Basics of Hydraulic Fracturing

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5-1. Introduction

Since its introduction, hydraulic fracturing has been, and will remain, one of the primary engineering tools for improving well productivity. This is achieved by

- placing a conductive channel through near-wellbore damage, bypassing this crucial zone
- extending the channel to a significant depth into the reservoir to further increase productivity
- placing the channel such that fluid flow in the reservoir is altered.

In this last instance, the fracture becomes a tool for true reservoir management including sand deconsolidation management and long-term exploitation strategies. As first visualized (see the Appendix to this chapter), the concept of hydraulic fracturing was quite straightforward. This visualization is described in the following, and in general, for reasonably simple geology, the basic physics of fracturing is straightforward and well established. Complexity arises from two directions: geologic reality and the inherent multidisciplinary nature of the fracturing process.

Historically, the control of fracturing has rested with drilling and operations groups owing to the nature of field procedures using pumps, packers, pressure limits, etc. However, the final results (and thus design) are dominantly a production engineering exercise, and fracturing cannot be removed from intimate contact with reservoir engineering. At the same time, designing a treatment to achieve the desired results is also intimately connected with rock mechanics (which controls fracture geometry; see Chapters 3 and 4), fluid mechanics (which controls fluid flow and proppant placement inside a fracture; see Chapter 6) and the chemistry that governs the performance of the materials used to conduct the treatment (see Chapters 7 and 8). However, the design must also be consistent with the physical limits set by actual field and well environments. Also, treatments must be conducted as designed to achieve a desired result (i.e., full circle to the critical role of operations). Proper treatment design is thus tied to several disciplines:

- production engineering
- rock mechanics
- fluid mechanics
- selection of optimum materials
- operations.

Because of this absolutely essential multidisciplinary approach, there is only one rule of thumb in fracturing: that there are no rules of thumb in fracturing.

The multidisciplinary nature, along with the difficulty in firmly establishing many of the design variables, lends an element of art to hydraulic fracturing. This is not to say that the process is a mystery nor is it to say that for most cases the basic physics controlling the process is not defined (see Chapter 6). It simply says that the multitude of variables involved, along with some uncertainty in the absolute values of these variables, makes sound engineering judgment important.

5-1.1. What is fracturing?

If fluid is pumped into a well faster than the fluid can escape into the formation, inevitably pressure rises, and at some point something breaks. Because rock is generally weaker than steel, what breaks is usually the formation, resulting in the wellbore splitting along its axis as a result of tensile hoop stresses generated by the internal pressure. The mechanics of this process are described in Section 3-5.7, and the simple idea of the wellbore splitting like a pipe (shown as a cartoon in Fig. 5-1) becomes more complex for cased and/or perforated wells and

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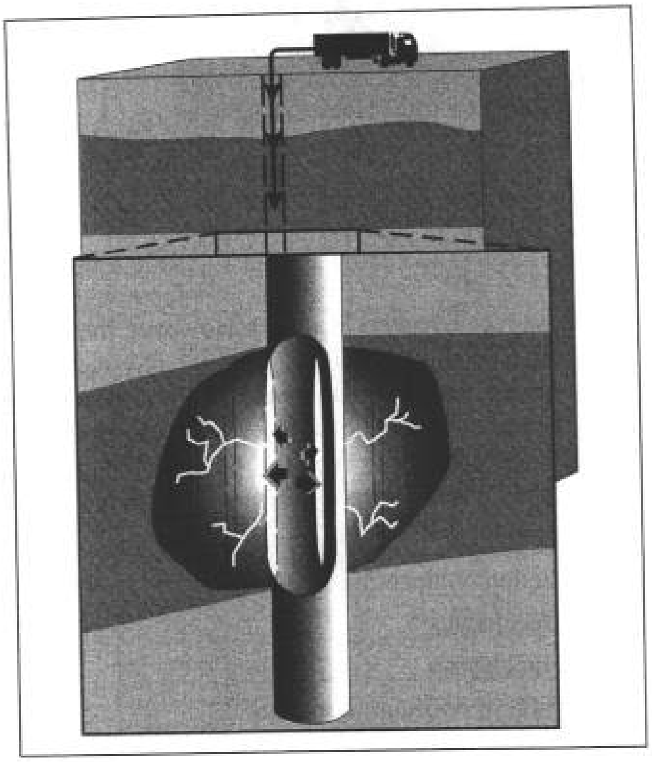


Figure 5-1. Internal pressure breaking a vertical wellbore.

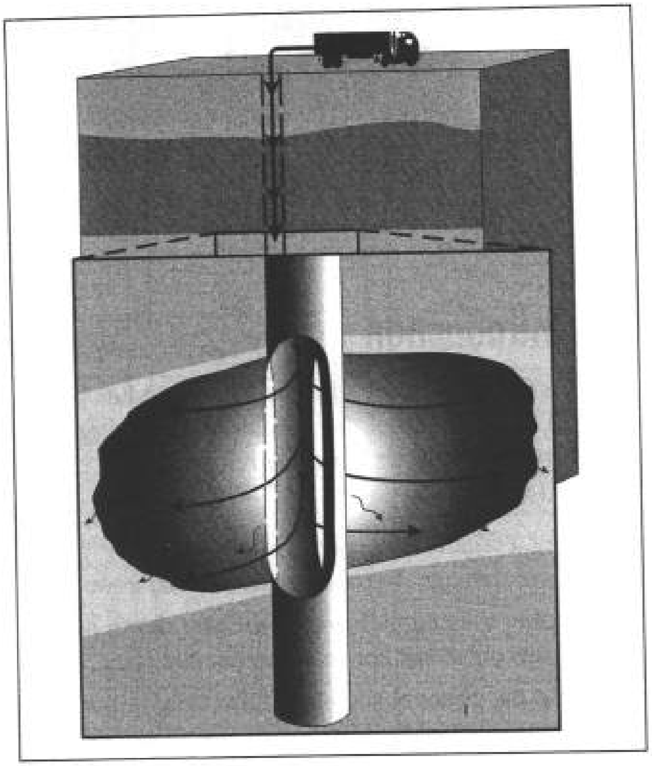


Figure 5-2. Cross-sectional view of a propagating fracture.

nonvertical wells. However, in general, the wellbore breaks—i.e., the rock fractures—owing to the action of the hydraulic fluid pressure, and a "hydraulic" fracture is created. Because most wells are vertical and the smallest stress is the minimum horizontal stress, the initial splitting (or breakdown) results in a vertical, planar parting in the earth.

The breakdown and early fracture growth expose new formation area to the injected fluid, and thus the rate of fluid leaking off into the formation starts to increase. However, if the pumping rate is maintained at a rate higher than the fluid-loss rate, then the newly created fracture must continue to propagate and grow (Fig. 5-2). This growth continues to open more formation area. However, although the hydraulic fracture tremendously increases the formation flow area while pumping, once pumping stops and the injected fluids leak off, the fracture will close and the new formation area will not be available for production. To prevent this, measures must be taken to maintain the conductive channel. This normally involves adding a propping agent to the hydraulic fluid to be transported into the fracture. When pumping stops and fluid flows back from the well, the propping agent remains in place to keep the fracture open and maintain a conductive flow path for the increased formation flow area during production. The propping agent is generally sand or a high-strength, granular substitute for sand (see Section 7-7). Alternatively, for carbonate rocks, the hydraulic fluid may consist of acid that dissolves some of the formation, leaving behind acid-etched channels extending into the reservoir.

After the breakdown, the fracture propagation rate and fluid flow rate inside the fracture become important. They are dominated by fluid-loss behavior. As introduced by Carter (1957) and discussed in the following (and in Chapters 6 and 9), the fluid-loss rate q_L from a fracture can be expressed as

$$q_L \approx \frac{2C_L A}{\sqrt{t-\tau}}, \qquad (5\text{-}1)$$

where C_L is the fluid-loss coefficient, A is an element of the fracture area (i.e., increased inflow area), t is time measured from the start of pumping, and τ is the time when each small area element of a fracture is created or opened. As a direct consequence of this relation, the highest rate of fluid loss is always at the fracture tip. Newly created fracture area exists at that point ($t - \tau = 0$ in the denominator), making q_L instantly infinite.

Initially, fracture penetration is limited, and hence fluid loss is high near the wellbore. For that reason, the first part of a hydraulic fracture treatment consists of fluid only (no proppant); this is termed the pad. The purpose of a pad is to break down the wellbore and initiate the fracture. Also, the pad provides fluid to produce sufficient penetration and width to allow proppant-laden fluid stages to later enter the fracture and thus avoid high fluid loss near the fracture tip. After the pad, proppant-laden stages are pumped to transport propping agent into the fracture. This chapter describes the process for propped fracture treatments; acid fracture treatments are discussed in Section 10-6.

However, because fluid loss to the formation is still occurring, even near the well, the first proppant is added to the fluid at low concentrations. The proppant-laden slurry enters the fracture at the well and flows toward the fracture tip (Fig. 5-3). At this point, two phenomena begin. First, because of the higher fluid loss at the fracture tip, slurry flows through the fracture faster than the tip propagates, and the proppant-laden slurry eventually overtakes the fracture tip. Next, because of fluid loss, the proppant-laden slurry stages lose fluid (but not proppant) to the formation.

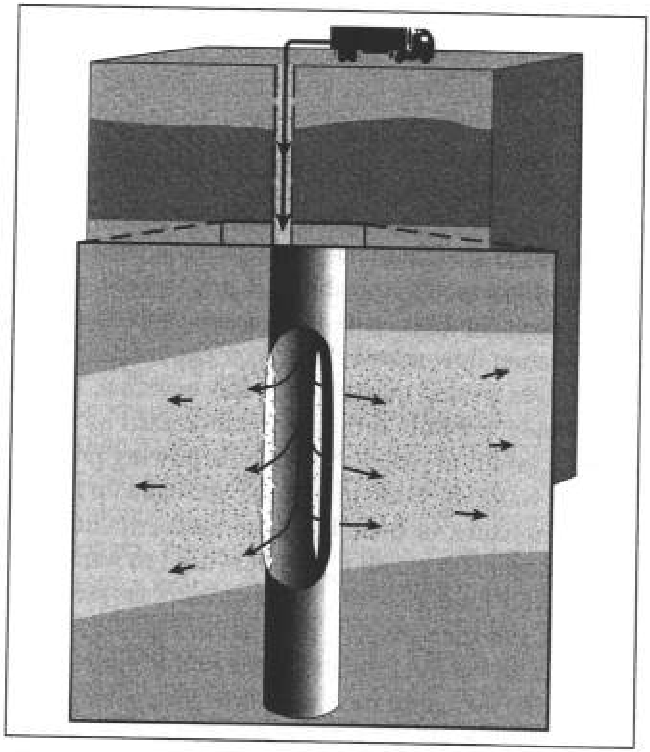


Figure 5-3. Introducing proppant into the fracture.

Thus, proppant concentration (i.e., volume fraction of solid proppant) increases as the slurry stages dehydrate. The pump schedule, or proppant addition schedule, must be engineered much like handicapping horse races, but with no single winner. Rather, all stages should finish at the right place, at the right time, with the right final proppant concentration. The pad should be completely lost to the formation, and the first proppant stage should be right at the fracture tip (which should be at the design length).

As the proppant slurry stages move down the fracture, they dehydrate and concentrate. Slurry stages pumped later in the treatment are pumped at a higher concentration. These stages are not in the fracture for long prior to the treatment end (i.e., prior to shutdown) and are thus exposed to less fluid loss and less dehydration. Ideally, the first proppant stage pumped reaches the fracture tip just as the last of the pad fluid is lost into the formation (a correctly handicapped race), and this first stage has concentrated from its low concentration to some preselected, higher final design concentration. Meanwhile, the slurry concentration being pumped is steadily increased to the same final design concentration. At treatment end, the entire fracture is filled with the design concentration slurry. Design considerations for the final concentration are discussed later in this section and in detail in Section 10-4.

The preceding description might be termed a "normal" design, where the entire fracture is filled with a uniform, preselected, design proppant concentration just as the treatment ends. If pumping continues past that point, there would be little additional fracture extension because the pad is 100% depleted. Continued pumping forces the fracture to become wider (and forces the pressure to increase) because the increased volume simply acts like blowing up a balloon. In some cases the additional propped width that results may be desirable, and this procedure is used purposely. This is termed tip-screenout (TSO) fracturing.

At the conclusion of the treatment, the final flush stage is pumped. This segment of a treatment consists of one wellbore volume of fluid only and is intended to sweep the wellbore clean of proppant (Fig. 5-4). The well is generally then shut-in for some period to allow fluid to leak off such that the fracture closes on and stresses the proppant pack. Shut-in also allows temperature (and chemical breakers added to the fluid while pumping) to reduce

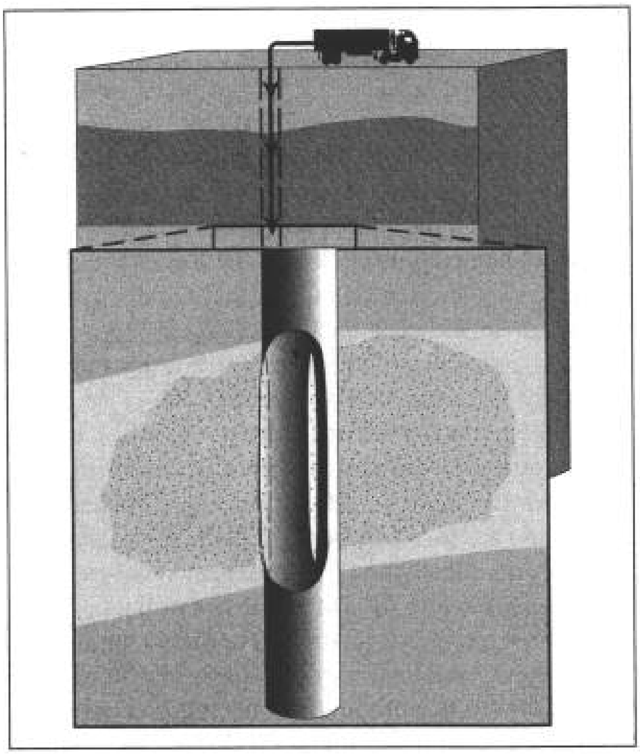


Figure 5-4. Flushing the wellbore to leave a propped fracture.

the viscosity of the fracturing fluid (see Section 7-6.2). Ideally, this process leaves a proppant-filled fracture with a productive fracture length (or half-length x_f), propped fracture height and propped fracture width (which determines the fracture conductivity k_fw). Here, x_f is the productive fracture half-length, which may be less than the created half-length L or less than the propped length.

5-1.2. Why fracture?

Hydraulic fracture operations may be performed on a well for one (or more) of three reasons:

- to bypass near-wellbore damage and return a well to its "natural" productivity
- to extend a conductive path deep into a formation and thus increase productivity beyond the natural level
- to alter fluid flow in the formation.

In the third case, fracture design may affect and be affected by considerations for other wells (e.g., where to place other wells and how many additional wells to drill). The fracture becomes a tool for reservoir management. Although these three motivations are addressed separately in this section, they frequently overlap.

