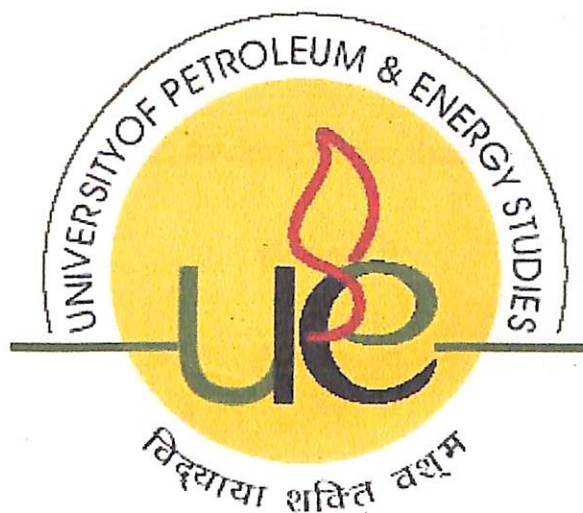


Analytical & Computational analysis of hydraulic fracture behaviour using a P3D simulator

By

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Dehradun
May, 2011*

**Analytical & Computational analysis of hydraulic fracture behaviour using a
P3D simulator**

**A thesis submitted in partial fulfilment of the requirements for the Degree of
Bachelor of Technology
(Applied Petroleum Engineering, Upstream)**

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CERTIFICATE

This is to certify that Aseem Pandey & Shubham Chauhan, students of B.Tech (Applied Petroleum Engineering) have written their thesis on "Analytical & Computational analysis of hydraulic fracture behaviour using a P3D simulator " under my supervision and have successfully completed their project within the stipulated time.

They have demonstrated high performance levels and dedication during the completion of their thesis.

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ABSTRACT

The hydraulic-fracturing technique of well stimulation is one of the major developments in petroleum engineering of the last decade. Hydraulic fracturing is the process of injecting the fluid into the well to create stresses in a formation exposed to fluid pressure, causing local stresses in the formation to exceed the tensile strength of the rock.

First, the formation “breaks down,” and a fracture is formed, then the injected fluid begins to move down the fracture. In most of the formations, a single, vertical fracture is created because the minimum stress is the horizontal stress. The created fracture propagates in two directions from the wellbore.

The “wings” of the fracture are 180° apart and are normally assumed to be identical in shape and size at any point but however, in actual cases, the fracture wing dimensions may not be identical. In naturally fractured formations, it is possible that multiple fractures can be created and propagated during a hydraulic fracture treatment.

There are various mathematical models to design a fracture job. The decision of selecting the right model for fracture modelling is a very critical job in order to create the suitable fracture into the formation. The objective of this study is to study the fracture behaviour using different types of fracture models and then selecting the right candidate which would give the best results in the stimulation job.

CONTENTS

INTRODUCTION.....	12
LITERATURE REVIEW.....	13
1. INTRODUCTION TO HYDRAULIC FRACTURING	13
1.1 HISTORY.....	13
1.2 THE PROCESS.....	14
2. BASICS OF HYDRAULIC FRACTURING.....	15
2.1 THE BASIC PROCESS.....	15
2.2 PRESSURE.....	16
2.2.1 SURFACE TREATING PRESSURE, <i>STP</i>	17
2.2.2 HYDROSTATIC PRESSURE.....	17
2.2.3 TUBING FRICTION PRESSURE.....	17
2.2.4 BOTTOM HOLE TREATING PRESSURE.....	17
2.2.5 PERFORATION FRICTION PRESSURE.....	18
2.2.6 NEAR WELLBORE FRICTION PRESSURE.....	18
2.2.7 CLOSURE PRESSURE.....	18
2.2.8 EXTENSION PRESSURE.....	18
2.2.9 NET PRESSURE.....	18
2.2.10 INSTANTANEOUS SHUT IN PRESSURE.....	18
2.3 BASIC FRACTURE CHARACTERISTICS.....	19
2.4 FLUID LEAKOFF.....	20
2.5 NEAR WELLBORE DAMAGE AND SKIN FACTOR.....	22
3. HYDRAULIC FRACTURE TREATMENT SELECTION GUIDELINES.....	24
4. FRACTURE STIMULATED WELL INFLOW PERFORMANCE.....	26
5. A BRIEF REVIEW OF ROCK MECHANICAL ISSUES RELATED TO HYDRAULIC FRACTURING.....	30
5.1 INSITU STRESS.....	34
5.2 EFFECTIVE STRESSES.....	34
6. CREATION OF A PROPPED HYDRAULIC FRACTURE.....	34

7. MODELLING THE SHAPE OF THE INDUCED FRACTURE.....	38
7.1 2D FRACTURE MODELS.....	38
7.1.1 2D FRACTURE MODELS.....	40
7.1.1.1 CONSTANT HEIGHT FRACTURE MODELS.....	40
7.1.1.1.1 THE KHRISTIANOVIC-GEERTSMA-DE KLERK (KGD) MODEL.....	41
7.1.1.1.2 THE PERKINS-KERN-NORDGREN (PKN) MODEL.....	43
7.1.1.2 CIRCULAR FRACTURES.....	46
8 FLUID SYSTEMS.....	50
8.1 WATER-BASED LINEAR SYSTEMS.....	50
8.2 WATER-BASED CROSSLINKED SYSTEMS.....	52
8.3 OIL-BASED SYSTEMS.....	55
8.4 EMULSIONS.....	55
8.5 VISCO-ELASTIC SURFACTANT FLUIDS.....	55
9 PROPPANTS.....	56
9.1 PROPPANT PACK PERMEABILITY AND FRACTURE CONDUCTIVITY.....	57
10. OVERVIEW OF EQUATIONS AND METHODS USED IN CASE STUDY.....	61
11. CASE STUDY ANALYSIS.....	63
12. RESULTS AND DISCUSSION.....	78
13. CONCLUSIONS.....	79
REFERENCES.....	80
APPENDIX.....	81

