Numerical study of different forms of synergetic CO_2 injection and storage as an Enhanced Oil Recovery method

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Abstract. Carbon capture, utilization, and storage (CCUS) is already seen as essential for sustainable development. In the oil & gas sector, injecting CO_2 into the reservoir is also an important Enhanced Oil Recovery (EOR) method, producing effects on oil properties. Continuous injection, the CO_2 use in Alternating Water and Gas (WAG) and carbonated water injection, for example, can contribute to further oil recovery. This study aims to compare the recovery factor (RF) and the geologic storage for different CO_2-EOR techniques through numerical simulation. For this, a reservoir model and a compositional fluid model were implemented in a commercial software. Then, different injection settings were compared. As a benchmark, the injection flows were selected to maintain a similar average Bottom Hole Pressure (BHP). As results, all CO_2-EOR methods were better than water injection, with an emphasis on continuous CO_2 injection, with increases of more than 33% in the RF. The selection between CO_2-WAG cycles showed differences of more than 4.5% in the final RF. The tertiary CO_2 injection, after water injection, had the highest geological carbon storage efficiency, of 23%. With the results, it is expected to contribute to the analysis of the CCUS potential and in optimizing the use of CO_2-EOR.

Keywords: Enhanced Oil Recovery (EOR), carbon capture utilization and storage (CCUS), compositional simulation of reservoirs, CO_2 injection, Alternating Water and Gas (WAG).

1 Introduction

Oil and natural gas now account for over 54% of the global total energy supply, but also for over 55% of global carbon dioxide emissions [1]. Debates about sustainable development today point to decarbonization, and a path already recognized as essential for meeting the century's climate goals is the carbon capture, utilization, and storage (CCUS). Only through it we can achieve neutral and even negative emissions within development paths. To reach the IEA Sustainable Development Scenario, for example, by 2070 CCUS must contribute about 15% of the cumulative reduction in emissions, with a capture of 10.4 $GtCO_2$ per year on that date, of which 9.5 $GtCO_2$ should be intended to geological storage and the remainder for utilization [2]. At the present time, however, only about 30 $MtCO_2$ are captured per year, being 70% from oil and gas operations, which indicates a long way to go in the development of this technology [3].

There are three main types of reservoirs suitable for carbon geological storage: depleted oil/gas fields, saline aquifers and coal beds. CO_2 can be trapped in geological formations due to mechanisms: physical trapping (geological structure and stratigraphy), residual trapping (capillarity), water solubilization, precipitation in form of minerals and adsorption [4]. When the CCUS concept is brought to petroleum engineering, the CO_2 injection into a producing formation corresponds to a well-known Enhanced Oil Recovery (EOR) method on the reservoir, allowing an improvement in the field's recovery factor (RF).

RF is the quotient between the recoverable volume (expected amount of production) and the original volume of an oil/gas reservoir. Today the global average recovery factor for fields is around 35%, and even lower for

Brazil, estimated at 15% to the proven reserves, according to ANP [5] data. Therefore, this indicates that most of the oil remains in a field after it is abandoned, due to reservoir retention forces. However, as pointed out by Thomas et al. [6], RF can undergo changes during the productive life with more information about the field, changing the economic situation or with the adoption of special recovery methods.

Conventional oil recovery and EOR methods use the injection of a dislocating fluid that, when flooding the porous media, will mobilize and/or react with the displaced fluid of interest, stimulating its production. The movement of an injected fluid in a reservoir tends to follow a central flow line towards the producer well, where the pressure gradient is greater. As a result, when the displacer fluid reaches the producer, not every reservoir has had contact with it. This instant is called *breakthrough*, and after it only part of the injected volume will displace the oil, as it also starts to be produced with oil [7]. In the characteristic curve of displaced volume versus injected volume, breakthrough can be identified by the change in the curve slope. If the injection flow is constant, the curve of cumulative production versus time will show the same profile.

