

Article

Techno-Economic Analysis of CO₂ Capture Technologies in Offshore Natural Gas Field: Implications to Carbon Capture and Storage in Malaysia

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Received: 18 November 2019; Accepted: 15 December 2019; Published: 19 March 2020



Abstract: Growing concern on global warming directly related to CO₂ emissions is steering the implementation of carbon capture and storage (CCS). With Malaysia having an estimated 37 Tscfd (Trillion standard cubic feet) of natural gas remains undeveloped in CO₂ containing natural gas fields, there is a need to assess the viability of CCS implementation. This study performs a techno-economic analysis for CCS at an offshore natural gas field in Malaysia. The framework includes a gas field model, revenue model, and cost model. A techno-economic spreadsheet consisting of Net Present Value (NPV), Payback Period (PBP), and Internal Rate of Return (IRR) is developed over the gas field's production life of 15 years for four distinctive CO₂ capture technologies, which are membrane, chemical absorption, physical absorption, and cryogenics. Results predict that physical absorption solvent (Selexol) as CO₂ capture technology is most feasible with IRR of 15% and PBP of 7.94 years. The output from the techno-economic model and associated risks of the CCS project are quantified by employing sensitivity analysis (SA), which indicated that the project NPV is exceptionally sensitive to gas price. On this basis, the economic performance of the project is reliant on revenues from gas sales, which is dictated by gas market price uncertainties.

Keywords: CO₂ capture; carbon capture and storage (CCS); offshore gas field; techno-economic analysis

1. Introduction

Anthropogenic carbon dioxide (CO₂) emissions in the atmosphere are significantly increasing and critically impacting global climate. Thus, there is an urgent need to gauge and combat its effect on global climate change. In general, the source of CO₂ comes mostly from combustion of fossil fuel, natural gas stream, and industrial processes [1–5]. As stated in BP energy statistics in 2018, there were 33,890.8 MT (metric tonne) of CO₂ emission worldwide and the value was driven by the high energy demand. Moreover, recently in the year 2018, the global energy consumption grew at a rate of 2.9%, which is almost twice its 10-year average of 1.5% per year that is the fastest trend since the year 2010. For natural gas, its production increased by 5.2% to 136,594 Tscf (Trillion standard cubic feet) while its consumption rose by 5.3% to 135.92 Tscf, which is one of the fastest rates of increase since the year 1984. This high demand is mainly driven by the booming Liquefied Natural Gas (LNG) industry in

China, Australia, the United States of America (USA), and Russia, accounting for the vast majority of the gains in both consumption and production [6].

Malaysia is an oil and natural gas producer and is strategically situated within the significant seaborne energy trade route and one of the largest energy consumers in Southeast Asia. Natural gas is indeed a very important commodity in Malaysia, as its effect extends far beyond the national power sector to further downstream products, the national economy, and international relationships. According to the BP energy statistics, natural gas production in Malaysia is steady at 2.56 Tscf per year, while the consumption is 1.46 Tscf in 2018 [6]. As LNG exporter, Malaysia is placed second after Qatar and has one of the world's largest LNG production facilities; Malaysia Liquefied Natural Gas (MLNG) complex that is aimed to supply the demand of their primary customer from Japan, Korea, and Taiwan [7]. There is an estimated 37 Tscf of natural gas that remains undeveloped in Malaysia's gas fields, whereby its CO₂ compositions exceed 10% volumetric of the produced acid gas [8]. Most of these gas fields were not economically viable in the past due to the presence of large capacities of CO₂ and are always associated with potentially high corrosion risks to the topside facilities and pipelines. The development of offshore high CO₂ gas fields requires prudent strategies of CO₂ separation technology in order to optimize both the capital and the operating expenses for CCS [9].

Nonetheless, Malaysia is committed to mitigating CO₂ emissions and has assigned its Ministry of Energy, Science, Technology, Environment, and Climate Change (MESTECC), with the responsibility of developing the national emissions reduction plan. The commitment was to voluntarily reduce the economy's carbon intensity by 40% by 2020 during the Copenhagen 2009 Climate Summit and has repledged to attain 45% CO₂ emission by 2030 [10–12]. The repledge was motivated by promising results with a reduction of 33% of CO₂ achieved between 2005 and 2015 [11,13]. The Government of Malaysia is gauging various mitigation plans and energy efficiency alternatives, including joint CCS feasibility study with International Energy Agency (IEA) as well as future implementation of the Energy Efficiency and Conservation policy to be tabled estimated by the end of 2019 or early 2020 [14,15]. Since its inception in 1974, Petroliaam Nasional Berhad (PETRONAS), solely owned by the Government of Malaysia, is the national oil and gas company and has been entrusted with the responsibility of developing the nation's oil and gas resources. To address the CO₂ emission, PETRONAS has developed its Carbon Commitment pledge to support the initiatives by promoting natural gas as low-carbon fuel and application in the power and transportation industry. This is supported by their success in building the world's first pioneer floating Liquefied Natural Gas (LNG) facility. In their enhanced Carbon Commitment 2017, all future PETRONAS's projects for CO₂ containing gas field development in upstream shall incorporate CCS technologies during conceptual design stage [16].

Carbon capture and storage (CCS) is a methodology to separate CO₂, then to store the CO₂, commonly originating from power generation, industrial processes, and from CO₂ gas fields. CCS is an offset for continued fossil fuel exploration, while at the same time achieving the targeted reduction of carbon emissions. Hence, CCS has high prospects to be one of the solutions for CO₂ emission mitigation technology in Malaysia, with added advantage especially if a particular technology is suitable for deployment, has competitive cost, and has nearby storage capacity availability.

The Intergovernmental Panel on Climate Change (IPCC) report [17] has indicated that in the absence of CCS implementation, the required total cost to mitigate global climate change may escalate up to 138%. Furthermore, it is a real challenge to reach the targeted limit of temperature increase to 2 °C scenario and an even greater one to achieve to 1.5 °C based on the Paris Agreement enacted in 2015 [18–20]. To achieve this ambitious goals, various international bodies such as the Global Carbon Capture Storage Institute (GCCSI), Carbon Capture & Storage Association (CCSA), Cooperative Research Centre for Greenhouse Gas Technologies (CO2CRC), and many other prominent research centers has been established to innovate CCS technologies solutions for economically viable path for CO₂ emissions reduction [21]. CCS has been recently known to play a vital role in global climate change mitigation, however, there are certain challenges that need to be addressed before its implementation. One of the main challenges recognized is the fairly high cost of the CCS technology for integration

with the existing facilities as well as for widespread replicated implementation [17,22]. Currently, the high-cost driver is highly dependent on technology maturity as well as the availability of the storage sites [23]. In terms of the CCS process, the capture stage is certainly the highest cost in the CCS chain [24]. The capture stage is generally estimated to represent 70–80% of the overall total cost for CCS chain [25–27]. Reducing the CO₂ capture cost is the utmost essential phase in the CCS chain in order to be economically viable in the energy industry [27]. In this study, it focuses on the techno-economic of CO₂ capture technologies suitable for natural gas field applications.

2. Materials and Method

This techno-economic analysis of CCS includes a gas field model, a revenue model, and a cost model as shown in Figure 1. This analysis framework is adopted from previous work by GCCSI [28] and CO2CRC [29]. These previous studies are largely recognized and the method is used regularly for estimating CCS costs. In this study, calculation methods were adapted from the existing studies and tabulated to describe the parameters of natural gas field economic performance for different cases of CO₂ capture technology. In the instance where no specific data on the subject is available, assumptions were made using comparative data. This study also focuses on the capture step as it contributes to the highest cost in CCS chain.

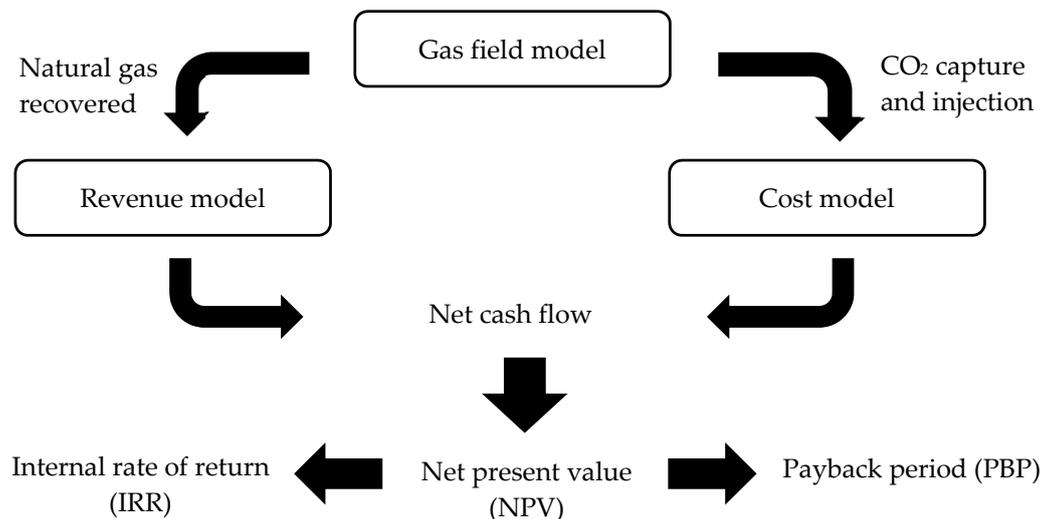


Figure 1. Schematic of the techno-economic analysis framework.

