Optimizing Disproportionate Permeability Reduction
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Introduction
Many polymers and gels can reduce permeability to water more than that to oil or gas.1-5 This disproportionate permeability reduction (or “relative permeability modification”) is essential if polymers or gels are placed in production wells without protecting hydrocarbon-productive zones.6 With existing polymers, gels, and technology, disproportionate permeability reduction may have its greatest value when treating production wells that intersect a fracture or fracture-like features.7-9 Nonetheless, many people are very interested in exploiting this property to reduce excess water production from unfractured wells (i.e., radial flow into porous rock or sand). The idealistic goal of this technology is to develop a material that can be injected into any production well (without zone isolation) and will substantially reduce water productivity index without significantly impairing hydrocarbon productivity. Several obstacles must be overcome before this ideal can be achieved.

Challenges for Applications of Disproportionate Permeability Reduction
Variable Performance. Field applications of polymer and gel treatments have shown substantial variations in performance from one application to the next. In part, these variations arise from differences in reservoir conditions, well conditions, and mixing and injection procedures. However, significant performance variations appear inherent for some polymers and gels.10,11 During replicate experiments (in Berea sandstone) with a commercially available weak gel, oil residual resistance factors (Frro) permeability reduction factors) ranged from 2.7 to 59 (median of 5.9, average of 9.7, and standard deviation of 13.5), while water residual resistance factors (Frww) ranged from 1.5 to 317 (median of 6.6, average of 32, and standard deviation of 78).10

Uncontrolled variability of residual resistance factors may be an inherent flaw for adsorbed polymers and weak gels. Permeability reduction by adsorbed polymers can be strongly influenced by mineralogy of the rock. In turn, rock mineralogy typically exhibits significant variations locally within a porous medium. Consequently, these mineralogical variations could lead to wide differences in performance for adsorbing polymers.

Weak gels are typically suspensions of gel particles—not a continuous three-dimensional gel structure.12-15 These suspensions have a particle size distribution—they are not monodisperse. Pores within a rock also have a size distribution. Since the particles reduce permeability by lodging in pore throats, the ratio of particle size to pore throat...
size is important in determining residual resistance factors for these suspensions. Variations in particle size distribution (especially resulting from unknown or uncontrolled particle generation) and variations in throat size distribution (resulting from normal geologic processes) may cause wide variations in performance for particle suspensions. An extensive effort is underway at Institut Francais du Pêrole (IFP) to address this issue. IFP is developing suspensions of “microgels” that are manufactured with very narrow particle size distributions.16

**F_{rrw} Must Be < 2 for Radial Flow.** A second challenge is presented by the requirements for successful application of disproportionate permeability reduction for different types of problems. For example, consider an unfractured (i.e., radial flow) production well with one water zone, one oil zone, and a separating impermeable shale barrier. Fig. 1 illustrates that productivity losses in radial flow are much more sensitive to residual resistance factors than to radius of gel penetration \((r_{gel})\). To avoid excessive losses in oil productivity when gelant is placed using unrestricted injection (i.e., no zone isolation), the gel must provide a residual resistance factor less than 2 in the oil zone.7,8,9,16 Preferably, the gel should provide a residual resistance factor greater than 20 in the water zone (Fig. 1). The variations in residual resistance factors mentioned above point to the difficulties in reliably attaining permeability reductions to oil that are less than two.

![Fig. 1—Losses of zone flow capacity for radial flow.](image)

**Permeability Dependence of F_{rrw}.** A third challenge comes from the dependence of residual resistance factors on the permeability of the porous media. For adsorbing polymers and weak gels, resistance factors and residual resistance factors increased with decreased permeability (Fig. 2).14,15,18-21 In other words, these materials damage low-permeability rock more 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.7,8,9,16

**Overcoming the Obstacles Variability.** Variability of residual resistance factors was the first challenge mentioned above. This variability can be attributed to uncontrolled particle size distributions for suspensions of gel particles and to mineralogical variations for both adsorbed polymers and suspensions of gel particles. Perhaps this variability in performance can be mitigated by using a permeability reduction mechanism with better control. In particular, if all aqueous pore space was filled with a uniform gel, the permeability reduction (at least for water flow) would be controlled by flow through the gel itself. If the inherent permeability of the gel to water was much less than the permeability of the original porous media, the permeability reduction would not be sensitive to variations in mineralogy, pore size, or pore size distribution.

Concerning variability of oil residual resistance factors, our recent work22 suggested that re-establishing oil permeability in a gel-filled porous media can be predicted using concepts of mobility ratios and stable-versus-unstable displacements.

**Linear versus Radial Flow.** The second hurdle mentioned depended on the type of problem to be treated. Our work suggests that disproportionate permeability reduction currently has its greatest utility in treating fractures and fracture-like features.7,9,16 If gelant is allowed to leakoff a short, controlled distance from the fracture faces and if the gel provides predictable residual resistance factors, water entry into the fracture can be greatly impeded while causing minimal reduction in hydrocarbon productivity. This process does not require that the gel provide very low oil residual resistance factors—only that the gel provides water residual resistance factors that are reliably much greater than oil residual resistance factors (see Fig. 2 for an example).

![Fig. 2—Gel restricting water entry into a fracture.](image)
showed an endpoint permeability to oil of 508 md (i.e., at \(S_{or}\)) and an endpoint permeability to water of 120 md (i.e., at \(S_{wr}\)). After placement of a Cr(III)-acetate-HPAM gel [with 0.5% HPAM and 0.0417% Cr(III) acetate], the permeability during brine injection quickly stabilized at 0.17 md (open circles in Fig. 3)—indicating a water residual resistance factor of 706 (i.e., 120/0.17). In contrast, during oil (hexadecane) injection (i.e., 508/105). Since the permeability to oil was still rising at 100 \(PV\) (Fig. 3), hope exists that even lower oil residual resistance factors could be achieved.

