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AN EXPERIMENTAL INVESTIGATION OF GRAVITY DRAINAGE DURING IMMISCIBLE GAS INJECTION IN CARBONATE ROCKS UNDER RESERVOIR CONDITIONS

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ABSTRACT

Gravity drainage is one of the important recovery mechanisms in fractured carbonate and conventional reservoirs. It occurs due to density difference between the gas in fracture and the oil in matrix as well as in conventional tilted reservoirs. Oil phase will form films which are produced under gravity forces (film flow). Many gas injection experiments have been done on laboratory scales with dead oil, but, herein, we would like to recombine oil under reservoir conditions. In this paper, the gravity drainage process is considered during immiscible gas injection in carbonate core saturated with recombined oil at reservoir temperature and pressure. Recombined oil was prepared from dead oil and a solvent (methane and propane) mixed in recombination apparatus. In these experiments, nitrogen gas is injected in a single matrix block at different rates and directions. Since the recovery of oil depends on the gas injection flow rate, the recovery of oil is maximized at a specific flow rate. The results show that gas injection at gravity drainage rate gives the maximum recovery, and ultimate recovery decreases at much higher injection rates. Comparing the gas injection results in horizontal and vertical directions shows that the recovery is higher in the vertical direction than the horizontal direction.

Keywords: Immiscible Gas Injection, Gravity Drainage, Recovery Factor

INTRODUCTION

Enhanced oil recovery (EOR) is defined as the production of crude oil through processes to increase the primary reservoir drive. These processes may include pressure maintenance, the injection of displacing fluids, or other methods such as thermal techniques. Therefore, by definition, EOR techniques include all the methods used to increase the cumulative produced oil (oil recovery) as much as possible [1].

Gravity drainage is the main mechanism of production in fractured reservoirs. Density difference between the oil in matrix and the gas in fracture causes oil production until the gravity forces and capillary forces reach an equilibrium in the porous media [2].

In addition to fractured reservoirs, gravity drainage can occur in tilted conventional reservoirs. Immiscible gas injection is employed herein; nitrogen is immiscible with oil at pressures below 5000 psi [2] and thus it was selected

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as an immiscible gas to be injected to the cores. In former studies, gas was injected to glass micro-models in order to see displacement mechanism, and experiments were also carried out on core scales under reservoir conditions. The current study follows former works with a forward step and hence the experiments are performed by using recombined oil under reservoir conditions (pressure and temperature) in the presence of connate water saturation.

In order to see gravity drainage under reservoir conditions, it is important to pay attention to velocity displacement under reservoir conditions. Velocity displacement in reservoir is very low (1 ft/day). For the comparison of velocity displacement on reservoir scale and core scale, dimensionless parameters like capillary number are used [2].

$$N_c = \frac{V \times \mu}{\sigma} \tag{1}$$

where, V is velocity and σ is the surface tension between the injected fluid and reservoir fluid; μ represents viscosity.

Capillary number for fluid flow under reservoir conditions, N_c, is less than 10^{-7}; thus for the simulation of fluid flow under actual reservoir conditions with experimental core data, injecttion flow rate should be selected in such a way that capillary number varies in the proper range.

A critical gas injection flow rate is defined in studies of rate sensitivity analysis. At critical injection flow rate gravity, capillary and viscous forces interact in such a way which results in the maximum oil recovery. At injection rates lower than the critical rate, capillary forces dominate viscous forces and, due to capillary forces, some of the oil is trapped in the core. For injection rates greater than the critical rate, final recovery decreases because of fingering and a decrease in piston-like displacement [3].

Terwilliger et al. reported the result of salt water-air displacement in a 13 ft packed sand column with high permeability at a constant pressure of 50 psi at different flow rates [4].

Mohammadi et al. performed an investigation on the immiscible recycle gas injection as an EOR scenario for improving recovery efficiency in one of the south-west Iranian oil reservoirs. They concluded that the completion of injection wells in fracture and production wells in matrix had better oilfield efficiency in comparison to other cases [5].

Haghighi and Yortsos studied the oil displacement by gas. Their experimental results showed that as injection flow rate decreased, capillary forces to viscous forces ratio increased and displacement was more stable, which was considered as the cause of trapping oil at high injection rates. Haghighi et al. pointed to the existence of a critical injection flow rate as the minimum injection rate required for having a base recovery [6].

