Further Investigations of Why Gels Reduce Water Permeability More Than Oil Permeability

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Summary

In this paper, we investigate why some gels can reduce the permeability to water much more than to oil. This property is critical to the success of chemical-based water-shutoff treatments in production wells if hydrocarbon-productive zones cannot be protected during placement. We first briefly review previous findings and the validity of several possible explanations for this disproportionate permeability reduction. Next, we describe experiments that test the validity of a promising mechanism—the segregated pathway theory. This theory speculates that on a microscopic scale, aqueous gelants follow water pathways more than oil pathways. Our experimental results in cores support this mechanism for oil-based gels, but not for water-based gels. We also explore another interesting mechanism that involves a balance between capillary and elastic forces. Results from our experiments support this mechanism for flow in tubes and micromodels, but not in porous rock. Other mechanisms are also discussed.

Introduction

The ability of blocking agents to reduce the permeability to water much more than to oil is critical to the success of water-shutoff treatments in production wells if hydrocarbon-productive zones cannot be protected during placement.[1,2] Results from the literature and our own experimental work[3-14] have shown that many polymers and gels exhibit this disproportionate permeability reduction. However, the magnitude of the effect has been unpredictable from one application to the next. Presumably, the effect would be more predictable and controllable if we understood why the phenomenon occurs. In our previous studies, we examined six possible mechanisms for this disproportionate permeability reduction (see **Table 1**).[12-14] Although we have not yet definitively explained this phenomenon, some possible mechanisms have been identified.

In this paper, we first briefly review previous findings and the validity of several possible explanations for the disproportionate permeability reduction. Next, we describe experiments that test the validity of a promising mechanism, the segregated pathway theory (see **Fig. 1** and Mechanism 6 in Table 1). Third, we explore another interesting mechanism that was suggested after viewing a videotape of micromodel experiments performed by Dawe and Zhang.[15] This mechanism involves a balance between capillary and elastic forces (Mechanism 7). Finally, we examine yet another mechanism that assumes that, during brine injection, polymer leaches from the gel and significantly decreases the brine mobility (Mechanism 8).

Review of Previous Findings

The ability to reduce permeability to water more than that to oil or gas has been reported for some adsorbed polymers and many gels of different strengths and generic types.[2-17] Earlier work (at 41°C) showed that this effect was not caused by simple hysteresis of relative permeabilities or by gel breakdown during successive injection of oil and water banks.[2,3] Thus, the effect does not appear to be an experimental artifact.

Mechanism 1 in Table 1 speculates that the disproportionate permeability reduction occurs because gels shrink when in contact with oil but swell when in contact with water. This mechanism is counterintuitive because it requires that a hydrophilic gel give up water to a hydrophobic oil.[12] Also, experiments in beakers show no tendency for oil to synerese or degrade aqueous gels (assuming that the oil does not contain corrosive agents). Furthermore, in contact with water, gels can shrink, swell, or remain unchanged, depending on the salinity and pH of the water.[18] Finally, in cores, the oil/water disproportionate permeability reduction was insensitive to system pressure between 0 and 1,500 psi.[12] These facts all argue against the shrinking/swelling mechanism (Mechanism 1).

The disproportionate permeability reduction was not sensitive to flow direction or core orientation (vertical or horizontal) during flooding or to water/oil density differences between 0.12 and 0.24 g/cm^3. These facts indicate that gravity effects (Mechanism 2 in Table 1) do not cause the disproportionate permeability reduction.[12]

The effect was not sensitive to oil viscosity between 1 and 31 cp.[12] Also, behavior observed in water/gas experiments (using either N_2 or CO_2 at 900 to 1,500 psi) was analogous to that in water/oil experiments.[14] These facts argue against the importance of lubrication effects (Mechanism 3 in Table 1), where a low-viscosity wetting layer lubricates or reduces the apparent resistance associated with flow of the nonwetting phase.[12]

Mechanism 4 in Table 1 suggests that the disproportionate permeability reduction should be greatest in water-wet cores. However, cases have been observed where the effect is significantly more pronounced in cores of intermediate wettability than in water-wet cores.[3] Thus, although we suspect that wettability may play a role in the disproportionate permeability reduction, its effects are unclear.

