

**FOAM AND EMULSION EFFECTS ON
GAS DRIVEN OIL RECOVERY**

Supri TR 62

**By
James Farrell
S.S. Marsden, Jr.**

November 1988

**Performed Under Contract No. FG19-87BC14126
and AC03-81SF11564**

**Stanford University Petroleum Research Institute
Stanford, California**



**Bartlesville Project Office
U. S. DEPARTMENT OF ENERGY
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ABSTRACT

The aim of this research was to investigate the gas mobility reducing effects that a gas driven surfactant slug has on enhanced oil recovery (EOR). Three chemically similar surfactants whose properties graded from foaming agent to emulsifying agent were used to study the effects that foam and emulsion formation have on enhanced oil recovery in an unconsolidated Ottawa sand model at room temperature. Both the foam lamellae and the emulsion droplets act to reduce the mobility of the injected gas in the swept zone thus increasing the vertical sweep efficiency. Shell's Enordet series of alcohol ethoxylate surfactants were used in the study at three different concentrations of, 0.01%, 0.03% and 0.100% (wt.).

The experimental procedure consisted of displacing oil from a porous medium at residual water saturation by injecting carbon dioxide, followed first by the injection of a 0.20 pore volume slug of surfactant solution, then by carbon dioxide gas at low pressure. Measurements were made of the cumulative produced gas and liquids.

Performance differences between different surfactants are small but consistent. Combining the foam and emulsion mechanisms seems to lead to more efficient oil recovery than either mechanism alone.

I. INTRODUCTION

Isothermally displacing oil by injecting gas into a porous medium is a relatively inefficient process. This is true whether the injected gas is steam, nitrogen, carbon dioxide or some type of enriched gas. The inefficiency is the result of two phenomena, low areal and vertical sweep efficiency and viscous instabilities in the displacement process. Since the injected gas is both less dense and less viscous than the oil, it is subject to gravity override and preferential channeling through zones with lower liquid saturations and higher permeabilities.

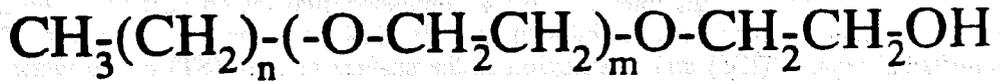
One way of improving the efficiency of the displacement process is to inject a surfactant solution either simultaneously or alternatively (WAG) with the injection of the gas. The injection of the surfactant solution into the oil and water containing porous medium has a number of consequences. One is the formation of a foam between the aqueous surfactant-containing phase and the injected gas phase. Also an emulsion may be formed from the in-situ oil and the the aqueous surfactant-containing phase. In addition, there is a lowering of the water/oil interfacial tension (IFT) and a reduction in the surface tension (ST) of the water in the porous medium.

Due to its high apparent viscosity, foam acts to reduce the mobility of the injected gas in the zones with lower fluid saturations and thus improves both areal and vertical sweep efficiencies. The emulsion has a similar effect in blocking the flow of gas through the more permeable zones. A low IFT will reduce the pressure required to deform and displace the oil ganglia through the pore constrictions. A reduction in the surface tension of the in-situ water will reduce the capillary forces and thus release some of the water trapped by capillary forces. The lowered surface tension in the aqueous phase may also result in some wettability changes in the porous medium.

This study focused on the improved oil recovery brought about by a reduction in injected gas mobility resulting from both foam and emulsion generation in the porous medium. Generally, surfactant EOR work has focused on either the foam or emulsion mobility reduction mechanisms. This investigation looked at the EOR effectiveness of the foam and emulsion mechanisms separately as well as in combination through the use of a homologous series of surfactants whose properties graded from those of a good foaming agent to good emulsifying agent.

The surfactants used in this study are a series of nonionic alcohol ethoxylate surfactants which are characterized by a linear carbon chain of 12 to 15 carbons in length attached by an ether linkage to an ethylene oxide polymer chain of different lengths. The chemical structure of these surfactants is depicted in Figure 1. The length of the ethylene oxide (EtO) chain is the primary factor which controls the behavior of the surfactant. A surfactant whose EtO chain is short relative to the linear carbon chain is more hydrophobic than hydrophillic and will tend to partition into the oleic phase more strongly than the aqueous phase. This behavior leads to a surfactant which is a good emulsifying agent. A surfactant with a relatively long EtO chain would be more hydrophillic in character and thus partition less into the oleic phase. Surfactants of this type would be better at producing foam and less proficient at emulsification than those surfactants whose EtO chains are shorter. A surfactant whose EtO chain is intermediate in length as compared to the good foaming and good emulsifying surfactants would be expected to be effective at both foam and emulsion formation. The surfactants used in this study have EtO chains whose average lengths are 3, 7, and 12 EtO monomers. The surfactant with the EtO chain of length 12 is the best foaming agent, while the surfactant whose EtO chain is of length 3 is the best emulsifying agent, and the intermediate surfactant with EtO chain length of 7 is both a relatively good foaming agent and emulsifying agent.

Alcohol Ethoxylate



$n=11-14$

$m=2,6,11$

Fig. 1. Structural formula of an alcohol ethoxylate.

2. LITERATURE REVIEW

Much research has been done on the use of surfactants in EOR. This literature review will focus on the gas mobility reducing effects of foams and of emulsions in porous media. The former has been critically reviewed recently by Marsden (1986).

Bond and Holbrook (1958) were among the first to suggest that gas driven oil recovery could be improved by the alternate injection of surfactant solution and gas. The alternate injection of aqueous surfactant solution and gas generated foam in the porous medium. They claimed that because of the foam's high apparent viscosity, an observation first pointed out in the literature by Sibree (1943), the areal sweep efficiency of both miscible and immiscible gas drives would be increased. Fried (1961) also did early work on the use of foam in EOR. He reported that oil recovery from unconsolidated sand packs was increased when foam was used as the displacing agent over that when either gas, water, or surfactant solution alone were used.

A study to investigate the effect of foam on the permeability to gas in both consolidated and unconsolidated porous media was performed by Bernard and Holm (1964). They found that the presence of foam in the porous medium reduced the specific permeability to gas to less than one percent of its prior value when no foam was present. Bernard and Holm also found that the reduction in permeability was greater the higher the permeability of the porous medium. Similar results where the blocking effects of foam were greater for media with higher permeabilities were reported by Smith *et al.* (1969), Albrecht and Marsden (1970), Heller (1980), and Sharma *et al.* (1982).

Along these same lines, Marsden and Khan (1966) studied apparent viscosity and relative permeability effects of foam in porous media. They reported ratios of effective permeability to apparent viscosity for different foam qualities, and ratios of relative permeability to apparent viscosity for porous media with differing permeabilities. Among their conclusions was that the apparent viscosity of foam decreases with increasing shear rate. This pseudoplastic behavior of foam in porous media has been widely reported in the literature: David and Marsden (1969), Aizad and Okandan (1977) and Ali *et al.* (1985).

Most of the recent research involving foam in EOR has been in the application of steam foam as a mobility control agent in steam injection. The literature is replete with both field and laboratory tests reporting reduced steam mobility due to the formation of steam foams: Needham (1968), Chiang *et al.* (1980), Al-Khafaji *et al.* (1982), Dilgren *et al.* (1978 & 1982), Brigham *et al.* (1984), Ploeg and Duerksen (1985), Falls *et al.* (1986), Keizer *et al.* (1986), Mohammadi *et al.* (1986) and Wang *et al.* (1986).

Another area where there is research activity is in the use of foam for carbon dioxide mobility control in miscible carbon dioxide flooding. Recent papers in this area are: Heller *et al.* (1985), Casteel and Djabbarah (1985) and Wellington and Vinegar (1985).

Although most of the research concerning the use of emulsions in EOR has focused on the low IFT properties of micellar floods, a few papers have dealt with the use of emulsions as mobility control agents in porous media.

There are primarily two means by which an emulsion exerts its mobility reducing effects. If the emulsion includes droplets which are larger in size than some of the pore-throat constrictions, these can lodge in the pore-throats and thus impede flow. This phenomenon is referred to as straining capture by Soo and Radke (1984). In their paper they investigate the role of

flow velocity on the type of capture and release mechanisms in emulsion flow in porous media. The mechanism which traps droplets that are smaller than the pore constrictions is referred to as interception capture. This phenomenon involves colloidal attractive forces between the drops and the sand grains which can hold emulsion droplets in crevices between the grains and thus reduce the area open to flow.

In laboratory work, Jennings *et al.* (1974) report improved volumetric sweep efficiency by a waterflood due to the formation of a crude oil-in-water emulsion that had the effect of plugging water fingers and high permeability channels. In addition to the laboratory studies, field tests have been reported increased oil recovery as a result of the selective blocking action of emulsions. Grau and Johnson (1974) reported an increased recovery from a waterflood of 400,000 bbl which they attributed to the selective blocking of the oil depleted zones. The selective blocking may be the result of more emulsion flow into the high permeability zones and thus more flow restriction, or possibly because the shear forces, which are needed to generate the emulsion, are greater in the more permeable zones.

