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Sizing Gelant Treatments in Hydraulically Fractured Production Wells

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Abstract

Often, when production wells are stimulated by hydraulic fracturing, the fracture unintentionally extends through shale barriers into water zones, causing substantially increased water production. Gelant treatments have frequently been applied in an attempt to correct this problem. However, the design of the gelant volumes for these applications has been strictly empirical, and consequently, the success rates for these treatments have been erratic. In this paper, we develop a sound engineering basis for sizing gelant treatments. We present a simple 11-step procedure for sizing gelant treatments in hydraulically fractured production wells. We incorporated this procedure in user-friendly graphical-user-interface software.

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 1/2 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 since most treated wells are thought to be fractured, where the flow geometry is described better as linear rather than radial.[1]

Substantial improvements are needed in the design methods used for sizing gel treatments. We strongly 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 (1) flow-behind-pipe problems, (2) unfractured wells where crossflow cannot occur, (3) unfractured wells where crossflow can occur, (4) hydraulically fractured wells, and (5) naturally fractured reservoirs. The focus in this paper is on sizing gelant treatments in hydraulically fractured production wells. First, the volume of gelant that leaks off into porous rock is shown to be usually substantially greater than that in a fracture. Second, conditions are quantified when leakoff occurs at a rate that is independent of length along the fracture. Third, we quantify oil and water productivity losses and improvement in the water/oil ratio after a gel treatment. Next, parameters are discussed that are necessary to design a gel treatment, and the most expedient methods to obtain that information are identified. Finally, we present a simple 11-step procedure for sizing gelant treatments in hydraulically fractured production wells. This procedure has been incorporated in a software package.

Fracture Volume Versus Leakoff Volume

When a gelant is injected, what fraction of the gelant volume locates in the fracture versus 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, w_f, porosity, ϕ_f, and half-length, L_f. The total fracture volume, V_f, in both wings of the fracture is given by Eq. 1.

$$V_f = 2h_f L_f w_f \phi_f \quad \ldots\ldots (1)$$

For gelant that leaks off evenly from the fracture faces, Eq. 2 describes the relation between gelant volume in the matrix, V_m, 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.

$$V_m = 4h_f L_p L_f \phi_m \quad \ldots\ldots (2)$$

Dividing Eq. 2 by Eq. 1 reveals that the ratio, V_m/V_f, equals $(2L_p\phi_m)/(w_f\phi_f)$. If L_p=1ft, w_f=0.1 in., ϕ_f=1, and ϕ_m=0.2, then the gelant leakoff volume is 48 times greater than the volume

in the fracture. Thus, in a typical gel treatment, unless the fractures are unusually 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 Appendix A of Ref. 4.

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

Using Eq. 3, **Fig. 1** plots the fracture volumes of gelant injected (V/V_f) versus 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. 1** shows that injection of 1, 2, 3, and 4 fracture volumes leads to L/L_f values of 0.63, 0.87, 0.95, and 0.98, respectively. Interestingly, much more than 1 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 3 or 4 fracture volumes. This volume is very small for most gel treatments.

Leakoff Distance Versus 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? This question is addressed by Eq. 4, which is derived in Appendix B of Ref. 4.

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

In Eq. 4, q_o is the total volumetric injection rate, and C is a constant given by Eq. 5.

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

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

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

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

Fig. 2 plots u/u_o versus 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.

Using Eq. 6, Eq. 7 was derived (in Appendix B of Ref. 4).

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

Eq. 7 was used to produce **Fig. 3**. This figure, which is analogous to **Fig. 1**, plots V/V_f versus 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. 1**. 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.

Use of Viscous Gelants

In the above 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 the above results change if the gelant is more viscous than the reservoir fluids? Appendix C of Ref. 4 demonstrates that increased gelant viscosity (or resistance factor, F_r) affects the propagation of a gelant front by increasing C. In Eq. 8 (from Appendix C of Ref. 4), C′ is defined for viscous gelants.