In a previous paper,[12] we reported evidence that supported Mechanism 6. On a microscopic scale, aqueous gelants follow water pathways more than oil pathways. The main evidence supporting this mechanism was that an oil-based gel reduced permeability to oil much more than that to water. Our previous paper acknowledged that additional work was needed to support Mechanism 6. The remainder of this paper documents our efforts to find that support, as well as our investigation of two new mechanisms (Mechanisms 7 and 8 in Table 1).

Segregated Oil and Water Pathways

If (on a microscopic scale) a water-based gelant follows primarily the pathways available to water, then many of the oil pathways could remain open (relatively gel-free) after treatment while most of the water pathways would be blocked by the gel (Fig. 1). In this way, the water-based gel could reduce permeability to water more than to oil.

Following the same logic, during high oil fractional flow, if an oil-based gel follows primarily the pathways available to oil on a microscopic scale, then many of the water pathways could remain open after treatment while most of the oil pathways would be blocked by the gel. In support of this theory, we found that an oil-based gel (12-hydroxystearic acid in Soltrol 130) reduced permeability to oil much more than to water.[12,13]

If this segregated-pathway theory is valid, we speculate that the disproportionate permeability reduction could be enhanced by simultaneously injecting oil with a water-based gelant or water with an oil-based gelant. Presumably, simultaneous injection of oil and a water-based gelant should allow a larger fraction of oil pathways to remain open than if a water-based gelant is injected by itself. Using similar logic, simultaneous injection of water and an oil-based gelant should allow a larger fraction of water pathways to remain open than if an oil-based gelant is injected by itself.

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TABLE 1—PROPOSED MECHANISMS FOR THE DISPROPORTIONATE PERMEABILITY REDUCTION

Previously Examined Mechanisms

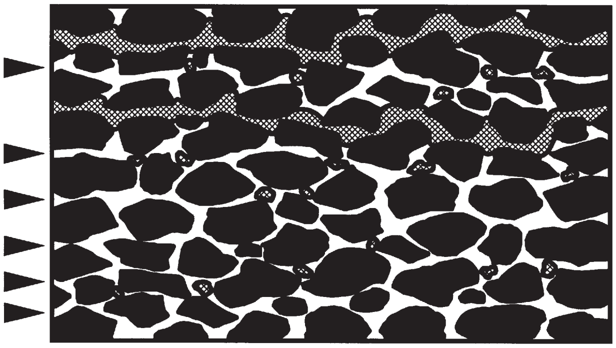
1. Gels shrink in oil but swell in water.
2. Gravity affects gel locations in pores.
3. Lubrication effects.
4. Gelants or gels alter rock wettability.
5. In a given pore, gels constrict water pathways more than oil pathways.
6. On a microscopic scale, gelants follow water pathways more than oil pathways.

New Mechanisms

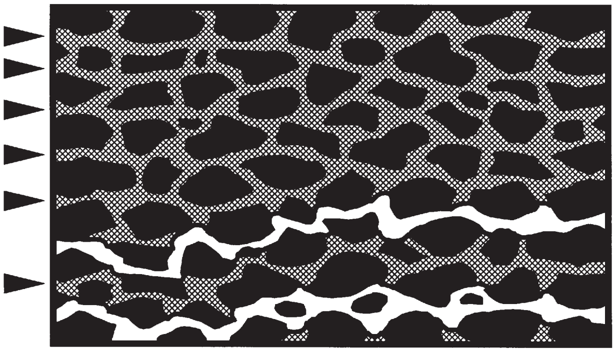
7. Balance between capillary forces and gel elasticity affects oil and water flow differently.
8. During brine injection, polymer leaches from the gel and significantly decreases the brine mobility.

Simultaneous Injection of Water and an Oil-Based Gelant. To test this theory, we used an oil-based gel that contained 18% 12-hydroxystearic acid in Soltrol 130. Two experiments were performed using high-permeability Berea sandstone cores. (Ref. 17 contains a detailed description of the experiments.) **Table 2** shows that for the case where brine was injected with the gelant (using a 50/50 volume ratio), the water residual resistance factor ($F_{rrw}=5$) was much lower than that for the case where no brine was injected with the gelant ($F_{rrw}=34$). Interestingly, F_{rro} values were comparable for both cases. These results indicate that the disproportionate permeability reduction was enhanced by the simultaneous injection of water with an oil-based gelant. These findings support the segregated-pathway theory.

