A laboratory study of hot WAG injection into fractured and conventional sand packs

M J Dorostkar, A Mohebbi*, A Sarrafi and A Soltani

Department of Chemical Engineering, College of Engineering, Shahid Bahonar University of Kerman, Kerman, Iran

Abstract: Gas injection is the second largest enhanced oil recovery process, next only to the thermal method used in heavy oil fields. To increase the extent of the reservoir contacted by the injected gas, the gas is generally injected intermittently with water. This mode of injection is called water-alternating-gas (WAG). This study deals with a new immiscible water alternating gas (IWAG) EOR technique, “hot IWAG” which includes combination of thermal, solvent and sweep techniques. In the proposed method CO₂ will be superheated above the reservoir temperature and instead of normal temperature water, hot water will be used. Hot CO₂ and hot water will be alternatively injected into the sand packs. A laboratory test was conducted on the fractured and conventional sand packs. Slugs of water and CO₂ with a low and constant rate were injected into the sand packs alternatively; slug size was 0.05 PV. Recovery from each sand pack was monitored and after that hot water and hot CO₂ were injected alternatively under the same conditions and increased oil recovery from each sand pack and breakthrough were measured. Experimental results showed that the injection of hot WAG could significantly recover residual oil after WAG injection in conventional and fractured sand packs.

Key words: Hot water-alternating-gas (WAG), enhanced oil recovery (EOR), fractured sand pack, conventional sand pack, gas injection

1 Introduction

Under conditions prevailing in many oil reservoirs, gas-oil immiscible displacement has higher microscopic sweep efficiency than water-oil displacement. However, gas as a displacing agent suffers the obvious drawback because of its very high mobility (Lawrence et al, 2003). The WAG process has been proven effective in providing mobility control for horizontal gas floods, as demonstrated by many field applications, most of which aimed at reaching miscibility between the injected gas and the reservoir fluid. Immiscible WAG (IWAG), on the other hand, has a smaller record of field experience (Christensen et al, 2001). The development of the water-alternating-gas (WAG) process aims at improving flood profile control. The higher microscopic displacement efficiency of gas combined with the better macroscopic sweep efficiency of water significantly increases the incremental oil production over that from a plain water flood. Nearly all the commercial gas injection projects today employ the WAG method (Kulkarni and Rao, 2005). In spite of these improvements, the field performance of WAG process (5%-10% OOIP recovery) is disappointing (Rao, 2001). In the United States, most of the WAG applications are onshore, employing a wide variety of injection gases for a wide range of reservoir characteristics in the miscible mode. Although many types of injectant gases have been attempted in the

past, CO₂ and hydrocarbon gases constitute the major share of injectants (~90%). CO₂ is ideally suited for use in gas injection projects in the U.S. scenario. Abundance of reserves of almost pure CO₂ and availability of technical know-how has been the cause for the growth of CO₂ injection processes in the U.S. Carbon sequestration is now an added advantage of the CO₂ injection projects (Kulkarni and Rao, 2005).

The main design parameters that need to be evaluated on a laboratory scale to evaluate the feasibility of the process are: reservoir heterogeneity, rock type, fluid characteristics, injection gas, WAG ratio, and gravity considerations. Other parameters those are important for gas injection and tertiary recovery in general, are those of miscibility development and composition of oil and brine (Kulkarni, 2003).

Little is known about the application of WAG injection in naturally fractured reservoirs. It was believed that it was impossible to use the advantages of water flooding and gas injection together due to the existence of fractures in reservoirs (Haghighat, 2004). Fractures cause rapid advancement of injected fluids that changes a major advantage of WAG injection; namely, water cycles that are stabilizing the flooding front (Heeremans et al, 2006). However, there are some examples from the field that show that there is potential of WAG injection in naturally fractured reservoirs (Christensen et al, 2001).

The main objective of this work is to investigate the feasibility of hot WAG injection by using hot CO₂ and hot water in conventional and fractured sand packs, focusing on the heat transfer of hot CO₂ and hot water and hydrocarbons in these sand packs.

