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GEL TREATMENTS IN PRODUCTION WELLS WITH WATER-CONING PROBLEMS

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ABSTRACT

This paper discusses some of the reservoir conditions, gel properties, and placement problems that influence how effectively gel treatments reduce water coning. For gel treatments in unfractured production wells, analysis using different theoretical coning models suggests that the desired production rate should be less than one and one-half to five times the pretreatment critical rate. Calculations also suggest that under ideal conditions, gel treatments in fractured wells could increase the critical rate by two orders of magnitude. For gels applied to reduce water coning, an essential property is an ability to reduce water permeability much more than oil permeability. Some studies directed at understanding this phenomenon are described.

INTRODUCTION

This paper discusses gel treatments in production wells with water-coning problems. Water coning is a common problem encountered when a reservoir is produced by bottomwater drive. The excess water production associated with this phenomenon can significantly shorten the economic producing life of a well. The hydrostatic pressure created by high fluid levels is also detrimental to oil production.

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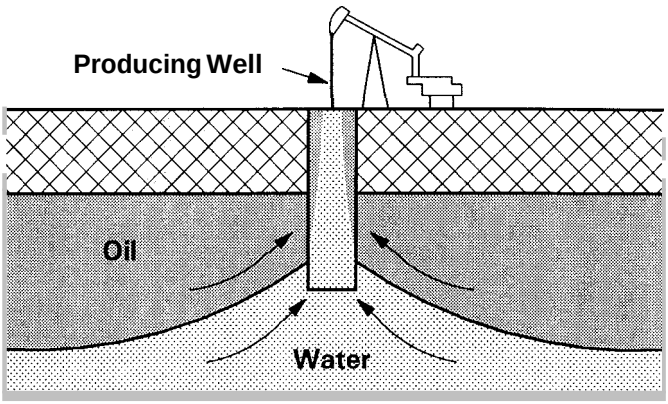
In 1934, Muskat and Wyckoff[1] first proposed that an extended shale streak at the bottom of a well can reduce water coning by preventing bottomwater from entering the well. Karp *et al.*[2] expanded this idea by proposing the placement of a horizontal barrier at the bottom of a well to reduce water coning. Specifically, they suggested inducing a horizontal fracture above the water-oil contact and then filling it with cement (see Fig. 1). A major limitation of Karp's idea is that horizontal fractures can be induced only at very shallow depths.[3] However, other methods are available for introducing a horizontal barrier. Here, we focus on the use of gels to form a horizontal barrier to reduce water coning. Using simple equations and ideas, we will consider some of the conditions, gel properties, and placement problems that influence how effectively gel treatments reduce water coning.

GEL PLACEMENT

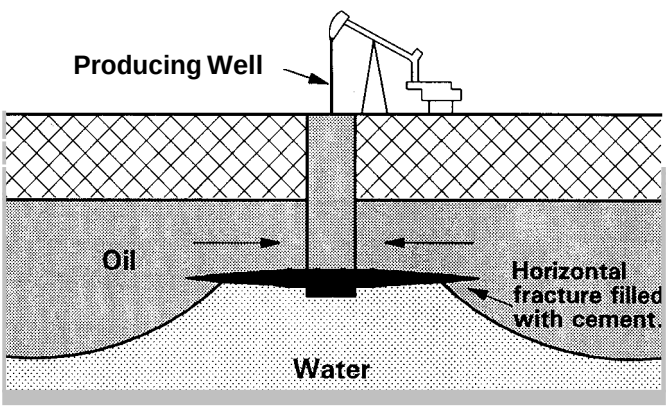
A common misconception is that aqueous gelants will not penetrate to any significant extent into zones with high oil saturations.[4] Thus, Fig. 2 illustrates a typical view of gel placement in a production well with a water-coning problem. In this view, the gelant enters only the water cone. However, this picture is correct only if the oil is extremely viscous and/or the aqueous gelant is injected at an extremely low rate (to exploit gravity during gelant placement). For the majority of field applications to date, the crude oils were not particularly viscous and gelant injection rates were relatively high (i.e., gelant injection rates were not greatly different from the fluid production rates before the gel treatment).*

Straightforward applications of the Darcy equation and fractional-flow theory demonstrate that gelants can penetrate to a significant degree into all open zones—not just those zones with high water saturations.[5] Also, in field applications, capillary effects will not prevent gelant penetration into oil-

*Based on interviews with gel vendors and service companies during 1992.



a. Before treatment.



b. After inducing a horizontal fracture and filling with cement.

FIG. 1. Reduction of water coning using idea from Karp et *al.*[2]

productive zones.[6] Thus, Fig. 3 is usually more representative of the gel placement process than Fig. 2. When the gel forms, oil productivity can be damaged significantly unless the gel has a special property—i.e., an ability to reduce water permeability much more than oil permeability. To understand why this property is desirable, consider Fig. 3. If the gel does not significantly lower

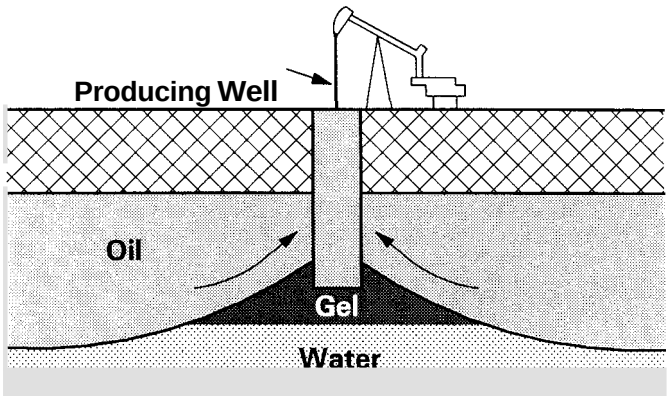


FIG. 2. Incorrect view of gel placement. (Gelant enters only zones with high water saturations.)

