Research

Reducing Oil Bypassed during CO_2 Flooding in Fracture-Dominated Reservoirs

Deepak Chakravarthy [1]*, Vivek Muralidharan[1]*, Erwinsyah Putra [2]*[§], Dewi T. Hidayati[2]* and David S. Schechter[2]*

Address: [1]Occidental Oil and Gas Corporation, Houston, Texas, USA, [2]Petroleum Engineering Department, Texas A&M University, Texas, USA
http://pumpjack.tamu.edu/Faculty&Staff/faculty/schechter/baervan/homepage.html

Email: Deepak Chakravarthy - deepak_chakravarthy@oxy.com: Vivek Muralidharan - vivek_muralidharan@oxy.com: Erwinsyah Putra - putra@tamu.edu: Dewi T. Hidayati - dewi@tamu.edu: David S. Schechter - schech@spindletop.tamu.edu
*These authors contributed equally to this work
[§]Corresponding author

Published: 27 September 2005 Received: 14 September 2005

E-Journal of Reservoir Engineering 2005, *ISSN: 1715-4677.* Accepted: 27 September 2005

This article is available from: http://www.petroleumjournals.com/

Abstract

Injection rates play a very important role in affecting the recovery process, especially in the presence of fractures. At high injection rates faster CO_2 breakthrough of CO_2 and higher oil bypass were observed than at low injection rates. But very low injection rates are not attractive from an economic point of view. Hence water viscosified with a polymer was injected directly into the fracture, to divert CO_2 flow into the matrix and delay breakthrough, similar to the WAG process. Although the breakthrough time reduced considerably, water "leak off" into the matrix was very high. To alleviate this problem, a cross-linked gel was used in the fracture for conformance control. The gel was found to overcome "leak off" problems and effectively divert CO_2 flow into the matrix. This experimental research will serve to increase the understanding of fluid flow and conformance control methods in fractured reservoirs.

Introduction

Fractured reservoirs form a large percentage of the world's hydrocarbon reserves. However, in spite of their wide occurrence and huge reserves, the oil recovery from most of these reservoirs is extremely low. This can be attributed to their poor response to both secondary and tertiary recovery operations. In a fractured system, the displacement process is dependent on the fracture-matrix geometry, size and interaction apart from other physical phenomena (Yaghooby *et al.*, 1996). Uleberg and Hoier (2002) suggest that the injection fluid tends to flow through the highly permeable fractures, often resulting in early breakthrough and poor sweep efficiency. This is especially true when the displacing phase is a highly mobile fluid like CO_2. In order to improve the sweep efficiency and delay breakthrough, the mobility of the displacing fluid in fractures, has to be controlled.

In the recent years, there has been an increasing interest in the WAG process, both miscible and immiscible. The continuous CO_2 injection process is an important process to identify displacement mechanisms but is not likely to be economic in practice unless significant recycling of gas is employed. Inherent in all gas injection processes is the lack of mobility and gravity control (areal and vertical sweep) necessary to sweep significant portions of the reservoir. Therefore, the replacement of high cost CO_2 by a cheaper chase fluid such as water for horizontal displacements appears economically attractive.

The WAG process involves alternate injections of small pore volumes (5% or less) of CO_2 and water until the desired volume of CO_2 has been injected. The oil recovery by WAG has been attributed to the contact of unswept zones, especially the recovery of attic or cellar oil by exploiting the segregation of gas to the top or accumulating water towards the bottom (Rogers and Grigg, 2001). Since the microscopic displacement oil by gas normally is better than by water, the WAG injection combines the improved displacement efficiency of gas flooding with an improved macroscopic sweep by the injection of water. This has resulted in an improved recovery (compared to pure water injection) for most field cases. WAG has been applied with success in most field trials. Very few field trials have been reported as unsuccessful though operational problems have been reported.

The WAG process can be grouped in many ways. The most common is to distinguish between the miscible and the immiscible WAG process. In the miscible WAG process, multi-contact gas-oil miscibility is obtained, although a lot of uncertainty exists about the actual displacement process. For the miscible process to be observed, the pressure of the reservoir must be above the minimum miscibility pressure (MMP) of the oil. The reservoir is often repressurized to this pressure before the initiation of the WAG process. In many cases, it is not possible to maintain the reservoir pressure above the MMP, especially in gas injection and hence the process oscillates between miscible and immiscible. The immiscible WAG process has usually been applied with the aim of improving frontal stability or contacting unswept zones. The application has mainly been in reservoirs where gravity stable gas injection has been difficult because of limited gas availability or unfavorable reservoir properties like low dip or strong heterogeneities. There are other WAG processes like the hybrid WAG where a large slug of gas is followed by small slugs of alternate water and gas, and the simultaneous WAG or SWAG where water and gas are injected simultaneously.

Several field cases (Hsie and Moore, 1986; Holm and O'Brien, 1971; Kane, 1979; Aarra *et al.*, 2002) and laboratory experiments (Prieditis *et al*., 1991; Akervoll *et al*., 2000) indicate that the WAG process has been an effective mobility control method in most cases. In a fairly homogeneous system, water invades the zones previously invaded by the gas, subsequently diverting the gas into other zones (Holm, 1982). But a completely different situation prevails in the presence of extreme heterogeneities like fractures. In such a case, the conformance control agent must be able to effectively divert the fluid into the matrix, thereby delaying breakthrough and reducing oil bypass. But the performance of WAG in terms of mobility control in fractures has not been adequately studied.

In oil recovery operations, several different types of processes have been proposed to reduce channeling of fluids through fractures and streaks of very high permeability. These include several processes like gels, particulates, precipitates, microorganisms, foams and emulsions. Of these, processes that use cross-linked polymers or other types of gels have been the most common (Seright and Liang, 1995). The goal of gel treatment to date has been fairly simple – to improve the macroscopic sweep efficiency by providing a fairly uniform sweep across the entire reservoir. This is true when water is the displacing fluid. Several other EOR processes are also used to improve the microscopic sweep efficiency by recovering the hydrocarbon that is stuck to the reservoir rock. Typically, a gel is composed of a gelant (which is usually a polymer in an aqueous solution) mixed with a small quantity of cross-linker which causes gelling. The type of gel to be used is decided based on the resistance factors that develop during the injection of the gelant into the fracture.

The goal of this work is to investigate CO_2 flow in fractures, in the presence of water as a mobility control agent. The cores were fractured using a core splitter. Experiments were conducted in fractured cores with continuous CO_2 injection and injection of specific pore volumes of water and CO_2. One experiment was also performed after adding a cross-linker to the solution to form a gel. During each injection, CT scans covering the entire length of the core were taken in order to study fluid transport in the matrix and the fracture. Saturation distributions were obtained at various stages during the course of the experiment.

Experimental Setup

The experimental setup can be divided into five main components – the injection system, the coreflood cell, HD 200 X-Ray CT scanner, the production system and the data acquisition system. A brief description of each of the components is given below.

Injection System. The injection system consists of two sets of one-liter accumulators one each for the oil and water. These accumulators can withstand a maximum pressure of 3000 psi. There is also a two-liter Temco™ accumulator with a maximum pressure rating of 2500 psi. Each of these accumulators is connected to an ISCO 5000 D syringe pump using stainless steel tubing. The syringe pump, with a nominal cylinder capacity of 508 ml, consists of a programmable pump controller with an RS-232 serial interface for computer control or monitoring of operating parameters. The pump can operate at flow rates starting from 0.01cc/min. The maximum pressure rating for the pump is 3000 psi @ 200 ml/min. Using the programmable controller, the pump can be set to deliver at a constant pressure or at a constant flow rate. Water is injected from the pump under set conditions below the piston in the accumulator. This increases the pressure of the fluid above the piston to the desired level. A Swagelok SS-41XS2 ball valve is used to switch the flow from the pump to either the CO_2 accumulator or the secondary ball valve which divides the flow between the oil and the water accumulator.

