Gel Placement in Production Wells

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Summary. Straightforward applications of fractional-flow theory and material-balance calculations demonstrate that, if zones are not isolated during gel placement in production wells, gelant can penetrate significantly into all open zones, not just those with high water saturations. Unless oil saturations in the oil-productive zones are extremely high, oil productivity will be damaged even if the gel reduces water permeability without affecting oil permeability. Also, in field applications, capillary pressure will not prevent gelant penetration into oil-productive zones. An explanation is provided for the occurrence of successful applications of gels in fractured wells produced by bottomwater drive. With the right properties, gels could significantly increase the critical rate for water influx in fractured wells.

Introduction

Coping with excess water production is always a challenging task for field operators. The cost of handling and disposing produced water can significantly shorten the economic producing life of **a** well. The hydrostatic pressure created by high fluid levels in the well also is detrimental to oil production. The two major sources of excess water production are coning and channeling. Water coning is common when a reservoir is produced by a bottomwater-drive mechanism. Fractures and high-permeability streaks are the common causes of premature water breakthrough during water-floods. Polymer gels have been applied to many wells to reduce excess water production without adversely affecting oil production.[1-6] Moffitt[1] reported that polymer gels are particularly effective in suppressing water coning. In many cases, however, gel treatments have not been successful. Part of the reason for the sporadic success was problems with gel placement. During gel placement in production wells, much of the gel formulation will enter zones responsible for the excess water production. However, some of this fluid may enter and damage oil-productive strata.

The objectives of this study are to model gel placement in production wells mathematically and to examine the potential effect of gelant invasion into oil-producing zones. Particular attention is paid to the importance of two phenomena. The first is hysteresis of oil/water relative permeability curves during the "pump-in, pump-out" sequence used during gel placement in production wells. The second phenomenon is that gels (or polymers) can reduce the relative permeability to water more than to oil.

Sensitivity studies covering most known field and laboratory applications are discussed. In particular, we study permeability contrasts from 1 to 1000, oil/water viscosity ratios ranging from **0.1** to 100, endpoint water relative permeabilities ranging from 0.1 to 0.7, water saturations ranging from 0.2 to 0.8, and fractured and unfractured wells. Therefore, our conclusions should be applicable to most field applications of gels in production wells.

Examples are provided to illustrate and contrast situations where gels are or are not expected to damage oil productivity. In these examples, we assume that the gels reduce water permeability without affecting oil permeability. This assumption is made as a best-case scenario to demonstrate that oil productivity can be damaged even if the gels do not affect oil permeability. If gels reduce oil permeability, then further oil productivity reduction should be expected. Our equations and analyses are general and can be applied readily for any degree of oil permeability reduction caused by the gel.

Several terms should be defined. "Gelant" and "gelling agent" refer to the liquid formulation before gelation. Resistance factor, F_r, is defined as water mobility divided by gelant mobility. It is equivalent to the effective gelant viscosity in porous media relative to that of water. Residual resistance factor, F_{rrw}, is defined as water mobility in the absence of gel divided by water mobility in the presence of gel and is a measure of the permeability reduction caused by gel.

Theoretical Model

The first objective of this analysis is to develop a theoretical model for gel placement in production wells. Fractional-flow theory is ap-

plied to model mathematically the degree of gelant penetration into zones with different permeabilities during unrestricted injection.

Basic Assumptions. In examining the placement of gels in production wells, we made these assumptions.

1. All fluids are incompressible and Newtonian.
2. Gelant formulations are miscible with water.
3. The gelation reaction is slow relative to the placement process.
4. Dispersion, retention, and inaccessible PV are negligible.
5. F_r is independent of permeability.
6. There is no mass transfer between phases.
7. Gravity and capillary effects are negligible.
8. Darcy's law applies, and no fingering occurs during displacement.
9. Each layer is homogeneous, isotropic, and isothermal.
10. The reservoir consists of a number of horizontal, noncommunicating layers.
11. All layers have the same areal dimensions and share the same injector and producer. (The layers can have different thicknesses.)

For simplicity, we assume that the water and oil relative permeabilities are functions of water saturation only. **Eqs.** 1 and *2* are used throughout this analysis for relative permeability calculations.[7]

$$k_{rw} = k_{rw}^0 \left(\frac{S_w - S_{wr}}{1 - S_{wr} - S_{or}} \right)^{n_w} \qquad (1)$$

$$\text{and } k_{ro} = k_{ro}^0 \left(\frac{1 - S_w - S_{or}}{1 - S_{wr} - S_{or}} \right)^{n_o} \qquad (2)$$

Linear Flow. For near-wellbore gel treatments in production wells, the gelation reaction often is slow relative to the placement process. Thus, the fluid flow in a porous medium during the placement of aqueous gelants can be assumed to be the same as that of aqueous polymer solutions during the polymer-flooding process.[8] **Fig. 1** is a schematic of the saturation profile in Layer i at a certain instant during the placement process. In linear flow, the instantaneous pressure drop in Layer i between the producer and the injector is

$$\Delta p_i = \frac{\mu_w \phi_i \bar{S}_{wi}}{k_i} \left[F_r \int_0^{L_{pi}} \frac{f_{wi}^p}{k_{rwi}} dx + \int_{L_{pi}}^{L_{pki}} \frac{f_{wi}}{k_{rwi}} dx + \frac{f_{wIi}}{k_{rwIi}} \right.$$

$$\left. \times (L_{pm} - L_{pki}) + \frac{f_{wIi}}{k_{rwIi}} \Delta p_{Di} L_{pm} \right] \frac{dL_{pi}}{dt}. \qquad (3)$$

Δp_D is defined as the ratio of the pressure drop between L_{pm} and the injection well to the pressure drop between the production well and L_{pm} just before the injection of any gelants (see Ref. 9 for a more detailed discussion). The average water saturation behind the gelant front, $\bar{S}_{wi}$, is determined with the Welge integration procedure.[10] Eq. 3 is simply a Darcy equation.

Consider the case in which all layers share the same injector and producer and all fluids involved are incompressible. The instanta-
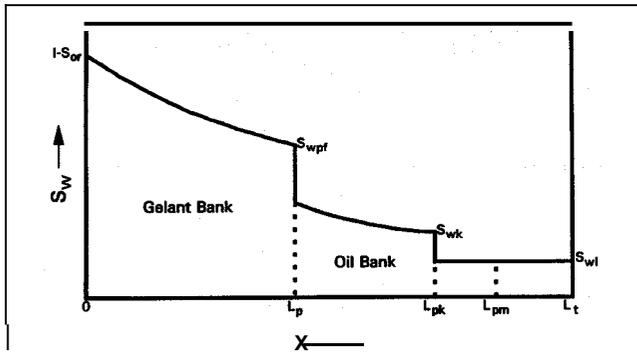
Fig. 1—Saturation profile in Layer i during placement.