Simultaneous Injection of Oil and a Water-Based Gelant. We performed similar experiments using a water-based gel to test the validity of the segregated-pathway theory. If this theory is valid, simultaneous injection of oil and a water-based gelant should enhance the disproportionate permeability reduction. Four core experiments were conducted using different gelant/oil volume ratios during placement. These core experiments were performed in high-permeability Berea sandstone cores using a Cr(III)-acetate-HPAM gel. This water-based gel contained 0.5% HPAM (Alcoflood 935, 5 to 10% degree of hydrolysis), 0.0417% Cr(III) acetate, and 1% NaCl. For the base case, the water-based gelant was injected alone during placement. The second, third, and fourth core experiments were performed using 95/5, 50/50, and 30/70 gelant/oil volume ratios during placement, respectively. **Table 3** shows that, in all four cases, the gel reduced permeability to water significantly more than to oil. The ratio, F_{rrw}/F_{rro}, provides a measure of the disproportionate permeability reduction. This ratio was 58 (i.e., 2,450/42), 28, 46, and 41 for gelant/oil injection ratios of 100/0, 95/5, 50/50, and 30/70, respectively. Thus, contrary to the case for oil-based gelant injected with water, simultaneous injection of oil with a water-based gelant using gelant/oil injection ratios of 95/5, 50/50, and 30/70 failed to enhance the disproportionate permeability reduction. These findings do not support the segregated-pathway theory.



High Water Fractional Flow



High Oil Fractional Flow

☐ Water or Water-Based Gel ▨ Oil or Oil-Based Gel ■ Rock

Fig. 1—Segregated oil and water pathways.

One might argue that the experiments with oil-based gelants are not symmetrical to those with water-based gelants because both sets of experiments used strongly water-wet cores. Nevertheless, with any wettability, the segregated pathway theory predicts that oil and water phases basically take different flow paths on a microscopic scale. Thus, the appropriate method to test this theory is to perform oil and water flow experiments in a system of fixed wettability (as we have done). Even so, to further probe the disproportionate permeability reduction, our future plans include experiments in systems with other wettabilities.

Balance Between Capillary Forces and Gel Elasticity

Because our experimental evidence does not completely support the segregated-pathway theory, we continue consideration of other possible mechanisms. After viewing the results from the micromodel experiments of Dawe and Zhang,[15] we wondered whether capillary forces and gel elasticity might contribute to the disproportionate

TABLE 2—F_{rrw} AND F_{rro} VALUES FOR AN OIL-BASED GEL* IN BEREA SANDSTONE

Gelant/Water Volume Ratio During Placement	kw (md)	First F_{rrw}	First F_{rro}	Second F_{rrw}	First F_{rro}/F_{rrw}
100/0	599	34	300	30	9
50/50	586	5	225	14	45

*18% 12-Hydroxystearic acid and Soltrol130

TABLE 3—F_{rrw} AND F_{rro} VALUES FOR A WATER-BASED GEL* IN BEREA SANDSTONE

Gelant/Oil Volume Ratio During Placement	kw (md)	First F_{rro}	First F_{rrw}	Second F_{rro}	First F_{rrw}/F_{rro}
100/0	793	42	2,450	37	58
95/5	655	390	11,100	500	28
50/50	520	27	1,255	16	46
30/70	622	26	1,075	20	41

*0.5% HPAM, 0.0417% Cr(III) acetate,1% NACL

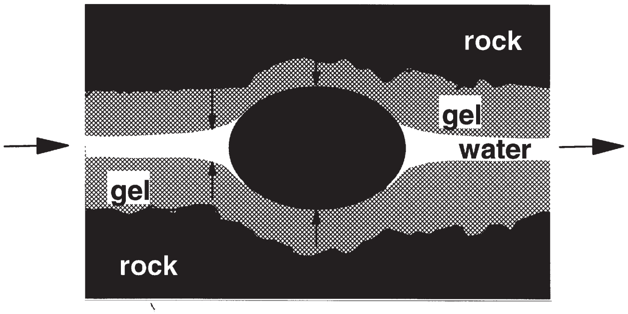


Fig. 2—Balance between capillary forces and gel elasticity when forcing oil or water through an aqueous gel.

