**UNIT I**

**Introduction, fracturing, Stress Distribution, Vertical Versus Horizontal Fractures, Pressure Related to Fracturing, Closure Pressure, Fracturing Pressure –Decline analysis, Pressure Interpretation after Closure, Properties of Fracturing Fluids.**

**Fracturing:**

Hydraulic fracturing of petroleum reservoirs is a reasonably new activity, spanning 40 years. The understanding of fracture propagation, its geometry, and direction is even newer, and addition to the body of knowledge of fracturing as a reservoir stimulation treatment is a very active process.

A classic concept introduced in 1957 concluded that **fractures are "approximately perpendicular to the axis of least stress."**

The stress field can be decomposed into three principal axes:

- **A vertical and two horizontal, which are unequal**.

For most reservoirs the minimum stress is horizontal, resulting in vertical hydraulic fractures.

**Hydraulic fracturing:**

**(also fracking, fraccing, hydrofracturing or hydrofracking)**

It is a well stimulation technique in which rock is fractured by a pressurized liquid. The process involves the high pressure injection of '**fracking fluid' (primarily water, containing sand or other proppants suspended with the aid of thickening agents)** into a wellbore to create cracks in the deep rock formations through which natural gas, petroleum, and brine will flow more freely.

**When the hydraulic pressure is removed from the well, small grains of hydraulic fracturing proppants (either sand or aluminium oxide) hold the fractures open.**

**Method:**

A hydraulic fracture is formed by pumping fracturing fluid into a wellbore at a rate sufficient to increase pressure at the target depth (determined by the location of the well casing perforations), to exceed that of the fracture *gradient* (pressure gradient) of the rock.

The fracture gradient is defined as pressure increase per unit of depth relative to density, and is usually measured in pounds per square inch, per square foot, or bars. The rock cracks, and the fracture fluid permeates the rock extending the crack further, and further, and so on. Fractures are localized as pressure drops off with the rate of frictional loss, which is relevant to the distance from the well.

**Operators typically try to maintain "fracture width", or slow its decline following treatment, by introducing a proppant into the injected fluid – a material such as grains of sand, ceramic, or other particulate, thus preventing the fractures from closing when injection is stopped and pressure removed**.

Consideration of proppant strength and prevention of proppant failure becomes more important at greater depths where pressure and stresses on fractures are higher. The

propped fracture is permeable enough to allow the flow of gas, oil, salt water and hydraulic fracturing fluids to the well. During the process, fracturing fluid leak off (loss of fracturing fluid from the fracture channel into the surrounding permeable rock) occurs. If not controlled, it can exceed 70% of the injected volume.
This may result in formation matrix damage, adverse formation fluid interaction, and altered fracture geometry, thereby decreasing Efficiency. The location of one or more fractures along the length of the borehole is strictly controlled by various methods that create or seal holes in the side of the wellbore.
Hydraulic fracturing is performed in cased wellbores, and the zones to be fractured are accessed by perforating the casing at those locations. Hydraulic fracturing equipment used in oil and natural gas fields usually consist of a slurry blender, one or more high pressure,
High volume fracturing pumps (typically powerful triplex or quintuplex pumps) and a monitoring unit. Associated equipment includes fracturing tanks, one or more units for storage and handling of proppant, high pressure treating iron, a chemical additive unit (used to accurately monitor chemical addition), low pressure flexible hoses, and many gauges and meters for flow rate, fluid density, and treating pressure.
**Chemical additives are typically 0.5% percent of the total fluid volume. Fracturing equipment operates over a range of pressures and injection rates, and can reach up to 100 megapascals (15,000 psi) and 265 litres per second (9.4 cu ft/s) (100 barrels per minute**).

**Fracturing fluids:**
The main purposes of fracturing fluid are to **extend fractures, add lubrication, change gel strength, and to carry proppant into the formation**.
There are two methods of transporting proppant in the fluid –

1. High rate and high viscosity. High viscosity fracturing tends to cause large dominant fractures, while high rate (slick water) fracturing causes small spread out micro fractures.
2. Water soluble gelling agents (such as guar gum) increase viscosity and efficiently deliver proppant into the formation

**Fracture monitoring:**
Measurements of the pressure and rate during the growth of a hydraulic fracture, with knowledge of fluid properties and proppant being injected into the well, provides the most common and simplest method of monitoring a hydraulic fracture treatment. This data along with knowledge of the underground geology can be used to model information such as length, width and conductivity of a propped fracture.

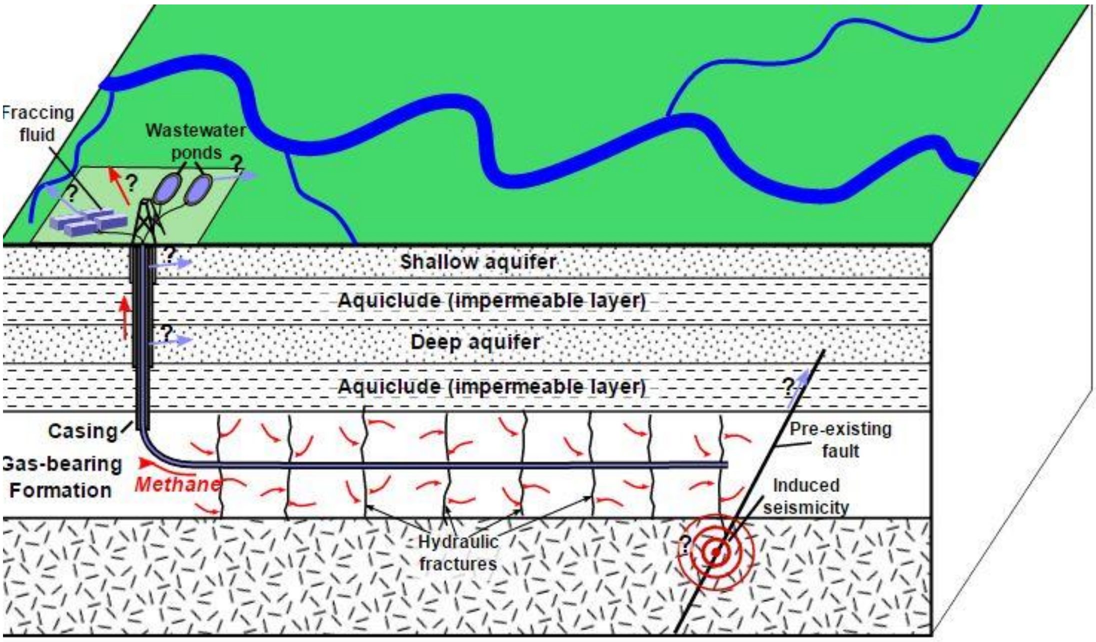



**Figure: Hydraulic fracturing process**

***Stress Distribution***

In a sedimentary environment, the vertical stress sv is equal to the weight of the overburden and can be calculated from

$$\sigma_v = \frac{1}{144}\int_0^H \rho\, dH$$

where p = density of each layer in lb/ft.3

H = thickness of overburden in ft.

Equation can be evaluated using a density log. In its absence, a value of 1.1 psi/ft. can be used as a reasonable approximation.

A porous medium, containing fluid, is subjected to an *effective* stress, rather than the absolute stress given by Equation. The effective stress is related to the pore pressure which is