In the analysis and selection of production strategies for a field, the numerical simulation of reservoirs is an important tool that allows estimating the behavior of a reservoir through the theoretical conception of its characteristics. However, CO_2 injection simulations require the implementation of *compositional models*, which use equations of state (EOS) to calculate the thermodynamic phase equilibrium, allowing the definition of various components for the fluid. Not met in the *black oil models* (more simplified), the compositional model is necessary in this study due to, according to Mello [8], the large variation in the number of components in each phase, the presence of CO_2 and its reinjection, the volatilization effect generated in the oil and the possible formation of by-products during the process.

1.1 The CO_2-EOR

Carbon dioxide has a critical temperature of 31°C and a critical pressure of 72.85 atm. As the petroleum reservoirs, in general, are in superior conditions, the CO_2 normally reaches the supercritical form in the reservoir, leading to a behavior closer to the liquid in relation to density, and closer to the gas in relation to viscosity [9]. For CCUS, this means storing large amounts of CO_2 in much smaller volumes in underground conditions, due to increased density with depth and facilitated mobilization in the porous media due to the low viscosity.

Unlike the conventional recovery, where the mechanism is basically the pressurization and a mechanic displacement (as the case of water injection), in the CO_2-EOR several effects can contribute with the recovery, mainly when in its miscible form. The miscibility of CO_2 in oil occurs in multiple contact: to generate a homogeneous phase, several mixtures are needed so that the oil loses its intermediate components to the gas. The extraction of these components in CO_2 injection is done in a much wider range than other miscible EOR methods, extracting from C_2 to C_{30}, giving applicability to a wide range of reservoirs [10]. Multiple contact miscibility occurs when reaching the so-called minimum miscibility pressure (MMP), mainly influenced by the temperature, density and composition of oil and CO_2 contaminants [11].

Regarding the effects of CO_2 injection, dissolution leads to *oil swelling*, whose volume can expand between 10 and 20% or more [12]. This allows the mobilization of part of the residual oil, increase in internal pressure in the pores and increase in oil saturation, improving its mobility [13] [14]. CO_2 also leads to a *reduction in oil viscosity*, which can occur in the order of 10 times and contributes to recovery due to the mobilization of trapped oils and a reduction in the mobility ratio [12] [15]. During the process of multiple contact miscibility, another important effect of the method is the *reduction in interfacial tensions*, which allows the formation of a new mobile phase during CO_2 injection, and it is determined by the MMP [11]. And a last important effect is the *acidic dissolution* in carbonate reservoirs, due to the reaction of CO_2 with the water that generates carbonic acid (H_2CO_3), today it is highlighted by the difficulty of characterization and by its applicability to cases such as pre-salt.

An important EOR technique is the Water Alternating Gas (WAG) injection, once that, in general, water injection results in better sweeping efficiency, while gas injection generates greater displacement efficiency [16]. The three-phase flow and the cyclical changes in saturation in the WAG method can lead to the phenomenon of *relative permeability hysteresis*, changing the behavior of the relative permeability curves. Rosa et al. [7] pointed that a benefit of this is the trapping of part of the CO_2, occupying spaces filled with oil, while the disadvantage may be a possible loss of well injectivity, making it difficult to maintain constant pressures and flows. Another method with the CO_2 use is the injection of carbonated water, using the water as a good agent for introducing CO_2 into the reservoir, which, as it is already dissolved, can have its diffusion to the oil facilitated [17].

2 Methods

For the development of the study, a compositional fluid model and a reservoir model were implemented, then joined to create the different study scenarios and, finally, the results were compared. The software used was the OpenFlow Suite™, an integrated platform from Beicip-Franlab. The analysis of results was done in MS Excel™.