In surfactant EOR studies it is often difficult to attribute the results to a particular surfactant effect. For instance, lowering the IFT can lead to improved recovery by more than one mechanism. The low IFT reduces the force needed for the deformation and flow of the oil ganglia, while at the same time promotes the formation of an emulsion.

Also complicating matters is the fact that surfactant induced wettability changes can lead to EOR. If a porous medium is completely water wet, a change in wettability towards a more intermediate wetness can lead to greater oil recovery. This was first reported by Uren and Fahmy (1927) and has since been confirmed by others: Beeson (1963), Salathiel (1973), and Cooke *et al.* (1974). Surfactant induced wettability changes have also been reported to affect the permeability of a porous medium to gas. In their study of foam and surfactant solution properties, Kanda and Schechter (1976) found that the permeability of their porous medium to injected nitrogen gas was sensitive to the wettability of the system.

Because the mechanisms by which surfactant solutions effect EOR are interrelated, it is often difficult to study isolated effects. This research focused on the EOR resulting from reduced injected gas mobility. Most previous work in this area has focused on either foams or emulsions as mobility control agents. This research investigated the combined effects of these two mechanisms through a stepwise variation in surfactant character.

3. EXPERIMENTAL APPARATUS AND PROCEDURE

The following is a description of the experimental apparatus and procedure. Appendix A contains the descriptions of a different model and a different experimental procedure both of which were unsatisfactory.

3.1. DESCRIPTION OF THE APPARATUS

An unconsolidated sandpack filled with Ottawa sand of internal dimensions 58.9 cm × 14.6 cm × 0.75 cm was used for the investigation. The model was constructed from stainless steel, aluminum and 1/2 in. thick tempered safety glass. The front face of the model, which allowed for visual observation of the flow, was safety glass, reinforced on the exterior by aluminum buttressing. The back face of the model was stainless steel, also reinforced with aluminum buttressing. Fluids were injected through the entire injection end of the model. The 0.125 in. I.D. nylon tubing leading from the injection cylinders branched into six stainless steel ports which fed the injection header. To prevent sand migration, both the injection and production headers were covered with a 300 mesh stainless steel screen. Production of fluids was through the entire production face of the model. Again six stainless steel ports from the header merged into a single stream from which both gas and liquid production volumes were measured.

The bulk volume of the model was 646 cc and when filled with 60 to 140 mesh sand, the model had a pore volume of 248 cc and a porosity of 38.0%. In order to remove any adsorbed clays or surface contaminants, the sand was cleansed with 0.10 M nitric acid, neutralized with 0.10 M ammonium hydroxide and dried prior to its placement in the model. Pneumatic vibrators were used to settle the sand during the dry packing procedure. The model was not completely homogeneous in that there were visible horizontal striations of slightly varying grain size and permeability. The layering of the model was not intentional but was a consequence of the vibrational method used in settling the sand. Having a completely homogeneous model was not requisite to the investigation and therefore was of little concern. The measured absolute permeability to water was 19.4 darcies and at a residual water saturation of 21.0%, the oil volume in the model was 196.0 cc or 79.0% oil saturation. Distilled water and Klearol, a white mineral oil of 0.815 g/cc density and 15.0 cp viscosity at room temperature, were used. The properties of the model are summarized in Table 1 and a schematic diagram of the apparatus is shown in Figure 2. Appendix B contains a partial list of the components and suppliers of the equipment.

TABLE 1
OTTAWA SAND MODEL DATA

Internal dimensions (cm):	58.9 × 14.6 × 0.75
Sand mesh size range:	60-140
Bulk volume (cc):	646
Pore volume (cc):	248
Porosity:	38.4%
Permeability (Darcies):	19.4
Residual water saturation:	21.0%
Residual oil saturation:	4.6%
Initial oil saturation:	79.0%
Oil viscosity (cp):	15
Oil density (g/cc):	0.815

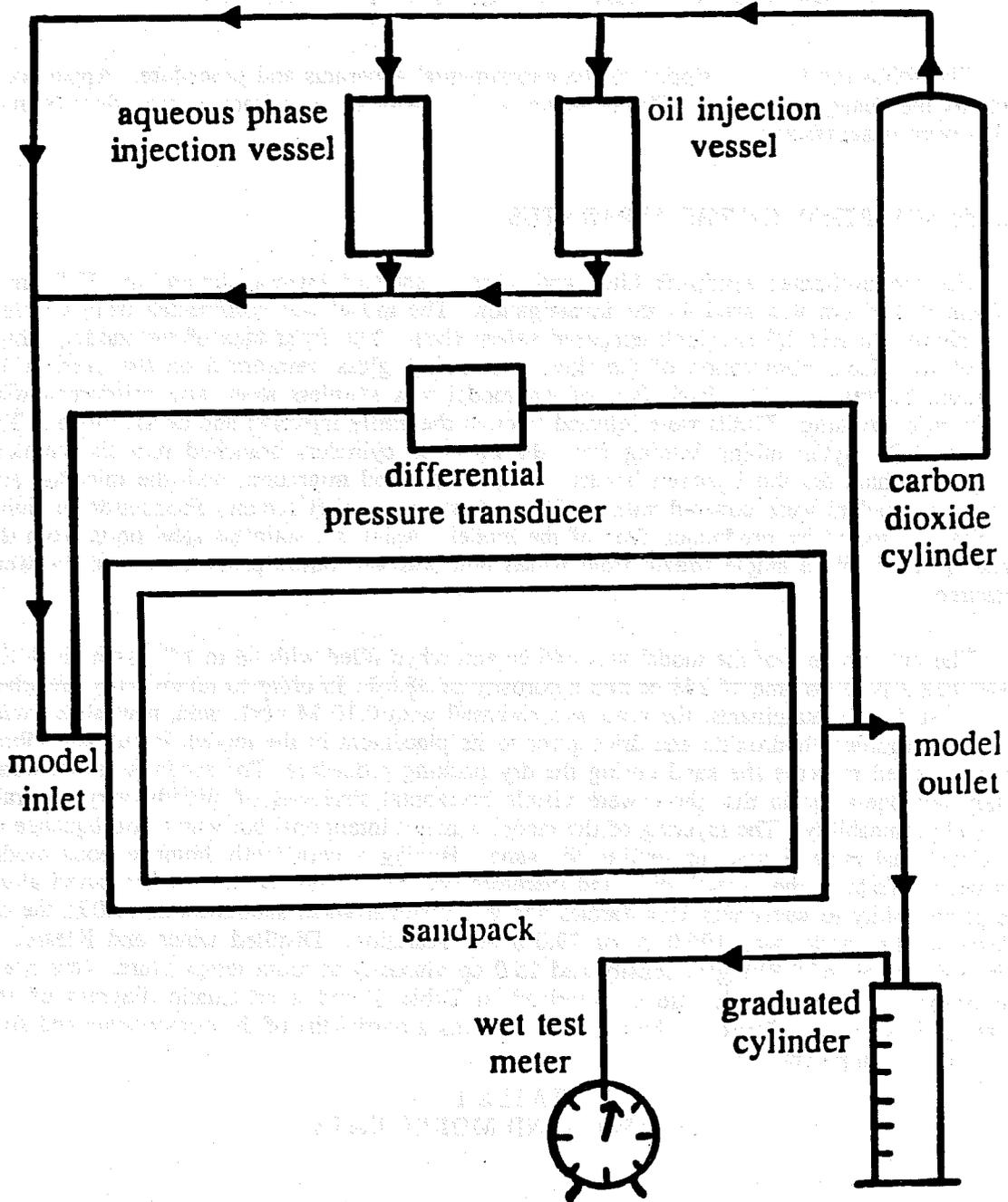


Fig. 2. Schematic diagram of the apparatus.

3.2. EXPERIMENTAL PROCEDURE

The experimental procedure began by saturating the model with distilled water followed by the displacement of the water by injecting oil until an irreducible water saturation was reached. The oil was then displaced with carbon dioxide gas at low pressure and room temperature while measuring the cumulative gas and liquid produced from the model. Carbon dioxide gas was chosen as the displacing agent in order to facilitate re-saturating the model. Since carbon dioxide gas is significantly more water soluble than air or nitrogen, it is more easily displaced when the model is re-saturated with water. The downstream end of the model was at atmospheric pressure and the upstream pressure was adjusted so as to give a constant pressure drop across the model of 3.00 psi. Since the displacements were carried out at such low pressures, the carbon dioxide acted as an inert gas. A diaphragm pressure transducer with a precision of 0.0025 psi was used to measure the pressure difference between the injection and production ends of the model. After 135 cc of oil had been produced, equivalent to a 24.6% oil saturation, a 50.0 cc (0.20 pore volume) slug of surfactant solution was injected into the model and the cumulative production readings of gas and liquid were each recorded at 3.0 min intervals. A 250 cc graduated cylinder was used to collect and measure the fluid production from the model and both the oil phase and the aqueous phase cumulative production volumes were recorded. A wet test meter was used to measure the cumulative gas produced from the model.