Soroush and Saidi carried out experiments on a carbonate core with a length of 150.9 cm and a porosity of 16.5% to estimate the dynamic behavior of immiscible displacement and miscible gas and to show the recovery potential of a reservoir with a permeability of 1 md. Oil recovery at injection rates of 1 and 10 cc/hr was 74% and 62% respectively. They also investigated the effect of gas oil ratio (GOR) and gas composition during gas injection [7].

These injection rates are several times greater than gravity stable flow rate for this low permeability core. This means that gas injection at flow rates greater than gravity stable flow rate can produces more than 60% of original oil in place. In fractured reservoirs with low threshold, oil recovery can reach the maximum value which is as large as recovery under gravity drainage mechanism [6].

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EXPERIMENTALS

Recombined Oil Preparation

Recombined oil was prepared from solvent and dead oil by using recombination apparatus (Table 1). Solvent was prepared by solvent apparatus, and composition of solvent was 19.2 gr methane and 17.6 gr propane, which was injected to the cylinder of solvent apparatus (25 mol.% propane and 75 mol.% methane).

Table 1: Recombined oil parameters

Bubble point pressure (psi) at 60 °C	ρ (gr/cm^3)	μ (cp)	GOR	B_o	Solution gas compounds
1900	0.65	1.38	58.8	1.15	%25 CH_4 %75 C_3H_8

After opening the gas-oil recombination cell and cleaning it, 500 cc of Ahwaz dead oil was poured into it and the cell was closed. Then, the prepared solvent was mixed with dead oil and the cell temperature and pressure were slowly raised above its bubble point pressure until a single phase fluid was obtained.

Core Preparation

These experiments were conducted on a carbonate core. A cylindrical sample core was prepared by core sampler apparatus. The absolute permeability of core was measured at different water injection flow rates by using of Darcy formula (Figure 1):

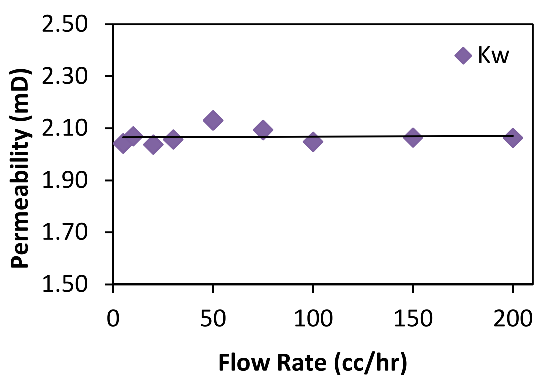

Figure 1: Absolute core permeability (water)

$$q = -\frac{k_w A}{\mu_w}\frac{\Delta P}{L} \tag{2}$$

where, L, A, and k_w are the length of core, the cross section area of core, and the permeability of water respectively. q, ΔP, and μ_w represent flow rate, pressure difference, and the viscosity of water respectively.

For measuring the oil formation volume factor (B_O), the volume of the oil under reservoir and atmospheric conditions is required. An approximate value is 1.15 bbl/STB at 60 °C (Figure 2). The characteristics of the core are mentioned in Table 2.

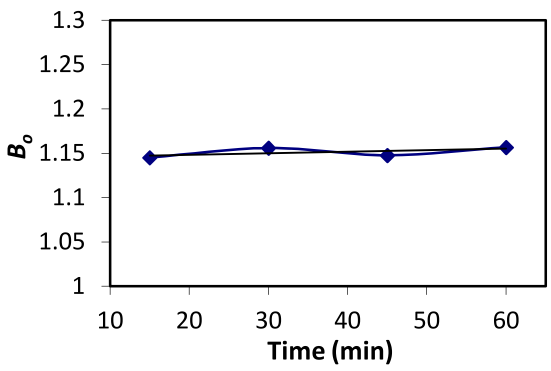

Figure 2: Oil formation volume factor (B_o)

Table 2: Core parameters

Core Type	φ	K (md)	L (cm)	A (cm^2)	Connate water saturation (Swc) (%)
Limestone	0.17	2	13.5	11.946	0.267

Seven experimental runs at pressures of 3500, 3000, 2500, 2000, 1800, 1500, and 1250 psi were conducted. The volume of injected gas is plotted versus pressure (Figure 3). The bubble point is considered as the point where the slope is changed.

Gas Injection Experiments

These experiments were done with high pressure and temperature COREFLOOD apparatus (maximum pressure: 10000 psi and maximum temperature: 200 °C). Core was connected to an injecting pump from one side (input line) and, from the other side, it was connected to back pressure apparatus in which fluid exits from the core by a production line.

