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WAG-CO2 Light Oil Recovery from Deep Offshore Carbonate Reservoirs

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SUMMARY

Brazilian pre-salt reservoirs are constituted by carbonate rock and light oil with some CO2 and high solution gas ratio. A sustainable production of oil from pre-salt reservoirs requires a destination for the produced CO2 to mitigate its emission into the atmosphere. CO2 has been used to improve oil recovery when combined with water injection in the water-alternating-gas process (WAG). WAG-CO2 is an Enhanced Oil Recovery (EOR) method that modifies the fluid and rock-fluid properties. This injection process is associated to hysteresis of relative permeability and capillary pressure. Before implementation of the WAG injection in a field, the use of the reservoir simulation is required, a tool used to predict the oil recovery. A more rigorous way to simulate this process is by using a compositional reservoir simulator, given that an Equation of State (EOS) must be used to represent the pressure, volume, temperature (PVT) data that is different from the representation considered in conventional Black-Oil models. An EOS obtained from conventional PVT experiments and swelling tests must be employed to adequately represent the phase behavior resulting from the CO2 dissolution in the oil. Changes in relative permeability and capillary pressure resulting from hysteresis associated with the alternation between the injected fluids in the WAG process must be considered in the simulation model, avoiding a non-realistic oil recovery prediction. The impact of changes in oil properties and the hysteresis effect are considered in the prediction of WAG-CO2 oil recovery from a reservoir with petrophysical properties similar to a real carbonate reservoir constituted by light oil (about 8% molar of CO2). Reservoir simulation results give an indication of the expected oil recovery from a reservoir with pre-salt characteristics, enabling one to decide if the WAG-CO2 process is indicated for implementation in practice.
Introduction

Recent discoveries of light oil in Brazilian pre-salt reservoirs indicate that this oil should contain a variable quantity of dissolved carbon dioxide (CO₂). A sustainable production of these reservoirs requires a destination for the produced CO₂, which must not be released into the atmosphere. In such cases in which the oil contains CO₂ and is produced under surface conditions, environmental issues can indulge the gas injection. In fact, CO₂ is an attractive gas to be used in Enhanced Oil Recovery (EOR) methods. The injection of CO₂ in highly heterogeneous and fractured reservoirs such as carbonate rocks, present in pre-salt reservoirs, is capable of increasing oil recovery. As CO₂ flooding is related to the high mobility of the injected gas, the water-alternating-gas injection (WAG) is a way to reduce this disadvantage, since water controls the gas mobility.

WAG was firstly proposed by Caudle and Dyes (1958) to improve the sweep efficiency of the gas injection process. Recently, the interest in WAG injection has increased since the gas produced from the reservoir can be used as an injection fluid. The use of produced gas can be indicated for offshore operations due to the limitations of gas manipulation, storage and exportation. Its use is mainly attractive if the offshore field produces CO₂, as is expected in Brazilian pre-salt oil reservoirs.

According to Pizzarro and Branco (2012), in the initial stages of the pre-salt development projects, studies were conducted in order to evaluate recovery methods to produce the light oil from the reservoirs. EOR methods were considered since the beginning of the life cycle. WAG injection was considered an effective method due to the scenario of pre-salt reservoirs: ultra-deep offshore reservoirs, available sea water and gas production during the depletation. If the gas produced is insufficient, it is possible to import gas from other reservoirs in the pre-salt cluster.

The potential of WAG-CO₂ injection for recovery of light oil from Brazilian pre-salt reservoirs was analysed through reservoir simulation and reported in the literature. Beltrão et al. (2009) mentioned that gas injection and WAG presented excellent results when the CO₂ was miscible in the reservoir oil. Numerical simulation results reported by Almeida et al. (2010) demonstrated that WAG duplicated the oil recovery when compared to water flooding. Preliminary tests in pre-salt reservoirs indicated that WAG-CO₂ injection can increase the oil recovery in approximately 50% when compared to water flooding (Vigliano, 2011).

