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Improved Efficiency of Miscible C02 Floods and Enhanced Prospects for C02 Flooding Heterogeneous Reservoirs

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Quarterly Technical Progress Report

IMPROVED EFFICIENCY OF MISCIBLE CO_2 FLOODS AND ENHANCED PROSPECTS FOR CO_2 FLOODING HETEROGENEOUS RESERVOIRS

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ABSTRACT

The PRRC-modified DOE pseudomiscible reservoir simulator MASTER was used to conduct a systematic investigation of CO_2 flooding using horizontal wells in conjunction with foam. We evaluated the effects of horizontal well radius, length, and location on oil recovery through our testing. This work is necessary to provide field predictions for the use of foam and/or horizontal wells.

A number of coreflood tests were performed to examine the effect of foam on oil recovery in heterogeneous porous media. Two coaxial composite cores were used to simulate layered formation systems. The first, an isolated coaxial composite core, was used to simulate a layered formation system of which the layers were not in communication. The second, in capillary contact, simulated layers in communication. Preliminary results suggest that oil displacement is more efficient when surfactant solution is used with CO_2 to form CO_2-foam. Results from both systems indicate the potential of using foam for improving oil recovery in heterogeneous porous media.

Since injectivity loss is a problem in a number of gas injection projects, a preliminary investigation of injectivity loss in WAG was performed. A number of tests were carried out to investigate injectivity loss, indicating that for a given rock the injectivity loss depends on oil saturation in the core during WAG flooding. Higher loss was found in cores with high in-situ oil saturations. No injectivity loss was observed with the naturally fractured carbonate core.

EXECUTIVE SUMMARY

A grant, "Improved Efficiency of Miscible CO_2 Floods and Enhanced Prospects for CO_2 Flooding Heterogeneous Reservoirs," DOE Contract No. DE-FG26-97BC15047, was awarded and started on June 1, 1997. This project examines three major areas in which CO_2 flooding can be improved: fluid and matrix interactions, conformance control/sweep efficiency, and reservoir simulation for improved oil recovery.

The PRRC-modified DOE pseudomiscible reservoir simulator MASTER was used to conduct a systematic investigation of CO_2 flooding using horizontal wells in conjunction with foam. We evaluated the effects of horizontal well radius, length, and location on oil recovery through our testing. This work is necessary to provide field predictions for the use of foam and/or horizontal wells.

Coreflooding experiments are being used to examine the effect of foam on oil recovery in heterogeneous porous media. A capillary contact coaxial composite core was used to simulate a communicating layered formation system while an isolated coaxial composite core was used to simulate a noncommunicating layered formation system. Preliminary results show favorable indications, suggesting that, when surfactant solution is used with CO_2 to form CO_2-foam, oil displacement is more efficient. Results from both systems indicate the potential of using foam for improvement of oil recovery in heterogeneous porous media.

Since injectivity loss is a problem in a number of gas injection projects, a preliminary investigation of injectivity loss in WAG was performed during this reporting period. A number of tests were carried out to investigate injectivity loss. Results indicate that for a given rock, the injectivity loss depends on oil saturation in the core during WAG flooding, with a higher loss in cores with high in-situ oil saturations. No injectivity loss was observed with the naturally-fractured carbonate core.

INTRODUCTION

Because of the importance of CO_2 flooding to future oil recovery in New Mexico, west Texas, and the United States, the Petroleum Recovery Research Center (PRRC) pursues a vigorous research program to improve the effectiveness of CO_2 flooding in heterogeneous reservoirs. The results of our research continue to expand the list of viable candidates for CO_2 flooding. Our primary interests are to include more low-pressure reservoirs and many more heterogeneous or fractured reservoirs in our research.

Continued support for oil recovery research by CO_2 flooding has been provided by the U.S. Department of Energy for an additional three years through a grant entitled: "Improved Efficiency of Miscible CO_2 Floods and Enhanced Prospects for CO_2 Flooding Heterogeneous Reservoirs." The New Mexico Petroleum Recovery Research Center (PRRC) is well known as a premier institution for improved oil recovery (IOR) research and, in particular, for its research on the use of high-pressure CO_2 injection. The extension will continue the progress on understanding CO_2 flooding in heterogeneous reservoirs, further the development of methods to enable CO_2 flooding in more heterogeneous reservoirs, and continue the dissemination of this information to promote successful implementation of these methods. The research proceeds in three related areas:

- Fluid and matrix interactions (understanding the problems): interfacial tension (IFT), phase behavior, development of miscibility, capillary number (Nc), injectivity, wettability, gravity drainage, etc.
- Conformance control/sweep efficiency (solving the problems): reduction of mobility using foam, diversion by selective mobility reduction (SMR) using foam, improved injectivity, WAG, horizontal wells, etc.
- Reservoir simulation for improved oil recovery (predicting results): gravity drainage, SMR, CO_2/foam flooding, IFT, injectivity profile, horizontal wells, and naturally fractured reservoirs.

All areas originate from research on the mechanics of oil recovery by high-pressure CO_2. Experience gained during the current project is relevant to our continued efforts. Future research in each of the three areas will increase both the quantity of oil produced and the efficiency of oil recovery from CO_2 flooding. Special attention will be given to disseminating research results through an extensive technology transfer effort. Because of the importance of CO_2 flooding in New

Mexico reservoirs, additional funds are being provided through a combination of state and industry funds.