LIST OF FIGURES

<u>FIGURE NO.</u>	<u>FIGURE TITLE</u>	<u>PAGE NO.</u>
<u>1</u>	Typical hydraulic fracture treatment job plot	16
<u>2</u>	Diagram showing fracture half Length x_f , fracture height H, and fracture width W	19
<u>3</u>	Illustration of the reduction in permeability around the wellbore	23
<u>4</u>	The Producing System	25
<u>5</u>	Factors contributions to the dimensionless fracture conductivity	27
<u>6</u>	Cinco-Ley and Samaniego's 1981 correlation between effective wellbore radius and fracture conductivity	28
<u>7</u>	Fracture skin effect varies with fracture conductivity	29
<u>8</u>	Well productivity response to hydraulic fracturing	29
<u>9</u>	Insitu stresses in the subsurface	31
<u>10</u>	Measurement of Rock properties:Poissons's Ratio (ν)	32
<u>11</u>	Magnitude of Insitu stress	33
<u>12</u>	Effective stress acting on a propped fracture	34
<u>13</u>	Creation of a propped hydraulic fracture	35
<u>14(a)</u>	Hydraulic fracturing proppant concentration schedule during an hydraulic fracturing treatment	36
<u>14(b)</u>	Proppant profile development during a hydraulic fracture treatment	37
<u>15(a)</u>	Fracture shapes predicted by two dimensional hydraulic fracturing models(KGD)	39
<u>15(b)</u>	Fracture shapes predicted by two dimensional hydraulic fracturing models(PKN & Radial)	39
<u>16</u>	The vertical growth of hydraulic fracture is contained by the contrast in in-situ stresses	41
<u>17(a)</u>	The KGD constant height fracture model	42
<u>17(a)</u>	The PKN constant height fracture model	44

<u>18</u>	A circular fracture with dry zone	48
<u>19</u>	Hydration of polymer gels in water. 'A' shows a polymer molecule before hydration in water, whilst 'B' shows a polymer molecule after hydration in water.	51
<u>20</u>	A crosslinked polymer. 'A' shows the hydrated polymer prior to addition of the crosslinker. 'B' shows the crosslink chemical bonds between the polymer molecules.	52
<u>21</u>	pH ranges for crosslinkers	53
<u>22</u>	Temperature range for crosslinkers	54
<u>23</u>	Aluminium phosphate association polymer	55
<u>24</u>	The effect of uniform and natural grain size distribution on porosity	58
<u>25</u>	Diagram illustrating how larger grains have larger pore spaces and hence greater permeability.	58
<u>26</u>	Diagram illustrating the difference between a proppant with good sphericity and roundness (left), and a proppant with poor sphericity and roundness (right)	59
<u>27</u>	Three SEM micrographs showing the effects of frac fluid residue. The micrograph on the left shows undamaged proppant before the addition of the frac fluid. The centre micrograph shows the residue left by a poorly designed crosslinked system. The final micrograph shows the same proppant pack after an enzyme breaker has been used	60
<u>28</u>	Well depth Vs Fracture half length	67
<u>29</u>	Net pressure Vs Treatment time	68
<u>30</u>	Well depth Vs Stress, Width , half length	68
<u>31</u>	Well depth Vs Stress, Width , half length (proppant concentration)	68
<u>32</u>	Well depth Vs Fracture half length(3D view)	69
<u>33</u>	Net pressure Vs Treatment time	70
<u>34</u>	Proppant coverage plot	71
<u>35</u>	Well depth Vs Stress, Width , half length	71
<u>36</u>	Well depth Vs Stress, Width , half length (proppant concentration)	71
<u>37</u>	Well depth Vs Fracture half length(3D view)	72

<u>38</u>	Net pressure Vs Treatment time	73
<u>39</u>	Proppant coverage plot	74
<u>40</u>	Well depth Vs Stress, Width , half length	74
<u>41</u>	Well depth Vs Stress, Width , half length (proppant concentration)	74
<u>42</u>	Well depth Vs Fracture half length(3D view)	75
<u>43</u>	Net pressure Vs Treatment time	76
<u>44</u>	Proppant coverage plot	77
<u>45</u>	Well depth Vs Stress, Width , half length	77
<u>46</u>	Well depth Vs Stress, Width , half length (proppant concentration)	77
<u>47</u>	Well depth Vs Fracture half length(3D view)	78

LIST OF TABLES

<u>TABLE NO.</u>	<u>TABLE TITLE</u>	<u>PAGE NO.</u>
<u>1</u>	Minimum hydraulic fracturing candidate well selection screening criteria	26
<u>2</u>	Formation Properties	65
<u>3</u>	PropFRAC Placement Simulator Predictions	66
<u>4</u>	Fracture conductivity and ACL propped length Per Zone Data	67
<u>5</u>	PropFRAC Placement Simulator Predictions	69
<u>6</u>	Fracture conductivity and ACL propped length Per Zone Data	70
<u>7</u>	PropFRAC Placement Simulator Predictions	72
<u>8</u>	Fracture conductivity and ACL propped length Per Zone Data	73
<u>9</u>	PropFRAC Placement Simulator Predictions	75

<u>10</u>	Fracture conductivity and ACL propped length Per Zone Data	76
<u>11</u>	Comparison of the analytical results and the simulated results	79

INTRODUCTION

BACKGROUND:

The hydraulic fracturing technique was basically developed to increase the rate of flow/productivity of the hydrocarbons. In this highly conductive channels are made in the reservoir to increase the productivity.

Earlier the modelling of fractures was done by the 2D fracture models. The 2D fracture models utilise analytical equations and they require engineer to specify the fracture height. This was a significant limitation as it wasn't clear from the logs that the height will be contained or not. Also, the fracture height varies from well to the fracture tip. Therefore to solve the modelling difficulties fracture simulators were developed based on P3D assumptions.

AIM:

The aim of the project is to study the different fracture models used to depict the fracture behaviours and then analyse which model is the best suited model to the provided reservoir in the case study.

OBJECTIVE:

- (i) To compare the fracture properties for the various 2D models and the P3D model theoretically and compare the theoretical results with the results obtained using the simulator
- (ii) To select the best fracture models using the given fluid properties.

SCOPE:

The project has its application in the fracture treatment design at the time of modelling the fracture.