Three different alcohol ethoxylate surfactants, Enordet 1215-3 (with an average of three molecules of EtO per 12 to 15 carbon length linear chain), 1215-7 (7 EtO molecules), and 1215-12 (12 EtO molecules) at three different concentrations each, 0.010%, 0.030% and 0.100% by weight, were used in the investigation. Distilled water was used to prepare the surfactant solutions. The surface tension of each solution and the water/oil IFT produced by each solution were measured with a Fisher ring tensiometer and are presented in Table 2. The surface tension of the distilled water was measured to be 68.0 dyne/cm and the distilled water/Klearol IFT was 42.6 dyne/cm.

TABLE 2
SURFACE TENSIONS AND WATER/OIL
INTERFACIAL TENSIONS (DYNE/CM)

Surfactant	Concentration	Surface Tension	Interfacial Tension
Enordet 1215-3	0.010%	28.2	15.4
	0.030%	28.6	12.3
	0.100%	26.4	10.8
Enordet 1215-7	0.010%	28.7	6.7
	0.030%	29.3	5.0
	0.100%	29.4	4.3
Enordet 1215-12	0.010%	32.3	6.8
	0.030%	32.2	6.5
	0.100%	32.2	6.3

To give qualitative verification that the surfactants would behave as expected, i.e., the surfactant with the longest ethylene oxide chain being the best foamer, the surfactant with the shortest ethylene oxide chain being the best at emulsification, and the surfactant with the intermediate length chain being somewhere in between, a simple shake test was performed. Equal volumes of surfactant solution and oil were placed into glass stoppered graduated cylinders and shaken for 15 s. After 1.0 min, the height of the head of foam in each cylinder was recorded. After 15 min the volume of the emulsion phase in each cylinder was recorded. Figure 3 shows

The following table shows the results of the shake test for the emulsions prepared with the various surfactants. The relative foam height and relative emulsion height are given in the table. The relative foam height is defined as the height of the foam layer divided by the height of the liquid layer. The relative emulsion height is defined as the height of the emulsion layer divided by the height of the liquid layer. The results show that the emulsions prepared with the various surfactants have different relative foam heights and relative emulsion heights. The emulsions prepared with the various surfactants have different relative foam heights and relative emulsion heights.

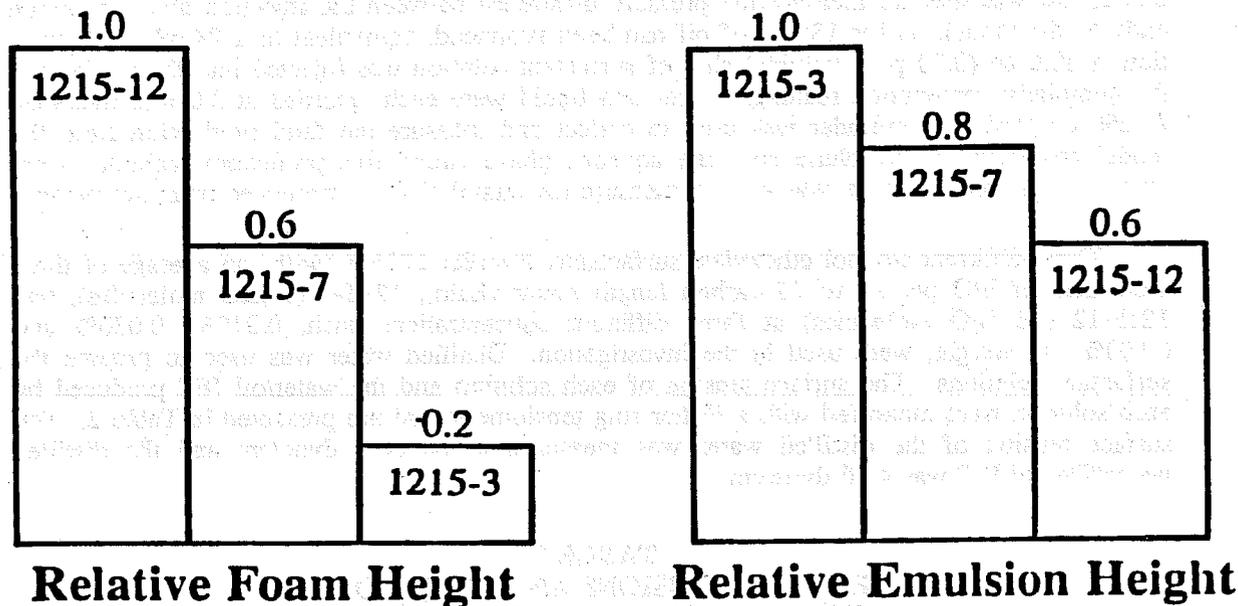


Fig. 3. Shake test relative foam and emulsion heights.

Surfactant	Relative Foam Height	Relative Emulsion Height
1215-12	1.0	0.6
1215-7	0.6	0.8
1215-3	0.2	1.0

The results of the shake test show that the emulsions prepared with the various surfactants have different relative foam heights and relative emulsion heights. The emulsions prepared with the various surfactants have different relative foam heights and relative emulsion heights. The emulsions prepared with the various surfactants have different relative foam heights and relative emulsion heights.

the relative foam heights and relative emulsion heights in the graduated cylinders for 0.100% surfactant concentration. Presented in Table 3 are the volumes of the foam, emulsion, and aqueous phases in the graduated cylinders in the shake test. The results in the shake test for the other two concentrations used in the study, 0.010% and 0.030%, were substantially the same.

TABLE 3
SHAKE TEST PHASE VOLUMES (cc)

Surfactant	Foam Phase	Emulsion Phase	Aqueous Phase
Enordet 1215-3	1	7.2	2.2
Enordet 1215-7	3	6	3
Enordet 1215-12	5	4.3	1

It is important to note that this is only a qualitative test since the mechanisms of foam and emulsion generation in the porous medium are substantially different.

To clean the model after each run, the model was flushed with approximately 100 pore volumes of distilled water. At this point the surface tension of the effluent water was the same as that for the pure distilled water. For each surfactant the sequencing of the runs was from lowest to highest concentration and the sequencing of the different surfactants was: first the 1215-12, followed by the 1215-3, and the 1215-7. Prior to the runs for which the experimental data is presented, numerous runs with each surfactant were made to stabilize the system. Thus any permanent changes in wettability or fluid saturations due to irreversible surfactant adsorption would have reached a steady state.

After all the experimental runs had been completed, the oil saturation and irreducible water saturation were again measured. The irreducible water saturation remained constant at its initial value as did the irreducible oil saturation when measured after flooding with 100 pore volumes of water.

4. RESULTS AND DISCUSSION

In analyzing any experimental research, the first topic that must be addressed is the reliability of the results. This aspect must be investigated to ensure that differences in the experimental results are in fact true differences and not the result of random processes or experimental error.

Not all of the experimental runs were repeated since those that were showed good reproducibility. All of the experimental runs at a surfactant concentration of 0.030% were repeated as was the control run where distilled water was the injected slug. Figure 4 indicates the degree of reproducibility of the results in a graph of oil produced after breakthrough of the oil front versus pore volumes of gas injected after frontal breakthrough. The precision to which the produced oil volumes and injected gas volumes were read was $\pm \frac{1}{2}$ cc and ± 0.04 pore volumes, respectively. Thus it would be appropriate to include vertical error bars of $\pm \frac{1}{2}$ cc and horizontal error bars of ± 0.04 pore volumes in Figs. 4-13, but to avoid cluttering the figures, these error bars were omitted.

4.1. EFFECTS OF IFT REDUCTION

In this study the lowered IFT is expected to have only a negligible effect on the oil recovery. To get increased oil recovery from lowering the IFT, it needs to be reduced to values in the range of 0.01 to 0.0001 dyne/cm. As shown in Table 2, the interfacial tensions produced by these surfactants in distilled water are several orders of magnitude above this.

4.2. EFFECTS OF WETTABILITY CHANGES

The acid cleansed Ottawa sand used in this investigation is believed to be completely water-wet. The surfactants used here are unlikely to have induced any change in the wettability of the system, especially since highly refined white mineral oil was the nonwetting phase. Whereas crude oils frequently contain surface active materials, e.g. asphaltenes and organic acids, this highly refined paraffinic mineral oil does not contain those compounds which might increase the oil wetness.

4.3. GAS MOBILITY REDUCTION EFFECTS

Because of the insignificant effects of the lowered IFT and no wettability changes, the enhanced recovery effects can probably be attributed to the foam and emulsion gas mobility control mechanisms. The following discussion represents the focus of this study which is to see which mechanism, if either, is more effective at reducing injected gas mobility or whether a combination of both mechanisms is more effective.