The CCS performance results for the natural gas field models are incorporated into two types of models, which are the revenue model and cost model. The revenue model comes from the value of the recovered natural gas, while the cost model is the cost of CCS, including CO₂ capture, transportation, and injection for storage. The output of both models is net cash flow that is then discounted to obtain fiscal precursors comprising of Net Present Value (NPV), Internal Rate of Return (IRR), and Pay Back Period (PBP) of the project as shown in Figure 1.

Since Malaysia has not yet regulated CCS implementation in its national regulatory setting, the cost model does not take into consideration the value of incentives and credits that could be obtained for CO₂ storage, which would be a potentially added economic benefit to offset cost framework [30,31]. In this study, the economic analysis evaluates a CCS project's impact by evaluating its costs and benefits to the overall economy. This techno-economic analysis compares four scenarios where the project is implemented using various CO₂ capture technology options, assessing the effects, including quantifying parameters in quantitative terms.

2.1. Gas Field Model

This paper investigates the cost of carbon capture from the natural gas field through a case study. In this paper, Tangga Barat Cluster situated in the PM (Peninsular Malaysia) 313 Block, as the referred case study is a typical natural gas field at water depths in the range of 60 m to 71 m, about 150 km north-east of Kertih, Terengganu offshore Peninsular Malaysia. Tangga Barat Cluster is presently operated by PETRONAS Carigali Sdn Bhd (PCSB), the upstream arm for PETRONAS that has 100% working interest. The content level of CO₂ at Tangga Barat is above the gas specifications required for sales gas. Tangga Barat Cluster consists of a total of 3 producing platforms, which are Laho (LHDP-A), Melor (MLDP-A), and Tangga (TGDP-A), and a central processing platform, which is Tangga Barat (TBCP-A), while a separate riser and wellhead platform TBDR-A bridge-linked to TBCP-A will accommodate the development wells for the Tangga Barat field as shown in Figure 2. Existing gas facilities nearest to the Tangga Barat Cluster fields are the gas production and pipeline facilities of the Resak field, which is located 52 km away. The main power generation, processing facilities, natural gas compression, utilities, and living quarters is located at the central processing platform (TBCP-A). The Tangga Barat field was chosen as the gathering point for gas from the Tangga, Melor, and Laho fields based on the fact that the Tangga Barat gas volumes remain the largest along the four fields and distance is the shortest to the Resak complex. It is designed for a peak capacity of 440 MMscf/d of raw gas with an initial blended CO₂ level of 37 mole% (Tangga Barat CO₂ content) prior to CO₂ removal. The raw gas is then processed, pretreated, reducing the CO₂ content to 8 mole% to meet the specifications of the downstream sales gas process requirement from the PETRONAS gas processing plant at Kertih Terengganu [32].

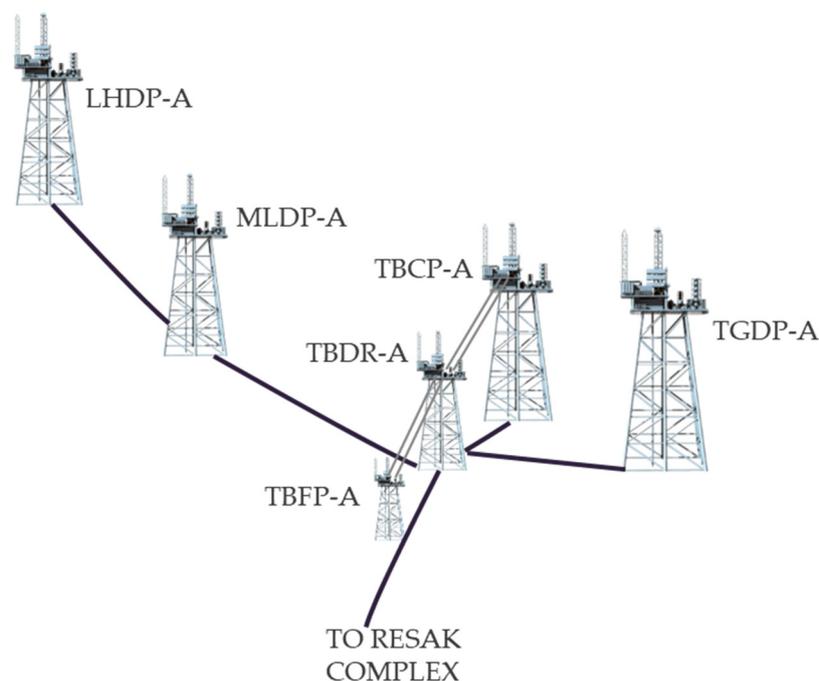


Figure 2. Tangga Barat Development Project.

In this case study, an annual average sales gas of 220 MMscf/d with 15 years of production life is estimated [33]. CO₂ storage identified for this study is situated at an underground geological storage site approximately 20 km away from the Tangga Barat fields (near the Laho and Tangga fields) whereby the injected CO₂ is to be stored while ensuring there is no increase of the reservoir pressure above the fracture pressure of the storage formation [34,35]. The facilities required will be a dedicated CO₂ compression platform and its associated pipelines and injection wells at the Tangga wellhead platform [34,35].

2.1.1. CO₂ Capture Technologies

There are several routes available for CO₂ capture technologies from the gas stream. The technologies are generally based on different physical and chemical processes comprising of absorption, cryogenic distillation, and membrane. The selection of technology route mainly relies on the type of plant, gas type, and CO₂ separation level. In this study, to meet the Tangga Barat gas field sales gas specifications, suitable CO₂ capture technologies that have been widely used for CO₂ separation from natural gas were evaluated. Four technologies have been selected for this techno-economic analysis study, which are:

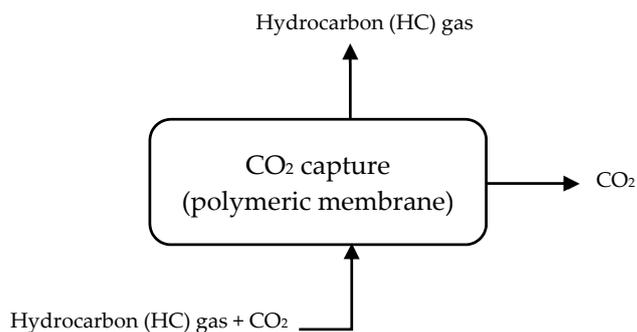
1. Polymeric membrane
2. Chemical absorption amine (MEA)
3. Physical absorption solvent (Selexol) (UOP LLC, IL, USA)
4. Cryogenic distillation

Membrane is a type of semipermeable barrier that has the ability to separate components using various separation mechanisms such as sorption/diffusion, adsorption/diffusion, ion-conducting, and molecular sieving, with selection of organic material (polymeric) and inorganic material (metallic, zeolite, ceramic). Figure 3a shows the basic method for membrane separation for CO₂ capture. Among all the available mechanisms, polymeric membrane with solution-diffusion has been commercially applied in the upstream business for natural gas separation at offshore CO₂ containing gas fields. Natural gas separation utilizing polymeric hollow fiber cellulose triacetate membrane has been installed at an offshore platform in Thailand [36]. In this solution-diffusion process, it starts with gas molecules from the feed side being absorbed by the membrane, which is then diffused across the membrane matrix and finally desorbed through to the other permeate side. The membrane selectivity is dependent on the polymer molecular structure that allows preferential passing of selected gas based on their molecule sizes, while the membrane permeability is highly dependent on the gas solubility [37–39].