- Damage bypass

  Near-wellbore damage reduces well productivity. This damage can occur from several sources, including drilling-induced damage resulting from fines invasion into the formation while drilling and chemical incompatibility between drilling fluids and the formation. The damage can also be due to natural reservoir processes such as saturation changes resulting from low reservoir pressure near a well, formation fines movement or scale deposition. Whatever the cause, the result is undesirable. Matrix treatments (discussed in Chapters 13 through 20) are usually used to remove the damage chemically, restoring a well to its natural productivity. In some instances, chemical procedures may not be effective or appropriate, and hydraulic fracture operations are used to bypass the damage. This is achieved by producing a high-conductivity path through the damage region to restore wellbore contact with undamaged rock.

- Improved productivity

  Unlike matrix stimulation procedures, hydraulic fracturing operations can extend a conductive channel deep into the reservoir and actually stimulate productivity beyond the natural level.

  All reservoir exploitation practices are subject to Darcy's law:

$$q \approx \frac{kh}{\mu}\frac{\Delta p}{\Delta x}\left(\frac{A}{h}\right), \tag{5-2}$$

where the all-important production rate q is related to formation permeability k, pay thickness h, reservoir fluid viscosity μ, pressure drop Δp and formation flow area A. Reservoir exploitation revolves around manipulating this equation. For example, pressure drop may be increased by using artificial lift to reduce bottomhole flowing pressure, water injection to increase or maintain reservoir pressure, or both. For other cases, in-situ combustion or steam injection is used to reduce reservoir fluid viscosity and thus increase productivity. For fracturing, as pictured in Fig. 5-5, operations are on the formation area in the equation, with the increased formation flow area giving the increased production rate and increased present value for the reserves. (Strictly speaking, it is the

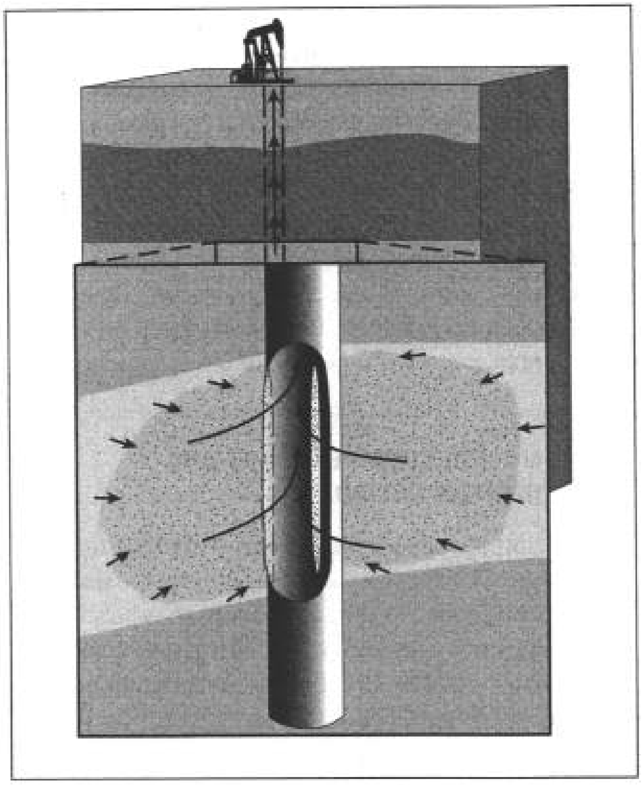


Figure 5-5. Increased flow area resulting from a fracture.

flow shape that is altered, as discussed in detail in Chapter 1.)

This is the classic use of fracturing, to increase the producing rate by bypassing near-wellbore formation damage or by increasing exposure of the formation area and thus stimulating well performance beyond that for no damage. For a single well, treatment design concentrates on creating the required formation flow area to yield increased production at minimal cost. More formally, the design should optimize economic return on the basis of increased productivity and treatment cost.

- Reservoir management

  Along with improving well productivity, fractures also provide a powerful tool for altering reservoir flow. In combination with the other parts of field development, the fracture becomes a reservoir management tool. For example, creating long fractures in tight rock ($k < 0.1$ md) enables field development with fewer wells. However, even fewer wells are required if the fracture azimuth is known and the wells are located appropriately (e.g., not on a regulatory-required square pattern). The actual philosophy shift for fracturing, from accelerating production from a single well to reservoir management, occurred with the application of massive stimulation treatments in tight gas formations (see Appendix to this chapter). Although outwardly a traditional application of fracturing to poorer quality reservoirs, these treatments represented the first engineering attempts to alter reservoir flow in the horizontal plane and the methodology for well placement (e.g., Smith, 1979).

  Fracturing for vertical inflow conformance (i.e., reservoir management) was successfully used in the Gullfaks field (Bale *et al.*, 1994), where selective perforating and fracturing were used to optimize reserve recovery and control sand production while maintaining (but not necessarily increasing) the required production rates. This is illustrated in Fig. 5-6, where the bottom, low-permeability Rannoch-1 zone was perforated to create a propped fracture that extends up and into the high-permeability (>1000-md) Rannoch-3 zone. Without fracturing, the entire zone can be perforated, and a low drawdown allows a significant production rate on the order of 20,000 STB/D, sand free. However, sand production is triggered by water breakthrough in the high-permeability zone (from downdip water injection). The resulting wellbore enlargement caused by sand production acts to stimulate production from the high-permeability zone. To stop sand production, draw-

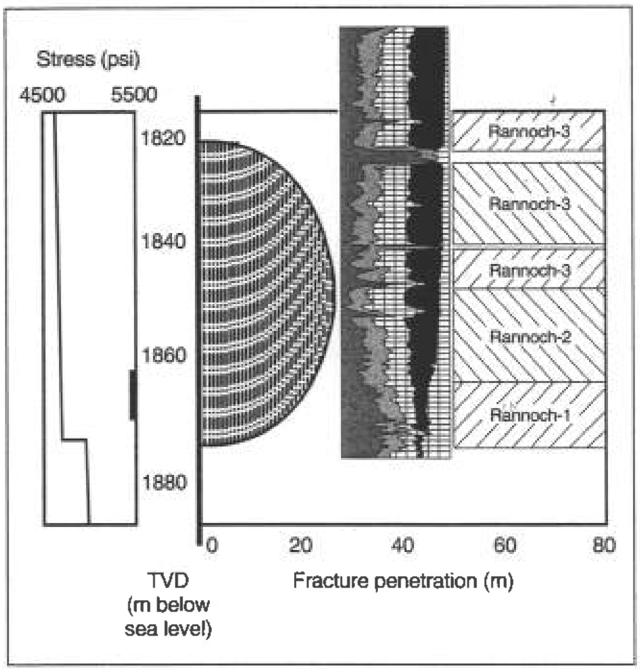


Figure 5-6. Fracturing for vertical inflow conformance.

down must be reduced even more. The production is then essentially 100% water coming from the stimulated high-permeability zone, and the well must be abandoned. This further diminishes production from the large reserves found in the deeper zones with lower permeability.

Open- or cased hole gravel packing could be used to eliminate the sand production. However, such completions are less than satisfactory for two reasons. First, the deeper, lower permeability zones can significantly benefit from stimulation. Second, significant scaling occurs with water breakthrough and quickly plugs the gravel pack.

The fracturing tool selected to manage the Gullfaks field is termed an indirect vertical fracture completion (IVFC). The IVFC accomplishes several goals:

- Some (although choked) production is achieved from the main zone to enable the well to reach minimum productivity standards.
- Production from the lower, moderate-permeability zone is stimulated, maximizing reserves from this zone.
- Greater drawdown is allowed because the weak high-permeability rock is separated from the perforations, and greater drawdown increases the total rate and significantly increases recovery from the lower zones.
- If the upper high-permeability zone has sand production tendencies (as is typically the case), then producing this zone via the fracture totally avoids the need for sand control.
- Any potential for water breakthrough in the high-permeability zone is retarded, and post-water-breakthrough oil production is significantly increased.

To achieve these goals, fracture conductivity must be tailored by synergy between the reservoir and fracture models. Too much conductivity accelerates production and the time to water breakthrough from the high-permeability main zone. Also, too much conductivity, because of surface or tubular limits for the production rate, restricts drawdown on the lower zones, and the desired, more uniform vertical production profile is not achieved. The fracture design goal is not to simply accelerate the rate but to achieve maximum reserves recovery with no sacrifice of rate (as compared with a simple completion in which the entire zone is perforated).

Another example of reservoir management is waterflood development utilizing fractures and a "line drive" flood pattern (i.e., one-dimensional [1D] or linear flow from injection fractures to production fractures). Knowledge of the fracture azimuth, combined with conductive fractures (or correctly controlled injection greater than the fracture pressure) results in improved sweep efficiency and enables more efficient field development.

5-1.3. Design considerations and primary variables

This section introduces the primary variables for fracture design. Sidebar 5A summarizes how the design variables originate from treatment design goals.

As mentioned previously, fracturing was controlled historically by operational considerations. This limited its application because fracturing is dominantly a reservoir process, and hence why a reservoir is fractured and what type of fracture is required should be dominated by reservoir engineering considerations. The permeability k becomes the primary reservoir variable for fracturing and all reservoir considerations. Other, so-called normal reservoir parameters such as net pay and porosity dominate the economics and control the ultimate viability of a project but do not directly impact how the fracturing tool is employed. As discussed in Chapter 12, postfracture productivity is also governed by a combination of the fracture conductivity k_fw and x_f, where k_f is the permeability of the proppant in the fracture, w is the propped fracture width, and x_f is the fracture penetration or half-length. These variables are controlled by fracturing and therefore identify the goals for treatment design.

The productive fracture half-length x_f may be less than the created (or the created and propped) half-length L because of many factors (see Section 12-3). For example, the fracture width near the tip of a fracture may be too narrow to allow adequate propped width. As another example, vertical variations in formation permeability, or layering, can cause the apparent productive length x_f to be less than the actual propped length (Bennett *et al.*, 1986). Similarly, this also makes the fracture height h_f important in several ways (Fig. 5-7):

5A. Design goals and variables

This discussion briefly summarizes the design goals of hydraulic fracturing that provide a road map for the major design variables.

Design goals

Design goals result from Darcy's law (Eq. 5-2), in which the dimensionless term $A/(\Delta xh)$ is defined by flow conditions and equals $\ln(r_e/r_w')$ for steady-state flow (as discussed in Chapter 1). For steady-state flow, Prats (1961) showed that a fracture affects productivity through the equivalent wellbore radius r_w' and that r_w' is related to the fracture half-length or penetration x_f by the dimensionless fracture conductivity ($C_{fD} = k_f w/kx_f$). Cinco-Ley *et al.* (1978) extended these concepts for transient flow with the relation among x_f, r_w' and C_{fD} shown in Fig. 5-11 for pseudoradial flow (where the pressure-depletion region >> x_f but is not affected by external boundaries). Thus, the primary design goals are fracture half-length or penetration and the fracture conductivity $k_f w$, with their relative values defined by C_{fD}.

Design variables

Design variables result from material balance, rock mechanics and fluid mechanics considerations.

The material balance is (Eqs. 5-10 through 5-12)

$$V_f = V_i - V_{Lp};\; V_f = 2Lh_f\bar{w},\; V_i = q_i t_p \text{ and } V_{Lp} \approx 6C_L h_L L\sqrt{t_p} + 4Lh_L S_p\,, \tag{5A-1}$$

where C_L and S_p are fluid-loss parameters that can be determined by the results of a fluid-loss test (Fig. 5A-1) for which the filtrate volume divided by the exposed area $V_L/A = S_p + 2C_L\sqrt{t}$. Combining the relations in Eq. 5A-1 gives Eq. 5-13:

$$L = \frac{q_i t_p}{6C_L h_L\sqrt{t_p} + 4h_L S_p + 2\bar{w}h_f}\,,$$

where fracture penetration L is related to pump rate, fluid loss, height, width, etc.

Next is the elasticity equation (Eq. 5-14):

$$w_{max} = \frac{2p_{net}d}{E'}\,,$$

where $p_{net} = p_f - \sigma_c$, and width is related to net pressure as a function of modulus and geometry and the pressure required to propagate the fracture (Eq. 5-21):

$$p_{tip} = (p - \sigma_c) \text{ at tip } \propto K_{Ic\text{-}apparent}\sqrt{1/d}\,, \tag{5A-2}$$

where d is the characteristic fracture dimension and generally is the smaller dimension between h_f and L.

Third is the fluid flow equation (Eqs. 5-15 through 5-19), in which Eq. 5-15 ($dp_{net}/dx = 12\mu q/h_f w^3$) is combined with the width equation:

$$p_{net} \approx \left[\frac{E'^3}{h_f^4}\left\{\kappa\mu q_i L\right\} + p^4_{net\,tip}\right]^{1/4}, \tag{5A-3}$$

where the pressure drop down the fracture is related to viscosity, pump rate, fracture length (and thus to fluid loss), etc. The net pressure distribution gives the fracture width distribution and thus the final propped fracture width (i.e., $k_f w$). Hence the primary design variables are C_L, h_L, S_p, h_f, E', $K_{Ic\text{-}apparent}$, q_i, μ and σ_c.

Optimum design

The optimum design results from maximizing revenue $\$(r_w')$ minus the costs $\$(x_f, k_f w)$ by using the preferred economic criteria.

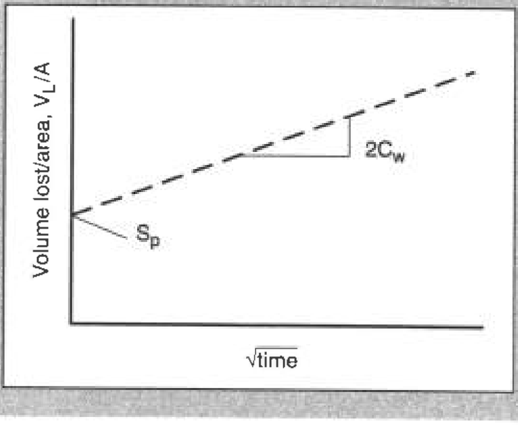


Figure 5A-1. *Ideal laboratory fluid-loss data for spurt loss S_p and the wall-building or filter-cake fluid-loss coefficient C_w. If the total fluid loss is dominated by the filter cake, then the total fluid-loss coefficient $C_L = C_w$.*

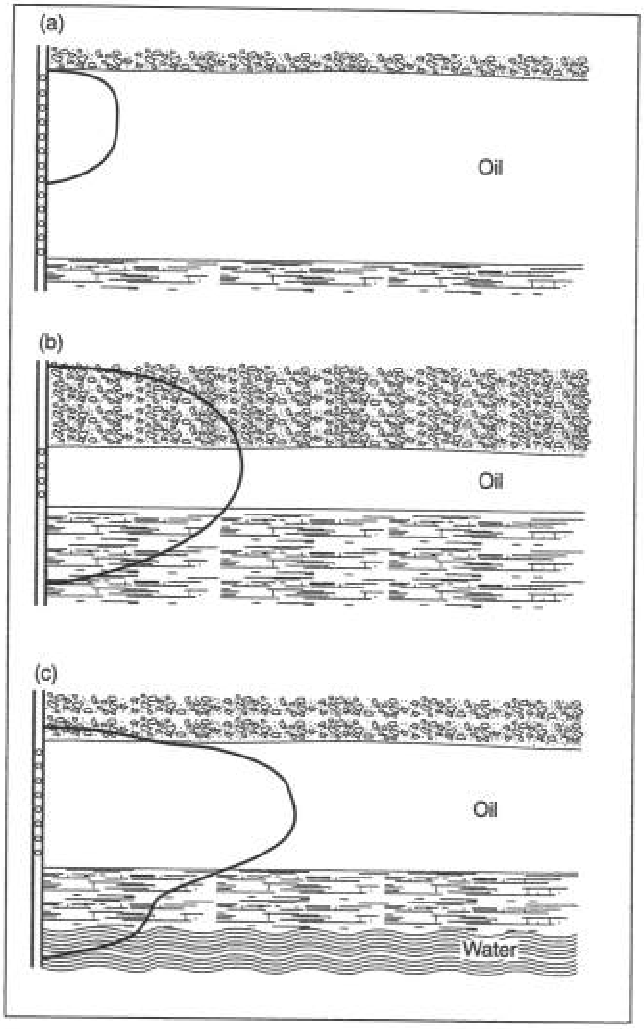


Figure 5-7. *The importance of fracture height.*

- In Fig. 5-7a, the fracture is initiated near the top of the interval, and h_f is not large enough to contact the entire zone, which is clearly an important reservoir concern.
- In Fig. 5-7b, the fracture grew out of the zone and contacted mostly nonreservoir rock, diminishing x_f relative to the treatment volume pumped.
- In Fig. 5-7c, the fracture grew downward past the oil/water contact and if propped would possibly result in unacceptable water production.

