Introduction

In order to achieve the target towards Net Zero Carbon Emission 2050, PETRONAS actively venturing into development of CO_2 storage fields to sequester the CO_2 that would be produced from their high CO_2 gas fields. Field X, which is a depleted clastic gas field, located in offshore Malaysia has been selected as one of the storage candidates to serve the abovementioned cause. Among many aspects in de-risking the subsurface uncertainties for CO_2 storage study in Field X, geochemistry stands as one of the top aspects in the list.

This is because the interaction between CO_2, rock, and fluid can lead to rock petrophysical properties alterations and changes on multiphase flow characteristics in the reservoir which would impact the injectivity performance and storage capacity. Numerous experimental studies have been conducted to investigate the reactivity of CO_2 with sandstone rocks (Farquhar et al., 2015; Othman et al., 2018; Pearce et al., 2022; Mahmud et al., 2023). Besides, there are also numbers of numerical modeling studies that has been conducted to examine the fluid flow and transport behavior during CO_2 injection into sandstone reservoirs (Balashov et al., 2013; Jin et al., 2016; Shabani et al., 2022; Rezk & Ibrahim, 2025). The reaction of CO_2 with the rock is expected to dissolve the reactive minerals (especially carbonate) and enhance the rock porosity and permeability. However, another aspect of mineral dissolution process is that it can contribute to fines production and mobilization, counteracting the mineral volume losses during the dissolution process. Consequently, the net effect of these interactions may reduce the effective porosity and permeability of the rock at different magnitude depending on fluid and reservoir properties (Wang et al., 2022).

Thus, this study aimed to characterize and understand the chemical response of depleted clastic gas field (Field X) due to CO_2-water-rock interactions. Core samples from two targeted reservoir unit from Field X of varying porosity and permeability properties were reacted with carbonated brine in dynamic (20 PV of injection) and static (14 days) conditions under simulated in situ reservoir conditions. The petrophysical changes and structural changes were examined after the core has been exposed with carbonated brine to understand the impact of geochemistry in this field.

Methodology

Sample

Four representative samples have been selected from the targeted zone of injection from Field X. Two samples have been acquired from D zone and another two samples were selected from E zone. Two geochemical tests were conducted for their respective zones in which two samples was used for each testing. In this paper, sample acquired from D zone will be denoted as D1 and D2 and samples acquired from E zone will be named E1 and E2. In term of mineralogy, the core samples of D zone are mainly composed of quartz (~60 %) followed by plagioclase (~20 %), clays (10 %), K-feldspar (~7 %), carbonates (~2 %) and pyrite (~1 %). Similar to D zone, core samples of E zone mainly composed of quartz (~67 %) followed by plagioclase (~18 %), clays (7 %), K-feldspar (~6 %), carbonates (~1 %) and pyrite (~1 %). The petrophysical properties of the selected samples are as per shown in Table 1.

Table 1 *Petrophysical properties of the selected core samples for geochemical tests.*

	Test#1		**Test#2**	
Properties	**D1**	**D2**	**E1**	**E2**
Porosity (%)	32.52	32.26	25.76	24.36
Permeability (mD)	1170.70	1010.20	187.98	163.76

Synthetic brine

The synthetic brine was prepared in accordance with the actual formation brine composition. However, to eliminate the possibility of precipitate/scale formation even before the geochemical experimental analysis, geochemical modelling using open-source code was conducted to determine the stable brine composition. The formulated brine mainly composed of sodium chloride ($NaCl$) with concentration of 0.38 mol/kg. For the preparation of carbonated brine, the synthetic brine was mixed with high purity grade CO_2 (99.9 wt%) using PVT cell using rocking method to ensure complete CO_2 dissolution at desired pressure and temperature conditions.

Geochemical experiment

The geochemical experiments were conducted using high pressure-high temperature (HPHT) multiphase core-flooding system which could withstand temperature up to 373.15 K and pressure (pore pressure and confining pressure combined) up to 68.9 MPa. The equipment set-up is as per shown in the Figure 1.

