"HYDRAULIC FRACTURING IN VERTICAL WELLS"

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CERTIFICATE

This is to certify that this report on **"Hydraulic Fracturing in Vertical Wells"** submitted to the **University of Petroleum and Energy Studies, Dehradun,** by **Shivam Kothiyal** of Int. B.Tech (Applied Petroleum Engineering)+M.B.A(Oil & Gas) is a bonafide work carried out by him under my supervision and guidance.

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Shivam Kothiyal

ABSTRACT

During the late 1970s, considered the banner years of fracturing technology advances, there was a saying often used in jest by most of the people working on fracturing:

"When everything else fails, frac it."

How true this has been, a lot of "fraccing" was done for well stimulation in those days and since. We now speak more appropriately about improved well performance, downhole flow integrity and enhanced productivity or injectivity.

Hydraulic fracturing is a particularly complicated enterprise. The purpose of hydraulic fracturing is the placement of an optimum fracture of a certain geometry and conductivity to allow maximum incremental production (over that of the unstimulated well) at the lowest cost. This process combines the interactions of fluid pressure, viscosity and leak off characteristics with the elastic properties of the rock, which have been the subjects of the preceding chapters. Accomplishing this, while taking into account all the presented technology, requires significant attention to the treatment execution involving optimized completion and perforating strategies, appropriate treatment design, control and monitoring of rate, and pressure and fluid characteristics.

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CHAPTER 1

WELL STIMULATION

1.1 Introduction

Reservoir stimulation and artificial lift are the two main activities of the production engineer in the petroleum and related industries. The main purpose of stimulation is to enhance the property value by the faster delivery of the petroleum fluid and to increase ultimate economic recovery. Matrix stimulation and hydraulic fracturing are intended to remedy, or even improve, the natural connection of the wellbore with the reservoir, which could delay the need for artificial lift. To be done properly, the engineering exercise of the decision process for well stimulation requires considerable knowledge of many diverse processes. Few activities in the petroleum or related industries use such a wide spectrum of sciences and technologies as well stimulation, both matrix and fracturing.

Cost-effective production improvement has been the industry focus for the past several years. Fracturing, stimulating, reperforating and recompleting existing wells are all widely used methods with proven results in increasing the NPV of old fields. Now reentry drilling is generating high interest for the potential it offers to improve recovery from damaged or depleted zones or to tap into new zones at a generally low cost. Applied to mature reservoirs, all these strategies have the advantage of starting with a fair to good reservoir description as well as a working trajectory to the target formation. Even when a new well is drilled, the decision whether to drill a vertical, slanted or horizontal well and how to complete the productive interval can profoundly affect the well's productivity and the size of the volume drained by the well.

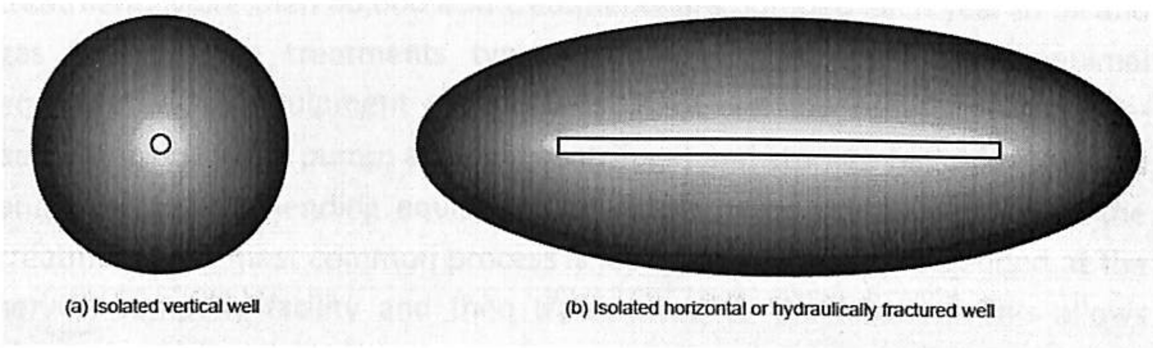


Figure 1.1: Geometry of the well drainage volume before and after fracture.

The geometry of the well drainage volume plays an important role. The geometry of the well drainage volume depends on the well trajectory within the productive zone, neighbouring wells, geometry of hydraulic fractures, nearby reservoir limits and reservoir flow characteristics. A vertical well creates a circular cylinder pressure sink whereas a hydraulically fractured well creates a pressure sink in the shape of a finite slab with dimensions defined by the formation thickness and the total fracture length. With adequate vertical permeability the horizontal well drainage area is similar to that of a vertical fracture, with the total fracture length equal to that of the horizontal well.

A good understanding of job execution is necessary for making decisions on the applicability and risk of various treatments. As with any well work, basic safety procedures must be developed and followed to prevent catastrophic failure of the treatment, which could result in damage to or loss of the well, personnel and equipment. Specific standards and operating procedures have been developed for stimulation treatments, which if followed can lead to a safe, smooth and predictable operation.

The various well stimulation operations are:

1.2 Matrix Stimulation

Matrix stimulation, mainly acidizing, is the original and simplest stimulation treatment. More than 40,000 acid treatments are pumped each year in oil and gas wells. These treatments typically involve small crews and minimal equipment. The equipment usually consists of one low-horsepower, single-action reciprocating pump, a supply centrifugal and storage tanks for the acid and flush fluids. Blending equipment is used when solids are added to the treatment. The most common process is for the fluids to be preblended at the service company facility and then transported to the location. This allows blending small volumes accurately, controlling environmental hazards. The fluids are then pumped with little effort or quality risk.

1.3 Hydraulic Fracturing

Hydraulic fracturing is an important part of stimulation. It enhances the connection between the wellbore and the reservoir by creating a conductive flow path.

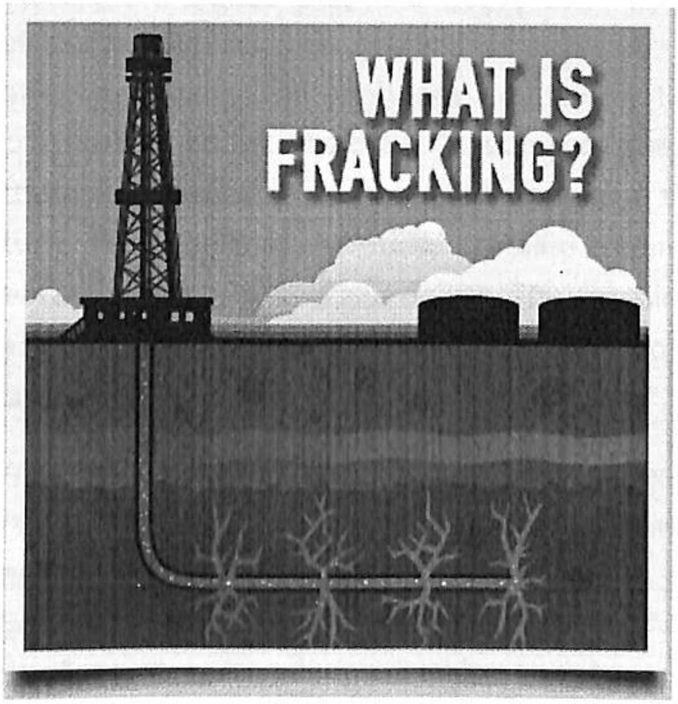


Figure 1.2: Hydraulic Fracturing

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.

The problem with the formation is its elasticity. When the fractures are created they automatically close due to the elasticity of the formation. Therefore we need something that keeps the fracture open. This is where the proppant comes into play. The first fluid that goes inside is called the pad. The pad creates the fracture. Second fluid that goes inside also carries the proppant in it and is called the slurry.

Stoke's law states that if a heavy solid particle like sand moves in a less viscosity fluid like water, it will settle down. So we need something that can effectively carry the proppant i.e. sand into the formation. This is where crosslinkers come into play. Crosslinkers are polymers with high viscosity so that they can carry the proppant deep into the fracture and the proppant in turn keeps the fracture open. Crosslinkers are basically chemical like metallic borate, zirconium, and aluminium. The crosslinkers connect the polymer chains and increase the viscosity. If the viscosity of a fluid is 1cp, then on adding crosslinkers it becomes 1500 cp.

After the crosslinker and the proppant has entered the formation we need to reduce its permeability so that it can be flowed back to the surface and does not by any chance reduce the permeability of the formation. Hence we add breakers in the slurry. The breakers break the x-linking and help to flow back the fluid. These breakers are either time based or temperature based.

Aims of hydraulic fracturing:

- Stimulate the well.
- Increase production.
- Get the sand or proppant in the formation and ensure that after a while this carrier fluid breaks.
- Flowback the fluid so that in no case it hurts my formation.

The typical production increase is 2 to 10 fold.

In USA the permeability in shale gas reservoirs is only 0.001 mD. The low permeability is improved by hydraulic fracturing.

$$Q = (Kh\Delta p)/(141.2\mu B[ln\left(\frac{0.472r_e}{r_w}\right) + s]$$

This is the radial flow equation derived from the Darcy's law.

Fracturing increases the effective wellbore radius r_w.
Fracturing increases kh.
Fracturing removes skin.
The skin should vary upto -8.

Flash Production: Just after hydraulic fracturing has been done our formation is supercharged as fluid is filled into it with high pressure, and therefore we get a very high production. This is called flash production.

Fracture Conductivity (F_{CD})

It is a measure of how good our fracture is.

F_{CD} = conductivity of fracture / conductivity of formation

Whenever we design a frac job we keep the F_{CD} more than 10. The proppant damage is also taken into account. A factor of 0.6 is multiplied to the denominator.
And F_{CD} of 30 is the best.

The fracture propagates perpendicular to the minimum horizontal stress.

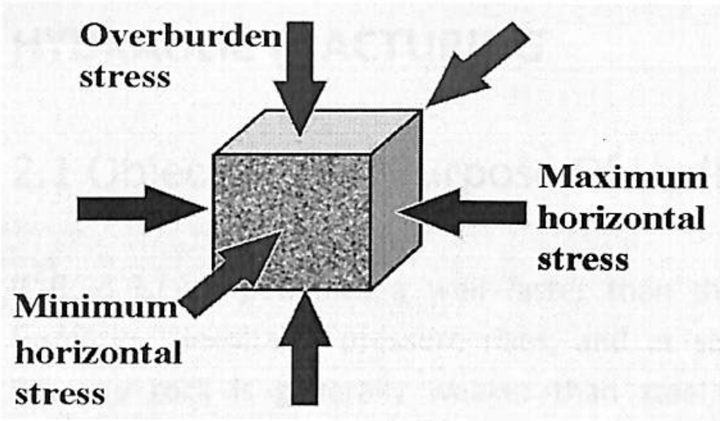


Figure 1.3: Insitu stresses on a solid.

Insitu stress or the closure stress is the most important factor controlling hydraulic fracturing.

Net Pressure = Fracture Pressure – Closure Pressure

If our net pressure is less that means our hydrofrac job is not good.
Therefore we have datafrac in which we determine the closure pressure. Datafrac involves introducing a small amount of fluid in the formation and see how it is closing and then we design our frac job according to it.
With the help of datafrac we also get to know the efficiency i.e. how much the pad will fracture the formation. Screen out occurs if the pad is not enough. The proppant will not be able to get into the fracture as we are not giving it enough space.

Unlike matrix stimulation, fracturing can be one of the more complex procedures performed on a well. This is due in part to the high rates and pressures, large volume of materials injected, continuous blending of materials and large amount of unknown variables for sound engineering design.

CHAPTER 2
HYDRAULIC FRACTURING

2.1 Objective And Purpose Of Hydro Frac

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 stresses generated by the internal pressure.

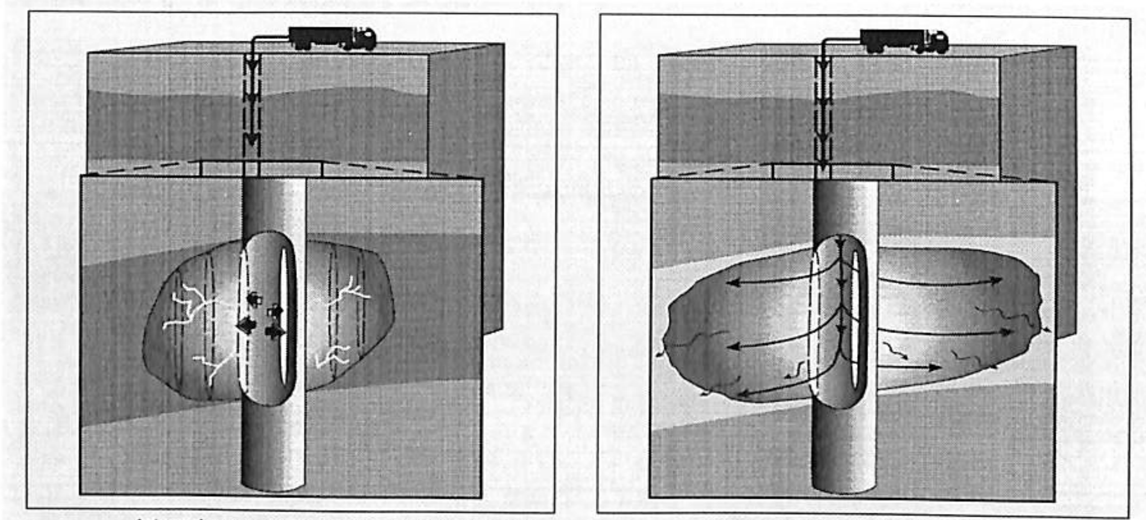


Figure 2.1: Initiation and propagation of fracture

Our goal is to enhance the connection between a wellbore and the reservoir by creating a conductive flow path.

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.

2.1.1 Damage Bypass

Formation damage is considered as any process that impairs the permeability of reservoir formations such that production or injectivity is decreased. Formation damage can be recognized by lower than expected productivity and accelerated production decline on affected wells. This is due to a reduced permeability in the near wellbore vicinity, which has been affected by the damage mechanism. This area of reduced permeability results in an additional pressure drop imposed on the producing system, which is proportional to the rate of production. Formation damage can occur at any time during a well's history from the initial drilling and completion of a wellbore through the depletion of a reservoir by production.

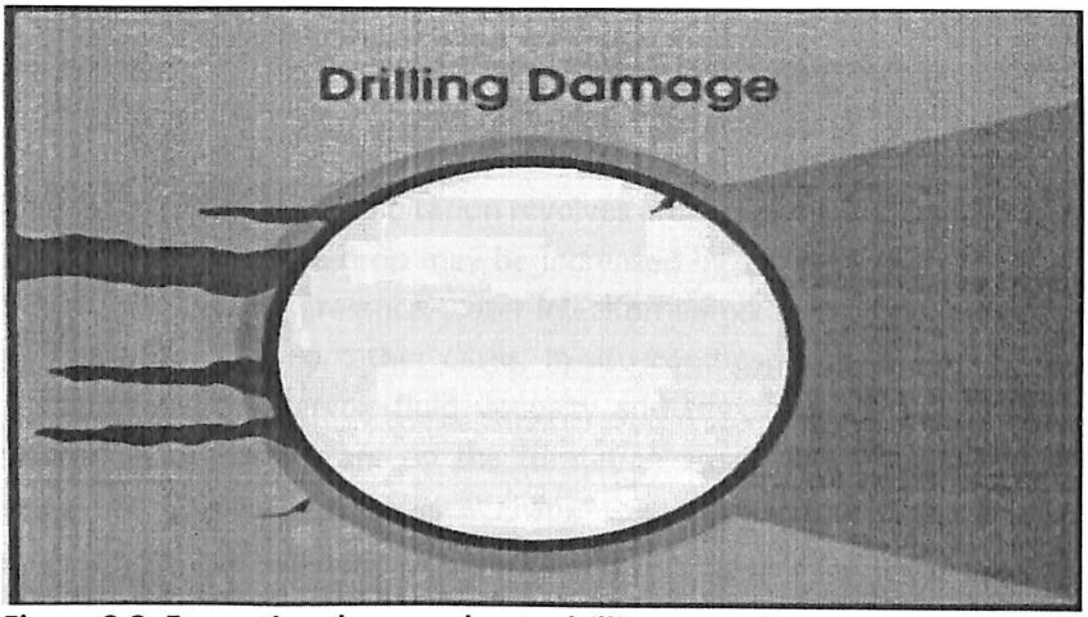


Figure 2.2: Formation damage due to drilling operations

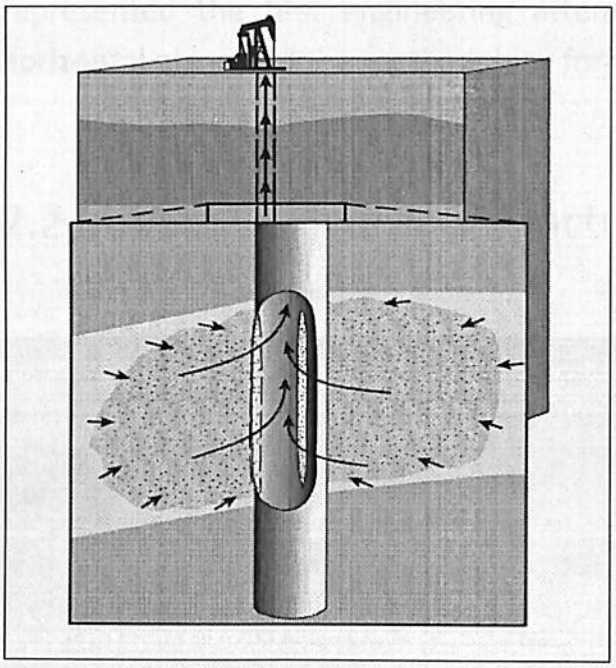
Near-wellbore damage reduces well productivity. This damage can occur from several sources, including drilling-induced damage resulting from fines invasion into the formation while drilling and chemical incompatibility between drilling fluids and the formation. The damage can also be due to natural reservoir 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 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.

2.1.2 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:

$$q = \frac{k}{\mu} A \frac{dP}{L}$$

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, 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.



Increased flow area resulting from a fracture.

Figure 2.3: Increased flow area resulting from a fracture

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.

2.1.3 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. 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. 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.

