case is Break-even analysis. This analysis determines at what point a company, or a new product or service, will be profitable. It's a financial calculation used to determine the volume of sales to at least cover your production costs.

$$BEP = \frac{FC}{TSR - OC} \tag{2}$$

In the above equation, BEP is the breakeven point, FC is fixed costs, TSR is total sales revenue and OP is operating cost. The IRR is a crucial measure in the economic analysis of oil and gas projects. It is the discount rate at which the NPV of a project reaches zero, indicating the point at which the project breaks even. A greater IRR signifies a more appealing investment that exceeds the minimum required rate of return. In addition, the research takes into account carbon taxes when evaluating the cost-effectiveness of establishing CCS facilities. The inclusion of a carbon tax assumption is conditional upon the precise rate and framework established by regulatory bodies. The prospective adoption of a carbon tax in Malaysia would depend on various factors, including environmental goals, economic circumstances, and the design of the tax structure. The carbon tax used in this economic model is derived from a comprehensive analysis of existing literature, which encompasses global rates as well as rates seen in nearby regions. The carbon tax for oil and gas operating offshore was United States dollar (USD) 25 only based on the nearest country Singapore. In this modelling, 5% inflation is assumed. In evaluating the cost benefits, a tornado chart is used to compare the relationship between the change in key project variables and the measure of value. It also measures the project's robustness as a result of changes in key variables (e.g. Production, Capital Cost, Operating Cost for each case).

2.3. Data model and assumptions of offshore fields

In reference to several offshore development concepts and costing, data models were developed to make comparisons and relationships between field development cost and carbon capture storage cost benefit. The gas production profile with a decline rate is based on the concept that gas production from a reservoir typically follows a decline curve over time. This decline curve represents the gradual reduction in gas production rates as the reservoir pressure decreases and the gas becomes more challenging to extract. Here's the basis of a gas production profile with a decline rate. For initial production, production ramped up on the 1st and in the 2nd year, achieved the targeted rate. When a gas well is first drilled and brought into production, it often experiences a period of high initial production rates. This is due to the release of reservoir pressure, which facilitates the flow of gas to the surface. In terms of the decline phase, as time progresses, the reservoir pressure gradually decreases. This reduction in pressure leads to a decline in gas production rates. Moreover, in the case of a decline rate, the decline rate represents the rate at which gas production decreases over time. It is usually expressed as a percentage of the initial production rate per unit of time (e.g., per month or year). The decline rate can vary depending on reservoir characteristics, well design, and production strategies.

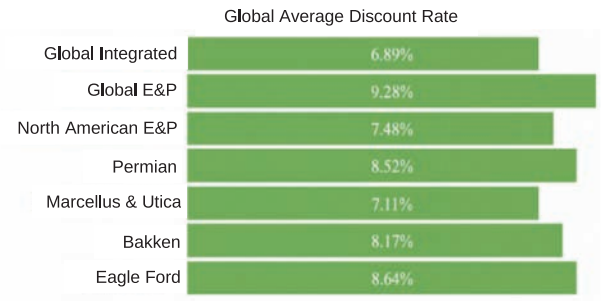


Fig. 1. Discount rate used by for oil and gas industry.

This study focuses specifically on the deployment of CCS in existing offshore oil and gas fields in Malaysia. These depleted fields offer pre-existing infrastructure, known reservoir characteristics, and reduced uncertainty, making them more economically attractive for early-stage CCS projects. In contrast, Saline aquifers have huge potential for CO_2 storage in Malaysia, but because they need detailed geological studies, new wells, high upfront cost, and more data, they are considered too risky and expensive for early CCS projects. Instead, Malaysia is starting with depleted oil & gas reservoirs, where data and infrastructure already exist. Therefore, saline aquifers were not included in economic modeling. Future research should examine the techno-economic feasibility of CO_2 storage in saline formations as data and investment interest increase.

A gas production profile with a decline rate is one of the most fundamental tools in the oil and gas industry for forecasting how reservoir production will decrease over time. As gas is produced, the reservoir pressure gradually declines, which directly reduces the rate at which gas can flow to the surface. This predictable decline in production is crucial for reservoir management, project planning, and economic analysis because it allows operators to estimate future cash flows, schedule facility upgrades, and determine the optimal timing for additional drilling or abandonment. To quantify this, engineers often rely on estimates of ultimate recovery (EUR), which can be derived through volumetric methods in early-stage fields, or through performance-based approaches such as decline curve analysis (DCA) in mature fields where sufficient historical data is available. Decline curve analysis (DCA) is one of the most widely used methods for forecasting production and estimating reserves because it is relatively straightforward and data driven. The process begins with collecting reliable historical production data, typically daily, monthly, or annual gas production rates. This data is then plotted on specialized graphs, most commonly production rate versus time or production rate versus cumulative production and mathematical models such as exponential, hyperbolic, or harmonic declines are fitted to match reservoir behaviour. The selected curve is then extrapolated to forecast future production, estimate remaining reserves, and determine the economic life of the field. DCA provides essential insights for both technical decisions and financial planning, making it a key tool in reservoir management and economic evaluation. Three data model assumptions were developed for this study and summarized in Table 1.

These four cases were selected to represent a realistic policy spectrum for Malaysia: a base case (no tax, no CCS), a tax-only

scenario, a tax + CCS scenario, and a combined policy mix including subsidies. Additional scenarios, such as subsidies without carbon tax, were excluded because they do not reflect Malaysia's stated policy direction under the 12th Malaysian Plan, which prioritizes carbon pricing as the primary driver of emissions reduction.

2.4. Data collection

Gather historical production data for the gas field such as production rates, cumulative production, and duration. This data should ideally cover a significant period to capture different production phases. To plot historical data, create a graph with time on the x-axis (usually in months or years) and production rate (usually in MMscf/d or Bcf/d) on the y-axis. Plot the historical production data points on the graph, and for a select decline curve model, there are several decline curve models available, but the most used for gas fields are the exponential decline model, the hyperbolic decline model, and

Extrapolated future production, which is the most used one. It's important to note that decline curve analysis is a simplified method and provides estimates based on historical data and mathematical models. Fig. 2 illustrates the production profile for this study forecasted for 30 years plotted with a decline rate range of 3–5% assumption.

2.5. Sensitivity analysis

A sensitivity analysis was designed to test the robustness of the results for Cases 2–4. The analysis varied key parameters, including gas price, production volume, CAPEX, OPEX, carbon price, and emissions, by ±10%. Spider plots and tornado charts were employed to visualize the influence of these parameters on project outcomes. This approach provides a structured means of evaluating how changes in technical and economic assumptions impact project viability.

Table 1
Data model assumptions.

Case	Assumption
Case 1 New Field Development	The development concept consists of the new field development with Wellhead platform (WHP) and Central processing platform (CPP). Drilling of 6 new producing wells. Gas price assumption RM 8/MMBtu. No condensate or biproduct considered.
Case 2 New Field Development with Carbon Tax	The development concept consists of the new field development with WHP and CPP. Drilling of 6 new producing wells. Gas price assumption RM 8/MMBtu. No condensate or biproduct considered. Carbon Tax estimated USD 25 with 5% escalation and exchange rate of RM 4.5/USD (Average on Bank Negara Malaysia Rate)
Case 3 New Field Development with CCS and Carbon Tax	The development concept consists of the new field development with WHP and CPP with CCS platform. Drilling of 6 new wells and 3 injection wells for CCS. Gas price assumption RM 8/MMBtu. No condensate or biproduct considered. Carbon Tax estimated USD 25 with 5% escalation and exchange rate of RM 4.5/USD (Average on Bank Negara Malaysia Rate)
Case 4 New Field Development with CCS, Carbon Tax, and Subsidy	The carbon tax assumption (USD 25/tCO_2 with 5% annual escalation), Case 4 incorporates: **A 30% Capital Expenditure (CAPEX) subsidy**, representing direct government support to reduce upfront investment costs. **A CO_2 storage credit of RM 100/tCO_2**, similar to the U.S. 45Q tax credit mechanism, providing additional revenue per tonne of stored CO_2. The purpose of Case 4 is to assess how a combined policy mix (carbon tax + CCS + subsidies) alters project economics, reflecting potential Malaysian adoption of global best practices.