METHODOLOGY:

Using the provided case study we are going to design different fracture designs by using the different types of 2D and P3D model available. Then based on the post stimulation changes in the properties we will be deciding which type of model is best applicable to the reservoir in consideration.

LIMITATION: The main limitation of the project is that it doesn't include the post-fracturing analysis which shows the production increase from the various fracture design. The selection of appropriate model is only based on the physical properties that we obtain from different models.

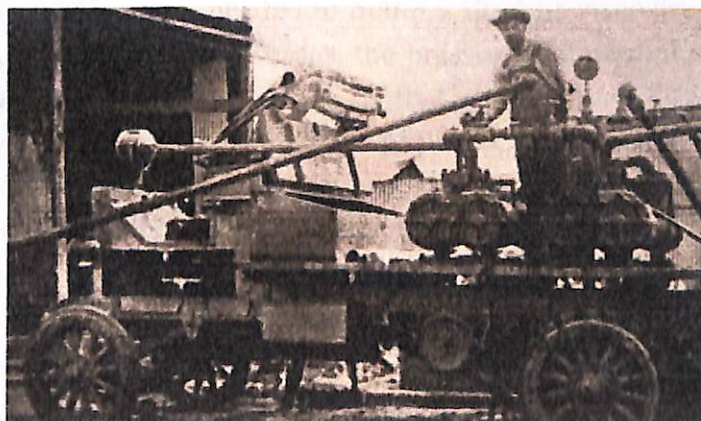
LITERATURE REVIEW

1. INTRODUCTION TO HYDRAULIC FRACTURING

1.1 HISTORY:

The first attempts at fracturing formations were not hydraulic in nature – they involved the use of high explosives to break the formation apart and provide “flow channels” from the reservoir to the wellbore. There are records indicating that this took place as early as 1890. Indeed, one of the predecessor companies of BJ Services, the Independent Torpedo Company (founded in 1905), used nitro-glycerine to explosively stimulate formations in Ohio. This type of reservoir stimulation reached its ultimate conclusion with the experimental use of nuclear devices to fracture relatively shallow, low permeability formations in the late 1950’s and early 1960’s.

In the late 1930’s, acidizing had become an accepted well development technique. Several practitioners observed that above a certain “breakdown” pressure, injectivity would increase dramatically. It is probable that many of these early acid treatments were in fact acid fractures. In 1940, Torrey recognized the pressure induced fracturing of formations for what it was. His observations were based on squeeze cementing operations. He presented data to show that the pressures generated during these operations could part the rocks along bedding planes or other lines of “sedimentary weakness”. Similar observations were made for water injection wells by Yuster and Calhoun in 1945.



The first intentional hydraulic fracturing process for stimulation was performed in the Hugoton gas field in western Kansas, in 1947. The Klepper No 1 well was completed with 4 gas producing limestone intervals, one of which had been previously treated with acid. Four separate treatments were pumped, one for each zone, with a primitive packer being employed for isolation. The fluid used for the treatment was war-surplus napalm, surely an extremely hazardous operation. However, 3000 gals of fluid were pumped into each formation. Although post treatment tests showed that the gas injectivity of some zones had been increased relative to others, the overall deliverability from the well was not increased. It was therefore concluded that fracturing would not replace acidizing for limestone formations.

However, by the mid-1960's, propped hydraulic fracturing had replaced acidizing as the preferred stimulation method in the Hugoton field. Early treatments were pumped at 1 to 2 bpm with sand concentrations of 1 to 2 PPA. Today, thousands of these treatments are pumped every year, ranging from small skin bypass frac at \$20,000, to massive fracturing treatments that end up costing well over \$1 million. Many fields only produce because of the hydraulic fracturing process. In spite of this, many industry practitioners remain ignorant of the processes involved and of what can be achieved.

1.2 THE PROCESS

Hydraulic fracturing occurs as a result of the phenomenon described by Darcy's law for radial flow:-

$$q = \frac{kh\Delta P}{\mu \ln(r_e/r_w)} \quad \dots\dots\dots (1)$$

Where q is the flow rate, k the formation permeability, h the net height, ΔP the pressure differential (or drawdown), μ the fluid viscosity, r_e the drainage radius and r_w the wellbore radius. This Equation describes the flow rate for a given reservoir-wellbore configuration, for an applied pressure differential. Re-arranging this Equation gives a different emphasis:

$$\Delta P = \frac{q\mu \ln(r_e/r_w)}{kh} \quad \dots\dots\dots (2)$$

This Equation describes the pressure differential produced by a given flow rate. Remembering that Darcy's Equation applies equally to injection and to production, Equation 2 tells us the pressure differential needed to pump a fluid of viscosity into a given formation at a given rate q . As the flow rate increases, the pressure differential also increases. Pressure and stress are essentially the same thing, so that as the fluid flow generates a pressure differential, it also creates a stress in the formation. As flow rate (or viscosity) increases, so does the stress. If we are able to keep increasing the rate, eventually a point will be reached where the stress becomes greater than maximum stress that can be sustained by the formation and the rock physically splits apart.

This is how we frac, by pumping a fluid into a formation at high rate and consequently high pressure. However, it is important to remember that it is pressure not rate that creates fractures (although we often use rate to create the pressure). Pressure and stress is stored energy, or more accurately stored energy per unit volume. Energy is what hydraulic fracturing is all about. In order to create and propagate a fracture to useful proportions, we have to transfer energy to the formation. Producing width and physically tearing the rock apart both require energy. Overcoming the often highly viscous frac fluid's resistance to being pumped also takes energy. So the key to understanding the hydraulic fracturing process is to understand the sources of energy gain, such as the frac pumps and the well's hydrostatic head, and the sources of energy loss and use. The sum of these is always equal to zero.

As pressure is energy, a great deal can be learned about a formation by studying the pressures produced by a treatment. The product of the pressure and the flow rate gives us the rate at which energy is being used, i.e. work. This is usually expressed as hydraulic horsepower. The analysis of the behaviour of fracturing pressures is probably the most complex aspect of the process that most Frac Engineers will become involved in.