neous pressure drop across Layer **1** is the same as that across Layer i. Thus,

$$\int_0^{L_{pi}} \left[F_r \int_0^{L_{pi}} \frac{f_{wi}^p}{k_{rwi}} dx + \int_{L_{pi}}^{L_{pki}} \frac{f_{wi}}{k_{rwi}} dx - \frac{f_{wIi}}{k_{rwIi}} L_{pki} + \frac{f_{wIi}}{k_{rwIi}} \right.$$

$$\left. \times (\Delta p_{Di} + 1) L_{pm} \right] dL_{pi}$$

$$= \frac{\phi_1 k_i \bar{S}_{w1}}{\phi_i k_1 \bar{S}_{wi}} \int_0^{L_{p1}} \left[F_r \int_0^{L_{p1}} \frac{f_{w1}^p}{k_{rw1}} dx + \int_{L_{p1}}^{L_{pk1}} \frac{f_{w1}}{k_{rw1}} dx - \frac{f_{wI1}}{k_{rw1}} L_{pk1} \right.$$

$$\left. + \frac{f_{wI1}}{k_{rwI1}} (\Delta p_{D1} + 1) L_{pm} \right] dL_{p1}. \qquad (4)$$

(**Eq.**4 is derived in more detail in Ref. *1*1. A computer program that solves this equation is listed in Appendix G of Ref. *12.*) Eq. 4 gives the penetration of a gelant into Layer i, L_{pi}, when the oil bank reaches L_{pm} in Layer **1**. Fractional-flow theory is applied to determine the frontal position of the oil bank, L_{pki}, relative to that of the gelant front, L_{pi}, and the saturation profile during the dis-

placement process. Analytical solutions for the integrations are difficult to obtain because of the complexity of the functions involved. Instead, the trapezoidal rule is used to evaluate the integrations numerically. Finally, the secant method is applied to solve for the degree of gelant penetration (L_{pi}/L_{p1}).

For laboratory parallel linear corefloods, the $\Delta p_D = 0$ for all layers. When the oil bank, L_{pk}, reaches the outlet of the most permeable core (Core 1), the distance that a gelant has propagated in less permeable core (Core i) can be calculated with

$$\int_0^{L_{pi}} \left[F_r \int_0^{L_{pi}} \frac{f_{wi}^p}{k_{rwi}} dx + \int_{L_{pi}}^{L_{pki}} \frac{f_{wi}}{k_{rwi}} dx + \frac{f_{wIi}}{k_{rwIi}} (L_t - L_{pki}) \right] dL_{pi}$$

$$= \frac{\phi_1 k_i \bar{S}_{w1}}{\phi_i k_1 \bar{S}_{wi}} \int_0^{L_{p1}} \left(F_r \int_0^{L_{p1}} \frac{f_{w1}^p}{k_{rw1}} dx + \int_{L_{p1}}^{L_t} \frac{f_{w1}}{k_{rw1}} dx \right) dL_{p1}. \quad \dots (5)$$

Radial Flow. A similar procedure is followed in developing the radial model for gel placement in production wells. The degree of gelant penetration, $(r_{pi} - r_w)/(r_{p1} - r_w)$, is determined by solving the following equation:

$$\int_{r_{wD}}^{r_{pDi}} \left(F_r \int_{r_{wD}}^{r_{pDi}} \frac{f_{wi}^p}{k_{rwi}} \frac{dr_D}{r_D} + \int_{r_{pDi}}^{r_{pkDi}} \frac{f_{wi}}{k_{rwi}} \frac{dr_D}{r_D} + \frac{f_{wIi}}{k_{rwIi}} \ln \frac{r_{pmD}}{r_{pkDi}} \right.$$

$$\left. + \frac{f_{wIi}}{k_{rwIi}} \Delta p_{Di} \ln \frac{r_{pmD}}{r_{wD}} \right) dr_{pDi}$$

$$= \frac{\phi_1 k_i \bar{S}_{w1}}{\phi_i k_1 \bar{S}_{wi}} \int_{r_{wD}}^{r_{pDi}} \left(F_r \int_{r_{wD}}^{r_{pD1}} \frac{f_{w1}^p}{k_{rw1}} \frac{dr_D}{r_D} + \int_{r_{pD1}}^{r_{pkD1}} \frac{f_{w1}}{k_{rw1}} \frac{dr_D}{r_D} + \frac{f_{wI1}}{k_{rw1}} \right.$$

$$\left. \times \ln \frac{r_{pmD}}{r_{pkD1}} + \frac{f_{wI1}}{k_{rwI1}} \Delta p_{D1} \ln \frac{r_{pmD}}{r_{wD}} \right) dr_{pD1}. \quad \dots \dots \dots (6)$$

(Eq. 6 is derived in Ref. 11. A computer program that solves this equation is listed in Appendix F of Ref. *12.*)
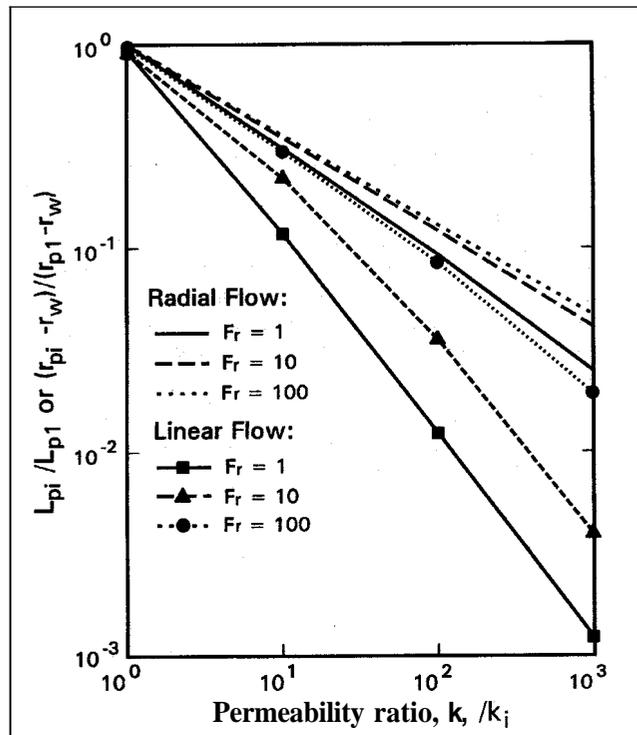
A dimensionless variable,

$$r_D = (r/r_e)^2, \quad \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots (7)$$

Fig. 2—Radial vs. linear parallel corefloods ($\mu_o/\mu_w = 10$); degree of penetration into Core i ($r_{p1} = 100\, r_w$, $\phi_1 = \phi_i$).
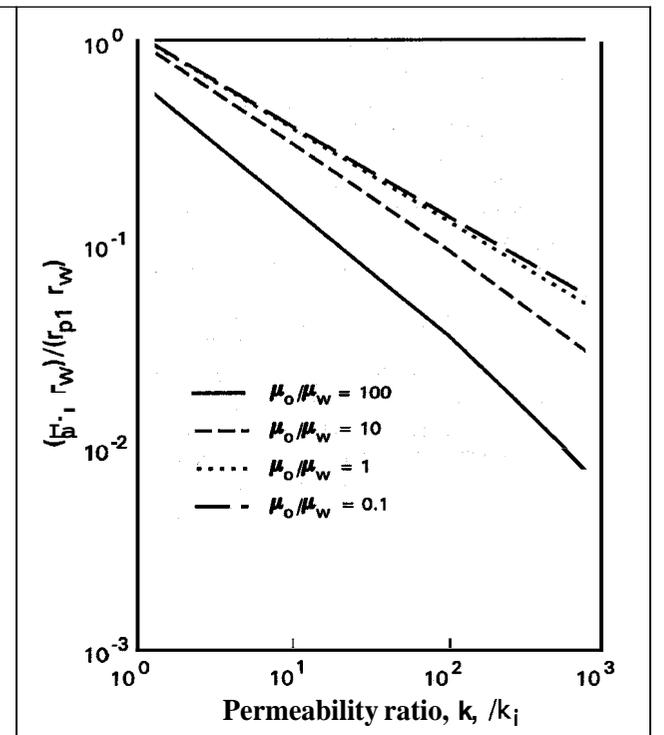

Fig. 3—Effect of oil/water viscosity ratio on degree of penetration into Core i (radial flow, $F_r = 1$).