$$\sigma' = \sigma - \alpha p$$

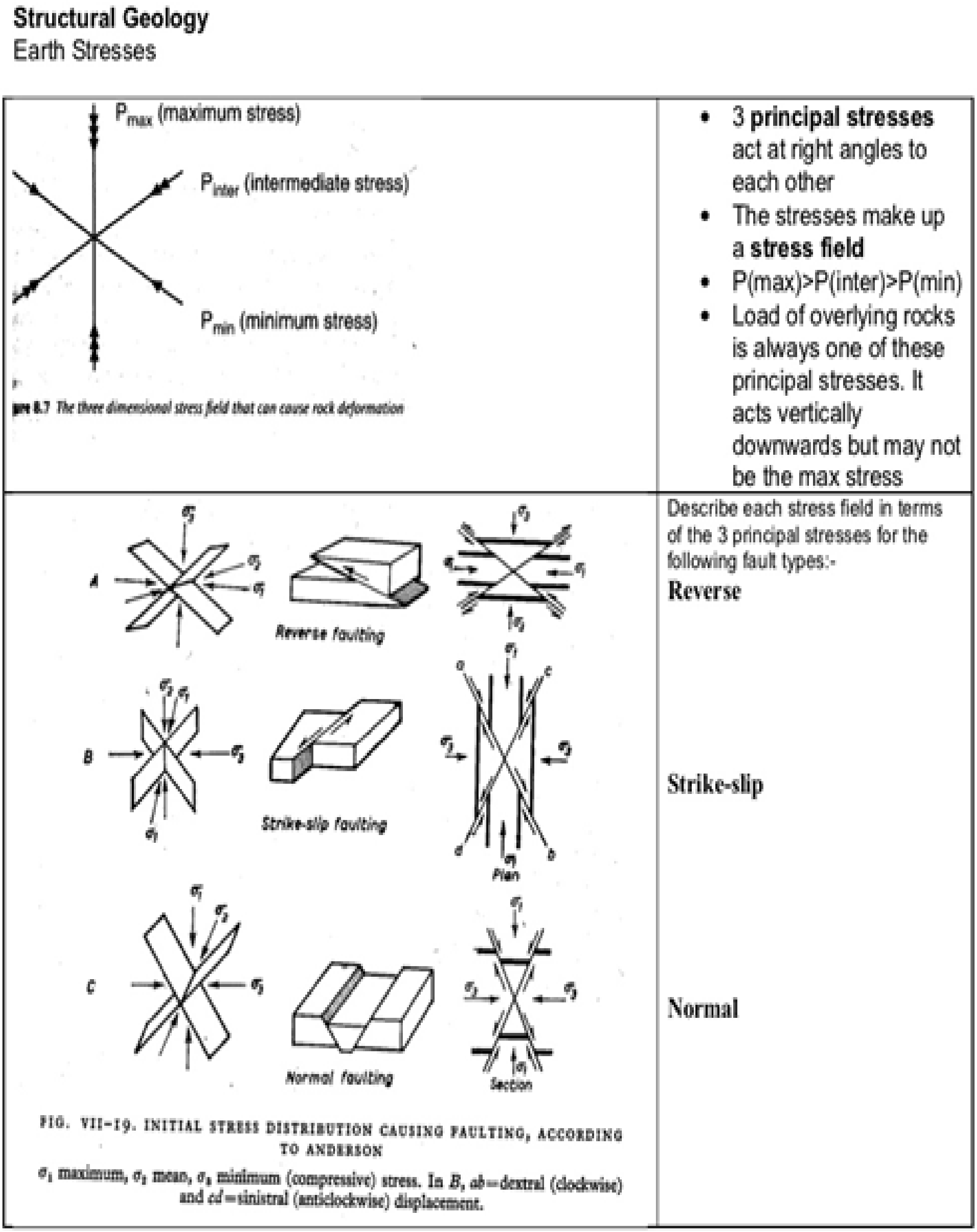
where α is Biot's "poroelastic" constant and varies from 0 to 1. For most petroleum reservoirs, it is equal to 0.7. It is important that the concept of the effective stress is understood.

An implication is that in a propped hydraulic fracture, the effective stress on the proppant is greatest during production (p = pwf ) and must be considered in the proppant selection.

Although the absolute and effective overburden stress can be computed via Equations, the two principal horizontal stresses are more complicated and their determination requires either field or laboratory measurements.

In a tectonically inactive formation, the elastic properties of the rock (Poisson ratio) may be used to relate the effective vertical stress with the effective minimum horizontal stress.

**`Figure:Stress distribution to form oil traps:**



$$\sigma'_{H,\min} = \frac{\nu}{1-\nu}\sigma'_{v}$$

where v = Poisson ratio
For sandstone formations, the Poisson ratio is approximately equal to 0.25, leading to a value of **σ** H,min approximately equal to **σ** v' . For most shale the Poisson ratio is larger, leading to abrupt changes in the horizontal stress profile.
This variation, which can envelope a sandstone reservoir because of overlaying and underlying shales, is the single most important reason for fracture height containment.

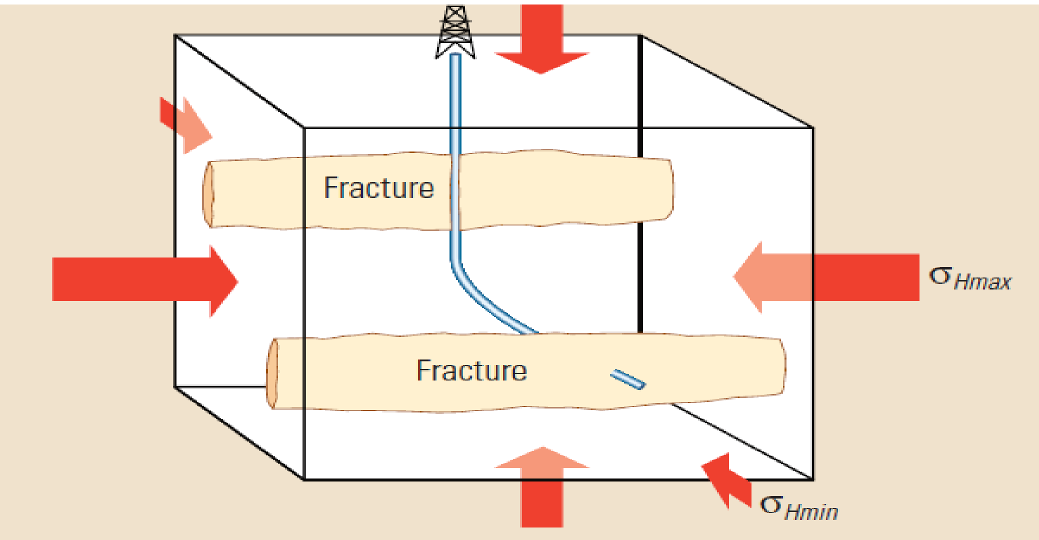
***Vertical versus Horizontal Fractures***

**DEFINITION OF FRACTURES:**
A fracture is a surface along which a loss of cohesion in the rock texture has taken place. A fracture is sometimes called a joint and, at the surface, is expressed as cracks or fissures in the rocks. The orientation of the fracture can be anywhere from horizontal to vertical. The rough surface separates the two faces, giving rise to fracture porosity.
The surfaces touch at points called asperities. Altered rock surrounds each surface and infilling minerals may cover part or all of each surface.
Minerals may fill the entire fracture, converting an open fracture to a healed or sealed fracture.

Fractures are caused by stress in the formation, which in turn usually derives from tectonic forces such as folds and faults. These are termed natural fractures, as opposed to induced fractures. Induced fractures are created by drilling stress or by purposely fracturing a reservoir by hydraulic pressure from surface equipment. Both kinds of fractures are economically important. Induced fractures may connect the wellbore to natural fractures that would otherwise not contribute to flow capacity.

Natural fractures are more common in carbonate rocks than in sandstones. Some of the best fractured reservoirs are in granite - often referred to as unconventional reservoirs. Fractures occur in preferential directions, determined by the direction of regional stress. This is usually parallel to the direction of nearby faults or folds, but in the case of overthrust faults, they may be perpendicular to the fault or there may be two orthogonal directions. Induced fractures usually have a preferential direction, often perpendicular to the natural fractures. A schematic diagram of these relationships is shown above, bottom right.

A fracture is often a high permeability path in a low permeability rock, or it may be filled with a cementing material, such as calcite, leaving the fracture with no permeability. Thus it is important to distinguish between open and healed fractures. The total volume of fractures is often small compared to the total pore volume of the reservoir.




^ In situ stresses and hydraulic fracture propagation. The three principal compressive stresses (red arrows) are a vertical stress ($\sigma_V$) and a maximum and minimum horizontal stress ($\sigma_{Hmax}$ and $\sigma_{Hmin}$). Hydraulic fractures open in the direction of the least principal stress and propagate in the plane of the greatest and intermediate stresses.

Consider Figure Graphed are the three principal stresses, σn, σH,min, σH,max. The maximum horizontal stress σH,max can be considered as equal to σH,min plus some tectonic component σtec .

If the original ground surface remains in place, then σH,min is less than σn, leading always to a vertical fracture which would be perpendicular to σH,min. However, if the present ground surface has been the result of massive glaciation and erosion, as depicted in Figure the overburden is reduced.

Because the horizontal stresses are “locked” in place, there exists a critical depth, shallower of which the minimum horizontal stress is no longer the minimum stress.

In such a case, a horizontal fracture will be created in the reservoir.

This has been observed in a number of shallow reservoirs.

The definition of *principal* stress direction implies that all shear stresses vanish.

Thus, when a vertical well is drilled, usually it coincides with a principal stress direction.

This is not the case when a deviated or horizontal well is drilled (unless, in the latter case, the well is drilled in the direction of one of the principal horizontal stresses).

However, for the mass of deviated wells that are drilled from platforms or drilling pads, their direction implies a nonvanishing shear stress [3].

The implications for fracturing are substantial. A deviated well requires a higher fracture initiation pressure. Furthermore, the production performance of a fractured deviated well is impaired.