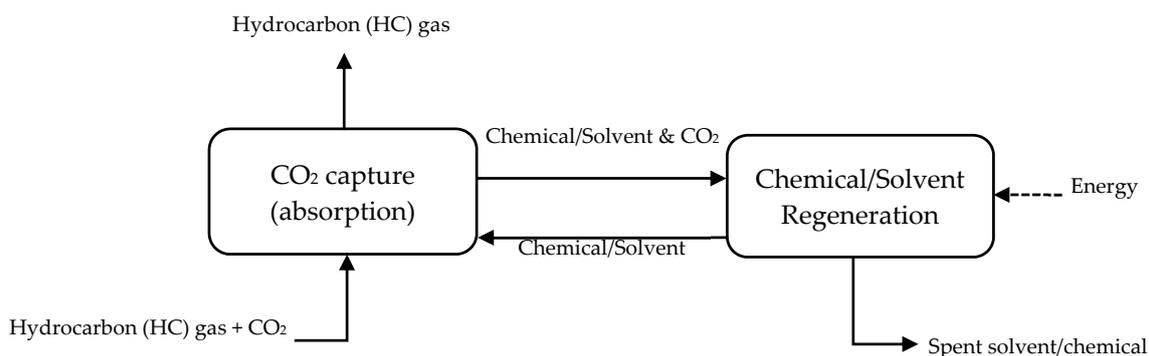
Chemical absorption technology for CO₂ capture has been commonly applied in the petroleum and natural gas industry. CO₂ is an acidic gas; therefore, chemical absorption of CO₂ is a method that utilizes necessary solvents for acid-based neutralization reactions in gaseous streams/flue gas. In this process, CO₂ reacts with chemical solvents to produce an intermediate compound that is weakly bonded, which is further broken down using heating, then regenerating back into the original solvent to produce pure CO₂ stream. For more than 60 years, chemical absorption process using amine chemical solution, such as monoethanolamine (MEA), has been commercially applied in the natural gas industry and is considered as one of the most well-known chemical absorption technologies to absorb CO₂ from natural gas [27]. In this process, in order to capture CO₂, in a packed absorption column, the flue gas is bubbled through the solvent during which preferentially separates the CO₂ from the flue gas stream [40,41]. Next, the solvent flows through a regenerator unit, whereby the absorbed CO₂ is separated from the solvent by counterflowing the steam at temperature between 100–200 °C. This results in condensation of water vapor that leaves a high concentration of more than 99% of CO₂ stream, which would then be compressed and used for storage or commercial. Finally, the lean solvent is cooled down to the temperature of 40–65 °C and is recycled back into the absorption column. In fundamental, the chemical reaction is shown as follows:



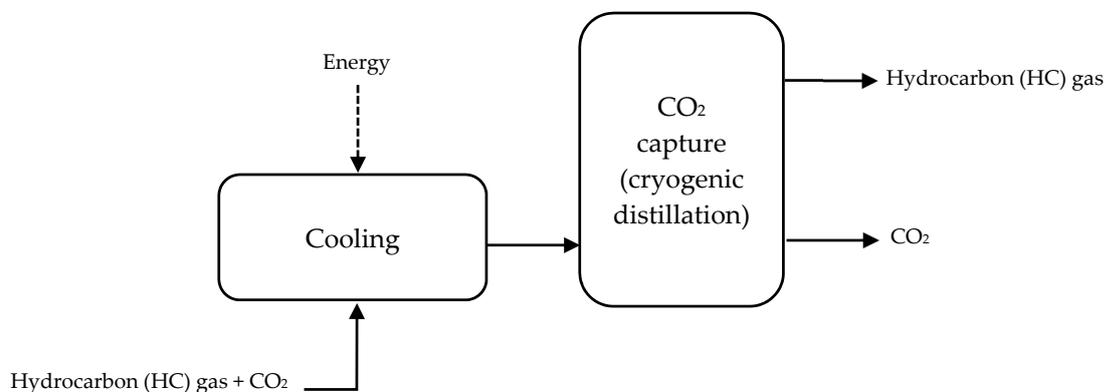
During the absorption process using MEA, the chemical reaction starts from left to right while during regeneration, the reaction is from the opposite direction, right to left [40,42].



3a. Separation with membrane.



3b. Separation with chemical/physical absorption.



3c. Separation with cryogenic distillation.

Figure 3. (a–c) Basic methods for CO₂ capture from natural gas.

Physical absorption is also a commercially available CO₂ capture method in the petroleum and natural gas industry. In this physical solvent process, it employs organic solvents to absorb gas components physically rather than reacting chemically. The solubility of CO₂ of solvents determines the separation rate of CO₂ by physical absorption processes, in which the solubility hinge on the temperature and the partial pressure and of the feed gas. Low temperature and high CO₂ partial pressure will increase the CO₂ in the solvent solubility. Selexol (dimethylether of polyethylene glycol) is a liquid glycol-based solvent and has since been used to process natural gas especially for bulk CO₂ removal. In the Selexol process, the flue gas is first dehydrated. After that, in an absorption column at a pressure about 450 psi with a low temperature of 0–5 °C, the flue gas is contacted with the solvent to produce a loaded CO₂ solvent. Then, flash desorption or separation of the CO₂ loaded solvent will regenerate the original solvent. Finally, the produced CO₂ gas stream is compressed and stored while

the regenerated solvent is recycled back to the column [25,40,43]. Figure 3b shows the basic method for CO₂ capture through absorption.

In the cryogenic distillation CO₂ separation method, CO₂ is purified by separating the gas mixtures using distillation at low temperature and fractional condensation, leveraging on their de-sublimation properties and different condensation level as shown in Figure 3c. The low-temperature distillation is a mature process used to liquefy and purify CO₂ from relatively high purity (>90%) sources. The process starts with the cooling of the gas to a very low temperature of <−73.3 °C, to freeze out/liquefied and separate the CO₂. During which, cryogenic air separation unit (ASU) was used to supply high purity oxygen to a boiler. This step condenses most of the moisture and removes any carried over particles. The produced high purity oxygen is then blended with the recycled flue gas before combusted in the boiler to maintain combustion conditions comparable to air fired configuration. This is crucial as the presently existing materials for construction could not survive the high temperatures resulting from combustion in pure oxygen [44]. Table 1 shows the advantages and disadvantages of the selected CO₂ capture technologies.

Table 1. Advantages and disadvantages of the selected CO₂ capture technologies.

CO ₂ Capture Technology	Advantages	Disadvantages
Membrane	<ul style="list-style-type: none"> • High recovery rate (up to 95%) • Regeneration energy not required • Simple modular system, small footprint • No waste stream • No chemical process [36] • Ability to adapt to changing gas compositions • Highly require pretreatment [36] 	<ul style="list-style-type: none"> • Could be clogged by impurities in the gas stream • Membrane wetting prevention is a challenge • Plasticization of the membrane (polymeric membrane) • Sensitive to trace elements, e.g., sulfur compound [38]
Chemical absorption using amine (MEA)	<ul style="list-style-type: none"> • High recovery rate (up to 95%) and product purity >99 vol.% achievable [42] 	<ul style="list-style-type: none"> • Process consumes considerable energy • In presence of O₂, occurrence of solvent degradation and equipment corrosion • Concentration of SO_x and NO_x existence in the gas stream combined with amine produces heat-stable salt • High energy for solvent regeneration is required [45]
Physical absorption solvent (Selexol)	<ul style="list-style-type: none"> • Low utility consumption • Higher capacity to absorb gases than amines • Able to remove H₂S and organic sulfur compound • Able to simultaneous gas stream dehydration [38] 	<ul style="list-style-type: none"> • Hydrocarbon losses, resulting in reduced product output and often require recycle compression • High energy for solvent regeneration is required [45]
Cryogenic distillation	<ul style="list-style-type: none"> • High recovery rate (>90%) • Eliminates water consumption and chemicals, hence no corrosion issues • Allows pure CO₂ recovery (liquid), and transportable or pumpable to injection site conveniently [38] 	<ul style="list-style-type: none"> • Process consumes high energy

2.1.2. CO₂ Storage and Abandonment

The storing of the produced CO₂ underground could benefit in addressing climate change by ensuring it is not released into the atmosphere. The prospective opportunities for CO₂ storage are at geological storage saline aquifers and depleted oil and gas reservoirs. These approaches are considered as the most feasible storage as there is great potential capacity for storage at an estimation of 236 Gt, worldwide [46,47].

In CCS chain, after the capture process, the CO₂ is compressed into a ‘supercritical phase’ whereby it becomes fluid almost as dense as water and is transported by pumping it along the pipeline to the storage site and subsequently into an underground geological formation that is typically situated several kilometers under the earth’s surface. As the injected CO₂ is slightly more buoyant than the salty water that coexists within the storage reservoir, a portion of the injected CO₂ will migrate to the

top of the formation and acts as a seal as it is trapped underneath the impermeable caprock structure. Some of the trapped CO₂ will dissolve slowly into the saline water and become trapped permanently (solution trapping), whilst others become trapped in tiny pore spaces (residual trapping). The ultimate trapping process involves dissolved CO₂ reacting with the reservoir rocks, which forms into a new mineral. This process called mineral trapping effectively locks the CO₂ into a solid mineral. As the storage mechanisms change over time from solution to residual then to mineral, the CO₂ becomes less and less mobile. Therefore, the longer the CO₂ is stored, the lower the risk of any leakage. Typically, the following geologic characteristics are associated with effective storage sites, whether at onshore or offshore site [48]:

- rock formations have adequate millimeter-sized voids or pores; this is to ensure available capacity to store the CO₂;
- pores in the rock are efficiently linked, which is a feature called permeability for injectivity; this is to receive the amount of CO₂ at the rate it is injected, allowing the CO₂ to move and spread out within the underground storage formation;
- extensive cap rock or barrier at the top of the storage formation; this is to contain the CO₂ permanently;
- stable geological environment; this is to avoid any potential geological effect that could compromise the storage site integrity.