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

In Eq. 8, L_p is the distance of gelant leakoff from the fracture face. Dividing Eq. 8 by Eq. 5 yields Eq. 9.

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

Eq. 9 was used to produce **Fig. 4**, which plots C′/C versus gelant resistance factor for L_p values ranging from 0.1 to 10 ft (r_e=500 ft). **Fig. 4** shows that increasing the gelant resistance factor from 1 to 10 increases C′/C by a factor of 3. Also, **Fig. 4** shows that the leakoff distance has a relatively minor effect unless gelant resistance factors are large.

Productivity Losses and WOR Improvement

What reductions in oil and water productivity can be expected after a gel treatment? Consider the case where 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. 5) 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.

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

Based on Eq. 10, **Fig. 5** plots J_a/J_b (the fraction of original productivity retained) versus the residual resistance factor for leakoff distances ranging from 0.1 to 30 ft. (In **Fig. 5**, r_e=500 ft. Also, we assumed that the well productivity was affected by gel in the porous rock much more than by gel in the fracture—i.e., the gel does not significantly restrict flow in the fracture.)

As mentioned above, Eq. 10 and **Fig. 5** assume that the gel leakoff distance is the same along the entire length of the fracture. What if the gel leakoff distance is uniform but only to some distance, L, along the fracture? In that case, J_a/J_b is given by Eq. 11.

$$\frac{J_a}{J_b} = \frac{1+(L_p/r_e)(F_{rr}-1)[1-(L/L_f)]}{1+(L_p/r_e)(F_{rr}-1)} \quad \text{.....(11)}$$

Figs. 6 and 7 were generated using Eq. 11, assuming leakoff distances of 1 ft and 10 ft, respectively. **Figs. 5-7** reveal that productivity losses from a well are influenced in important ways by all three variables—residual resistance factor, leakoff distance, and distance of gel propagation along the fracture.

Figures like **Figs. 5-7** can be very useful when designing a gel treatment for a fractured production well.[5-8] Two examples will be given to illustrate this point.

Example 1—Gel Extends Over the Entire Fracture Face. First, consider the case illustrated by **Fig. 8**. 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 ten-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≈500 ft). Using 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. Using either Eq. 10 or **Fig. 5**, we determine (see Eq. 12) 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.

$$0.9 = \frac{1}{1+(6.2/500)(10-1)} \quad \text{.....(12)}$$

For this distance of gelant penetration in the oil zone, the distance of gelant penetration in the water zone (L_{p1}) can be estimated using Eq. 1 of Ref. 5 (i.e., Eq. 13).

$$\frac{L_{p2}}{L_{p1}} = \frac{\sqrt{1+(F_r^2-1)(\phi_1 k_2)/(\phi_2 k_1)}-1}{F_r-1} \quad \text{.....(13)}$$

This calculation estimates L_{p1} to be 21.8 ft in the water zone (see Eq. 14).

$$\frac{6.2}{21.8} = \frac{\sqrt{1+(20^2-1)(1/10)}-1}{20-1} \quad \text{.....(14)}$$

Using Eq. 10, the productivity retained in the water zone is 19% for F_{rrw}=100 and L_p=21.8 ft (see Eq. 15).

$$0.19 = \frac{1}{1+(21.8/500)(100-1)} \quad \text{.....(15)}$$

Before the gel treatment, the producing water/oil ratio (WOR) was 10. After the treatment, the final WOR expected is (10x0.19)/(1x0.9) or 2.1.

