Sizing Gelant Treatments in Hydraulically Fractured Production Wells

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Summary

Often, when production wells are stimulated by hydraulic fracturing, the fracture unintentionally breaks into water zones causing substantially increased water production. To correct this problem, we developed an engineering basis for designing and sizing gelant treatments in hydraulically fractured production wells. In these treatments, gelant penetrates a short distance from the fracture face into the porous rock associated with both water and hydrocarbon zones. Success for a given treatment requires that the gel reduce permeability to water much more than that to hydrocarbon. We present a simple 11-step procedure for sizing these gelant treatments. This procedure was incorporated in user-friendly graphical-user-interface software that can be downloaded from our web site at http://baervan.nmt.edu/ResSweepEffic/reservoir.htm.

Introduction

A large number of gel treatments have been applied in production wells with the objective of reducing water production without sacrificing hydrocarbon production.[1] The most successful treatments occurred when the excess water production was caused either by flow behind pipe or by channeling or coning through fractures.[1-3] For gel treatments in fractured production wells, the design of the gelant volumes has been strictly empirical. A survey of field activity revealed that the vast majority of gel treatments were very small—less than 1,000 bbl/well.[1] The sizing of gelant treatments varies somewhat from vendor to vendor. For some vendors, the gelant volume is initially planned as ½ to 1 day's production volume. Other vendors plan for a certain number of barrels of gelant per foot of net pay. Still others plan to inject gelant to reach a certain radius from the wellbore. The latter plan seems ironic because most treated wells are thought to be fractured with the flow geometry better described as linear rather than radial.[1] The empirical nature of these methods may be partly responsible for the erratic success rates for gel treatments.

Substantial improvements are needed in the design methods for sizing gel treatments. We suspect that the most effective design procedures will vary with the type of problem being treated. In particular, different design procedures should be used for flow-behind-pipe problems, unfractured wells in which crossflow cannot occur, unfractured wells in which crossflow can occur, hydraulically fractured wells, and naturally fractured reservoirs. In this paper, we develop a method to size gelant treatments in hydraulically fractured production wells.

Fig. 1 illustrates the basic idea behind the gelant treatments that we propose. We assume that the fracture in a production well cuts through at least one hydrocarbon zone and at least one water zone. The well may be vertical, deviated, or horizontal, but we use a vertical well for illustrative purposes. Multiple hydrocarbon and water zones are permissible. From a rigorous viewpoint, our method assumes that impermeable barriers (e.g., shale or calcite) separate adjacent zones. However, the method frequently should provide acceptable predictions even if crossflow can occur. One important assumption is that the fracture has only two vertical wings. We do not advocate use of our method for treating naturally fractured wells in which multiple fractures of different orientation intersect the wellbore (especially not when fracture intensity is high).

During gel placement, our method assumes that the gelant flows freely along the length of the fracture and that the gelant leaks off from the fracture face into the porous rock. Of course, the distance of gelant leakoff (or penetration into the porous rock) varies with the permeabilities of the strata that are cut by the fracture. In a given stratum, gelant is assumed to leak off evenly along the length of the fracture. We show that this assumption is generally valid if the pretreatment productivity for the well is at least five times greater than the productivity calculated by use of the Darcy equation for radial flow.

Note that we define gelant as the fluid solution that can flow through porous rock before the gelation reactions become important. In contrast, a gel is the product from the gelation reactions that will no longer flow through porous rock at any significant rate.[4] We note that some gelants contain high-molecular-weight polymers that may not penetrate significantly into low-permeability porous rock (e.g., with permeabilities less than 20 md).[4-6] This work may not be relevant to those gelant formulations.

After the gelant is placed and the gel forms, the performance of the gel treatment depends critically on the ability of the gel to reduce permeability to water more than to oil (in porous rock adjacent to the fracture). The objective is for the gel to inhibit substantially flow into the fracture from the water zone(s) while not impeding flow into the fracture from the hydrocarbon zone(s). Our method also neglects the effects of gel that forms in the fracture. So, for some gelant systems, our method may require injection of a small post-flush to displace gelant from the fracture before gelation.

The remainder of this paper summarizes the mathematical development of our method. (Details of the derivations can be found in Ref. 7.) Ultimately, we present a simple 11-step procedure for sizing gelant treatments in hydraulically fractured production wells. This procedure has been incorporated into software that can be downloaded from our web site. This software also allows in-situ water and oil residual resistance factors (permeability reduction values provided by the gel) to be backcalculated from field applications of gelant treatments in hydraulically fractured production wells.

Fracture Volume Vs. Leakoff Volume

When a gelant is injected, what fraction of the gelant volume locates in the fracture vs. in the porous rock? Usually, the volume associated with a given fracture is quite small unless the fracture is exceptionally wide. To illustrate this point, consider a vertical two-wing fracture with height, h_f; effective width, b_f; porosity, ϕ_f; and half-length L_f. The total fracture volume, V_f, in both wings of the fracture is given by

$$V_f = 2h_f L_f b_f \phi_f. \qquad (1)$$

For gelant that leaks off evenly from the fracture faces, Eq. 2 describes the relation between gelant volume in matrix V_m, average leakoff distance L_p, and matrix porosity ϕ_m for two wings of a fracture that cut through a single zone of height h_f.

