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Research Paper

OPTIMIZATION OF CO2 WAG PROCESSES IN A SELECTED CARBONATE RESERVOIR: AN EXPERIMENTAL APPROACH

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Miscible gas flooding using carbon dioxide is currently being investigated as a possible EOR process for a number of United Arab Emirates (UAE) reservoirs. It has a high potential to improve oil recovery in addition to possibly of utilizing most of the carbon dioxide emissions from industrial sources. The major factors affecting implementation of CO_2 floods are the availability of CO_2 at economic prices (generally within 2-3 $/MSCF) and the net utilization ratio of CO_2 per barrel of additional oil recovered. To control the mobility ratio, the Water-Alternating CO_2-Gas (WAG) technique is proposed by injecting alternately small solvent [CO_2] and water slugs. The slug of water reduces the speed of the solvent and solvent fingering thus improving the mobility ratio of the injected fluids to fluids in place. The objective of this work is to experimentally assess the recovery of oil with CO_2 injection in a selected UAE carbonate reservoir. Two types of CO_2-flooding experiments were conducted, continuous miscible CO_2 injection and CO_2-WAG injection using a specialized experimental rig. The effects of changing the CO_2-Water ratio and WAG timing on the overall performance of the flood were investigated. All laboratory tests were conducted under controlled conditions of pressure and temperature corresponding to field conditions. Results of this laboratory investigation reveal a general trend of improved oil recovery with increased volume of CO_2 inside core samples during the flood process. The observed ultimate oil recoveries range from 52% with continuous water injection to 72% of the original oil in place with continuous CO_2 injection over the full period of the experiment with recoveries of the CO_2-WAG floods falling in between. The optimum CO_2-WAG ratio was found to occur at 1:2. The outcomes of this work should contribute to our understanding of WAG CO_2 floods for the carbonate reservoirs and support the ongoing R&D efforts made by the operating oil companies worldwide toward application of CO_2-WAG floods.

Keywords: CO_2, WAG, Optimization, Carbonate, Mobility

INTRODUCTION

The main goal of any Enhanced Oil Recovery (EOR) method is to increase the capillary number thus providing "favorable" mobility ratios (M < 1.0).

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The capillary number is defined as the ratio of viscous to capillary forces.

$$N_{ca} = \frac{ViscousForces}{CapillaryForces} = \frac{v\mu}{\sigma\cos\theta} \quad ...(1)$$

where v and μ are the velocity and viscosity, respectively of the displacing fluid, σ is the oil-water interfacial tension and θ is the contact angle between the oil-water interface and the rock surface measured between the rock surface and the denser phase (water in this case).

The mobility ratio, M, is defined as the ratio of mobility of the displacing fluid to that of the displaced fluid.

$$M = \frac{(k/\mu)_{Displacing}}{(k/\mu)_{Displaced}} \quad ...(2)$$

where k is the relative or effective permeability.

The overall efficiency of any EOR process depends on both the microscopic and macroscopic sweep efficiencies. While the fluids density difference and rock heterogeneity affect the macroscopic efficiency, the microscopic displacement efficiency is influenced by the interfacial interactions involving interfacial tension and dynamic contact angles.

Gas injection is the second largest process in enhanced oil recovery processes today (Hinderaker *et al.,* 1996). The residual oil saturations in gas swept zones have been found to be quite low. However, the volumetric sweep of the flood has always been a cause of concern (Hinderaker *et al.,* 1996). The mobility ratio, which controls the volumetric sweep, between the injected gas and displaced oil bank in gas processes, is typically highly unfavorable due to the relatively low viscosity of the injected phase. This difference makes mobility and consequently flood profile control the biggest concern for the successful application of this process.

The above concern has led to the development of the Water-Alternating-Gas (WAG) process for flood profile control. The higher microscopic displacement efficiency of gas combined with the better macroscopic sweep efficiency of water has been found to significantly increase the incremental oil production over the plain waterflood. The WAG process was first proposed by Caudle and Dyes in 1958 and has remained the industry default mobility control method for gas injection, mainly due to the lack of proven flood profile control alternatives. Reservoir key parameters such as wettability, interfacial tension, connate water saturation and gravity segregation could add complexity to the design of a successful WAG flood.

Christensen *et al.* (1998) showed that this process has been applied to rocks from very low permeability chalk up to high permeability sandstone. Most of the applied processes were miscible. The miscibility issue is generally based on gas availability, but is mainly reported as an economic consideration and the extent of reservoir repressurization required for process application. The major design issues for WAG are reservoir characteristics and heterogeneity, rock and fluid characteristics, composition of injection gas, injection pattern, WAG ratio, three-phase relative permeability effects and flow dispersion. It is important to note that plain gas injection is considered as a part of WAG process with a WAG ratio of 0:1, hence the design issues pertinent to WAG are applicable to plain gas injection as well.