The total volume of gelant injected is given by Eq. 16.

$$V = 4L_f(h_{fo}\phi_i L_{p2} + h_{fw}\phi_i L_{p1})$$
$$V = 4(50)[25(0.15)6.2 + 25(0.15)21.8]/5.61 = 3{,}750 \text{ bbl} \quad \text{.....(16)}$$

Therefore, using 3,750 bbl of gelant, the WOR was reduced 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.

$$V = 4\sum_i L_{fi} L_{pi} h_{fi} \phi_i \quad \text{.....(17)}$$

In Eq. 17, the i subscripts refer to 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 easily be taken into account using Eq. 21 of Ref. 5 instead of Eq. 13 above. The example also assumed that placement could be approximated using single-phase flow calculations. Refs. 5 and 6 show that this is a reasonable assumption for most light-to-medium gravity oils. For heavy oils, two-phase flow effects can be taken into account using the methods described in Ref. 6.]

What would happen if different gelant volumes were used? This question can easily be answered using Eqs. 10-16. The results from these calculations are summarized in **Fig. 9**. 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. 9** 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.

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. 10**. 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 were 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 above. Thus, in hydraulically fractured production wells, a substantial incentive exists to identify relatively strong gels that reduce permeability to water much more than that to oil. Careful consideration of Eq. 10 reveals 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 using gelant, oil, brine, rock, and temperature that are representative of the intended application.

Example 2—Gel Covers Only Part of the Fracture Face. Next, consider an example where the gel does not cover the entire distance along the fracture. In particular, assume that the fracture from Example 1 becomes extended by 50% (e.g., from a stimulation operation) sometime after the 3,750-bbl gel treatment was applied. What effect would be seen on the WOR and productivities? In both zones, the fracture half-length, L_f, grows from 50 ft to 75 ft. (The gel still exists along only the first 50 ft of the fracture in both zones.) By inputting numbers from Example 1 into Eq. 11, Eq. 18 calculates that the fraction of the original (before gel) productivity in the oil zone will be 0.93.

$$0.93 = \frac{1+(6.2/500)(10-1)(1-50/75)}{1+(6.2/500)(10-1)} \quad \text{.....(18)}$$

Thus, stimulation increases J_a/J_b from 0.9 to 0.93 for the oil zone. A similar calculation can be made for the water zone.

$$0.46 = \frac{1+(21.8/500)(100-1)(1-50/75)}{1+(21.8/500)(100-1)} \quad \text{.....(19)}$$

So, stimulation increases J_a/J_b from 0.19 to 0.46 for the water zone. After the stimulation, the WOR is given by Eq. 20.

$$WOR_{final} = (WOR_{initial})\frac{(J_a/J_b)_{water}}{(J_a/J_b)_{oil}} \quad \text{.....(20)}$$

In this particular case, Eq. 20 provides a WOR of (10x0.46)/(1x0.93) or 4.9. Therefore, stimulation increases the WOR from 2.1 to 4.9—a significant increase.

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—(1) productivity data, (2) pressure transient analysis, and (3) reservoir simulation (history matching).

For those circumstances where 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.[11] We encourage the use of the more sophisticated methods when practical.

If these methods are not practical, then we recommend that simple calculations using productivity data should be used. McGuire and Sikora[9] and Holditch[10,11] have produced charts that predict the increase in productivity caused by a hydraulic fracture as a function of fracture conductivity and fracture length. **Fig. 11** illustrates one of these charts.

Fig. 11 can be used to act in a manner reverse to 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 well spacing. The first step in this process is to estimate the well productivity in the absence of the fracture. This calculation is made using the simple Darcy equation for radial flow (Eq. 21).

$$J_o = \frac{\sum kh}{141.2\mu \ln(r_e/r_w)} \quad \text{.....(21)}$$

In Eq. 21, the permeability to water (k_w) should be corrected so that it reflects the permeability at the resident 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).

$$J = q / \Delta p \quad \text{.....(22)}$$

Next, the term on the y-axis of **Fig. 11** is calculated.

$$y = \frac{J}{J_o} \frac{7.13}{\ln(0.472 r_e / r_w)} \quad \text{.....(23)}$$

Then, **Fig. 11** is used to look up an x-value associated with the upper left envelope of curves. This x-value provides the minimum relative conductivity.

