



Assessment of continuous and alternating CO₂ injection under Brazilian-pre-salt-like conditions

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Abstract

Carbonate rocks have become very important in Brazil with pre-salt reservoir discoveries in Santos and Campos Basins. Since then, great efforts in research and technology have been made to characterize and develop these reservoirs. In this sense, outcrop analogue studies have become a powerful tool for helping the recognition of geological heterogeneities responsible for controlling the fluid flow in hydrocarbon reservoirs. Besides that, pre-salt oil recovery is associated with high carbon dioxide (CO₂) production, and due environmental issues, it is required a sustainable destination for this contaminant. CO₂ injection in the reservoir, either pure or mixed to the produced gas stream, could be a good manner to deal with this undesirable component and increase the oil recovery. This work uses outcrop analogue characterization to understand how carbonate reservoir characteristics impact the selection of the best recovery strategy under Brazilian-pre-salt-like conditions. Numerical simulation models were run using the flow simulator TEMPEST MORE (version 7.1) with isothermal compositional modeling. The oil recovery process was modeled by continuous and alternating injection of CO₂ and water. The recovered oil fractions for the simulation case with water alternating CO₂ injection were higher than with the use of continuous injection of CO₂ or water.

Keywords Compositional simulation · CO₂ injection · Water alternating CO₂ injection · Carbonate rocks · Pre-salt

Introduction

In Brazil, carbonate rocks have become very important since giant pre-salt reservoirs discovered in Santos and Campos Basins. Great efforts in research and technology have been made to characterize and develop these reservoirs, such as analogue outcrop studies. Analogue outcrop information may be helpful for understanding physical processes that caused sediments to settle, allowing the prediction of lateral changes in geometry and facies distribution of hydrocarbon reservoirs. It is important to note that diagenetic differences between the reservoir and the analogue outcrop must be respected (Aderaldo 1994; Gauw 2007).

Although carbonate rocks form most oil reservoirs in the world, the knowledge about these reservoirs is still low if compared to siliciclastic reservoirs. Due to their more prominent reactive nature, carbonate rocks usually suffer a more intense chemical diagenesis, resulting in more heterogeneous pore systems. Moreover, as regards wettability, carbonates tend to range from neutral to oil-wet, which may affect multi-phase displacement and capillary behavior of the porous medium (Pizarro and Branco 2012).

During the early cretaceous, the breakup of the Gondwana supercontinent led the formation of a series of sedimentary basins in the Brazilian continental margin. The pre-salt reservoirs result from this separation and were developed within in a rift stage of basin evolution, where in its upper stages, from the Aptian to Barremian, a series of shallow lakes were installed creating the conditions for deposition of the carbonate sediments (Kukla et al. 2018).

The pre-salt rocks can be subdivided in two main stratigraphic intervals. The basal layer known as “coquinas” is formed by the bioclastic accumulation of mollusk shells, and the upper layer is composed of microbial carbonates. Nowadays there is a huge interest on the knowledge about

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the genesis and evolution of the Brazilian pre-salt reservoirs once these deposits represent a very singular geological record holding a huge amount of light oil. These reservoirs have impressive quality with high porosity and permeability values and are responsible for 60% of the Brazil's production (Ávila 2020).

Besides that, pre-salt oil recovery is associated with high carbon dioxide (CO₂) production, and due to environmental issues, it is required a sustainable destination for this contaminant. CO₂ injection is an enhanced oil recovery process that has become a trend in order to avoid the emission of this gas into atmosphere and also to increase oil recovery.

An alternative for the CO₂ produced is its injection in the reservoir, either pure or mixed to the produced gas stream. The high initial pressure of pre-salt Brazilian reservoirs may cause an efficient miscible displacement of oil by the CO₂-rich stream injected (Formigli et al. 2009; Almeida et al. 2010).

Recovery mechanisms related to CO₂ injection include oil volume expansion, oil viscosity reduction and transference of intermediate/heavy hydrocarbons to the CO₂ by the development of multi-contact miscibility. The injected CO₂ can become miscible or remain immiscible with the oil in the reservoir, depending on reservoir pressure, temperature and oil properties. High pressure is necessary to compress the CO₂ down to a density at which this fluid becomes a solvent for light hydrocarbons in the crude oil. Thus, the miscible displacement technique is only implementable when the CO₂ injection can occur at pressure values greater than the minimum miscibility pressure (MMP) (Whitson and Brulé 2000).

In the multiple-contact miscibility process, the injected fluid is not miscible with the reservoir oil in the first contact. The process depends on the modification of the injected fluid and reservoir oil by multiple contacts mass transfer between phases in the reservoir. Under optimal pressure, temperature and composition conditions, this change in composition results in the miscibility between the displacing and displaced phases of the reservoir (Sequeira 2006).

So, miscibility conditions between the CO₂ and the reservoir oil develop dynamically in the reservoir due to the change in composition when CO₂ flows through the reservoir and gradually interacts with oil, forming a miscible zone between oil bank and the injected CO₂ (Verma 2015).

However, CO₂ injection can increase oil recovery even when reservoir pressure is below the MMP or when reservoir oil composition is not favorable to developing miscibility. Under such conditions, despite CO₂ is not fully miscible with oil, it can partially dissolve and lead to oil viscosity reduction (Tzimas et al. 2005; Verma 2015).