*Corresponding author. email: amohebbi2002@yahoo.com, amohebbi@mail.uk.ac.ir

Received January 27, 2009

2 Water-alternating-gas (WAG) technique

Water-alternating-gas (WAG) injection is a tertiary oil recovery process that has been growing in popularity since it was first introduced in the 1950's. The tertiary recovery process known as WAG is a combination of two secondary recovery processes of water flooding and gas injection. The WAG process was proposed originally to aim for an ideal system of oil recovery: improvements in macroscopic and microscopic sweep efficiencies at the same time. The water is used to control the mobility of the gas. The cyclic nature of the WAG process causes an increase in water saturation during the water injection half cycle and a decrease in water saturation during the gas injection half cycle. This process inducing cycles of flooding and drainage causes the residual oil levels when using WAG to be typically lower than that of water flooding and similar to those of gas flooding or even better if capillary trapping due to small scale heterogeneities is significant (van Lingen et al, 1996).

3 Materials and methods

For a reservoir with a long CO₂ injection history, the reservoir temperature will be reduced a little. The highest reduction is seen in the proximity of injection wells. In this study, the temperature was set at 100 °C to represent the temperature of CO₂ flooded zones. The pressure was one atmosphere because the process was immiscible. The full details of the sand packs, fluids, and experimental set up are given in the following sections.

3.1 Sand pack samples

In this study, two sand packs were used. The structure of two sand packs was the same with a length of 35 cm and a diameter of 4.2 cm. One of the sand packs as a fractured model contains a fracture in its middle. The properties and dimensions of the two sand packs are summarized in Table 1.

Table 1 Model properties

Sample	Permeability D	Porosity %	Connate water %	Diameter cm	Length cm	Area cm ²	Bulk volume cm ³
Conventional	1.1	20	15.66	4.2	35	13.8	484.9
Fractured	5.0	28	15.06	4.2	35	13.8	484.9

3.2 Fluid samples

Oil used in all experiments was prepared from the Maroon reservoir at south of Iran and its composition is given in Table 2. The composition of the experimental brine (prepared in the laboratory) is similar to that of reservoir brine and is given in Table 3. Injected gas was pure CO₂. The viscosity and density of fluids in WAG experiments are given in Table 4.

Table 2 Oil composition at 220 °F (%)

C ₁	C ₂	C ₃	<i>i</i> -C ₄	<i>n</i> -C ₄	<i>i</i> -C ₅	<i>n</i> -C ₅	C ₆	C ₇₊	H ₂ S	CO ₂
48.45	9.223	5.144	0.867	2.507	1.032	1.289	2.129	29.36	0	0

Table 3 Brine composition (%)

Component	KC	MgCl ₂	CaCl ₂	NaCl	H ₂ O
Composition, %	0.03	0.43	3.20	3.60	92.74

Table 4 Fluids used in WAG experiments and their viscosities and densities

Fluid	Density, g/mL	Viscosity, cp
Oil	0.87	2.168
Water	1.00	1.020
Gas	1.6e-03	0.0182

3.3 Matrix and fracture system

Both sand packs were conventional at first. For fabricating a fractured sand pack, one of the sand packs was selected and cut in the middle and the space between two halves of the sand pack was filled with glass wool with a diameter of 2 mm. The artificial fracture acted similar to an actual fracture. The glass wool had no effect on the surface area of the middle of the sand pack and did not influence the fluid which was used later to saturate the sand pack. This was investigated by measuring sand pack permeability before and after using glass wool. The middle of the sand pack filled with sealing material had zero permeability, and the sand pack had its initial permeability of 1.1 D. The glass wool was a porous medium with high permeability so in the middle of the sand pack it acted like a real fracture.

3.4 Initial saturations

The pore volume was measured by saturating the sand packs with brine. The oil with a composition as shown in Table 2 was then injected into the sand packs at a rate of 0.5 cm³/min. In this case the sand packs were vertical and oil was injected from the top of the sand packs. In the conventional sand pack, oil breakthrough was observed after 69.06 cm³ of brine was produced. The total volume of oil injected into the sand pack was 145.5 cm³ (1.5 PV) and the total volume of brine produced from the conventional sand pack was 81.8 cm³. In the fractured sand pack, oil breakthrough was observed after 97.78 cm³ of brine was produced. The total volume of oil injected into the sand pack was 204.3 cm³ (1.5 PV) and the total volume of brine produced from the fractured sand pack was 115.3 cm³. Thus, the initial water saturations,

S_{wi} for conventional and fractured sand packs were 15.66% and 15.06%, respectively. Also, the initial oil saturations, S_{oi} for conventional and fractured sand packs were 84.3% and 84.9%, respectively. This initialization was done at 25 °C and the pressure was one atmosphere.

