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Conformance and Mobility Control: Foams versus Polymers

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Abstract

This paper considers whether foams can be superior to polymers for improving vertical sweep efficiency in reservoirs. Our focus is on vertical sweep improvement during waterflooding and chemical flooding rather than gas flooding. Both linear and radial flow geometries were considered, with and without crossflow. We found that foams can provide improved sweep compared to polymer solutions if (1) foam forms in high permeability zone(s) but not in low permeability zone(s), (2) no crossflow occurs between high and low permeability zones, AND (3) the foam resistance factor in the high permeability zone(s) is sufficiently high to overcome the permeability contrast and the unfavorable mobility ratio between the gas bank and the oil/water bank in the less permeable zones. Foams will generally not be superior to polymers under other circumstances unless gravity effects provide a fortuitous benefit. Other limitations for foams must be recognized, including (1) challenges with formulating foams to meet the above requirements, (2) limitations on foam propagation, especially due to surfactant retention, (3) compression costs during foam injection, and (4) limitations on foam stability under reservoir conditions.

The paper also examines limitations for polymers. Historically, permeability reduction by polymers was advocated as advantageous since reduction in polymer mobility was greater than anticipated based on solution viscosity. However, this permeability reduction generally increases with decreasing permeability, thereby diminishing sweep efficiency. Applications in linear flow (i.e., fractured wells) can be reasonably forgiving of this effect if the permeability contrast and the polymer solution resistance factors are sufficiently large. For radial flow (i.e., wells that do not intersect fractures) with crossflow between layers, the effect has little consequence. However, for radial flow with no crossflow, the effect is quite damaging to sweep.

Introduction

One special property of foams is their ability to collapse in low permeability rock if capillary forces are sufficiently strong to drain water from foam films (i.e., the limiting-capillary-pressure effect).¹⁻³ Under certain circumstances, this property may allow a gas/water/surfactant formulation to penetrate into low permeability zones to a much greater extent than that using an aqueous polymer solution. Thus in concept, vertical sweep could be more efficient during a foam flood than during a polymer flood. However, sweep efficiency could be poor within a low permeability zone because of fingering associated with high mobility gas flow. This paper examines the tradeoff for these effects. Our focus is on vertical sweep improvement during waterflooding and chemical flooding rather than gas flooding.

We first review vertical sweep behavior during floods using viscous Newtonian fluids and polymer solutions in a two-layer reservoir, both with and without crossflow. Next, because the level of permeability reduction by polymers generally increases with decreasing permeability, we examine how this effect influences vertical sweep. Finally, we consider the distribution of flow for foam formulations compared with polymer solutions. Both linear and radial flow geometries are considered.

Normal Behavior of Newtonian Fluids

In this section, we point out some “rules of thumb” that help estimate vertical sweep for various conditions using normal Newtonian fluids. This analysis can serve as a valuable reality check on results from more extensive simulations. Even though very sophisticated chemical flooding simulators are available, they can readily produce unrealistic results if inappropriate default or input parameters are used (i.e., garbage in, garbage out).

For simplicity, the following discussion will consider a two-layer reservoir. The concepts presented here can easily be extended to more complex layering. The most permeable layer will be called “Zone 1”, while the second, less permeable layer will be called “Zone 2.” For a fluid injected to a distance, L_{p1} (for linear flow) or r_{p1} (for radial flow), in Zone 1, we are interested in the distance of fluid penetration, L_{p2} (for linear flow) or r_{p2} (for radial flow), in Zone 2. As a measure of vertical sweep efficiency, we are interested in the quantities, L_{p2}/L_{p1} for linear flow or r_{p2}/r_{p1} for radial flow. If one of these quantities has a value of unity, the injected fluid penetrates the same distance into both zones. In contrast, if the value is zero, no fluid penetrates into Zone 2.

In most of this work, we neglect imbibition and gravity forces to highlight the impact of viscous forces. We will return to a discussion of imbibition and gravity forces near the end of the paper.

Linear Flow, No Crossflow. Consider a two-layer reservoir where an impermeable barrier separates the two zones. If flow is linear (e.g., leakoff into two zones that are cut by a vertical fracture) and if the injected fluid has the same mobility as the fluid being displaced, then the distance of injectant penetration should be proportional to the permeability/porosity ratio (k/ϕ) for a given zone.⁴⁻⁷ For example (first data entry in Table 1), if Zones 1 and 2 have the same porosity but Zone 1 is ten times more permeable than Zone 2, the injectant flows 10 times farther in Zone 1 than in Zone 2 ($L_{p2}/L_{p1}=0.1$). Incidentally, for the case of unit mobility, the resistance factor, F_r , has a value of one. Resistance factor is defined as brine mobility divided by mobility of the viscous injectant. Think of it as the effective viscosity of the injected fluid relative to the viscosity of water.

If the injected fluid is quite viscous, the distance of penetration should be roughly proportional to the square root of the permeability/porosity ratio for a given zone.⁴⁻⁹ For the example above, if $F_r = 1,000$, the injectant flows about three times farther in Zone 1 than in Zone 2 ($L_{p2}/L_{p1}=0.316$). Table 1 illustrates results for these cases and others, as described below. Ref. 9 provides a spreadsheet that performs these calculations (specifically see: Designing Gel Treatments/Leakoff From Fractures Into Matrix Rock/Topic 1).

Table 1— L_{p2}/L_{p1} or r_{p2}/r_{p1} when $k_1\phi_2/(k_2\phi_1)=10$.

F_r	Linear flow		Radial flow	
	No crossflow	Free crossflow	No crossflow	Free crossflow
1	0.100	0.1	0.316	0.316
2	0.140	0.2	0.326	0.45
5	0.211	0.5	0.339	0.71
10	0.256	>0.9	0.347	>0.9
20	0.284	~1.0	0.352	~1.0
50	0.303	~1.0	0.356	~1.0
100	0.310	~1.0	0.356	~1.0
1000	0.316	~1.0	0.356	~1.0

Radial Flow, No Crossflow. For the case of radial flow with barriers to crossflow,^{4,7,9} the distance of penetration is roughly proportional to the square root of the permeability/porosity ratio for a given zone (Table 1). Certainly, more viscous fluids penetrate to a greater extent than low viscosity fluids into low permeability zones. Nonetheless, the square root of the permeability/porosity ratio provides a reasonable approximation regardless of injectant viscosity for normal Newtonian and non-Newtonian polymeric fluids.^{4,7,9} Ref. 9 provides a spreadsheet that performs these calculations (specifically see: Designing Gel Treatments/ Unfractured Wells/Topics 2 and 3).

