

Research Project II
Geological storage of CO₂ in glauconite-rich sandstones of Mangyshlak Basin: physical and mineral trapping

by
Nazira Kuzhamratova

THESIS SUPERVISOR
Milovan Fustic

THESIS CO-SUPERVISOR
Mahmoud Leila

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Nazarbayev University

ORIGINALITY STATEMENT

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ABSTRACT

Geological storage of carbon dioxide (CO₂) in the sedimentary formations is now considered an attractive practical route to reduce anthropogenic CO₂ emissions. This work evaluates the storage potential of Albian glauconite-bearing sandstones in the Dunga oil field, Mangyshlak Basin, western Kazakhstan, by assessing both physical and mineral trapping mechanisms. The study investigated both physical and mineral trapping mechanisms of CO₂ through integration of petrophysics, hydraulic flow unit (HFU) interpretation, and batch CO₂-water-rock interaction experiment.

The petrophysical interpretation revealed heterogeneity across the Albian interval. The porosity values ranged from 9.9 to 32.6% and permeability from 0.06 to 1473.8 mD, which suggests the heterogeneous reservoir is characterized by defined categories of baffles, transitional intervals, and flow conduits. The laminated sandstone (LF9) and stratified sandstone (LF10) facies are described as the best-quality reservoir units, while massive siltstone (LF1), massive heterolithic sandstone-siltstone (LF4), and laminated heterolithic sandstone-siltstone (LF5) represent the weaker hydraulic interval, which may act as internal baffles. A glauconite-rich (roughly 3.7%) massive sandstone sample with good petrophysical properties (Porosity = 28.2 %, Permeability = 38.40 mD) was selected for the batch reactor experiment. The mineralogical and microtextural observations showcase that the pre-reaction sample consisted mostly of quartz, albite, microcline, mica/glauconite, chlorite, and kaolinite, confirming the presence of reactive phases relevant to mineral trapping. The experiment carried out in the batch reactor resulted in the decrease of the sample mass from 67.19 to 66.4 g and increased porosity, permeability, R₃₅, and RQI, while photomicrographs reveal widening of the cracks and much more open post-reaction microfabric. These results indicate the dissolution-driven pore-system alteration and support the interpretation that the Dunga Albian glauconitic sandstones are a promising candidate for the combined physical and progressive mineral trapping of CO₂.

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1. INTRODUCTION

While global efforts to decrease the emission of greenhouse gases are rising, fossil fuels are expected to remain a significant component of the world's energy supply for the coming decades (International Energy Agency, 2022), as showcased in Figure 1. Thus, carbon capture and storage (CCS) remains one of the most efficient technologies for the reduction of anthropogenic CO₂. CCS implies CO₂ sequestration in subsurface reservoirs due to their ability to store large volumes of CO₂ (Wu et al., 2014; Zhang & Tutolo, 2022; Askarova et al., 2023). Depleted oil and gas fields are highly attractive targets for geological carbon dioxide storage because of their proven long-term sealing capacity to hold trapped oil and gas over geological time and, importantly, because of possibility to reuse existing subsurface and surface infrastructure, including wells, pipelines, and production facilities, as well as extensive geological and petrophysical datasets (Hameli et al., 2022; Askarova et al., 2023).

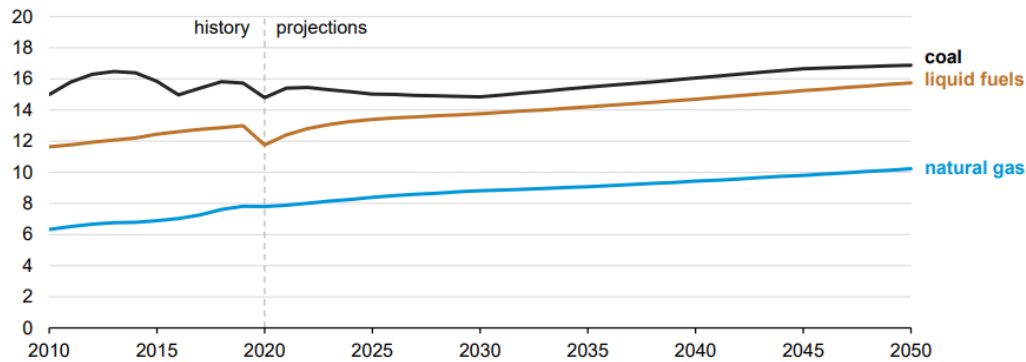


Figure 1. Energy-related carbon dioxide emissions in billion metric tons

(U.S. Energy Information Administration, 2021).

Two storage mechanisms are quite relevant in sedimentary reservoirs. The first one is physical trapping, which includes structural and stratigraphic trapping, residual or capillary trapping, and CO₂ dissolution in formation fluids (Wu et al., 2014; Zhang & Tutolo, 2022; Askarova et al., 2023). The benefit of this mechanism is that large volumes of CO₂ can be injected rapidly (Rasool et al., 2023; Worden, 2024). However, the performance of this method is highly dependent on reservoir heterogeneity, injectivity, caprock integrity, and the distribution of internal baffles and flow barriers. The second pathway is a mineral trapping, in which the supercritical CO₂ is transformed into carbonate minerals through the interaction with the cations dissolved from the host rock (Soong et al., 2003; Torp & Gale, 2004; Hameli et al., 2022; Zhang & Tutolo, 2022;

Zhang & Arif, 2024). This mechanism requires that reservoir rocks contain reactive minerals, such as Fe²⁺ glauconite-bearing sands (Zhang & Tutolo, 2022; Zhang & Arif, 2024). The process is slower; however, it provides the most permanent and secure type of storage (Zhang & Tutolo, 2022).

The present study is focused on the Albian glauconite-bearing sandstones of the Dunga oil field in the Mangyshlak Basin, western Kazakhstan. Currently, the interval is described as a laterally extensive siliciclastic reservoir belonging to a soon-to-be-depleted oil field with favorable infrastructure for future storage operations. The Albian formation is notable for the glauconite-bearing composition (Dujoncqoy et al., 2017). In combination with the reported presence of meter-scale concretions of sideritic composition (Dujoncqoy et al., 2017), the field showcases the possibility of in-situ mineral trapping in the Albian formation. Additionally, the system exhibits dual porosity that is possibly produced by the dissolution of feldspar and cement (Dujoncqoy et al., 2017). These features make the Dunga Oil Field a promising candidate for both physical and mineral trapping potential worth examination.

This thesis aims to assess the CO₂ storage potential for the Dunga Albian reservoirs. On one hand, the reservoir contains glauconite-bearing sandstone, which is potentially favorable (when enough ferrous iron is present) for the geochemical reaction with injected CO₂. On the other hand, the studied interval is heterogeneous by petrophysical data and contains both highly conductive and tight intervals. Without the robust interpretation of the architecture, petrophysical properties, and mineralogical reactivity, it is rather difficult to evaluate injectivity, storage distribution, plume containment, and the likelihood of progressive mineral trapping. The next uncertainty concerns whether the earliest interaction of host rock and dissolved CO₂ enhances the connectivity of pore systems through dissolution or reduces it through secondary precipitation.

Accordingly, the main objective of this work is to assess the suitability of the Albian sandstones of the Dunga field for geological storage through both physical and mineral trapping mechanisms. The specific objectives are:

- 1) Classify the main lithofacies of the Albian cored interval
- 2) Evaluate porosity, permeability, and hydraulic flow unit behavior across the reservoir
- 3) Characterize the pre-reaction mineralogical and microtextural composition of the selected sample using XRD, SEM, and petrography

- 4) Assess the short-term reaction of the formation through a batch reactor experiment

The significance of this work lies in the direct relevance of the decarbonization potential of mature hydrocarbon regions in Kazakhstan. By integrating sedimentological, petrophysical, and experimental observations, this study contributes to the evaluation of a realistic regional storage target and gives a framework for distinguishing favorable flow units from barriers, while also assessing whether the glauconite-bearing sandstone can act as a reactive substrate for the potential long-term geochemical trapping. The scope of the thesis includes facies analysis, petrophysical characterization, mineralogical and petrographic description, and one laboratory batch-reactor experiment on a representative core plug. The study excludes field-scale dynamic simulation, full reactive transport modeling, post-reaction SEM/XRD verification, caprock integrity testing, or reservoir-scale injection design. The mentioned aspects remain outside the scope of the present work and represent directions for future study.

2. LITERATURE REVIEW

Geological sequestration is the process of removing carbon dioxide from the atmosphere and injecting it into the subsurface rock formations for long-term or permanent storage (Aslannezhad et al., 2023; Zhang & Arif, 2024; Q. Zhang & Tutolo, 2022; Hameli et al., 2022). The subject has been studied for a long time, with distincting several types of mechanisms (Figure 2) that will be discussed in the following section. The effectiveness of the selected mechanism depends on the unique characteristics of the reservoir, including porosity, permeability, architecture, mineralogical composition, caprock integrity, reservoir heterogeneity, pressure-temperature conditions, and the chemistry of the formation fluids. This is why, rather than exploiting one approach for each, the formation's innate traits, such as petrophysical, physiochemical, and hydrodynamic processes, are studied beforehand (Zhang & Arif, 2024; Hameli et al., 2022).

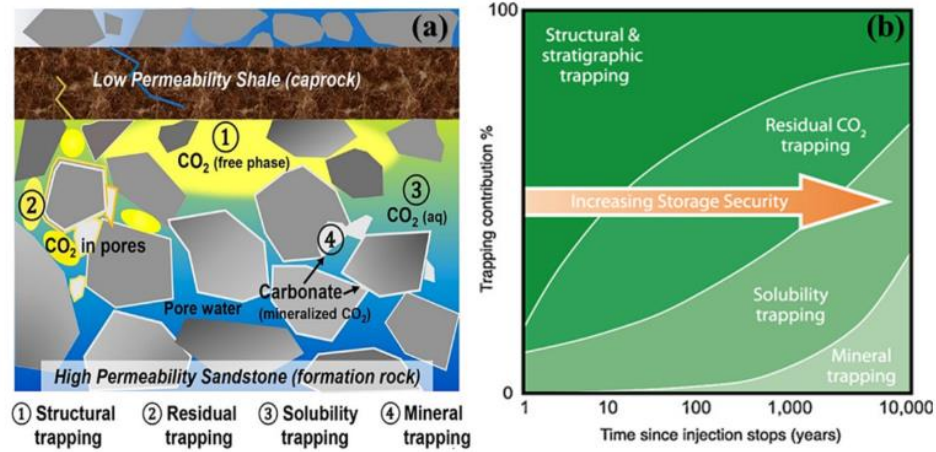


Figure 2. Schematic illustration of (a) CO₂ geo-storage trapping mechanisms, (b) Performance of CO₂ trapping mechanisms over time (Bashir et al., 2024).

This way, for ultramafic or basaltic formations, the chemical trapping mechanism is applied, due to the formation's high concentration of Magnesium and Iron silicates that easily react with the injected CO₂ and turn it into carbonate minerals, which implies the permanent and safe storage (Rasool et al., 2023). On the other hand, for the depleted oil and gas fields, structural trapping is used as these formations are known for their ability to withhold gases and liquids that exert buoyancy due to the structural forms (Q. Zhang & Tutolo, 2022; Wei et al., 2023).

Ultimately, the selection of a CO₂ storage formation should be aligned with the principal storage objective and the governing geological constraints of the target system. Where rapid mineralization and secure long-term containment are prioritized, basaltic formations may represent the most suitable option owing to their strong reactivity and high potential for permanent mineral trapping (Xiong et al., 2017; Hellevang et al., 2017; Wu et al., 2021; Rasool et al., 2023). In contrast, if the primary objective is to accommodate large storage volumes efficiently, depleted hydrocarbon reservoirs may offer a more practical solution, particularly where residual trapping can be effectively mobilized within an already proven subsurface framework (Hameli et al., 2022; Callas et al., 2022; Raza et al., 2017). Accordingly, no single trapping mechanism is universally optimal; rather, the most effective strategy is formation-specific and should be identified through careful integration of lithological, petrophysical, geochemical, and structural controls to optimize the dominant trapping process under the unique conditions of each reservoir.

2.1 Physical trapping

Physical trapping is the most immediate mechanism for storing carbon dioxide in the subsurface structures (Hameli et al., 2022). This mechanism solely relies on the physical pore spaces, traps, and barriers to flow (Askarova et al., 2023).

Physical trapping sub-mechanisms include:

- 1) Structural or stratigraphic trapping: The dominant mechanism, which is based on the impermeable rock (like shale or anhydrite) or geological features like anticline folds to stop the upward migration of the injected gas (Wei et al., 2023).