3.5 Experiments

To generate accurate predictions by field simulations of WAG injection into conventional and fractured reservoirs, a set of WAG injection experiments should be performed under near reservoir conditions to check EOR mechanisms.

In this study, the sand packs were placed horizontally in the oven. The whole setup is shown in Fig. 1. In the first step, the conventional sand pack was targeted. The temperature of oven was set at 100 °C and CO₂ and water (room temperature (25 °C)) were injected alternatively into the conventional sand pack at a rate of 0.5 cm³/min. Gas and water slug sizes were about 0.05 PV and WAG ratio was 1. The volume of CO₂ and water injected into and the cumulative volume of fluids produced from the sand pack and the breakthrough time were measured. The WAG injection was continued until no oil was produced at the outlet. After that the heater which was in the direction of CO₂ and water injection was turned on

and the CO₂ temperature increased to 120 °C and the water was heated to 90 °C. Hot CO₂ and hot water were injected alternatively into the conventional sand pack. The volume of injected fluids, the cumulative volume of produced fluids, and the breakthrough time were measured too. Hot gas and hot water slug sizes were about 0.05 PV and WAG ratio was 1.

The next experiment was done on the fractured sand pack to indicate the feasibility of hot WAG injection in a fractured sand pack. The temperature of oven was set at 100 °C and CO₂ and water were injected into the fractured sand pack at a rate of 0.5 cm³/min and 25 °C. All the process was similar to the conventional sand pack runs. The volume of CO₂ and water injected into and the cumulative volume of fluids produced from the fractured sand pack, and the breakthrough time were measured. The WAG injection was continued until no oil was produced at the outlet. After that the heater which was in the direction of fluid injection was turned on and the CO₂ temperature increased to 120 °C and the water was heated to 90 °C. Hot WAG was injected into the fractured sand pack and the volume of fluids injected into and the cumulative volume of fluids (oil, water and CO₂) produced from the fractured sand pack were measured too.

The capillary number is a dimensionless group that represents the ratio of viscous forces to the interfacial forces affecting the flow of fluid in porous media. The main goals of any EOR method are increasing the capillary number and providing 'favorable' ($M < 1.0$) mobility ratios. The capillary number is defined as the ratio of viscous to capillary forces.

$$N_{ca} = \frac{\text{Viscous forces}}{\text{Capillary forces}} = \frac{v\mu}{\sigma} \quad (1)$$

where v and μ are the velocity and viscosity of the displacing fluid, respectively; σ is the oil-water interfacial tension. In this study, the capillary number was 2.171×10^{-7} for the sand packs. This shows that the flow in our models is dominated by capillary forces.

4 Results and discussion

Fig. 2 shows the cumulative oil produced by WAG flooding at a rate of 0.5 cm³/min in the conventional sand pack. The cumulative volume of oil produced was 0.61 PV after 2.7 PV of fluids (water and CO₂) were injected into the conventional sand pack. CO₂ breakthrough was observed before the water injection because CO₂ is more mobile than water and the CO₂ breakthrough was observed after 0.68 PV

Fig. 1 Schematic diagram of set up

Fig. 2 Produced oil versus WAG injection in the conventional sand pack

injection. Also, the results show that hot WAG injection is a feasible method to increase oil recovery in conventional sand packs.

Fig. 3 shows the volume of oil produced while the conventional sand pack was targeted with hot WAG injection. Before the conventional sand pack was flooded with hot WAG, it has been flooded by WAG completely. As shown in Fig. 3, after 2.7 PV of hot fluids were injected into the sand pack the increased oil recovery was 0.16 PV with respect to WAG injection and CO₂ breakthrough was observed at an injection of 0.57 PV of hot fluids, so the hot WAG breakthrough was observed earlier than that of WAG. The earlier breakthrough was due to lower viscosity and higher mobility of hot CO₂ and hot water.