$$x = \frac{12 k_f w_f}{k_m} \sqrt{40 / A} \quad \text{.....(24)}$$

Once the minimum x-value is known, the minimum fracture conductivity, $k_f w_f$, can be found from Eq. 24. For example, if the y-value is 8, **Fig. 11** 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 Eq. 25.

$$r_e = \sqrt{A(43{,}560) / (2\pi)} \quad \text{.....(25)}$$

For 40-acre spacing, r_e is 527 ft. The maximum C value can be calculated using Eq. 5. In this example, the maximum C value is given by Eq. 26.

$$C = \sqrt{\frac{2(0.01)}{16.7(527)}} = 0.0015 \text{ ft}^{-1} \quad \text{.....(26)}$$

Fig. 11 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. 11** 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. Thus, the estimated CL_f value for this example is (0.0015)(263) or 0.4. This value is less than 1, so fluid leakoff should be uniform over the length of the fracture.

Actually, one can use **Fig. 11** 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, 24 and 25 can be combined to produce Eq. 27.

$$x = 12{,}640 \left(\frac{L_f}{r_e} \right)^2 \left(\frac{1}{CL_f} \right)^2 \quad \text{.....(27)}$$

From **Figs. 2 and 3**, we noted that uniform leakoff occurs from the fracture faces if $CL_f \leq 1$. Thus, Eq. 27 suggests that if $CL_f \leq 1$, uniform leakoff should occur if $x > 12{,}640$. In **Fig. 11**, 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_o 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. 11 also suggests that if $J/J_o \geq 5$, then $L_f/r_e \geq 0.3$. For higher J/J_o values, the right side of **Fig. 11** provides greater estimates for the minimum fracture length. Note that **Fig. 11** 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. 9 and 10** suggest that the performance of a gel treatment is not particularly sensitive to the treatment volume, so long as that volume is roughly in the proper range. For example, in **Fig. 9**, we suggested that the gelant volume should be 3,750 bbl. **Fig. 9** 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. 11** can be used to make the following approximation.

$$L_f \approx [(J / J_o)(0.09) - 0.14] r_e \quad \text{.....(28)}$$

Eq. 28 is the result of a linear least-squares regression of the relation between the J/J_o values on the y-axis of **Fig. 11** and the L_f/r_e values on the right sight of **Fig. 11**.

What range of CL_f values is commonly encountered in field applications? This range can be estimated using 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. Inserting these values into Eq. 5 suggests 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.

Limitations

An unfortunate reality for many operators is that they do not have the time, information, or resources to adequately diagnose the nature of their excess water-production problem or to adequately engineer the best solution. For those cases, this paper provides a very simple method to screen and 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 from laboratory measurements. Also, the reader should note that our method assesses (1) whether fractures are conductive enough to allow uniform leakoff along the fracture and (2) 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.[11] Also, our method assumes that the resistance to flow provided by gel in the fracture is small compared to that provided by gel in the porous rock adjacent to the fracture.

Conclusions

Based on the work described in this paper, the Appendix provides a simple 11-step procedure for sizing gel treatments in hydraulically fractured production wells. A critical step in designing a gel treatment using this method is to determine water and oil residual resistance factors for the selected gelant using the fluid, rock, and temperature conditions representative of the actual application. Our procedure has been incorporated in user-friendly graphical-user-interface software that can be made available upon request (especially for those who will help us test the validity of our model).

To test the utility of our procedure, we need field data coupled with results from two simple laboratory experiments. The needed field data includes: (1) fluid production rates before and after the gel treatment, (2) downhole static and flowing pressures before and after the gel treatment, (3) permeabilities, porosities, and thicknesses of the relevant zones, (4) water and oil viscosities at reservoir temperature, (5) well spacing or distance between wells, and (6) the volume of gelant injected. These parameters are normally available during conventional gel treatments. To properly test our model, we also need oil and water residual resistance factors (F_{rro} and F_{rrw} values) from laboratory core experiments. These experiments are easy to perform;[7,8] however, they must be conducted using 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. However, this procedure does not test the validity of our model. Since our model quite definitively predicts oil and water productivity losses and WOR changes, its validity can be tested in a straightforward fashion. Therefore, oil and gas producers and gel vendors are encouraged to test our procedure in their field applications. We emphasize that our method is specifically directed at hydraulically fractured production wells. Work is currently underway to design gel treatments for other circumstances (including naturally fractured reservoirs).