permeability reduction.[13] In a video from Dawe and Zhang, we observed that during oil injection, oil drops squeezed through an elastic, aqueous gel. During water injection, most of the water flowed through the pathways created by oil, except the pathways were more constricted. Dawe and Zhang[15] reported that the gel reduced the permeability to water significantly more than that to oil. We suspect that the disproportionate permeability reduction was caused by the balance between capillary forces and gel elasticity. As illustrated in **Fig. 2**, when an oil droplet extrudes through an aqueous gel, two opposing forces act. On the one hand, a capillary force acts to maintain a minimum droplet radius, which in turn forces open a channel through the gel. On the other hand, the gel exerts an elastic confining force to close the channel. The final radius of the oil droplet and the size of the oil pathway depend on the balance between the two forces. The effective permeability to oil increases with increasing radius of the flow path around the oil droplet. In contrast, when water flows through the same channel, no capillary force acts to open the channel. Therefore, the effective permeability to water should be less than that to oil. There are two possible ways to test this theory: to vary the capillary force and to change the gel elasticity. We are investigating both approaches.

Confirming the Results of Dawe and Zhang

To confirm the micromodel results of Dawe and Zhang,[15] we developed a simple experiment using small glass conduits to visualize the disproportionate permeability reduction. The flat-shaped glass conduits were 0.05 cm high, 0.5 cm wide, and 3 cm in length. A video camera was mounted on a microscope to monitor and record fluid movements in the glass conduit. Glass-conduit experiments were performed at 41°C. We used an aqueous gel consisting of 0.5% HPAM, 0.0417% Cr(III) acetate, 1% NaCl, and 0.1% $CaCl_2$.

An aqueous gelant was placed in the glass conduits. (Experimental details can be found in Ref. 19.) Next, a dyed oil (Soltrol 130) was injected into the glass conduit at 0.5 mL/hr. The pressure drop across the glass conduit stabilized at 0.2 psi. During oil injection, we observed that oil forced its way through the gel by creating a channel through the center of the conduit. During oil flow, the gel acted as an elastic material, creating just enough room for the oil drops to squeeze through (as illustrated in Fig. 2). Next, a dyed brine (with 1% NaCl and 0.1% $CaCl_2$) was injected using the same flow rate. The pressure drop across the glass conduit stabilized at 3 psi. This number was significantly higher than the 0.2-psi pressure drop during oil injection. Also, we observed that the pathway created during oil injection closed significantly during water injection (apparently because of the elasticity of the gel). These observations are consistent with the micromodel results reported by Dawe and Zhang.[15] After brine injection, oil was injected again at 0.5 mL/hr, and the pressure drop across the glass conduit was 0.3 psi. The pressure behavior indicates that the water-based gel reduced the permeability to water significantly more than that to oil.

Effect of Oil/Water Interfacial Tension

For an oil droplet in water (Fig. 2), the capillary pressure across the interface is proportional to the interfacial tension divided by the oil-drop radius. Therefore, reducing the interfacial tension decreases the capillary pressure. With a weaker capillary force to counter a given elastic force from the gel, the radius of the flow channel around the oil droplets is reduced. Therefore, if this theory is valid, lowering the interfacial tension should reduce the permeability to oil while the permeability to water should not be affected. In other words, the disproportionate permeability reduction should become less pronounced if the oil/water interfacial tension is reduced. To test this theory, we used an oil-soluble surfactant, Shell Neodol(R) 1-3 (a C_{11}-alcohol ethoxylate), to lower the oil/water interfacial tension. The addition of 0.1% surfactant to the oil phase lowered the oil/water interfacial tension from 42.5 dyne/cm to 8 dyne/cm. Incidentally, the critical micelle concentration was 0.1% for this surfactant in 1% NaCl brine at 41°C.

Glass-Conduit Experiment. A second glass-conduit experiment was conducted using the Cr(III)-acetate-HPAM gel. The experiment was similar to that described above, except that oils with and without surfactant were used to visualize the effect of interfacial tension on the disproportionate permeability reduction. From this experiment (details in Ref. 19), we found that the permeability to oil was more than two times greater in the absence of surfactant than in the presence of 0.1% surfactant. This finding supports Mechanism 7, at least for flow in glass conduits.

Core Experiment. Mechanism 7 was further tested using a Cr(III)-acetate-HPAM gel in a 532-md Berea sandstone core at 41°C. (Details of the core preparation, gel placement, and flood results can be found in Ref. 19.) As we have found consistently in the past,[12] the water residual resistance factor was substantially greater than the oil residual resistance factor. During the first cycle of oil injection, F_{rro} was 77 for Soltrol 130 oil that contained no surfactant. This oil was displaced with many pore volumes (PV's) of Soltrol 130 oil that contained 0.1% surfactant, and the F_{rro} value stabilized at 50. This slight reduction of the F_{rro} value indicates that the surfactant slightly increased the effective permeability to oil. (We were careful to note that surfactant injection did not change the resident water saturation.) Contrary to the behavior that we observed in the glass conduits, reduction of the interfacial tension did not reduce the effective permeability to oil. Thus, we question whether the behavior observed in glass conduits or micromodels is representative of the behavior in cores.