**Permeability Dependence.** The third challenge mentioned above was the permeability dependence of residual resistance factors. For adsorbing polymers and suspensions of gel particles, residual resistance factors increased with decreased permeability. In contrast, pore-filling gels reduced the permeability to water of all porous media to the same low value—a value that approximates the inherent permeability of the gel to water. Consequently, use of pore-filling gels may provide a means to overcome some of the important challenges that have limited applications of disproportionate permeability reduction.

**Permeability to Water after Gel Placement \(k_w\) versus Initial Core Permeability and Core Material.**

With the above considerations in mind, we performed several experiments in an effort to use pore-filling Cr(III)-acetate-HPAM gels to optimize disproportionate permeability reduction. One goal was to ensure that water residual resistance factors \(F_{rwr}\) are reliably high. For radial flow, Fig. 1 suggests that \(F_{rwr}\) values should be greater than 20. For linear flow applications (e.g., fractured wells), much larger \(F_{rwr}\) values are desirable (see Fig. 2). Thus, we performed experiments to establish whether a pore-filling gel can provide reliable \(k_w\) and \(F_{rwr}\) values. In particular, for the first set of experiments (all at 41°C), we wished to confirm that a pore-filling gel reduces the permeability \(k_w\) of all porous media to the same low value—that reflects the inherent permeability of the gel to water. In Table 1, the first six entries describe experiments where cores at residual oil (hexadecane) saturation \(S_{or}\) were flooded with a Cr(III)-acetate-HPAM gelant [with 0.5% Ciba Alcoflood 935™ HPAM, 0.0417% Cr(III) acetate, 1% NaCl, 0.1% CaCl\(_2\)], shut in for 3 days to allow gelation, followed by brine injection (1% NaCl, 0.1% CaCl\(_2\)) at a fixed pressure gradient. Initial core permeabilities ranged from 746 to 15,270 md in core materials including Berea sandstone, fused silica, and porous polyethylene. At \(S_{or}\), \(k_w\) values before gel placement ranged from 120 to 6,500 md. For the first six post-gel cases, \(k_w\) at \(S_{or}\) averaged 0.24 md (± 0.084 md), and no trend was evident when correlating with material type or initial core permeability (solid circles in Fig. 4). These results support our previous finding that pore-filling gels reduce permeability of all porous media to a value that reflects the inherent permeability of the gel to water. In contrast, in Berea sandstone with \(k_w\) (at \(S_{or}\)) ranging from 222 to 363 md, a weak gel (with 0.18% polymer) exhibited a much wider range of post-polymer \(k_w\) values—from 0.75 to 202 md (open circles in Fig. 4, data from Ref. 10). Thus, pore-filling gels can provide greater reliability and behavior that is insensitive to the initial rock permeability.

**Fig. 3—Permeabilities to oil and water after gel placement.**

**Fig. 4—Variations in \(k_w\) for pore-filling gels versus weak gels.**
However, for this mechanism, the ability to form a pathway between the gel and the walls of the porous media. Additional work is needed to clarify the importance of these mechanisms.

A second conceivable mechanism is that brine could force a pathway between the gel and the residual oil. Interestingly, post-gel permeability of the gel to water. So, we examined the initial rock permeabilities (before gel placement) varied from 40 to 274 md. We should mention one “trick” to ensure that pore-filling Cr(III)-acetate-HPAM gels form in Berea sandstone. That trick involved flushing the cores with a few pore volumes of brine containing 0.12% Cr(III) acetate before injecting the gelant. This process saturates chromium adsorption sites and minimizes depletion of chromium from the gelant during placement. Prior to using this procedure, we often had problems with incomplete gel formation in Berea sandstone.

During brine flow (at 58 psi/ft) after gelation, post-gel \( k_w \) values were 0.01 md, 0.019 md, and 0.055 md, respectively. For the gel with 0.5% HPAM, the 0.01-md value (Entry 9) was similar to the 0.015-md and 0.005-md values associated with Entries 7 and 8—indicating a reasonable degree of reproducibility for the results. However, these values were substantially lower than the 1-md value predicted from Eq. 1. This discrepancy may be tied to differences in porosity of the porous media. In particular, Eq. 1 was based on flow through solid pieces of gel—i.e., 100% porosity with no rock.

On the other hand, if we accept the 0.01-md value for the gel with 0.5% HPAM, the post-gel \( k_w \) values for Entries 10 and 11 were consistent with the cubic relation of Eq. 1 between polymer concentration and inherent gel permeability. In particular, for Entries 9-11, post-gel \( k_w \) values of 0.01 md, 0.019 md, and 0.055 md were observed, while Eq. 1 predicted values of 0.01 md, 0.019 md, and 0.046 md (if 0.01 md was accepted as correct for the 0.5%-HPAM case).

Entries 12 and 13 in Table 1 provide another set for comparison, using low-permeability Berea sandstone cores with residual oil present before gelant placement. Here, the gel with 0.3% HPAM (Entry 13) exhibited a post-gel \( k_w \) value that was 13 times that for the gel with 0.5% HPAM (Entry 12).