The saline aquifers can be found at 700–1000 m below ground level and it consists of porous rocks with high salinity formation brine. These saline aquifers have no commercial value but it can be used to store the captured CO₂. These aquifers can be found at onshore/offshore and are usually estimated to have large storage potential volume. However, from an economic view, it is less desirable as storage option due to the unavailability of required infrastructure such as injection wells, surface equipment, and pipelines that would need a brand new capital investment altogether as compared to depleted oil and gas reservoirs. Depleted oil and gas reservoirs are more likely to be used for projects as extensive information from geological and hydrodynamic assessments is already available and equipped with readily available infrastructures. On average, about 40% of the residual is left after a typical oil and gas field production. The CO₂ can be injected in the depleted (or almost depleted) oil and gas reservoirs to increase their pressure, which in turn could provide the driving force to extract residual oil and gas while the CO₂ can then be stored inside permanently. This makes it more economical than storage in saline aquifers [46].

After the geological storage has reached its capacity, it will be retained for an extremely long period with an estimated minimum residence time of 1000 years without seepage/leakage back to the surface, also referred to as abandonment phase [48]. During which, the migration of the injected CO₂ in the storage volume will be monitored to ensure that it will not have any negative effect on the surrounding environment, e.g., groundwater pollution. In the monitoring stage, there are a few available methods that are commonly used, seismic monitoring, geo-electrical methods, temperature logs, gravimetry methods, remote sensing, geochemical sampling, atmospheric monitoring, tracers, soil gas monitoring, and microbiology [46]. These methods have since been applied at offshore CO₂ storage sites worldwide, such as at the Sleipner and Snohvit project. For example, at Sleipner, since the start of injection, it was found that the CO₂ plume has risen through shale rock layers nearing the caprock using seismic monitoring method. The project is currently under post-injection process and no leakage has been reported to date [48,49].

2.1.3. Carbon Capture and Storage (CCS) at Tangga Barat

The Tangga Barat CCS case study comprising of different CO₂ capture technologies units, transportation, and storage is shown in Figure 4. It begins with the central processing platform TBCP-A that will treat all produced gas originating from the producing platforms, TGDP-A, LHDP-A, and MLDP-A. The selected CO₂ capture technologies options consist of polymeric membrane, chemical

absorption amine, physical absorption solvent (Selexol), and cryogenic distillation. Among the main criteria used to shortlist the selected CO₂ capture technologies is that the technologies have already been proven and suitable for large applications (>200 MMscfd) and capable of bulk removal of CO₂ (37% mole to 8% mole) as per Tangga Barat sales gas specification requirement. Following the CO₂ capture, the treated gas is transported via offshore pipeline to Resak platform for compression followed by pumping for sales export. Then, the captured CO₂ will be stored at the identified geological site near Tangga Barat. Moreover, please note that the intention of this study is not to endorse nor discriminate any of the CO₂ capture technologies presented, but rather to gauge the CCS techno-economic impact of using different method of CO₂ capture.

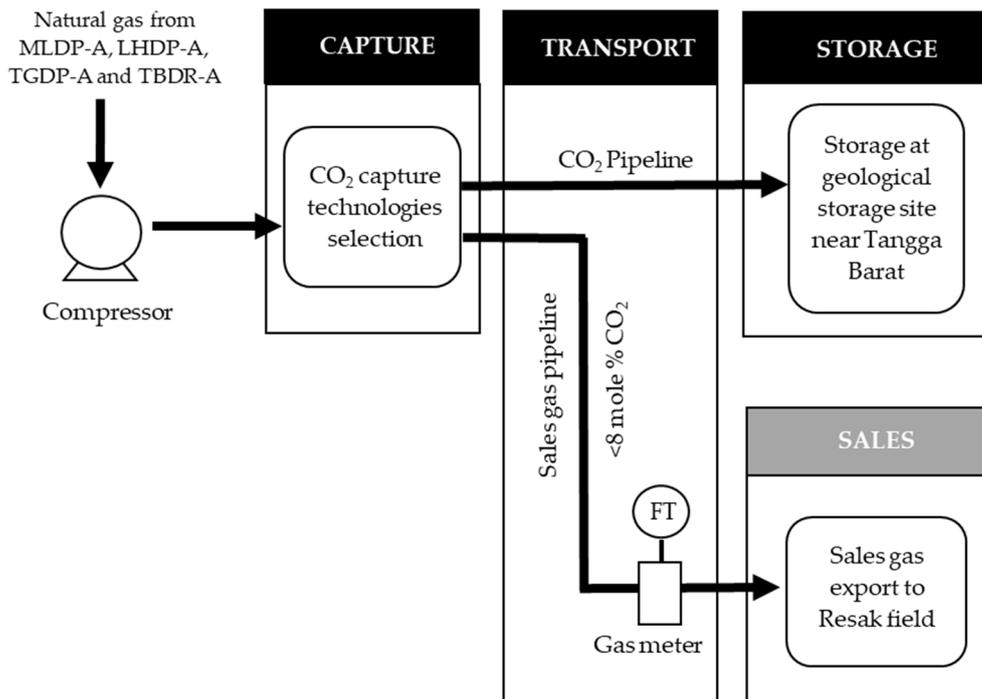


Figure 4. Carbon capture and storage (CCS) concept at Tangga Barat gas field.

2.2. Revenue Model

Based on the annual gas production estimates, the annual revenue estimation could be generated. In the US Energy Information Administration (EIA) projections reference case, natural gas prices remain comparatively low as compared to average historical prices. To estimate the economic, an average gas price between the year 2000 and projection up to 2050 whereby the estimated gas price for the year 2020 was used for this analysis [50]. The gas produced from Tangga Barat data is based on estimated studies from PETRONAS [33]. The revenue model calculates net revenue from the recovered gas production and then sold at a specified gas price, with a 10% deduction in royalty and 38% tax deduction based on Malaysian Petroleum Income Tax Act [34]. This revenue model structure will generate a time series of incoming net cash flows in which the resultant net revenue of the project could be assessed incrementally during production lifetime period and also cumulatively during the end of the project life. The tax payment is based on the estimation of capital cost depreciation of 5 years. There are also tax incentives being introduced by some countries, for example in the United States, the federal government has sanctioned supplementary tax credit for CO₂ sequestration activities that provide USD 10 per ton CO₂ stored, 15% tax credit applied to all costs associated with CO₂ purchase cost as well as CO₂ operation cost for injection [51]. For this study, since there is no tax incentive for CCS projects implemented in Malaysia, hence no additional tax incentives have been calculated. Table 2 shows the associated parameters assessed in this revenue model.

Table 2. Input and definition for parameters assessed in the revenue model.

Parameter	Input/Definition
Gas produced (Million British Thermal Unit (MMBtu))	Incremental or cumulative natural gas production volume simulated for reservoir performance estimation
Gas price (USD)	Average market price of natural gas
CO ₂ produced (tonne)	Incremental or cumulative CO ₂ production volume simulated for reservoir performance estimation
CO ₂ price (USD)	Average market price of CO ₂
Gross revenue (USD)	Revenue from natural gas recovered and cost and sold at specified gas price
Royalty (%)	10% of gross revenue
Tax (%)	38% of (revenue- royalty - maintenance cost- abandonment cost - capital cost depreciation)
Net revenue (USD)	Revenue after deduction of royalty and tax (Gross revenue (\$) – Royalty (\$) + Tax (\$))

2.3. Cost Model

In this study, the CCS project cost model could be categorized into four main types: capital cost, CO₂ capture cost, operation and maintenance (O&M) cost, and abandonment cost. In the cost model, the capital costs are accrued at the start of the project. Capital cost accounts for the gas field, compressor, pipeline, wells, and injection platforms. These capital costs are amortized over the lifetime of the field using the project discount rate [52]. For CO₂ capture cost, it is estimated based on the requirement of the gas field, including the processing equipment, production equipment, injection of platforms, and wells along with transportation pipeline. Furthermore, it includes ‘on-cost’ which is the insurance, obtaining rights-of-way, and legal and regulatory cost. CO₂ capture cost is the capital cost to implement the selected CO₂ capture technologies for the CCS project. O&M costs comprise of services, consumables, labor for site operation and maintenance (surface & subsurface), as well as general administration purposes [53]. Abandonment cost is the decommissioning cost after the injection period. These thorough analyses of CCS cost have been conducted by prominent research centers in this field. The costs in this study were estimated based on studies conducted by established studies by reputable bodies such as Asia Pacific Economic Cooperation (APEC), CO₂CRC, IEAGHG, and GCCSI as well as previous research reports [22].