Stratification and heterogeneities strongly influence the oil recovery process. Reservoirs with higher vertical permeability are influenced by cross flow perpendicular to the bulk flow direction. Viscous, capillary, gravity and dispersive forces generally influence this phenomenon (Rogers and Grigg, 2000). Cross-flow may influence to increase the vertical sweep, but generally the effects are detrimental to oil recovery—mainly due to the gravity segregation and decreased flow velocity in the reservoir. This leads to reduced frontal advancement in lower permeability layer. WAG recoveries and continuous gas injections are more strongly affected by these phenomena. Reservoir heterogeneity controls the injection and sweep patterns in the flood. The reservoir simulation studies for various k_v/k_h (vertical to horizontal permeability) ratios suggest that higher ratios adversely affect oil recovery in WAG process.

Fluid characteristics are generally black-oil or compositional PVT properties obtained in the laboratory by standardized procedures (Rogers and Grigg, 2000). Very accurate determination of fluid properties can be obtained with current techniques. However, rock-fluid interactions such as adhesion, spreading and wettability affect the displacement in the reservoir. In reservoir simulators, rock-fluid interactions are generally lumped into one parameter—relative permeability. The relative permeability is the connecting link between the phase behavior and transport properties of the system. Relative permeability is an important petrophysical parameter, as well as a critical input parameter in predictive simulation of miscible floods. Relative permeability data are generally measured in the laboratory by standardized procedures with actual reservoir fluids and cores and at reservoir conditions (Rogers and Grigg, 2000)

The optimum WAG ratio is influenced by the wetting state of the rock (Jackson *et al.,* 1985; and Zekri and Natuh, 1992). WAG ratio of 1:1 is the most popular for field applications (Christensen *et al.* 1998). However, gravity forces dominate water-wet tertiary floods while viscous fingering controls oil-wet tertiary floods. High WAG ratios have a large effect on oil recovery in water-wet rocks resulting in lower oil recoveries. Tertiary CO_2 floods controlled by viscous fingering had a maximum recovery at WAG ratio of about 1:1. Floods dominated by gravity tonguing showed maximum recovery with the continuous CO_2 slug process. The optimum WAG ratio in secondary floods was a function of the total CO_2 slug size.

The current work involves a laboratory investigation to evaluate the performance of CO_2-WAG process, WAG ratio, WAG timing, and the relative merits and demerits of the miscible CO_2 WAG flooding over continuous CO_2 or water flooding under specific reservoir conditions. For a more detailed list of references on the subject, the reader may refer the original thesis (Amin, 2012) from which this work has been extracted.

Experimental Fluids, Design, and Procedures

Coreflood experiments to identify the multiphase flow characteristics of the fluids are central to this work. The corefloods are of the dynamic displacement type. Identification and separation of parameters to effectively study their effects on the process are required. Pure CO_2 gas and actual injecting brine were used as injectants in the floods. Dead oil sample from the field of interest was used as the 'Oleic' phase and the brine sample from the same field was used as the aqueous phase.

Initially, base case flooding experiments were conducted using actual carbonate cores, actual formation brine and dead oil. The base case experiments were conducted with continuous water injection and continuous CO_2 gas injection (CCGI) corefloods in miscible flow mode using a vertical core system set up. Similar experiments were conducted using CO_2 WAG flow mode using different WAG ratios so as to examine the effects of WAG ratio and WAG timing on the ultimate oil recovery.

Experimental Fluids

Analytic grade reagents were used in all the experiments. The salts that were used for synthetic formation brine preparation were with a purity of 99.99%. Actual injection water, Umm Erraduma (UER) brine, was filtered and used in the experiments. To prepare the formation brine, deionized water from the United Arab Emirates laboratories was used. The compositions of the various brines used in the tests are shown in Table 1. The carbonate core samples used in the experiments were taken from Bu Hasa Field, Abu Dhabi, UAE. The compositional analysis of Bu Hasa crude oil is presented in Table 2.

Experimental Design

The plan of experiments which was implemented to accomplish the objectives of this study is presented in a block diagram as shown in Figure 4.

