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Abstract

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Sizing Gelant Treatment for Conformance Control in Hydraulically-fractured Horizontal Wells

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Abstract
Horizontal wells are subject to water breakthrough problems caused by natural or hydraulic fracture connections. Treatment with gelant normally is an effective choice. However, at present, no methods can provide quantitative guidance for designing gelant treatment in fractured horizontal wells. In this paper, we proposed a fracture-conductivity-based analytical model to guide sizing gelant treatment in hydraulically fractured horizontal wells. It includes the evaluation of fracture number intersected with the horizontal well, calculation of gelant leakoff distance according to the desired water productivity reduction, and the method to determine optimal gelant volume. The principle for controlling gelant injection and the method for forecasting water shutoff performance are also included. The successful application is based on two requirements: (1) gelant can penetrate a short distance from fracture surface into adjacent matrices; and (2) gelant or gel can reduce permeability to water more than to hydrocarbon. Finally, we summarize a 9-step procedure for sizing gelant treatment in fractured horizontal wells. This work provides quantitative guidance for water shutoff treatment using cross-linked polymer gels that create disproportionate permeability reduction.

Introduction
Unconventional reservoirs generally have low-permeability matrix, and thus require either natural or induced fracture networks to maintain the economic rate of recovery (Cramer 2008). Hydraulic fracturing, horizontal and multilateral wells, and well stimulation, are common ways to improve ultimate oil recovery in unconventional reservoirs (Lake et al. 2014). However, when an injector is connected to fractures, these express flow channels can lead to an undesirable early breakthrough of injected fluids. If some producers are drilled near or into an aquifer, water influx becomes a severe problem as water can easily travel through the fracture network. This phenomenon makes extensively developed fracture systems more susceptible to excess water production. In the past decade, horizontal drilling has been employed extensively to increase the contact area between the wells and the reservoir to enhance productivity. However, this means more fractures are induced during hydraulic fracturing operations and the aforementioned problems become accentuated. It is reported that for every barrel of oil produced, 3 barrels (or more) of additional water came with it, costing oil companies billions of dollars in the treatment of waste water (Bailey et al. 2000; El-

karsani et al. 2014). We must then strive to reduce water production during the oil extraction process for economic and environmental considerations (Joshi 1991).

The industry as well as academia has invented many different methods and incorporated many different materials to reduce excessive water production. These methods can be generally categorized as chemical or mechanical depending on the materials used (Seright et al. 2001). One must then understand fully what the exact mechanism of excessive water production in order to select a suitable method for treatment (Seright and Liang 1994). Water problems caused by fractures are defined as linear flow problems. Several methods are available in the current literature on determining the flow patterns near a wellbore, utilizing various sources of data (Seright and Martin, 1991; Aguilar 1980; Chen et al. 2016). Seright and other authors have investigated problems where performed or partially formed gel are the best solution (Seright 1988). These studies have been conducted in reservoirs without fractures, or radial flow scenarios. We must modify these methods when encountering linear flow problems to reach the optimal strategy of gel treatment, which concerns gel properties, placement procedures, gel volume and etc. Gelant is the crosslinked polymer solution with low viscosity which will form a gel after gelation. The advantage of gelant over other treating agents is that usually it flows more easily into restricted locations.

A potential problem with gelant treatments in reservoirs without fractures is that during oil and water crossflow, the gelant will cross flow and not be able to effectively plug the water production zone without damaging hydrocarbon production. In this case, the gel treatment is completely wasted unless otherwise modified (Sorbie and Seright 1992). Therefore, in this work, the barriers to crossflow between oil and water zones are a precondition for successful treatment (Bergem et al. 1997). The disproportionate permeability reduction (DPR) is a property of various polymers and gels that reduce the relative permeability of water more than hydrocarbon (Sparlin 1976; Liang et al. 2018). The DPR property is accentuated when the oil and gas zones are distinctively separated from the water zone (Liang et al. 1993). One can show via elementary calculations that DPR will better enhance gel treatments in linear flow than in radial flow systems, which means that fractures system will benefit more. As the gel is introduced into the fractures and leaks off into the matrix nearby (Marin et al. 2002), the pressure gradient might not be able to carry the oil through the gel after the treated well resumes production if the leakoff distance is too large, which in turns means that we must control the leakoff distance.

The approaches to planning a gelant treatment differ for production well treatment using gelant. The empirical nature of those methods may be a key reason for their erratic uncontrollable success rates. Seright et al. (1997) previously developed a method for sizing gelant treatments in hydraulically fractured vertical wells. However, their method didn't consider the conditions of horizontal wells. In this paper, we extend their work to sizing gelant treatments in hydraulically fractured horizontal wells. The goal of this work is to provide quantitative guidance for gel treatments in fractured horizontal wells. This paper will first show the mathematical development of our method. Then a 9-step procedure is summarized for sizing gelant treatments in hydraulically fractured horizontal wells.

Methodology

Figure 1 shows the general gelant treatment process in fractured horizontal wells. If there are several vertical fractures intersecting a horizontal wellbore, gelant will leak off from fracture surface into the matrix during gelant injection. After gelation, a gel barrier will form and provide additional flow resistance. There are three key issues in this process. The first is fracture number intersecting the horizontal wellbore. The second is the gelant leakoff distance. If the fractures penetrate into two layers, the leakoff distance should be calculated separately. The third is the productivity reduction caused by the gel barrier. Section Total Gelant Volume explains how to calculate the total gelant volume. Section Fracture Parameters shows the calculation of fracture number based on reservoir engineering analysis. Section Leakoff Distance Considering Oil Productivity Recovering answers the second and third issues during gelant treatment. The last section provides principle methodology for gelant injection and the method of forecasting water shutoff performance.