In all these cases, as discussed in Section 5-4.2, fracture height growth is controlled by rock mechanics considerations such as in-situ stress, stress gradients, stress magnitude differences between different geologic layers and differences in strength or fracture toughness between different layers. All these rock mechanics considerations are related to the net pressure p_{net}:

$$p_{net} = p_f - \sigma_c , \qquad (5\text{-}3)$$

where p_f is the pressure inside the fracture and σ_c is the minimum in-situ stress (or fracture closure pressure).

For an ideal, homogeneous zone, closure pressure is synonymous with the minimum in-situ stress. However, such ideal conditions do not exist. Stress is a point value, and stress varies from point to point. For realistic in-situ conditions, closure pressure reflects the pressure where the fracture is grossly closed, although the pressure may still be greater than the minimum in-situ stress at some points. For zones that are only slightly nonhomogeneous, the closure pressure represents a zone-averaged stress over the fracture. However, other conditions may be more complex. Consider the three-layer case of two low-stress sandstone intervals with a thick interbedded shale. The correct closure pressure may be the zone-averaged stress over the two low-stress zones, without including the higher stress interbedded zone.

The fracture width is also of major importance for achieving the desired design goals. Typically, this is expressed as the product of fracture permeability times fracture width; i.e., k_fw is the dimensional conductivity of the fracture. Figure 5-8 is an ideal wellbore/fracture connection for a propped fracture that is intended to bypass near-wellbore formation damage. To achieve the desired production goals, a narrow fracture must, at a minimum, carry the flow that

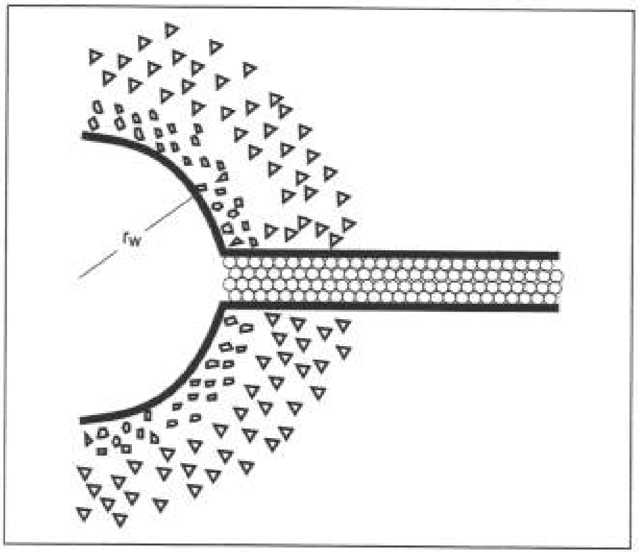


Figure 5-8. *An ideal wellbore/fracture connection for a propped fracture that is intended to bypass near-wellbore formation damage.*

would have been produced through the entire wellbore circumference (had there been no damage). The fracture conductivity k_fw must be greater than $2\pi r_wk$, where r_w is the wellbore radius. For higher permeability formations that can deliver high rates with sufficient fracture permeability, fracture width and any variables that affect width become important. As discussed in the following and in Section 6-2, width is controlled by the fracture dimensions (h_f and L), net pressure inside the fracture acting to open and propagate the fracture, and another property, the modulus or stiffness of the rock.

As implied by the term hydraulic fracturing, fluid mechanics is an important element in fracturing. The two dominant fluid mechanics variables, injection (pump) rate q_i and fluid viscosity μ, affect net pressure inside the fracture (and thus width) and largely control transport and the final placement of proppant in the fracture. These variables also have a role in controlling the volume of fluid lost to the formation during pumping. For example, high pump rates reduce the total fluid loss because for a given volume pumped there is less time for fluid loss to occur.

Another key factor of a good design is selection of the fluid and proppant systems with performance characteristics (e.g., μ, C_L, k_f) that best meet the requirements for the fracture treatment (i.e., material selection). In addition, the performance variables for the materials must be properly characterized. Fluids and proppants are addressed in Chapter 7, and their performance is discussed in Chapter 8.

Finally, all the design parameters must be molded to be compatible with existing well conditions (i.e., operational considerations). For example, it does little good to complain that the detailed design and analysis done in planning a treatment for an existing well call for a high pump rate of 60 bbl/min when the wellbore conditions limit the maximum allowable pump rate to one-half that rate. Clearly, for new wells the operational considerations (detailed in Chapter 11) should be an integral part of planning for the drilling and completion process (e.g., well trajectory for extended reach wells) (Martins *et al.*, 1992c).

5-1.4. Variable interaction

It is clear that with major design considerations coming from multiple disciplines, the variables will react, interact and interconnect in multiple ways and that many of these interactions will be contradictory or incompatible. This is discussed later, but an example is as follows. Consider a case where reservoir goals require a long fracture. With deep penetration into the pay zone, getting good proppant transport down a long fracture clearly requires high fluid viscosity. However, high viscosity increases the net pressure inside the fracture. This reacts with the stress difference between the pay and the overlying and underlying shales and causes height growth, resulting in less penetration than desired, and thus less viscosity is required.

Inherent contradictions controlling fluid selection abound:

- Good viscosity is required to provide good proppant transport, but minimal pipe friction is also desirable to reduce surface pump pressure.
- The fluid system is expected to control fluid loss, but without damage to the formation or fracture permeability.
- Performance at high temperature, for long periods of time, is required from a fluid system that does not cost much.

5-2. In-situ stress

In-situ stress, in particular the minimum in-situ stress (termed the fracture closure pressure for nonhomogeneous zones, as discussed earlier) is the dominant parameter controlling fracture geometry. It is discussed in detail in Chapter 3. For relaxed geologic environments, the minimum in-situ stress is generally horizontal; thus a vertical fracture that formed when a vertical wellbore broke remains vertical and is perpendicular to this minimum stress. Hydraulic fractures are always perpendicular to the minimum stress, except in some complex cases, and even for those cases any significant departure is only at the well. This occurs simply because that is the least resistant path. Opening a fracture in any other direction requires higher pressure and more energy.

The minimum stress controls many aspects of fracturing:

- At very shallow depths or under unusual conditions of tectonic stress and/or high reservoir pressure, the weight of the overburden may be the minimum stress and the orientation of the hydraulic fractures will be horizontal; for more normal cases, the minimum stress is generally horizontal and the maximum horizontal stress direction determines whether the vertical fracture will run north–south, east–west, etc.

- Stress differences between different geologic layers are the primary control over the important parameter of height growth (Fig. 5-9).
- Through its magnitude, the stress has a large bearing on material requirements, pumping equipment, etc., required for a treatment. Because the bottomhole pressure must exceed the in-situ stress for fracture propagation, stress controls the required pumping pressure that well tubulars must withstand and also controls the hydraulic horsepower (hhp) required for the treatment. After fracturing, high stresses tend to crush the proppant and reduce k_f; thus, the stress magnitude dominates the selection of proppant type and largely controls postfracture conductivity.

Therefore, the detailed design of hydraulic fracture treatments requires detailed information on in-situ stresses. An engineer must know the magnitude of the minimum in-situ stress for the pay zone and over- and underlying zones and in some cases must know the direction for the three principal stresses. For a simple, relaxed geology with normal pore pressure, the closure stress is typically between 0.6 and 0.7 psi/ft of depth (true vertical depth, TVD). More generally, as discussed in Chapter 3, the minimum stress is related to depth and reservoir pressure by

$$\sigma_c \cong K_o(\sigma_v - p_r) + p_r + T, \qquad (5\text{-}4)$$

where K_o is a proportionality constant related to the rock properties of the formations (possibly to both the elastic properties and the faulting or failure properties), σ_v is the vertical stress from the weight of the overburden, p_r is the reservoir pore pressure, and T accounts for any tectonic effects on the stress (for a relaxed, normal fault geology, T is typically small). K_o is typically about ⅓. For fracture design, better values are required than can be provided by such a simple relation, and methods of measuring or inferring the in-situ stress are discussed in Chapters 3 and 4. For preliminary design and evaluation, using Eq. 5-4 with K_o = ⅓ is usually sufficient.

5-3. Reservoir engineering

As previously mentioned, because the ultimate goal of fracturing is to alter fluid flow in a reservoir, reservoir engineering must provide the goals for a design. In addition, reservoir variables may impact the fluid loss.

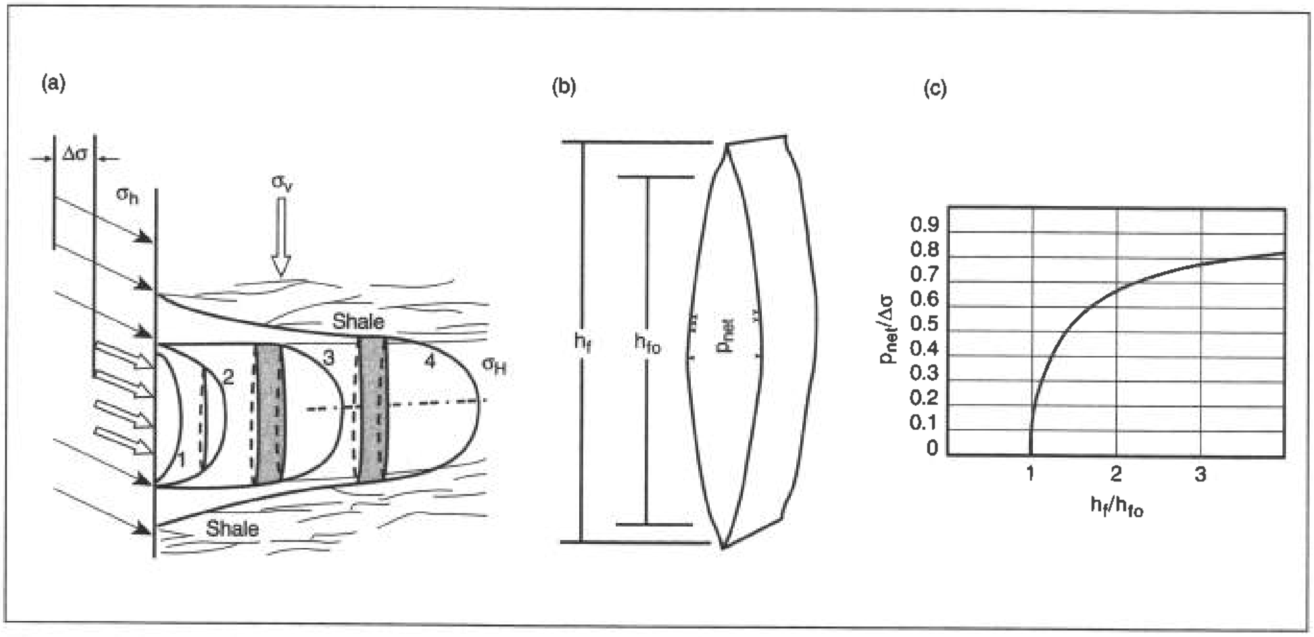


Figure 5-9. *Fracture height growth. (a) Idealized fracture profile of the relation of fracture geometry to in-situ stresses. σ_h = minimum horizontal stress, σ_H = maximum horizontal stress. (b) Typical fracture vertical cross section illustrating the relation of the total fracture height h_f to the "original" fracture height h_{fo}. (c) Theoretical relation among h_f/h_{fo}, p_{net} and the in-situ stress difference $\Delta\sigma$ (Simonson* et al.*, 1978).*

5-3.1. Design goals

Historically, the emphasis in fracturing low-permeability reservoirs was on the productive fracture length x_f. For higher permeability reservoirs, the conductivity k_fw is equally or more important, and the two are balanced by the formation permeability k. This critical balance was first discussed by Prats (1961), more than 10 years after the introduction of fracturing, with the important concept of dimensionless fracture conductivity C_{fD}:

$$C_{fD} = \frac{k_f w}{k\, x_f}. \tag{5-5}$$

This dimensionless conductivity is the ratio of the ability of the fracture to carry flow divided by the ability of the formation to feed the fracture. In general, these two production characteristics should be in balance. In fact, for a fixed volume of proppant, maximum production is achieved for a value of C_{fD} between 1 and 2, as discussed in Chapters 1 and 10, with an analogy to highway design in Sidebar 5B.

Prats also introduced another critical concept, the idea of the effective wellbore radius r_w'. As shown in Fig. 5-10, a simple balancing of flow areas between a wellbore and a fracture gives the equivalent value of r_w' for a propped fracture (qualitative relation only):

$$r_w' \approx \frac{2}{\pi} x_f. \tag{5-6}$$

However, this simple flow area equivalence ignores the altered pore pressure field around a linear fracture and also assumes infinite conductivity. Prats correctly accounted for the pressure distribution around a fracture and provided a general relation between dimensionless conductivity and r_w' for steady-state conditions (see Chapter 1). The relation shows that for infinite-conductivity fractures, the upper limit on r_w' is slightly less than that from the flow area balance in Eq. 5-6. For infinite k_fw, Prats found

$$r_w' = 0.5x_f. \tag{5-7}$$

Cinco-Ley *et al.* (1978) later integrated this into a full description of reservoir response, including tran-

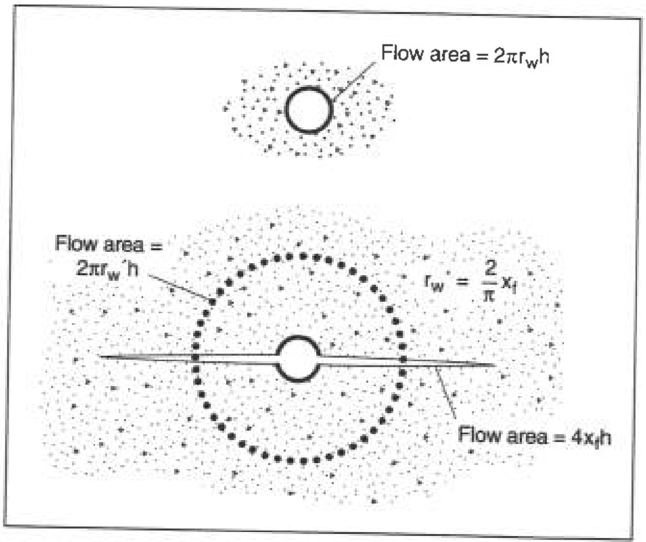


Figure 5-10. Equivalent wellbore radius r_w'.