Unit-Mobility Displacement with Crossflow. Next, consider cases where fluids can freely crossflow between layers. For the case of linear flow and a unit-mobility displacement (e.g., a water-like fluid, $F_r=1$), the distance of injectant penetration should be proportional to the permeability/porosity ratio for a given zone—just as in the no-crossflow case (Table 1). For the case of radial flow and a unit-mobility displacement,¹⁰ the radius of penetration is roughly proportional to the square root of the permeability/porosity ratio for a given zone.

Normal Viscous Fluids with Crossflow, $F_r < k_1\phi_2/(k_2\phi_1)$. Consider the case where the injectant is a normal viscous fluid that freely crossflows. Also, let the resistance factor of the injectant (F_r) be less than the permeability/porosity contrast for the two zones ($k_1\phi_2/(k_2\phi_1)$). Then, for linear flow, the distance of injectant penetration should be proportional to the product of the resistance factor and the permeability/porosity ratio.¹⁰ Ref. 9 provides a spreadsheet that performs these calculations (specifically see: Designing Gel Treatments/Leakoff From Fractures Into Matrix Rock/Topic 2).

For radial flow, the distance of injectant penetration should be proportional to the square root of the product of the resistance factor and the permeability/porosity ratio.¹⁰ Ref. 9 (see: Designing Gel Treatments/Unfractured Wells/Topic 4) provides a spreadsheet for this calculation.

Normal Viscous Fluids with Crossflow, $F_r \geq k_1\phi_2/(k_2\phi_1)$. Now consider the case where the resistance factor of a normal viscous fluid is greater than the permeability/porosity contrast, $F_r \geq k_1\phi_2/(k_2\phi_1)$. For this case, the distance of injectant penetration can be almost the same distance in both zones (Fig. 1). This observation is true for both linear and radial flow if free crossflow can occur for normal viscous fluids.¹⁰

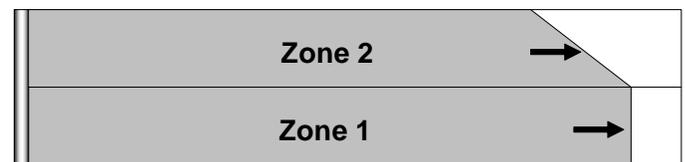


Fig. 1—Either linear or radial flow, free crossflow, $F_r \geq k_1\phi_2/(k_2\phi_1)$.

Effect of Polymer Rheology

The previous section only considered Newtonian fluids, where viscosity or resistance factor was independent of flow rate. In this section, we briefly review the impact of non-Newtonian rheology associated with xanthan or HPAM (partially hydrolyzed polyacrylamide) solutions. A basic principle of fluid displacement is that the efficiency of the displacement increases with decreasing mobility (or increasing viscosity) of the displacing phase.^{5,7,10} This is also a basic principle of polymer flooding. For a given distance of viscous fluid penetration into a high permeability zone, the distance of penetration into less permeable zones becomes greater with increased viscosity or resistance factor of the injected fluid.^{5,7} This concept is illustrated in Fig. 2 for a polymer solution displacing water in a radial system with non-communicating zones. The y-axis in Fig. 2 plots the radial distance of polymer penetration in a low permeability zone (Layer 2) when the polymer reaches 50 ft in the most permeable zone (Layer 1).

This quantity is plotted versus the permeability contrast, k_1/k_2 . Fig. 2 shows that at any given permeability contrast, the degree of polymer penetration (i.e., the distance of penetration in a low permeability zone relative to that in the most permeable zone) is greater for a fluid with $F_r=100$ than for a fluid with $F_r=1$.

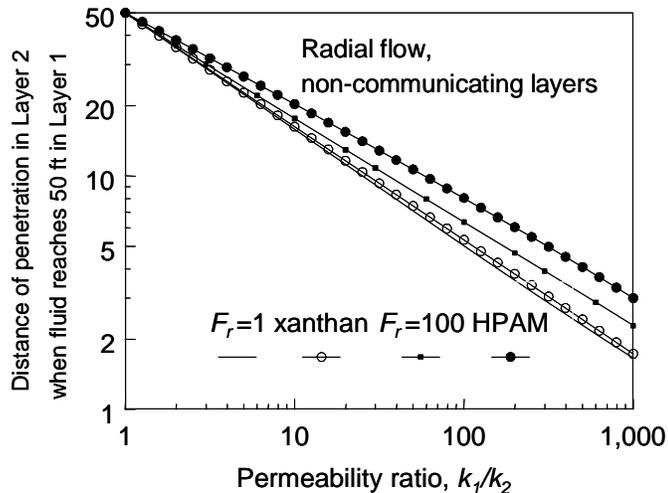


Fig. 2—Distances of penetration for Newtonian versus non-Newtonian fluids.

Fig. 2 also shows that for any given permeability contrast, a fluid with $F_r=1$ provides a lower degree of penetration than non-Newtonian polyacrylamide or xanthan solutions. In Ref. 7, we considered eight different rheological models that have been used to describe the behavior of polyacrylamide and polysaccharide solutions in porous media. We considered shear-thinning models, shear-thickening models, and models that showed combined shear-thinning and shear-thickening behavior. All of the models were examined during simulation of placement behavior in parallel linear corefloods, parallel radial corefloods, fractured wells, and wells without fractures. The analysis revealed that in radial flow, for all models tested, the rheology of existing polymeric solutions will not provide a r_{p2}/r_{p1} value that is less than that for a fluid with a water-like viscosity or resistance factor (i.e., $F_r=1$).

For shear-thinning fluids in reservoirs with crossflow, an injection profile measured at the wellbore might suggest that an unexpectedly high fraction of the fluid enters the most permeable zone. This might mislead one to *incorrectly* conclude that shear-thinning fluids penetrate a lesser distance into low permeability zones than will fluids with water-like viscosities.¹¹

When Resistance Factors Vary With Permeability

In the above discussion of Newtonian fluids, the resistance factor of the injected fluid was assumed to be the same in all zones (i.e., not dependent on initial rock permeability). This section considers cases where resistance factor varies with permeability.

