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Mechanistic Investigation of Vertical Sweep Efficiency in Miscible CO2-Water-Coinjection for EOR and CCUS

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Summary

The main objective of this study is to understand the vertical sweep efficiency with miscible CO2-water-coinjection as a secondary recovery method, from multiple perspectives: phase behavior, total relative mobility, fluid densities/viscosities, the driving forces and consequent phase distributions etc. We also seek to provide insights into modeling approaches for representing the injection process by comparing compositional simulation results to those of the fractional-flow method and the model of Stone and Jenkins (Stone, 1982; Jenkins, 1984).

We combine compositional simulation and analytical models to interpret the dynamics that affect vertical sweep efficiency in miscible CO2-water-coinjection. Stone's model for gravity segregation at steady state predicts three phase-distribution zones: mixed zone, override zone and underride zone. In addition to these three zones, we identify from simulations an extended mixed zone and extended override zone in miscible CO2-water-coinjection, contributing to additional oil recovery and CO2 trapping. The extended zones are a result of dispersion that reflects physical and numerical dispersion in the gas-oil displacement front. To the extent that it reflects numerical dispersion, the extended zones can be considered as a numerical artifact.

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Introduction

Miscible gas EOR can achieve excellent displacement efficiency, leaving near-zero residual oil where gas sweeps (Holmgren and Morse, 1951; Lake et al., 2014; Skauge A. et al., 2014). A main issue for gas EOR is poor vertical conformance, in large part a result of upward gas segregation under gravity (Stone, 1982; Yu et al., 2017; Rossen et al., 2010). Alternating gas and water injection (WAG) improves the trapping efficiency of gas at the microscopic scale (Skauge et al., 2014) and the vertical conformance of gas at the macroscopic scale (Rossen et al., 2010). which substantially increases oil production.

We model a process of first-contact miscible displacement. With this, the complications involved in three-phase relative permeabilities, three-phase capillary pressures, and hysteresis in relative permeabilities and gas saturation during cyclic drainage and imbibition are excluded. As a simplified representation of WAG, we co-inject gas and water over the whole reservoir depth (Stone, 1982). WAG is usually implemented as a tertiary-stage EOR method when the reservoir is at waterflood oil saturation. In this study, we assume the reservoir is initially saturated with oil at connate water saturation.

There have been many studies on the steady-state sweep efficiency of gas-injection EOR (Stone, 1982; Jenkins, 1984). The simulation of Namani et al. (2013) and Yu et al. (2017) demonstrate the formation of a thicker override zone during the displacement and its beneficial effect on oil recovery. However, their conclusions are drawn from a black-oil-model simulation of a miscible flood using Todd-Longstaff mixing rules. The resulting phase saturations, density/viscosity of gas and oil, and the oil-recovery factor may be imprecise. This study investigates the flow performances of miscible WAG injection with compositional simulation.

The main objective of this study is to understand the vertical sweep efficiency with miscible CO_2-water-coinjection as a secondary recovery method, from multiple perspectives: phase behavior, total relative mobility, fluid densities/viscosities, the driving forces and consequent phase distributions etc. We also seek to provide insights into modeling approaches for representing the injection process by comparing compositional simulation results to those of the fractional-flow method and the model of Stone and Jenkins (Stone, 1982; Jenkins, 1984).

We combine compositional simulation and analytical models to interpret the dynamics that affect vertical sweep efficiency in miscible CO_2-water-coinjection. Stone's model for gravity segregation at steady state predicts three phase-distribution zones: mixed zone, override zone and underride zone. In addition to these three zones, we identify from simulations an extended mixed zone and extended override zone during transient state of miscible CO_2-water-coinjection, which contribute to additional oil recovery and CO_2 trapping. The extended zones are a result of dispersion that reflects physical and numerical dispersion in the gas-oil displacement front. To the extent that it reflects numerical dispersion, the extended zones can be considered as a numerical artifact.