Experimental Setup

The high-pressure coreflood apparatus was setup to conduct unsteady-state coreflood experiments. The schematic of the apparatus is

Table 1: Compositional Analysis of Different Brines

Brine	mg/L								TDS Salinity (ppm)
	Ca^{++}	K^{+}	Mg^{++}	Na^{+}	CO_3	HCO_3^-	Cl^-	SO_4^-	
TDS of Formation Brine	15992	–	1282	51820	–	391	111852	272	181,609
TDA of UER	14033	–	3024	57613	–	244	122023	420	197,357

Table 2: Crude Oil Compositional Analysis

Component	Mole%	Component	Mole%
H_2	0	C5	0.01
H_2S	0	iC5	1.99
CO_2	2.59	nC5	2.66
N_2	0.12	C6	4.78
C1	34.16	C7	3.82
C2	6.72	C8	6.11
C3	6.36	C9	2.58
iC4	1.54	C10+	22.51
nC4	4.05	Total	100

Figure 1: Vertical Core Flooding System Schematic

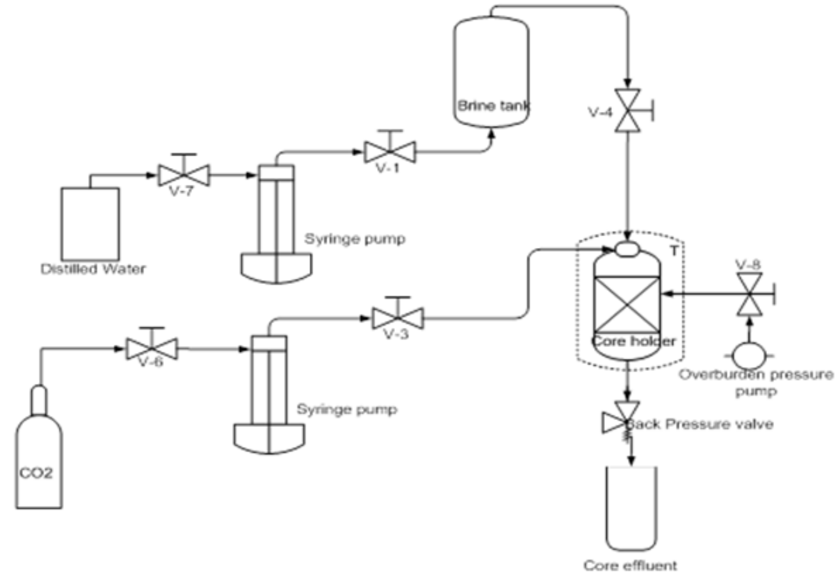
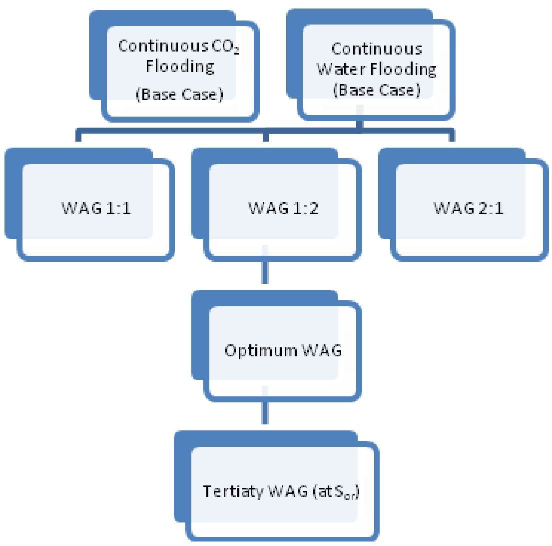


Figure 2: Block Diagram Showing the Sequence of Core Flooding Experiments



shown in Figure 1. It consists of a two high-pressure syringe pumps, one for injecting fresh (tap) water at desired flow rate to the bottom part of the floating piston transfer vessel, and the other for injecting supercritical CO_2 into the core. The transfer vessel was filled with the fluid (injection brine) to be injected into the core. High-pressure steel piping (1/8" ID) carries the fluid to be injected into the core with the assistance of a liquid re-distributor plate. The produced fluids were allowed to pass through the backpressure regulator (with a pre-set pressure of 3000 psi) into a measuring cylinder/electronic balance to determine cumulative fluids production as a function of run time/pore volumes injected. The inlet, outlet, differential, back and annulus pressures were measured using pressure regulators (previously calibrated against a standard dead-weight tester) mounted on the coreflood apparatus.

In this work, selected fresh short carbonate core samples were used as the porous medium. The cores have a single coating of Teflon on them to prevent damage during handling and processing of the core such as end facing, polishing and cutting.

Experimental Procedure

Two types of experiments were performed in the present study. These include continuous CO_2 gas injection and WAG. All the experiments consisted of the following steps: Saturation with brine, determination of pore volume and absolute permeability, oil flood to connate water saturation, end point oil-permeability, waterflood to waterflood residual oil saturation, end point water-permeability and finally tertiary gas flood, or secondary gas flood in case of investigating the secondary WAG performance. All cores were saturated with brine solution after core cleaning to determine pore volume and absolute permeability. They were then brought to connate water saturation by flooding with crude oil at high flow rate (160 cc/h). The cores were then water flooded (60 cc/h) using brine of similar composition as the connate water to bring the cores to water-flood residual oil saturation which represents the secondary recovery process. At the end of the brine flooding process, significant residual oil remains in the core. WAG injection and continuous CO_2 injection tests were then conducted after the secondary recovery process.