The plots in Figs. 5-13 all show the cumulative oil recovered after breakthrough of the oil bank generated by the slug injection versus the volume of gas injected after breakthrough of the front of the oil bank.

At the time of injection of the surfactant slug, the model contained 61.0 cc of oil and of this, 11.5 cc were residual oil. This left 49.5 cc of mobile oil. The distribution of oil in the model was as would be expected in a gas-driven process. It was observed visually that

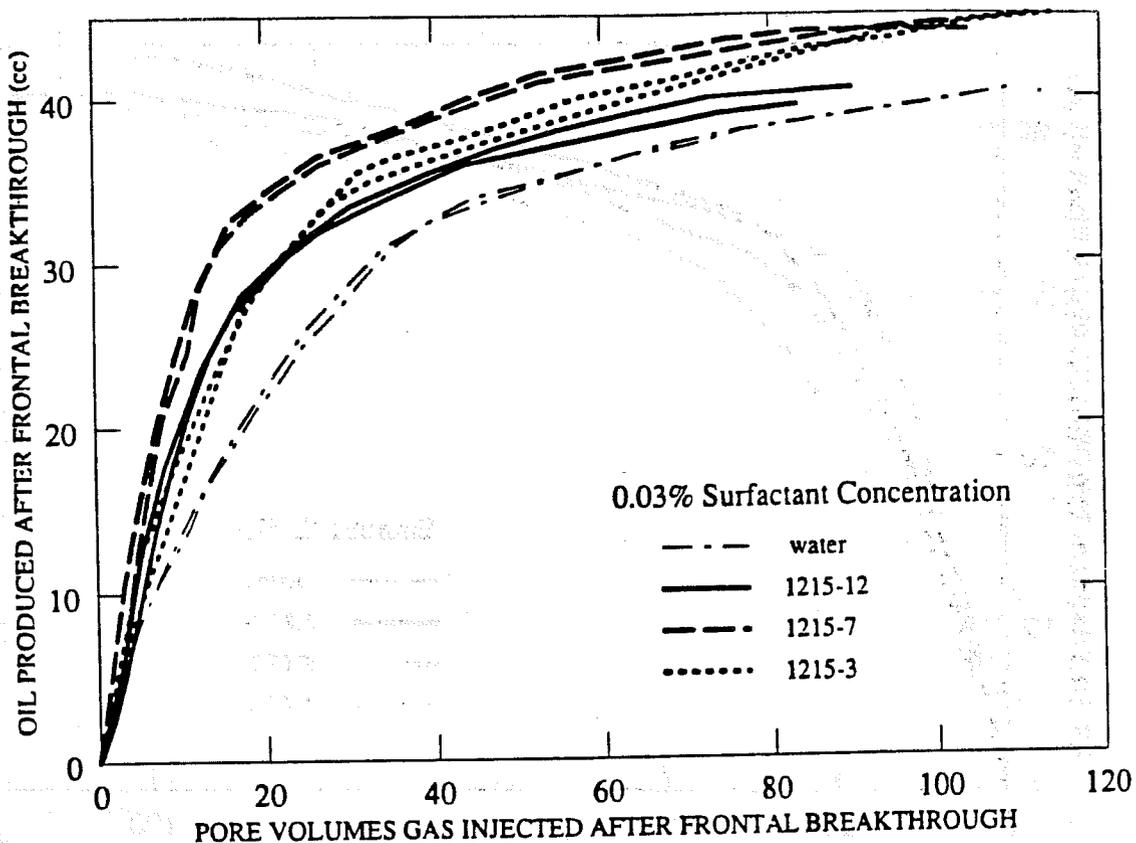


Fig. 4. Comparison of repeated runs.

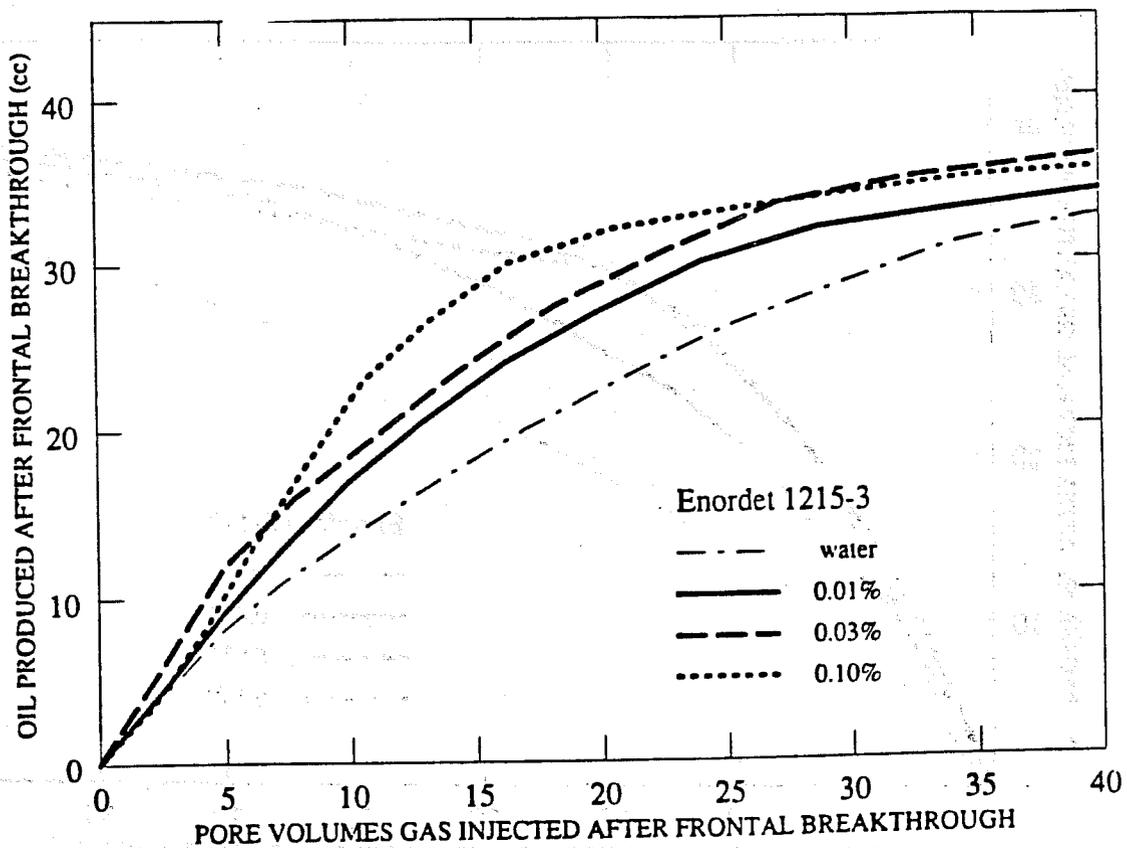


Fig. 5. Early time oil produced vs. volume of gas injected for Enordet 1215-3.

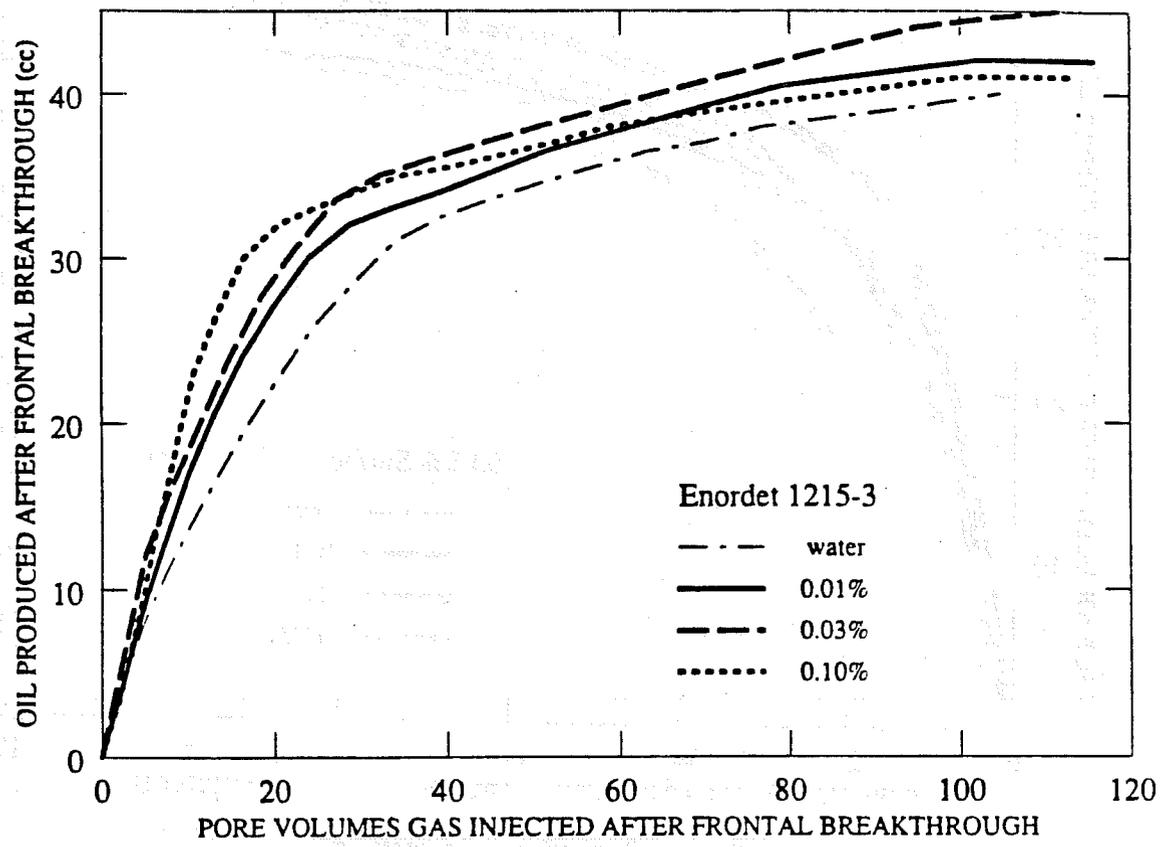


Fig. 6. Oil produced vs. volume of gas injected for Enordet 1215-3.

