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Placement Properties of Foams Versus Gelants When Used as Blocking Agents

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Abstract

In this paper, we investigate whether foams can show placement properties that are superior to those of gels, when used as blocking agents. Specifically, we examine whether the concept of limiting capillary pressure can be exploited to form a persistent, low-mobility foam in high-permeability zones while preventing foam production and formation damage in low-permeability zones. Using a $C_{14\text{-}16}$ α-olefin sulfonate, we measured mobilities of a nitrogen foam in cores with permeabilities from 7.5 to 900 md (750 psig back pressure, 104°F), with foam qualities ranging from 50% to 95%, and with Darcy velocities ranging from 0.5 to 100 ft/d. We also extensively studied the residual resistance factors provided during brine injection after foam placement. The results from our experimental studies were used during numerical analyses to establish whether foams can exhibit placement properties that are superior to those of gelants. This study found that compared with water-like gelants, the foam showed better placement properties when the permeabilities were 7.5 md or less in the low-permeability zones and 80 md or more in the high-permeability zones.

Introduction

Gels have often been used to reduce fluid channeling in reservoirs.[1] Several other types of materials (including foams) have also been considered for this purpose.[2] When using blocking agents to reduce channeling, a critical question is, How can the blocking agent be placed in high-permeability zones without damaging less-permeable, hydrocarbon-productive zones? Here, we investigate whether foams can show placement properties that are superior to those of gels, when used as blocking agents. Specifically, we examine whether the "limiting-capillary-pressure" concept[3] can be exploited to form a persistent, low-mobility foam in high-permeability zones while preventing foam production and formation damage in low-permeability zones.

In this paper, we first explain the concept of limiting capillary pressure. Second, we summarize our experiments where foam mobilities were determined over a wide range of conditions. Using a $C_{14\text{-}16}$ α-olefin sulfonate, we measured mobilities of a nitrogen foam in cores with permeabilities from 7.5 to 900 md (750 psig back pressure, 104°F), with foam qualities (gas volume fractions) ranging from 50% to 95%, and with Darcy velocities ranging from 0.5 to 100 ft/d. We also extensively studied the residual resistance factors provided during brine injection after foam placement. Finally, the results from our experimental studies were used during numerical analyses to establish whether foams can exhibit placement properties that are superior to those of gelants.

Limiting Capillary Pressure

Khatib *et al.*[3] applied the concept of limiting capillary pressure to predict foam flow through porous media. To explain this concept, consider two gas bubbles that are flowing through a porous medium. Because of their close proximity, these bubbles are separated by a film of water. A pressure difference, called the capillary pressure, exists between the gas phase and the liquid phase. The limiting-capillary-pressure concept recognizes that if the capillary pressure is too great, water will be sucked away from the film, the film separating the bubbles will collapse, and the bubbles will coalesce. The capillary pressure at which this coalescence occurs is called the limiting capillary pressure. According to Khatib *et al.*, this limiting capillary pressure could depend on (1) the type and concentration of surfactant and electrolyte, (2) the gas velocity, and (3) the rock permeability.

We are interested in how the limiting capillary pressure affects foam placement in heterogeneous reservoirs. This can be understood by considering Figs. 1 and 2, which were taken from Figs. 11 and 12 of Ref. 3. The solid curve in Fig. 1 illustrates how the limiting capillary pressure varies with permeability, as speculated by Khatib *et al.*[3] (Aronson *et al.*[4] argue, in contrast, that the limiting capillary pressure is basically independent of permeability. However, Aronson's argument does not change the qualitative shape of Fig. 2.) The dashed curve in Fig. 1 shows how the capillary entry pressure varies with permeability. The capillary entry pressure is the injection pressure that must be exceeded to overcome capillary forces and allow the non-wetting phase to enter the porous medium.

Low Permeabilities. For the gas/brine/surfactant system considered by Khatib, Fig. 1 indicates that the capillary entry pressure exceeds the limiting capillary pressure in low-permeability rock ($<$800 md in this particular case). In this situation, water films between flowing gas bubbles will always be unstable and bubbles will coalesce very rapidly. As a result, normal gas and liquid flow behavior will be observed—that is, gas mobility will increase linearly with increasing rock permeability. The case of normal gas-liquid flow through porous media is illustrated by the top dashed line in Fig. 2. Khatib *et al.*[3] point out that gas mobility in the presence of surfactant solutions in low-permeability rock may be lower than that in the absence of surfactant because the surfactant solutions can increase the trapped gas saturation. Thus, they predict that until the limiting capillary pressure exceeds the capillary entry pressure, gas mobility increases linearly with increased rock permeability, as indicated by the first linear portion of the solid curve in Fig. 2. If the capillary entry pressure exceeds the limiting capillary pressure for all zones in a reservoir, no placement advantage exists for foams over gelants. Since both foams and gelants exhibit analogous flow behavior in this situation, their placement characteristics in heterogeneous reservoirs will be similar (if gravity effects are neglected).

