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An experimental study of gas sequestration efficiency using water alternating gas and surfactant alternating gas methods

Abdulrauf Rasheed Adebayo [a, *], Muhammad Shahzad Kamal [a], Assad A. Barri [b]

[a] Center for Integrative Petroleum Research, King Fahd University of Petroleum & Minerals, Dhahran 31261, Saudi Arabia
[b] Petroleum Engineering Department, King Fahd University of Petroleum & Minerals, Dhahran 31261, Saudi Arabia

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ABSTRACT

Capillary trapping plays an important role in the geological storage of Carbon dioxide (CO_2) because of its ability to immobilize a significant fraction of the injected gas. Numerous papers have investigated various factors that affect capillary trapping. Recently, gas-mobility control methods are being investigated through simulation studies, for improving capillary trapping of CO_2 in saline aquifers. The results published so far are inconclusive and sometimes conflicting. In this study, a series of laboratory experiments was conducted to investigate and compare the effects of two mobility control methods namely, water alternating gas (WAG) and surfactant alternating gas (SAG), on gas sequestration efficiency. Efficiency was measured by injectivity and residual trapping capacity. The two methods were tested in both vertical and horizontal flow directions using rock samples of varying lithology and permeability. The different gas injection schemes were compared with the continuous gas injection method. WAG method consistently reduced residual gas saturations in all the experiments while SAG method significantly increased residual gas saturation for both horizontal and vertical flows. Comparison of performance of SAG method in horizontal flow with its performance in vertical flow revealed a significant increase in residual gas saturation when applied in vertical flow direction. However, SAG method resulted in decreasing injectivity as the SAG cycles increase while WAG injectivity remained unaffected throughout its cycles except in tight samples. Furthermore, higher residual gas saturations were observed in high permeability rocks compared to tight rocks when subjected to vertical-SAG sequestration method. The possible reasons for such efficiency in the vertical-SAG method are discussed in detail.

1. Introduction

Multiphase flow of water, gas, and oil in a geological reservoir are believed to flow through their respective network of interconnected and tortuous channels-a flow process called channel flow. As the saturation of one channel increases, so does the width of its network of flow channels. Experimental observations showed that some channels are continuous throughout the porous media (e.g. from one end of a core sample to the other end) while some other channels are non-continuous but connected at some points to continuous channels (Willhite, 1986). Hence, there must be one or more continuous flow channels for one phase to flow through a cross section of a reservoir. The minimum saturation of a phase, below which continuous flow channel cease to exist is called its critical saturation. At this critical phase saturation, the fluid phase cannot be recovered from the porous medium and are said to be trapped by a capillary action. The critical saturations for water, oil, and gas are called the irreducible water saturation, residual oil, and trapped gas (residual gas) saturations respectively. They are functions of interfacial tension (IFT), wettability, and rock type. At higher flow rates, the flow channels can rupture resulting in one or both phases flowing in isolated globules-a flow mechanism called slug or dispersed-phase flow. When one phase is dispersed, it is transported through the reservoir by the continuous phase (Willhite, 1986).

Previous researchers have shown that residual saturation is dependent on the interplay between the viscous, capillary, and gravitational forces existing during multiphase flow in porous media (Abrams, 1975; Kuo et al., 2011; Melrose and Brandner, 1974; Moore and Slobod, 1956; Perkins, 1957). Their experimental observations have shown that residual saturation is a strong function of capillary number, and that residual saturation increases as

* Corresponding author.
E-mail address: abdulrauf@kfupm.edu.sa (A.R. Adebayo).

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capillary flow dominate. Capillary number is a dimensionless number that relates the ratio of viscous forces to capillary forces. Generally, capillary flow dominate multiphase fluid flow in porous media at a capillary number of $<10^{-6}$, which is also the dominant force acting in underground multiphase flow (Willhite, 1986).

The ease with which one fluid flows relative to the others is called its relative permeability. The relative permeability of a phase is highest when other phases are at their residual saturations and becomes minimum (zero) at its own residual saturation. During normal gas injection into a saline aquifer, the relative permeability of the aquifer's brine gradually reduces from its highest value when only aquifer water was present down to zero when the injected gas has displaced the resident brine to an irreducible water saturation. In that process, the relative permeability of the injected gas gradually increased to its maximum. The irreducible water saturation is being held by high capillary forces. Secondary imbibition or underground water movement slowly displaces the injected gas in either a channel flow or dispersed flow mechanism until some gases are trapped. The trapping is caused by the gradual discontinuity in the gas flow channels as the imbibing water saturation increases.