Moreover, CO₂ is a gas and tends to move faster than oil inside the reservoir, which may result in low areal sweep efficiency and early production of the injected CO₂. In general, volumetric sweep efficiency decreases when mobility

ratio between the CO₂ and oil increases. When the mobility ratio is greater than 1, fluid flow becomes unstable and the displacement front becomes non-uniform. As a result, the CO₂ does not sweep the maximum volume possible of the reservoir, possibly going around the oil bank and reaching producer wells prematurely (Mangalsingh and Jagai 1996).

Water alternating CO₂ injection, which is part of water alternating gas flooding process (WAG), is an alternative to improve the mobility of the flooding system and that will result in better volumetric sweep efficiency and may improve the oil recovery (Tzimas et al. 2005).

This work uses outcrop analogue characterization to understand how carbonate reservoir characteristics impact the selection of the best recovery strategy under Brazilian-pre-salt-like conditions. Continuous injection of CO₂ or water and water alternating CO₂ injection (WAG-CO₂) were assessed using numerical reservoir simulation.

Materials and methods

CAMURES Methodology (Multiscale Reservoir Characterization) (Garcia et al. 2015) focuses on the understanding of the genetic process that build the sedimentary heterogeneities, through the mapping of geometries and facies distribution in its different stratigraphic contexts, developing robust reservoir models to flow simulations.

CAMURES is developed on outcrop data acquisition with description of facies, associated to logs, 3D digital images and sampling collected from zones of interest to perform petrographic and petrophysical analysis. This approach applies different scales of characterization in analogue outcrops in order to contribute for the understanding and developing of difficult-to-access reservoirs, such as pre-salt carbonate reservoirs.

Mathematical modeling

Flow simulations were run using the reservoir simulator TEMPEST MORE (version 7.1) with isothermal compositional modeling and employing finite volume discretization method. Further information about mathematical formulation can be found in Roxar (2012).

Study domain

The outcrop under study is the Atol Quarry Complex (Fig. 1), the most expressive outcrop of the Morro do Chaves Formation, in the Sergipe-Alagoas Basin, Brazil. The Morro do Chaves Formation presents ages between the Barremian and Aptian and encompasses carbonate rocks called coquinas, intercalated with shales, sandstone and conglomerates



Fig. 1 Overview of Atol Quarry Complex, located in the town of São Miguel dos Campos, State of Alagoas, Brazil

that settled during different tectonic pulses in the rift phase (Campos Neto et al. 2007).

Coquinas from the Morro do Chaves Formation are classified as grainstones and rudstones (Dunham 1962; Embry and e Klován 1971) and are analogue in age and sedimentary facies to those deposited on the Coqueiros and Itapema Formations.

The Atol Quarry has hundreds of meters thick and kilometers exposure, what enables map the heterogeneities seen at outcrop scale, mainly those referents to the geometries and facies variation, making this outcrop one of the main analogue to the pre-salt shell-rich reservoirs (Kinoshita 2010; Tavares et al. 2015).

The geological model used in flow simulations was built from multiscale characterization of the Atol Quarry. The grid geometry covers an area of approximately 556,200 km². A corner point grid was built with 25 cells in the *x*-direction (360 m), 50 cells in the *y*-direction (1545 m) and 55 cells in the *z*-direction (335.5 m), for a total of 68750 cells. Figure 2 shows the study domain discretization.

Some regions of the geological model were defined as no reservoir according to their petrophysical properties. In Fig. 3, red regions represent the reservoir facies which contribute to the calculation of oil in place volume and transmissibility, whereas regions in gray were considered inactive during the simulation due to their low storage capacity and very low fluid transmission. In blue, we can also see connected non-neighbor cells. There is a great amount of non-neighbor connections on the fault plane due to the displacement of layers.

Figure 4 illustrates porosity and permeability distributions in the simulation model. Porosity has a heterogeneous distribution with values ranging between 0.0% and 27%. Permeability distribution follows the same trend of porosity, and it was defined the same values for the permeability in the *x* and *y*-directions (horizontal), whereas the permeability in

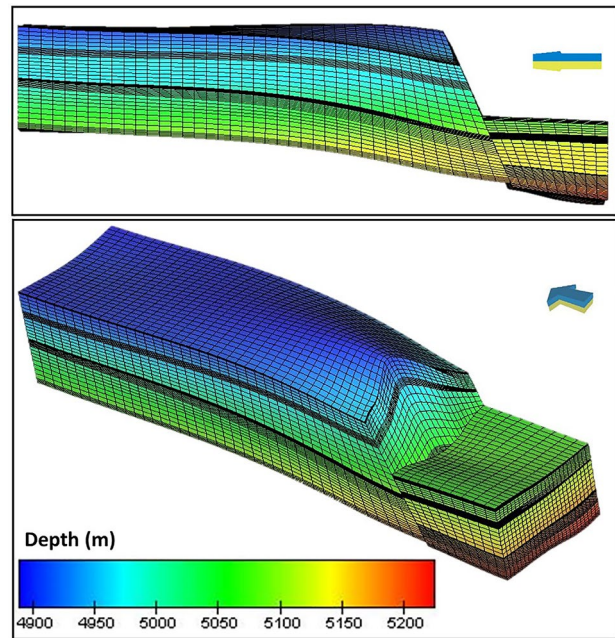


Fig. 2 Simulation grid features

the *z*-direction (vertical) was defined as 20% of the horizontal permeability.