Intermediate Permeabilities. If the limiting capillary pressure exceeds the capillary entry pressure (e.g., for permeabilities above 800 md in Fig. 1), Khatib *et al.*[3] predict that gas mobility should decrease with increasing permeability up to a point (see the middle part of the solid curve in Fig. 2). This property promotes foam as a mobility-control agent. Foams will penetrate more efficiently into the less-permeable zones because the foams can exhibit a higher mobility in low-permeability rock than in high-permeability rock. However, this behavior is opposite of the desired performance for a blocking agent. We want to minimize penetration of blocking agents into the less-permeable zones. If the injectant was a foamed gelant that behaved as shown in the middle part of the solid curve in Fig. 2, the low-permeability zones could be seriously damaged after the gel forms. Thus, if all zones in a reservoir are in this regime of behavior, a placement disadvantage exists for foam blocking agents when compared to gelants.

High Permeabilities. In very high-permeability porous media, Khatib *et al.*[3] predict that gas mobility again increases linearly with increased permeability (Fig. 2). Following the same argument that was given earlier, if all zones in a reservoir fall in this regime of behavior, no placement advantage exists for foams over gelants.

High/Low-Permeability Combinations. Using the limiting-capillary-pressure concept, one circumstance can be identified where a foam blocking agent could have a placement advantage over a gelant. That is the case where the capillary entry pressure is less than the limiting capillary pressure in the offending high-permeability zone(s) but is greater than the limiting capillary pressure in the less-permeable hydrocarbon-productive zones. In that case, a low-mobility foam will be generated in the high-permeability zone(s) but not in the less-permeable zones. Since no foam is generated in the less-permeable zones, injected fluids will not be inhibited from entering and displacing oil from these zones. In contrast, as long as the foam persists in the high-permeability zones, it will restrict fluid entry. Of course, exploitation of this concept requires identification of the permeability where the limiting capillary pressure equals the capillary entry pressure. Two other limitations must be recognized. First, the injected foam must *not* undergo a reaction that forms a blocking agent after placement. For example, the surfactant solution must not include a gelant. A low-mobility foam generated in the high-permeability zone(s) will cause the gelant to penetrate an excessive distance into the less-permeable zones. Second, if water or gas is injected after placement of a foam bank, the foam may eventually wash out or diminish in effectiveness. One possible method to maintain the integrity of the foam bank was suggested by Kovscek and Radke.[5] This method involves continuous injection of a dilute surfactant solution (with or without gas) after placement of the foam bank. The surfactant concentration in the foam bank must be sustained at a level high enough to prevent collapse of the foam.

Khatib's experimental support of the limiting-capillary-pressure concept was confined to results from studies in high-permeability beadpacks (72 to 8,950 darcys).[3] Additional support for the theory is needed in both low- and high-permeability rock. The data of Lee *et al.*[6] could be viewed as supportive of the limiting-capillary-pressure concept. Their work used cores with permeabilities ranging from 0.4 to 302 md. Fig. 3 replots data from Fig. 2 of Lee *et al.* in a form that is comparable with Fig. 2. The solid curves show the forms predicted by the limiting-capillary-pressure model. (The solid curves are conceptual only—they should not be considered quantitative.) Of course, the model would appear to be more valid if more data were available in low- and high-permeability rock. Also, Lee *et al.* used a small range of fluid velocities and foam qualities in their work. To more thoroughly examine the technical viability of using foams instead of gels, we performed the following experimental study.

Experimental Procedure

Our coreflood equipment and experimental procedure are described in detail in Ref. 7. The equipment design was based on coreflood experiments performed during previous research with gels[8,9] (with some modifications). All experiments reported here used nitrogen foams and were performed at 104°F (40°C) using a backpressure of 750 psig.

The brine used in this work contained 1% NaCl and 0.1% $CaCl_2$. The surfactant used was Bio-Terge® AS-40 (Stepan Co.), a C_{14-16} α-olefin sulfonate with an activity of 38.7%. The surfactant concentration was 0.3% by active weight unless stated otherwise. The critical micelle concentration (cmc) for the surfactant was reported to be 0.25% in distilled water.[10] We determined the cmc to be 0.01% in our brine (1% NaCl, 0.1% $CaCl_2$) at 104°F.

Four cores were used in this work. Three cores were Berea sandstone, with permeabilities of 80, 482, and 899 md. We also used one 7.5-md Indiana limestone core. None of the cores were fired. The core lengths were typically 6 inches, and the cross-sectional areas were 1.6 in^2. Two pressure taps were drilled in each core, located about 1 inch from each end. The first 1-inch section of the core was used as a filter and foam generator. The second section of the core (about 4 inches) was used for the measurements that we report.