RESULTS AND DISCUSSION

The objective of the tests was to determine the effects of mode of gas injection (CCGI or WAG), WAG ratio, WAG Timing and brine composition on dynamic displacement tests in selected carbonate cores from UAE. Consequently, core flooding tests were conducted in three steps. The preliminary oil flood was used to measure the connate water saturation of the core. Brine was injected into the core to determine the secondary recovery and residual oil saturation after waterflooding. Secondary (or tertiary) miscible gas injection (Continuous CO_2 Gas Injection, CCGI, or WAG injection) was used to evaluate the efficiency of this process. The results of the core tests conducted in this work are discussed below. These tests were conducted at 3000 psi (miscibility pressure). Actual field injection brine (Umm-Erraduma brine) was used for flooding. CO^-_2 floods were conducted in two modes (Continuous CO_2 Gas Injection, CCGI, and WAG). WAG experiments were carried out at different ratios and timings (Figure 2).

The carbonate cores used for the test were aged for 14 days, to restore their original wettability. In order to eliminate the effects of rock heterogeneity, all tests were conducted on cores from the same reservoir unit, having similar properties in terms of porosity, permeability and pore size distribution. Also, actual oil sample from the field of interest as the oleic phase was used as in all experiments and standard cleaning procedure was implemented between various displacements.

Results of Oil Flooding Tests

This group of tests involves injection of crude oil into core samples that were initially saturated with brine to achieve connate water saturation. This process was an important step to determine the original oil in place (OOIP). The results of these experiments are summarized in Table 3.

Results of Brine Flooding Tests

This group of experiments constitutes the process of brine injection into the core samples, which were at connate water saturation to achieve after waterflooding residual oil saturations. Brine was injected at stable flow rates into the core after the oil flooding. This step would indicate the feasibility of secondary oil recovery scheme.

Results of the brine flooding phase of experiments are summarized in Table 4 and

Table 3: Summary of Results of Oil Flooding Tests								
Expt. No.	**Experiment Title**	**Brine Salinity ppm**	**p_{test} psia**	**k_{abs} md**	**Φ fraction**	**PV cc**	**S_{wc} fraction**	**S_{oi} fraction**
1	Continuous Brine	197,584	3000	13.7	0.24	17.7	0.4	0.6
2	Continuous Miscible CO_2	197,584	3000	15.5	0.21	17.94	0.5	0.5
3	Miscible WAG 1:1	197,584	3000	13.1	0.24	19.66	0.33	0.67
4	Miscible WAG 1:2	197,584	3000	16.6	0.24	18.86	0.33	0.67
5	Miscible WAG 2:1	197,584	3000	14.6	0.26	19.93	0.38	0.62
6	Tertiary Miscible WAG 1:1	197,584	3000	13.7	0.24	17.7	0.4	0.45

Figure 3. The ultimate oil recovery in Figure 6 is about 52 % of OOIP after flooding the core sample with about 12 PV of UER brine.

Results of Gas Injection Floods

This set consists of two types of experiments: Continuous CO_2 Gas Injection (CCGI) and Water-Alternating-Gas (WAG). Gas injection is a popular EOR process in light oil reservoirs. As the literature review suggests, almost 80% of the gas injection processes employ the WAG method. The continuous CO_2 injection process and 1:1 WAG (with 0.2 PV slug size) are considered as the most popular gas injection EOR processes employed in the field today. Hence, investigation of the displacement characteristics for these processes was conducted. The results of the gas flooding phase of experiments were summarized in Table 5 and Figures 4 through 9.

The continuous CO_2 injection process (Figure 4) showed high oil recovery at 73.5% OOIP and the

Table 4: Summary of Results of Brine Flooding Tests									
Expt. No.	**Experiment Title**	**Brine Salinity ppm**	**p_{test} p_{sia}**	**k_{abs} md**	**Φ Fraction**	**S_w Fraction**	**S_{or} Fraction**	**Recovery % OOIP**	**E_d Fraction**
1	Continuous Brine	197,584	3000	13.7	0.24	0.71	0.29	51.9	0.52