Fluid and rock data

Hydrocarbons composition was represented by 9 pseudo-components (N₂-C₁, CO₂, C₂, C₃, IC₄-C₄, IC₅-C₅, C₆, C₇-C₁₇, C₁₈+). The differential liberation and compositional characterization pressure/volume/temperature (PVT) data used in this study came from a separator oil sample coming from Brazilian pre-salt reserves in the Campos Basin region, available in Elias Jr and Trevisan (2016). Dead oil and synthetic gas were recombined in order to obtain the original composition of the original oil, which originally contained 17.84% molar of CO₂.

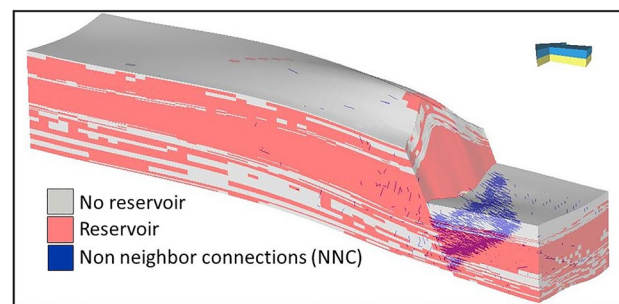


Fig. 3 Definition of the reservoir facies

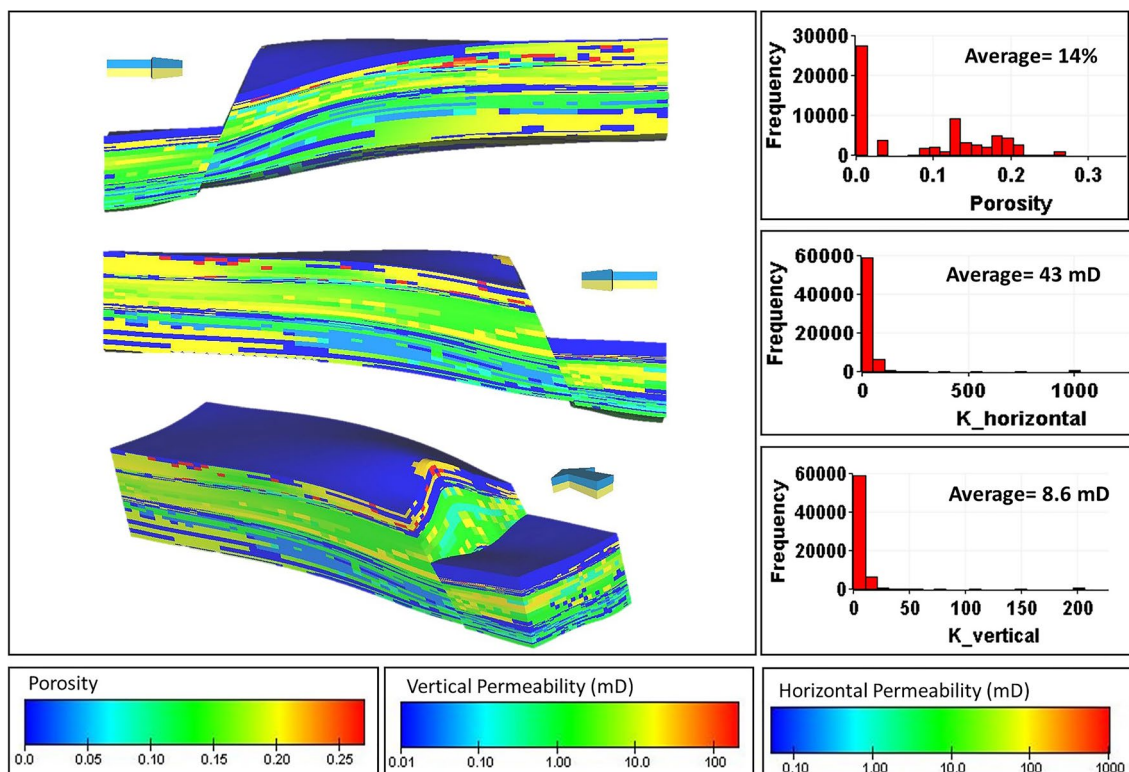


Fig. 4 Spatial distribution of the porosity, horizontal and vertical permeability of the simulation model