2.6. Environmental impact of GHG emissions

Assessing the environmental impact due to emissions from flaring and venting in oil and gas production is a crucial step in managing and mitigating the industry's contribution to air pollution and climate change. Below is a comprehensive methodology for conducting such an assessment. Firstly, define specific oil and gas production facilities or operations to be assessed. The next step is to gather comprehensive data on flaring and venting activities from the selected facilities. This includes production data and emission data. Then, define the types of emission flaring, venting, combustion, and fugitive. After that, calculate emissions based on industry standards, local regulations, and specific facility data, and finally, discuss the impact based on emissions on the environment, health, and economy.

2.7. Emission data model for field Z

GHG emissions are classified being Scope 1, Scope 2, or Scope 3 emissions by the GHG Protocol in 2021 as shown in Fig. 3 (Read and Shine, 2022). For Scope 1, emissions a company produces directly through its activities. These are often subdivided into four categories: stationary combustion, mobile combustion, fugitive emissions, and process emissions. In Scope 2, emissions are produced in the generation of imported energy, usually electricity that the company has purchased through a utility's provider e.g., to run pumps or charge electric vehicles. The important differentiator between Scope 1 (direct) and Scope 2 (indirect) is who is controlling the process. For example, if a company produces its electricity on-site, this would be Scope 1. In the case of Scope 3, these are emissions that occur along the reporting company value chain. They cover emissions starting with the procurement of the raw materials, through manufacturing, distribution, and finally the customer use of the product. The terms Scope 1, 2, and 3 emissions were created by the GHG Protocol in 2001, and their meaning is demonstrated in the following graph.

2.8. GHG calculation methodology

Emissions based on their Global Warming Potentials (GWPs), the mass of emissions of each GHG is multiplied by its corresponding GWP. The result is referred to as the CO_2-equivalent (CO_2e) emissions. In line with the principles outlined in the GHG Protocol and GHG accounting and reporting, a review of open-source emission factors has been made, and the most representative emission factors have been used in this assessment (GGP, 2024). The general equation for calculating the air emissions is as follows.

$$Emission\ Inventory = \sum_{i=1}^{\#sources} EF_i \, x \, AF_i \quad (3)$$

Where, Emission inventory is equal to total emission, EF_i means emission factor for source i and AF_i means activity factor for source i. The basic equation for calculating GHG emission estimates, expressed in the of CO_2e is as per below.

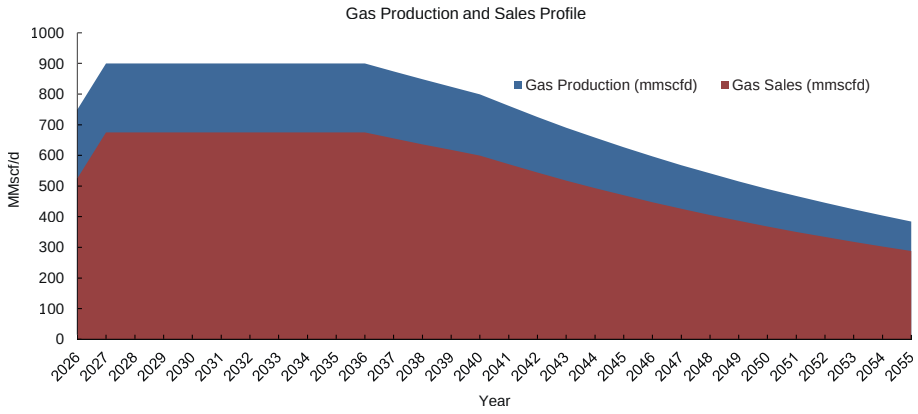


Fig. 2. Production profile.

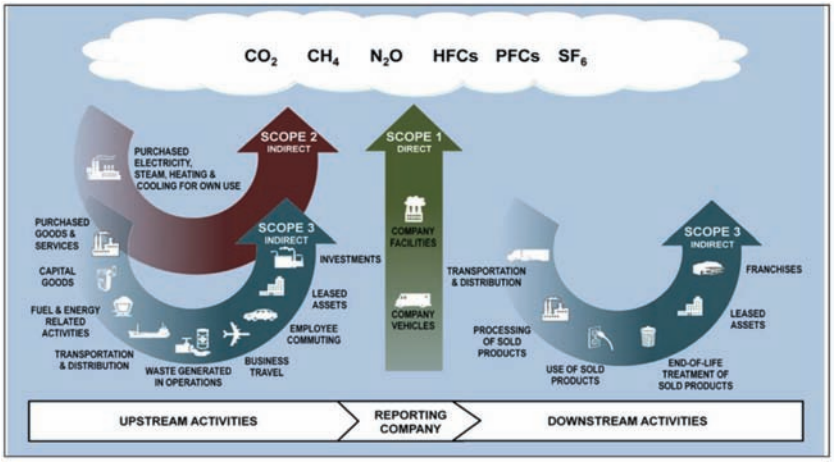


Fig. 3. Overview of GHG Protocol across the value chain.

$$tCO_2e = \sum_{i=1}^{\#GHG\ Species} tonnes_i \times GWP_i \quad (4)$$

Where, CO_2e is carbon dioxide equivalent emissions (tonnes), tonnes are in GHG emissions of pollutants (tonnes) and GWPi means Global warming potential of pollutant i. For this evaluation, all GHG emissions were reported in terms of tonnes of carbon dioxide equivalent (tCO_2e) for CO_2, CH_4, and N_2O and the values of GWP were 1, 25, and 298, respectively. The conditions are as follows: operating years – 30 years, the first CO_2 injection in 2026, with the corresponding emissions considered negligible. Fugitive emissions are based on generic component count per equipment from the API compendium 2021 (API, 2023). No continuous flaring and venting are anticipated. Facility uptime emissions calculation is 95%. This is equivalent to approximately 346 days of plant operation, with once in 5 years of planned shutdown. Flaring and venting flow rate during depressurization. Combustion, Flaring/Venting, and Fugitive are separate sources of emissions that come under emission scope 1. Combustion sources include power generating, booster compressors, and CO_2 injection compressors. Flaring sources encompass depressurization, blowdown, and start-up CO_2 depressurization flares. Venting and fugitive equipment leaks are the sources of venting and fugitive emissions, respectively. The characteristics of emitted gases, such as N_2, H_2O, CO_2, CH_4 and C_2H_6, differ depending on the type of emission. More precisely, the mole percentages of CO_2 escaping were 0.0013, 0.0001, 0.8836, 0.1134, and 0.0011, in that order.

2.9. Methane emission intensity (MEI)

Methane emissions intensity is a measure of methane emissions relative to natural gas throughput, also referred to as the methane intensity rate. This measures the methane component of natural gas emissions relative to the methane component of natural gas produced in the natural gas system (Spirit, 2021). Intensity is becoming a preferred approach for communicating methane emissions data throughout the oil and gas industry for two primary reasons: first, it enables a comparison of performance between similar business operations within a company or between different companies which is not reflected when comparing total methane emissions and secondly, it can track performance over time to meet Environmental, Social, and Governance (ESG) targets and communicate progress.

$$Methane\ Intensity\ (MI) = \frac{Amount\ of\ Methane\ Emission\ (tco2e)}{Amount\ of\ total\ production\ or\ througput\ (kboe)} \quad (5)$$

3. Results and discussion

3.1. Case 1 cost cost-benefit new field development

A data model was created for offshore fields without CCS and bound with a basic processing system. This field development, which includes four wells and processing buildings, is situated in the South China Sea (Malaysia). There is no new technology anticipated for the field, which consists of facilities for processing gas to export and venting/flaring excess gas. The main sources of carbon emission in this model are continuous emissions due to flaring, fuel gas combustion, and operational utility gas emissions. Based on the concept, select the study outcome, the selected development concept for Case 1 on the following scheme.

- 8-legged platform as a CPP facility with processing, living quarters, and utilities on a single platform
- 4-legged platform as WHP with a capacity of 900 MMscfd

The estimated cost assumption (Case-1) for the field involves a projected field lifespan of 30 years. The total cost of developing the CPP, WHP, and Flare Platform, including expenses for infrastructure, construction, and drilling, was 6.5 RM (Billion). The projected expenses for gas and condensate processing operations and maintenance amount to 8.0 RM (Billion). The abandonment costs were estimated at 10% of the total cost of developing the facilities, amounting to 0.4 RM (Billion).

The operation and maintenance costs are modelled with the assumption of 5-yearly major maintenance and cost increments due to aging equipment. The operation and maintenance cost profile for producing field development is as per Fig. 4.

The abandonment cost for this data model is assumed to be 10% of the facility development cost (RM 3.5 Billion), which is RM 0.4 Billion. The abandonment payment is spread as per production year to ensure the project is economically viable and to reduce high-cost impact at the end of field production life as Fig. 5.