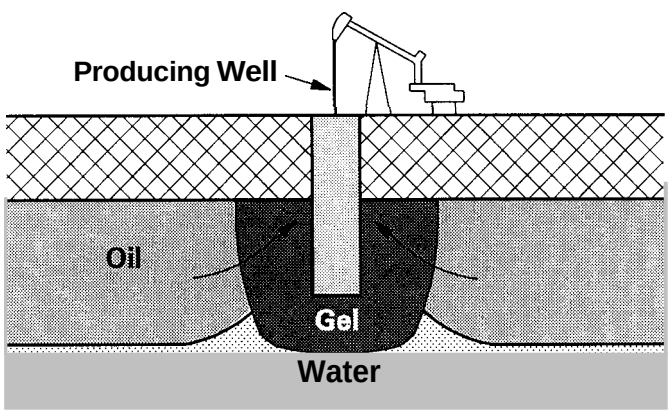
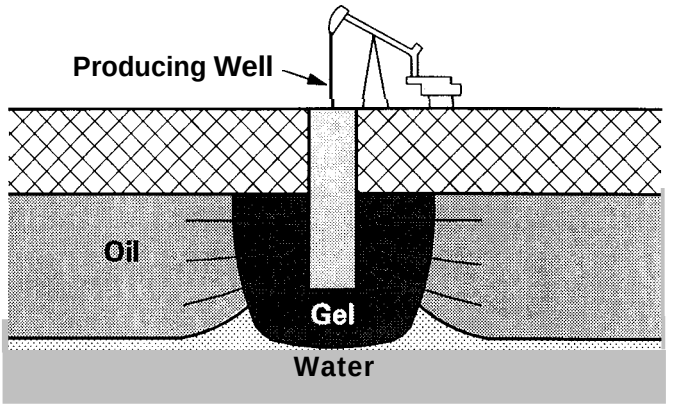
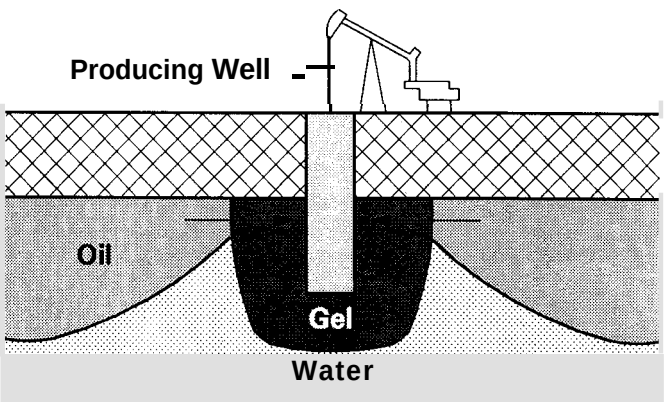


FIG. 3. Correct view of gel placement. (Gelant enters all open zones.)



a. Low cone height: oil flow is not restricted.



b. High cone height: water block restricts oil flow.

FIG. 4. Effect of water cone height outside of the gel-treated region.

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. This result does not necessarily mean that the gel will allow a higher oil production

rate. If the cone height outside of the gel-treated region is high, the high water saturation can significantly restrict the rate at which oil can flow to the well (see Fig. 4).

EFFECT OF GEL ON THE CRITICAL RATE IN UNFRACTURED WELLS

Over the years, a number of theoretical models have been developed to describe water coning.[7-18] Here, we examine several coning models to establish the effect of a horizontal barrier (e.g., a gel bank) on coning in unfractured wells. We note that different coning models can predict very different critical rates. (The critical rate is the maximum allowable production rate for water-free production.) However, the following discussion will demonstrate that, for most models, predictions are fairly similar for the effect of a horizontal barrier on the critical rate.

The following is a brief review of the theoretical coning models. Unless otherwise mentioned, all reservoirs are assumed to be homogeneous and isotropic. The fluids are assumed to be incompressible. All models presented in this study assume a steady-state flow condition.

Muskat Model

Muskat[7] proposed Eq. 1 to estimate the critical production rate for three-dimensional water coning.

$$q_c = \frac{\pi k_m g(\rho_w - \rho_o)(h_e^2 - h_w^2)}{\mu_o \ln(r_e/r_w)} \quad (1)$$

After placing a horizontal barrier near the wellbore, Karp et *al.*[2] proposed that the critical rate after treatment can be calculated by substituting the radius of

the horizontal barrier, r_b, for the wellbore radius, r_w, in ***Eq.*** 1. Thus, ***Eq.*** 2 is used to estimate the critical rate, q_{cb}, after placement of the horizontal barrier.

$$q_{cb} = \frac{\pi k_m g(\rho_w - \rho_o)(h_e^2 - h_w^2)}{\mu_o \ln(r_e/r_b)} \quad (2)$$

Since r_b and r_w **are** the only parameters that **are** different before versus after a treatment, ***Eq.*** **3** was used in our previous study[5] to estimate the effect of a gel treatment on the critical rate in an unfractured well. In the study, r_b was redefined as the horizontal radius of the gelant bank.