Effect of Gel Elasticity During Core Experiments

Gelled Foams. To further test Mechanism 7, we examined the effects of gel elasticity on the disproportionate permeability reduction. In concept, increasing gel elasticity should allow the capillary force to open a larger path around the oil droplet, resulting in a higher effective permeability to oil. One way to increase the elasticity of a gel is to incorporate gas into the system. Therefore, if this theory is valid, we expect a gelled foam to show a more pronounced disproportionate permeability reduction. Two core experiments (both in 700-md Berea sandstone) were performed to verify this theory. In both cases, the gelant/surfactant solution contained 0.5% HPAM, 0.0417% Cr(III) acetate, 1% NaCl, 0.1% $CaCl_2 \cdot H_2O$, and 0.3% Stepan Bio-Terge® AS-40 (a $C_{14\text{-}16}$ alpha-olefin sulfonate). Nitrogen was the gas used for foaming. To maximize gel elasticity (or more correctly in this case, to maximize compressibility), the experiments were performed at atmospheric pressure.

For each core experiment, multiple cycles of brine and oil were injected after treatment. We compared results from experiments using the gelled foam with results from a previous experiment using a gel without gas or foam. (Ref. 13 provides details of the core experiments.) The disproportionate permeability reduction (F_{rrw}/F_{rro}) was more pronounced at low flow rates for both the gelled foam and the gel without gas or foam. For example, for both blocking agents, $F_{rrw}/F_{rro} \approx 7$ at 0.8 ft/D, and $F_{rrw}/F_{rro} \approx 2$ at 16 ft/D. The disproportionate permeability reduction was not more pronounced for a gelled foam than for a gel without foam or gas. This finding does not support Mechanism 7. This result may be interpreted in one of three ways. First, perhaps the gelled foam in the po-

TABLE 4—F_{rrw} AND F_{rro} VALUES FOR A HQ-HMT-HPAM GEL IN BEREA SANDSTONE

Days at 110°C	kw (md)	Sydansk Gel Code[21]	First F_{rro}	First F_{rrw}	Second F_{rro}	Second F_{rrw}
2	467	C	20	4.7	20	4.2
8	286	D-E	13.6	10.2	14.6	8.7

TABLE 5—EFFECT OF PERMEABILITY ON F_{rrw} AND F_{rro} VALUES FOR A Cr(III)-ACETATE-HPAM GEL

Berea Sandstone Permeability (md)	First F_{rro}	First F_{rrw}	Second F_{rro}	Second F_{rrw}
793	42	2,450	37	$227\,u^{-0.54}$
95	470	2,830	138	$276\,u^{-0.48}$

rous rock was not as elastic as we had hoped. Second, as suggested earlier, perhaps Mechanism 7 is not the primary mechanism responsible for the disproportionate permeability reduction in porous rock. Third, gelled foams may not be a good analogy for studying the elastic mechanism. Work at the U. of Michigan[20] suggests that gelled foams primarily function as gelled lamellae located within pore throats. To allow fluid flow through a gelled-foam-blocked pore throat, gel lamellae may be required to rupture. Thus, the mechanism for disproportionate permeability reduction with gelled foams may be different from that for gels with no gas present.

Quenched Gels. Another possible way to change the gel elasticity is to quench the gelation reaction at different stages of the gelation process. In this study, we chose a hydroquinone-hexamethylenetetramine-HPAM gel (abbreviated HQ-HMT-HPAM).[16] The gel contained 0.5445% HPAM, 0.25% hydroquinone, 0.1% hexamethylenetetramine, and 1% $NaHCO_3$. This gelant requires high temperatures for the gelation reaction to proceed at a significant rate.[16] Based on our past experience,[16,17] we aged the gelant at 110°C, followed by quenching to 41°C. Two oil/water experiments were performed in high-permeability Berea sandstone cores. In both cases, 10 PV of the gelant were injected into the core at room temperature (26°C). For the first oil/water experiment, the core was shut in at 110°C for 2 days. After the 2-day shut-in period, the temperature was lowered to 41°C to quench the gelation reaction. For the second oil/water experiment, the core was shut in at 110°C for 8 days before lowering the temperature to 41°C. Results from beaker tests showed that with the gelation reaction quenched after 2 days at 110°C, the gel had a Sydansk gel code[21] of C (flowing gel). The gel with the gelation reaction quenched after 8 days at 110°C was less elastic with a gel code between D and E (between moderately flowing gel and barely flowing gel).