For this quarter, a summary is presented in three areas: sensitivity studies of the horizontal well option in MASTER, foam for mobility control, and preliminary investigations on injectivity loss in WAG flooding with extended results in the later two.

TECHNICAL PROGRESS

SUMMARY

One of the objectives of this work is to conduct a systematic investigation of CO_2 flooding using horizontal wells in conjunction with foam. A DOE pseudomiscible reservoir simulator, MASTER, which has been modified by incorporating the foam and horizontal-well features, is used in this investigation. Tests continue to evaluate the effects of horizontal well radius, length, and location on oil recovery. This sensitivity study on these parameters will be used in conjunction with our numerical tests on the comparison of foam injection processes and horizontal well injection processes.

A number of coreflood tests were performed to examine the effect of foam on oil recovery in heterogeneous porous media. Two coaxial composite cores were used to simulate layered formation systems. The first, an isolated coaxial composite core, was used to simulate a layered formation system of which the layers were not in communication. The second, in capillary contact, simulated layers in communication. Preliminary results suggest that oil displacement is more efficient when surfactant solution is used with CO_2 to form CO_2-foam. Results from both systems indicate the potential of using foam for improving oil recovery in heterogeneous porous media.

Preliminary results show a delay in CO_2 breakthrough in the high permeability region. This is a favorable indication, suggesting that oil displacement is more efficient when surfactant solution is used with CO_2 to form CO_2-foam. Substantial reduction of CO_2 mobility in the higher permeability regions or diversion of CO_2 from high-permeability to low-permeability regions helps improve the sweep efficiency. Under our test conditions, all favorable oil recovery results from both systems indicate the potential of using foam for improvement of oil recovery in heterogeneous porous media. Details beyond this discussion can be found in paper SPE 39677.[1]

A preliminary investigation of injectivity loss in WAG was performed during this reporting period. A number of tests were done to investigate injectivity loss. The purposes of the experiments were to duplicate situations of injectivity loss in WAG flooding and identify factors affecting injectivity loss. Our preliminary results indicate that for a given rock, injectivity loss depends on oil saturation in the core during WAG flooding. The injectivity loss is higher in cores with high in-situ oil saturations. No injectivity loss was observed with the naturally-fractured carbonate core. More experiments are being conducted using reservoir cores to identify factors affecting the injectivity loss.

Foam for Mobility Control

Experiments were divided into two phases. In the first phase, experiments using composite cores were first saturated with either brine or surfactant solution prior to injection of CO_2. In the second phase experiments, cores were saturated with crude oil to residual water saturation prior to the injection of CO_2. The crude oil was filtered Sulimar Queen oil with a density of 0.83 g/cc and viscosity of 2.9 cp at the test condition of 101°F and 2100 psi. Brine was a synthetic solution with composition of 1.5 wt% NaCl and 0.5 wt% $CaCl_2$ in distilled water. The foaming agent was 2500 ppm surfactant Chaser™ CD1045, which was identified as one of the best foaming agents in several other studies.[2-3] All the tests were conducted at a constant injection rate for either CO_2 alone, CO_2/brine, or CO_2/surfactant with a volumetric ratio of 4 to 1.

Isolated coaxial core system. In each series of experiments a test was conducted in the core system without the presence of oil. Prior to the injection of CO_2, the core was either saturated with brine or surfactant solution. When CO_2, CO_2/brine or CO_2/surfactant was injected into the core, the breakthrough time of CO_2 in both regions were recorded and the results summarized in Table 1.

When CO_2 alone was used as a displacing agent, breakthrough of CO_2 occurred earlier in the high permeability zone (annulus) than in the low permeability zone (center), after 0.62 pore volumes (PV) of CO_2 were injected versus 1.13 PV. Simulating a quick and short cycle of WAG in the field by coinjection of CO_2 and brine slightly delayed CO_2 breakthrough to 0.64 PV in the high permeability region and 1.17 PV in the low permeability region. When surfactant was added to the brine, foam displacement significantly delayed CO_2 production in both regions. The breakthrough of CO_2 occurred at 1.12 PV in the high permeability region and 1.86 PV in the low permeability region. The success of using surfactant to delay the production of CO_2 in the isolated coaxial composite core supports what has been reported previously about foam's effectiveness in delaying production of CO_2 in a capillary contact composite core.[4] The remaining question is to what extent foam can assist CO_2

floods in the oil recovery processes. In a layered model study,[5] we demonstrated theoretically that the breakthrough time of the high permeability layer is delayed and the sweep efficiency of the model is improved if the mobility of the injected fluid is reduced.

To experimentally demonstrate the benefits of using foam in an oil recovery process, the next experiments used a core that was presaturated with crude oil prior to injection of CO_2, CO_2-brine or CO_2-surfactant. The breakthrough times of CO_2 for both regions of the composite core in each run are summarized in Table 1. The results are generally in agreement with what was observed previously in cases where the core was not saturated with oil. In other words, when a core was presaturated with oil and displaced by CO_2 alone, a very early breakthrough of CO_2 occurred in the high permeability region (annulus) at 0.24 PV. As the mobility of the injected fluid was reduced by using CO_2-brine, the production of CO_2 in the annulus was not observed until 0.74 PV of total fluid was injected. In addition, no breakthrough of CO_2 was observed in the low permeability (center) region in these two cases before the end of the experiment, 15 PV of total fluid having been injected.

