

Article

Numerical Investigation of Offshore CCUS in Deep Saline Aquifers Using Multi-Layer Injection Method: A Case Study of the Enping 15-1 Oilfield CO₂ Storage Project, China

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Abstract

Geological storage of CO₂ in offshore deep saline aquifers is widely recognized as an effective strategy for large-scale carbon emission reduction. This study aims to assess the mechanical integrity and storage efficiency of reservoirs using a multi-layer CO₂ injection method in the Enping 15-1 Oilfield CO₂ storage project which is the China's first offshore carbon capture, utilization, and storage (CCUS) demonstration. A coupled Hydro-Mechanical (H-M) model is constructed using the TOUGH-FLAC simulator to simulate a 10-year CO₂ injection scenario, incorporating six vertically distributed reservoir layers. A sensitivity analysis of 14 key geological and geomechanical parameters is performed to identify the dominant factors influencing injection safety and storage capacity. The results show that a total injection rate of 30 kg/s can be sustained over a 10-year period without exceeding mechanical failure thresholds. Reservoirs 3 and 4 exhibit the greatest lateral CO₂ migration distances over the 10-year injection period, indicating that they are the most suitable target layers for CO₂ storage. The sensitivity analysis further reveals that the permeability of the reservoirs and the friction angle of the reservoirs and caprocks are the most critical parameters governing injection performance and mechanical stability.

Keywords: CCUS; deep saline aquifers; multi-layer injection; CO₂ storage capacity; TOUGH-FLAC



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1. Introduction

Carbon capture, utilization, and storage (CCUS) is one of the most effective technologies to reduce CO₂ emissions, and the use of CCUS technology is expected to achieve net-zero emissions from fossil energy utilization [1,2]. Deep saline aquifers are widely distributed in marine sedimentary basins, and their enormous CO₂ storage capacity is conducive to the implementation of CCUS projects [3,4].

With the widespread implementation of CCUS projects worldwide [5–8], the safe and economical injection of CO₂ has become an important research topic for CCUS [9,10]. As a large amount of CO₂ is injected into the saline aquifer, phenomena such as pressure accumulation and transmission, CO₂ migration, etc., will occur in the deep saline aquifer. If the pressure increases to a certain extent, it will affect the mechanical stability of the

reservoir and caprock, thereby increasing the risk of CO₂ leakage and ultimately affecting the storage safety of the entire storage site [11,12].

Research has shown that in geological settings characterized by heterogeneous and low-permeability reservoirs, CO₂ sequestration in a single reservoir is often insufficient to meet the goals of efficient and cost-effective carbon storage [13,14]. In contrast, the use of multiple reservoirs facilitates multi-directional lateral pressure diffusion, especially in formations with different permeabilities and storage capacities. This approach fosters a more isotropic stress response within the surrounding rock mass and contributes to long-term hydro-mechanical stability. As a result, stress redistribution is smoother, and the structural integrity is better preserved. From an operational perspective, multi-layer injection not only enhances storage capacity but also improves safety margins for large-volume CO₂ storage in offshore sedimentary basins [15,16].

Zhu et al. [17] and Shi et al. [18] investigated the geomechanical response of reservoirs in the Shenhua CCUS project under CO₂ multi-layer injection conditions. It is found that due to the differences in permeabilities between injection layers, CO₂ is preferentially injected into reservoirs with relatively high permeability, and the pore pressure rapidly diffuses along the horizontal direction of the reservoirs. However, in the low-permeability layers, CO₂ injection and pore pressure diffusion are relatively slow. Therefore, in order to enhance the carbon storage potential of multi-layer reservoirs, it is necessary to control the CO₂ injection rate based on the permeability of each injection layer [19]. The CO₂ injection pressure is a key factor determining reservoir risk, as an increase in CO₂ injection pressure significantly increases the risk of CO₂ leakage [20]. Ma et al. [21] studied the influence of CO₂ multi-layer injection method on the sealing of the caprock in the Ordos Basin. They also employed tornado analysis for sensitivity evaluation and screened out factors that have a significant impact on the sealing of the caprock. The research results indicate that the main controlling factors of caprock sealing are Poisson's ratio, Young's modulus, reservoir thickness, permeability coefficient, and injection rate. Li et al. [22] evaluated the CO₂ storage potential in the offshore region of the western Taiwan Basin using a numerical model. Their findings indicate that CO₂ injection causes a rapid and extensive increase in formation pressure. Li et al. [23] conducted numerical simulations of CO₂ injection in the Pearl River Estuary offshore basin in China. The results demonstrate that the injection rate, reservoir pressure, CO₂ migration distance, and the amount of CO₂ dissolved in the aquifer exhibit nonlinear characteristics. Overall, research on CO₂ injection into multiple reservoirs has mainly focused on onshore CCUS. Although onshore CCUS offers advantages such as technological maturity and construction convenience, it imposes higher demands on the subsurface space utilization and may conflict with other underground resource uses, such as groundwater extraction and geothermal energy development. By contrast, offshore CCUS benefits from extensive sedimentary basins providing favorable geological conditions for long-term storage. In addition, offshore CCUS is typically situated away from densely populated areas, which reduces the risk that potential CO₂ leakage poses to public safety and freshwater resources, and is generally linked to lower environmental sensitivity.