All cost data were updated to represent constant 2020 US Dollar (USD):

$$PV = \frac{FV}{(1 + i\%)^n} \quad (2)$$

Whereby, *PV* is present value, *FV* is future value, *i* is discount rate, and *n* is the project lifetime number of years. Table 3 shows the parameters included in the cost model.

Table 3. Input and definition of the cost model.

Cost Model Parameter	Input/Definition	Study Referenced
Capital cost	Estimated unit cost for Tangga Barat	Asia-Pacific Economic Cooperation (APEC) and Asia Cooperative Research Centre for Greenhouse Gas Technologies (CO ₂ CRC) [34]
CO ₂ capture cost	Mean percentage increase in capital cost (over reference plant)	Rubin et al. [22]
Operation and Maintenance (O&M) costs	Cost data	Muhamad et al. [33]
Abandonment cost	2.5% from plant cost	Klemes et al. [53]
	Estimated unit cost for Tangga Barat	APEC and CO ₂ CRC [34]

2.4. Cost Evaluation Metrics

2.4.1. Net Present Value (NPV)

NPV represents the value of future cash flows that is accrued incrementally and also cumulatively over the CCS project lifetime duration. It is the total value of cash inflows and outflows that are discounted to account for the time value of money and the risks/uncertainties associated with future cash flows. Net revenues (cash inflows) obtained from the revenue model was incorporated with the

total costs (cash outflows) calculated by the cost model to develop NPV estimates in time series (years). At the end of the project lifetime, the cumulative NPV calculated is used as input to estimate the CCS project profitability, whereby positive values represent scenarios of profit while negative values represent fiscal losses sustained by investors/stakeholders in the project. The project is considered feasible if $NPV > 0$ and vice versa. NPV calculation is as presented [54]:

$$NPV(i, N) = \sum_{t=0}^N \frac{C_t}{(1+i)^t} \quad (3)$$

Whereby; i is the discount rate, C_t the annual cash flow in the t th year, and N the total number of years. Time period $t = 0$ relates to the investment during the project lifetime.

2.4.2. Internal Rate of Return (IRR)

In the CCS project, the overall investment along with its profit gain could be gauged using IRR. From the calculations, as the IRR value increases, the greater the project gain will be and vice versa. Moreover, it is the discount rate value that is resulting the project cash flow NPV to become equal to zero (0), hence defining the least rate of return required in order to achieve project viability. If the IRR value obtained is higher than the defined discount rate, hence the CCS project is considered viable. The IRR is calculated and shown as [54,55]:

$$NPV(IRR, N) = \sum_{t=0}^N \frac{C_t}{(1+IRR)^t} = 0 \quad (4)$$

Whereby; i is the discount rate, C_t the annual cash flow in the t th year, and N is the total number of years. Time period $t = 0$ relates to the investment during the project lifetime.

2.4.3. Payback Period (PBP)

The duration of time needed to recover the initially invested capital cost in a CCS project is represented by PBP. From the calculations, as the PBP value becomes shorter, the project fiscal viability strength will increase and vice versa. Moreover, PBP is defined by identifying the specific year when the calculated cumulative cash flow becomes positive and achieves breakeven. The PBP is expressed as below [54]:

$$PBP = 1 + A - \frac{B}{C} \quad (5)$$

Whereby; A is the final year with negative cumulative cash flow, B is the value of cumulative cash flow at the end of year A , and C is the total annual cash flow during the year after A .

2.4.4. Sensitivity Analysis (SA)

SA is an assessment of the projected performance with key assumptions and projections based on the base values. There are several important key variables that could impact CCS project, which are the gas price, discount price, initial capital cost, and CO_2 capture cost and tax. Key economic assumptions and associated references used as input in this study are listed in Table 4.

Table 4. Key economic assumptions and references in this study.

Input Data	Data	Remarks
Year Enacted	2020	
Project lifetime (N, year)	15	from Reference [34]
Interest rate (%)	3	from Reference [56]
Discount rate (R, %)	8	from Reference [57]
Plant capacity (MMscf/d)	440	from Reference [32]
Average gas sales (MMscf/d)	220	from Reference [34]
Gas price (\$/MMBtu)	2.8	from Reference [58]
CO ₂ price (\$/tonne)	23	from Reference [59,60]
Volume of CO ₂ (tonne/d)	1646	equivalent to (81 MMScf/d) from Reference [34]
Capital cost USD Million	427.9	estimate basis constant year 2020 with reference location Malaysia, modified from Reference [34]
CO ₂ capture technologies cost (USD Million):		
– polymer membrane	212	modified from Reference [33]
– chemical absorption (Amine)	410.79	96% increase in capital cost [22]
– physical absorption solvent (Selexol)	162.61	38% increase in capital cost [22]
– cryogenic distillation	289.39	91% increase in capital cost [22]
Tax (%)	38	from Reference [61]
Operation and maintenance cost (%)	2.5	from Reference [53]
Abandonment cost (USD Million)	50	from Reference [34]

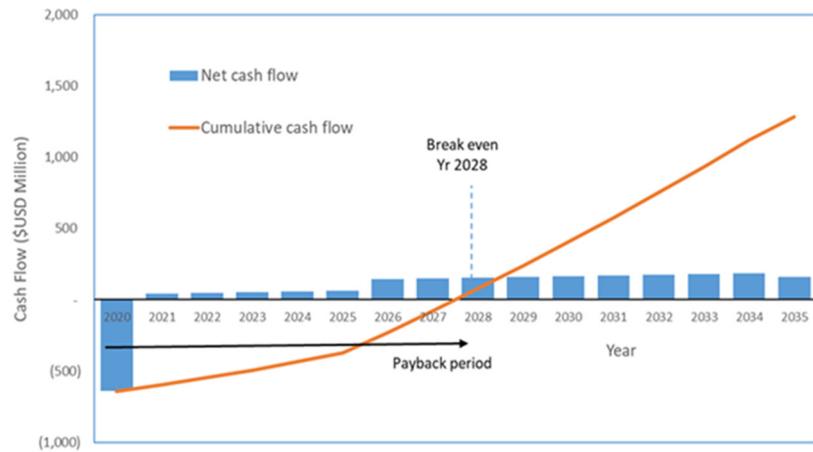
3. Techno-Economic Model Results and Discussion

This study on techno-economic analysis provides the fiscal precursor and its outlook for Tangga Barat natural gas field for CCS implementation starting from the year 2020 with a projection of 15 years project lifetime. The calculation outputs of project cash flow and total annual cash outflows, as well as its inflows throughout its lifetime, is as shown in Figure 5a–d. It can be seen that as the project extends into the exploration stage, the annual project cash flow will begin to increase in a positive note. During operation, inflow arrives from the natural gas sales revenue and outflows derive from the O&M, royalty, and tax costs.

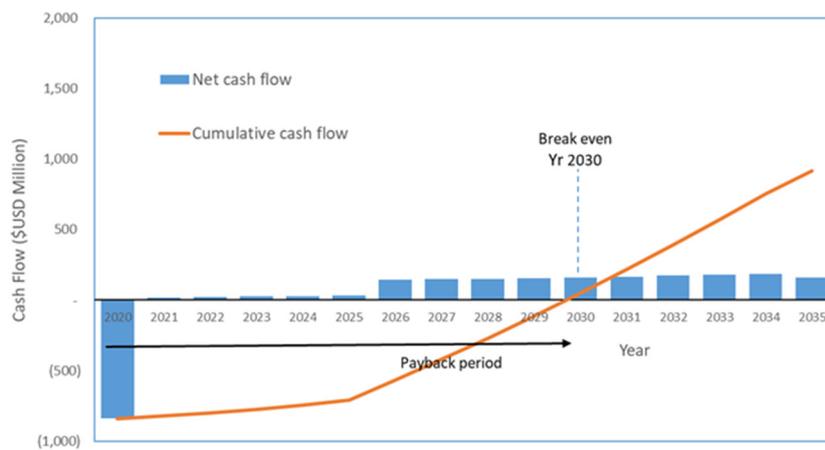
For base case (without any CO₂ capture technology implementation), during project investment in the year 2020, the initial sum proceeding from equity and capital cost is USD 427.9 Million [34]. It reflects the extent of the total cost expenses required to start a project indeed. The initial investment increases as it includes the implementation of CO₂ capture technologies. The total capital cost required including the CO₂ capture technologies implementation for the polymeric membrane is USD 639.9 Million, chemical absorption (Amine) is USD 838.69 Million, using physical absorption solvent (Selexol) is USD 590.51 Million, and using cryogenic distillation is USD 817.29 Million (refer Table 5). These costs are investments to achieve the targeted natural gas production output of 83,512,000 MMBtu per year for the overall project lifetime of 15 years.