For yet another comparison, Entry 17 in Table 1 lists results for a gel that contained 0.125% xanthan (Kelco Kelzan XCD™), 0.0125% Cr(III) acetate, 1% NaCl, and 0.1% CaCl₂.
Before adding crosslinker, the xanthan polymer solution was clarified by filtration to remove cellular debris. Use of xanthan allowed formation of a pore-filling gel with a considerably lower polymer concentration than when using HPAM. Presumably, the semi-rigid-rod structure of xanthan allows the critical overlap concentration to be much lower than that for the random-coil structure of HPAM in solution.

The Cr(III)-acetate-xanthan gelant was placed in a 3.2-darcy polyethylene core (no residual oil present), and a brine pressure gradient of 24.5 psi/ft was applied (41°C). During brine injection, the post-gel \( k_w \) quickly stabilized at 0.23 md. This value can be compared with 0.06 md for Entry 14 or with 0.14 for Entry 16 (which used gels with 0.5% HPAM in porous polyethylene). Since the polymer concentration for Entry 17 was four times less than those for Entries 14 and 16, the post-gel \( k_w \) for Entry 17 might be expected to be 64 times (i.e., \( 4^4 \)) greater than those for Entries 14 or 16—i.e., 3.8 md (0.06 md x 64) or 9.0 md (0.14 md x 64) instead of 0.23 md. Alternatively, Entry 17 can be compared with Entry 11, where the post-gel \( k_w \) was 0.055 md for a gel with 0.3% HPAM in Berea sandstone. For this case, the polymer concentration for Entry 17 was 2.4 times less than that for Entry 11, the post-gel \( k_w \) for Entry 17 might be expected to be 13.8 times (i.e., \( 2.4^4 \)) greater than that for Entry 11—i.e., a value of 0.76 md (0.055 md x 13.8) instead of 0.23 md. Thus, for both comparisons, the post-gel \( k_w \) for the Cr(III)-acetate-xanthan gel was significantly less than expected from the behavior of Cr(III)-acetate-HPAM gels. This result reveals limitations in using Eq. 1 for estimating post-gel \( k_w \) values. Nevertheless, the post-gel \( k_w \) value for Entry 17 was the highest for any pore-filling gel examined to date for cases where residual oil was not present during gelant placement.

**Stability of Post-Gel \( k_w \).** In the next section, we show that permeability to oil \( (k_w) \) after gel placement was a strong function of time and throughput. In contrast, if the gel was not compromised (e.g., by exposure to high pressure gradients), Fig. 5 demonstrates that the post-gel \( k_w \) was stable for a substantial period. In particular, for the gel associated with Entry 14 in Table 1, \( k_w \) held a value of about 60 µd (0.06 md) for over 500 days during continuous exposure to a pressure gradient of 30 psi/ft at 41°C. At 530 days, the permeability jumped from 60 to 80 µd, for unexplained reasons. Since then, the permeability has been stable.

**Are \( F_{rrw} \) Values High Enough?** For radial flow, the residual resistance factor in the water zone should be at least 20 (Fig. 1). Will the results from Table 1 meet this requirement? The highest post-gel \( k_w \) value listed was 0.37 md. Given the definition of water residual resistance factor (i.e., permeability to water before gel placement divided by permeability to water after gel placement), \( F_{rrw} \), will be \( \geq 20 \) if the permeability to water before gel placement is greater than 7.4 md (i.e., 20x0.37). Many engineers and geologists (including the author) believe that if a productive oil reservoir has a matrix permeability below 20 md, fractures or fracture-like features probably play a major role in allowing fluid to flow to the wells. Consequently, these gels would provide acceptable \( F_{rrw} \) values for radial flow applications.

When treating fractures using the concept illustrated in Fig. 2, will the post-gel \( k_w \) values from Table 1 be satisfactory? The degree of productivity impairment \( (q/q_o) \) for flow into a fracture can be estimated using Eq. 2:

\[
\frac{q}{q_o} = \frac{L_c}{(F_{rrw} L_p + L_c)},
\]

where \( L_p \) is the distance of polymer or gelant leakoff from the fracture face and \( L_c \) is the effective external drainage distance. From Eq. 2, reducing water productivity index by at least 50% requires that \( F_{rrw} L_p \geq L_c \). If \( L_p \) is 100 ft, \( F_{rrw} \) must be at least 10 if \( L_p \) is 10 ft and at least 100 if \( L_p \) is 1 ft. If \( k_w \) after gel placement is 0.37 md (Table 1), a \( F_{rrw} \) value of at least 10 can be achieved if \( k_w \) before gel placement is at least 3.7 md (i.e., 10x0.37 md). A \( F_{rrw} \) value of at least 100 can be attained if \( k_w \) before gel placement is at least 37 md (i.e., 100x0.37 md).

These calculations reveal that gels can achieve beneficial reductions in water productivity for both linear and radial flow problems. However, they will not be effective in all situations. Effective applications require attention to ensure that the distance of gelant penetration is adequate for rock of a given permeability. For example, many West Texas fractured dolomite reservoirs have rock permeability around 10 md. If a gel provides a \( k_w \) after gel placement of 0.24 md (average of Entries 1-6 in Table 1), a fairly large gelant leakoff distance may be needed (i.e., > 2.4 ft) to reduce water productivity by more than 50%. Alternatively, if a gel provides a \( k_w \) after gel placement of 0.007 md (Entry 12 in Table 1), a much smaller gelant leakoff distance (i.e., 0.07 ft) may provide the same effect. Large gelant leakoff distances present challenges—especially with respect to penetration of high molecular weight polymers into tight rock. Different gel formulations—e.g., using higher concentrations of lower molecular weight polymers—may require consideration for these applications. Additional work is needed to determine \( k_w \) values after gel placement in low-permeability rock.