Nomenclature

- A = well spacing, acres [m^2]
- 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 placement divided by mobility after gel placement)
- F_{rro} = oil residual resistance factor
- F_{rrw} = water residual resistance factor
- h_f = fracture height, 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_o = initial productivity for an undamaged well before fracturing, bbl/D-psi [m^3/s-Pa]
- 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_{pi} = distance of gelant penetration (leakoff) from a fracture face in Zone i, ft [m]
- p = pressure, psi [Pa]
- q = volumetric rate at a given point in a fracture, bbl/D [m^3/s]
- q_o = 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_o = 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]
- w_f = fracture width, inches [m]
- x = abscissa value in Fig. 11
- y = ordinate value in Fig. 11
- 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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APPENDIX—Method 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_o in bbl/D-psi, using Eq. A-1.

$$J_o = \sum kh / [141.2\mu \ln(r_e / r_w)] \quad \text{(A-1)}$$

3. Calculate the actual total well productivity for the fractured well, J in bbl/D-psi, and determine the ratio, J/J_o. The well may be a good candidate for a gel treatment if all five of the following conditions are met: a) J/J_o is greater than 5, b) the WOR is high, c) the fracture cuts through distinct water and hydrocarbon zones, d) barriers to vertical flow exist except in the fracture, and e) a satisfactory mobile oil target exists.

4. In the laboratory, determine the water and oil residual resistance factors (F_{rrw} and F_{rro}) using gelant, oil, brine, rock, and temperature that are representative of the intended application.

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

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

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). (J_a/J_b=J_{after}/J_{before}.)

$$L_{p2} = r_e[(J_b / J_a) - 1] / (F_{rro} - 1) \quad \text{(A-3)}$$

7. Use Eq. A-4 (or use Eq. 21 of Ref. 5 if chemical retention must be considered and/or use the methods in Ref. 6 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.)

$$L_{p1} = (F_r - 1)L_{p2} / [\sqrt{1 + (F_r^2 - 1)(\phi_1 k_2)/(\phi_2 k_1)} - 1] \quad \text{(A-4)}$$

8. Use Eq. A-5 and F_{rrw} to calculate J_a/J_b values for the water zone(s).

$$J_a / J_b = 1 / [1 + (L_{p1} / r_e)(F_{rrw} - 1)] \quad \text{(A-5)}$$

9. Find L_f, assume that L_f=0.5 r_e, or use Eq. A-6.

$$L_f \approx [(J / J_o)(0.09) - 0.14] r_e \quad \text{(A-6)}$$

10. Determine the gelant volume to be injected.

$$V = 4L_f \sum_i L_{pi} h_{fi} \phi_i \quad \text{(A-7)}$$

11. Estimate the final expected WOR.

$$WOR_{final} = (WOR_{initial})(J_a / J_b)_{water} / (J_a / J_b)_{oil} \quad \text{(A-8)}$$

SI Metric Conversion Factors

cp x 1.0*	E-03 = Pa·s
ft x 3.048*	E-01 = m
in. x 2.54*	E+00= cm
bbl x 1.589 873	E-01 = m^3
md x 9.869 233	E-04 = μm^2
psi x 6.894 757	E+00= kPa

*Conversion is exact.