$$\frac{q_{cb}}{q_c} = \frac{\ln(r_e/r_w)}{\ln(r_e/r_b)} \quad (3)$$

Schols Model

Schols[8] derived an empirical formula ***(Eq.4)*** for critical rate estimation based on experimental results.

$$q_c = \left[\frac{(\rho_w - \rho_o)k_m(h_e^2 - h_w^2)}{2049\,\mu_o}\right]\left[0.432 + \frac{\pi}{\ln(r_e/r_w)}\right]\left(\frac{h_e}{r_e}\right)^{0.14} \quad (4)$$

Following Karp's logic, we can calculate the critical rate after a gel treatment by substituting r_b for r_w (Eq. 5).

$$q_{cb} = \left[\frac{(\rho_w - \rho_o)k_m(h_e^2 - h_w^2)}{2049\,\mu_o}\right]\left[0.432 + \frac{\pi}{\ln(r_e/r_b)}\right]\left(\frac{h_e}{r_e}\right)^{0.14} \quad (5)$$

We note that the only parameters that are different before versus after a gel treatment **are** r_b and r_w. Thus, the effect on the critical rate can be estimated using Eq. 6.

$$\frac{q_{cb}}{q_c} = \frac{0.432 + \dfrac{\pi}{\ln(r_e/r_b)}}{0.432 + \dfrac{\pi}{\ln(r_e/r_w)}} \tag{6}$$

Abass and Bass Model

Using a volume-averaged two-dimensional radial flow model, Abass and Bass' derived the following equation for critical rate calculation:

$$q_c = \frac{3.07 k_m h_w (\rho_w - \rho_o)(h_e - h_w)}{\mu_o\left[\dfrac{(h_e - h_w)^2}{(h_e - h_w)^2 - r_w^2} \ln[(h_e - h_w)/r_w] - 0.5\right]} \tag{7}$$

By substituting r_b for r_w in Eq. 7, Eq. 8 can be used to calculate the critical rate after a gel treatment.

$$q_{cb} = \frac{3.07 k_m h_w (\rho_w - \rho_o)(h_e - h_w)}{\mu_o\left[\dfrac{(h_e - h_w)^2}{(h_e - h_w)^2 - r_b^2} \ln[(h_e - h_w)/r_b] - 0.5\right]} \tag{8}$$

The effect of a gel treatment on the critical rate can be estimated by Eq. 9.

$$\frac{q_{cb}}{q_c} = \frac{\dfrac{(h_e - h_w)^2}{(h_e - h_w)^2 - r_w^2} \ln[(h_e - h_w)/r_w] - 0.5}{\dfrac{(h_e - h_w)^2}{(h_e - h_w)^2 - r_b^2} \ln[(h_e - h_w)/r_b] - 0.5} \tag{9}$$

Meyer and Garder Model

Meyer and Garder[10] derived the following equation to estimate the effect of an impermeable barrier on the critical production rate:

$$\frac{q_{cb}}{q_c} = \frac{1}{1-\frac{\ln(r_b/r_w)}{}} \cdot \tag{10}$$

By redefining r_b as the horizontal radius of the gelant bank, Eq. 10 can be used to estimate the effect of a gel treatment on the critical rate.

Chappelear and Hirasaki Model

Chappelear and Hirasaki[11] derived Eq. 11 for critical rate calculations. In their derivation, they assumed vertical equilibrium and segregated flow. A correction factor, r', was incorporated in their model to account for the departure from vertical equilibrium in the immediate vicinity of the well.

$$q_c = \frac{2\pi h_t k_m \overline{k_{ro}} (\rho_w - \rho_o) g (h_e - h_w)}{887.2\,\mu_o \left(\frac{\ln[r_e/(r_w + r')]}{[1-(r_w + r')^2/r_e^2]} - 0.5\right)} \tag{11}$$

By substituting r_b for r_w in Eq. 11, the critical rate after a gel treatment can be estimated by the following equation:

$$q_{cb} = \frac{2\pi h_t k_m \overline{k_{ro}} (\rho_w - \rho_o) g (h_e - h_w)}{887.2\,\mu_o \left(\frac{\ln[r_e/(r_b + r')]}{[1-(r_b + r')^2/r_e^2]} - 0.5\right)} \tag{12}$$

Thus, the effect of a gel treatment on critical rate can be estimated by Eq. 13.

$$\frac{q_{cb}}{q_c} = \frac{\frac{\ln[r_e/(r_w + r')]}{[1-(r_w + r')^2/r_e^2]} - 0.5}{\frac{\ln[r_e/(r_b + r')]}{[1-(r_b + r')^2/r_e^2]} - 0.5} \tag{13}$$

Other Models

Since the wellbore radius is generally very small and does not change much from one well to another, its effect on the critical rate is often considered negligible. Therefore, in several other coning models, the wellbore radius was not included.[12-18] Without the wellbore radius in the equations, we can not evaluate the effect of gelant penetration on the critical rate. Thus, in this study, we used only those models[17] where the wellbore radius was included in the derivations.

Comparison of Model Predictions

How much can a gel treatment be expected to affect the critical rate? The critical rate for water coning indicates the maximum production rate at which water from an underlying aquifer does not reach the wellbore. For economic reasons, the *desired* production rate is often greater than the critical rate. In order 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.

Fig. 5 illustrates the effect of gel treatments on the critical production rate, based on the coning models presented in the previous sections. In this figure, the critical rate increase is defined as the critical rate after treatment divided by the critical rate before treatment. The ratio is plotted against the radius of gelant penetration into the formation. Eqs. 3, 6, 9, 10, and 13 were used to generate the results shown in Fig. 5. The well has a drainage radius, r_e, of 372 ft (10-acre well spacing). The wellbore radius, r_w, is 0.33 ft, the oil zone thickness, h_e, is 100 ft, and the depth of well penetration into the oil zone, h_p, is 25 ft.