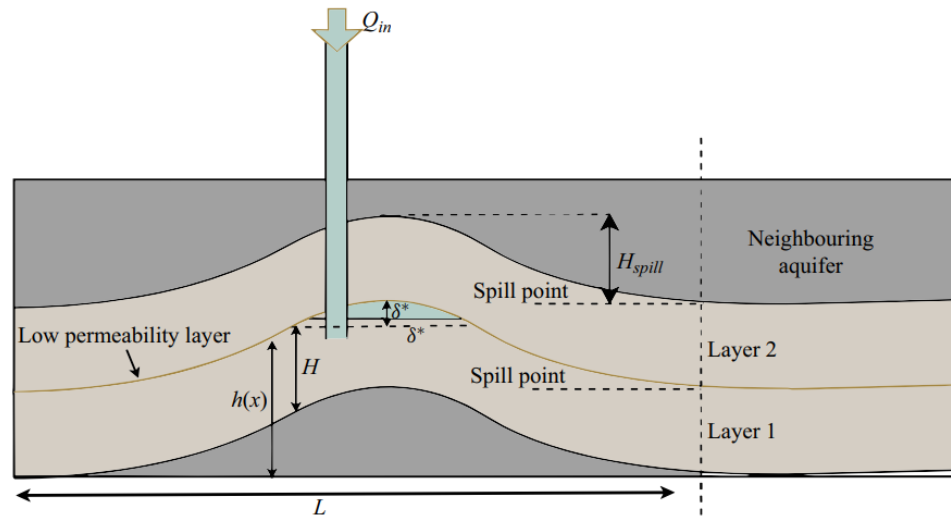


Figure 3. Injection of CO₂ (green) into the lower layer of a two-layered formation (Mortimer et al., 2024).

- 2) Capillary trapping: When CO₂ travels through the rock with moderate to high porosity, brine re-enters the pore spaces behind the plume, which leads to the so-called “snap-off” where CO₂ is trapped as immobile droplets within the pore spaces of the rock (Altman et al., 2014; Gershenson et al., 2016).

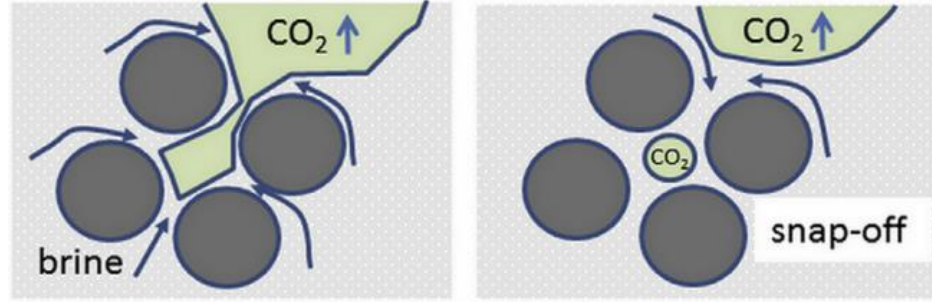


Figure 4. Schematic drawing of snap-off trapping (Gershenzon et al., 2017).

- 3) Adsorption Trapping: Used for unconventional reservoirs like organic-rich shales, where CO₂ physically adheres to the surface of organic matter or clay minerals.

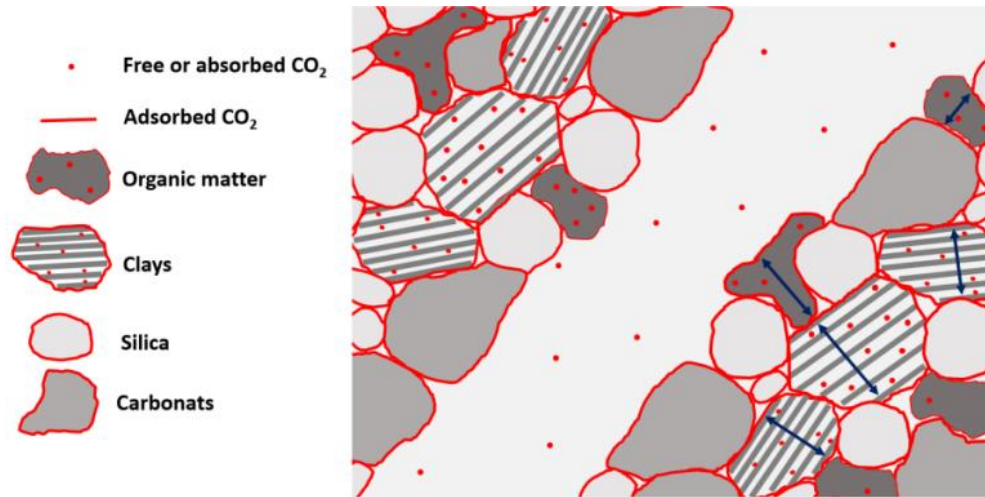


Figure 5. Schematic illustration of CO₂ adsorption on mineral grains, absorption inside the organic matter, and clay particles in true dry conditions (Bhuiyan et al., 2020).

The factor that influences the extent of carbon dioxide saturation is affected by the petrophysical, physiochemical, and hydrodynamic properties of CO₂ -Fluid-Rock systems and conditions of the operation (Zhang & Arif, 2024). One of the factors to facilitate the saturation is the reservoir's heterogeneity, because it can enhance the capillary pinning (Gershenzon et al., 2016), which is the immobilization of carbon dioxide at the contacts of different lithologies (and subsequent different capillary entry pressures). In reverse, the change in the wettability of the reservoir can decrease the saturation of the residual CO₂. If lithology is exposed to prolonged initial CO₂ saturation, it becomes more CO₂ -wet (Al-Menhali and Krevor, 2016; El-Maghraby and

Blunt, 2013), thus it does not create exertion forces that are supposed to snap off the CO₂ and reach successful trapping.

The advantage of the physical trapping is that it provides a first line of containment by accumulating large volumes of CO₂ (Askarova et al., 2023). In the depleted reservoirs, despite inferred integrity of caprock (Heidarabad & Shin, 2024), the primary risk is CO₂ leakage via abandoned wells, over- containment pressure injection, which might lead to the fracturing of the caprock (Wu et al., 2014), and natural processes such as natural, post-injection fractures.

2.2 Sleipner field - physical trapping

The Sleipner project, located in the Norwegian North Sea, is widely known as the world's first commercial-scale initiative for carbon dioxide storage in the deep saline aquifer (Torp & Gale, 2004). The Sleipner uses natural gas produced during the production of the Sleipner West gas field and injects it into the Utsira formation. The project began in October 1996 and successfully sequestered 1 million tons of CO₂ per year in depths of approximately 800 to 1000 meters below the seabed (Nwafor et al., 2026).

The carbon dioxide in a supercritical state is injected into the base of Utsira Sand (Figure 6), where it is approximately 30% less dense than the areal brine (Arts et al., 2004). Injected gas migrates upward by the buoyancy forces until it reaches the impermeable shale layer. The Sleipner project pioneered in using time-lapse (4D) seismic monitoring, which successfully imaged the CO₂ plume's behavior over decades (Nwafor et al., 2026). The imaging revealed that the plume does not travel uniformly, but rather accumulates in a series of thin, laterally extensive layers beneath intra-reservoir shales. The data also unraveled a vertical so-called chimney above the injection point, which serves as a main pathway for the carbon dioxide to reach the impermeable layer (Nwafor et al., 2026).

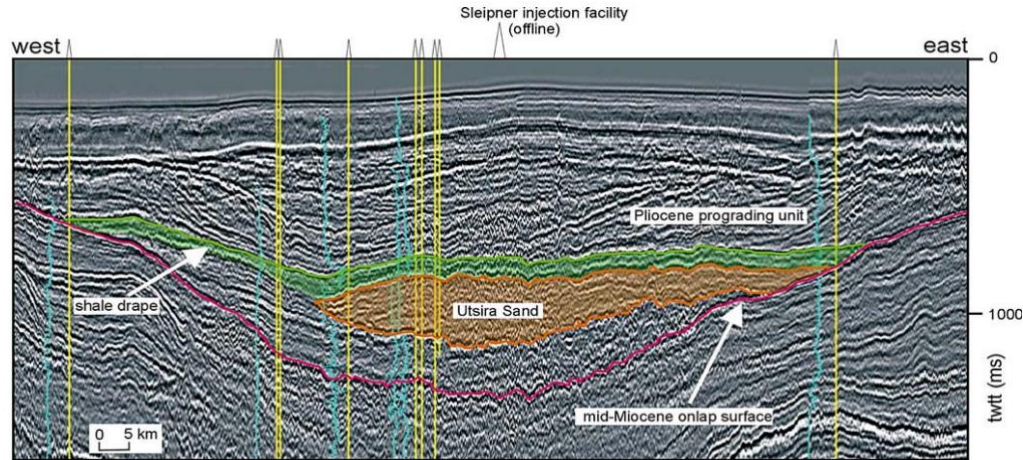


Figure 6. Regional seismic line through the southern part of the Utsira formation (Torp & Gale, 2004).

The Utsira Sandstone is an excellent reservoir, with porosity reaching up to 42% and permeability up to 8 Darcy (Nwafor et al., 2026). However, the internal complications present some containment challenges due to stratigraphic compartmentalization, channel terminations, and incised-valley geometries. Additionally, there is an ongoing debate about whether the internal shale barrier with a thickness of 7-9 meters has been breached (Nwafor et al., 2026). Mineralization of carbon dioxide is said to be impossible in the region due to the sand being composed mostly of unreactive minerals such as quartz. Wellbore integrity is maintained, and vertical faults were visible; the reservoir should be monitored with high-resolution characterization to ensure long-term containment.

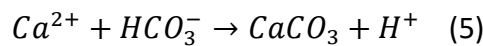
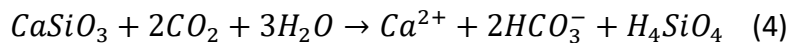
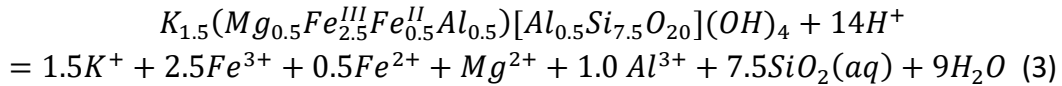
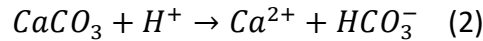
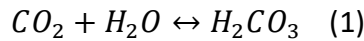
2.3 Mineral trapping

Mineral trapping, also referred to as carbonation, is the most stable and permanent form of carbon dioxide sequestration, where the injected gas is in situ transformed into carbonate minerals (Snæbjörnsdóttir et al., 2020). Injected gas in the state of the supercritical CO_2 phase dissolves in the formation water and subsequently produces weak carbonic acid, which then facilitates the dissolution of the reactive host-rock minerals (Xu et al., 2004; Tutolo et al., 2020; Heidarabad & Shin, 2024). The dissolved divalent cations, such as Calcium (Ca^{2+}), Magnesium (Mg^{2+}), and Iron (Fe^{2+}), later react with the dissolved CO_2 to precipitate minerals like magnesite, calcite, siderite, dolomite, and ankerite (Soong et al., 2003; Bourg et al., 2015) or nesquehonite (Leila et al., 2025).

The efficiency of the method is dictated by the presence of the divalent cations in the minerals of the formation and their readiness to dissolve. The ideal targets for this method are peridotites and basalts due to their high content of ultramafic minerals, which allow for the rapid mineralization. While previous studies often overlooked sedimentary facies such as sandstones for this type of sequestration, recent findings proved that some glauconite-bearing sandstones have carbonation potential (Tutolo et al., 2020b). Though the reactivity of the glauconite is far less than that of ultramafics, the reservoirs with glauconite mineral, which bear iron ($\square\square^{2+}$) and magnesium ($\square\square^{2+}$) cations, may have high carbonation potential. The advantage of glauconite-bearing sand reservoirs is high porosity, which allows for good injectivity.

One of the key factors influencing the success of this method is the redox state of the solution (Tutolo et al., 2020b). This way, the reducing environment of the reservoir can transform the unfavorable ferrous iron ($\square\square^{2+}$) to the ferric iron ($\square\square^{3+}$) to increase the potential of carbonate precipitation (Q. Zhang & Tutolo, 2022c).

Additionally, the reaction is highly dependent on the pH conditions. The first introduction of the $\square\square_2$ into the reservoir lowers the pH due to the formation of carbonic acid (equation 1), which triggers the dissolution of reactive framework minerals. The first minerals to dissolve in that environment are carbonates (2), because they are more reactive in the low pH environments. Silicates, such as glauconites (3), are less sensitive to those pH conditions, so they dissolve later in the reaction. Dissolution of silicates liberates divalent cations and subsequently brings the environment to the alkaline state (4), which is favorable for the precipitation of carbonates (5).