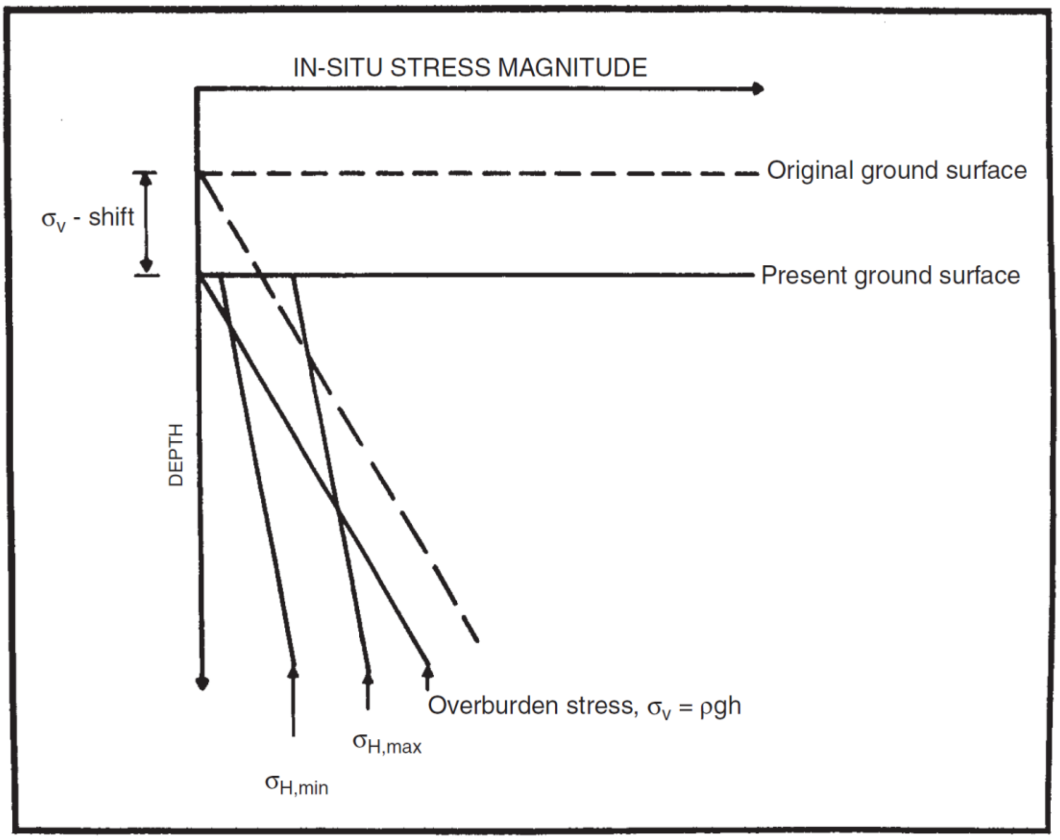



***Figure 6.5.1*** *Stress profiles (vertical and two horizontal stresses). Glaciation and erosion reduced the overburden, enabling a critical depth above which horizontal fractures may be generated. Below, only vertical fractures, normal to the minimum horizontal stress, are generated.*

### *Pressure Related to Fracturing*

The pressure signature created during the pumping of a fracturing treatment, and the associated pressure decline after injection, contains a significant amount of information relating to the fracture itself as well as the reservoir where the fracture has been placed. Applying specialized analysis of pressure during the various stages of the fracturing process provides a powerful technique for developing a comprehensive understanding about this process. Analysis during pumping provides a qualitative indicator of fracture growth, as well as estimates of several primary fracture parameters. The analysis of pressure decline after pumping can be broken into two distinct periods, with the early period being dominated by pressure falloff that is related to the fracture closing, whereas late time is governed by the transient pressure response of the reservoir. Figure1 shows the pressure response during the three stages of fracture evolution: growth, closure, and after closure reservoir response. Pressure measured during pumping provides an indication of the fracture growth process. The primary diagnostic tool for this period is the slope of the log-log plot of net pressure (i.e., the fracturing pressure above the reference closure pressure) versus pumping time. Figure 2 demonstrates how the slope of the log-log plot is used to characterize the fracture geometry. The pressure response during fracture closure is governed largely by the rate of fluid loss. The analysis of pressure during this period estimates the fluid efficiency and the leak off coefficient. These parameters are determined from a plot of the pressure decline versus a specialized function of time, commonly referred to as the *G*-plot. This specialized plot provides the fracturing analog to the Horner plot for well testing.

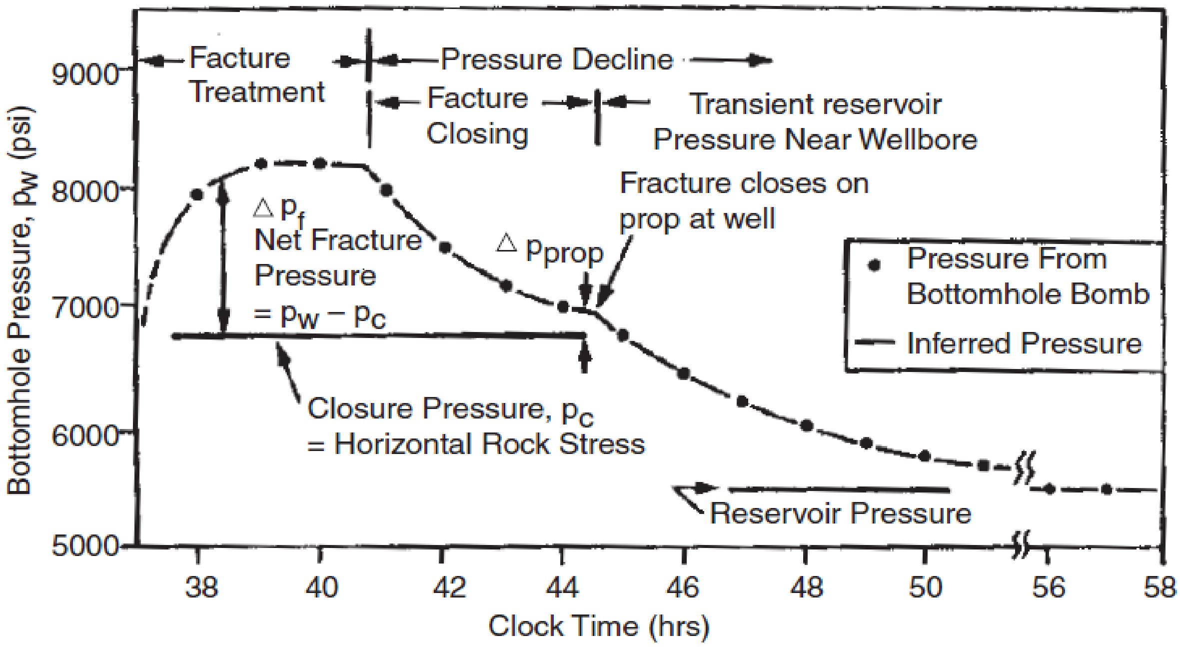
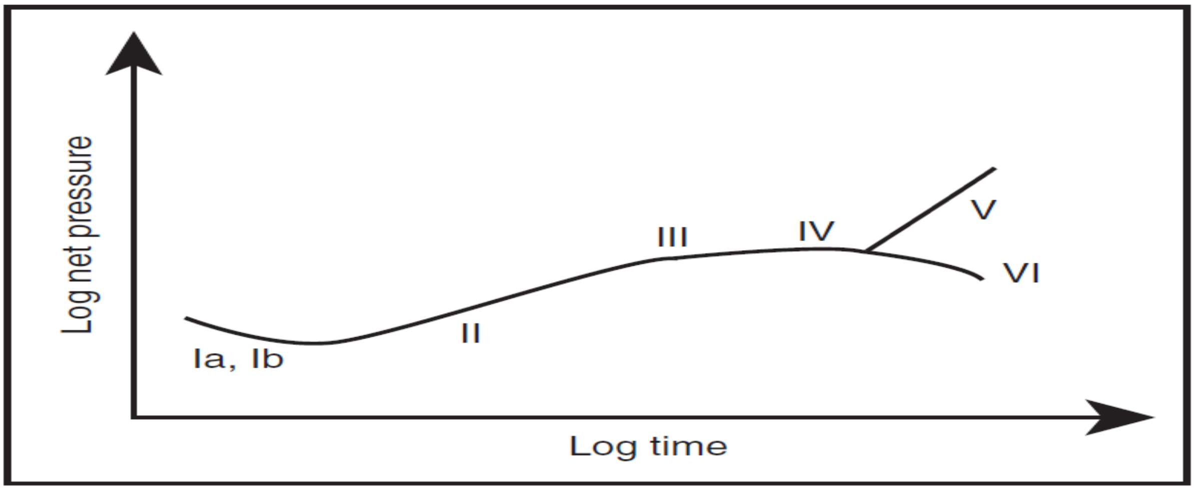



***Figure 6.5.2*** *Expected pressure response during a hydraulic fracture treatment [6].*



| Interpretation of log-log plot fracture pressure slopes | | |
|---|---|---|
| Propagation Type | Log-Log Slope | Interpretation |
| Ia | $-\frac{1}{2}$ to $-\frac{1}{3}$ | Frac Height growing faster than length; KGD |
| Ib | $-\frac{1}{2}$ to $-\frac{1}{3}$ | Frac Height growing faster than length; Radial |
| II | $\frac{1}{2}$ to $\frac{1}{4}$ | Confined Frac Height. Length growing faster than height; PKN |
| III | Reduced from II | Controlled height growth Stress-sensitive fissure |
| IV | 0 | Height growth through pinch point Fissure dilation T-shaped fracture |
| V | $\geq 1$ | Restricted extension |
| VI | Negative following IV | Uncontrolled height growth |
| Note: $n = 0.5$ | | |

***Figure2: Interpretation of log-log plot fracture pressure slopes.***

The final fracturing pressure analysis pertains to the evaluation of pressure after fracture closure. The pressure response during this period loses its dependency on the mechanical response of an open fracture and is governed by the transient pressure response within the reservoir. This transient results from fluid loss during fracturing and can exhibit either linear flow or a long-termradial response. Each of these flow patterns can be addressed in a manner analogous to conventional well test analysis for a fixed-length conductive fracture. The after closure period characterizes the reservoir's production potential.