Early work¹²⁻¹⁶ recognized that high molecular weight partially hydrolyzed polyacrylamides (HPAM) sometimes reduced the mobility (λ or k/μ) of aqueous solutions in porous media by a greater factor than can be rationalized based on the

viscosity (μ) of the solution. The incremental reduction in mobility was attributed to reduction in permeability (k), caused by adsorption or mechanical entrapment of the high molecular weight polymers—especially from the largest polymers in the molecular weight distribution for a given polymer. In the 1960s and 1970s, this effect was touted to be of great benefit^{12,14} for polymer floods (simply because the polymer appeared to provide significantly more apparent viscosity in porous media than expected from normal viscosity measurements). However, during the 1980s, at least some research labs recognized that unexpectedly high mobility reductions from HPAM solutions were either (1) often not achievable in practical field applications or (2) not necessarily of benefit. They were often not achievable in field applications because normal field handling and flow through an injection sand face at high velocities mechanically degraded the large molecules that were responsible for the permeability reduction.^{17,18} Also, the largest molecules were expected to be preferentially retained (i.e., by mechanical entrapment in pores) and stripped from the polymer solution before penetrating deep into the formation.

This section addresses the second concern that was raised: Even if high permeability reductions could be achieved, would this effect actually be of benefit? More specifically, the concern focuses on how the mobility reduction varies with permeability of porous media. For adsorbed polymers and suspensions of gel particles, resistance factors (F_r , apparent viscosities in porous media relative to brine) and residual resistance factors (F_{rr} , permeability reduction values) increase with decreasing permeability.^{12-16,19-23} In other words, these materials reduce the flow capacity of low permeability rock by a greater factor than high permeability rock. Depending on the magnitude of this effect, these polymers and gels can harm injection or production flow profiles in wells, even though the polymer or gelant penetrates significantly farther into the high permeability rock.⁵⁻⁹

Linear Flow, No Crossflow. For the calculations cases discussed earlier, the resistance factors (effective viscosities) in Zones 1 and 2 were assumed to be equal. The spreadsheets mentioned in Ref. 9 are capable of performing calculations with different resistance factors in different zones. We used these spreadsheets to generate Fig. 3 for linear flow with no crossflow. The x -axis plots the resistance factor in Zone 1 (F_{r1}). We are interested in how high the resistance factor can be in Zone 2 (F_{r2}) without impairing sweep efficiency. For this criterion to be met, the ratio, L_{p2}/L_{p1} , must be greater than the zonal permeability contrast, k_2/k_1 . Consequently, the y -axis plots the maximum allowable ratio, F_{r2}/F_{r1} , that meets this criterion. These calculations were made for several permeability ratios, k_1/k_2 , between 2 and 20. Fig. 3 shows that for F_{r1} values greater than 10, the maximum allowable ratio of F_{r2}/F_{r1} was about the same as the permeability ratio, k_1/k_2 . Thus, linear flow applications can be reasonably forgiving if the permeability contrast and the polymer solution resistance factors are sufficiently large.

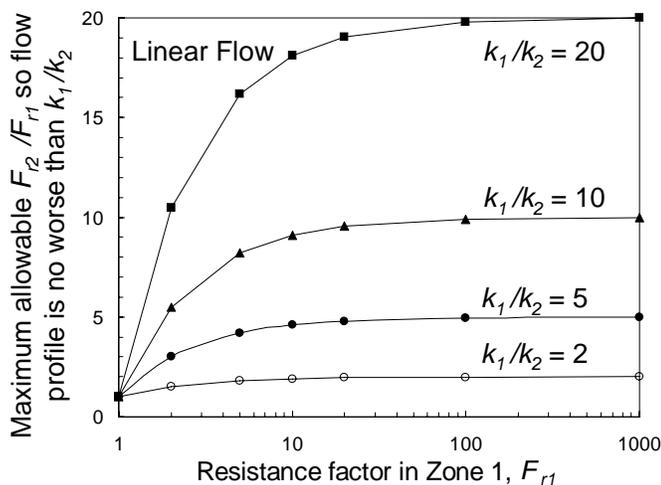


Fig. 3—Maximum allowable F_{r2}/F_{r1} for linear flow, no crossflow.

Radial Flow, No Crossflow. Similar calculations were performed for radial flow (with no crossflow), and the results are shown in Fig. 4. These calculations reveal that radial flow is much less forgiving to high values of F_{r2}/F_{r1} . Even for high permeability contrasts (e.g., $k_1/k_2 = 20$), the maximum allowable F_{r2}/F_{r1} values were less than 1.4.

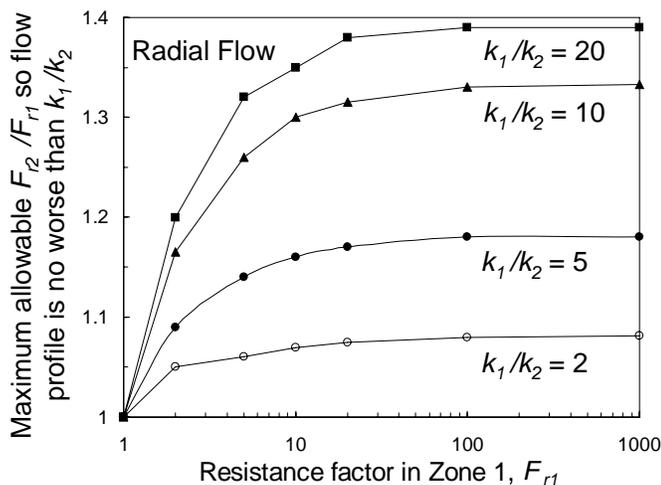


Fig. 4—Maximum allowable F_{r2}/F_{r1} for radial flow, no crossflow.

Comparison with Laboratory Data. Vela *et al.*²² and Hirasaki and Pope¹³ reported resistance factors obtained in cores with a range of permeability. Both groups used Dow Pusher 700™ HPAM, which had a molecular weight of $5\text{--}5.5 \times 10^6$ daltons. Vela *et al.* used 0.06% HPAM in 13.3% total dissolved solids brine at 150°F. Their reservoir cores were all polymer flooded at residual oil saturation (S_{or}) using cores with pre-polymer k_w at S_{or} ranging from 12 to 453 md. Measured resistance factors from Vela *et al.* are plotted in Fig. 5. The thin dashed line in Fig. 5 plots the maximum acceptable behavior of resistance factors for linear flow cases, while the thick dashed line plots the maximum acceptable behavior of resistance factors for radial flow cases. In these plots, F_{r1} refers to the measured resistance factor in the 453-md rock,

while F_{r2} refers to the maximum acceptable resistance factor in a given less permeable rock or zone. For the data provided, the measured behavior of resistance factors was barely acceptable for linear flow, and definitely unacceptable for radial flow. A logical remedy for this situation would be to choose a polymer with a lower molecular weight, so resistance factors do not increase so much with decreasing permeability.