The ideal scenario described above cannot be achieved due to the initial dissolution of the carbonates before sufficient alkalinity is reached, thus not yielding net CO_2 carbonation (Q. Zhang

& Tutolo, 2022c). It was found that when the aqueous phase is acidic, the conversion rates are limited (Park et al., 2003). When there is a high partial pressure of CO_2 , the thermodynamic equilibrium equation shows that the concentration of divalent cations is much higher than that of CO_3^{2-} . Hence, the carbonation at low pH is rather limited. So, it is vital to reach the “pH swing” by increasing the pH to an alkaline state for the carbonation to happen. Park and Fan (2004) found that the optimum pH for carbonation of serpentine is around 10, and in the case of glauconite-bearing sandstone, the optimum was not yet defined.

The most notable advantage of this mechanism is permanence, because when compared to mobile gas, the solid mineral has a negligible risk of escaping. However, the reaction kinetics require long-term reactions, as long as millennia, to contribute to the significant amounts of storage (Zhang & Arif, 2024). Furthermore, the precipitation of minerals decreases both porosity and permeability, which then affects the fluid flow and injectivity potential of the aquifer.

2.4 Nini West field - mineral trapping

Project Greensand is the pioneering initiative in carbon capture and storage as a permanent CO_2 facility in Denmark (Weibel et al., 2025). The Nini West field, located in the Danish North Sea (Figure 7), was previously known as a productive hydrocarbon reservoir within the Siri oil fairway (Szabados & Poulsen, 2023). The oil field is now depleted and is an ideal candidate for sequestration due to the presence of glauconite mineral and a structural trap.

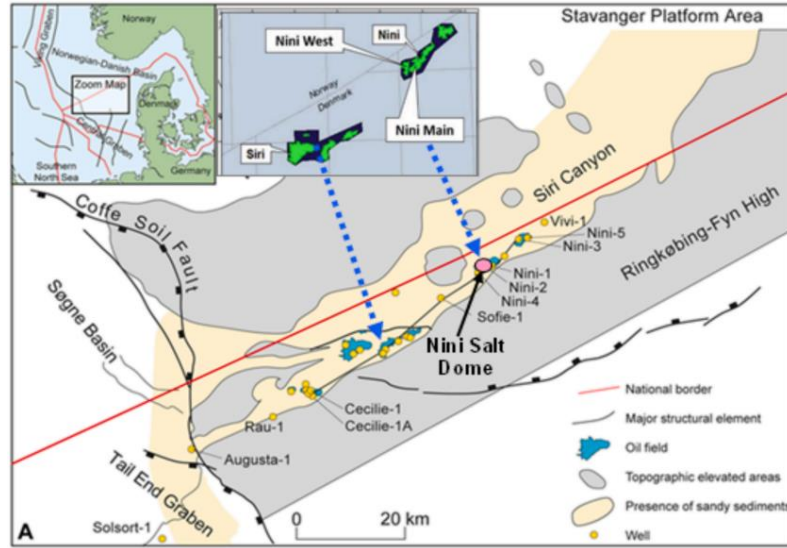


Figure 7. Structural map of Siri Canyon, which hosts the Nini Salt Dome located near the boundary between Norway and Denmark (see inset map upper left) (Al-Raeeini et al., 2026).

The 90-day operation ended in the spring of 2023 and successfully injected 4,000 tons of CO₂ into the reservoir (Szabados & Poulsen, 2023). First, the carbon dioxide was captured in Belgium from the chemical plant and later transported via tanks to the offshore site for injection. Another novelty of this site is the novel pattern being exploited to detect the CO₂ migration. By incorporating the neighboring fields such as Nini main, Cecilie, and Siri, injection of 8 million tons per year is planned to be achieved by 2030 (Weibel et al., 2025).

Nini West reservoir constrains unique geology as the concentration of glauconite clasts reaches up to 35% of the sandstone (Weibel et al., 2023), which may pose a few risks due to this lithology:

- 1) The ionic composition of water may cause the glauconite mineral to swell, thus potentially reducing the reservoir's permeability and impeding injection rates (Weibel et al., 2025).
- 2) The high-velocity injection may mobilize the detrital clays and clog the pore throats (Civan, 2010; Mohammadkhani et al., 2024).
- 3) If the injected gas is contaminated by the SO_x or NO_x, it can facilitate lowering of the pH and lead to the precipitation of new minerals like barite or gypsum, which will reduce the geochemical strength (Weibel et al., 2025).
- 4) Cyclic injections coupled with the formation saturated in Na and Cl may lead to the precipitation of halite (Weibel et al., 2023; Weibel et al., 2025).

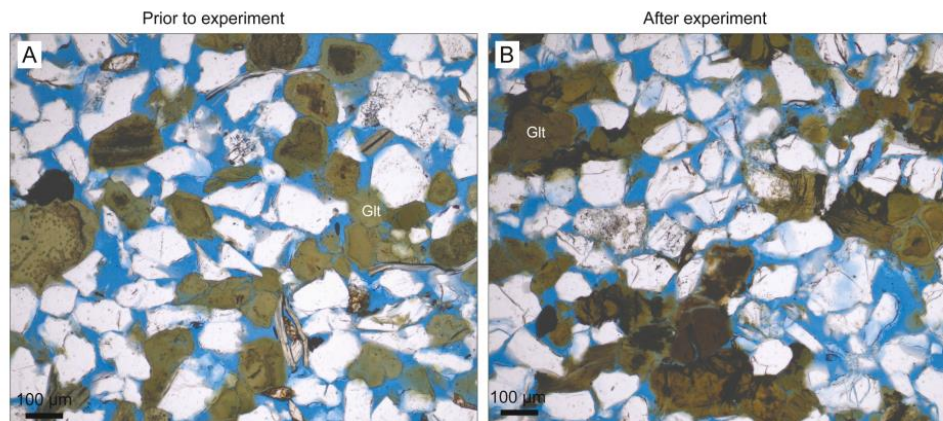


Figure 8. Colour-change in glauconitic clasts (Glt) during experiment. Prior to (A) and after (B) the experiment (Weibel et al., 2025).

As a result of the experiment, there were a few key findings. First is that glauconite grains are encapsulated by the hydrocarbon residue, such as asphaltenes and bitumen, which prevents swelling (Weibel et al., 2023), but also induces the liberation of divalent cations. It is also worth mentioning that even though there is a slight decrease in the rock strength (Figure 8), the reservoir integrity remains sufficient for safe long-term storage (Weibel et al., 2023; Weibel et al., 2025). Nonetheless, the mineral trapping in this field is only a secondary mechanism as the high content of glauconite grains contains mostly unreactive ferric iron, which does not favor the carbonation process.

2.5 Geological setting of Dunga oil field

The Dunga Oil Field is located in the Mangyshlak Basin, along the eastern coastline of the Caspian Sea in southwestern Kazakhstan (Figure 9). The basin is structurally bounded by the Karabogaz Arch to the south, the Mangyshlak Mountains to the north and northeast, and the Central Caspian Arch to the west. In the northern part of the basin, northwest-trending faults form a system of step-like structural terraces that descend toward the South Mangyshlak Trough. These terraces host many of the hydrocarbon accumulations in the region, where compressional tectonics and regional uplift contributed to the formation of anticlinal traps (Blackbourn, 2007). The broader tectono-stratigraphic evolution of the Mangyshlak Basin has been linked to the long-term development (Figure 10A) of the southern Eurasian margin, including Tethyan subduction, microcontinental collision, post-rift subsidence, and later regional uplift (Sholokhov and Tiunov, 2003; Golonka, 2007; Blackbourn, 2013; Sim et al., 2019; Kozhagulova et al., 2023). However,

for this study, the most relevant part of the basin history is the Lower Cretaceous succession, particularly the Albian interval, which occurred approximately 113 million to 100.5 million years ago.

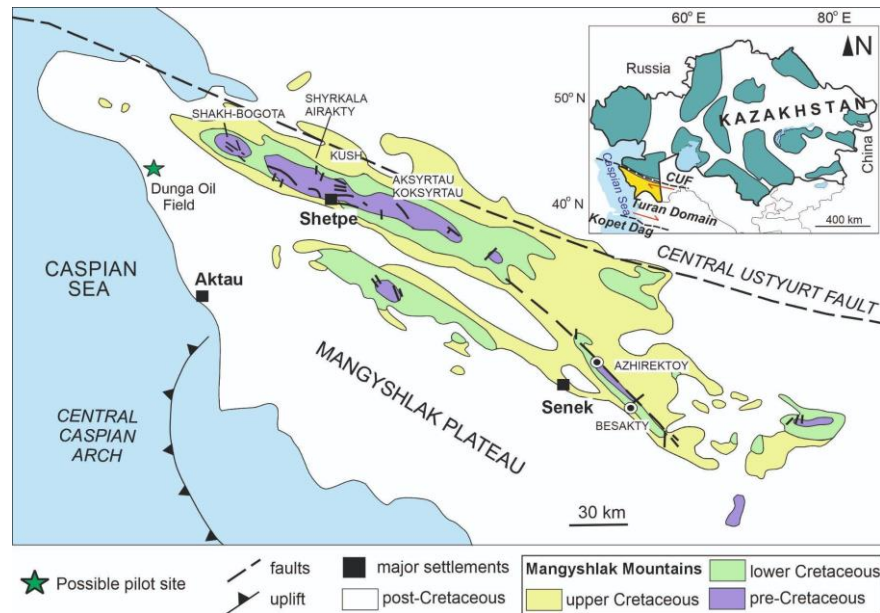


Figure 9. A simplified geologic map of Mangyshlak Basin, south western Kazakhstan.

The Dunga field is situated in the Tupkaragan district of the Mangistau Region and is estimated to contain 106 million tons of oil and more than 6 billion cubic meters of gas (Kikvidze & Baisarova, 2024). Although hydrocarbon production in the Mangyshlak region is commonly associated with Jurassic reservoirs, Dunga is unusual because it also produces from Lower Cretaceous reservoirs, including Valanginian, Barremian, Aptian, and Albian formations (Petersen et al., 2017). The field is therefore important for understanding the reservoir potential of Cretaceous siliciclastic systems in the basin.

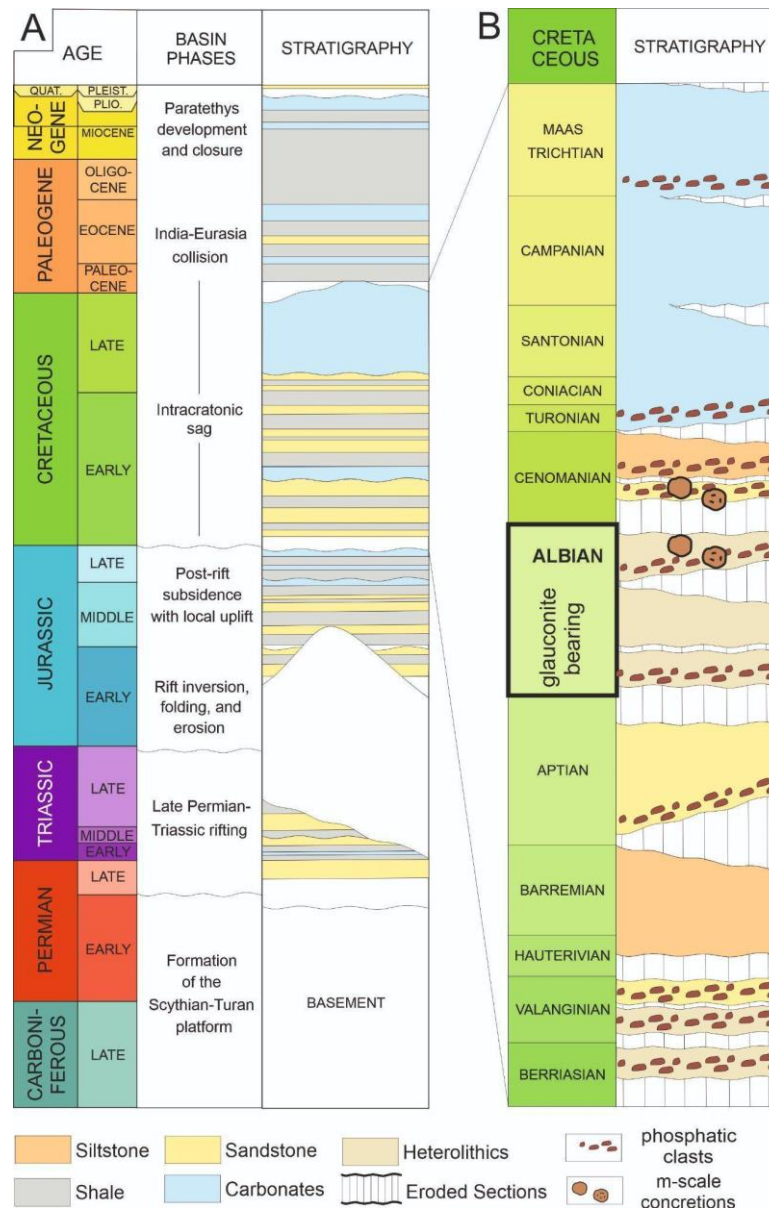


Figure 10. Stratigraphic chart of the Mangyshlak Basin, including dominant lithologies and basin evolution phases (A) (modified after [Kozhagulova et al., 2023](#)); (B) Cretaceous stratigraphy highlighting biostratigraphically defined gaps and glauconite-bearing Albian interval. Modified after [Kopaewich et al., \(1999\)](#).