After shut-in, two cycles of oil/water injection were conducted to measure the residual resistance factors. Surprisingly, the 2-day gel reduced the permeability to oil significantly more than to water. Perhaps, an water-insoluble organic byproduct from the reaction created an oil-wet surface that affected the disproportionate permeability reduction. **Table 4** shows that the ratio of F_{rro}/F_{rrw} was about 4 for the 2-day gel. Interestingly, this reverse disproportionate permeability reduction was less pronounced for the less-elastic 8-day gel. Perhaps this was caused by the less-permeable rock used with the 8-day gel (as will be discussed in the next section.) More work will be required to understand this unusual phenomenon.

Effect of Rock Permeability

We also compared the disproportionate permeability reduction for a Cr(III)-acetate-HPAM gel in a 793-md Berea sandstone core versus in a 95-md Berea sandstone core. Again, the gel contained 0.5% HPAM, 0.0417% Cr(III)-acetate, and 1% NaCl. Both cores were saturated with 10 PV of gelant.[19] After gelation, two cycles of oil/water injection were performed to measure the residual resistance factors. To minimize gel breakdown, residual resistance factors were measured using a single flow velocity (0.025 ft/D) during the first cycle of oil/water injection. During the second cycle of oil/water injection, the residual resistance factors were measured using different flow velocities. **Table 5** summarizes the F_{rrw} and F_{rro} values after treatment. In both cores, the gel reduced permeability to water much more than that to oil. The residual resistance factor for oil, F_{rro}, was flow-rate independent and the residual resistance factor for water, F_{rrw}, exhibited an apparent shear-thinning behavior, which was fit using power-law equations (fifth column of Table 5).

The gel reduced the permeability to water by about the same factor in 793-md sandstone as in 95-md sandstone. However, the gel reduced the permeability to oil 4 to 11 times more in the 95-md core than in the 793-md core. After two cycles of oil/water injection, the F_{rrw}/F_{rro} at 1 ft/D superficial velocity was 6 in 793-md sandstone and 2 in 95-md sandstone (compare the fourth and fifth columns of Table 5). These results suggest that disproportionate permeability reduction may be more pronounced in high-permeability rock than in low-permeability rock.

The above behavior could support several of the proposed mechanisms. For example, for the capillary-force-gel-elasticity mechanism, one could argue that larger pores (associated with higher permeabilities) could allow larger oil droplets to flow through the gel. Thus, as observed, the disproportionate permeability reduction becomes more pronounced as rock permeability increases. However, the segregated pathway mechanism could also be argued. In water-wet rock, a higher fraction of relatively large pores would be available for oil flow as rock permeability increases. Thus, we cannot yet use our permeability variation results to choose between mechanisms.

Polymer Washout During Brine Injection

Results from our oil/water experiments revealed that many gels exhibit a shear-thinning behavior during brine injection. The residual resistance factors for water decrease with increasing fluid velocity.[12,13] In contrast, during oil injection, the residual resistance factors for oil were independent of flow rate. To date, we do not understand why this occurs. Our previous study showed that the non-Newtonian F_{rrw} values were not caused by gel breakdown.[12] Was this non-Newtonian behavior caused by polymer being leached from the gel during brine injection? Because the polymers were hydrophilic and not soluble in oil, this might explain why we observed non-Newtonian flow behavior only during brine injection and not during oil injection. We also wondered whether polymer dissolution might cause the disproportionate permeability reduction.

Polymer Dissolution and Non-Newtonian Behavior During Brine Injection. To test this theory, we performed an oil/water experiment in a 679-md Berea sandstone core. Again, the gel contained 0.5% HPAM, 0.0417% Cr(III)-acetate, and 1% NaCl, and the oil was Soltrol 130. During brine injection after gel placement, we collected effluent samples and measured polymer concentrations.[19] We also measured residual resistance factors at different injection rates. After brine injection, oil was injected to measure F_{rro}. Multiple cycles of water/oil injection were performed.