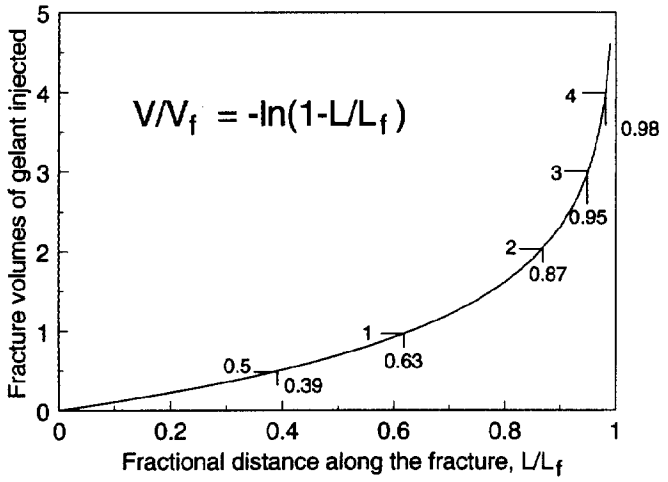

Fig. 1—Gelant volume versus front position when the leakoff flux is independent of distance along the fracture.

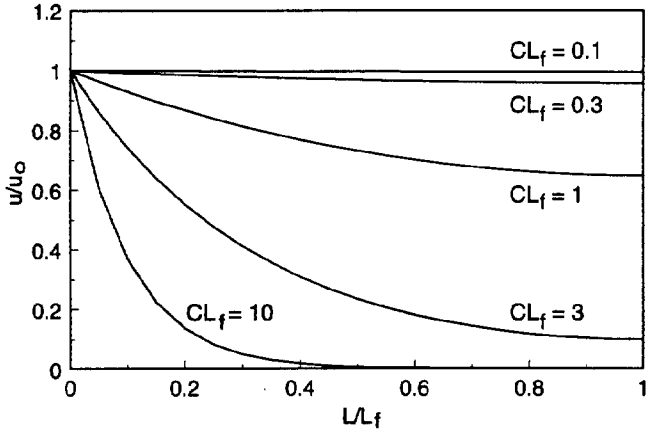

Fig. 2—Leakoff flux versus distance along the fracture.

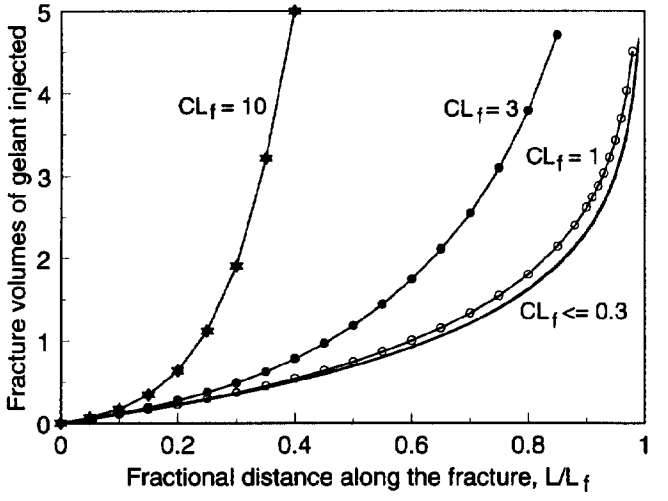

Fig. 3—Gelant volume versus front position when the leakoff flux depends on distance along the fracture.

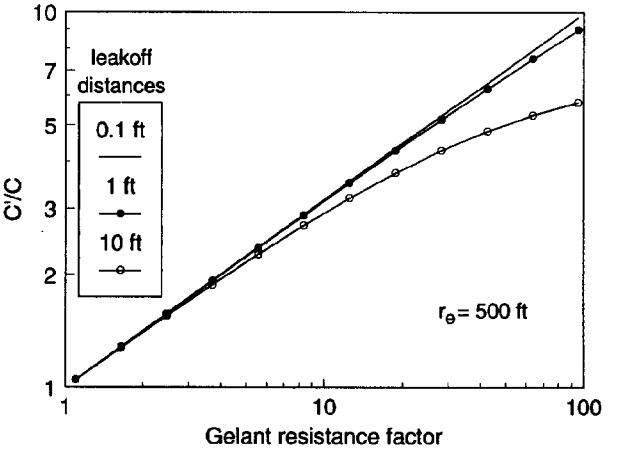

Fig. 4—Effect of gelant resistance factor on C values.