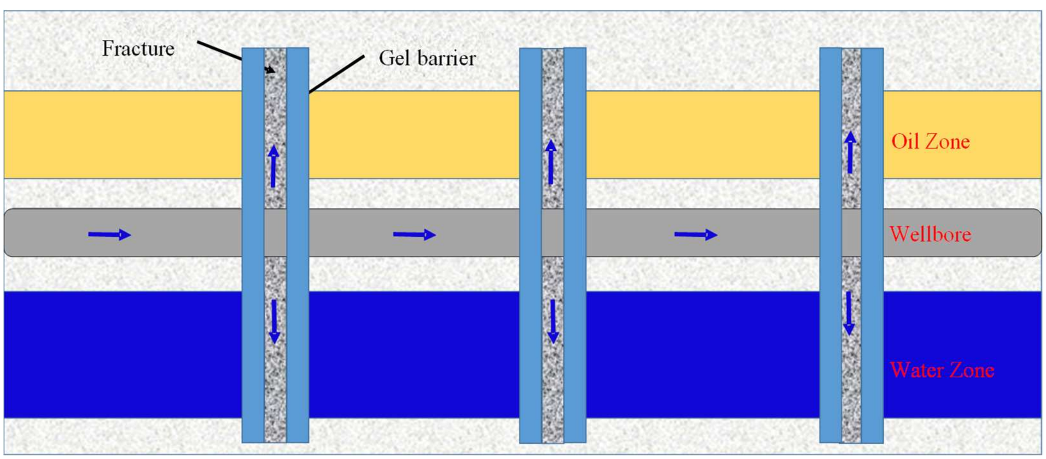

Figure 1—Schematic diagram of gelant treatment in fractured horizontal wells

Total Gelant Volume

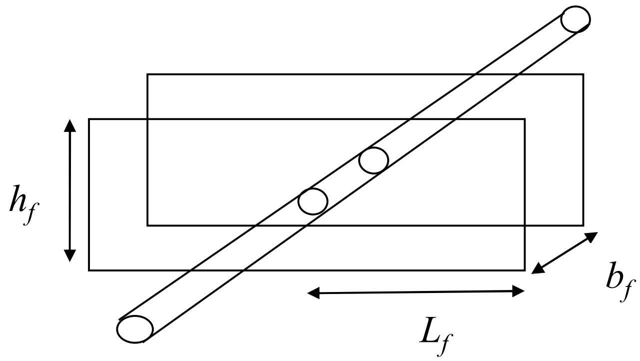

Figure 2—Schematics of vertical fractures meeting with horizontal well

As shown in Fig. 2, suppose the fracture is perpendicular to the horizontal wellbore. The fracture has two wings with height h_f, half-length L_f, porosity ϕ_f, and effective width b_f. The total gelant volume in the fracture is expressed as

$$V_f = 2h_f L_f b_f \phi_f \tag{1}$$

During treatment, gelant leaks off into the matrix nearby the fractures. Assume the leakoff profile is even with a leakoff distance L_p and the matrix porosity is ϕ_m. We will discuss the more complicated case of L_p later. The total gelant volume in the matrix V_m is given by

$$V_m = 4h_f L_p L_f \phi_m \tag{2}$$

V_m is much larger than V_f. And,

$$V_m / V_f = 2L_p \phi_m / b_f \phi_f \tag{3}$$

If L_p =0.6 m, ϕ_f =0.6, b_f =3 mm, and ϕ_m =0.3, then V_m / V_f is 100. Use of Eq. 3 can demonstrate that the gelant leakoff volume is substantially greater than gelant volume in fractures. In practical calculations for sizing gelant treatments, we can neglect V_f.

A gel or gelant that exhibits disproportionate permeability reduction works only when there exist distinct oil zones and water zones. Hence, we assume the horizontal well or the vertical fractures intersect multiple layers. Suppose there are n' vertical fractures intersecting the wellbore with height h_{fi}, effective width b_f, porosity ϕ_f, half-length L_{fi}, and leakoff distance L_{pi} for the layer i. The total gelant volume is

$$V = V_f + V_m = 2n' L_f \sum (h_{fi} b_f \phi_{fi} + 2h_{fi} L_{pi} \phi_m) \tag{4}$$

The unknowns in Eq. 4 are the fracture parameters and the gelant leakoff distance, which will be elaborated in the following sections.

Fracture Parameters

The oil production equation for a horizontal well (Joshi, 1988) is given by

$$Q_H = \frac{2\pi K_H h \times \Delta P / (B\mu)}{\ln\left[\frac{a+\sqrt{a^2-\left(L/2\right)^2}}{L/2}\right] + \frac{\beta h}{L}\ln(\frac{\beta h}{2r_w})} \tag{5}$$

Where a represents the half-length of the major axis of a drainage ellipse. a is defined as

$$a = \frac{L}{2}[\frac{1}{2} + \sqrt{\frac{1}{4} + (2r_{eH}/L)^4}]^{\frac{1}{2}} \tag{6}$$

Here, $L > h$, $(L/2) < 0.9r_{eH}$. r_{eH} represents the drainage radius. β represents the reservoir anisotropy and can be written as

$$\beta = \sqrt{K_H / K_V} \tag{7}$$

Equation 5 is the production equation for an openhole completion, which neglects skin factors caused by the completion method and formation damage. Without the existence of natural fractures or hydraulic fractures, the actual production rate from a horizontal well will be less than the value from Eq. 5.

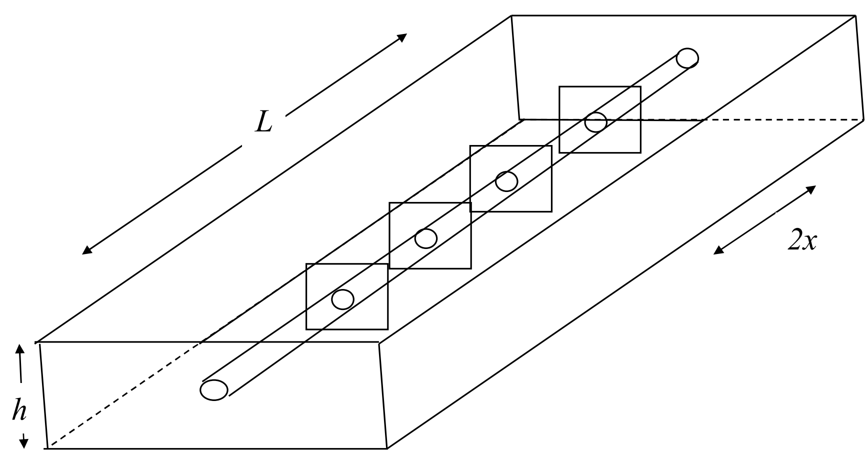

Figure 3—Vertical fractures in a horizontal well

Mukherjee and Economides developed a method to estimate the minimum number of infinite-conductivity vertical fractures that are required to match the openhole production (Mukherjee and

Economides, 1991). This method is also applicable when massive natural fractures in a tight formation are penetrated by a horizontal wellbore. As shown in Fig. 3, if n orthogonal hydraulic fractures of half-length L_f are required to match the openhole production, and each fracture produces with a production rate q_{fH}, where

$$Q_H / \Delta p = n q_{fH} / \Delta p \tag{8}$$

Assuming the distance between two fractures is $2x$ and the linear flow from a formation to a fracture is the only contributor to the horizontal well, then

$$x = L / [2(n-1)] \tag{9}$$

$$q_{fH} / \Delta p = [2k_H (2L_f h)] / \mu B x \tag{10}$$

Combining Eq. 5, Eq. 8 and Eq. 10, we get

$$J_H = \frac{2\pi K_H h / (B\mu)}{\ln\left[\dfrac{a + \sqrt{a^2 - (L/2)^2}}{L/2}\right] + \dfrac{\beta h}{L}\ln(\dfrac{\beta h}{2r_w})} = [2nk_H (2L_f h)] / \mu B x \tag{11}$$

Let

$$C_0 = \ln\left[\frac{a + \sqrt{a^2 - (L/2)^2}}{L/2}\right] + \frac{\beta h}{L}\ln(\frac{\beta h}{2r_w}) \tag{12}$$

Replacing the x and C_0 yields

$$n(n-1) = [L\pi / (4C_0 L_f)] = D \tag{13}$$

The number of fractures n is given by

$$n = (1 + \sqrt{1+4D}) / 2 \tag{14}$$

Assuming the actual production rate of one horizontal well is m times of the openhole production, the number of vertical fractures required to match the actual production rate n' must satisfy

$$mJ_H = \frac{2m\pi K_H h/(B\mu)}{\ln\left[\frac{a+\sqrt{a^2-(L/2)^2}}{L/2}\right]+\frac{\beta h}{L}\ln(\frac{\beta h}{2r_w})} = [2n'k_H(2L_f h)]/\mu Bx \tag{15}$$

Similarly, we can combine Eq. 15, Eq. 9 and Eq. 12 gives

$$n'(n'-1) = [mL\pi/(4C_0 L_f)] = D' \tag{16}$$

$$n' = (1+\sqrt{1+4D'})/2 \tag{17}$$

Equation 17 gives the number of infinite-conductivity vertical fractures required to match the total production rate of a fractured horizontal well.

