Hydraulic fracturing

Hydraulic fracturing is the process of pumping a fluid into a wellbore at an injection rate that is too high for the formation to accept in a radial flow pattern. As the resistance to flow in the formation increases, the pressure in the wellbore increases to a value that exceeds the breakdown pressure of the formation that is open to the wellbore.

Once the formation "breaks down," a crack or fracture is formed, and the injected fluid begins moving down the fracture. In most formations, a single, vertical fracture that propagates in two directions from the wellbore is created.

These fracture "wings" are 180° apart and are normally assumed to be identical in shape and size at any point in time.

In naturally fractured or cleated formations, such as gas shales or coal seams, it is possible that multiple fractures can be created and propagated during a hydraulic fracture treatment.

Fluid that does not contain any propping agent, often called "pad," is injected to create a fracture that grows up, out, and down; therefore, the fluid creates a fracture that is wide enough to accept a propping agent.

In general, hydraulic fracture treatments are used to • increase the productivity index of a producing well or the injectivity index of an injection well.

The productivity index defines the volumes of oil or gas • that can be produced at a given pressure differential between the reservoir and the wellbore. The injectivity index refers to how much fluid can be injected into an injection well at a given pressure differential.

The EPA (2004) report lists different applications for • hydraulic fracturing, such as:

• Increasing the flow rate of oil and/or gas from low-permeability reservoirs

• Increasing the flow rate of oil and/or gas from wells that have been damaged

• Connecting the natural fractures and/or cleats in a formation to the wellbore

• Decreasing the pressure drop around the well to minimize sand production

• Decreasing the pressure drop around the well to minimize problems with asphaltine and/or paraffin deposition

• Increasing the area of drainage or the amount of formation in contact with the wellbore

• Connecting the full vertical extent of a reservoir to a slanted or horizontal well

The most critical parameters for hydraulic fracturing are: •

• Formation permeability •
• *In situ* stress distribution •
• Reservoir fluid viscosity •
• Skin factor •
• Reservoir pressure •
• Reservoir depth •

Hydraulic fracturing theory and design has been developed • by other engineering disciplines. However, certain aspects, such a poroelastic theory, are unique to porous, permeable underground formations. The most important parameters are: Poisson's ratio; Young's modulus; and in situ stress.

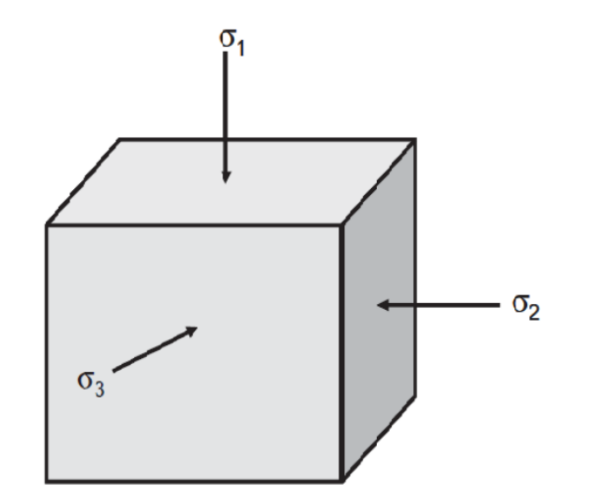
Poisson's ratio (v), named after Simeon Poisson, is • defined as the ratio of the relative contraction strain (transverse strain) divided by the relative

extension strain (or axial strain). •

Young’s modulus is defined as “the ratio of stress to strain •
for uniaxial stress.” The theory used to compute fracture
dimensions is based upon linear elasticity.
To apply this theory, Young’s modulus of the formation •
is an important parameter. •
<u>The modulus of a material is a measure of the stiffness of the material.</u> •
If the modulus is large, the material is stiff. In hydraulic •
fracturing, a stiff rock will result in more narrow fractures.
If the modulus is low, the fractures will be wider.
The modulus of a rock is a function of the lithology, •
porosity, fluid type, and other variables. Typical ranges for •
Young’smodulus as a function of lithology are tabulated
below.

Lithology Young’s Modulus (psi) •
Soft sandstone 2–5 ×□106 •
Hard sandstone 6–10 ×□106 •
Limestone 8–12 ×□106 •
Coal 0.1–1 ×□106 •
Shale 1–10 ×□106 •

In situ stresses. Underground formations are confined and •
under stress.
illustrates the local stress state at depth for an element of •
formation. The stresses can be divided into the following
three principal
stresses: •



• the vertical stress σ1, •

• the maximum horizontal stress σ2, and •

• the minimum horizontal stress σ3. •

where σ1 > σ2 > σ3. Depending on geologic conditions, • the vertical stress

could also be the intermediate (σ2) or minimum stress • (σ3). These stresses

are normally compressive and vary in magnitude • throughout the reservoir,

particularly in the vertical direction (from layer to layer). • The magnitude

and direction of the principal stresses are important • because they control:

• the pressure required to create and propagate a fracture, •

• the shape and vertical extent of the fracture, •

• the direction of the fracture, and •

• the stresses trying to crush and/or embed the propping • agent during production.