CO₂ geological storage sites in Chinese marine sedimentary basins have the characteristics of insufficient reservoir thickness, mostly consisting of thin layers overlapping vertically [24]. Therefore, traditional CO₂ single-reservoir injection methods cannot meet the needs of marine CCUS [25]. This study aims to assess the mechanical integrity and storage efficiency of reservoirs using a multi-layer CO₂ injection method in the Enping 15-1 Oilfield group in the Pearl River Mouth Basin, which is China's first offshore CCUS demonstration. Firstly, numerical models are established using the TOUGH-FLAC coupling simulation, a numerical approach used to describe the interaction between underground multiphase fluid flow and geomechanical responses to analyze the responses of the reser-

voir and caprock under multi-layer injection conditions. Secondly, the tornado analysis method is used to analyze the coupling response of reservoir and caprock parameters and injection rates to the flow stress coupling of the multi-layer system and to determine the optimal multi-layer injection rate in the target area. The results of this study can provide technical support for the evaluation of target storage capacity under CO₂ multi-layer injection conditions.

2. Numerical Model

2.1. Location of the CCUS Project

The Huizhou hydrocarbon field, located in the north of the Pearl River Mouth Basin, has an area of approximately 11,000 km², which provides favorable conditions for the application of the CCUS project. The 3D lithofacies model, which contains sandstone and mudstone interlayers of the reservoir, is shown in Figure 1. This lithology model is constructed based on well logging curves, as well as sandstone and mudstone layer data derived from seismic inversion.

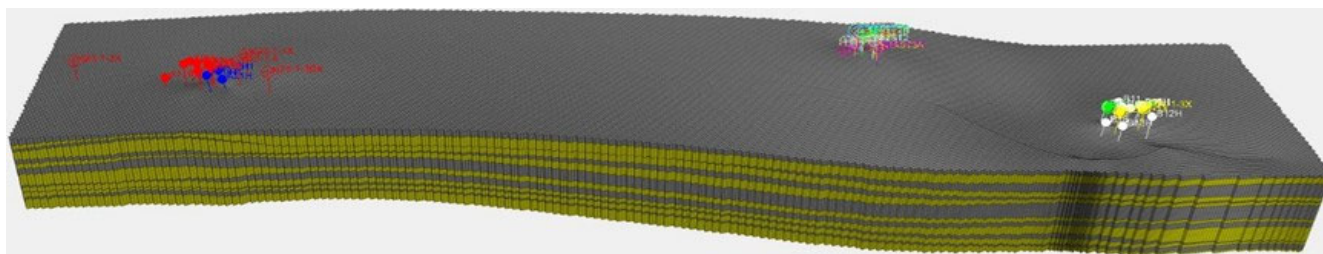


Figure 1. The 3D lithofacies model of the Huizhou hydrocarbon fields.

The Enping 15-1 oilfield group, located in the Huizhou hydrocarbon field, was selected as the target area. The caprock is buried at a depth of approximately 1500 m, as shown in Figure 2. Sandstone and mudstone layers are interbedded in the target area; therefore, the multi-layer injection method is employed in this study.

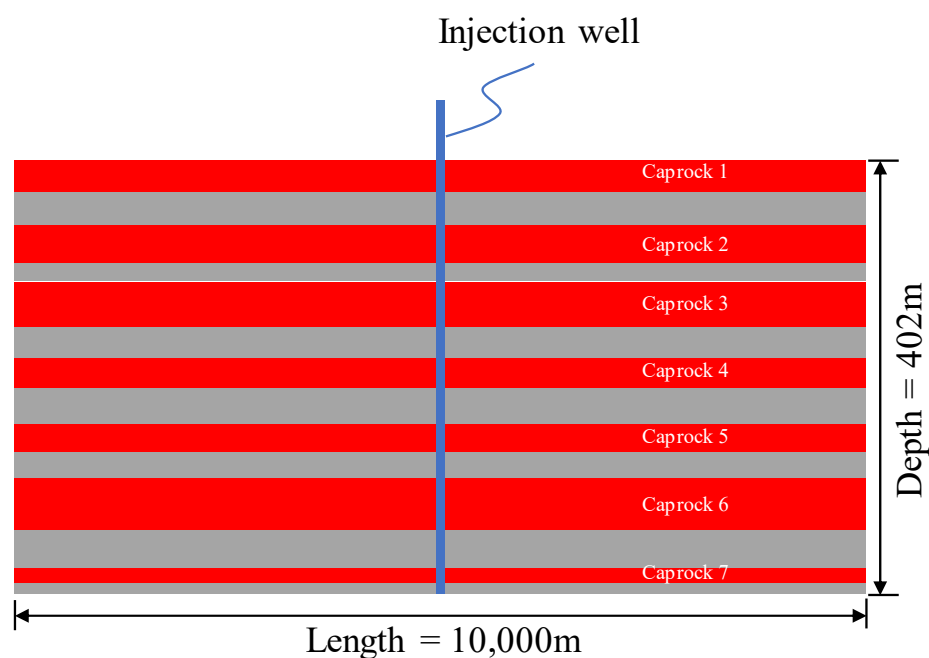


Figure 2. Numerical model of the multi-layer reservoirs.