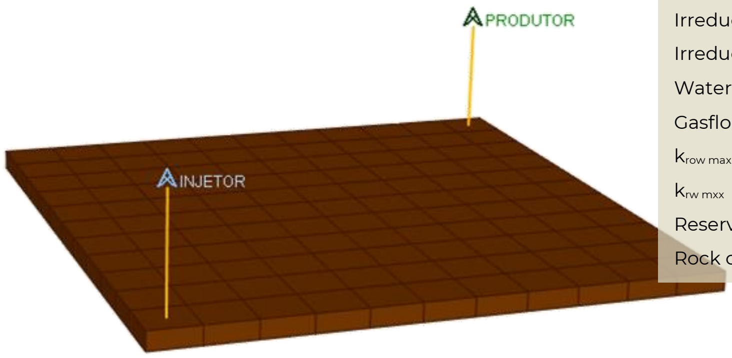
The fluid model was implemented in the PVTFlow, one of the software modules, from the PVT reports of Alwyn field, North Sea, UK. Its properties indicate a light oil, of 37º API, under-saturated in the initial conditions (oil with dissolved gas) and with a saturation pressure of 270 bar [18]. The PVTFlow tutorial itself uses field data to exemplify the creation of a compositional model. Reproducing the tutorial, therefore, it was possible to develop a compositional fluid model with real recurrence and application already validated in the used software. Table 1 shows the composition of the fluid in the considered reservoir.

Table 1. Reservoir fluid composition considered in the study [19].

Component	Fluid (% mol.)	Component	Fluid (% mol.)
H_2S	0	iC_5	1.26
N_2	0.64	nC_5	2.01
CO_2	1.14	C_6	2.51
C_1	46.55	C_7	3.54
C_2	7.34	C_8	3.33
C_3	7.45	C_9	2.61
iC_4	1.06	C_{10}	1.55
nC_4	3.77	C_{11+}	15.24
		Total	100.00

Tests data from the differential liberation, constant depletion and two-stage separator were inserted on the model. The EOS used in equilibrium was "Peng-Robinson and corrected polynomial for the acentric factor" and the viscosity was computed by the Lohrenz-Bray-Clark (LBC) model. Laboratory experiments were also simulated, and regressions were made for saturation pressure, volumetric functions and oil viscosity. Then, the so-called *lumping* was performed, the grouping of components into *pseudocomponents* to reduce computational time. All this was done according to the software's tutorial [19]. Finally, the fluid model was exported as "three-phase PVT model, compositional, type K-value for gas-oil and gas-water equilibrium". After importing the model into PumaFlow, the last step was marking the CO_2 in the component list and its selection as a water-soluble component.

For the reservoir model, a Cartesian grid consisting of 11 x 11 x 01 blocks, each with dimensions of 40 x 40 x 15 m, was created in the PumaFlow module. A constant porosity of 0.20 and constant permeabilities of 50 md were considered. For the rock-fluid model, the creation of the relative permeability curves through the Corey and Brooks model and the three-phase relative permeability through the geometric model were selected. The injection scheme was a quarter five spot configuration and consisted of an injection well at one grid end and a producer well at the opposite end, both with a radius of 8.89 cm. An illustration of the reservoir model and the other values determined in this step are shown in Fig. 1. Hysteresis and other parameters were kept automatic.



Irreductible water saturation (S_{wi})	0.21
Irreductible oil saturation (S_{oi})	0.79
Waterflood residual oil saturation (S_{orw})	0.25
Gasflood residual oil sat. (S_{org}) [automatic]	0.00
$k_{row\ max}$	1.00
$k_{rw\ mxx}$	0.60
Reservoir pressure (P_i)	300 bar
Rock compressibility	1×10^{-6} bar^{-1}

Figure 1. Reservoir grid, well positioning and saturation values set.

2.1 Scenario simulation

With the base model completed, the cases of interest were implemented in different workflows in PumaFlow. The simulations were run for a period of 15 years and, for all cases, a limit bottom hole pressure (BHP) in the producing well was defined in 300 bar, equal to the initial pressure of the reservoir. The base case was the conventional recovery for water injection, for which a maximum injection flow rate of 100 m³std/day was defined. The injection flow selection for the other cases was made having as a parameter the generation of an average BHP in the injector well like the generated in the base case, which was 332 bar during the simulated period. The use of the injector's BHP in this study as a "calibration" between the different methods allowed leveling the amounts of injected fluid in relation to the reservoir pressurization, giving more validity to the other effects comparison of each method used. The configuration of the different study scenarios is presented below.