Theory and method

Stone (1982) argues that co-injection of gas and water is an accurate model for WAG if the slug sizes are not too large. In steady-state co-injection, the reservoir can be divided into 3 regions of uniform saturation (Stone, 1982; Jenkins, 1984): 1) mixed zone – a two-phase region which forms near an injection well with concurrent flow of gas and water (with no mobile oil); 2) override zone – a region that forms at reservoir top with only gas flowing; and 3) underride zone – the region below the override zone with only water flowing. The end-point of the mixed zone marks the location of complete segregation. Stone's model was extended by Jenkins (1984) to predict the thicknesses of override and underride zones. Ultimate oil recovery can thus be approximated by combining the two models. Rossen and van Duijn (2004) prove that the assumption of uniform regions at steady state is justified using the method of characteristics.

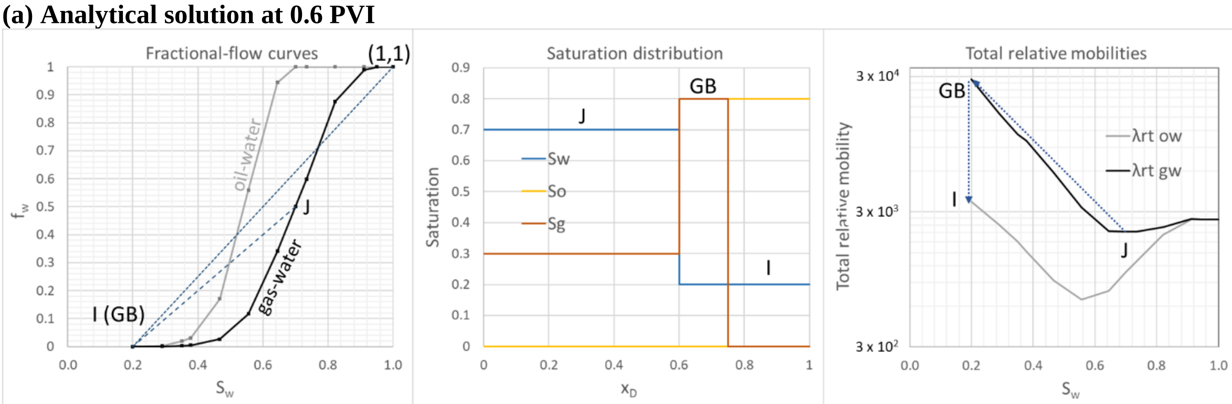
Here we solve the compositional model using the Automatic Differentiation General Purpose Research Simulator (AD-GPRS) (Zhou et al., 2011; Longlong et al., 2018), to represent the phase behaviour during miscible WAG injection. Our simulation assumes compressible matrix, liquid phase, and gas phase. The impact of capillary pressure is neglected by setting both P_{cow} and P_{cog} to zero. The simulation assumes an isothermal process without significant temperature fluctuations. Production wells are controlled at a bottom-hole pressure of 120 bar (above the minimum miscibility pressure). The reservoir depth is 1000 ft, with an initial pressure of 150 bar and an initial temperature of 348.15 K (75 ˚C). At reservoir condition, the CO_2 injected and the initial reservoir hydrocarbon, 60% n-butane (C_4H_{10}) and 40% n-decane ($C_{10}H_{22}$), achieve first-contact miscibility. With the usual assumption of instantaneous chemical equilibrium between solvent and oil, the equilibrium phase compositions are calculated in the simulator using flash. A three-phase system of gas/oil/water is thus simplified into a two-phase system between miscible-gas/oil and water.

The non-aqueous phase is treated as defined by the simulator as gas or oil based on a phase-identification criterion. In our simulations, the miscible fluid is defined as a “gas” or “gas-like” phase when the total molar fraction of CO_2 and C_4H_{10} exceeds 85%; at molar fractions lower than this threshold value, the miscible fluid is treated as an “oil” or “oil-like” phase (Liu and Rossen, 2011). We use the Stone I model for oil relative permeability (Killough and Kossack, 1987). The initial saturations are S_{oi} = 0.8 and S_{wi} = S_{wc} = 0.2. Rock and fluid properties are based on the data and input of the 5th SPE comparison simulation study (Killough and Kossack, 1987; Namani et al., 2013).