$$V_m = 4h_f L_p L_f \phi_m. \qquad (2)$$

Dividing Eq. 2 by Eq. 1 reveals that the ratio $V_m/V_f = 2L_p\phi_m/b_f\phi_f$. If $L_p = 1$ ft, $b_f = 0.1$ in., $\phi_f = 1$, and $\phi_m = 0.2$, then the gelant leakoff volume is 48 times greater than the volume in the fracture. So, in a typical gel treatment, unless the fractures are unusually

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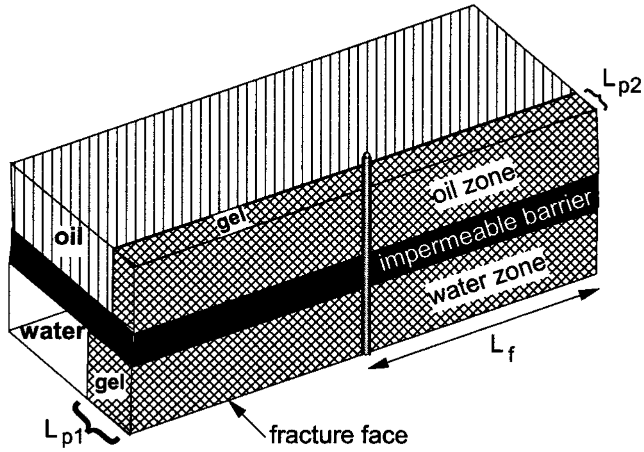

Fig. 1—A gelant treatment in a vertical fracture that cuts through oil and water zones.

wide, the gelant volume in the matrix will be substantially greater than that in the fracture.

Now, consider the propagation of a gelant front in a fracture as a function of volume of gelant injected. To simplify this problem, assume that fluid leaks off from the fracture faces at a flux that is independent of distance along the fracture. Also, assume that the gelant has the same viscosity and mobility as the water that originally occupies the fracture. (We will relax both of these assumptions in later sections.) Then, Eq. 3 describes the relation between the gelant front in the fracture, L, and the volume of gelant injected, V. Eq. 3 is derived in Ref. 7.

$$V/V_f = -\ln(1 - L/L_f). \quad (3)$$

By use of Eq. 3, **Fig. 2** plots the fracture volumes of gelant injected, V/V_f, vs. the position of the gelant front relative to the total fracture length, L/L_f. The plot is fairly linear for L/L_f values between 0 and 0.6. At higher values, the plot curves sharply upward. Fig. 2 shows that injection of one through four fracture volumes leads to L/L_f values of 0.63, 0.87, 0.95, and 0.98, respectively. Interestingly, much more than one fracture volume of gelant must be injected to fill the fracture. In fact, Eq. 3 predicts that the gelant front will never reach the end of the fracture. However, for practical purposes, the fracture is effectively filled after injecting three or four fracture volumes. This volume is very small for most gel treatments.

Leakoff Distance vs. Length Along a Fracture

An important assumption made in deriving Eq. 3 was that the leakoff flux, u, was independent of distance along the fracture. When is this assumption valid, and what does the leakoff profile really look like along a fracture? These questions are addressed by

$$u = -\frac{q_0 C[e^{CL} + e^{2CL_f}e^{-CL}]}{2h_f(1 - e^{2CL_f})}. \quad (4)$$

In Eq. 4, which derived in Ref. 7, q_0 = the total volumetric injection rate, and C = a constant given by

$$C = \sqrt{2k_m/(k_f b_f r_e)}. \quad (5)$$

In Eq. 5, k_m = the permeability of the porous rock and r_e = the external drainage radius of the well. Eq. 6 (from Ref. 7) expresses Eq. 4 in a slightly different form.

$$\frac{u}{u_0} = \frac{e^{CL} + e^{2CL_f}e^{-CL}}{1 + e^{2CL_f}}. \quad (6)$$

Here, u_0 is the leakoff flux at the wellbore (i.e., at $L = 0$).

Fig. 3 plots u/u_0 vs. L/L_f for several values of the parameter, CL_f. Note that the leakoff flux is basically independent of distance along the fracture when CL_f is 0.3 or less. However, for CL_f values above 3, the leakoff flux is quite sensitive to distance along the fracture; therefore, CL_f is an important parameter for gel treatments in hydraulically fractured wells.

By use of Eq. 6, Eq. 7 was derived (in Ref. 7).

$$\frac{V}{V_f} = \left[\frac{e^{-CL_f} - e^{CL_f}}{2CL_f}\right]\ln\left[\left(\frac{e^{CL_f} - e^{CL}}{e^{CL_f} + e^{CL}}\right)\left(\frac{e^{CL_f} + 1}{e^{CL_f} - 1}\right)\right]. \quad (7)$$

Eq. 7 was used to produce **Fig. 4**. This figure, which is analogous to Fig. 2, plots V/V_f vs. L/L_f for various values of CL_f. For CL_f values below 1, the plots are virtually the same as the curve in Fig. 2. However, significant deviations are seen when CL_f is greater than 1. Again, this result indicates that CL_f is an important parameter for gel treatments in hydraulically fractured wells.

What range of CL_f values is commonly encountered in field applications? This range can be estimated by Eq. 5 and results from a survey of field gel treatments.[1] In previous field applications, formation permeabilities varied from 4 to 5,000 md, with a median permeability of 100 md.[1] Well spacings varied from 10 to 160 acres, so r_e values ranged from 250 to 1,050 ft. We suspect that fracture conductivities typically varied from 1 to 1,000 darcy-ft. By inserting these values into Eq. 5, we can see that C values can range from 0.0001 to 0.2 ft^{-1}. If fracture lengths vary from 10 to 500 ft, CL_f values could range from 0.001 to 100. Assuming that k_m = 100 md, r_e = 500 ft, and L_f = 100 ft, CL_f will be less than 1 if the fracture conductivity is greater than 4 darcy-ft.