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is introduced here so that the solution scheme used in solving Eq. 4 can be applied in solving Eq. 6.

For laboratory parallel radial corefloods, Eq. 8 is used to determine the degree of gelant penetration when the oil bank reaches the outlet of the most-permeable core:

$$\int_{r_{wD}}^{r_{pDi}}\left(F_r\int_{r_{wD}}^{r_{pDi}}\frac{f_{wi}^p}{k_{rwi}}\frac{dr_D}{r_D}+\int_{r_{pDi}}^{r_{pkDi}}\frac{f_{wi}}{k_{rwi}}\frac{dr_D}{r_D}-\frac{f_{wIi}}{k_{rwIi}}\ln r_{pkDi}\right)dr_{pDi}$$

$$=\frac{\phi_1 k_i \bar{S}_{w1}}{\phi_i k_1 \bar{S}_{wi}}\int_{r_{wD}}^{r_{pDi}}\left(F_r\int_{r_{wD}}^{r_{pD1}}\frac{f_{w1}^p}{k_{rw1}}\frac{dr_D}{r_D}+\int_{r_{pD1}}^{r_{pkD1}}\frac{f_{w1}}{k_{rw1}}\frac{dr_D}{r_D}-\frac{f_{wI1}}{k_{rw1}}\right.$$

$$\times\left.\ln r_{pkD1}\right)dr_{pD1}. \dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots(8)$$

For both the radial and linear models, the degree of gelant penetration is determined when the oil bank in the most permeable layer reaches r_{pm} (L_{pm} for the linear model) or the core outlet. However, if no oil bank forms in the most-permeable layer (e.g., if the most-permeable layer is watered-out), then the degree of penetration is determined when the gelant front reaches r_{pm} or the core outlet. In some unusual cases ($k_1/k_i \sim 1$), gelant invasion into a given less permeable layer can be slightly greater than that into the most permeable layer. The degree of gelant penetration, in this case, is determined when the oil bank in the less permeable layer reaches r_{pm} or the core outlet. In all the cases studied, the degree of gelant penetration is insensitive to the choice of r_{pm} or the gelant front position. The theoretical model is applicable to both constant-rate and constant-pressure-drop placement processes. Ref. 12 gives a more detailed description of our theoretical model.

Linear vs. Radial Corefloods

To quantify the effect of the factors affecting the degree of gelant penetration, consider gelant injection into a number of parallel homogeneous cores of equal length from a common injection port. The most permeable core is completely watered-out, and Table 1 summarizes the rock and fluid properties.

Fig. 2 shows the degree of gelant penetration into a less permeable core (Core i). (These results were generated with Eqs. 5 and 8.) As expected, Fig. 2 shows that the degree of gelant penetration into the less permeable cores decreases with increasing permeability contrast. Fig. 2 also demonstrates that the degree of gelant penetration into the less permeable cores is less in linear flow than in radial flow. This fact also was noted for gel placement in injection wells.[9] It is partly the reason that zone isolation is more likely to be needed during gel placement in radial flow than in linear flow.

A basic principle in polymer flooding is that an increase in resistance factor will increase the degree of penetration into the less permeable layer.[9] Fig. 2 demonstrates that this principle is generally valid in production-well treatments. However, this trend is moderated significantly at low oil/water viscosity ratios.

A comparison of our Fig. 2 with Fig. 1 from Ref. 9 reveals that the degree of gelant penetration into a given less permeable layer in production-well treatments is similar to that in injection-well treatments.' Hence, the need for zone isolation is of concern during gel placement in production wells.

Fluid flow during gel placement in production wells can be characterized with fractional-flow theory. The factors affecting fractional flow (such as the oil/water viscosity ratio, the water/oil relative permeability curves, and the fluid saturations in the porous medium) also can affect the degree of gelant penetration.

As Fig. 3 shows, the degree of gelant penetration into a given less permeable layer increases with a decreasing oil/water viscosity ratio. However, the effect becomes less significant at low oil/water viscosity ratios.

Fig. 4 shows that the degree of penetration is fairly insensitive to the endpoint relative permeability to water, k_{rw}^0. Fig. 4 also demonstrates that gelants penetrate less into the less permeable layer as the initial water saturation increases in the most permeable layer. In examining the effect of water/oil relative permeabilities on

TABLE 1—ROCK AND FLUID PROPERTIES FOR DEGREE OF PENETRATION CALCULATIONS

k_{rw}^0	0.1
ϕ_1/ϕ_i	1
S_{wr}	0.2
S_{w1}	0.8
F_r	1
k_{ro}^0	1
μ_o/μ_w	10
S_{or}	0.2
S_{wi}	0.2
Well pattern: 20-acre five-spot	
r_w, ft	0.5
r_{p1}, ft	50
r_e, ft	372.4
r_{pm}, ft	100
For radial coreflood cases	
r_w, ft	0.5
r_e, ft	50

the degree of gelant penetration, we assume that the water relative permeability curve shifts proportionately with the changing endpoint values. The oil relative permeability curve remains unchanged throughout this analysis. As mentioned earlier, this assumption is a best-case scenario. Our equations and analyses are general and can be applied readily for any degree of oil permeability reduction caused by the gel.

Flow in Reservoirs

In actual field applications in unfractured wells, gelants usually penetrate a relatively short distance into the formation (e.g., 50 ft into the most permeable layer). Thus, in this study, the greatest distance that gelants penetrate into the most permeable layer, r_{p1}, is set at 50 ft from the wellbore. Because an oil bank often precedes the gelant front, a gel treatment can affect fluid saturations at distances beyond the greatest depth of gelant penetration. A distance, r_{pm}, will be chosen so that gelant injection has no effect on fluid saturations at distances greater than r_{pm} from the wellbore. Somewhat arbitrarily, we will assume that $r_{pm}=100$ ft.

For the case of a waterflood in a five-spot pattern, Δp_D in Eq. 6 can be approximated by[13,14]

$$\Delta p_{Di}=\frac{\ln\left(\frac{r_e}{r_{pm}}\right)+\frac{1}{M}\ln\left(\frac{r_e}{r_w}\right)}{\ln\left(\frac{r_{pm}}{r_w}\right)} \qquad (9)$$

For simplicity, the water front is assumed to coincide with the external drainage radius of the reservoir. However, the Δp_D value is insensitive to the position of the water front. According to Eq. 9, Δp_D is strongly dependent on the water/oil mobility ratio. The value of Δp_D is fairly insensitive to other factors, such as well spacing and the choice of r_{pm}.[9]

Consider an example where the most permeable layer is completely watered-out (Table 1). Because water is the only mobile fluid in the most permeable layer, $M=1$ in Eq. 9. Hence, in the most permeable layer, $\Delta p_{Di}=1.5$. However, in the less-permeable layers, Δp_{Di} could have any value (in this example) in the practical range of 0.3 to 16, depending on the water/oil mobility ratio.