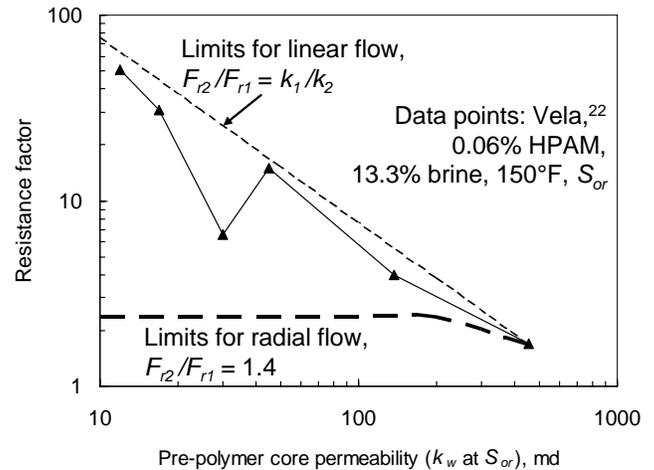


Fig. 5—Data from Vela *et al.*²² compared with maximum allowable F_{r2}/F_{r1} values.

Hirasaki and Pope used 0.05% HPAM in an unspecified brine at 95°F. Their sandstone cores had no oil saturation (S_{or}) and ranged in permeability from 22 to 359 md. Their measured resistance factors are plotted in Fig. 6. Again, the thin dashed line plots the maximum acceptable behavior of resistance factors for linear flow cases, while the thick dashed line plots the maximum acceptable behavior of resistance factors for radial flow cases. In Fig. 6, F_{r1} refers to the measured resistance factor in the 359-md rock, while F_{r2} refers to the maximum acceptable resistance factor in a given less permeable rock or zone. For the data provided, the measured behavior of resistance factors was acceptable for both linear and radial flow for rock permeabilities above 100 md. For rock with permeability below 100 md, the behavior was still acceptable for linear flow, but not for radial flow. Comparing Figs. 5 and 6 suggests that whether or not a given polymer will be acceptable in a given reservoir may depend on a number of factors, including rock permeabilities, water salinity, presence of residual oil, reservoir temperature, and possibly other factors (such as clay content, pore structure, and degree of mechanical degradation before entering the rock).

Cases with Crossflow. The discussion thus far in this section focused exclusively on cases with no potential for crossflow between layers (i.e., impermeable barriers exist between zones). In most cases when crossflow can occur, the F_{r2}/F_{r1} ratio has little effect on the relative distance of polymer penetration into the various zones. To understand this conclusion, recognize that the distance between wells is usually much greater than the height of any given strata. If a pressure difference (after compensating for gravity) exists between two adjacent communicating zones, crossflow

quickly dampens any pressure difference because of the close proximity of zones. These observations form the basis of the concept of vertical equilibrium.^{10,24-26} For vertical equilibrium, the pressure gradients in two adjacent zones (with no flow barriers) are the same for any given horizontal position. Put another way, for a given distance from the wellbore (if gravity can be neglected), the pressure is the same in both zones.

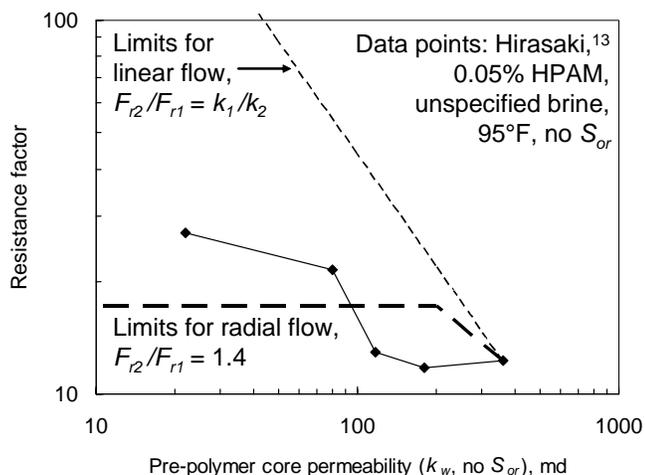


Fig. 6—Data from Hirasaki and Pope¹³ compared with maximum allowable F_{r2}/F_{r1} values.

Consider a polymer solution flowing through two adjacent zones where crossflow can occur (Fig. 7). Zone 1 (the high permeability zone) has a permeability of k_1 , a porosity of ϕ_1 , and exhibits a polymer resistance factor of F_{r1} . Zone 2 (the low permeability zone) has a permeability of k_2 , a porosity of ϕ_2 , and exhibits a polymer resistance factor of F_{r2} . The average movement rates for polymer fronts in the two zones are v_1 and v_2 . Of course, crossflow may make the polymer front uneven (i.e., not vertical) in Zone 2. So in the simple analysis here, we consider the average front positions. If vertical equilibrium exists, the pressure difference between the polymer fronts will be the same in the two zones. Darcy’s law can then be applied to estimate the average front movement rates. For Zone 2, this rate, v_2 , is

$$v_2 \cong \Delta p k_2 / (\mu \phi_2 L) \dots\dots\dots (1)$$

For Zone 1, this rate, v_1 , is

$$v_1 \cong \Delta p k_1 / (\mu F_{r1} \phi_1 L) \dots\dots\dots (2)$$

The ratio of average front rates is

$$v_2 / v_1 \cong F_{r1} k_2 \phi_1 / (k_1 \phi_2) \dots\dots\dots (3)$$

Consequently, the relative rate of polymer front movement is not sensitive to the resistance factor in Zone 2. Eq. 3 is the same expression that is derived when resistance factors are equal for the two zones.¹⁰

Table 1 illustrates the approximate front profiles anticipated for several cases with crossflow.

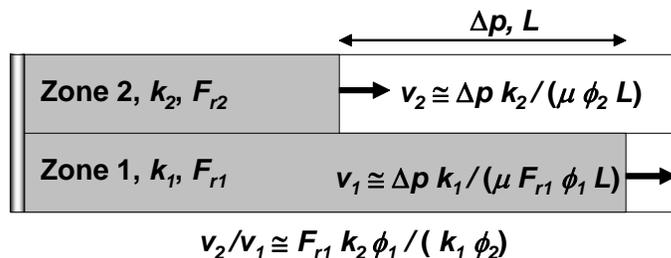


Fig. 7—Understanding front movements for linear flow with crossflow, moderate F_r values.