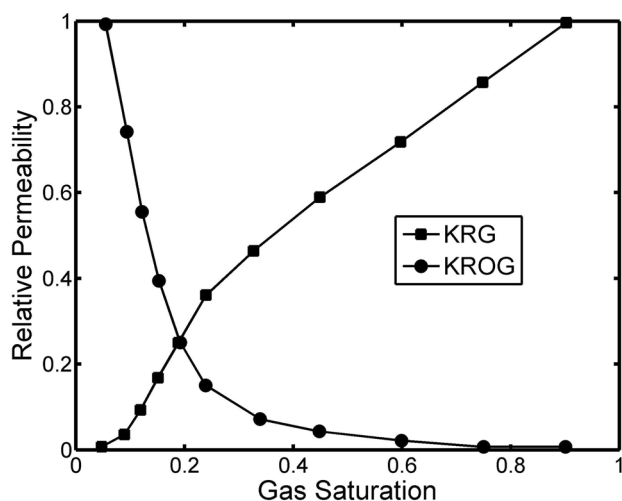


Fig. 5 Relative permeability curves for the oil–gas (KROG) system

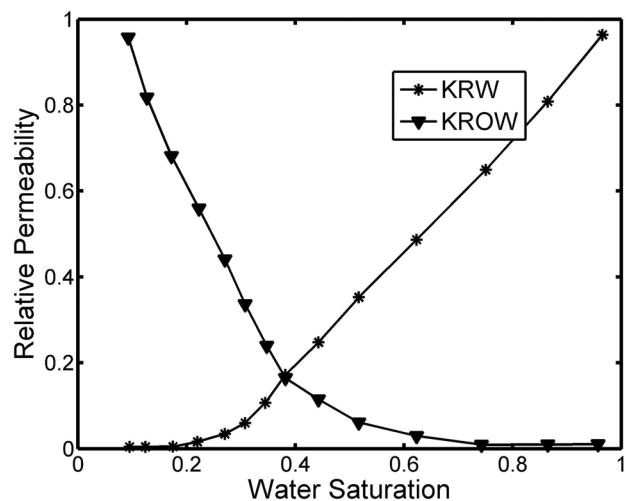


Fig. 6 Relative permeability curves for the water–oil (KROW) system

It was employed the Peng–Robinson cubic equation of state to describe the volumetric behavior of the components using TEMPEST PVTx software (version 7.1). Differential liberation data, available Elias Jr and Trevisan (2016), were used to change the original parameters of the equation of state by the regression method. One important

requirement for the use of compositional models based on equations of state is that equation of state results satisfactorily match laboratory data (Coats and Smart 1986).

Connate water properties were defined as follows: 1000 kg/m³ specific mass; 1.01 m³/m³ std formation

volume factor; $2.07\text{e-}08 \text{ (MPa)}^{-1}$ compressibility and 0.3 cp viscosity under reservoir conditions.

The reservoir is preferably oil-wet, and the relative permeability of wetting and non-wetting phases is a function of their respective saturations. Figures 5 and 6 present the relative permeability curves of gas (KRG), of water (KRW), water–oil system (KROW) and of oil–gas system (KROG).

The simulator used the generalized version of Stone's second method (Stone, 1973) to calculate the relative permeability of the solvent (CO_2 -rich phase) under miscible conditions. The reservoir has 9.6% connate water saturation (S_{wi}), 5% critical gas saturation (S_{gcr}) and 25% residual oil saturation (S_{or}).

Starting conditions and constraints

It was adopted the reservoir pressure of Lula Field in the Santos Basin (Formigli et al. 2009), whereas the reservoir temperature was considered as the temperature at which PVT data were obtained, according to Elias Jr and Trevisan (2016). Moreover, the natural mechanism acting is solution gas. Reservoir properties are summarized in Table 1. The operating constraint adopted in all the simulation models was maximum injection pressure of 58.8 MPa.

Case studies

Three production strategies were assessed: continuous injection of water, continuous injection of CO_2 and water

alternating CO_2 injection (WAG- CO_2). The well arrangement is shown in Fig. 7. Injection wells (I1 to I4) appear in red, whereas production wells (P1 to P10) appear in green. All wells are vertical and were opened at the same time. Moreover, both wells were completed in the cells from 21 to 33 in the z-direction.

It was defined the same operational conditions for the cases under analysis: injection flow rate per well of $120 \text{ ksm}^3/\text{day}$ for CO_2 and $240 \text{ sm}^3/\text{day}$ for water, bottom-hole pressure for all the producer wells of 51 MPa, a 30-day water alternating CO_2 injection cycle and a simulation time of 10 years.

Gas-oil ratio, water cut, recovered oil fraction and injected porous volume fraction were compared for the studied cases.

Results and discussion

Continuous water injection

The oil saturation distribution due to waterflooding is illustrated in Fig. 8 by a vertical plane, taken so as to include one injector well (I1) and two producer wells (P1 and P7).

Since the reservoir is preferably oil-wet, during the displacement of the oil through the water, water normally does not adhere to the grains of the reservoir rock and tends to move through the center of the porous channels, resulting in an inefficient displacement of the oil.

As we can see in Fig. 8, there is a high residual oil saturation (about 25%) close to the injector, after 10 years of production, which happens because the oil droplets get stuck in the porous medium due to capillary forces. According to Clark et al. (1958), the oil-wettability of a reservoir rock has a negative influence on the displacement efficiency of fluids in the reservoir.