***Breakdown Pressure (Fracture Initiation Pressure)***

The fracture initiation pressure is estimated via Terzaghi's criterion [4], giving an upper bound for the value of the breakdown pressure pb, such that

$$p_b = 3\sigma_{H,min} - \sigma_{H,max} + T_0 - p$$

Where T0 = tensile strength of the formation (psi) Hence, hydraulic fracturing describes the tensile failure of the rock and Equation can be used during a fracture calibration treatment to calculate the horizontal stress components.

**Closure pressure**:

Fracture closure pressure is the fluid pressure needed to initiate the opening of a fracture. This is not the same as the breakdown pressure, which is the fluid pressure required to initiate a fracture in intact rock. Closure pressure is equal to the minimum in-situ stress because the pressure required to open a fracture is the same as the pressure required to counteract the stress in the rock perpendicular to the fracture.

***Determination of Closure Pressure***

Closure pressure is defined as the pressure when the fracture width becomes zero. In a homogenous reservoir and where σH,min is the smallest stress, the closure pressure is approximately equal to this value. Nolte pioneered the analysis of the pressure response during fracture calibration treatments and the calculation of important fracture variables.

The pressurization/pressure decline stages shown in Figure 4 can be refined and used in accordance with Nolte's analysis to calculate the closure pressure and, as will be shown in the next subsection, the leakoff coefficient and fracturing fluid efficiency. The closure pressure is not exactly the minimum horizontal stress. With very little fluid leakoff (i.e., not upsetting the pore pressure in Equation 2) and with a contained fracture height, the closure pressure is very near the minimum horizontal stress. Otherwise, the closure pressure is a bulk variable taking into account fluid leakoff and especially horizontal stress heterogeneities along the fracture area. If the injected fluid is minimized, then with both leakoff and fracture height migration also minimized, the closure pressure is approximately equal to the effective minimum horizontal stress.

The pump-in/flowback test, which can be done as the first peak in Figure 3 has been devised to allow for the estimation of the closure pressure. The test involves injecting fluid, normally treated water, at rates (e.g., 5 to 10 bpm) and volumes (e.g., 30 to 50 bbl) sufficient to create a fracture. Of particular importance is the flowback period. This must be done at rates between 13 and 14 of the injection rate. The flowback rate must be held constant via a regulating valve exactly to prevent any flowrate transients to mask the pressure response. During this flowback period, the interpretation is qualitative and based on a deduction of the ongoing closure process and should have two distinctly different periods:

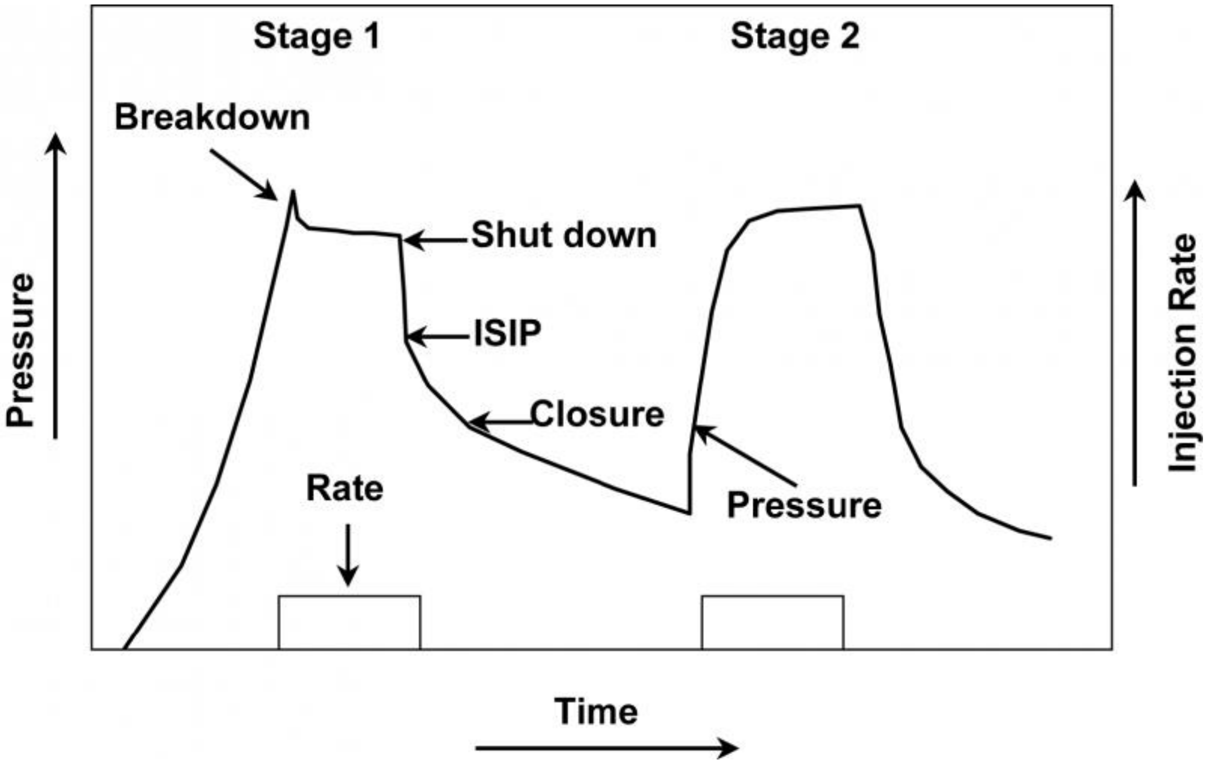
● While the fracture is closing

● after the fracture is closed

The pressure profile would then have two regions reflecting the two different phenomena. These two regions would be separated by a clear change in slope, and the pressure corresponding to this inflection point is **the *fracture closure pressure*.**

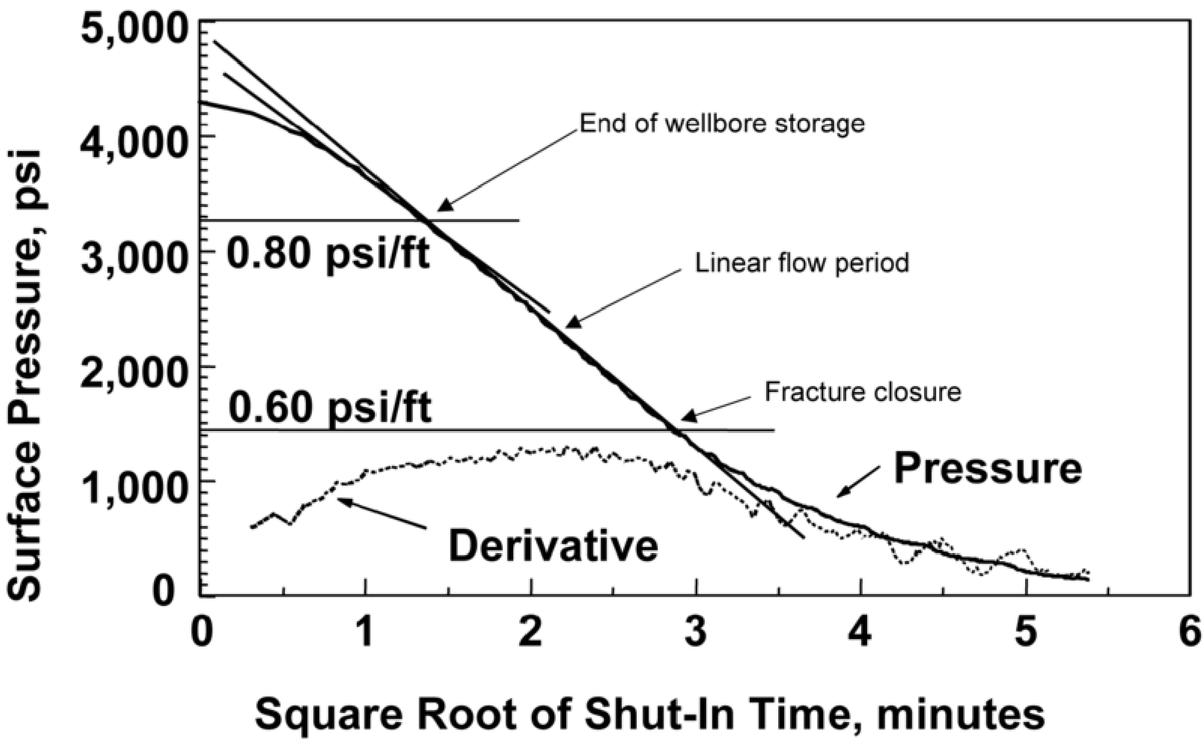
Another method for determining fracture closure pressure is called the "equilibrium test". This is an injection test similar to the conventional pump-in/shut-in/decline, with one exception: instead of shutting in the well, the fluid continues to be injected at a small rate, as illustrated in Fig 5. The treating pressure will initially decline as in the conventional shut-in decline because the new injection rate will approach or even be less than the leak-off rate. The fracture volume and the pressure will decrease with time as more fluid leaks off than is injected. This will result in the fracture volume being sufficiently reduced, and therefore, the fracture length will recede as the fracture approaches closure.