To examine the potential of foams as blocking agents, we measured mobilities of a nitrogen foam in the four cores using foam qualities ranging from 50% to 95% and Darcy velocities ranging from 0.5 to 100 ft/d. Foams were generated by simultaneously injecting gas and surfactant solution into surfactant-saturated cores. We also extensively studied the residual resistance factors provided during brine injection after foam placement. This paper summarizes the important experimental results from our study. More detailed results from the study can be found in Refs. 7 and 8.

Nitrogen-Foam Mobility Versus Permeability, Fluid Velocity, and Foam Quality

When foams are applied in field applications, foam properties should be known over the range of permeabilities encountered in the reservoir. Also, in unfractured wells, since the fluid velocity varies with the radius from the wellbore, the foam properties should be determined as a function of flow rate. Therefore, we must determine foam mobilities over an appropriate range of fluid velocities and rock permeabilities.

For a 50%-quality foam, Fig. 4 shows how foam mobility varies with Darcy (superficial) velocity during steady-state foam injection in each of our four cores. Analogous results are shown in Fig. 5 for a 95%-quality foam. (Detailed results for the 80%-quality foam can be found in Ref. 7.) Each set of mobility-versus-velocity data was fit using a power-law equation. These power-law correlations are listed in Table 1, where the Darcy velocities (u) are input in units of ft/d and foam mobilities are provided in units of md/cp.

For the 80-, 482-, and 899-md cores, Table 1 and Figs. 4 and 5 demonstrate that foam mobilites show a distinct shear-thinning behavior, with power-law exponents ranging from 0.26 to 0.73. In these cores, the shear-thinning behavior was generally more pronounced as the foam quality decreased.

Our results in Table 1 are consistent with the results and concepts reported by Falls *et al.*,[11] who measured the apparent viscosity of foams of known texture in glass bead packs. For a foam quality above 95%, they argued that the foam mobility varied with velocity to the ⅓ power when the average bubble size was larger than the pore size and to the ⅔ power when the bubble size was smaller than the pore size. Falls *et al.*[11] used nitrogen gas and 1% sodium dodecylbenzene sulfonate in distilled water. Their glass bead packs had permeabilities ranging from 5,000 to 9,000 darcys.

For a foam quality of 95%, Table 1 shows that our foam mobilities varied with velocity to a power close to ⅓ (0.39, 0.28, and 0.26 in the cores with permeabilities of 80, 482, and 899 md, respectively). In contrast, for 50% foam quality, our results showed that foam mobilities varied with velocity to a power close to ⅔ (0.62, 0.70, and 0.73 in the cores with permeabilities of 80, 482, and 899 md, respectively). From the work of Falls *et al.*,[11] our results might indicate that the bubble size was smaller than the pore size at a quality of 50% and greater than the pore size at a quality of 95%. However, more direct measurements of bubble size should be made before accepting this suggestion.

In contrast to the shear-thinning behavior observed in the three more-permeable cores, foam behavior was essentially Newtonian for all three foam qualities in the 7.5-md core. Table 1 shows that power-law exponents ranged from -0.03 to 0.08 in the 7.5-md core. Higher mobilities were observed as the quality increased in the 7.5-md core. When the quality increased, the mobility increased because of the higher gas fraction. The resistance factors were 2.2, 1.9, and almost 1 for qualities of 50%, 80%, and 95%, respectively.[7] These results indicate very weak or no foam generation (two-phase surfactant-solution and nitrogen flow with no gas-blocking effect). For comparison, the resistance factor varied from 40 to 1,000 in the 899-md core, from 60 to 1,500 in the 482-md core, and from 20 to 300 in the 80-md core, depending on the flow rate and the quality of the foam.

Experiments were also performed with the 7.5-md core where surfactant-free brine and nitrogen were simultaneously injected into a brine-saturated core. The results with gas/brine/surfactant and gas/brine combinations are shown in Fig. 6 for a foam quality of 95%. The similarity of results with versus without surfactant confirms that the core contained a very weak foam or no foam.

Implications for Selective Fluid Diversion

Our experiments revealed that a low-mobility foam formed when the rock permeability was 80-md or greater and that no foam (or a very weak foam) formed when the rock permeability was 7.5 md. These results suggest that a potential placement advantage exists when the permeability is 7.5 md or less in the low-permeability zones and 80 md or more in the high-permeability zones.