The following is an example showing the application of Eq. 17. Suppose the length of a given wellbore is 600 m, the layer thickness is 30 m, the heterogeneity factor is 3, the drainage radius is 450 m, r_w is 0.11 m, m is 4, the half-length of the fracture is 61 m. The fracture number is calculated as below

$$\begin{aligned} a &= \frac{L}{2}[\frac{1}{2}+\sqrt{\frac{1}{4}+(2r_{eh}/L)^4}]^{\frac{1}{2}} \\ &= \frac{600}{2}[\frac{1}{2}+\sqrt{\frac{1}{4}+(\frac{900}{600})^4}]^{\frac{1}{2}} = 502.4 \end{aligned}$$

$$\begin{aligned} C &= \ln\left[\frac{a+\sqrt{a^2-(L/2)^2}}{L/2}\right]+\frac{\beta h}{L}\ln(\frac{\beta h}{2r_w}) \\ &= \ln\left[\frac{502.4+\sqrt{502.4^2-(300)^2}}{300}\right]+\frac{90}{600}\ln(\frac{90}{0.22}) = 1.1+0.9 = 2 \end{aligned}$$

$$D' = [mL\pi/(4CL_f)] = 15.44$$

$$n' = (1+\sqrt{1+4D'})/2 = 4.46 \approx 5$$

Thus, at least five 61-meter-long infinite-conductivity vertical fractures are required to match the production rate of the stimulated horizontal well.

If there is no tracer data and well-logging data, the half-length of the fracture can be set as the distance between the target producer and the injector with the strongest connectivity within one or two injector-producer pairs. The height of the fracture is the sum of the thickness of all the layers that the fracture cuts through.

In the upper part, the fracture is assumed to be infinite-connectivity. Agarwal et al. (1979) gives the equation describing the dimensionless fracture flow capacity

$$F_{CD} = \frac{k_f b_f}{k_m L_f} \tag{18}$$

According to the cubic law (Zimmerman 1996)

$$k_f b_f = \frac{b_f^{\ 3}}{12} \tag{19}$$

Combining the two equations gives

$$F_{CD} = \frac{b_f^{\ 3}}{12 k_m L_f} \tag{20}$$

A F_{CD} greater than 500 approximately represents an infinite flow-capacity fracture. We can estimate the minimum fracture aperture using this equation. Assuming the half-length of the fracture is 100 m, the matrix permeability is 50 mD. Then, the width of the fracture should be more than 3.1 mm if the fracture has infinite conductivity.

Leakoff Distance Considering Oil Productivity Recovering

Uniform Leakoff Profile

According to Seright et al. (1997), the leakoff profile along a fracture can be described through the following equation

$$\frac{\mu}{\mu_0} = \frac{e^{CL} + e^{2CL_f} e^{-CL}}{1 + e^{2CL_f}} \tag{21}$$

Where C is a constant given by

$$C = \sqrt{2k_m / (k_f b_f r_e)} \tag{22}$$

L_f represents the half-length of the fracture, L represents the position of gelant front along the fracture. μ denotes the leakoff flux, and μ_0 denotes the leakoff flux at the wellbore. Fig. 3 shows the relationship between μ / μ_0 and L / L_f.

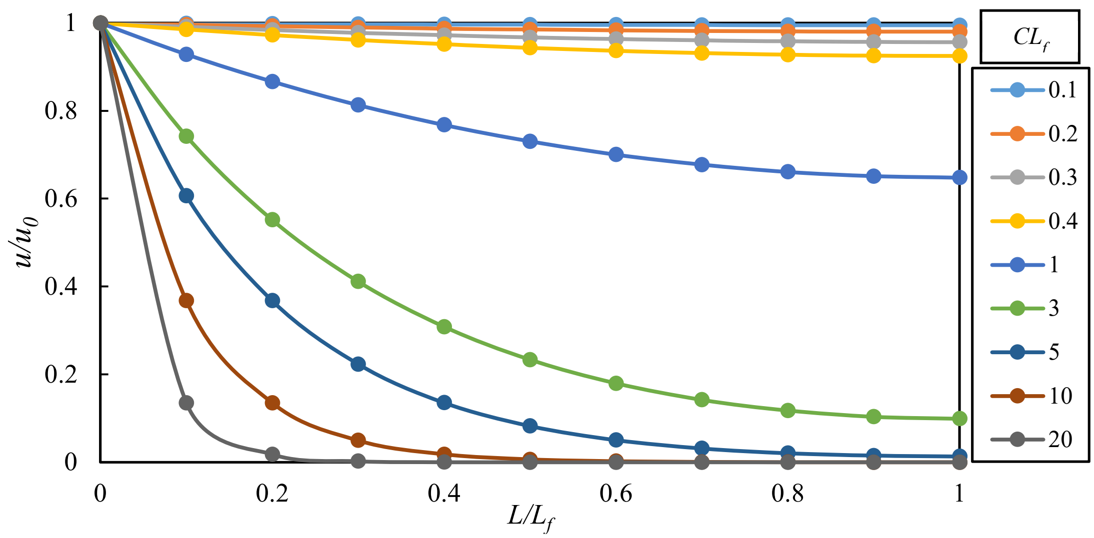

Figure 4—Leakoff flux of gelant vs. gelant front location in fracture under different CL_f

Equation 22 and Fig. 4 provide the fundamental relationship between gelant leakoff and fracture conductivity. When CL_f value is less than 0.3 or 0.4, gelant leakoff flux is almost the same along the fracture. When CL_f is greater than 1, leakoff flux is very dependent on the front position in the fracture.

By re-organizing Eq. 22, the volumetric leakoff profile is given by

$$\frac{V}{V_f} = [\frac{e^{-CL_f} - e^{CL_f}}{2CL_f}]\ln[(\frac{e^{CL_f} - e^{CL}}{e^{CL_f} + e^{CL}})(\frac{e^{CL_f} + 1}{e^{CL_f} - 1})] \tag{23}$$

V denotes the total gelant volume injected, V_f denotes fractures volume behind the gelant front. Eq. 23 is used to generate Fig. 5.