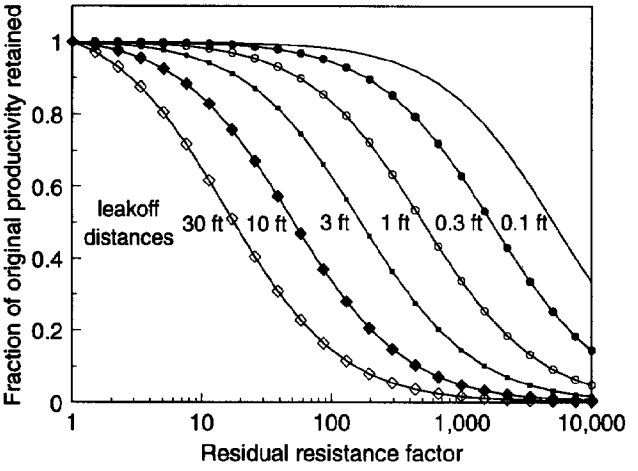

Fig. 5—Productivity retained when gel extends over the entire fracture face. r_e=500 ft.

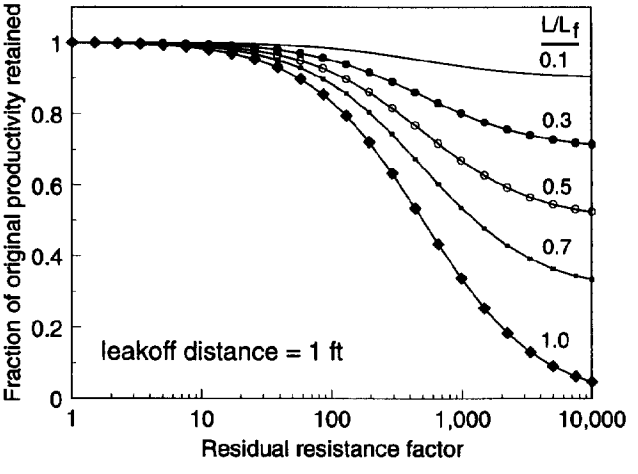

Fig. 6—Productivity retained when gel covers part of the fracture area. L_p=1 ft, r_e=500 ft.

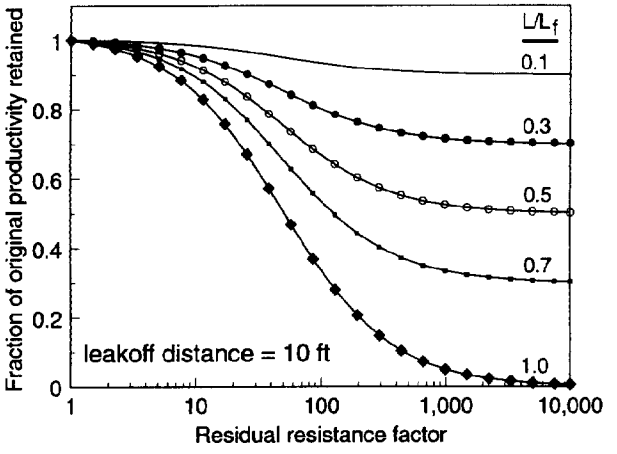

Fig. 7—Productivity retained when gel covers part of the fracture area. L_p=10 ft, r_e=500 ft.