As shown in Fig. 5, the critical rate increase predicted by Abass model[9] is much more sensitive to the radius of gelant penetration than that predicted by other models. In their derivations, they assumed that the thickness of the oil zone dominated by radial flow was the same as the gross perforated interval and that

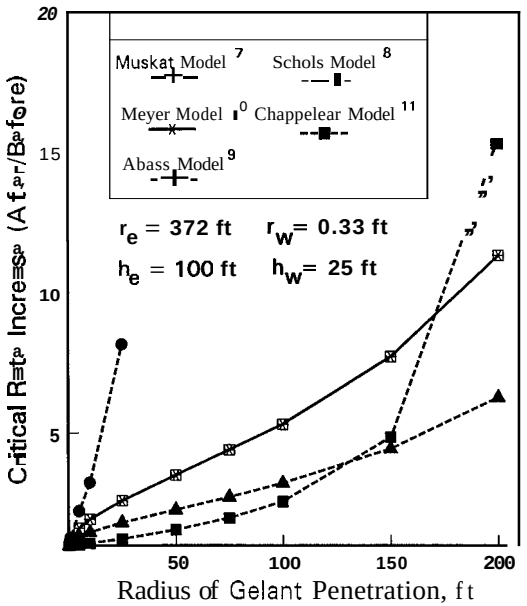


FIG. 5. Effect of gel treatments on critical rate in unfractured production wells.

only the oil flow in the radial-flow region contributed to the upward movement of the cone. A volume-averaged two-dimensional radial flow model was used to calculate the pressure drawdown between the wellbore and the radial-flow region extending from the wellbore to the radius of the cone. Since this model is actually two-dimensional in nature, it is not surprising that the critical rate increase predicted by this model is much more sensitive to the radius of gelant penetration than that predicted by other three-dimensional models. Also, Fig. 6 shows that this model predicts unrealistic values when the radius of gelant penetration exceeds 45 ft.

Fig. 5 shows that, for gel treatments with a radius of gelant penetration less than 200 ft, the theoretical models predict that the critical rate after treatment should not be expected to increase by more than a factor of 5 to 15. For typical gel treatments with the radius of gelant penetration ranging from 20 to 100 ft,

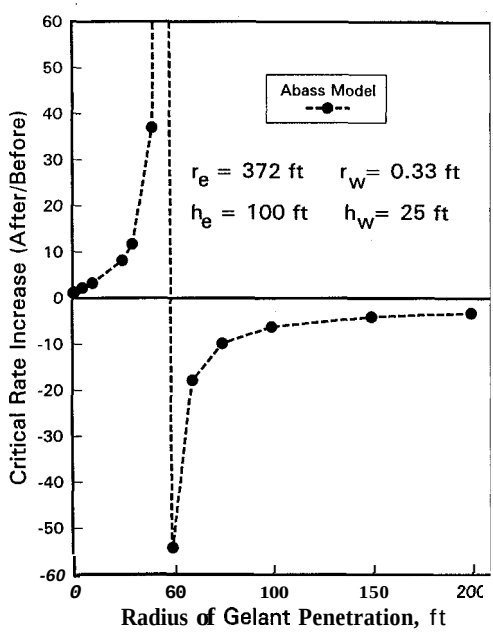


FIG. 6. Effect of gel treatments on critical rate (Abass Model).

Fig. 5 shows that the models (excluding the Abass model) predict a factor of 1.5 to 5 increase in critical rate after treatment. In other words, the desired production rate should be less than one and one-half to five times the pretreatment rate in order for gel treatments to be effective in unfractured wells.

EFFECT OF GEL ON THE CRITICAL RATE IN FRACTURED WELLS

For gel treatments in bottomwater drive reservoirs, a recent survey revealed that more than 90 percent of the applications occurred in production wells that were known to be fractured.[19] Thus, "coning" in fractured systems may be of greater interest than in unfractured systems. Muskat[20] presented Eq. 14 to estimate the critical rate in a two-dimensional geometry (e.g., a vertical fracture).

$$q_{cf} = \frac{k_f g W(\rho_w - \rho_o)(h_e^2 - h_w^2)}{2\mu_o(L - r_w)} \quad (14)$$

Eqs. 1 and **14** can be used to compare the critical rates in fractured versus unfractured wells.' Dividing **Eq.** 1 by **Eq. 14** yields **Eq. 15.**

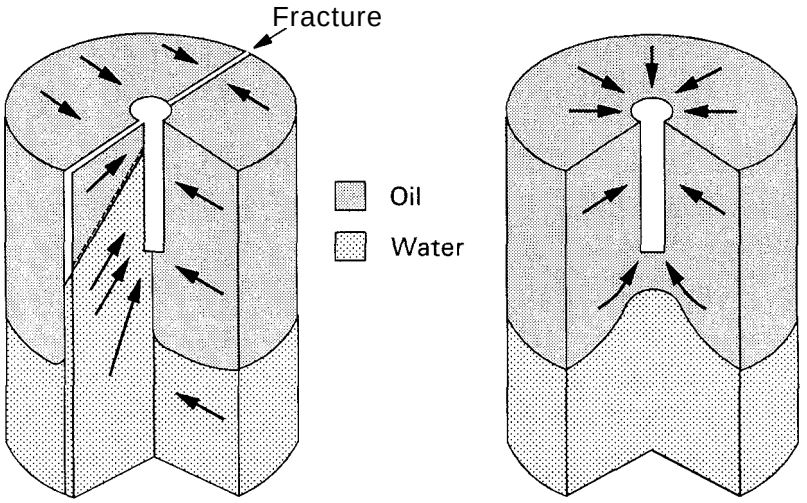
$$\frac{q_c}{q_{cf}} = \frac{2\pi(L - r_w)k_m}{W \ln(r_e/r_w)k_f} \quad (15)$$