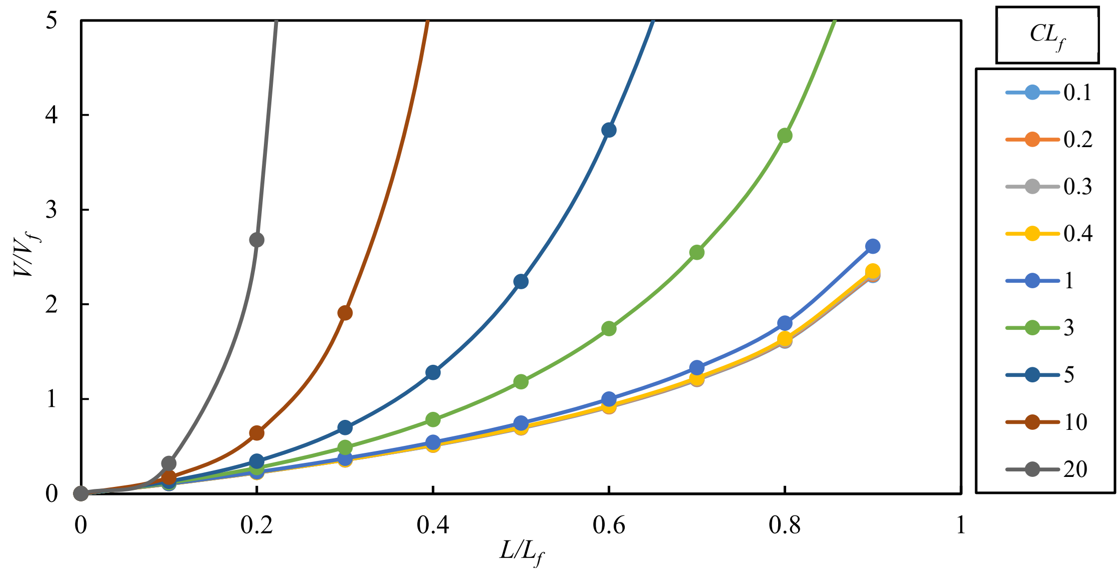

Figure 5—Gelant volume vs. gelant front position in fracture under different CL_f

When CL_f is less than 1, we can observe a stable leakoff profile along the fracture. However, when CL_f is greater than 1, significant variations occur. For example, assuming two fracture volumes of gelant are injected, the position of gelant front is 0.82 for $CL_f = 1$, while the position of gelant front is 0.3 for $CL_f = 10$. The example shows that CL_f value is an important parameter for designing gelant treatment in fractured reservoirs and 1 is supposed to be a threshold. If CL_f is less than 1, the leakoff profile is independent of fracture length. Thus, it is essential to evaluate CL_f to figure out the leakoff profile.

In our procedure, we assume all fractures have infinite-conductivity. Combining Eq. 18 and Eq. 22 yields

$$CL_f = \sqrt{2k_m L_f^{\ 2} / (k_f b_f r_e)} = \sqrt{2L_f / (F_{CD} r_e)} \tag{24}$$

For infinite-conductivity fracture, the CL_f is apparently less than 1. According to the discussion in Fig. 5, we can get that the leakoff profile in the infinite-conductivity fracture is independent of distance along the fracture.

If well-logging data is accessible in determining fracture apertures and other fracture parameters, we should carefully evaluate CL_f and it is possible that the CL_f value would be less than 1. For this consideration, we will discuss the leakoff profile along the fracture with a CL_f less than 1.

Leakoff Distance vs. Oil Productivity Recovery Rate

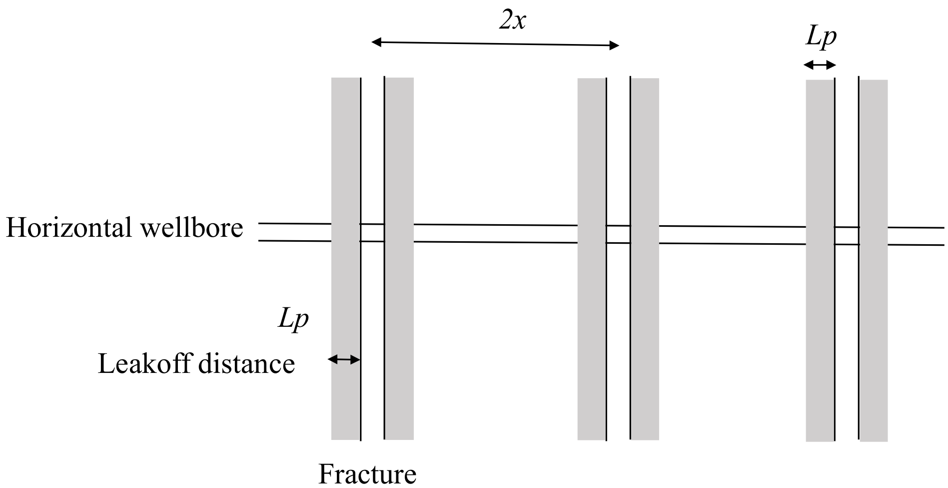

Figure 6—Schematic diagram of gel leakoff distance from the fracture surfaces

Figure 6 shows the even leakoff distance along fractures. Based on Mukherjee's assumption, the production rate in each infinite-conductivity fracture before gel treatment is

$$Q_b = \frac{2k_m \Delta p (2L_f h)}{\mu B x} \tag{25}$$

After gel treatment, assuming L_p represents the leakoff distance and F_{rr} represents the residual resistance factor (relative permeability reduced by the gel) in the matrix after gel treatment, the post-gel treatment production rate is

$$Q_a = \frac{2\Delta p (2L_f h)}{\mu B} \frac{1}{(\frac{L_p F_{rr}}{k_m} + \frac{x - L_p}{k_m})} \tag{26}$$

The ratio is

$$\frac{J_a}{J_b} = \frac{1}{1 + (L_p / x)(F_{rr} - 1)} \tag{27}$$

Figure 7 plots the J_a/J_b vs. F_{rr} under different leakoff distance with the assumption that the distance between the two fracture $2x$ is 120 m. For gelant treatment, we assume the well productivity was reduced by the gel in the matrix more than that in the fracture.

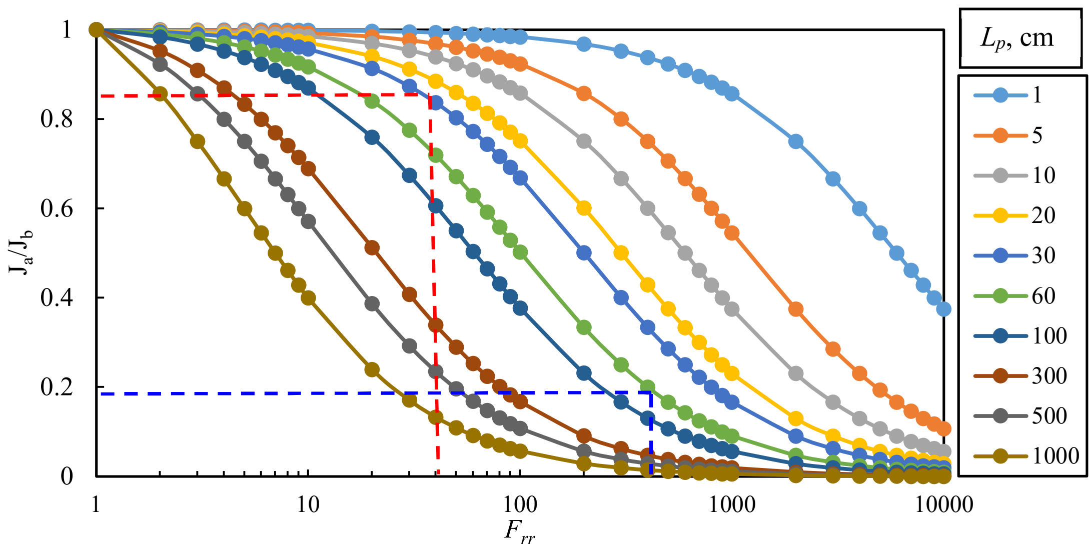

Figure 7—Effect of F_{rr} on productivity index ratio J_a/J_b

Figure 7 and Eq. 27 provide very useful guidance for designing gelant treatments in fractured production wells. For example, assuming the residual resistance factor to water is 400 and the water production rate is reduced to 20%, the leakoff distance in the water zone should be 60 cm. Or, assuming the residual resistance factor to oil is 40, if we want to retain 90% of the oil productivity, the oil-zone leakoff distance should be 20 cm. Please note we can only set either water productivity reduction or oil productivity retained as the goal when designing a gelant treatment.

