Sizing Gelant Treatments in Hydraulically Fractured Production Wells
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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 gel 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 gel 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, \( w_0 \), porosity, \( \psi_f \), and half-length, \( L_f \). The total fracture volume, \( V_f \), in both wings of the fracture is given by Eq. 1.

\[
V_f = 2h_f L_f w_f \phi_f 
\]

For gel 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, \( \phi_m \), for two wings of a fracture that cut through a single zone of height, \( h_f \).

\[
V_m = 4h_f L_p L_f \phi_m 
\]
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, \( L_f \), and the volume of gelant injected, \( V \). Eq. 3 is derived in Appendix A of Ref. 4.

\[
\frac{V}{V_f} = -\ln(1 - \frac{L}{L_f})
\]  

(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.

\[
u = -\frac{q_w C \left[ e^{-CL} + e^{2CL} e^{-CL} \right]}{2h_f (1 - e^{2CL})}
\]  

(4)

In Eq. 4, \( q_w \) is the total volumetric injection rate, and \( C \) is a constant given by Eq. 5.

\[
C = \sqrt{2k_m / (k_f w_j r_e)}
\]  

(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.

\[
\frac{u}{u_0} = \frac{e^{CL} + e^{2CL} e^{-CL}}{1 + e^{2CL}}
\]  

(6)

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

**Fig. 2** plots \( u/u_0 \) 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).

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

(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.

\[
C = \sqrt{\frac{2F_r k_m}{k_f w_j (r_e - L_p) + F_r L_p}}
\]  

(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.

\[
\frac{C'}{C} = \sqrt{\frac{F_r r_e}{(r_e - L_p) + F_r L_p}}
\]  

(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, $F_m$, (i.e., the residual resistance factor) in the gel-contacted part of the rock.

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

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 geometry factor is uniform but only to some distance, $L$, along the fracture? In that case, $J_a/J_b$ is given by Eq. 11.

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

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. Examples of such calculations are given in the following sections.

**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. 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., $C_{L_r} < 1$). The water zone is effectively ten-times more permeable than the oil zone, the aqueous phase porosity (at $S_w$) 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., $F_{mw}=100$) and permeability to oil by a factor of 10 (i.e., $F_{mo}=10$). Before gelation, the gel is 20 times more viscous than water ($F_v=20$). How much gel 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 $F_{mw}=10$ provides a 10% loss of oil productivity if the leakoff distance in the oil zone ($L_{p1}$) is 6.2 ft.

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

For this distance of gelation penetration in the oil zone, the distance of gelation penetration in the water zone ($L_{p2}$) can be estimated using Eq. 1 of Ref. 5 (i.e., Eq. 13).

$$\frac{L_{p2}}{L_{p1}} = \frac{\sqrt{1 + (F_{rr}^2 - 1)(\phi_k k_2) / (\phi_k k_1)} - 1}{F_r - 1} \tag{13}$$

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

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

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

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

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.

$$V = 4 L_f (h_o \phi_l L_{p2} + h_w \phi_l L_{p1})$$

$$V = 4(50)(25(0.15)6.2 + 25(0.15)21.8)/ 5.61 = 3,750 \text{ bbl...} \tag{16}$$

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.

$$V = 4 \sum L_{p0} \phi_l h_p \phi_i \tag{17}$$

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 gels (e.g., containing ≥0.5% HPAM). For dilute gels, 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 $F_{rw}=1$ and $F_{ro}=100$? 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 $F_{rw}/F_{ro}$ ratio, the gelant volume required to achieve a given WOR reduction is inversely proportional to $F_{ro}$, if $F_{ro}$ 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.

\[
0.93 = \frac{1 + (6.2/500)(10 - 1)(1 - 50/75)}{1 + (6.2/500)(10 - 1)} \quad (18)
\]

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

\[
0.46 = \frac{1 + (21.8/500)(100 - 1)(1 - 50/75)}{1 + (21.8/500)(100 - 1)} \quad (19)
\]

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

\[
WOR_{\text{final}} = \left( \frac{J_a^o/J_b^o}{J_a^w/J_b^w} \right)_{\text{water}} \quad (20)
\]

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 CLf Values.**

The previous sections demonstrated that the CLf value must be below a value of 1 to ensure that leakoff is uniform along the length of the fracture. How are CLf 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. 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 and Holditch 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 CLf 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).

\[
J_a = \frac{\sum kh}{141.2 \mu \ln(r_e / r_w)} \quad (21)
\]

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 $S_o$). (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).