the term "fracture-closure pressure" is synonymous with minimum in-situ stress and minimum horizontal stress. When the pressure in the fracture is greater than the fracture-closure pressure, the fracture is open. When the pressure in the fracture is less than the fracture-closure pressure, the fracture is closed. **Fig. 2** illustrates a typical wellbore configuration for conducting an in-situ stress test. **The following figure** shows typical data that are measured. Multiple tests are conducted to ensure repeatability. The data from any one of the injection-falloff tests can be analyzed to determine when the fracture closes.




The leak-off rate will decrease with time, and eventually, the leak-off rate and the injection rate q become equal. At that time, the fracture volume will stop decreasing, and the wellbore pressure will flatten out and start increasing. The minimum pressure when rate equilibrium is reached will be called the *equilibrium pressure*.

**The following figure** illustrates how one such test can be analyzed to determine in-situ stress.



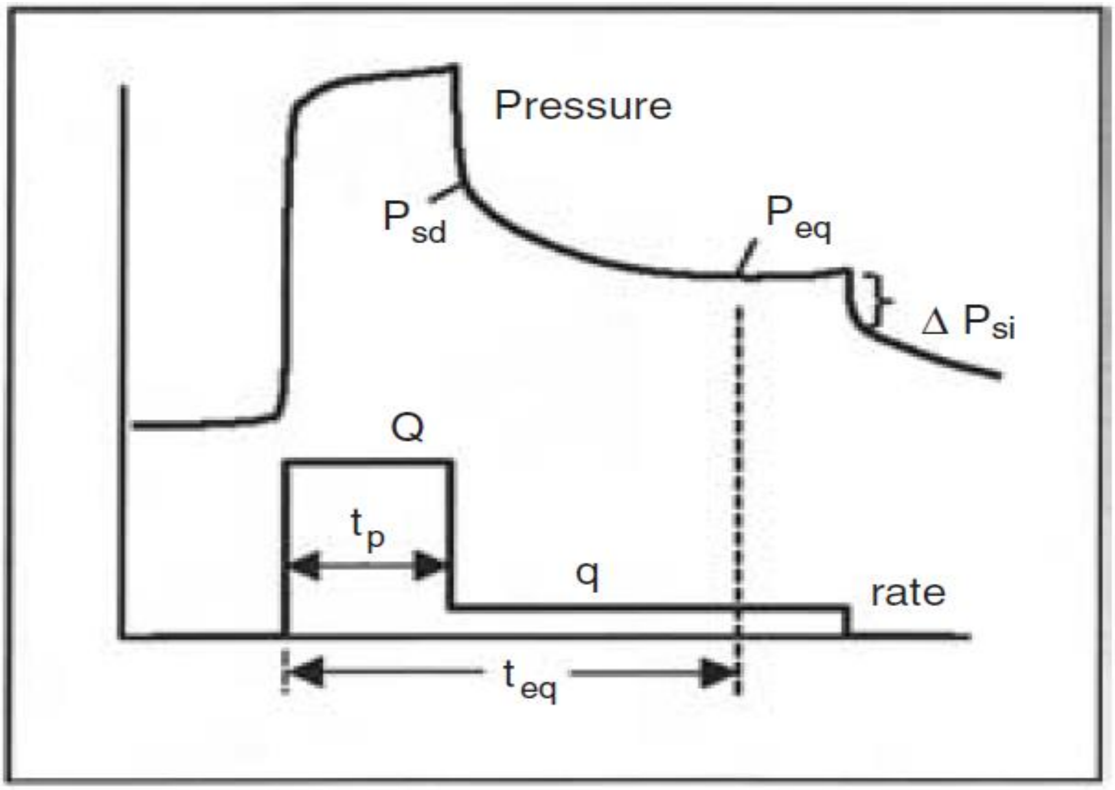



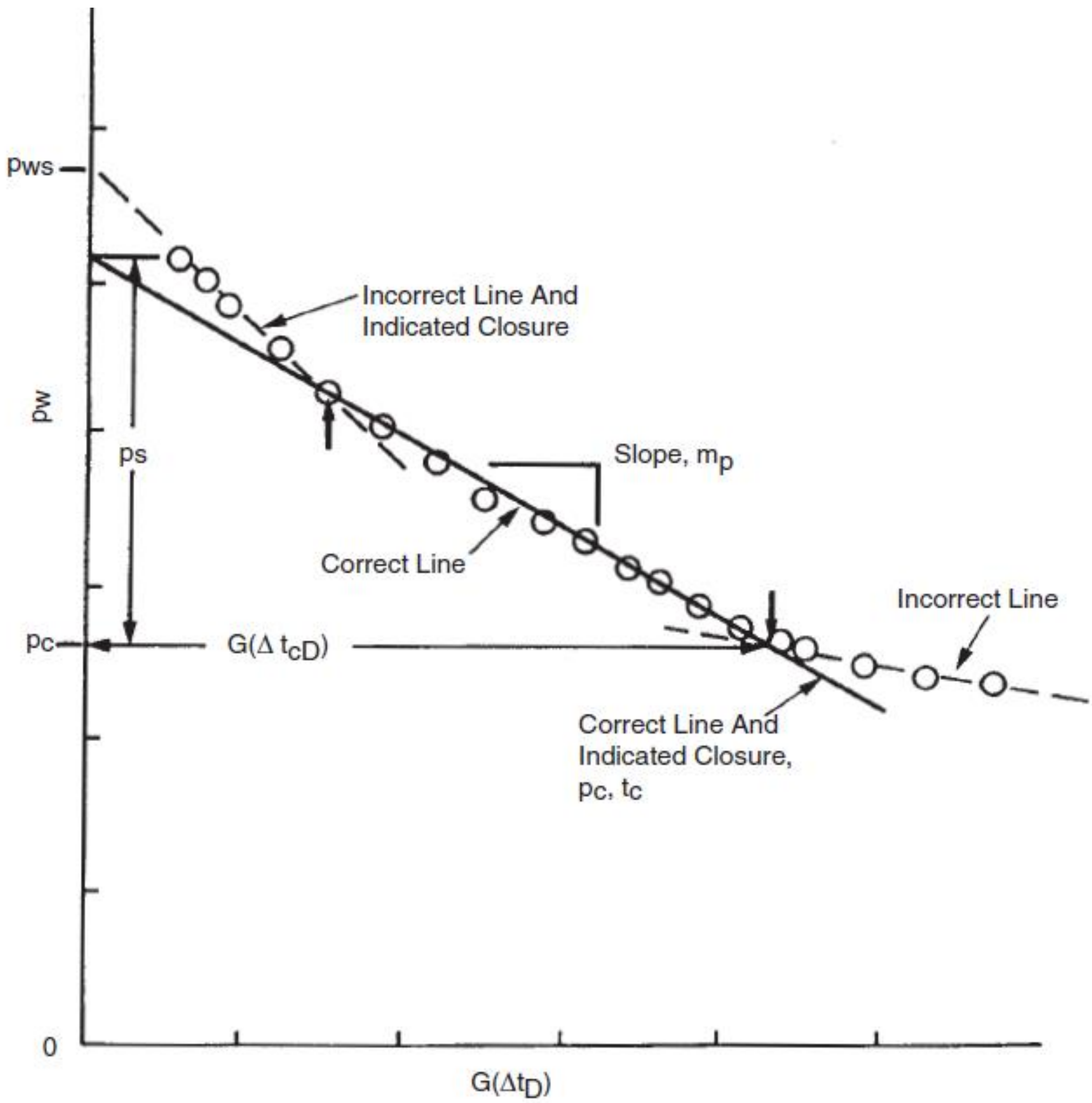

***Figure 5: Equilibrium test***

The equilibrium pressure Peq is an upper bound of the closure pressure Pc. By subtracting the instantaneous pressure change at the final shut-in, DPsi , any remaining pressure relating to friction or tortuosity is removed. The corrected equilibrium pressure, Peq − DPsi , differs from closure pressure only by the net pressure in the fracture, which should be relatively small because the rate q is small and therefore provides a direct approximation of closure pressure.