Coreflood Cell. The core holder measuring 21 in. long is made up of aluminum and was designed specially for use with the CT scanner. It is capable of holding cores up to 1 ft. in length and 1 in. in diameter. The maximum pressure rating of the coreflood cell is approximately 7000 psi. The cell consists of detachable end pieces with plungers on both ends. One end has a fixed plunger while at the other end, the plunger can be moved by rotating a screw at the end piece, to make sure that the core is in contact with the plungers.

A viton Hassler sleeve surrounds the core and is secured to the plungers. When cores less than 1 ft. in length are used, aluminum spacers with spider grooves are used in the remaining space. The coreflood cell has an inlet for hydraulic oil, which is used to apply overburden pressure. A hydraulic hand pump is used to pressurize the cell by injecting hydraulic oil into the Hassler sleeve – inner wall annulus and pressures up to 7000 psi can be obtained in this manner. Another inlet in the core holder can be used to fix a thermocouple for temperature measurement or another device like a pressure tap. The layout of the core holder is shown in **Figs.1** and **2**.

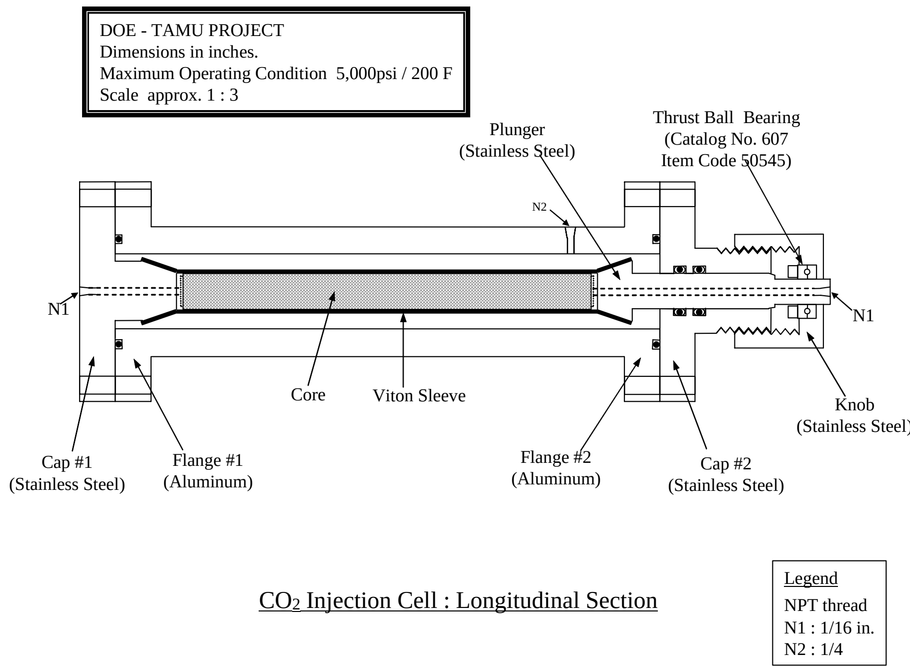


Fig. 1—Design of aluminum core holder used for X-ray CT scanning

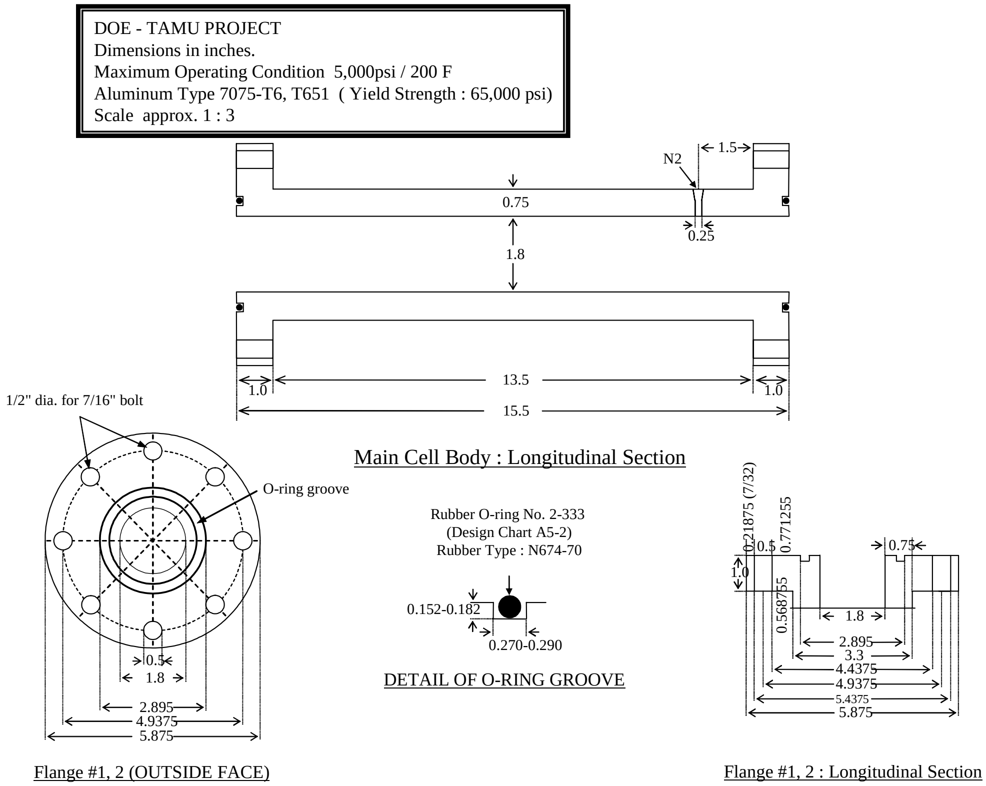


Fig. 2—Cross-sectional view of the core holder

X-Ray CT scanner. The X-Ray CT scanner is a fourth generation Universal systems HD 200 system with a resolution of 0.3 mm x 0.3 mm. This scanner can be used to scan a maximum diameter of 48 cm with a maximum scan time of 4 sec per scan. Cross sectional scans of the core sample are made at regular intervals during the experiment. An image appears on the video screen as a filled in circle, and the image information is in a 512 by 512 matrix. Each pixel represents a CT number that is related to the average absorption coefficient of a spatial volume within the scanned field. The volume of each pixel varies according to scanned field size and beam thickness selections. The CT numbers are compared to that of water, which is assigned a value of zero. The data obtained from the CT scanner is transferred to the image processing system installed in a Sun workstation. The cross sectional images can then be used for porosity and saturation determination or reconstructed for flow visualization.

Production System. The outlet end of the core holder is connected to a Swagelok SS-ORS2 precision needle valve which serves as the back pressure regulator and is used to increase pressure in the system. Connected further down is a Swagelok SS-SS2-VH high precision metering valve with a vernier handle. This valve was required to allow minute adjustments to the fluid flow rate so as to avoid a large pressure drop. The produced fluid is collected in a graduated cylinder and any gas produced is allowed to flow to a gas chromatograph and then measured using a wet test meter.

Data Acquisition System (DAQ). Two Omega pressure transducers one each at the inlet and the outlet are used to measure pressure at the two ends. The pressure data is then transferred to an Omega OMB-DAQ-55 data acquisition system. The OMB-DAQ-55 Personal DAQ is a full-featured data acquisition system that utilizes the Universal Serial Bus (USB), which is built into almost every new PC. Designed for high accuracy and resolution, the 22-bit OMB-DAQ-55 data acquisition system directly measures multiple channels of voltage, thermocouple, pulse, frequency, and digital I/O. A single cable to the PC provides high-speed communication and power to the OMB-DAQ-55. No additional batteries or power supplies are required, except when using bus-powered hubs. This DAQ is connected to a Pentium III computer system and the pressures can be observed and acquired real time using the software that is available with the DAQ. A schematic of the experimental setup is shown in **Fig. 3**.