If $L = 100$ ft, $r_w = 0.33$ ft, $k_f / k_m = 1{,}000$, $\ln(r_e / r_w) = 6$, and $W = 0.001$ ft, then $q_c / q_{cf} \approx 100$. Thus, for a typical set of parameters, the critical rate in a three-dimensional system (i.e., an unfractured well) can be two orders of magnitude greater than that in a two-dimensional system (i.e., a fractured well). In other words, if a gel treatment simply healed the fracture (see Fig. 7), it could increase the critical rate by a factor of **100.**

A number of factors could prevent a gel treatment from completely healing a fracture. If a gel treatment cannot completely heal the fracture, how will the critical rate be affected by partial gelant penetration in the fracture? The logic that Karp et *al.*[2] used for the three-dimensional coning problem should also be applicable to the two-dimensional problem. In particular, the effect of placing an impermeable material (e.g., gel) in the fracture should be to increase r_w in **Eq. 14.** If x_b is the distance of gelant penetration in a fracture of length L, then the critical rate after gelation can be estimated using Eq. **16.**

$$q_{cf} = \frac{k_f g W(\rho_w - \rho_o)(h_e^2 - h_w^2)}{2\mu_o(L - x_b)} \quad (16)$$

This equation predicts that the critical rate should vary inversely with $L - x_b$. Of course, the equation becomes invalid as x_b approaches L, since an infinite critical rate is predicted. In reality, the critical rate should approach that for an unfractured well as x_b approaches L.



a. Before gel

b. After gel: healed fracture

FIG. 7. Reduced coning by healing a fracture.

Although healing a fracture could dramatically increase the critical rate, it could also significantly reduce the well's productivity. The productivity loss associated with complete healing of the fracture may not be acceptable, especially in tight formations. *An* alternative objective could be to place the gel some distance into the rock matrix along the fracture face, while leaving the fracture open to flow. This course of action relies, again, on an ability of the gel to reduce water permeability much more than oil permeability. Ideally, this property, in concert with gravity, would prevent water **in** the aquifer from entering the fracture. In contrast, oil could still enter the fracture and flow to the production well (see Fig. **8). A** third objective could be to place the gel only in the lower part **of** the fracture, as indicated in Fig. 9. Of course, one must exploit gravity during the gelant placement process for this scheme. If this placement can be achieved, then water production could be reduced substantially while maintaining high oil productivity.

TABLE 1

Effects of Multiple Water-Oil Injection Cycles and Flow-Direction Reversal on Endpoint Permeabilities.
Berea Sandstone Cores, Soltrol 130® Oil. 41°C.

Fluid injected	Flow direction	Core SSH-17		Core SSH-22		Core SSH-26	
		k_w, md	k_o, md	k_w, md	k_o, md	k_w, md	k_o, md
Brine (no S_{or})	Original	795		809		742	
Oil	Original		719		674		582
Brine	Original	186		187		184	
Oil	Original		708		736		604
Brine	Original	177		184		169	
Oil	Reversed		730		782		611
Brine	Reversed	173		215		172	
Oil	Reversed		700		801		579
Brine	Reversed	165		196		168	

reversed. Of course, these experiments were performed before a gelant was injected into the core.

Table 1 summarizes some of our results. The endpoint permeabilities were reproducible during replicate cycles. Also, no significant hysteresis of endpoint permeabilities (either for water or oil) was observed as a result of the flow-direction reversal. The studies described here were performed using strongly water-wet cores. Additional experiments using cores of intermediate wettability are described in Ref. 23. The main value of these studies is that they quantify the importance of hysteresis in our fluid/rock systems before introduction of gel. Gel effects can now be distinguished from hysteresis effects during our subsequent gel studies, especially for those parameters that were unaffected by flow-reversal and multiple imbibition and drainage cycles.

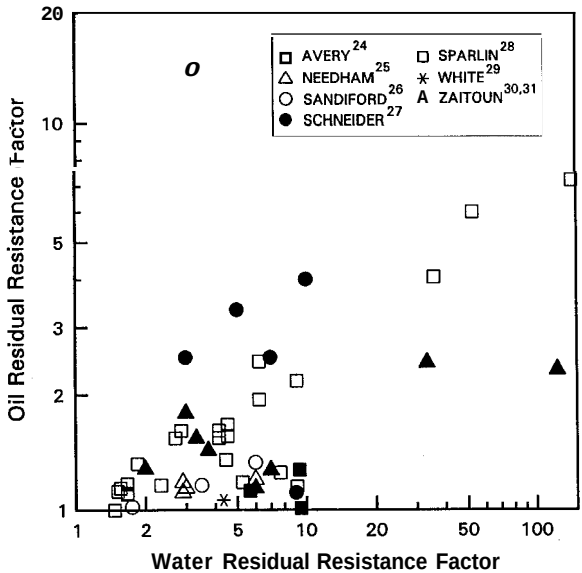


FIG. 10. Disproportionate permeability reduction by polymers and gels (literature data).