Figure 3: Experimental Results of Continuous Water Flooding

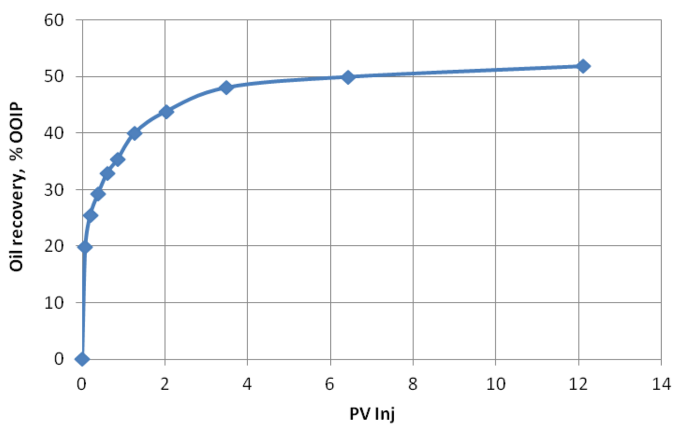


Table 5: Summary of Results of Gas Injection Tests

Expt. No.	Experiment Title	Brine Salinity ppm	p_{test} psia	k_{abs} m d	Φ fraction	S_{or} fraction	Recovery % OOIP	E_d fraction
2	Miscible Continuous CO2	197,357	3000	15.5	0.21	0.13	73.44	0.73
3	Miscible WAG 1:1	197,357	3000	13.1	0.24	0.2	69.85	0.7
4	Miscible WAG 1:2	197,357	3000	16.6	0.24	0.2	69.84	0.7
5	Miscible WAG 2:1	197,357	3000	14.6	0.26	0.27	56.1	0.56
6	Tertiary Miscible WAG 1:1	197,357	3000	13.7	0.24	0.25	58.87	0.59

Figure 4: Experimental Results of Continuous CO_2 Injection

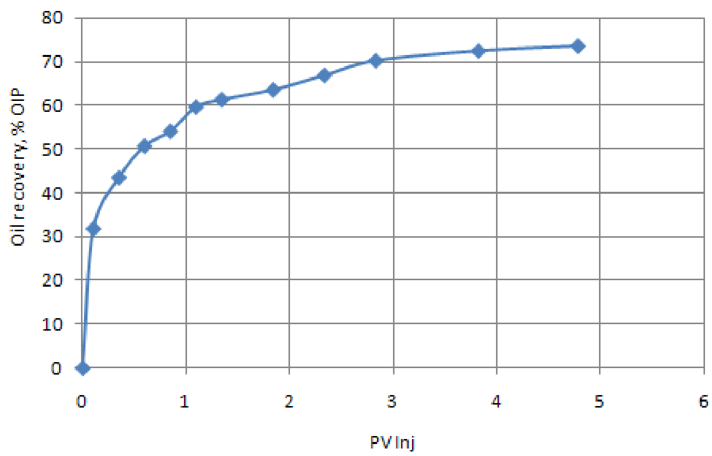
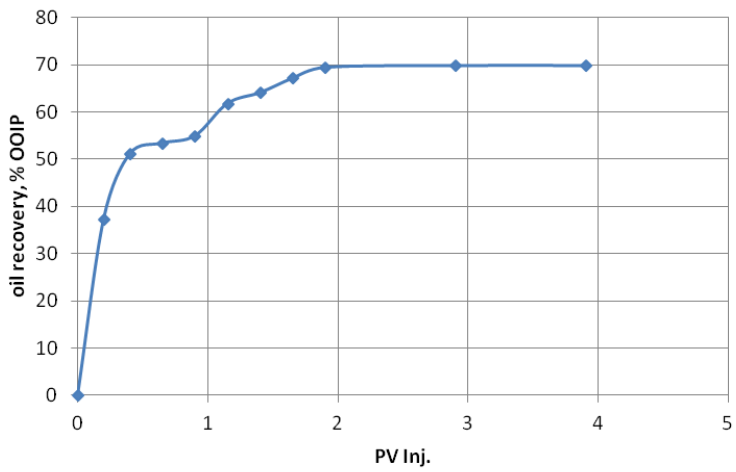


Figure 5: Experimental Results of WAG Ratio1:1 in Secondary Recovery Scheme



CO_2-WAG process of WAG ratios 1:1 and 1:2 (Figures 5 and 6, respectively) showed close results in terms of ultimate oil recovery at 70%. Tertiary stage recovery yielded around 59 % OOIP (Figure 11).