5B. Highway analogy for dimensionless fracture conductivity

A simplistic analogy for dimensionless fracture conductivity C_{fD} is a highway system. The numerator of this dimensionless variable is k_fw, which is the capacity of the highway or the ability of the highway to carry traffic. The denominator is kx_f; this is the ability of the feeder roads to supply traffic to the highway.

The famous old U.S. highway known as Route 66 ran, for much of its length, across sparsely populated areas where feeder roads were few, narrow and far between. The ability of the feeder road network to supply traffic to the highway was limited (similar to the conditions existing when a propped hydraulic fracture is placed in a formation with very low permeability). In this case, the width, or flow capacity, of the highway is not an issue (k_fw does not have to be large). What is needed (and was eventually built) is a long, narrow (low-conductivity) highway.

As a comparison, consider Loop 610, the "superhighway" surrounding the city of Houston. The feeder system is located in a densely populated area, and the feeder roads are numerous and wide. Here, the width, or flow capacity, of the highway is critical. Making this highway longer has no effect on traffic flow, and the only way to increase traffic flow is to widen (i.e., increase the conductivity of) the road. This is obviously analogous to placing a fracture in a higher permeability formation, with the postfracture production limited by the fracture width (or, more accurately, limited by k_fw).

If C_{fD} is the ratio of the ability of a highway to carry traffic to the ability of the feeder system to supply that traffic to the highway, clearly a highway should be engineered to approximately balance these conditions. That is, a C_{fD} value > 50 is seldom warranted, because a highway would not be constructed to carry 50 times more traffic than the feeder system could supply. In the same way, a value of 0.1 makes little sense. Why construct a highway that can only carry 10% of the available traffic? In general, an ideal value for C_{fD} would be expected to be about 1 to result in a balanced, well-engineered highway system.

A balance of about 1 is certainly attractive for steady-flow traffic conditions that may exist through most of the day. However, during peak traffic periods the feeder system may supply more traffic than normal, and if this rush hour or transient traffic period is a major consideration, then a larger ratio of C_{fD} may be desirable. Thus, a C_{fD} of 10 may be desirable for peak flow (transient) periods, as opposed to a C_{fD} value of approximately 1 for steady-state traffic conditions.

sient flow. For pseudoradial flow, Cinco-Ley *et al.* expressed r_w' as a function of length and C_{fD} (Fig. 5-11).

The chart in Fig. 5-11 (equivalent to Prats) can be used (when pseudoradial flow is appropriate) as a powerful reservoir engineering tool to assess possible postfracture productivity benefits from propped fracturing. For example, the folds of increase (FOI) for steady-state flow can be defined as the postfracture increase in well productivity compared with prefracture productivity calculated from

$$FOI = \frac{\ln(r_e / r_w) + s}{\ln(r_e / r_w')}, \tag{5-8}$$

where r_e is the well drainage or reservoir radius, r_w is the normal wellbore radius, and s is any prefracture skin effect resulting from wellbore damage, scale buildup, etc. An equivalent skin effect s_f resulting from a fracture is

$$s_f = -\ln(r_w' / r_w) \tag{5-9}$$

for use in reservoir models or other productivity calculations. Equation 5-8 provides the long-term FOI. Many wells, particularly in low-permeability reservoirs, may exhibit much higher (but declining) early-time, transient FOI. The preceding relations are for transient pseudoradial flow before any reservoir boundary effects; the case for boundary effects is discussed in Section 12-2.6.

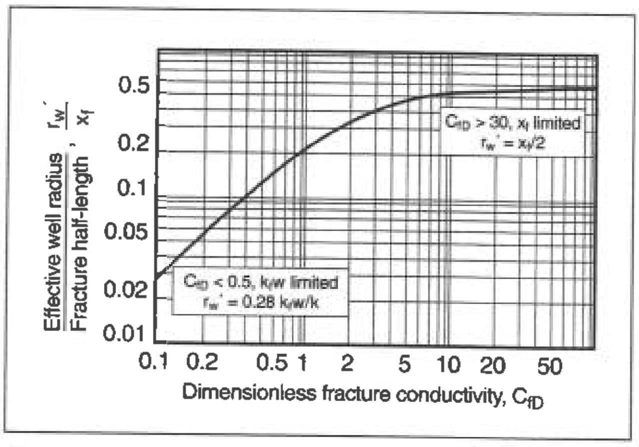


Figure 5-11. *Equivalent wellbore radius as a function of dimensionless fracture conductivity and fracture length.*

5-3.2. Complicating factors

These principal concepts give a straightforward method for predicting postfracture production; however, complications can reduce postfracture productivity below the levels expected or give better productivity than that calculated. The major complications include non-Darcy (or turbulent) flow, transient flow regimes, layered reservoirs and horizontal permeability anisotropy (particularly any natural fissure permeability).

For high-rate wells, non-Darcy or turbulent flow can be an important factor that causes an increased pressure drop along the fracture. This creates an apparent conductivity that is less than the equivalent laminar flow conductivity. The apparent C_{fD} is also reduced and productivity is less than that expected. Another complicating effect that can reduce productivity from expected levels is formation layering, where a fracture is in multiple layers with significantly different values for porosity, permeability or both. Unlike radial flow into a wellbore, average values of permeability and porosity do not apply, and for layered formations, postfracture performance falls below simple calculations based on average permeability (Bennett *et al.*, 1986). These and other effects are discussed in Section 12-3.

For lower permeability formations and for some time period, postfracture performance is dominated by transient flow (also called flush production) as discussed by Cinco-Ley *et al.* (1978). For transient conditions, reservoir flow has not developed into pseudoradial flow patterns, and the simple r_w' relations are not applicable. In the example in Fig. 5-12, pseudoradial flow did not develop until about 48 months. During the prior transient flow regimes,

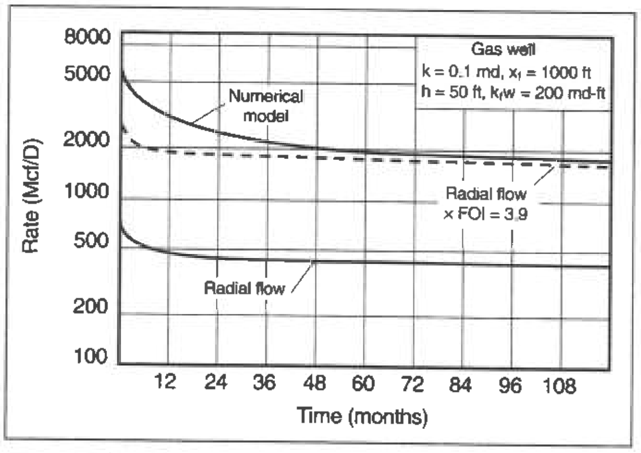


Figure 5-12. *Late development of pseudoradial flow.*

productivity was better than that predicted from the pseudoradial flow r_w'. The duration of the transient flow period is a function of permeability, C_{fD} and x_f^2 such that for moderate- to high-permeability wells the period is too short to have practical significance for fracture design. However, it may be important for postfracture well test analysis. For low-permeability wells with long fractures, transient flow may dominate most of the productive well life.

5-3.3. Reservoir effects on fluid loss

Reservoir properties such as permeability to reservoir fluid, relative permeability to the fracturing fluid filtrate, total system compressibility, porosity, reservoir fluid viscosity and reservoir pressure all play a role in fluid loss while pumping (see Section 6-4). Thus, certain reservoir information is required for treatment design, as well as for specifying design goals.

5-4. Rock and fluid mechanics

Rock and fluid mechanics (along with fluid loss) considerations control the created fracture dimensions and geometry (i.e., fracture height h_f, length L and width w). These considerations all revolve around the net pressure p_{net} given by Eq. 5-3. However, p_{net}, which controls h_f and L, is itself a function of h_f and L, and the various physical behaviors connecting height, net pressure, width, etc., interact in many ways. This makes simple statements about the relative importance of variables difficult or impossible. However, the basic physical phenomena controlling fracture growth are understood and are well established.

5-4.1. Material balance

The major equation for fracturing is material balance. This simply says that during pumping a certain volume is pumped into the earth, some part of that is lost to the formation during pumping, and the remainder creates fracture volume (length, width and height). It is the role of fracture models to predict how the volume is divided among these three dimensions. The volume pumped is simply

$$V_i = q_i \times t_p, \qquad (5\text{-}10)$$

where q_i is the total injection rate and t_p is the pumping time for a treatment. Equally simple, the fracture volume created during a treatment can be idealized as

$$V_f = h_f \times \bar{w} \times 2L = \eta \times V_i, \qquad (5\text{-}11)$$

where h_f is an average, gross fracture height, $\bar{w}$ is the average fracture width, L is the fracture half-length or penetration, and η is the fluid efficiency. Finally, as discussed by Harrington *et al.* (1973) and Nolte (1979), the volume lost while a hydraulic fracture treatment is being pumped can be approximated by

$$V_{Lp} \cong 6C_L h_L L\sqrt{t_p} + 4Lh_L S_p, \qquad (5\text{-}12)$$

where C_L is the fluid-loss coefficient (typically from 0.0005 to 0.05 ft/min$^{1/2}$), h_L is the permeable or fluid-loss height, and S_p is the spurt loss (typically from 0 to 50 gal/100 ft^2). Because material balance must be conserved, V_i must equal V_{Lp} plus V_f, and Eqs. 5-10 through 5-12 can be rearranged to yield

$$L \cong \frac{q_i t_p}{6C_L h_L \sqrt{t_p} + 4h_L S_p + 2\bar{w}h_f}, \qquad (5\text{-}13)$$

showing a general relation between several important fracture variables and design goals.

Modeling of hydraulic fracture propagation in low- to medium-permeability formations typically shows an average width of about 0.25 in. (±50%) over a fairly wide range of conditions (e.g., Abou-Sayed, 1984). Using this value, the effect of the primary variables height h_f and fluid-loss coefficient C_L on fracture penetration L are investigated in Fig. 5-13. This is for a simple case of a constant 0.25-in. fracture width. Figure 5-13a shows length as a strong, nearly linear function of h_f, e.g., doubling h_f cuts fracture penetration by 50%. For similar conditions, Fig. 5-13b shows that the fluid-loss coefficient is not as important; e.g., doubling C_L reduces L by only about 20%. However, with fracturing, such simple relations are never fixed. As seen in Fig. 5-13c, for a higher loss case, doubling C_L from 0.005 to 0.01 reveals a nearly linear relation between C_L and L, just as for height in Fig. 5-13a. Basically, for Figs. 5-13a and 5-13b, the loss term (first term in the denominator of Eq. 5-13) is small compared with the fracture volume term (third term in the denominator). Therefore, the fluid loss is relatively low and fracture fluid efficiency (η, as defined in Eq. 5-11) is high. In Fig. 5-13c, the loss term is large compared with the volume term (high loss and low efficiency), and the loss coefficient becomes the dominant variable, with L less sensitive to variations in h_f or equivalently $\bar{w}$ if it varies from the fixed value of 0.25 in.

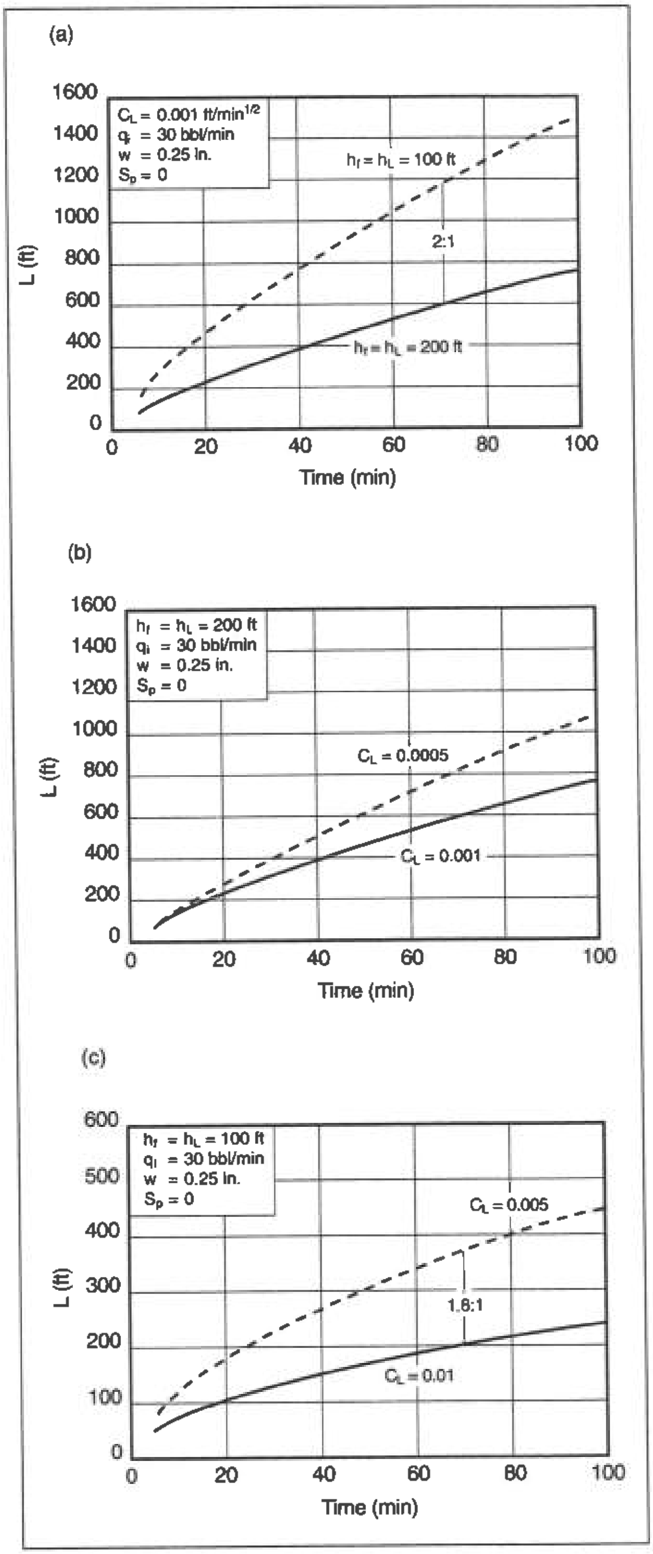


***Figure 5-13.** Effect of* h_f *and* C_L *on* L.

5-4.2. Fracture height

Equation 5-13 demonstrates that fracture height h_f and fluid-loss height h_L are important parameters for fracture design. Loss height is controlled by in-situ variations of porosity and permeability. Fracture height is controlled by the in-situ stresses, in particular by differences in the magnitude or level of stress between various geologic layers. More formally, height is controlled by the ratio of net pressure to stress differences $\Delta\sigma$, as illustrated in Fig. 5-9, where $\Delta\sigma$ is the difference between stress in the boundary shales and stress in the pay zone. Ignoring any pressure drop caused by vertical fluid flow, the relation among fracture height, initial fracture height, p_{net} and $\Delta\sigma$ can be calculated as demonstrated by Simonson *et al.* (1978). This relation is included in Fig. 5-9c.