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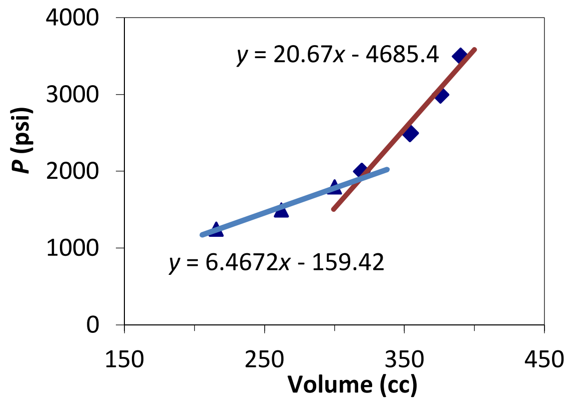

Figure 3: Bubble point pressure (psi)

Core Preparation Process

After cutting and preparing the core with a proper diameter, it was cleaned and dried. The core was washed in core washing-machine and dried in oven for each experiment. Washing process was done in washing machine using toluene and CO_2 gas for 8 to 10 hours; then, the core was placed for 10 to 12 hours in oven for complete drying. Before laying the core in the core holder, the core was sealed in a plastic cover, which heated to stick to core, and the core was then connected to the core holder by metal fasteners.

Connate Water and Recombined Oil

In addition to pressure and temperature, connate water saturation should exist in the core; thus the core was saturated with water to create connate water saturation in it. Moreover, overburden pressure should be applied on the core; this overburden pressure was supplied by a pump which pumped water into the shell around the core. In these experiments, overburden pressure was always 200 psi greater than the core pressure. For the better saturation of core, the core was vacuumed by a suction pump for 5 hours and water was injected at a rate of 2 cc/hr from the bottom of the core. 4 pore volumes of water were injected to the core. Heating system kept the temperature of oil, gas cylinders, which were placed in the oven, and the core holder section at 60 °C. The core temperature was increased to 60 °C by the sensor and heater elements placed in the core holder. After some minutes the temperature stabilized.

Afterwards, the core was saturated with recombined oil. Since the pressure of the oil cylinders should be kept at a pressure higher than the bubble point (1900 psi, Figure 3) of recombined oil so that the gas remains soluble in oil, the back pressure regulator (BPR) was set at 2400 psi. The back pressure regulator controlled the outlet pressure of core. Oil was not produced unless its pressure was higher than that of the back pressure regulator. The pressure of core and overburden pressure was simultaneously increased step by step to 2400 psi and 2600 psi respectively. As mentioned above, the overburden pressure was higher than the core pressure by 200 psi in order to tightly keep the core sleeve and prevent sleeve rupturing. After the production of water from BPR and the stabilization of water injection at the pressure of 2400 psi, the recombined oil was injected to core. Because oil density was lower than water density, the recombined oil was injected from the top of the core by rotating the core holder vertically. Recombined oil was injected to core at a 2 cc/hr flow rate, and 4 pore volumes of recombined oil were injected to the core to assure oil saturation. Connate water saturation of oil was calculated by knowing the pore volume of the core and the water produced from the core. In most of the cases, it was determined that immobile connate water saturation had a small effect on the relative permeability of oil-water and oil recovery.

Gas Injection

Gas injection was performed by using nitrogen, the specifications of which are given in Table 3. Since the used core was carbonate rock with very low permeability, theoretically obtained

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critical flow rate was very low. Since gravitational stable flow rate for the used core in the vertical position was very low, gas injecting was started at a flow rate of 1 cc/hr. It was observed that injection at low flow rates increased oil recovery, but a further reduction of gas injection flow rate did not lead to higher values of oil recovery. Therefore, in practice, there is no need to inject gas at very low flow rates to have high recovery (Figure 4).