3.2. Case 1 new field development Cost-Benefit Result

The data used for the cost-benefit analysis of new field development without CCS and Carbon Tax is Total gas of 6190.0 (TBTU), Capital Expenditure (CAPEX) 6.5 RM (Billion), Operating Expenditure (OPEX) 8.0 RM (Billion), Abandonment Expenditure (ABEX) 0.4 RM (Billion) with Total Cost of RM 14.9 RM (Billion) and the result is illustrated in Fig. 6 for a discount rate of 8%and Fig. 7 for a discount rate of 10%. The comparison of both analyses is illustrated in Table 2.

Based on the results above for Case 1, the project has a positive NPV of RM 4.2 billion at an 8% discount rate and RM 2.7 billion at a 10% discount rate. A higher discount rate reduces the projects' net present value by RM 1.5 billion. However, at 0%, a very large NPV of RM 18.4 billion is generated. A higher interest rate is imposed on a project with a higher risk based on the assessment of the literature review. The investment curve experiences a downward trend during the project's initial years (2023) because of substantial initial expenses incurred for drilling operations, platform construction, and equipment procurement. Subsequent increments occur, encompassing the costs of drilling wells, expanding

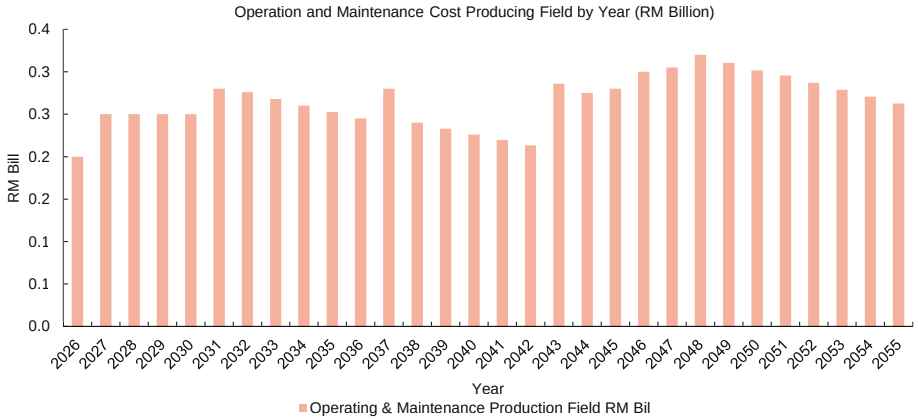


Fig. 4. Case 1 operation & maintenance cost.

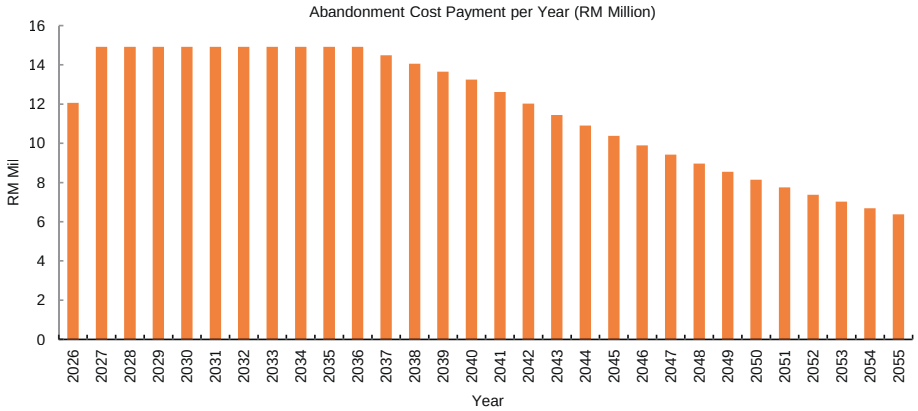


Fig. 5. Case 1 Abandonment Cost - Spread across production years to reduce cost impact.

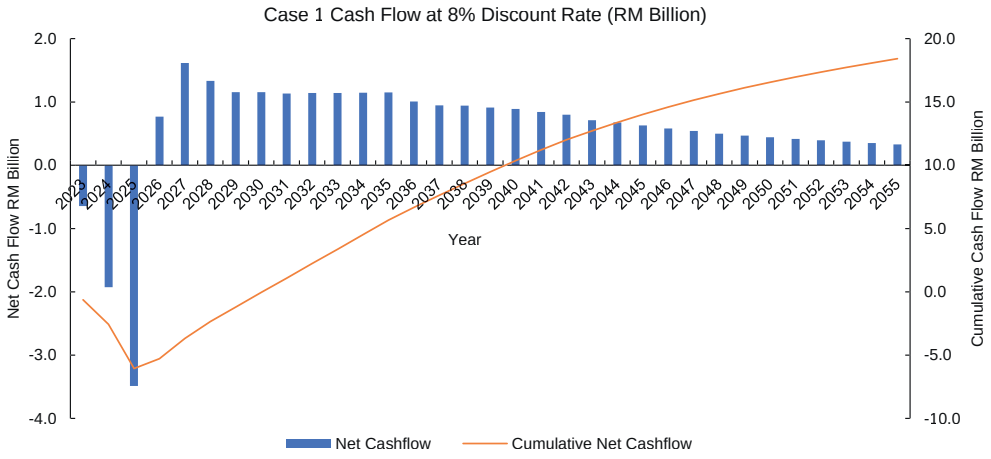


Fig. 6. Case 1 cost benefit result at 8% discount rate.

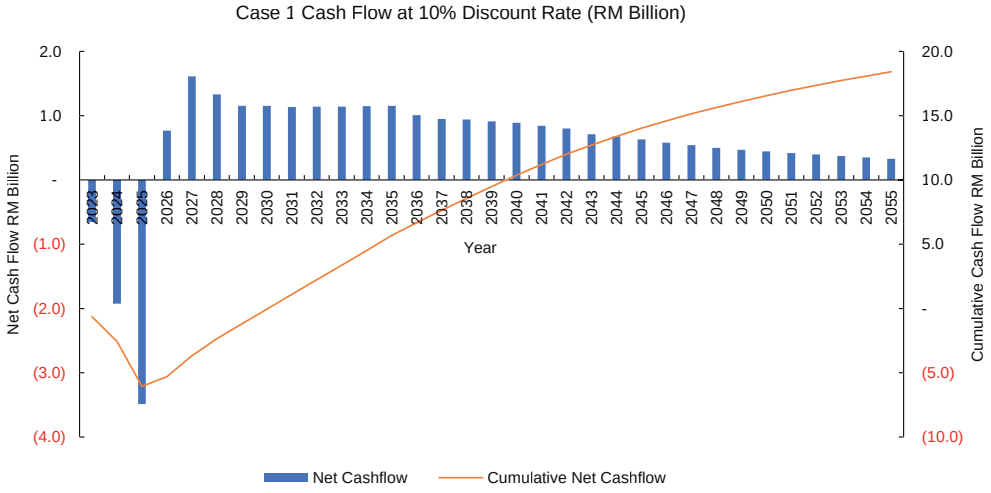


Fig. 7. Case 1 cost benefit result at 10% discount rate.

Table 2
Case 1 economic results.

Indicator	Discount Rate 8%	Discount Rate 10%
NPV0	RM 18.4 billion	
NPV	RM 4.2 billion	RM 2.7 billion
IRR	16.5%	
EL	2055	2055

infrastructure, and maintaining continuing operations. Following the initial stage, the curve reaches a stable state, indicating consistent maintenance expenses. Revenue exhibits a growth trajectory beginning in the eighth year, signifying the cumulative income generated from the sale of gas. The revenue curve exhibits a slight incline at the beginning because of expanding production. The break-even threshold is achieved by year 9, indicating the recoupment of the initial investment, followed by consistent positive net revenue. The IRR of this project is roughly 16.5%.

3.3. Case 2 cost benefit new field development with carbon tax

Case 2 employs the same development cost approach as Case 1, but places extra focus on carbon emissions. The carbon emissions associated with development, operation and maintenance, and abandonment costs (estimated to be 10% of the Facilities Development Cost) were 6.5, 8.0, and 0.4 RM (billion) respectively. The carbon emission assumption from this model is from flaring, fuel gas combustion, and operational utilities gas emission as Fig. 8, and data is plotted as a graph in Fig. 9. The carbon pricing is estimated to be USD 25 per tCO_2e with a 1.5% yearly escalation rate to assess the effects of the carbon tax.