CO_2 breakthrough occurred much earlier in the high permeability region, as compared with the case where brine was displaced instead of oil. This result indicates that an unfavorable mobility ratio between CO_2 and oil causes a severe fingering or channeling of CO_2 in the high permeability region. When surfactant was added to the brine and coinjected with CO_2 into the core, production of CO_2 from the high permeability region was observed at 0.88 PV while substantial CO_2 production from the low permeability region started at 2.56 PV. The further delay of CO_2 breakthrough in the high permeability (annulus) region and production of CO_2 in the low permeability (center) region indicated that foam diverted part of the injected CO_2 from the high to the low permeability region.

Oil production history from both regions of the composite core supports the fact that foam improves the displacement efficiency in each region and, as a consequence, foam displacement improves the total sweep efficiency. The total oil recovery history (Fig. 1) summarizes the sweep efficiency of this composite core that was improved from 60% for CO_2 injection to 80% for CO_2-brine injection and 95% for CO_2-foam injection.

Capillary contact core system. The second series of experiments were conducted with a composite core that contained coaxial zones of high and low permeability in capillary contact. The breakthrough times of CO_2 from each region of the composite core are summarized in Table 2. The first two tests were performed with no oil present inside the core. When CO_2 and brine were coinjected into the core, production of CO_2 started at 0.42 PV in the high permeability (annulus) region and 0.62 PV in the low permeability (center) region. When surfactant was used to generate foam in the next test, no production of CO_2 in the annulus was observed until 0.66 PV of total fluid was injected. The production of CO_2 in the low permeability region, however, occurs slightly earlier at 0.61 PV. The flowing behavior of CO_2 in these two zones indicates a possible effect of selective mobility reduction as a result of foam displacement. In fact, the mobility of displacing fluid was reduced from 123 to 12.7 md/cp in the low permeability region and from 287 to 1.7 md/cp in the high permeability region. A significant selective mobility reduction behavior was observed in this case.

To examine the effectiveness of foam on oil recovery, three tests were performed on a core that was presaturated with the crude oil. The first test was performed using CO_2 as the displacing agent. As expected, the CO_2 breakthrough occurred earlier in the annulus region, 0.44 PV, than in the center region, 0.50 PV. Using CO_2-brine to displace the oil resulted in a slight delay of CO_2 breakthrough in both regions. However, when foam was used to displace the oil, a significant delay in breakthrough time in the annulus region and an earlier breakthrough in the center region were observed.

The oil production history plotted in Fig. 2 shows that after 4 PV of total fluid was injected, the sweep efficiency was improved from 49% for CO_2 injection to 92% for CO_2-brine injection and a lower 88% for CO_2-foam injection. Using foam is less effective than using CO_2-brine in improving sweep efficiency. This was probably because most of the displacing fluid was diverted into the center region, which had a much smaller pore volume containing a small portion of recoverable oil. The performance of foam in oil recovery should have improved if the target (low permeability) zone contained most of the original oil in place, or the high permeability zone was swept before introducing foam. In other words, if we conducted the experiments on a composite core having a low permeability region with a high portion of recoverable oil, high recovery would be expected as a result of using foam in the oil displacement.

The results presented here are based on a preliminary study. Similar experiments will continue. Parameters such as permeability contrast between two zones, the layout of the different permeability zones, core length, and oil saturation will be changed. Nevertheless, the preliminary results show that the delay of CO_2 breakthrough in the high permeability region is a favorable indication that suggests that, when surfactant solution is used with CO_2 to form CO_2-foam, oil displacement is more efficient. Substantial reduction of CO_2 mobility in higher permeability regions or diversion of CO_2 from high permeability to low permeability regions helps improve the sweep efficiency. Under our test conditions, although the results show that foam is more effective in assisting oil recovery in the isolated coaxial core system than in the capillary contact core system, all favorable oil recovery results from both systems indicate the potential of using foam for improvement of oil recovery in heterogeneous porous media.

Conclusions. The experimental results with two composite core samples of known heterogeneity led us to the following observations and conclusions:

1. Breakthrough time of CO_2 was substantially delayed in the high permeability region in both composite core systems when foam was used as a displacing agent.
2. Foam improved the sweep efficiency during oil displacement. This improved efficiency results from a more substantial reduction of CO_2 in the higher permeability region or a diversion of CO_2 from the high permeability to the low permeability region.
3. A foam flood is more effective in assisting oil recovery in an isolated coaxial core system than in a capillary contact core system.