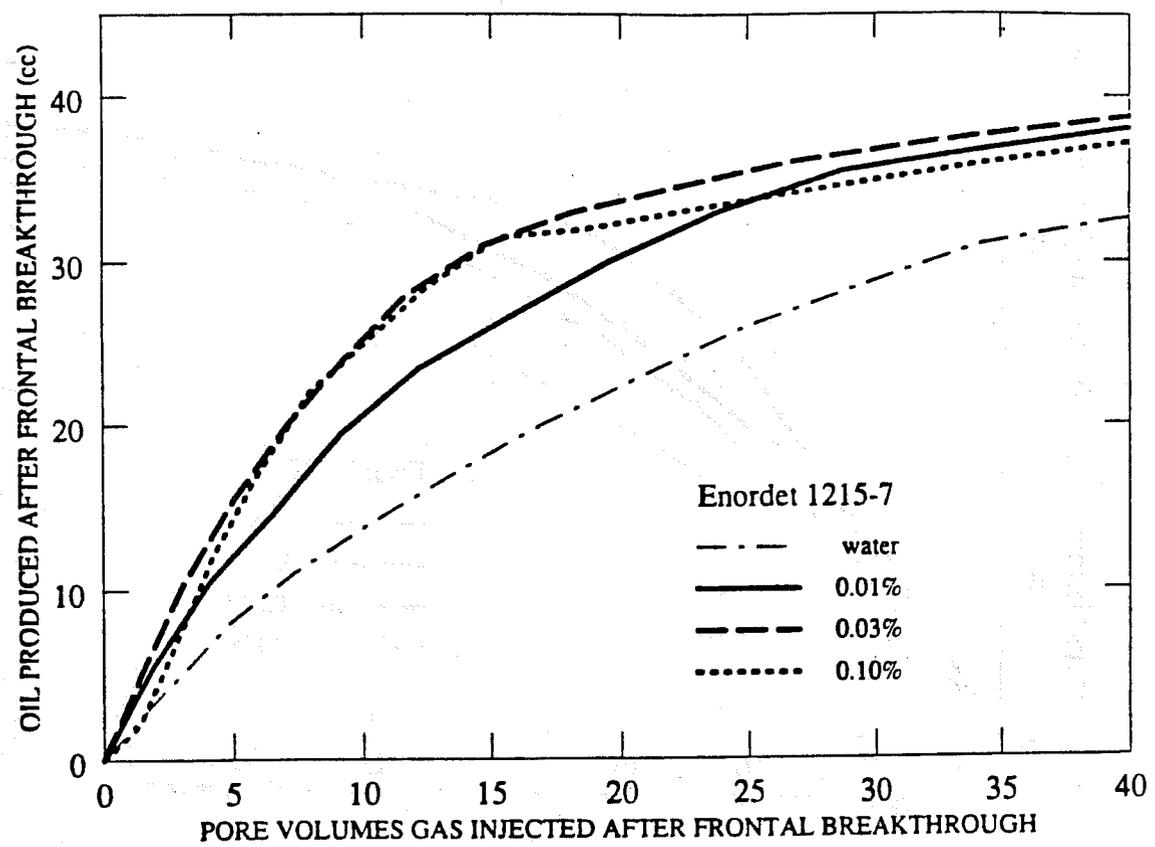


Fig. 7. Early time oil produced vs. volume of gas injected for Enordet 1215-7.

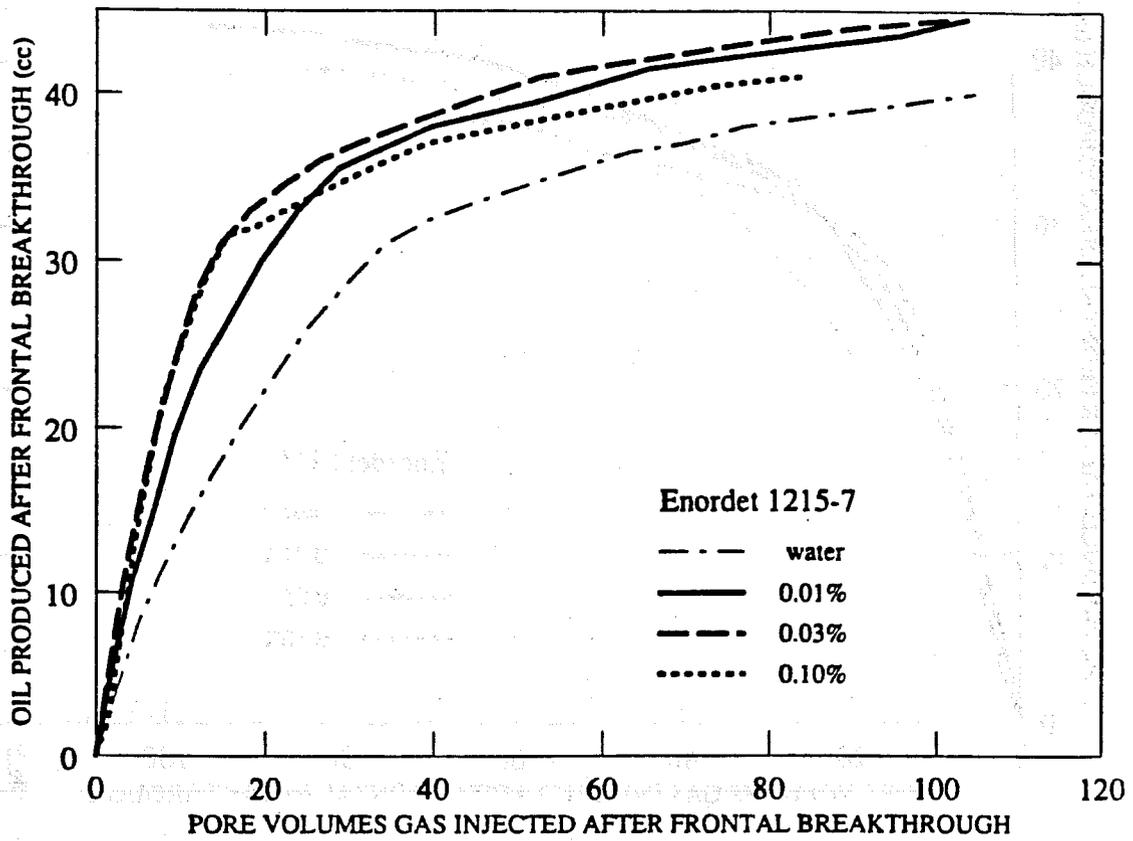


Fig. 8. Oil produced vs. volume of gas injected for Enordet 1215-7.