The Albian stratigraphy of the Mangyshlak Mountains was described by Marcinowski et al. (1996) and is separated from the underlying Aptian by a distinct erosional surface. The Albian succession records a phase of marine transgression and subsequent gradual shallowing of the shelf basin. In the regional stratigraphic framework, the Albian interval includes glauconite-bearing deposits and biostratigraphically defined gaps, which are useful for correlating the Lower

Cretaceous succession across the Mangyshlak Basin ([Marcinowski et al., 1996](#); [Kopaewich et al., 1999](#); [Kozhagulova et al., 2023](#)). Considerable parts of the Albian stratigraphy contain phosphatized burrow clasts, phosphatized molluscs, and broken phosphate nodules, indicating episodes of reduced sedimentation, reworking, and condensation during shelf deposition.

In the Dunga Oil Field, the Albian reservoir was first proven in 2012 and has been interpreted as a siliciclastic prograding system ([Dujoncquoy et al., 2017](#)). Seismic data show clear clinoform geometries that prograde from east to west, indicating deposition in a shoreface to deltaic environment ([Dujoncquoy et al., 2017](#); [Zhumekeshov & Elbattawy, 2014](#)). This lower prograding interval is overlain by an upper interval that reflects an aggrading offshore-to-shoreface depositional setting. Together, these deposits form an approximately 300 m thick Albian reservoir succession composed mainly of clastic sediments, including siltstones, claystones, and glauconite-bearing sandstones, as can be seen in Figure 10B. The interval investigated in this study supports this lithology and is summarized by Figure 11.

The glauconite-bearing sandstones are particularly important for this study because they control both the reservoir properties and the potential for CO₂ storage. The Albian reservoir contains cemented nodules and metre-scale concretions, locally reaching up to 4 m in diameter, which are also observed in Albian outcrops of the Karatau Ridge. These concretions include carbonate minerals such as siderite, suggesting that the reservoir may have the capacity for CO₂ mineral trapping under suitable geochemical conditions. However, drilling data do not show a clear pattern in the distribution of these concretions and nodules, making it difficult to determine whether they form laterally continuous barriers or only local heterogeneities affecting fluid flow ([Zhumekeshov & Elbattawy, 2014](#)).

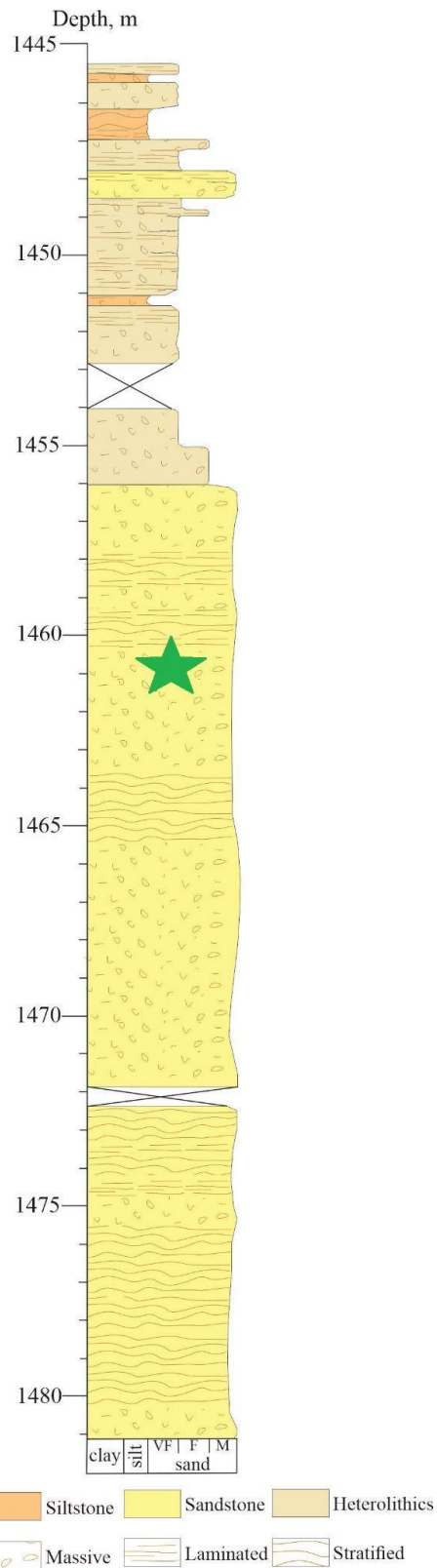


Figure 11. A simplified cross-section of the cored interval of Dunga oil field (Well DNG-154), batch reactor sample location is marked by the green star (1461.31 m).

The reservoir also has a dual-porosity character typical of glauconitic sandstones. Primary intergranular pores are locally modified by cement dissolution and feldspar leaching, producing secondary microporosity between clay minerals and glauconite grains. This pore system may influence both hydrocarbon recovery and injected-fluid migration during potential CO₂ storage operations (Zhumabekov et al., 2022; Weibel et al., 2025). Overall, the Dunga Oil Field represents a relevant case study for evaluating CO₂ storage potential in a depleted or near-depleted hydrocarbon field. Its Albian reservoir is laterally extensive, relatively homogeneous at the field scale, rich in glauconite-bearing sandstones, and located at a favorable depth with existing field infrastructure. These characteristics make the Albian interval a suitable target for investigating both physical trapping and mineral trapping potential in the Mangyshlak Basin.

3. METHODOLOGY

3.1 Sedimentary facies analysis and Gamma Ray logs

The core Gamma Scan was performed before the experiment by the Weatherford company. Sodium Iodide crystal scintillator was exploited to record the natural gamma radiation from the original core. The detected signals were amplified through a photo multiplier tube and recorded by the computer-connected multi-channel analyzer. Specific energy levels are emitted by various radioactive minerals that include Potassium, Uranium, and Thorium. The apparatus was allowed to reach the room temperature and checked with standard calibration tubes supplied by the Institute for Energiteknikk, Kjeller. The core was passed by the conveyor at a speed of 6 meters per hour. The background radiation elimination was achieved by covering the core and crustal detectors with lead shielding.

Core photos, core description, and gamma ray data were used to evaluate lithology, sedimentary structure, grain size, sorting, color, degree of bioturbation, and facies boundaries. This analysis allowed detailed lithofacies classification and improved understanding of the depositional processes within the formation, resulting in the identification of key intervals with potential suitability for CO₂ storage.

3.2 Routine Core Analysis, Porosity and Permeability

Porosity and permeability of the core sample were observed by the Weatherford company prior to the batch reactor experiment. The calibrated Helium gas volume expansion meter was exploited in the helium porosimeter. Every 20 samples, the apparatus was tested for leaks by the steel blank in the matrix cup and calibrated using five stainless steel discs of known volumes. The porosity was calculated via equation 6.

$$\text{Porosity (\%)} = \frac{\text{Volume of gas displaced} - \text{Volume of sample}}{\text{Volume of sample}} * 100\% \quad (6)$$

Permeability was determined by pressing a small probe onto the core surface and passing nitrogen gas through the core until steady-state flow was achieved. Prior to the analysis, the equipment was tested for leaks and calibrated by testing a standard sample of known permeability value. Permeability is calculated as follows:

$$k(\text{Darcy}) = \frac{Q * \mu * L * 2000}{60 * A * \Delta P * (\frac{L^2}{l^2} - \frac{L^2}{l_0^2})} \quad (7)$$

The core plug exploited in the reaction was dried for 2 days in the oven to evaporate all the excess liquids. After drying, the plug weighed 66,4 grams and had dimensions of 38,09 mm in diameter and 31,37 mm in length. To measure the porosity and permeability after reaction, the analyses were performed using a permeameter (Figure 12) and porosimeter (Figure 13) of the School of Mining and Geosciences at Nazarbayev University. The dried core was tested by loading billets #1, #3, and #6 to achieve a tight fit of the equipment and prevent leakage of gas. The same equations 6 and 7 were applied.



Figure 12. Nitrogen permeameter.



Figure 13. Helium porosimeter.

To further interpret the data, the Hydraulic Flow Unit 9HFU) methodology was applied in order to classify the samples into reservoir rock types, by calculating parameters such as Reservoir Quality Index (RQI), Normalized Porosity Index (NPI), and Flow Zone Indicator (FZI), using equations 8,9 and 10.

$$RQI = 0.0314 \sqrt{\frac{K}{\phi}} \quad (8)$$

$$NPI = \frac{\phi}{1 - \phi} \quad (9)$$

$$FZI = \frac{RQI}{\phi^{0.588}} \quad (10)$$

$$R_{35} = 5.395 \frac{\phi^{0.588}}{(100 - \phi)^{0.864}} \quad (11)$$

Next, the calculation of effective pore throat radius (R35) was acquired for each of the plug samples. The calculation was used to explain the influence of the pore sizes on reservoir quality, following equation 11.

3.3 Petrography and mineralogy

The petrographic analysis was carried out on a set of polished thin sections (Figure 14) prepared in the School of Mining and Geosciences at Nazarbayev University from a core plug used in the experiment. The small portion of the core plug, before and after the reaction, was filled with epoxy, glued to the glass, and polished until the desired thickness was achieved. The sections were examined under plane-polarized (PPL) and cross-polarized (XPL) light using an optical microscope to identify textural features, grain composition, and any alterations.



Figure 14. Thin Sections prepared from the core plug. Before the reaction (left) and after the reaction (right).

The scanning electron microscope (SEM) analysis was performed before the reaction. A representative portion of up to 1 cm was chopped from the core and placed into the sample holder. After spraying Au/Pd allow on the surface of the sample at a ratio of 80/20, probing was conducted along the whole surface using a field emission scanning microscope Merlin (Carl Zeiss, Germany). Imaging was performed by Weatherford company, exploiting an accelerating voltage of 5 kEV to improve the depth of the imaging.

The X-Ray diffraction (XRD) was done before the experiment using the Diffractometer XRD-7000S (Shimadzu, Japan) by Weatherford company. Finely powdered core material was treated with acetic acid and hydrogen dioxide to remove carbonates and humic-type organic material,

respectively. The analysis was later performed according to the DIFFRAC plus Evaluation Package in the EVA Search/Match Software.

3.4 Batch reactor experiment



Figure 15. Batch reactor experiment setup.

A batch CO_2 -water-glaucanite sandstone interaction experiment (Figure 15) was conducted via a 67.19 gram whole core plug sample (Figure 16), which was submerged in 403.14 mL of deionized water. The PARR batch reactor vessel was exploited, and a constant temperature of 65°C and 130 bar was maintained to simulate the formation conditions. The experiment continued for 15 days without any mixing or disturbance. The selected plug is located at the favorable depth for sequestration and exhibits moderate porosity and permeability values, thus allowing moderately unbiased conclusion.

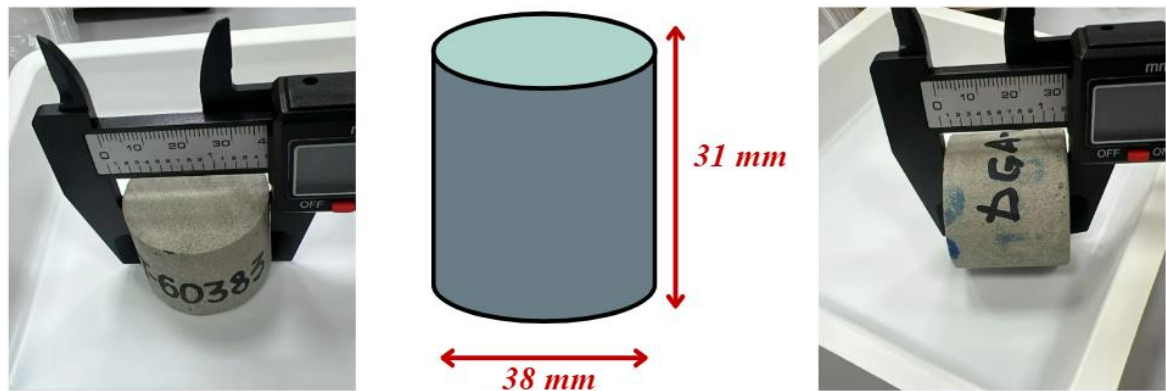


Figure 16. Selected core plug width and length measurement.

