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Minimum Carbon Credit Cost Estimation for Carbon Geological Storage in the Mae Moh Basin, Thailand

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Abstract: Carbon geological storage (CGS) is one of the key processes in carbon capture and storage (CCS) technologies, which are used to reduce CO_2 emissions and achieve carbon-neutrality and net-zero emissions in developing countries. In Thailand, the Mae Moh basin is a potential site for implementing CGS due to the presence of a structural trap that can seal the CO_2 storage formation. However, the cost of CGS projects needs to be subsidized by selling carbon credits in order to reach the project breakeven. Therefore, this paper estimates the economic components of a CGS project in the Mae Moh basin by designing the well completion and operating parameters for CO_2 injection. The capital costs and operating costs of the process components were calculated, and the minimum carbon credit cost required to cover the total costs of the CGS project was determined. The results indicate that the designed system proposes an operating gas injection rate of 1.454 MMscf/day, which is equivalent to 29,530 tCO_2e per year per well. Additionally, the minimum carbon credit cost was estimated to be USD 70.77 per tCO_2e in order to achieve breakeven for the best case CGS project, which was found to be much higher than the current market price of carbon credit in Thailand, at around USD 3.5 per tCO_2e. To enhance the economic prospects of this area, it is imperative to promote a policy of improving the cost of carbon credit for CGS projects in Thailand.

Keywords: carbon geological storage; injection well completion; gas injection optimization; economic analysis; minimum carbon credit cost

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1. Introduction

Carbon dioxide gas (CO_2) is a significant component of greenhouse gases, accounting for more than 50% of all emissions. These emissions have been contributing to climate change and global warming [1]. The primary source of CO_2 emissions is from the combustion of fossil fuels for power generation and transportation. To address the environmental concerns associated with carbon emissions, carbon capture and storage technology has been developed [2–5]. This technology is now being adopted by developing countries, including Thailand, as part of their efforts to achieve carbon-neutrality by 2050 and net-zero emissions by 2065 [6]. CCS involves two main processes: CO_2 capture and CO_2 storage. CO_2 capture can be carried out at manufacturing industries, such as cement and power plants, before the CO_2 is released, or directly from the air [7]. The permanent storage of CO_2 in subsurface geological structures can be achieved through various trapping mechanisms, including structural trapping, residual trapping, solubility trapping, and mineral trapping. Among these mechanisms, structural trapping is the most dominant due to the buoyant characteristics of CO_2 in subsurface reservoirs [8,9].

Carbon credits are financial instruments that companies use to offset their carbon emissions. These credits represent a certain amount of carbon dioxide or other greenhouse gases that a company is allowed to emit. If a company exceeds its emission limit, it is fined. On the other hand, companies that emit less than their limit can either save the credits

for future use or sell them to other companies. The goal of carbon credits is to reduce carbon dioxide emissions and mitigate the effects of global warming. Carbon credits are traded in carbon markets, which can be mandatory or voluntary, allocation or offset, and international or regional. Thailand's carbon credit market is classified as voluntary, regional, and offset, meaning that it is controlled by companies and projects rather than government quotas. In Thailand, carbon credit trading is facilitated through the Thailand Voluntary Emission Reduction Program (T-VER). Although it is a voluntary market, Thailand's carbon credit market has been growing steadily. The turnover of carbon credits has increased from THB 0.85 million in 2016 to THB 129 million in 2022, with a total trading volume of 1.19 million tons of carbon dioxide equivalent (tCO_2e). The average price of a carbon credit is around THB 108.2 or USD 3.5 per ton [10].

The CO_2 injection phase is a key component of carbon geological storage, which also includes the completion and operation of the injection well. Most aspects of drilling and completing CO_2 injection wells are similar to those of conventional gas injection wells or gas storage wells. However, downhole equipment can be upgraded to withstand high pressure and corrosion [11]. The CO_2 injection phase accounts for a significant proportion of the overall cost of CGS, in addition to the costs of capture and transportation to the injection site. To make a CGS project financially feasible, it has to be subsidized by selling carbon credits. Therefore, the minimum carbon credit cost, or the total cost of injection, will determine the feasibility of a CGS project in a specific area.

The PROSPER® v17.0 simulation program is used in gas injection design to optimize operating parameters and predict well performance for different cases. This tool is particularly useful for CO_2 injection well design and determining the conditions necessary to sustain gas flow using nodal analysis, which involves selecting a division point or node in the well and dividing the system at that point [9]. The inflow section includes all components upstream of the node, while the outflow section includes all components downstream. The intersection point on the pressure and flow rate plot between inflow and outflow sections represents the equilibrium condition at the node, typically located at the bottom of the well depth.

Therefore, this study designed the related equipment for CO_2 injection wells during both the drilling and injection phases. The cost of the injection well was evaluated, taking into account the capital cost from well equipment selection and the operating cost associated with energy usage for injection, and capture and transport costs. The minimum carbon credit cost for the CGS project was then determined by converting the capital and operating costs into the net present value (NPV), with the carbon credit sale serving as the project income. Furthermore, the study varied key design parameters such as tubing size, wellhead pressure, and injection temperature to analyze their impact on the operating injection rate and the minimum carbon credit cost of the well. This analysis proposes an optimal design for CO_2 injection in the Mae Moh basin, which is a potential site for CGS in Thailand.