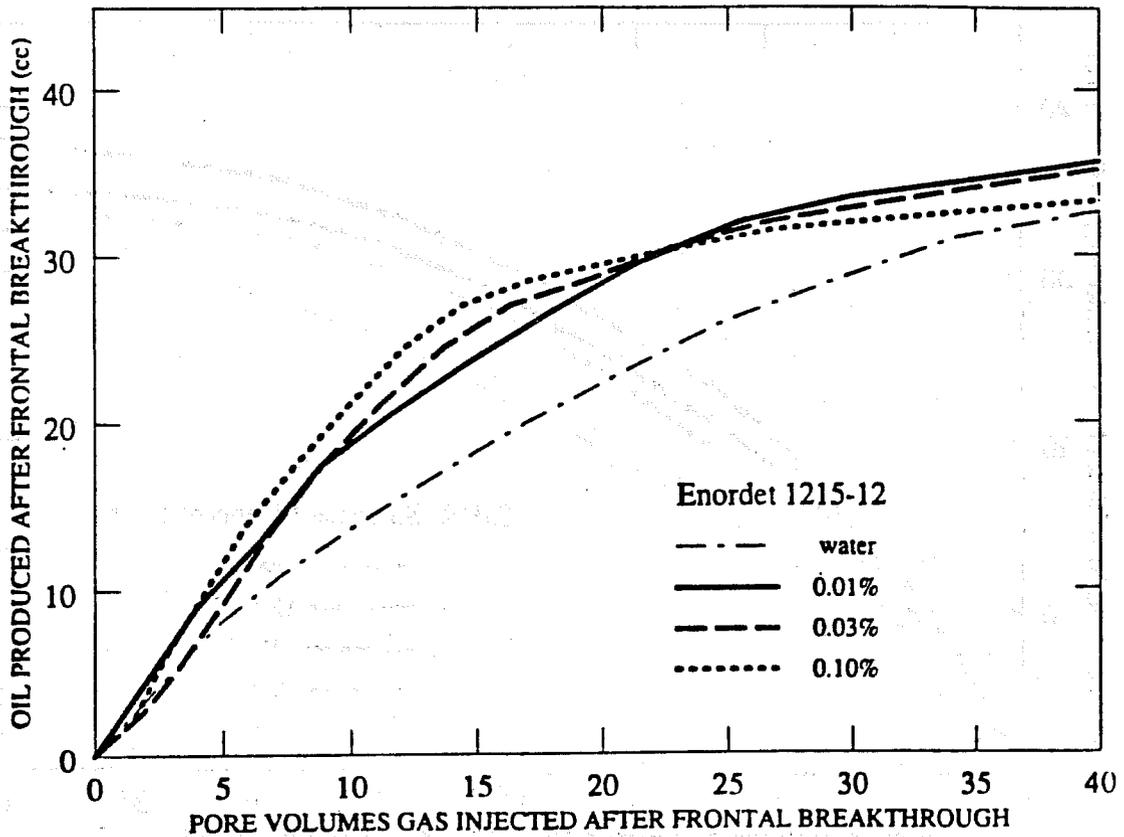


Fig. 9. Early time oil produced vs. volume of gas injected for Enordet 1215-12.

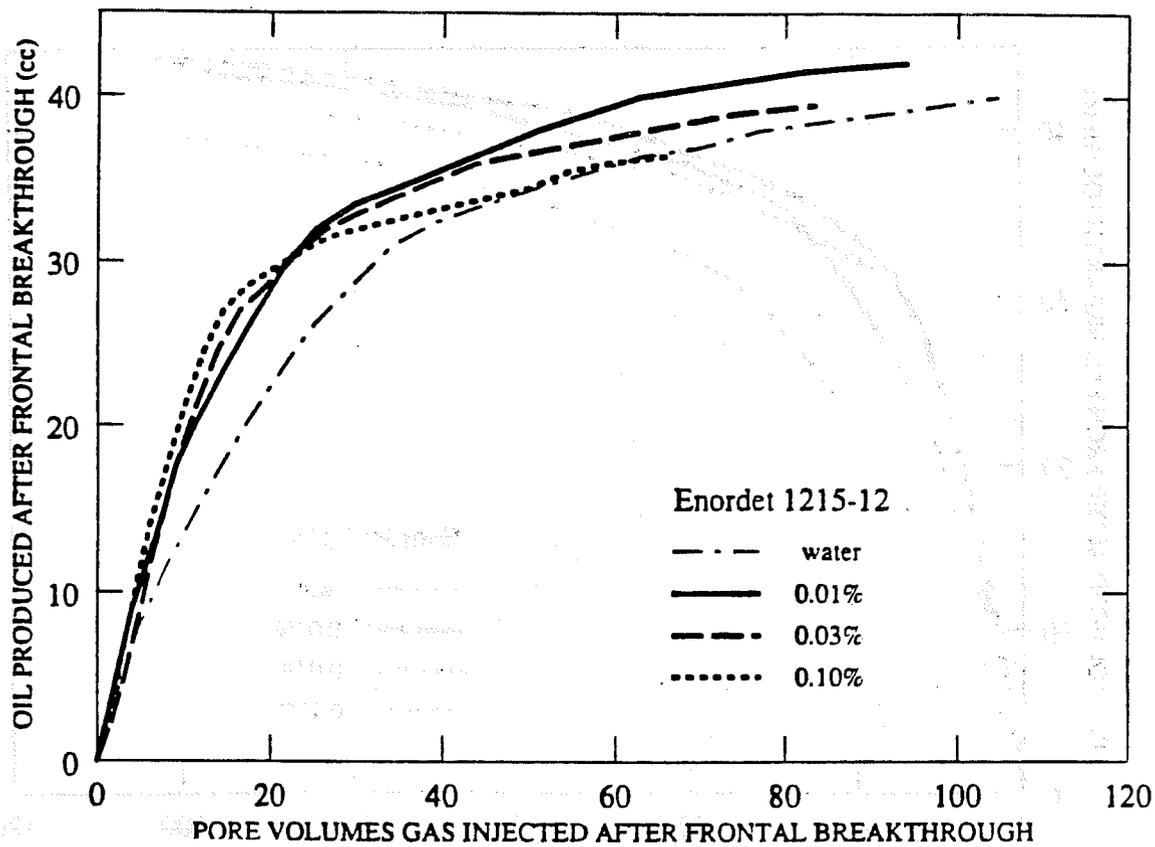


Fig. 10. Oil produced vs. volume of gas injected for Enordet 1215-12.

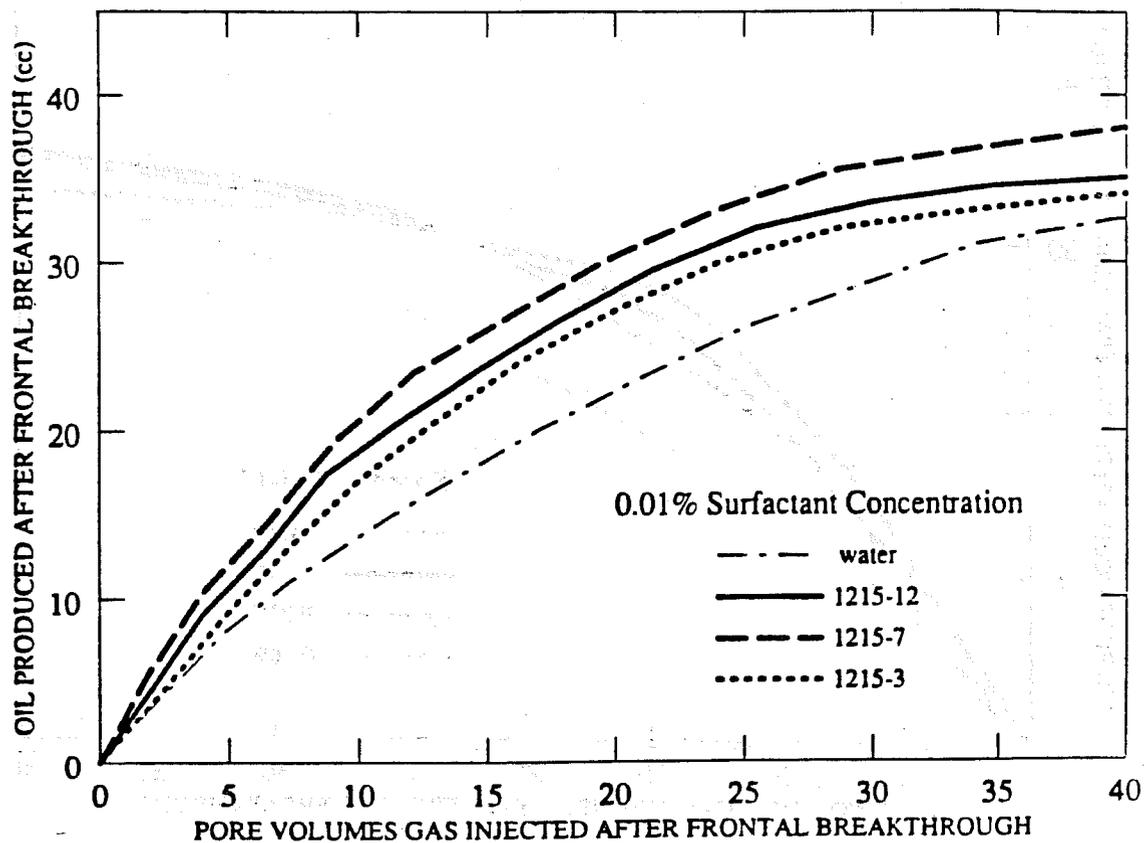


Fig. 11. Early time oil produced vs. volume of gas injected for 0.01% concentration.