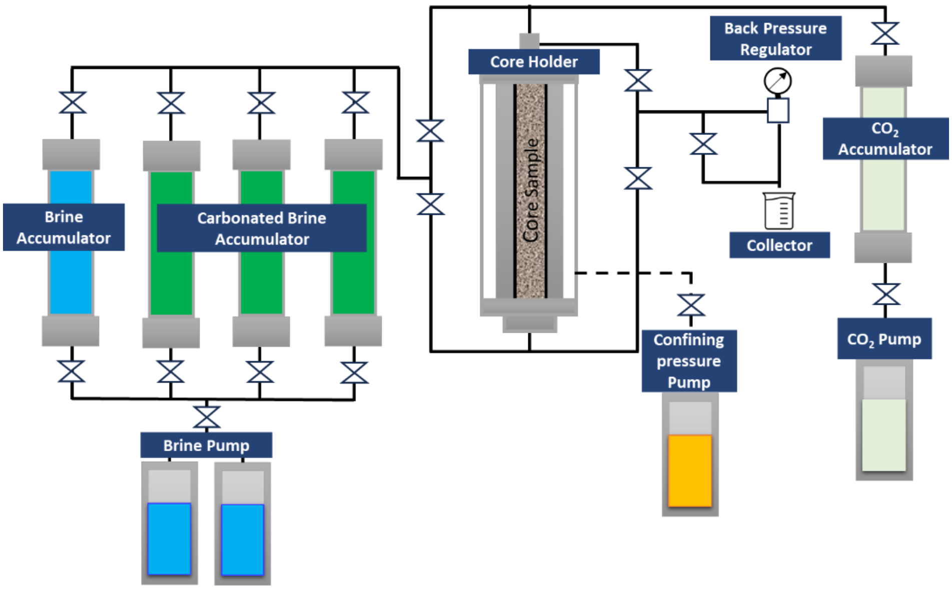

Figure 1 *This Schematic diagram of the HPHT core-flooding equipment utilized for geochemical experiment.*

Two geochemical tests were conducted in this study and each of the test was done using composite core for their respective injection zone (D sand and E zone). For the composite core arrangement, the cores were ordered in decreasing permeability manner. The procedure listed below briefly explains on the methodology of geochemical experiments.

1. After the brine saturated core samples were inserted in the core-holder inside the core-flooding system, the pore-pressure and confining pressure were systematically increased using the injection pump and confining pump as per shown in Table 2. Synthetic brine was used to increase the pore pressure while de-ionized water was used to increase the confining pressure.
2. Once the pressure stabilized, the temperature was increased according to the condition highlighted in Table 2.
3. The prepared carbonated brine was then transferred to core-flooding accumulators (see Figure 1) once the temperature of the system stabilizes.
4. Then, carbonated brine was injected at flowrate of $8.33e^{-9}$ m^3/s for 20 PV.

5. The carbonated brine injection was then ceased, and the inlet and outlet line of the core holder was secured to leave the core to react with carbonated brine for 14 days.
6. After 14 days, supercritical CO_2 was injected to displace the carbonated brine for 100 PV at rate of $3.33e^{-8}$ m^3/s.
7. Once the supercritical CO_2 injection has been completed, the pressure and temperature of the core-flooding system is reduced systematically, and the core samples were retrieved from the core holder.
8. The core samples were placed in the humidity oven for further drying.

The cores were then undergone Routine Core Analysis to determine the porosity and permeability changes that has taken place due to CO_2-water-rock reaction. Besides, the core samples have also been examined under CT-scan system to observe if there is any density and structural changes post carbonated brine reaction.

Table 2 *Experimental conditions for geochemical tests.*

Test	Zone	Pore pressure (MPa)	Net confining pressure (Mpa)	Temperature (K)
Test#1	D	8.3	5.5	373.15
Test#2	E			

Results

Routine Core Analysis

Routine Core Analysis was conducted to determine the petrophysical changes (porosity and permeability) that occurred resulted from the reaction of the rock with carbonated brine. The results of pre- and post-test analysis for Test#1 and Test#2 is as per shown in Table 3.