Table 3: Injected gas parameters

Gas	ρ (gr/cm^3)	μ (cp)
N_2	0.00114	0.0175

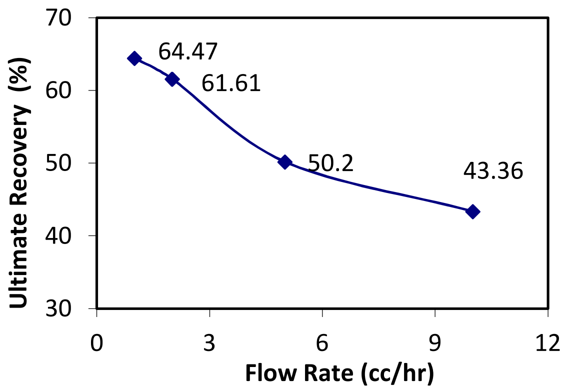

Figure 4: Critical gas injection flow rate

In order to find the critical gas injection flow rate, at which the maximum oil recovery occurs, tests were conducted at different flow rates. To observe gravity drainage in the vertical position, oil recoveries in different directions were compared. The core rotation system changed the direction of gas injection. Oil recoveries at different gas injection flow rates in the vertical and horizontal directions were also compared. Since the aim of these experiments was to see the vertical gravity drainage process, the horizontal tests were also conducted to be compared with the vertical ones. Gas injection flow rates of 1, 2, 5, and 10 cc/hr were selected for the vertical mode and flow rates of 5 and 10 cc/hr were selected for the horizontal mode. Figure 5 shows recovery versus time at a flow rate of 5 cc/hr in the vertical direction. For the comparison of different flow rates in the vertical direction, the variation of oil recovery versus time is shown in Figure 6. The recoveries are presented versus pore volume injected and capillary numbers are also calculated (Figure 7). Furthermore, the horizontal and vertical recoveries at the same injection flow rate are compared. Figures 8 and 9 compare oil recoveries versus pore volume injected in the horizontal and vertical directions at gas injection flow rates of 5 and 10 cc/hr respectively.

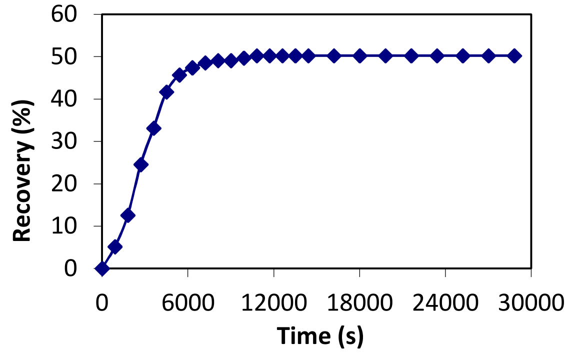

Figure 5: Critical recovery versus time in the vertical direction at a flow rate of 5 cc/hr

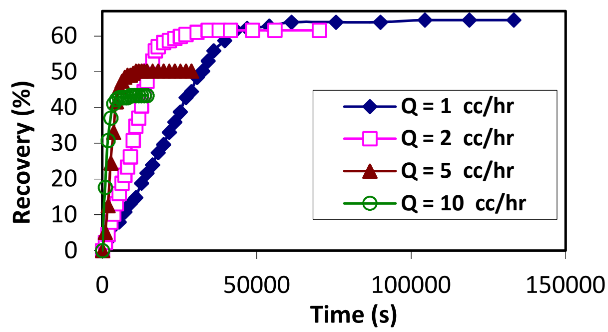

Figure 6: Recovery versus time at different flow rates in the vertical position

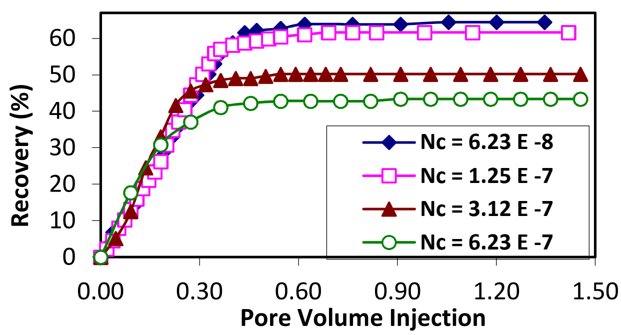

Figure 7: Recovery versus injected pore volume at different capillary numbers in the vertical position

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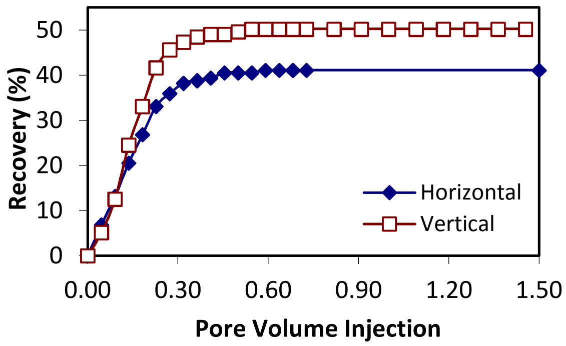