***Fracturing Pressure - Decline Analysis***

Castillo extended Nolte's techniques for pressure decline analysis. He introduced a time function G(DtD), which, graphed against pressure during the closing period of the fracture calibration treatment, forms a straight line.

A second expression, for lower bound, is given in Castillo [8]. The dimensionless time DtD is simply the ratio of the closing time Dt and the injection time tp.



The slope of the straight line in Figure 6.5.5, $m_p$, is

$$m_p = \frac{\pi C_L r_p \sqrt{t_p}}{2c_f}$$

where $C_L$ = leakoff coefficient in ft./min$^{1/2}$
$r_p$ = ratio of the leakoff height ($h_p$) to the fracture height ($h_t$)
$t_p$ = pumping time in min
$c_f$ = fracture compliance in ft./psi

Nolte [6] contains all pertinent equations for fracturing pressure decline analysis. Another important variable that can be extracted from pressure decline analysis is the fluid efficiency. The independently determined closure pressure identifies not only the end of the straight line in Figure 6.5.5 but also the fracture closure time, corresponding to DtcD. This is a particularly important variable and allows the determination of the total fluid requirements and the ratio of "pad" volume to the proppant carrying fluid. Recently Mayerhofer, Economides, and Nolte [9, 10] investigated the stress sensitivity of crosslinked polymer filtercakes in an effort to decouple the components of fracturing pressure decline. Fracturing fluid leak off can be regarded as a linear flow from the fracture into the reservoir. Therefore, a new approach to analyze the pressure decline of a fracturing treatment is visualized. The concept of individual pressure drops in series, constituting the overall pressure drop between the fracture and the reservoir, can be used and is given by

$$\Delta p_{total} = \Delta p_{cake} + \Delta p_{iz} + \Delta p_{res} \qquad [6.5.11]$$

where $\Delta p_{total}$ = pressure drop across the filtercake
$\Delta p_{iz}$ = pressure drop within the polymer invaded zone
$\Delta p_{res}$ = pressure drop in the reservoir

The effects of stress-sensitive filter cake leak off were described by the hydraulic filter cake resistance, which is defined (with Darcy's law) as

$$R = \frac{l_c}{k_c} = \frac{\Delta p_{cake} A}{\mu q}$$

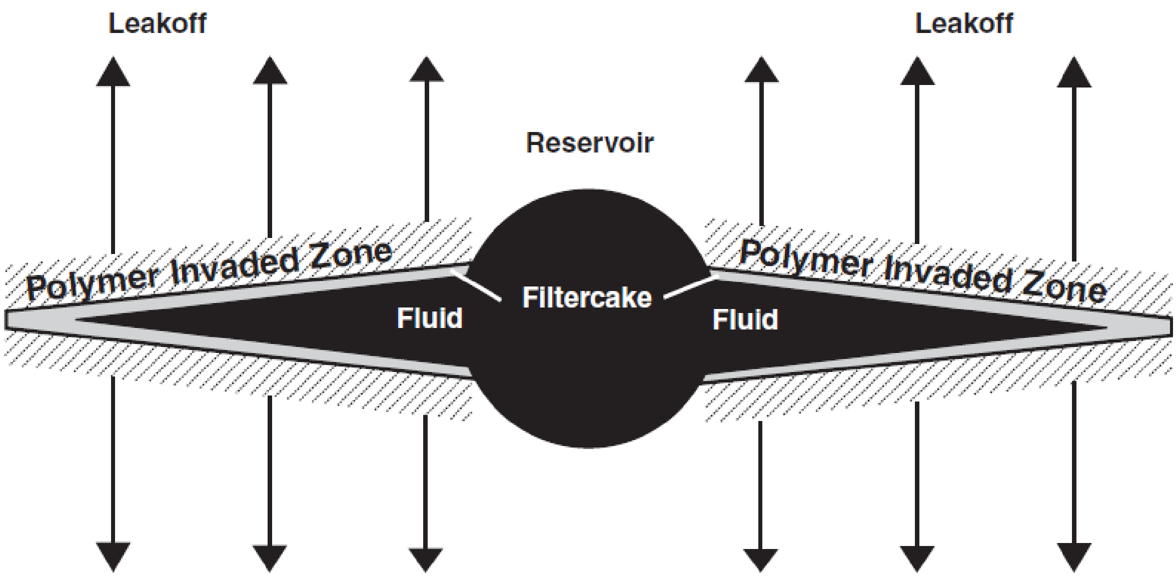



*Figure 6.5.7* *Hydraulic fracture with filtercake and invaded zone.*

It was found [9, 10] that polymer filter cakes behave as viscoelastic bodies. The Kelvin or Voight model, which is a mechanical analog commonly used in linear viscoelastic theory, was found to be an appropriate model for analyzing the relation between differential pressure across the filter cake and the dimensionless resistance:

$$R_D(t) = \frac{1}{\mu}\int_0^t \sigma(t-\tau)e^{-\tau/\lambda}\, d\tau \qquad [6$$

where $\sigma(t-\tau)$ = change of the differential pressure
$\lambda$ = retardation time
$\mu$ = viscosity

The viscoelastic filter cake relaxation, which was described by Equation and the additional cake increase are the essential features during closure. Figure 6.5.8 shows, in a plot of RD versus Dp, the dominance of the stress sensitive relaxation of the filtercake deposited and compressed during pumping over the additional cake increase.

The stress-sensitive filter cake resistance is equivalent to a skin-effect and can therefore be incorporated as a component of the linear flow from the fracture into the reservoir.

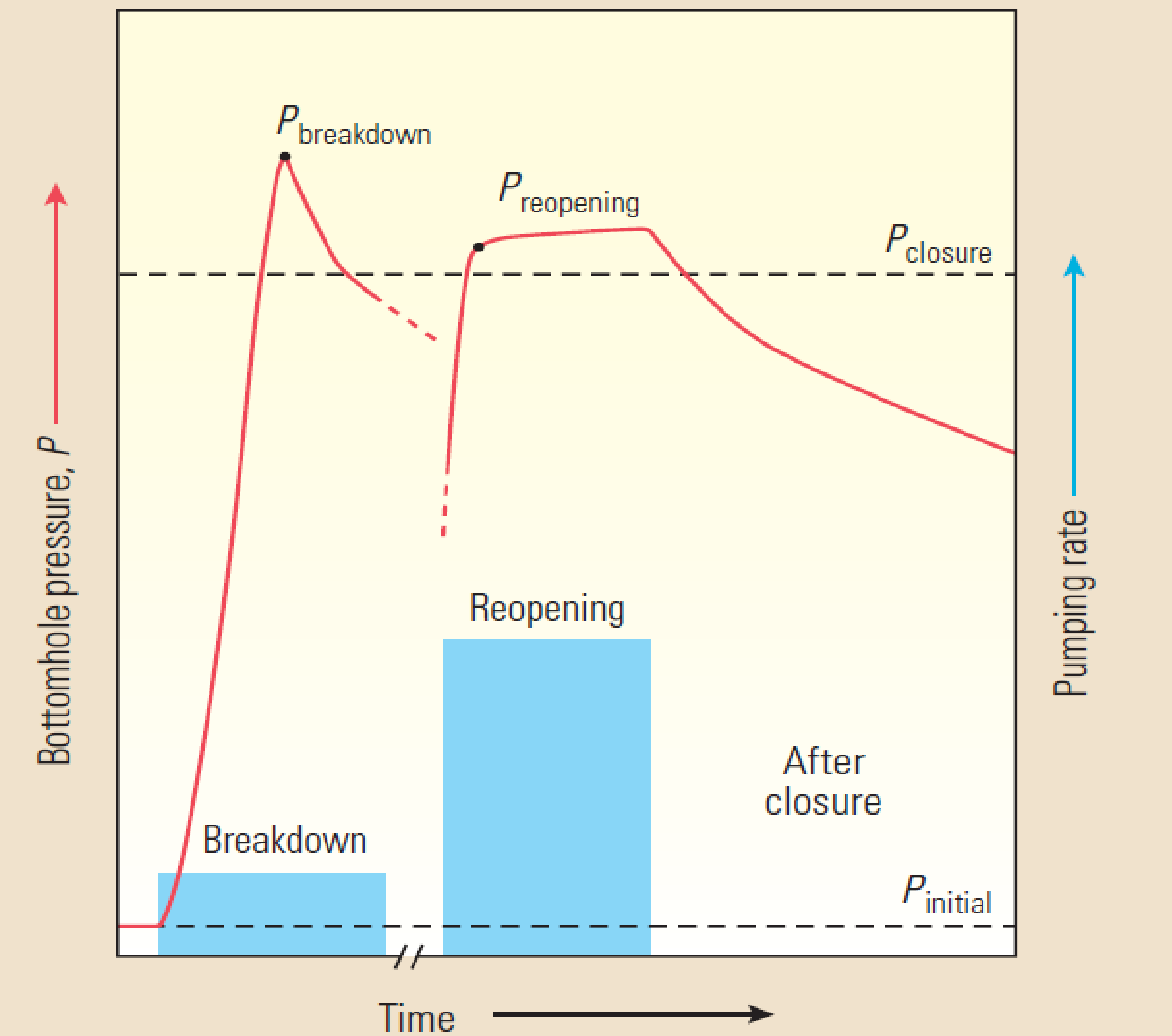
**Pressure Interpretation after Closure**

Another application of pressure evaluation pertains to the pressure response after fracture closure. The pressure during this period reflects the transient reservoir response to fracturing and is independent of the mechanisms governing fracture propagation. Its character is determined entirely by the response of a reservoir disturbed by the fluid-leak off process. During this period, the reservoir may initially exhibit formation linear flow, followed by transitional behavior and finally long-term pseudo radial flow.