PRELIMINARY INVESTIGATIONS ON INJECTIVITY LOSS IN WAG FLOODING

Injectivity loss is one of the frequently reported problems in water-alternating-CO_2 (WAG) flooding.[6-16] We conducted experimental investigations on injectivity loss using four cores during the past three months: the first two cores were Berea cores, the third core was a naturally fractured carbonate reservoir core, and the fourth core was a sandstone reservoir core. The purposes of the experiments were to duplicate situations of injectivity loss in WAG flooding and identify factors affecting the injectivity loss. Our preliminary results indicate that for a given rock the injectivity loss depends on oil saturation in the core during WAG flooding. The injectivity loss is higher in cores with high in-situ oil saturations. No injectivity loss was observed with the naturally-fractured carbonate core. More experiments are being conducted using reservoir cores to identify factors affecting the injectivity loss.

Experimental Procedure. The following procedure was followed in all the experiments:

1. Seal a cleaned core sample in a core holder with CERROTRU®.
2. Inject water into the core sample until full saturation is reached. Determine core porosity and permeability to water. This step simulates the initial condition in the reservoir before oil accumulation.
3. Inject crude oil into the core until irreducible (initial) water saturation is established. Determine oil saturation in the core sample. This step simulates oil migration and accumulation in the reservoir.
4. Inject water into the core sample to reduce oil saturation to a desired level. This step simulates the waterflooding process in the oil reservoir.
5. Inject CO_2 into the core at a pressure slightly higher than minimum miscibility pressure (MMP) of the oil until desired oil saturation is reached.
6. Inject water into the core until desired oil saturation is reached.
7. Repeat steps 5 and 6 to simulate WAG process.

Materials and Conditions. The first two cores used in the experiments are Berea cores. The third core is a carbonate reservoir core with natural fractures. Petrophysical properties of the cores are summarized in Table 3. Distilled water was used after degassing. A separator oil with an MMP of 1,650 psig was used in the experiments. All the experiments were conducted at back pressures between 1661 psig and 1667 psig and temperatures ranging from 147^{o}F to 149^{o}F. Volumetric flow rate was kept constant in each experiment run.

Results. Figure 3 presents recorded pressure drop across core sample No. 1 (100 md Berea). The pressure drop was about 106 psi during the pre-CO_2 waterflooding. The average pressure drop increased to 111 psi during the post-CO_2 waterfloods in the WAG period. This is equivalent to a 5% loss in water injectivity.

Figure 4 shows recorded pressure drop across core sample No. 2 (650 md Berea) on the first run with initial water saturation S_{wi} = 0.23. The pressure drop was about 12 psi during the pre-CO_2 waterflooding. The average pressure drop increased to about 17 psi during the post-CO_2 waterfloods in the WAG period. This is equivalent to about 40% loss in water injectivity. Figure 5 demonstrates recorded pressure drop across core sample No. 2 (650 md Berea) on the second run with initial water saturation S_{wi} = 0.14. The pressure drop was about 15 psi during the pre-CO_2 waterflooding. The average pressure drop increased to about 18 psi during the post-CO_2 waterfloods in the WAG period. This is equivalent to about 20% loss in water injectivity. The major difference between the two runs is that the residual oil saturation in the second run during WAG is significantly lower than that in the first run. It appears that the higher the residual oil saturation is, the higher the injectivity loss is.

Figure 6 illustrates recorded pressure drop across core sample No. 3 (315 md fractured carbonate). The pressure drop was about 2 psi during the pre-CO_2 waterflooding. The average pressure drop is slightly higher during the post-CO_2 waterfloods in the WAG period. Since the natural fracture provided a relatively large flow channel for fluids in the small core plug, the results should not be simply scaled up to the field level. A reservoir core without natural fractures is currently being tested to enable better data interpretation.

Figure 7 shows recorded pressure drop across core sample No. 4 (3.5 md reservoir sandstone). The pressure drop was about 24 psi during the pre-CO_2 water flooding. The initial pressure drops are 30 psia and 37 psia during the first two post-CO_2 waterfloods in the WAG period. This indicates an injectivity loss of about 40%.

Conclusion. In order to duplicate situations of injectivity loss in WAG flooding and identify factors affecting injectivity loss, we conducted experimental investigations on injectivity loss using four cores during the past three months. Two of them are Berea cores and the other two are a naturally fractured carbonate reservoir core and a sandstone reservoir core. The preliminary results indicate that for a given rock the injectivity loss depends on oil saturation in the core during WAG flooding. The injectivity loss is higher in cores with high in-situ oil saturations during WAG flooding. This effect is being verified by more experimental data.

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Table 1. Summary of capillary-isolated composite core experiments

Run #	Description	Flow rate (cc/hr)	Ratio	Breakthrough in Annulus region (PV)	Breakthrough in center region (PV)
1	CO_2 displace brine	16.00	1	0.63	1.13
2	CO_2/brine displace brine	16.45	4:1	0.64	1.17
3	CO_2-foam displace surf.	16.45	4:1	1.12	1.86
4	CO_2 displace oil	16.00	1	0.24	N/A
5	CO_2/brine displace oil	16.45	4:1	0.74	N/A
6	CO_2-foam displace oil	16.45	4:1	0.88	2.56