Case 1: Continuous CO_2 injection. In this case the CO_2 was injected continuously since the beginning of the simulated period. Several operational flows were tested and a CO_2 maximum injection flow rate of 100,000 m³std/day was selected to the study sequence, whose BHP in the injector well was closest to the base case. The composition of the injection gas was considered pure CO_2.

Case 2: CO_2-WAG injection. For the alternate injection, maximum injection flows of 100 m³std/day of water and 100,000 m³std/day of CO_2 were used. The scenarios were simulated with the cycle starting with water injection (here called just "WAG") and starting with CO_2 injection (called "inverted WAG"). For each, cycles of 2 months, 6 months, 1 year and 2 years were applied, with the same injection period for each fluid: the 1-year WAG cycle, for example, consisted in 6 months of water injection followed by 6 months of CO_2 injection, alternating until the end of the simulation.

Case 3: Tertiary CO_2, after water injection. Here, continuous injection of CO_2 was simulated as a tertiary method, injected only after the breakthrough of conventional recovery by water injection. For this, first water was injected with a maximum flow rate of 100 m³std/day and, after the breakthrough (identified in the 6th year of simulation), the injection fluid was replaced by CO_2. Different flows are tested to the CO_2 period and, again by the injection BHP criterion, the maximum CO_2 injection flow rate of 60,000 m³std/day was selected to evaluate the results.

Case 4: Carbonated water injection. The composition of the injection fluid has now been defined as 50% water and 50% CO_2. For a proportion between the injected flows, again different flow rates were tested and, by the average of the injection BHP equivalent to the base case, the maximum flow rates of 75 m³std/day of water and 75,000 m³std/day of CO_2 were selected.

With the cases generated, results of the injected and produced volumes, saturations and cumulative pressures were analyzed. Focus of this study, the recovery factor obtained in each method was compared to the base case. For the end, through a balance of volumes obtained in each case, a simplified analysis of the geological carbon storage efficiency was performed. Without considering other reactions, losses and mass transfer, the storage efficiency was calculated by the ratio between the net volume of stored gas and the total volume of injected gas until the end of the period, according to the eq. (1):

$$\text{Storage efficiency} = \frac{\text{total volume of injected gas} - \text{total volume of produced gas}}{\text{total volume of injected gas}}. \qquad (1)$$

As the simulations were carried out above the saturation pressure and only pure CO_2 was injected as a gas in the cases, the presence of other gases is relatively negligible, allowing such analysis.

3 Results

The base case of this study, the recovery by water injection, led to a recovery factor of 62% on the model and the breakthrough was identified in the 6th year of simulation, when the curve has its slope changed. The cumulative oil production historic for each case is shown in the Fig. 2. For the CO_2-WAG case, only the cycles with the best results are shown: the water-initiated WAG with 2-month cycle and, for the inverted WAG, the 2-year cycle initiated by CO_2.