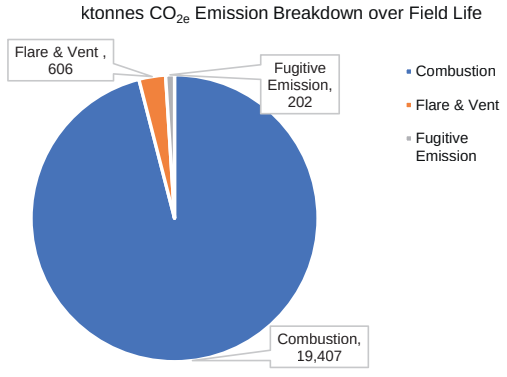


Fig. 8. Case 2 CO_2e Emission breakdown.

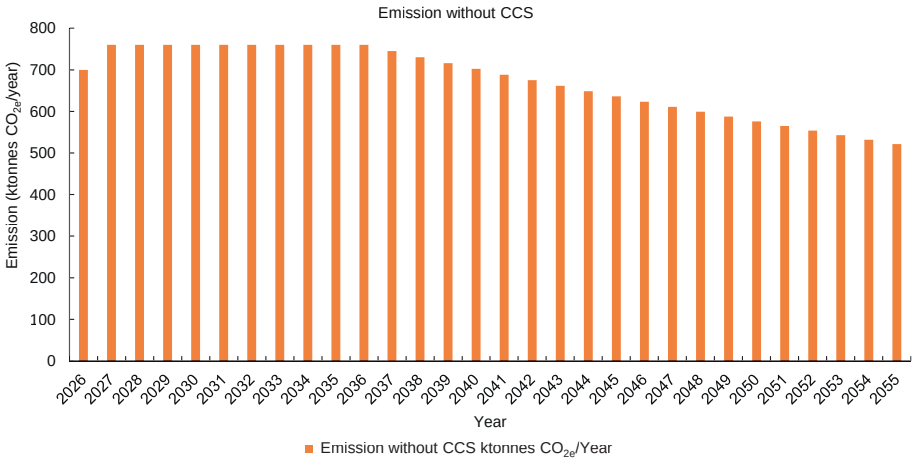


Fig. 9. Case 2 Emission without CCS.

3.4. Case 2 new field development with carbon tax Cost-Benefit Result

The data used for cost-benefit analysis of new field development with Carbon Tax was 6190.0 (TBTU), Capital Expenditure (CAPEX) 6.5 RM (Billion), Operating Expenditure (OPEX) 8.0 RM (Billion), Abandonment Expenditure (ABEX) 0.4 RM (Billion), Carbon Tax 4.8 RM (Billion) with total cost RM 19.6 RM (Billion) and the result is illustrated in Fig. 10 for a discount rate of 8% and Fig. 11 for a discount rate of 10%. The comparison of both analyses is illustrated in Table 3.

The project has a positive NPV of RM 2.9 billion at an 8% discount rate and RM 1.7 billion at a 10% discount rate, based on the results for Case 2. A higher discount rate reduces the net present value of the projects by RM 1.2 billion. However, at 0%, the NPV is RM 13.6 billion, which is somewhat lower due to the RM 4.8 billion Carbon Tax payment. Case 2's break-even point occurs in year 9 with a much smaller revenue of RM 0.5 billion, whereas Case 1's is RM 1.0 billion. This project's IRR is approximately 14.5%.

In contrast to Case 1, which excludes a carbon tax, Case 2 exhibits a diminished net present value (NPV), decreasing from RM 4.2 billion to RM 2.9 billion at an 8% discount rate. The internal rate of return (IRR) decreases from 16.5% to 14.5%. This underscores the economic ramifications of carbon taxes. Despite Case 2's sustained profitability, the implementation of the tax escalates the overall project cost by an extra RM 4.8 billion in carbon tax liabilities. This comparison underscores the significance of policy formulation in reconciling environmental objectives with economic viability.

3.5. Case 3 cost cost-benefit new field development with CCS and carbon tax

Case 3 cost development approach is identical to Case 2, but with an additional CCS facility and a reduction of emissions due to injection facilities. The carbon emissions associated with development (Drilling and facilities), operation and maintenance, and abandonment costs (estimated to be 10% of the Facilities Development Cost) were RM 9.0 billion, RM 10.5 billion and RM 0.6 billion. The operation and maintenance cost model for case 3 with CCS, with the assumption of 5 yearly major maintenance and cost increments due to aging equipment. The operation and maintenance cost profile for producing field development is as per Fig. 12.

The abandonment cost for this data model is assumed to be 10% of the facility development cost (RM 5.8 billion) which is RM 0.6 billion. The abandonment payment is spread as per production year to ensure the project is economically viable and to reduce high-cost impact at the end of field production life as Fig. 13. The carbon emission assumption from this model is from flaring, fuel gas

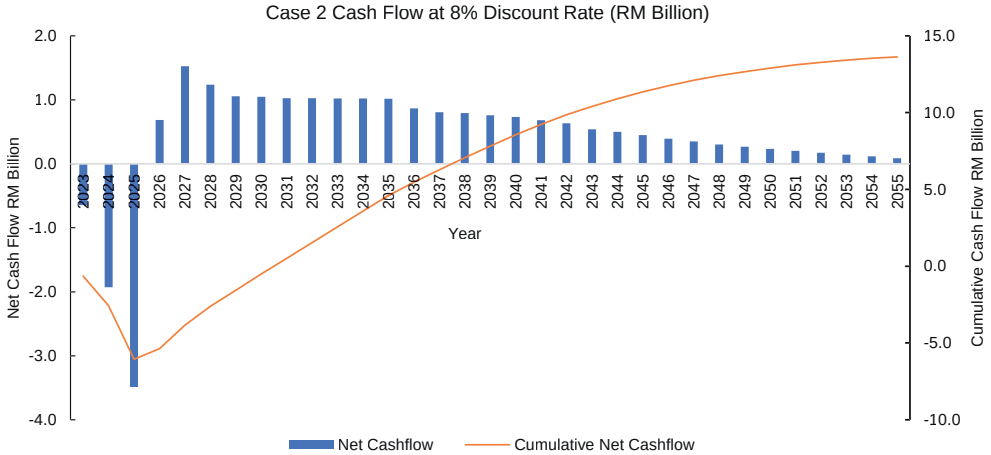


Fig. 10. Case 2 cost benefit result at 8% discount rate.

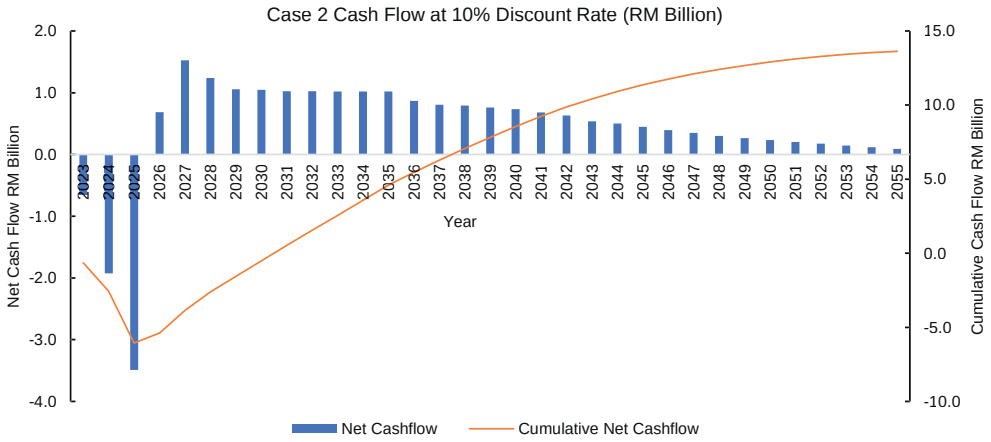


Fig. 11. Case 2 cost benefit result at 10% discount rate.

Table 3
Case 2 economic results.

Indicator	Discount Rate 8%	Discount Rate 10%
NPV0	RM 13.6 billion	
NPV	RM 2.9 billion	RM 1.7 billion
IRR	14.5%	
EL	2055	2055

combustion, and operational utilities gas emission for CCS facilities, while the CO_2 from WHP and CPP are injected into the injection wells. Fig. 14 shows the emission for development with CCS.

3.6. Case 3 new field development with CCS and carbon tax Cost-Benefit Result

The data used for the cost-benefit analysis of new field development with Carbon Tax is 6190.00 (TBTU), RM 9.0 billion, RM 10.5 billion, RM 0.6 billion RM 0.01 billion with RM 20.1 billion for Total Gas, CAPEX, OPEX, ABEX, Carbon Tax, and Total Cost respectively and the result is illustrated in Fig. 15 for discount rate 8% and Fig. 16 for discount rate 10%. The comparison of both analyses is illustrated in Table 4.