N/A: no breakthrough was observed

Table 2. Summary of capillary-contact composite core experiments					
Run #	Description	Flow rate (cc/hr)	Ratio	Breakthrough in annulus region (PV)	Breakthrough in center region (PV)
1	CO_2/brine displace brine	16.45	4:1	0.42	0.62
2	CO_2-foam displace surf.	16.45	4:1	0.66	0.61
3	CO_2 displace oil	16.00	1	0.44	0.50
4	CO_2/brine displace oil	16.45	4:1	0.46	0.61
5	CO_2-foam displace oil	16.45	4:1	0.86	0.34

Table 3. Dimensions and petrophysical properties of core used in the injectivity experiments				
Core No.	1	2	3	4
Core Type	Berea	Berea	Fractured Carbonate	Reservoir Sandstone
Diameter, cm	3.81	1.27	3.68	3.61
Length	5.39	7.44	7.65	7.65
Porosity	0.21	0.37	0.05	0.12
Initial Water Saturation	100	650	315	35

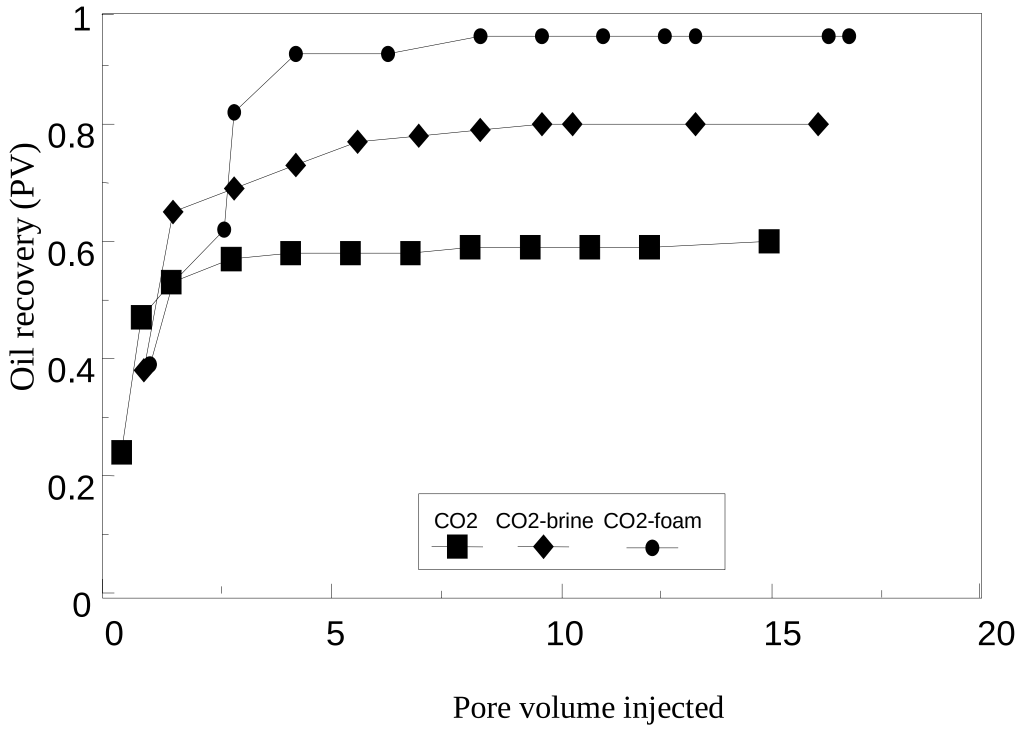

Fig.1. Total oil recovery in a capillary-isolated composite core.

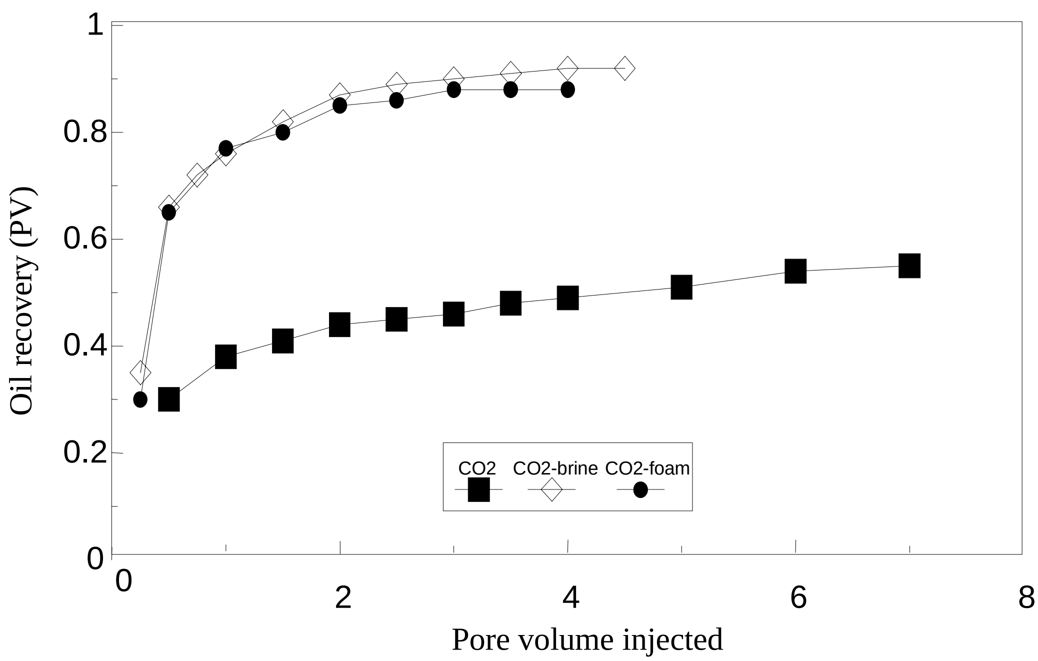

Fig. 2. Total oil recovery in a capillary-contact composite core.