2.2 Impact Of Hydraulic Fracturing

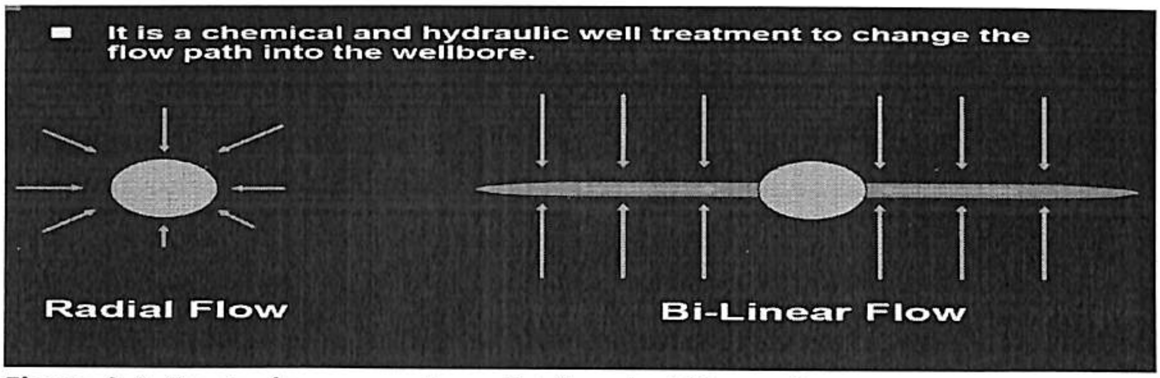


Figure 2.4: Fracturing converts radial flow to bilinear flow

- Typical production increase is 2 to 10 fold
- A great deal of today's oil & gas development is economic only with hydraulic fracturing
- Fracturing provides significant economic improvements even in conventional reservoirs
- More than $10,000,000,000 USD in economic value from hydraulic fracturing

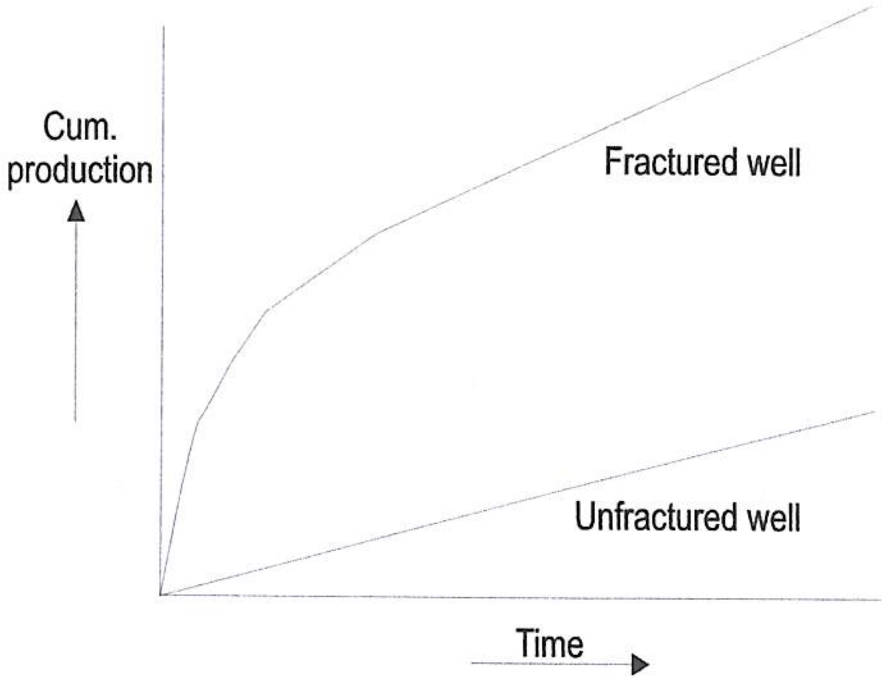


Figure 2.5: Improved productivity due to fracturing

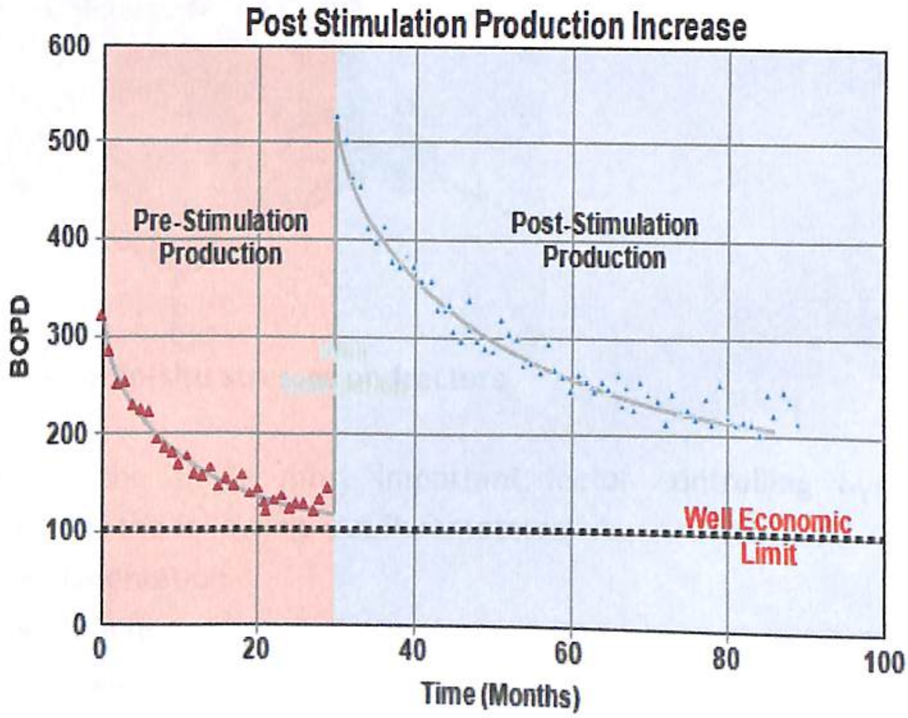


Figure 2.6: Graph showing results before and after fracturing.

2.3 IN-SITU STRESS

When a rock specimen or an element of the earth is submitted to load, it deforms, the higher the stress level, the more strain the rock experiences. It is an important aspect of rock mechanics, and solid mechanics in general, to determine the relationship between stress and strain. Various theories have been developed to describe, in a simplified way, this relationship. The simplest one is the theory of elasticity, which assumes that there is a one-to-one correspondence between stress and strain (and, consequently, that the behaviour is reversible). Because this is usually the assumed case in hydraulic fracturing, most of the simulation models use the theory of elasticity.

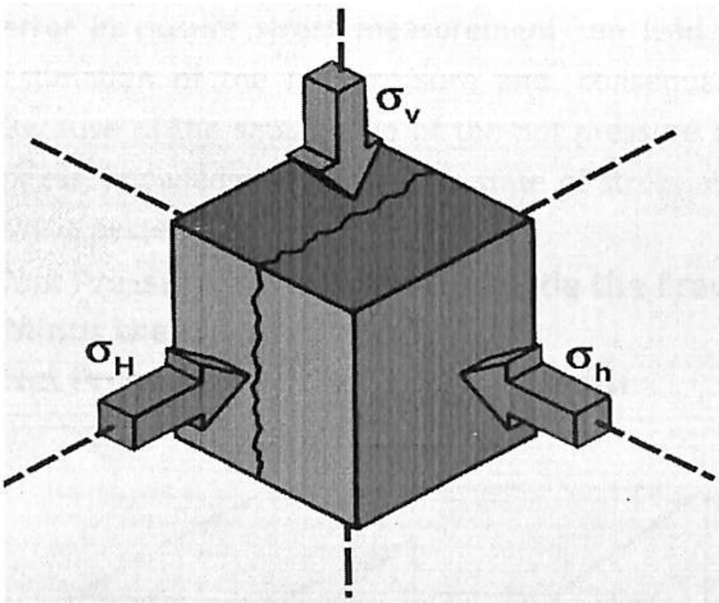


Figure 2.7: Effect of in-situ stresses on fracture

In-Situ Stress is the single most important factor controlling hydraulic fracturing. It affects the following Frac Parameters:

- Orientation
- Height
- Treating pressure
- Proppant crushing and embedment
- Width profiles

Determination of In Situ-Stress

- Microfracturing
- Pump-in/flowback test
- Logging techniques
- Specialized core test

The value of minimum stress is one of the most important parameters in hydraulic fracturing. At typical reservoir depths, the fracturing pressure is a strong function of the minimum stress (or closure pressure). With some pumping regimes, the value of the net pressure, which is the fracturing pressure minus the closure pressure, could be quite small compared with the closure pressure. The net pressure is the most robust and usually the only parameter that is available for obtaining information on fracture geometry. An error in closure stress measurement can lead to a significant error in the estimation of the net pressure and, consequently, the fracture geometry. Because of the small value of the net pressure compared with the minimum stress, knowledge of the in-situ state of stress at depth also gives insight into the expected treatment pressures.

Net Pressure is the Pressure Inside the Fracture
Minus the Closure Pressure
Net Pressure = 2,500 - 2,000 = 500 psi

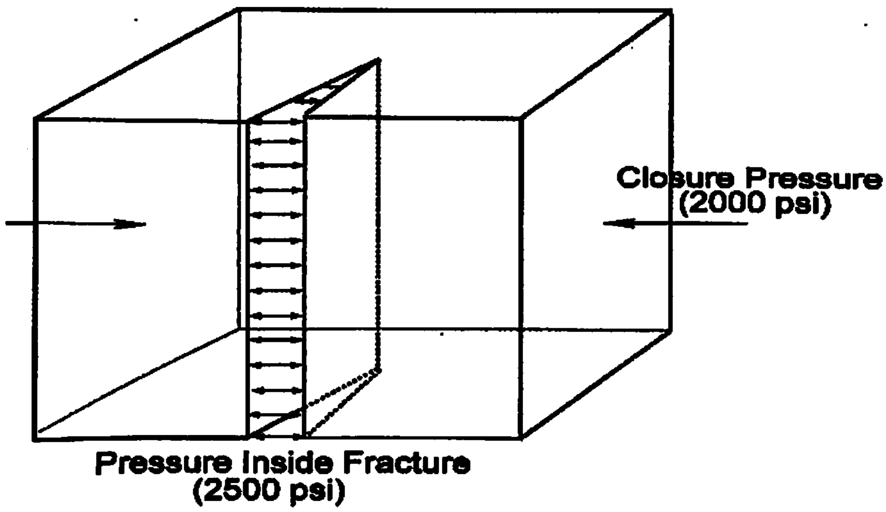


Figure 2.8: Calculation of closure pressure

2.3.1 Microfracturing Technique For The Determination Of Insitu Stresses:

Fracturing techniques are commonly used to measure the minimum stress. The micro-hydraulic fracturing technique is certainly the most reliable technique if conducted properly, although it could be used in conjunction with other methods for added completeness. This technique uses the pressure response obtained during initiation, propagation and closure of a hydraulically induced fracture to accurately determine the state of stress. Because stresses are functions of rock properties, it is quite important to ensure that the test provides a measure that is representative of a given lithology. Small-scale hydraulic fractures are usually required, especially if the measurements will be correlated with log or core information. However, the fracture must be large compared with the wellbore radius to measure the far-field minimum stress component, and a fracture with a size of 5–15 ft is a good compromise. At this scale, a tool that includes a gamma ray sonde is recommended for accurate placement with regard to lithology. Analysis of the sonic and gamma ray logs should be made prior to testing to decide on the location of the most appropriate lithologies for the tests. It is recommended to select locations that span lithologies with different values of Poisson's ratio and Young's modulus if the objective of the measurement is to establish a complete stress profile

The tool used is:

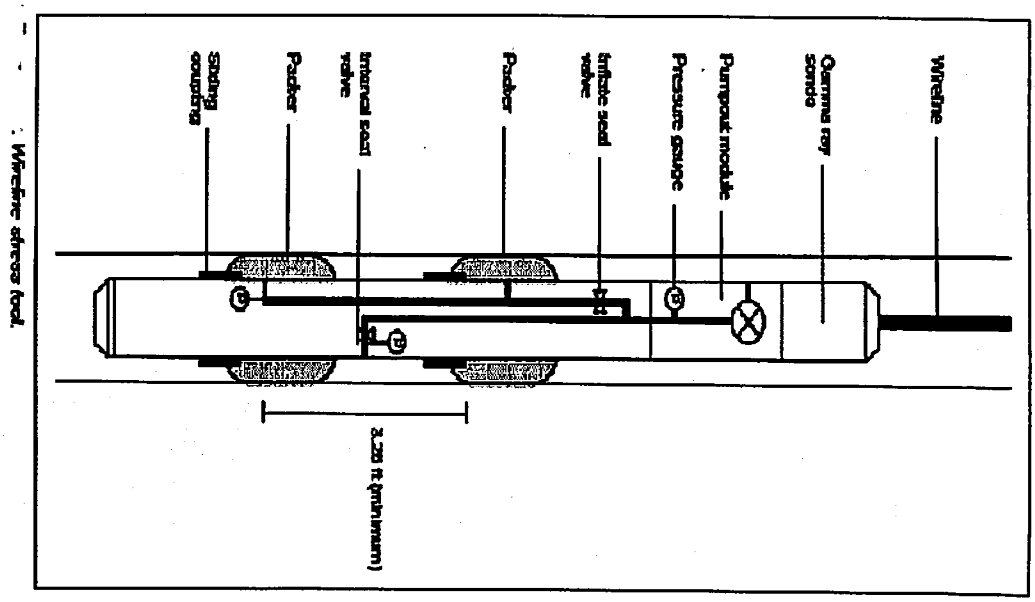


Figure 2.9: Microfracturing tool used for determination of in-situ stresses

CHAPTER 3
FRACTURING FLUIDS AND ADDITIVES

The fracturing fluid is a critical component of the hydraulic fracturing treatment. Its main functions are to open the fracture and to transport propping agent along the length of the fracture. Consequently, the viscous properties of the fluid are usually considered the most important. However, successful hydraulic fracturing treatments require that the fluids have other special properties. In addition to exhibiting the proper viscosity in the fracture, they should break and clean up rapidly once the treatment is over, provide good fluid-loss control, exhibit low friction pressure during pumping and be as economical as is practical.

The frac fluid:

- Provides hydraulic energy to
  - Initiate a fracture
  - Propagate or extend the fracture
- Transports propping agent to the fracture
- Needs to be flowed out of well after treatment.

<u>The desired fluid properties are:</u>

- Low (or controlled) fluid loss
- Low friction in pipe
- Sufficient viscosity to transport proppant
- Yield viscosity quickly
- Maintain viscosity at shear and temperature
- Clean breaking
- Break after desired time at temperature
- Break to low viscosity and no yield-point
- Non-damaging
- Leave no residue behind
- Do not cause capillary or phase trapping

3.1 Types of Frac Fluid

- Water Based
- Emulsion Based
- Foam Based
- Acid Based
- Oil Based

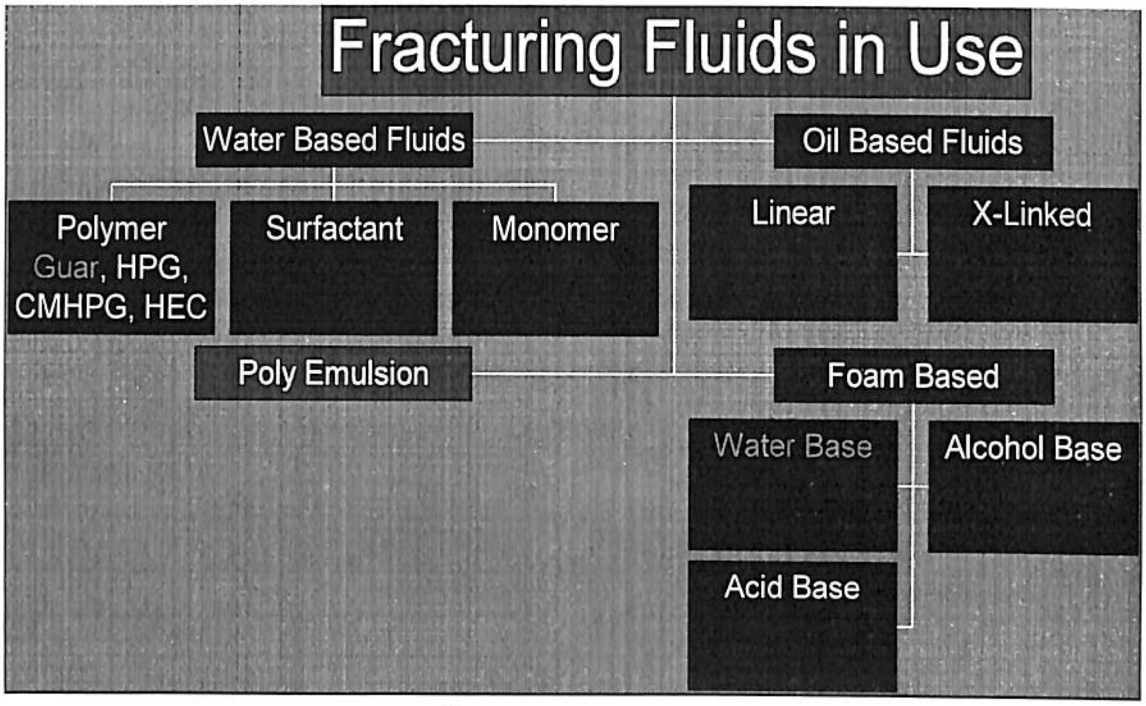


Figure 3.1: Types of frac fluid

3.1.1 Water Based

- Linear or Crosslinked
  - Guar based and other Polymers
  - Variable Polymer Loading
  - Various Crosslinkers
- Low Residue
- High pH and Low pH Fluids
- Base Fluid (Water) Is Inexpensive
- Continuous or Batch Mix
- Excellent Rheological Properties
- Ease of handling

3.1.2 Foam Based

- CO_2 water-based foams
  - CO_2 density close to water
  - More an emulsion than a foam
  - High CO_2 solubility in water
  - Good cleanup
- N_2 based foams
  - Low density and high friction (high WHTP)
  - Less efficient proppant transport
  - Useful in low pressure gas reservoirs for lift
  - Added flowback energy for cleanup in tight zones
- Binary foams ($CO_2 + N_2$)
  - Benefits of CO_2 solubility
  - Disadvantages of N_2 density

3.1.3 Oil Based

- Diesel
  - Seasonal variations
  - Often have added surfactants
- Lease crude
  - Wide range of compositions
  - Danger of precipitation and damage
- Condensate
  - Safety concerns with volatility and flash point
- Frac oils (FracSol, etc.)
  - Clean and easy to crosslink
  - expensive

3.1.4 Acid Based

- Usually hydrochloric acid (HCl) used
- Mostly used for acid fracturing
- Excessive fluid loss is a big concern
- No effective filter-cake barrier
- Acid leak off extremely non uniform and results in wormholes and enlargement of natural fractures

3.1.5 Emulsion Based

- Makes highly viscous solutions with good transport properties
- Commonly termed Polyemulsion

(67% hydrocarbon internal phase+33% viscosified brine external phase +emulsifying surfactant)

- Significantly reduces friction pressure
- Emulsion usually breaks due to adsorption of emulsifier onto formation rock
- Less formation damage and faster clean up
- High fluid cost
- Become less viscous as the temperature increases

A comparison of the various fluids used for hydraulic fracturing is given on the next page.

Base Fluid	Fluid type	Main Composition	Merits	Demerits
Water based	Linear	Guar, HPG, HEC, CMHPG, CMHEC etc	Short Fractures (WaterFrac), Low temperatures	Thinning of fluid with temperature, High polymer loading needed
	Cross linked	X-linker + HPG, HEC or CMHEC etc	Medium to Long Fractures, Medium to High temperatures	
Oil based	Linear	Oil, Gelled Oil	Water sensitive formations, short Fractures	Not Eco-friendly, Expensive, Operationally difficult to handle, Gelling time is more
	Cross linked	X-linker + Oil	Water sensitive formations, High Fractures	
Poly emuls-ion	External Water	Emulsifier + Oil + Water	Useful for High Fluid loss wells, Less formation damage	High friction pressure, limitations in high temperature wells
Foam based	Water based	Water + Foamer + N2 / CO2	Useful for Low pressure wells	Additional Pumping systems needed, Erosion, Suitable only for Lower proppant concentrations, Acid based is much expensive and poses Fluid loss problem
	Acid based	Acid + Foamer + N2	Useful for Low pressure and Water sensitive wells	
	Alcohol based	Methanol + Foamer + N2 / CO2	Useful for Low pressure and Water blocking wells	

Table 3.1: Comparison of various fluids used for hydro fracturing

3.2 Gellants

The fracturing fluid is mainly a mixture of base fluid and a gellant which provides viscosity to the frac fluid. This gellant is responsible for providing viscosity to the frac fluid so that it efficiently carries the proppant along with it into the fracture. The kind of gellant depends on the kind of the frac fluid.