For cases when p_{net} is relatively small compared with the existing stress differences (e.g., less than 50% of $\Delta\sigma$), there is little vertical fracture growth and the hydraulic fracture is essentially perfectly confined. This gives a simple fracture geometry (Fig. 5-14a) and increasing net pressure (Fig. 5-14b). For cases when p_{net} is much larger than the existing stress differences, vertical fracture height growth is essentially unrestrained. Again, the geometry is a fairly simple radial or circular fracture (Fig. 5-14c) and declining net pressure (Fig. 5-14b).

For more complex cases when p_{net} is about equal to $\Delta\sigma$, fracture geometry becomes more difficult to predict, and significant increases in height can occur for small changes in net pressure. Also, for this case, the viscous pressure drop from vertical flow retards fracture height growth (see Weng, 1991), and the equilibrium height calculations in Fig. 5-9 are no longer applicable.

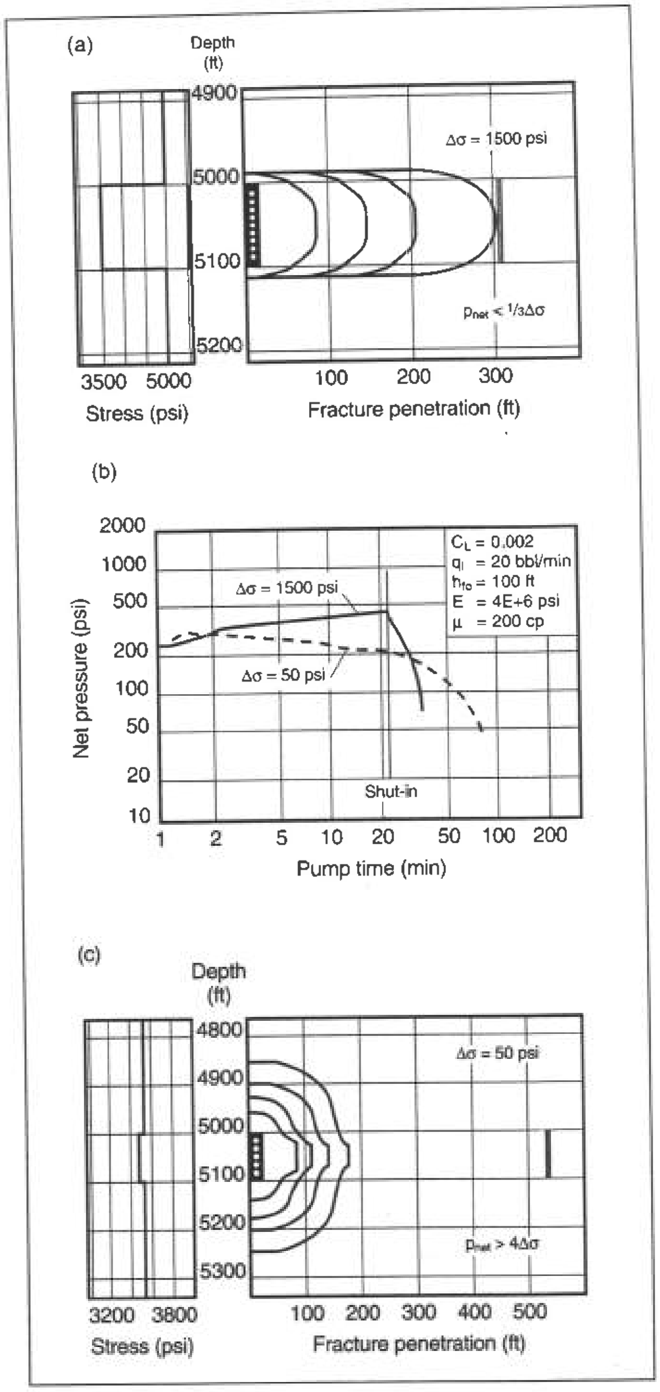


Figure 5-14. *Relationship of p_{net} to stress differences.*

5-4.3. Fracture width

Consider a slit in an infinite elastic media (i.e., the earth). Also consider that the slit is held closed by a fracture closure stress but is being opened by an internal pressure equal to the closure stress plus a net pressure p_{net}. Under these conditions (discussed in detail in Chapter 6), the slit opens into an elliptical shape, with a maximum width

$$w_{max} = \frac{2p_{net}d}{E'}, \tag{5-14}$$

where E' is the plane strain modulus ($E' = E/(1 - \nu^2)$, ν is Poisson's ratio and typically equals about 0.2), and d is the least dimension of the fracture. For a confined-height fracture with a tip-to-tip length greater than h_f, d equals h_f. This shows a direct relation between net pressure and width and introduces an important material property, the plane strain modulus. However, because typically $\nu^2 < 0.1$, the plane strain modulus seldom differs from Young's modulus E by a significant amount.

5-4.4. Fluid mechanics and fluid flow

The major fluid flow parameters are the fluid viscosity (resistance to flow) μ and injection rate q_i. The rate also effects the pump time and hence is important to fluid-loss and material-balance considerations, as discussed previously. Both parameters are critical for proppant transport, and both parameters also affect net pressure and thus affect fracture height and width.

As an example, consider a Newtonian fluid flowing laterally through a narrow, vertical slit (i.e., fracture) (Fig. 5-15). For laminar flow (the general case for flow inside hydraulic fractures), the pressure drop along some length Δx of the slit is

$$\frac{\Delta p_{net}}{\Delta x} = \frac{12\mu q}{h_f w^3}. \tag{5-15}$$

Assuming a simple case of a long, constant-height and -width fracture with two wings and zero fluid loss (i.e., the flow rate in each wing is $q = q_i/2$) and also assuming zero net pressure at the fracture tip,

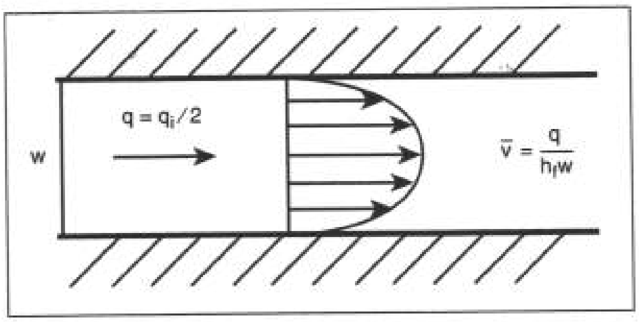


Figure 5-15. *Fluid flowing laterally through a narrow vertical fracture.*

Eq. 5-15 is integrated from the fracture tip back to the wellbore to give

$$p_{net} = \frac{6\mu q_i L}{h_f w^3}. \tag{5-16}$$

For this long, confined-height fracture, h_f is the minimum fracture dimension for Eq. 5-14, and the fracture width and net pressure are related by

$$p_{net} = \frac{E'w}{2h_f}. \tag{5-17}$$

Combining the two equations gives the proportionality

$$w \propto \left\{\frac{\mu q_i L}{E'}\right\}^{1/4}. \tag{5-18}$$

The exponent of ¼ for this simple fracture geometry and for Newtonian fluids implies that the fracture width is virtually constant; e.g., doubling the pump rate from 20 to 40 bbl/min increases the width only by about 20%. The same effect is found for all the variables in Eq. 5-18. Generally, for non-Newtonian fluids, the exponent is approximately ⅕.

This relationship for fracture width can also be used with Eq. 5-17 to give net pressure expressed as

$$p_{net} = \frac{E'^{3/4}}{h_f}\left\{\kappa \mu q_i L\right\}^{1/4}, \tag{5-19}$$

where κ is a constant (see Eq. 6-11) to provide an equality for this expression.

Thus, as a result of viscous forces alone, net pressure inside the fracture develops as a function of the modulus, height and $(q\mu)^{1/4}$. From the nature of this relation, however, it is clear that modulus and height are much more important in controlling net pressure than are pump rate and viscosity, the effect of which is muted by the small exponent for the relation.

5-4.5. Fracture mechanics and fracture tip effects

The fluid mechanics relations show p_{net} related to modulus, height, fluid viscosity and pump rate. However, in some cases, field observations have shown net pressure (and presumably fracture width) to be greater than predicted by Eq. 5-19 (Palmer and Veatch, 1987). In such cases the fluid viscosity has a smaller effect on fracture width than predicted by Eq. 5-19. This is probably because the simple relation in Eq. 5-16 assumes no net pressure at the fracture tip; i.e., fracture tip effects or fracture propagation effects are ignored. When tip effects are taken into account, the fracture width is affected by both fluid viscosity and tip effects (Shlyapobersky *et al.*, 1988a, 1988b). As shown by Nolte (1991), tip effects can be approximated by considering the net pressure within the tip region to equal p_{tip} (as opposed to zero) in Eq. 5-16. For a positive tip pressure, the net pressure equation becomes

$$p_{net} \approx \left[\frac{E'^3}{h_f^4}\left\{\kappa \mu q_i L\right\} + p_{tip}^4\right]^{1/4}, \tag{5-20}$$

where p_{tip} is the pressure required at the fracture tip to open new fracture area and keep the fracture propagating forward. This simple relationship serves to illustrate that there are always two components to net pressure: a viscous component and a fracture tip-effects component. The relative magnitude of the two effects varies from case to case, and because of the small exponent, the combined effects are much less than the direct sum of the individual effects. For example, when the viscous component and the tip component are equal, the net pressure is increased by only 20% over that predicted when one of the components is ignored.

- Fracture toughness and elastic fracture mechanics

  The fracture tip propagation pressure, or fracture tip effect, is generally assumed to follow the physics of elastic fracture mechanics. In that case, the magnitude of the tip extension pressure p_{tip} is controlled by the critical stress intensity factor K_{Ic} (also called the fracture toughness). Fracture toughness is a material parameter, and it may be defined as the strength of a material in the presence of a preexisting flaw. For example, glass has a high tensile strength, but the presence of a tiny scratch or fracture greatly reduces the strength (i.e., high tensile strength but low fracture toughness). On the other hand, modeling clay has low strength, but the presence of a flaw or fracture does not significantly reduce the strength. Laboratory-measured values for the material property K_{Ic} show toughness ranging from about 1000 to about 3500 psi/in.$^{1/2}$, with a typical value of about 2000 psi/in.$^{1/2}$. These tests (after Schmidt and Huddle, 1977; Thiercelin, 1987) include a range of rock types from mudstones and sandstones to carbonates and consider confining pressures from 0 to 5000 psi.

From elastic fracture mechanics, for a simple radial or circular fracture geometry with a penetration of L, the fracture tip extension pressure is

$$p_{tip} = K_{Ic}\sqrt{\frac{\pi}{48L}}, \qquad (5\text{-}21)$$

and it decreases as the fracture extends. For even a small fracture penetration of 25 ft, this gives a tip extension pressure of 29 psi, whereas viscous pressures (Eq. 5-19) are typically 10 or more times larger. Thus normal linear elastic fracture mechanics considerations indicate that fracture mechanics, or the tip extension pressure, generally plays a negligible role for hydraulic fracturing.

- Apparent fracture toughness

  Field data typically show fracture extension pressure to be greater than that given by Eq. 5-21, with 100 to 300 psi as typical values and even higher values possible. This difference is due to several behaviors not included in elastic fracture mechanics calculations. One important (and long-recognized) consideration is that the fracturing fluid never quite reaches the fracture tip; i.e., there is a "fluid lag" region at the tip that increases the apparent toughness and tip pressure (Fig. 5-16). In other cases, tip pressure may be even greater. Other tip phenomena include nonelastic rock deformation near the fracture tip and tip plugging with fines, with these mechanisms acting alone or in conjunction with the fluid flow and/or fluid lag phenomena. Tip phenomena are discussed in detail in Chapters 3 and 6.

  Measured values for tip extension pressure that are higher than predicted from laboratory-measured rock toughness K_{Ic} can be accounted for in hydraulic fracture calculations through the use of the effective, or apparent, fracture toughness $K_{Ic\text{-}apparent}$ (Shlyapobersky, 1985). In practice, because $K_{Ic\text{-}apparent}$ is not a material constant, the tip effects should be defined or calibrated by fracturing pressure data for a particular situation (see Sidebar 9B).

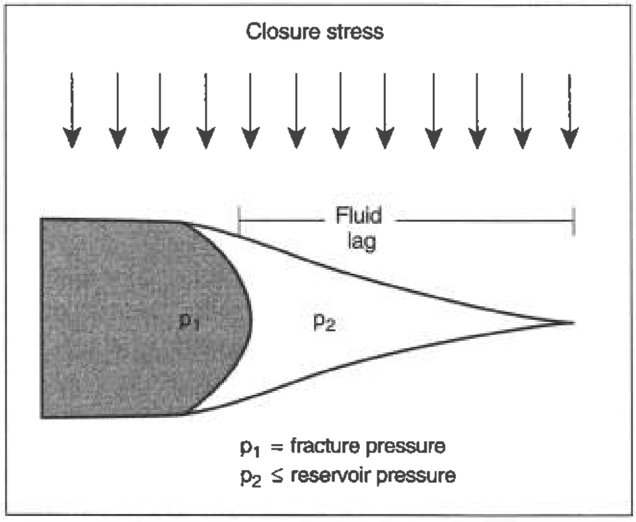


Figure 5-16. Unwetted fracture tip (fluid lag).

5-4.6. Fluid loss

As seen from the material balance (Eq. 5-13), fluid loss is a major fracture design variable characterized by a fluid-loss coefficient C_L and a spurt-loss coefficient S_p. Spurt loss occurs only for wall-building fluids and only until the filter cake is developed. For most hydraulic fracturing cases, the lateral (and vertical) extent of the fracture is much greater than the invasion depth (perpendicular to the planar fracture) of fluid loss into the formation. In these cases, the behavior of the fluid loss into the formation is linear (1D) flow, and the rate of fluid flow for linear flow behavior is represented by Eq. 5-1.

This assumption of linear flow fluid loss giving the $C_L/\sqrt{t}$ relation has been successfully used for fracturing since its introduction by Carter (1957). The relation indicates that at any point along the fracture, the rate of fluid loss decreases with time, and anything that violates this assumption can cause severe problems in treatment design. For example, fluid loss to natural fissures can result in deep filtrate invasion into the fissures, and the linear flow assumption may no longer be valid. In fact, for the case of natural fissures if net pressure increases with time, the fluid-loss rate can increase, and treatment pumping behavior may be quite different from that predicted. The total fluid loss from the fracture is controlled by the total fluid-loss coefficient C_L, which Howard and Fast (1957) decomposed into the three separate mechanisms illustrated in Fig. 5-17 and discussed in Section 6-4.