Table 3 *Petrophysical changes of core samples after carbonated brine exposure for 14 days.*

Sample ID	Porosity (%)			Permeability (mD)		
	Pre	Post	Change (%)	Pre	Post	Change (%)
D1	32.52	33.29	(+) 2.4	1170.70	1144.80	(-) 2.2
D2	32.26	32.61	(+) 1.1	1010.20	961.80	(-) 4.8
E1	25.76	26.39	(+) 2.4	187.98	217.40	(+) 15.7
E2	24.36	24.81	(+) 1.8	163.76	138.95	(-) 15.2

In both tests, it can be observed that all the core samples experienced increase in porosity in the range between 1.1 % to 2.4 % with E1 and D1 core samples experience the highest changes. The highest changes (increase) of porosity commonly take place near to the inlet as the carbonated brine has the lowest pH at this point before the brine pH is buffered (due to reaction with the mineral) as it travels to the core outlet. The same observation has also been shown from another research study which injected pre-equilibrated brine into the carbonate core (Kashim et al., 2024). In term of permeability, increase and decrease trends were observed after reaction with carbonated brine, in which in Test#1, both D1 and D2 cores experienced decrease in permeability, while for Test#2, only E2 core sample experienced decrease in permeability. E1 core sample was shown to have an increase in permeability post carbonated brine injection. In this study, the results showed that the permeability change is inversely proportional to porosity change, which in not common in traditional petrophysics understanding. However, this change may be attributed by the alterations at pore-level where the changes of larger pores might be reduced with increasing smaller pores development. For Test#1, permeability changes in D2 core sample are higher as compared to D1 core sample. This may be caused by the mobilization of fines (as a results of mineral dissolution) which leads to formation of mobile mineral aggregates that is being transported along the core and plugged in pore spaces especially in D2 core sample. Similar observation is shown in Test#2 in which E1 core sample experienced increase in porosity and permeability while E2 core sample experience slight porosity increases, and noticeable permeability changes as compared to E1 core sample. These observations are in line with the research conducted by Wang et al. (2022) which highlighted that mineral dissolution resulted in formation of fines and decrease in permeability.

CT-scan Analysis

CT-scan is a non-destructive imaging analysis which was used to examine the changes in internal structure and density changes of the core that has been caused by the reaction with carbonated brine. Specifically in this study, CT-values which is in Hounsfield Units (HU) were derived to quantitively assess the alterations due to the carbonated brine interaction. The results of the CT-scan analysis are as per shown in Figure 2 and Figure 3 for Test#1 and Test#2 respectively.

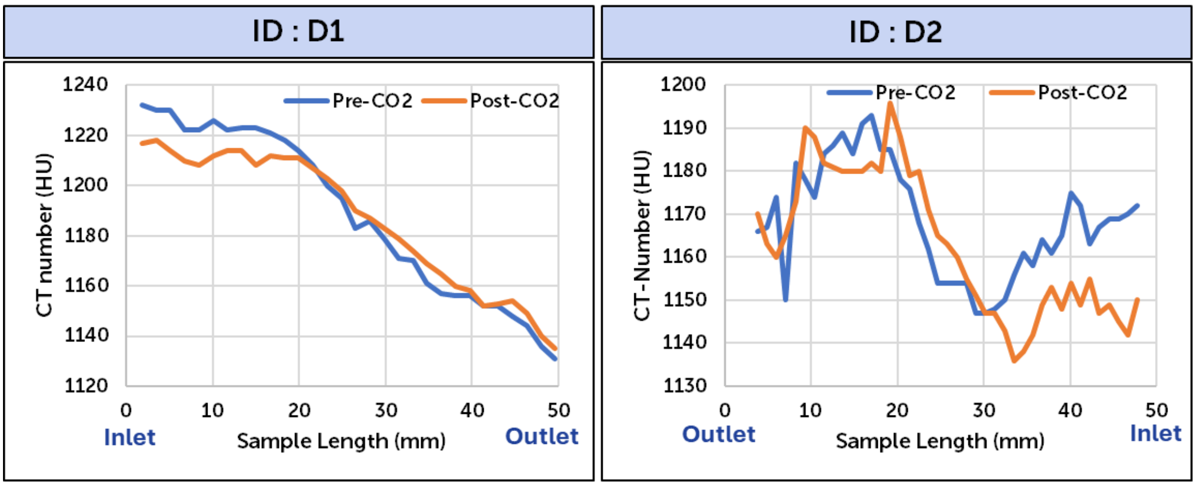

Figure 2 *Comparison of CT-values for Test#1 samples (D1 and D2) before and after carbonated brine exposure.*