Once a fracture has been created, proppant is placed inside it. If the treatment has been designed effectively and pumped without any problems, then this proppant should form a highly conductive path from the reservoir to the wellbore. This is what makes the well produce more.

2. BASICS OF HYDRAULIC FRACTURING

Hydraulic fracturing is the process of providing a conductive path from the reservoir to the wellbore. How this is achieved depends upon the objectives, the reservoir and the well.

2.1 THE BASIC PROCESS

As fluid is pumped into a permeable formation, a pressure differential is generated that is proportional to the permeability of the formation, k_f . As the rate increases, this pressure differential between the wellbore pressure and the original reservoir pressure also increases.

This pressure differential causes additional stress around the wellbore. Eventually, as the rate is increased, this pressure differential will cause stresses that will exceed the stress needed to break the rock apart, and a fracture is formed. At this point, if the pumps are shut down or the pressure is bleed off, the fracture will close again. Eventually, depending on how hard the rock is and the magnitude of the force acting to close the fracture, it will be as if the rock had never been fractured. By itself, this would not necessarily produce any increase in production. However, if we pump some propping agent, or *proppant*, into the fracture and then release the pressure, the fracture will stay propped open, providing the proppant is stronger than the forces trying to close the fracture. If this proppant also has significant porosity, then under the right circumstances a path of increased permeability has been created from the reservoir to the wellbore. If the treatment has been designed correctly, this will produce an increase in production.

Generally, the process requires that a highly viscous fluid is pumped into the well at high rate and pressure, although this is not always the case (see Skin Bypass Fracturing, below). High rate and high pressure mean horsepower, and this is why the process generally involves large trucks or skids with huge diesel engines and massive pumps. A typical frac pump will be rated at 700 to 2700 *hydraulic horsepower* (HHP) – to put this in perspective, the average car engine (outside North America, that is) has a maximum power output of 80 to 100 HP. In order to create the fracture, a fluid stage known as the *pad* is generally pumped first. This is then followed by several stages of proppant-laden fluid, which actually carries the proppant

into the fracture. Finally, the whole treatment is displaced to the perforations. These stages are pumped consecutively, without any pauses. Once the displacement has finished, the pumps are shut down and the fracture is allowed to close on the proppant. The Frac Engineer can vary the pad size, proppant stage sizes, number of proppant stages, proppant concentration within the stages, the overall pump rate and the fluid type in order to produce the required fracture characteristics. Typically, the treatment will look like Figure 1

:-

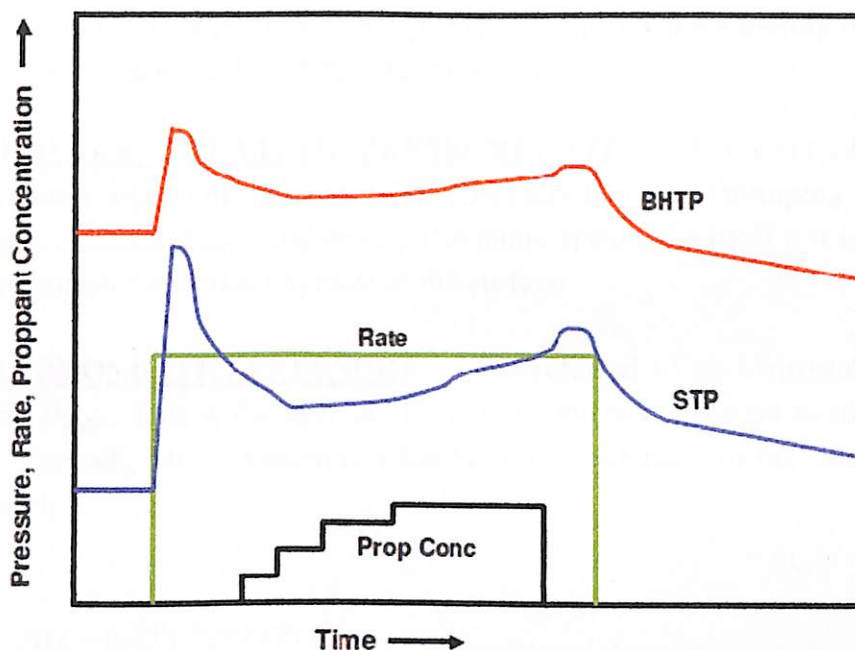


Figure 1 – Typical hydraulic fracture treatment job plot

2.2 Pressure:

Everybody understands what pressure is. Or at least, everyone thinks they understand what pressure is. If you ask someone to define pressure, then they will usually say “force divided by area”, or something similar. This is not what pressure is - it is merely how we measure, create and use pressure.

The simple fact is that pressure is stored energy, and we use that energy to perform work on the formation during the fracturing process. Everything we do in fracturing can be thought of in terms of energy. For instance, when we pump a fluid into a fracture we start out with chemical energy – in the form of diesel fuel. This is converted to mechanical energy by the diesel engine. The high pressure pump then transfers this mechanical energy into pressure in the fracturing fluid. As the fluid moves into the formation, the pressure is transformed into stress in the formation (see below), which is another form of stored energy, and so the walls of the fracture are pushed back, creating fracture width and forcing the fracture to propagate. Work is defined as the rate at which energy is used – in the SI system; one watt is defined as a joule per second. Therefore, by observing the way the pressure is changing, or not changing, with respect to time, we can tell how much work we are performing on the formation.

Pressure and stress are essentially the same thing. The only difference is that stresses act in solids and pressures act in liquids and gases. Because liquids and gases easily deform away from any applied force, pressures tend to act equally in all directions. Stresses, however, tend to act along planes, so that a solid experiencing a stress will always have a plane where the stresses are a maximum, and a plane perpendicular to this where the stresses are at a minimum.

In fracturing, we refer to several different pressures. These names merely refer to where and when we are measuring (or calculating) the pressure;

2.2.1 SURFACE TREATING PRESSURE, STP – also referred to as wellhead pressure, injection pressure, tubing pressure (if we are pumping down the tubing), P_{STP} , $P_{wellhead}$, P_{tubing} and so on. The name speaks for itself – it is the pressure that the pumps have to act against at the surface.