The first mechanism is the wall-building characteristics of the fracturing fluid, defined by the wall-building coefficient C_w. This is a fluid property that helps control fluid loss in many cases. For most fracturing fluid systems, in many formations as fluid loss

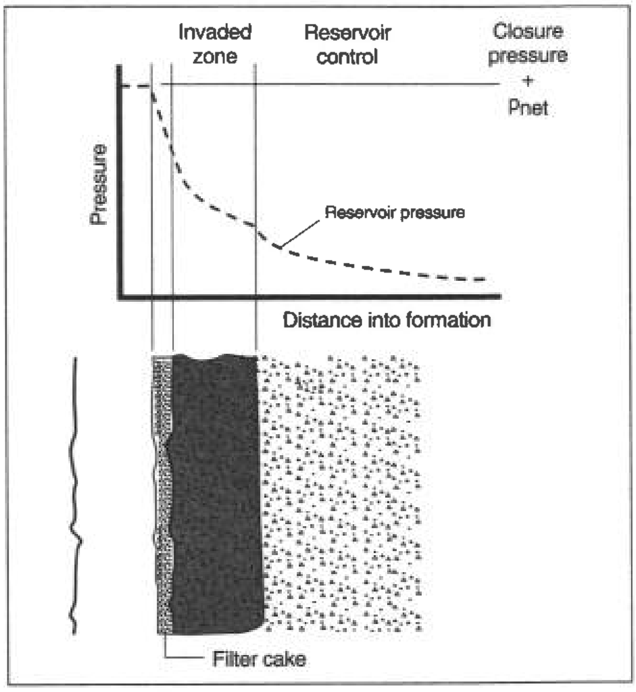


Figure 5-17. *The three regions of fluid loss.*

occurs into the formation, some of the additives and chemicals in the fluid system remain trapped on or near the formation face, forming a physical filter-cake barrier that resists fluid loss.

Outside of the filter cake is the invaded zone, which is the small portion of the formation that has been invaded by the fracturing fluid filtrate. This mechanism is the filtrate effect, or invaded zone effect, and it is characterized by the viscosity or relative permeability control coefficient C_v. As discussed in Chapter 6, C_v can be calculated, and this parameter is governed by the relative permeability of the formation to the fracturing fluid filtrate k_{fil}, the pressure difference Δp between the pressure inside the fracture (i.e., closure pressure + p_{net}) and the reservoir pressure, and the viscosity of the fracturing fluid filtrate μ_{fil}. This mechanism is usually most important in gas wells, where the invading fluid has much higher viscosity than the reservoir fluid being displaced, or where relative permeability effects produce a filtrate permeability that is much less ($<k/10$) than the permeability to the reservoir fluid. Other cases are where a clean fluid is used such that no filter cake develops or for fracturing high-permeability wells where no filter cake develops and high-viscosity crosslinked gel may be lost to the formation (i.e., μ_{fil} is very high).

For fluid to leak off from the fracture, the reservoir fluid must be displaced. This sets up some resistance to fluid loss, and this reservoir effect is characterized by the compressibility coefficient C_c. As discussed in Chapter 6, the parameter for this calculation is governed by a pressure difference Δp between the pressure inside the fracture (i.e., closure pressure + p_{net}) and the reservoir pressure, permeability to the movable formation fluid k, total system compressibility for the reservoir c_t, and the viscosity of the reservoir fluid (gas or oil) μ. This parameter is usually more important for a liquid-saturated reservoir (low compressibility and relatively high reservoir fluid viscosity) and when a filter cake does not develop.

Each of these three mechanisms provides some resistance to fluid loss, and all three act as resistors in series (although the fluid-loss coefficient itself is defined in terms of conductance, or the inverse of resistance). The three mechanisms variously combine in different situations to form the total or combined fluid-loss coefficient C_L, which is used for fracture design (see Chapter 6). This clearly complex situation makes it desirable to measure fluid loss from field tests (just as permeability must be measured from field flow, buildup tests or both) whenever possible (see Chapter 9).

5-4.7. Variable sensitivities and interactions

The complexity of hydraulic fracture design comes from the interactions of the major design variables (h_f, E, $\Delta\sigma$, K_{Ic} and C_L) and that different variables affect different aspects of fracturing in different ways. As discussed in Section 5-4.1 concerning the sensitivity of fracture penetration to h_f and C_L, the importance of various variables can change from case to case. Several examples of this are discussed here.

- Net pressure

  The magnitude of net pressure for a specific fracture treatment is a major concern, because the ratio of net pressure to stress differences between the pay zone and bounding zones controls fracture height. Also, net pressure directly controls width. However, what controls net pressure varies significantly from case to case.

  In the case of hard-rock formations (i.e., formations with values for Young's modulus of 2×10^6 psi or greater) with height confinement and for treatments pumping viscous fluids at normal fracturing rates, the viscous term of the net pressure equation dominates any fracture tip effects. Toughness or tip effects become important for cases where fracture height is unconfined (e.g., radial or circular fractures) or for very soft rocks (e.g., formations such as unconsolidated sands with $E \leq 0.5 \times 10^6$ psi). For treatments using low-viscosity fluid or pumping at very low rates, the viscous term of the net pressure equation becomes small, and fracture toughness becomes a dominant parameter. Although many cases fall into one of these extremes, neither effect should be overlooked for the prudent application of fracturing.

The magnitude of net pressure may also be controlled by in-situ stress differences between the pay and the bounding layers. Consider a case where barrier zones (e.g., formations with higher closure stress) surround the pay zone (Fig. 5-9) and further assume that because of either viscous or toughness effects, p_{net} increases to the level of the stress differences. Massive height growth then begins, and only very small increases in the net pressure are possible. Net treating pressure is now controlled directly by $\Delta\sigma$ and is essentially independent of both fluid viscosity and apparent fracture toughness effects. This case is illustrated in the next section.

- Fracture height and net pressure

For a fracture with significant stress barriers and in a formation with a medium to high value for the modulus, the viscous term in Eq. 5-20 controls the net treating pressure. In such a case, p_{net} becomes a strong function of fracture height. However, as illustrated in Fig. 5-9, fracture height h_f is controlled by net pressure. To put it in another form, fracture height is a function of fracture height. As discussed in Chapter 6, this is where fracture models become important.

As an example, consider the case of a thin (h = 25 ft) sandstone pay zone in a hard-rock formation ($E = 5 \times 10^6$ psi). Further assume that this zone is surrounded by shales with an in-situ stress 1000 psi greater than the stress in the sand, making them what would normally be considered good barriers to vertical fracture growth. As seen in Fig. 5-18a, even for pumping a moderate (50-cp) viscosity fluid at a moderate rate, net pressure immediately jumps to a level slightly greater than 1000 psi (i.e., $\Delta\sigma$ is controlling p_{net}), and extensive height growth occurs. Because $\Delta\sigma$ is controlling the allowable net pressure, increasing the fluid viscosity fourfold has essentially no effect on net pressure after the first few minutes. The vertical fracture width profile plotted in Fig. 5-18b shows that for p_{net} about equal to $\Delta\sigma$, fracture width in the bounding layers may be too small for proppant admittance. This is discussed in the subsequent section on proppant admittance.

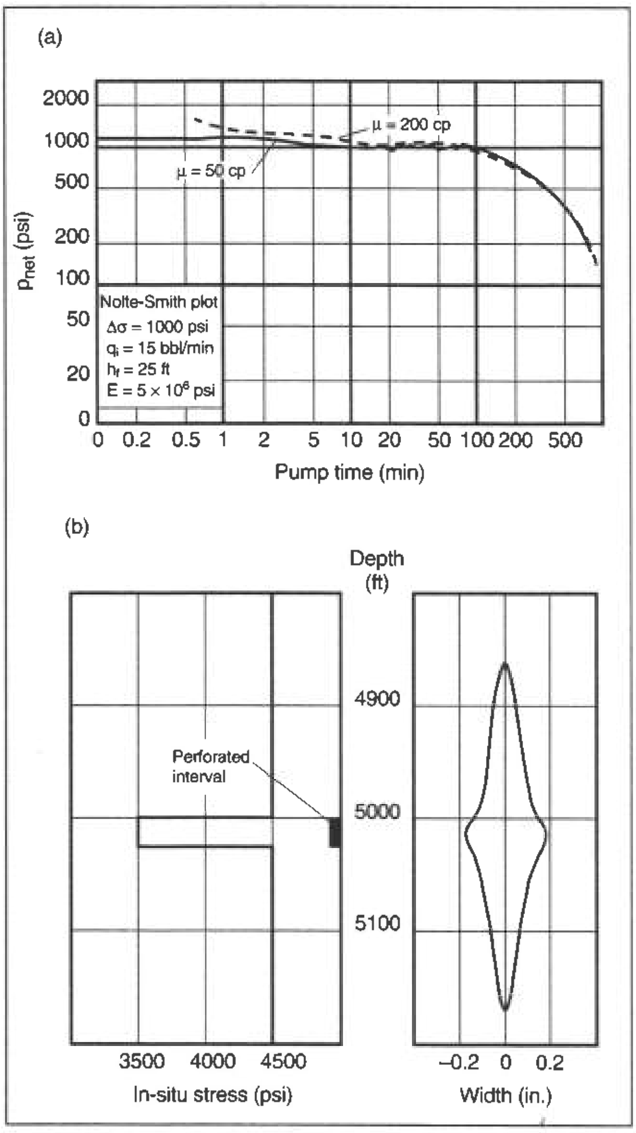


Figure 5-18. *Height growth example in a hard-rock formation.*

Now consider the same case but with a 50-ft thick sandstone section. As seen in Fig. 5-19, p_{net} stays below $\Delta\sigma$ for the 50-cp fluid case and little

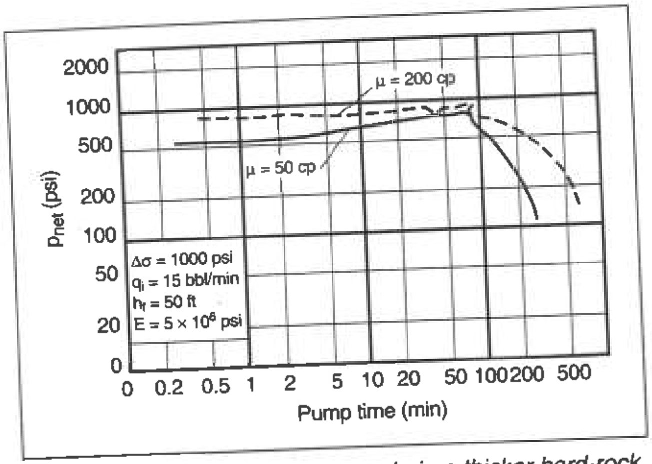


***Figure 5-19.** Height growth example in a thicker hard-rock formation.*

height growth occurs. For a more viscous (200-cp) fluid, net pressure again approaches the stress difference of 1000 psi, and again extensive height growth occurs. These examples show that fracture height is a function of fracture height.

Finally, consider the original (h = 25 ft) case again, but assume this is a soft-rock (unconsolidated sand with $E < 0.5 \times 10^6$ psi) zone. Further assume that because of high permeability, fluid loss is much greater than for the previous two cases. Figure 5-20 shows p_{net} is much less than $\Delta\sigma$, with essentially no height growth. Also, the flat nature of the net pressure behavior in the Nolte-Smith log-log plot of p_{net} versus time indicates that fracture tip effects are dominating net pressure behavior, as expected from Eq. 5-20. Chapter 9 discusses net pressure behavior and the means to determine the controlling conditions.

- Fluid viscosity

  Fluid viscosity provides an example of how variables affect different parts of the fracturing process in different ways. Consider a case of radial fracture growth in a soft rock ($E < 1 \times 10^6$ psi). Toughness dominates p_{net} and fracture width, and viscosity becomes unimportant in controlling fracture geometry. However, viscosity can remain a critical consideration for proppant transport if a long fracture is desired and for fluid-loss control.

  Further assume this case is a very high permeability formation, such that only a short fracture is required. Thus, high viscosity is not required for proppant transport. However, in this very high permeability formation it is probable that the fracturing fluid cannot build a filter cake to control fluid loss, and the only fluid-loss control will come from the viscosity (or invaded zone) effect C_v (see Section 5-4.6). Viscosity is therefore a major factor for fluid selection, despite having no effect on geometry and not being critical for proppant transport.

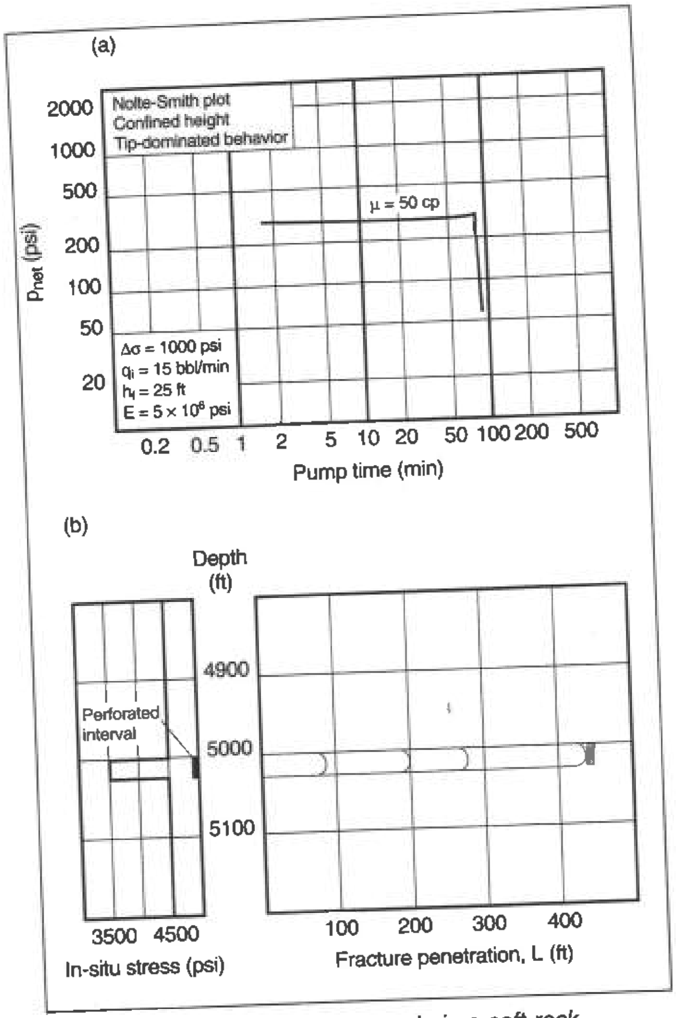


***Figure 5-20.** Height growth example in a soft-rock formation.*

5-5. Treatment pump scheduling

The fracture design process involves reservoir engineering to define the x_f and k_fw goals. It involves rock mechanics to consider the possibility of obtaining a desired fracture geometry. It includes fluid mechanics considerations to confirm that the required proppant transport is possible and rheology to determine if the required fluid properties are possible. It also includes material selection and on-site operational considerations as discussed in Section 5-6. The product of this process is a treatment pump schedule. This includes the pad volume necessary to create the desired fracture penetration, along with acid or proppant scheduling to achieve the desired postfracture conductivity. For propped fracturing, pump scheduling includes fluid selection, proppant selection, pad volume, maximum proppant concentration to be used and a proppant addition schedule. After the design goals and variables are defined, the proppant addition schedule is usually obtained by using a fracture simulator, although for many cases analytical calculations based on fluid efficiency are also easily implemented. Chapter 10 provides additional detail for treatment design.

5-5.1. Fluid and proppant selection

Fracturing materials are discussed in Chapter 7, and their performance characterization is discussed in Chapter 8. The major considerations for fluid selection are usually viscosity (for width, proppant transport or fluid-loss control) and cleanliness (after flowback) to produce maximum postfracture conductivity. Other considerations that may be major for particular cases include

- compatibility with reservoir fluids and reservoir rock
- compatibility with reservoir pressure (e.g., foams to aid flowback in low-pressure reservoirs)
- surface pump pressure or pipe friction considerations
- cost
- compatibility with other materials (e.g., resin-coated proppant)
- safety and environmental concerns (see Chapter 11).