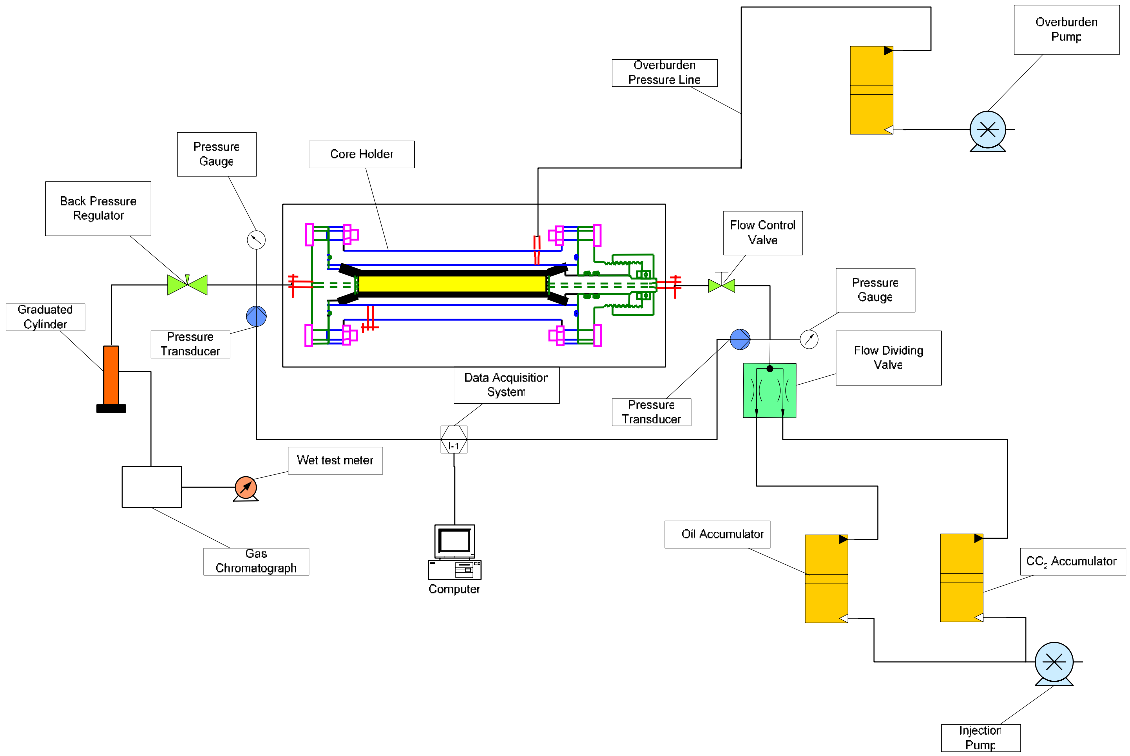


Fig. 3—Schematic of the experimental setup

Experimental Procedure. The oil used for the experiments is a mixture of refined Soltrol 130™ and 1-iodohexadecane. Previous measurements have shown that the iodohexadecane serves only as the doping phase and does not alter the interfacial tension between the fluids (Wellington and Vinegar, 1987). The cores used were Berea sandstones with a diameter of 2.5 cm (1 inch) and a length of about 10 cm (3.9 inches). Porosity measurements made using CT scanner revealed that the cores have porosity in the range of 18 to 21 %.

Since the X-ray CT provide the density of the object, we run our experiments below MMP to differentiate between CO_2 and oil. Holm and Josendal (1974) reported that for miscible displacement to take place, the density of CO_2 should be at least 0.25 to 0.35 gm/cc. There are various reservoir pressure-temperature combinations that yield these densities. In order to have immiscible displacement, the density of CO_2 must be less than this range. For our immiscible displacements we decided to maintain the density of CO_2 around 0.l5 gm/cc. This density can be achieved at a temperature of 70º F and a pressure of 800 psia. At this temperature and pressure, the major mechanisms of oil recovery are swelling of oil, reduction in viscosity and an internal solution gas drive (Holm, 1987). These parameters were important to ensure that the displacements were immiscible and also obtain a clear contrast between the fluids in the CT scans. Fluids were injected into cores at constant rates or at rates that were varied to maintain constant pressure. Produced fluids were collected in graduated cylinders. The displacement processes were studied during the experiment where the injection rates, production volumes and pressure drops were measured. Fluid saturation distributions were also indirectly measured using X-Ray CT. The overall efficiency of the process was analyzed by combining the CT measurements and the external effluent volume measurements. A general outline of the experimental procedure is given below:

1. The core is first heated at about 150º F for a sufficient period to remove all residual water saturation and evacuated using a vacuum pump. The evacuated dry core is scanned at a confining pressure of about 1000 psi.
2. For a fractured core experiment, the above steps are repeated after fracturing the core.
3. The core is flooded with CO_2 at the desired temperature and pressure to obtain the scans at 100% CO_2 saturation.
4. The core is then evacuated again in the vacuum chamber. The evacuated core is saturated with doped oil in the vacuum chamber for a period of 48 hours. The oil saturated core is transferred to the aluminum core holder and about 15 pore volumes of oil are injected to ensure complete saturation.

5. The backpressure regulator at the outlet is fully closed and the pressure in the core holder is allowed to build up. Care is taken that the overburden pressure is always at least 300 psi higher than the pressure inside the sleeve. Once the desired pressure is reached, oil injection is stopped.
6. The oil-saturated core is now scanned again.
7. The pressure in the CO_2 accumulator is increased to be about 50 psi higher than the pressure in the coreflood cell to prevent back flow of oil.
8. CO_2 is now allowed to enter the coreflood cell and any excess pressure above the desired pressure is released using a valve available for this purpose. Injection is then started at the desired rate.
9. The core is scanned at various times to visualize fluid flow and determine saturations at various times.
10. For a WAG experiment, doped/viscosified water is injected when desired and the core is scanned during the injection process. For the experiment with the cross-linker, the gel is injected into the fracture prior to CO_2 injection.

CT numbers, N_{CT}

The CT number scale has two fixed values independent of photon energy. N_{CT} is given in the dimensionless unit, *Hounsfield number*. For vacuum, air or body gas,

$$NCT = -1000$$

and for water,

$$NCT = 0.$$

The common method used for calculating porosity from CT images is:

$$\phi = \frac{N_{CT100\%Sat} - N_{CTDry}}{N_{CTWater} - N_{CTAir}} \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots(1)$$

For water displacing air in the core, then saturation is given by:

$$S_w = \frac{N_{CTMat} - N_{CTDry}}{N_{CT100\%Sat} - N_{CTDry}} \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots(2)$$

For oil-water phase, the saturation is calculated with the help of the following relation:

$$S_w = \frac{N_{CTMat} - N_{CT100\%Sat}}{\phi(N_{CTOil} - N_{CTWater})} \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots(3)$$

For mixture of two fluids, the saturation is calculated with the following:

$$S_{FluidA} = \frac{N_{CTMat} - N_{CTmix}}{\phi(N_{CTFluidA} - N_{CTFluidB})} \quad \ldots\ldots\ldots(4)$$