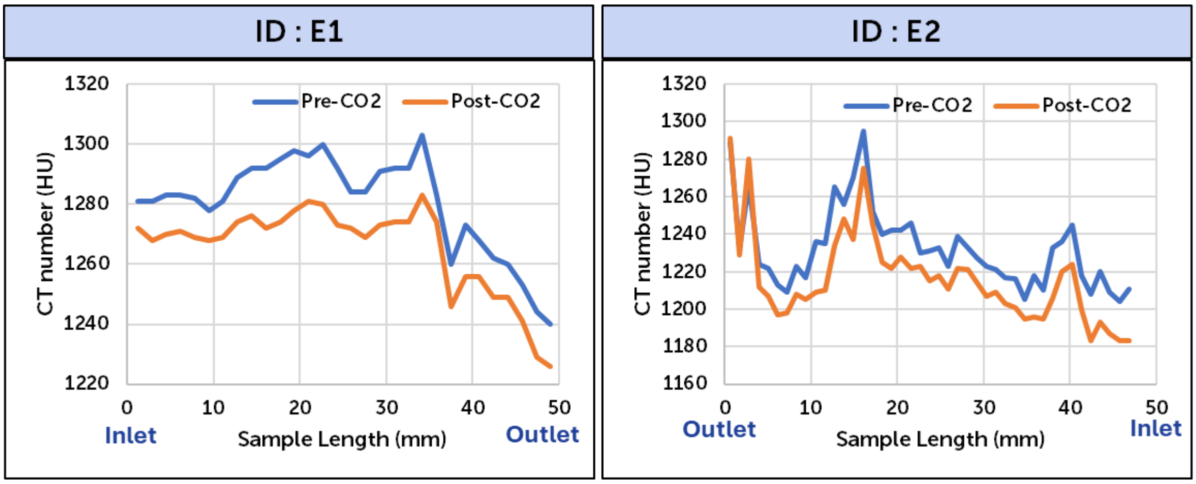

Figure 3 *Comparison of CT-values for Test#2 samples (E1 and E2) before and after carbonated brine exposure.*

For both tests, it can be observed that the earlier part of the core on the inlet has lower CT-values after carbonated brine injection which indicates loss of grains/minerals. This might be attributed by dissolution of some minerals (especially carbonates) that was caused by lower pH carbonated brine reaction with the minerals. The CT-values of D2 core sample (towards the end of the core) for post geochemical test in Test#1 is higher as compared pre-test. For E2 core sample, there is very minimal difference in term of CT-values both pre- and post-tests. These findings (especially for Test#1) clearly indicate that there is mobilization of fines that been transported to the outlet part which causes the core density to increase. Although there is minimal change observed in term of CT-values for outlet core in Test#2 (E2 core sample), it is expected that there are some alterations at pore-scale level (which is not resolvable in CT-scan resolution) that cause the permeability to decrease by ~15%.

Conclusions

Based on geochemical tests conducted on samples acquired from D and E zone in Field X, it can be generally concluded that:

1. The highest reaction take place in the core inlet where most of the mineral dissolution is expected to take place. The resultant of mineral dissolution creates fines which mobilized along the core samples (towards the outlet).
2. The reaction of CO_2 with rocks is a complex phenomenon, even though sandstone rocks are generally known to be highly resistant to CO_2. Despite the nearly similar mineralogical compositions of the D and E zones, there is a notable difference in the magnitude of petrophysical changes between them. This difference can be attributed to the distinct petrophysical characteristics of each zone. The D zone samples exhibit higher porosity and permeability compared to the E zone samples, suggesting that the D zone has larger pore-throat sizes, which reduces the risk of fines plugging compared to the E zone. This showed that CO_2 injection in lower permeability zone has higher geochemical risk as compared to higher permeability zone.
3. These findings necessitate a full-field geochemical modelling to determine the extent of the changes in field-scale, which often orders of magnitude lower from the lab-scale observed results.

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