Proppant selection must consider conductivity at in-situ stress conditions (i.e., the effect of stress on proppant permeability k_f). Proppant size must also be considered. In general, bigger proppant yields better conductivity, but size must be checked against proppant admittance criteria, both through the perforations and inside the fracture (see Section 5-5.4). Finally, the maximum in-situ proppant concentration at shut-in must be selected, as it determines how much of the hydraulic width created by the fracture treatment will be retained as propped width once the fracture closes.

5-5.2. Pad volume

For a treatment using viscous fluid, the fluid carries the proppant out to the fracture tip. For these cases the pad volume determines how much fracture penetration can be achieved before proppant reaches the tip and stops penetration in the pay zone. Once the pad is depleted, a fracture may continue to propagate into impermeable layers until the proppant bridges in low-width areas. Thus, pumping sufficient pad to create the selected length is critical. For treatments using very low viscosity fluid (i.e., "banking"-type treatments), proppant settles out of the fluid and essentially replenishes the pad. The pad volume must only be sufficient to open enough fracture width for proppant admittance, and the carrying capacity of the fluid, as opposed to the pad volume, determines the final propped length.

On the other hand, too much pad can in some instances be even more harmful, particularly for cases requiring high fracture conductivity. The fracture tip continues to propagate after pumping stops, leaving a large, unpropped region near the fracture tip. Significant afterflow can then occur in the fracture, carrying proppant toward the tip and leaving a poor final proppant distribution. This afterflow occurs because the widest section of the fracture is near the wellbore at shut-in, and most of the proppant pumped is stored there. However, the highest fluid-loss rates are near the fracture tip. Thus, proppant-laden slurry continues to flow toward the tip of the fracture. Afterflow continues until either the fracture closes on the proppant, stopping proppant movement, or until proppant-laden slurry reaches the fracture tip. At that point the slurry dehydrates and stops any additional fracture propagation. Ideally, of course, it is better to have the proppant at the fracture tip at shut-in and thus minimize afterflow.

An ideal schedule for a normal treatment (as opposed to subsequently discussed TSO designs) is one where the pad depletes and proppant reaches the fracture tip just as the desired fracture penetration is achieved and also just as pumping stops. This is the sequence in Figs. 5-2, 5-3 and 5-4.

The critical parameter of the pad volume or pad fraction f_{pad} is related directly to the fluid efficiency for a treatment (Nolte, 1986b). This relation from Sidebar 6L gives the pad volume expressed as a fraction of the entire treatment volume:

$$f_{pad} \approx \frac{1-\eta}{1+\eta}. \qquad (5\text{-}22)$$

That is, a treatment with an expected efficiency η of 50% would require a pad fraction of about ⅓. As discussed in Chapter 9, the efficiency for a specific formation and fluid system can be determined by a calibration treatment.

This discussion of pad volume has so far concentrated on the fluid-loss aspects of the pad volume; i.e., the pad is pumped first to serve as a sacrificial stage of the treatment to enable the fracture to penetrate into permeable formations. This important effect of the pad volume may be the critical aspect governing the size of the pad for most applications. However, hydraulic fracturing is complicated, in that most things are done for at least two reasons, which applies to pad volume specification. The second purpose of the pad volume is to create sufficient fracture width to allow proppant to enter the fracture (see Section 5-5.4 on proppant admittance). Even for a case of very low fluid loss, some minimum pad volume is required. Both of these aspects of the pad volume must always be considered for treatment design.

- Propped width

  A major design goal is fracture conductivity $k_f w$, which consists of proppant pack permeability and propped fracture width. Proppant permeability k_f is a function of the proppant selected, in-situ stress and residual damage from fluid additives (see Chapter 8). Propped width is controlled by the treatment design.

  The effective propped width $w_{p\text{-}eff}$ is a function of the average fracture width w_f at shutdown (i.e., hydraulic width at the end of pumping a treatment), proppant concentration C in the fracture at that time (i.e., giving the ideal propped width w_p) and the volume of proppant w_{lost} that is lost on the faces of the fracture to embedment, gel residue, etc. (usually expressed as lbm/ft^2 "lost"). In terms of these parameters, the effective propped width can be expressed as

$$w_{p\text{-}eff} = w_p - w_{lost} = w_f \times F - w_{lost} \qquad (5\text{-}23)$$

$$F = \frac{C}{\left(8.33 \times \gamma_{prop} + C\right) \times (1-\phi)}, \qquad (5\text{-}24)$$

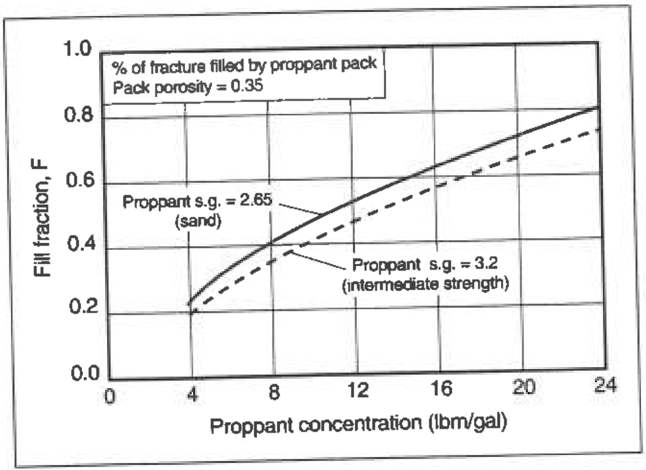


Figure 5-21. *Fill fraction versus proppant concentration.*

where F is the fill fraction (Fig. 5-21), the constant 8.33 converts the units to lbm/gal, γ_{prop} is the specific gravity (s.g.) of the proppant, C is the final in-situ proppant concentration at shut-in expressed as pounds of proppant per fluid gallon (ppg), and ϕ is the porosity of the proppant pack, typically about 0.35.

Increasing the concentration from 8 ($F \approx 0.4$) to 16 ppg ($F \approx 0.6$) significantly increases the propped fracture width (50% increase in the fill fraction). However, this large increase in propped width is accomplished at the expense of additional risk to the job and to the well, because of either surface mechanical problems or an unexpected total screenout somewhere in the fracture or in the near-wellbore region between the well and the far-field fracture (see the discussion of tortuosity in Section 6-6). In practice, most treatments use a maximum concentration of about 8 to 14 ppg, although concentrations of 20 ppg have been pumped.

Another manner of increasing propped width is to increase fracture width. Theoretical and numerical models generally show that the fracture width, while the fracture is growing, is relatively insensitive to the controllable job variables of pump rate and fluid viscosity. For a simple fracture geometry, width is proportional to rate and viscosity raised to a small power. For Eq. 5-18 with the exponent ¼, doubling the pump rate increases fracture width by only 18%, at the expense of significant pipe friction and surface pressure increases. Viscosity is easily increased by an order of magnitude (e.g., 10 times increase in μ increases the width by 77%), but only at the expense of using more fluid additives and with additional conductivity damage potentially negating the extra width.

Thus, the hydraulic fracture width is fairly fixed (±50%, at least in terms of the treatment's controllable parameters), and the proppant fill fraction has a practical limit of about 0.5 (±0.1). Without TSO designs (discussed in the following) the final, effective propped width is almost fixed by nature. The goal for a normal fracture design is then to achieve a required $k_f w$ within these limits, with proppant concentration, proppant selection and fluid selection allowing a large range of values.

- Tip-screenout designs

  As mentioned previously, as long as a fracture is free to propagate, the hydraulic fracture width is relatively insensitive to the controllable treatment parameters of fluid viscosity and pump rate. If more conductivity is required than can be achieved from a normal design, the only effective manner to increase the propped width is to stop the fracture from propagating but to continue to pump. This technique has come to be called TSO fracturing (Smith *et al.*, 1984).

  For a normal treatment, the pad volume is designed to deplete just as pumping stops. What would happen if pumping simply continued beyond that time? If the pad is depleted, then proppant-laden slurry will be located everywhere around the fracture periphery. If there is fluid loss, then this slurry will dehydrate and leave packed proppant around the periphery. Even with no fluid loss, the proppant may bridge in the narrow fracture width around the periphery, particularly in places where the width is extremely narrow as a result of the fracture penetrating a boundary layer. In either case, any additional propagation is restricted and further pumping causes an increase of net pressure and thus an increase of fracture width. TSO designs are discussed in detail in Chapter 10.

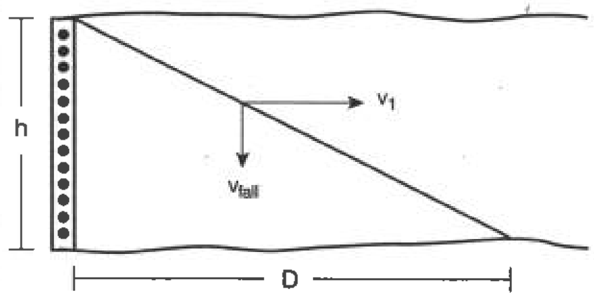
5-5.3. Proppant transport

Several modes of proppant settling can occur while proppant is being transported into a hydraulic fracture (see Section 6-5). First is what may be termed simple or single-particle settling. Behavior of this type is governed by Stokes law, in which the velocity of a single particle falling through a liquid medium is

$$v_{fall} = 1.15 \times 10^3 \frac{d_{prop}^2}{\mu} \left(\gamma_{prop} - \gamma_{fluid} \right), \qquad (5\text{-}25)$$

where v_{fall} is the settling rate in ft/s, d_{prop} is the average proppant particle diameter in in., μ is the fluid viscosity in cp, and γ_{prop} and γ_{fluid} are the specific gravity of the proppant and the fluid, respectively. The settling rate, and thus the efficiency with which proppant can be transported into the fracture, is directly related to the fluid viscosity. This is usually the main consideration for how much viscosity is required for a fracture treatment. However, there are additional considerations for calculating settling following Stokes law. At low proppant concentrations (e.g., less than 1 or 2 ppg) particles may clump, producing an apparent diameter greater than the actual particle diameter and accelerating settling. Higher particle concentrations act to increase the slurry viscosity and retard settling (also known as hindered settling). The pump rate is also an important parameter controlling proppant transport for simple settling by Stokes law.

As shown in Fig. 5-22, for a Newtonian fluid the distance D a proppant particle is transported into a fracture, before that particle can fall from the top of



$$D/h = v_1/v_2$$

v_1 = fluid velocity $\propto q_i/hw \propto q_i/h(\mu q_i)^{1/4} \propto q_i^{3/4}/h\mu^{1/4}$

v_{fall} = fall rate $\propto 1/\mu$

$D/h \propto (q_i\mu)^{3/4}/h$

D is independent of h

Figure 5-22. Stokes law.

the fracture to the bottom, is related to $(q_i\mu)^{3/4}$. This distance is independent of the fracture height and, more significantly, shows that for some given transport distance, less viscosity can be used at higher pump rates. This relation can be important for higher temperature applications, where fluid viscosity can degrade significantly with time. At higher rates (and hence shorter pump times), less viscosity is required for proppant transport. Also, the fluid is exposed to the high formation temperature for less time, so the fluid system maintains better viscosity. In general, considering how fluid viscosity degrades down a fracture, including the effect of proppant concentration increasing the effective slurry viscosity, and considering the non-Newtonian nature of most fracturing fluids, if a fracturing fluid retains 50- to 100-cp viscosity (at reservoir temperature and at a shear rate of 170 s^{-1}) at the end of the fracture treatment, it will provide essentially perfect proppant transport (Nolte, 1982).

The next mode of proppant settling is termed convection, and it was probably first included in fracture modeling in the context of a fully three-dimensional (3D) planar model by Clifton and Wang (1988). This type of settling is controlled by density differences (i.e., buoyancy) between two fluids. For example, a proppant-laden fluid stage with an 8-ppg concentration has a slurry density of 11.9 lbm/gal (s.g. = 1.44). If this slurry is placed directly next to a clean fluid stage with a density of 8.5 lbm/gal (s.g. = 1.02), the heavier slurry will tend to sink and underride the lighter clean fluid, simply carrying the proppant toward the bottom of the fracture. However, a treatment does not normally follow clean pad fluid with a heavy 8-ppg slurry. Rather, the treatment increases proppant concentration slowly to account for fluid-loss effects and mitigate convection effects. Only near the end of pumping (when the need for transport decreases), when the initial proppant stages have undergone significant dehydration, can a significant density difference begin to develop. In general, rigorous numerical modeling of this phenomena shows convection is not a major factor during pumping (Smith *et al.*, 1997). If excessive pad is used, such that a large unpropped region of the fracture exists after shut-in, convection can occur during the shut-in after flow, with potentially significant adverse effects on the final proppant placement.

The third effect on proppant transport is termed migration (see Chapter 6). In brief, a viscoelastic fluid (which describes most fracturing fluid systems) flowing down a channel imparts a normal force to particles entrained in the fluid such that the particles tend to migrate to and concentrate in the center of the channel. For low average concentrations, this can result in a center core of high-proppant-concentration slurry, with a region of essentially clean fluid on either side. This heavier core of concentrated slurry tends to fall owing to its greater density, carrying the entrained proppant toward the bottom of the fracture at a faster rate than for a dispersed slurry (Nolte, 1988b).

Finally, any calculations for proppant settling must consider geologic reality. Detailed examinations of hydraulic fractures both at the wellbore using television cameras (Smith *et al.*, 1982) or away from wells in mineback tests (see Warpinski, 1985) show something other than the smooth fracture walls assumed for settling calculations. Small shifts and jogs of the fracture probably have no significant impact on fluid flow or on lateral proppant transport into the fracture. However, these small irregularities could significantly impact settling. Calculations for proppant settling that ignore these effects will be a worst-case scenario.

5-5.4. Proppant admittance

Proppant admittance is critical to hydraulic fracturing in two forms: entrance to the fracture through perforations and entrance of proppant into the fracture itself. These effects were recognized early, and the original fracture width models were used primarily for determining a pad volume that would allow admittance by generating a fracture width greater than $2.5d_{prop}$, where d_{prop} is the average proppant particle diameter. Before these models, operators were reluctant to pump significant volumes of pad as it was considered expensive and potentially damaging.

The laboratory data in Fig. 5-23 (Gruesbeck and Collins, 1978) illustrate two important ideas:

- A minimum perforation diameter is required for proppant to flow through the perforations.
- Minimum perforation diameter is a function of the slurry concentration.

At low concentrations (e.g., 1 ppg), the perforation hole diameter must be only slightly greater than that of the proppant particles. The required hole diameter increases with concentration until at about 6 ppg

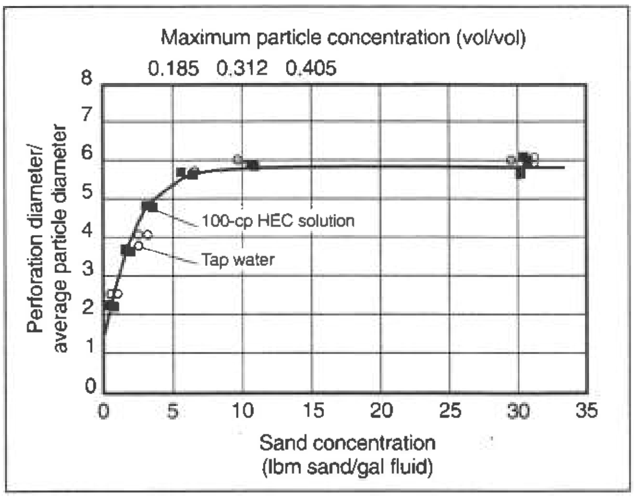


Figure 5-23. *Proppant admittance through perforations (Gruesbeck and Collins, 1978).*

(solid volume fraction of about 0.20), the perforation hole diameter must be 6 times the average particle diameter.