Figure 9 illustrates temporal evolution of the water saturation on that same plane. The water sweep front is not uniform since the porous medium under study is heterogeneous. Besides, as the water is denser than oil, it tends to move through the lower regions of the reservoir. Besides,

Table 1 Reservoir data

Property	Value (SI)	Value (FIELD)
Datum	4895 (m)	16059.71 (ft)
Initial pressure	54.9 (MPa)	7962.6 (psi)
Temperature	95.5 °C	203.9 °F
Bubble pressure	39.7 (MPa)	5758 (psi)
Pore compressibility	$4.35113\text{e-}03 \text{ (kPa}^{-1}\text{)}$	$6.31078\text{e-}04 \text{ (psi}^{-1}\text{)}$

Fig. 7 Well location. The model comprises 14 wells, of which 10 are producers and 4 are injectors

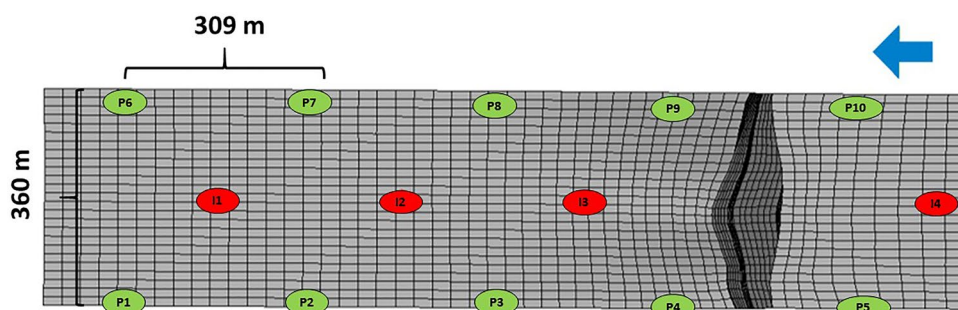


Fig. 8 Oil saturation on a plane intercepting the wells P-7, I-1 and P-1. **a** Starting oil saturation. **b–d** oil saturation after 6 months, 5 years and 10 years of production, respectively

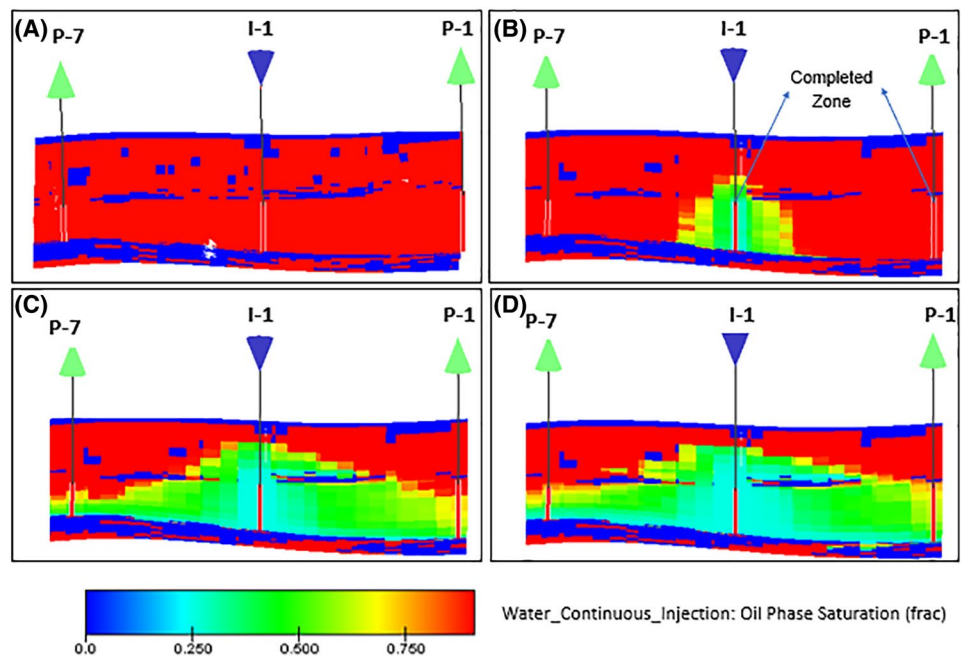
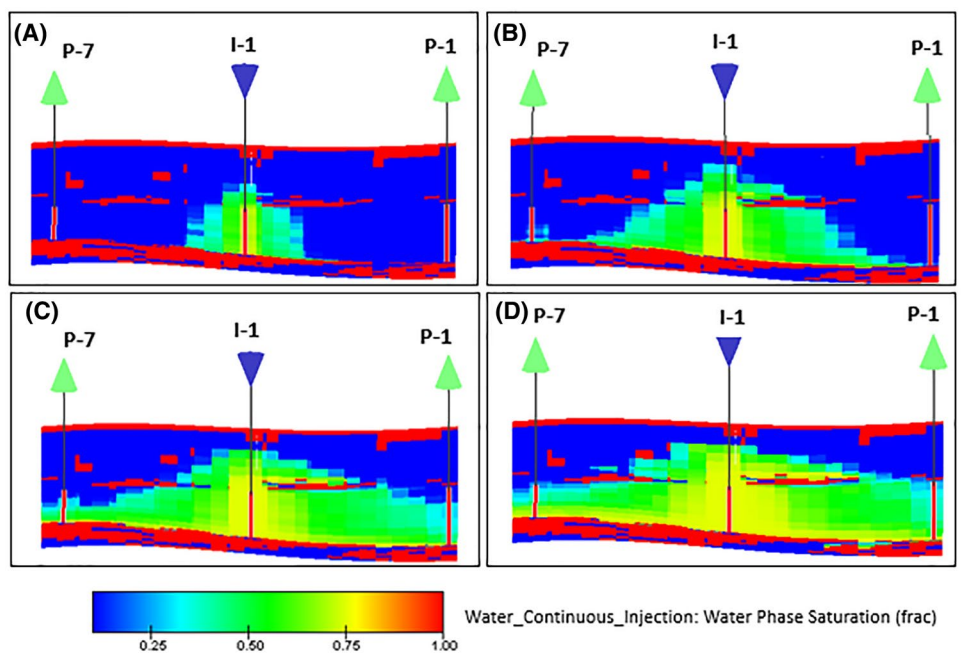


Fig. 9 Water saturation distribution **a** 6 months; **b** 2 years **c** 5 years and **d** 10 years



the more drained areas were exactly those that had the highest permeability values, as shown in Fig. 10.