4. RESULTS

4.1 Petrophysical properties of the Albian sandstones

4.1.1 Sedimentary facies analysis

Sedimentary facies analysis was done by using GR logs, core photos, descriptions of industry reports, and core plugs observation. As a result, overall 10 lithofacies were defined, each having unique lithological properties. A summary of the lithofacies classification can be found in Table 1. Core photos with lithofacies and GR logs can be found in the Appendix of this document.

Table 1. Summary of sedimentary facies identified in the Dunga oil field for the cored interval.

Lithofacies	Lithology description	Sedimentary structures	Sedimentary processes
Massive Siltstone (□□ ₁)	Medium grey to grey colored, argillaceous, with common inclusions of organic matter and glauconite	Sedimentary structures were not identified	Slow precipitation of fine-grained sediments in a low-energy environment and minimal bottom-current reworking
Laminated Siltstone (□□ ₂)	Medium grey to grey colored, argillaceous, with common inclusions of organic matter and glauconite	Planar laminations	Slow precipitation of fine-grained sediments in the low-energy environment. Migration of small silty bedforms.
Stratified Siltstone (□□ ₃)	Medium grey to grey colored, argillaceous, with common	Lithofacies is characterized by	Alternating precipitation and weak current

	inclusions of organic matter and glauconite	well-developed bedding	reworking in a low to moderate energy environment
Massive Heterolithic Sandstone-Siltstone (□□ ₄)	Rare inclusions of green-colored sandstone interbedded with siltstone.	Sedimentary structures were not identified	Intermittent influxes of fine sand into a dominantly quiet-water environment
Laminated Heterolithic Sandstone-Siltstone (□□ ₅)	Rare inclusions of green-colored sandstone interbedded with siltstone.	Planar laminations	Migration of small bedforms in the low-energy environment with occasional influence of the nearby fluvial/alluvial sediments
Massive Heterolithic Siltstone-Sandstone (□□ ₆)	Rare inclusions of grey-colored argillaceous siltstone interbedded with sandstone	Sedimentary structures were not identified	Rapid deposition of sandy sediment during short high-energy events, followed by the settling of silt during slack water periods
Laminated Heterolithic Siltstone-Sandstone (□□ ₇)	Rare inclusions of grey-colored argillaceous siltstone interbedded with sandstone	Planar laminations	Alternation of the traction transport of sand and suspension of silt under weak-current conditions
Massive Sandstone (□□ ₈)	Evenly grained grey to greenish sandstone. Inclusions of clay minerals such as chlorite and mica. Pores are loose and poorly interconnected. Rare inclusions of pyrite next to organic matter. Abundant in glauconite	Sedimentary structures were not identified	High-energy environment with rapid deposition of sediments
Laminated Sandstone (□□ ₉)	Evenly grained, grey to greenish sandstone. Often, there are feldspar traces of intensive dissolution. Rare	Planar laminations	Traction deposition of sand with parallel lamination in a moderate to high-energy shallow-

	inclusions of pyrite and regenerative quartz. Interconnected pores of moderate size. Abundant in glauconite		marine environment setting
Stratified Sandstone (□□ ₁₀)	Evenly grained, grey to greenish, poorly argillaceous sandstone. Inclusions of clay minerals such as chlorite and mica. Pores are evenly distributed and interconnected. Abundant in glauconite	Lithofacies is characterized by well-developed bedding	Repeated reworking and deposition of sand by currents and/or waves in a moderate to high energy environment in a shallow-marine environment

The cored interval showcases an overall aggradational stacking pattern on the gamma-ray log (Figure 17). This suggests that vertical accumulation of sediment with no clear evidence for major shoreline advance or retreat. According to the subdivision proposed by Dujoncqouy (2017), the lower to middle Albian interval is associated with clinoform geometries and shoreface to deltaic deposition. In contrast, the upper Albian interval is characterised by aggradational stacking in an offshore to shoreface environment.

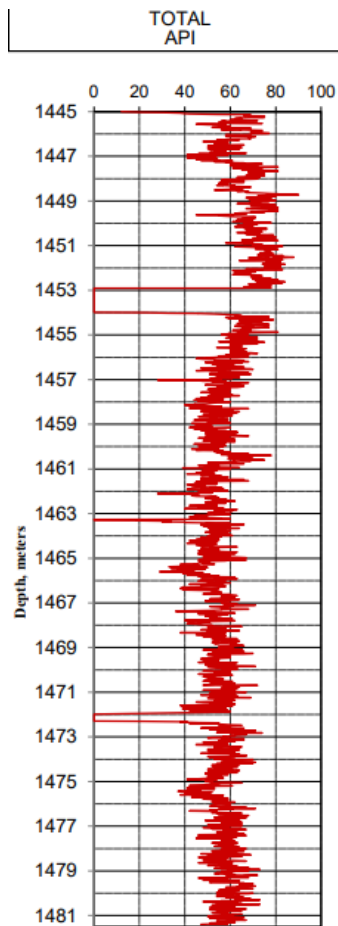


Figure 17. Selected core plug width and length measurement.

Based on the gamma-ray response and core observations, the studied interval is interpreted to correspond to the upper Albian succession. The presence of laminated siltstones with bioturbation, including *Schaubcylindrichnus*, suggests relatively low-energy offshore conditions, while massive sandstones indicate higher-energy depositional episodes closer to the shoreface.

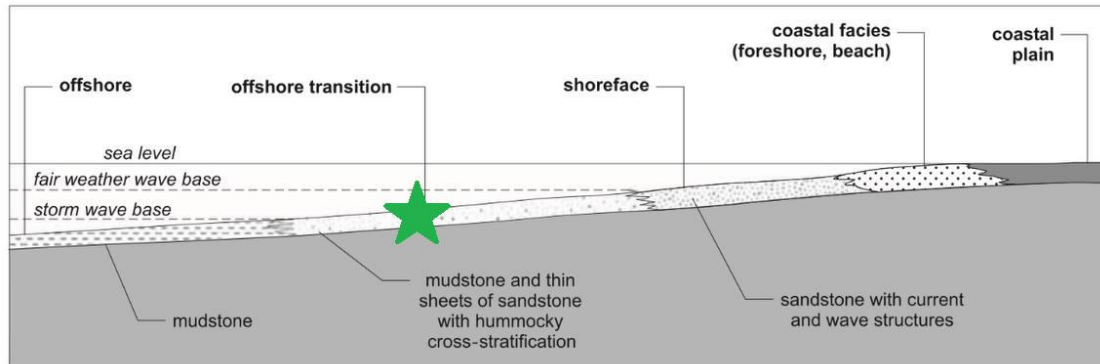


Figure 18. Characteristics of the shelf environment showcasing the offshore transition zone (Nichols, 2009).

Together, these features suggest deposition in an offshore to shoreface transitional environment (Figure 18) in the shallow clastic seas with the following depositional model:

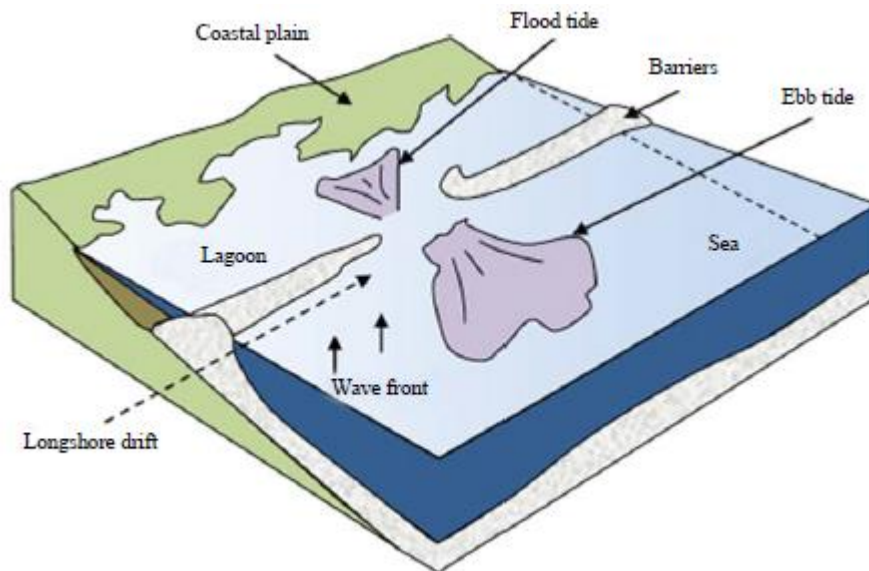


Figure 19. Proposed shallow marine depositional model (Siddiqui et al., 2017).

4.1.2 Porosity and Permeability by lithofacies

The lithofacies were studied for their porosity and permeability parameters (Figure 20). Facies such as LF2, LF3, and LF7, being very rare, their petrophysical properties were not recorded. The rest of the dataset (102 measurements) ranges with permeability values from 9.9 to 32.6%, whereas permeability values range from 0.06 to 1437.8 mD, which indicates a broad

spectrum of reservoir quality. The widespread data confirms that the reservoir is petrophysically heterogeneous, even if the mineralogical composition is rather the same.

LF1 is represented by a single sample with porosity of 19.4% and a permeability of 0.06mD. Although the sample has a moderate pore volume, the permeability value is extremely low, placing it at the tight end of the dataset. Since there is only one measurement for this lithofacies, its petrophysical behavior should be considered as preliminary.

LF4 porosity values range from 17.7 to 23.2%, with permeability values between 0.13 and 3.98 mD. The lithofacies occupy a relatively narrow porosity interval and thus a low-permeability field. Most of the samples lie in the baffles domain in the plot, which indicates that moderate storage capacity is not occupied by equally effective transmissibility.

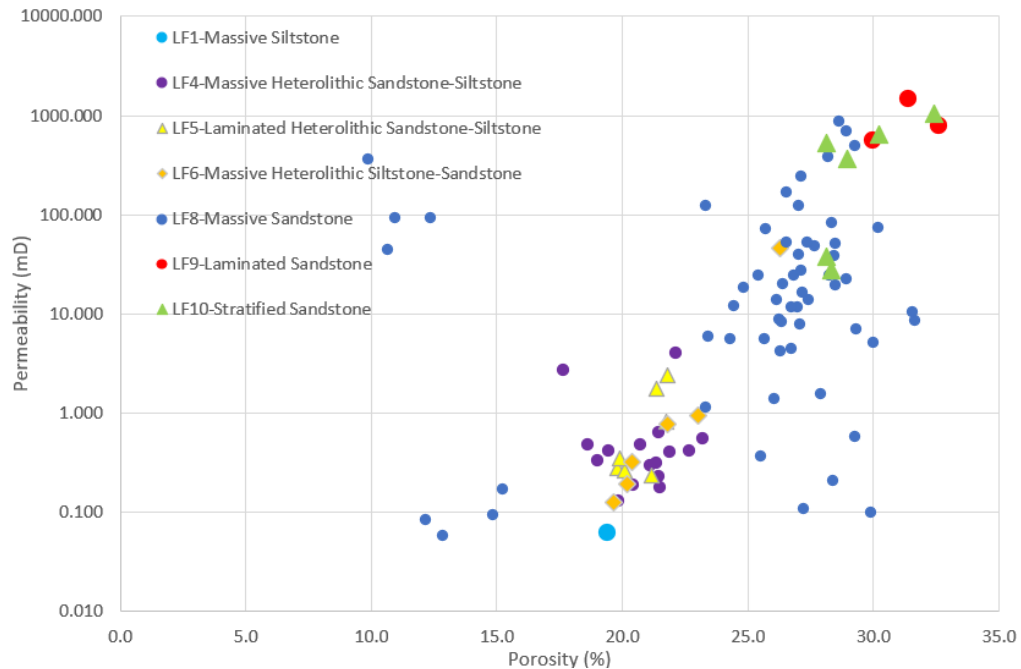


Figure 20. Cross-plot of permeability versus porosity for the studied Albian lithofacies (log scale for permeability).

LF5 facies show a similar restricted petrophysical distribution. Porosity values vary from 19.8 to 22.2%, while permeability ranges from 0.24 to 2.43 mD. Compared with LF4, LF5 occupies a slightly narrower porosity range and a comparable low-permeability domain. Overall, LF5 remains at the low transmission lithofacies despite exhibiting moderate pore volume.