Fig. 3 plots the effluent polymer concentration vs. the cumulative brine pore volumes injected during multiple cycles of brine injection. During the first brine injection, a total of 12.7 PV of brine were injected using different fluid velocities. Fig. 3 shows that the effluent polymer concentration averaged 800 ppm during the first 0.5 PV of brine injection. It then dropped dramatically during the next pore volume and finally stabilized at about 30 ppm after injecting 5 PV of the brine.

Similar behavior was observed during the subsequent brine injection cycles. As shown in Fig. 3, the effluent polymer concentration jumped to a relatively high value each time after switching from oil to brine injection, and then quickly stabilized between 20 and 50 ppm. **Table 6** shows that during each cycle of brine injection, a strong shear-thinning behavior was observed that can be described by a power-law equation. (The power-law equations in Table 6 were obtained after the stabilization of effluent polymer concentration.) Because 50-ppm HPAM does not significantly affect the viscosity of a 1% NaCl brine, our results suggest that polymer dissolution is not

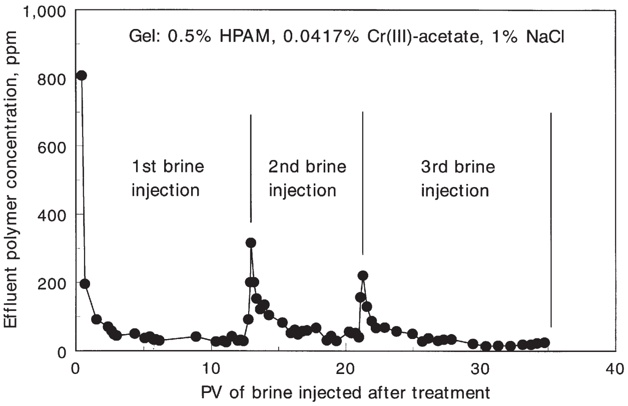


Fig. 3—Effluent polymer vs. PV of brine injected after treatment.

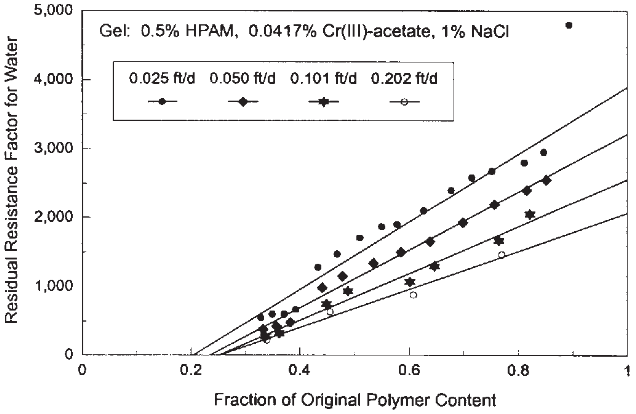


Fig. 4—Effects of polymer produced after treatment on F_{rrw}.

TABLE 6—F_{rrw} AND F_{rro} VALUES FOR A Cr(III)-ACETATE-HPAM GEL IN 679-md BEREA SANDSTONE

Injectant	PV Injected	Residual Resistance Factor
Brine	12.7	$889\ u^{-0.30}$
Oil	4.9	99
Brine	8.4	$469\ u^{-0.38}$
Oil	6.2	58
Brine	13.9	$354\ u^{-0.34}$

the cause for either the disproportionate permeability reduction or the non-Newtonian behavior observed during brine injection.

F_{rrw} vs. Amount of Polymer Produced. Table 6 also shows that both F_{rrw} and F_{rro} were lower after each cycle of water/oil injection. We wondered if the amount of polymer produced correlated with F_{rrw}. **Fig. 4** plots F_{rrw} vs. the fraction of polymer remaining in the porous medium during multiple cycles of brine injection. Ref. 19 describes details of how the experiment was performed. To summarize the process, we first injected water (after gel placement) at a low rate (0.025 ft/D) and recorded the residual resistance factor and the cumulative amount of polymer that was produced with the core effluent. These values were used to determine the y-axis and x-axis values, respectively, plotted in Fig. 4. Next, the injection rate was increased, and the measurements were repeated. Then, the rate was decreased to determine whether the F_{rrw} values had changed at lower rates. This process was repeated at successively higher rates to ultimately provide the data for Fig. 4.