Continuous CO₂ injection

Figure 11 illustrates the temporal evolution of the oil saturation in the reservoir on a plane intercepted by two producer wells (P1 and P7) and one injector well (I1).

Contrary to the continuous water injection (Fig. 8), practically all of the oil is mobilized by the CO₂ in the region close to the injector well since the injection of a miscible solvent into the oil allows it to be displaced more efficiently.

In other words, there is a sharp reduction of the residual oil saturation. This is due the decrease of capillary forces that cause the oil retention in the porous channels through which the solvent flows, forming a homogeneous mixture,

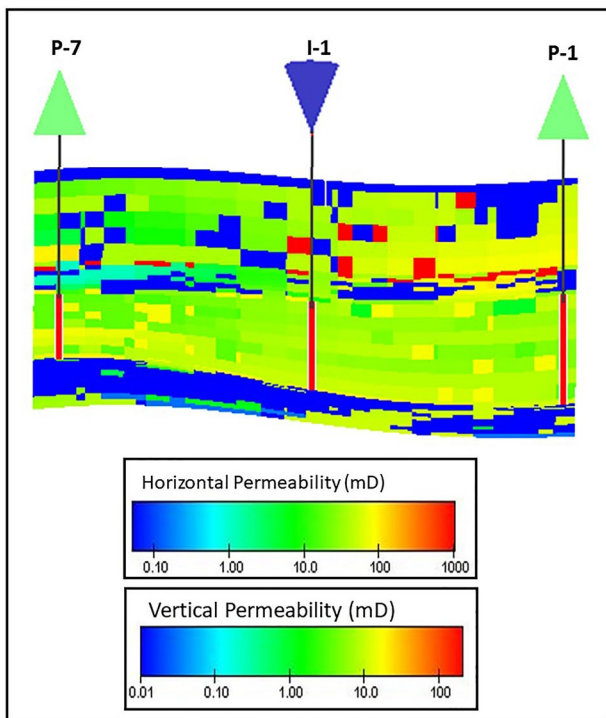


Fig. 10 Distribution of the horizontal and vertical permeability for a plane intercepted by the wells P-7, I-1 and P-1

which is a characteristic of the miscible method. Clark et al. (1958) have reported similar behavior.

Water alternating CO₂ injection

The water alternating CO₂ injection is designed to improve the sweep efficiency during the CO₂ injection, due to the high mobility of this fluid. First, CO₂ is injected to expand the oil and improve the displacement efficiency by reducing capillary forces. Then, water comes alternating with CO₂ in order to improve the mobility of the flooding system and, consequently, recover more oil.

Figure 12 illustrates the temporal evolution of the oil saturation in the reservoir on a plane intercepted by two producer wells (P1 and P7) and one injector well (I1).

When compared to the continuous CO₂ injection (Fig. 11), the water alternating CO₂ injection led to the enhancement of sweep efficiency since the oil saturation, after ten years of production, decreased in a greater area of the reservoir.

The water alternating CO₂ injection contributed to the development of the multiple-contact miscibility between the CO₂ and the oil in the reservoir. This happened because the method lowers the total mobility ratio, reducing the formation of CO₂ fingers and retarding the production of these gas, which causes the injected CO₂ to remain longer in contact with the oil of the reservoir without being produced.

Figure 13 illustrates water production curves for the cases that employed continuous water injection and the water alternating CO₂ injection. The alternating method requires the injection of less water than the continuous water injection method. For this reason, it was observed that the injected water spent approximately twice the time

Fig. 11 Oil saturation on a plane intercepted by the wells P-7, I-1 and P-1. **a** Starting oil saturation. **b–d** oil saturation after 6 months, 5 years and 10 years of production, respectively