Permeability Reduction Using Gels

Several researchers[24-31] reported that some polymers and gels can reduce permeability to water more than to oil. Fig. 10 summarizes results that were reported by previous researchers. In this figure, the water residual resistance factors are plotted against the oil residual resistance factors. A given residual resistance factor or permeability-reduction value was determined by dividing the endpoint permeability (or mobility) before exposure to polymer or gel by the endpoint permeability (or mobility) after exposure to polymer or gel. Using this definition, two factors contributed to the permeability reductions: (1) changes in permeability at a given fluid saturation and (2) changes in endpoint fluid saturations. The available evidence indicates that polymers or gels usually shifted the entire water relative permeability curve to lower values without significantly changing the residual oil saturation. In contrast, the position of the oil relative

TABLE 2

Gelant Compositions for Oil/Water Corefloods.

Gelant Composition	pH
3% resorcinol, 3% formaldehyde, 0.5% KCl, 0.42% $NaHCO_3$	6.5
0.4% xanthan, 154-ppm Cr^{3+} (as $CrCl_3$), 0.5% KCl	4.0
1.39% polyacrylamide (HPAM), 636-ppm Cr^{3+} (as acetate), 1% NaCl	6.0
1.39% polyacrylamide (HPAM), 212-ppm Cr^{3+} (as acetate), 1% NaCl	6.0
0.7% polyacrylamide (HPAM), 318-ppm Cr^{3+} (as acetate), 1% NaCl	6.0
10% colloidal silica, 0.7% NaCl	8.2
0.4% cationic polyacrylamide (CPAM), 1520-ppm glyoxal, 2% KCl	7.3
0.3% HPAM-AMPS, 100-ppm Cr^{3+} (as acetate), 2% KCl	5.0

permeability curve was often unaffected by the polymer or gel, except that the irreducible water saturation was increased. Thus, the increase in the irreducible water saturation was largely responsible for permeability reductions for oil.

We are examining how different types of gels reduce oil and water permeabilities in Berea sandstone. The gel formulations that we have investigated include (1) resorcinol-formaldehyde, (2) Cr^{3+}(chloride)-xanthan (Pfizer Flocon 48W xanthan), (3) Cr^{3+}(acetate)-polyacrylamide (Marathon MARCIP), (4) colloidal silica (DuPont Ludox SM®), (5) a cationic polyacrylamide (CPAM) crosslinked with glyoxal (Pfizer Floperm 500®), and (6) an acrylamide-AMPS copolymer (Drilling Specialties HE-100®) crosslinked with Cr^{3+}(acetate). Compositions of the gelants are listed in Table 2. Some of our results are summarized in Fig. 11. We observed that several gels clearly reduced water permeability significantly more than oil permeability. Whereas previous literature reported this phenomenon for polymers and "weak" polymer-based gels, we also observed the disproportionate permeability reduction with a monomer-based gel (resorcinol-formaldehyde), as well as with "weak" Cr^{3+}(chloride)-xanthan and glyoxal-CPAM gels and relatively "strong" Cr^{3+}(acetate)-HPAM gels. In

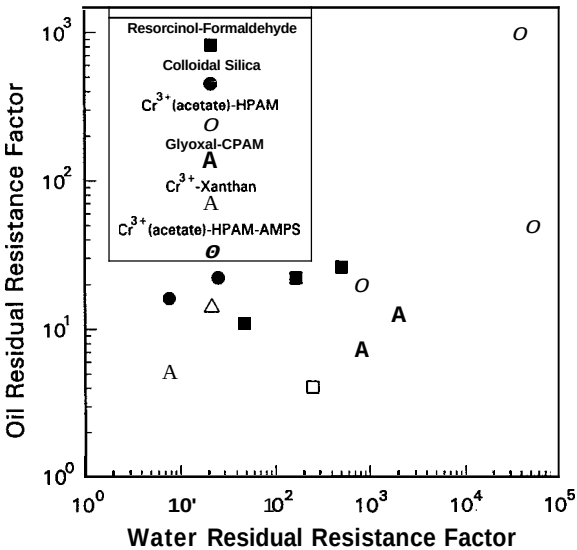


FIG. 11. Disproportionate permeability reduction by gels (NM **PRRC** data).

contrast, a colloidal-silica gel reduced water and oil permeabilities by about the same factor.'' All of these experiments were performed at 41°C using 700-md (nominally) Berea sandstone cores.

Note that some of the permeability-reduction values (residual resistance factors) in Fig. 11 are very high—as high as 1,000 for oil and 53,000 for water. One might argue that gels that provide these large values **are** impractical for use in field applications. If the gelant penetrates many feet into an oil-productive zone, then a gel with an oil-permeability reduction of 100 will create essentially the same result as that for a gel that provides a value of 1,000,000; both gels will effectively stop all **flow.** However, this logic is not necessarily valid in fractured wells. In a fractured well, an important factor is the product of the permeability reduction and the distance of gelant leakoff from the fracture face. A gel that extends 0.01 ft from the fracture face and has a residual resistance factor of

10,000 will provide the same flow restriction as a gel that extends 20 ft from the fracture face and has a residual resistance factor of 5.