LF6 is more variable than LF4 and LF5. The porosity measurements range from 19.7 to 26.3%, with permeability ranging from 0.24 to 2.43 mD. Most samples are found in the low-

permeability field, but one sample extends toward a substantially higher permeability value, thus broadening the facies distribution. So LF6 lies within a barrier group of consistently tight lithofacies and clearly high-quality reservoirs.

LF8 is the broadest petrophysical spread of all lithofacies and comprises 62 measurements. Porosity values lie between 9.9 and 32.6%, and permeability ranges from 0.06 to 869.4 mD. The lithofacies characterize nearly the entire reservoir-quality spectrum in the dataset, from tight samples that exhibit poor flow capacity to highly permeable samples that come close to the best-performing intervals. The wide range of the LF8 indicates pronounced internal variability.

LF9 is one of the highest quality petrophysical groups in the dataset. The porosity values range from 30.0 to 32.6%, and permeability values range from 551.8 to 1473.8 mD. Even though the group is represented by 3 samples, all of them can be seen in the uppermost part of Figure 7, which indicates consistently strong reservoir performance.

LF10 also represents high-quality lithofacies, with porosity values between 28.2 and 32.4% and permeability values from 27.9 to 1035.5 mD. When compared to LF9, LF10 occupies a broader range of values, but it still lies within the upper part of the dataset. In combination, LF9 and LF10 define the most favorable petrophysical end members of the investigated interval.

Overall, the porosity-permeability data showcase that the reservoir contains both tight and highly transmissive lithofacies, with LF4 and LF5 worsening the quality of the reservoir, LF6 occupying a moderate position, LF8 exhibiting the greatest internal variability, and LF9-LF10 corresponding to the best-quality reservoir units.

4.1.3 Hydraulic Flow Unit parameters and pore system classification

To further characterize the pore-system behavior of the studied lithofacies, Hydraulic Flow Unit parameters were applied. Following the procedure described in the methodology, NPI, RQI, FZI, and R35 were calculated from the provided porosity-permeability dataset to compare storage capacity, flow efficiency, hydraulic similarity, and effective pore-throat size across the lithofacies (Figures 21, 22, and 23). In the dataset, NPI values range from 0.109 to 0.484, RQI values from 0.018 to 2.152, FZI values from 0.073 to 4.706, and R35 values from 0.080 to 20.043 μm .

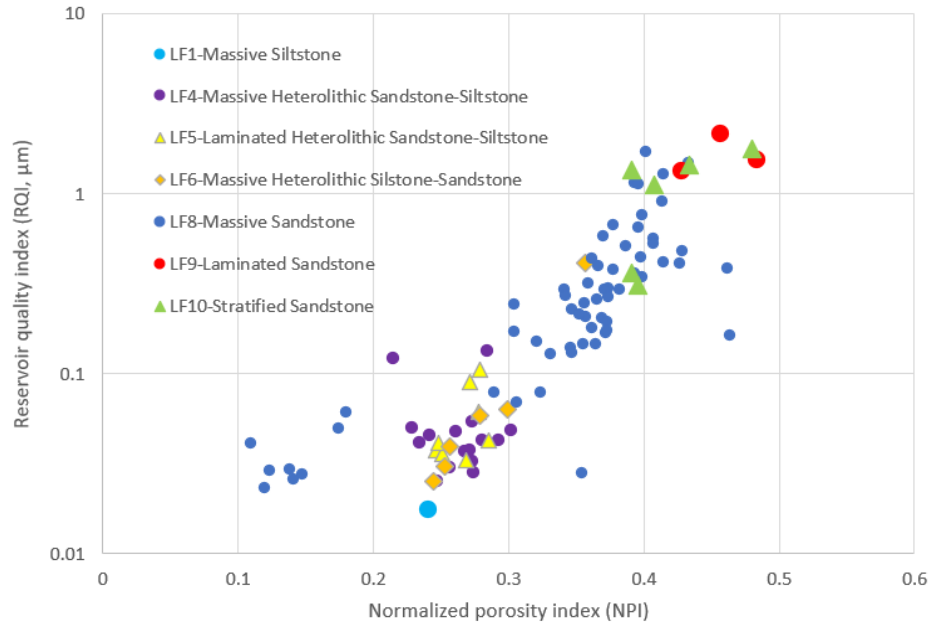


Figure 21. Cross-plot of Reservoir Quality Index (RQI) versus Normalized Porosity Index (NPI) for the studied Albian lithofacies.

LF1 yields the lowest hydraulic indices in the dataset, with NPI of 0.241, RQI of 0.018, FZI of 0.073, and R35 of 0.080 μm . The values locate the LF1 sample in the lowest-quality pore-system category recognized in the analysis.

LF4 and LF5 have similar low-hydraulic domains. LF4 is characterized by mean RQI, FZI, and R35 values of 0.051, 0.199, and 0.286 μm , respectively, whereas LF5 shows mean values of 0.056, 0.208, and 0.312 μm . The NPI values are moderate, with an average of 0.263 for LF4 and 0.266 for LF5, indicating that the pore volume is present, but it is not converted into efficient hydraulic flow. For the NPI-RQI and FZI-R35 space, both lithofacies are clustered in the lower part of the graphs and define low-quality efficiency pore systems.

LF6 has a broader range of hydraulic behavior than that of LF4 and LF5. The NPI values range from 0.245 to 0.357, RQI from 0.025 to 0.415, FZI from 0.103 to 1.162, and R35 from 0.122 to 3.034 μm . The calculated values indicate that LF6 does not form a uniform compact hydraulic class. Instead, it is in the transitional domain between the tight lithofacies and efficient reservoir representatives.

LF8 is the most heterogeneous lithofacies in the HFU measurements, too. It spans almost the full range of calculated hydraulic parameters, with NPI values from 0.109 to 0.484, RQI from 0.023 to 1.730, FZI from 0.079 to 4.310, and R35 from 0.128 to 15.899 μm . The mean values,

when compared to the LF4-6, are higher, but the intake values are still very broad. This shows that the samples marked as LF8 include different pore-system behavior rather than a uniform hydraulic unit.

LF9 exhibits the highest average hydraulic quality in the dataset. It is characterized by mean NPI, RQI, FZI, and R35 values of 0.456, 1.679, 3.679, and 15.039 μm , respectively. The values correspond to a highly effective pore system with the largest pore-throat dimensions observed in the lithofacies.

LF10 plots in the high-quality hydraulic field, with mean NPI, RQI, FZI, and R35 values of 0.416, 1.064, 2.498, and 9.134 μm . Although it is a bit more dispersed than LF9, LF10 consistently remains in the upper-hydraulic domain of the dataset.

Overall, the HFU parameters define three broad pore-system groups in the studied interval. LF1, LF4, and LF5 form a low-efficiency group characterized by low RQI, FZI, and R35 values. The transition to a highly variable hydraulic field consists of LF6 and LF8. At last, LF9 and LF10 are defined by the high-efficiency end of the reservoir, showing the largest effective pore-throat radii and highest flow-quality indices.

4.1.4 Hydraulic variability of the reservoir

The studied Albian interval shows substantial hydraulic variability across the analyzed lithofacies. Porosity values range from 9.9 to 32.6%, whereas permeability values range from 0.06 to 1473.8 mD. This means that the variation in permeability is considerably greater than the variation in porosity, which indicates that the lithofacies differ more strongly in the flow behavior rather than in pore volume.

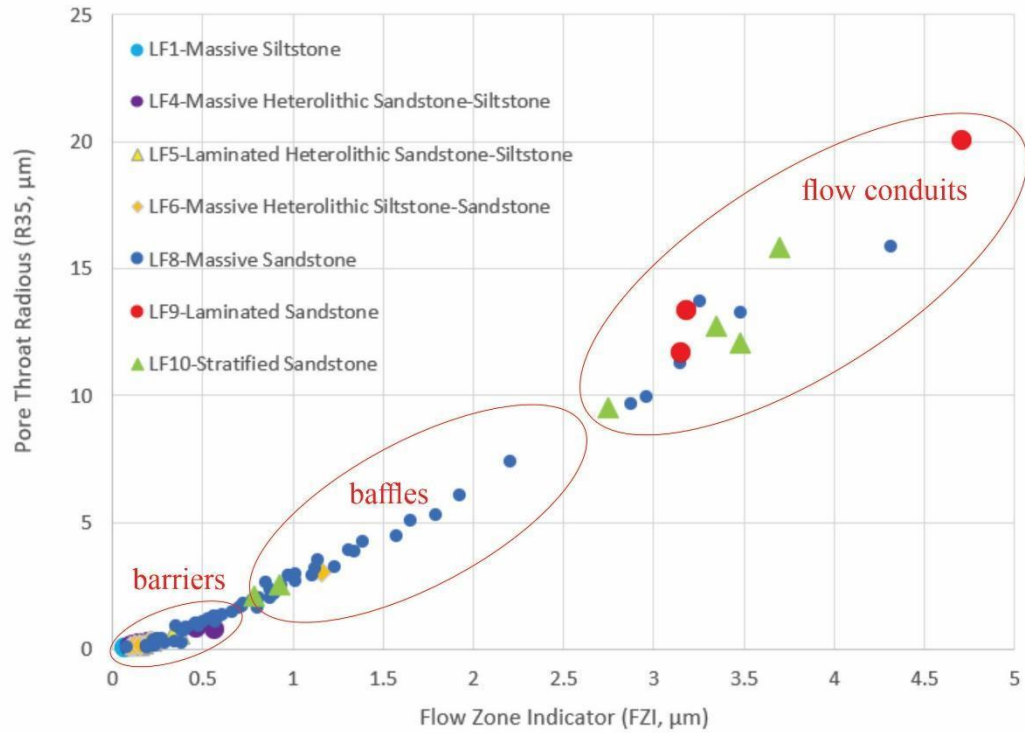


Figure 22. Cross-plot of pore throat radius (R35) versus Flow Zone Indicator (FZI) for the studied Albian lithofacies, showing baffles, barriers, and flow conduits groups.

LF1, LF4, and LF5 occupy the lower hydraulic part of the dataset. The samples show rather moderate porosity, but consistently low permeability, as well as low RQI, FZI, and R35 values. In contrast to that, LF9 and LF10 are in the upper hydraulic part of the graph, with high porosity, high permeability, and the highest hydraulic flow unit parameters.

LF6 occupies a barrier position. Most of the samples exhibit low permeability. LF8 has the broadest spread in all measured and calculated petrophysical parameters. The samples range from low-porosity, low -permeability values to highly porous and highly permeable values, and the same widespread is observed in RQI, FZI, and R35.

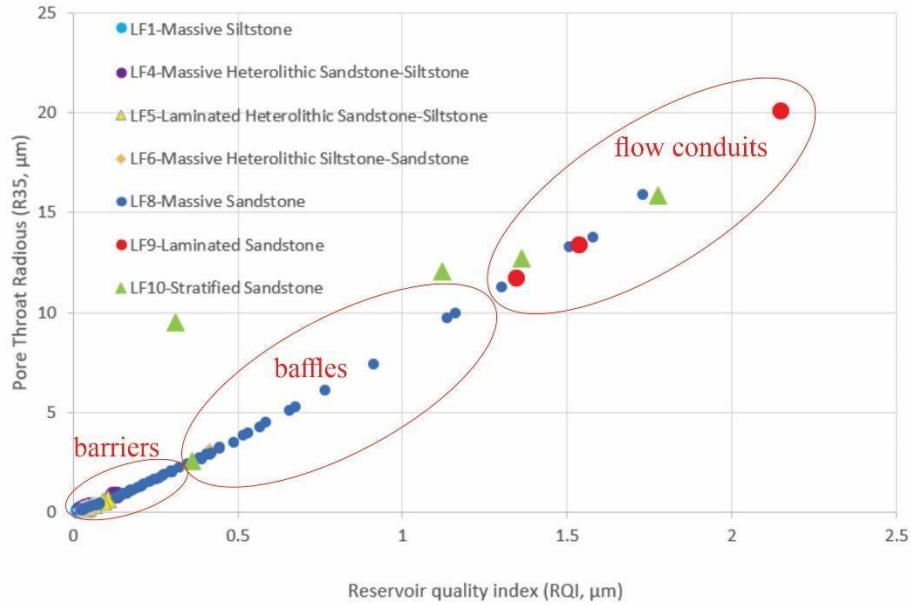


Figure 23. Cross-plot of pore throat radius (R35) versus Reservoir Quality Index (RQI) for the studied Albian lithofacies, showing baffles, barriers, and flow conduits groups.