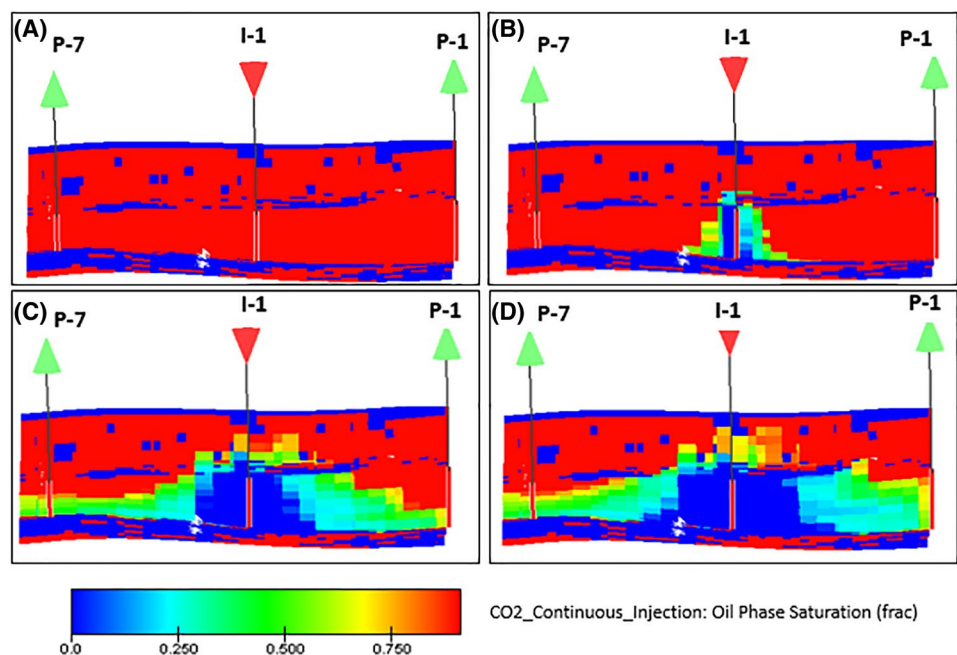


Fig. 12 Oil saturation on a plane intercepted by the wells P-7, I-1 and P-1. **a** Starting oil saturation. **b–d** oil saturation after 6 months, 5 years and 10 years of production, respectively

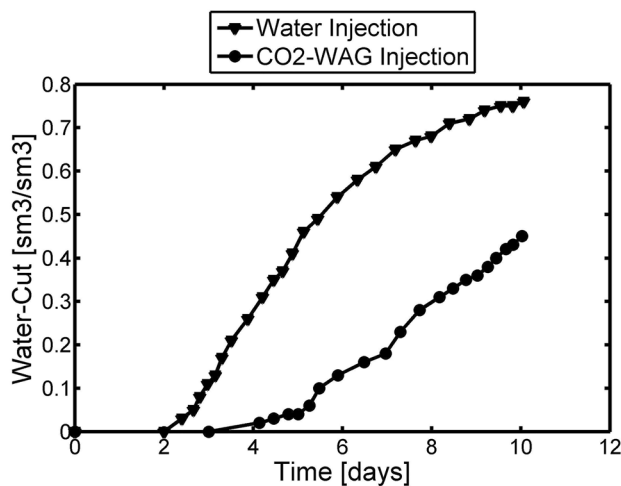
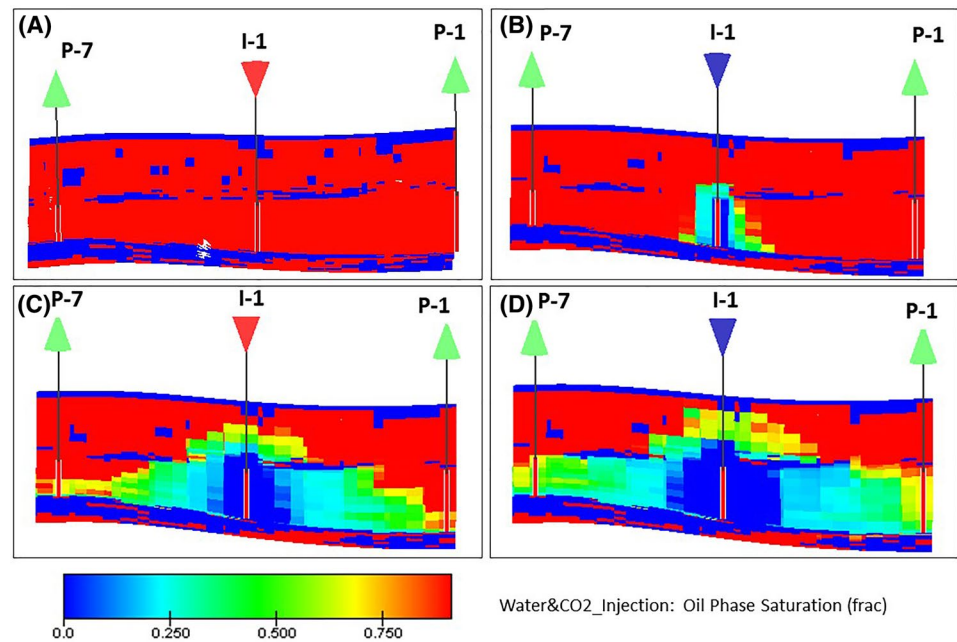


Fig. 13 Water cut. The curves represent the reservoir behavior considering the contribution of all the production wells

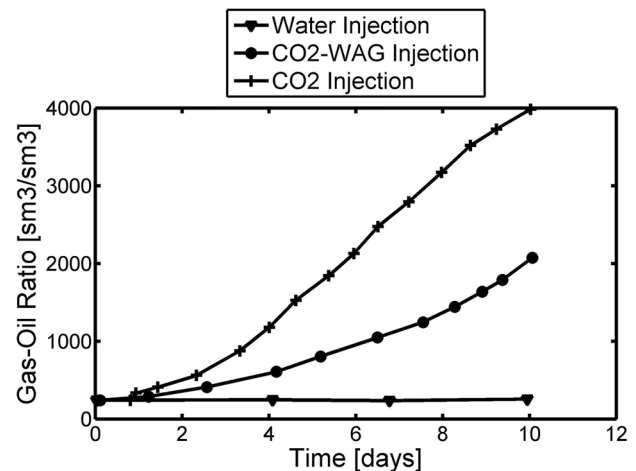


Fig. 14 Behavior of the gas-oil ratio. The curves represent the reservoir behavior considering the contribution of all the production wells

to reach the producer wells. This behavior reduces costs related to the treatment of wastewater.