Results and Discussion

Continuous CO2 injection. The permeability of a fracture is typically about 10^3 to 10^6 times greater than the permeability of the porous rock. In a fractured system, the tendency of the fluid would be to flow through the high permeability fracture which leads to early breakthroughs. In the case of gas injection, the injection rate plays an important role. In the case of waterflooding, a low injection rate facilitates dynamic imbibition of the wetting phase into the matrix, when gravity effects are neglected. Putra *et al.,*(1999) found that, for water wet cores very low injection rates helped in obtaining a better oil recovery due to imbibition. But when the injection rate exceeded a particular value, no oil was produced, no matter how much water was injected. In this case, viscous forces played a minor role while capillary forces played an important role in recovery. But in the case of gas injection, the process is one of drainage and gas is the non-wetting phase. Here, the drainage mechanism could be either one of counter or co-current drainage. In counter current drainage, diffusion of gas into the matrix causes an equivalent amount of oil to flow into the matrix. In the case of co-current drainage, the gas causes viscous displacement of oil in the direction of flow. A schematic of the drainage process is provided in **Fig. 4**. In gas injection, the gravity and capillary forces play an important role in the recovery process. During the injection process, the viscous forces are high at the injector end and reduce as we proceed towards the producer end. Hence, the recovery of oil at the injector end is higher due to the diffusion of gas into the matrix and the recovery from the producer end is lower and the time taken for complete recovery is very high. Continuous CO_2 injection was started at a very low rate of approximately 0.03cc/min in a fractured core with a vertical fracture. Only a very small amount of oil was recovered after about 1.5 PV of injection, most of which was from the fracture. In this case, the breakthrough from the fracture was almost instantaneous. Scans were taken at different time during the experiments. The flow of CO_2 through the fracture was identified by the decrease in the CT number in the fracture and the change in color in the cross-sectional scans in the fracture. **Figs. 5** and **6** show the oil saturated core scans and the scans

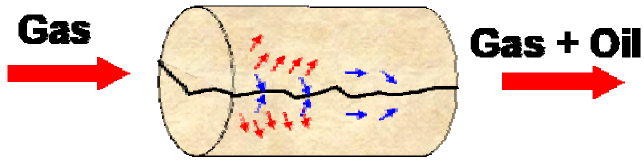


Fig. 4—Schematic of drainage process

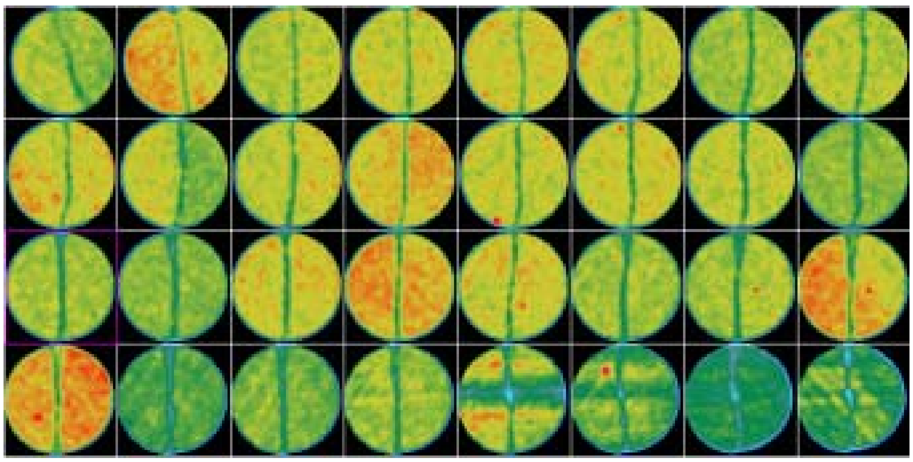


Fig. 5—Oil saturated core scans with the fracture seen at the center

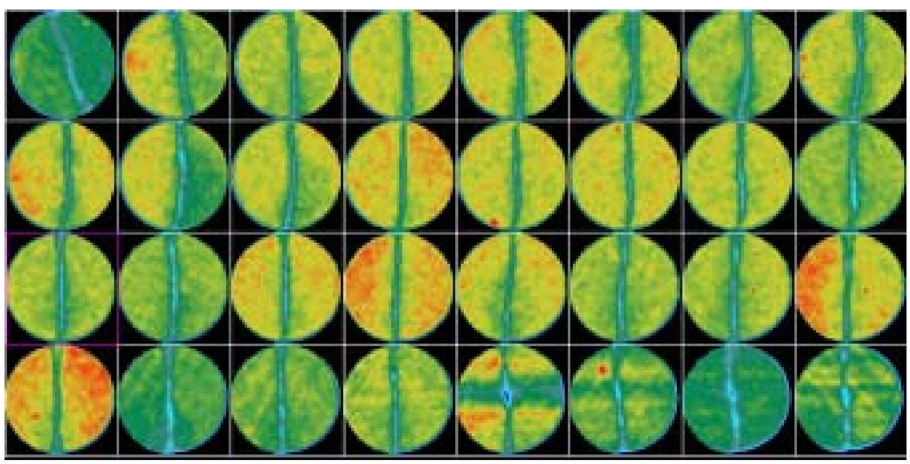


Fig. 6—CO_2 flow can be identified by a change in color at the fracture

after CO_2 injection was started respectively.

The flow of CO_2 through the fracture was also identified by the reduction in the CT number at the fracture after injection was started. Reconstructions of the horizontal scans also indicate the CO_2 flowing over the fracture surface (**Fig. 7**). In this reconstruction, the bottom reconstruction represents a cross section parallel to the fracture surface (along the fracture) while the top reconstruction represents section perpendicular to the fracture surface (which shows the fracture as a blue streak at the center).

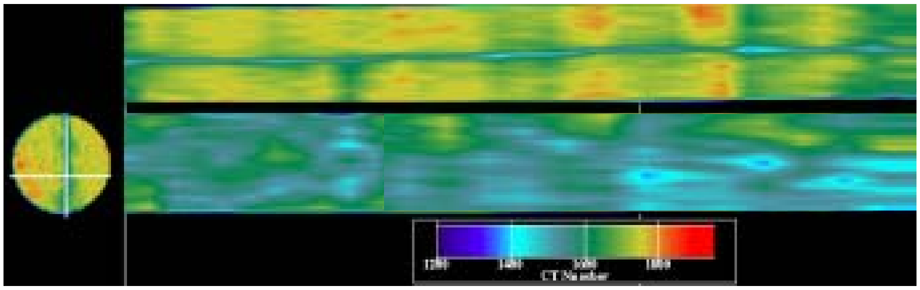
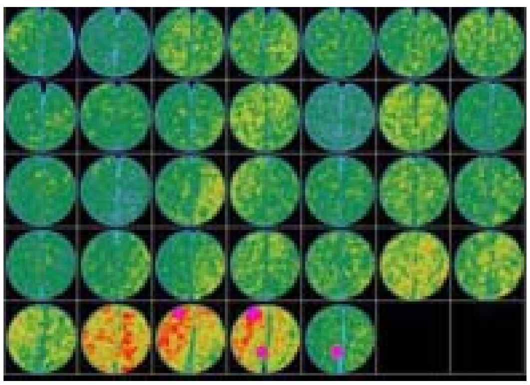
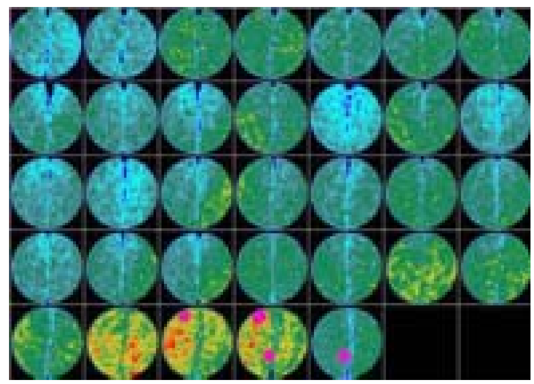