This article is divided into five sections. Section 2 explains the methodology used in this study, including information and lithologies of the Mae Moh basin. It also discusses the methodology for well completion and CO_2 injection design, as well as the economic analysis to determine the minimum carbon credit cost for the project breakeven. Section 3 presents the results of the well completion and injection design, including the specifications for casing, cementing, and tubing, as well as the economic analysis for the base case design. Section 4 discusses the sensitivity analysis for tubing diameter, wellhead pressure, and injection temperature, and how they affect the operating injection rate and minimum carbon credit cost. Finally, Section 5 provides the conclusions drawn from the study, summarizing the research findings concisely.

2. Methodology

The overall framework of methodology is illustrated in Figure 1, which includes a literature review of the prospected area, the acquisition of formation and well properties,

well completion design, nodal analysis of CO_2 injection rate, and economic analysis and carbon credit cost estimation of the carbon injection project.

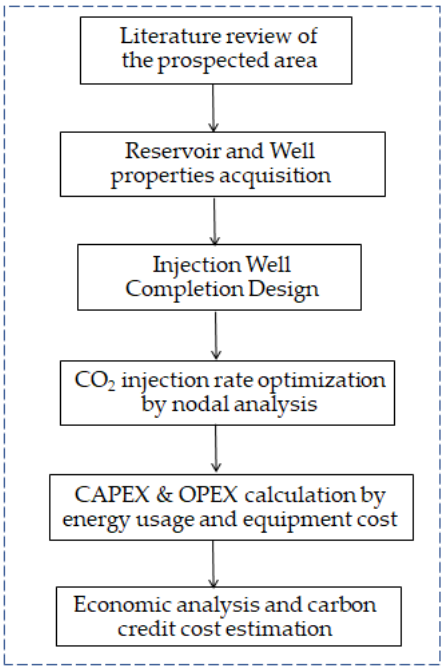

Figure 1. Overall framework of this study.

2.1. Prospected Storage Formation

The Mae Moh basin, proposed as the study site in this study, is located in Lampang province of Thailand (see Figure A1 in Appendix A). The area has the potential for carbon capture and storage due to the presence of a structural trap that seals the limestone formation used for storage [12]. According to the study by Pailoplee et al. [13], probabilistic seismic hazards (PSHAs) were assessed using spatial mapping, which indicated that the southern region of the mine in southeastern Lampang is the area at risk. This area has a 60–80% and 30–40% probability of exceedance (POE) of a Modified Mercalli Intensity (MMI) level III and IV, respectively, in the next 50 years. However, these values indicate only a slight possibility of a significant impact on the stability of the well due to earthquakes. Additionally, this basin is bound to the Mae Moh coal-fired power plant, one of the largest in Thailand, which generates approximately 2200 MW of energy and releases around 13 million tons of CO_2 annually [14,15]. The power plant is conveniently located within its own coal mine area, which covers 37.5 km^2 of operating space and an additional 41.5 km^2 for overburden dumping [16]. This proximity between the power plant and the coal mine makes transportation of CO_2 from the source to the sink area advantageous, as the distance is only around 15 km [15]. The CO_2 storage formation, or host rock, is situated approximately 400 m below the surface of the mine. The overburden pressure is around 5 MPa, and the storage temperature is about 25 °C. However, the stored CO_2 is found to be either as a gas or dissolved gas in formation brine, as it is not in the supercritical phase [17,18]. The salinity of the formation brine in this mine area is approximately 840 ppm. The lithologies of the Mae Moh basin are depicted in Figure 2.

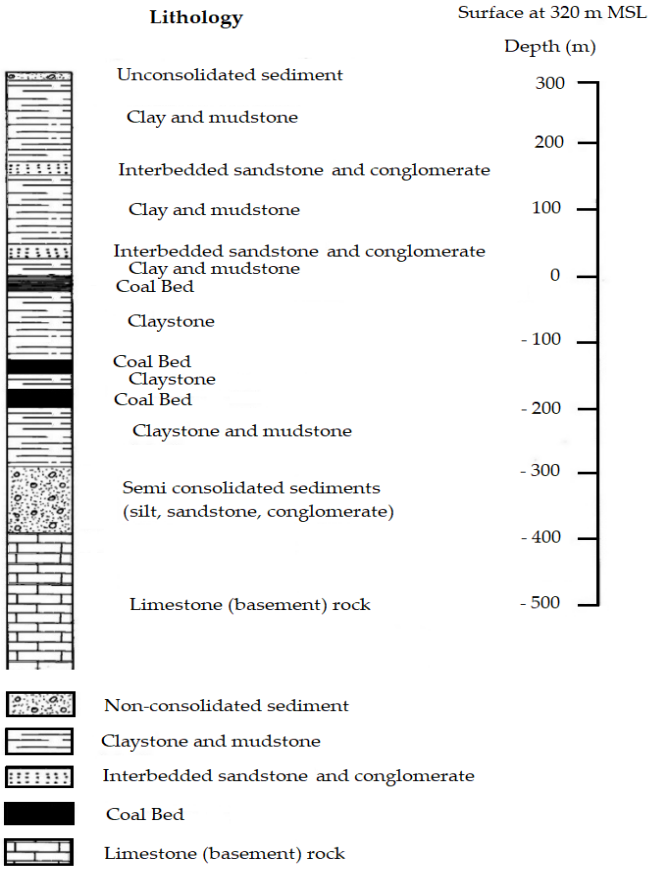

Figure 2. Lithologies of the Mae Moh basin.

