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Results of Phase I of CO2 EOR Pilot in Thin, Microporous Carbonate Reservoirs

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Abstract

Substantial volumes of hydrocarbons are trapped in micro-porous low permeability, transition zone, thin reservoirs in the north of Oman. Developing these resources under depletion or by waterflooding is not economically attractive due to the low resource density and poor water injectivity. Numerical modeling studies showed the potential to unlock these volumes economically through CO_2 injection. Therefore, a field pilot, an Oman and PDO first, was executed to demonstrate the feasibility and success of CO_2 injection.

Detailed modeling work indicated that the injectivity of CO_2 is the key risk for the success of CO_2 development in these reservoirs. Thus, the field pilot was executed to de-risk the CO2 injectivity, establish communication between injector and producer, and ensure a sustainable production rate. A horizontal CO_2 injector was drilled 100 meters away from an existing horizontal producer, which also had a horizontal water injector on the other side. This oil producer lacked pressure support during primary and waterflooding, and thus, it was producing intermittently. CO2 was supplied to the injector and pumped for four months. A surveillance program was put in place to monitor the CO_2 injection and production.

The pilot demonstrated good and sustainable injectivity of CO2. The injection rate, on average, was higher than the target rate of 30 tons per day, and almost 2-3 times the average injection rate of water at subsurface conditions. This was achievable by maintaining the pressure below the fracture pressure at the injector. The results of this pilot demonstrate the potential of CO2 EOR to economically recover oil reserves from tight reservoirs while simultaneously contributing to CO2 emission reduction by utilizing captured CO2 from gas processing plant and power plants. Moreover, the success of this pilot project paves the way for unlocking oil reservoirs facing similar challenges.

Introduction

The reservoirs under study are very thin (3–5 m in thickness), microporous carbonates with low permeability (0.1–3 mD), and the full oil column is a capillary transition zone. This combination of thinness and transition zone characteristics results in low resource density, making the economic development challenging. Furthermore, due to the low permeability and thickness of the units, both productivity and water injectivity were limited, even when the wells were drilled horizontally with lengths of 1.5–2.0 km. This added to the economic challenges of development.

Several water injectivity trials and well stimulations were conducted, but they were not successful to achieve sustainable injection rates and pressure support for the producers to produce economic rates (Kumar at al. 2020). On average, water injectivity was approximately 0.003 m^3/day/kPa for most of the wells drilled in these thin and microporous units, resulting in water injection rates below 15 m^3/day. Gas injection was proposed as an alternative because of its low viscosity and potential to achieve higher injection rates, which could provide pressure support and lead to increased production rates.

Additionally, with the growing interest in CCUS and ambitions to reduce CO2 emissions, screening studies were conducted across the PDO oil and gas portfolio to identify and rank opportunities for CO2 Enhanced Oil Recovery (EOR) and Enhanced Gas Condensate Recovery (EGCR), see Nasralla et al. (2022) and Nasralla et al. (2024a). These carbonate fields were identified as front runners for CO2 EOR due to their significant target volumes and attractive net gas utilization (NGU). Unlike conventional reservoirs, the volumes in these fields could not be unlocked using other primary or secondary recovery methods, e.g. waterflood, meaning all the recoverable volumes could be attributed to the CO2 EOR project.

Based on the findings of these screening studies, a detailed numerical reservoir simulation study was conducted to evaluate the potential of gas injection (Nasralla et al., 2025). The results were encouraging, demonstrating the feasibility of CO2 injection to accelerate oil production and achieve higher recovery factors as CO2 injection was near-miscible conditions. However, developing the field with CO2 EOR would require substantial capital expenditure due to the need for CO2 capture plants and injection/production facilities capable of handling back produced CO2. To minimize the investment risks associated with full-field development, a trial was planned to demonstrate the ability of CO2 injection to address the main challenges of the field.

A comprehensive work plan was developed to design and execute a fit-for-purpose pilot. The primary goal was to de-risk full-field development without causing delays to its implementation. The pilot execution was divided into two phases, each with distinct objectives outlined in Table 1.

Phase II was contingent upon the outcomes of Phase I, which helped minimize the pilot's costs in case of unexpected results. The design aspects of the trial were discussed in detail in Nasralla et al. (2024a). In this paper, we present the results and findings from Phase I of the pilot.