Fig. 7—Reconstructions parallel and perpendicular to the fracture surface

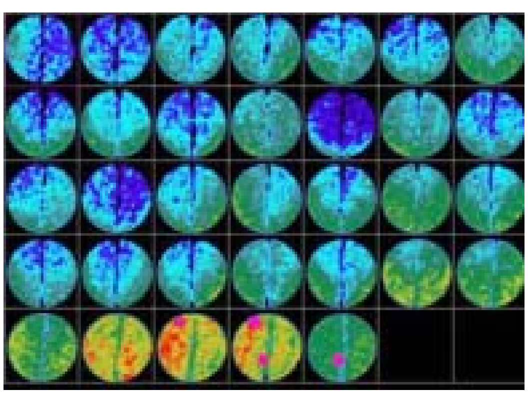
Following this, another experiment was performed with a higher injection rate of 0.1cc/min. The fracture configuration used in this case was similar to the previous case. The breakthrough of CO_2 occurred after about 10 minutes corresponding to about 0.09 PV of injection. Although this was not as early as the previous case, this can still be considered very early for economic operation. **Fig. 8** shows the various scans taken during the course of the experiment.



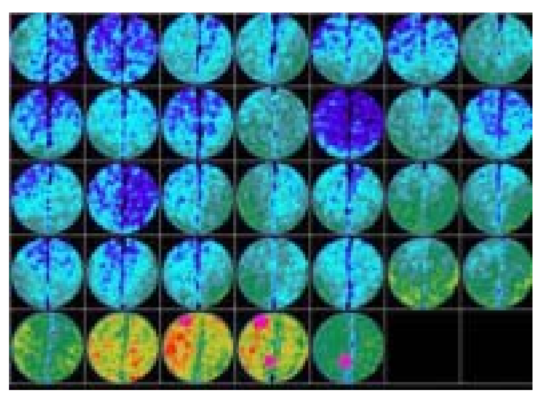
(a). Oil saturated core



(b). CO_2 saturation after about 0.7 PV of injection

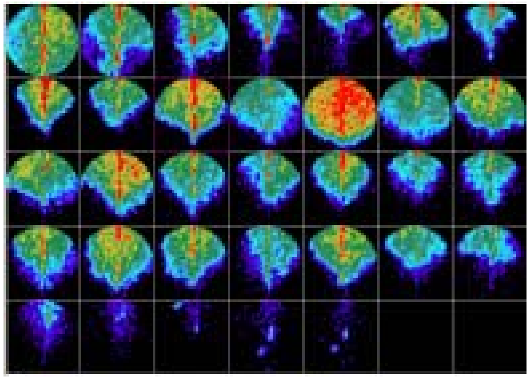


(c). CO_2 saturation after about 1.3 PV of injection

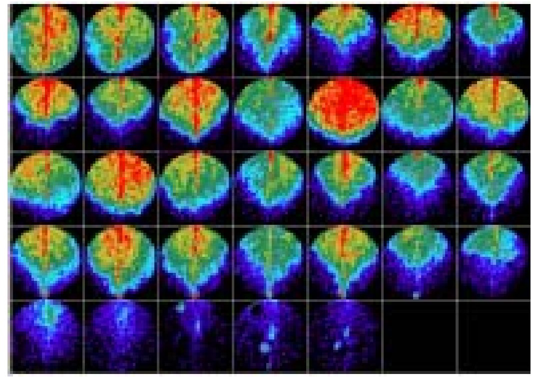


(d). CO_2 saturation at the end of experiment

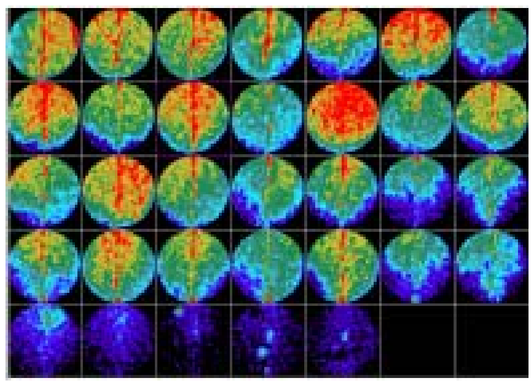
Fig. 8—Cross-sectional scans taken during the continuous CO_2 injection experiment



CO_2 saturations at about 0.7 PV of injection



CO_2 saturations at about 1.3 PV of injection



CO_2 saturations at the end of the experiment

Fig. 9—CO_2 saturation images converted from CT images Fig. 8.

In these scans the color scale has been chosen such that the blues indicate the lowest CT numbers while red and pink indicate the highest CT numbers with green and yellow being the intermediates. Thus, with an increase in CO_2 saturation, the CT number decreases and hence the color changes to a dark shade of blue. In order to better understand the displacement process, the CT number images were converted into saturation images. The CO_2 saturations from the continuous CO_2 injection process are shown in **Fig. 9**.

The CO_2 saturation images give a clear insight into the displacement mechanism acting in the flooding process. It is well known that gravity drainage is an important oil recovery mechanism in naturally fractured reservoirs. In some cases it is the only mechanism that allows oil recovery and production of oil from the matrix blocks. Oil recovery by gravity drainage strongly depends on the height of the capillary continuity. Hence gravity drainage has always been associated with tall matrix blocks. But these saturation images obtained clearly show the influence of gravity segregation in the displacement process. The fact that the oil recovery takes place mainly from the top part of the core and some amount of oil is recovered towards the bottom as time progresses indicates that gravity segregation is possible in a 1 inch core. The force required for CO_2 to flow sideways into the matrix is provided by the viscous drive mechanism. Thus the displacement is seen to be a combination of gravity and viscous forces. It can be seen that although CO_2 has invaded a large portion of the core, the recovery of oil from these regions is not complete. It is observed that the maximum saturation of CO_2 occurs at the fracture, indicating that CO_2 is following the path of least resistance. The oil recovery curve from the displacement process is shown in **Fig. 10**. This curve shows that the initial recovery is high and this reduces as time progresses. Towards the end of the experiment, the recovery obtained is seen to be a constant low value. In this kind of displacement, there is always some amount of CO_2 that breaks through without contacting any oil, thus greatly reducing the sweep efficiency.

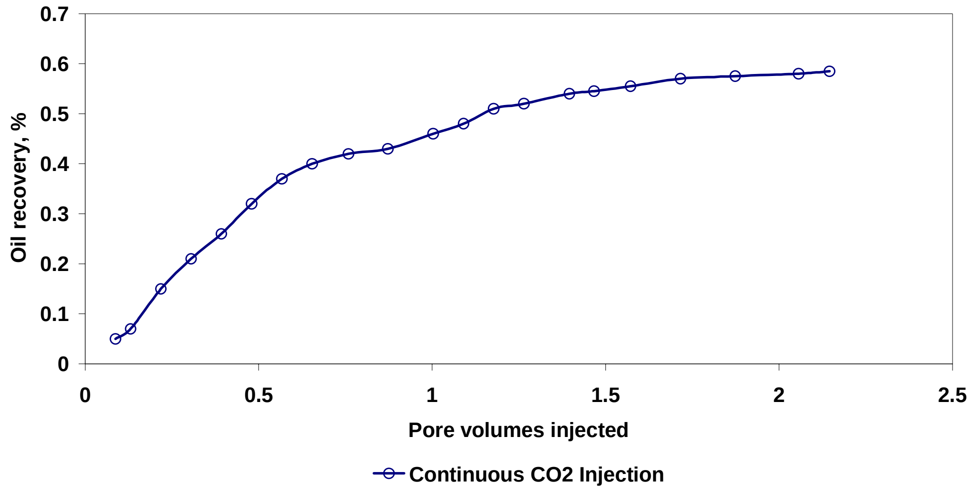


Fig. 10—Oil recovery vs. pore volumes injected for continuous CO_2 injection.