- Water Gellants
  - Guar Gum (Normally used by ONGC)
  - HPG, CMG, CMHPG, HEC, CMHEC (imported)
- Methanol Gellants
  - HPG
- Oil Gellants
  - Phosphate ester
- Acid Gellants
  - Nonylphenol, Alkylphenol

The most common gellant added to water based fluids is guar. Guar is responsible for the high viscosity and converts the low viscosity water into high viscosity frac fluid. This guar is generally grown in India and Pakistan and is often exported to other countries.

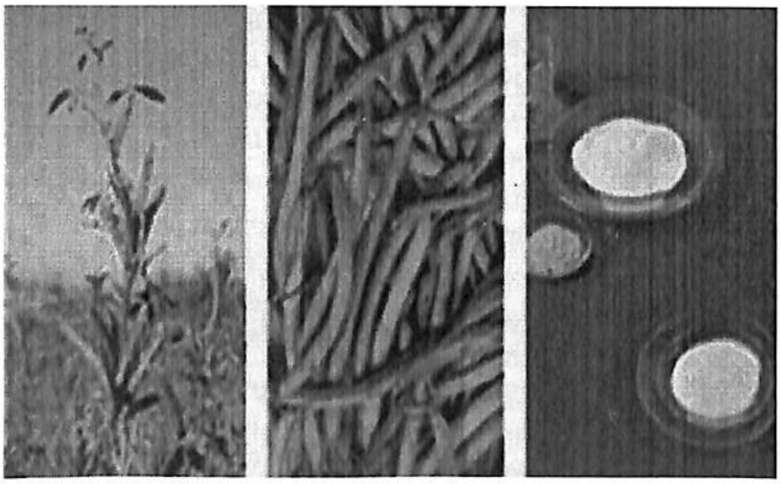


Figure 3.2: Guar plant, beans and powder

Guar gum

- Made from guar beans
- High molecular weight mannose and galactose sugars (polysaccharides)
- High residue (6-10%) but can be reduced by processing

Hydroxy-propyl Guar, HPG

- Derivative of guar
- Lower residue (2-4%) and more soluble in alcohol
- Similar formation damage to guar
- More stable at higher temperatures (>150°C)

Carboxymethyl-Hydroxypropyl Guar, CMHPG

- Popular as a high temperature base gel
- Frequently crosslinked with Zr

Carboxymethyl Guar, CMG

- Yields viscosity in fresh water
- Intolerant to salts

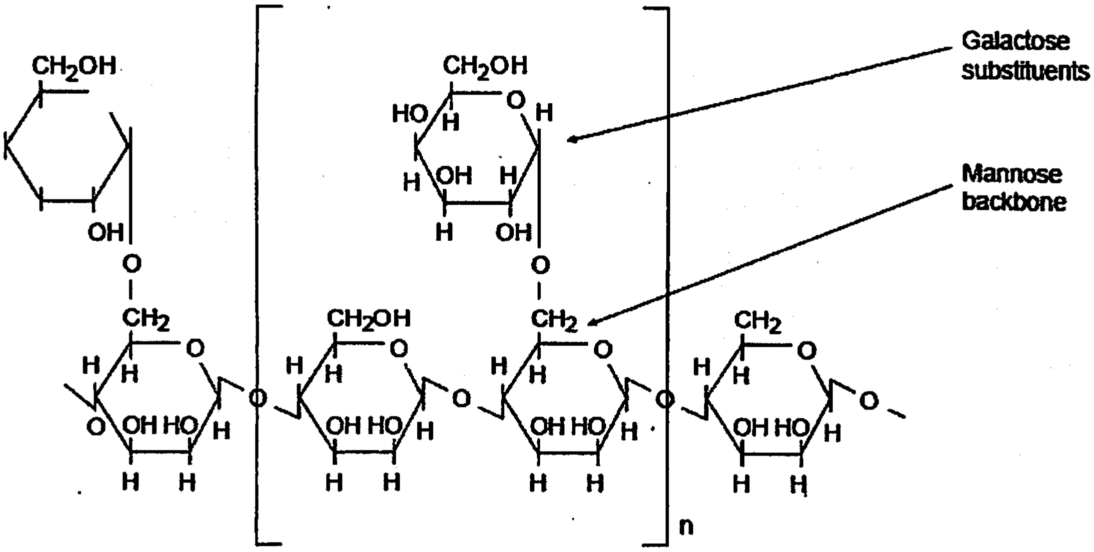


Figure 3.3: Structure of Guar

3.3 Additives

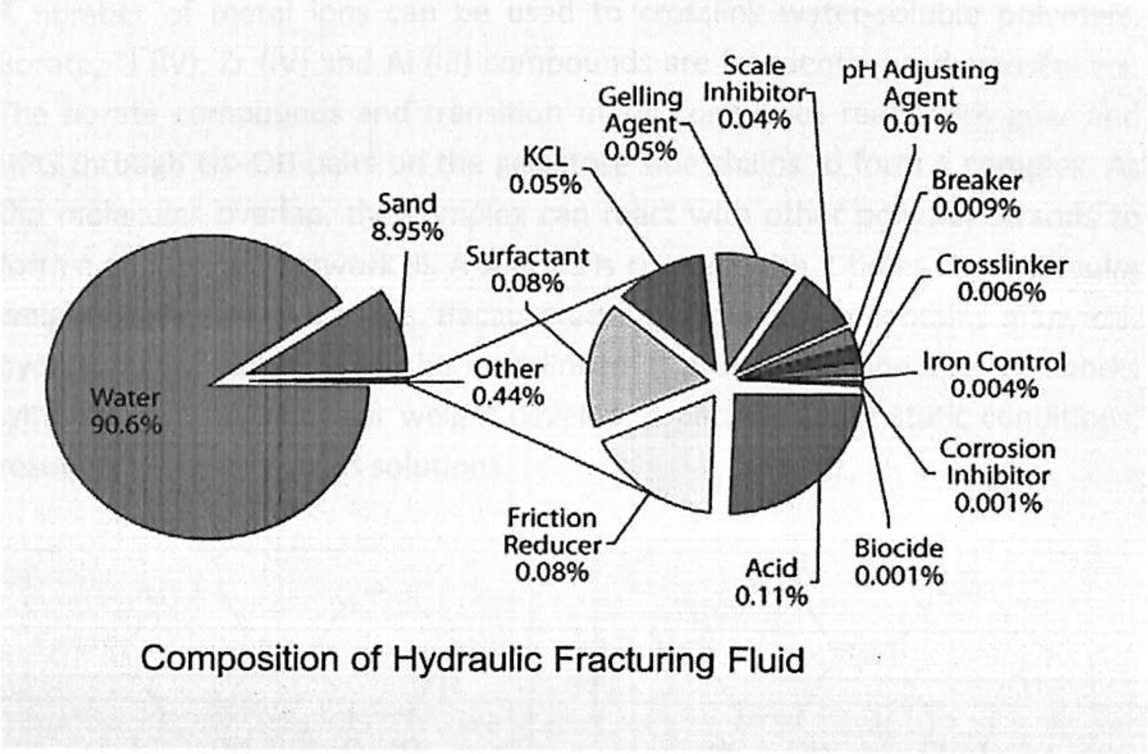


Figure 3.4: Composition of frac fluid

A fracturing fluid is generally not simply a liquid and viscosifying material, such as water and HPG polymer or diesel oil and aluminium phosphate ester polymer. Various additives are used to break the fluid once the job is over, control fluid loss, minimize formation damage, adjust pH, control bacteria or improve high-temperature stability. Care must be taken when using multiple additives to determine that one additive does not interfere with the function of another additive.

The various additives added to the frac fluid are:

- Crosslinkers
- Breakers
- Fluid loss additives
- Bactericides
- Gel stabilizers
- Non emulsifier/ Surfactants
- Clay stabilizers
- Buffering agents

3.3.1 Crosslinkers:

A number of metal ions can be used to crosslink water-soluble polymers. Borate, Ti (IV), Zr (IV) and Al (III) compounds are frequently used crosslinkers. The borate compounds and transition metal complexes react with guar and HPG through cis–OH pairs on the galactose side chains to form a complex. As the molecules overlap, the complex can react with other polymer strands to form a crosslinked network ill. A species is created with 2 times the molecular weight of the polymer alone. Because each polymer chain contains many cis-hydroxyls, the polymer can be crosslinked at more than one site. Networks with a very high molecular weight develop, especially under static conditions, resulting in highly viscous solutions.

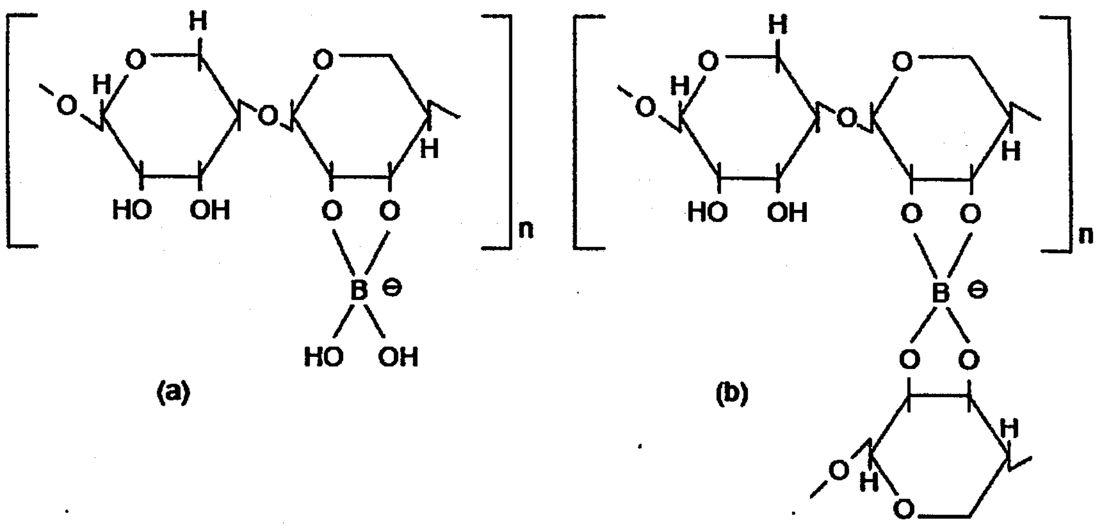


Figure 3.5: The crosslinking mechanism is shown

One of the simplest crosslinkers, the borate ion, is used to produce very viscous gels with guar and HPG that can be stable above 300°F. At a pH above 8, borate ions and guar form an extremely viscous gel in a matter of seconds.

The table gives some details about the various crosslinkers used

Crosslinker	Borate	Titanate	Zirconate	Aluminate
Crosslinkable Polymers	Guar, HPG, CMHPG	Guar, HPG, CMHPG, CMHEC	Guar, HPG, CMHPG, CMHEC	CMHPG, CMHEC
pH range	8-12	3-11	3-11	3-5
Upper temp. limit (°F)	325	325	400	150
Shear degraded	No	Yes	Yes	Yes

Table 3.2: Properties of various crosslinkers

3.3.2 Breakers:

- Controllably degrades viscous gelled fluids back to thin base fluids
- Most are pH dependant
- Attack the polymer backbone and break it into smaller molecular weight fragments
  - Viscosity of polymer suspension decreases
  - Filter cake remains and becomes more compressed
- Lab studies are required to ascertain the concentration (loading) of breakers

Relatively high viscosity fluids are used to transport proppant into the fracture. Leaving a high-viscosity fluid in the fracture would reduce the permeability of the proppant pack to oil and gas, limiting the effectiveness of the fracturing treatment. Gel breakers are used to reduce the viscosity of the fluid intermingled with the proppant. Breakers reduce viscosity by cleaving the polymer into small-molecular-weight fragments. It has been estimated that fluid loss during the treatment and during closure increases the polymer concentration in the fracture after closure 5–7 times to as much as 20 times higher than the surface concentration. The increased polymer concentration causes a major increase in viscosity. The most widely used fracturing fluid breakers are oxidizers and enzymes. The most common oxidative breakers are the ammonium, potassium and sodium salts of peroxydisulfate. Thermal decomposition of peroxydisulfate (persulfate) produces highly reactive sulfate radicals that attack the polymer, reducing its molecular weight and its viscosifying ability

Breaker	Temp. range oF	Comments
Enzyme	60 - 200	Efficient breaker. Limit to below pH 10
Encapsulated enzyme	60 - 200	Allows higher concentrations for faster breaks
Persulfates (Sodium, Ammonium)	120 - 200	Economical. Very fast at high temp.
Activated persulfates	70 - 120	Low temp. & high pH
Encapsulated persulfates	120 - 200	Allow higher concentrations for faster breaks
High temp. oxidizers	200 - 325	Used where persulfates are too quick

Table 3.3: Properties of various breakers

3.3.3 Fluid Loss Additives:

Good fluid-loss control is essential for an efficient fracturing treatment. Several types of materials are used to provide fluid-loss control, but the effectiveness of the various types depends on the type of fluid-loss problem: loss to low or high-permeability matrix or loss to microfractures. During leakoff into the rock matrix, fluid enters the pore spaces of the rock. Some polymers, such as guar and HPG, are filtered out on the surface of low permeability rocks. Fluids containing these polymers are called wall-building fluids because of the layer of polymer and particulates that builds up on the rock. This layer, called a filter cake, is generally much less permeable than the formation. If the fluid contains particulates of the proper size, these particulates tend to plug the pore spaces and enhance the formation of filter cake. The fluid volume lost before an effective cake forms is called spurt loss.

3.3.4 Bactericides

Bactericides are added to polymer-containing aqueous fracturing fluids to prevent viscosity loss caused by bacterial degradation of the polymer. The polysaccharides (sugar polymers) used to thicken water are an excellent food source for bacteria. Bacteria not only ruin gel by reducing the molecular weight of the polymer, but some can turn the reservoir fluids sour. Once introduced into the reservoir, some bacteria can survive and reduce sulfate ions to hydrogen sulphide (H2S). Materials such as glutaraldehyde, chlorophenates, quaternary amines and isothiazoline are used to control bacteria.

3.3.5 Gel Stabilizers

- Methanol and sodium thiosulfate ($Na_2S_2O_3$)
- Act as oxygen scavengers and prevent the rapid gel degradation caused by dissolved oxygen
- Increases viscosity at elevated temperatures by a factor of 2 to 10, depending on temp. and time of exposure to temp.

3.3.6 Surfactants/ Non-emulsifiers

- Modifies wettability of formation
- Used to create, break, prevent or stabilize emulsions
- Helps to suspend fines
- Promotes cleanup of fracturing fluid
- Some bactericides and clay-control agents are surfactants.

3.3.7 Clay Stabilizers

- Minimizes permeability impairment from clay swelling
- May control migrating clay
- Normally 2% KCl used

3.3.8 Buffering Agents

- Adjusts and maintains pH to allow the gellant to hydrate and maximize viscosity
- Can be used to control hydration / cross-link
- Soda & acetic acid

3.4 PROPPANT

Proppants are used to hold the walls of the fracture apart to create a conductive path to the wellbore after pumping has stopped and the fracturing fluid has leaked off. Placing the appropriate concentration and type of proppant in the fracture is critical to the success of a hydraulic fracturing treatment. Factors affecting the fracture conductivity (a measurement of how a propped fracture is able to convey the produced fluids over the producing life of the well) are:

- proppant composition
- physical properties of the proppant
- proppant-pack permeability
- effects of post closure polymer concentration in the fracture
- movement of formation fines in the fracture
- long-term degradation of the proppant.

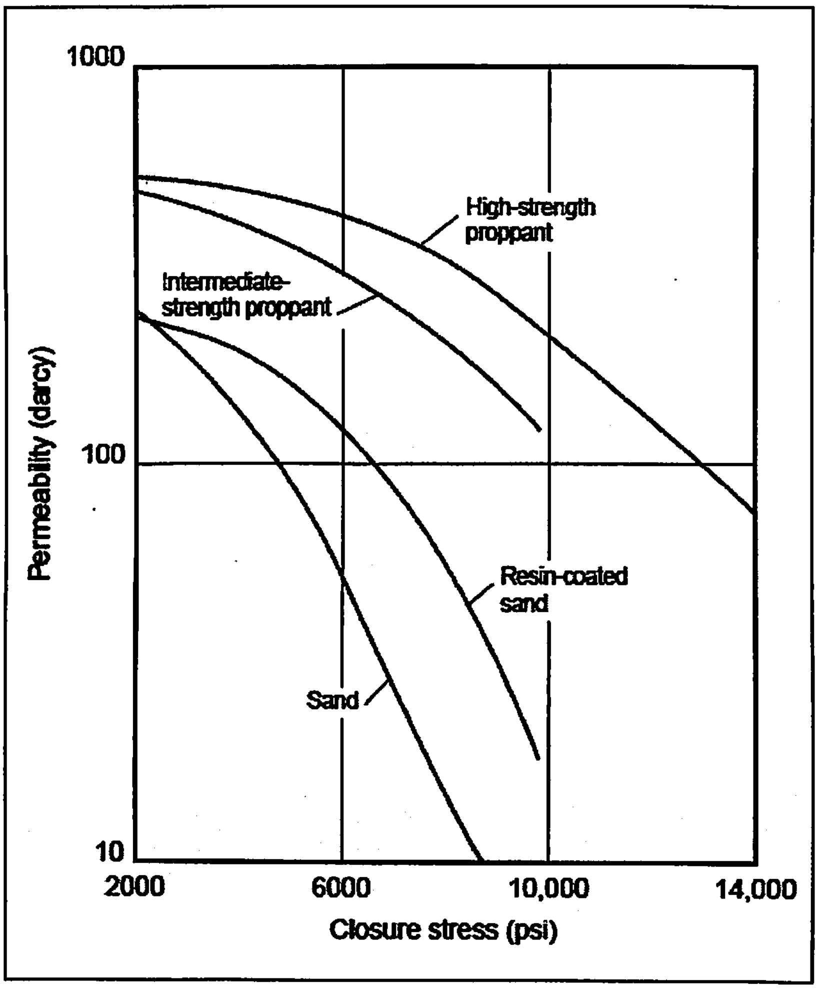
3.4.1 Physical properties of proppants:

The physical properties of proppants that have an impact on fracture conductivity are

- proppant strength
- grain size and grain-size distribution
- quantities of fines and impurities
- roundness and sphericity
- proppant density.

To open and propagate a hydraulic fracture, the insitu stresses must be overcome. After the well is put on production, stress acts to close the fracture and confine the proppant. If the proppant strength is inadequate, the closure stress crushes the proppant, creating fines that reduce the permeability and conductivity of the proppant pack. Proppants can be produced from a variety of materials and in a variety of size ranges to meet the conductivity requirements of the fracture design.