Fig. 7 shows how our data support the limiting-capillary-pressure concept. This figure suggests four different slopes for the variation of foam mobility with core permeability. For 95%-foam quality, the (hypothetical) dashed line between 1 and 7.5 md suggests that normal gas and liquid flow occurred (i.e., no foam generation). The upper limit of the normal two-phase flow region for 95% quality was not specifically identified by our data, although the limit must be less than 80 md. At qualities of 80% and 50%, weak foams were generated in the 7.5-md core, and much less-mobile foams were observed in the 80-md core. Therefore, for a given foam quality between 7.5 and 80 md, lines with negative slopes represent this data in Fig. 7. Between 80 and 482 md, the foam mobility generally did not vary much. Also, in all cases shown in Fig. 7, foam mobilities increased sharply between 482 and 899 md. These trends are qualitatively consistent with those predicted by Khatib *et al.* (see Fig. 2).

Foam Persistence During Brine Injection

For a successful blocking treatment, foam in the high-permeability zones should not wash out easily during brine flow after foam placement. Fig. 8 shows nitrogen-foam residual resistance factors during injection of 80-100 PV of brine through the 80-, 482-, and 899-md cores. After injecting about 20 PV of brine, the residual resistance factors in the three Berea cores levelled off at different values. Lower residual resistance factors were observed as the permeability increased. Because the foam reduces the flow capacity of the low-permeability rock more than that in the high-permeability rock (for permeabilities between 80 and 899 md), this behavior is disadvantageous for a blocking agent.

After 20 PV, surfactant dilution probably caused the gradual decrease in residual resistance factor with increased brine throughput.[5] As the surfactant concentration decreased, the ability of foam to hold the trapped gas was reduced. Consequently, gas evolved from the backpressure outlet during brine injection. As the gas was removed from the core, the water saturation increased.

In the 7.5-md core, resistance factors were low during foam injection, and during brine injection after foam placement, residual resistance factors quickly decreased to values between 1 and 1.3.[7]

Ref. 7 describes an extensive investigation of other factors that affect residual resistance factors during brine injection after foam placement. We found that brine residual resistance factors were insensitive to (1) the velocity during foam placement (4-40 ft/d), (2) the surfactant concentration during foam placement (0.3-1% surfactant), (3) foam quality (50-95% gas), and (4) the presence of surfactant in the brine postflush (0-0.03% surfactant).

Comparison With Gel Treatments

Extensive theoretical and experimental work[12-14] has shown that gel treatments are not expected to be effective in unfractured injection wells (i.e., radial flow) unless hydrocarbon-productive zones are protected during gel placement. Therefore, we wish to determine conditions where foam treatments might be superior to gel treatments. Ideally, we want a foam blocking agent to substantially reduce the flow capacity of high-permeability zones without damaging low-permeability zones. With any blocking agent, we must be concerned about both placement and permeability reduction.[2] During placement, the penetration of blocking agent into the low-permeability zones should be much less than that into high-permeability streaks. During brine or gas injection after placement, the blocking agent must persist (not wash out) in the high-permeability zone during fluid injection, and the treatment must restrict the flow capacity of the high-permeability zones by a greater factor than in the low-permeability zones.

Placement of Foams Versus Water-Like Gelants. Using eight rheological models, Seright[13] concluded that the non-Newtonian rheology of existing polymeric gelants will not reduce the degree of penetration into low-permeability zones below the value achievable with a water-like gelant (i.e., unit resistance factor). Therefore, we use the behavior of water-like gelants as a standard for comparison during placement. In any zone, the distance of penetration for a water-like gelant can easily be calculated using a very simple form of the Darcy equation.[12]

For linear flow, the degree of penetration is defined as the distance, L_{p2}, of penetration in a low-permeability layer (Layer 2) divided by the distance, L_{p1}, reached in the most-permeable layer (Layer 1). In radial flow, the degree of penetration[12] is defined as $(r_{p2}-r_w)/(r_{p1}-r_w)$, where r_{p2} is the radius of penetration in a low-permeability layer when the blocking agent reaches a predetermined radius of penetration, r_{p1}, in the most-permeable layer. The wellbore radius is represented by r_w.

Our reservoir models included two non-communicating layers. Both linear and radial flow were considered. In radial flow, r_w was 0.33 ft, and the external reservoir radius was 50 ft. For each flow geometry, six cases were examined. In each case, the blocking agent penetrated throughout Layer 1. To calculate values for the degree of penetration for our non-Newtonian foams, we used our experimental results (Table 1 and Figs. 4 and 5) along with the numerical methods that we applied in Ref. 13. Table 2 compares the results of foam (95% quality) placement to those of water-like gelants for different permeabilities in Layers 1 and 2. For the three cases where the permeability of Layer 2 was 7.5 md (Cases 1, 2, and 3 in Table 2), no foam was formed in Layer 2, so the degree of penetration was effectively zero. Of course, this situation is the best case that can be achieved. When foam forms in the high-permeability zones but not in the low-permeability zones, the foam has a distinct placement advantage over gelants.