The diffusion process is extremely slow, and given enough time and CO_2, a good recovery may be obtained. The final recovery obtained in this experiment after about 2.2 PV of injection is about 58%.

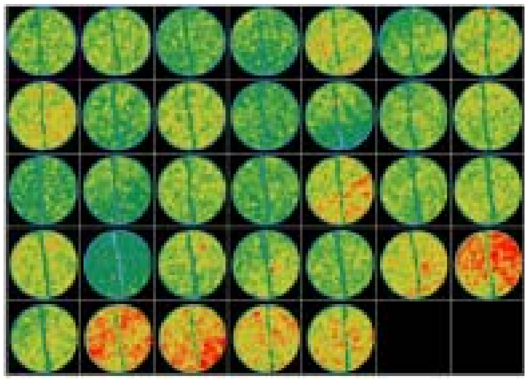
Water Alternating Gas (WAG). Experiments were performed to test the performance of WAG in the presence of extreme heterogeneities like fractures. The first task was to test the mobility of water in the core. Brine was prepared and tagged with both sodium iodide and potassium iodide to artificially its CT number. The properties of brine are provided in Table 1. This tagged brine was injected into an oil saturated core at a rate of about 0.1cc/min. During the experiment, it was observed that the water mobility in the core was very high, Berea being a core with very high permeability. The presence of a fracture in the core increased the mobility even more and a very early breakthrough was observed, at about 0.12 PV of injection.

Table 1—Synthetic Brine Composition

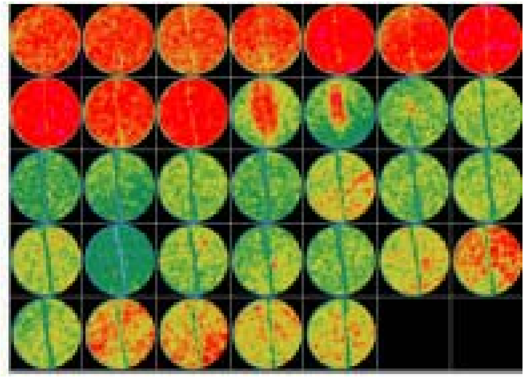
Brine Properties	
Composition	**Concentration**
Nacl	122699 mg/L
$Cacl_2.2H_2O$	7497 mg/L
NaI	500 ppm
KI	500 ppm

This early breakthrough of brine indicated that pure brine by itself will not be able to delay the breakthrough of CO_2 from the fracture. The mobility of water in the fracture had to be reduced and this requires that its viscosity be increased. A conventional WAG process involves alternate injection of specific pore volumes of gas and water to reduce the relative permeability of the gas and hence its mobility. But here, our aim is to delay CO_2 breakthrough and hence we decided to inject the viscosified water into the fracture to "heal" it to some extent so as to the reduce CO_2 mobility in fracture. Xanthan was chosen to increase the viscosity of water due to its good injectivity and relative insensitivity of its viscosity to salinity (Cannella *et al.*, 1988). Sufficient amount of Xanthan was added to the iodated brine to increase the viscosity to about 20 cp. This was then injected into the core with the injection port aligned with the fracture. Although no problems were encountered with the injectivity of the liquid, it was observed that there was a large amount of liquid "leakoff" into the matrix. Liquid "leakoff" is a term used to describe the loss of water into the matrix, from the viscosified mixture in the fracture. This causes the fracture to be left open for CO_2 flow. By the time the liquid filled the entire fracture and breakthrough occurred, a considerable quantity had leaked off into the rock and more than 65% of the oil had already been recovered. **Fig. 11** show the scans obtained at various times during the experiment.

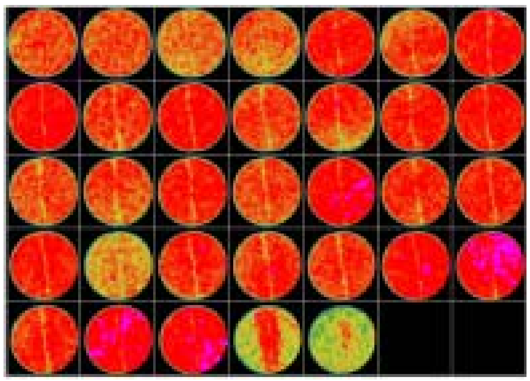
In these scans the red color represents the higher CT numbers where the viscous brine has invaded the pore spaces. Once breakthrough of brine was observed, injection of brine was stopped and CO_2 injection started. By the time CO_2 displaced the remaining brine in the tubing and reached the core, about 80% of the oil had been recovered.



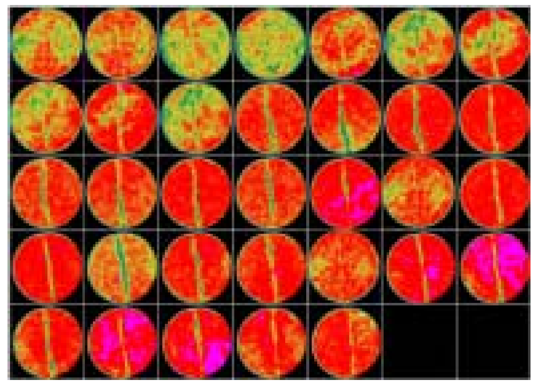
Scans taken at about 0.08 PV of injection



Oil saturated core scans in WAG experiment



Scans taken at about 0.25 PV of injection



Scans taken at the end of WAG experiment

Fig. 11—Scan images taken during WAG experiment

This was considered to be the residual oil saturation for the core to water. CO_2 injection resulted in an incremental recovery of only about 4.5% during which time, viscosified brine was also observed at the outlet. Although, the incremental recovery obtained in this case was low, the important result obtained is that the breakthrough of CO_2 was delayed considerably compared to the continuous CO_2 injection case. Here, the breakthrough of CO_2 occurred after 0.44 PV of injection. Although the overall recovery obtained was higher than that obtained by continuous CO_2 injection, most of the recovery was due to the viscous water and very little due to CO_2. This again might be due to the strong water-wet nature of the cores and the very low viscosity of the oil used. Using brine of higher viscosity (about 30 cp) also gave us similar results. The success of this process depends on preventing liquid leakoff into the matrix, because in actual conditions, the reservoir is likely to be at residual oil conditions and any entry of water into the matrix will not help in recovering more oil and only result in leaving the fracture open for CO_2 flow. Liquid leakoff into the porous rock can be minimized by using suspended particulate matter (Seright and Lee, 1998). Also, in an oil-wet core, the amount of water imbibing into the porous rock would obviously be lesser and hence the viscous liquid can remain in the fracture, healing it to some extent. But this liquid can still flow and would be produced when CO_2 flows through the fracture. So CO_2 and liquid have to be injected alternately similar to the WAG process. Another method suggested in the literature to minimize leakoff is the addition of a cross-linker to form a gel, when its propagation becomes extremely slow or negligible (Seright, 1997). **Fig. 12** represents the oil recovery curve for this experiment. Here the red curve represents the oil recovery due to viscosified water and the green curve represents the incremental oil recovery. It can be seen that the green curve is flat for most part. This is because most of the fluid recovered was brine and very little oil was recovered.