2.2. Injection Well Completion Design

For the mud design, a normal pore pressure gradient was assumed. The mud weight for each casing interval was selected based on the equivalent density, which was calculated from the mud hydrostatic pressure between the formation pressure and fracture pressure (P_{ff}). In this pressure range, the drilling operation will not experience kick fluid or drilling fluid loss through the formation fracture. The fracture pressure can be calculated by

$$P_{ff} = (2/3)P_f + (1/3)P_{ob} \quad (1)$$

where P_f is the formation pressure (psi) and P_{ob} is the overburden pressure that is calculated from

$$P_{ob} = 0.433D[(1 - \varnothing)\rho_{ma} + \varnothing\rho_f] \quad (2)$$

where D is the formation depth (ft), $\varnothing$ is the porosity, ρ_{ma} is the formation rock density (g/cm^3), and ρ_f is the formation fluid density (g/cm^3).

Additionally, fracture pressure was used to determine the cement slurry density in order to prevent cement loss as similar as the design of mud density. To ensure the hydrostatic pressure did not exceed the fracture pressure, conventional Portland cement (class A) was mixed with CO_2-resistant additives [19]. The selected casing and tubing grade specifications were based on the burst pressure (formation pressure with safety factor) and collapse pressure (mud hydrostatic pressure with safety factor) of the worst-case condition to ensure that the casing and tubing could withstand within the life of the injection well and considering the corrosive resistance for CO_2 injection.

2.3. CO_2 Injection Design

This study utilized injection model analysis in the PROSPER® simulation program, using the Peng–Robinson equation of state (EOS) to predict the PVT properties of the CO_2

stream. The simulation model included information on the downhole equipment, injection well, and reservoir properties. The well input data also consider the casing and tubing sizes from the drilling program, as well as the depth profile. The CO_2 stream is injected into a target zone that is completely perforated. Vertical lift performance (VLP) correlations are established using the "Beggs and Brill" model, which is suitable for gas wells [20]. The inflow performance relationship (IPR) equation is based on the reservoir parameters provided in Table 1. Analysis of the well's performance primarily focuses on the operating injection rate. However, the anisotropy of the reservoir was not studied here due to a lack of field data. Sensitivity analyses were conducted by varying important inputs such as the wellhead pressure, tubing size, and injection temperature to optimize these parameters based on the project's economics.

Table 1. CO_2 injection system parameters for the Mae Moh basin area.

System Parameters	Value	Unit	Value	Unit
Formation thickness	355	ft	108	m
Formation temperature	25	°C	25	°C
Formation permeability	50	mD	50	mD
Reservoir pressure	721	psig	4.97	MPa
Porosity	0.2	fraction	0.2	fraction
Connate water saturation	0.1	fraction	0.1	fraction
Drainage area, acres	49,000	acres	198	km^2
Heat transfer coefficient	2	$Btu/(h.ft^2.°F)$	11.35	$W/m^2.K$

2.4. Economic Analysis

The simulation results were used to analyze the cost of injecting and storing CO_2 in order to determine the economics of the project. The costs associated with drilling and completing the well, as well as the annual operating expenses, were estimated based on previous economic studies conducted by energy industries [21–25]. A CO_2 injection well lifespan of 25 years and a discounted rate of 15% were used to calculate the net present value (NPV) of the project [21]. The carbon credit calculation assumed that the energy used for well completion and CO_2 injection came from the Mae Moh power plant source, with the proportions shown in Table A1 of Appendix A. The minimum carbon credit cost was determined to compare the total related cost of injection, which included all capital and operating expenses. This cost per ton of CO_2 injected represented the breakeven point for the project's NPV (zero value). Therefore, it served as an indicator of the potential of carbon underground storage compared to other CCS technologies, as it represents the expense that organizations would incur when implementing CGS in the specific field.

3. Results

3.1. Well Completion Design

During the drilling phase, water-based drilling mud with fluid loss control agents will be used for the entire operation, which is expected to last for 3 days as the penetration rate is estimated to be around 163 m/day [22,26]. There are no anticipated issues with hole stability or over-pressured intervals that could cause fluid flow into the wellbore. A moderately over-balanced drilling program will be implemented, using a mud weight of 10 ppg (lb/gal) in order to maintain a low fluid loss because the equivalent density of normal pressure condition is assumed to be 8.94 ppg. This closed system will result in only rock cuttings as waste materials, with all mud and fluids being recycled. Thus, a minimal reserve pit and little to no offsite fluid disposal is required.

The cementing procedures for the surface and conductor casing strings will primarily use traditional oilfield types/grades of cement. However, there will be one exception for the injection casing cement job, as CO_2-resistant additives will be included in the cement mixture. For the surface and injection casing strings, it is expected that 12 ppg cement slurries with a cement-to-gilsonite additive ratio of 35:65 will be used. This combination

has been proven to strengthen Portland cement used for CO_2 storage sites, which is supplemented from conventional petroleum well cementing as it does not require the CO_2-resistant additives [27,28]. The total volumes of cement used in the surface and injection casing intervals are 529.8 and 147.2 ft^3, respectively. The cement will be pumped through the 8-5/8-inch casing, passing through the float shoe and float collar (which have one-way flow ball valves) at the setting depth of the string. Consequently, the cement slug will change direction and flow in the 14-1/2- and 10-5/8-inch annular area from the target depth to the ground surface.