**Permeability to Oil after Gel Placement**

Of course, the key to utilizing disproportionate permeability reduction is to identify conditions where a polymer or gel will reduce permeability to water much more than that to hydrocarbon. The previous section was concerned with whether water residual resistance factors were sufficiently high. This section will examine whether oil residual resistance factors can be sufficiently low. We also investigate how fast oil zones regain oil productivity after gel placement.
Concepts from Previous Work. Previous work⁵,²⁵,²⁶ revealed that gels can dehydrate during oil injection, thus causing disproportionate permeability reduction. Although oil cannot enter or flow through the gel matrix, pressure applied by the oil forces water to flow through and out from the gel. In locations where the gel has been compressed and dehydrated, oil forms "fingers" or "wormhole" pathways. These oil wormholes grow with time (and the entire gel structure continues to dehydrate with time under pressure), gradually increasing permeability to oil (note the solid circles in Fig. 3). This time- and throughput-dependent behavior during oil flow through gel-filled cores has important consequences for increasing permeability to oil (and Berea, the curves shifted to greater permeability reductions. Although oil cannot enter or flow through the gel matrix, pressure applied by the oil forces water to flow through and out from the gel. In places where the gel is compressed and dehydrated, oil forms "fingers" or "wormhole" pathways. These oil wormholes grow with time (and the entire gel structure continues to dehydrate with time under pressure), gradually increasing permeability to oil (note the solid circles in Fig. 3). This time- and throughput-dependent behavior during oil flow through gel-filled cores has important consequences for increasing permeability to oil.

For many of the experiments described in Table 1, oil (hexadecane for Entries 1-6 and Soltrol 130™ for Entries 7-17) was injected after gel placement and determination of oil forces water to flow through and out from the gel. In places where the gel is compressed and dehydrated, oil forms "fingers" or "wormhole" pathways. These oil wormholes grow with time (and the entire gel structure continues to dehydrate with time under pressure), gradually increasing permeability to oil (note the solid circles in Fig. 3). This time- and throughput-dependent behavior during oil flow through gel-filled cores has important consequences for increasing permeability to oil.

Table 2—Ultimate \( k_o \) and \( F_{rro} \) during oil flow after gel placement.

<table>
<thead>
<tr>
<th>Entry</th>
<th>Core material</th>
<th>Initial ( k_o ), md</th>
<th>( k_o ) at ( S_{w} ) before gel, md</th>
<th>HPAM in gel, %</th>
<th>( dp/dl ), psi/ft</th>
<th>Final ( k_o ), md</th>
<th>Final ( F_{rro} )</th>
<th>Final ( F_{rro}/F_{rro} )</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Berea</td>
<td>746</td>
<td>508</td>
<td>0.5</td>
<td>40</td>
<td>105</td>
<td>4.8</td>
<td>147</td>
</tr>
<tr>
<td>2</td>
<td>fused silica</td>
<td>1,820</td>
<td>1,240</td>
<td>0.5</td>
<td>30</td>
<td>307</td>
<td>4.0</td>
<td>485</td>
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<tr>
<td>3</td>
<td>fused silica</td>
<td>2,390</td>
<td>1,632</td>
<td>0.5</td>
<td>10</td>
<td>208</td>
<td>7.8</td>
<td>683</td>
</tr>
<tr>
<td>4</td>
<td>polyethylene</td>
<td>6,400</td>
<td>6,400</td>
<td>0.5</td>
<td>100</td>
<td>515</td>
<td>12.4</td>
<td>1,210</td>
</tr>
<tr>
<td>5</td>
<td>polyethylene</td>
<td>9,530</td>
<td>9,530</td>
<td>0.5</td>
<td>30</td>
<td>531</td>
<td>17.9</td>
<td>1,363</td>
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<tr>
<td>6</td>
<td>polyethylene</td>
<td>15,270</td>
<td>11,410</td>
<td>0.5</td>
<td>10</td>
<td>637</td>
<td>17.9</td>
<td>983</td>
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<tr>
<td>7</td>
<td>Berea</td>
<td>356</td>
<td>242*</td>
<td>0.5</td>
<td>2.7</td>
<td>209</td>
<td>1.2</td>
<td>19,800</td>
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<tr>
<td>8</td>
<td>Berea</td>
<td>389</td>
<td>389</td>
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<td>4.9</td>
<td>330</td>
<td>1.2</td>
<td>64,800</td>
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<tr>
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<td>Berea</td>
<td>100</td>
<td>68*</td>
<td>0.5</td>
<td>12</td>
<td>16.8</td>
<td>4.0</td>
<td>2,500</td>
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<tr>
<td>10</td>
<td>Berea</td>
<td>40</td>
<td>27.2*</td>
<td>0.4</td>
<td>12</td>
<td>13.4</td>
<td>2.0</td>
<td>1,050</td>
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<tr>
<td>11</td>
<td>Berea</td>
<td>274</td>
<td>186*</td>
<td>0.3</td>
<td>12</td>
<td>110</td>
<td>1.7</td>
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<td>12</td>
<td>Berea</td>
<td>98</td>
<td>132</td>
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<td>21.6</td>
<td>60.1</td>
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<td>15</td>
<td>sand pack</td>
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<td>8,100**</td>
<td>0.5</td>
<td>1.5</td>
<td>1,840</td>
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<td>63,400</td>
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<td>2,000**</td>
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<td>9.8</td>
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<td>1.4</td>
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</tr>
<tr>
<td>17</td>
<td>polyethylene</td>
<td>3,200</td>
<td>3,200**</td>
<td>0.125†</td>
<td>9.2</td>
<td>1,052</td>
<td>3.0</td>
<td>4,630</td>
</tr>
</tbody>
</table>

* Estimate based on Entry 1.  ** Estimate based on Entries 4 and 5.  † xanthan instead of HPAM.