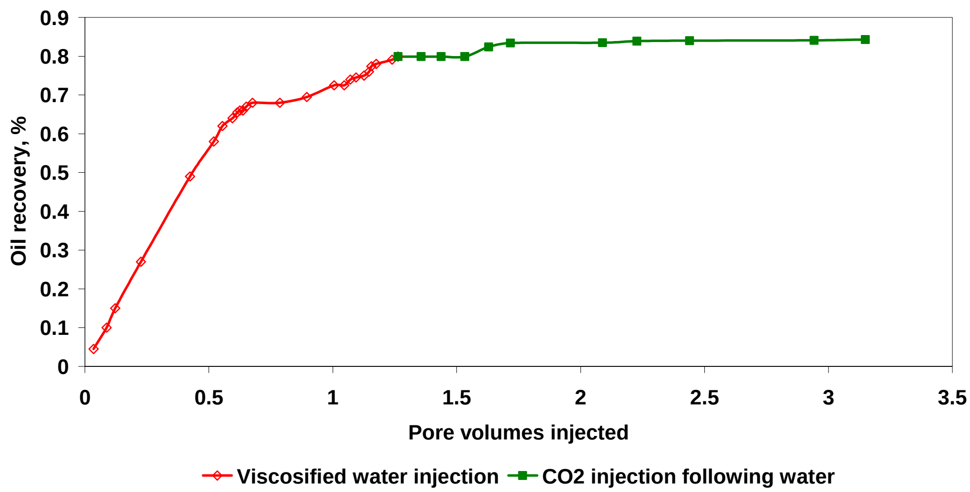
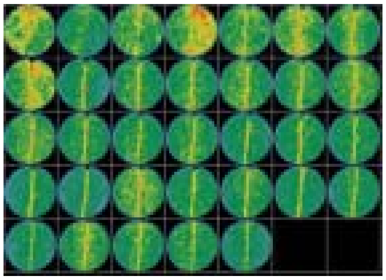


Fig. 12—Oil recovery vs. pore volumes injected for WAG injection

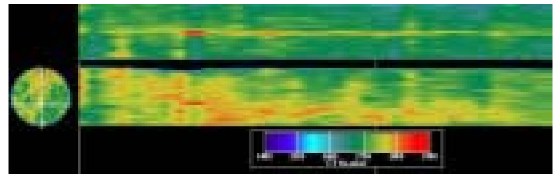
Experiment using cross-linked gel. It was seen in the previous experiments using a polymer without cross-linker that there was excessive leakoff of the viscous fluid into the matrix. Also, alternate injection of brine and CO_2 was required to prevent CO_2 breakthrough from fracture. These two problems can effectively be eliminated by injecting a pre-formed or a delayed cross-link gel into the fracture.

In this experiment, the main objective was to investigate the performance of CO_2 in the presence of gel for conformance control. Here, a delayed cross-link gel was used to delay breakthrough and improve recovery. For this purpose, Guar gum was used with a borate cross linker. Our aim here is not to investigate the use of different types of gels and any gel that can heal the fracture effectively would serve the purpose. Guar and borate cross linker were chosen because of their easy availability and the gel was formed using this combination. One of the important considerations in using a gel for conformance is the injection pressure. As discussed earlier, once the gel is formed by the cross link process, there is a huge increase in the resistance to flow. But gels with low resistance factors can be injected into the fracture without experiencing "screen out". In this case, the partially formed gel with the borate cross linker was injected directly into the fracture and allowed to set for a period of 16 hours. **Fig. 13** depicts the scans taken at different times after CO_2 injection was started.

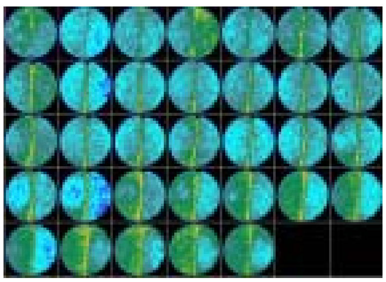
In this experiment, the brine used for forming the gel was doped with sodium iodide and potassium iodide. This was to ensure that the gel was clearly visible once injected into the fracture. It was also important to note the amount of leak off that occurred into the matrix. As can be seen from the figures, the leak off in this case is not very high. This might be due to the fact that the gel was partially formed before being injected into the fracture. Thus the gel is seen as a bright yellow streak at the centre throughout the fracture. The injection of the gel was carried out slowly by scanning different portions of the core and ensuring that the fracture was completely filled with the gel. Once CO_2 injection is started, CO_2 invasion in the core is identified by the change in color to a shade of blue. But the important thing to be noted is that the gel which is seen to be yellow at the beginning of the experiment is still seen to be intact at the end of the experiment. During the experiment, CO_2 is seen to preferentially move into one half of the core compared to the other. Investigation after the experiment showed that two of the grooves on the injection face were blocked by the gel, on one side. This caused most of the injected CO_2 to flow to the other half of the injection face (open grooves). This also led to a much earlier breakthrough than one would have expected. But it can clearly be observed from the cross sections and the reconstructions that a good sweep has been obtained on both halves of the core. The final recovery in this case was about 95% after approximately 2.5 PV of injection. The movement of CO_2 inside the core can be better understood by looking at the ortho reconstructions shown in **Fig. 13.**



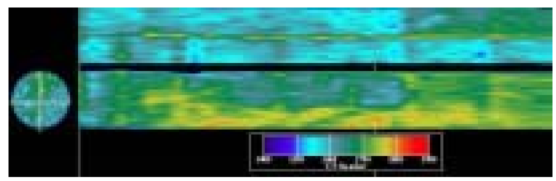
(a). Cross-sectional scans before injection



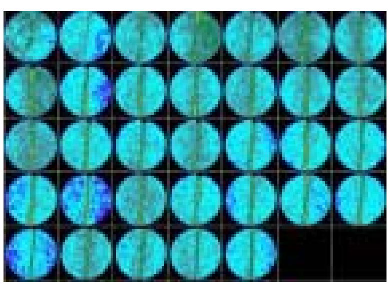
(b). Ortho reconstruction showing gel in the fracture (top) and on the fracture surface (bottom)



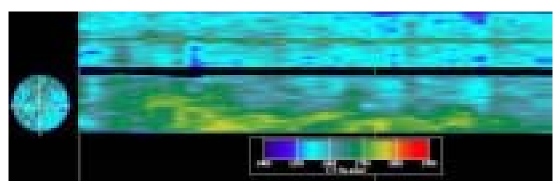
(c). Cross-sectional scans taken at CO_2 breakthrough



(d). Reconstructions of cross-sectional scans showing preferential movement of CO_2 on one half of the core



(e). Cross-sectional scans taken at end of injection



(f). Ortho reconstructions showing gel intact at the end of the experiment

Fig. 13—Scan images taken at various stages of the experiment in the presence of gel

In the above reconstructions, the top reconstruction was made using sections perpendicular to the fracture, while the bottom reconstructions were made using sections along the fracture surface. **Fig. 14** shows the saturation of CO_2 inside the core at the end of CO_2 injection. It can be seen that most of the core is almost fully saturated with CO_2. The centre of the image where the gel was previously present shows a CO_2 saturation value of zero, confirming that no CO_2 is flowing through the fracture and the gel is still intact at the end of he experiment.

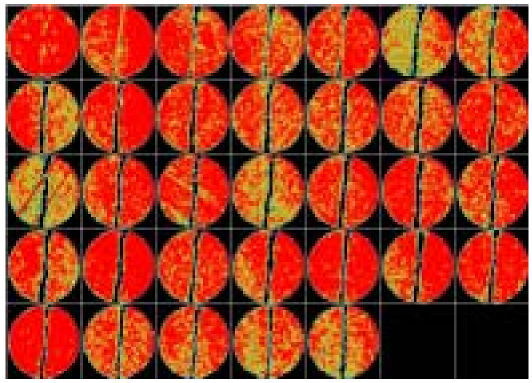


Fig. 14—CO_2 saturations at the end of the experiment converted from Fig. 13e

Fig. 15 shows a comparison of the oil recovery obtained from the three different experiments. It can be seen that the process with the cross-linked gel indicates the highest efficiency.