2.2. TOUGH-FLAC Model

TOUGH-FLAC coupling simulation is a numerical approach used to describe the interaction between underground multiphase fluid flow and geomechanical responses [26]. Within this coupling framework, TOUGH calculates multiphase flow, heat conduction, and mass transport in porous media, enabling simulations of subsurface processes such as CO₂ injection and thermal energy storage. FLAC, in turn, solves stress-induced deformations and fracture propagation in the formations resulting from fluid injection or pressure variations. The TOUGH-FLAC model has been widely applied in areas such as CO₂ geological storage [27], geothermal energy extraction [28], and unconventional oil and gas development [29], offering a robust predictive tool for geotechnical engineering.

Indeed, Thermo-Hydro-Mechanical-Chemical (T-H-M-C) coupling plays a critical role in long-term CO₂ geological storage, particularly in assessing the evolution of reservoir properties over decades to centuries. However, this study focuses on the short-term behavior (10 years) of CO₂ injection into offshore saline aquifers. During this period, the dominant factor influencing storage integrity is pore pressure. Therefore, we adopted a Hydro-Mechanical (H-M) coupling approach, which captures the essential interactions between fluid flow and rock deformation. This simplification is consistent with other studies that focus on injection-phase assessments [30,31].

The basic assumptions of numerical models are as follows: (1) not considering the impact of chemical reactions generated by CO₂ injection on the response of geomechanical response; (2) not considering the impact of pore pressure caused by CO₂ injection on porosity of rocks; (3) not considering the thermal stress caused by CO₂ injection; (4) the formation is in a fully saturated state before injection and flow follows Darcy's law.

A two-dimensional multi-layer reservoir and caprock model is established using the TOUGH-FLAC framework for investigating the interaction between mechanical deformations and fluid flows during CO₂ injection, as shown in Figure 3.

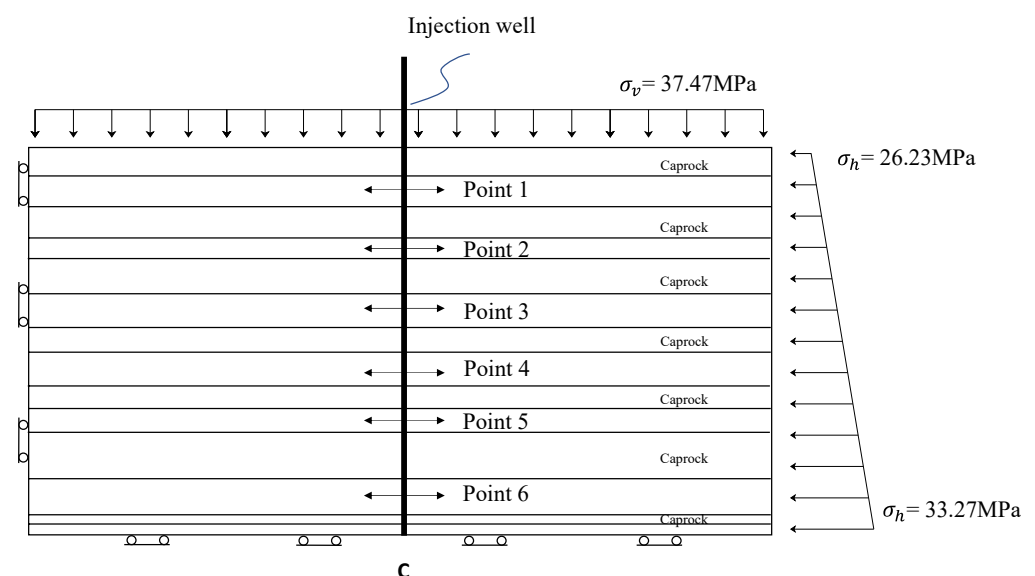


Figure 3. Boundary conditions used in the numerical model.

The model contains six high-permeability reservoirs and six low-permeability caprocks. From top to bottom, the thicknesses of the caprocks are 30, 36, 42, 24, 24, 48, and 12 m, and the thicknesses of the reservoirs are 30, 18, 30, 36, 24, 36, and 12 m.