Effect of Pressure Gradient. The effects of pressure gradient on the \( k_o \)-versus-\( PV \) curves are shown for gel in polyethylene cores in Fig. 6, in Berea sandstone cores in Fig. 7, and in fused silica cores in Fig. 8. For a given porous medium, the curves generally had similar shapes. However, in polyethylene and Berea, the curves shifted to greater \( PV \) throughput values as the pressure gradients were increased. If pressure gradient had no effect on the gel structure, the curves should have overlapped. If the gel structure was compromised by applications of higher pressure gradients, the curves should have shifted to the left (i.e., higher permeabilities achieved with smaller throughput values.). Instead, the curves in Figs. 6 and 7 shifted right. It is possible that the differences are inherent variations associated with the gel and porous media. In fused silica (Fig. 8), the curves shifted left with increased pressure gradient.

Interestingly, \( k_o \) jumped from ~0.2 md to ~2 md between 0 and 0.1 \( PV \) in the polyethylene and silica cores. In Berea, \( k_o \) at 0.1 \( PV \) was more similar to \( k_o \) before oil flow. As a possible explanation, a rapid increase in \( k_o \) may have been facilitated by imbibition of oil along the oil-wet surfaces of the porous polyethylene. Upon first consideration, this explanation is not very satisfying for the same behavior in fused silica (Fig. 8), which we assumed was water-wet. However, since we did not measure the wetting characteristics of the fused silica cores, they may have been more oil-wet than we expected.
Effect of HPAM Content in the Gel. In Table 1, post-gel $k_w$ values increased with decreased polymer content in the gel—from 0.01 md for the gel with 0.5% HPAM (Entry 9) to 0.055 md for the gel with 0.3% HPAM (Entry 11). Fig. 9 reveals that for early oil throughput values, the $k_w$ values were qualitatively consistent with the post-gel $k_w$ trends. However, at higher throughput values, the separation of the curves became less evident. Fortunately, because the clean up behavior is dominated by the post-gel $k_w$ values and the early $k_w$ values, an advantage in clean up time can be realized by using gels with low polymer concentrations. However, this suggestion must be moderated by a realization that if the polymer content is too low, a pore-filling gel will not form. Instead, a weak gel or suspension of gel particles will form.

Effect of Initial $S_{or}$. Figs. 10 and 11 show $k_w$ versus $PV$ for cases with and without an initial residual oil saturation. In Fig. 10, Berea sandstone cores were used with an initial (absolute) permeability (to water) of about 100 md. Both Berea cores had the same dimensions, and both were flooded with the same gel (0.5% HPAM, 0.0417%, 1% NaCl, 0.1% CaCl$_2$). One core had no residual oil saturation before gelant placement (Entry 9). The other core (Entry 12) had a $S_{or}$ of 31% before gelant placement and a $k_w$ value (at $S_{or}$) of 31 md. Table 1 reveals that the $k_w$ values during brine injection (at $dp/dl$ = 58 psi/ft) immediately after gel placement were similar for the two cases (0.01 versus 0.007 md). Fig. 10 shows that the development of $k_w$ versus $PV$ was also similar for the two cases.
promoted a rapid initial increase in $k_o$. A similar jump did not happen for Entry 16 (where no residual oil was present before gelant placement) until about 10 $PV$ of oil injection, when the $k_o$ curve increased to match the curve for Entry 6. The large initial jump in $k_o$ was noted for the three polyethylene cores with $S_{or}$ before gel (Fig. 6 and Entries 4, 5, and 6 in Table 1). It was also noted for the two fused silica cores (Fig. 8 and Entries 2 and 3 in Table 1), which we assumed (perhaps incorrectly) were strongly water-wet. In water-wet Berea, this rapid initial increase in $k_o$ was not observed, with or without the presence of residual oil before gelant placement (Fig. 10).

**Effect of Porous Medium.** Fig. 12 shows $k_o$ versus pore volume for different porous media (with no residual oil before gel placement). The three porous media, Berea sandstone, quartz sandpack, and porous polyethylene, show significantly different curves for $k_o$ versus pore volume. However, for Entries 8, 9, and 15 in Table 1 and Fig. 12 (i.e., the cases with strongly water-wet porous media) the early-throughput $k_o$ values were fairly similar.

**Effect of Polymer Type in the Gel.** For Entry 17, the gel contained 0.125% xanthan. During oil injection for Entry 17, $k_o$ increased steadily with throughput, as shown in Fig. 13. For comparison, results from a similar experiment (Entry 16) using a Cr(III)-acetate-HPAM gel (with 0.5% HPAM) are also shown. The low-concentration, pore-filling Cr(III)-acetate-xanthan gel showed behavior similar to the Cr(III)-acetate-HPAM gel during the first 10 $PV$ of oil flow. Beyond 10 $PV$, the curves deviated markedly, as the curve for Entry 16 experienced a sharp jump. Perhaps the xanthan gel adhered more tenaciously to the polyethylene pore walls than did the HPAM gel.