Fig. 5 illustrates the effect of Δp_D on the degree of gelant penetration. The results presented in Fig. 5 were generated with Eq. 6. As Fig. 5 shows, the degree of gelant penetration into the less permeable layer increases with increasing Δp_{Di}. However, the effect is not as great as that for injection-well treatments.[9] The degree of penetration becomes insensitive to the Δp_{Di} value for high F_r.

Numerical Model

To verify the solutions from Eqs. 4 through 6 and 8, a numerical-simulation model was developed. The implicit pressure, explicit
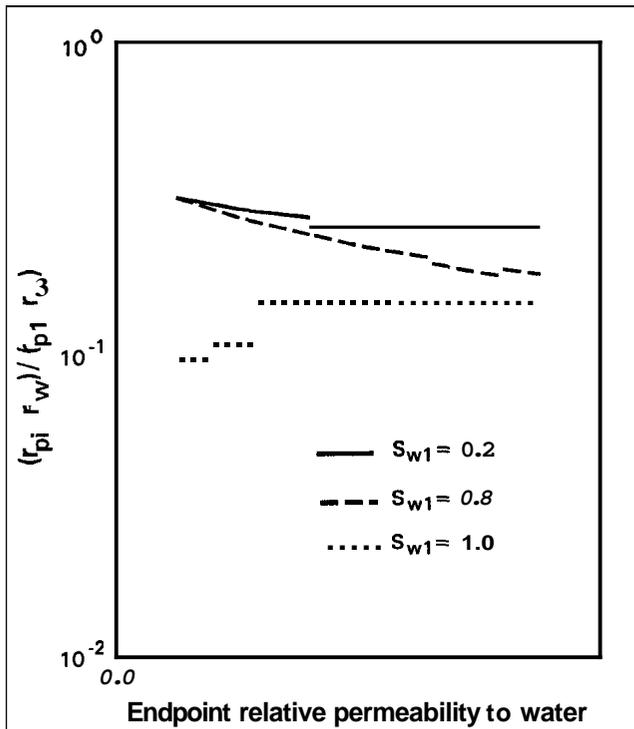
Fig. 4—Degree of penetration into Core i; effects of endpoint permeability to water and S_{w1} ($k_1/k_i = 10$, $S_{wi} = 0.2$).
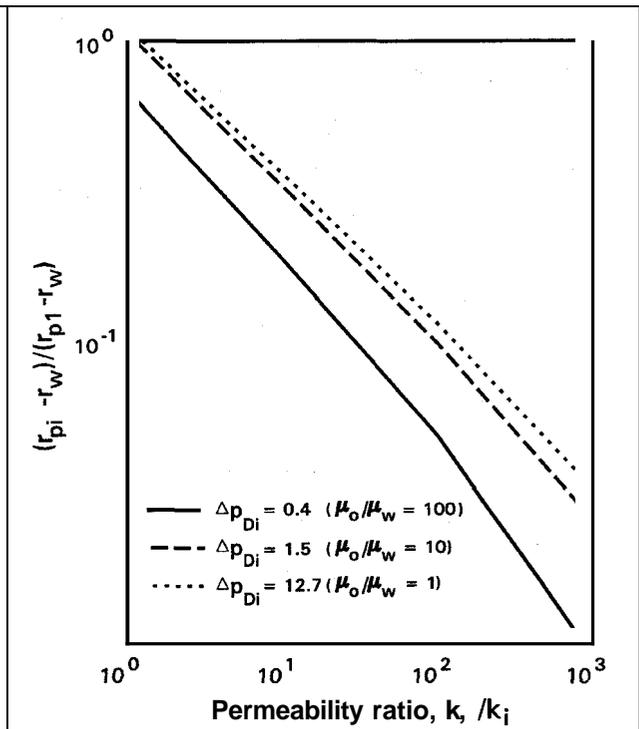

Fig. 5—Effect of Δp_{Di} variations ($F_r = 1$) on degree of penetration into Layer i.

saturation method and upstream weighting on mobilities were used. Good agreement between numerical solutions and solutions from Eqs. 4 through 6 and 8 was found. Appendix H of Ref. 12 describes more fully the formulation of the numerical model and compares it with the theoretical model.

Relative Permeability Changes After Treatment. Several researchers[4,15-23] reported that some polymers or gels reduce permeability to water significantly more than they reduce permeability to oil. In examining the potential effect of this disproportionate permeability reduction, we will assume the best-case scenario where the permeability to oil is not affected by gel treatment. The water relative permeability, however, is decreased in proportion to the F_{rr} of the particular gelant involved.

For near-wellbore gel treatments in unfractured production wells, gelants penetrate a relatively short distance into the formation (e.g., 50 ft into the most permeable zone). The water saturation, water and oil relative permeability curves, and fluid fractional-flow curves remain unchanged in the region not contacted by the gelant. However, the reduced water permeability in the gel-treated region reduces production of all fluids from the treated zone. This can be illustrated by the following example.

Consider a reservoir that consists of a single stratum. Let the rock properties and relative permeabilities be described by the parameters in **Table 2.** As **Fig. 6** shows, the water relative permeability curve is shifted downward as a result of a gel treatment, while the oil relative permeability curve remains unchanged. This shift also changes the fractional-flow curve governing the fluid flow in the treated region **(Fig. 7).** Because gels usually invade only a relatively short distance into the formation during treatments, it is reasonable to expect that a local steady-state flow condition can be achieved in the vicinity of the treated region after flow resumes. Under steady-state conditions, the fractional flow of water in the gel-treated region must be the same as that in the untreated region (a consequence of mass balance). Therefore, the water saturation in the gel-treated region must shift (as Fig. 7 illustrates) from 0.5 (the initial water saturation before treatment) to 0.625 after treatment to maintain the same fractional flow of water under the new fractional-flow curve. This increase in water saturation after treatment can cause significant reduction in oil relative permeability in the treated region. As Fig. 6 indicates, the oil relative permeabil-

TABLE 2—ROCK AND FLUID PROPERTIES FOR PRODUCTIVITY LOSS CALCULATIONS

k_{rw}^0	0.1
n_w	2
S_{wr}	0.2
S_{wi}	0.8
k_{ro}^0	1
n_o	3
S_{or}	0.2
F_r	1

ity is reduced from 0.125 before treatment to 0.025 after treatment as a result of the water saturation increase. The effect of the reduced oil permeability on oil productivity is discussed in the next section.