Strength comparisons are shown in the figure



... - -- *Strength comparison of various types of proppants.*

Figure 3.6: Strength comparison of various types of proppant

The following general guidelines may be used to select proppants based on strength and cost:

• sand—closure stresses less than 6000 psi

• resin-coated proppant (RCP)—closure stresses less than 8000 psi

• intermediate-strength proppant (ISP)—closure stresses greater than 5,000 psi but less than 10,000 psi

• high-strength proppant—closure stresses at or greater than 10,000 psi.

Proppant type and size should be determined by comparing economic benefits versus cost.

CHAPTER 4

THE PROCESS

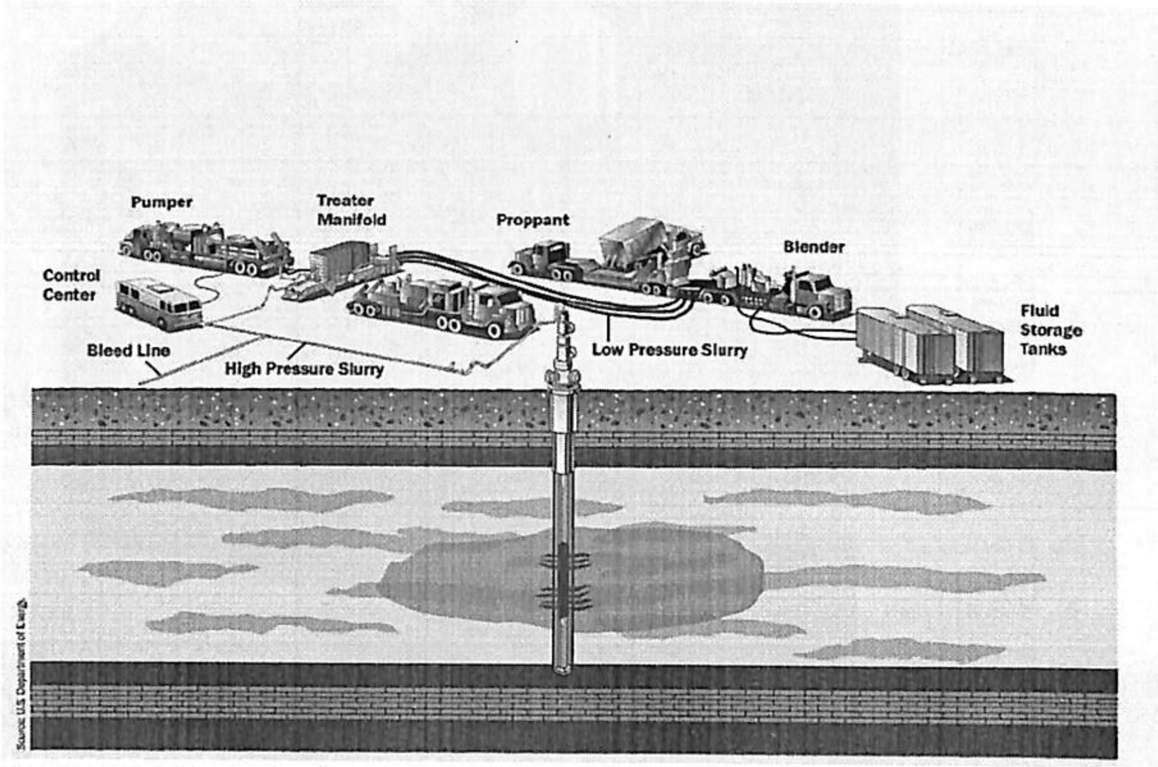


Figure 4.1: The hydro frac process

Hydraulic fracturing is generally a five-step process:

- Pre-fracturing treatment
- Fracture initiation and breakdown
- Fracture extension
- Proppant injection
- Cleanout and production

4.1 Fracture Conductivity:

$$C_{fD} = \frac{k_p w}{k_{EH} x_f}$$

Where k_p = proppant permeability at producing closure conditions, md

w = producing fracture width, ft

k_{EH} = effective horizontal formation permeability , md

x_f = fracture half length, ft.

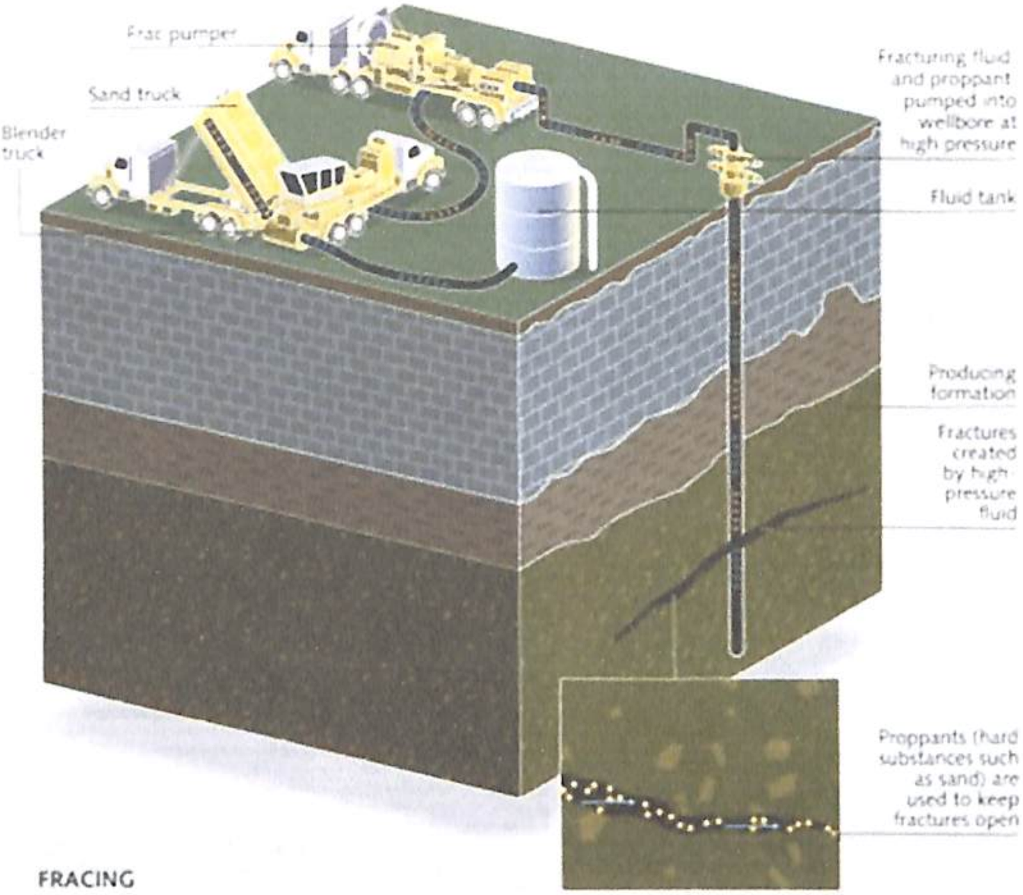


Figure 4.2: A hydro frac job in progress

During the fracturing treatment, fluid chemistry comes together with proppant handling, mixing and pumping equipment to create the desired propped fracture. The field environment is often quite different from the ideal laboratory conditions in which the fracturing fluid or additive was developed. The following sections address the field environment.

4.2 Mixing

Fluids may be batch mixed or continuously mixed. Batch mixing has slightly different meanings, depending on the fluid prepared. For oil-base fluids, it means that all ingredients (except fluid-loss additive, breaker and proppant) are blended together in the fracture tanks (typically, 500-bbl capacity) before pumping begins. The tanks are usually mixed the day before pumping because the gel takes several hours to form. A fluid-loss additive and a breaker are added on the fly as the gel is pumped. These materials are added on the fly to prevent the fluid-loss additive from settling out in the fracture tanks or the

Figure 5.2: The various equipments involved in hydro frac

CHAPTER 6
FRACTURE CALCULATION

6.1 Fracturing Pressure

Normally, more pressure is required to initially break down a formation than is required to propagate a fracture. A fracture is more easily created using a low viscosity, penetrating fluid. A penetrating fluid pressurizes a large area, and the total force on the formation is greater than if a non penetrating fluid which acts only on the area near the wellbore is used. The surface pressure is different from the bottom hole pressure because of the weight of the fluid and the friction losses in the well bore. The critical portions of the pressure history are shown in figure:

- Break down pressure: the pressure required to break down the formation and initiate fracture.
- Propagation pressure: the pressure required to continually enlarge the fracture.
- Instantaneous shut in pressure: the pressure that is required to just hold the fracture open.

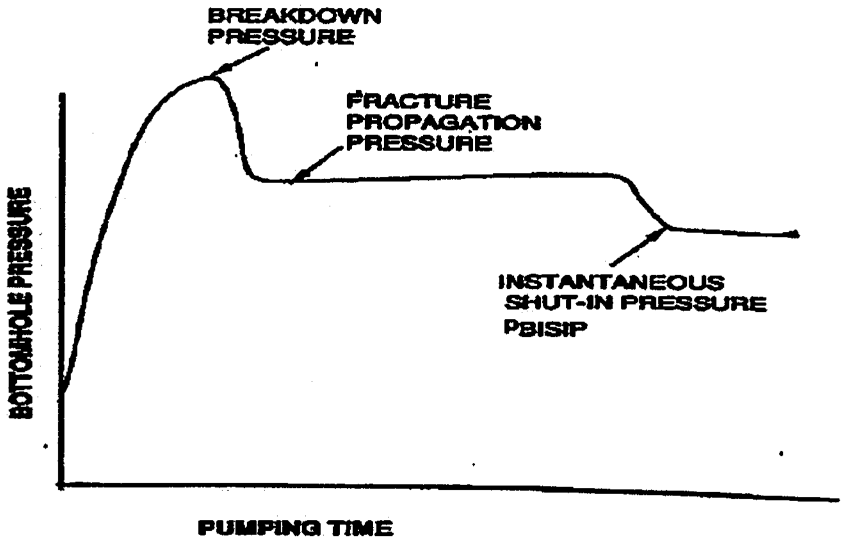


Figure 6.1: idealized pressure behavior during fracturing

The instantaneous shut in pressure measured by stopping the flow will depend on the width of the fracture at this point and the pore pressure surrounding the fracture. If P_{ISIP} is the instantaneous shut in pressure measured at the surface, then the bottom hole shut in pressure (P_{BISIP}) is given by:

$$P_{BISIP} = P_{ISIP} + \rho g D$$

D = formation depth

The bottom hole pressure required to maintain a fracture divided by the reservoir depth (D) is defined as fracture gradient (FG).

$$FG = P_{BISIP} / D$$

The orientation of the fracture depends on the value of the horizontal and vertical stresses. Generally at higher depths the vertical fracture are formed as the magnitude of vertical stress is more than horizontal stresses.

The FG of vertical fracture is:

$$FG = (v/1-v)\rho_o g + P/D\{1-(v/1-v)\}$$

v = Poisson's ratio

g = acceleration due to gravity

P = formation pressure

D = depth of wellbore

ρ_o = density of overburden

A fracture will propagate whenever the stress intensity factor reaches a critical value (K_c) which is thought to be a material property called the critical stress intensity factor, fracture toughness or fracturability.

$$K = 1.25\Delta P\sqrt{h}$$

$$\Delta P = P_f - P_{BISIP}$$

P_f = pressure of the fluid in the fracture

K = stress intensity factor

6.2 Fracture Height

Fractures that grow extensively in the vertical direction will ultimately extend beyond the pay zone and fracture into undesirable zones, such as aquifers, either above or below the pay zone. The in situ stresses are the most important factor that determines the fracture containment.

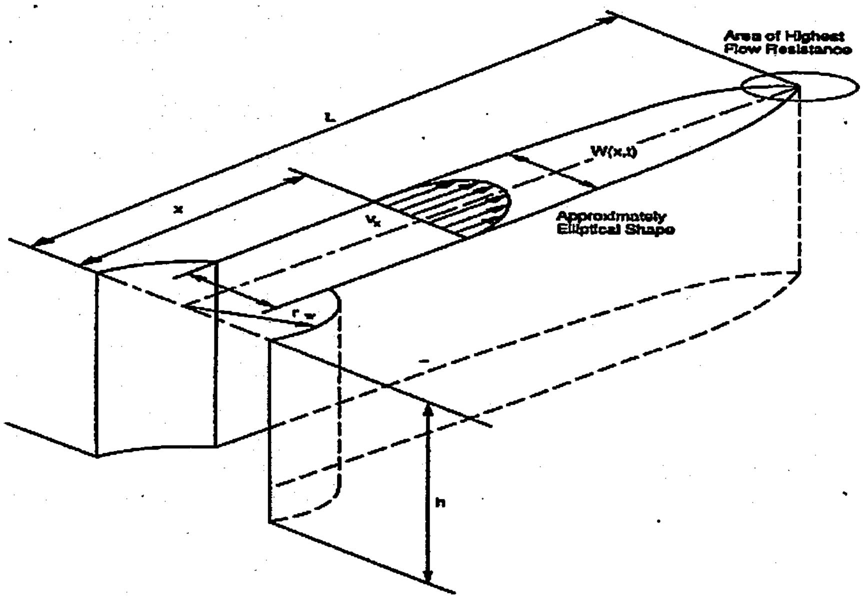


Figure 6.2: A typical fracture front propagation

Depending on the in situ stress contrast and the formation properties, a given fracture treatment may be contained within the pay zone. The most important variable is the contrast in the horizontal in situ stresses between zones.

6.3 Dyanamic Width Of Fracture

The size of proppant that can be transported into the fracture depends on dynamic width of fracture.

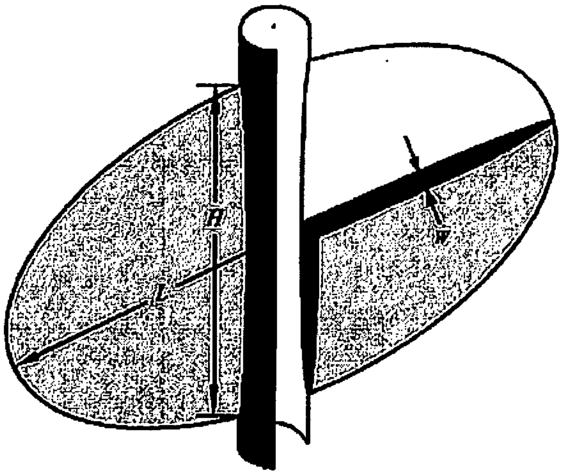


Figure 6.3: Fracture length, width and height

The width of a crack in an elastic body depends on the fluid pressure if the strain is confined to the y-z plan, then the width is given by:

$$W(x,z,t) = \frac{1-v}{G}(h^2 - 4z^2)^{\frac{1}{2}}\Delta P(x,t) \quad for\ z < \frac{1}{2}h$$

H: fracture height

G: shear modulus

V: poisson ratio

According to the above equation in order to create wide fractures, the fluid pressure must be large. The width of the fracture is maximum at a particular x when z=0

$$W = \frac{\pi}{4}W_{max}$$

W = Average width of fracture

W_{max} = Maximum width of fracture

The average dynamic width of the fracture decreases with increase in distance from the well bore. It is given by:

$$W(0,t) = 1.12[\frac{(1-v)\mu i^2}{GCh}]^{\frac{1}{4}} t^{\frac{1}{8}}$$

μ = Viscosity of fracturing fluid

i = Rate of injection of fracturing fluid

C = Total fluid leak off test

t = Time of injection of fracturing fluid

6.4 Length of Fracture

The productivity of the well increases with the increase in the length of fracture. The magnitude in the increase in productivity depends on the relative permeability of the fracture and formation. The length of the fracture is calculated by the volume balance of fracturing fluid. The volume of the fracturing liquid injected is used up in occupying the increased fracture volume and some of it is leaked off in the formation. The length of the fracture increases with the time of injection.

The length of the fracture is given by the expression:

$$L(t) = \frac{1}{2\pi}(\frac{i}{Ch})t^{\frac{1}{2}}$$

L(t) = length of fracture at time t

i = the rate of injection of fracturing fluid

6.5 Well Bore Pressure

The net pressure in the well bore (fluid pressure less the instantaneous shut in pressure) can be used for finding the time at which a fracture may extend vertically suddenly penetrating through a bounding layer of high in-situ stress in to a zone of low in situ stress. For the limited vertical growth the net pressure increases once the length increases the height.

The net pressure of the well bore is given by the expression:

$$\Delta p(0,t) = 1.43\left[\frac{\mu i^2 G^3}{Ch^5(1-v)^3}\right]^{\frac{1}{4}} t^{\frac{1}{8}}$$

6.6 Fluid Loss

The overall fluid loss coefficient (C) has been seen to be an important, perhaps the most important, factor determining the effectiveness of a given fracture treatment. It is therefore necessary to estimate C as accurately as is possible if reasonable approximations to fracture geometry are to be obtained. As shown in figure the fluid loss is controlled by three mechanisms:

1) The comparison of reservoir fluids.
2) The thickness of the invaded zone which is filled with viscous fracture fluid
3) The filter cake which may not be present depending on the additives contained in the fracture fluid

$$\textit{Compressibility fluid loss coefficient } C_c = \sqrt{\frac{\phi K_{fl} k}{\pi \mu_f}} \Delta p$$

$$\textit{Viscous fluid loss coefficient } C_v = \sqrt{\frac{\phi k}{2\mu}} (\Delta p)^{\frac{1}{2}}$$

$$\textit{Wall building fluid loss coefficient } C_w = \alpha_w(\Delta p)^{\frac{1}{2}}$$

Φ = Porosity of formation

μ_f = Viscosity of formation

k = Formation Permeability

K_{fl} = Isothermal compressibility of formation fluid

μ = Viscosity of Fracturing Fluid

$$\textit{Overall fluid loss coefficient } C = \frac{\frac{1}{C_c} + \sqrt{\left(\frac{1}{C_c^2} + 4\left(\frac{1}{C_v^2} + \frac{1}{C_w^2}\right)\right)}}{2\left(\frac{1}{C_v^2} + \frac{1}{C_w^2}\right)}$$

The value of the fluid loss coefficient decreases with increase in concentration of polymer in fracturing fluid.

6.7 Propped Fracture Conductivity:

Fracture Conductivity

$$FC = w_f k_f$$

w_f = Final average fracture width

k_f = Permeability of proppant packed fracture

This equation is valid if the proppant forms a multilayer as shown in figure. The partial monolayer can have higher fracture conductivity than multilayer packing but the partial monolayer packing is difficult to achieve.

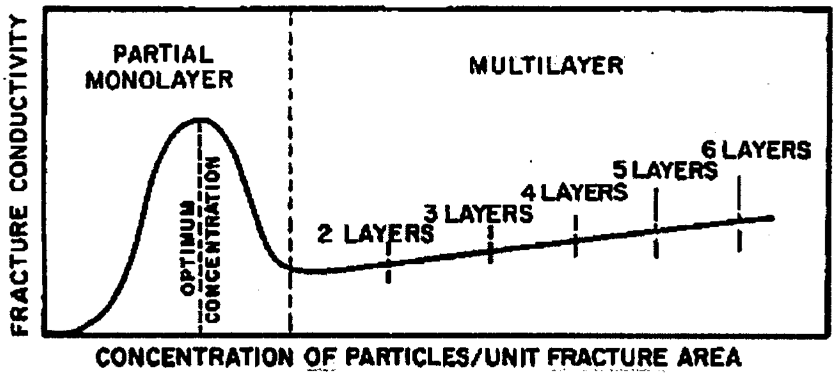


Figure 6.4: Effect of particle concentration on fracture conductivity

The figure shows the effect of particle concentration on fracture conductivity. The conductivity of the fracture increases with the increase in the surface concentration of proppants.