The project has a positive NPV of RM 3.0 billion at an 8% discount rate and RM 1.5 billion at a 10% discount rate, based on the results for Case 2. A higher discount rate reduces the net present value of the projects by RM 1.5 billion. However, at 0%, the NPV is RM 17.2 billion, which is somewhat higher than Case 2 due to low Carbon Tax payments. Case 3's break-even point occurs in year 10 with a large revenue of RM 0.9 billion. The longer payback period for Case 3 was due to higher CAPEX for the installation of CCS facilities. This project's IRR is approximately 12.8%. The complete data input for this economic analysis is specified in Appendix I of this research report.

3.7. Cost-benefit analysis of new field development with CCS, carbon tax, and subsidy

The cost assumptions for Case 4 are based on Case 3, with adjustments to account for the CAPEX subsidy and CO_2 storage credit. The analysis shows that a 30% CAPEX subsidy reduces effective upfront investment by RM~2700 million, while the storage credit provides additional annual revenues equivalent to RM 300–500 million, depending on injection volume. The economic indicators for Case 4 are summarized in Table 5. Case 4, which combines CCS, carbon tax, and targeted subsidies, significantly improves project economics compared to Case 3, restoring the IRR to levels close to Case 1. This result

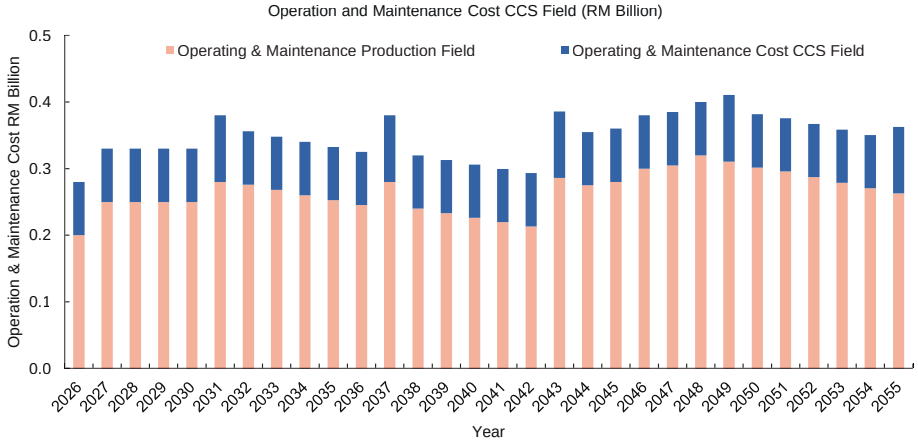


Fig. 12. Case 3 operation & maintenance cost CCS field.

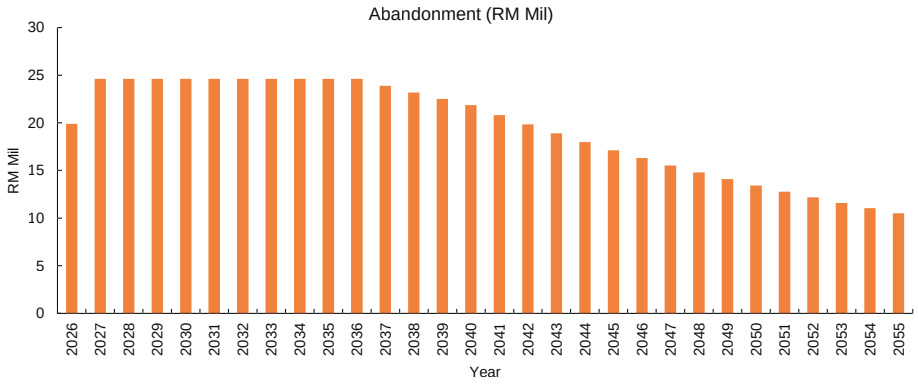


Fig. 13. Case 3 Abandonment Cost - 10% of development cost distributed over production life.

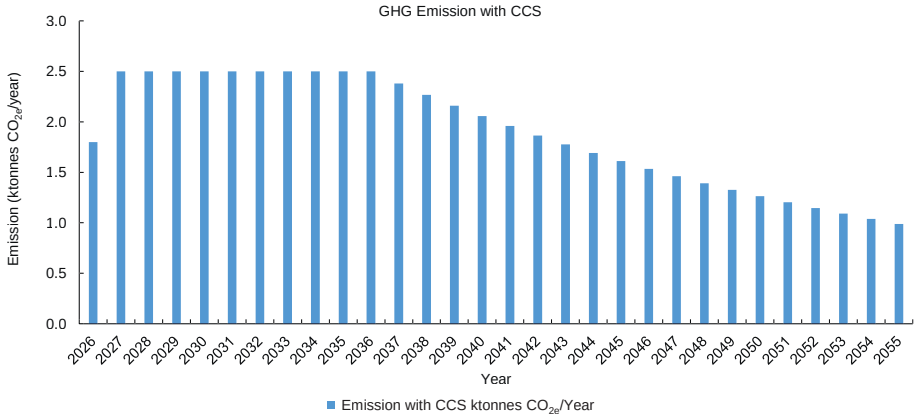


Fig. 14. Case 3 Emission with CCS.

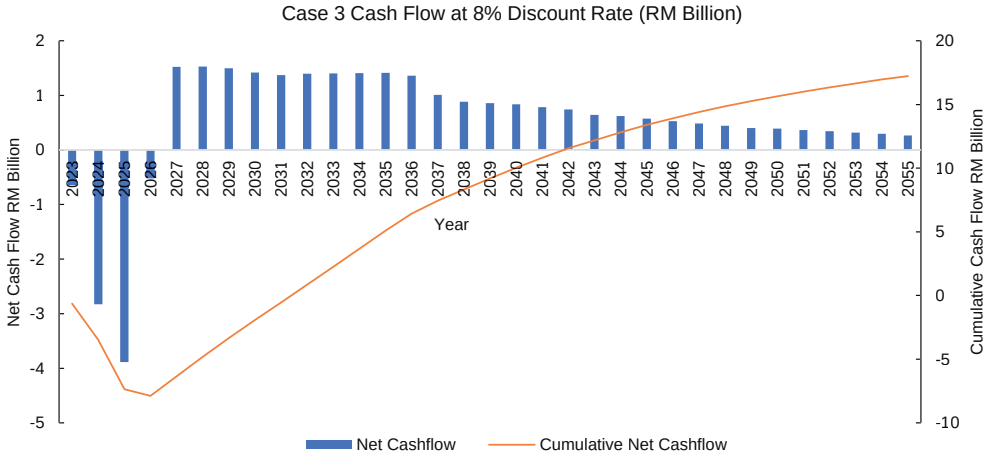


Fig. 15. Case 3 cost-benefit result at 8% discount rate.

demonstrates that a well-designed policy mix can overcome the high upfront cost barrier of CCS and incentivize large-scale deployment. In the Malaysian context, this finding suggests that a moderate carbon tax, when complemented with investment subsidies or CO_2 storage credits, could simultaneously meet environmental targets and maintain investor interests.

3.8. Sensitivity analysis for case 2-4

A tornado chart is used in this project evaluation as a sensitivity analysis to visualize the impact of various factors or variables on a specific project outcome, such as gas price, production, CAPEX, OPEX, Carbon Price, and emissions. It helps evaluate which factors

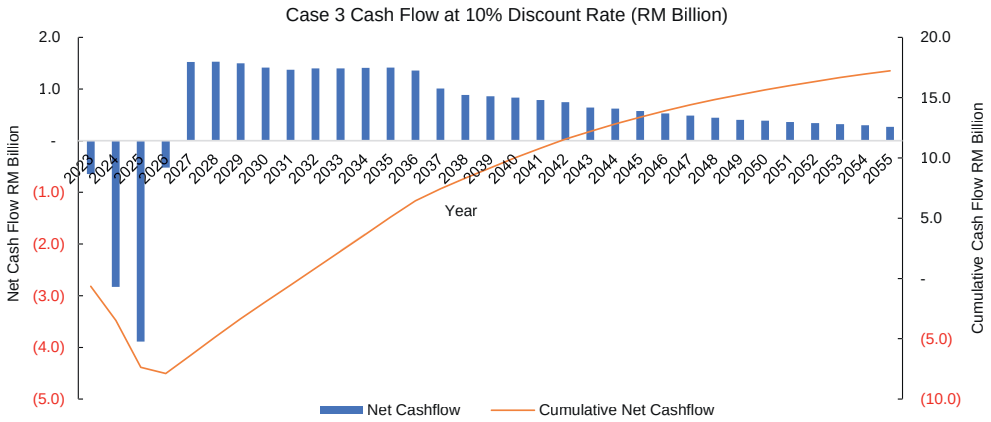


Fig. 16. Case 3 cost benefit result at 10% discount rate.