Effect of Differential Retention. For many years, people have recognized that polymer resistance factors, residual resistance factors, and chemical retention values in porous media increase with decreasing permeability.^{12,20,22,27-29} These trends tend to impede polymer propagation into the less permeable zones, and therefore do not aid vertical sweep.^{5,7,11,19,20}

Summary. For applications with linear flow (e.g., fractured wells), the maximum allowable ratio of F_{r2}/F_{r1} (so that polymer injection does not harm vertical sweep) is about the same as the permeability ratio, k_1/k_2 . Thus, linear flow applications can be reasonably forgiving if the permeability contrast and the polymer solution resistance factors are sufficiently large.

Radial flow is much less forgiving to high F_{r2}/F_{r1} values. Even for high permeability contrasts (e.g., $k_1/k_2 = 20$), the maximum allowable F_{r2}/F_{r1} values were less than 1.4.

In most cases when crossflow can occur, the F_{r2}/F_{r1} ratio has little effect on the relative distance of polymer penetration into the various zones.

Foam Flow

Foam Forms in Both Zones. Now we consider cases where foam flows instead of polymer solutions or Newtonian fluids. If the foam forms in both zones, the cases discussed earlier for normal viscous fluids generally cover the range of possibilities. This statement assumes that the mobility of the foam (or of the injected polymer solution) is no greater than that of the oil/water banks that are being displaced.

Foam Forms in Zone 1, but Not in Zone 2. Free Crossflow.

Under some circumstances, the limiting-capillary-pressure effect could allow low mobility foams to form in high permeability zones, but not in low permeability zones. In low permeability zones, capillary forces may draw water from liquid films, minimizing bubble and foam formation.¹⁻³ Consequently, the mobility of the gas/water/surfactant mixture could be quite high in low permeability zones, while foam mobility remains low in high permeability zones.

If free crossflow can occur, the distance of penetration of the gas/water mixture in the low permeability zones (i.e., Zone 2 in our simple example) can be no greater than that in the high permeability zone (Zone 1). If gas and water in Zone 2 attempt to outrun the foam bank in Zone 1, the fluids will simply crossflow back into Zone 1 near the foam front (see

Fig. 8). Thus, sweep improvement from foams in this scenario is not expected to be significantly greater than that for viscous polymer solutions (Fig. 1).

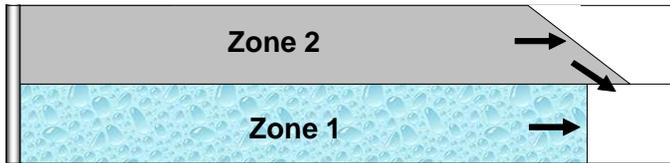


Fig. 8—Foam forms in Zone 1 but not in Zone 2, free crossflow.

Foam Forms in Zone 1, but Not in Zone 2. No Crossflow.

We now come to the cases where foams are anticipated to provide superior mobility control to polymer solutions. These cases require that (1) foam forms in the high permeability zones (i.e., Zone 1), (2) foam does not form in the low permeability zones (i.e., Zone 2), and (3) no crossflow occurs between zones. If these conditions are met, upon first consideration, Fig. 9 illustrates an ideal scenario. That is, the foam bank in Zone 1 provides enough resistance to force the front of the gas/water/surfactant formulation in Zone 2 (the low permeability zone) well beyond the foam front in Zone 1.

However, an important flaw exists with the picture illustrated by Fig. 9. In particular, the gas/water/surfactant formulation will have a high mobility and will form viscous fingers³⁰ through the oil/water bank in Zone 2 (Figs. 10 and 11). The mobility of nitrogen (or a similar gas) might be 50 or more times greater than that for oil or water. In some cases (with dense phase CO₂ or hydrocarbon gases), gas mobility might be only ten times greater than the mobility of oil or water.³¹ The severity of fingering increases with increasing mobility ratio.³⁰ Inefficient displacement associated with these fingers will partially offset the improvement in vertical sweep provided by increased penetration of gas/water/surfactant formulation into Zone 2.

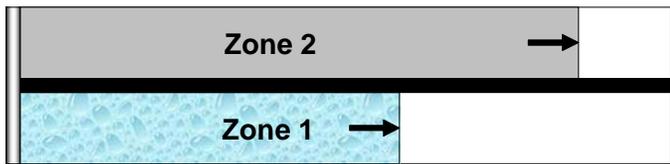


Fig. 9—Incorrect view of gas/water flow in Zone 2 after foam forms in Zone 1.

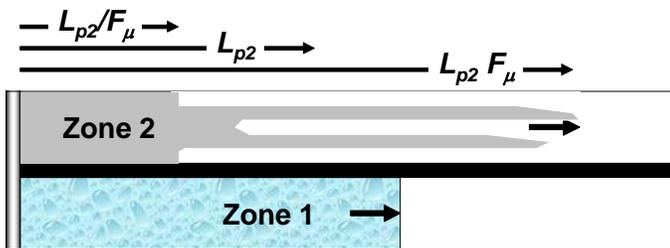


Fig. 10—Gas/water flow in Zone 2 after foam forms in Zone 1. No Crossflow. Linear flow.

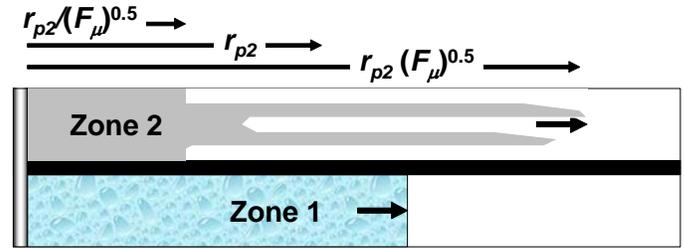


Fig. 11—Gas/water flow in Zone 2 after foam forms in Zone 1. No Crossflow. Radial flow.