1D solution

Here we show an example of the gas-saturation distribution after 0.6 PV gas and water injected.

(a) Analytical solution at 0.6 PVI



(b) 1D fine-grid simulation result at 0.6 PVI

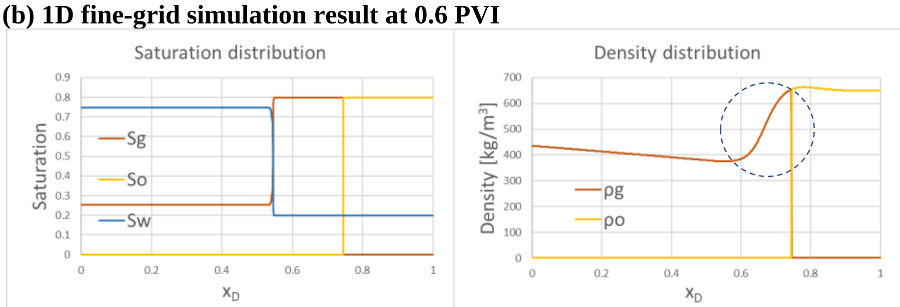


***Figure 1** Comparison of (a) Fractional-flow solution and (b) 1D simulation result.*

Fig. 1a shows the fractional-flow solution (Lake et al., 2014). The two fractional-flow curves (oil-water, gas-water), saturation profile, total relative mobility, and the solution path are illustrated in **Fig. 1a**. Three regions of displacement can be identified,

- A uniform wave at the injection condition (J), with S_w = 0.65 (and S_g = 0.35).
- A gas-bank within which only gas flows (S_g = 0.8). The total relative mobility of gas reaches a maximum value of 32 cp^{-1} in the gas bank as shown in Fig. 1.
- The initial condition (I) of connate water saturation (S_w 0.2, S_o = 0.8).

The total relative mobility at initial condition I is 2 orders of magnitude lower than that of the gas bank. This unfavourable mobility ratio at the gas front suggests an instability of displacement and the severity of gas fingering in 2D and 3D displacements.

At 0.6 PVI, **Fig. 1b** shows a 1D simulation with 1000 grid blocks. The results show a slightly wider gas bank than that predicted by fractional-flow theory. This can be explained by the exchange of components at the displacement front of CO_2, where there is a gradual transition from a region of high

CO_2 concentration to a region of greater n-decane ($C_{10}H_{22}$) concentration. Within this, the density of CO_2 increases gradually and approaches the density of oil asymptotically. The implication of the density increase on gravity segregation is discussed below. In addition, 1D simulation shows a slower propagation of mixed zone in comparison to the result of the fractional-flow method. This can be explained by gas compressibility and the resulting reduction of gas velocity near injection well.

2D coarse-grid simulation

The 2D simulation model is 400 m long, 400 m wide, and 75 m thick. In the coarse-grid model, the grid resolution is 100:1:25 on x, y, and z directions, respectively. The injection-rate ratio (Q_g/Q_w) is 1. **Fig. 2** shows the 2D saturation distribution at 1.0 PVI injection. In total five regions are evident: 1) uniform mixed zone; 2) transient mixed zone extended forward; 3) steady-state override zone; 4) transient override zone extended downward; 5) underride zone.

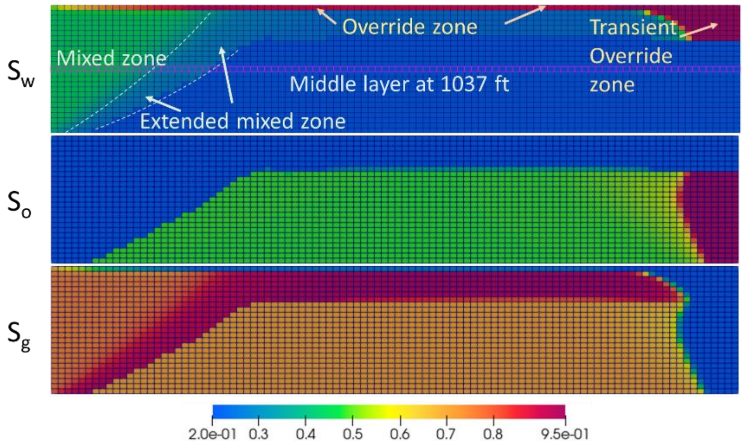


Figure 2 *2D coarse-grid simulation result (1.0 PVI). Illustration of regions and saturation distribution.*