For Cases 4 and 5 in Table 2, foam was formed in both Layers 1 and 2, and the degree of penetration was greater for the foam than for the water-like gelant. For example, for Case 5 in linear flow, the distance of gelant penetration in Layer 2 was 17% of that in Layer 1. In contrast, the distance of foam penetration in Layer 2 was 98% of that in Layer 1. Table 2 indicates that the water-like gelant has a placement advantage over the foam in Cases 4 and 5, both for linear flow and radial flow.

For Case 6 in Table 2, the degree of penetration was less for the foam than for the water-like gelant. For example, in linear flow, the distance of gelant penetration in Layer 2 was 53% of that in Layer 1. In contrast, the distance of foam penetration in Layer 2 was only 37% of that in Layer 1. For this permeability combination, the degree of foam penetration in radial flow was also less than that for the water-like gelant. Upon first consideration, this result suggests that the foam will be superior to a gelant when used as a blocking agent. However, the next section will demonstrate that this suggestion is not correct. Although the foam placement was apparently better than that for a water-like gelant, the permeability-reduction properties ultimately favor the gel instead of the foam for Case 6.

Relative Injectivity Losses After Foam Placement. To evaluate the success of a treatment, we must determine how the flow profiles are modified in each layer. This determination requires both the distances of blocking-agent penetration into the various layers (as shown in the previous section) and the permeability-reduction properties (residual resistance factors) in the various layers. The data in Fig. 8 and Ref. 7 provided the foam residual resistance factors that we used in our analysis.

In a successful treatment, the brine injectivity in high-permeability zones should be reduced by a much greater factor than in the low-permeability zones. Using the equations and methods described in Refs. 7, 12, and 13, we calculated the relative injectivity retained, I/I_o, in each layer during brine injection after foam placement. These I/I_o values are listed in the sixth and seventh columns of Table 3.

Table 3 compares nine cases that show how a foam treatment modifies brine-injection profiles in two-layered radial systems (no communcation between layers). The fourth and fifth columns of this table list values of the residual resistance factors that were assumed in Layers 1 and 2, respectively. These values were based on our experimental results. In the 80-, 482-, and 899-md layers, the residual resistance factors of 8.9, 4.3, and 2.7, respectively, were the values from Fig. 8 after 80 PV of brine injection. (A more extensive analysis using residual resistance factors measured before 80 PV of brine can be found in Ref. 7.)

In the 7.5-md layer for Cases 1a, 2a, and 3a, we assumed that the residual resistance factor was 1, so the I/I_o calculation was independent of the distance that the foam formulation penetrated into Layer 2. The I/I_o values were always 100%. Since some permeability reduction occurred in the 80-, 482-, and 899-md layers, Cases 1a, 2a, and 3a show that the foam treatments improved the injection profiles.

In Cases 1b, 2b, and 3b, the foam was assumed to fill the 7.5-md layer, and the residual resistance factor in the 7.5-md layer was assumed to have a value of 2. Based on our experimental results, these were conservative assumptions, which led to I/I_o values of 50% in the 7.5-md layer. In spite of these conservative assumptions, comparison of Columns 6 and 7 of Table 3 reveals that the foam treatments provided lower I/I_o values in the high-permeability layers, so the injection profiles were improved in Cases 1b, 2b, and 3b.

Cases 4, 5, and 6 in Table 3 list the I/I_o values for the corresponding Cases 4, 5, and 6 in Table 2. (Column 6 of Table 2 provided the radii of foam penetration for each of the three cases.) In Cases 4 and 5, we confirmed that the injection profiles were not improved by the foam treatment. These results were expected since the degrees of penetration into Layer 2 were greater than those for water-like gelants.

Case 6 in Table 3 shows the result when Layers 1 and 2 had permeabilities of 899 md and 482 md, respectively. Even though Case 6 of Table 2 indicated that foam placement was apparently superior to that for a water-like gelant, Case 6 of Table 3 shows that the profile was not improved. This result was obtained because the residual resistance factor in the 482-md layer (4.3) was significantly greater than that in the 899-md layer (2.7). Therefore, in radial flow, foams may only be superior to gels when the foam does not form in the less-permeable zones (Cases 1 through 3 in Table 3).