To further illustrate the importance of the above concept, consider a "strong" gel that provides residual resistance factors of 1,000 for oil and 53,000 for water. If the gel penetrates 10 ft from the fracture face into both the oil and water zones, then no significant flow can be expected through the gel barrier in either zone. However, if the gel penetrates only 0.01 ft into both the oil and water zones, then a beneficial result could be obtained. In the oil zone, the thin gel barrier would provide an additional resistance to oil flow that was equivalent to only 10 ft of additional rock (0.01 x 1,000). In contrast, in the water zone, the gel barrier would provide an additional resistance to water flow that was equivalent to 530 ft of additional rock (0.01 x 53,000). Thus, both the permeability reduction and the distance of gelant penetration are important in determining the performance of a gel treatment.

Gel Behavior During Multiple Cycles of Water and Oil Injection

For the experiments reported in Fig. 11, the residual resistance factors for water were determined before those for oil. In other words, after gelation, water was injected first; then oil was injected. To test whether the process of switching from water to oil injection affected gel performance, multiple cycles of water and oil were injected after gelation. Fig. 12 shows the results of two core experiments that were performed using a gel that contained 1.39% polyacrylamide (HPAM) and 212-ppm Cr^{3+} (as acetate). In one set of experiments (represented by the circles in Fig. 12), water was the first fluid injected after gelation, while in the other set (represented by the squares), oil was injected first after gelation. Fig. 12 shows residual resistance factors for successive cycles of water and oil injection after gelation. The solid symbols show values during water injection, and the open symbols show values during oil injection.

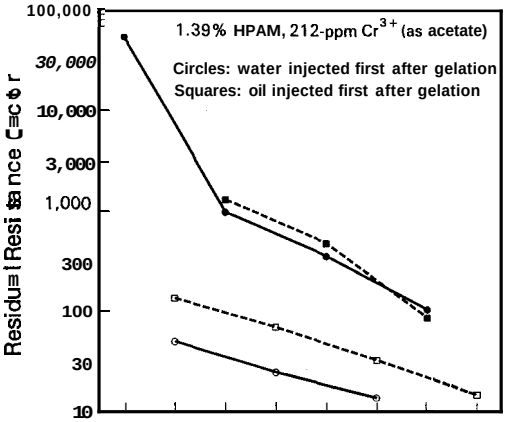


FIG. 12. Effect of multiple water-oil injection cycles on gel performance in Berea sandstone.

Note for the case where water was injected first after gelation (the first solid circle in Fig. 12), the residual resistance factor was extremely high—53,000. During the subsequent injection of oil, the residual resistance factor was only 50. When water was injected after the oil, the residual resistance factor was 970. Thus, the oil residual resistance factor was substantially less than the water residual resistance factors that were determined immediately before and immediately after oil injection.

Fig. 12 shows that with each successive cycle of water and oil injection, the residual resistance factors decreased for both water and oil. The reduction was particularly large for the water residual resistance factor during the first cycle (i.e., a drop from 53,000 to 970). This erosion suggests that the gel physically breaks down during the water-oil injection cycles. In spite of this erosion during the various cycles, residual resistance factors for oil were consistently much less than those for water.

For the core experiment where oil was injected first after gelation, the first oil residual resistance factor was 135. This value is more than twice the

corresponding value from the experiment where water was injected first after gelation (see Fig. 12). For the subsequent cycles of oil injection, the oil residual resistance factors from the second experiment (the open squares) were consistently between two and three times greater than the corresponding values from the first experiment (the open circles). In contrast, for a given cycle, the water residual resistance factors were fairly similar for the two experiments.

The main value of these experiments is in demonstrating that the disproportionate oil/water permeability reduction is real and not an experimental artifact that depends on which fluid was injected first after gelation. Results from similar experiments with other gels can be found in Refs. 6 and 23.

Two data points in Fig. 12 would be relevant to a field application—the first solid circle and the first open square. For this gel, 53,000 is the residual resistance factor experienced in zones with high water saturations. In contrast, 135 is the residual resistance factor experienced in zones with high oil saturations. Therefore, in the gel-contacted portions of the rock, the permeability reduction for water would be about 400 times greater than that for oil. This large difference would be very desirable for applications in production wells. However, since the permeability reduction for oil is fairly large (135), the gel would be most useful in fractured wells where the gelant leaks off only a short distance into the rock matrix.

Tracer Studies

We routinely performed tracer experiments to determine core dispersivities and the fraction of the pore volume that was occupied by water, oil, and gel at various points during our core experiments. Water-tracer studies were performed after the core was first saturated with brine and after each wateflood. These studies involved injecting a brine bank that contained 40-ppm potassium iodide as a tracer. The tracer concentration in the effluent was monitored spectrophotometrically at a wavelength of 230 nm. Also, oil-tracer studies were

TABLE 3

Pore Volume Determinations from Water-Tracer Studies.
Berea Sandstone Core, 41°C, Oil Phase: Soltrol-130®,
Gelant: Cr^{3+} (acetate)-HPAM; 1.39% HPAM, 212-ppm Cr^{3+}.

Water-Tracer Results	V_p/V_{po}	S_{or}	S_{gel}	F_{rrw}
After 1st waterflood	0.72	0.29	--	1
1st waterflood after gel treatment	--	0.29	--	53,000
2nd waterflood after gel treatment	--	0.34	--	$972\ u^{-0.50}$
3rd waterflood after gel treatment	0.15	0.33	0.52	$357\ u^{-0.49}$
4th waterflood after gel treatment	0.16	0.33	0.51	$105\ u^{-0.55}$

u: superficial velocity, ft/d

performed after each oilflood. These studies involved injecting an oil bank that contained 20-ppm trans-stilbene as a tracer. The tracer concentration in the effluent was monitored spectrophotometrically at a wavelength of 300 nm. Usually, four replicates were performed for each tracer study. Also, the replicates included studies performed at different injection rates. Additional details of these studies can be found in Ref. 23.