Productivity Loss After Treatment

The goal of near-wellbore gel treatments in oil-producing wells is to reduce water production without sacrificing oil production. For the constant-pressure-drop case, the fraction of the original water productivity in Zone i that remains after the gel treatment is

$$\frac{q_{wi}}{q_{woi}} = \frac{(\Delta p_{Di}+1)\ln\left(\dfrac{r_{pm}}{r_w}\right)}{\dfrac{k_{rwi}}{k_{rwti}}\ln\left(\dfrac{r_{pi}}{r_w}\right)+\ln\left(\dfrac{r_{pm}}{r_{pi}}\right)+\Delta p_{Di}\,\ln\left(\dfrac{r_{pm}}{r_w}\right)},$$

$$\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots(10)$$

and the fraction of the original oil productivity in Zone i that remains after gel treatment is

$$\frac{q_{oi}}{q_{ooi}} = \frac{(\Delta p_{Di}+1)\ln\left(\dfrac{r_{pm}}{r_w}\right)}{\dfrac{k_{roi}}{k_{roti}}\ln\left(\dfrac{r_{pi}}{r_w}\right)+\ln\left(\dfrac{r_{pm}}{r_{pi}}\right)+\Delta p_{Di}\,\ln\left(\dfrac{r_{pm}}{r_w}\right)}.$$

$$\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots(11)$$
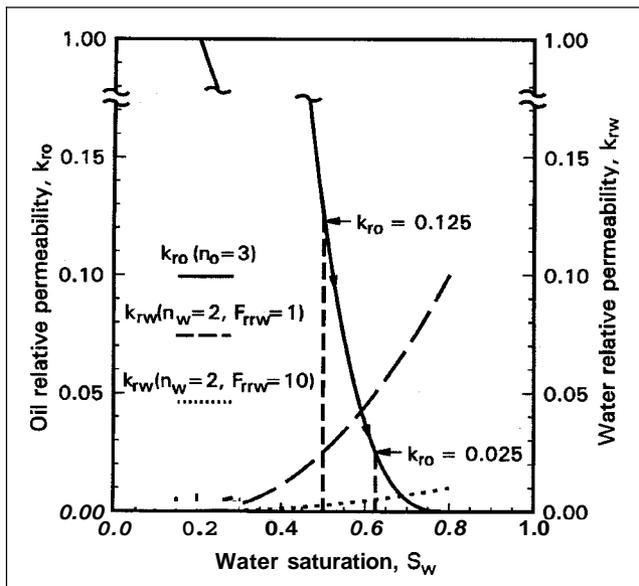
Fig. 6—Oil and water relative permeability curves before and after gel treatment.
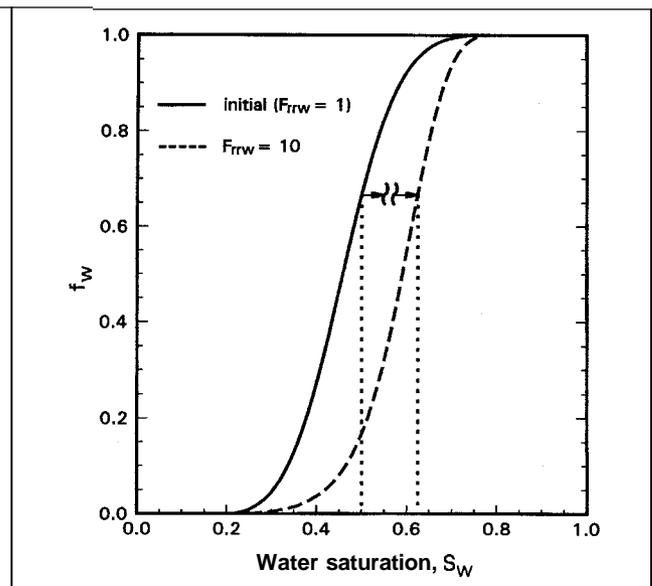

Fig. 7—Water fractional-flow curves before and after gel treatment.

The relative permeabilities in the treated region can be calculated based on the new oil/water relative permeability curves and the new oil and water saturations. Thus, the productivity loss in a given zone depends on the degree of gelant penetration, the Δp_D value of the zone, the changes in the oil and water relative permeabilities, and the resulting changes in saturations in the treated region. As mentioned, the fractional flow of water and oil from a given zone must remain fixed. Consequently, if the water productivity from a given zone changes, then the oil productivity from that zone must change by the same fraction. In other words, the right and left sides of Eqs. 10 and 11 are equal.

Hysteresis of Oil and Water Relative Permeability Curves. The relative permeability of a given phase is often both path- and history-dependent.[14] Roszelle and Jones[24] reported that the relative permeability to oil is relatively unchanged from the imbibition values. For a water-wet core, however, the water relative permeability curves during imbibition (waterflooding) can be different from those during drainage (oilflooding after waterflooding). Because gel treatments in production wells involve both imbibition (injection of an aqueous gelant) and drainage cycles (resumption of oil production), the effect of this hysteresis should be considered.

To examine the effect of the hysteresis, consider injection of a small volume of water into an unfractured production well. Reservoir and fluid properties are the same as those in Table 2, except that $n_w = 6$ during drainage. **Fig. 8** shows the relative permeability curves of the imbibition and drainage cycles.

After production is resumed and steady state is achieved, the water saturation in the region contacted by the injection water must be increased to maintain the level of water fractional flow. However, the increase in water saturation would reduce the oil relative permeability and impair the oil productivity of the oil-productive zones. **Fig. 9** illustrates the effect of the hysteresis of relative permeability curves on the productivity loss at various initial water saturations. For this example, a single layer is used, and the water front is allowed to penetrate 50 ft into the layer. (Remember that oil and water productivities must experience the same fractional change.) As Fig. 9 shows, hysteresis of the water relative permeability curve can cause significant damage to oil productivity for most water saturations. Thus, hysteresis of relative permeability curves should be considered when gel treatments are applied.

Productivity Loss After Gelation. Because hysteresis alone can impair oil productivity, the effects of a gel treatment on productivity loss with and without hysteresis are examined. Consider the case where no hysteresis is involved. Table 2 lists the parameters used in the example. Figs. **6** and 7 show the relative permeability curves and the corresponding fractional-flow curves, respectively. The oil and water productivity losses after gel treatment (expressed as the fraction of the original productivity) are plotted vs. the depth of gelant penetration into the formation in **Fig. 10a**. The material balance dictates that the level of water fractional flow in a given zone in the formation remain unchanged after treatment; thus, the fraction of productivity loss of oil for a given zone after treatment is the same as that of water after treatment.

Fig. 10a demonstrates that the productivity loss after treatment increases as the water saturation increases in the zone of interest. As expected, post-treatment productivity declines with increasing depth of gelant penetration. **Fig. 10b** shows the productivity loss after gel treatment with hysteresis. Comparison of Figs. 10a and 10b reveals that, as expected, the hysteresis of relative permeability curves further impairs oil productivity.

A key in Figs. 10a and 10b is that the gel will cause significant reduction in oil productivity unless oil saturation is very high. This occurs even though the gel did not affect oil permeability in the gel-treated region. If gel does reduce oil permeability, then some of our calculations will underestimate the loss of oil productivity. In other words, if zones cannot be isolated during placement, gel treatments in unfractured production wells can cause significant damage to the oil-productive zones.

Fractured Systems

In this section, our analysis focuses on vertically fractured wells. The fractures are assumed to extend through all the productive zones, which are separated by impermeable layers (except at the fracture face). Because the length of a vertical fracture generally is much longer than the wellbore radius and the "permeability" of a fracture is much greater than that of the porous medium, gelant flow from the fracture face into the rock matrix is considered linear.