As addressed in the introduction, gelant exhibits the DPR property and our method is only valid for production wells with flow barriers between the oil and water zones. For different zones that horizontal wells or the perpendicular fractures cut through, the leakoff distances in these zones are different, as shown in Fig. 8.

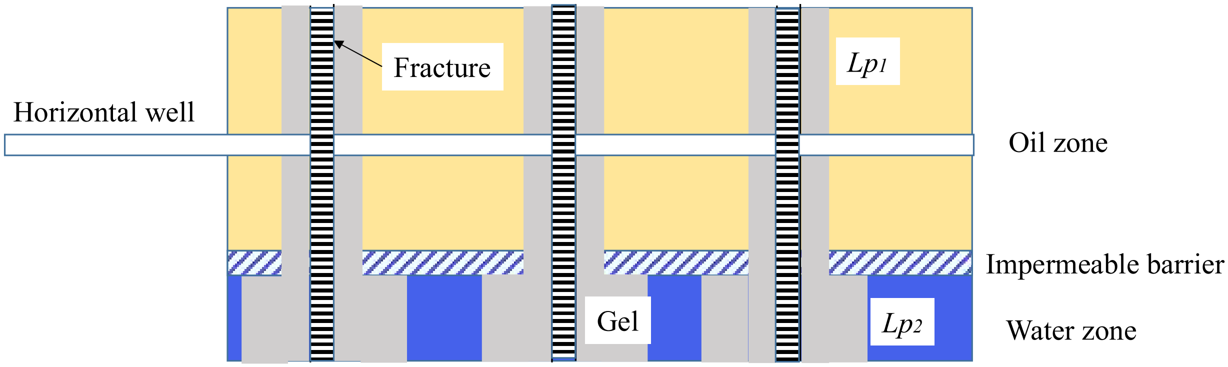

Figure 8—Gelant leakoff in fractured horizontal wells

Assuming the water-zone leakoff distance is L_{p1}, the oil-zone leakoff distance is L_{p2}, the resistance factor of gelant to water is F_r, the porosity in the water zone is ϕ_1 with a permeability k_1, the porosity in the oil zone is ϕ_2 with a permeability k_2, then the relationship between the leakoff distance in the water zone and that in the oil zone is (Seright and Martin 1997)

$$\frac{L_{p2}}{L_{p1}} = \frac{\sqrt{1+\left(F_r^{\,2}-1\right)\left(\phi_1 k_2\right)/\left(\phi_2 k_1\right)}-1}{F_r-1} \tag{28}$$

The Optimal Gelant Leakoff Distance

Table 1—Model parameters

Parameters	**Value**
Fr	30
k_1	0.9 Darcy
k_2	0.1 Darcy
ϕ_1	0.2
ϕ_2	0.14
F_{rro}	30
F_{rrw}	400

We elaborate on the optimal gelant leakoff distance by an example. Suppose the fracture has infinite-conductivity and the basic parameters are the same as in Table 1. The relationship between leakoff distance and water shutoff performance is shown in Fig. 9. J_a/J_b of oil and water are calculated based on Eq. 27. The leakoff distance of water is calculated based on Eq. 28.

With increasing oil leakoff distance, production index ratio (J_a/J_b) of water (solid blue line) decreases faster than oil initially. Meanwhile, the gradient of J_a/J_b curve for water (dashed blue line) decreases faster than that of oil, which means that the productivity of water decreases faster than that of oil. When L_{p2} reaches 39 cm, the slope of J_a/J_b for water is equal to that of oil. After that, the slope of the J_a/J_b curve for oil decreases faster than that of water, which means the productivity of oil decreases faster than that of water. Also, the J_a/J_b of water is not sensitive to leakoff distance as before. Therefore, the optimal oil-zone leakoff distance is 39 cm, which can be calculated using

$$\partial\left(\frac{J_a}{J_b}_{oil}\right)/\partial L_{p2} = \partial\left(\frac{J_a}{J_b}_{water}\right)/\partial L_{p2} \tag{29}$$

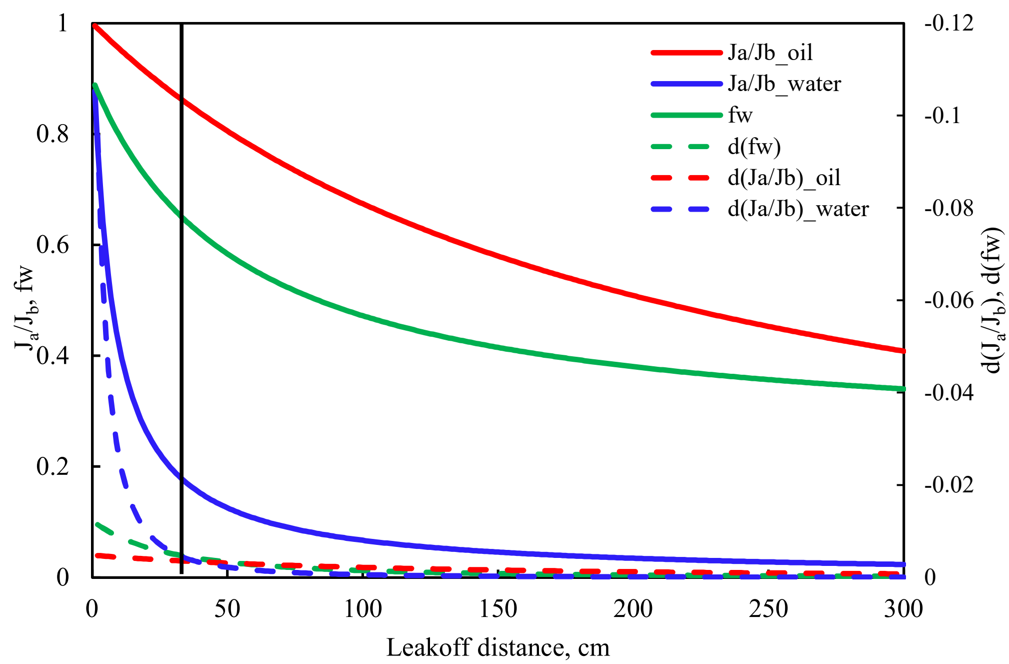

Figure 9—The optimal gelant leakoff distance

When the oil-zone leakoff distance is 39 cm, the post-gel treatment production rate of oil recovers 85% of the initial rate, the post-gel treatment production rate of water recovers 15.5% of the initial rate. That is, the decrease in water productivity is 84.5% indicating a good water shutoff performance. More gelant injection doesn't work better. For example, if the oil leakoff distance increases to 80 cm, the post-gel treatment production rate of oil recovers 72% of the original rate, the post-gel treatment production rate of water recovers only 8.2% of the initial rate. The gelant injection volume doubled, but the further decrease in water productivity is only 7.3% of the initial rate, and the productivity loss of oil is more than water. Therefore, further gelant injection is inadvisable.