The casing program will start with a 16-inch outer diameter (O.D.) casing or the largest conductor that will be set to a depth of approximately 30 feet using a casing hammer. If this casing cannot be driven, a spud hole will be drilled, and the conductor casing will be welded and grouted in place [29]. Then, the surface hole will be drilled to approximately 1200 feet using a 14-1/2-inch bit. An 11-3/4-inch surface casing will be cemented from depth back to the surface to protect all sources of underground water. The "C-75" casing grade is selected for CO_2 injection purposes to extend the casing lifespan as this grade is more resistant to the corrosive environment than other conventional casing grades. After that, the remaining interval will be drilled using a 10-5/8-inch drill bit to an expected total depth (TD) of about 1560 feet, reaching the base of the limestone. The hole will be completed with 8-5/8-inch casing and cemented from total depth into the surface casing string. The proposed well casing specification is shown in Table 2. By following this drilling and casing methodology, it is appropriate to use each of these well sections for CO_2 injection purposes [29].

Table 2. Injection well casing program.

Tubular	Depth (ft)	Grade	O.D. (in)	Weight (lb/ft)	Collapse Pressure (psi)	Burst Pressure (psi)
Conductor	0–30	H-40	16	65	670	1640
Surface Casing	0–1200	C-75	11 3/4	60	3070	5460
Injection Casing	0–1555	C-75	8 5/8	36	4020	6090

In addition to the casing strings, other equipment that may be used during completion include centralizers to center the casing in the hole and cement baskets to mitigate the weight of the cement. The perforation process will use standard charges and does not require any specialized techniques or tools for cost-effectiveness and convenience. The perforating casing guns may be conveyed using wireline services, which is faster than tubing conveyed systems. The perforation holes should be no less than 0.3 inches in size, with a shot density of at least 4 shots per foot (spf) and phased at 90 degrees to access the formation effectively. It is a standard requirement to shoot through packed-off tubing at the bottom, and the L-80 tubing grade will be used based on the purpose of the injection operation. The technical specifications of the tubing can be found in Table 3. The tubing will need to be packed off at the base (approximately 1550 ft) using a permanent production packer system [19].

Table 3. Specifications of the injection well tubing.

Tubular	Depth (ft)	Grade	O.D. (in)	Weight (lb/ft)	Collapse Pressure (psi)	Burst Pressure (psi)
Tubing	0–1550	L-80	2 7/8	6.5	11,170	10,570

3.2. CO_2 Injection Design

The IPR curve is established using the input data of porous media properties from Table 1. This curve includes the value of the mechanical skin factor, which is determined by the perforation configuration and formation damage, and is combined in the IPR model. The characteristic of the IPR curve is shown in Figure 3, which predicts the absolute open flow potential (AOF) to be 2991.0 MMscf/day when the mechanical skin factor is expected

to be zero. This means that the flow is not restricted, as the skin factor in the actual gas well could be zero or negative [30,31]. On the other hand, the VLP curve is based on the selected tubing configurations from Table 3. By intersecting the IPR and VLP curves, the flowability that will be achieved in this injection well under continuous gas injection at a certain wellhead pressure is demonstrated in Figure 3. This indicates the optimum gas injection rate for the studied system, which is 1.454 MMscf/day or 29,530 ton/year. The configuration and parameters of the injection well from the well completion and CO_2 injection design section will then be used to perform the economic analysis.

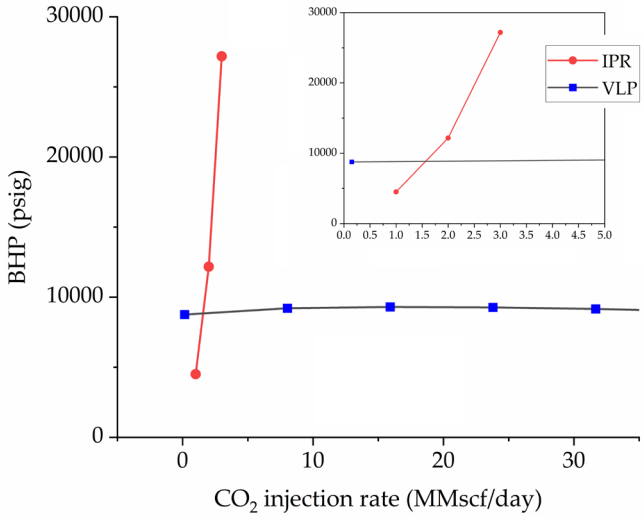

Figure 3. Characteristics of the inflow performance relationship (IPR) and vertical lift performance (VLP) curve for the CO_2 injection system in the Mae Moh area.

3.3. Economic Analysis

The project expenses for this study can be divided into two main components: capital costs (CAPEX) and operating costs (OPEX). CAPEX primarily includes the cost of well drilling and completion, which can be further divided into various categories such as fuel, drilling bits, casing, wellhead, cementing, mud and chemicals, completion and injection equipment, labor, and overhead [22]. Among these categories, the cost of mud and chemicals for well drilling is the highest, followed by completion costs, fuel, and other components. Specifically, the cost of mud and chemical accounts for 19.0% of the total CAPEX, casing accounts for 16.0%, completion costs account for 15.5%, fuel accounts for 11.7%, and the remaining costs come from other components, as shown in Figure 4. The total CAPEX for this project is estimated to be USD 756,600 per well. When taking into account an average inflation rate of 5% per year, this estimation is comparable to the cost estimates provided by Gul et al. [26] and Ogden et al. [32] for well construction, at a similar target depth of approximately 1600 ft. The calculated CAPEX values from the aforementioned studies are USD 733,000 and USD 715,000 per well, respectively.