2.2.2 HYDROSTATIC PRESSURE – also referred to as hydrostatic head, P_H , HH and P_{hydro} . This is the pressure downhole due to the weight of the column of fluid in the well. This pressure is a function of the density of the fluid and the vertical depth:

$$HH = 0.433 * \gamma * TVD \dots \dots \dots (3)$$

Where HH is the hydrostatic head in psi, γ is the specific gravity of the fluid and TVD is the true vertical depth at which the pressure is acting. This looks relatively easy to calculate, but can get quite complicated in a dynamic system in a deviated well with fluids of several different densities actually in the well – which is the usual situation during a frac job. We use computers to keep track of this.

2.2.3 TUBING FRICTION PRESSURE – also known simply as friction pressure, P_{frict} or $?P_{frict}$. This pressure will be covered in more detail in later sections of this manual. For now, we can define it qualitatively as the pressure caused by the resistance of the fluid to flow down the tubing. Friction pressure decreases with increasing tubular diameter and increases with rate.

2.2.4 BOTTOM HOLE TREATING PRESSURE – $BHTP$ or P_{BHT} . This is the pressure inside the well, by the formation being treated. Generally, it is calculated at the centre of the perforated interval. At this point, the fluid has not passed through the perforations or into the fracture. Unless there are gauges in the well, or there is a static column, this pressure is usually calculated:-

$$BHTP = STP + HH - ?P_{frict} \dots \dots \dots (4)$$

As there are always uncertainties with the calculation of $?P_{frict}$ (unless fluid rate is zero), there will always be uncertainties in calculated *BHTP*.

2.2.5 PERFORATION FRICTION PRESSURE – also known as perforation friction or $?P_{perf}$. This is the pressure drop experienced by the fluid as it passes through narrow restrictions generally referred to as perforations:-

$$?P_{perf} = (2.93 SG (q/n)^2) / d^4 \dots\dots\dots (4)$$

Where $?P_{perf}$ is in psi, *SG* is the specific gravity of the fluid, *q* is the slurry rate in bpm, *d* is the perforation diameter in inches and *n* is the number of perforations.

2.2.6 NEAR WELLBORE FRICTION PRESSURE – a.k.a. near wellbore friction or $?P_{nwb}$. This is the sum of the perforation friction and any pressure losses caused by tortuosity.

2.2.7 CLOSURE PRESSURE – P_c or $P_{closure}$. This is the force acting to close the fracture. Below this pressure the fracture is closed, above this pressure the fracture is open. This value is very important in fracturing and is usually determined from a minifrac, by careful examination of the pressure decline after the pumps have been shut down.

2.2.8 EXTENSION PRESSURE – or P_{ext} . This is the pressure required in the frac fluid in the fracture in order to make the fracture propagate. It is usually 100 to 200 psi greater than the closure pressure, and this pressure differential represents the energy required to actually make the fracture propagate, as opposed to merely keeping it open (i.e. $P_{closure}$). In hard formations, fracture extension pressure is close to the closure pressure. In softer formations, where significant quantities of energy can be absorbed by plastic deformation at the fracture tip, extension pressure can be significantly higher than closure pressure. The fracture extension pressure can be obtained from a step rate test.

2.2.9 NET PRESSURE – or P_{net} . This is a fundamental value used in fracturing and the analysis of this variable forms a whole branch of frac theory by itself. This will be discussed in detail later on in this manual. For now, P_{net} is the difference between the fluid pressure in the fracture and the closure pressure, such that:-

$$P_{net} = BHTP - ?P_{nwb} - P_{closure} \dots\dots\dots (5)$$

$$= STP + HH - ?P_{frict} - ?P_{nwb} - P_{closure} \dots\dots\dots (6)$$

2.2.10 INSTANTANEOUS SHUT IN PRESSURE – or *ISIP* or *ISDP*. This is the pressure, which can be determined either at surface or bottom hole, which is obtained just after the pumps are shut down, at the start of a pressure decline. If measured at bottom hole, the *ISIP* should be equal to the *BHTP*, provided P_{nwb} is

zero. One of the methods for determining if the P_{nwb} is significant is to compare the $ISIP$ and the $BHTP$ from a minifrac (provided the $BHTP$ is reliable).

2.3 BASIC FRACTURE CHARACTERISTICS:

Every fracture, regardless of how it was pumped or what it is designed to achieve, has certain basic characteristics, as shown in Figure 2.3a (below).

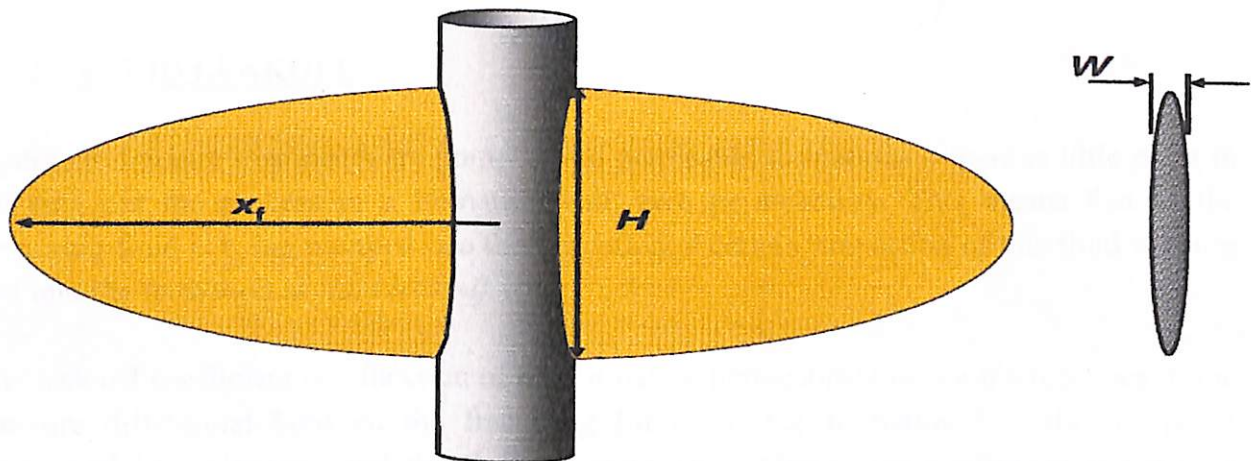


Figure 2 – Diagram showing fracture half Length x_f , fracture height H , and fracture width W