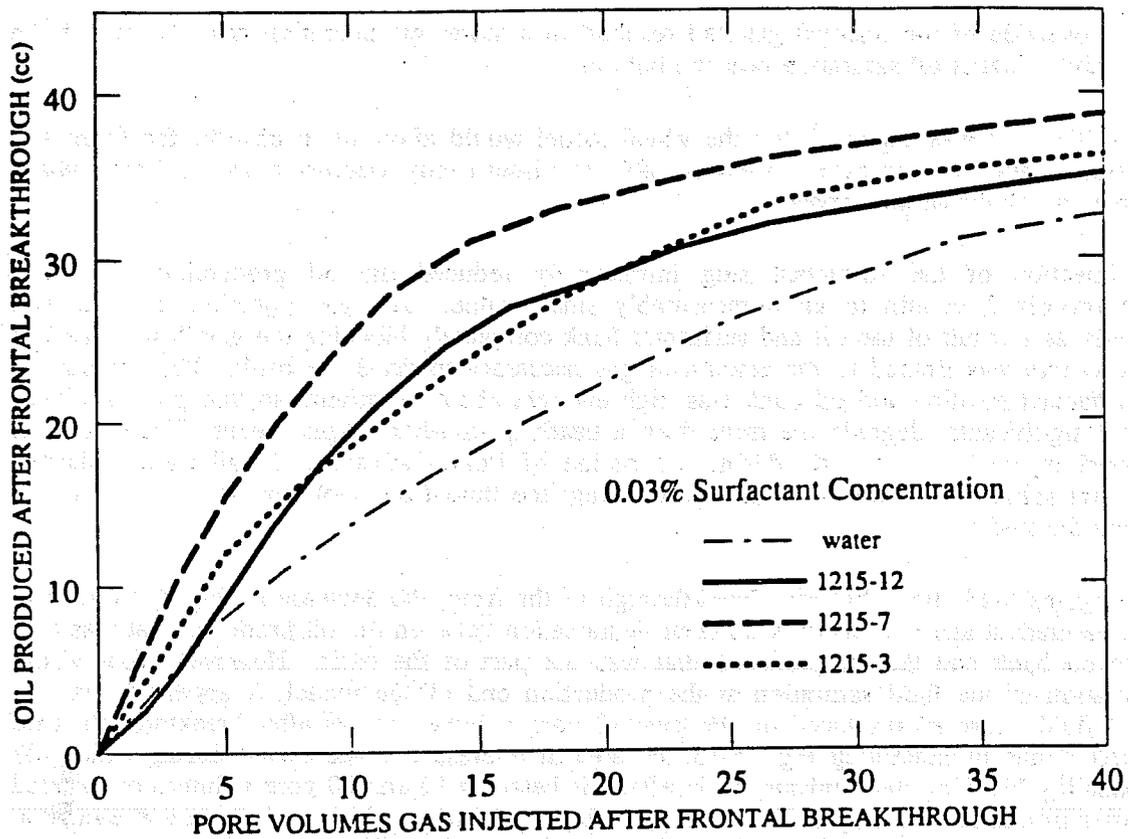


Fig. 12. Early time oil produced vs. volume of gas injected for 0.03% concentration.

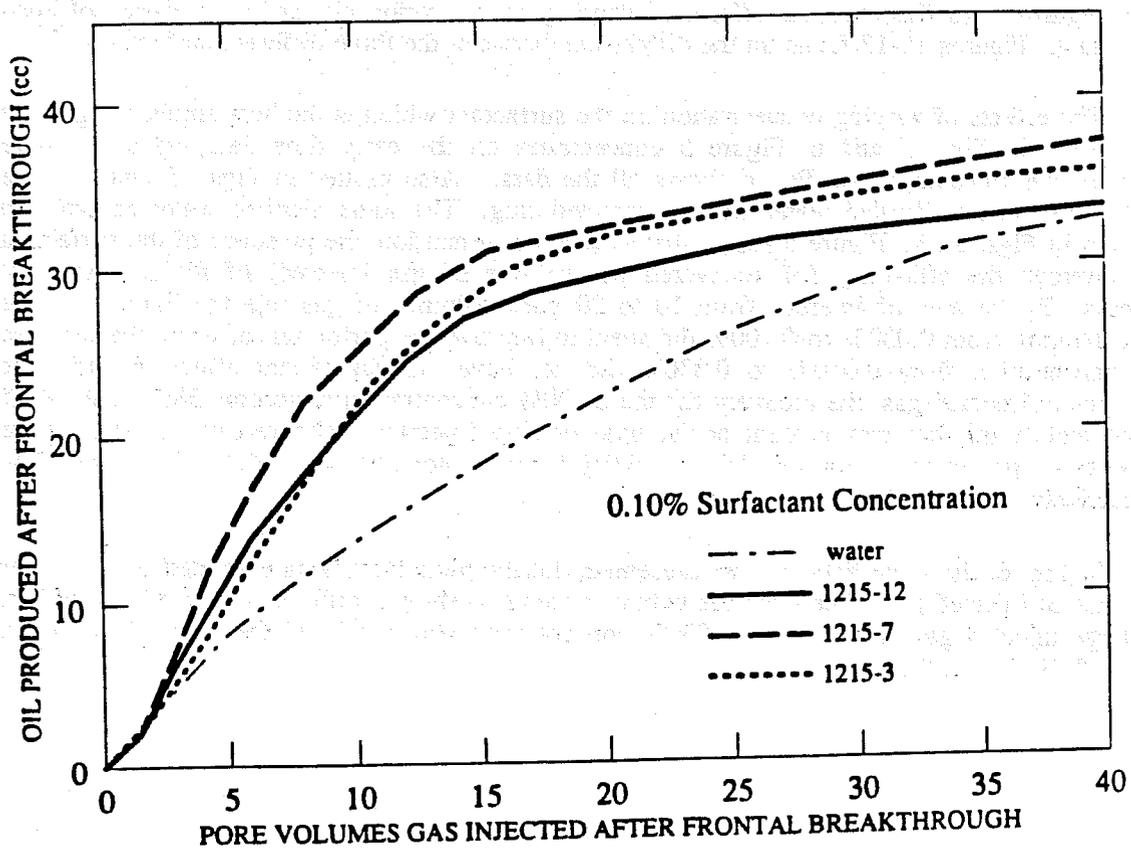


Fig. 13. Early time oil produced vs. volume of gas injected for 0.10% concentration.

gravity override of the injected gas had resulted in a lower oil saturation near the top of the model and a higher oil saturation near the bottom.

Initially, it was expected that the visual model would allow us to observe the foam and emulsion banks. Unfortunately, we were able to discern only whether a gas or liquid phase occupied a volume of pore space.

Injection of the surfactant slug immediately reduced the oil production rate from approximately 1 cc/min to an immeasurably small value. The gas injection rate behaved similarly as a result of the oil and surfactant bank completely blocking the gas flow. The gas injection rate was limited to the amount of gas necessary to drive the bank. The velocity of the surfactant solution and oil bank was high enough, about 5 cm/min, so that gravity effects did not significantly degrade the front from a nearly piston-like displacement. There was no observed injected gas override during the period of frontal advance. In all cases, whether surfactant solution or water was the injected slug, the fluid front took about 10 min to move through the system.

Figures 5-13 show that after breakthrough of the front, the decrease in the oil production rate was gradual and thus there is no clear demarcation between the oil produced that was part of the oil bank and the oil produced that was not part of the bank. However, from visual observation of the fluid saturation at the production end of the model, it appeared that the frontal fluids were all produced by the time 10 pore volumes of gas after breakthrough were injected. Thus in examining Figs. 5-13, the area of interest, i.e., the period during which the gas mobility blocking mechanisms are in effect, is between 10 and 20 pore volumes of injected gas after frontal breakthrough. This was also the period during which both foam and emulsion were produced from the model. Before 10 pore volumes, the effects of the frontal saturations are primarily what is seen and at the higher injected pore volumes, the effects of the emulsion and foaming mechanisms have been dissipated.

Figures 5-10 illustrate the effects of varying concentration on the performance of each surfactant. Figures 11-13 focus on the differences between the three different surfactants.

The effects of varying concentration on the surfactant which is the best emulsifying agent are shown in Figs. 5 and 6. Figure 5 concentrates on the early time data, up to 40 pore volumes gas injected, while Fig. 6 shows all the data. Also plotted in Figs. 5 and 6 is the control run where distilled water was the injected slug. The same distilled water control run appears in Figs. 5-13. Figure 5 shows that at each concentration, the presence of the surfactant did improve the efficiency (oil recovered per volume of gas injected) of the displacement process. In the area of interest, from 10 to 20 pore volumes of gas injected, increasing the concentration from 0.030% to 0.100% did seem to improve the performance, while the increase in concentration from 0.010% to 0.030% did not have any significant effect. At 15 pore volumes of injected gas, the recovery for the 0.100% concentration represents 58% of the 49.5 cc of mobile oil that was present at the time of slug injection. The recoveries, at 15 pore volumes of gas injected, for the 0.030%, 0.010% and water runs were 49%, 48% and 37%, respectively.

In Fig. 6, the same data sets are presented, but the plots have been extended out to larger volumes of injected gas. The late time behavior seems to show a different concentration effect. At large injected gas volumes, the 0.030% concentration slug produced the most oil followed by the 0.010% and 0.100%.