CO₂ is injected into the numerical model using the multi-layer injection method. There are six injection points in the injection well, and these points are located in the middle of

the upper six reservoirs at depths of -1543 , -1603 , -1669 , -1729 , -1777 , and -1855 m. The injection rate is assigned to each layer according to Equation (1).

$$q_i = \frac{k_i H_i}{\sum_i k_i H_i} q \quad (1)$$

where q is the total flow, q_i is the flow of each layer, k_i is the permeability of each layer, and H_i is the thickness of each layer. In this research, the target total injection volume of the numerical simulation is 1.0 million tons/year which is equal to 30 kg/s. Equation (1) is used to calculate the injection rate for each layer, and the results are 5.2, 3.1, 5.2, 6.2, 4.1, and 6.2 kg/s, respectively. The reservoirs and the caprocks are considered elastoplastic and described using the Mohr–Coulomb model. The hydrologic and mechanical parameters are shown in Table 1.

Table 1. Parameters of the caprock and the reservoir used in the numerical model.

Indicators	Parameters	Values	Units
Caprock			
Young's modulus	E_c	8	GPa
Poisson's ratio	ν_c	0.3	-
Permeability	k_c	1×10^{-17}	m^2
Void ratio	n_c	0.01	-
Angle of friction	φ_c	30	$^\circ$
Dry density	ρ_c	2550	kg/m^3
Reservoir			
Young's modulus	E_r	8	GPa
Poisson's ratio	ν_r	0.3	-
Permeability	k_r	5×10^{-13}	m^2
Void ratio	n_r	0.24	-
Angle of friction	φ_r	30	$^\circ$
Dry density	ρ_r	2550	kg/m^3

The boundary conditions of the numerical model are also shown in Figure 3. The upper boundary is a constant pressure with $\sigma_v = 37.47$ MPa and is calculated from the self-weight of the overlying rock. The left side is set as a fixed displacement boundary. The right side is set as a static water pressure boundary, which increases linearly from top to bottom along the depth, and the top horizontal stress σ_h is 26.23 MPa, which is 0.7 times the vertical stress σ_v . The vertical and horizontal displacements of the bottom boundary are both limited to zero.

3. Numerical Simulation Results

In the early stages of injection, CO_2 migrates upwards and accumulates at the bottom of the caprock. When the saturation of accumulated CO_2 reaches a certain value, CO_2 begins to displace reservoir fluid and diffuse further away, which can cause uplift and deformation of the caprock [32]. If the pore pressure of the reservoir exceeds the rupture pressure of the caprock, the interface between the reservoir and the caprock is subjected to shear or tension, which can easily cause hydraulic rupture of the caprock and generate high permeability channels, leading to CO_2 leakage. Therefore, CO_2 saturation, pore pressure, and Coulomb failure stress were selected as indices to evaluate the influence of sensitivity parameters on CO_2 sequestration capacity in this research.

3.1. CO₂ Saturation

Figure 4 shows the distribution of CO₂ saturation in the reservoirs after one year and ten years of CO₂ injection. It can be observed that the distribution of CO₂ in the reservoir roughly presents an inverted triangle shape. This is because the density of the injected CO₂ is lower than that of the reservoir fluid. Therefore, CO₂ first migrates upward to the bottom of the caprock. When the saturation of accumulated CO₂ reaches a certain value, CO₂ begins to displace the reservoir fluid and diffuse further along the bottom of the caprock, gradually forming an inverted triangle distribution shape of CO₂ in the reservoir.