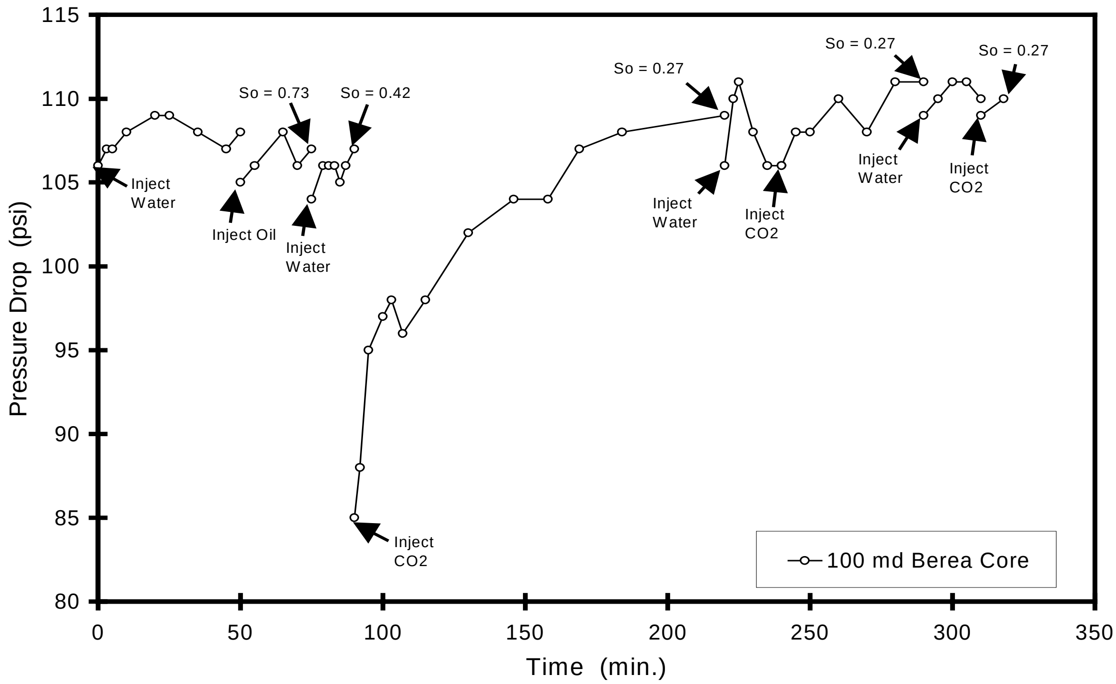

Fig. 3. Recorded pressure drop during WAG injection for a 100 md Berea core.

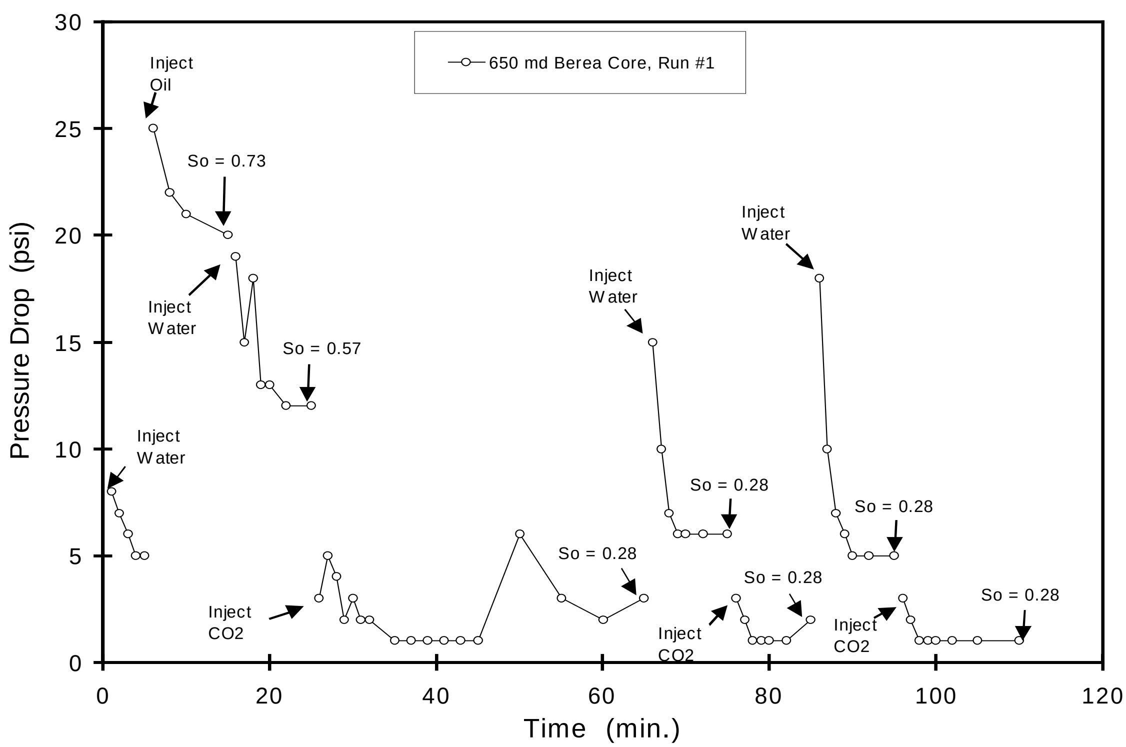

Fig. 4. Recorded pressure drop during WAG injection for a 650 md Berea core, Run #1.