Figures 7 and 8 show the effect of concentration on the surfactant which is both the relatively good foaming agent and emulsifying agent. In the area of interest (10 to 20 pore volumes), an increase in concentration from 0.010% to 0.030% does seem to improve the performance while the increase in concentration from 0.030% to 0.100% does not increase the efficiency. At 15 pore volumes of gas injected, the recovery for both the 0.030% and 0.100% is 63% of the mobile oil present at the time of slug injection. The recovery of the 0.010% concentration was 53% compared to 37% for the water slug. Figure 8 is the same plot including the late time data. At large injected gas volumes, increasing the concentration decreases the overall oil recovery.

The effect of concentration on the surfactant which was the best foaming agent is shown in Figs. 9 and 10. Figure 9 shows that in the area of interest (10 to 20 pore volumes), increasing the concentration only marginally improves the displacement efficiency. The fraction of the mobile oil recovered at 15 pore volumes injected gas for the 0.100%, 0.030%, and 0.010% were 55%, 52%, and 48%, respectively, compared to 37% for the water slug. Figure 10 shows that at the high injected gas volumes, the effectiveness of the surfactants decreased with increasing concentration. At 60 pore volumes injected gas, the overall recovery was the lowest for the 0.100% and highest for the 0.010% concentration. The oil recovery for the 0.100% was about the same as that for the control run.

As seen with all three surfactants, at high injected gas volumes, i.e. when the mobility blocking mechanisms are no longer in effect, increased surfactant concentration adversely effects the oil recovery. A possible explanation for this is that the higher surfactant concentrations result in a greater reduction in the surface tension of the water in the sandpack and therefore a greater reduction in the capillary forces which hold the water. Thus the higher concentrations release more trapped water resulting in a higher gas saturation and a higher gas mobility.

Figure 11 compares the performance between the three surfactants at 0.010% concentration. The surfactant which is both the good foaming and emulsifying agent results in the most efficient oil recovery.

Figure 12 compares the performances of the surfactants at 0.030% concentration. Again the surfactant which is both the good foaming agent and emulsifying agent results in the most efficient oil recovery. The fractional recoveries at 15 pore volumes injected for the 1215-7, 1215-12 and 1215-3 are 63%, 52%, and 49%, respectively.

Figure 13 compares the performance of the surfactants at 0.100% concentration. As at the other two concentrations, the surfactant which is both the good foamer and emulsifier results in the most efficient recovery process.

Figure 14 summarizes the fractional recoveries at 15 pore volumes of injected gas for each surfactant.

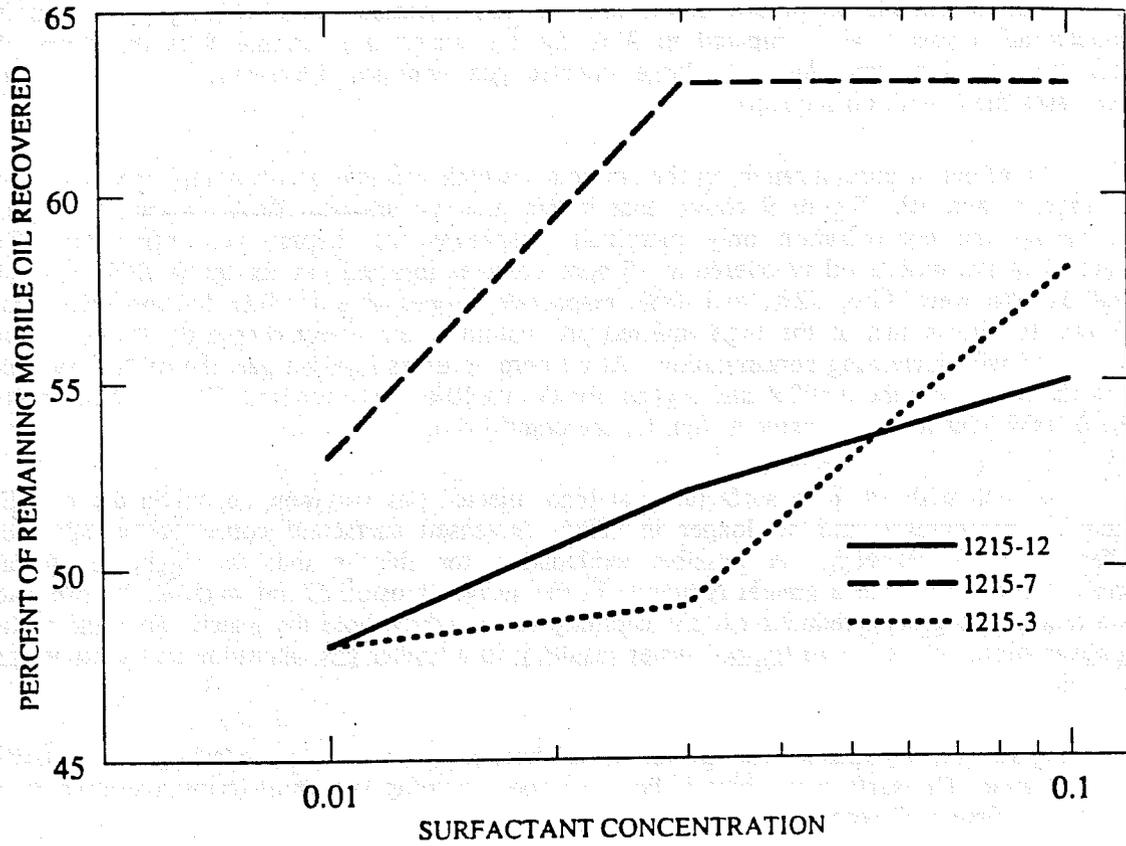


Fig. 14. Percent of remaining mobile oil recovered vs. surfactant concentration at 15 pore volumes of gas injected.

6. CONCLUSIONS

The main conclusion to be drawn from this study is that combining the foam and emulsion mechanisms may lead to more efficient oil recovery than either mechanism alone. Also the difference between the surfactants are small but consistent.

Although the conditions of this study are not representative of actual field conditions, it is believed that the recovery mechanisms in real situations are substantially the same. The fact that the displacement process with or without the surfactants is extremely inefficient, should not detract from the overall conclusions. The findings here may make it possible to improve the effectiveness of processes that have been shown to be economically feasible such as steam-foam operations.

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APPENDIX A

A.1 FAILED APPARATUS

It was originally intended that this experiment be carried out using a sandpack constructed from $\frac{1}{4}$ in. thick Lucite sheets. A partial vacuum, drawn at the production end of the model, was to be used instead of the injected gas as the driving mechanism for the displacement. A Lucite model of internal dimensions $11 \text{ cm} \times 48 \text{ cm} \times 0.64 \text{ cm}$ was constructed and filled with sand. Two nylon pipe fittings, attached at opposite ends of the model, served as the injection and production ports.

This small Lucite model performed satisfactorily and was to serve as a prototype for a larger sized version. A larger sized model was needed to reduce the relative magnitude of the material balance errors that would occur as a consequence of the limited precision of the measuring devices.

The larger model of internal dimensions $116 \text{ cm} \times 30 \text{ cm} \times 0.64 \text{ cm}$, proved to be unsatisfactory. The stress on the sides of the model, imparted by the sand during the packing process, inelastically deformed the model. For the packing procedure, the model was placed with its long axis oriented vertically which caused the sides of the model to bow out, despite the fact that two screws were sunk through the center of the model, and three wooden support planks were clamped on opposite sides of the model to prevent this occurrence. When the model was placed in the horizontal position which was necessary for the experiment, the bowing out of the sides resulted in a gap between the sand grains and the walls of the model. After several repackings it was concluded that it was impossible to eliminate the gap and that the Lucite model should be abandoned.

A.2 FAILED PROCEDURE

A different experimental procedure than the one that was finally used was tried first but proved to be unsatisfactory. This first procedure was similar to the one that was finally used except in the timing of the injection of the surfactant slug. Instead of injecting the surfactant slug after producing 135 cc of oil, the slug was injected at the start of oil production. With this manner of slug injection, the initial oil production was driven by the injection of the surfactant slug.

The problem with this procedure arose during the period when the last part of the surfactant slug was being injected. During this period, both gas and liquid were being injected and it was impossible to keep injection pressure constant. This problem did not arise when the slug was injected after 135 cc of oil had been produced since the two phase injection period was of much shorter duration.

APPENDIX B

LIST OF COMPONENTS AND SUPPLIERS

Surfactants, *Shell Chemical Co.*

Enordet Alcohol Ethoxylate 1215-3

Enordet Alcohol Ethoxylate 1215-7

Enordet Alcohol Ethoxylate 1215-12

Surface Tensiometer, *Fisher Scientific Co.*

Model 20, Serial No. 712

Wet Test Meter, *Precision Scientific Co.*

Pressure Transducer, *Celeco Transducer Products Inc.*

Model CD10B, Serial No. A020204

Oil, *Witco Chemical Corp.*

Klearol