Model for Unstable Displacement. Our objective now is to assess which effect will dominate sweep efficiency: (1) the positive effects associated with increased fluid diversion into Zone 2 by the foam or (2) the negative effects from the viscous fingers in Zone 2. To make this determination, we rely on the quarter-power mixing rule and the method of Koval.^{6,30} In this method, Zone 2 is divided into three regions. In the region farthest from the wellbore, the oil/water bank has a relatively constant saturation and fractional flow, with an average mobility of λ_{ow} . If Zone 2 is an unswept oil zone, oil will dominate the determination of this mobility. In the region closest to the wellbore, the gas/water/surfactant formulation has driven oil to a residual value and the average mobility is λ_{gw} . Since foams usually have high gas saturations and because gas is substantially more mobile than water, gas dominates the determination of this mobility. In the intermediate region, high mobility gas forms viscous fingers through the oil/water bank. The average mobility in this region, $\lambda_{ow} F_\mu$, is estimated using the quarter-power mixing rule³⁰ (Eq. 4).

$$F_\mu = [0.78 + 0.22 (\lambda_{gw}/\lambda_{ow})^{0.25}]^4 \dots\dots\dots (4)$$

If the total volume of gas/water/surfactant formulation that penetrates into Zone 2 can be determined, the bank sizes associated with each of the three regions can be estimated.^{5,6,30} From the total volume entering Zone 2 and the formation height and porosity, an average distance (L_{p2}) or radius (r_{p2}) of formulation penetration can be calculated. For linear flow (e.g., leakoff from fracture faces), the length of the gas/water region (see Fig. 10) in Zone 2 (i.e., the distance from the well or fracture face to the trailing edge of the fingering region) is given by Eq. 5.

$$L_{gw} = L_{p2} / F_\mu \dots\dots\dots (5)$$

For radial flow, the radius of the gas/water region (see Fig. 11) in Zone 2 is given by Eq. 6.

$$r_{gw} = r_{p2} / (F_\mu)^{0.5} \dots\dots\dots (6)$$

For linear flow, the distance from the well or fracture face to the furthest extent of the fingering region (see Fig. 10) in Zone 2 is given by Eq. 7.

$$L_{vf} = L_{p2} F_\mu \dots\dots\dots (7)$$

For radial flow, the radius from the well to the furthest extent of the fingering region (see Fig. 11) in Zone 2 is given by Eq. 8.

$$r_{vf} = r_{p2} (F_r \mu)^{0.5} \dots\dots\dots (8)$$

Given these equations, the methods from Refs. 5 and 6 can be used to estimate front positions and sweep efficiencies during foam injection under various circumstances. These methods simply employ the Darcy equations for flow in parallel and series. Appendix C of Ref. 32 provides derivations of the relevant equations.

The above equations were developed assuming that displacements were miscible. Thus, diffusion and dispersion may mitigate the severity of viscous fingering to some extent. Viscous fingering is expected to be more severe with immiscible displacements than for miscible displacements. Many field situations involve immiscible displacements—in particular, gas fingering immiscibly through either oil or water. (Natural gas, CO₂, or N₂ miscibly displacing oil provides notable exceptions.) Thus, for the analysis shown below, one could argue that the results err in favor of foams over polymers. To balance this point, the analysis below assumes that polymer resistance factors do not depend on permeability. If polymer resistance factors increase with decreasing permeability (as discussed in a previous section), the following analysis may be overly optimistic in favor of polymers. These points should be kept in mind during the following discussion.

Comparing Foams versus Polymers

Two fronts are of interest in Zone 2. One is the trailing edge of the region of viscous fingering, and the other is the front (end) of the region of viscous fingering, as illustrated in Figs. 10 and 11. Figs. 12-17 show the positions of these fronts (relative to the foam front in Zone 1, L_{p1} or r_{p1}) for various circumstances. The thick solid curves show the positions of the trailing edge of the viscous fingering regions, while the thin solid curves show the positions of the viscous fingering fronts. For comparison, the thick dashed curves show the behavior provided by polymer solution (10 cp, except for figures where resistance factor, F_r , is the variable).

In these figures, the finger fronts (the thin solid curves) are the most optimistic projections of sweep in Zone 2. The trailing edges of the fingering region (the thick solid curves) provide more realistic projections.

Linear Flow, No Crossflow. Figs. 12-14 show behavior predicted for linear flow (e.g., leakoff from fracture faces). Fig. 12 considers cases where the permeability contrast (k_1/k_2) is 10 and the foam resistance factor (F_r) is 10. Penetration into Zone 2 is plotted versus the ratio gas mobility (λ_{gw}) to mobility of the oil/water bank (λ_{ow}). If this ratio is greater than 10 (i.e., the value of the foam resistance factor in Zone 1), 10-cp polymer solutions provide a better vertical sweep (greater penetration into Zone 2) than the gas/water/surfactant formulation (compare dashed curve with the thick solid curve).

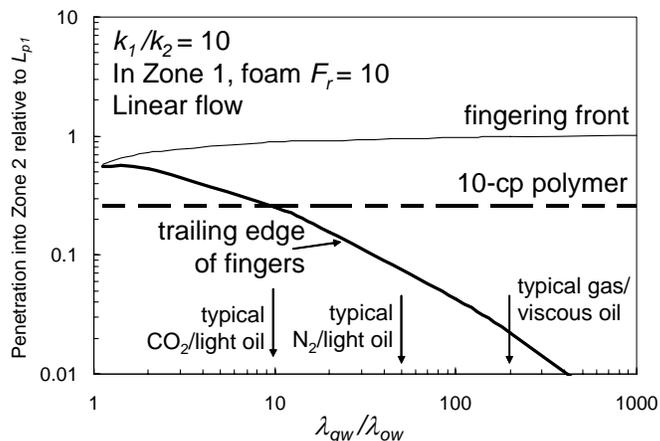


Fig. 12—Zone 2 linear fronts versus mobility ratio.

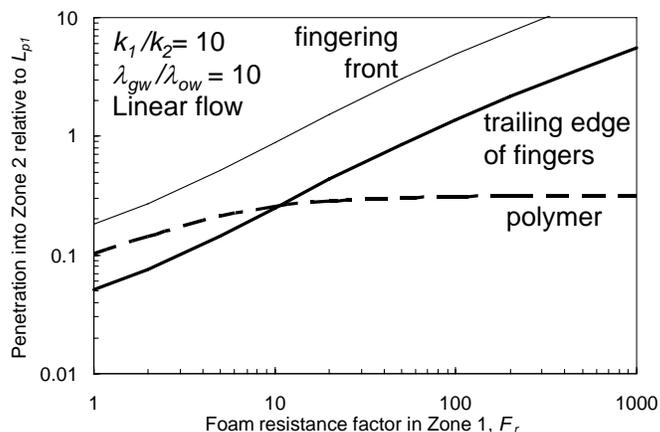


Fig. 13—Zone 2 linear fronts versus resistance factor in Zone 1.