The after closure response is similar to the behaviour observed during a conventional well test of a propped fracture. It therefore supports an evaluation methodology analogous to the established principles of pressure transient evaluation. The after closure period provides information that is traditionally determined by a standard well test (i.e., transmissibility and reservoir pressure). It completes a chain of fracture pressure analysis that provides a continuum of increasing data for developing a unique characterization of the fracturing process.

The closure and reopening pressures are controlled by the minimum principal compressive stress.

Therefore, induced downhole pressures must exceed the minimum principal stress to extend fracture length. After performing fracture initiation, engineers pressurize the zone for the planned stimulation treatment. During this treatment, the zone is pressurized to the fracture propagation pressure, which is greater than the fracture closure pressure. Their difference is the net pressure, which represents the sum of the frictional pressure drop and the fracture-tip resistance to propagation.

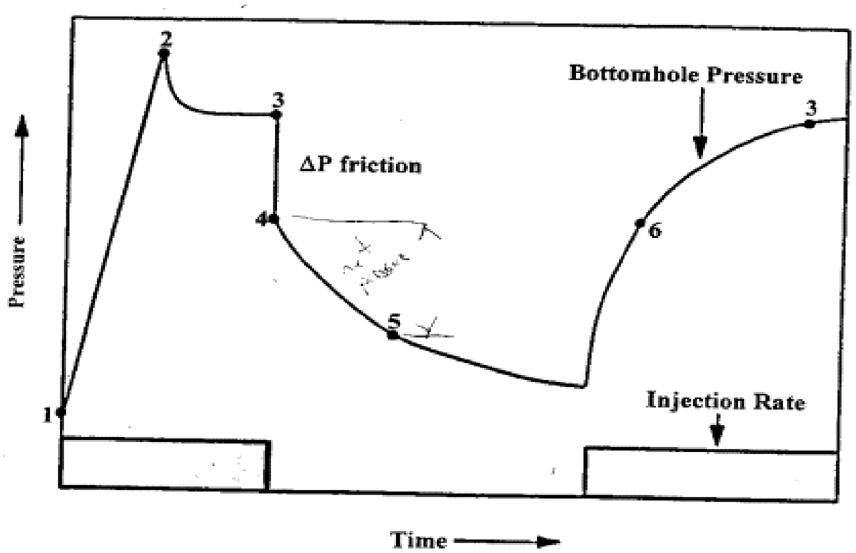


Fracture pressures. During a stimulation treatment, engineers pump fluid into the targeted stimulation zone at a prescribed rate (blue polygons), and pressure (red line) builds to a peak at the breakdown pressure, then it drops, indicating the rock around the well has failed. Pumping stops and pressure decreases to below the closure pressure. During a second pumping cycle, the fracture opens again at its reopening pressure, which is higher than the closure pressure. After pumping, the fracture closes and the pressure subsides. The initial pore pressure is the ambient pressure in the reservoir zone.

Fracture pressure is the pressure needed to create a fracture in a rock while drilling in open hole. Closure stress is the pressure needed to fracture a rock through perforations in cased hole. In some literature, closure stress and fracture pressure are used interchangeably or ambiguously.

Both are determined by the overburden pressure (a function of depth and rock density), pore pressure, Poisson's Ratio, porosity, tectonic stresses, and anisotropy. Breakdown pressure is the sum of the closure stress and the friction effects of the frac fluid being delivered to the formation. Breakdown pressure can be considerably higher than closure stress.

Closure stress is the pressure at which the fracture closes after the fracturing pressure is relaxed. It is usually between 80 and 90% of breakdown pressure. Rocks with high closure stress are harder to frac (take more horsepower) than the same rocks with lower closure stress. Shallow shaly sands have high closure stress because they have high Poisson's Ratio.




1. Hydrostatic pressure
2. Breakdown pressure
3. Fracture extension pressure
4. Initial shut-in pressure (fracture gradient)
5. Fracture closure pressure (closure stress gradient)
6. Fracture reopening pressure

**Properties of Fracturing Fluids:**

Fracturing fluids are pumped into the well to create conductive fractures and bypass near-wellbore damage in hydrocarbon-bearing zones. The net result is an expansion in the productive surface-area of the reservoir, compared to the unfractured formation. A series of chemical additives are selected to impart a predictable set of properties of the fluid, including viscosity, friction, formation-compatiblity, and fluid-loss control.

To create the fracture, a fluid is pumped into the wellbore at a high rate to increase the pressure in the wellbore at the perforations to a value greater than the breakdown pressure of the formation. The breakdown pressure is generally believed to be the sum of the in-situ stress and the tensile strength of the rock. Once the formation is broken down and the fracture created, the fracture can be extended at a pressure called the fracture-propagation pressure. The fracture-propagation pressure is equal to the sum of:

- The in-situ stress
- The net pressure drop
- The near-wellbore pressure drop

The net pressure drop is equal to the pressure drop down the fracture as the result of viscous fluid flow in the fracture, plus any pressure increase caused by tip effects. The near-wellbore pressure drop can be a combination of the pressure drop of the viscous fluid flowing through the perforations and/or the pressure drop resulting from tortuosity between the wellbore and the propagating fracture. Thus, the fracturing-fluid properties are very important in the creation and propagation of the fracture.

**The ideal fracturing fluid should:**

- **Be able to transport the propping agent in the fracture**
- **Be compatible with the formation rock and fluid**
- **Generate enough pressure drop along the fracture to create a wide fracture**
- **Minimize friction pressure losses during injection**
- **Be formulated using chemical additives that are approved by the local environmental regulations.**
- **Exhibit controlled-break to a low-viscosity fluid for cleanup after the treatment**
- **Be cost-effective.**

**The viscosity of the fracturing fluid is an important point of differentiation in both the execution and in the expected fracture geometry. Many current practices, generally referred to as "slickwater" treatments, use low-viscosity fluids pumped at high rates to generate narrow, complex fractures with low-concentrations of propping agent (0.2-5 lbm proppant added (PPA) per gallon**).

**The density of the carrier-fluid is also important. The fluid density affects the surface injection pressure and the ability of the fluid to flow back after the treatment. Water-based fluids generally have densities near 8.4 ppg.**

**Oil-base fluid densities will be 70 to 80% of the densities of water-based fluids. Foam-fluid densities can be substantially less than those of water-based fluids. In low-pressure reservoirs, low-density fluids, like foam, can be used to assist in the fluid cleanup.**

Conversely, in certain deep reservoirs (including offshore frac-pack applications), there is a need for higher density fracturing fluids whose densities can span up to > 12ppg.

A fundamental principle used in all fracture models is that "the fracture volume is equal to the total volume of fluid injected minus the volume of fluid that leaks off into the reservoir. The fluid efficiency is the percentage of fluid that is still in the fracture at any point in time, when compared with the total volume injected at the same point in time. The concept of fluid loss was used by Howard and Fast to determine fracture area. If too much fluid leaks off, the fluid has a low efficiency (10 to 20%), and the created fracture volume will be only a small fraction of the total volume injected. However, if the fluid efficiency is too high (80 to 90%), the fracture will not close rapidly after the treatment. Ideally, a fluid efficiency of 40 to 60% will provide an optimum balance between creating the fracture and having the fracture close down after the treatment.

In most low-permeability reservoirs, fracture-fluid loss and efficiency are controlled by the formation permeability. In high-permeability formations, a fluid-loss additive is often added to the fracture fluid to reduce leakoff and improve fluid efficiency. In naturally fractured or highly cleated formations, the leakoff can be extremely high, with efficiencies down in the range of 10 to 20%, or less. To fracture treat naturally fractured formations, the treatment often must be pumped at high injection rates with fluid-loss additives.