Figure 6: Experimental Results of WAG Ratio 1:2 in Secondary Recovery Scheme

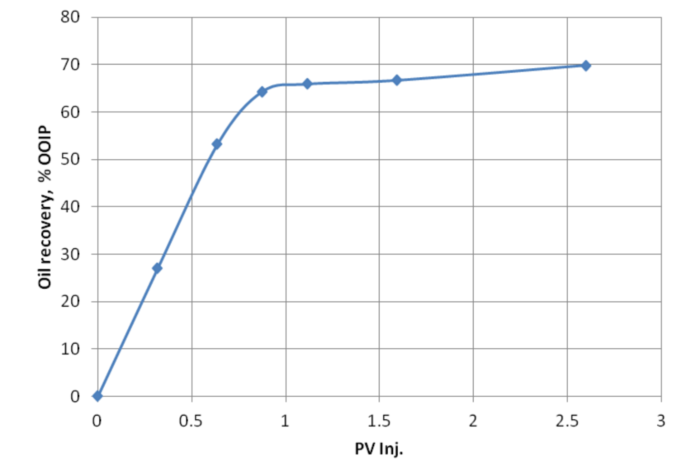


Figure 7: Experimental Results of WAG Ratio 2:1 in Secondary Recovery Scheme

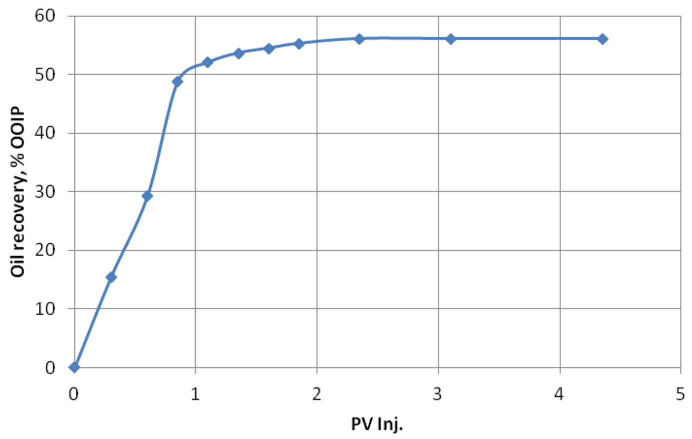
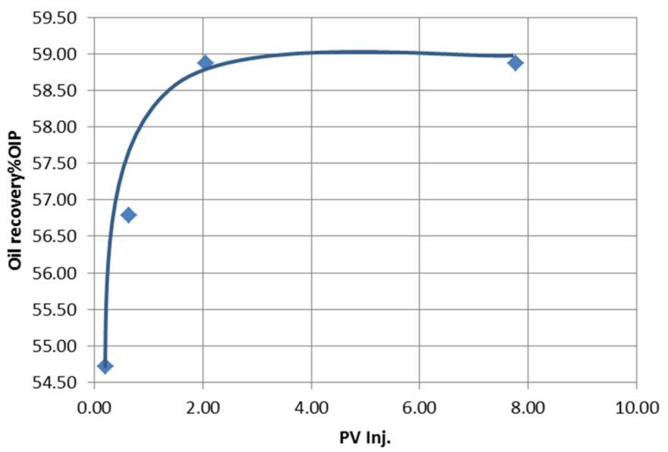


Figure 8: Experimental Results of WAG Ratio 1:1 in Tertiary Recovery Scheme



RESULTS AND DISCUSSION

Effect of WAG Ratio on Oil Recovery

For comparison purposes, the results of the various sets of experiments are combined in Figure 9.

The continuous miscible CO_2 flooding shows the highest oil recovery of 73.44% OOIP after injection of about 5 pore volumes of CO_2, Figure 4. This observation agrees with published work on sandstone, chalk, and limestone (Kulkarni and Rao, 2005; Karimaie *et al.,* 2008; and Aleidan *et al.,* 2011). Continuous brine flooding shows about 52% OOIP after injecting 12 pore volumes of water which is comparable to some published work on carbonate cores (Aleidan and Mamora, 2010). This can be attributed to miscibility between oil and CO_2 which would eliminate the interfacial tension between oil and CO_2 significantly and, hence, increasing the capillary number which affects the oil recovery positively.

WAG ratios 1:1 and 1:2 seem to give comparable results to that of CCGI (continuous CO_2 gas injection) in terms of ultimate oil recovery, 69.85 % and 69.84 %, respectively. The latter, however, requires lower volume of injected fluid than the former, around 4 PVs for WAG 1:1 and 2.5 PVs for WAG 1:2, Figures 5 and 6. These lower volumes of fluid needed in these two WAG ratios may be due to the enhancement of mobilization efficiency by introducing a fluid with high viscosity (brine) which could reduce the mobility ratio and improve the volumetric sweep efficiency. WAG ratio 2:1 shows better results than the continuous water flooding, 56.1% oil recovery after 4.5 PVs of brine injected. This improvement in oil recovery may be attributed partially to miscibility between oil and CO_2 and partially to improved mobility ratio. Yet, This WAG ratio doesn't seem to be as effective as WAG 1:1 and WAG 1:2. From economic perspective and based on the aforementioned discussions, the WAG ratio 1:1 seems to be the best option compared to all of the other methods as it requires the least amount of compressed CO_2.