Use of Viscous Gelants

In the previous figures and equations, we assumed that the gelant had the same viscosity and mobility as that of the fluid that was displaced from the fracture and porous rock. How will these results change if the gelant is more viscous than the reservoir fluids? Ref. 7 demonstrates that increased gelant viscosity (or resistance factor,

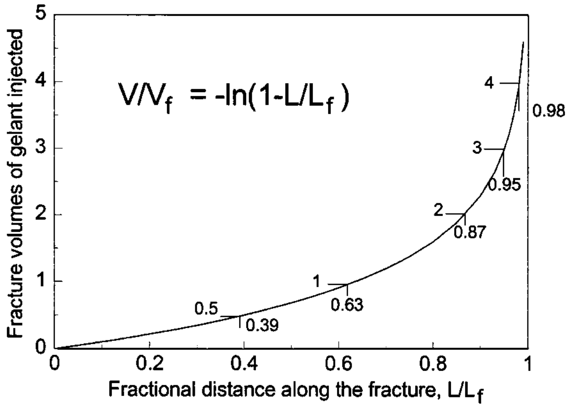

Fig. 2—Gelant volume vs. front position when the leakoff flux is independent of distance along the fracture.

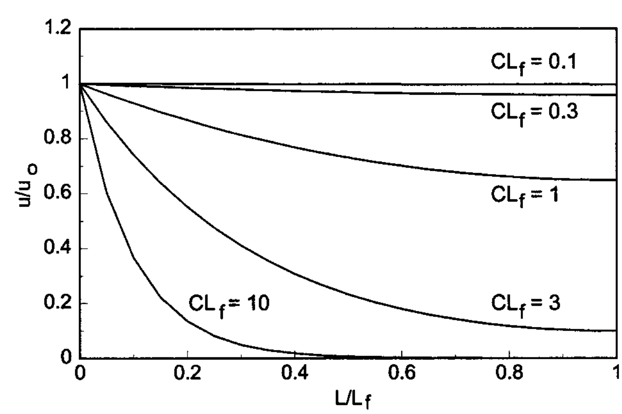

Fig. 3—Leakoff flux vs. distance along the fracture.

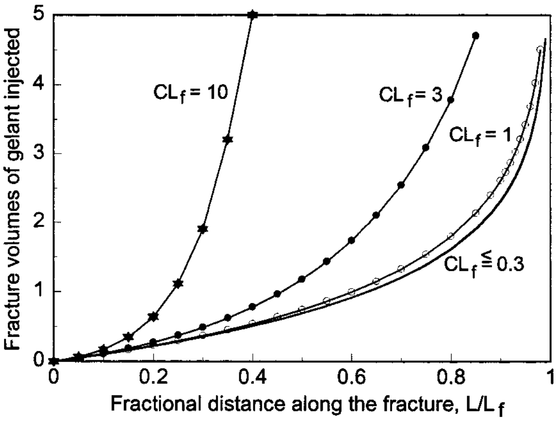

Fig. 4—Gelant volume vs. front position when the leakoff flux depends on distance along the fracture.

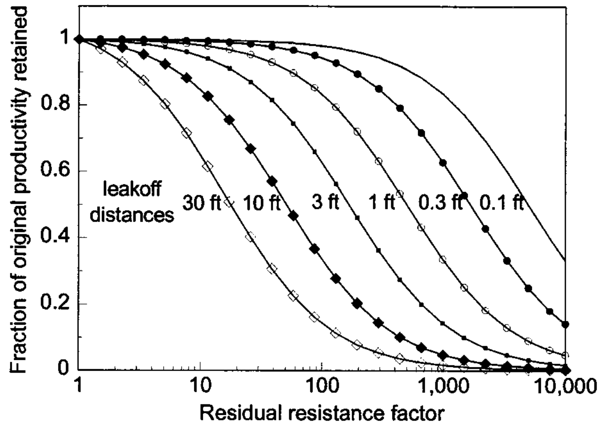

Fig. 6—Productivity retained when gel extends over the entire fracture face; r_e = 500 ft.

F_r) affects the propagation of a gelant front by increasing C. From Ref. 7, C' is defined for viscous gelants as

$$C' = \sqrt{\frac{2F_r k_m}{k_f b_f[(r_e - L_p) + F_r L_p]}}. \quad \text{(8)}$$

Dividing Eq. 8 by Eq. 5 yields

$$\frac{C'}{C} = \sqrt{\frac{F_r r_e}{(r_e - L_p) + F_r L_p}}. \quad \text{(9)}$$

Eq. 9 was used to produce **Fig. 5**, which plots C'/C vs. gelant resistance factor for L_p values ranging from 0.1 to 10 ft ($r_e = 500$ ft). Fig. 5 shows that increasing the gelant resistance factor from 1 to 10 increases C'/C by a factor of 3. Also, Fig. 5 shows that the leakoff distance has a relatively minor effect unless gelant resistance factors are large.