Objectives

The main goal of this work was to predict the light oil production from a synthetic carbonate reservoir submitted to the WAG-CO₂ EOR method. The rigorous simulation of WAG injection required a compositional model instead of the simplified Black-Oil formulation since the behavior of the oil mixture and dissolved CO₂ is highly complex. Two important effects to be implemented in the simulation models were the hysteresis of relative permeability and capillary pressure. Changes in these properties are associated with the alternation of the injected fluids during WAG. The hysteresis was implemented in the simulation models, allowing for a more realistic oil recovery prediction.

Water-Alternating-Gas Injection and Hysteresis

WAG injection improves the sweep efficiency of the gas through water injection, which controls the displacement efficiency and stabilizes the gas front. According to Christensen et al. (2001), this EOR method combines the favourable aspects of gas and water flooding: better oil displacement and better water macroscopic sweep, respectively. Also, WAG injection provides compositional exchanges that should give some additional oil recovery and influence the fluid density and viscosities.

During the WAG process, gas and water saturations increase and decrease alternatively. This behavior demands an adequate description of the relative permeability for the three phases: oil, gas and water (Christensen et al., 2001). In a three-phase flow, the relative permeabilities and capillary pressures depend on the saturation path and saturation history. The path dependence or irreversibility is referred
to as hysteresis (Spiteri and Juanes, 2006). The presence of a multiphase flow requires an accurate estimate of three-phase permeability.

A common practice to evaluate three-phase permeability in WAG simulation is through empirical correlations based on two-phase relative permeability data. Shahverdi et al. (2011) reported a brief description of the most common models used to predict the three-phase permeability and indicated the models that are available in commercial reservoir simulators. The use of two-phase permeabilities to calculate the three-phase permeability were supported by the high cost and the difficulty and elevate time to experimentally measure the three-phase relative permeability (Spiteri and Juanes, 2006).

In a WAG injection occur changes in the saturation direction, which need to be modelled with history-dependent relative permeability methods (Shahverdi et al., 2011). One possible approach to consider the cyclic hysteresis of the three-phase relative permeability in the WAG combines an empirical model to predict the three-phase permeability with a two-phase hysteresis model, such as the model proposed by Killough (1976).

The Killough’s hysteresis model predicts the trapping of the non-wetting phase and the reduction of permeability during the process of imbibition, which is assumed to be a reversible process. The amount of trapped non-wetting phase is predicted using Land’s model (1968). So, the trapped non-wetting phase saturation is a function of the critical gas saturation, gas saturation at the flow reversal and Land trapping parameter (Element et al., 2003).

Killough’s model allows relative permeabilities and capillary pressures to range between imbibition and drainage curves through intermediate curves called scanning curves. Each scanning curve corresponds to a reversal in the direction of saturation. Killough’s model is based on remembering the saturation history and provides an interpolative scheme for determining the intermediate values. Transitions in either direction between drainage and imbibition curves are represented smoothly, as observed experimentally. The model requires only experimental data for bounding imbibition and drainage curves. The equations to predict the hysteresis of relative permeability and capillary pressure were well explained by Killough (1976).

Methodology

The methodology was proposed in order to facilitate the analysis of studied case and the sequence of the simulation runs. The first step was the adjustment of the injection and production rates to ensure that an average reservoir pressure profile was constant after the decline period. The results of WAG-CO₂ injection without hysteresis were considered as a reference in order to analyse the effects of considering hysteresis of relative permeability and capillary pressure in the simulation models.

The three-phase relative permeability was predicted considering the two-phase models: Stone 1 (1970), Stone 2 (1973), Segregated and Linear Isoperm (Baker, 1988). Commercial simulators normally adopt the Stone 1 model modified by Aziz and Settari (1979). The data necessary to execute these simulations were oil-water and oil-gas relative permeability curves. These models were implemented in the WAG simulation model without considering any hysteresis effects. The field objective functions analysed were cumulative oil and gas production and the average pressure in order to select the most appropriate model to predict the three-phase permeability.

A sensitivity analysis was executed to determine the influence of the hysteresis of relative permeability and capillary pressure in a light oil recovery from a carbonate reservoir. This procedure isolated one effect from the others, since hysteresis effects were implemented one by one in the reference model (WAG model without hysteresis). The hysteresis was modelled based on the two-phase hysteresis model developed by Killough (1976). The following steps were performed: (1) hysteresis was considered in the oil phase relative permeability in a two-phase oil-water system (k₉₉); (2) hysteresis was implemented in the gas phase relative permeability (k₉₆); and (3) hysteresis of oil-
water capillary pressure was implemented ($P_{cw}$). Although Killough’s model should also be applied to predict the hysteresis effect in the gas-water capillary pressures ($P_{gw}$), it was not included in this study.