Recovery efficiency for any EOR process is function of displacement efficiency, mobilization efficiency and capture efficiency. In terms of displacement efficiency, [$(S_{oi}-S_{or})$ / S_{oi}], Figure 13, shows that CGI yields the highest value, 0.73, followed by WAG ratios 1:1 and 1:2 at 0.7, which is indicative that WAG 1:1 may be considered as

Figure 12: Combined Experimental Results of all Runs; Selection of Optimum WAG Ratio

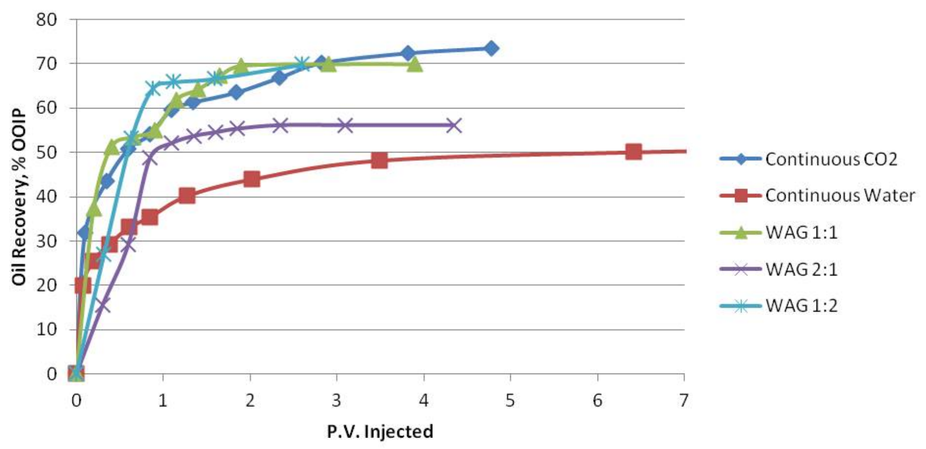
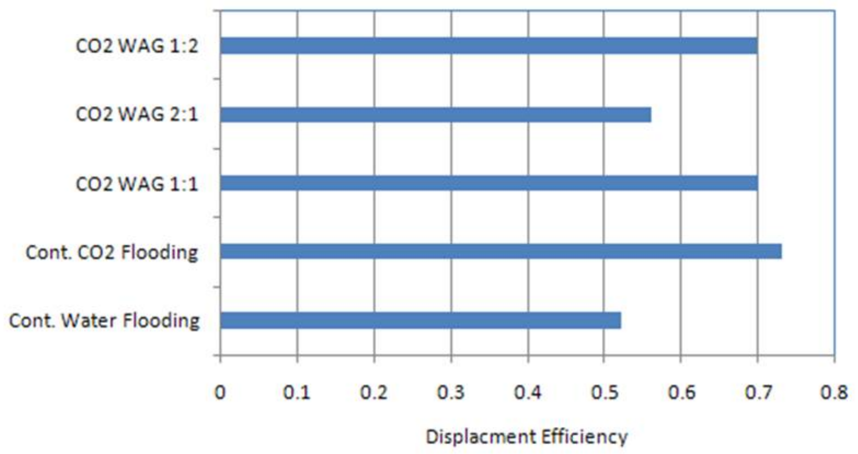


Figure 13: Displacement Efficiencies by Various Flooding Methods



an acceptable alternative for CCGI and the optimum CO_2 flooding system for the selected field. On the other hand, WAG 2:1 and Continuous brine injection came in last in this comparison.

Effect of WAG Timing on Oil Recovery

The optimum WAG ratio 1:1 for this selected oil field was used to optimize the time to commence the WAG process. For this purpose two stages of recovery were examined, namely, secondary recovery at S_{oi} and tertiary recovery at S_{or}. The results of these runs are shown in Figures 8, 11 and 14. Comparing the ultimate oil recoveries by secondary and tertiary stages of production, it is noticed that secondary recovery yields around 70% oil recovery with 4 pore volumes of fluids injected. The tertiary stage of recovery, however, yields around 59% oil recovery after injection of about 8 pore volumes of fluids. The better performance of the WAG in secondary mode of production may be attributed to presence of a larger volume of oil in the pores of the sample and thus a better chance of forming a more stable Oil-CO_2 miscibility bank and thus a better mobilization efficiency.

