Viability of foam to enhance capillary trapping of CO_2 in saline aquifers—An experimental investigation

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A B S T R A C T

Capillary trapping is one of the quickest mechanism by which carbon dioxide (CO_2) is trapped during geological sequestration. It is also of the most immediate importance because a significant fraction of the injected CO_2 can be stored and rendered immobile in the event of a leak. Many research papers have been published in the past decade focusing on improving capillary trapping of CO_2 during geological sequestration. In this study, a different approach was investigated, which involved the use of colloidal materials to enhance capillary trapping of CO_2 during sequestration in saline aquifers. A suite of reservoir condition laboratory experiments was conducted on some selected reservoir rock samples saturated with synthetic brine to mimic actual saline aquifers. A foaming agent (0.025% wt. nonionic surfactant) was dissolved in the brine. Foams were then generated in the rock samples by alternate injection of gas and brine using a coreflooding setup. An electrical resistivity measuring tool attached to the setup was used for real-time and in-situ tracking of pore-scale events such as gas movement, capillary trapping of gas, and the stability of the trapped gas. Both Nitrogen (N_2) and CO_2 gases were investigated and the results showed a tremendous increase in the amount of trapped N_2 and CO_2 gases when foams were applied compared to gas injection without foams. However, low interfacial tension between CO_2 and the surfactant solution affected the viability of foams in trapping CO_2. Nevertheless, the use of CO_2 foam stabilizers is promising in addressing this challenge. The methodology described in this paper can be used to test the efficiency of a variety of CO_2 foam stabilizing agents that may be developed.

1. Introduction

Gasenhanced oil recovery (EOR) is the most commonly used EOR method. It involves the use of gases such as N_2, CO_2, and hydrocarbon gas to improve oil displacement. A major setback of this method is early gas breakthrough in the production well brought about by gravity override or gas channeling through high permeability layers instead of the low permeability oil zones. Because foams have plugging characteristics, they are recommended to address this setback (Bernard and Holm, 1964; Wang, 1984). When injected into a porous rock, foams plug some of the high permeability pores and divert the injected gas to low permeability zones. They can be injected into a porous rock in three major ways namely by co-injection of surfactant solution with gas at a defined ratio, continuous foam injection, and by surfactant alternating gas injection (SAG). SAG injection is the most preferred because of several advantages. There is a minimal contact of CO_2 and water with surface facilities compared to dual injection or continuous foam injection where contact between CO_2 and water can cause severe corrosion of surface facilities. Furthermore, SAG has more injectivity than continuous injection and co injection. In SAG method, slugs of surfactant solution and gas are injected alternatingly into a porous medium resulting in in-situ generation of foams in the porous medium. The generated foam traps gases in liquid films and reduces gas mobility (Al-Mossawy et al., 2013). The foams flow 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). During flow in a porous medium, foam is partitioned into three main fractions namely, trapped foam bubbles, flowing foam bubbles, and free continuous gas phase (Persoff et al., 1989).

The main challenge of foams in oil and gas applications is their instability at high temperature, high pressure, and high salinity. There is thus an extensive research interest towards improving the stability of CO_2 under such conditions. Some researchers have tested the use of nanoparticles to improve the interfacial tension of foam lamellae (e.g. Farhadi et al., 2016; Guo and Aryana, 2016; Emrani and Nasr-El-Din, 2017a). Some others have suggested the mixture of CO_2 with Nitrogen (e.g. Siddiqui and Gajbhiye, 2017). Others tested the use of polymers with nanoparticles (e.g. Ali and Selby, 1986; Emrani and Nasr-El-Din,

2017b). There is also an idea of generating CO_2 foam by either co-injecting or alternately injecting an aqueous dispersion of nano-silica followed by CO_2 injection. The foams generated this way are believed to have better stability than the surfactant based foams (Enick and Olsen, 2012; Worthen et al., 2013; Yu et al., 2014). Most of these research works have focused on improving the stability of foams particularly CO_2 foams and a tremendous success has been reported in this regard. However, the methodology of testing the foam stabilizers varies among researchers. Most importantly, the testing are not always performed in a foam flow mode in a porous media. Other challenges associated with foam applications in oil and gas exploration 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. Capillary trapping is one of the main mechanism by which CO_2 is trapped during geological sequestration. It is also 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 even in the event of a leak (Juanes et al., 2006). Other mechanisms by which the injected CO_2 is trapped include solubility trapping, structural trapping, and mineral trapping. A significant number of research papers exist in the literature on factors that affect capillary trapping of CO_2. Niu et al. (2015) investigated the effect of variation in pressure, temperature, and brine salinity on residual trapping of CO_2 in 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 Bentheimer sandstone sample. Herring et al. (2016) used X-ray tomographic imaging to study the effect of cyclic injection of CO_2 with water in enhancing CO_2 trapping. Some other related experimental studies include the work of Wang et al. (2012) and Kazemifar et al. (2016) who investigate residual trapping behavior of supercritical CO_2 using two dimensional micromodels (quasi-2D flow). Other authors investigated through simulation the effect of flow rate/capillarity on the multiphase flow of CO_2/brine (Kuo and Benson, 2013; Kuo et al., 2011; Spiteri et al., 2005; Juanes et al., 2006, 2010; Kumar et al., 2005).