Linear Leakoff Profile

When CL_f is less than 1, the leakoff distance will not be uniform. Assume a linear leakoff profile as shown in Fig. 10.

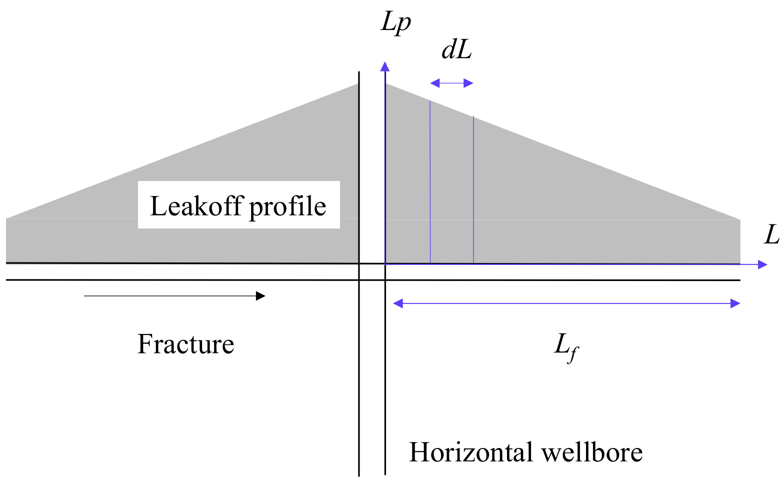

Figure 10—Schematic diagram of the linear leakoff profile along a fracture

Assume the leakoff distance L_{pL} along the fracture is

$$L_{pL} = aL + b \tag{30}$$

Parameter a and b are the leakoff parameters determined by laboratory experiments by simulating the target reservoir conditions. For a small distance dL, the production contribution of this part to the fracture is

$$dQ_a^{'} = \frac{\Delta phk_m}{\mu B} \frac{1}{L_{pL}(F_{rr}-1)+x} dL \tag{31}$$

Integrate Eq. 30 along the whole fracture distance L

$$Q_a^{'} = \int_0^{L_f} 4dQ_a = \int_0^{L_f} \frac{4\Delta phk_m}{\mu B} \frac{1}{L_{pL}(F_{rr}-1)+x} dL = \frac{4\Delta phk_m}{a\mu B(F_{rr}-1)} \ln \frac{(aL_f+b)(F_{rr}-1)+x}{b(F_{rr}-1)+x} \tag{32}$$

$$\frac{J_a^{'}}{J_b} = \frac{x}{L_f a(F_{rr}-1)} \ln \frac{(aL_f+b)(F_{rr}-1)+x}{b(F_{rr}-1)+x} \tag{33}$$

Equation 32 can be used to design gelant volumes when the CL_f value is less than 1. Suppose the distance between two fractures $2x$ is 120 m, L_f is 60 m, b is 0.6 m, this means the maximum leakoff distance near the wellbore is 60 cm. At this time, the effect of a on J_a/J_b is shown below

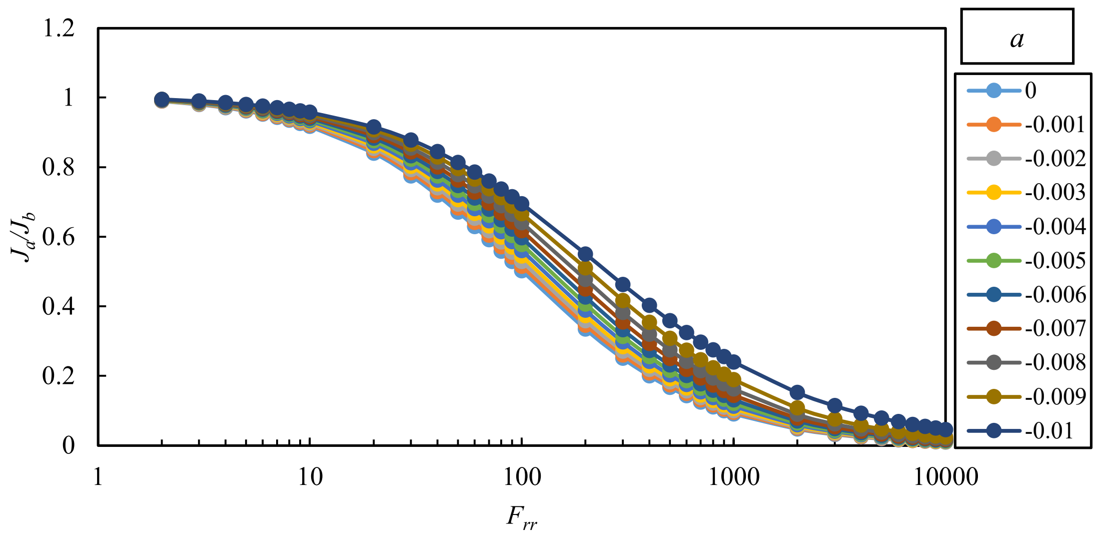

Figure11—Effect of leakoff gradient a on production index ratio J_a/J_b

The changing interval of the parameter a is -0.01 to 0. When a is 0, the leakoff profile is even along the fracture. Compared to Fig. 7, the variation caused by different a is not as obvious as the L_p. Fig. 12 shows the effect of the parameter b, assuming the leakoff gradient a is -0.001.

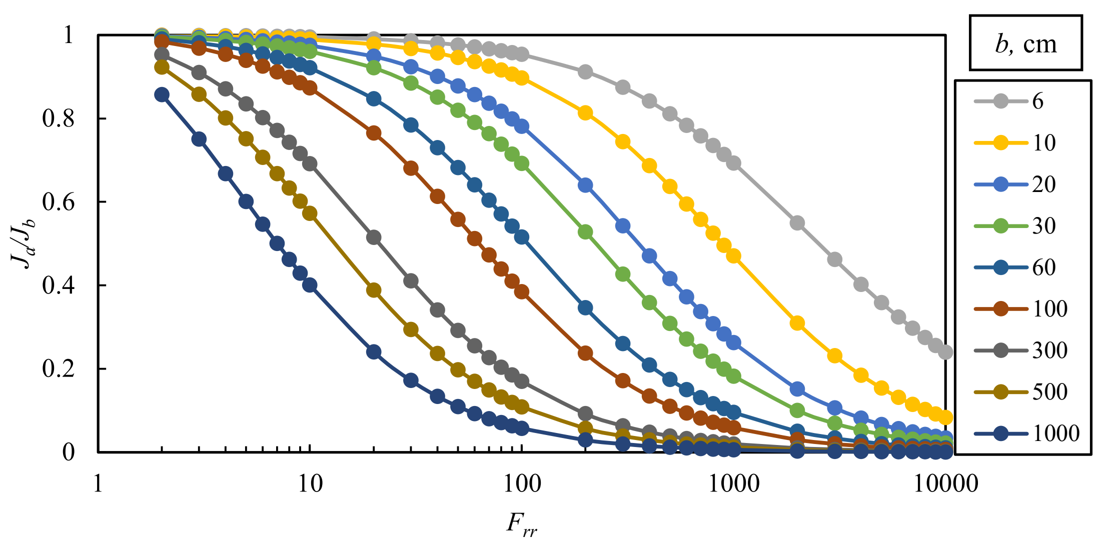

Figure 12—Effect of leakoff Y-intercept b on production index ratio J_a/J_b

The parameter b has a larger effect on J_a / J_b than the parameter a. When performing gelant treatments, these two values should be carefully determined by laboratory experiments that simulate reservoir conditions. We can use Eq. 32 to design gelant volumes based on oil/water productivity reduction when CL_f is less than 1.