The effect of project timing is clearly shown in Figure 15 in terms of displacement efficiency

Figure 14: Comparison Between Performances of Secondary and Tertiary Schemes

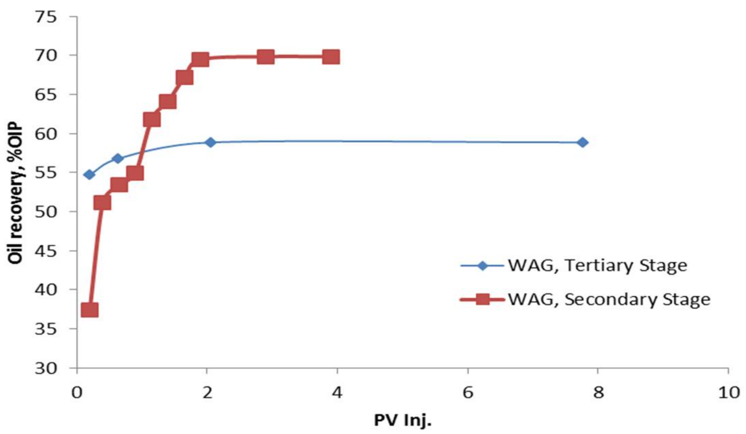
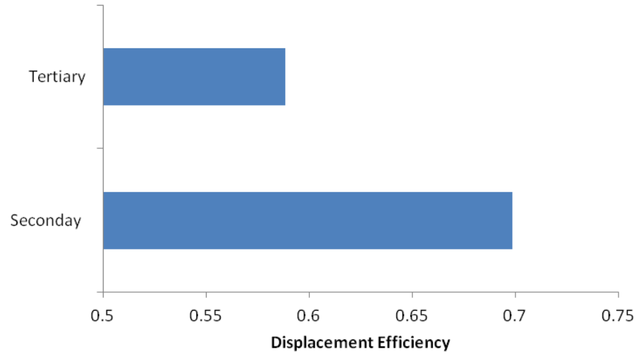


Figure 15: Displacement Efficiencies of Secondary and Tertiary Schemes



which shows that secondary mode has a value of 0.7 with only 0.59 in the case of tertiary stage of production.

CONCLUSION AND RECOMMENDATIONS

Core flooding experiments were carried out to evaluate the performance of CO_{-2}-WAG process, WAG ratio, WAG timing, brine composition and the relative merits and demerits of the miscible CO_2^- WAG flooding over continuous CO_2 injection or water flooding under specific reservoir conditions. Selected carbonate core samples from Bu-Hassa Field, UAE were used as the porous medium in all runs. Dead crude oil sample from the same field was used as the oleic phase. Umm Erraduma Brine was used as the injection brine, pure CO_2 was used as the Injection gas. A total of six different runs were conducted in this study. Three of the tests were performed to investigate the effect of WAG ratio on oil recovery and selecting the optimum of those studied. Two tests in terms of continuous water flooding and Continuous CO_2 Gas Injection (CCGI) were performed as reference tests for comparison purposes. Additional test was conducted to investigate the effect of WAG timing on oil recovery during the WAG process.

CONCLUSION

Based on the experimental results of this work, the following conclusions may be drawn:

1. The optimum carbon dioxide flooding system for Bu Hassa oil field seems to be for CO_2-WAG ratio of 1:1. Continuous carbon dioxide flooding resulted in a slight improvement in the displacement efficiency over CO_2-WAG 1:1.
2. Continuous carbon dioxide flooding, however, required more than twice the injection pore volume required by the CO_2-WAG 1:1 process to achieve oil recovery of 70% of the OOIP.
3. It was found that implementing CO_2-WAG flooding at early stages of the life of the reservoir can increase the displacement efficiency and subsequently the ultimate oil recovery.

RECOMMENDATIONS

The recommendations for future work could include:

1. Attempting longer core samples, composite cores or whole cores, to better understand the effect of the miscibility bank on the oil recovery.
2. Implementing live reservoir oil instead of dead oil to see the effect on the gas dissolved in oil on the miscibility between CO_2 and oil.

3. Incorporating sophisticated laboratory systems equipped with X-ray facilities to detect and visualize the miscibility bank during the experiment. It would be also possible to determine the in-situ saturation profiles.

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NOMENCLATURE

A	Cross Sectional Area (cm^2)
$CCGI$	Continuous CO_2 Gas Injection
CGI	Continuous Gas Injection
k	Permeability (effective / relative) (md)
L	Length (cm)
M	Mobility Ratio
MMP	Minimum Miscibility Pressure (psi)
N_{ca}	Capillary Number.
$OOIP$	Original Oil in Place (bbl)
P_{TEST}	Test pressure (psi)
ΔP	Pressure Drop (psi)
PV	Pore Volume (cc)
Q	Flow Rate (cc/sec)
$ROIP$	Residual Oil in Place (bbl)
S_G	Gas Saturation (%)
S_{GC}	Connate Gas Saturation (%)
S_L	Liquid Saturation (%)
S_{oi}	Initial Oil Saturation (%)
S_{or}	Residual Oil Saturation (%)
S_{wc}	Connate Water Saturation (%)
T	Temperature (^oF or ^oR)
V	Velocity (ft/D or cm/min)
WAG	Water Alternating Gas
σ	Interfacial tension (dynes/cm)
μ	Kinematic Viscosity (cp)
θ	Contact angle (degrees)

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