The simulation results obtained from Steps 1 to 3 were compared to those from the WAG without hysteresis. Cumulative oil and gas production and average pressure were the main objective-functions analysed for the field. Considering the wells, the objective-functions were water and CO$_2$ injection rates and well bottom-hole pressure (BHP) of water and CO$_2$ injectors.

The possibility of hysteresis modelling in WAG simulation having some effect on the well injectivity was also investigated, since some authors reported the injectivity loss as a problem in WAG injection (Goodyear, 2003; LaForce and Orr, 2008; Grigg, and Svec, 2008).

**Application**

The reservoir simulation model was represented by a synthetic carbonate reservoir (Figure 1) with geological characteristics of trombolite-stromatolite formations as described in Adams et al. (2005). Its petrophysical properties were described as having high vertical heterogeneity with high permeability layers and sealing layers. The 3D reservoir model had a Corner Point grid with 86x77x24 cells.

The reservoir fluid was light oil with about 8% molar of CO$_2$. The initial reservoir conditions were high pressure (about 6400 psi) and low temperature (138°F). The parameters of Equation of State (EOS) employed to represent the phase behavior of the mixture of the oil and CO$_2$ were the same reported by Moortgat et al. (2010). The EOS contemplated the swelling to adequately represent the phase behavior resulting from the CO$_2$ dissolution in the oil. These characteristics are similar to those of a Brazilian pre-salt reservoir: Lula field, initially known as Tupi field (Beltrão et al., 2009; Formigli et al., 2009; Nakano et al., 2009; Almeida et al., 2010).

The field production strategy consisted of 19 wells: 9 producers and 10 injectors (Figure 1). Injector and producer were modelled to operate at a constant rate. Producer wells’ bottom-hole pressures (BHP) were higher than the bubble point of the fluid (5580 psia). Injectors were modelled with BHP above the initial reservoir pressure. Also, all the values of BHP were defined in order to maintain the reservoir average pressure higher than minimum miscibility pressure (MMP) of CO$_2$ in the oil, ensuring a CO$_2$ miscible displacement. The predicted MMP was about 3700 psia (Yuan et al., 2004).

![Figure 1](image-url)  
*Figure 1 Corner point simulation model: absolute permeability in x direction and the locations of injector and producer wells.*
In order to represent the WAG injection, the injector wells were alternately shut-in and shut-off to change the injection fluid: water or CO₂. Water was the first fluid injected during the first 360 days of simulation. After that, pure CO₂ was injected for 360 days. This sequence of injection fluids (cycles of 360 days) was followed during the entire simulation time (more than 28 years). The simulation runs were executed in a commercial compositional reservoir simulator.

Hysteresis of the oil phase relative permeability in two-phase oil-water system (kr_{ow}) was implemented in the simulation model as function of the maximum imbibition residual oil saturation (S_{ormax}). This saturation represents the endpoint of an imbibition branch that leaves the drainage curve (Killough, 1976; User Guides GEM, 2011). The hysteresis of the oil phase relative permeability was modelled considering a range of values for S_{ormax} from 0.35 to 0.55.

Analogous to kr_{ow} hysteresis, the gas phase relative permeability (kr_{g}) was implemented in the WAG simulation. Hysteresis was a function of the maximum residual gas saturation (S_{gmax}) as reported by Killough (1976); User Guides GEM (2011). The values of this saturation were varied from 0.20 to 0.60, and the hysteresis effect was analysed for the values comprehended in this range.

The hysteresis of oil-water capillary pressure (P_{cow}) depended on a regression parameter (S_{pc}) that determines the transition between the imbibition and drainage curves for P_{cow}. Usual values for S_{pc} are between 0.05 and 0.1 (Killough, 1976; User Guides GEM, 2011).