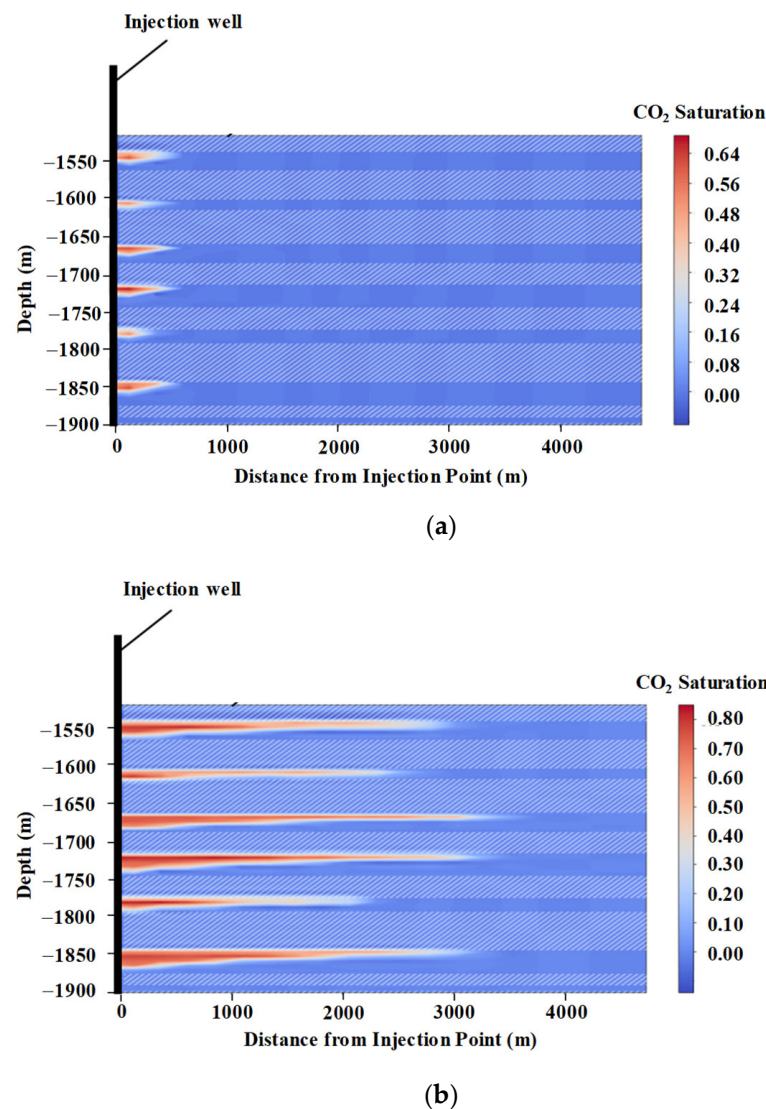


Figure 4. CO₂ saturation and migration distance in the reservoir. (a) 1 year; (b) 10 years.

The values of the horizontal migration distance of CO₂ are shown in Table 2. It can be found that after one year of injection, the maximum and minimum CO₂ horizontal migration distances are 572.0 and 400.0 m, respectively, with an average migration distance of 531.3 m. After ten years of CO₂ injection, the maximum and minimum CO₂ horizontal migration distances increase to 3300.0 and 2270.0 m, respectively, with an average migration distance of 2988.8 m, which is 5.6 times that of the first year of injection.

This phenomenon reflects buoyancy-driven CO₂ migration and lateral pressure dissipation, which are characteristic of offshore deep saline aquifers. In addition to the overall migration trend, an analysis of individual reservoir layers reveals that Reservoirs 3 and 4 exhibit the greatest CO₂ migration distances—3505 m and 3300 m, respectively—during

the 10-year injection period, as shown in Table 2. These results suggest that Reservoirs 3 and 4 are the most favorable targets for CO₂ storage, and the injection strategies should prioritize them to enhance storage efficiency and safety.

Table 2. Horizontal migration distance of CO₂ in the reservoir.

Number of Reservoir	Injection Rate, kg/s	Thickness of Reservoir, m	Horizontal Migration Distance, m	
			1 Year	10 Years
1	5.5	30	572	3008
2	3.1	18	500	2650
3	5.2	30	572	3505
4	6.2	36	572	3300
5	4.1	24	400	2270
6	6.2	36	572	3200

3.2. Pore Pressure

The distribution of reservoir pore pressure increments ΔP after injecting CO₂ into the reservoir for one year and ten years is shown in Figure 5 and Table 3.

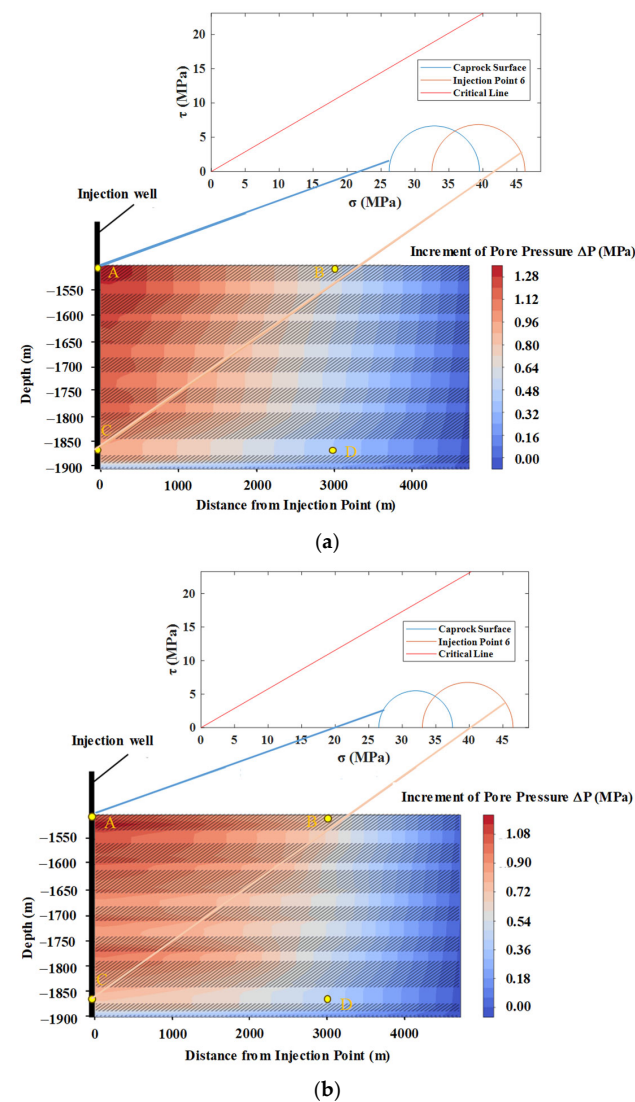


Figure 5. Increment of pore pressure in the reservoir. (a) 1 year; (b) 10 years.