Figure 14 illustrates the behavior of the gas-oil ratio (GOR) for the cases under study. It is possible to see that the GOR rises fast in the continuous CO₂ injection, whereas it remains constant in the continuous water injection since the pressure of the reservoir is kept above the bubble point pressure (39.7 MPa), as seen in Fig. 15.

On the other hand, in the alternating injection, the rise of the GOR is minimized by the alternation between the injection of water and CO₂. Similar behavior was observed

for the water cut since the production of water is delayed and a smaller water volume is produced over time when compared to the continuous water injection.

Figure 16 illustrates the oil fraction recovered (oil volume produced with respect to the original oil volume in place) versus porous volume injected (PVI), which relates the injected fluid volume to the porous volume. When the PVI was below 10%, the three methods under study had the same performance. However, for higher PVI values, the alternating method was the one that presented the best results under the tested conditions.

Furthermore, it is possible to see that the recovered oil fraction increases as more fluid is injected. However, the

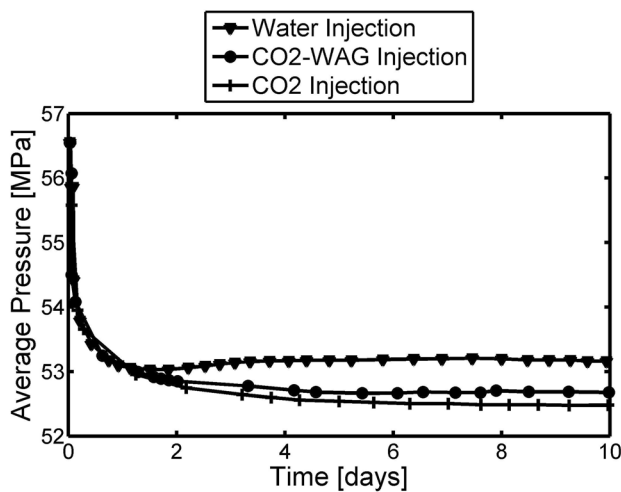


Fig. 15 Average pressure of the reservoir

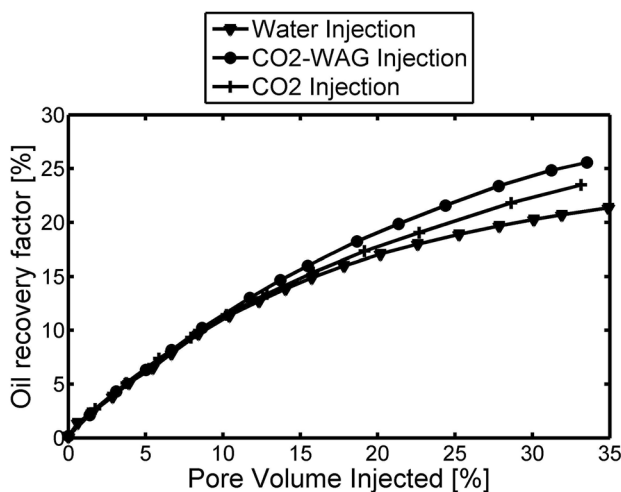


Fig. 16 Oil fraction recovered versus pore volume injected

increase in the oil recovery stops being proportional to the injected volume for a PVI of about 10%. The results found match those by Shedid et al. (2005), who report that the increase in the oil recovery using large injection banks does not represent such significant improvement when compared to the use of smaller injection banks.

For a 30% PVI, recovered oil fractions were 20.36%, 22.37% and 24.42% for the continuous water injection, continuous CO₂ injection and water alternating CO₂, respectively.

Conclusions

The results showed that CO₂ injection increased microscopic displacement efficiency because the residual oil after CO₂ flooding was lower than the residual oil after water flooding. CO₂ flooding from the beginning of the production lowers the remaining oil saturation in the reservoir and could be a good alternative for the exploitation of pre-salt reservoirs due to the availability of this gas, once oil recovery is associated with high CO₂ production, and due environmental issues.

In addition, due to the heterogeneous pore system of carbonate reservoirs and wettability, continuous injection of CO₂ or water resulted in high gas-oil ratio and water cut, respectively, for the evaluated cases. WAG-CO₂ process helped to reduce the viscous fingering effect associated with CO₂ injection technique, thanks to the better mobility ratio provided by the alternate water injection.

At the end of the 10-year production period, the recovered oil fraction with the alternating method (WAG-CO₂) was greater than that achieved with the continuous injection of CO₂ or water, as expected, but no big difference was observed. This could be a result of the wettability of the reservoir. Many studies attribute the efficiency of the WAG to greater volumetric sweep efficiency. However, in this case that the reservoir is wettable to oil and highly heterogeneous, water spreads over a larger region of the reservoir, but leaves much of the oil behind and water rapidly achieves production wells.

Moreover, it was also possible to observe that the oil fraction recovered increases as more fluid is injected. Nevertheless, the increment in the oil recovery is not always proportional to the increase in the injected volume, which highlights the importance of technical and economic analyses for the proper dimensioning of injection banks.

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