Of course, the merits of using foams versus gels are also affected by other factors, such as chemical-rock interactions and the stability in the presence of oil.[2,8]

Conclusions

For nitrogen foams at 104°F with an aqueous phase containing 0.3% C_{14-16} α-olefin sulfonate (Stepan Bio-Terge AS-40®), 1% NaCl, and 0.1% $CaCl_2$:

1. A permeability (7.5 md) was identified where no foam or only weak foam was generated. In a 7.5-md core, the resistance factors were 2.2, 1.9, and almost 1 for qualities of 50%, 80%, and 95%, respectively.
2. For the 80-, 482-, and 899-md cores, foams exhibited relatively low mobilities and showed shear-thinning behavior. Depending on fluid velocity and foam quality, foam resistance factors varied from 20 to 300 for the 80-md core, from 60 to 1,500 for the 482-md core, and from 40 to 1,000 for the 899-md core.
3. For the 80-, 482-, and 899-md cores, brine residual resistance factors decreased as the permeability increased.
4. A modeling study revealed that compared with water-like gelants, this foam showed better placement properties when the permeabilities were 7.5 md or less in the low-permeability zones and 80 md or more in the high-permeability zones.

Nomenclature

F_{rr} = residual resistance factor
I = injectivity, BPD/psi
I_o = initial injectivity, BPD/psi
k = permeability, md
L_p = distance of blocking-agent penetration, ft
r_p = radius of blocking-agent penetration, ft
r_w = wellbore radius, ft
u = superficial or Darcy velocity, ft/d

Subscripts

1 = high-permeability layer (Layer 1)
2 = low-permeability layer (Layer 2)

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Table 1. Correlations Between Foam Mobility (in md/cp) and Darcy Velocity (u, in ft/d)

Quality	50%	80%	95%
k, md	Foam mobility, md/cp		
7.5	$3.68\ u^{-0.03}$	$5.63\ u^{0.04}$	$11.6\ u^{0.08}$
80	$0.36\ u^{0.62}$	$1.51\ u^{0.37}$	$1.52\ u^{0.39}$
482	$0.42\ u^{0.70}$	$1.28\ u^{0.45}$	$2.65\ u^{0.28}$
899	$1.21\ u^{0.73}$	$3.16\ u^{0.52}$	$9.9\ u^{0.26}$

Table 2. Gelant Placement Versus Foam* Placement in Two-Layered Systems

Case	k_1, md	k_2, md	Blocking agent	L_{p2}/L_{p1}	$(r_{p2}-r_w)/(r_{p1}-r_w)$	Best placement?
1	899	7.5	1. Water-like gelant 2. Foam	0.008 0.000	0.091 0.000	Foam
2	482	7.5	1. Water-like gelant 2. Foam	0.016 0.000	0.125 0.000	Foam
3	80	7.5	1. Water-like gelant 2. Foam	0.094 0.000	0.306 0.000	Foam
4	899	80	1. Water-like gelant 2. Foam	0.09 0.32	0.30 0.52	Gelant
5	482	80	1. Water-like gelant 2. Foam	0.17 0.98	0.41 0.93	Gelant
6	899	482	1. Water-like gelant 2. Foam	0.53 0.37	0.73 0.55	Foam (apparently)

*95% quality foam

Table 3. Profile Modification During Brine Injection After Foam Treatments in Two-Layered Systems (Radial Flow)

Case	k_1, md	k_2, md	F_{rr1}	F_{rr2}	I_1/I_{1o}, %	I_2/I_{2o}, %	Profile improved?
1a	899	7.5	2.7	1.0	37.0	100.0	yes
1b	899	7.5	2.7	2.0	37.0	50.0	yes
2a	482	7.5	4.3	1.0	23.3	100.0	yes
2b	482	7.5	4.3	2.0	23.3	50.0	yes
3a	80	7.5	8.9	1.0	11.2	100.0	yes
3b	80	7.5	8.9	2.0	11.2	50.0	yes
4	899	80	2.7	8.9	37.0	12.7	no
5	482	80	4.3	8.9	23.3	11.4	no
6	899	482	2.7	4.3	37.0	25.6	no

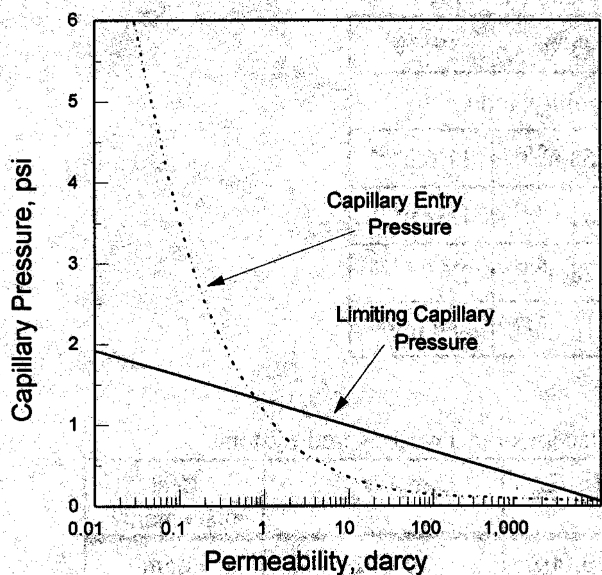

Fig. 1—Permeability dependence of capillary pressures (from Khatib et al.[3]).