The annual operating costs of the injection project calculated from the operating premises are shown in Table 4, and the results from the economic analysis in terms of project economic components, including CAPEX, annual OPEX, annual sale, and revenue, are shown in Figure 5. According to the analysis, the total annual OPEX per well is around USD 2.03 million per year, including the cost of CO_2 capture and transport of around USD 1.58 million per year, or approximately USD 53 per ton of CO_2 [23,24]. Thus, the minimum sale unit price, in the term of carbon credit cost of USD 72.50 per ton of CO_2e is required to reach the breakeven for this project, which results in an annual revenue of USD 117,000 year per well.

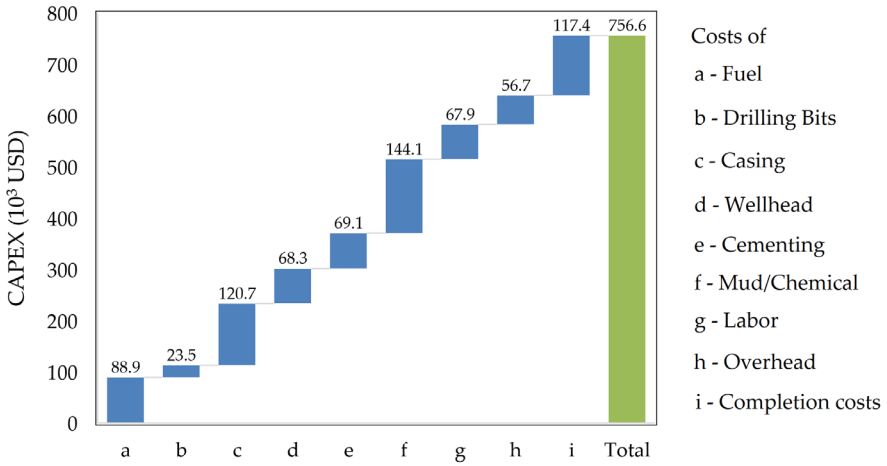

Figure 4. CAPEX distribution of CO_2 injection well construction in the Mae Moh area.

Table 4. Operational premises and calculated values of OPEX in the economic analysis.

Component	Description	Value (USD/Year)	Ref.
Injection cost	Calculated from injection pump capacity and power usage from simulation results	50,300	-
Overhead	2.5% of total operating cost	41,000	[22]
Maintenance cost	6% of capital cost	4500	[22]
Capture and Transport cost	USD ~53 per ton CO_2	1,575,000	[23,24]
Operating labor cost	15% of total operating cost	244,000	[25]
General and administrative	7% of total operating cost	114,000	[25]

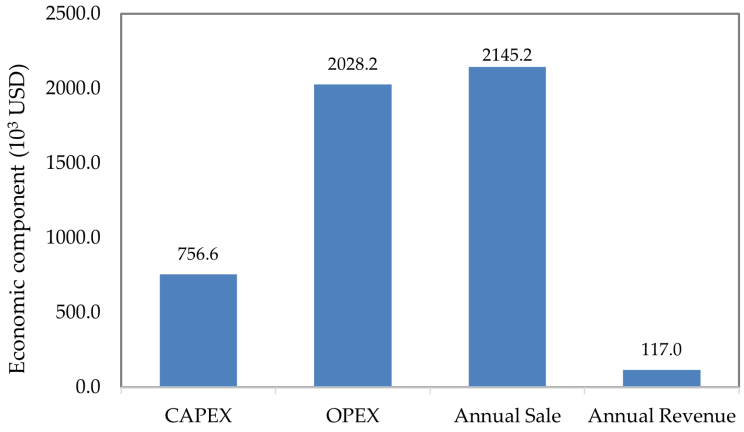

Figure 5. Economic components of the CO_2 injection well project in the Mae Moh area.

4. Discussion

This study performed sensitivity analysis to examine the impact of wellhead pressure, tubing or pipe diameter, and injection temperature on the flow condition of the well and the total injection cost, specifically in terms of the minimum carbon credit cost. The results from the sensitivity analysis are shown in Figure 6. The discussions for the effect of each studied parameter are as follows:

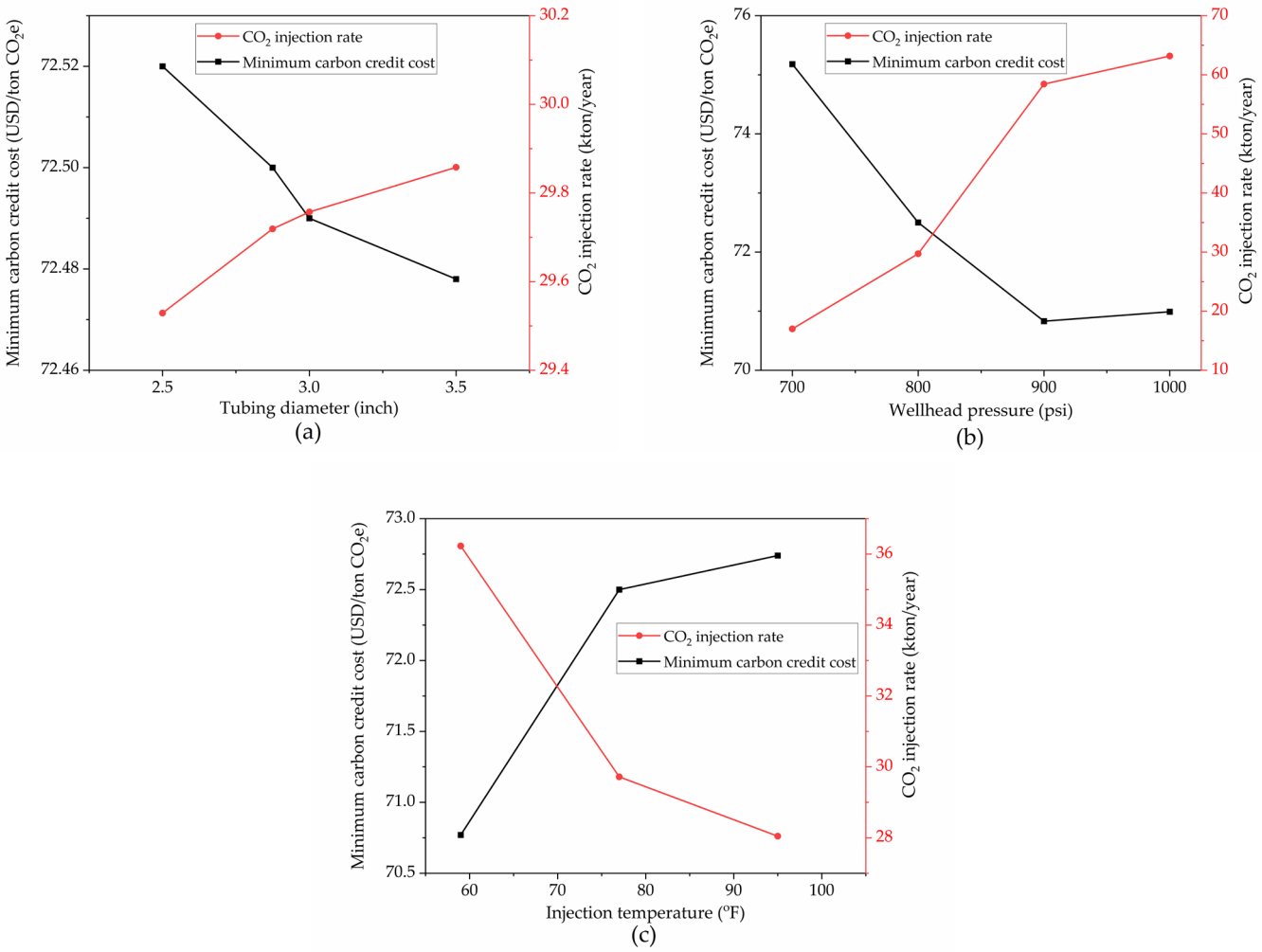

Figure 6. Effect of different parameters on the CO_2 injection rate and the minimum carbon credit cost: (**a**) tubing diameter; (**b**) wellhead pressure; and (**c**) injection temperature.

Effect of tubing diameter. The effect of tubing diameter to the CO_2 injection rate and minimum carbon credit cost is shown in Figure 6a. The results indicate that increasing the tubing diameter from 2 1/2 to 3 1/2 inches leads to an increment in the injection rate from 29,500 to 29,900 tons of CO_2 per year. This increase is attributed to a reduction in frictional pressure loss within the tubing, allowing the energy from the wellhead pressure to support the higher injection rate. Consequently, the minimum carbon credit cost slightly decreases from USD 72.52 to 72.47 per ton of CO_2e as the tubing size increases. This reduction is a result of a larger proportion of CO_2 being injected. However, it is important to note that the well casing size poses a limitation, as a larger tubing diameter may not fit within the designed casing size of this particular well.

Effect of wellhead pressure. The injection rate increases from 17,000 to 63,200 tons of CO_2 per year when the wellhead pressure is increased from 700 to 1000 psi, as shown in Figure 6b. This trend is comparable to study of the effect of wellhead pressure on the gas injection rate from Liu et al. [33] and Bai et al. [34], as more energy is supplied from the pressure pumping equipment, allowing for a higher injection rate. As a result, the minimum carbon credit cost decreases from USD 75.18 to around USD 71 per ton of CO_2e with the increment in wellhead pressure. The minimum value of carbon credit cost is reached at a wellhead pressure of 900 psi. However, the trend reverses at a wellhead pressure of 1000 psi due to the increase in both values of CAPEX and OPEX resulting from the higher injection rate. Additionally, the well fracture pressure is serving as the limitation, as a larger wellhead pressure results in the increment of bottomhole pressure,

and exceeding the formation fracture pressure (~1000 psi) when the wellhead pressure exceeds 800 psi.

Effect of injection temperature. When the injection temperature is decreased from 95 to 59 °F, the injection rate increases from 28,000 to 36,200 ton/year per well, as shown in Figure 6c. This trend is comparable to a study of the effect of injection temperature on the gas storage capacity by Jing et al. [35], as the increase in injection temperature leads to a larger amount of CO_2 in the gas phase and a higher formation pressure [35]. As a result, more energy is required from the pumping equipment to inject a higher volume of gas. Consequently, the minimum carbon credit cost decreases from USD 72.74 to 70.77 per ton CO_2e with the lower injection temperature. This reduction is due to both the higher rate of CO_2 injected and the lower operating wellhead pressure required.