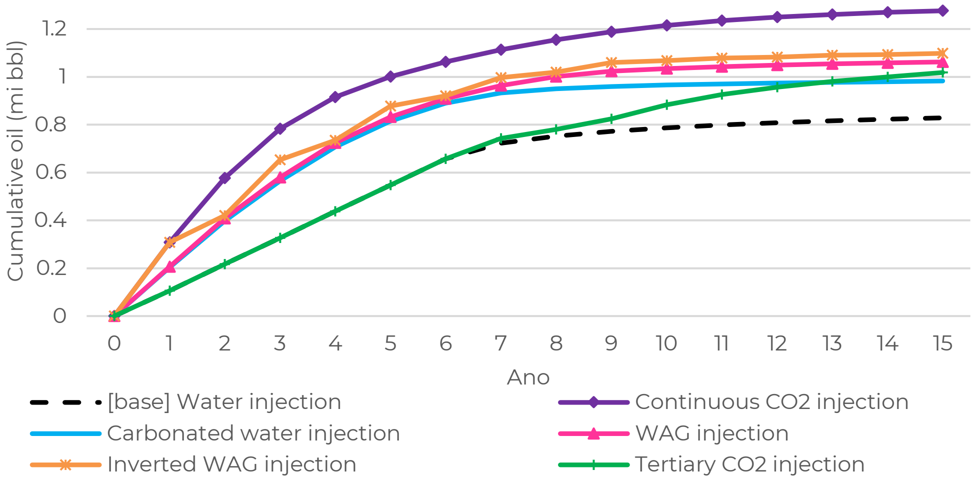


Figure 2. Comparison of cumulative volume of oil production for each case.

Continuous CO_2 injection showed the best results on cumulative oil production and an early breakthrough, in half the time of water injection. In practice, this can represent a disadvantage due to corrosion of production equipment, need for separation of CO_2 and greater requirement of CO_2 injected per incremental barrel produced [20]. However, the cumulative oil production in this period took almost 4 times longer to be achieved with the water injection.

Behind continuous injection, CO_2-WAG cases also showed good results. Table 2 shows the recovery factor obtained for the tested injection cycles, in descending order. It is possible to notice that the inverted WAG injection, initiated by CO_2, was better for the larger cycles, while the WAG injection initiated by water showed better results the shorter the cycle used. Anyway, even the lowest results for the inverted WAG were still better than those for the WAG, indicating an advantage in starting the alternated injection by CO_2.

Table 2. Recovery factor obtained with WAG injection and inverted WAG injection.

Study cases	Recovery factor (%)
Inv. WAG (2-years cycle)	81.74
Inv. WAG (1-year cycle)	80.79
Inv. (6-months cycle)	80.04
Inv. WAG (2-month cycle)	79.54
WAG (2-months cycle)	79.06
WAG (6-months cycle)	78.71
WAG (1-year cycle)	78.26
WAG (2-years cycle)	77.12
Water injection [base]	61.66

The injection of tertiary CO_2, after the beginning of the decline by the water injection, still by the Fig. 2, showed better results than the carbonated water injection only in the final years, when the effect of the CO_2 flooding has already been reflected in the reservoir. A second displacement wave is generated with the fluid change, allowing for increased production compared to water injection. The injection of carbonated water, in turn, led to a late breakthrough in relation to continuous CO_2 injection, closer to the breakthrough of pure water injection.

Corresponding to the cumulative production results, the increase in the recovery factor of each tested method in relation to water injection can be seen in Fig. 3. The results indicate that, comparing CO_2 injection methods by maintaining a similar BHP in the injector well, continuous injection of CO_2 stands out from a productive point of view, leading to a 33% increase in the model recovery factor. It is then followed, in descending order: by the inverted CO_2-WAG injection, the one initiated by CO_2; CO_2-WAG, initiated by water; tertiary CO_2 injection, injected after water injection decline; and, finally, the carbonated water injection, still representing an increase of over 11% in the RF.