Eqs. 4 and **9** can be applied to solve for the degree of gelant penetration into the rock matrix adjacent to a fracture face. However, L_{pi} now is defined as the distance from the fracture face into the formation that a gelant has propagated in Layer i when the oil bank reaches L_{pm} in the most permeable layer (Layer 1). Also, r_w and r_{pm} in Eq. **9** are replaced by L and $L+L_{pm}$, respectively.

Ref. 12 gives example calculations illustrating the depth of gelant penetration in fractured wells. The degree of gelant penetration in the less permeable layers generally is less in fractured wells than in unfractured wells.[9,12] Thus, the need for zone isolation is less for vertically fractured wells than for unfractured wells.
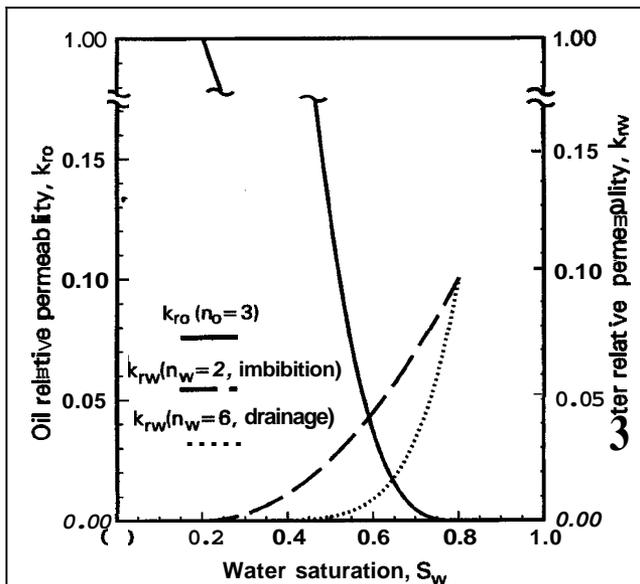
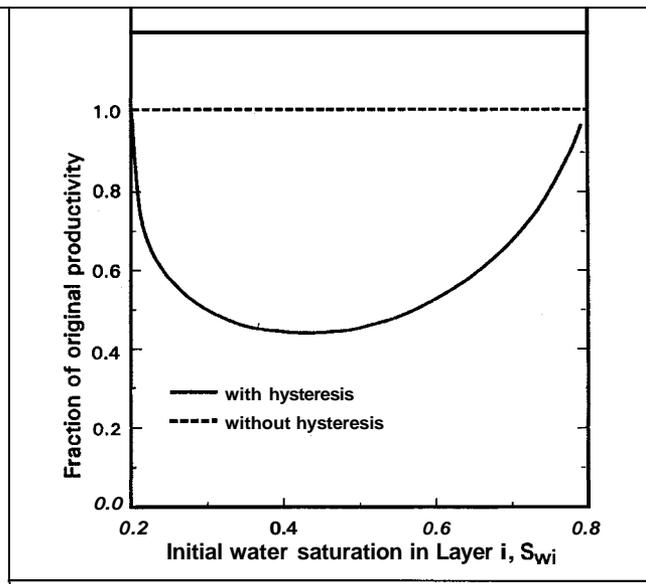Fig. 8—Oil and water relative permeability curves with/without hysteresis.

Fig. 9—Effect of hysteresis of relative permeability curves on productivity loss (depth of water penetration= 50 ft, radial flow).

For the case of constant pressure drop, the fractions of the original water and oil productivities after treatment in vertically fractured reservoirs are

$$\frac{q_{wi}}{q_{woi}} = \frac{(\Delta p_{Di}+1)L_{pm}}{\dfrac{k_{rwi}}{k_{rwti}}L_{pi}+(L_{pm}-L_{pi})+\Delta p_{Di}L_{pm}} \quad \ldots\ldots\ldots(12)$$

and

$$\frac{q_{oi}}{q_{ooi}} = \frac{(\Delta p_{Di}+1)L_{pm}}{\dfrac{k_{roi}}{k_{roti}}L_{pi}+(L_{pm}-L_{pi})+\Delta p_{Di}L_{pm}} \quad \ldots\ldots\ldots(13)$$

As for unfractured wells, the material balance dictates that the fraction of productivity loss of oil for a given zone after treatment is the same as that of water after treatment.

As **Fig. 11** shows, the productivity loss after treatment in a vertically fractured reservoir is relatively insensitive to invasion by the gelant (up to ≈ 10 ft). Fig. 11 also shows that the productivity loss increases with increasing water saturation. Comparison of Figs. 10a and 11 discloses that, under similar circumstances, the productivity loss after treatment is less in a vertically fractured reservoir than in an unfractured reservoir. Even by taking hysteresis into account, the decline in productivity (that results from the invasion of gelants) is far less dramatic in vertically fractured wells than in unfractured wells.[12] Therefore, without zone isolation, gel treatments are much more likely to be effective in fractured wells than in unfractured wells.

Effects of Crossflow

In the analysis presented to **this** point, no crossflow occurs between adjacent layers. If crossflow can occur between layers or flow paths in a reservoir, viscous gelants will penetrate into low-permeability layers to a greater extent than if crossflow is impossible.[25] In fact, under some circumstances (if the gelant/water mobility ratio is less than the permeability contrast between adjacent layers), the depth of gelant penetration in a low-permeability layer can be the same as that in an adjacent high-permeability layer.[26] Thus, if crossflow can occur, viscous gelants will damage oil-productive zones to a greater extent than if crossflow is impossible.[25] Even with zone isolation, a viscous gelant still can cross flow into the low-permeability oil-productive zones as soon as it leaves the wellbore, thereby significantly damaging oil productivity. Because zone isolation is ineffective when crossflow exists between layers, to minimize the damage to oil productivity, the gel must reduce water

permeability much more than oil permeability, and oil saturations in the oil-productive zones must be very high.

Effect of Capillary Pressure on Gel Placement

In the theoretical model, the effects of capillary pressure were neglected to obtain a closed-form solution to the water conservation equation. In a separate study, we examined the effect of capillary pressure on the gel placement process.[27] This study showed that, in coreflood experiments in oil-wet cores, capillary effects could inhibit an aqueous gelant from entering a core. In field applications, however, the pressure drop between injection and production wells usually is **so** large that capillary effects will not prevent gelant penetration into oil-productive zones. Under field-scale conditions, the effects of capillary pressure on gelant fractional flow are negligible. Hence, capillary pressure effects do not change the conclusions reached in this study.

Control of Water Coning

Field experience in the Arbuckle formation in western Kansas' demonstrates that gels can be very effective in treating production wells with water-coning problems.

Water coning is a rate-sensitive phenomenon. The rise of a water table under a partially penetrated oil well is caused by the motion of oil above it. Hence, the maximum cone height at a given oil production rate is dictated by the balance between the hydrostatic head of the elevated water column and the upward pressure gradients associated with the oil flow.

Based on the free-surface concept, Eq. 14[28] is used to solve for the maximum production rate at which a well can maintain water-free production:

$$q_o = \frac{\pi k_{ma} g(\rho_w - \rho_o)(h_e^2 - h_w^2)}{\mu_o \ln(r_e/r_w)} . \quad \ldots\ldots\ldots\ldots\ldots (14)$$

In 1934, Muskat and Wyckoff[29] first proposed that an extended shale streak at the well bottom can reduce water coning by preventing bottomwater from entering the well. Karp *et al.*[30] expanded this idea by proposing the placement of a horizontal barrier at the well bottom to suppress water coning. Specifically, they suggested inducing a horizontal fracture above the water/oil contact and then filling it with cement. The placement of horizontal barriers increases the effective wellbore radius.[30] According to Eq. 14, this would increase the critical rate for water-free production.