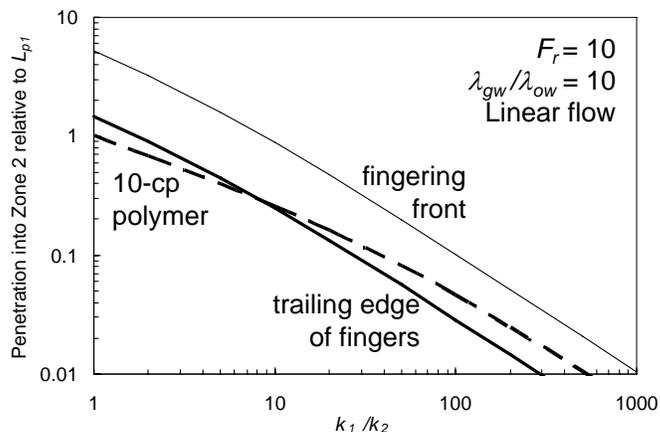


Fig. 14—Zone 2 linear fronts versus permeability contrast.

Fig. 13 shows the effects of resistance factor on vertical sweep for cases where the permeability contrast and the ratio, $\lambda_{gw}/\lambda_{ow}$, were both fixed at values of 10. For the foam cases (thin and thick solid curves), the resistance factor in Zone 1 is indicated on the x-axis. In Zone 2, no foam forms, so front positions are determined by λ_{gw} and λ_{ow} . For the polymer cases, the resistance factor indicated on the x-axis applies to both Zone 1 and Zone 2. Fig. 13 shows that foam resistance factor in Zone 1 has a major impact on vertical sweep. For the

conditions given, polymer solutions provide better sweep for resistance factors below 10. For resistance factors above 10, vertical sweep favored the use of foams. In fact, for resistance factors above 100, gas/water/surfactant penetration into Zone 2 exceeded foam penetration into Zone 1.

Fig. 14 shows the effects of permeability contrast on vertical sweep for cases where the resistance factor in Zone 1 and the ratio, $\lambda_{gw}/\lambda_{ow}$, were both fixed at values of 10. For both foams and polymers, vertical sweep efficiency decreased significantly as permeability contrast (k_1/k_2) increased.

Radial Flow, No Crossflow. Figs. 15-17 show behavior predicted for radial flow. Qualitatively, the trends and observations from these figures were similar to those from the linear flow cases (Figs. 12-14). However, the effects of variations in mobility ratio, resistance factor, and permeability contrast were typically less for radial flow than for linear flow.

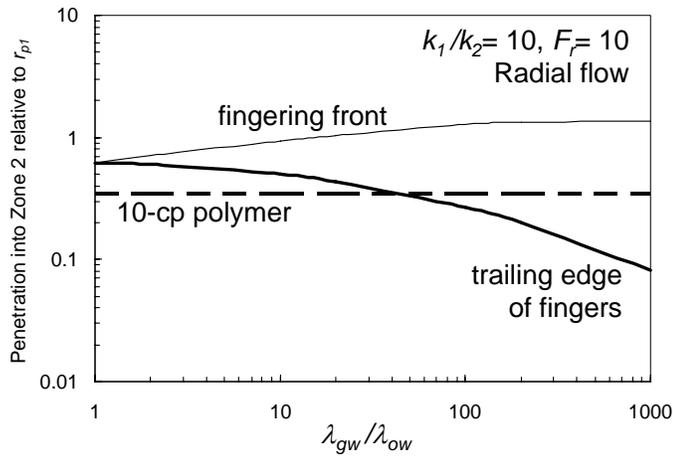


Fig. 15—Zone 2 radial fronts versus gas-water mobility.

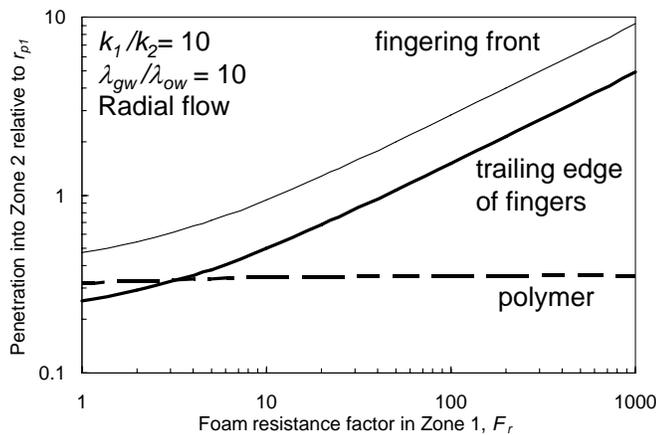


Fig. 16—Zone 2 radial fronts versus Zone 1 resistance factor.

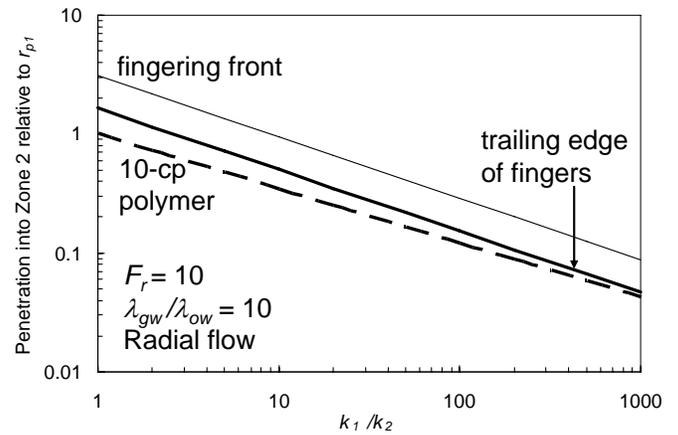


Fig. 17—Zone 2 radial fronts versus permeability contrast.

Examination of Figs. 12-17 indicates that achieving a high resistance factor in Zone 1 (while preventing foam formation in Zone 2) is the key to making foam flooding superior to polymer flooding. In Figs. 18 and 19, we plot penetration for a gas/water/surfactant formulation in Zone 2 versus permeability contrast and mobility ratio for cases where the product, $F_r k_1/k_2$, is held constant at unity. The flat curve profiles in these figures emphasize that a sufficiently large foam resistance factor in Zone 1 can overcome detrimental sweep associated with a large permeability contrast. As a reminder, with viscous polymer solutions, the distance of penetration into Zone 2 is limited by the square root of the permeability contrast.⁴⁻⁷

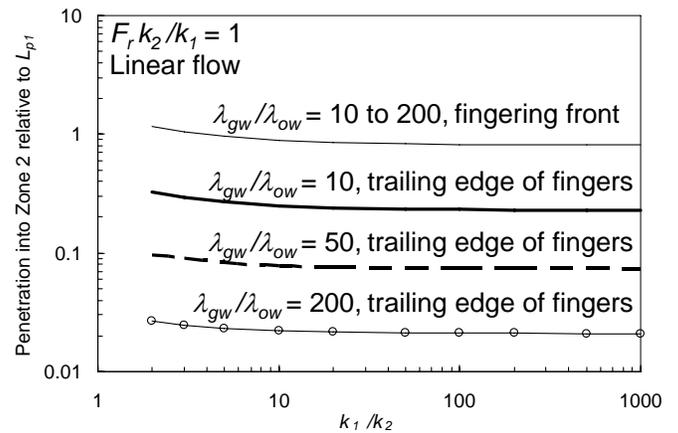


Fig. 18—Zone 2 linear fronts for constant $F_r k_2/k_1$.