\[
J = \frac{q}{\Delta p}
\]  

(22)

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

\[
y = \frac{J}{J_o} \ln(0.472 \frac{r_o}{r_w})
\]  

(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.

\[
x = \frac{12k_f r_f \sqrt{40}}{k_m A}
\]  

(24)

Once the minimum x-value is known, the minimum fracture conductivity, \( k_{mf} \), 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 estimated from Eq. 25.

\[
r_e = \sqrt{A/(43,560)(2\pi)}
\]  

(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.

\[
C = \sqrt{\frac{2(0.001)}{16.7(527)}} = 0.0015 \text{ ft}^4
\]  

(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 \( C/L_f \) 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.

\[
x = 12,640 \left( \frac{L_f}{r_e} \right)^2 \left( \frac{1}{C/L_f} \right)^2
\]  

(27)

From Figs. 2 and 3, we noted that uniform leakoff occurs from the fracture faces if \( C/L_f \leq 1 \). Thus, Eq. 27 suggests that if \( C/L_f \leq 1 \), uniform leakoff should occur if \( x \geq 12,640 \). In Fig. 11, this x-value corresponds to a y-value (on the upper-left envelope) of about 6. The y-axis term, \( 7.13(\ln(0.472 \frac{r_o}{r_w})) \), 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 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 (\( L_f = 0.5r_e \)). Alternatively, the right side of Fig. 11 can be used to make the following approximation.

\[
L_f = \left[ \frac{J}{J_o} \right] (0.09 - 0.14) \frac{r_e}{L_f}
\]  

(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 side of Fig. 11.

What range of \( C/L_f \) values is commonly encountered in field applications? This range can be estimated using Fig. 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. If fracture lengths vary from 10 to 500 ft, \( C/L_f \) values could range from 0.001 to 100. Assuming that \( k_m = 100 \) md, \( r_e = 500 \) ft, and \( L_f = 100 \) ft, \( C/L_f \) 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. 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 ($F_{ro}$ and $F_{rw}$ values) from laboratory core experiments. These experiments are easy to perform; 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 $F_{ro}$ and $F_{rw}$ 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

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<thead>
<tr>
<th>Symbol</th>
<th>Description</th>
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<tbody>
<tr>
<td>$A$</td>
<td>well spacing, acres [m²]</td>
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<tr>
<td>$C$</td>
<td>constant defined by Eq. 5, ft⁻¹ [m⁻³]</td>
</tr>
<tr>
<td>$C'$</td>
<td>constant defined by Eq. 8, ft⁻¹ [m⁻³]</td>
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<tr>
<td>$F_r$</td>
<td>resistance factor (brine mobility before gelant placement divided by gelant mobility)</td>
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<td>$F_{rw}$</td>
<td>residual resistance factor (mobility before gel placement divided by mobility after gel placement)</td>
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<td>oil residual resistance factor</td>
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<td>$k_w$</td>
<td>permeability to water at resident oil saturation, md [μm²]</td>
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<td>$L$</td>
<td>distance along a fracture, ft [m]</td>
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<td>$L_f$</td>
<td>length of one wing of a fracture, ft [m]</td>
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<td>$L_{pi}$</td>
<td>distance of gelant penetration (leakoff) from a fracture face in Zone i, ft [m]</td>
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<td>pressure, psi [Pa]</td>
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</tr>
<tr>
<td>$r_w$</td>
<td>wellbore radius, ft [m]</td>
</tr>
<tr>
<td>$S_{or}$</td>
<td>residual oil saturation</td>
</tr>
<tr>
<td>$u$</td>
<td>superficial or Darcy velocity or flux, ft/d [cm/s]</td>
</tr>
<tr>
<td>$u_o$</td>
<td>flux at the wellbore, ft/d [cm/s]</td>
</tr>
<tr>
<td>$V$</td>
<td>gelant volume, bbl [m³]</td>
</tr>
<tr>
<td>$V_f$</td>
<td>fracture volume, bbl [m³]</td>
</tr>
<tr>
<td>$V_m$</td>
<td>gelant volume in the rock matrix, bbl [m³]</td>
</tr>
<tr>
<td>$w_f$</td>
<td>fracture width, inches [m]</td>
</tr>
<tr>
<td>$x$</td>
<td>abscissa value in Fig. 11</td>
</tr>
<tr>
<td>$y$</td>
<td>ordinate value in Fig. 11</td>
</tr>
<tr>
<td>$\mu$</td>
<td>fluid viscosity, cp [mPa-s]</td>
</tr>
<tr>
<td>$\mu_w$</td>
<td>water viscosity, cp [mPa-s]</td>
</tr>
<tr>
<td>$\phi_r$</td>
<td>porosity in the fracture</td>
</tr>
<tr>
<td>$\phi_i$</td>
<td>effective aqueous-phase porosity in Zone i</td>
</tr>
<tr>
<td>$\phi_m$</td>
<td>porosity in the rock matrix</td>
</tr>
</tbody>
</table>