The ability of foams to plug some pore throats and make a significant part of the injected gas phase immobile has often been downplayed obviously due to lack of interest in gas trapping in EOR processes. However, in CO_2 sequestration where trapping of the injected gas is the major objective, this important foam characteristic can be effectively utilized. However, the gas trapping capability of foams is also dependent on the stability of the foams. The absence of oil and high salinity brine in saline aquifer makes foam application in CO_2 sequestration application more viable. A simulation study by Obi and Blunt (2006) and Al Sofi et al. (2013) showed that foam injection by SAG method improved CO_2 sequestration efficiency. Few experimental works were also carried out on foam application for CO_2 sequestration in the light of mobility control and retention of applied foam stabilizing agents (such as nanoparticles) in porous medium (e.g. Uemura et al., 2016; Rognmo et al., 2017). However, they did not highlight the significant capillary trapping of CO_2 and the stability of the trapped CO_2 associated with the process. In view of the progress made thus far in the synthesis and application of CO_2 foam stabilizing agents, there is a need to develop a simplistic and yet accurate laboratory method to test those agents with respect to their ability to stabilize foam and also to immobilize and permanently trap injected CO_2. In this study, a new experimental procedure is introduced to help evaluate the viability and stability of CO_2 foam for enhancing capillary trapping of CO_2 for geological storage in saline aquifers. The method is based on a systematic and cyclic injection of gas and foaming agent (e.g. surfactant solution) using core flooding set up incorporated with electrical resistivity measuring tool to track in-situ gas saturation and gas trapping. The method allows for quantitative evaluation of both trapped and mobile gas. It is simple, quick and inexpensive. It will also be useful for screening

Table 1
Sample properties.

Sample#	Length cm	Diameter cm	Porosity %	K_{brine} mD
Sample-1	10.6	3.74	13.11	3
Sample-2	10.6	3.74	14.71	5
Sample-3	10.5	3.74	21.0	227

surfactant and surfactant stabilizing agents for CO_2 sequestration.

2. Materials and methods

Rock samples were extracted from outcrop formations that is representative of underground rock formations. Two rock types were extracted representing high and low permeability carbonate formations, out of which a total of three cylindrical subsamples were extracted. The samples were labelled, cleaned, and characterized for petrophysical properties as given in Table 1. The samples were cleaned with methanol by reflux extraction using a Soxhlet apparatus. Since the samples are outcrop samples, only methanol was used to flush the pores at 80 °C for three days in order to remove all salt deposits that may be present. The samples were subsequently dried in a vacuum oven at 60 °C for another two more days. They were then saturated with either brine or a surfactant solution by vacuum saturation method. The surfactant solution was prepared by dissolving 0.025% wt. of a non-ionic ethoxylated fluorocarbon surfactant in a synthetic brine of 54,000 ppm salt concentration. The surfactant served as the foaming agent. A high purity nitrogen (99.99%) and carbon dioxide (99.99%) gas were also used as the gas phases.

A high pressure high temperature core flooding apparatus depicted in Fig. 1 was used for this study. A hydrostatic core holder held the sample that was pre-saturated with surfactant solution. The core holder was then loaded in the high pressure high temperature cell capable of applying a maximum temperature of 150 °C and a maximum confining pressure of 15,000 psi. Two high-pressure fluid accumulators were used to store the surfactant solution and gas at the experimental conditions. The setup also has a syringe pump capable of injecting fluids at a constant injection rate in the range of 0.001 cc/min–30 cc/min or a constant injection pressure range of 10 psi–10,000 psi. A resistivity meter was connected between the sample inlet and outlet to continuously measure the electrical resistivity across the sample. The pre saturated samples were further flushed with either brine (for water alternating gas, WAG, experiments) or surfactant solution (for SAG experiments) at a rate of 0.5 cc/min under a backpressure of 1450 psi and a confining pressure of 2200 psi. The essence of flushing was to remove any trapped gas from the pores of the sample and in the case of SAG, to allow all surfactant adsorption process to be completed before the start of experiments. The oven temperature was also gradually raised to 45 °C during the flushing process, which continued until 2 pore volume (PV) of surfactant solution had been injected. A thermodynamic equilibrium had also been attained at this point as was observed from the steady state pressure drop and electrical resistivity measurements. SAG experiments were then conducted by starting with gas injection at a constant rate of 0.5 cc/min until about 0.2 PV of gas was injected after which gas injection was terminated and 0.2 PV of surfactant solution was injected as the chase liquid to complete the first cycle. The next cycle began by injecting another 0.2 PV of gas followed by another 0.2 PV of surfactant solution. The cyclic injection continued for about 5 cycles. All core flooding measurements were transmitted in real time to a computer station at an interval of five seconds, which allowed the experiments to be closely monitored.