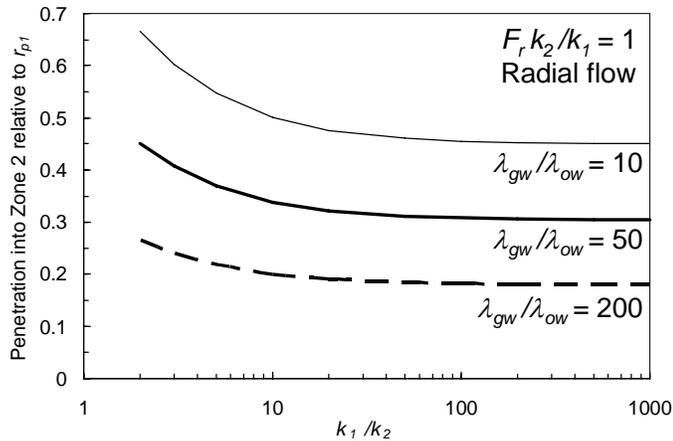


Fig. 19—Trailing edges of the fingering region in Zone 2 for constant $F_r k_2/k_1$. Radial flow.

Effect of Gravity. Density differences between gas, foam, water, and oil will certainly impact vertical sweep, especially in reservoirs with crossflow. If low permeability oil zone(s) are above high permeability water channels, gas injection should enhance vertical sweep. Gravity effects should also enhance vertical sweep for foam injection over water or polymer injection, although perhaps not as well as during injection of gas alone.

On the other hand, if low permeability oil zone(s) are positioned below high permeability water channels, gravity effects should enhance vertical sweep for water or polymer injection over gas or foam injection.

If no crossflow occurs between zones, gravity effects may be important only to the degree that they impact fluid segregation with the wellbores.

In summary, gravity effects can influence whether foams (or gas) have a vertical sweep advantage over polymer solutions (or water), depending on the fortuitous positioning of oil zones relative to water zones.

Effect of Imbibition. Imbibition typically pulls the aqueous phase from permeable zones into less permeable zones. For waterfloods, this effect aids vertical sweep. For polymer floods, the viscous nature of the polymer solutions and the permeability dependence of resistance factors tend to mitigate this benefit. For foam floods, imbibition of the aqueous phase from high-to-low-permeability zones may compromise the integrity of the foam bank in the high permeability zone.³³ Imbibition is most likely to impact vertical sweep when fluids can crossflow between zones. However, the analysis in this paper indicates that foams are only likely to provide superior vertical sweep over polymers if no crossflow occurs.

Conclusions

Use of foams could provide superior vertical sweep compared to polymer solutions if (1) foam forms in the high permeability zone(s) but not in the low permeability zone(s), (2) no crossflow occurs between the high and low permeability zones, AND (3) the foam resistance factor in the high permeability zone(s) is sufficiently high to overcome the permeability contrast and the unfavorable mobility ratio between the gas bank and the oil/water bank in the less

permeable zones. Foams will generally not be superior to polymers under other circumstances (unless gravity effects provide a fortuitous benefit³³).

Other limitations associated with foam use must also be recognized,^{1-3,33} including (1) challenges with formulating foams for individual reservoirs to meet the above requirements, (2) limitations on foam propagation, especially due to surfactant retention, (3) compression costs associated with foam injection, and (4) limitations on foam stability under reservoir conditions.

We also examined vertical sweep efficiency as a function of the ratio of resistance factors in neighboring zones, F_{r2}/F_{r1} . (Subscript 1 applies to the high permeability zone, while Subscript 2 to refers to the low permeability zone).

For applications with linear flow (e.g., fractured wells) when crossflow cannot occur, the maximum allowable ratio of F_{r2}/F_{r1} (so that polymer injection does not harm vertical sweep) is about the same as the permeability ratio, k_1/k_2 . Thus, linear flow applications can be reasonably forgiving if the permeability contrast and the polymer solution resistance factors are sufficiently large. Radial flow is much less forgiving to high values of F_{r2}/F_{r1} . Even for high permeability contrasts (e.g., $k_1/k_2=20$), the maximum allowable F_{r2}/F_{r1} values were less than 1.4. In most cases when crossflow can occur, the F_{r2}/F_{r1} ratio has little effect on the relative distance of polymer penetration into the various zones.

Acknowledgments

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Nomenclature

F_r = resistance factor

F_{r1} = resistance factor in Zone 1

F_{r2} = resistance factor in Zone 2

F_{rr} = residual resistance factor (permeability before/after gel placement)

F_μ = resistance factor in the region of fingering

k_1 = permeability for Zone 1, darcys [μm^2]

k_2 = permeability for Zone 2, darcys [μm^2]

L_p = distance of polymer or gelant leakoff, ft [m]

L_{p1} = polymer or foam penetration distance in Zone 1, ft [m]

L_{p2} = polymer or foam penetration distance in Zone 2, ft [m]

Δp = pressure drop, psi [Pa]

r_{p1} = polymer or foam penetration radius in Zone 1, ft [m]

r_{p2} = polymer or foam penetration radius in Zone 2, ft [m]

r_w = wellbore radius, ft [m]

v = velocity, m/s

v_1 = polymer or foam front velocity in Zone 1, ft/d [m/d]

v_2 = polymer or foam front velocity in Zone 2, ft/d [m/d]

λ_{gw} = mobility of the gas/water bank, md/cp [$\mu\text{m}^2/\text{mPa}\cdot\text{s}$]

λ_{ow} = mobility of the oil/water bank, md/cp [$\mu\text{m}^2/\text{mPa}\cdot\text{s}$]

μ = viscosity, cp [mPa·s]

ϕ = porosity

ϕ_1 = porosity in Zone 1

ϕ_2 = porosity in Zone 2

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SI Metric Conversion Factors

cp x 1.0*	E-03	= Pa·s
ft x 3.048*	E-01	= m
in. x 2.54*	E+00	= cm
md x 9.869 233	E-04	= μm ²
psi x 6.894 757	E+00	= kPa

*Conversion is exact.