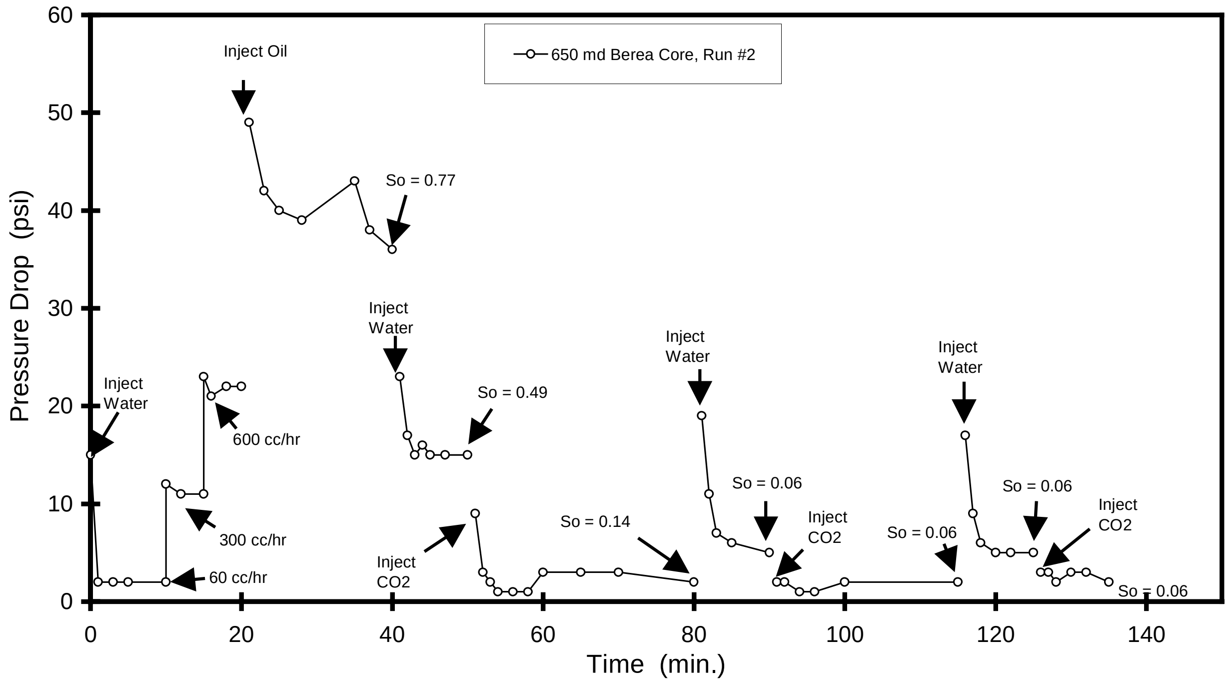

Fig. 5. Recorded pressure drop during WAG injection for a 650 md Berea core, Run #2.