Table 3. Increase in pore pressure and average effective stress in the reservoir.

Location	Increase in Pore Pressure, MPa		Effective Stress, MPa	
	1 Year	10 Years	1 Year	10 Years
A	1.3	1.1	33.0	32.0
B	0.56	0.64	32.8	32.5
C	0.91	0.76	39.5	39.5
D	0.37	0.38	39.5	39.5

From the results of Figure 5 and Table 3, it is found that the value of ΔP near the injection point decreases slowly with an increase in injection time. The values of ΔP at Points A and C are 1.3 and 0.91 MPa after one year of CO₂ injection, and these values decrease to 1.1 and 0.76 MPa, respectively, after ten years of CO₂ injection. This is because at the initial stage of injection, CO₂ accumulates at the bottom of the caprock, causing an increase in pore pressure. When the saturation of accumulated CO₂ reaches a certain value, CO₂ begins to displace reservoir fluid and the pore pressure gradually dissipates. In contrast, the pore pressure far from the injection point continues to increase slowly with the increase in injection time. The values of ΔP at Points B and D which are located at a horizontal distance of 3000 m from the injection point are 0.56 and 0.37 MPa, and these values slightly increase to 0.64 and 0.38 MPa after ten years of CO₂ injection.

Figure 5 also shows the stress state at the injection points. After one year of CO₂ injection, the average effective stress at Point C in the deep reservoir is 39.5 MPa, which is larger than the 33.0 MPa at Point A in the shallow reservoir. The Mohr circle of Point C is far away from the rock failure line, which means that the deep reservoir is safer than the shallow reservoir. After ten years of CO₂ injection, the average effective stress at Point C in the deep reservoir remains unchanged, but the average effective stress at Point A in the shallow reservoir decreases to 32.0 MPa.

3.3. The Coulomb Failure Stress

In general, a high injection rate can increase the CO₂ storage capacity. However, it can also increase the pore pressure in the reservoir, leading to reservoir and caprock fractures and increasing the risk of CO₂ leakage. Therefore, it is necessary to determine a reasonable injection rate based on the safety of caprocks and the economy of the reservoirs.

In this research, the Coulomb failure stress (CFS) is selected as the indicator to identify the impact of injection rate on the safety of the caprocks during numerical simulations. The value of the CFS can be calculated from Equation (2).

$$CFS = \tau / (C + \mu(\sigma + P)) \quad (2)$$

where τ is the magnitude of the shear stress on the plane, σ is the normal stress on the plane, P is the pore pressure, C is the cohesion force, and μ is the friction coefficient. The larger the CFS is, the worse the stability of the caprock. When the value of CFS is greater than or equal to 1, it indicates that the rock stress reaches its failure state.

The maximum CFS values that occur in the reservoirs and the caprocks at different injection rates (30, 60, 90, 120, 240, 270, and 300 kg/s) were monitored. The simulation results are shown in Figure 6. It is found that the CFS value reaches its peak at 0.65 within one year when the injection rate is 30 kg/s. Then, as the injection time increases, the pore pressure gradually dissipates, resulting in a slow decrease in the CFS value. After ten years of injection, the value of CFS decreases by 1.5%. In addition, it is found that under the same conditions, the higher the injection rate, the higher the CFS value. At an injection rate of 300 kg/s, the CFS value peaks at 0.87 within one year. However, as the injection time

increases, the CFS value rapidly decreases; the CFS value is 0.72 after ten years of injection, a decrease of 17.2% compared to the peak condition.

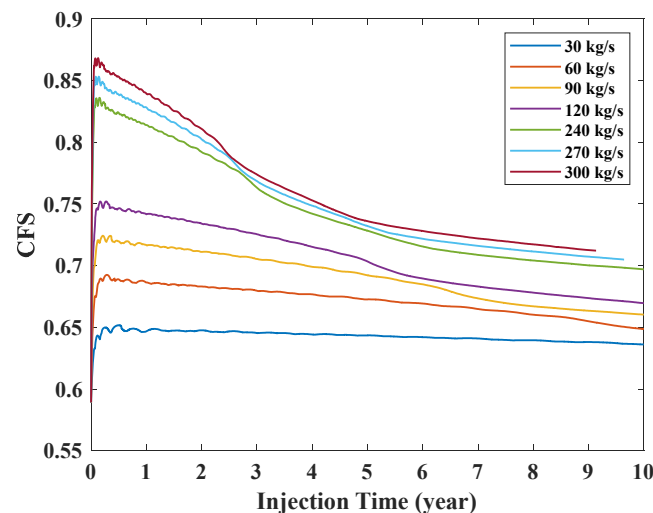


Figure 6. CFS values of the caprock surface under different injection rates.