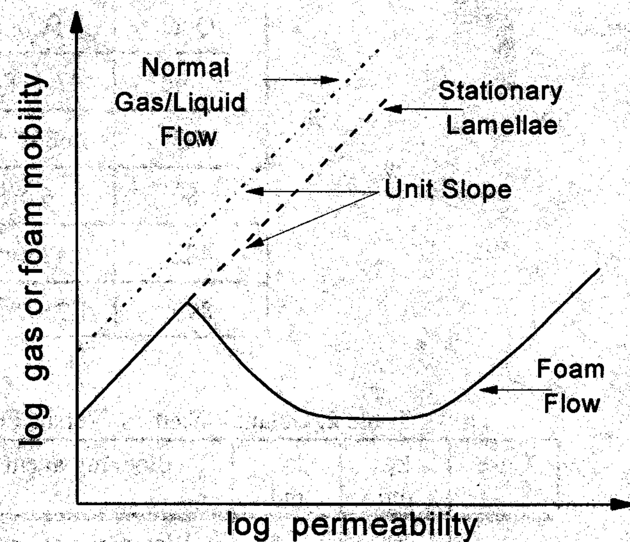

Fig. 2—Permeability dependence of gas mobility (from Khatib et al.[3]).

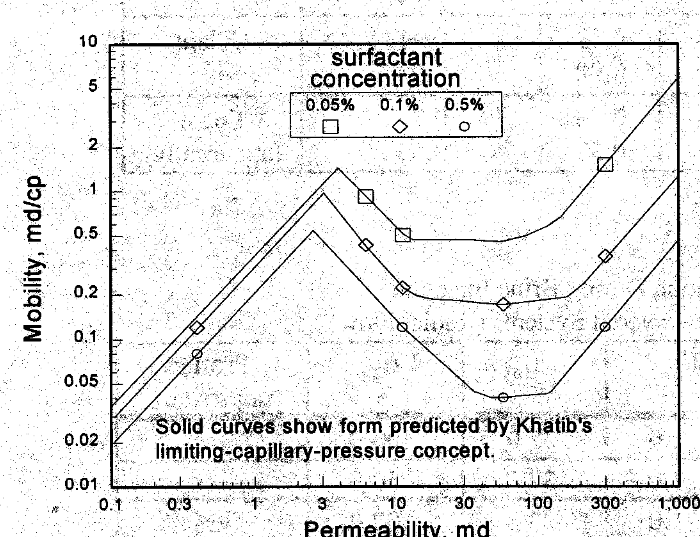

Fig. 3—Replotted data from Lee, Heller, and Hoefer.[6]

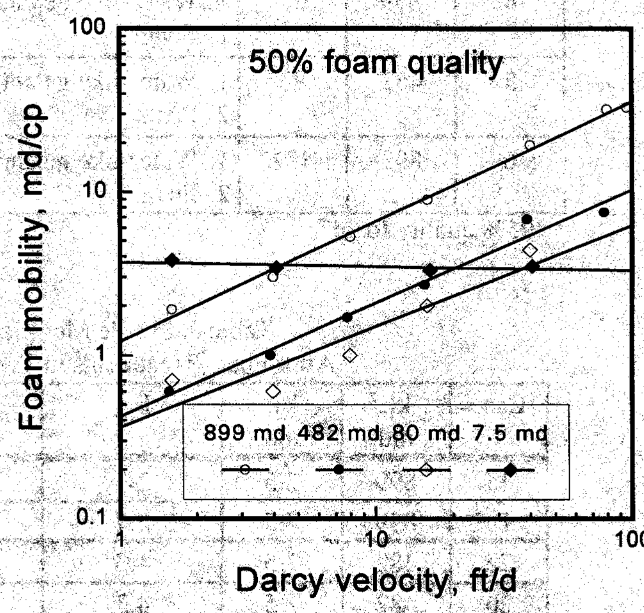

Fig. 4—Foam mobility versus velocity and permeability. 50 % foam quality.

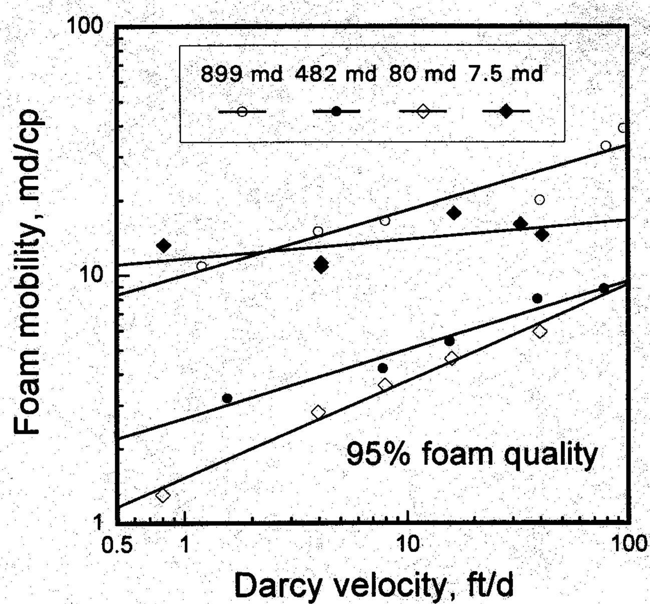

Fig. 5—Foam mobility versus velocity and permeability. 95 % foam quality.