This same trend applies for slurry flow down a narrow fracture. An approximate proppant bridging or proppant admittance criteria can be derived by calculating an equivalent hydraulic radius for a narrow slot, $r_{hyd} = w/2$, where w is the average width of the fracture. For a round perforation hole, the hydraulic radius is $d/4$, where d is the perforation hole diameter. Equating the two hydraulic radius values shows that $2w$ is equivalent to the diameter of a round hole. Using this along with two lines fitting the data of Gruesbeck and Collins leads to an approximate admittance criteria for a hydraulic fracture:

- For a proppant solid volume fraction f_v less than 0.17, the average width must be greater than $(1 + 2f_v/0.17) \times d_{prop}$.
- For f_v greater than 0.17, the average width must be greater than $3d_{prop}$ (i.e., a width greater than three proppant grain diameters).

This approximate correlation also compares well with other experimental data from proppant-laden slurry flowed through a narrow slot (van der Vlis *et al.*, 1975), although the correlation may be optimistic for low proppant concentrations. As shown in Table 5-1, the behavior for bridging in a fracture is similar to bridging in perforation holes. At low proppant concentrations, the average fracture width must be only slightly greater than the average particle diameter. As the proppant concentration increases toward 6 to 8 ppg, the required average fracture width increases to $3d_{prop}$.

Table 5-1. Proppant admittance criteria.

Proppant[†] Concentration (lbm proppant/gal fluid)	$\bar{w}/d_{prop}$	
	Experimental Bridge Formation[‡]	Correlation Bridge
0.5 to 2	1.8	1.15 to 2.0
2 to 5	2.2	2.0 to 3.0
5 to 8	2.6	3.0

[†] Sand as proppant
[‡] Data from van der Vlis *et al.* (1975)

This critical width is important to the hydraulic fracturing process. Should proppant enter a part of the fracture where sufficient width does not exist, the proppant will bridge and no longer flow down the fracture. Additional slurry flowing in this direction will cause proppant to pile up, dehydrate and block that part of the fracture. Should this occur near the wellbore, possibly as a result of some form of near-wellbore width restriction (see tortuosity discussion in Section 6-8), a total screenout can result with serious consequences for the success of the fracture treatment.

5-5.5. Fracture models

Clearly, developing a final treatment pump schedule must consider many options. The interactive roles of the various major variables (h_f, E, C_L, $K_{Ic\text{-}apparent}$, μ and q_i) must be considered along with the various roles of fluid viscosity for net pressure, width, proppant transport and fluid loss. In addition, the design must consider the various roles of the pad volume concerning fluid loss and creating fracture width. Fracture simulators, or fracture placement models, provide the means to handle this complexity and to consider the interaction of the multitude of variables. For this reason, a final schedule is generally developed using a fracture geometry model. However, as discussed in Section 5-5.2, Sidebar 6L and Section 10-4, in many instances an acceptable pump schedule can be developed more simply for a treatment on the basis of the expected fluid efficiency (as determined from a calibration treatment). The use of a properly calibrated fracture geometry model also enables the consideration of multiple scenarios for designing the optimum treatment for a specific application. This approach is briefly discussed in Section 5-6.1.

5-6. Economics and operational considerations

The preceding discussion covers most of the technical aspects of hydraulic fracturing (reservoir engineering, fluid mechanics, rock mechanics, etc.) and reviews the complex interactions that exist between the various, often competing design variables. However, to complicate things further, hydraulic fracturing and treatment design are generally governed by—or are at least sensitive to—two final considerations: economics and field operations.

5-6.1. Economics

At the most basic level, hydraulic fracturing is about time and money: "economics." Given reasonable geologic continuity, a single well would, given sufficient time, drain an entire reservoir. However, the operating costs of maintaining a well over the decades required to accomplish this drainage would probably make the entire operation unattractive from a commercial viewpoint. Alternatively, a single well with a large hydraulic fracture may drain the reservoir much faster, making the economics much more attractive despite the additional cost of the treatment. Carrying this forward, 2, 10 or 100 or more wells could be drilled and/or fractured. Between these extremes is the optimum plan, which is the number of wells, number of fractured wells or both that maximize the economic value of the production compared with the development capital costs and the ongoing operating costs.

As a simple example, the process (at least for a single well) could proceed as pictured in Fig. 5-24 (Veatch, 1986). First, reservoir engineering calculations provide a production forecast for various combinations of fracture half-length x_f and conductivity k_fw (including the case of no fracture at all). Based on some future price forecast, this allows calculation of a present value, which is the future revenue from the production less future operating costs and discounted back to the present. Hydraulic fracturing calculations based on fluid loss, fracture height, etc., are used to determine the treatment volumes required to generate various combinations of fracture length and propped fracture width, and these calculations are easily converted into estimated treatment costs. Some form of net revenue economic analysis is then used to determine the best type of proppant, desired

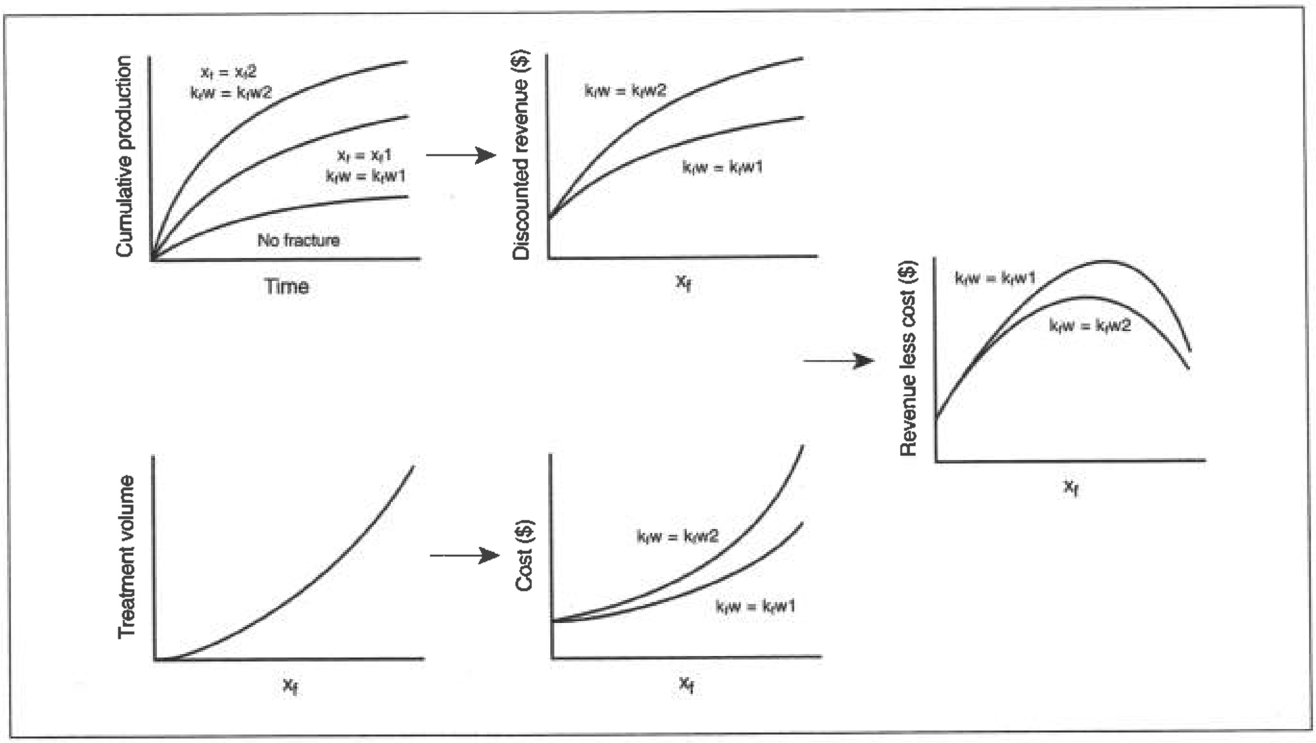


__Figure 5-24.__ Veatch (1986) economics diagrams.

fracture length and other requirements for the optimum treatment.

There are, of course, many variations of this basic process. For example, full-cycle economics includes drilling and other completion costs, along with fracture treatment costs, in determining the optimum fracture design. This type of analysis is usually appropriate in any case involving multiple wells (e.g., should a resource be developed using 10 wells with huge fractures or 20 wells with smaller or no fracture treatments?). Point-forward analysis, on the other hand, considers only the fracture treatment costs (because drilling and other completion costs are already expended) and is most appropriate for working over existing wells.

5-6.2. Operations

As discussed in the preceding section, economics provides the final design consideration for hydraulic fracturing, whereas field conditions provide the practical limits within which the design must fit. Even beyond defining these limiting conditions, however, any design is only as good as its execution; thus the treatment must be pumped as designed. Field operations and operational considerations impact hydraulic fracturing in two ways:

- prefracture condition of the wellbore, quality of the cement job, perforations, pressure limits, etc., with these considerations defining practical limits that the design must meet
- quality assurance and quality control (QA/QC) before and during the actual treatment.

These operational considerations are discussed in Chapters 7 and 11, with some of the major items highlighted in the following.

- Wellbore considerations

  Some of the major wellbore considerations for hydraulic fracturing include
  - size and condition of wellbore tubulars
  - quality of the cement job for zonal isolation
  - perforations
  - wellbore deviation.

  During a hydraulic fracture treatment, the predicted surface pressure p_{surf} and the hydraulic horsepower required for a treatment are related to the hydrostatic head of the fluid in the wellbore p_{head} and the pipe friction $p_{pipe\,friction}$:

$$p_{surf} = \sigma_c + p_{net} + p_{pipe\,friction} - p_{head} \qquad (5\text{-}26)$$

$$hhp \propto q_i \times p_{surf}. \qquad (5\text{-}27)$$

  Pipe friction is a major term, and thus the size of the well tubulars has a strong influence on allowable pump rates (because pipe friction is typically related to v^e, where $v = q_i/A$ is the flow velocity down the tubing, and e is typically about 1.1 to 1.7). Also, the strength and condition of the tubulars (along with the associated wellhead equipment) set an allowable surface pressure and thus indirectly set an allowable injection rate. In addition, the size, type and condition of the wellbore tubulars may limit (or prohibit) future workover and recompletion opportunities.

  A critical aspect of wellbore considerations is a good cement job around the casing or liner to provide zonal isolation. In general, a fracture grows where nature dictates, and the engineer has little control over fracture height growth. The only control possible is the ability to specify where the perforations are placed and the fracture initiates. If that ability is compromised by a poor cement sheath around the casing that allows the perforations to communicate directly with an undesired interval, then even this minimal level of control is lost, and the hydraulic fracture treatment may be seriously compromised.

  Another important consideration is the perforations that allow the fluid to leave the wellbore and create the fracture. The number and size of the perforation holes are important for proppant admittance, as discussed briefly in Section 5-5.4 and in detail in Section 11-3.

- Quality assurance and quality control

  Quality issues are critical for hydraulic fracturing. After proppant pumping starts, a treatment cannot be stopped because of problems without significantly compromising the design goals. For this time period, everything must work, including the wellbore equipment, pumping and blending equipment and chemicals (i.e., the fluid system). To cite a simple example, if a treatment uses 10 tanks of batch-mixed fluid, and one of the tanks is bad, then the QA score is a relatively high 90%. However, if the bad fluid is pumped just after proppant addition starts, it may easily cause total failure of the treatment, and if successful treatment is critical to economic success of the well, this causes total economic failure. Typically, this type of failure cannot be overcome without completely redrilling the well (refracturing operations are usually a risky procedure), and thus 90% can be a failing grade for QA.

Appendix: Evolution of Hydraulic Fracturing Design and Evaluation

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Overview

This Appendix to Chapter 5 reviews the evolution of hydraulic fracturing design and evaluation methods. Complementary reviews are the application of fracturing by Smith and Hannah (1996) and fracturing fluids by Jennings (1996). This review of design and evaluation considers three generations of fracturing: damage bypass, massive treatments and tip-screenout (TSO) treatments.

The first two generations of fracturing and their links to practices are emphasized because these contributions are not likely well known by the current generation of engineers. The review focuses on propped fracturing and does not explicitly consider acid fracturing. Although the principles governing the mechanics of both are essentially the same, the fluid chemistry for obtaining fracture conductivity is quite different (see Chapter 7). These principles have their roots in civil and mechanical engineering, more specifically in the general area of applied mechanics: solid mechanics for the rock deformation and fluid mechanics for the flow within the fracture and porous media. For the porous media aspects, fracturing evaluation has benefited greatly from the reservoir engineering practices discussed in Chapters 2 and 12.

This review reflects the author's perspective and bias in interpreting the impact of past contributions, and therefore parts of this review should be anticipated to raise objections from others with an extensive knowledge of fracturing. In addition to this volume, the Society of Petroleum Engineers (SPE) Monograph *Recent Advances in Hydraulic Fracturing* (Gidley *et al.*, 1989) provides balanced, detailed coverage of the diverse areas of fracturing from the perspectives of more than 30 fracturing specialists.

This review concludes with speculation concerning a future generation, in which fracture design and reservoir engineering merge into fracturing for reservoir management (i.e., control of both the vertical and horizontal flow profiles within the reservoir). Similar speculation in a 1985 lecture suggested that development of the technical foundation for the TSO generation would quickly bring higher permeability formations into consideration as typical fracturing candidates (i.e., "moderate *k* (2×)" on Appendix Fig. 1a, with 2× indicating a target for folds of increase [FOI] in the production rate, in contrast to 10× for tight gas and massive treatments). However, the advent of this generation was considerably delayed because of two factors that have generally dominated technical considerations during the history of fracturing. These dominating factors are hydrocarbon prices and resistance to trying something new until established practices fail to allow the economic development of a prospect.

The cycles of fracturing activity in Appendix Fig. 1a clearly reflect the timing of the first two fracturing generations. Appendix Fig. 1b identifies economic drivers for corresponding cycles in the U.S. rig count. The first surge of activity resulted when rotary drilling was introduced, which enabled the development of deeper reserves. Fracturing activity followed this trend soon after its commercialization in 1949 because it was found to be an effective, low-cost means of mitigating the resulting drilling mud damage to reservoir sections (i.e., the damage bypass generation). Both drilling and fracturing activities began a long-term decline after 1955 because of degrading prices caused by imported oil and regulated gas prices. Similarly, both activities began a rapid increase at about 1979 as prices increased because the Organization of Petroleum Exporting Countries (OPEC) reduced its oil supplies and a natural gas shortage developed in the United States. The gas shortage, and its 10-fold-plus increase in price, encouraged the development of tight gas reserves and an associated demand for massive fracturing treatments to develop the tight reserves. The failure of past fracturing practices for