Water alternating gas (WAG) is a type of gas injection method used to enhance oil recovery from oil reservoirs. It involves alternating water and gas injection. Since the injected gases have much lower density and higher mobility than the resident oil, they move quickly upward (buoyancy effect) and/or channel through high permeability zones thereby bypassing the oil in the lower permeability zones. WAG method is thus used to reduce gas channeling and improve sweep efficiency. A significant body of literature showed the success of WAG in reducing mobility of injected gas (e.g. Awan et al., 2008; Zekri et al., 2011; Tewari et al., 2010; Holtz, 2016). Despite its wide application and recorded level of success in EOR applications, WAG still suffers some setbacks due to viscous fingering and gravity segregation, which persist particularly in heterogeneous reservoirs (Rogers and Grigg, 2000). Surfactant alternating gas (SAG) was later introduced to overcome these setbacks. Slugs of surfactant solution and gas are injected alternatingly. Foams are formed when the surfactant solution and gas flow together in a porous medium. The generated foam traps gases in liquid films and reduce gas mobility (Al-Mossawy et al., 2013). Unlike in bulk foams such as those found on top of a glass cup of beer where large volume of gas is trapped in continuous and interconnected liquid films as gas bubbles, foams flowing in porous media exist as micro gas bubbles dispersed in the continuous liquid phase and separated by liquid lamellae. The diameter of the micro gas bubbles are in the range of 50–1000 μm. The liquid film separating the gas bubbles can make some gas flow path discontinuous (Gauglitz et al., 2002).

The physics of the flow mechanism in these gas injection methods in EOR process have not been adequately captured in reservoir simulation models. This is because of the high uncertainty in the selection of the three-phase relative permeability curves of WAG injection (Shahverdi et al., 2011). In immiscible WAG EOR process, three-phase flow exist namely water, gas and oil. Measurements of the three-phase relative permeability in the lab is very complex, time consuming, and costly. Hence, the standard practice is to interpolate two-phase relative permeability experimental data-a technique that has also been criticized using experimental data (Oak, 1990). Moreover, the fluids' relative permeability in WAG and SAG processes are strongly affected by hysteresis due to trapping of the non-wetting phase for every successive water injection. Consequently, many relative permeability hysteresis models have been developed but unfortunately, they cannot adequately reproduce experimental measurements during WAG (Spiteri and Juanes, 2006). Hence, research is still ongoing on estimating the accurate relative permeability models for WAG and SAG injection methods (e.g. Al-Mossawy et al., 2013; Beygi et al., 2015). Other challenges and flow complexities in WAG and SAG have been described extensively in the literature (Rogers and Grigg, 2000; Talebian et al., 2014).

There is a growing interest in optimizing the volume of CO_2 sequestered in geological formations such as saline aquifer and depleted oil and gas fields. Our expertise and understanding of the multiphase flow behaviour in oil and gas field provides the prerequisite capability to do so safely and effectively. Residual (capillary) trapping is one of the main mechanism by which CO_2 is trapped during CO_2 sequestration in subsurface geological formations (Al-Menhali and Krevor, 2016; Herring et al., 2016; Raza et al., 2015; Suekane et al., 2008). Other mechanisms by which the injected CO_2 is trapped include solubility trapping, structural trapping, and mineral trapping. It is generally believed that capillary trapping of CO_2 is the quickest and of the most immediate importance because a significant fraction of the injected CO_2 can be stored in this way and rendered immobile in the event of a leak (Juanes et al., 2006). This trapping occurs when underground water migration displaces the injected CO_2 plume upward/vertical leaving a trail of residual CO_2. Numerous studies have investigated different factors that affect residual trapping. Niu et al. (2014) investigated the effect of variation in pressure, temperature, and brine salinity on residual trapping of CO_2 in horizontal Berea sandstones. Reynolds et al. (2014) studied the effect of viscosity ratio and IFT under a capillary dominated flow regime of the CO_2/brine system in a single horizontal Bentheimer sandstone sample. Different authors investigated through simulation or laboratory experiments, the effect of flow rate/capillarity on the multiphase flow of CO_2/brine in either a horizontal and vertical core-flood (Akbarabadi and Piri, 2013; Kuo and Benson, 2013; Perrin et al., 2009). Recently, the concept of WAG is beginning to gain relevance in CO_2 sequestration for increasing sequestration efficiency; however, most studies of this type are at the simulation stage. Okwen et al. (2011) carried out a simulation study of the effect of well orientation on sequestration efficiency. Their results suggested that there is no difference in storage efficiency when vertical flow (horizontal injection well) and horizontal flow (vertical injection wells) were compared. Zhang and Agarwal (2012) carried out a similar simulation study to investigate the performance of WAG in CO_2 sequestration during vertical and horizontal injection schemes. Their results showed that WAG resulted in slower CO_2 migration, more solubility trapping, and higher injection pressure when compared to conventional gas injection method. Their results also showed that WAG in the vertical flow direction (horizontal well) resulted in higher migration rate and lower gaseous CO_2 saturation, when compared to horizontal flow (vertical well). A simulation study by Sofi et al. also showed that SAG method improved CO_2 sequestration efficiency (Al Sofi et al., 2013). In all the previous studies mentioned, experimental study was not performed to validate their results. Juanes et al. (2006) also raised concerned about pressure limitation that can be imposed by the aquifer seal integrity, regulatory and economic constraints, during WAG application in CO_2 sequestration projects.

To the best of our knowledge, limited or no experimental works have been reported on the application of WAG and SAG in CO_2 sequestration efficiency. SAG and WAG are expected to reduce the relative permeability of the injected gas at any given phase (water) saturation. By that, the water flow channels advance much faster than the gas channels. Eventually, the fast moving water channels trap the gas channels across the reservoir. According to Dullien (1992), the non-wetting phase is trapped in the rock pore spaces when a portion of it is disconnected from the continuum. This study involved an extensive experimental study of the effect of the two