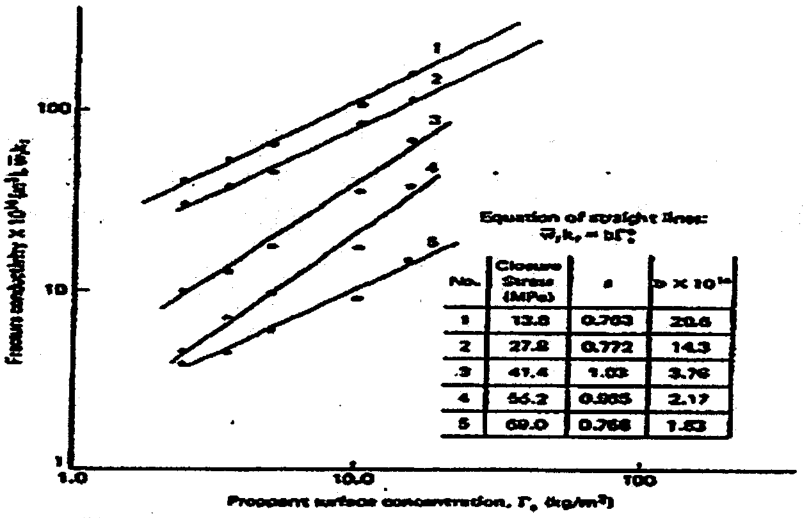


Figure 10.5 Graph showing conductivity of 20/40 sand as a function of proppant concentration. (Adapted from data supplied by the Norton Company.)

– Graph showing conductivity of 20/40 sand as a function of proppant concentration

Figure 6.5: Conductivity of 20/40 sand as a function of proppant concentration

6.8 Fracture Permeability:

Final permeability is strictly a function of the diameter of proppant particles used in the treatment. According to the Blake – Kozeny equation

$$k_f = \frac{d_p^2 \phi_f^3}{150(1-\phi_f)^2}$$

Where DP is the diameter of the prop pants particles and Φ_f is the porosity of packed, multilayered bed of prop pant particles.

The fracture permeability increases with the square of the proppant particle diameter. The larger particles will require more expensive fluids to transport them. The permeability of the propped fracture decreases with the increase in closure stress.

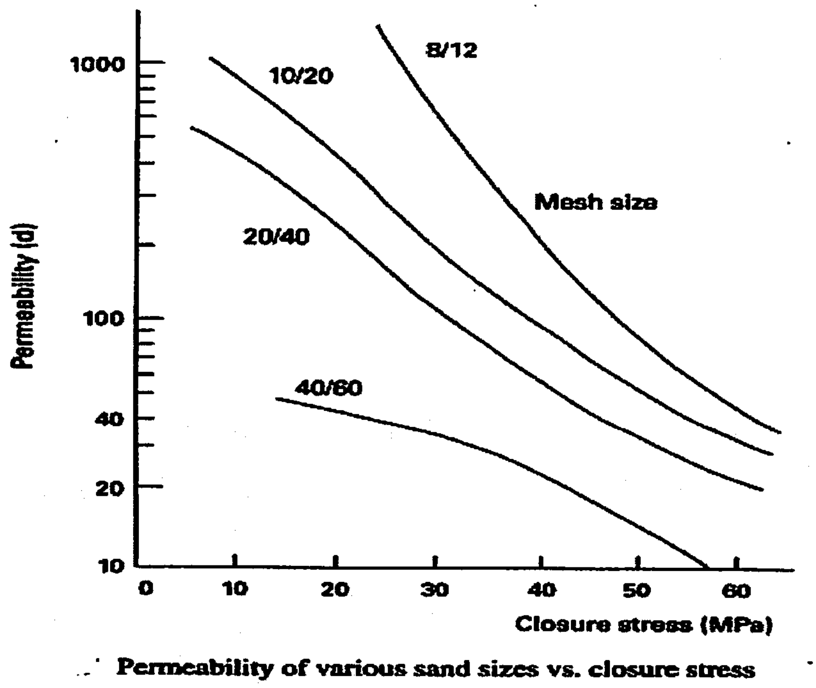


Figure 6.6: Effect of closure stress on fracture permeability

6.9 Fracture Closure Time

A fracture does not immediately close once fluid injection has stopped and well is shut-in. The fluid contained in the fracture will be forced into the formation since the fluid pressure will be approximately, P_{BISIP} which is in excess of the reservoir pressure.

$$W(t_f) - W_f = 2\pi C[(t_f + \Delta t)^{\frac{1}{2}} - t_f^{\frac{1}{2}}]$$

W = Average dynamic width of the fracture

W_f = Final average width of fracture

C = Total fluid loss coefficient

t_f = Time of injection of fracture fluid

Δt = Time taken by fracture to set on proppant

This equation is important because it defines the time (Δt) required to reach the final width. During this time, proppant will continue to settle and thus Δt is an important factor in fracture design.

6.10 Productivity of Fractured Well

To increase the productivity of the well is the ultimate goal of the fracturing process. The estimation of the productivity increase can be made from the following graph:

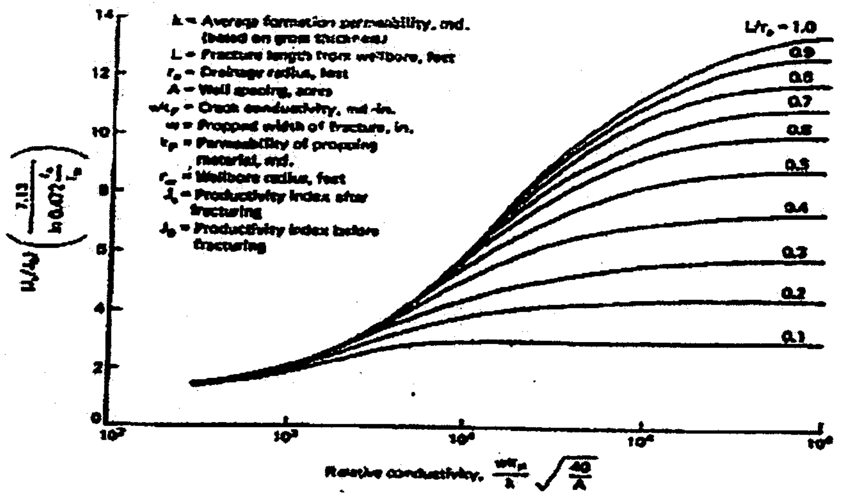


Figure 11.3 Graph showing increase in productivity from fracturing (4). (With permission from the Society of Petroleum Engineers.)

Graph showing increase in productivity from fracturing.

Figure 6.7: Increase in productivity from fracturing

6.11 Injection Rate of Fracturing Fluid

Injection rate of fracturing fluid is given by the expression:

$$i = \frac{Gw^4}{8.38\mu L}$$

i = injection rate

w = average dynamic fracture width

μ = viscosity of fracturing fluid

L = length of fracture

Volume of fracturing fluid needed = injection rate * time of injection

6.12 Mass of Proppant Required

It is calculated by the following expression:

$$M_o = 2hL\Gamma_s$$

Γ_s = surface concentration of proppant

L = length of fracture

6.13 Surface Pressure and Power Needed

Pressure of fracturing fluid at the surface = Pressure of the fracturing fluid needed at the bottom of the well – Change in pressure due to fluid column

Change in pressure due to fluid column = ρgD

ρ = density of fracturing fluid

D = Depth of well

Hydraulic power needed = injection rate * surface pressure

CHAPTER 7

WELL SELECTION FOR HYDRAULIC FRACTURING

7.1 Candidate Selection

Virtually any zone in any well is a potential candidate for hydraulic fracturing. Given a free hand, it is possible to produce an increase in productivity index in almost any formation using hydraulic fracturing. However, often the Frac Engineer is limited by considerations such as water oil contacts, gas –oil contacts, poor cement bonding, completion restrictions and placement of perforations. Moreover, the formation must have the reserves and production potential to economically justify the large expense often associated with fracturing.

It should never be forgotten that the best wells are also the best candidates for fracturing. Fracturing cannot add reserves nor can it increase reservoir pressure – if there is nothing there to start with there will be nothing there afterwards. A 50% increase in production from a good well is often more valuable than 500% increase from a poor well.

7.2 Economic Justification for Fracturing

Fracturing as with any other operation performed on an oil or gas well – has to be economically justified. That is to say the increased revenue generated by the treatment must satisfy economic criteria set by the operating company. This is vitally important it is not enough for the Frac Engineer must usually either produce at least a minimum production increase economically recoverable reserves in order to meet the economic criteria.

Part of the skill in designing a fracture treatment is deciding whether or not these economic justifications can be met. However, given that the treatment such as a skin bypass fracture can cost less than $20,000 to carry out, usually any reasonable criteria can be satisfied, unless a well has a very low productivity increase.

Economic criteria can often be simple. For instance, many companies insist that the cost of the treatment be paid within a period of three months. In such a case the frac engineer has to estimate the increase in production and from that the total extra production over the first three months. Once the extra production has been calculated, the total extra revenue can easily be calculated by multiplying the oil or gas price. If the total extra income is greater than the cost of treatment, then the treatment is economically justified.

All parties involved in the job of fracturing must be ready to accept a certain element of risk. Fracturing is not an exact science. Although many theories involved in the process are rigorous and thoroughly proven. Often this data is of poor quality or is absent entirely. Even when considerable time effort, time and expenditure have been taken to obtain data, it is usually only valid for a few inches around the wellbore. In order to complete a frac design the engineer has to sometimes assume that this data is valid for sometimes hundreds of feet from the wellbore, encompassing a huge volume of risk. The frac engineer also has to cope up with the fact that no one really understands how a fracture propagates. This is illustrated by the fact that there are several different fracture simulators on the market, all using different methods to model the fracture.

7.2.1 Internal Rate of Return

Many operating companies use criteria of internal rate of return. This is a percentage value, and any potential project requiring an AFE (Authorization for Expenditure) must make a return on investment greater than this value. The theory is that the company would be better off spending the money elsewhere if a project cannot meet its criterion. For instance if a company man wishes to spend $1,000,000 on a project, and his company has an internal rate of return criterion of 18% over one year, then the expenditure of $1,000,000 must generate additional production worth at least $1,180,000 in the first year after the treatment.

7.2.2 Net Present Value

Net present value is a tool that can be used in two ways. First the operating company can set an NPV criterion to be met. Secondly, it can be used to compare different fracture designs, and decide which one is most cost effective. For instance, a fracture Engineer may be confronted with the following question- is it worth pumping twice the quantity of proppant for only a 10% gain in production? This can be answered using NPV analysis.

7.3 Completion limitations:

7.3.1 Tubing Cool Down

As relatively cold fracturing fluid is pumped down a completion, the tubing will start to cool down. As it cool down, it will shrink and decrease in length. In some wells, this can result in shrinkage of several feet.

Usually, wells are completed using packers with polished seal bores, and tubing with seal assemblies. When the completion is run, the packer is set at the required depth. Then the tubing is run, complete with a seal assembly on the bottom.

The seal assembly is a length of pipe with a number of rubber seals on the outside. The idea is that these seals slide into the polished bore of the production packer, providing the required isolation. The seal assembly is usually several feet in length, so that it can slide up and down inside the polished bore, allowing the tubing to expand or contract whilst still retaining complete integrity. However, if the tubing is cooled down too much, the seal assembly can sting right out of the polished bore, and the completion will lose integrity. This is highly undesirable.

There are two obvious answers to a tubing cool down problem:

1. Reduce the size of the treatment, so that the tubing does not get cooled down as much, or pump the treatment at the lower rate, so that the fluid heats up more as it travels down the well.

2. Heat up the treating fluid before it goes down the well. This can be done in two ways. The first way is to pump the fluid through a heat exchanger, which contains a hot fluid, such as steam or burning oil. Such heat exchangers are often called 'hot oilers.' The advantage of this system is that it can be used on the fly. The second way is to circulate the fluid through a choke, using the high pressure frac pumps. A frac tank of fluid circulated through a choke can be quickly heated up – if the choke is set small enough so that the pumps can develop significant horse power 4000 HHP produces approximately same amount of energy as a 3 MW plant. The disadvantages of this method are that heating multiple frac tanks can be very time consuming, and individual tanks will cool down as others are heated up. Therefore, hot oilers are used for large treatment while pumping through a choke is used for smaller treatments.

7.3.2 Maximum Wellhead Pressure

Often, a treatment will be constrained by a low maximum wellhead pressure. It is very rare that a treatment is completely prevented by this, but a low wellhead rating can sometimes severely limit what can be achieved by the treatment.

One solution to this problem is to use wellhead isolation tool or WIT (commonly referred to as a 'Tree Saver'). This tool actually bypasses the wellhead, by allowing the frac fluid to be pumped directly into the tubing, rather than through the wellhead and then into the tubing.

Another potential solution to this problem is to reduce the friction pressure. This can be done by either reducing the pumping rate or by altering the friction properties of the fluid (which can be done by either reducing the polymer loading or by delaying the crosslinking). Both of these parameters are usually flexible to certain extent. However some wells have a fracture gradient so high that even with zero friction pressure, the maximum wellhead pressure is exceeded.

A third method for reducing the wellhead pressure is to pump a high density frac fluid. This has the effect of increasing the hydrostatic head, which in turn lowers the wellhead pressure. These fluids are usually mixed using high density brine.

7.3.3 Completion Jewelry

Completion jewelry is a general term, used to describe all the various special tools that were added to the completion as it was run. Examples include:

- Subsurface safety valve (SSSV)
- Sliding side doors (SSD)
- Gas lift mandrels
- Blanks, used to close off gas lift mandrels
- Gauges and gauge carriers
- Non-return valves

All of these items will have a pressure rating. Ideally, this should be in excess of the overall pressure rating for the completion.

7.3.4 Things to Look For

Listed below are a number of items that may make an interval a good or bad candidate for hydraulic fracturing.

Skin Factor: All wells have skin damage to a greater or lesser extent unless they have been stimulated in some fashion. An interval with a high skin factor is a good candidate for fracturing.

Low Permeability Wells: So called 'tight' formations are where fracturing first became widely accepted by the industry. These formations cannot produce enough hydrocarbons purely because the rock matrix itself is not conductive enough. Therefore in order to unlock the potential of the reservoir, a fairly large hydraulic fracture treatment is required.

Weak or Unconsolidated Formations: Hydraulic fracturing is a very effective method for completing a weak or unconsolidated formation. Fracturing can help reduce or eliminate sand production by a number of methods:-

- By reducing the drawdown on the formation
- By re-stressing the formation
- By acting as a filter, provided that a proppant is sized correctly.

Water and Gas Contacts: In general, these are to be avoided. The presence of a water or gas contact close to the perforations can often prevent fracturing. If the propped fracture were to propagate into a water or gas zone, then the well will quickly stop producing oil and start producing water or gas. Once a propped fracture has connected with a water or gas zone, it is very difficult to halt the water or gas production.

Poor Cement Bond: If the bond between the casing and cement, or cement and formation, is poor or nonexistent, then fracturing should be avoided. In these situations, it is possible to make the poor bond even worse and to connect with separate formations above and below the zone of interest.

Corroded Casing or Tubulars: Badly corroded casing or tubular will probably not stand up to the differential pressures produced by fracturing. Therefore these wells should be avoided.

Perforation Strategy: The position of the perforations can often prove to be the difference between a successful and an unsuccessful frac.

Logistics: This is a measure of how easy it is to get materials and equipment to location. For instance, there is a big difference between a land location a few miles down the road from the base, and an offshore location on a satellite platform with a 5 tonne crane limitation. These two locations may have wells and formation that require similar treatments. However, it is very unlikely that the offshore would be treated in the same manner to the land well, unless a stimulation vessel was available. More often than not, it is the logistics of the operations rather than any formation parameters that has the biggest influence on the treatment.

CHAPTER 8

HYDRAULIC FRACTURING IN HORIZONTAL WELLS

8.1 Horizontal Wells – An Overview

The application of horizontal drilling technology to the discovery and productive development of oil reserves has become a frequent, worldwide event over the years. A widely accepted definition of what qualifies as horizontal drilling has yet to be written. The following combines the essential components of two previously published definitions:

"Horizontal drilling is the process of drilling and completing, for production, a well that begins as a vertical or inclined linear wellbore which extends from surface to a subsurface location just above the target oil or gas reservoir called the 'kickoff point,' then bears off on an arc to intersect the reservoir at the 'entry point,' and, thereafter, continues at a near-horizontal attitude tangent to the arc, to substantially or entirely remain within the reservoir until the desired bottomhole location is reached."

The technical objective of horizontal drilling is to expose significantly more reservoir rock to the wellbore surface than can be achieved via drilling of a conventional vertical well. The applications of horizontal drilling technology have included the drilling of fractured conventional reservoirs, fractured source rocks, stratigraphic traps, heterogeneous reservoirs, coalbeds, older fields and heat injection wells intended to boost both production rates and recovery factors.

8.2 Horizontal Well vs. Fracturing

In many cases we consider that a horizontal well is going to serve our purpose for optimum production in all cases. This can now be said with sufficient proof, is not always true. Now it can be said that a combination of the horizontal well with fracturing is supposedly going to increase the production to the desired extent.

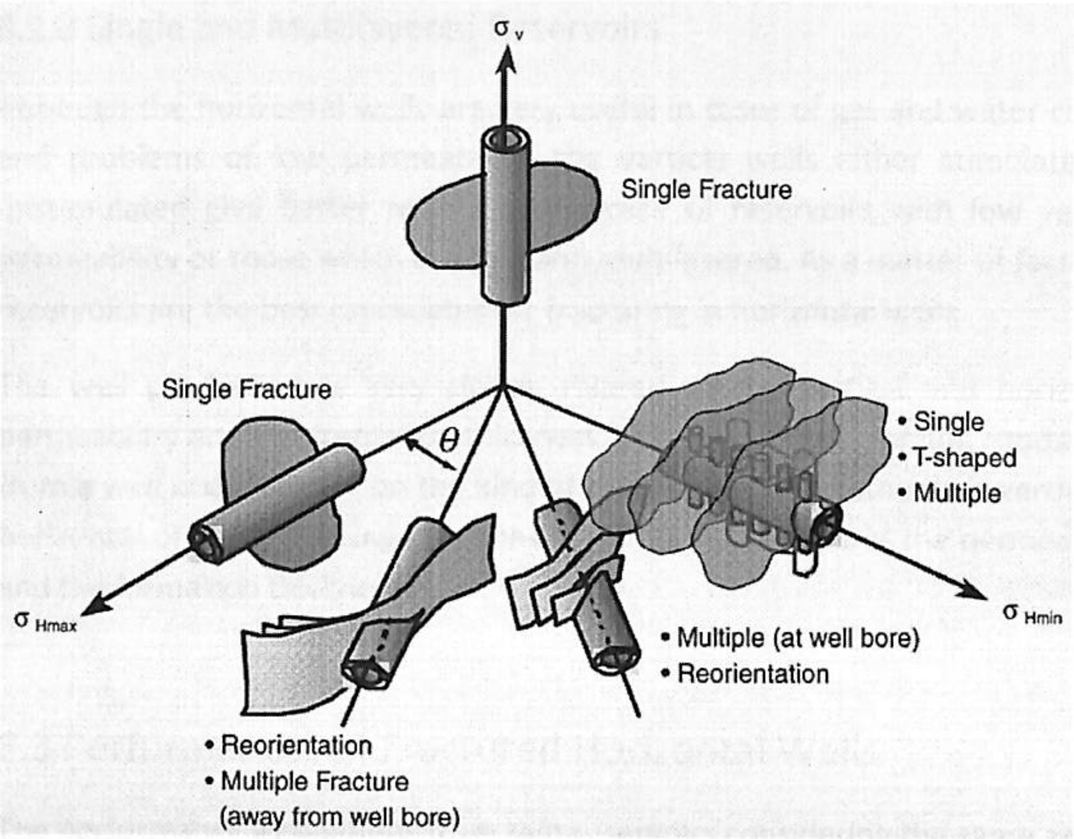


Figure 8.1: Fracture orientation in horizontal wells

8.2.1 Alternative or Combination

While in most fracturing jobs the formation is having a conductive path which surely does not offer free conductivity and on the other hand its conductivity decreases with time. In case of a horizontal hole, we can say that the borehole acts as a fracture of infinite conductivity where the fracture width is restricted by the diameter of the borehole only. In addition to this it gives protection from so many other problems such as water or gas coning.