Results

Figure 2 shows the simulation results obtained when the three-phase relative permeability was predicted using the models of Stone 1, Stone 2, Segregated and Linear Isoperm. This permeability should be evaluated when three phases flow simultaneously in the reservoir, as in WAG, and when a two-phase hysteresis model is used in the simulation model. The cumulative oil and gas production suffered practically no influence of the model used to calculate the three-phase relative permeability.

As these models did not influence the oil prediction, the model of Stone 2 was implemented in all simulation models to represent the WAG-CO₂ injection. It is important to mention that for this case, each one of the other models could have been used to predict the three-phase relative permeability.

![Figure 2: Effect of model to predict the three-phase relative permeability: (a) cumulative oil produced and (b) cumulative gas produced.](image-url)

The oil-phase relative permeability in the two-phase oil-water system (kr_{ow}) was the first property in which the hysteresis effect was considered. Figure 3(a) shows that the cumulative oil productions were affected by the kr_{ow} hysteresis. The oil productions strongly decreased by increasing the
maximum imbibition residual oil ($S_{o_{r max}}$). For this case, the fact to consider the $k_{row}$ hysteresis reduced the oil production when compared to the model without hysteresis. If the hysteresis were not considered, the oil recovery would be overestimated. Also Figure 3(a) shows the importance of executing a sensitivity analysis to predict the oil recovery, when the value of $S_{o_{r max}}$ is unknown. The model without $k_{row}$ hysteresis also produced more gas when compared to models with hysteresis (Figure 3b). As the cumulative oil production in the models with hysteresis decreased, the cumulative gas production (Figure 3b) also decreased when the value of $S_{o_{r max}}$ was increased from 0.35 to 0.65.

The average reservoir pressures (Figure 3c) for the models with $k_{row}$ hysteresis were superior to that of the model without hysteresis. This was associated to the injectivity loss occurred in the water and CO2 injectors. To illustrate this, Figures 4(a) and 4(b) for well I07, show, respectively, that when the $k_{row}$ hysteresis was implemented in the WAG simulation model, the BHP of water and CO2 injectors increased in order to maintain the water and CO2 injection rates constant.

It is important to observe that, for some models that had the $k_{row}$ hysteresis implemented, the water rate was not maintained constant at the beginning of simulation (Figures 5a). As a consequence, the cumulative water injected in some models with hysteresis were inferior to the model without hysteresis (Figure 6a). Otherwise, whether considering the hysteresis or not, the CO2 rate was maintained constant during all simulation time in all models as shown in Figure 5(b) and, as expected, the cumulative CO2 injection was not influenced, whether considering the hysteresis or not as indicated in Figure 6(b).

![Figure 3](image)

Figure 3 Effect of $k_{row}$ hysteresis on reservoir: (a) cumulative oil produced, (b) cumulative gas produced and (c) average pressure.
**Figure 4** Effect of $k_{rw}$ hysteresis on well bottom-hole pressure (BHP) of injector I07 - (a) water injection cycles and (b) carbon dioxide injection cycles.

**Figure 5** WAG-CO$_2$ injection with $k_{rw}$ hysteresis - fluid injection rates of injector I07: (a) water rate and (b) carbon dioxide rates.

**Figure 6** WAG-CO$_2$ injection with $k_{rw}$ hysteresis: (a) cumulative water injected and (b) cumulative gas injected.
The effect of considering the hysteresis on the gas-phase relative permeability ($k_{rg}$) in the oil production was also investigated. The sensitivity analyses were also executed since the maximum residual gas saturation ($S_{gr_{\text{max}}}$) was unknown. As the gas-phase relative permeability values influenced the gas displacement, the cumulative oil production (Figure 7a) suffered almost no influence when considering the $k_{rg}$ hysteresis. In this case, the effect of $k_{rg}$ hysteresis was more significant in the cumulative gas production (Figure 7b). As can be observed, the cumulative gas production without hysteresis was higher when compared to the models with hysteresis and the higher was the value of $S_{gr_{\text{max}}}$, smaller was the gas production.