Gelant can be injected into a formation to serve as a horizontal barrier. Gelants will enter all open zones, not just the water cone; thus, oil productivity can be damaged significantly unless the gel
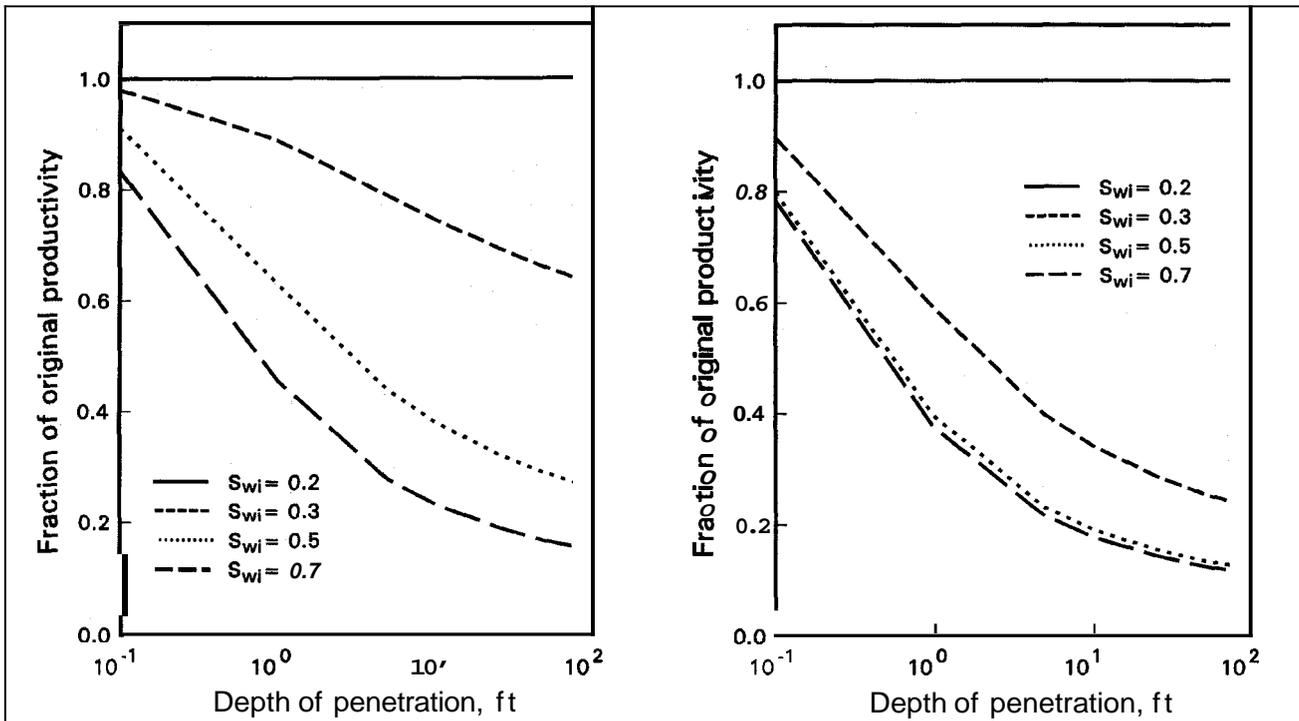
Fig. 10—(a) Effect of depth of penetration and S_{wi} on productivity retained after gel treatment (F_{rrw} = 10, F_{rro} = 1, no hysteresis, n_w = 2, n_o = 3, radial flow); **(b)** productivity retained after gel treatment with hysteresis of relative permeability curves (F_{rrw} = 10, F_{rro} = 1, n_w = 6, n_o = 3, radial flow).

can reduce water permeability without affecting oil permeability. If the gel does not significantly lower the permeability to oil, then oil can flow through the gel barrier in the upper portion of the oil zone. In contrast, when the rising water cone reaches the gel barrier, a low permeability to water impedes water influx into the well. The net effect is that the gel forms a horizontal barrier that inhibits water coning.

For economic reasons, the desired production rate often is greater than the critical rate. For a gel treatment to be effective, the critical rate must be increased to exceed the rate at which the well will actually be produced. How much can a gel treatment be expected to affect the critical rate? In a separate study,[31] we examined the effect of gel treatments on the critical rate in unfractured wells based on different theoretical coning models (including Muskat's[28] model). Following Karp et al.'s[30] logic, the study demonstrated that the models predicted a factor of 1.5 to 5 increase in critical rate after treatment. In other words, the desired production rate should be less than 1½ to **5** times the pretreatment rate for gel treatments to be effective in unfractured production wells.

For gel treatments in production wells in bottomwater-drive reservoirs, a recent survey of field cases revealed that more than 90% of the wells were fractured.[32] In these reservoirs, water from the underlying water zone migrates through a fracture system into oil-producing wells. Fracture permeability is much greater than the permeability of the adjacent formation rock. Thus, the behavior of fluid flow from the underlying water zone through a fracture into a production well can be approximated by a 2D linear-flow model rather than by a 3D radial-flow model. The critical rate for water-free production in a 2D linear system can be estimated with[33]

$$40 = \frac{k_f g b (\rho_w - \rho_o)(h_e^2 - h_w^2)}{2\mu_o(L_f - x_w)} \quad\quad\quad\quad .(15)$$

During treatment, gelants flow preferentially into the fracture because of the enormous permeability contrast between the fracture and the formation rock. By filling the fracture with a gel, we essentially convert the 2D linear flow geometry into a 3D radial flow geometry. Dividing the critical rate in **Eq.** 14 by that in **Eq.** 15 provides a means of comparing the severity of coning problems in fractured and unfractured wells.

For the typical set of parameters in the following example calculation, the critical production rate is about two orders of magnitude higher in an unfractured well than in a fractured well.

$$\frac{q_{o(3-D)}}{q_{o(2-D)}} = \frac{2\pi(L_f - x_w)k_{ma}}{b \ln(r_e/r_w)k_f} = \frac{2\pi(372 - 0.5)1}{0.01 \ln(372/0.5)1,000} \approx 400.$$
$$\cdots\cdots\cdots\cdots\cdots\cdots\cdots\cdots\cdots\cdots\cdots\cdots\cdots .(16)$$
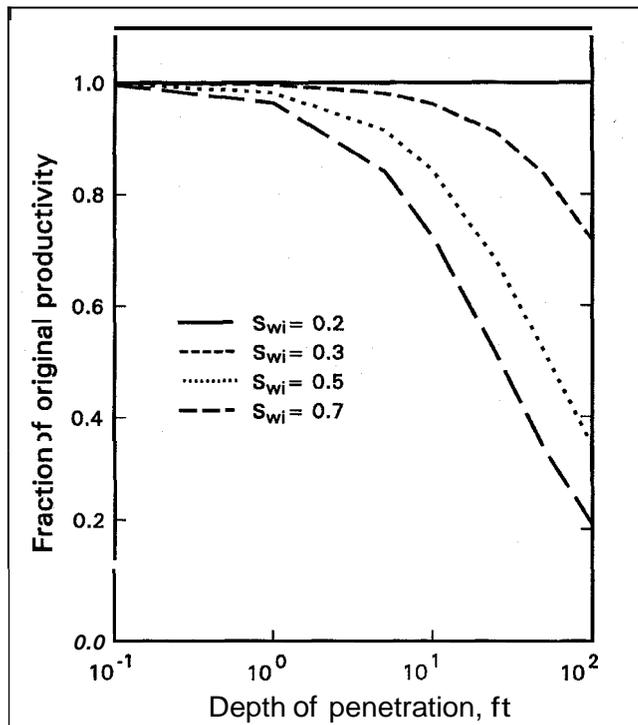

Fig. 11—Effect of degree of penetration and S_{wi} on productivity loss after gel treatment (F_{rrw} = 10, F_{rro} = 1) in vertically fractured zones.