Timing for Gelant Injection

The goal for gel treatments is to not only reduce water production but also maintain oil productivity. Therefore, the gelant should be successfully injected as designed. However, there are several concerns should be considered to achieve this objective. The first concern is the gelation time. Fig. 13 shows a typical curve of viscosity vs. time for gelant.

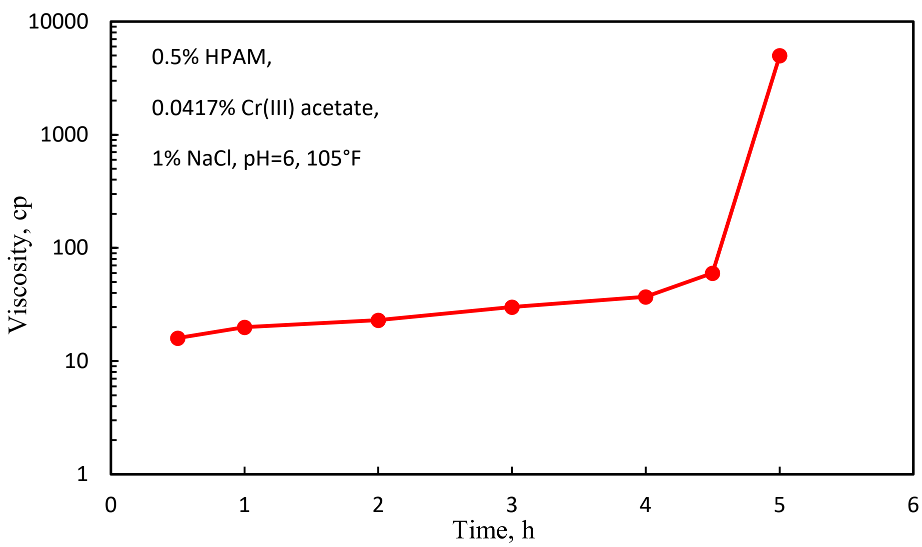

Figure 13—Visco2.sity vs. time during gelation (Seright 1995)

The gelation time is about 4 hours, after which the viscosity of the gel will significantly increase to a large value. After the gel is formed, the gel cannot penetrate into porous rock. Although gel can dehydrate during extrusion through fractures, leakoff of dehydrated water into the matrix has no contribution to our water control as designed. Therefore, all the gelant should be placed before gelation. Based on this consideration, the minimum injection rate we suggest is

$$I_{gelant} = \frac{V}{T} \tag{34}$$

T is time duration before gelation; this value is very important and should be carefully determined in the laboratory. V is the total gelant volume that we design considering water/oil productivity reduction.

If the inherent gelation time is too short or the gel is very sensitive to reservoir conditions, T will be too short and the minimum injection rate may be extremely high, which will require high-pressure differences to push the gelant into the fracture. If the pressure difference is higher than the formation breakdown pressure P_{thres}, new fractures will be created. Therefore, to avoid this situation, the pressure difference required to push the gelant should satisfy

$$P(I_{gelant}) = P(\frac{V}{T}) \le P_{thres} \tag{35}$$

If $P(I_{gelant})$ is larger than P_{thres}, we should add some retarder to prolong the gelation time and accordingly reduce the injection rate.

Procedures for Designing Gelant Treatments

The following is the main steps for designing gel treatment in fractured horizontal wells.

1. Gather the parameters of oil/water zones that of interest (i.e., porosity ϕ_{mi}, permeability K_H, and thickness h_i) and the parameters for horizontal wells (i.e., the length of the horizontal wellbore L, the external drainage radius r_{eH}, and the production rate Q_H).
2. Check whether linear flow exists in the candidate wells using the following equation

$$Q_H \ge \frac{2\pi K_H h \times \Delta P / (B\mu)}{\ln\left[\dfrac{a + \sqrt{a^2 - (L/2)^2}}{L/2}\right] + \dfrac{\beta h}{L}\ln(\dfrac{\beta h}{2r_w})}$$

   If the actual production rate satisfies the equation above, the well is a good candidate for gelant treatment. Otherwise, the flow is not caused by fractures and the procedure in this work is not applicable.
3. Estimate the fracture parameters including the number of vertical fractures, the half-length L_f, the aperture b_f, and the height h_{fi}. If there is well-logging data, take the accurate b_f as a reference.
4. Calculate the key parameter CL_f. If the value is more than 1, the leakoff profile is supposed to be even and stays the same along the fracture. If the value is less than 1, the leakoff profile parameters a and b should be carefully determined by simulating the target reservoir conditions.
5. Determine the F_{rrw} and F_{rro} by use of brine, oil, gelant, rock, a temperature that represents the target reservoirs.

6. Determine the gelant volume according to oil/water productivity design after gelant treatment. If CL_f is more than 1, use

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

Otherwise, use

$$\frac{J_a^{'}}{J_b} = \frac{x}{L_f a(F_{rr}-1)} \ln \frac{(aL_f + b)(F_{rr}-1)+x}{b(F_{rr}-1)+x}$$

Please note, we can only design gelant treatment exclusively based either for a target level of oil productivity (relative to that before the treatment) or for a target level of water production reduction. If we design the oil production in the oil zone, then we should calculate the leakoff distance in the water zone by using

$$\frac{L_{p2}}{L_{p1}} = \frac{\sqrt{1+\left(F_r^{\,2}-1\right)\left(\phi_1 k_2\right)/\left(\phi_2 k_1\right)}-1}{F_r - 1}$$

7. Calculate the total gelant volume

$$V = V_f + V_m = 2n' L_f \sum (h_{fi} b_f \phi_{fi} + 2h_{fi} L_{pi} \phi_m)$$

8. Determine the minimum injection rate

$$I_{gelant} = \frac{V}{T}$$

Make sure that the pressure difference pushes the gelant is less than the formation breakdown pressure. If not, add retarder into the gelant to prolong the gelation time, which will accordingly reduce the required pressure difference.

9. Estimate the oil productivity recovering time (Seright 2006)

$$q_{oil} = q_{end} \frac{2}{\pi} \arctan(9280 t \Delta p k_w / L_p^{\,3})^{\pi/4}$$

We can also estimate the final water cut after gel treatment using the following equation

$$f_w = \frac{Q_{w0}\left(\dfrac{J_a}{J_b}\right)_w}{Q_{w0}\left(\dfrac{J_a}{J_b}\right)_w + Q_{o0}\left(\dfrac{J_a}{J_b}\right)_o}$$

Where Q_{w0} is the water rate before gelant treatment, Q_{o0} is the oil rate before gelant treatment.