Table 1 – Pilot Phases and the key uncertainties and risk to be addressed in each phase, and the success criteria

Pilot Phase	*Key Uncertainty & Risk to address*	*Success Criteria*
Phase I	Prove CO_2 sustainable injectivity at target rate	• Achieve a minimum of **50 rm3/d** CO_2 subsurface injection rate equivalent • Demonstrate no injectivity loss occurs over the injectivity pilot period • Prove the well concept/design feasibility as well as CO_2 supply chain and management capability
Phase II	Prove pressure support & sweep efficiency	• Demonstrate CO_2 injection pressure support in the nearby producer and corresponding production rate increases. • No early CO_2 breakthrough as a result of poor conformance

Approach: Pilot Concept

Pilot Location

The field is considered a greenfield, as the majority of the oil in place have not been developed; only a few horizontal well pairs of oil producers and water injectors were drilled. It was decided to execute the CO2 pilot in a developed area of the reservoir rather than in an undeveloped area. This approach provided a baseline for water injection rates and oil production rates. It also helped to reduce well costs by utilizing an existing producer as part of the trial. Thus, only a new horizontal CO2 injector well was drilled 100 m from an existing horizontal producer.

The existing producer had been in operation for seven years but was producing intermittently due to gas lock issues in the electrical submersible pump (ESP). This problem resulted from the formation of a secondary gas cap near the producer, caused by pressure dropping below the bubble point during production. Despite the presence of a water injector 200 m away on the other side of the newly drilled CO2 injector, poor water injectivity failed to provide adequate pressure support. Thus, the location of the new injector was ideal, as the nearby water injector and producer experienced poor injectivity and productivity. Consequently, any improved performance could be attributed to the mechanism of gas injection rather than geological factors, i.e. better rock properties.

The new well was successfully drilled into the target formation using geo-steering and was placed in the top one meter of the unit, where permeability is highest. Pressure data recorded with Modular Dynamics Tester (MDT) showed an average pressure of 110 bar, compared to the initial reservoir pressure of 135 bar. This confirmed reservoir depletion and communication with the nearby producer.

Injection Rate and Well Spacing

The target injection rate was critical to be determined in advance to plan the CO2 supply accordingly. In addition, it was important to estimate the time required for concluding the pilot for planning and arranging all the logistics. A numerical simulation model was used to determine the target injection rate, the spacing between the injector and producer, and time required to reach sustainable production rate. The model was compositional model using Equation of State (EOS) to capture interactions between CO2 and hydrocarbon components. It also accounted for all the physics of three phase flow in porous media, including the oil-water relative permeability hysteresis due to transition zone and the dependency of oil-gas on Interfacial Tension (IFT). The model was calibrated using the field data from the nearby producers and injectors. Further details of the model are discussed in Nasralla et al. (2025).

The estimated injection rate was 30 tons/day, equivalent to ~50 m^3/day at subsurface conditions near the injector. This rate was nearly 2-3 times the sustained injection rate achieved through waterflooding. Various spacing scenarios between the injector and producer were modeled to select an appropriate distance for the trial. A spacing of 100 meters was chosen to accelerate pilot response, as larger distances would require a longer pilot duration to confirm production rate improvements. The shorter spacing also would lead to a sharper production response due gas injection, as presented in Nasralla et al. (2024b).

CO2 Supply and Injection

The injected CO2 was purchased from local market supply and transported via trucks during the trial. Given the relatively small CO2 volumes required for injection (~30 tons/day on average), it was feasible to follow this approach to accelerate pilot execution and results, enabling earlier full-field implementation. In contrast, sourcing CO2 from a capture plant would have required a lengthy commissioning and construction period for capture and transport facilities, as well as significant capital expenditure.

CO2 was supplied to the well site and stored in storage ISO-tanks in dense phase. CO2 was fed to a high-pressure pump to boost the pressure to the injection pressure. Afterwards, the CO2 was heated to 30°C to avoid any thermal stress to the formation and potential fracture.

The injector well was equipped with a permanent downhole gauge (PDHG) to continuously monitor the pressure and temperature. The CO_2 injection flow rate and THP were also continuously measured.

Results

CO_2 was injected in dense phase for nearly four months. Figure 1 illustrates the wellhead and bottom-hole pressures along with the average daily injection rate. On average, the injection rate exceeded the target of 30 tons/day, while the injection pressure remained below the fracture pressure. The results demonstrated that gas injectivity was sustained at a rate approximately 2–3 times higher than water injectivity.