![Fig. 11—$k_o$ with/without an initial $S_{or}$ in polyethylene.](image1)

**Are $F_{rwo}$ Values Low Enough?** With radial flow, oil residual resistance factors must be less than 2 to mitigate damage caused by polymer or gel to oil productive zones. Can $F_{rwo}$ values this low be attained using pore-filling gels? The seventh and eighth columns in Table 2 list the final $k_o$ and $F_{rwo}$ values for each case. Typically, these values were measured after over 100 $PV$ of oil were injected. The lowest $F_{rwo}$ value was 1.2. We found five cases where gels provided water residual resistance factors greater than 2,100 and ultimate $F_{rwo}$ values of 2 or less (see Entries 7, 8, 10, 11, and 16 in Tables 1 and 2). These cases used gels with 0.3% to 0.5% HPAM. As noted above, $F_{rwo}$ must be less than 2 for radial flow treatments where hydrocarbon zones are not protected during gel placement. So, our recent results provide hope that our current approach will identify a gel that can successfully and reliably treat either fractured or unfractured production wells without zone isolation.

For linear flow applications (wells that intersect fractures), our main requirement was that the gel reduce permeability to water much more than that to oil. The last column in Table 2 lists the ratio, $F_{rwo} / F_{rwo}$. These ratios range from 147 to 64,800. These values would be very acceptable for applications in very permeable media. Unfortunately, fractures and fracture-like features are less likely to present channeling problems as the permeability of the media increases. The greatest need for high $F_{rwo} / F_{rwo}$ ratios exists in tight rock. As mentioned earlier, if the $F_{rwo}$ value is too low when treating a fracture, the gelant must leakoff a substantial distance from the fracture faces. In addition to the expense of requiring large gelant volumes, this situation may be limiting because many polymer-based gelants cannot penetrate into tight rock. On a positive note, the case for Entry 10 (using gel with 0.4% HPAM in 40-md Berea) exhibited $F_{rwo} = 2,110$, $F_{rwo} = 2.0$, and
F_rvw /F_ro = 1,050. These values would be quite acceptable for applications in either fractured or unfractured wells. Since they were measured in 40-md rock, we see hope that our approach will identify a gel that can successfully and reliably treat either fractured or unfractured production wells without zone isolation.

How Fast Will Oil Zones Clean Up?

Previous Approach. In Ref. 22, a means was described to estimate how rapidly productivity can be restored in an oil zone that was invaded by a polymer or gel. A simple mobility-ratio model was used to predict clean up times for both fractured and unfractured wells after a gel treatment. Conventional relative permeability equations were used (Eqs. 3 and 4).

\[ k_{ro} = k_r^o ((S_o - S_{or})/(1-S_o - S_{or}))^{m_w} \] ................................. (3)

\[ k_{rw} = k_r^o ((1-S_o - S_{or})/(1-S_o - S_{or}))^{m_w} \] ................................. (4)

The time to restore productivity to a gel-treated oil zone (1) was similar for radial versus linear flow, (2) varied roughly with the cube of distance of gel penetration, (3) varied inversely with pressure drawdown, (4) varied inversely with the inherent permeability of the gel to water. It neglected the detailed shapes of the \( k_o \)-versus-\( PV \) curves in Figs. 6-13. Consequently, an effort was made to consider how clean up time was influenced by these curves. A power regression worked reasonably well in fitting the curves in Figs. 6-13. Columns 8-10 in Table 3 list regression parameters associated with fitting the data with the equation,

\[ k_o = k_o + B \ (PV)^n \] ................................. (6)

\[ q_{oil}/q_{end} = (2/\pi) \arctan([64 t \Delta p \ k_o \mu_w/(\mu_o L_p^3)])^{1/4} \] .... (5)

New Approach. The approach taken in Ref. 22 and Eq. 5 assumed that recovery of oil productivity was dominated by the inherent permeability of the gel to water. It neglected the detailed shapes of the \( k_o \)-versus-\( PV \) curves in Figs. 6-13. Columns 8-10 in Table 3 list regression parameters associated with fitting the data with the equation,

\[ k_o = k_o + B \ (PV)^n \] ................................. (6)

This equation was used as the basis for our new model. The last column in Table 3 lists the calculated time (i.e., the estimated clean up time) for \( k_o \) to reach 50% of its final value. For comparison, the second to last column in Table 3 lists clean up times using our previous model.22 Calculated clean up times from the new method were consistently greater than those from the old method and were generally closer to the actual laboratory values (third to last column in Table 3), except for the cases using fused silica cores.

### Table 3—Actual versus predicted times to recover 50% of ultimate \( k_o \).

<table>
<thead>
<tr>
<th>Core properties</th>
<th>Parameters from power regression, (Eq. 6)</th>
<th>Time to reach 50% of ultimate ( k_o ), days</th>
</tr>
</thead>
<tbody>
<tr>
<td>Entry</td>
<td>Core material</td>
<td>Initial ( k_o ), md</td>
</tr>
<tr>
<td>1</td>
<td>Berea</td>
<td>746</td>
</tr>
<tr>
<td>2</td>
<td>fused silica</td>
<td>1,820</td>
</tr>
<tr>
<td>3</td>
<td>fused silica</td>
<td>2,390</td>
</tr>
<tr>
<td>4</td>
<td>polyethylene</td>
<td>6,400</td>
</tr>
<tr>
<td>5</td>
<td>polyethylene</td>
<td>9,530</td>
</tr>
<tr>
<td>6</td>
<td>polyethylene</td>
<td>15,270</td>
</tr>
<tr>
<td>7</td>
<td>Berea</td>
<td>356</td>
</tr>
<tr>
<td>8</td>
<td>Berea</td>
<td>389</td>
</tr>
<tr>
<td>9</td>
<td>Berea</td>
<td>100</td>
</tr>
<tr>
<td>10</td>
<td>Berea</td>
<td>40</td>
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<td>11</td>
<td>Berea</td>
<td>274</td>
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<tr>
<td>12</td>
<td>Berea</td>
<td>98</td>
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<tr>
<td>13</td>
<td>sand pack</td>
<td>8,100</td>
</tr>
<tr>
<td>14</td>
<td>polyethylene</td>
<td>2,000</td>
</tr>
<tr>
<td>15</td>
<td>polyethylene</td>
<td>3,200</td>
</tr>
</tbody>
</table>
Using parameters associated with Entry 1 in Tables 1-3, Fig. 14 was generated to compare predictions from the two models as a function of distance of gelant penetration into porous rock. For the old model, the saturation exponents, \( n_w \) and \( n_o \) were 2, \( S_{wr} \) was 0.3, \( S_{or} \) was 0.3, \( k_w \) (at \( S_{or} \) after gel placement) was 0.17 md, \( k_o \) (ultimate value after gel placement and 100 PV of oil injection) was 104 md, oil viscosity, \( \mu_o \), was 3.34 cp, and water viscosity was 1 cp. For the new model, \( k_w \) was 0.17 md, \( B \) was 13 and \( n \) was 0.52.