For polymeric membrane, the case is shown in Figure 5a, where the project annual cash flow will gradually surpass its values in the succeeding years, which is the result of large investments for the capital cost being subjected to reduction from financial amortizations. This trend is reflected by the slope of the curve ranging between the year 2020 and 2027. Only by 2028 onwards, the gas field is anticipated to operate at a fairly constant speed and ultimately reaches breakeven. After that, the project cash flow is inclined to increase continuously as the revenue exceeds the cost expenditures during which its inflows and outflows also increase based on the specified discount rates over the project lifetime. From which, the revenue demonstrates a relatively optimistic cash flow increment over the years, which in turn highlights the significance of the profit obtained from natural gas sales price toward the overall feasibility of the CCS project. The entire field system and equipment will free from debt without further amortization by the end of the field production lifetime. Case using chemical absorption (Amine) is shown in Figure 5b, whereby a larger capital investment than the previous case (polymeric membrane) was made causing the project annual cash flow exceeds even higher. This is shown by the curve slope between 2020 and 2029. By 2030 onwards, the gas field reaches breakeven. For physical absorption solvent (Selexol) case shown in Figure 5c, the initial capital

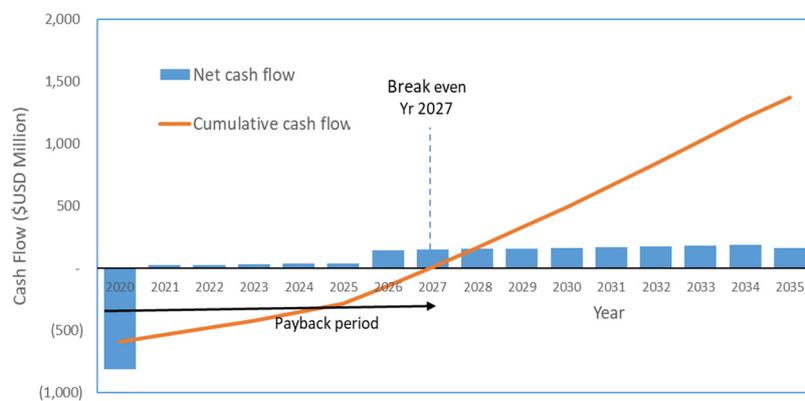
cost is the lowest of all the CO₂ capture technologies analyzed. The project is projected to breakeven in 2027 with payback obtained 7.94 years, which is about half of the project lifetime. In the case of using cryogenic distillation, the initial capital cost is slightly lower as compared to using Amine. As a result, the project is projected to breakeven one year earlier in 2029 (Figure 5d).



(a)

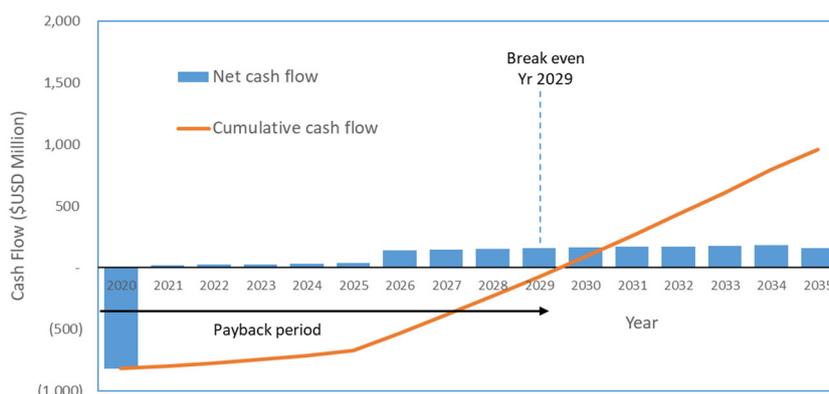


(b)



(c)

Figure 5. Cont.



(d)

Figure 5. (a) Project cash flow base case using polymeric membrane. (b) Project cash flow using chemical absorption (Amine). (c) Project cash flow using physical absorption solvent (Selexol). (d) Project cash flow using cryogenic distillation.

Table 5. Economic results of the base case and the four CO₂ capture technologies.

Parameter	Polymeric Membrane	Chemical Absorption (Amine)	Physical Absorption (Selexol)	Cryogenic Distillation
Capital cost (USD Million)	639.90	838.69	590.51	817.29
O&M cost including abandonment cost (USD Million)	289.96	364.51	271.44	356.49
Net revenue (USD Million)	1923.06	1753.59	1965.17	1771.83
Payback period (PBP)	8.55	10.68	7.94	10.45
Net present value (NPV)	292.94	(6.67)	367.39	25.58
Internal rate of return (IRR)	13%	8%	15%	8%

Table 5 displays the main outputs from the model for the four CO₂ capture technologies scenarios. Generally, a CCS project is considered to be techno-economically viable when it achieves the trio combination fiscal precursor of NPV > 0, followed by IRR value higher than the specified discount rate along with PBP value being lower than the gas field production lifetime. The physical absorption solvent using Selexol result shows the most favorable profitability with a fairly positive NPV equal to USD 367.37 Million with an IRR equal to 15% with the shortest PBP as compared to the other capture technologies. This is followed by CO₂ capture using a polymeric membrane with just a slight difference with NPV of USD 292.94, IRR at 13%, which is higher than the specified discount rate, and PBP of 8.55 years. Cryogenic distillation comes third at NPV of USD 25.58, IRR at 8%, which is the same as the specified discount rate, and PBP of 10.45 years. And finally, the least feasible CO₂ capture is by using chemical absorption (Amine) as the NPV has negative value at –USD 6.67, IRR same as the specified discount rate at 8%, and the longest PBP at 10.68 years. Even so, although the obvious viability is by physical absorption solvent using Selexol, oil and gas producers/investors may not find it as economically attractive since there are many other factors that may directly influence project decision making. External factors such as market price and financial support also are very likely to have either a negative or positive impact. On that account, it is imperative that consideration of associated risks are analyzed when conducting investment analysis. For that reason, in order to decide which considered variables are the most significant to the CCS project, SA would be the best path to reflect its worthiness.

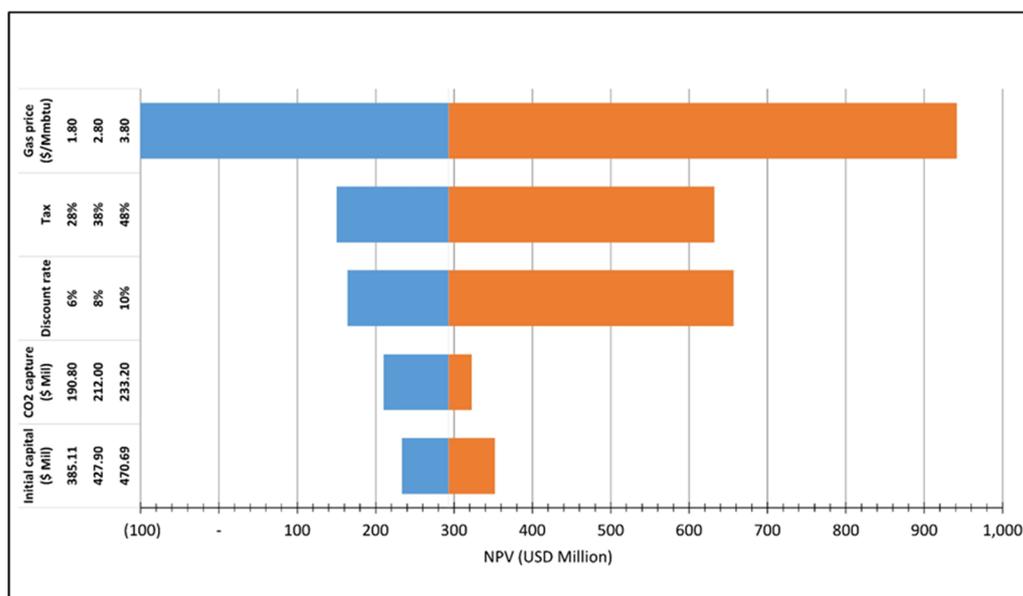
3.1. Sensitivity Analysis (SA) Results and Discussion

Sensitivity Analysis (SA) examines the effect of input variables variation on the model's conclusion to gauge and identify the most significant variables affecting the CCS project performance. By quantifying their elasticity range and assessing the project performance effect when subjected to different scenarios impacted either by the favorable or unfavorable perspective of the variables

concurrently, the feasibility of the project fiscal precursor could be defined. In this study, these variables are considered to be significantly affecting the project viability in terms of economic as well as performance risks:

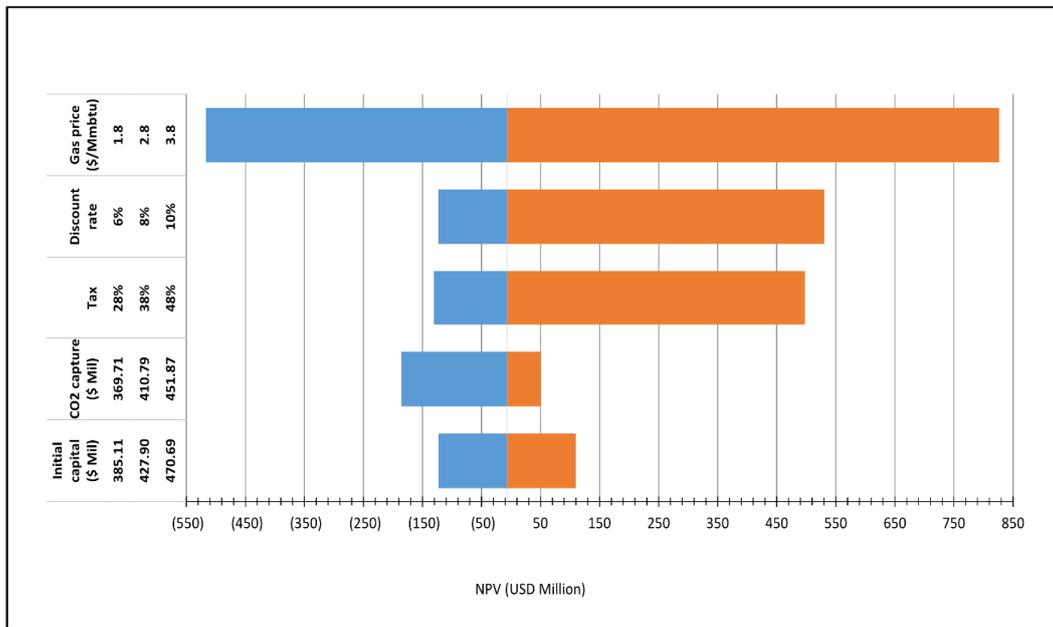
- Gas price provides input to the project revenue and has long-term uncertainty as it is highly dictated by supply and demand, global market fluctuation, and political–economic decisions;
- Tax is dependent on the country tax requirement as well as its government political decision;
- Discount rate directly affects the present value of future costs and its profits;
- Initial capital cost is highly reliant on the capital outflow investment ability by the oil and gas producers and investors.
- CO₂ capture technology cost is highly reliant on the technology provider profit margin and its maturity status;

Figure 6a–d depicts variation scenarios and its impact change to the five input variables, gas price, discount rate, tax, CO₂ capture technology cost, initial capital cost, and its effect on the risks affecting the fiscal precursor that is NPV and its sensitivity range. The sensitivity bound is defined as favorable/unfavorable by changing the baseline value, testing the different scenarios of that certain investment based on the specified five input variables. A $\pm 10\%$ range was implemented for the initial capital cost, tax, and CO₂ capture technologies and this is as supported by the literature [54]. For the gas price, the range of \pm USD 1.0 Million/MMBtu was selected as it reflects the gas price trend for the past 5 years [58]. The discount rate of $\pm 2\%$ was estimated based on previous studies conducted by established bodies such as the US Department of Energy, International Energy Agency Greenhouse Gas (IEAGHG), Electric Power Research Institute (EPRI), and UK Department of Energy and Climate Change (DECC) [62].

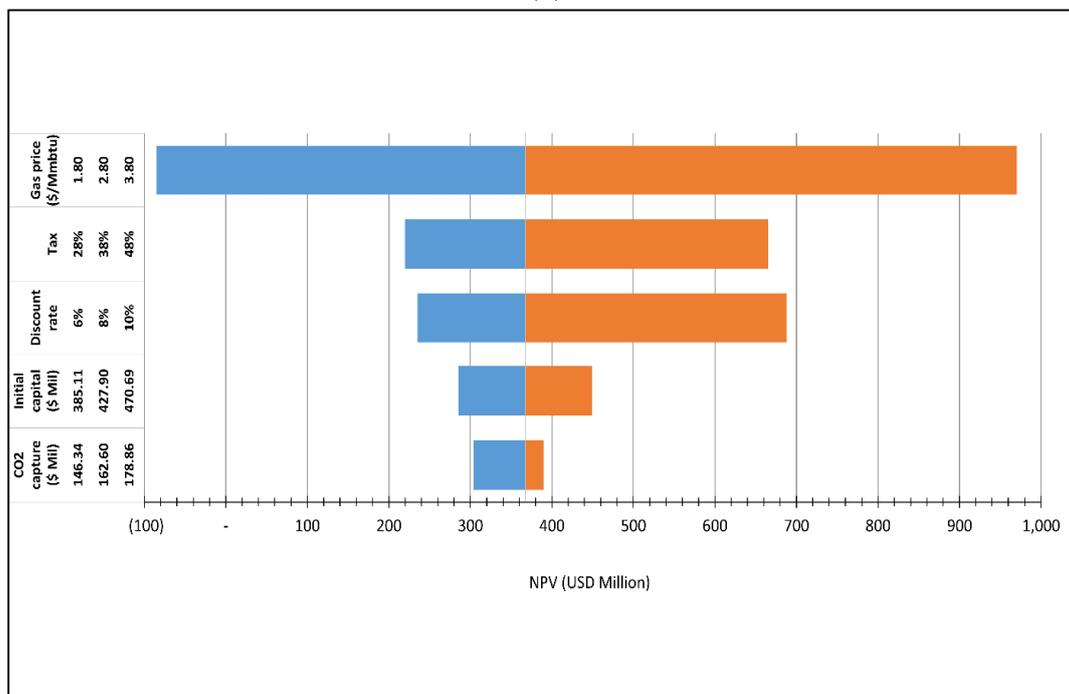


(a)

Figure 6. Cont.

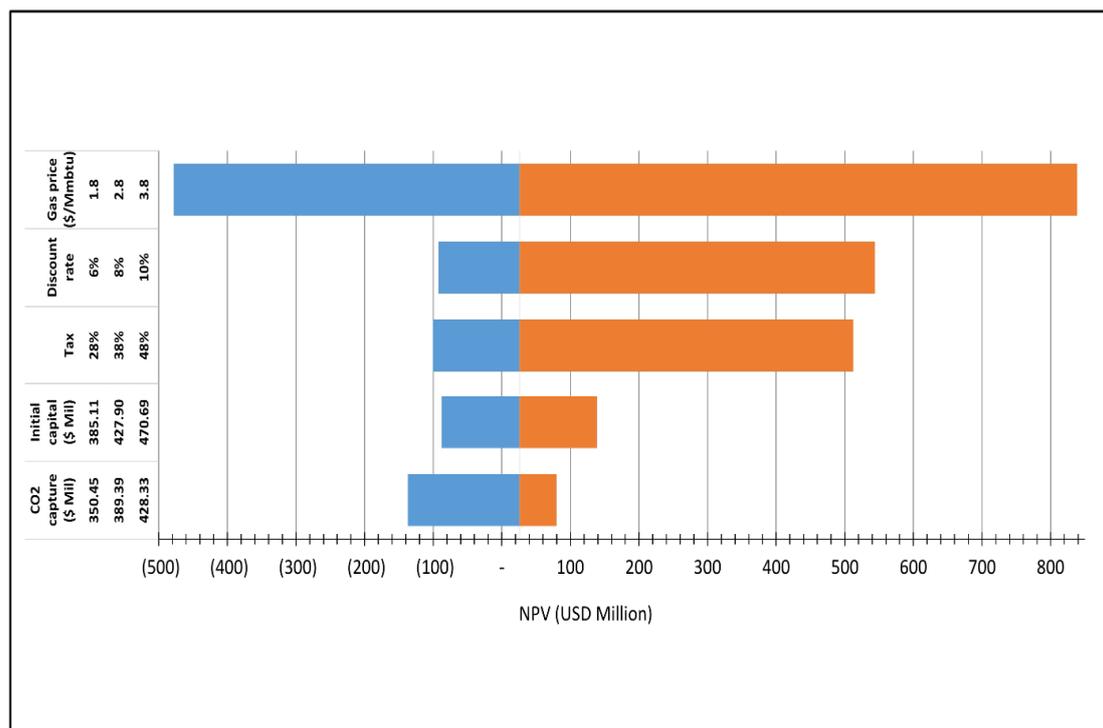


(b)



(c)

Figure 6. Cont.



(d)

Figure 6. (a) Sensitivity analysis (SA) of Net Present Value (NPV) for CO₂ capture using membrane. (b) SA of NPV for CO₂ capture using chemical absorption (Amine). (c) SA of NPV for CO₂ capture using physical absorption solvent (Selexol). (d) SA of NPV for CO₂ capture using cryogenic distillation.