Implementation in the Mae Moh basin. Even supposing that the geological characteristics of the Mae Moh basin are feasible for implementation of the CGS operation, there are limitations and concerns that need to be further investigated. Firstly, the characteristics of the proposed well in the basin need to be considered. The basin, which encompasses the location of the currently operated mine and spans approximately 132 km^2, may lead to increased capital costs during the installation period of the CCS system. Secondly, by the 2030s, the mining pit, which could serve as the injection site, is projected to reach a depth of approximately 400 m. This will result in increased logistic and management costs compared to the current values. According to the reference price from EGAT [36], the estimated price for area and pit preparation can be up to approximately USD 1.36 per m^3 of soil and sediment removal. Moreover, it is necessary to address the stability issues associated with the groundwater system in this area, particularly at the basin within a coal mine. Therefore, development of the drilling and injection of CO_2 in the area must be closely monitored to prevent failure in the operation [37].

Economic opportunities in Thai carbon market. In Thailand, the rules and regulations regarding emissions reductions are enforced through the Thailand Voluntary Emission Reduction (T-VER) program, which is managed by the Thailand Greenhouse Gas Management Organization (TGO). As a result, the carbon market in Thailand primarily operates on a voluntary basis. As per the prescribed T-VER-S-METH-14-01 guideline for capturing, storing, and utilizing greenhouse gases (GHGs), the measurable GHGs must be obtained by calculating the difference between the baseline GHG emissions and the reduction in GHGs resulting from both direct operations and auxiliary activities. Based on the research conducted by Win et al. [38], the Electricity Generating Authority of Thailand (EGAT) has reported total emissions of 31.382 $MtCO_2e$ or 0.515 kg CO_2eq/kW.h. Consequently, the coal power plant in the basin emits 6.57 $MtCO_2e$ annually. Given that the annual capture rate of greenhouse gases (GHGs) from the study is only 0.29 $MtCO_2e$, it can be concluded that the project is not valuable due to the low rate of carbon reduction (refer to Table A1 in Appendix A). To enhance the economic prospects of the area, it is imperative to promote a policy aimed at reducing greenhouse gas emissions in conjunction with other supplementary activities. This will help mitigate the high emission levels in this area.

In conclusion, the minimum carbon credit costs for the CGS project are found to be much higher than the current market price of carbon credit in Thailand, which is only around USD 3.5 per ton CO_2e and the capture rate is far lower than those produced from the emission. However, it is found that the amount of CO_2 storage achieved by the CGS project is significantly higher than the carbon sequestration achieved through planting [16]. Therefore, if the market value of carbon credit costs is improved, the CGS project in the Mae Moh basin of Thailand can be economically feasible.

5. Conclusions

The economic analysis of CO_2 injection in Mae Moh basin area was implemented in this study to estimate the total costs of carbon geological storage. The well completion design was employed to specify the necessary well equipment and materials for the determination of CAPEX while the CO_2 injection design was performed by nodal analysis

in the PROSPER® simulation program to estimate the operating injection rate and costs. The completion of a CO_2 injection well is similar to that of a conventional petroleum well, with the exception being that CO_2-resistant equipment and materials are required for casing, cementing, and tubing. Based on these considerations, the calculated value of the CAPEX for constructing a well to the target depth of 1600 ft is approximately USD 756,600. In addition to the CAPEX, the study estimated the total OPEX for CO_2 capture, transport, and injection. The annual OPEX is approximately USD 2,030,000 per well, with an injecting capacity of 29,530 tons of CO_2 per year. To make this project financially feasible, the minimum carbon credit cost required is USD 72.50 per tCO_2e, which is significantly higher than the market value of carbon credit in Thailand. This breakeven point can be reduced by increasing the tubing diameter or wellhead pressure, as this would increase the injecting capacity and reduce the cost per injected unit. However, it is noted that higher injection costs are required when the injection temperature is increased due to a larger proportion of CO_2 in the gas phase.

However, this study has several limitations that need to be considered. Firstly, the capital and operating costs of carbon geological storage were estimated specifically for the Mae Moh basin area. Therefore, these values may vary in other locations and need to be recalculated on a case-by-case basis. Another limitation is that the carbon storage cost, in terms of capture cost, was chosen based on a conservative estimate from the literature related to coal power plants. If CO_2 is generated from a different energy source, the actual cost may differ from the value selected in this study, impacting the economic analysis of carbon geological storage costs. Hence, this factor also needs to be taken into account on a case-by-case basis.

Since the beginning of the 2020s, Thailand has seen a growing awareness of the Sustainable Development Goals (SDGs) and greenhouse gas emissions. This has prompted both the government and private sector to step up and play their part in reducing emissions. Consequently, the carbon market in Thailand has a tendency of growth, leading to an expansion of incentives and regulations. This upward trend could potentially drive up the price of carbon, making it financially feasible to pursue the operation of CGS projects. However, since the regulatory framework is still in its early stages of development, Thailand's capacity of carbon trading in the global market is not verified. Therefore, Thailand's full engagement in the global carbon market is still uncertain because of this limitation.

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Data Availability Statement: Any geological and analytical data assigned and retrieved in this study are the private information of the Electricity Generating Authority of Thailand (EGAT). The availability of these data, which were used during this study, is restricted and not publicly available due to the privacy policy of the organization. Data are, however, available from the authors upon reasonable request and with permission of the Electricity Generating Authority of Thailand (EGAT).