For the Cr^{3+}(acetate)-HPAM gel with 1.39% HPAM and 212-ppm Cr^{3+}, the pore volume determinations from the water- and oil-tracer studies are summarized in Tables 3 and 4, respectively. Extremely high residual resistance factors for water precluded water-tracer studies during the first water-oil injection cycle. However, water- and oil-tracer studies were performed throughout the remainder of the study. The ratio V_p/V_{po} represents the fraction of the original pore volume that was sampled by the tracer during a given tracer study. The difference $1-V_p/V_{po}$ represents the fraction of the original pore volume that was occupied by the immobile phase and/or gel. Material balance calculations (Table 3) show an increase in residual oil saturation during the first oil-water injection cycle after

TABLE 4

Pore Volume Determinations from Oil-Tracer Studies.
Berea Sandstone Core, 41°C, Oil Phase: Soltrol-130®,
Gelant: Cr^{3+} (acetate)-HPAM: 1.39% **HPAM**. 212-ppm Cr^{3+}

Oil-Tracer Results	V_p/V_{po}	S_{wr}	S_o(trap)	F_{rro}
After 1st oilflood	0.72	0.29	--	1
1st oilflood after gel treatment	0.12	0.59'	0.29	50
2nd oilflood after gel treatment	0.14	0.57*	0.29	25
3rd oilflood after gel'treatment	0.20	0.55'	0.25	14

*$S_{wr} + S_{gel}$

gelation (from 29% to 34%). The water-tracer studies and the material balance calculations (last row of Table 3) indicate that gel occupied 51% of the original pore volume after three oil-water injection cycles ($1-V_p/V_{po}-S_{or}$ or 1-0.16-0.33).

The last row in Table 4 shows that the oil tracer sampled only 20% of the original pore volume. However, material balance calculations indicate that gel plus trapped water occupied about ***55***% of the original pore volume. This means that about 25% of the original pore volume was occupied by immobile oil. This value is near the residual oil saturation before gel treatment (Table 3). Apparently, the gel encapsulated the original residual oil saturation—rendering it immobile during subsequent oil floods.

Comparing the last V_p/V_{po} entries in Tables 3 and 4 suggests that between 16% and 20% of the pore space was open to flow for both oil and water. This result is interesting since the residual resistance factor for water was about eight times greater than that for oil at this point in the experiment. We have performed similar experiments with this gel and with other gels. Although we do not yet have a clear understanding of why some polymers and gels can reduce water permeability more than oil permeability, we have introduced some new tools and

clues in this quest. We are continuing our efforts to understand the reason why the disproportionate permeability reduction occurs and to identify conditions that maximize this phenomenon.

CONCLUSIONS

This paper discusses some of the reservoir conditions, gel properties, and placement problems that influence how effectively gel treatments reduce water coning. Analysis using different theoretical coning models suggests that in order for a gel treatment to be effective in unfractured production wells, the desired production rate should be less than one and one-half to five times the pretreatment critical rate. These calculations also suggest that under ideal conditions, gel treatments in fractured wells could increase the critical rate by two orders of magnitude. For gels applied to reduce water coning, an essential property is an ability to reduce water permeability much more than oil permeability.

Several methods were applied to obtain a better understanding of why gels can reduce water permeability more than oil permeability. First, before gel placement in cores, multiple imbibition and drainage cycles were performed in both flow directions. Results from these studies established that hysteresis of oil and water relative permeabilities was not responsible for the behavior observed during our subsequent gel studies. Second, several gels clearly reduced water permeability significantly more than oil permeability. Whereas previous literature reported this phenomenon for polymers and "weak" polymer-based gels, we also observed the disproportionate permeability reduction with a monomer-based gel (resorcinol-formaldehyde) as well as with "weak" Cr^{3+}(chloride)-xanthan and glyoxal-CPAM gels and relatively "strong" Cr^{3+}(acetate)-HPAM gels. In contrast, a colloidal-silica gel reduced water and oil permeabilities by about the same factor. Residual resistance factors for several gels were found to erode during multiple cycles of oil and water injection. In spite of this erosion, the disproportionate permeability reduction persisted through the cycles for most of

the gels. Studies using both oil and water tracers provided insight into the fraction of the pore volume occupied by gel. The strongest gels appeared to encapsulate the original residual oil saturation—thus rendering the residual oil inaccessible during subsequent oil flooding.

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NOMENCLATURE

g = acceleration of gravity, ft/s^2 [m/s^2]

h_e = thickness of oil zone, ft [m]

h_t = total zone thickness, ft [m]

h_w = depth of well penetration in the oil zone, ft [m]

k_f = effective fracture permeability, md [μm^2]

k_m = matrix permeability, md [μm^2]

$\overline{k_{ro}}$ = depth-averaged oil relative permeability

L = fracturelength, ft [m]

q_c = critical rate, B/D [m^3/s]

q_{cf} = critical rate for a fracture system, B/D [m^3/s]

r_e = external drainage radius, ft [m]

r_w = wellbore radius, ft [m]

r' = $4h_e(\left|\frac{h_e - h_w}{h_e}\right| \frac{h_e}{h_e + h_w})^{\frac{4}{2h_w}}$, ft [m]

W = fracture width, ft [m]

Greek Symbols

μ_o = oil viscosity, cp [mPa-s]

ρ_o = density of oil, g/cm^3

ρ_w = density of water, g/cm^3

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