As a consequence of $k_{rg}$ hysteresis, the average reservoir pressure increased when compared to the case without hysteresis (Figure 7c). Similarly, when the $k_{rw}$ hysteresis was implemented in the WAG simulation models, the $k_{rg}$ hysteresis induced an increase in the values of well bottom-hole pressure (BHP) of water and CO$_2$ injectors. Figure 8(a) and 8(b) illustrated this behavior for the Well I04 in the cycles of water and CO$_2$, respectively. The higher the value of $S_{gr_{\text{max}}}$ was, the higher was the increase of the BHP. Also, the BHP of the injectors was increased due to the injectivity loss in order to maintain the water and CO$_2$ injection rates constant. Figure 9(a) is an example of an injector well that was not capable of maintaining the water injection rate constant during the entire simulation time. Otherwise, in the cycle of CO$_2$ injection (Figure 9b), the gas injection rate was constant during all simulation time. The amount of injected water into the reservoir was not constant and decreased with the value of the saturation $S_{gr_{\text{max}}}$ (Figure 10a). Also, in this sensitivity analysis, the quantity of injected CO$_2$ did not depend on the model having the $k_{rg}$ hysteresis implemented or not (Figure 10b).

Figure 7 Effect of $k_{rg}$ hysteresis on reservoir: (a) cumulative oil produced, (b) cumulative gas produced and (c) average pressure.
**Figure 8** Effect of $k_{rg}$ hysteresis in well bottom-hole pressure (BHP) of injector I04: (a) water injection cycles and (b) carbon dioxide injection cycles.

**Figure 9** WAG-CO$_2$ injection with $k_{rg}$ hysteresis - fluid injection rates of injector I03: (a) water injection cycles and (b) carbon dioxide injection cycles.

**Figure 10** WAG-CO$_2$ injection with $k_{rg}$ hysteresis: (a) cumulative water injected and (b) cumulative gas injected.
Besides the hysteresis of the oil phase relative permeability in the two-phase oil-water system and the hysteresis of the gas phase relative permeability, the impact of hysteresis of oil-water capillary pressure ($P_{cow}$) in the light oil recovery was investigated. As can be noticed in Figures 11(a) and 11(b), the $P_{cow}$ hysteresis had practically no impact on the production parameters: cumulative oil and gas production. The same was observed for the average reservoir pressure (Figure 11c). The injective loss was not observed in the studied case when the $P_{cow}$ hysteresis was modeled to represent the WAG-CO$_2$ simulation.

![Figure 11](image)

**Figure 11** Effect of $P_{cow}$ hysteresis on reservoir: (a) cumulative oil produced, (b) cumulative gas produced and (c) average pressure.

**Conclusions**

The WAG injection has as a principle the alternation of the injection fluids during the process. Consequently, hysteresis of relative permeability and capillary pressure are mostly probable to be associated with the method. For this reason, when a reservoir model with WAG injection is simulated, it is recommended to implement the hysteresis phenomenon.

The studied case was represented by a reservoir model constituted by light oil and the recovery process was WAG-CO$_2$. The impact of the hysteresis of relative permeability and capillary pressure was investigated in the oil production forecasting. A two-phase hysteresis model was implemented in the reservoir simulation model to consider hysteresis of the oil phase relative permeability in the two-phase oil-water system, gas phase relative permeability and oil-water capillary pressure. A sensitivity analysis was executed and hysteresis effects were implemented, one by one, in the simulation models.
For the case studied, hysteresis of the oil phase relative permeability in two-phase oil-water system had more influence on the oil production than the hysteresis of the gas phase relative permeability. For these two scenarios, cumulative oil production obtained from the model without hysteresis was higher than the oil production from the model with relative permeability. Consequently, the model without relative permeability hysteresis overestimated oil production. Otherwise, the oil production was not influenced by the consideration of capillary pressure hysteresis. The injectivity loss was not observed in the models without hysteresis. Otherwise, the injectivity loss was contemplated in the models with hysteresis of relative permeability.

This work evidenced the importance of using of the reservoir simulation to predict the oil recovery, before implementation of the WAG injection in a field. Also it was evidenced the importance to consider the hysteresis in the modeling of WAG injection. If the necessary parameters to predict the hysteresis effects were unknown, the sensitivity analysis proved to be a procedure to give an idea of the pessimistic and optimistic scenarios of oil recovery prediction.

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References