Table 4
Case 3 economic results.

Indicator	Discount Rate 8%	Discount Rate 10%
NPV0	RM 17.2 billion	
NPV	RM 3.0 billion	RM 1.5 billion
IRR	12.8%	
EL	2055	2055

Table 5
Case 4 economic results.

Indicator	Case 1	Case 2	Case 3	Case 4
NPV (8% discount rate)	RM 4199 Mil	RM 2930 Mil	RM 3003 Mil	**RM 3800–4200 Mil**
NPV (10% discount rate)	RM 2734 Mil	RM 1751 Mil	RM 1500 Mil	**RM 2300–2600 Mil**
IRR	16.50%	14.50%	12.80%	**15.0–15.5%**

have the most significant influence on project results and where potential risks or opportunities lie. The sensitivity analysis was limited to Cases 2 and 3 because Case 1 is fairly similar to Case 2 with the only variation being the exposure to the Carbon Tax. The result of the sensitivity analysis is illustrated in Fig. 17 (Case 2) and Fig. 18 (Case 3).

The base case for this sensitivity analysis is NPV at 8% for Case 2 RM 2.9 bil and Case 3 RM 3.0 billion. The factors evaluated for both cases are gas price, production volume, CAPEX, OPEX, Carbon Price, and emission cost at ±10%. In general, it is observed that in sequence the gas price, production, CAPEX, and OPEX have a significant impact on the economy of a project while emission and carbon tax have a minimal impact for Case 2 and negligible for Case 3. The NPV is affected by the ±10%. changes in natural gas prices by roughly 20–50%, whereas production volume is affected by changes by 30–40% giving a higher NPV with higher gas price or production volume. In terms of CAPEX & OPEX, it gives an adverse effect whereby the NPV declines with increasing costs about 10–20% for CAPEX and 0–10% for OPEX. The overall changes and impact are tabulated in Appendix II of this research report.

Sensitivity analyses for Cases 2–4 are presented in Figs. 17 and 18. Key parameters such as gas price, production volume, CAPEX, OPEX, and carbon price were varied by ±10%. Results show that NPV is most sensitive to gas price and production volume, followed by CAPEX, while carbon tax and emissions costs have only a marginal effect. These findings suggest that project economics are primarily driven by market factors rather than carbon pricing, making subsidies a critical enabler for CCS deployment (as shown in Case 4).

3.9. Environmental impact analysis result

A GHG intensity analysis chart is a graphical representation that provides insights into the emissions of greenhouse gases in relation to a specific metric, such as economic output, energy production, or population. This analysis is done to assess and compare the environmental impact of gas field production with and without CCS. Based on Case 1, the emission for the field development without CCS is as per Fig. 18. The CO_2 emissions depicted in

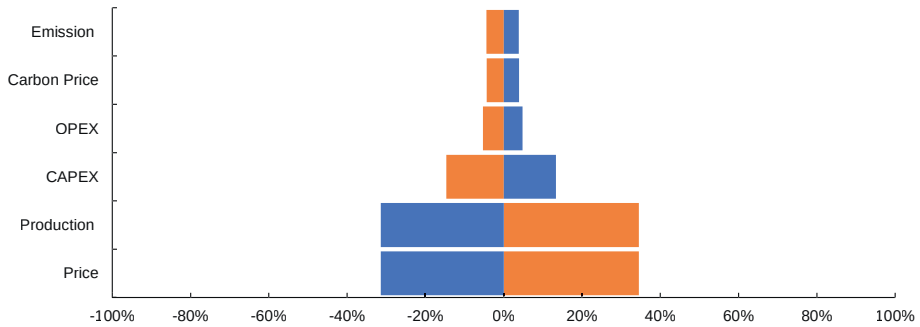


Fig. 17. Case 2 sensitivity analysis.

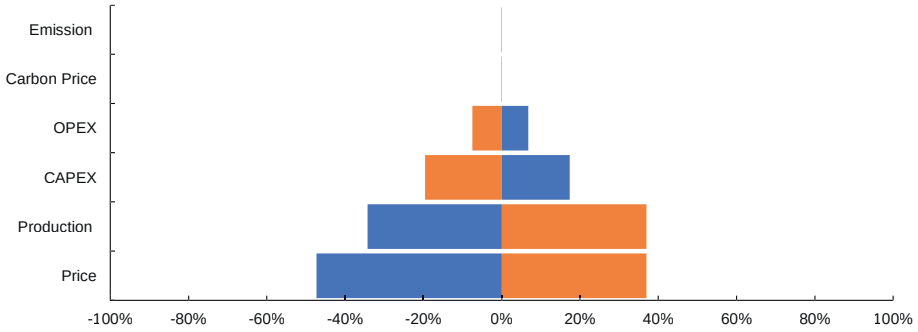


Fig. 18. Case 3 sensitivity analysis.

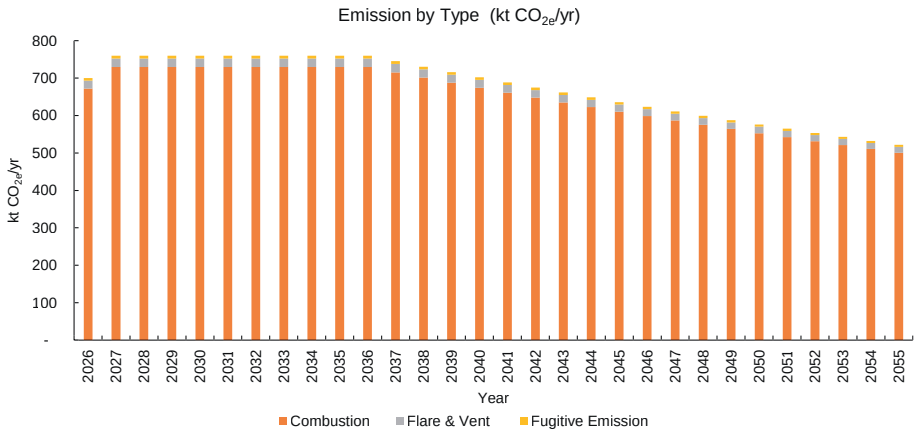


Fig. 19. Total CO_2e Emissions - "Flare & Vent" includes emissions resulting from depressurization and operational venting, whereas "Fugitive Emissions" pertains to inadvertent leaks from equipment.

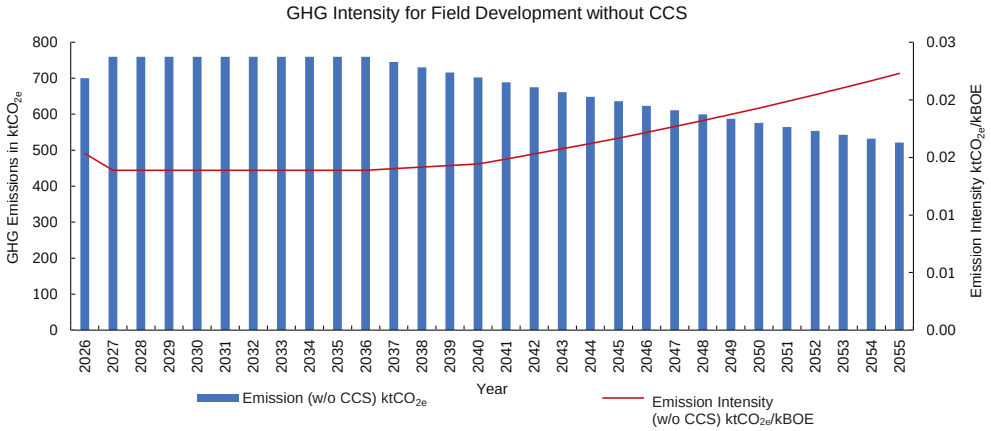


Fig. 20. GHG Intensity for field without CCS.

Fig. 19 are classified as Scope 1 and divided into three categories: combustion (planned emissions), venting/flaring (semi-controlled), and fugitive (unintentional leakage). "Flare & Vent" denotes emissions resulting from blowdown, depressurization, and emergency flaring, while "Fugitive Emissions" pertain to gas losses from valves, compressors, and pipelines. The GHG intensity analysis is plotted in Fig. 20 for facilities without CCS and Fig. 21 for facilities with CCS while Fig. 22 shows the GHG intensity between two development concepts.