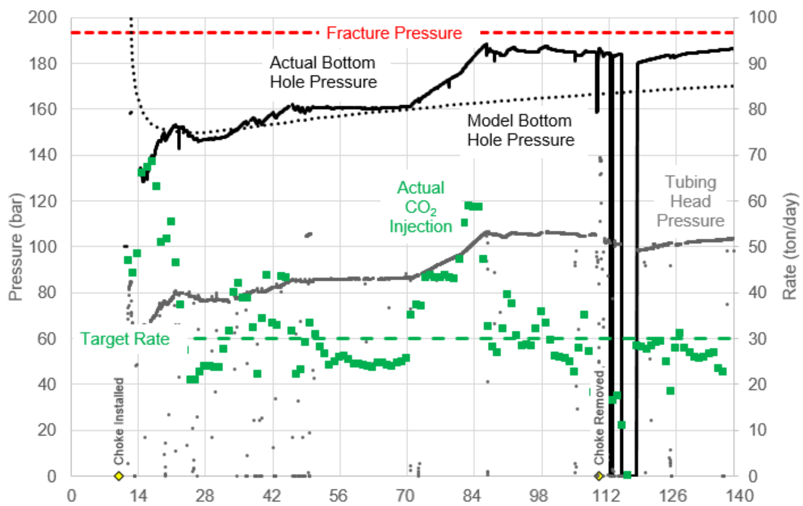

Figure 1— CO_2 Injector Well Data: Tubing head-Pressure, bottom-hole pressure, average daily injection rate; and the numerical reservoir model, used for designing the pilot, bottom-hole pressure and target injection rate.

The injection rate varied for several reasons. In some instances, the daily average rate decreased due to operational issues or supply constraints. On a few occasions, the injection rate was intentionally increased to test the formation's limits and potentially expedite the pilot's conclusion. When the injection rate exceeded 30 tons/day, a continuous pressure buildup was observed at a certain rate. Further increases in the injection rate resulted in a sharper rise in pressure. This behavior of pressure increase was consistent with pre-pilot modeling forecasts for a 30 tons/day injection rate, as shown in Figure 1. The observed pressure buildup at high injection rates was attributed to local pressure increase near the injector due to slow dissipation in the low-permeability, thin reservoir unit. Pressure dissipation was further hindered by the nearby producer being shut-in during the three-month injection period to monitor pressure buildup. Furthermore, when the injection rate was reduced to 30 tons/day or lower, the pressure buildup ceased, confirming the rate-dependent nature of pressure behavior.

Discussion

The CO_2 injection pilot was critical in demonstrating the potential of CO_2 to economically recover stranded oil from microporous carbonate reservoirs. These reservoirs pose significant challenges due to their low permeability and thinness. During the pilot, CO_2 was injected sustainably at rates exceeding the target, achieving more than 2-3 times the average water injection rate observed in water injectors in similar units. This demonstrated the feasibility of CO_2 injection in thin, microporous reservoirs and its potential to provide sustained pressure support to producers. Such pressure support would enable production at economic rates, thereby unlocking significant oil volumes from similar reservoirs in the northern of Oman.

The observation of pressure behavior at injection pressure of 20-25 tons/day and the insights from the reservoir modeling demonstrated that was no evidence of formation damage during the injection phase. However, the pilot confirmed that these reservoir units have a certain flow capacity, by exceeding this capacity, the pressure increased locally and there was slow dissipation of the pressure.

The pilot results verified the predictions of the numerical reservoir model demonstrating the potential of CO2 to deliver higher injection rate low-permeability reservoirs, which would eventually lead to sufficient pressure support to the producers in. Additionally, the pilot validated key aspects of the trial design, including the target injection rate estimated by the reservoir simulation models. The consistency between pilot results and model forecasts proving the reliability of using reservoir simulation for full-field development planning and optimization. Based on the positive outcomes of Phase I, it was decided to proceed with Phase II to confirm production improvements in the nearby producer.

Conclusions

This paper presents the results of Phase I of a fit-for-purpose CO2 injection pilot in a thin, microporous carbonate reservoir. The objective of this phase of the pilot was to demonstrate the higher CO2 injectivity than waterflood, which can unlock significant oil volumes economically that are stranded. This pilot serves as a critical step toward de-risking the full-field development of similar reservoirs and advancing the application of CO2 EOR and CCUS in the Sultanate of Oman. Based on the outcome of this pilot, the following conclusions could be withdrawn:

- The pilot demonstrated that CO2 injection is a feasible recovery mechanism for thin, microporous carbonate reservoirs. The subsurface injection rates of CO2 were almost two to three times higher than water injection rates observed in nearby wells, confirming the better and sustained injectivity of CO2. This would result in sufficient pressure support to the producer, leading to producing at economic rates.
- The promising results from Phase I justified the continuation of the pilot to Phase II. Phase II will focus on observing production improvements in the nearby producer, further validating CO2's ability to enhance oil recovery and sustain economic production rates.
- The success of this CO2 pilot enables the application of CCUS in these reservoirs, providing a pathway for reducing CO2 emissions while enhancing oil recovery.

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