Productivity Losses and Water/Oil Ratio (WOR) Improvement

What reductions in oil and water productivity can be expected after a gel treatment? Consider the case in which the gel has penetrated a distance, L_p, from the fracture face into the porous rock for the entire length of the fracture. Eq. 10 (taken from Ref. 8) estimates the productivity after a gel treatment, J_a, relative to that before the gel treatment, J_b, for a gel that reduces permeability by a factor, F_{rr}, (i.e., the residual resistance factor) in the gel-contacted part of the rock.

$$\frac{J_a}{J_b} = \frac{1}{1 + (L_p/r_e)(F_{rr} - 1)}. \quad \text{(10)}$$

On the basis of Eq. 10, **Fig. 6** plots J_a/J_b (the fraction of original productivity retained) vs. the residual resistance factor for leakoff distances ranging from 0.1 to 30 ft. In Fig. 6, r_e = 500 ft. Also,

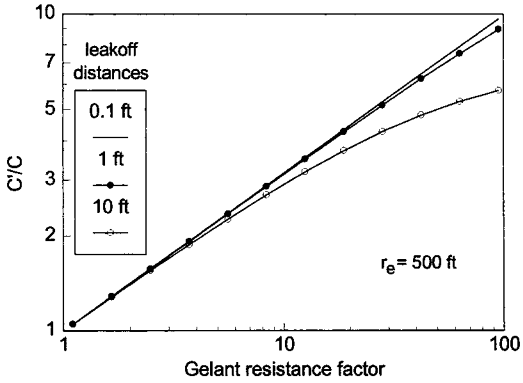

Fig. 5—Effect of gelant resistance factor on *C* values.

we assumed that the well productivity was affected by gel in the porous rock much more than by gel in the fracture.

The final producing WOR after a gelant treatment can be calculated by multiplying the initial WOR (before gelant) by the J_a/J_b value for water (i.e., by use of F_{rrw} for F_{rr} in Eq. 10) and dividing the result by the J_a/J_b value for oil (i.e., inserting F_{rro} for F_{rr} in Eq. 10).

Figures like Fig. 6 can be very useful when designing a gel treatment for a fractured production well.[9-11] An example will be given to illustrate this point.

Example. Consider the case illustrated by Fig. 1. A hydraulically fractured production well produces 10 times as much water as oil. The fracture cuts through one oil zone and one water zone. An impermeable shale barrier separates the two zones except at the fracture. Each zone is 25 ft thick; the fracture half-length, L_f, is 50 ft; and the fracture is conductive enough so that leakoff in a given zone is uniform along the length of the fracture (i.e., $CL_f < 1$). The water zone is effectively 10 times more permeable than the oil zone, the aqueous phase porosity (at S_{or}) is 0.15 in both zones, and the oil/water mobility ratio is about 1. This well is roughly 1,000 ft from the nearest well, so $r_e \approx 500$ ft. By use of a core from each zone, laboratory studies identified a gel that will reduce permeability to water by a factor of 100 (i.e., $F_{rrw} = 100$) and permeability to oil by a factor of 10 (i.e., $F_{rro} = 10$). Before gelation, the gelant is 20 times more viscous than water ($F_r = 20$). How much gelant should be injected, and what effect should be seen from the gel treatment?

In solving this problem, losses to oil productivity should be minimized while maximizing losses to water productivity. For example, we may want the oil productivity after the gel treatment to retain at least 90% of its original value. By use of either Eq. 10 or Fig. 6, we determine that a gel with $F_{rro} = 10$ provides a 10% loss of oil productivity if the leakoff distance in the oil zone, L_{p2}, is 6.2 ft. For this distance of gelant penetration in the oil zone, the distance of gelant penetration in the water zone, L_{p1}, can be estimated by

$$\frac{L_{p2}}{L_{p1}} = \frac{\sqrt{1 + (F_r^2 - 1)(\phi_1 k_2)/(\phi_2 k_1)} - 1}{F_r - 1} \quad \text{(11)}$$

(from Eq. 1 of Ref. 8).

This calculation estimates L_{p1} to be 21.8 ft in the water zone. By use of Eq. 10, the productivity retained in the water zone is found to be 19% for F_{rrw} = 100 and L_p = 21.8 ft. Before the gel treatment, the producing WOR was 10. After the treatment, the final WOR expected is (10 × 0.19)/(1 × 0.9) or 2.1. The total volume of gelant injected is given by

$$V = 4L_f(h_{f2}\phi_2 L_{p2} + h_{f1}\phi_1 L_{p1}). \quad \text{(12)}$$

From this equation, 3,750 bbl of gelant should ultimately reduce the WOR from 10 to 2.1 while maintaining 90% of the original oil productivity.

Of course, if more than two zones are present, the total volume of gelant injected is the sum of the gelant volumes in all zones,

$$V = 4 \sum_i L_{fi} L_{pi} h_{fi} \phi_i . \quad \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots (13)$$

In Eq. 13, the subscripts i = individual zones.

This example assumed that retention of gelant components by the rock did not significantly affect the L_p values. This is a reasonable assumption for concentrated gelants (e.g., containing ≧0.5% HPAM). For dilute gelants, the effects of retention and inaccessible pore volume can be included by use of Eq. 21 of Ref. 8 instead of Eq. 11 here. The example also assumed that placement could be modeled adequately by use of single-phase flow calculations. Refs. 8 and 9 show that this is a reasonable assumption for most light to medium-gravity oils. For heavy oils, two-phase flow effects can be included by use of the methods described in Ref. 9.