Fig. 4 shows that the most significant drop in F_{rrw} occurred after the first brine injection at 0.025 ft/D. After that, a linear correlation existed between F_{rrw} and the fraction of polymer remaining in the porous medium. As shown in Fig. 4, for a given fluid velocity, F_{rrw} decreased with decreasing amount of polymer remaining in the porous medium. Fig. 4 projects that the gel should lose its effectiveness ($F_{rrw} = 1$) after producing 75 to 80% of the original polymer placed.

We note that Fig. 4 does not necessarily indicate that polymer gels will completely washout and/or become ineffective during field applications. First, the lowest F_{rrw} value reported in Fig. 4 was greater than 100. This value is considered fairly high for many field applications. Second, the results in Fig. 4 were generated by subjecting the gel to wide variations of flow rates and to multiple slugs of oil and water. Previous work[2,3,12,14] has demonstrated that this process can significantly degrade residual resistance factors. Gels in field applications may not experience conditions this severe. Because our results demonstrated that the polymer-leaching mechanism does not explain the disproportionate permeability reduction under our severe conditions, we increase confidence in our conclusion that this mechanism is unlikely to be responsible for the phenomenon under less severe conditions, where less polymer is likely to be leached from the gel.

Conclusions

The following conclusions were reached during our recent investigations of why gels reduce permeability to water more than that to oil.

1. In Berea sandstone, simultaneous injection of water with an oil-based gel (using a 50/50 gelant/water volume ratio) enhanced the disproportionate permeability reduction. In contrast, simultaneous injection of oil with an aqueous gel (using gelant/oil volume ratios of 95/5, 50/50, 30/70) did not enhance the disproportionate permeability reduction. The former finding supports the segregated-oil-and-water-pathway theory (Mechanism 6 in Table 1), while the latter finding does not support it.
2. In a small glass conduit, a Cr(III)-acetate-HPAM gel reduced the permeability to water more than that to oil. Observations made during this experiment, along with those from Dawe and Zhang,[15] suggest that in conduits and micromodels, the disproportionate permeability reduction may be caused by a balance between capillary and elastic forces (Mechanism 7 in Table 1).
3. In a small glass conduit that was filled with a Cr(III)-acetate-HPAM gel, lowering the oil/water interfacial tension from 42.5 dyne/cm to 8 dyne/cm resulted in a decreased permeability to oil. This finding supports the theory that capillary forces and gel elasticity contribute to the disproportionate permeability reduction. However, a similar experiment in a Berea sandstone core did not show a decrease in permeability to oil when the oil/water interfacial tension was reduced. Thus, we suspect that a capillary-elastic-force balance may not be the dominant mechanism in porous rock.
4. In Berea sandstone, the disproportionate permeability reduction was very similar for a Cr(III)-acetate-HPAM gel and a Cr(III)-acetate-HPAM-nitrogen gelled foam. This finding does not support the theory that capillary forces and gel elasticity contribute to the disproportionate permeability reduction in porous rock. (However, we recognize that gelled foams may not be a good analogy for studying the elastic mechanism.)
5. Surprisingly, a water-based hydroquinone-hexamethylenetetramine-HPAM gel reduced the permeability to oil more than that to water in Berea sandstone.
6. In Berea sandstone, the disproportionate permeability reduction was more pronounced in high-permeability (793-md) rock than in low-permeability (95-md) rock.
7. Results from a core experiment using a Cr(III)-acetate-HPAM gel indicated that polymer was leached from the gel and produced during brine injection. However, the polymer concentrations in the brine effluent were too low to be responsible for the disproportionate permeability reduction.

Of course, we recognize the possibility that multiple mechanisms may exist that promote disproportionate permeability reduction. For example, the mechanism may be different for gels vs. adsorbed uncrosslinked polymers; in porous rock vs. glass micromodels; in strongly water-wet rock vs. in mixed-wettability rock; and for nonwetting phases of oil vs. gas. Additional work is required to determine the mechanism or mechanisms responsible for the phenomenon.

Nomenclature

F_{rr} = residual resistance factor (fluid mobility before gel placement divided by fluid mobility after gel placement)
F_{rro} = oil residual resistance factor
F_{rrw} = water residual resistance factor
k_o = permeability to oil, md [m^2]
k_w = permeability to water, md [m^2]
u = flux (superficial velocity), ft/D [cm/s]

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*Conversion factor is exact.

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