Acknowledgments
Financial support for this work is gratefully acknowledged from the United States Department of Energy, BDM-Oklahoma, ARCO, British Petroleum, Chevron, Chinese Petroleum Corp., Conoco, Eni, Exxon, Halliburton, Marathon, Norsk Hydro, Phillips Petroleum, Saga, Schlumberger-Dowell, Shell, Statoil, Texaco, and Unocal.
APPENDIX—Method for Sizing Gelant Treatments in Hydraulically Fractured Production Wells

1. Estimate the rock permeabilities (k, in md), porosities (ϕ), and thicknesses (h, in ft) for the oil and water zones of interest. Core analysis data on unfractured cores are preferred. Correct the kw values so they reflect the permeability at the resident oil saturation (e.g., at Sw).  

2. Estimate the productivity of an unfractured, undamaged well, Jw, in bbl/D-psi, using Eq. A-1.  
   \[ J_w = \sum k_h / [141.2 \mu \ln (r_e / r_w)] \]  
   \[ \text{A-1} \]

3. Calculate the actual total well productivity for the fractured well, J, in bbl/D-psi, and determine the ratio, J/Jw. The well may be a good candidate for a gel treatment if all five of the following conditions are met: a) J/Jw 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 (Frw and Frm) using gelant, oil, brine, rock, and temperature that are representative of the intended application.  

5. Estimate the external drainage radius, re, in ft, for the well spacing, A, in acres.  
   \[ r_e = \sqrt{A(43,560)/(2\pi)} \]  
   \[ \text{A-2} \]

6. Calculate the desired distance of gelant leakoff in the oil zone(s), Lp2 in ft, for the target final oil-productivity level(s), J/Jo (e.g., J/Jo=0.9). (J/Jo=J_final/J_before)  
   \[ L_p = r_e [(J_o / J_a) - 1] / (F_{rw} - 1) \]  
   \[ \text{A-3} \]

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), Lp1 in ft. If more than two zones are present, repeat this step for each zone. (F, is the gelant resistance factor.)  
   \[ L_p = (F_r - 1) L_p / \left[1 + (F_r^2 - 1)(\phi_k_2/\phi_k_1) - 1\right] \]  
   \[ \text{A-4} \]

8. Use Eq. A-5 and Frw to calculate J/Jw values for the water zone(s).  
   \[ J_a / J_o = 1 / [1 + (L_{p1} / r_e)(F_{rw} - 1)] \]  
   \[ \text{A-5} \]

9. Find Lp, assume that L=0.5 re, or use Eq. A-6.  
   \[ L_p = (J / J_o)(0.09) - 0.14 r_e \]  
   \[ \text{A-6} \]

10. Determine the gelant volume to be injected.  
    \[ V = 4L_p \sum h_i \phi_i \]  
    \[ \text{A-7} \]

11. Estimate the final expected WOR.  
    \[ \text{WOR}_{final} = (\text{WOR}_{initial})(J_a / J_o)_{water} / (J_a / J_o)_{oil} \]  
    \[ \text{A-8} \]

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 = m³
- md x 9.869 233  E-04 = μm²
- psi x 6.894 757  E+00 = kPa

*Conversion is exact.
\[ \frac{V}{V_f} = -\ln(1-L/L_f) \]

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

\[ \frac{C}{C} \]

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

\[ \frac{L/L_f}{100} \]

Fig. 5—Productivity retained when gel extends over the entire fracture face. \( r_c=500 \text{ ft} \).

\[ \frac{L/L_f}{10000} \]

Fig. 6—Productivity retained when gel covers part of the fracture area. \( L_p=1 \text{ ft} \), \( r_c=500 \text{ ft} \).
Fig. 7—Productivity retained when gel covers part of the fracture area. \( L_p = 10 \) ft, \( r_p = 500 \) 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. \( F_{rw} = 100, F_{ro} = 10 \).

Fig. 10—Sensitivity of Example 1 to gelant volume. \( F_{rw} = 1,000, F_{ro} = 100 \).

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