![Figure 14](image_url)  
**Fig. 14—Predicted clean up times: old versus new models.**

For a given distance of gelant penetration, predicted clean up times from the new model were consistently about 2.5 times longer than those from the old model. For the conditions in Fig. 14, the new model indicates that the distance of gelant penetration must be less than 4 ft in order to keep the clean up time less than 10 days. For both models, the clean up time increased with the square of the distance of gelant penetration. In contrast in Ref. 22, we reported that the clean up time should increase with the cube of the distance of gelant penetration. A detailed reconsideration of the old analysis revealed that the apparent dependence of clean up time on length was influenced by the saturation exponents used and the range of lengths examined.

Laboratory results and the predictions from both models suggest that clean up time is strongly influenced by the magnitude of \( k_w \) immediately after gel formation. Consequently, there are three main choices to speed clean up time after a gel treatment: (1) limit gelant penetration into porous rock to small distances (i.e., no more than a few feet with current gels), (2) maximize pressure drawdown for the well, and (3) attempt to increase \( k_w \) in the gel-treated rock. The first two options should be employed as much as practical, but limits exist on how much they can be exploited. Our future work will focus on the third option: identifying a gel that provides higher, stable \( k_w \) values in the gel-treated rock.

**Reliability.** Reliability and reproducibility of performance are central issues for field applications of polymers and gels. Fig. 4 and Column 9 of Table 1 indicate that pore-filling gels can consistently reduce \( k_w \) to low values, regardless of the nature of the porous medium. Figs. 6-13 and Column 8 of Table 2 reveals that given enough oil throughput, pore-filling gels consistently provide low \( F_{rro} \) values—although not necessarily values below two. The main area of variability is the time or throughput dependence of achieving low \( F_{rro} \) values. If the distance of gelant penetration into porous rock is small, this variability will not matter, since all clean up times will be fast. However for intermediate distances of penetration (i.e., multiple feet), the variability may be of concern. For a given type of porous medium, the curves for \( k_w \) versus \( PV \) were fairly similar (see Figs. 6-10). Consequently, variability of clean up times may be manageable for wells within a given field. Since the greatest differences among the curves for \( k_w \) versus \( PV \) were seen when comparing different porous media (Fig. 12), significant variations in clean up times might be expected after gel treatments in wells from different fields.

**Second Water Flow after Oil Flow**

Water was injected again after the oil-flow experiments described in Table 2 and in Figs. 6-13. In all cases, the permeability to water stabilized quite quickly. Column 7 in Table 4 lists \( k_w \) values for these experiments. The last column in Table 4 converts the \( k_w \) values to water residual resistance factors. (For Entries 7-11 and 15-17, the initial core permeability to water was used when calculating \( F_{rrw} \) values, because \( k_w \) values were not measured at \( S_{wr} \) before gel placement.) For Entries 1-5 in Table 4, the second \( k_w \) values were quite low—0.22 to 1.17 md. In most cases, these values were higher than the first \( k_w \) values after gel placement (Table 1), but were still very low relative to the \( k_w \) values (Table 2). An explanation was provided in Refs. 25 and 26. (The explanation involves trapping of high residual oil saturations.)

For Entries 6-17 in Table 4, the second \( F_{rrw} \) values were between 126 and 29,400 times less than the values before oil injection (compare the last columns of Tables 1 and 4). Thus, extended oil injection caused substantial damage to the gel for these cases. Interestingly, this damage was much less severe for the cases associated with Entries 1-5, where residual oil was present during gel placement. For Entries 1-5, the second \( F_{rrw} \) values were between one and seven times less than the values measured before oil injection.

The results in this section (i.e., for water flow following both gel placement and subsequent oil flow) are generally more of academic interest than of practical interest. A polymer or gel treatment has been applied, brine is the first flowing fluid to contact the polymer or gel in the water zones, so the results from our “Permeability to Water after Gel Placement” section are of direct practical interest. Similarly, oil is the first flowing fluid to contact the polymer or gel in the oil zones, so the results from our “Permeability to Oil after Gel Placement” section are also of direct practical interest. The results from this current section could have practical application mainly if an oil zone becomes watered out after being treated by a polymer or gel.

**Conclusions**

We investigated the merits of pore-filling gels in providing disproportionate permeability reduction.

1. For porous media with pre-gel \( k_w \) (at \( S_{or} \)) ranging from 120 to 6,500 md, one strong pore-filling Cr(III)-acetate-HPAM gel (with 0.5% HPAM) consistently reduced \( k_w \) to about
0.24 md (ranging from 0.12 to 0.37 md). In contrast, in Berea sandstone with \( k_w \) (at \( S_{or} \)) ranging from 222 to 363 md, a weak gel (with 0.18% polymer) exhibited a much wider range of post-polymer \( k_w \) values—from 0.75 to 202 md. Thus, strong pore-filling gels can provide greater reliability and behavior that is insensitive to the initial rock permeability.