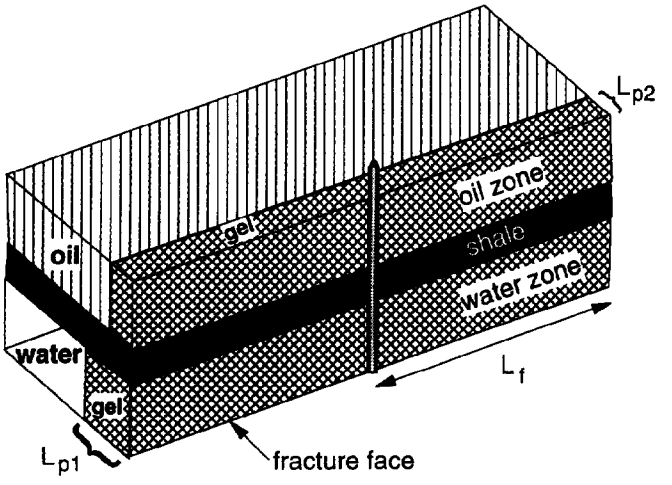

Fig. 8—A gel treatment in a vertical fracture that cuts through oil and water zones.

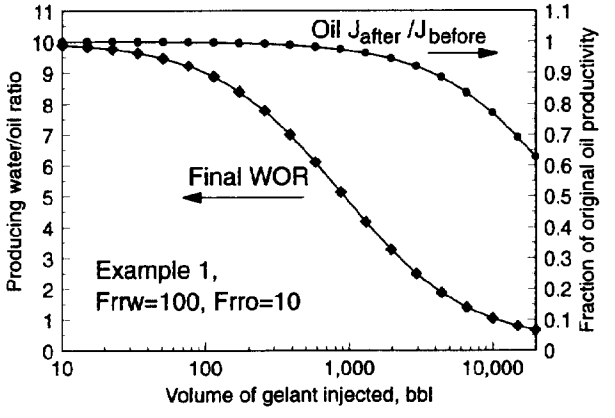

Fig. 9—Sensitivity of Example 1 to gelant volume. F_{rrw}=100, F_{rro}=10.

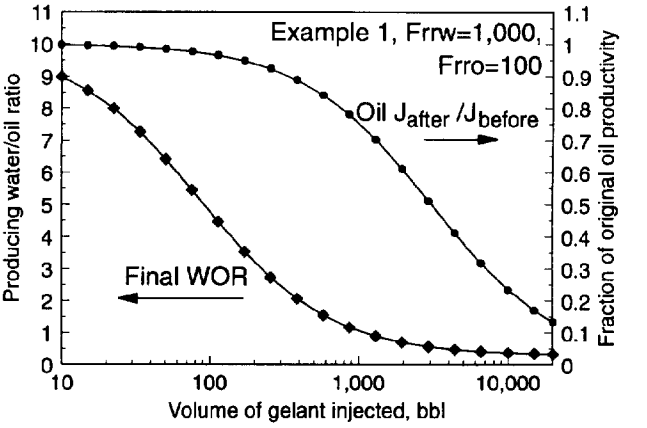

Fig. 10—Sensitivity of Example 1 to gelant volume. F_{rrw}=1,000, F_{rro}=100.

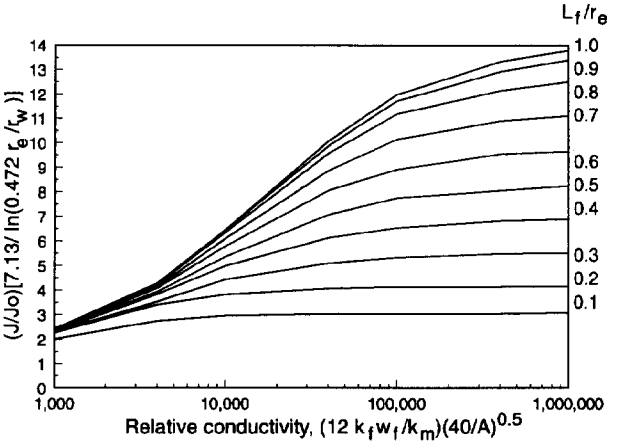

Fig. 11—Productivity increase from hydraulic fracturing (from Refs. 10 and 11).