All fracture modelling is designed around determining these three characteristics, height H , half length x_f and width W . Once these three characteristics have been determined, other quantities such as proppant volume, fracture conductivity and ultimately production increase can be determined. It is usually assumed that the two wings of the fracture are identical and 180° apart (i.e. on opposite sides of the wellbore). This is not necessarily the case. It is also normal to model the fracture wings as being elliptical in shape - however, the reality is that the geometry is probably quite a bit more complex. However, based on the three characteristics of width, half length and height, we can define a few simple parameters, which will be used frequently in this document:-

Aspect ratio;

$$AR = \frac{H}{x_f} \quad \dots\dots\dots (7)$$

So a radial frac, which is perfectly circular and has a height equal to twice the fracture half length, has an AR of 0.5

Fracture conductivity;

$$F_c = \bar{w} \cdot k_p \quad \dots\dots\dots (8)$$

Where $\bar{w}$ is the average fracture width and k_p is the permeability of the proppant pack.

Remember that the width in Equation 8 is the propped width, which is usually less than the width actually created during the treatment. The propped width is a function of the volume of proppant pumped into the fracture, expressed in terms of the mass of proppant per unit area of the fracture face. This areal proppant concentration is expressed in terms of lbs/sq ft, and is not to be confused with the slurry proppant concentration, that is expressed in lbs/gal (or ppg). This is a measure of how much proppant is added by the surface mixing equipment to a gallon of frac fluid. Another way of expressing slurry proppant concentration, which is used less often but is clearer and easier to understand, is PPA, or lbs of proppant added. This clearly illustrates the quantity of proppant being added to a gallon of clean fluid.

2.4 FLUID LEAKOFF:

Hydraulic fracture treatments are pumped into permeable formations – there is little point in carrying out the process in a formation with zero permeability. This means that as the fracturing fluid is being pumped into the formation, a certain proportion of this fluid is being lost into the formation as *fluid leak off*.

The leak off coefficient is a function of the formation permeability k_f , the fracture area A , the pressure differential between the fracturing fluid and the formation ΔP , the formation compressibility, viscosity and the fluid characteristics. Often, this coefficient is set as a constant throughout the treatment, which means that the fluid loss rate varies with time and fracture area only, and does not vary with pressure differential or fluid type. The effect of the formation permeability and the fluid characteristics are often combined together into a single leak off coefficient, variously called C_T , C_L or C_{eff} . We shall use C_{eff} . This coefficient defines the volume of fluid leaked off into the formation VL , as follows:-

$$VL = \pi * C_{eff} * A * \sqrt{t} \dots \dots \dots (9)$$

Where, t is the time that the fracture has been open. The units of C_{eff} are generally ft/min^{1/2}, so in Equation 9 if the area is in square feet, the leak off volume is in cubic feet. Remember that the area A is the surface area of the whole fracture, including both sides of both wings of the fracture. A fracture geometry model must be used to determine the value for A . In a multilayer reservoir, with different values of C_{eff} for each zone, the total leak off will be the sum of the leak off for each zone.

The leak off coefficient is usually determined from minifrac tests and from analysis of previous treatments. A more accurate method for calculating fluid loss is to use a dynamic leak off model, in which variations in the pressure differential and the fluid composition are taken into account. In dynamic leak off, the overall leak off coefficient is generally assumed to have three components; the viscosity controlled coefficient C_V or C_I , the compressibility controlled coefficient C_C or C_{II} and the wall-building coefficient C_w or C_{III} . The viscosity controlled coefficient is the effect of the fracture fluid filtrate moving into the formation under Darcy linear flow conditions, and is defined as (in field units):-

$$C_I = 0.0469 \sqrt{\frac{k_f \phi \Delta P}{2\mu_f}} \dots\dots\dots (10)$$

Where, k_f is the permeability of the formation to the frac fluid filtrate, ϕ is the formation porosity and μ_f is the frac fluid filtrate viscosity in cp.

The compressibility controlled coefficient defines the leak off which is due to the formation compressing, and allowing volume into which the frac fluid filtrate can move. It is defined, in field units, as:-

$$C_{II} = 0.0374 \Delta P \sqrt{\frac{k_r c_f \phi}{\mu_r}} \dots\dots\dots (11)$$

Where, k_r is the permeability of the formation to the reservoir fluid, c_f is the compressibility of the formation in psi^{-1} and μ_r is the reservoir fluid viscosity in cp.

The wall building coefficient is usually determined experimentally using a standard fluid loss test. The volume of filtrate is plotted against the square root of time, to give a slope m . The wall building coefficient is then defined as (in field units):-

$$C_{III} = \frac{0.0164 m}{A_f} \dots\dots\dots (12)$$

Where, A_f is the area of the filter cake in the fluid loss cell.

Generally, modern fracture simulator will have wall-building coefficients for a wide range of fracturing fluids, so that all the Engineers have to do is select the fluid type.

The three components can then be combined to produce C_{eff} as follows:-

$$C_{eff} = \frac{2 C_I C_{II} C_{III}}{1 + \sqrt{(C_I C_{III})^2 + (4 C_{II}^2 (C_I^2 + C_{III}^2))}} \dots\dots\dots (13)$$

This is for dynamic fluid leak off. The components can be arranged in a different form for harmonic fluid leak off:-

$$C_{eff} = \frac{(C_I C_{II} C_{III})}{(C_I C_{II} + C_{II} C_{III} + C_I C_{III})} \dots\dots\dots (14)$$

This process of deducing the theoretical leak off coefficient looks to be rather intimidating and in practice is only used in fracture simulators. During minifrac analysis, the permeability

of the formation and the wall building coefficient are varied to produce the required leak off rate.