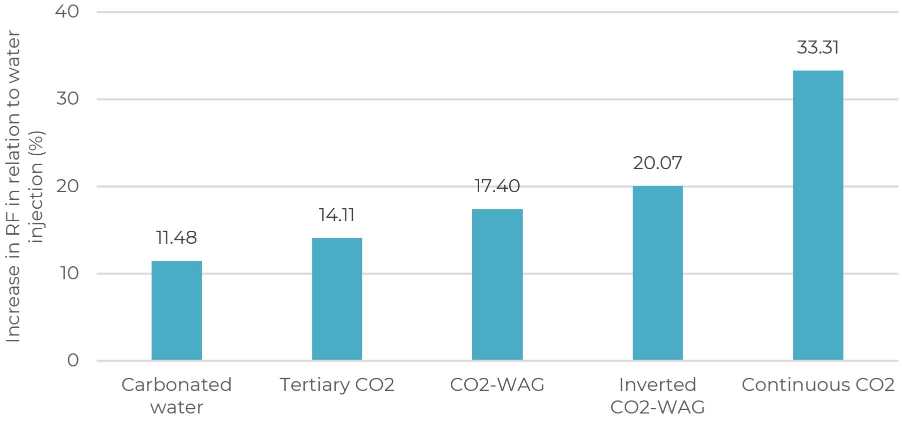


Figure 3. Increase in the recovery factor generated by each method in relation to the recovery by water injection on the model.

Finally, through a balance between the volumes of injected and produced gas in the reservoir, the efficiency in CO_2 storage was evaluated. The initial gas volume of the reservoir is 0.068 km³std. Table 3 compares the CO_2 storage efficiency between the methods on the model. The scenario that leads to the largest increase in the volume of gas in the reservoir was the continuous injection of CO_2, but it also was the one with the greater injected volume. The scenario that presented the best geological storage efficiency was the tertiary CO_2 injection, with storage of over 23% of the injected gas. In this case, the injected CO_2 finds a reservoir already invaded by water, which can contribute to such results by facilitating the dissolution of CO_2 inside the reservoir and advancing the effect of CO_2 trapping by water. Carbonated water injection showed a negative storage efficiency on the model, as the gas production obtained was higher than the injected volume.

Table 3: Storage efficiency of injected CO_2: comparative.

Case	Total injected CO_2 (km³std)	Total produced gas (km³std)	Stored gas volume (km³std)	Geological storage efficiency
Tertiary CO_2 injection	0.197	0.151	0.046	**23.2%**
Continuous CO_2 injection	0.548	0.467	0.081	**14.7%**
Inverted WAG injection (2 year)	0.292	0.274	0.018	**6.1%**
WAG injection (2 months)	0.274	0.263	0.011	**4.0%**
Carbonated water injection	0.218	0.222	-0.004	**-1.7%**
Water injection [base case]	0	0.042	-	-

4 Conclusions

Carbon capture, utilization and storage has become a key theme in the sustainable development debate. Its combination with CO_2-EOR can be an important way to assess potential techniques and economic viability of CCUS projects. Through compositional reservoir simulation, the results of this study showed the productive increase by different forms of CO_2 injection considering the generation of similar injection BHP.

The continuous CO_2 injection into the reservoir showed the best results, with an increase of more than 33% in the recovery factor in relation to the water injection. It is followed by inverted CO_2-WAG, initiated by CO_2 injection; CO_2-WAG initiated by water; tertiary CO_2 injection, when it is continuously injected soon after the water injection decline; and, finally, carbonated water injection, still with good results. The effects of CO_2 on the oil, therefore, may contribute an important portion of recovery, even seen under a simplified homogeneous model.

For the CO_2-WAG cases, the selection between different injection forms and cycles showed differences of more than 4.5% in the recovery factor. When initiated by water, the results were best to shorter cycle periods. The opposite is seen for CO_2-WAG initiated by CO_2 injection: longer cycles led to greater results. Furthermore, the CO_2-started WAG was better than the previous one in all cases. In addition to the fact that CO_2 has generated greater initial production than water injection, this occurs because starting the cycle by injecting CO_2 its effects act immediately, ensuring a better sweep in the subsequent water injection, which will displace an oil in solution with CO_2, and even a faster onset of the CO_2 trapping effect.

The best geological storage efficiency was observed in tertiary CO_2 injection, storing 23% of the injected gas. This may represent good prospects for CCUS projects in fields already recovered by water injection, including Brazilian fields, where water injection recovery is currently responsible by 74% of daily oil production [21]. It is expected that this study can contribute to the initial analysis of the potentialities of CCUS in face of CO_2-EOR. For its continuity, other injection techniques using CO_2 can be considered, more elaborate reservoir models can be implemented, and economic analyses can be included on the methods.

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