In other words, if a gel treatment simply healed the fracture, it could increase the critical production rate by two orders of magnitude, much more than the factor of 1.5 to 5 increase in unfractured wells. This explains why some of the most successful gel applications have occurred in fractured wells produced by bottomwater drive.[32]

A small amount of gelant still penetrates into the rock matrix, forming a thin layer of gel around the wellbore. However, damage to oil productivity in the well can be minimized if gels reduce the relative permeability to water much more than they reduce permeability to oil.

In the examples presented here, we have assumed that gel will not affect the relative permeability to oil. If gel does reduce oil permeability, then some of our calculations will underestimate the loss of oil productivity. **Thus,** determination of permeability reductions for both oil and water is very important when planning field applications of gels in production wells. The equations and analyses in this paper are general and will accommodate permeability reductions to oil and water.

Conclusions

The following conclusions are based on extensive studies covering most known field and laboratory applications. Therefore, the conclusions are applicable to most field applications of gels in production wells.

1. If zones are not isolated during gel placement in production wells, gelants can penetrate significantly into all open zones, not just those with high water saturations.

2. In coreflood experiments in oil-wet cores, capillary effects could inhibit an aqueous gelant from entering the core. In field applications, however, the pressure drop between injection and production wells usually is *so* large that capillary effects will not prevent gelant penetration into oil-productive zones.[27]

3. For gels that reduce permeability to water more than to oil, induced changes in the relative permeability curves near the wellbore will not necessarily enhance oil recovery from a particular zone. Depending on the steady-state fractional flows of fluid outside the gel-treated region, oil production could be impaired even though the gel reduces water permeability without affecting oil permeability. The principal advantage of the disproportionate reduction of the water and oil relative permeabilities is the reduced need for zone isolation during gel placement. Realizing this advantage generally requires high fractional oil flow from oil-productive zones.

4. Under similar circumstances, the oil productivity loss after treatment in vertically fractured wells is expected to be less than that in unfractured wells.

5. We explain why some of the most successful gel applications have occurred in fractured wells produced by bottomwater drive. With the right properties, gels could significantly increase the critical rate for water influx in fractured wells.
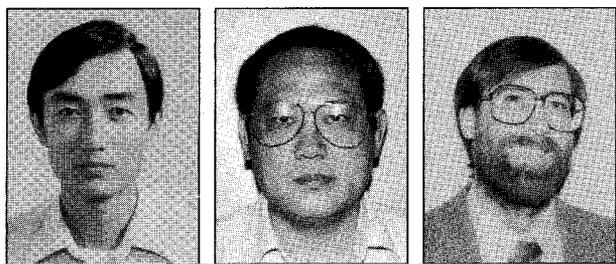
Nomenclature

b = fracture width, L, ft [m]
f_w = fractional flow of water
f_w^p = fractional flow of aqueous gelant
f_{wI} = fractional flow of water before gel treatment
F_r = resistance factor (brine mobility divided by gelant mobility)
F_{rrw} = residual resistance factor (brine mobility before gel placement divided by brine mobility after gel placement)
g = acceleration of gravity, L/t^2, m/s^2
h_e = thickness of oil zone, L, ft [m]
h_w = depth of well penetration, L, ft [m]
k = permeability, L^2, md
k_f = fracture permeability, L2, md
k_{ma} = matrix permeability, L^2, md
k_{ro} = oil relative permeability
k_{ro}^0 = endpoint oil relative permeability
k_{rot} = oil relative permeability in treated region

k_{rw} = water relative permeability
k_{rw}^0 = endpoint water relative permeability
k_{rwI} = water relative permeability before gel treatment
k_{rwt} = water relative permeability in treated region
L = system length, L, ft [m]
L_f = fracture length, L, ft [m]
L_p = depth of penetration of gelant front in linear flow system, L, ft [m]
L_{pk} = depth of penetration of oil bank in linear flow system, L, ft [m]
L_{pm} = reference distance from the wellbore or from a fracture face beyond which the gel treatment has no effect on fluid saturations, L, ft [m]
L_t = total core length, L, ft [m]
M = water/oil mobility ratio
n_o = exponent for oil relative permeability equation
$n,$ = exponent for water relative permeability equation
Ap = pressure drop, m/Lt^2, psi [Pa]
Δp_D = pressure drop between L_{pm} (or r_{pm}) and the injection well divided by the pressure drop between the production well and L_{pm} (or r_{pm}) just before gel injection
P_c = capillary pressure, m/Lt^2, psi [Pa]
q_o = oil production rate after gel treatment, L^3/t, B/D [m^3/s]
q_{oo} = oil production rate before gel treatment, L^3/t, B/D [m3/s]
q_w = water production rate after gel treatment, L^3/t, BID [m^3/s]
q_{wo} = water production rate before gel treatment, L^3/t, B/D [m^3/s]
r = radius of gelant penetration, L, ft [m]
r_D = dimensionless radius (square of the ratio of radius of penetration to drainage radius)
r_e = external drainage radius, L, ft [m]
r_p = radius of penetration of gelant front, L, ft [m]
r_{pD} = dimensionless radius of penetration of gelant front
r_{pk} = radius of penetration of oil bank, L, ft [m]
r_{pkD} = dimensionless radius of penetration of oil bank
r_{pm} = reference distance from the wellbore beyond which the gel treatment has no effect on fluid saturations, L, ft [m]
r_{pmD} = dimensionless reference distance from the wellbore beyond which the gel treatment has no effect on fluid saturations
r_w = wellbore radius, ft [m]
r_{wD} = dimensionless wellbore radius
S_o = oil saturation
S_{or} = residual oil saturation
S_w = water saturation
$\bar{S}_w$ = average water saturation behind gelant front
S_{wpf} = water saturation at gelant front
S_{wpk} = water saturation at oil bank
S_{wr} = residual water saturation
t = time, t, seconds
x = distance of gelant penetration in **2D** system, L, ft [m]
x_w = wellbore radius in Eqs. 15 and **16,** L, ft [m]
μ_o = oil viscosity, m/Lt, cp [mPa·s]
μ_w = water viscosity, m/Lt, cp [mPa·s]
ϕ = porosity
ρ_o = oil density, g/cm^3
ρ_w = water density, g/cm^3

Subscript
$1, i$ = layer

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Acknowledgments

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SI Metric Conversion Factors

acre × 4.046 873	E−01	= ha
ft × 3.048*	E−01	= m

*Conversion factor is exact. **SPEPF**