When CCS is used, emission intensity averages 0.00004 $ktCO_2e$/kboe, compared to 0.16 $ktCO_2e$/kboe without it. The development concept and CCS impact cause significant diversity. Due to flaring or venting, unplanned downtime (UPD) increases GHG intensity. Higher output volume reduces GHG intensity, and vice versa. In Case 3, injection emission gas venting and flaring increase GHG intensity during CCS facility downtime despite low intensity. For consistent GHG intensity over the field's life, facilities must have adequate ullage, shutdown philosophy, and operational thresholds.

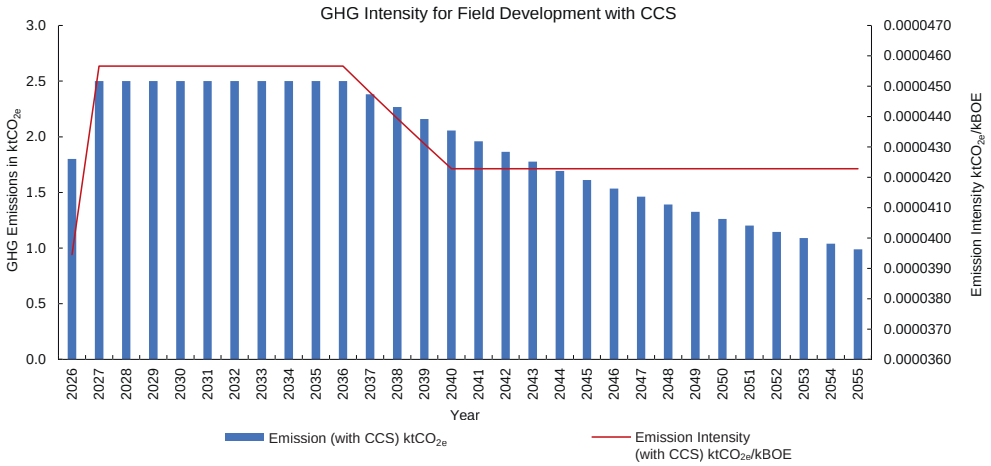


Fig. 21. GHG Intensity for field with CCS.

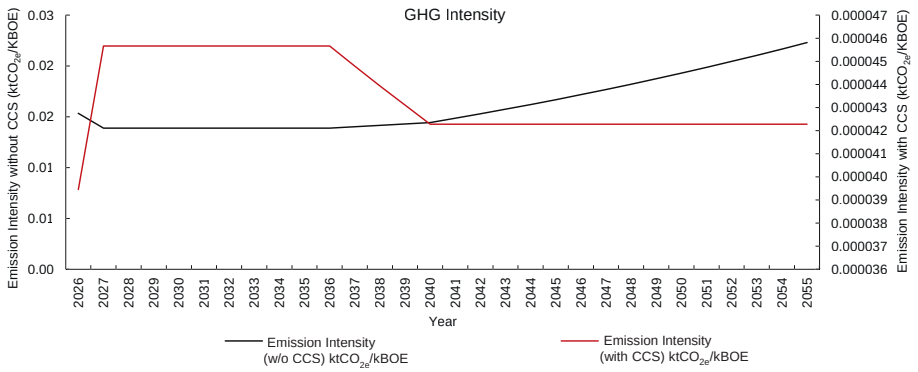


Fig. 22. GHG Intensity for field with CCS.

4. Discussion on cost-benefit and environmental impact

The economic assessment for all 4 cases demonstrates that all cases are economically viable. The comparison of all 4 cases is illustrated in Table 6. Case 3 demonstrates a favorable NPV of RM 3.0 billion, together with a Methane Intensity of 0.0005 $ktCO_2e$/kBOE, highlighting its better economic and environmental effects. Case 1, a new field development without carbon price and CCS facilities, is the most economically viable option, followed by Case 2 with carbon tax, and Case 3 with the least value. Case 3 becomes more feasible than Case 2 when discount rates are reduced. The analysis centers on assessing the economic advantages of developing CCS facilities and their environmental consequences, which is complicated by the scarcity of offshore CCS technology and research. Reducing the initial capital CAPEX investment improves the attractiveness of the NPV and IRR, offering potential to decrease CAPEX by converting the field. The project's NPV is positively affected by a large volume of gas and high gas prices. However, if the gas prices fall below RM 6.8 MMbtu, the project becomes economically unviable. A reduction of 20% in the volume of production or a carbon tax above RM500 per ton of CO_2 equivalent might lead to a negative NPV. Achieving economic sustainability requires establishing connections for future developments, maintaining a reservoir of adequate size, and implementing environmental monitoring measures for protection. The Malaysian government's assessment of the Carbon Tax rate is deemed to be modest, but, a future rise in the rate could have a detrimental effect on Case 2. Implementing a Carbon Tax that surpasses RM500 per ton of CO_2 equivalent might potentially lead to a negative NPV for Case 2. This highlights the importance of thoroughly evaluating both emissions and tax rates. While the investments for offshore CCS infrastructure are substantial, the long-term benefits far outweigh the costs. The reduction in greenhouse gas emissions achieved through effective CCS implementation translates into significant environmental benefits, including the mitigation of climate change impacts, decreased ocean acidification, and enhanced marine ecosystem resilience. Case 2 of this analysis shows a significantly high GHG Intensity and the component release through the emission and the gases are present in flared or vented gases. The specific composition of gases in flaring and venting operations can vary widely depending on the source, location, and purpose of the release. Regulations and

Table 6
Overall economic analysis result.

Indicator	Unit	Case 1	Case 2	Case 3	Case 4
NPV 0%	RM Billion	18.4	13.6	17.2	~19.0–19.5
NPV 8%	RM Billion	4.2	2.9	3.0	3.8–4.2
NPV 10%	RM Billion	2.7	1.7	1.5	2.3–2.6
IRR	%	16.5%	14.5%	12.8%	15.0–15.5%
Carbon Tax	RM Billion	–	4.8	0.01	–
Methane Intensity	ktCO2e/kBOE	–	0.15	0.0005	–

industry practices often dictate the permissible components and emission limits for these processes to minimize environmental and safety impacts.

Methane possesses a global warming potential (GWP) around 25 times that of CO_2 over a century, rendering it an exceptionally potent greenhouse gas. Increased methane levels can expedite climate change, resulting in more frequent and severe weather phenomena, elevated sea levels, and detrimental health impacts. The U.S. EPA has calculated the social cost of methane to exceed $1500 per metric ton, highlighting its environmental impact. In offshore activities, elevated methane intensity may result in operational problems, such as fire threats and regulatory sanctions. Quantifying and mitigating methane emissions is crucial for environmental preservation, as well as for maintaining long-term operational sustainability and adhering to evolving ESG norms. The data for methane intensity evaluation is as per Figs. 23 and 24.

Higher methane intensity can result in more severe weather events, rising sea levels, and other climate-related disruptions that can directly affect offshore operations. Moreover, when released into the water, methane can deplete oxygen levels, creating dead zones that are harmful to marine life. Methane emissions have an adverse effect on air quality near offshore platforms and drilling sites. Methane is a precursor to ground-level ozone formation, which can harm human health and damage vegetation. Workers on offshore platforms may also be exposed to methane emissions, which can pose health and safety risks. Increased emissions can result in regulatory fines, reputational damage, and the potential for carbon pricing mechanisms that impose additional costs on emissions-intensive operations. Furthermore, methane is highly flammable, and higher emissions can increase the risk of explosions and fires on offshore platforms. Considering the regulatory consequences, governments and international bodies are increasingly focused on reducing methane emissions from the oil and gas sector. Higher methane intensity can lead to stricter regulations, which can increase compliance costs and operational challenges for offshore operators. Moreover, companies with higher methane emissions may face legal liability for environmental damage and health impacts. Lawsuits related to emissions and their environmental consequences can result in substantial financial penalties. Most importantly, Investors and consumers are becoming more environmentally conscious, and companies with poor environmental records, including high methane emissions, may face difficulties accessing capital or markets. Sustainability and ESG (Environmental, Social, and Governance) considerations can impact a company's reputation and stock performance. Finally, local communities and environmental advocacy groups may oppose offshore drilling operations with high methane emissions due to concerns about environmental impacts and health risks. This opposition can lead to delays, regulatory challenges, and reputational damage.