They also help in cases where formation is layered and drilling a highly deviated hole at an angle greater than 60° can work wonders because now a single drilled horizontal well is draining more than one reservoir layers. Here comes the role of hydrofrac because in these cases it may also be extremely helpful to fracture the well because in this case we can reach more than one layered formation if the drilled formation is too thick for the well to drill past it into the next layer.

8.2.2 Single and Multilayered Reservoirs

Although the horizontal wells are very useful in cases of gas and water coning and problems of low permeability, the vertical wells either stimulated or unstimulated give better results in the case of reservoirs with low vertical permeability or those which are thin and multilayered. As a matter of fact such reservoirs are the best candidates for fracturing in horizontal wells.

The well production is very closely related to the vertical and horizontal permeability and the formation thickness. This is why the optimum production from a well is dependent on the kind of drilling we do, whether it is vertical or horizontal or slant, keeping into consideration the fact about the permeability and the formation thicknesses.

8.3 Performances of Fractured Horizontal Wells

The performance evaluations from thin reservoirs considering the same area of exploitation for horizontal fractured and vertically fractured if carried out gives interesting comparisons.

The horizontal wells give better results as compared to the vertically fractured wells for the case of tight reservoirs if they are thin. The situation still remains true for the case of thick well but the production from a horizontal well can be drastically improved if we consider a fractured horizontal well.

8.3.1 Reservoir Thickness and Permeability

If we consider a formation with low permeability and low thickness then the horizontal wells are of great help. Now let us consider a case of a formation which is anisotropic in nature with varying permeability and where the payzone is thick. In these formations we find that if we fracture the formation along the lines of maximum permeability then the fluid flow to the borehole can be increased immensely.

It's a costly affair but gives immense dividends if we are sure about the nature of the permeability in the formation cause then we can very surely fracture the formation and increase production.

8.3.2 Impact of Wellbore Placement in Fracturing:

The orientation of hydraulic fracturing primarily depends on the insitu stresses and its directions. For applying hydraulic fracturing in vertical wells, a 2-D stress model i.e. vertical and minimum horizontal stress is normally adequate. Moment the well bore turns to horizontal direction, the problems for fracturing becomes more complex. Therefore, the placement of wellbore becomes more critical, if the well needs hydraulic fracturing.

If the need of hydraulic fracturing is not considered in the initial planning of horizontal well, then the decision on horizontal direction usually depends on other factors such as:

1. Trying to intersect natural fractures.
2. Drilling to follow the dip of formation.
3. Drilling to maximize directional control.
4. Directionally to best drain reservoir reserves or connect reservoir components.

The direction of induced fracture is always unique with respect to the insitu direction, but differs with respect to direction of wellbore.

In a simplistic way, if fracturing is expected to be accomplished during initial completion of the well or at a later date of its production life, then the horizontal section should be drilled either parallel to the maximum or minimum horizontal stress direction.

In the first case, where the wellbore is perpendicular to the minimum stress direction, the induced fracture will be longitudinal fracture i.e. along the axis of the wellbore. In the second case, where the wellbore is parallel to the minimum stress direction, the induced fracture will be transverse fracture, i.e. perpendicular to the axis of the wellbore. If the lateral is somewhere in between the maximum and minimum horizontal stress direction, the formation of hydraulic fracture may experience serious problem in successful implementation.

8.3.2.1 Longitudinal Fracture:

If the formation is weak and it is known that there is major difference in magnitude of two principal horizontal stresses, then drilling the well parallel to the maximum horizontal stress is favorable to ensure borehole stability. In this condition, if the well is fractured, longitudinal fracture will be generated where the wellbore will be in the plane of the fracture.

Merits and demerits:

- More sure connection between fracture and wellbore.
- If multiple fractures are desired, it requires large spacing between perforated intervals.
- Production interference between fractures not a major concern.

8.3.2.2 Transverse Fracture:

If the formation is not so weak and there is no major difference of magnitude of two principal horizontal stresses, and hydraulic fracturing is envisaged after initial completion or at a later stage of the life of the well then drilling the well parallel to minimum horizontal stress is favorable. In this case, the induced fracture will be transverse fracture.

Merits and demerits:

- More number of fractures can be placed in a single wellbore.
- Better drainage area.
- Several completion options commercially available.
- Better management of production.
- Require short perforation intervals.
- Requires sufficient separation between fractures to avoid interference between fractures and during fluid flow.

8.4 Completions and Fracturing Options in Horizontal Wells

When planning and designing a new well there is a chance of selecting both the completions and fracture stimulation that are optimum to the field. When dealing with existing well the task of selecting the desired treatment may be a huge challenge. The selection of fracturing treatment is highly dependent on the lower completion or formation completion that can be comprises of cemented liner, non-cemented liner with annulus barrier tool, slotted or perforated liner without annulus barrier tool or simple barefoot.

8.4.1 Wells Completed With Cemented Liners

In this completion the well is cased, cemented and then perforated. Cased and cemented wells provide maximum freedom to define and control stimulation viz. Where the fracture will be placed and how large each fracture should be.

8.4.1.1 Bullheading Technique

A bullhead technique is a simple technique that can be applied down production tubing or operational string. It is difficult to predict where and how many fractures will be generated. For example long horizontal section bullheading can be assisted by diversion techniques such as sand plug, rock salt and fibers.

The major disadvantages of this technique are:

1) Only a few fractures propagate especially in the least resistance area.

2) No control over fracture propagation.

3) Required high fluid volume and high injection rate.

4) Diversion methods can bridge the annulus and cause premature screen-out.

8.4.1.2 Limited Entry fracturing:

The principle of the limited entry fracturing technique is the number and diameter of the perforations is to be strictly limited. The operation should be carried out with pumping rate as high as possible, so that the fracturing fluids are forced to be diverted to other perforation intervals. In this technique, all the layers with close fracturing pressure are fractured successively and, therefore, several intervals can be treated simultaneously.

However, this technique has many drawbacks that exacerbate the wellbore like:

1) High fluid friction along the horizontal section.

2) High perforation erosion.

3) Large variation of stress and near wellbore effects along the lateral.

4) The BHP is greatly increases due to friction caused by fracturing fluids.

8.4.1.3 Stage Multiple Fracturing

In this technique the wellbore is cased, cemented and perforated followed by fracturing and then isolated by the use of composite bridge plug set on coiled tubing (CT). The bridge plug provides the mechanical diversion in the liner to effectively fracture each selective section. Usually the first fracturing treatment is carried out in the toe of the lateral and the following treatments are placed sequentially towards the heel of the well.

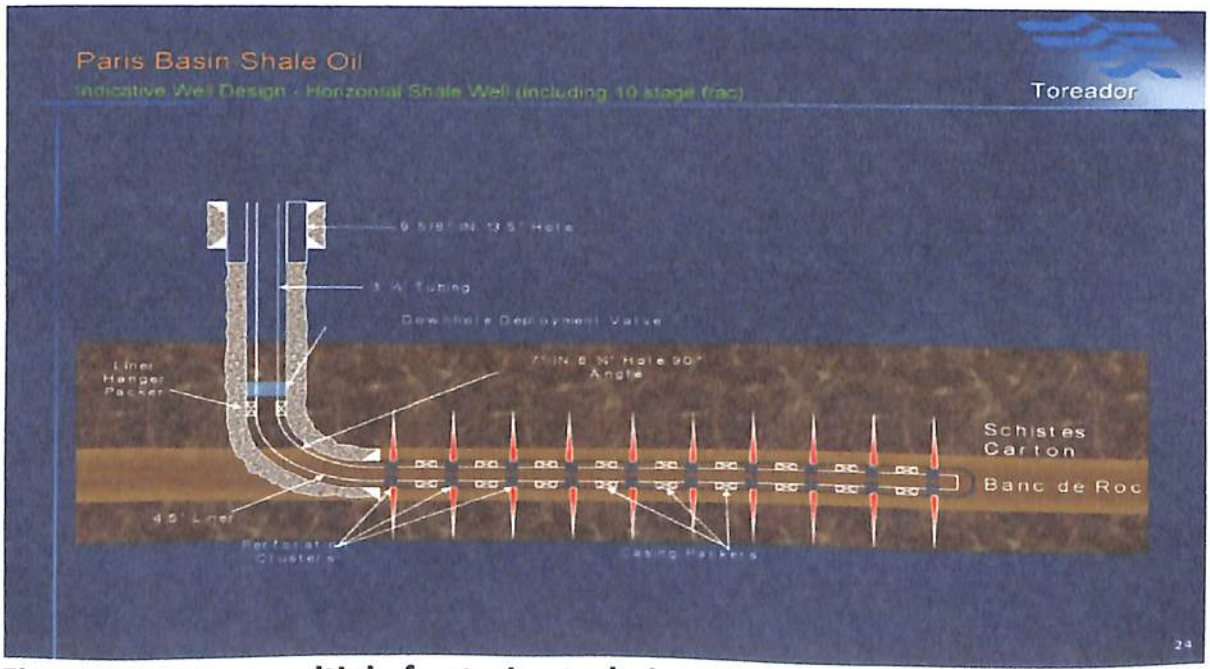


Figure 8.2: Stage multiple fracturing technique

The processes are then repeated for the number of stages desired for the wellbore. After completing the treatment in all the stages, CT is used to drill all the drill out the composite bridge plugs and establish access along the horizontal. The major advantages and disadvantages of the technique are:

1) Effective technique for creating multiple fractures in desired location.
2) Required multiple interventions with CT, perforation gun and deployment of fracturing fleet.
3) Very high cost and time consuming.
4) Association of mechanical risk.

8.4.2 Wells Completed Barefoot Or With Non-Cemented Slotted/Perforated Liner:

Open holes are still the popular completion option for horizontal wells because of the cost considerations. However, for better support from hole collapse in moderate to weak formations, perforated/ slotted liner completions is the better option. Besides the low cost, the open- hole or un-cemented liner completions offers benefits of potentially better production capability trough the large exposed area and connectivity with natural fractures and features.

Bullheading technique is predominately employed in both the completions. However, bullheading technique is having its own limitations in effective fracturing in desired locations of a horizontal wellbore.

There are some techniques developed by the service provider companies and available in the industry for effective placement of multiple fractures in horizontal wells without cemented liner completions. The techniques allow effective stage fracturing at the desired location of a horizontal wellbore as well as provide production management in the hole.

8.4.3 Hydraulic Fracturing In Open Hole Horizontal Wells:

8.4.3.1 Hydrajet Fracturing

The system enables the placement of multiple fracture of varying size in the desired locations of a horizontal wellbore. The major advantage of this technique is, it does not require any mechanical isolation or sealing for fracturing a particular location in a horizontal lateral. For this technique a special jetting tool with co-planner adjusted jets is lowered on conventional tubing or CT to the desired location of the wellbore. The jetting plan must approximately coincide with the reservoir's preferred fracture extension plan. The method uses dynamic fluid energy to jet a tunnel into the reservoir rock, the initiates fracture from these tunnels.

8.4.3.1.1 Mechanism of Hydrajet Fracturing

The fracturing fluid is forced from a jetting tool through a small orifice into the annulus. Pressure in the jetting tool must be higher than the annulus pressure. The fluid's high pressure energy within the tubing transform into kinetic energy, resulting in higher velocity fluids as demonstrated by the Bernoulli equation:

$$\frac{v^2}{2} + \frac{P}{l} + gz = C$$

In high pressure and high velocity application, ignoring gravitational effects yield:

$$\frac{v^2}{2} + \frac{P}{l} = C$$

In hydrajet system, the velocity inside the jetting tool is generally low. However, the pressure is usually 2000-3000 psi more than the annulus pressure, causing jet velocity to exceed 400 ft/sec.

Initially, jetting process creates a tunnel (cavity) with a larger inside diameter than the jet nozzle, as shown in the figure.

During continuous injection through the jet, if the annulus pressure is much lower than the jet pressure, the fluid returns back to the annulus. If the annulus pressure is maintained just below the fracture extension pressure (FEP), the combination of high wellbore pressure and the jet stagnation pressure forces the fracture to begin at the jet.

The treatment can be carried out either in open-hole or in cased hole completions.

8.4.3.1.2 Fracturing Operation with Hydrajet System:

To begin the treatment, the hydrajet tool is lowered with tubing or coiled tubing to the desired location. The annulus of the well is pressurized to a point just below the fracture extension pressure (FEP).Next tubing pressure is increased until jet differential pressure reaches to 4000-5000psig. From this point fracturing process continues in a conventional manner with pad, slurry and flush fluids. After initiation of the fracture, the fluid will be drawn from the annulus into the fracture and annulus pressure will drop rapidly, stopping fracture growth. As a result only a small fracture will be developed. Therefore,

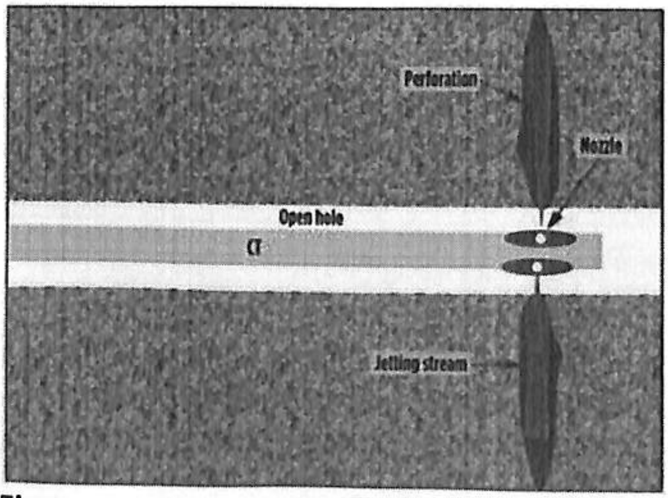


Figure 8.3: Hydrajetting Technique

the critical issue is that the bottom hole pressure must be maintained throughout the job. If annulus is maintained by pumping into the fracture, then the fracture can be extended substantially.

In any fracturing job, pressure, injection rate and fluid volume must be computed accurately. However, the procedure for computing hydrajet fracturing differs because of the equipment involved. A pre-job injection test helps in predicting the annular flow rate required to pressurize the well during job.

For multistage fracturing, the position of the jet is to be shifted to the new desired location and the same process is to be repeated.

8.4.3.2 StageFrac Technology

Stagefrac technology is applied for multistage fracturing of an un-cemented horizontal well in one pumping stage. The technique is applicable in sandstone carbonate, shale and coal formations. The technique addresses the problem of fracturing as well as completion of open-hole horizontal wellbore by the use of open-hole packers. The technique provides the mechanical diversion and allows multiple fracturing or other stimulation treatments along the entire horizontal lateral.

In this technique open-hole packers are run on conventional casing to segment the reservoir with ball activated sleeves (Frac ports) paced in between each set of open-hole packers. The sleeves are placed in the location desired to be fractured. The mechanical diversion system allows precise fluid placement, complete zonal coverage and better effective fracture conductivity. Stage fracturing is carried out sequentially from toe to the heel of the horizontal section.

8.5 Conclusion

To conclude we find fracturing is based on the simple concept of Darcy's law. The fracture can be developed by simple reversing the process of draw down. In drawdown we maintain a pressure difference to flow formation fluid into the wellbore on the other hand, the fracturing process needs us to flow the fluid at a high rate into the formation and thus develop a pressure differential. This pressure differential when exceeds the fracturing stresses of the formation, tear the formation apart.

The use of proppants and the additives added along with them have a very simple application, to create a high permeability conduit connecting the reservoir to the well. This is to optimize production. The process has its application in varying fields from minifracs to bypass the skin of the well, to small fracturing jobs to massive hydraulic fracturing.

We have seen that a major problem encountered during fracturing is not of fracturing but of fracture containment. Because, if in the case of low permeability thin reservoirs we are not able to contain the fracture's vertical extent, and in cases of braided beds and other slanting bed reservoirs its horizontal extent then in such cases the puncturing of water bearing sands along with the availability of a proppant laden flow path can in many ways defeat the entire purpose of the fracturing job, besides the wastage of fracturing fluid.

Horizontal well technology has developed radically over the last few years and become favourable choice of exploitation method of most of the oil and gas operators. Current drilling technologies have pioneered these advancements to the extent of thousands of feet through a thinly bedded hydrocarbon bearing reservoir. The motivations of drilling horizontal wells over the vertical or deviated wells are higher productions rates with maximum reservoir contact and better access to reserves.

The production scenario of a horizontal well is quite different from that of a vertical well. The productivity of a horizontal well is govern by 1) rock permeability 2) reservoir pressure 3) length of well bore within the production zone, 4) gravity effect, 5) reservoir compartmentalization effect etc. However, the possible reasons for low production rates in these wells are vertical heterogeneity, low horizontal permeability and even much lower vertical permeability. The heterogeneity in sandstone can act as barrier to vertical flow. Near wellbore damage is another possible reason for low production .The damage removal treatments have little impact especially in long horizontal wells drilled in low permeability reservoirs.

In recent years number of horizontal wells drilled in moderate to low permeability reservoirs have proven only marginally economic, many were not economic when in layered reservoirs. The assumption that horizontal wells in higher permeability reservoirs are not the candidate for stimulation is also being challenged by a large number of marginal to non economic wells. For many of these wells rapid production decline is experienced and cause them to become stimulation candidates.

So, the latest developments in the field of fracturing are the developments made in the field of fracture stimulation. Now computers and software like M-Frac have given us eyes to fracture specifically at the desired place with the desired shape and angle.

The use of horizontal wells is also a prevalent method in oil industry but is costly and more difficult than the fracturing technology. The combined use of the two has although worked wonders in the recent past and is the latest in the field. Fracturing along with acidizing also helps for carbonate reservoirs.

In the end we can just observe that fracturing is a technology which is here to stay and definitely stay till the time we find something more efficient, with such a high success rate and definitely more economical than Hydraulic Fracturing and its related methods.