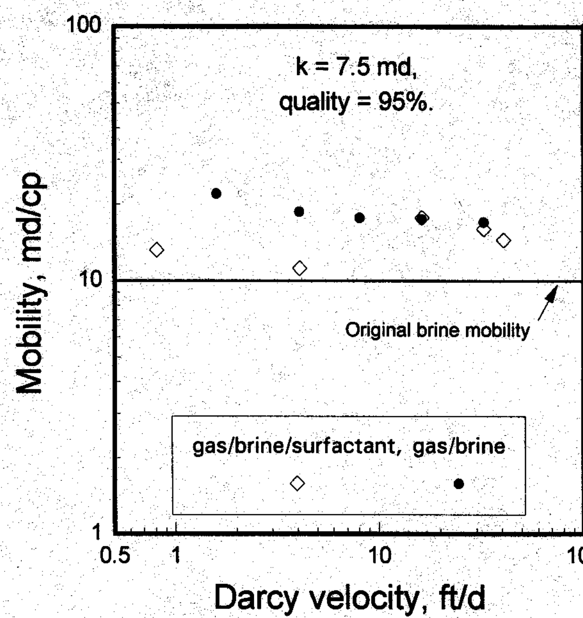

Fig. 6—Comparison of gas/brine/surfactant flow versus gas/brine flow in 7.5-md rock. 95% quality foam.

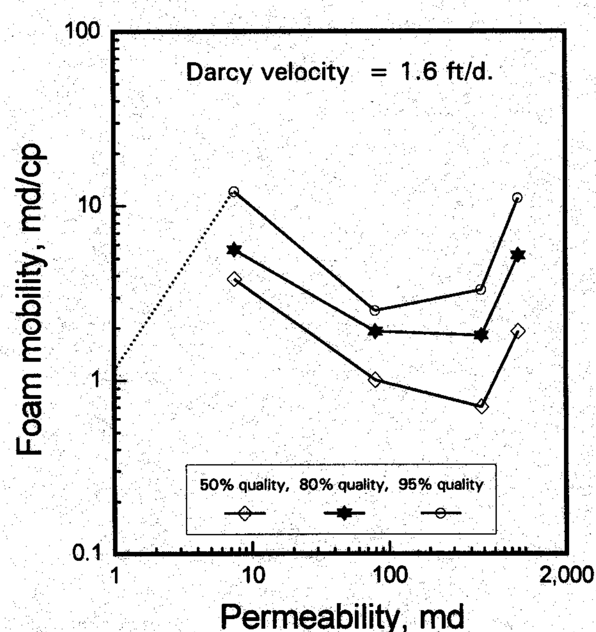

Fig. 7—Variation of foam mobility with permeability. 1.6 ft/d.

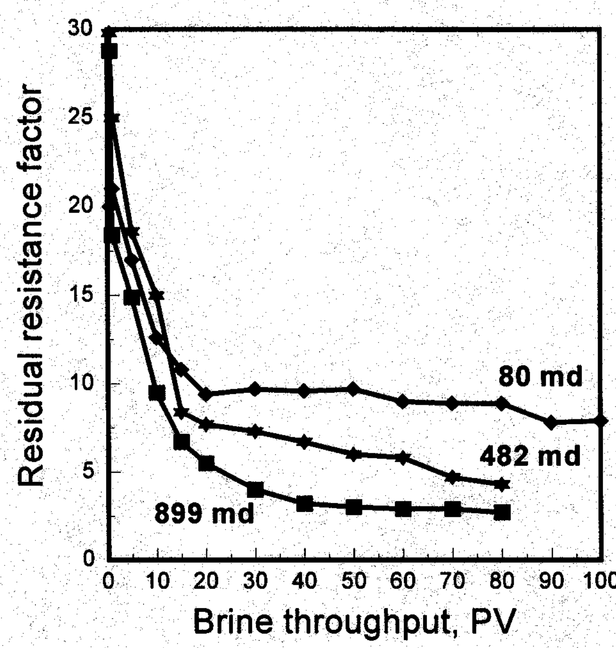

Fig. 8—Residual resistance factors during brine injection after foam placement.