Generally, the dynamic model is better than the harmonic, although under most circumstances there will not be much difference between the two. This is especially true for a non-wall-building fluid, or for gas reservoirs. Another form of fluid loss into the formation is called spurt loss. This is the fluid loss which occurs on "new" parts of the fracture, before the fluid has a chance to build up a filter cake. Usually, the fracture models take a simplistic approach to spurt loss and use a spurt loss coefficient, S_p , such that:-

$$V_s = A S_p \dots \dots \dots (15)$$

Where, V_s is the volume of fluid lost due to spurt loss and A is the total area of the fracture (both wings).

2.5 NEAR WELLBORE DAMAGE AND SKIN FACTOR

Darcy's Equation for radial flow defines the rate at which oil is produced from the reservoir into the wellbore, under steady state flow conditions. In field units for an oil well, Darcy's Equation becomes:-

$$q = \frac{0.00708 k h \Delta P}{\mu \ln (r_e/r_w)} \dots \dots \dots (16)$$

Where, q is the downhole flow rate in bbls/day. We can see that the wellbore radius, r_w has a huge impact on the flow rate. This is easily visualised, as the closer the fluid comes to the wellbore, the more congested the flow paths become and the faster the fluid has to move. Therefore, the final few inches by the wellbore are the most critical part of the reservoir.

Unfortunately, this is also the part of the reservoir most susceptible to damage. This damage can come from a variety of sources, but most often comes from the process of drilling the well in the first place.

However, the major sources are; particulates in the drilling fluid (barite, calcium carbonate etc), filtrate invasion, whole fluid invasion, pH of drilling fluid and surfactants in the drilling fluid.

What this results in, is a region around the wellbore of reduced permeability, as illustrated in Figure 3.

This reduction in permeability around the wellbore is generally referred to as the Skin, which was first rationalised by Van Everdingen and Hurst (1949). The skin factor, S , is a variable that is used to describe the difference between the ideal production given in Equation 16, and

the actual production through the damaged area. Generally, the skin is measured using a pressure build up test. The API has defined the skin factor for an oil well as follows

$$S = 1.151 \left(\frac{P_{1hr} - P_{wf}}{m} - \log_{10} \frac{k}{\phi \mu c r_w^2} + 3.23 \right) \quad \dots\dots\dots (17)$$

where P_{wf} is the bottom hole stabilised flowing pressure (psi), P_{1hr} is the bottom hole pressure after one hour of static pressure build up (psi), k is the formation permeability, m is the slope of the graph of P against $\log_{10}[(t + \Delta t)/\Delta t]$ (in psi per log10 cycle), Φ is the porosity (fraction), μ is the fluid viscosity (cp), c is the average reservoir compressibility (psi^{-1}) and r_w is the wellbore radius (feet).

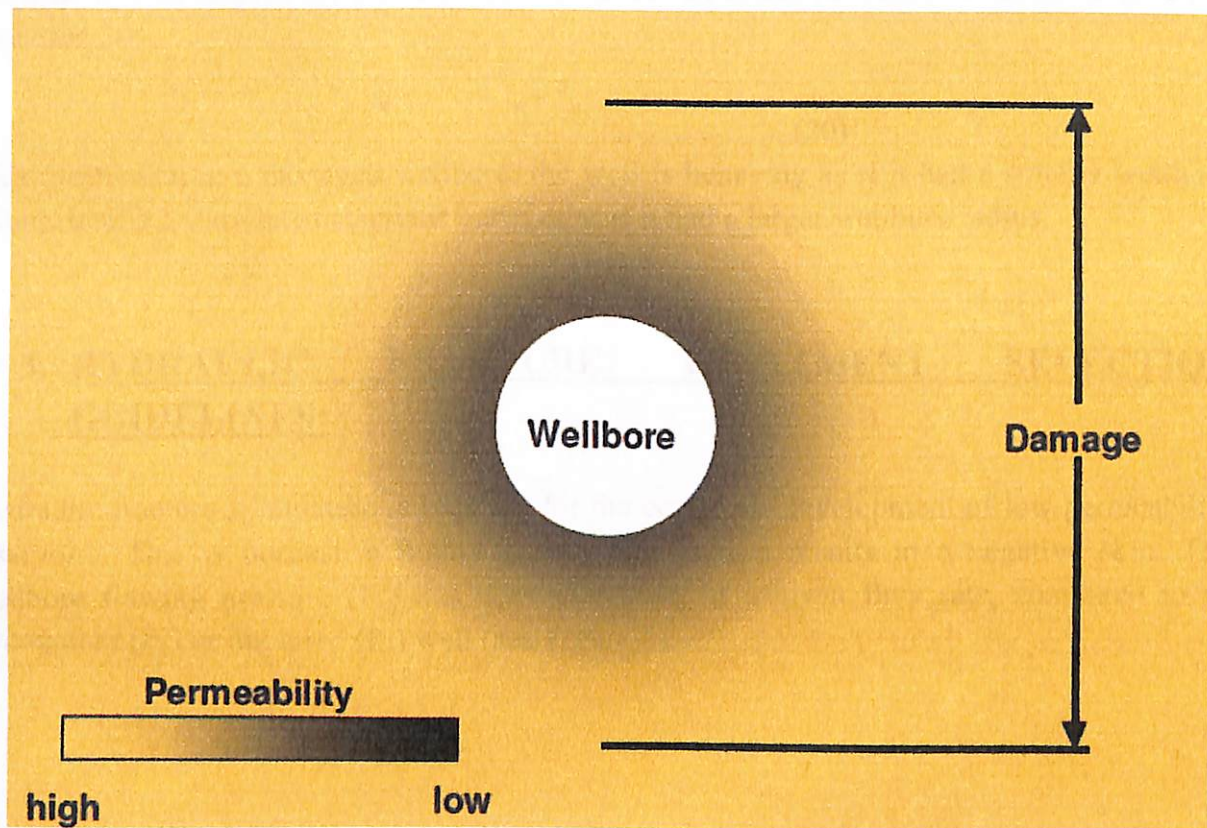


Figure 3 – Illustration of the reduction in permeability around the wellbore

To help matters, m can be found from the following (in field units):-

$$m = \frac{162.6 q \mu}{k h} \quad \dots\dots\dots (18)$$

Note that both q and μ are at bottom hole conditions. A completely undamaged reservoir will have a skin factor of zero. Damaged reservoirs will have skins in the ranging from 0 to 50 or even higher. Under certain circumstances, stimulation can result in a negative skin factor, which means that the well is producing more than predicted by ideal Darcy flow. Once the skin factor has been obtained, it can be used in Darcy's Equation to give the modified flow from a skin damaged reservoir:-

$$q = \frac{0.00708 k h \Delta P}{\mu [\ln(r_e/r_w) + S]} \dots\dots\dots (19)$$

This means that as S increases, flow rate decreases, and *vice versa*.