CHAPTER 9

HEALTH, SAFETY & ENVIRONMENT

9.1 Safety Considerations

At no time should the safety of a treatment be compromised, safety guidelines have been developed from experience derived from previous incidents. Many of these incidents have had great potential to seriously injure personnel or destroy valuable equipment. The inherent risk of dealing with high pressures can be greatly minimized by following simple safety procedures. Hydraulic fracturing treatment can never be considered a success if an accident results in the destruction of equipment or injury to personnel.

9.1.1 Personnel Safety Equipment

Each person on location should wear appropriate safety equipment to minimize the risk of injury. Hard hats, hard toed shoes and safety glasses should be the minimum level of safety equipment worn on location. Other equipment such as hearing protection, goggles, fire retardant fabrics and filter masks should be worn if exposure to the conditions they protect against is a possibility. Wearing safety equipment is a simple step that creates a positive safety atmosphere on location.

9.1.2 Safety Meeting

Holding a pretreatment safety meeting ensures that all personnel on location are aware of specific dangers and required procedures relative to the treatment. Each person on location should clearly understand his or her role during the treatment as well as individual responsibility during emergency situations. A head count must be taken to account for everyone on location. An escape route and meeting place should be agreed upon where all personnel will gather in case of an emergency situation. Personnel who are not directly involved in the treatment should have limited location access during the actual pumping operations. Everyone should be aware of unique danger of each treatment. Some locations may be in area with hydrogen sulphide or possibly the fluids being pumped are highly flammable. As many of the potential safety problems or concerns as possible should be brought to the attention of everyone. Maximum pressure limits should be set at this time, and every high pressure pump operator must be aware of these limits. The high pressure treating line, up to the wellhead valve, should be tested to slightly above the anticipated fracturing pressure. A properly tested line includes the test of each pump in addition to the main treating line. The pressure rating of the wellhead should be checked to make sure it exceeds the treating pressure. If the wellhead has a lower pressure rating than the anticipated treating pressure, a wellhead isolocation tool will be necessary to isolate the wellhead from this pressure level. The pretreatment safety meeting is the principle means of communication for giving final instructions to all personnel. A well organized safety meeting helps ensure that the treatment is an operational success without being a threat to human safety.

9.1.3 Well Control at the Wellhead

To ensure that well control is always maintained, the valve arrangement at the wellhead should consist of at least two valves. A frac or master valves should be installed above the main wellhead valve. If one valve fails to hold the pressure, the other valve can quickly be closed to control the well. It is preferable to have the main wellhead valve flanged to the casing head, rather than using a threaded connection. If a threaded connection is necessary, the condition of the thread must be thoroughly inspected for thread wear and proper taper.

9.1.4 Precautions for Flammable Fluids

Oil-based fluids should be tested for volatility before they are accepted as a fracturing fluid. An oil is generally considered safe to pump if it has a Reid vapour pressure less than 1, API gravity less than 50° an open-cup flash point of 10 °F [-12 °C]. However, even if the fluid is considered safe to pump, several additional safety rules should be followed when pumping oil. Storage tanks for flammable fluids should be dike and spotted at least 150 ft from the wellhead. Spotting the fluid in this manner helps minimize exposing the wellhead to fire if problems occur during pumping. Also, all low pressure hoses should be enclosed in a hose cover to prevent oil from spraying on hot engine components of the trucks, should a hose leak. Firefighting equipment should be on location and ready to be operated.

9.1.5 Precautions for Energized Fluids

N_2 and CO_2 are the gases most commonly used in foamed and energized fluids. During flow back following a treatment, they provide an efficient source of concentrated energy to aid rapid post treatment cleanup. There are potential associated with the use of N_2 and CO_2. As the fluid exits the flowline during flowback, the gaseous phase expands rapidly. This rapid release of energy must be controlled to avoid a loss of flowback efficiency and ensure personnel safety. Service companies have recommended procedures for the flow back of energized fluids. Another potential hazard that is often overlooked is asphyxiation. N_2 and CO_2 can collect in low areas displacing breathable air. Personnel should avoid these areas and remain upwind at all times. Only one person should be in the vicinity of the well during flowback operations. The use of remotely operated valves will improve margin of safety.

9.2 Environmental Considerations

Fracturing operations should be conducted using sound environmental practices to minimize the potential for contamination of air, water and soil. All operations should comply with all applicable environmental laws and regulations. Hazardous material spills should be cleaned up quickly in accordance with a spill plan. All waste and unused material should be cleaned, handled and disposed of in an environment friendly manner.

CHAPTER 10

CONCLUSION

Oil well stimulation plays a vital role in production operations. Due to high oil prices, it is imperative from an oil company's perspective and consumer's perspective that as much production as possible be safely extracted from the reservoir. So, the oil company can realize the highest price per barrel, and the reservoir consumer can get more oil circulating in supply to balance demand. Natural production tendencies for wells are for the oil production rates to be at its highest at initial production, and fall of considerably as the well is produced. Typically one finds oil rates declining as water production increases, driving up operations cost while revenue shrinks. This scenario continues until the well fails or becomes uneconomical to operate or repair.

The purpose of oil well stimulation is to increase the well's productivity by restoring oil production to original rates less normal decline, or to boost production above normal predictions.

The classic solution to maximizing a well's productivity is to stimulate it. However, as discussed earlier, the basis for selecting stimulating candidates should be a review of the well's actual and theoretical IPR. Low permeability wells often need fracturing on initial completion. In low permeability zone, additional post stimulation production can be significant to the economics, however, the production engineer needs to make the management aware of the true long term potential or else overly optimistic projection can easily be made.

A well stimulation by hydraulic fracturing encompasses a wide variety of alternative treatment designs; therefore it is important for the engineer to select the treatment carefully. Sophisticated formulations and techniques are easily needed only for difficult problems and the simplest, cheaper treatment that does not introduce problems is usually the best.

Special additives other than a corrosion inhibitor need real justification (e.g., an iron sequestering agent is needed only if the formation contains iron or the tubing is badly corroded). Any additives should be tested for compatibility with the reservoir fluids.

Strictly speaking, hydraulic fracturing affects only the rate at which hydrocarbons are withdrawn from the reservoir at a certain pressure drawdown. It does not increase the total amount of hydrocarbons that can be produced from the reservoir, provided time and economics are not relevant factors. But in the real world time and economics are important. Once economics enters the picture it is readily apparent that a large number of currently producing oil and gas wells could not have been produced at all without being fractured, because of their uneconomical rates of natural productivity. In this sense we can also consider fracturing as a means of increasing industrial reserves. It is estimated that over 25% of the total hydrocarbon reserves in the United States would not have been recovered without the advent of hydraulic fracturing. Similarly beneficial results from fracturing treatments have been realized in many fields outside United States.

CHAPTER 11

DESIGNING OF HYDRAULIC FRACTURING PROCESS

11.1 Well Data

Formation: Sandstone

Reservoir Pressure: 2200 psi

Fracture Gradient: 0.65 psi/ft

Pay Zone Thickness: 5 m

Depth of pay Zone: 1768 m

Young's Modulus (E): $5 * 10^6$ psi = $5 * 10^6 * 6.894 * 10^3 = 34.47 * 10^9$ Pa

Poisson's Ratio (v): 0.15

Critical Stress Intensity Factor or Fracturability (Kc): $0.55 * 10^3$ kPa/$m^{1/2}$

Wellbore Radius (r_w): 0.14 m

Reservoir Permeability: 1 md = 10^{-15} m^2

Total Fluid Leak off Coefficient (C): $4.9 * 10^{-4}$ m/$s^{1/2}$

Compressibility of Reservoir Rock: 0.0002 psi^{-1}

Porosity of Reservoir Rock: 0.2

Reservoir Fluid Viscosity: 2 cp

Well Spacing: 20 acres

Drainage Radius of Well (r_e): 154.8 m

Modulus of Rigidity (G): $\frac{E}{2(1+v)} = 15 * 10^9$ Pa

Relative Conductivity = 10^4

11.2 Designing

The height of the fracture is 5 m

The viscosity of fracturing fluid is = 100 cp

The productivity of the fractured well is expected to increase by 5 times its initial productivity.

Sand having a mesh size range (U.S. Series) 20-40 is used as proppant with dia = 0.63 mm

Pressure loss in the fracturing fluid due to friction is assumed = $6.55 * 10^6$ Pa

11.3 Calculations

11.3.1 Fracturing Fluid Pressure

Bottomhole Instantaneous Shut in Pressure (P_{BISIP}) = Fracture Gradient * Depth

$= 0.65$ psi/ft * 1768 psi

$= 0.65 * 3.28084 * 1768$

$= 3770.34$ psi * $6.894 * 10^3$

$= 26 * 10^6$ Pa

$Kc = 1.25 * \Delta P * h^{0.5}$

$0.55 * 10^6 = 1.25 * \Delta P * 5^{0.5}$

$\Delta P = 0.1967 * 10^6$ Pa

Pressure of Fracturing Fluid (P_f) = $P_{BISIP} + \Delta P$

$P_f = (26 + 0.1967) * 10^6$

Pressure of Fracturing Fluid (P_f) = $26.2 * 10^6$ Pa

11.3.2 Fracture Conductivity and Length

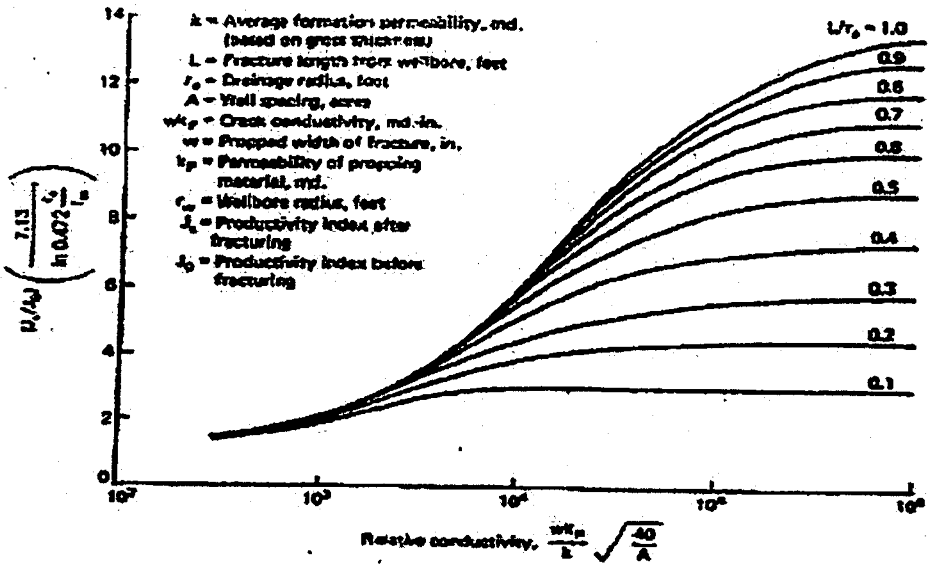


Figure 11.2 Graph showing increase in productivity from fracturing [4]. (With permission from the Society of Petroleum Engineers.)

Graph showing increase in productivity from fracturing.

Figure 11.1: Increase in productivity from fracturing

J_s = Productivity of Fractured Well

J_o = Initial Productivity of Well

A = Well Spacing in acres

r_e = Drainage Radius of the Well

$J_s / J_o = 5$

$$\frac{J_s}{J_o}\left(\frac{7.13}{\ln\left(0.472\left(\frac{r_e}{r_w}\right)\right)}\right) = 5.7$$

Relative Conductivity $\frac{W_f k_f}{k}\sqrt{\frac{40}{A}} = 10^4$

From the above graph

$L/r_e = 0.6$

$L = 0.6 * 154.8 = 93$ m

Length of Fracture = 93 m

Fracture Conductivity = $W_f k_f$

$\frac{W_f k_f}{k}\sqrt{\frac{40}{A}} = 10^4$

$W_f k_f = (10^4 * 1)/ 2^{0.5} = 7071.06$ md.in

The fracture conductivity is 7071.06 md.in

11.3.3 Fracture Permeability and Final Average Fracture Width

Sands having mesh size range (US Series) 20-40 is used as proppant

Dia $d_p = 0.63$ mm

Fracture Permeability,

$$k_f = \frac{d_p^2 \phi_f^3}{150(1-\phi_f)^2}$$

Φ_f is taken between 0.32 to 0.38

Φ_f = Porosity of fracture

$k_f = [(0.63 * 10^3)^2 (0.35)^3] / 150(0.65)^2$

$k_f = 2.697 * 10^{-10}$ m^2 = 269.7 darcy

Fracture Permeability = 269.7 darcy

$W_f k_f = 7071.06$ md.in

$W_f = 0.707 * 10^4 / 269.7 * 10^3$

$W_f = 0.02621$ in = 0.665 mm

Final Average Width of Fracture = 0.665 mm

11.3.4 Injection Rate of Fracturing Fluid

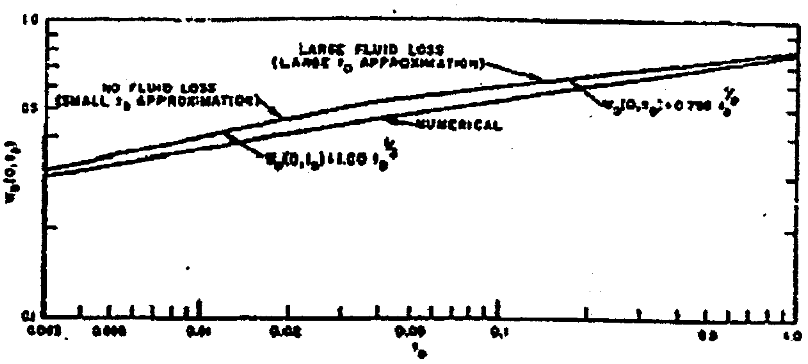


Figure 8.15 Dimensionless maximum fracture width at the wellbore as a function of dimensionless time [36]. [With permission of the Society of Petroleum Engineers.]

Dimensionless maximum fracture width at the wellbore as a function of dimensionless time

Figure 11.2

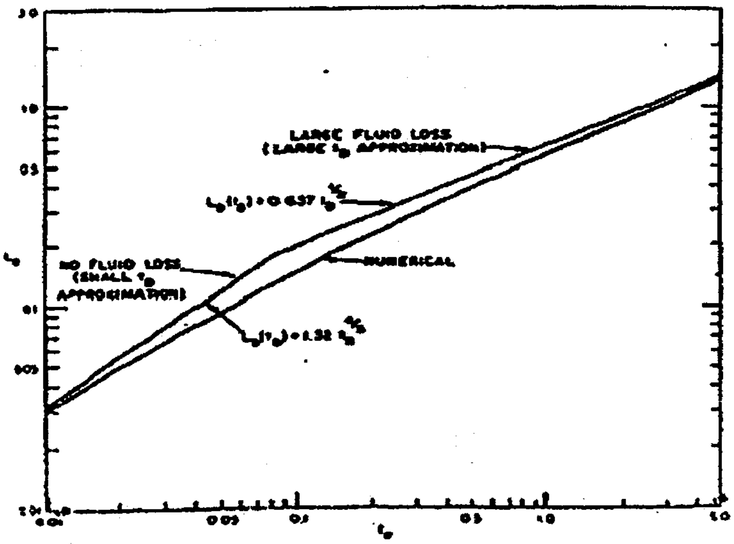


Figure 8.14 Dimensionless fracture length as a function of dimensionless time [36]. [With permission of the Society of Petroleum Engineers.]

Dimensionless fracture length as a function of dimensionless time

Figure 11.3

L_D = Dimensionless Length

T_D = Dimensionless Time

W_D = Dimensionless Width

From the graph:

$W_D(0,t_D) = 0.798\ t_D^{1/8}$ (1)

$LD\ (0,t_D) = 0.637\ t_D^{1/2}$ (2)

Also

$$L_D = \frac{16}{\pi}[\frac{2C^8Gh^4}{(1-v)\mu i^5}]^{1/3}L$$

$$W_D = \frac{4}{\pi}\left[\frac{C^2Gh}{(1-v)\mu i^2}\right]^{\frac{1}{3}} W_{avg}$$

W_{avg}= Dynamic average width. This is taken 6 times the diameter of proppant

W_{avg}= 6 * 0.63 = 3.78 mm

From equation (2)

$t_D = (W_D/0.798)^8$

Put the value of t_D in equation (1)

$L_D = 0.637\ (W_D/0.798)^4$

$L_D = 1.5708\ W_D^4$

$$\frac{16}{\pi}[\frac{2C^8Gh^4}{(1-v)\mu i^5}]^{1/3}L = 1.5708\left(\frac{4W_{avg}}{\pi}\right)^4 \left[\frac{C^2Gh}{(1-v)\mu i^2}\right]^{\frac{4}{3}}$$

On solving for i we get

$i = GW_{avg}^4/8.38\mu L$

$G = 15 * 10^9$ Pa $\quad W_{avg} = 3.78 * 10^{-3}$ m

$\mu = 0.1$ kg/m.s $\quad L = 93$ m

On solving we get

$i = 0.039\ m^3/s$

The injection rate of fracturing fluid = 0.039 m^3/s

11.3.5 Injection Time

$$L(t) = \frac{1}{2\pi}(\frac{i}{Ch})t^{\frac{1}{2}}$$

L = 93 m

$i = 0.039\ m^3/s$

h = 5 m

$C = 4.9 * 10^{-4}\ m/s^{1/2}$

$$93 = \frac{1}{6.28}[\frac{0.039}{4.9 * 10^{-4} * 5}]t^{1/2}$$

$t^{1/2} = 36.7$

t = 1347 sec

= 22 min 45 sec

The injection time is 22 min 45 sec

11.3.6 Volume of Fracturing Fluid

= Injection Rate * Time of Injection

= i * L(t)

= 0.039 * 1347

Volume of fracturing fluid = 52.533 m3

11.3.7 Fracture Closure Time

$$W_{avg}(t_f) - W_f = 2\pi C[(t_f + \Delta t)^{\frac{1}{2}} - t_f^{\frac{1}{2}}]$$

W_{avg} = Dynamic Average Fracture Width = 3.78 mm

W_f = Final Average Width of Fracture = 0.665 mm

t_f = Injection time = 1347 sec

Δt = Closure Time

$3.78 * 10^{-3} - 0.665 * 10^{-3} = 6.28 * 4.9 * 10^{-4} [(1347 + \Delta t)^{1/2} - (1347)^{1/2}]$

$3.115 * 10^{-3} = 30.77 * 10^{-4} [(1347 + \Delta t)^{1/2} - 36.70]$

$1.0123 + 36.70 = (1347 + \Delta t)^{1/2}$

Δt = 75.29 sec = 1 min 25 sec

The fracture closure time is 1 min 25 sec.