The SA result for all four scenarios of CCS with different CO₂ capture technologies is reflected by NPV, which visualizes the gas price as the main key influencer affecting the viability of the project. In comparison to the other variables, gas price demonstrates the most substantial NPV impact change. The output from discount rate, tax, CO₂ capture cost, and initial capital cost (from the most affecting) variables are found to less influencing as compared to gas price. The feasibility of the project could significantly be affected by gas price during all four scenarios that are using polymeric membrane, chemical absorption (Amine), physical absorption solvent (Selexol), and cryogenic distillation in an unfavorable scenario. For example, in the case of gas price of USD 1.8/MMBtu, it predicts a negative NPV of up to –USD 161 Million, –USD 517.15 Million, –USD 84.91 Million, and –USD 487.14 Million, respectively. On the other hand, when the gas price increases to USD 3.8/MMBtu, it considerably increases the projects NPV up to USD 941.54 Million, USD 826 Million, USD 970.25 Million, and USD 838.42 Million also, respectively. High gas prices would, therefore, be beneficial for the CCS project's economic feasibility. It also could be seen that, since the uncertainties of the gas price are heavily subjected to the global supply and demand, market fluctuation, political and economic decisions, and government subsidies, henceforth making it one of the most vital factors to deal with to ensure the project success.

In the case of discount rate and tax, both variables share a nearly similar impact on the NPV. The increase of the discount rate to 10% per annum results in a decrease in NPV to USD 163.90 Million for membrane, –USD 123.06 Million for chemical absorption (Amine), USD 235.21 for physical absorption solvent (Selexol), and –USD 92.18 Million for cryogenic distillation, meanwhile a decrease to 6% per annum resulting in an increase of NPV to USD 656.73 Million, USD 530.54 Million, USD 688.08 Million, and USD 544.12 Million, respectively. Increasing the tax to 48% decreases the NPV to USD 150.13 Million for membrane, –USD 130.85 Million for chemical absorption (Amine), USD 219.94 for physical absorption solvent (Selexol), and –USD 100.61 Million for cryogenic distillation,

whilst a decrease to 28% results in an increase of NPV to USD 632.05 Million, USD 497.86 Million, USD 665.39 Million, and USD 512.31 Million, respectively. Both variables are effective, whereby the specified discount rate exhibits high impact on the calculation for the discounted cash flow of NPV whilst tax is highly dependent on local government decision and profitability.

Both CO₂ capture technology cost and initial capital cost results variable are also almost similar and has the least effect on NPV. An increase of the capture technology by 10% results in a reduction in NPV to USD 210.14 Million for membrane, –USD 185.80 Million for chemical absorption (Amine), USD 303.88 for physical absorption solvent (Selexol), and –USD 136.95 Million for cryogenic distillation, to whilst a decrease by 10% results in an increase of NPV to USD 322.29 Million, USD 50.20 Million, USD 389.90 Million, and USD 79.48 Million, respectively. Meanwhile, when the capital cost is also increased by 10%, it also results in a reduction in NPV to USD 233.70 Million, –USD 122.78 Million for chemical absorption (Amine), USD 285.64 for physical absorption solvent (Selexol), and –USD 87.57 Million for cryogenic distillation, to whilst a decrease by 10% results in an increase of NPV to USD 352.18 Million, USD 109.43 Million, USD 449.14 Million, and USD 138.72 Million, respectively. This shows that the CO₂ capture technologies cost has the least compromising effect on the NPV performance as it has the least negative range scenario as compared to the other input variables.

3.2. Limitation of This Techno-Economic Analysis

The techno-economic analysis conducted in this study achieves the targeted evaluation of CCS prospect with four different CO₂ capture technologies scenarios at Tangga Barat gas field could be used as an early decision making indicator for investors and enabling other natural gas fields to be rapidly evaluated. However, this study was based on limited and readily available statistical economic parameters and storage reservoir properties. A more detailed storage site characterization and equipment and material cost parameters inventory for the Tangga Barat CCS during detailed engineering design stage could assist in obtaining a higher precision project techno-economics.

4. Conclusions

In this study, it presents a techno-economic analysis of an actual gas field Tangga Barat in Peninsular Malaysia and assesses its potential for CCS to be implemented in Malaysia as a means of achieving targeted CO₂ reduction aim. The deployment of this CCS project will contribute to a significant decrease of the environmental impact, by storing the captured CO₂ at an estimation of 1646 tonnes/day. The result of this paper focuses on the possibilities for CCS project comprising of 4 cases of CO₂ capture for offshore gas field along with a fixed CO₂ transport and storage infrastructure development. In this study analysis, a techno-economic model spreadsheet is established to obtain the fiscal precursors, which include NPV, IRR, and PBP. In the cost model, the considered cost factor is capital cost that includes CO₂ capture technology cost, O&M cost, and abandonment cost incurred. While for the revenue model, the estimation is based on the profit from the produced natural gas sales. The techno-economic analysis is conducted based on previous literature and then benchmarked and updated catering to suit market gas prices, plant equipment, revenues, operating cost, tax rates, and interest rates. Then, a SA is conducted to evaluate the risks and measures associated with the project investment uncertainties. Favorable and unfavorable scenarios are analyzed within a defined elasticity range basing from the baseline value input. The selected variables include gas price, discount rate, tax, CO₂ capture technology cost, and initial capital cost were used to evaluate CCS project feasibility potential.

From the techno-economic analysis model, it presents a positive outlook stating its achievability to deploy the project based on Malaysia's current market and economic setting. The analysis shows two prospective CO₂ capture technology with high positive NPVs by using physical absorption solvent (Selexol) followed by the polymeric membrane. The most prospective CO₂ capture method is using Selexol with IRR at 15% and PBP of 7.94 years. This is closely followed by CO₂ capture using membrane with just a slight difference with IRR at 13% and PBP of 8.55 years. From this analysis, it could be

concluded that these two variants of CO₂ capture have a huge economic prospect for deployment at Tangga Barat. Based on the SA, the NPV exhibits to be significantly most sensitive to gas price, followed by discount rate and tax. It also shows that both CO₂ capture technology and initial capital cost has minimal influence on NPV. Although the project feasibility and acceptable risks are provided by all four CCS scenarios from the economic model calculations, two distinct capture technologies, which are using membrane and physical absorption solvent (Selexol), give high IRR with an acceptable time of return period (less than half the production years). This study shows that either one of the CO₂ technologies could be implemented at Tangga Barat, which could further be influenced by the oil and gas producer or investor inclinations, starting with this economics and extending to political and geological factors. Furthermore, the SA illustrates that the gas price has the most significant impact over NPV as compared among all the considered variables. This scenario portrays that the gas sales revenues that is controlled by the uncertain market, tariffs, and reimbursements will eventually impact the overall economic viability of the CCS project.

In order to achieve successful deployment of CCS projects, collaborations between governments, international organizations, and the private sector would be essential and, of course, international financing will be critical to project success. In the scenario, for the case of Malaysia, to adopt and extend its current reduction of tax incentives for marginal field from 38% to 25% for CCS projects, this incentive would positively influence the key decision factor for oil and gas producers/investors to implement CCS. Furthermore, it is hopeful that the upcoming future implementation of the Energy Efficiency and Conservation act in Malaysia would be an appropriate avenue for the climate policy to manage and positively impact the control of CO₂ emissions. The accessibility to sufficient storage capacity could be another restrictive element to reduce CO₂ emissions through CCS, even though there are some fundamental studies that believe there are available geologic storage and also studies on storing back the CO₂ into the origin source well/depleted field. These uncertainties and lack of storage capacity could be overcome by implementing CO₂ utilization method, by transforming CO₂ into valuable products that could serve as project revenue and eventually offset the initial investment cost altogether. Finding creative, cost-effective ways to capture and profit from this CO₂ for use in CCS can result in a vast improvement in the long-term commercial viability of natural gas production in Malaysia, along with increasing the productive life of the economy's natural gas resources. This study on techno-economic analysis could be a reference point in terms of economic viability for implementation of CCS in other CO₂ gas fields in Malaysia and globally.

Author Contributions: N.R.S. conducted the techno-economic analysis and wrote the paper; T.M.I.M. reviewed the paper preparation; A.H.S. checked and proofread the final version of the paper; and M.F.M.I. provided the resources for the analysis and reviewed the paper. All authors have read and agreed to the published version of the manuscript.

Funding: This research was funded by the Centre for Advanced Modeling and Geospatial Information Systems (CAMGIS) [Grant no. 321,740.2232397] and research development fund; School of Information, Systems and Modelling, University of Technology Sydney, Australia. This research also received financial support from AAIBE Chair of Renewable Energy (Grant no: 201801 KETTHA).

Acknowledgments: The authors would like to acknowledge this research as supported by MyBrain15, Ministry of Higher Education Malaysia.

Conflicts of Interest: There is no conflict of interest.

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