The differences of the lithofacies also extend into the internal distribution of porosity and permeability values. LF10 is a relatively more homogeneous positive porosity-permeability trend, whereas LF4 and LF8 show broader scatter. Overall, the dataset records the coexistence of baffles, barriers, and flow conduits lithofacies in the studied interval.

4.2 Mineralogical composition

4.2.1 SEM and XRD

Before the reaction, mineralogical and microtextural characterization was carried out on sample 56 from core 2 (depth 1461.31 m) using XRD and SEM. Whole-rock XRD reveals that the sample is dominated by quartz, which constitutes 43% of the bulk mineral composition. Subordinate phases include ordered albite (21%), mica and glauconite (13%), and microcline (13%).

Chlorite and kaolinite occur in smaller amounts, accounting for 6% and 5%, respectively, whereas pyrite is present in trace quantities. The XRD diffractogram is characterized by a dominant quartz peak and low-intensity reflections of feldspar and clay mineral phases, which can correspond with Figure 11 and Table 2.

Table 2. Results of qualitative and quantitative analysis of the bulk mineral composition of rocks.

Sample number	Mineral composition, %						
	Quartz, syn	Albite, ordered	Mica+Glauconite	Microcline	Chlorite	Kaolinite	Pyrite
56	43	21	13	13	6	5	traces

XRD analysis of the clay fraction established that kaolinite is the dominant clay mineral and comprises 52.1% of the clay fraction. Chlorite is the second most abundant clay mineral at 35.37%, following mica at 12.53%. Mixed-layer illite-montmorillonite was absent. Overall, the clay fraction is mostly composed of kaolinite and chlorite, with subordinate micaceous components.

Table 3. Results of the qualitative and quantitative analysis of the clay fraction of samples.

Sample number	Mineral composition in clay fraction, %			
	Chlorite	Kaolinite	Mica	Mixed lattice illite-montmorillonite
56	35.37	52.1	12.53	0

SEM results show that the sample has an equigranular, non-homogeneous texture with alternating dense and loose intervals. The clastic framework is composed of coarse aleuritic grains, with the grain sizes falling in the range from 0.05 to 0.1 mm. Quartz and feldspar are detrital grains of the sample. Feldspar grains commonly display corrosion (Figure 26), and dissolved feldspar grains are observed among quartz grains. The cementing material is represented predominantly by chlorite and mica.

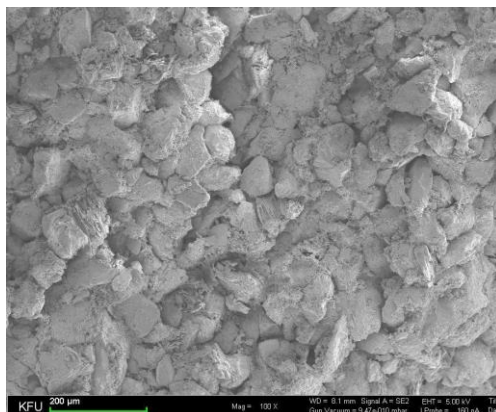


Figure 24. General view of the sandstone.

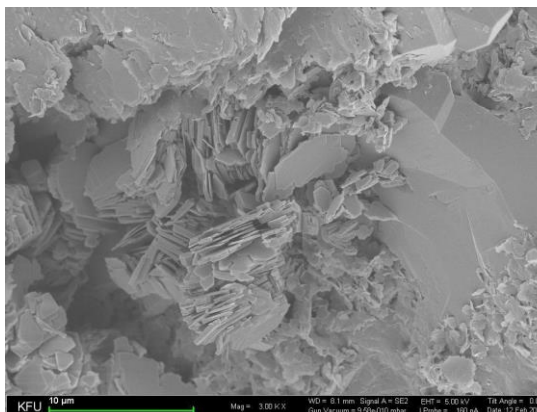


Figure 25. Kaolinite aggregates in pore space.



Figure 26. Grains of corroded feldspar.

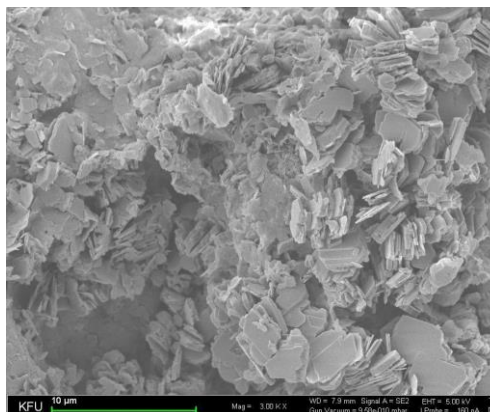


Figure 27. Kaolinite aggregates in pore space.

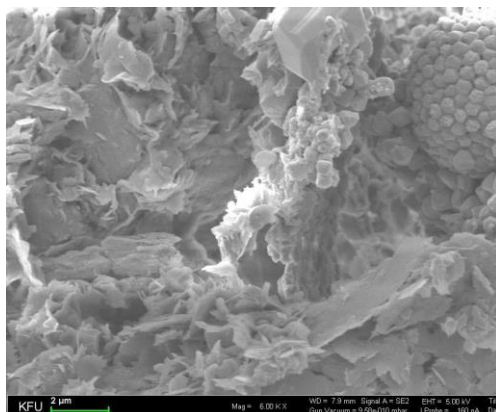


Figure 28. Isometric aggregate of pyrite (top right) within pore space.

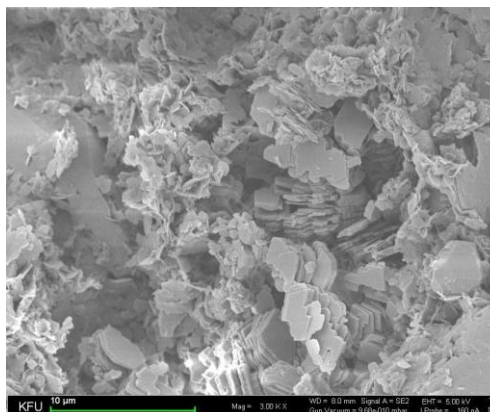


Figure 29. Kaolinite aggregates on pore walls.

Authigenic mineral phases are common within the pore system. Kaolinite occurs as flaky aggregates (Figure 29), commonly up to 10 μm in size, observed in both pore spaces and pore walls. Pyrite is noted locally as authigenic grains and isometric aggregates within the pore systems. The system is best developed in the loose intervals of the sample, with intergranular pores reaching a size of up to 20 μm and remaining interconnected.

4.2.2 Petrography

Petrographic examination of the sample before the reaction reveals glauconite-bearing siliciclastic rock composed of predominantly quartz framework grains with subordinate feldspar and abundant glaucony facies (Figure 30A, B). In PPL and XPL, quartz occurs as clear detrital grains, whereas feldspar is present as a subordinate framework component, which is consistent with the XRD results that show the presence of albite and microcline. Glauconite occurs as green grains located between the detrital framework grains. Clayey cement is common in the intergranular space and comprises the denser parts of the sample. In the photomicrograph before the reaction, the rock fabric appears comparatively compact, and relatively narrow cracks are observed.

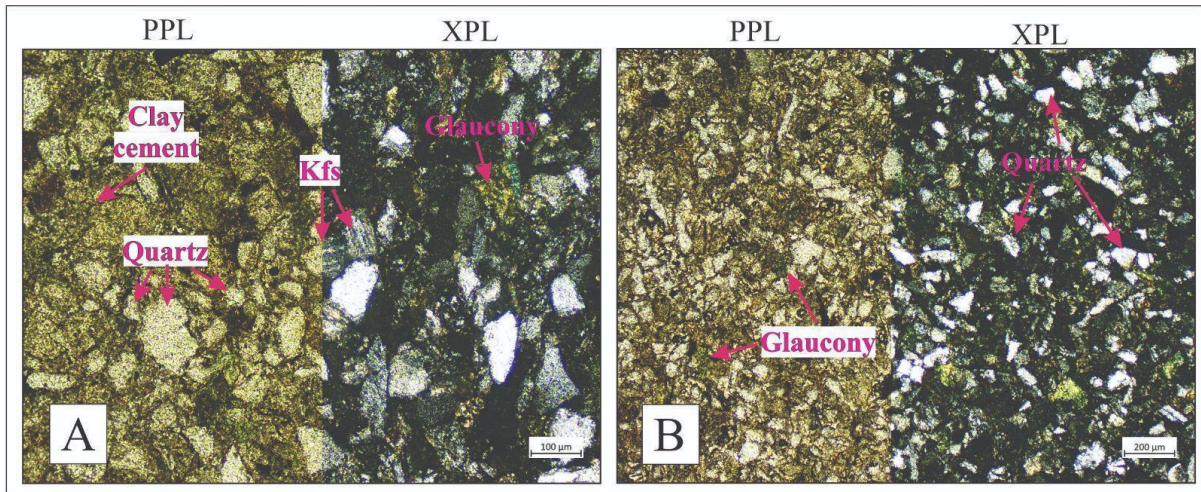


Figure 30. Thin Section photomicrograph of the sample before the reaction.

4.3 Batch reactor experiment

A batch CO_2 -water-rock interaction experiment was performed on a whole core plug sample under controlled laboratory conditions, which simulated the reservoir conditions. Before the experiment, the core plug had an initial mass of 67.19 g. After the reaction and subsequent

oven drying, the sample mass decreased to 66.4 g, corresponding to a net mass loss of 0.79. The substantial weight loss can be due to the dissolution of calcite minerals.

Petrophysical measurements conducted before and after the experiment indicate that the sample became more porous and more permeable after reaction. Porosity increased from 28.2% before the experiment to 29.9% after the experiment. Permeability also increased, from 38,4 mD to 52.006 mD. The results show that the reacted sample retained its reservoir character and recorded an overall improvement in both pore volume and flow capacity after the batch experiment.

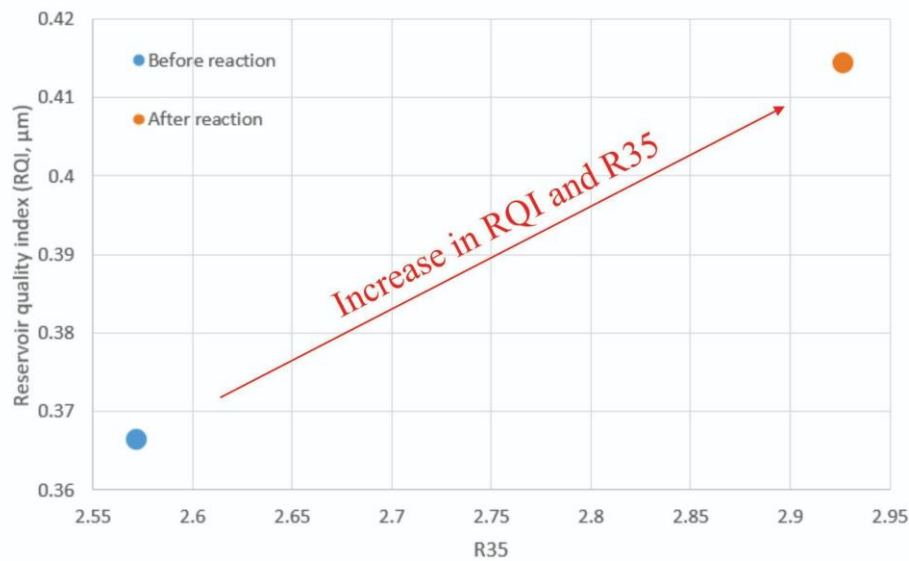


Figure 31. Pre and post reaction change in RQI versus R35 for the studied glauconitic sandstone sample.

The calculated pore-system parameters show the same trend. The effective pore throat radius increased from 2.57 to 2.93 μm , while the Reservoir Quality Index increased from 0.366 to 0.414 μm , as can be observed from Figure 18. On this figure, the post-reaction results shift upward and to the right relative to the pre-reaction point, which indicates an increase in both pore-throat size and reservoir quality.