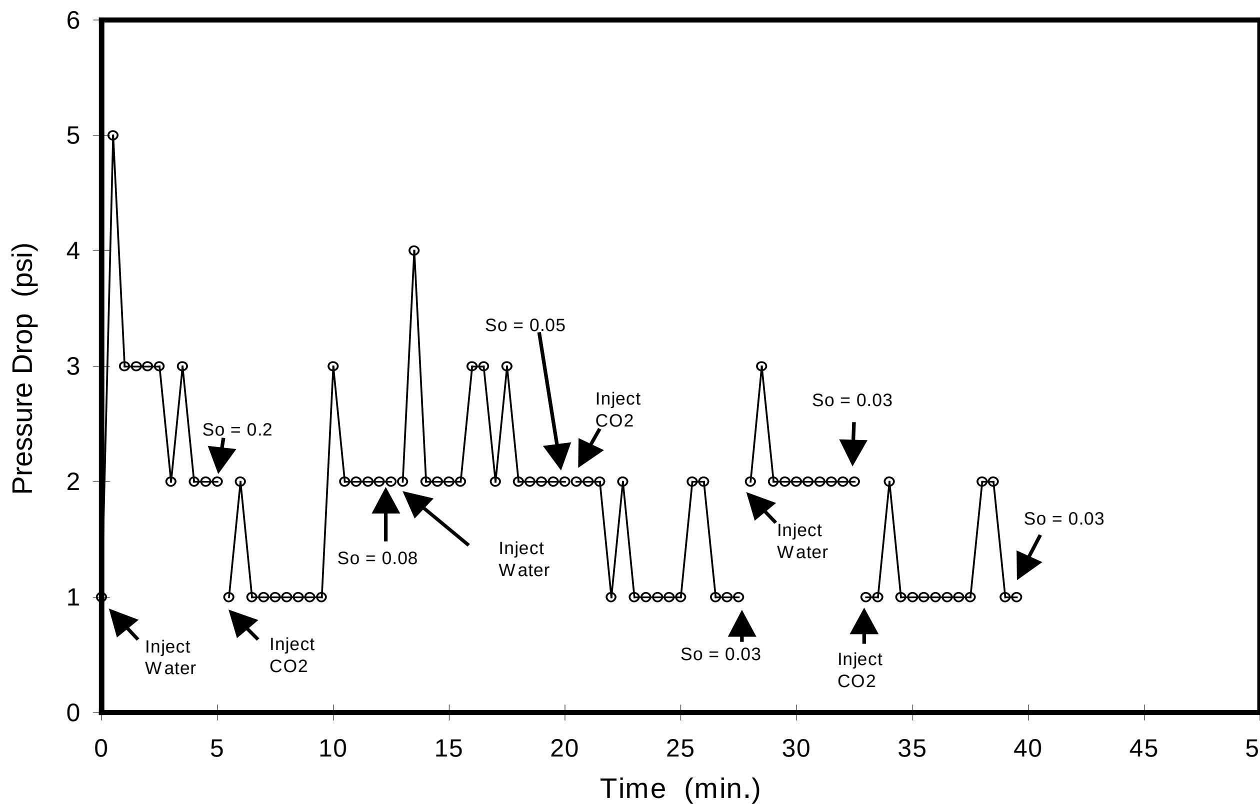

Fig. 6. Recorded pressure drop during WAG injection for a 315 md carbonate reservoir core plug.

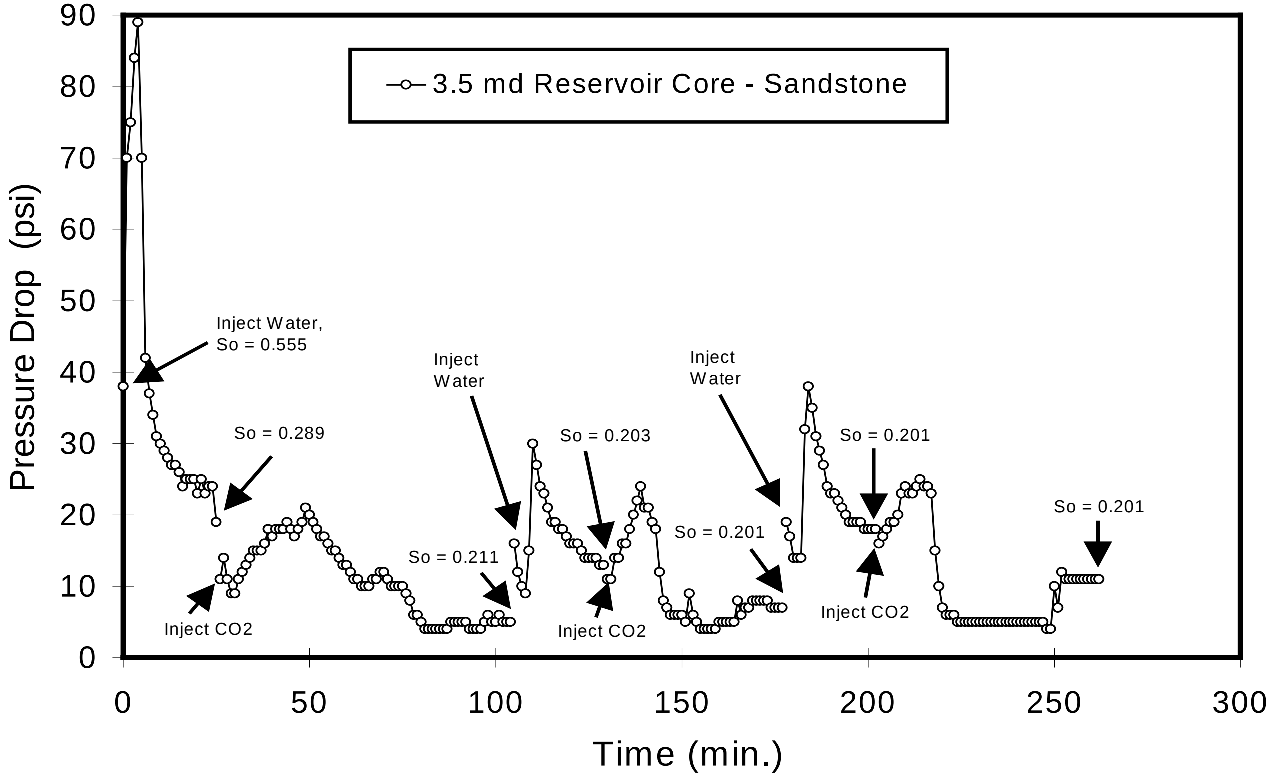

Fig. 7. Recorded pressure drop during WAG injection for a 3.5 md sandstone reservoir core plug.