Figure 14 shows the flow chart of the procedures for sizing gelant treatment in fractured horizontal wells.

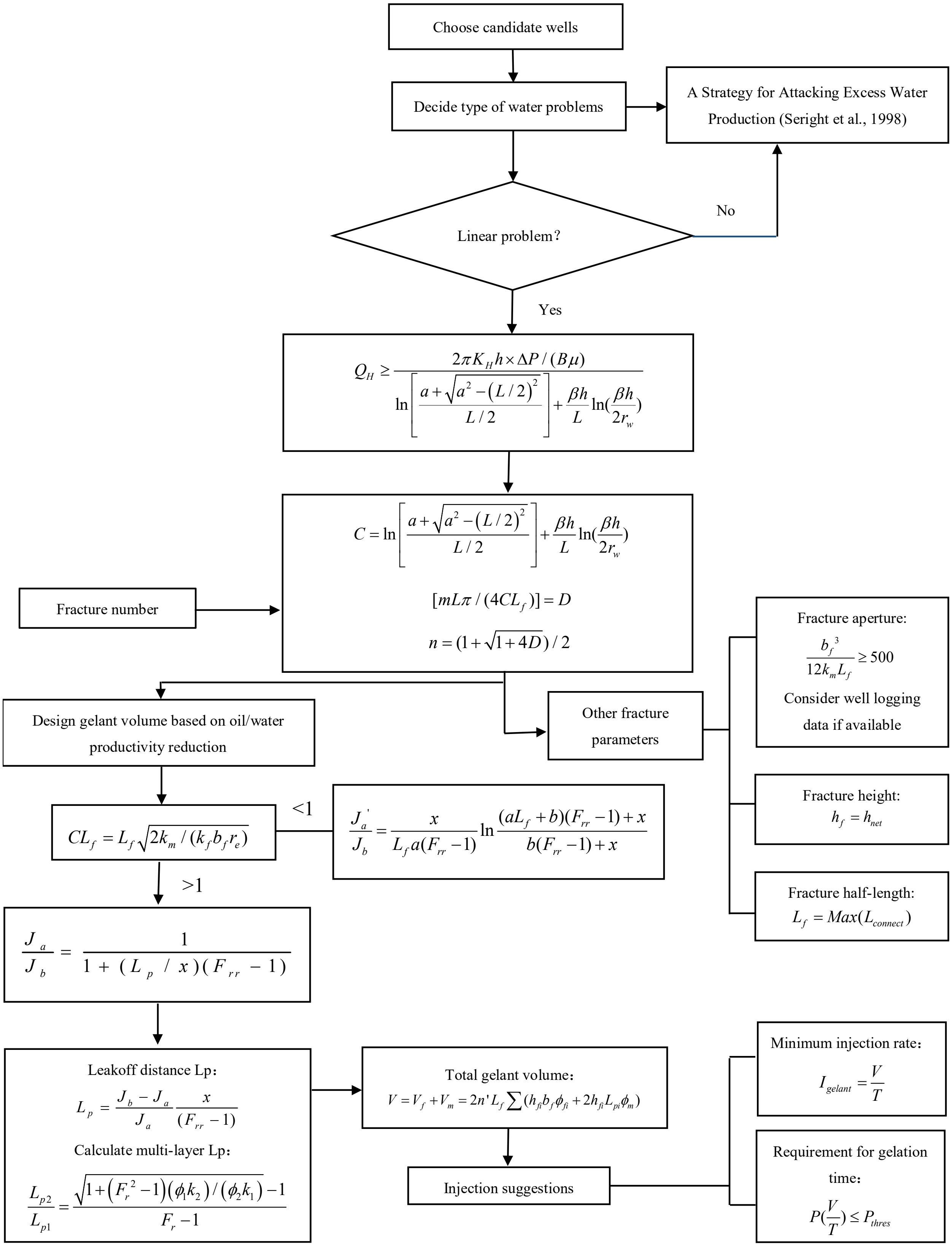

Figure 14—Flow chart of designing gelant treatment in horizontal wells with hydraulically fractures

Conclusions

A 9-step procedure for designing gelant treatment in fractured horizontal wells was presented. The method is proposed for providing quantitative guidance for planning gelant treatment in hydraulically fractured horizontal wells. The procedure should be useful when flow barriers exist between oil and water zones and applied in fractured horizontal wells. However, this procedure may be applicable for sizing gelant treatments in some naturally fractured horizontal wells. Also, this method requires a gel that exhibits the DPR (disproportionate permeability reduction) property, which can significantly reduce the permeability to water more than to oil.

For hydraulically fractured horizontal wells, the fracture parameters can be estimated based on the production dynamics and inter-well connectivity data. For infinite-conductivity fractures, the gelant leakoff profile is uniform and independent of fracture length. The gelant volume can be designed based either on oil productivity reduction or water production reduction. The optimal gelant volume can achieve fairly effective water shutoff performance with maximum cost performance.

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Nomenclature

V total gelant volume, m^3

V_f total gelant volume in the fracture, m^3

V_m total gelant volume in the matrix, m^3

L_f half-length of a fracture, m

h_f fracture height, m

b_f fracture aperture, m

ϕ_f porosity in a fracture

ϕ_m porosity in a rock matrix

L_p leakoff distance from fracture surface, m

n' number of vertical fractures

h_{fi} fracture height in a zone i, m

ϕ_{fi} porosity in a fracture in a zone i

L_{pi} leakoff distance in a zone i

Q_H flow rate into a horizontal well, m^3/D

a half the major axis of major drainage ellipse, m

L horizontal well length, m

β the heterogeneity factor

h the height of a production zone, m

Δp pressure difference, MPa

K_H horizontal permeability, um^2

K_V vertical permeability, um^2

B oil formation volume factor

r_w wellbore radius, m

r_{eH} the radius of an external drainage area, m

μ fluid viscosity, mPa·s

$2x$ the distance between two fractures, m

q_{fH} flow rate from a vertical fracture, m^3/D

F_{CD} dimensionless fracture flow capacity

k_f fracture permeability, um^2

k_m matrix permeability, um^2

μ_0 leakoff flux near a wellbore

μ leakoff flux along a fracture

r_e external drainage radius, m

Q_b flow rate before gelant treatment, m^3/D

Q_a flow rate after gelant treatment, m^3/D

F_{rr} the residual resistance factor

L_{p1} leakoff distance in the water zone, m

L_{p2} leakoff distance in the oil zone, m

F_r resistance factor of gelant to water

L_{pL} leakoff distance at L , m

$Q_a^{'}$ flow rate after gelant treatment for the linear leakoff profile, m^3/D

T gelation time, h

I_{gelant} minimum injection rate, m^3/D

P_{thres} formation breakdown pressure, MPa

q_{oil} oil rate at the time t, m^3/D

q_{end} final oil rate after gel treatment, m^3/D

k_w endpoint water permeability, um^2

Q_{w0} water rate before gelant treatment, m^3/D

Q_{o0} oil rate before gelant treatment, m^3/D

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