Effect of Gelant Volume. What would happen if different gelant volumes were used? This question can be easily answered by use of Eqs. 10 through 13. **Fig. 7** summarizes the results from these calculations. For reference, if the gelant volume was 1,875 bbl (instead of 3,750 bbl), the oil productivity would be reduced to 95% of the original (before gel) value and the final WOR would be 3.3. If the gelant volume was 7,500 bbl, the oil productivity would be reduced to 82% of the original value and the final WOR would be 1.3. Fig. 7 suggests that the gelant volume should be at least 1,000 bbl to cause a significant reduction in the WOR. However, the gelant volume should not be greater than 10,000 bbl because losses in oil productivity then become substantial.

Effect of F_{rr}. What would happen if a different gelant was used—for example, one with $F_{rrw} = 1{,}000$ and $F_{rro} = 100$? This question is answered in **Fig. 8**. This figure shows that increasing the water and oil residual resistance factors by a factor of 10 reduced the volume of gelant required by a factor of 10. For example, for this second gelant system, only 370 bbl of gelant was needed to reduce the WOR from 10 to 2.1 while maintaining 90% of the original oil productivity—the same effect that was produced by the 3,750-bbl treatment described previously. So, in hydraulically fractured production wells, a substantial incentive exists to identify relatively strong gels that reduce permeability to water much more than to oil. A detailed analysis[7] indicates that, for a given F_{rrw}/F_{rro} ratio, the gelant volume required to achieve a given WOR reduction is inversely proportional to F_{rro}, if F_{rro} is not too small (i.e., close to 1). Our analysis reveals that a critical step in this design process is determining the water and oil residual resistance factors by use of gelant, oil, brine, rock, and temperature that are representative of the intended application.

Effect of F_{rrw}/F_{rro}. Our analysis reveals that the performance of a gelant treatment depends critically on the ability of a gel to reduce permeability to water much more than to oil. **Fig. 9** illustrates this point for cases in which the initial WOR was 10, the final oil productivity was 90% of the initial oil productivity, and L_p/r_e was the same in all zones. As expected, a greater permeability reduction (i.e., greater F_{rrw}/F_{rro} values) allows lower final WOR values to be attained. Interestingly, Fig. 9 indicates that F_{rrw}/F_{rro} values of 100 or less should provide most of the benefit that can be expected. F_{rrw}/F_{rro} values up to 400 have been reported.[10] Also, for a given F_{rrw}/F_{rro} value, the WOR reduction is insensitive to F_{rro} if F_{rro} is greater than 10.

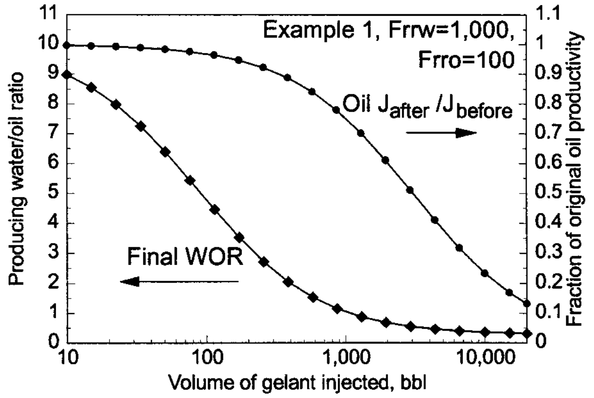

Fig. 8—Sensitivity to gelant volume.

Determining CL_f Values

The previous sections demonstrated that the CL_f value must be below a value of 1 to ensure that leakoff is uniform along the length of the fracture. How are CL_f values determined in field applications? At least three methods are available: productivity data, pressure transient analysis, and reservoir simulation (history matching).

For those circumstances in which operators have the time and resources to characterize their wells, pressure transient analysis or reservoir simulation can provide more accurate estimates of formation permeabilities, fracture conductivities, and fracture lengths than those available from productivity data.[12] We encourage the use of the more sophisticated methods when practical.

If these methods are not practical, then we recommend that simple calculations with productivity data should be used. Lee,[12] Holditch,[13] and McGuire and Sikora[14] have produced charts that predict the increase in productivity caused by a hydraulic fracture as a function of fracture conductivity and fracture length. **Fig. 10** illustrates one of these charts.

Fig. 10 can be used to act in reverse of that originally intended. In particular, field productivity data can be used to estimate C and L_f values. This method requires knowledge of rock permeabilities (i.e., from core analysis), flowing and static wellbore pressures, and

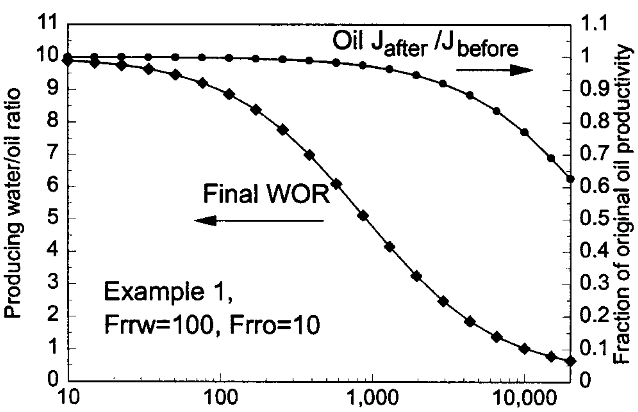

Fig. 7—Sensitivity to gelant volume.