Numerical results show that a CO₂ injection rate of 30 kg/s, corresponding to an annual injection volume of 1 million tons, results in acceptable increases in pore pressure and CFS values, staying within safe operational thresholds over a 10-year injection period. This indicates that the proposed injection plan is both technically feasible and geomechanically stable under multi-layer injection scenarios.

4. Sensitivity Analysis for Each Site Parameter

Parameters influencing CO₂ storage capacity can be categorized into three types, namely, physical parameters, mechanical parameters, and geological parameters. Physical parameters (e.g., permeability, porosity, density) are directly associated with the flow properties of the reservoir rocks, determining the injectivity of CO₂. High porosity and permeability enhance CO₂ migration and storage, while density influences buoyancy-driven flow dynamics. Mechanical parameters (e.g., Young's modulus, Poisson's ratio, friction angle) govern the stress–strain behavior and mechanical integrity of both reservoir and caprock. They are critical in evaluating the risk of shear failure or tensile fracturing under elevated pore pressures during injection. Geological parameters (e.g., depth, thickness of reservoirs and caprocks) affect the initial stress regime through lithostatic loading and constrain the vertical and lateral extent of CO₂ migration. Deeper and thicker formations typically provide more confinement and a greater safety buffer for injection.

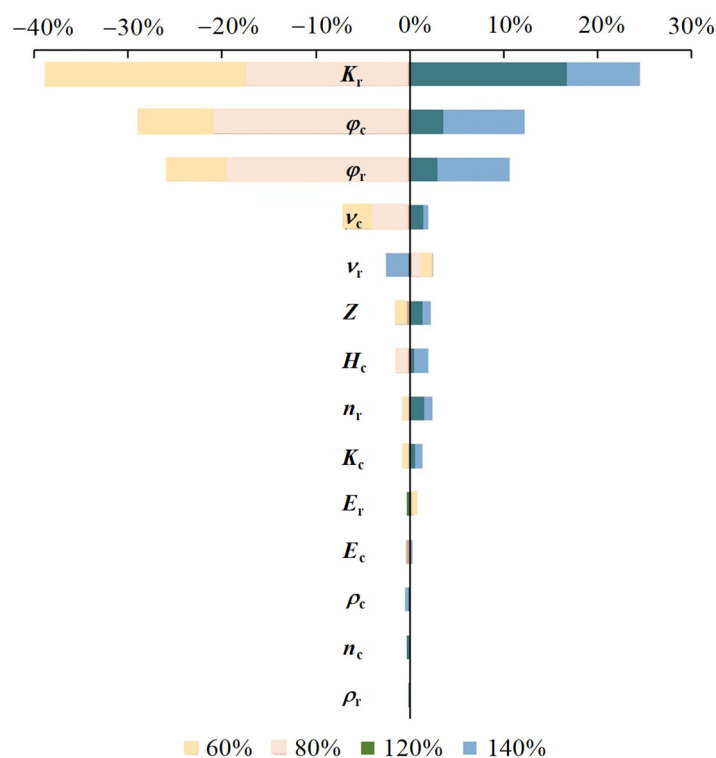
The influence of reservoir and caprock parameters on caprock stability during the CO₂ single-layer injection processes has been investigated by many researchers [33–35]. It is found that the depth, thickness, Young's modulus, permeability, and injection rate of the reservoir have a significant impact on caprock stability. As the seepage–stress coupling mechanism of reservoir and caprock under multi-layer injection is much more complex than that of the single-layer injection, sensitivity analyses were therefore carried out in this research using the tornado analysis method [36,37] to quantify the response of caprock sealing capacity caused by the reservoir and caprock parameters.

In this study, 60%, 80%, 100%, 120%, and 140% of the benchmark parameter values were taken as the values for a single simulation. The geological survey shows that the range of values from 60% to 140% is sufficient to cover the characteristics of rocks. The parameter values for the tornado analysis are shown in Table 4.

Table 4. Ranges of input parameters used in the tornado analysis.

Indicators		60%	80%	100%	120%	140%
Depth, m	Z	898.8	1198.4	1498	1797.6	2097.2
Top caprock thickness, m	H	18	24	30	36	42
Caprock						
Young modulus, GPa	E_c	4.8	6.4	8.0	9.6	11.2
Poisson's ratio	ν_c	0.18	0.24	0.3	0.36	0.42
Permeability, 10^{-17} m^2	k_c	0.6	0.8	1.00	1.20	1.40
Void ratio	n_c	0.006	0.008	0.01	0.012	0.014
Angle of friction, $^\circ$	φ_c	18	24	30	36	42
Dry density, kg/m^3	ρ_c	1530	2040	2550	3060	3570
Reservoir						
Young modulus, GPa	E_r	4.8	6.4	8.0	9.6	11.2
Poisson's ratio	ν_r	0.18	0.24	0.3	0.36	0.42
Permeability, 10^{-13} m^2	k_r	3.00	4.00	5.00	6.00	7.00
Void ratio	n_r	0.144	0.192	0.24	0.288	0.336
Angle of friction, $^\circ$	φ_r	18	24	30	36	42
Dry density, kg/m^3	ρ_r	1530	2040	2550	3060	3570