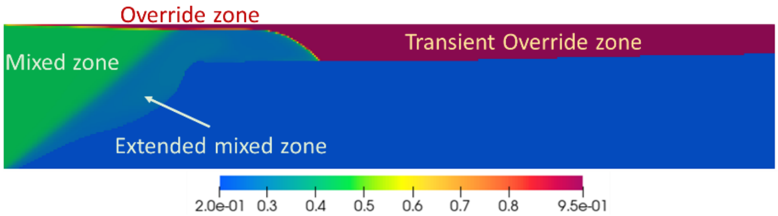


Figure 3 *2D fine-grid simulation result (0.45 PVI). Demonstration of transient override zone.*

Within the gas-bank shown in **Fig. 1**, the density of the non-aqueous phase approaches that of oil at the displacement front. Based on Stone's model (Stone, 1982), a reduction of the density difference between water and gas leads to an extension of the mixed zone. Later, mobile gas moves upward, and gas is left at the trapped-gas saturation $S_{gr} = 0.05$ (**Fig. 2**). Only water flows in this region since oil has been displaced completely during the transient displacement. This region is the "extended mixed zone" (**Fig. 2**). Its incremental oil recovery is not included in Stone's model (Stone, 1982). The extended mixed zone can be affected by factors such as initial saturation, oil relative permeability/viscosity, gas/water injection ratio etc. For example, in the simulations of immiscible displacement of Lyu et al. (2021), the extension of the mixed zone is a numerical artefact caused by low total relative mobility at gas front. In that study, the size of the mixed zone shrinks when the grid is refined.

2D fine-grid simulation

With the reservoir size kept constant, the fine-grid model resolution is 400:1:75. **Fig. 3** shows the fine-grid solution at transient state (0.45 PVI). Comparison of fine-grid (**Fig. 3**) and coarse-grid simulations (**Fig. 2**) implies that the thick transient override zone is not a numerical artefact. Based on Jenkins' model (Jenkins, 1984), the greater thickness of transient override zone can be explained by the relative mobility ratio between the override zone and the underride zone. The prediction of transient override zone thickness by Jenkins' model (Jenkins, 1984) agrees well with our 2D simulation results.

Conclusions

1. We identify five characteristic phase-distribution zones co-injection of miscible gas and water: mixed zone with gas and water flowing at $S_o = 0$; extended mixed zone with much lower S_g and $S_o = 0$; override zone with flowing gas and $S_o = 0$; extended override zone with $S_g = S_{gr}$ and $S_o = 0$; and underride zone with water displacing oil at $S_g = 0$.
2. Oil recovery is greater than that indicated by the gravity segregation model of Stone (Stone, 1982), because of the presence of the extended mixed and override zones which are not represented in the model.
3. Dispersion of the front as gas displaces oil, a combined effect of physical and numerical dispersion, affects the shape and thickness of the extended mixed and override zones.
4. Fractional-flow solution excludes physical and numerical dispersion. To the extent that the simulation reflects numerical dispersion, the extension of the extended mixed zone can be considered as a numerical artifact. However, the extended zones did not shrink greatly upon grid refinement in our study.
5. The extended mixed and override zones modestly increase residual trapping of CO_2. There is also some CO_2 dissolved in the residual oil.
6. This study makes several simplifying assumptions. Results could also be affected by initial oil saturation, gas-water injection ratio, and the relative mobility of oil, etc. Further investigation on the extension of the oil-displacement zone beyond that predicted by the steady-state is required.

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