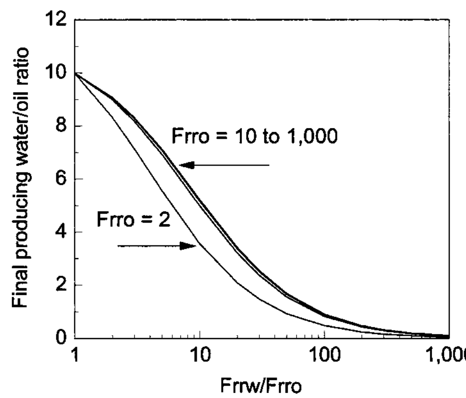

Fig. 9—Importance of F_{rrw} and F_{rro}. Initial WOR = 10. Final oil productivity is 90% of the initial oil productivity. L_p/r_e is the same in all zones.

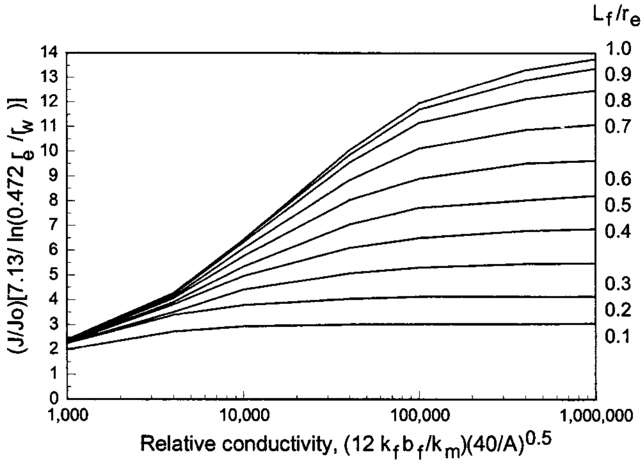

Fig. 10—Productivity increase from hydraulic fracturing (from Refs. 12 and 13).

well spacing. The first step in this process is to estimate the well productivity in the absence of the fracture. This calculation is made by use of the simple Darcy equation for radial flow.

$$J_0 = \frac{\sum kh}{141.2\mu \ln(r_e/r_w)}. \quad (14)$$

In Eq. 14, the permeability to water, k_w, should be corrected so that it reflects the permeability at the residual oil saturation (e.g., at S_{or}). (Of course, the permeability to oil should also be corrected if needed.)

Second, the actual well productivity, J, is the total production rate divided by the downhole pressure drop (reservoir pressure minus the wellbore pressure).

$$J = q/\Delta p. \quad (15)$$

Next, the term on the y-axis of Fig. 10 is calculated,

$$y = \frac{J}{J_0}\frac{7.13}{\ln(0.472 r_e/r_w)}. \quad (16)$$

Then, Fig. 10 is used to look up an x value associated with the upper left envelope of curves. This x value provides the minimum relative conductivity,

$$x = \frac{12 k_f b_f}{k_m}\sqrt{\frac{40}{A}}. \quad (17)$$

Once the minimum x value is known, the minimum fracture conductivity, $k_f b_f$, can be found from Eq. 17. For example, if the y value is 8, Fig. 10 indicates that the minimum x value is about 20,000. If the well spacing, A, is 40 acres and the rock permeability is 10 md, the fracture conductivity is 16.7 darcy-ft. The external drainage radius can be estimate from

$$r_e = \sqrt{A(43{,}560)/(2\pi)}. \quad (18)$$

For 40-acre spacing, r_e is 527 ft. The maximum C value can be calculated by Eq. 5. In this example, the maximum C value is calculated as 0.0015 ft^{-1}.

Fig. 10 can also be used to estimate the minimum fracture length, L_f. This can be done by extending a line from the given y value horizontally to the right side of Fig. 10 to determine the corresponding L_f/r_e value. In our example, where the y value is 8, the corresponding L_f/r_e value is 0.5. So, if the r_e value is 527 ft, the L_f value is 0.5(527) or 263 ft.

One can use Fig. 10 to demonstrate that the fluid leakoff from the fracture should be uniform if the well productivity is at least five times the value for an unfractured well. Eqs. 5, 17, and 18 can be combined to produce

$$x = 12{,}640\left(\frac{L_f}{r_e}\right)^2\left(\frac{1}{CL_f}\right)^2. \quad (19)$$

From Figs. 3 and 4, we note that uniform leakoff occurs from the fracture faces if $CL_f \leqq 1$. So, Eq. 19 suggests that, if $CL_f \leqq 1$, uniform leakoff should occur if $x > 12{,}640$. In Fig. 10, this x value corresponds to a y value (on the upper left envelope) of about 6. The y-axis term, $7.13/[\ln(0.472 r_e/r_w)]$, has a value typically near 1.15. Dividing 6 by 1.15 provides a J/J_0 value of about 5. Therefore, fluid leakoff from the fracture should be uniform if the well productivity is at least five times greater than that for an unfractured well.