Figure 8: Comparison of recovery in the vertical and the horizontal positions at a gas flow rate of 5 cc/hr

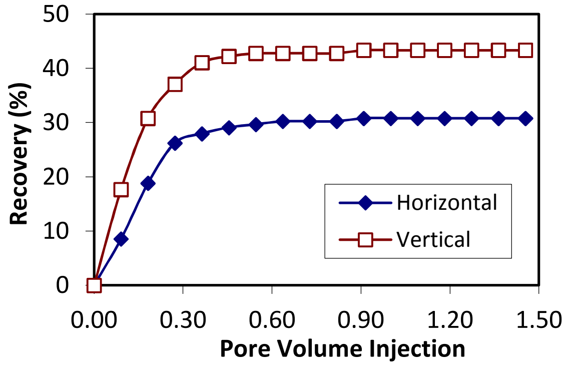

Figure 9: Comparison of recovery in the vertical and the horizontal positions at a gas flow rate of 10 cc/hr

For gas injection at each flow rate, the core holder was rotated in the proper direction and the pressure of nitrogen gas cylinder was reached the steady state pressure of the core. The injection rate was set to each flow rate, and, after closing recombined oil injection line, nitrogen gas was injected to the core. Oil was produced and measured in glasses. Gas Injection was continued until no more oil was produced,; usually after 1.5 pore volumes of gas injection there was no oil production. After oil production finished, gas injection was stopped; the gas input valve was then closed; next, pressure system was slowly dropped to atmospheric pressure, and, finally, the core holder was opened. Further tests were carried out using the same method.

The results and diagrams of recovered oil from the core and recoveries in the horizontal and vertical position were graphically compared. The plot of ultimate oil recoveries with respect to gas injection flow rates shows that, at a specific gas injection flow rate, ultimate oil recovery is maximized. Ultimate oil recoveries with respect to gas injection flow rates are shown In Figure 4. The studies show that injecting at a stable gravity drainage flow rate results in the maximum recovery. Since injection at gravity drainage flow rate takes a lot of time, injection at such a flow rate is not practical. Of course, if gas is not injected at such a flow rate, one may not lose a lot of recovery. It means that if the injection rate is stable gravity drainage, the maximum oil recovery does not increase so much. As can be seen for the injection flow rates of 1 and 2 cc/hr (Figures 6 and 7), oil recovery does not increases very much even when the flow rate is decreased by half. The trend of increasing oil recovery by decreasing the injecttion flow rate is shown in charts. It is expected that at stable gravity drainage injection flow rate, the maximum oil recovery is obtained.

RESULTS AND DISCUSSION

Immiscible displacement at different flow rates shows that the recovery is greater in the vertical position than the horizontal position, from which it is expected that film flow plays a role in the vertical position after the displacement of the mass. Higher oil recovery obtained by immiscible displacement in the vertical position can be due to the effective film flow phenomenon.

At high pressures, recovered oil increases due to an increase in formation volume factor (FVF) and a decrease in residual oil saturation for lower interfacial tension (IFT). It is expected that if the core is allowed to be drained in special circumstances, the mechanism of film flow continues after stopping the injection of the gas. It should be noted that this process occurs if the gravity forces overcome capillary forces.

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Therefore, the recovery measured after the injection of 1.5 pore volumes should not be thought as the ultimate recycling. This is one reason for recovery increasing at lower injection flow rates. Oil recovery graphs show that higher recovery is obtained at lower injection flow rates. Although injection flow rate is considerably lower than stable gravity drainage flow rate, recovery is higher than 60%. The vertical stable gravity drainage flow rate is obtained by:

$$q = \frac{\Delta\rho \times g \times K}{\mu} \quad (3)$$

q, $\Delta\rho$, and g stand for flow rate, density difference between oil and gas, and gravity acceleration respectively. K and μ express permeability and viscosity correspondingly. After converting data to c.g.s. system, vertical stable gravity drainage flow velocity (u) is equal to:

$$u = \frac{0.002 \times (0.65 - 0.00114) \times 980 \times 3600}{1.38 \times 1013250} = 0.00327 \left(\frac{cm}{hr}\right) \quad (3)$$

Injections at flow rates of 1 and 10 cc/hr, which are correspondingly proportional to 0.084 and 0.837 cm/hr, are 25 and 255 times higher than stable gravity drainage flow rate respectively.