11.3.8 Surface Pressure and Power Needed

Density of fracturing fluid = 1020 kg/m3

Surface Pressure = Frac fluid Pressure at Bottom – Change in pressure due to Fluid Column

Change in pressure due to fluid column = $\rho g D$

D = 1768 m g = 9.8 m/s^2

Change in Pressure = 1020 * 9.8 * 1768

= $17.67 * 10^6$ Pa

Friction Losses in the Pressure of Fracturing Fluid = $6.55 * 10^6$ Pa

Pressure at the Bottom = $26.2 * 10^6$ Pa

Surface Pressure = (26.2 + 6.55 - 17.67) * 10^6

= 15.08 * 10^6 Pa

Power Needed = Rate of Injection * Surface Pressure

= 0.039 * 15.08 * 10^6

= 588120 watts

1 watt = 746 HP

= 788.4 HP

The pressure at the surface is 15.08 * 10^6 Pa

The power needed is 788.4 HP

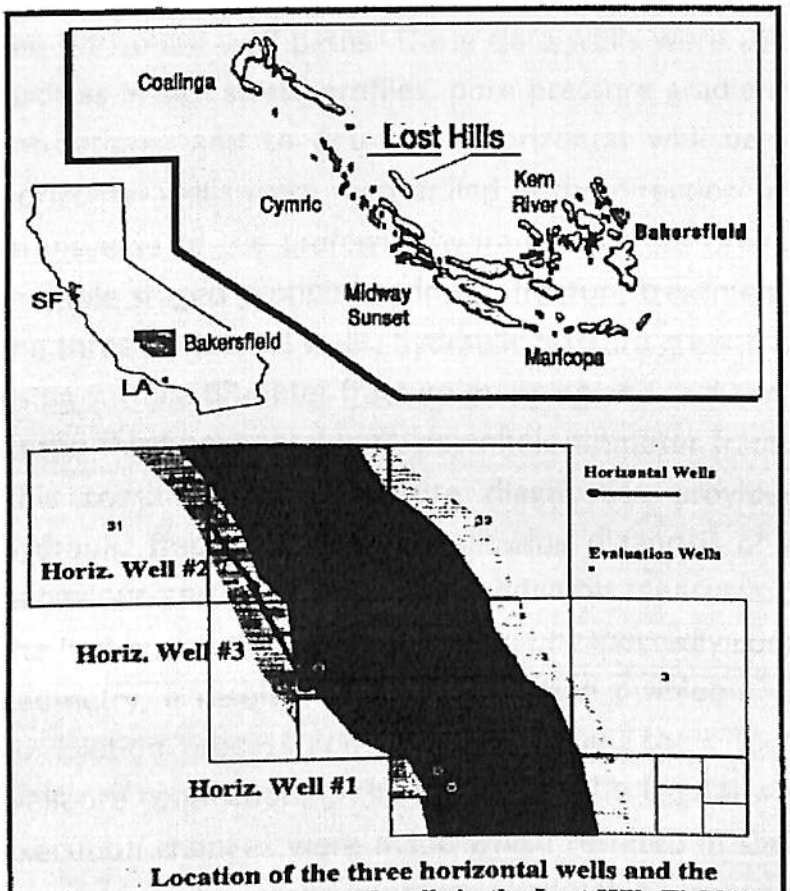
11.4 Results

The productivity of the well is increased by 5 times.
The height if the fracture = 5 m
Length of the fracture = 93 m
Final average width of the fracture = 0.665 mm
Conductivity of the fracture = 0.707 * 10^4 md.in
Permeability of the fracture = 269.7 darcy
Sand having mesh size range (U.S. Series) 20-40 is used as proppant.
Mass of proppant required = 1246.2 kg
The viscosity of the fracturing fluid = 100 cp
Density of the fracturing fluid = 1020 kg/m^3
The rate of injection of fracturing fluid = 0.039 m^3/sec
The time of injection of fracturing fluid = 22 min 45 sec
Pressure loss in the fracturing fluid due to friction = 6.55 * 10^6 Pa
The time required by fracture to set on proppant = 1 min 25 sec
Volume of fracturing fluid needed = 52.533 m^3
Bottomhole instantaneous shut in pressure = 26 * 10^6 Pa
Pressure of the fracturing fluid at the bottom of the well = 26.2 * 10^6 Pa
Pumping pressure of fracturing fluid = 15.08 * 10^6 Pa
Power needed to pump the fracturing fluid = 788.4 HP

CHAPTER 12
CASE STUDIES

Case Study 1

Completion and Stimulation of Horizontal Wells with MultipleTransverse Hydraulic Fractures in the Lost Hills Diatomite



Location of the three horizontal wells and the "horizontal analog" vertical wells in the Lost Hills Field in the San Joaquin Valley in California.

The Lost Hills Field Diatomite has traditionally been developed using vertical wells completed with multiple propped hydraulic fracture treatment stages. As the main portion of the field is nearing full development at 2 1/2-acres per producer, the search for additional reserves has moved out to the flanks of the field's anticlinal structure. Due to limited pay thickness, these flank portions of the field will not support economic vertical well development. The use of horizontal wells was determined to have the best chance to economically develop these areas of the field. To evaluate this development concept, three horizontal wells were drilled and completed over the time period from November 1996 to December 1997.

To assist with the horizontal well design and evaluation, several vertical data wells were drilled offset and parallel to the intended well path of each horizontal well. Additionally, two vertical core wells were drilled in line with the toe and heel of the horizontal well paths. These data wells were utilized to estimate properties such as in-situ stress profiles, pore pressure gradients, rock properties and fluid saturations, and to determine horizontal well vertical depth placement. The horizontal wells were then drilled in the direction of minimum horizontal stress (transverse to the preferred hydraulic fracture orientation) and completed with multiple staged propped hydraulic fracture treatments. During the completion of the three horizontal wells, hydraulic fracture growth behaviour was characterized using surface tiltmeter fracture mapping and real-time fracture pressure analysis. In the third horizontal well, downhole tiltmeter fracture mapping was also used. This combination of fracture diagnostics provided significant insights into hydraulic fracture behaviour, allowing diagnosis of anomalous fracture growth behaviour and evaluation of remediation measures. Fracture diagnostics during the first horizontal well revealed an unexpectedly complex near wellbore fracture geometry, a result of fracture initiation problems. These problems slowed the completion process and severely harmed the effectiveness of the fracture-to-wellbore connection. In the subsequent horizontal wells, a number of design and execution changes were made which resulted in simpler near-wellbore fracture geometry and a greatly improved production response.

Comparison of fracture treatment behavior in the three horizontal wells.

	Well #1	Well #2	Well #3
Number of stages	7	10	12
Horizontal section length (ft)	1350	2000	2400
Horizontal section TVD Depth (ft)	2250'	2000'	2000'
Overall fracture behavior summary	Near-wellbore & far-field fracture complexity, abnormally high net pressure, dominant upward growth	Normal net pressure, frac height growth centered at wellbore, good wellbore-fracture connection	Dominant upward growth into low stress interval, low net pressure, fractures offset from perf interval
Fracture initiation procedure	Water (KCl substitute), low flow rate, conventional perforating	Avoid perf in high natural frac intensity, 60# HEC viscous pill, high flow rate, overbalance perforating,	60# HEC viscous pill, extreme overbalance perforating, high flow rate
Fracture initiation perf plugging problems	stage 3, 4, 5, 6, 7	none	Stage 3
Premature bridging screen-out	stage 7	none	Stage 2
Average proppant per stage (lbs.)	250,000	300,000	260,000
Closure stress gradient (psi/ft)	0.51 - 0.71	0.55 - 0.61	0.53 – 0.64
Average near-wellbore fracture tortuosity during TMAC injections (psi)	470	540	440
End propped frac net pressure range (psi)	105 - 680	90 - 175	20-310
Average end propped frac net pressure (psi)	365	140	75
Average number of "equivalent" far-field fractures to explain prop frac observed net pressure	~6	~3	~3
Propped fracture half-length range (ft)	60 - 143	76 - 105	114 – 167
Average propped half-length (ft)	100	95	130
Propped fracture height range (ft)	118 – 277	165 – 226	165 — 410 *
Average propped height (ft)	190	200	205
Primary fracture azimuth	N43°E - N56°E	N39°E - N50°E	N38°E - N51°E
Fracture dip	Within 6° from vertical	Within 5° from vertical	Within 8° from vertical
Average horizontal fracture component (% of total frac volume)	8%	17 %	25%
Substantial longitudinal vertical fractures	stages 4 and 5	none	None
Main frac offset from perforation interval (displaced along wellbore)	stage 6 and 7	none	stage 1, 2, 3, 5, 7, 8, 10
Dominant upward fracture height growth	All stages	Stages 1, 8	All stages*
Initial production (BOPD)	~ 140	~ 440	~ 250
Production @ 6 months (BOPD)	10	100	not available

Well #1

The hydraulic fracture behaviour of Chevron's first horizontal well in the Lost Hills Field was dominated by problems resulting from insufficient wellbore cleanout between stages.

- Proppant left in the crossover from 5 1/2" to 7" production casing (located at the beginning of the horizontal section) caused problems with fracture initiation and breakdown.
- The initial breakdown injection tended to mobilize and transport the leftover proppant to the perfs. Before any significant fracture width was created, resulting in partial or total plugging of the near-wellbore fracture

region.

- The problem worsened with succeeding stages as the volume (casing length) between the crossover and the perforated interval decreased.
- The plugging and packing of the perforation region with proppant during breakdown resulted in highly abnormal fracture behaviour, as the preferred fracture initiation planes were screened out and formation stress in the perforation region was increased.

The well's production response from the seven frac stages placed was disappointing with an IP of 140 BOPD and a 6 month rate of 10 BOPD.

Well #2

Similar to well #1, this well also had a 7" x 5-1/2" casing crossover at the beginning of the horizontal section. However, the breakdown problems experienced during fracture stimulation in well #1 were mostly eliminated, due to the combination of different clean-out procedure between fracture stages, and a different fracture initiation procedure. As on well #1, a "point source" perforation strategy was employed, with 12 large holes spaced over 1 foot of interval.
However, fracture initiation procedures during well #2 were significantly changed, with the goals of minimizing near wellbore fracture tortuosity and reducing the wellbore initiation of multiple fractures. These revised fracture initiation procedures appeared to be effective in reducing near-wellbore fracture complexity and reducing the number of far-field multiple fractures required to explain observed levels of net pressure.

As a result of the good interval height coverage and the favourable wellbore-to fracture connection, initial production was better than expected at about 440 BOPD, with a 6 month production rate of about 100 BOPD.

Well #3

With the success of well #2, nearly all drilling and completion procedures were held constant for well #3, but there were several significant changes.

- Well #3 was completed with 5-1/2" casing from TD to surface. This change in casing diameter was implemented to reduce the high circulating rates required to clean out the composite bridge plugs.
- Second, well #3 could not be logged due to logging equipment problems, and thus the strategy of avoiding intervals of high natural fracture intensity, which was used on well #2, could not be used. It is likely that the hole problems resulted in significant areas of poor cement bond, but no cement bond logs were run because the cement pumping operation went well. Thus, cement bond quality could not be considered for selection of perforated intervals. Perforation intervals were thus evenly spaced along the horizontal section.
- All stages in well #3 were perforated using the extreme overbalance perforation (EOBP) technique, with a nitrogen cushion and downhole pressure gradient of 1.4 psi/ft. This decision was based on the success of EOBP on minimizing near wellbore friction (tortuosity) in stage 10 of well #2.

Downhole tiltmeter fracture mapping showed extreme upward fracture growth, with essentially no coverage of the lower part of the target interval.

The initial production of 250 BOPD from 12 hydraulic fracture stages was lower than desired, but not unexpected based upon the incomplete coverage of the lower portion of the target interval, and a strong connection into the depleted interval above.

Case Study 2

This case study is of a well drilled in the Bhuvanagiri field of the Cauvery Basin. The well is owned by ONGC. Bhuvanagiri is a small town in Tamil Nadu.

BVG # 02
OBJ – IV (3665 – 63, 3661 – 56 m)
Perforated @ 4spf

HF Job Details:

Date	18-10-1987
Pumping via	Tubing (3 ½"), 12.7 ppf
Acid spearhead	2.5 m3, 15% HCl
Prepad	Nil
Pad	156 bbl
Slurry	375 bbl
After flush	88 bbl
Proppant	10 MT
Avg. Conc.	250 kg/m3
Avg. Pumping rate	4 bbl / min
Breakdown pressure	8200 psi
Avg. Pressure	6040 – 7000 psi
ISIP	5630 psi
Frac gradient	0.8 psi / ft
Frac fluid	Cross-linked, Guar grade – III
Gel loading	1 %

Retest		FTHP	CHP	Production		
		Psi	Psi	Oil	Gas	Water
				m3/d	m3/d	%
I		60-100	Nil	Nil	3500	Nil
I		143-276	Nil	Nil	2678	Nil
II		97-192	Nil	Nil	3978	Nil
II		205-219	Nil	Nil	3122	Nil
Post – job production rates:						
		1371	Nil	30.5	47000	Tr-2
		2650	Nil	21.9	32400	Nil
		3244	Nil	16.53	25000	Nil
		1509	Nil	25	39000	Tr-3
Sq. 88		600-610	-	4.5		
AP. 89		500-550	-	4.5		
.Till 02-05-1989 cumulative oil produced 2326 MT..						

These are the results before and after the hydro frac job.

CHAPTER 13
SOFTWARES INVOLVED IN HYDRO FRAC

13.1 MFrac

Developer: Meyer & Associates, Inc. is the worldwide leader in hydraulic fracturing simulation software. MFrac, has been available since 1985.

MFrac is a comprehensive design and evaluation simulator containing a variety of options including three-dimensional fracture geometry and integrated acid fracturing solutions. Fully coupled proppant transport and heat transfer routines, together with a flexible user interface and object oriented development approach, permit use of the program for fracture design, as well as treatment analysis. MFrac is the calculation engine for real-time and replay fracture simulation. When operating in this manner, the program works in conjunction with our real-time data acquisition and display program, MView.

Capabilities

- Automatically design a pumping schedule to achieve a desired fracture length and conductivity
- Parametric studies, what-if scenarios
- Geometry and design optimization for proppant, acid and foam treatments
- Pressure History matching and model calibration in real-timė replay
- Perform analyses to anticipate fracture behavior (e.g., fracture growth, efficiency, pressure decline, etc.)
- Use MFrac in conjunction with MProd and MNpv to perform fracture optimization studies

13.2 Fracpro

It is a comprehensive software package that offers users more resources, more flexibility, more analytic capability and more effective ways to boost ROI than any other.
Fracpro contains four fully integrated modules for Frac Design, Frac Analysis, Economic Optimization and Reservoir Performance. It can model almost limitless combinations of well configuration, proppant placement, conductivity improvements and fracture dimensions, in any type of reservoir.

13.3 StimPlan

Developer: NSI Technologies

Key Features:

- Easy Data Handling and Analysis
- Rigorous Fracture Geometry Modeling
- Automated Treatment Schedule
- Post-Frac Production Analysis
- Economics and Fracture Optimization

CHAPTER 14
INNOVATIONS IN THE FIELD OF HYDRO FRAC

14.1 Total Frac Water Management

Developer: Ecosphere Technologies Inc.

Their mission is to identify and solve water recycling challenges in the oil & gas industry through the development of mobile water treatment technologies with proven economic and environmental benefit.

Manage & Extend The Life Cycle Of FracWater:

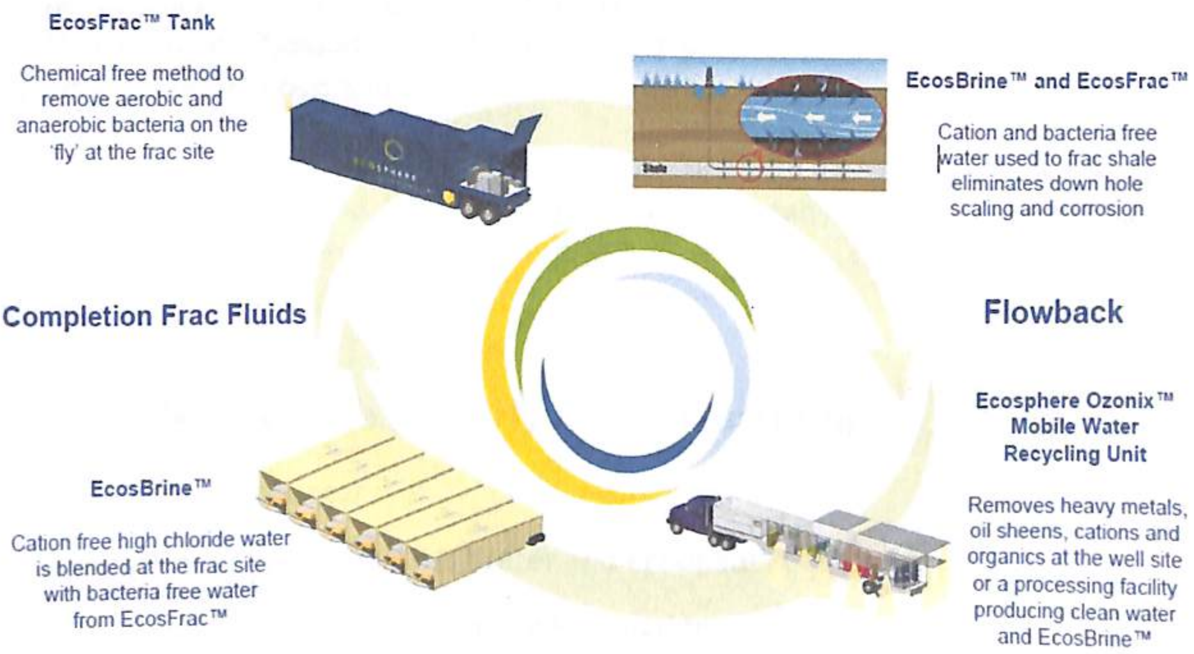


Figure 14.1: Total frac water management system

14.2 RapidFrac Completion System

Devloper: Halliburton

The new RapidFrac completion system allows operators to set new standards for fracture completion efficiency and post-fracture production.

This innovative horizontal sliding sleeve completion system is a differentiating technology that allows for enhanced reservoir contact. In a changing landscape where operators are drilling longer laterals that require increasingly complex completions, the RapidFrac system delivers several unique differences from the "plug and perforate" system and other similar techniques.

The RapidFrac system uses a metering process that enables a single ball to open multiple sleeves isolated within an interval by swellable packers. Each RapidFrac sleeve can be tailored to specific fracture requirements along a horizontal wellbore so as to enhance post-frac production. Up to 90 sleeves can be incorporated into any one horizontal completion, ensuring maximized stimulated reservoir volume. By facilitating continuous pumping, the RapidFrac system reduces stimulation cycle time from days to hours and reduces the volume of water consumed.

Although initial system deployments have occurred in the Bakken Shale with Brigham Exploration and Williams Production Company, this technology has application for shale developments on a global basis.

14.3 HiWAY Flow-Channel Hydraulic Fracturing

Developer: Schlumberger

Increases Production Using Less Water and Proppant

Reduce Footprint Without Sacrificing Production

HiWAY flow-channel hydraulic fracturing significantly increases fracture conductivity while reducing water and proppant consumption. This means higher short- and long-term production, simpler logistics, and a smaller operational footprint.

Create infinite fracture conductivity

HiWAY technology fundamentally changes the way proppant fractures generate conductivity. The first technique of its kind, HiWAY fracturing creates open pathways inside the fracture, enabling hydrocarbons to flow through the stablechannels rather than the proppant. This optimizes connectivity between the reservoir and the wellbore—resulting in infinite fracture conductivity.

Improves performance in vertical and horizontal wells

The HiWAY fracturing technique has improved time to sales, fluid recovery, initial production rate, and average-well estimated ultimate recovery (EUR) in more than 4,000 jobs worldwide including the Rocky Mountain region of the US and the Sierras Blancas formation in Argentina.

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