2. With sufficient oil throughput, pore-filling gels can be dehydrated, thus increasing permeability to oil. We found several formulations where gels provided water residual resistance factors greater than 2,000 and ultimate \( F_{rro} \) values of 2 or less. These results provide hope that our current approach will identify gels that can successfully and reliably treat either fractured or unfractured production wells without zone isolation.

3. Significant oil throughput was required to achieve low \( F_{rro} \) values, suggesting that gelant penetration into porous rock must be small (a few feet or less) for existing pore-filling gels to provide effective disproportionate permeability reduction.

### Table 4—Ultimate \( k_w \) and \( F_{rrw} \) during the second water flow after gel placement.

<table>
<thead>
<tr>
<th>Entry</th>
<th>Core material</th>
<th>Initial ( k_w ), md</th>
<th>( k_w ) at ( S_{or} ) before gel, md</th>
<th>HPAM in gel, %</th>
<th>( dp/dl ), psi/ft</th>
<th>2nd ( k_w ), md</th>
<th>2nd ( F_{rrw} )</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Berea</td>
<td>746</td>
<td>120</td>
<td>0.5</td>
<td>40</td>
<td>1.11</td>
<td>108</td>
</tr>
<tr>
<td>2</td>
<td>fused silica</td>
<td>1,820</td>
<td>447</td>
<td>0.5</td>
<td>30</td>
<td>0.22</td>
<td>2,030</td>
</tr>
<tr>
<td>3</td>
<td>fused silica</td>
<td>2,390</td>
<td>640</td>
<td>0.5</td>
<td>10</td>
<td>0.35</td>
<td>1,830</td>
</tr>
<tr>
<td>4</td>
<td>polyethylene</td>
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<td>4,810</td>
<td>0.5</td>
<td>100</td>
<td>0.74</td>
<td>6,500</td>
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<tr>
<td>5</td>
<td>polyethylene</td>
<td>9,530</td>
<td>5,860</td>
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<td>30</td>
<td>1.17</td>
<td>5,008</td>
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<tr>
<td>6</td>
<td>polyethylene</td>
<td>15,270</td>
<td>6,500</td>
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<td>106</td>
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<tr>
<td>7</td>
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<td>*</td>
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<td>42</td>
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<tr>
<td>8</td>
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<td>*</td>
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<td>30</td>
<td>26</td>
<td>15</td>
</tr>
<tr>
<td>9</td>
<td>Berea</td>
<td>100</td>
<td>*</td>
<td>0.5</td>
<td>58</td>
<td>2.5</td>
<td>40</td>
</tr>
<tr>
<td>10</td>
<td>Berea</td>
<td>40</td>
<td>*</td>
<td>0.4</td>
<td>58</td>
<td>2.4</td>
<td>16.7</td>
</tr>
<tr>
<td>11</td>
<td>Berea</td>
<td>274</td>
<td>*</td>
<td>0.3</td>
<td>58</td>
<td>18.5</td>
<td>14.8</td>
</tr>
<tr>
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<td>Berea</td>
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<td>31</td>
<td>0.5</td>
<td>58</td>
<td>2.2</td>
<td>14.1</td>
</tr>
<tr>
<td>15</td>
<td>sand pack</td>
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<td>*</td>
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<td>14.8</td>
<td>850</td>
<td>9.5</td>
</tr>
<tr>
<td>16</td>
<td>polyethylene</td>
<td>2,000</td>
<td>*</td>
<td>0.5</td>
<td>24.5</td>
<td>860</td>
<td>2.3</td>
</tr>
<tr>
<td>17</td>
<td>polyethylene</td>
<td>3,200</td>
<td>*</td>
<td>0.125†</td>
<td>24.5</td>
<td>210</td>
<td>15.2</td>
</tr>
</tbody>
</table>

* Since no residual oil was present, \( F_{rrw} \) was calculated using the initial core permeability. † xanthan instead of HPAM.

### Acknowledgments

Financial support for this work is gratefully acknowledged from the United States Department of Energy (NETL), the State of New Mexico, ConocoPhillips, ExxonMobil, and Marathon. Richard Schrader and Erica Ocampo conducted the experiments. I thank Julie Ruff and Robert Sydansk for reviewing this paper.

### Nomenclature

- \( L_p \) = distance of polymer or gelant leakoff, ft [m]
- \( n \) = pore volume exponent in Eq. 6
- \( n_o \) = oil saturation exponent in Eq. 4
- \( n_w \) = water saturation exponent in Eq. 3
- \( \Delta p \) = pressure drop, psi [Pa]
- \( dp/dl \) = pressure gradient, psi/ft [Pa/m]
- \( PV \) = pore volumes of fluid injected
- \( q \) = flow rate, BPD [m3/d]
- \( q_{end} \) = final oil rate after large throughput, BPD [m3/d]
- \( q_o \) = flow rate before polymer/gel placement, BPD [m3/d]
- \( q_{oil} \) = instantaneous oil rate after gel treatment, BPD [m3/d]
- \( r_{gel} \) = radius of gelant penetration, ft [m]
- \( S_{or} \) = residual oil saturation
- \( S_{wr} \) = residual water saturation
- \( t \) = time, d
- \( \mu_o \) = oil viscosity, cp [mPa-s]
- \( \mu_w \) = water viscosity, cp [mPa-s]
- \( \phi \) = porosity

### References