Numerical simulations were conducted at different CO_2 injection rates to determine the maximum injection capacity that the site can withstand under a specific combination of the physical and mechanical parameters of the reservoir and caprock listed in Table 4. The ratio of the maximum injection capacity of four parameter levels (80%, 100%, 120%, 140%) to the benchmark value (100%) which is 18 million tons/year calculated in Figure 7 is taken as the index to quantify the effect of caprock and reservoir parameters on the maximum injection capacity of CO_2 . Tornado sensitivity analysis results are shown in Figure 7.

**Figure 7.** The relative change in the maximum injection capacity using tornado analysis.

It is found that among the 14 input parameters, the reservoir permeability k_r has the greatest impact on the maximum injection capacity of CO₂. This result is consistent with the finding by Wei et al. [38]. The values of k_r decrease and increase by 40% under the benchmark conditions, resulting in a decrease of 39% and an increase of 25% in the maximum injection capacity, respectively.

The caprock friction angle ϕ_c and the reservoir friction angle ϕ_r have a significant impact on the maximum injection capacity. The values of ϕ_c and ϕ_r are reduced by 20% under the benchmark conditions, resulting in a decrease of 21% and 19% in the maximum injection capacity, respectively. This is because the friction angle directly enters into the CFS in Equation (2), where the friction coefficient $\mu = \tan\phi$. Therefore, both ϕ_r and ϕ_c critically control the threshold between safe storage and mechanical failure. This effect is particularly pronounced in offshore settings, where high in situ stresses amplify the mechanical response.

The Poisson's ratio ν_r of the reservoir and the Poisson's ratio ν_c of the caprock also have a certain impact on the maximum injection capacity. When the value of ν_r increases by 40%, the maximum injection capacity decreases by 2.5%, whereas when the value of ν_c increases by 40%, the maximum injection capacity increases by 2%.

On the other hand, the caprock dry density ρ_c , the caprock void ratio n_c , and the reservoir dry density ρ_r have the smallest impact on the maximum injection capacity. When these three parameters are changed by 80–140% under the benchmark conditions, the change in the maximum injection capacity is less than 1%.

In conclusion, the sensitivity analysis identified the permeability of the reservoirs and the friction angle of the reservoirs and caprocks as critical parameters influencing the storage performance. This finding implies that accurate characterization of these parameters is essential in field applications to ensure caprock integrity and optimized injection design.

5. Conclusions

This study presented a Hydro–Mechanical (H–M) coupled simulation of short-term CO₂ geological storage in the Enping 15-1 offshore saline aquifer, China. Numerical simulations using the TOUGH-FLAC model were carried out to estimate pore pressure, CO₂ migration, and Coulomb failure stress (CFS) of the reservoir and caprock to assess the mechanical stability and storage performance under various geological and operational conditions using a multi-layer injection method. The main findings are summarized as follows:

1. A total injection rate of 30 kg/s (equivalent to 1 Mt/year), distributed across six reservoir layers, was demonstrated to be geomechanically safe over a 10-year period, with the CFS values remaining below the critical thresholds in saline aquifers.
2. The average CO₂ migration distance increased by 5.6 times over the injection period, with Reservoirs 3 and 4 showing the greatest lateral migration distances (3505 m and 3300 m), indicating high storage potential and favorable containment conditions. From an engineering perspective, the results provide practical guidance for offshore CO₂ storage site selection and injection planning.
3. Sensitivity analyses showed that the permeability of the reservoirs and the friction angle of the reservoirs and caprocks were the dominant factors influencing mechanical safety and injection efficiency. This finding implies that accurate characterization of these parameters is essential in field applications to ensure caprock integrity and optimized injection design.

It should be noted that the model does not incorporate thermochemical effects and mineralization due to long-term chemical reactions. Moreover, the absence of site-specific

field validation introduces uncertainty in the absolute predictions. Future research should aim to develop fully coupled Thermo–Hydro–Mechanical–Chemical (T–H–M–C) models and utilize field monitoring data to calibrate and validate the simulation results. Long-term post-injection migration and trapping mechanisms should also be assessed to support safe and sustainable offshore carbon storage operations.

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Data Availability Statement: The data used to support the findings and results of this study are available from the corresponding author upon request.

Conflicts of Interest: Author Bo Gao and Tao Xuan were employed by the company Engineering Technology Branch, CNOOC Energy Development Co., Ltd. The remaining authors declare that the research was conducted in the absence of any commercial or financial relationships that could be construed as a potential conflict of interest.

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