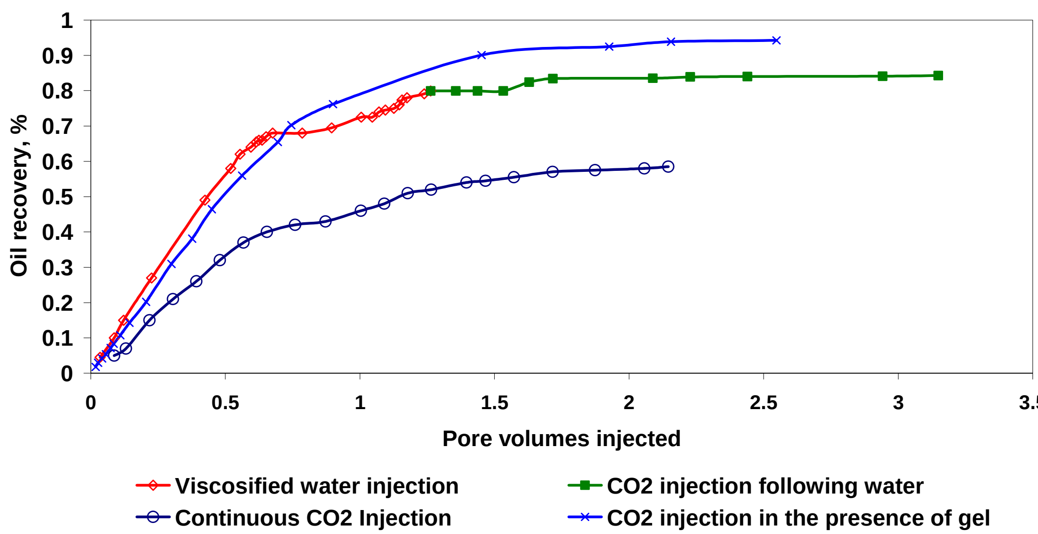


Fig. 15—Recovery curves for the various cases showing highest recovery in the presence of gel

Conclusions

The following conclusions can be derived from the core-flooding experiments performed in the laboratory.

1. Injection rates and heterogeneity play an important role in determining oil recovery and breakthrough. Although quantification of the effect of heterogeneity is very difficult, it can be said that heterogeneities always lead to a poor sweep during a flooding process.

2. In a fractured system, the high permeability fracture serves as the preferred path for the injected fluid. This leads to early breakthrough and higher oil bypass.

3. In the presence of fractures, the recovery of oil from the matrix is a very slow process. Considerable amount of time and CO_2 are required to obtain a good recovery.

4. Coreflood experiments using water viscosified with a polymer suggest that this technique can delay CO_2 breakthrough, provided the liquid “leak off” into the matrix is not very high. Leak off into the matrix might be low in oil wet rocks, but more work is needed to establish this.

5. Using a cross-linked gel for conformance control reduces the liquid leak off to a great extent. Certain partially formed gels can be injected into the fracture without facing "screen out" problems.

6. Cross-linked gels are effective in improving the sweep efficiency and oil recovery during CO_2 flooding. However, the type and composition of gel to be used in the presence of CO_2 needs more investigation.

Nomenclature

$NCT_{100\%Sat}$	CT number of 100% saturated voxel
NCTDry	CT number of dry voxel
NCTWater	CT number of Water = 0.0
NCTAir	CT number of Air = -1000.0
NCTMat	CT number of the matrix
NCTOil	CT number of Oil

Acknowledgement

The authors wish to thank the US Department of Energy (Project DE-FC26-01BC15361) for sponsoring this project.

References

1. Aarra, M.G, Skauge, A., and Martinsen, H.A. (2002). **FAWAG: A Breakthrough for EOR in the North Sea.** SPE 77695, Annual Technical Conference and Exhibition, San Antonio, TX, September 29 – October 2.
2. Akervoll, I., Talukdar, M.S., Midtlyng, S.H., and Torsaeter, O. (2000). **WAG Injection Experiments with In-Situ Saturation Measurements at Reservoir Conditions and Simulations.** SPE 59323, Improved Oil Recovery symposium, Tulsa, OK, April 3-5.
3. Cannella, W.J., Huh, C., and Seright, R.S. (1988). **Prediction of Xanthan Rheology in Porous Media.** SPE 18089, Annual Technical Conference and Exhibition, Houston, October 2-5.
4. Holm, L. W. (Nov. 1987): Evolution of the Carbon Dioxide Flooding Process. *JPT*, pp. 1337-1342.
5. Holm, L.W. (Dec. 1982). **CO_2 FLOODING: Its time has come**. *JPT*, 2739-2745.
6. Holm L.W. and Josendal, V.A. (Dec. 1974). **Mechanisms of Oil Displacement by Carbon Dioxide.** *JPT*, pp. 1427 – 1438.
7. Holm, L.W, and O'Brien, L.J. (April 1971). **Carbon-Dioxide Test at the Mead-Strawn Field.** *JPT*, 431-432.
8. Hsie, J.C. and Moore, J.S. (1986). **The Quarantine Bay 4RC CO_2-WAG Pilot Project: A Post Flood Evaluation.** SPE 15498, Annual Technical conference and Exhibition, New Orleans, 5-8 October.
9. Kane, A.V. (Feb. 1979). **Performance Review of a Large-Scale CO_2-WAG Enhanced Recovery Project - SACROC Unit- KELLY SNYDER.** *JPT*, 217.
10. Prieditis, J., Wolle, C.R. and Notz, P.K. (1991). **A Laboratory and Field Injectivity Study: CO_2 WAG in the San Andres Formation of the West Texas.** SPE 22653, Annual Technical Conference and Exhibition, Dallas, TX, October 6-9.
11. Putra, E., Fidra, Y., and Schechter, D.S. (1999). **Use of Experimental and Simulation Results for Estimating Critical and Optimum Water Injection Rates in Naturally Fractured Reservoirs.** SPE 56431, Annual Technical Conference and Exhibition, Houston, TX, Oct. 3-6.
12. Rogers, J. D. and Grigg, B. R. (Oct. 2001). A Literature Analysis of the WAG Injectivity Abnormalities in the CO_2 Process. *SPEREE*, 375-386.
13. Seright, R.S. and Liang, J. (1995). **A Comparison of Different Types of Blocking Agents.** SPE 30120, European Formation Damage Conference, The Hague, Netherlands, May 15-16.
14. Seright, R.S. (Feb. 1997). **Use of Preformed Gels for Conformance Control in Fractured Systems.** *SPEPF J.*, 59-65.
15. Seright, R.S. and Lee, R. (1998). **Gel Treatments for Reducing Channelling in Naturally Fractured Reservoirs.** SPE 39802, Permian Basin Oil and Gas Recovery Conference, Midland, Texas, 25-27 March.
16. Uleberg, K. and Hoier, L. (2002). **Miscible Gas Injection in Fractured Reservoirs.** SPE 75136, Improved Oil Recovery Symposium, Tulsa, Oklahoma, 13-17 April.
17. Wellington, S.L. and Vinegar, H.J. (Aug. 1987). **X-Ray Computerized Tomography**. *JPT*, pp. 885-898.
18. Yaghoobi, H., Tsau, J.S., and Heller, J.P. (1996). **Improving CO_2 Floods in Heterogeneous Media.** SPE 35403, SPE/DOE Symposium on Improved Oil Recovery, Tulsa, 21-24 April.