Fig. 10 also suggests that if $J/J_0 \geqq 5$, then $L_f/r_e \geqq 0.3$. For higher J/J_0 values, the right side of Fig. 10 provides greater estimates for the minimum fracture length. Note that Fig. 10 does not generally provide the actual fracture length. Even so, knowledge of the minimum fracture length could be useful when designing the gelant volume to be injected. To explain, Figs. 7 and 8 suggest that the performance of a gel treatment is not particularly sensitive to the treatment volume as long as that volume is roughly in the proper range. For example, in Fig. 7, we suggested that the gelant volume should be 3,750 bbl. Fig. 7 indicates that the treatment results would not be catastrophic if the treatment size was as little as half or as much as twice the proposed volume of 3,750 bbl. Therefore, if information on fracture length is not available, a reasonable approximation is to assume that the fracture length is half the external drainage radius ($L_f = 0.5 r_e$). Alternatively, the right side of Fig. 10 can be used to make the following approximation.

$$L_f \approx [(J/J_0)(0.09) - 0.14] r_e. \quad (20)$$

Eq. 20 is the result of a linear least-squares regression of the relation between the J/J_0 values on the y axis of Fig. 10 and the L_f/r_e values on the right side of Fig. 10.

Method for Sizing Gelant Treatments in Hydraulically Fractured Production Wells

The following is a summary of our proposed procedure for sizing gelant treatments in hydraulically fractured production wells.

1. Estimate the rock permeabilities (k_i in md), porosities (ϕ_i), and thicknesses (h_{fi} in ft) for the oil and water zones of interest. Core analysis data on unfractured cores are preferred. Correct the k_w values so they reflect the permeability at the resident oil saturation (e.g., at S_{or}).

2. Estimate the productivity of an unfractured, undamaged well, J_0 in bbl/D-psi, by Eq. 21.

$$J_0 = \sum kh/[141.2\mu \ln(r_e/r_w)]. \quad (21)$$

3. Calculate the actual total well productivity for the fractured well, J in bbl/D-psi, and determine the ratio, J/J_0. The well may be a good candidate for a gel treatment if all four of the following conditions are met: J/J_0 is greater than 5, the WOR is high, the fracture cuts through distinct water and hydrocarbon zones, and a satisfactory mobile oil target exists.

4. In the laboratory, determine the water and oil residual resistance factors (F_{rrw} and F_{rro}) by use of gelant, oil, brine, rock, and temperature that are representative of the intended application. Alternatively, F_{rrw} and F_{rro} values may be backcalculated from a previous treatment by use of the same gelant in a nearby well.

5. Estimate the external drainage radius, r_e in ft, for the well spacing, A in acres.

$$r_e = \sqrt{A(43{,}560)/(2\pi)}. \quad (22)$$

6. Calculate the desired distance of gelant leakoff in the oil zone(s), L_{p2} in ft, for the target final oil-productivity level(s), J_a/J_b (e.g., $J_a/J_b = 0.9$).

$$L_{p2} = r_e[(J_b/J_a) - 1]/(F_{rro} - 1). \quad (23)$$

7. Use Eq. 24 (or Eq. 21 of Ref. 8 if chemical retention must be considered or the methods in Ref. 9 if two-phase flow effects must be considered) to estimate the target distance of gelant penetration into the water zone(s), L_{p1} in ft. If more than two zones are present, repeat this step for each zone. (F_r is the gelant resistance factor.)

$$L_{p1} = \frac{(F_r - 1)L_{p2}}{\sqrt{1 + (F_r^2 - 1)(\phi_1 k_2)/(\phi_2 k_1)} - 1}. \quad \text{(24)}$$

8. Use Eq. 25 and F_{rrw} to calculate J_a/J_b values for the water zone(s).

$$J_a/J_b = 1/[1 + (L_{p1}/r_e)(F_{rrw} - 1)]. \quad \text{(25)}$$

9. Find L_f, assuming that $L_f = 0.5r_e$, or use Eq. 26.

$$L_f \approx [(J/J_0)(0.09) - 0.14]r_e. \quad \text{(26)}$$

10. Determine the gelant volume to be injected.

$$V = 4L_f \sum_i L_{pi} h_{fi} \phi_i. \quad \text{(27)}$$

11. Estimate the final expected WOR by multiplying the initial WOR (before gelant) by the J_a/J_b value for water (i.e., from Eq. 25) and dividing the result by the J_a/J_b value for oil.

Limitations

An unfortunate reality for many operators is that they do not have the time, information, or resources to diagnose the nature of their excess water-production problem adequately or to engineer the best solution adequately. For those cases, this paper provides a very simple method to screen and to engineer a reasonable gel treatment in hydraulically fractured production wells. In this method, we emphasize that water and oil residual resistance factors must be determined in advance. These values can be determined either from laboratory measurements or by calculation of in-situ residual resistance factors from a prior field test. Also, the reader should note that our method assesses whether fractures are conductive enough to allow uniform leakoff along the fracture and the minimum fracture length. (The method does not determine the actual conductivity or length of the fracture.) In many cases, these determinations are adequate to design a satisfactory gel treatment. The reader should also note that this method assumes that a reasonable estimate can be made of the undamaged rock permeabilities in the zones of interest in a well (e.g., through core analysis). If the near-wellbore region or fracture faces are known to be damaged and this damage can be quantified, methods are available to take this damage into account.[12] Also, our method assumes that the resistance to flow provided by gel in the fracture is small compared with that provided by gel in the porous rock adjacent to the fracture. Concern about the effects of gel in the fracture may be mitigated by use of a post-flush to displace gelant from the fracture before gelation.