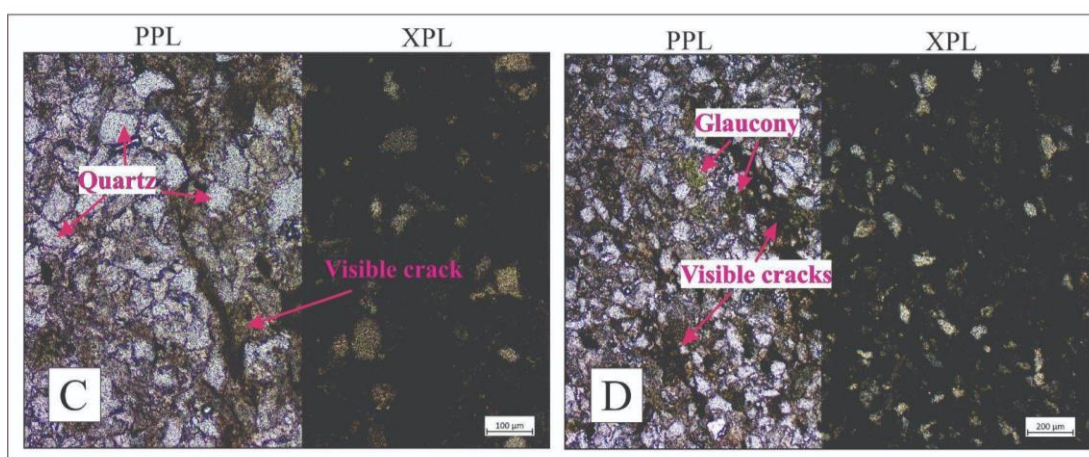


Figure 32. Thin Section photomicrograph of the sample after the reaction.

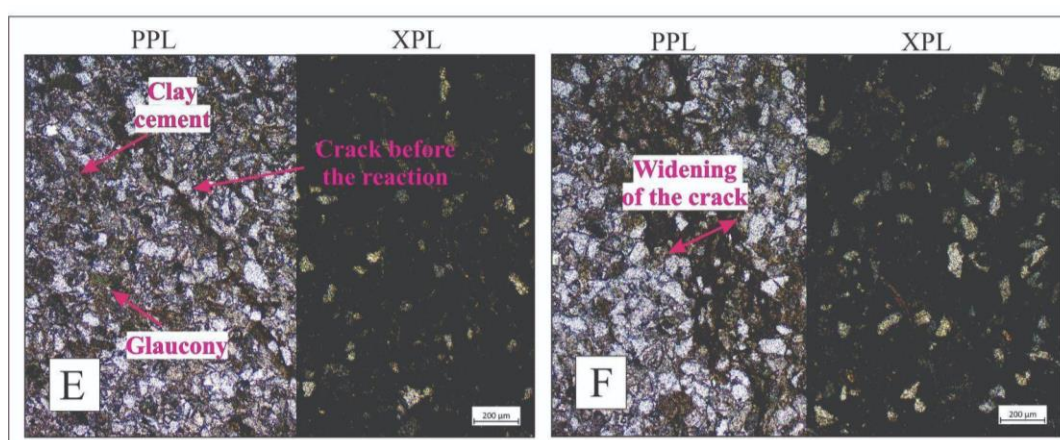


Figure 33. Representative thin-section photomicrographs of the sample before (left) and after reaction (right). The photographs are from different areas of the sample and are shown to illustrate the general increase in crack aperture after reaction.

The thin sections after reaction show that the main framework composition of the sample is still dominated by quartz and glaucony facies (Figure 32C, D). However, the reacted sample has more open microfabric when compared to the initial photomicrograph. The most notable petrographic change is the presence of wider and more visible cracks in the post-reaction sample. In addition, the clayey cement appears to be reduced in some parts of the reacted sample, and the rock fabric locally appears less compact than before the experiment.

Comparison between the samples' pre-reaction and post-reaction photomicrographs indicates an overall increase in cracks after the experiment. Although the compared images were

not taken from the same location within the thin section, the reacted sample consistently shows wider cracks and a more open intergranular fabric (Figure 33E, F). These petrographic observations are consistent with the petrophysical data received after the batch reactor experiment, which shows an increase in porosity and permeability.

Overall, the post-reaction measurements and petrographic results document a net enhancement in pore volume, pore-throat size, and flow capacity relative to the initial state of the sample due to the widening of the cracks and a more open fabric relative to the initial state.

5. DISCUSSION

5.1 Depositional and textural controls on reservoir quality

The petrophysical heterogeneity of the Albian interval is influenced by transitional facies architecture and post-depositional modifications during burial. The facies analysis shows that the reservoir comprises a spectrum from the fine silts and heterolithic beds to clean sandstone-dominated intervals. The variability of lithology is expressed in the dataset, where baffles facies (LF1, LF4, LF5), transitional facies (LF6 and L8), and flow conduits facies (LF9 and LF10) can be distinguished by properties such as porosity, permeability, and HFU parameters. Reservoir quality is not single-handedly dictated by a mineralogical trend, but rather by variations in grain size, clay content, internal fabric, and pore-throat connectivity.

The low-quality reservoir facies represent the intervals where fine-grained material and clay-abundant intergranular domains negatively impact pore connectivity. The interpretation is backed up by the SEM and XRD results, which show a quartz-rich framework with subordinate feldspar and glauconite, together with a predominantly clayey cement/matrix represented by chlorite, mica, and authigenic kaolinite. The kaolinite occurs in the pore spaces and pore walls, while feldspar exhibits such variabilities as corrosion and dissolution. Hence, even if the pore volume of some facies is present, the hydraulic efficiency can be limited due to the presence of clayey material or narrow pore throats.

In contrast to that, the flow conduits lithofacies correspond with the cleaner and better-connected sandstone units, where intergranular flow pathways seem to be more effective. This contrast is comparable with the studies done in the Farewell F ([Yahia et al., 2026](#)), where

framework components rich in quartz and feldspar and lower-clay reservoir rock types are identified as the best facies for storage, while tight and heterogeneous units are described as non-reservoir units. In this study, the widest spread of data within LF8 facies shows that typing on lithofacies alone is unable to fully predict the hydraulic behavior of the rock type. Hence, one facies can comprise more than one hydraulic unit, and it is very vital for the Dunga oil field, because of the conclusion that the classification should be integrated with the HFU-based reservoir analysis.

5.2 Implications for physical trapping

The studied Albian interval displays quite a favorable architecture for physical carbon dioxide storage. The Albian interval in the Dunga oil field is laterally extensive, glauconite-bearing, and is a host for a soon-to-be-depleted hydrocarbon field with existing infrastructure, which makes it a very attractive pilot site. In addition to that, the carried out petrophysical investigation concludes that LF9 and LF10, and some intervals of LF8 and LF6, possess sufficiently favorable porosity, permeability, RQI, FZI, and R35 data that act as target injection units.

The low-quality facies cannot be interpreted merely as unfavorable. It can be beneficial from a storage-security standpoint. Hydraulically weaker lithofacies can introduce capillary contrasts and areal permeability barriers within the formation. They create a stratigraphically organized reservoir architecture in which flow-conduit units can transmit and store CO₂, while tighter units can reduce vertical plume migration. The same interpretation was carried out by Yahia et al. (2026) for the Farewell F formation (currently studied for the CO₂ sequestration potential), where internal baffles and vertical seals were identified to support plume containment rather than for their injectivity potential. Therefore, the heterogeneity of the Dunga Albian interval should not be viewed solely as a drawback but as a feature that reduces flow continuity, thereby improving the security of physical trapping.

The experiment carried out in the batch reactor adds additional observation, which is relevant for the physical trapping. Post-reaction, the core plug sample showed a decrease in mass and higher measurements in porosity, permeability, R35, and RQI, in a complex with wider cracks and a more open petrographic fabric observed in photomicrographs, suggesting effective

dissolution. Though the experiment was carried out on a laboratory scale and under controlled conditions, it shows that the initial stage of the injection may locally increase the pore-connectivity rather than decreasing it immediately. In the context of storage, this implies that the first stage of introduction of carbon dioxide in the formation may be accompanied by a slight enhancement of injectivity in the intervals with reactive glauconite, specifically where effective flow pathways are increased by the dissolution of clayey cement and feldspar. In reality, this observation is only preliminary and local rather than a direct reservoir-scale prediction. The significance of this finding depends on whether the dissolution and precipitation are balanced through time and space.

5.3 Implications for mineral trapping

The Albian sandstone of the Dunga field possesses a mineralogical composition that is favorable for the CO₂-rock interactions and therefore is relevant to mineral trapping. Unlike mature quartz-dominated reservoirs, which have limited geochemical reactivity, the studied interval contains feldspar, glauconite, chlorite, mica, kaolinite, and trace pyrite. Such an assemblage indicates that the framework is not mineralogically inert and includes phases that are susceptible to alteration under carbon dioxide aqueous conditions. Particularly, the glauconite grains can act as a reactive Fe-bearing phase, which can contribute to the carbonation reactions in the prolonged fluid-rock interaction.

The experimental results showcase that the sample reacted measurably during the batch reactor experiment. Observed decrease in the mass, combined with the improvement in petrophysical data and petrographical evidence of the wider cracks, indicates that in the short-term response to the environment, dissolution occurred. These observations are consistent with early-stage alteration of reactive components within the sandstone framework and cement.

From the perspective of CO₂ storage, this initial reaction is vital because the mineral trapping process in glauconitic sandstones depends on the initial dissolution of the reactive phases and release of the cations into the fluid. In this sense, the opening of the pore-systems does not contradict mineral trapping potential but represents a very early stage of the overall reaction pathway, which starts with the dissolution and eventually can lead to the formation of carbonate minerals under favorable geochemical conditions. This interpretation is consistent with the broader behavior of glauconitic sandstones described in the experimental studies of the literature.

At the same time, the results do not demonstrate large-volume carbonate precipitation at the studied time scale (15 days) under the tested conditions. Therefore, the potential for mineral trapping in the Dunga oil field Albian sandstones is best interpreted as plausible and progressive, rather than immediate. The evaluation of the potential of glauconite dissolution and following mineral transformation would require post-reaction SEM and XRD characterization to observe petrographic changes.

5.4 Uncertainties and limiting factors

Several uncertainties restrict the extrapolation of the present results to the reservoir scale. The first is characterized by the representativeness of the dataset studied. Among 10 lithofacies, the provided petrophysical data are unevenly distributed, with some groups being represented by numerous measurements and others by only a few samples or none at all. As a result, the interpretation of hydraulic parameters is more robust for the dominant facies groups than for sparsely represented intervals.

A second limitation lies within the batch reactor experiment, which demonstrated modification of the pore system, with favorable results for both mineral and physical trapping. However, the experiment was carried out for a single whole-core plug in the very simplified conditions of the laboratory and thus cannot fully predict the chemical and hydrodynamic complexity of the subsurface reservoir.

Another uncertainty concerns the extent of mineral trapping potential. The achieved results indicate dissolution-driven alteration of the sample, but it does not demonstrate large-volume carbonate precipitation under the tested conditions. For this reason, the mineral trapping for the Dunga Albian sandstones is best regarded as progressive and condition-dependent. To achieve a more extensive and definitive assessment of glauconite dissolution and mineral transformation would require a longer experiment (minimum for 30 days), evaluation of the glauconite for ferric and ferrous cations ratio, and a post-reaction SEM and XRD characterization in addition to the observed petrophysical and petrographic changes.

Finally, the reservoir-scale performance will be dependent on the internal heterogeneity of the formation. As provided in the petrophysical results and similarly highlighted in the comparable glauconitic reservoir studies, the coexistence of higher-quality flow units and tighter internal

baffles may be beneficial for containment but still complicates the further prediction of injectivity and further plume migration. Carbonate-cemented concretions and dual-porosity behavior may further modify the vertical connectivity and storage distribution within the Albian interval.

6. CONCLUSIONS

This study evaluated the CO₂ storage potential of the Albian glauconite-bearing sandstones in the Dunga oil field, Mangyshlak Basin, by integrating lithofacies analysis, petrophysical interpretation, HFU classification, mineralogical observations, and a short-term batch reactor experiment. The results show that the studied interval is heterogeneous and consists of both high-quality flow units and tighter internal baffles. LF9 and LF10 represent the most favorable reservoir units due to their high porosity, permeability, RQI, FZI, and R35 values, whereas LF1, LF4, and LF5 form low-efficiency intervals that may contribute to internal flow restriction and plume containment.

Mineralogical and petrographic observations indicate that the selected sandstone sample is not chemically inert. The presence of quartz, feldspar, mica/glauconite, chlorite, kaolinite, and trace pyrite suggests that the rock contains reactive phases relevant to CO₂-water-rock interaction. The batch reactor experiment caused a decrease in sample mass, together with increases in porosity, permeability, RQI, and R35. Thin-section observations also show wider cracks and a more open post-reaction fabric, indicating dissolution-driven pore-system alteration.

Overall, the Dunga Albian sandstones appear to be a promising candidate for combined physical and progressive mineral trapping of CO₂. The high-quality sandstone facies may support injection and storage, while the tighter facies may improve containment. However, mineral trapping should be considered potential and progressive rather than immediate, because carbonate precipitation was not directly confirmed in this study. Future work should include longer reaction experiments, post-reaction SEM and XRD analysis, geochemical fluid analysis, and reservoir-scale modelling to better assess long-term injectivity, plume migration, and mineral trapping efficiency.

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APPENDIX