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Nomenclature

Abbreviations

AOF	Absolute open flow
CAPEX	Capital expenditure
CCS	Carbon capture and storage
CGS	Carbon geological storage
EGAT	Electricity Generating Authority of Thailand
EOS	Equation of state
GHGs	Greenhouse gases
IPR	Inflow performance relationship
MMI	Modified Mercalli Intensity
NPV	Net present value
O.D.	Outer diameter
OPEX	Operational expenditure
POE	Probability of exceedance
PSHA	Probabilistic seismic hazard
PVT	Pressure–volume–temperature
SDGs	Sustainable Development Goals
TD	Total depth
TGO	Thailand Greenhouse Gas Management Organization
T-VER	Thailand Voluntary Emission Reduction Program
USD	U.S. dollar
VLP	Vertical lift performance

Symbols

CO_2	Carbon dioxide
g/cm^3	Gram per cubic centimeter
in	Inch
kW.h	Kilowatt-hour
mD	Millidarcy
MMscf	Million standard cubic feet
MPa	Megapascal
ppg	Pound per gallon (lb/gal)
psi	Pound per square inch
spf	Shots per foot
tCO_2e	Ton of carbon dioxide equivalent

Appendix A

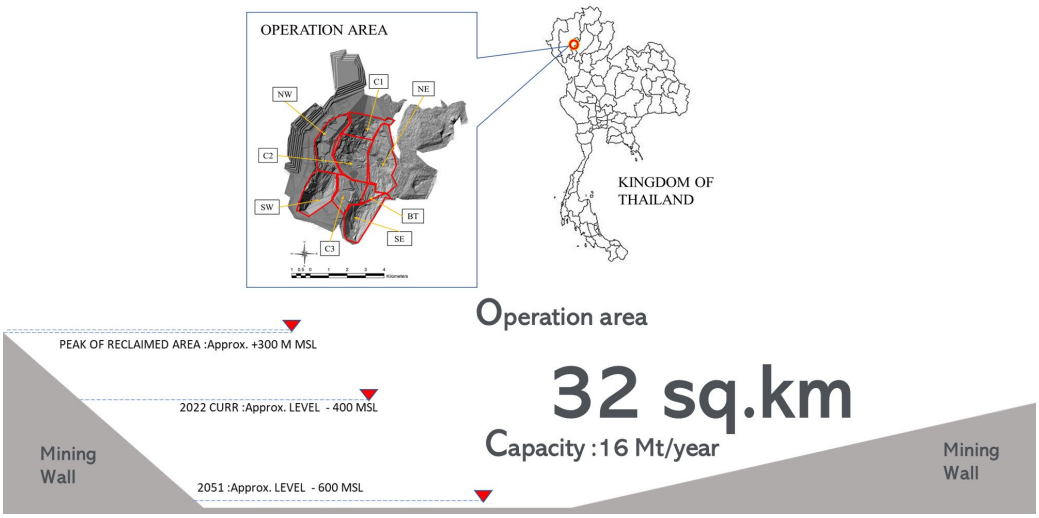

Figure A1. The location of the Mae Moh basin, which is currently the operational area of the Mae Moh coal mine and power plant.

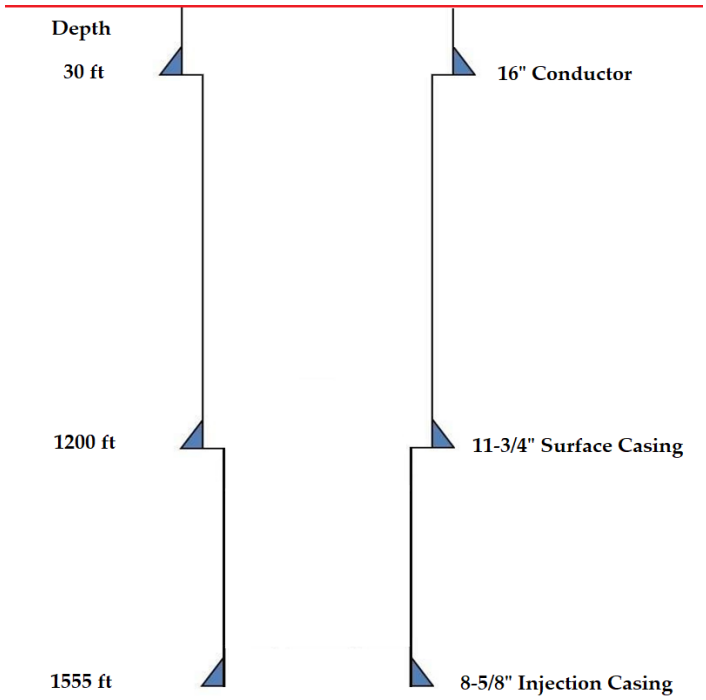

Figure A2. Well diagram of the CO_2 injection well.

Table A1. Estimation of GHG emissions from the Mae Moh Power Plant.

Power Generation of Thailand (MW)	Contribution of Energy Source (%)		Power Generation Based on Each Sector (MW)	Capacity of the Mae Moh Coal Power Plant (MW)	Total GHG Emissions ($MtCO_2e$)	Emission of Mae Moh Coal Power Plant ($MtCO_2e$)
32,255	Coal	16.76%	5405.94	2200	96.3	6.57
	Natural gas	52.15%	16,820.98			
	Renewable energy	7.31%	2357.84			
	Imports	17.64%	5689.78			
	Oil and others	6.14%	1980.46			

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