Fig. 3 Increased oil recovery versus hot WAG injection in the conventional sand pack

Fig. 4 shows the cumulative oil produced by WAG injection at a rate of 0.5 cm³/min in the fractured sand pack. This figure showed that the cumulative produced oil was 0.54 PV after 2.4 PV of fluids were injected into the fractured sand pack. The CO₂ breakthrough was observed after 0.43 PV of WAG injection. This rapid breakthrough was due to the high permeability of the fracture.

Fig. 4 Produced oil versus WAG injection in the fractured sand pack

After the fractured sand pack was completely flooded by WAG injection, hot CO₂ and hot water were alternatively injected. Fig. 5 showed that after 2.7 PV of hot fluids were injected the increased oil recovery was 0.10 PV compared with WAG injection and the CO₂ breakthrough was observed at an injection of 0.39 PV of hot fluids. Therefore, the hot WAG breakthrough was observed earlier than that of WAG.

The high temperature of CO₂ and hot water in hot WAG

reduced oil viscosity and interfacial tension and caused oil swelling; therefore, oil recovery increased. The tertiary recovery process known as hot WAG is a combination of two tertiary recovery processes of hot water flooding and hot gas injection. WAG flooding has become the leading enhanced oil recovery technique for light and medium oils but hot WAG can be used in heavy oil reservoirs because hot WAG injection is a combination of thermal and gas injection methods. Since the heat content of CO₂ is low, the use of hot WAG may not be feasible in deep reservoirs because of the heat losses and the high cost.

Fig. 5 Increased oil recovery versus hot WAG injection in the fractured sand pack

As can be expected, all EOR processes have limitations on their applicability. Some of the hot WAG limitations are the high cost of double injection and high cost of heating the water and CO₂. A large gas cap or aquifer are usually unfavorable factors. Large fractures provide preferential pathways from injection to production wells and this method may be not feasible in deep reservoirs because of heat losses, also naturally and economically availability of CO₂ and water are important.

5 Conclusions

To the best of our knowledge, this is the first time the hot WAG method has been used. Hot CO₂ alternating hot water were injected into the conventional and fractured sand packs. Use of the hot WAG method in comparison with the WAG method increased oil recovery 0.16 PV in the conventional sand pack and 0.10 PV in the fractured sand pack. Experimental results showed that the hot WAG method was a feasible enhanced oil recovery method in conventional and fractured sand packs and increased oil recovery significantly.

References

- Christensen J R, Stenby E H and Skauge A. Review of WAG field experience. SPE Reservoir Evaluation and Engineering. 2001. 4(2): 97-106 (SPE paper 71203)
- Haghighat S A. WAG Modeling in Fractured Reservoirs. Thesis Report MTA/PW/04-15 TU Delft, August 2004
- Heeremans J C, Esmail T E H and van Kruijsdijk C P J W. Feasibility study of WAG injection in naturally fractured reservoirs. SPE/DOE Symposium on Improved Oil Recovery held in Tulsa, Oklahoma, USA, April 22-26, 2006 (SPE paper 100034).
- Kulkarni M M. Immiscible and miscible gas-oil displacements in

- porous media. MSc Thesis. The Craft and Hawkins Department of Petroleum Engineering, Louisiana State University and Agricultural and Mechanical College, Baton Rouge, LA, July 2003
- Kulkarni M M and Rao D N. Experimental investigation of miscible and immiscible Water-Alternating-Gas (WAG) process performance. *Journal of Petroleum Science and Engineering*. 2005. 48(1-2): 1-20
- Lawrence J J, Teletzke G F, Hutfilz J M, et al. Reservoir simulation of gas injection processes. SPE 13th Middle East Oil Show & Conference held in Bahrain, April 5-8, 2003 (SPE paper 81459)
- Rao D N. Gas injection EOR: a new meaning in the new millennium. *Journal of Canadian Petroleum Technology*. 2001. 40(2): 11-18
- van Lingen P P, Barzanji O H M and van Kruijsdijk C P J W. WAG injection to reduce capillary entrapment in small-scale heterogeneities. SPE Annual Technical Conference held in Denver, Colorado, October 6-9, 1996 (SPE paper 36662)

(Edited by Sun Yanhua)