To mitigate these impacts, the offshore oil and gas industry should prioritize methane emissions reduction through improved technology, best practices in design and operation, enhanced monitoring and reporting, and compliance with stringent environmental regulations. Reducing methane intensity not only helps mitigate climate change but also reduces operational risks and

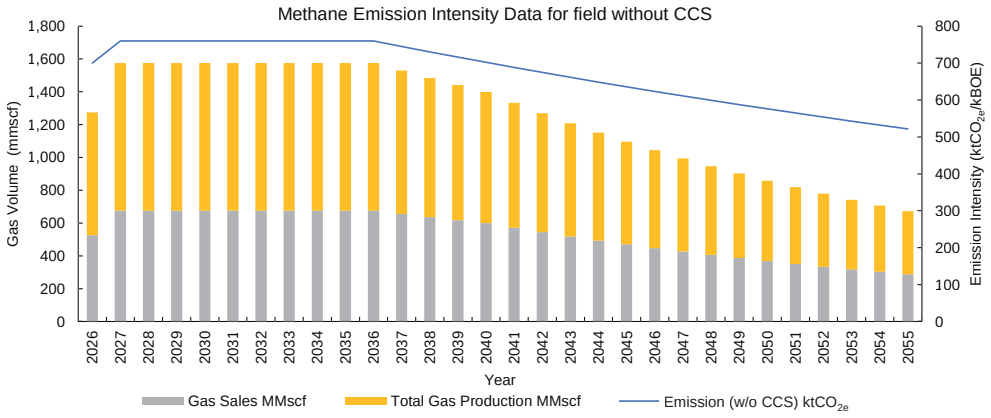


Fig. 23. Methane Emission Intensity Data for field without CCS.

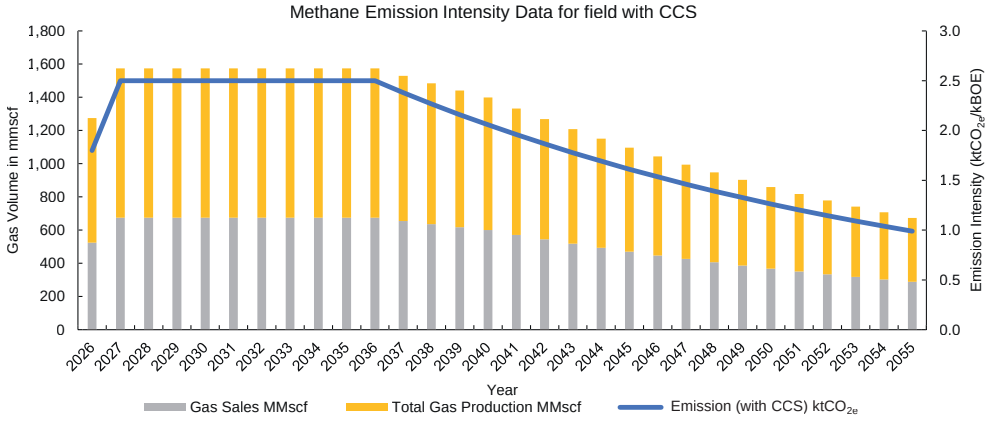


Fig. 24. Methane Emission Intensity Data for field with CCS.

ensures the long-term sustainability of offshore oil and gas operations.

The inclusion of Case 4 highlights the importance of combining carbon taxes with targeted subsidies to achieve both economic viability and environmental benefits. While carbon taxation alone (Case 2) reduces project profitability, and CCS with tax (Case 3) requires high upfront investment, the addition of subsidies and CO_2 storage credits (Case 4) restores competitiveness and aligns with global best practices such as the U.S. 45Q mechanism. From a policy perspective, Malaysia may consider implementing a hybrid framework, i.e., a moderate carbon tax, to discourage emissions and complementary subsidies or tax credits to offset CCS investment risks. Such a policy mix would provide stronger incentives for early-stage CCS deployment, reduce investor uncertainty, and accelerate Malaysia's progress towards its NDC targets and net-zero by 2050.

5. Conclusion

To summarize, the implementation of offshore CCS technology encounters difficulties due to the distant setting, leading to increased CAPEX. Nevertheless, it provides economic advantages, such as improved oil recovery, as well as environmental benefits. Government regulations, namely carbon pricing mechanisms, impact the economic feasibility of offshore CCS plants. Case 3, which incorporates CCS facilities, demonstrates greater cost-effectiveness and a reduced environmental footprint. Enhancing the appeal of CCS can be achieved by balancing the readiness of technology, developing cost-effective solutions, and monitoring the movement of CO_2 plumes. The correlation between carbon taxes and Gross Domestic Product (GDP) in Malaysia's oil and gas industry is intricate, contingent upon variables such as emission allowances and energy demand elasticity. Although carbon taxes may initially raise operational expenses, they have the potential to stimulate innovation and yield enduring economic advantages, particularly when allocated towards sustainable activities. Although there may be immediate obstacles, promoting the establishment of new sectors through the implementation of CCS facilities is consistent with achieving Net Zero Emissions by 2050. This approach promotes sustainability and facilitates sustainable economic expansion in the long run. While Case 3 shows that CCS with carbon tax can reduce emissions but slightly lower profitability, Case 4 highlights that the inclusion of subsidies and storage credits can restore economic attractiveness. This underscores the importance of integrated policy design. Malaysia could accelerate CCS deployment by combining carbon pricing with targeted fiscal incentives, thereby aligning economic and environmental goals and ensuring progress toward its 2050 net-zero commitment.

CRediT authorship contribution statement

Sitti Khadijah Shahul Hamid: Writing – original draft, Resources, Methodology, Formal analysis, Data curation. **M. Hasanuzzaman:** Writing – review & editing, Supervision, Project administration, Conceptualization. **Hossain Al Tanjil:** Writing – review & editing, Resources, Formal analysis.

Declaration of competing interest

Here we confirm that there is no conflict of interest.

Abbreviations

APS	Announced Pledges Scenario
ABEX	Abandonment Expenditure
BEP	Break Even Point
CAPEX	Capital Expenditure
CCS	Carbon Capture and Storage
CCUS	Carbon Capture Utilization and Storage
CH4	Methane
CO2	Carbon Dioxide
CPP	Central Processing Platform
ESG	Environmental, Social, and Governance
FC	Fixed Cost
GDP	Gross Domestic Product
GHG	Greenhouse Gas
GWP	Global Warming Potential
IPCC	Intergovernmental Panel on Climate Change
IRR	Internal Rate of Return
IIR	Instalment to Income Ratio
MEI	Methane Emission Intensity
MMBTU	One Million British Thermal Units
NDC	Nationally Determined Contribution
NOx	Nitrogen Oxides
NPV	Net Present Value
NZE	Net Zero Emission
OECD	Organization for Economic Co-operation and Development
OPEX	Operating Expenditure
OP	Operating Cost
RM	Malaysian Ringgit
TSR	Total Sales Revenue
WACC	Weighted Average Cost of Capital
WHP	Wellhead Platform
W/O	Without

Appendix: I

Capital Cost Breakdown Case 1 & 2.

Capital Cost	Unit	Total	2023	2024	2025	2026
Jacket/Subsctructure	RM Mil	3542	644	1127	1288	483
Drilling	RM Mil	3000		800	2200	

Capital Cost Breakdown Case 3.

Capital Cost	Unit	Total	2023	2024	2025	2026
Jacket/Subsctructure	RM Mil	5842	644	2027	2088	1083
Drilling	RM Mil	3200		800	1800	600

Appendix: II

Sensitivity Analysis Result Case 2.

Parameter	−10%	Norm	+10%	Value	Value (-10%)	Value (10%)
Price	7	8	9	2930	2010	3942
Production	7,099,370	7,809,307	8,590,237	2930	2010	3942
CAPEX	5947	6542	7196	2930	3320	2500
OPEX	7243	7967	8764	2930	3070	2775
Carbon Price	4353	4789	5267	2930	3045	2803
Emission	18,377,846	20,215,631	22,237,194	2930	3043	2800

Sensitivity Analysis Result Case 3.

Parameter	−10%	Norm	+10%	Value	Value (-10%)	Value (10%)
Price	7	8	9	3003	1581	4114
Production	7,099,370	7,809,307	8,590,237	3003	1973	4114
CAPEX	8220	9042	9946	3003	3524	2414
OPEX	9516	10,467	11,514	3003	3207	2779
Carbon Price	11	13	14	3003	3003	3003
Emission	51,830	57,013	62,714	3003	3003	3002

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