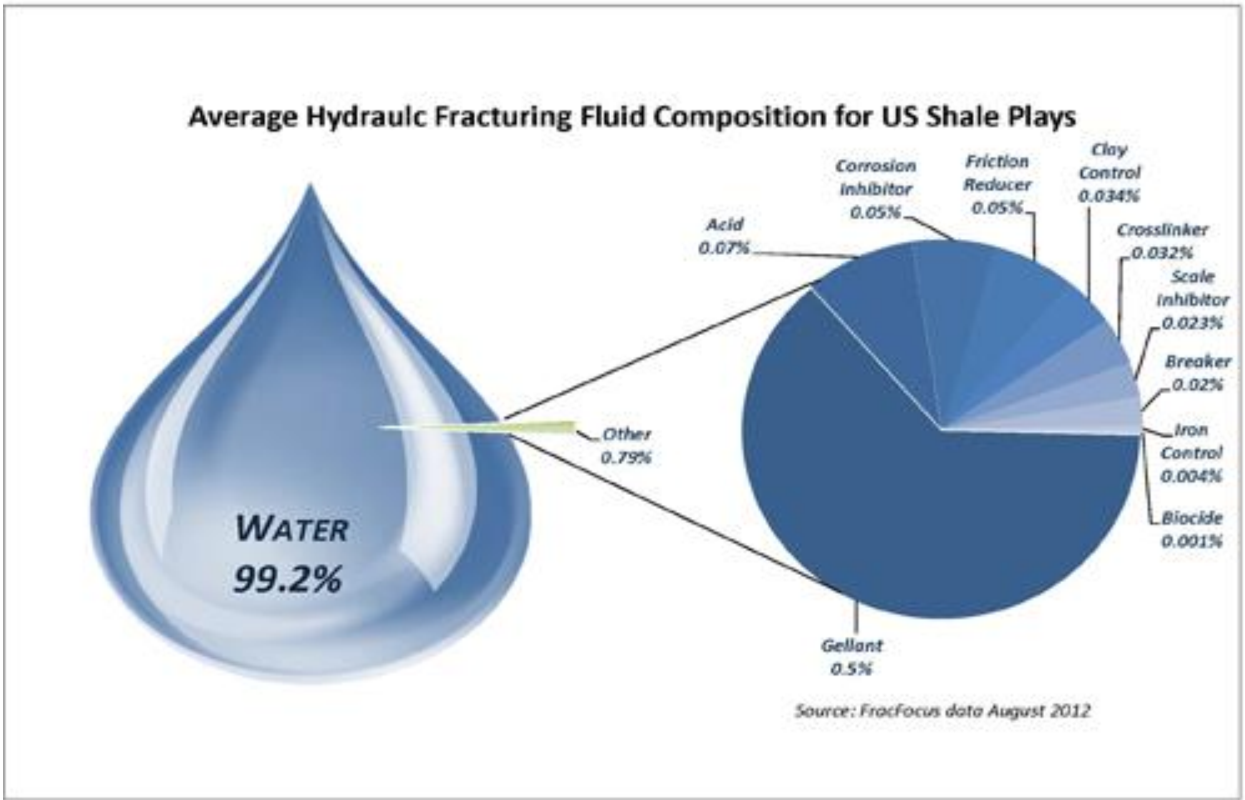



**TABLE 8.5—SUMMARY OF CHEMICAL ADDITIVES**

| Type of Additive | Function Performed | Typical Products |
|---|---|---|
| Biocide | Kills bacteria | Gluteraldehyde carbonate |
| Breaker | Reduces fluid viscosity | Acid, oxidizer, enzyme breaker |
| Buffer | Controls the pH | Sodium bicarbonate, fumaric acid |
| Clay stabilizer | Prevents clay swelling | KCl, NHCl, KCl substitutes |
| Diverting agent | Diverts flow of fluid | Ball sealers, rock salt, flake boric acid |
| Fluid loss additive | Improves fluid efficiently | Diesel, particulates, fine sand |
| Friction reducer | Reduces the friction | Anionic copolymer |
| Iron Controller | Keeps iron in solution | Acetic and citric acid |
| Surfactant | Lowers surface tension | Fluorocarbon, Nonionic |
| Gel stabilizer | Reduces thermal degradation | MEOH, sodium thiosulphate |

## Categories of fracturing fluids

The categories of fracturing fluids available consist of:

- Viscosified water-based fluids
- Nonviscosified water-based fluids
- Gelled oil-based fluids
- Acid-based fluids
- Foam fluids

**Table 1** lists the types of fracturing fluids that are available and the general use of each type of fluid. Reasons for selecting between these fluid types will depend on a variety of factors. For most reservoirs, water-based fluids with appropriate additives are most suitable, due to the historic ease with which large volumes of mix-water can be acquired. In some cases, foam generated with $N_2$ or $CO_2$ can be used to stimulate shallow, low-pressure zones successfully. When water is used as the base fluid, the water should be tested for quality due to some sensitivity of certain fluid chemistries to the mix-water composition.

**TABLE 8.3—FRACTURING FLUIDS AND CONDITIONS FOR THEIR USE**

| Base Fluid | Fluid Type | Main Composition | Used For |
|---|---|---|---|
| Water | | | |
| | Linear | Guar, HPG, HEC, CMHPG | Short fractures, low temperature |
| | Crosslinked | Crosslinker + Guar, HPG, CMHPG or CMHEC | Long fractures, high temperature |
| | Micellar | Electrolite + Surfactant | Moderate length fractures, moderate temperature |
| Foam | | | |
| | Water based | Foamer + $N_2$ or $CO_2$ | Low-pressure formations |
| | Acid based | Foamer + $N_2$ | Low-pressure, carbonate formations |
| | Alcohol based | Methonal + Foamer + $N_2$ | Low-pressure, water-sensitive formations |
| Oil | | | |
| | Linear | Gelling agent | Short fractures, water-sensitive formations |
| | Crosslinked | Gelling agent + Crosslinker | Long fractures, water-sensitive formations |
| | Water emulsion | Water + Oil + Emulsifier | Moderate length fractures, good fluid loss control |
| Acid | | | |
| | Linear | Guar or HPG | Short fractures, carbonate formations |
| | Crosslinked | Crosslinker + Guar or HPG | Longer, wider fractures, carbonate formations |
| | Oil emulsion | Acid + Oil + Emulsifier | Moderate length fractures, carbonate formations |

**Table 2** presents generally accepted levels of water quality for use in hydraulic fracturing.

**TABLE 8.4—ACCEPTABLE LEVELS FOR MIX WATER**

| Item | Value |
|---|---|
| pH | 6 to 8 |
| Iron | < 10 ppm |
| Oxidizing agents | None |
| Reducing agents | None |
| Carbonate* | < 300 ppm |
| Bicarbonate* | < 300 ppm |
| Bacteria | None |
| Cleanliness | Reasonable |

*Higher carbonate/bicarbonate content requires further pilot testing on gel break and crosslinking.

**Water-based fracturing fluids – uncross linked polymers and "slick water"**

A common practice in the hydraulic fracturing of gas-producing reservoirs is the use of nonviscous "slick water" fluids pumped at high rates (> 60bpm) to generate narrow fractures with low concentrations of proppant. In recent years, these treatments have become a standard technique in fracture stimulation of several U.S. shales, including the Barnett, Marcellus, and Haynesville and yield economically viable production. The low proppant concentration, high fluid-efficiency, and high pump rates in slick water treatments yield highly complex fractures. Additionally, compared to a traditional bi-wing fracture, slickwater fractures often find the primary fracture connected to multiple orthogonal (secondary) and parallel (tertiary) fracture networks as described by Fisher (2002). Coupled with multistage fracture completions and multiple wells collocated on a pad, complex fracture networks yield a high degree of reservoir contact.

The most critical chemical additive for slick water-fracture execution is the friction reducer (FR). The high pump rates for slick water treatments (often 60-100 bbl/minute) necessitate the action of FR accitives to reduce friction pressure up to 70%; this effect helps to moderate the pumping pressure to a manageable level during proppant injection. Common chemistries for friction reduction include polyacrylamide derivatives and copolymers added to water at low concentrations. Additional additives for slick water fluids may include biocide, surfactant (wettability modification), scale inhibitor, and others. The performance (friction reduction) of slick water fluids are generally less sensitive to mix-water quality, a large advantage over many conventional gelled fracturing fluids. However in high-salinity mix-water, many FR additives may see a loss in achievable friction reduction. Other advantages and disadvantages of slick water fluids and execution (compared to that of gelled fracturing fluids) are detailed below:

As the anticipated proppant-suspension capacity of slick water fluids is quite low, a complementary solution is the use of linear (uncross linked) gels. These fluids, based on uncross linked solutions of polysaccharides (i.e., guar, derivatized-guar, HEC, xanthan), have viscosities of up to 100cP at $100 sec^{-1}$ at surface temperature, which depend on polymer concentration. As this viscosity is several orders of magnitude higher than slick water, linear gels have improved proppant-suspension. When uncross linked gels are used in late-slurry stages of a fracturing treatment (where the pad and early-slurry stages used slick water), these are often referred to as "hybrid" fracturing treatments. [Note that "hybrid" may also refer to fracture treatments using crosslinked-gel to follow slick water, crosslinked-gel following linear/uncross linked, and other variations]