In addition to the effect of injection rate on recovery, wettability affects the residual oil saturation. It is expected that preferably the oil-wet cores have more remaining oil than the water-wet cores. Although high oil recovery with vertical gravity drainage can be obtained, low recovery can be due to the following reasons:

1- Insufficient time for the film flow;
2- High injection flow rates, which do not allow better oil displacement by gas. It can be due to the gas fingering in low permeability cores, and can cause bypassing oil.

For the practical application of these experiments, it can be concluded that gas injection has good recovery in the reservoirs with low permeability and high initial pressure. Threshold height is relatively small at high pressure due to small interfacial tension; furthermore, this method is more applicable to fractured reservoirs due to small threshold height in fractures. For example, a 10-feet block has been measured under atmospheric conditions; threshold height is 1 foot and interfacial tension is 30 mN/m; at the reservoir pressure, interfacial tension is 2 mN/m and threshold height is 0.067 foot. Since in the fractured reservoirs, displacement in matrix blocks occurs under stable gravity drainage, the maximum recovery should reach gravity drain-age recovery [2]. It is forecasted that gravity drainage process is a combination of single phase flow, primary drainage, and mainly a film flow after drainage. Gravity drainage has a higher relative speed in fractured reservoirs compared to the single porosity reservoirs.

Gas injection to fractured reservoirs only produces a few percent of oil in the matrix block. Due to low permeability of reservoir rock, some gas enters the reservoir rock and the remained gas bypasses blocks with low permeability and enters fractures (in single phase reservoirs, the injected fluid passes through interconnected pores). Therefore, gravity drainage is effective in the extraction of the remained oil from matrix blocks. Additionally, the threshold height and capillary characteristics of reservoir rock (capillary pressure) are factors which affect gravity drainage. In order to obtain capillary number, the interfacial tension of the injected fluid (nitrogen) and oil is required. Herein, a fair approximation of interfacial tension obtained by WINPROB simulator is about 5.15 Dyne/cm. As can be seen, capillary number is in the range of 10^{-7}. The variation of oil recovery versus capillary number is shown in Figure 10.

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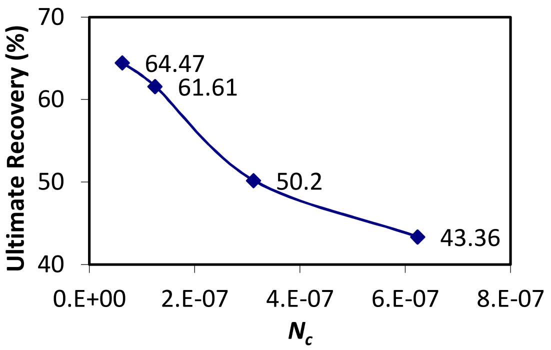

Figure 10: Recovery versus capillary number

CONCLUSIONS

The results show that increasing injection flow rate decreases final recovery, which confirms the results of previous works. Moreover, a decreasing trend of oil recovery was visible in glass micromodels. The comparison of the recovery in the horizontal and vertical position shows that the recovery of oil is higher in the vertical mode than the horizontal mode, which can be due to gravity drainage and the piston-like displacement of oil by gas occurring in the vertical mode. The following results of the gas injection experiments and the analysis of gravity drainage are achieved:

1- Oil recovery mechanism in the porous media with increasing pressure is basically either due to the desirable improvement in viscosity and a reduction in interfacial tension or because an increase in formation volume factor has a small effect on the residual oil saturation.
2- It is expected that gravity drainage displacement in the vertical gas injection provides better results due to film flow.
3- Gas injection can produce more than 60% of the initial oil in place of the reservoirs with low permeability, if the reservoir pressure is kept high enough under minimum miscible pressure (MMP) by controlling the flow.
4- It is expected that conventional reservoirs with low permeability can achieve a high oil recovery factor at injection rates higher than maximum gravity drainage.
5- –The experiments of the current work were performed on a single matrix block, since displacement in fractured reservoirs occurs under stable gravity drainage; thus a high oil recovery is expected from immiscible gas injection in low permeability fractured reservoirs kept at relatively high pressures.

NOMENCLATURE

A (m^2)	Cross section area
B_o (bbl/STB)	Formation volume factor
g (m/s^2)	Gravity acceleration
GOR	Gas oil ratio
K (D)	Permeability
K_w	Effective permeability of water
L (m)	Length
N_c	Capillary number
ΔP (Pa)	Pressure difference
q (m^3/s)	Flow rate
V (m/s)	Velocity

Greek symbols

φ	Porosity
μ (pa.s)	Viscosity
σ (N/m)	Surface tension

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