From a rigorous viewpoint, our method assumes that impermeable barriers (e.g., shale or calcite) separate adjacent zones. However, the method frequently should provide acceptable predictions even if crossflow can occur. For example, consider the case in which oil lies on top of water in a single formation (i.e., a common situation where coning becomes a problem). Previous work[9,10] showed that gravity can retard water influx into oil zones much more effectively when the water must cusp to a linear pressure sink (i.e., a vertical fracture or a horizontal well) than when the water cones to point pressure sink (i.e., a partially penetrating vertical well). For the type of treatment that we are proposing, in many cases, gravity may be sufficient to minimize water invasion into the hydrocarbon zones. Of course, the degree of water invasion into hydrocarbon zones will increase with increased production rate, pressure drawdown, vertical formation permeability, and hydrocarbon viscosity and will decrease with increased water/hydrocarbon density difference, horizontal formation permeability, and oil-column thickness.[9,10] If water invades too far into the hydrocarbon zone, of course, a water block could form that reduces hydrocarbon productivity.

To use our procedure, field data are needed, coupled with results from two simple laboratory experiments. The needed field data include: fluid production rates before and after the gel treatment; downhole static and flowing pressures before and after the gel treatment; permeabilities, porosities, and thicknesses of the relevant zones; water and oil viscosities at reservoir temperature; well spacing or distance between wells; and the volume of gelant injected. These parameters are normally available during conventional gel treatments. Use of the procedure also requires oil and water residual resistance factors (F_{rro} and F_{rrw} values) from laboratory core experiments. These experiments must be conducted with the gelant, oil, brine, rock, and temperature that are representative of the intended application.

In the absence of laboratory oil and water residual resistance factors, our model can use field data to back-calculate the F_{rro} and F_{rrw} values in situ after a gel treatment. This information may be useful when designing similar treatments in nearby wells. These calculations have also been incorporated into our software that can be downloaded from our web site. We emphasize that our method is specifically directed at hydraulically fractured production wells. Work is currently under way to design gel treatments for other circumstances (including naturally fractured reservoirs).

Conclusions

1. A simple 11-step procedure was developed for sizing gelant treatments in hydraulically fractured production wells. This procedure was incorporated in user-friendly graphical-user-interface software that can be downloaded from our web site.

2. The method generally requires the use of a gel that will reduce permeability to water much more than to hydrocarbon.

3. A critical step in designing a gelant treatment by this method is to determine water and hydrocarbon residual resistance factors for the selected gelant with the fluid, rock, and temperature conditions representative of the actual application. If this information is not available from laboratory data, our method and software can be used to backcalculate in-situ hydrocarbon and water residual resistance factors from previous field applications that used the same gelant in similar, nearby hydraulically fractured production wells.

4. The procedure will be most reliable if impermeable barriers (e.g., shale or calcite) separate water zones from the hydrocarbon zones. However, the procedure will often be valid if these barriers are not present.

Nomenclature

A = well spacing, acres [m^2]
b_f = fracture width, in. [m]
C = constant defined by Eq. 5, ft^{-1} [m^{-1}]
C' = constant defined by Eq. 8, ft^{-1} [m^{-1}]
F_r = resistance factor (brine mobility before gelant placement divided by gelant mobility)
F_{rr} = residual resistance factor (mobility before gel divided by mobility after gel placement)
F_{rro} = oil residual resistance factor
F_{rrw} = water residual resistance factor
h = height, ft [m]
h_f = fracture height, ft [m]
h_{fi} = fracture height in Zone i, ft [m]
J = productivity, bbl/D-psi [m^3/s-Pa]
J_a = productivity after gel placement, bbl/D-psi [m^3/s-Pa]
J_b = productivity before gel placement, bbl/D-psi [m^3/s-Pa]
J_0 = initial productivity for an undamaged well before fracturing, bbl/D-psi [m^3/s-Pa]
k = permeability, md [μm^2]
k_f = fracture permeability, md [μm^2]
k_i = permeability in Zone i, md [μm^2]
k_m = matrix permeability, md [μm^2]
k_w = permeability to water at resident oil saturation, md [μm^2]

L = distance along a fracture, ft [m]
L_f = length of one wing of a fracture, ft [m]
L_{fi} = length of one wing of a fracture in Zone i, ft [m]
L_p = average distance of gelant penetration (leakoff) from a fracture face
L_{pi} = distance of gelant penetration (leakoff) from a fracture face in Zone i, ft [m]
p = pressure, psi [Pa]
Δp = pressure difference between the external drainage radius and the well, psi [Pa]
q = volumetric rate at a given point in a fracture, bbl/D [m^3/s]
q_0 = total volumetric rate, bbl/D [m^3/s]
r_e = external drainage radius, ft [m]
r_w = wellbore radius, ft [m]
S_{or} = residual oil saturation
u = superficial or Darcy velocity or flux, ft/d [cm/s]
u_0 = flux at the wellbore, ft/d [cm/s]
V = gelant volume, bbl [m^3]
V_f = fracture volume, bbl [m^3]
V_m = gelant volume in the rock matrix, bbl [m^3]
x = abscissa value in Fig. 10
y = ordinate value in Fig. 10
μ = fluid viscosity, cp [mPa-s]
μ_w = water viscosity, cp [mPa-s]
ϕ_f = porosity in the fracture
ϕ_i = effective aqueous-phase porosity in Zone i
ϕ_m = porosity in the rock matrix

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SI Metric Conversion Factors

acre × 4.046 873	E+03	= m^2
bbl × 1.589 874	E−01	= m^3
cp × 1.0*	E−03	= Pa·s
ft × 3.048*	E−01	= m
in. × 2.54*	E+00	= cm
psi × 6.894 757	E+00	= kPa

*Conversion factors are exact.

SPEPF

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