Another way of employing the skin factor is to use an effective wellbore radius, as given in Equation 20:-

$$r_w' = r_w e^{-S} \dots\dots\dots (20)$$

This means that in a damaged wellbore, the well is behaving as if it had a smaller wellbore radius, whilst a stimulated reservoir behaves as if it had a larger wellbore radius.

3. HYDRAULIC FRACTURE TREATMENT SELECTION GUIDELINES:

Hydraulic fracture stimulation is required for the economic development of low permeability reservoirs. This is because a highly conductive fracture results in a negative skin. The wellbore flowing pressure (P_1) has been increased, at a given flow rate, compared to an unimpaired (P_2) or impaired (P_3) well (see Figure 4):

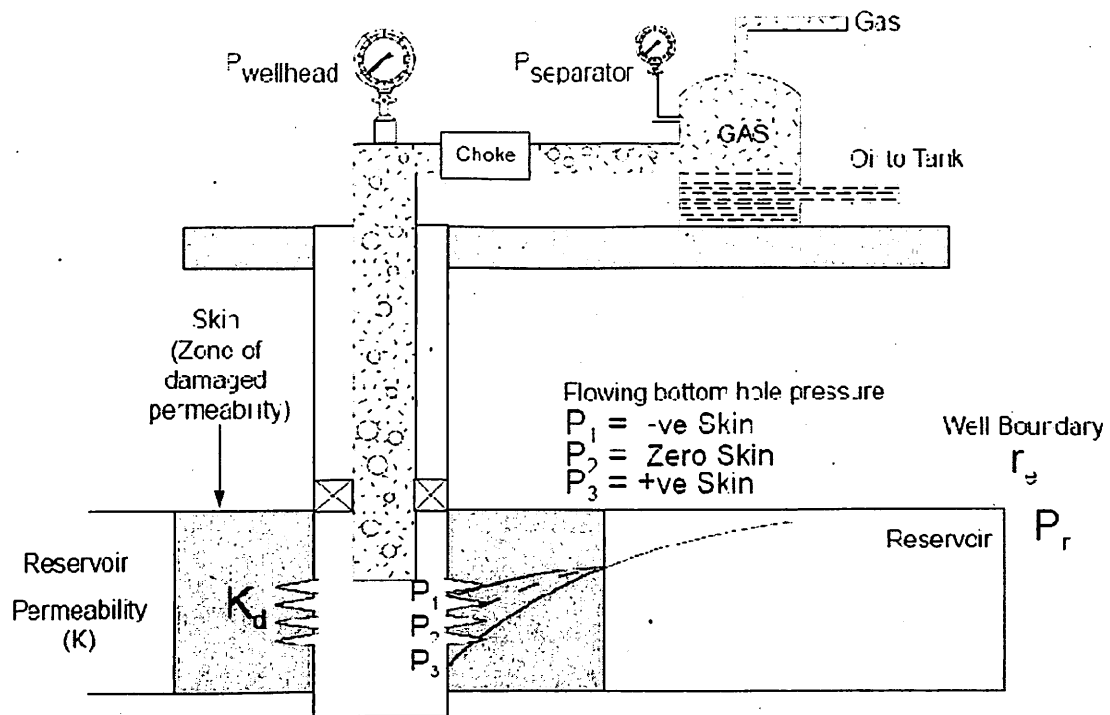


Figure 4 – The Producing System

- (i) The pressure observed (P_2) for the same flow rate for a well with an ideal ($S = 0$) completion or
- (ii) The even lower pressure (P_3) measured for the equivalent well showing a positive skin due to formation damage.

The hydraulically fractured well with the negative skin will have the greatest production rate. Propped hydraulic fracture well stimulation should only be considered when the:

- (i) Well is connected to adequate **produceable reserves**;
- (ii) **Reservoir pressure** is high enough to maintain flow when producing these reserves (or it is economically justifiable to install artificial lift);
- (iii) **Production system** can process the extra production.

These **minimum** criteria are equivalent to those used for matrix treatments and are summarised in table 1. There is, however, one extra, unique requirement for propped hydraulic fracturing:

Parameter	Oil Reservoir	Gas Reservoir
Hydrocarbon Saturation	>40%	>50%
Water Cut	<30%	<200 bbls/MMscf**
Permeability †	1-50 mD	0.01-10 mD
Reservoir Pressure	<70% depleted	twice abandonment pressure
Gross Reservoir Height	>10 m	>10 m
Production System	20% spare capacity °	

Table 1.
Minimum hydraulic fracturing candidate well selection screening criteria

- (iv) **Professional, experienced personnel** are available for treatment design, execution and supervision along together with high quality pumping, mixing and blending equipment.

This latter requirement arises because a propped hydraulic fracturing treatment has a complexity and difficulty an order of magnitude greater than that associated with matrix or acid fracturing treatments. This arises because the ability to complete the treatment to the specified design requires numerous, on-site adjustments during the treatment. The first hydraulic fracturing treatments in a new area often experience early screen out resulting in premature stopping of the treatment i.e. the "learning curve" has to be climbed. The steepness of this "learning curve" can be increased by employing personnel who have gained experience in successful fracturing treatments in another area.

4. FRACTURE STIMULATED WELL INFLOW PERFORMANCE:

The Inflow Performance of a Fracture Stimulated well is controlled by the dimensionless Fracture Conductivity (Fcd):

$$F_{cd} = \frac{k_f * w}{k * L_f} \dots\dots\dots (21)$$

Where:

$k_f * w$ = fracture permeability (k_f) * conductive fracture width (w)
= ability of the hydraulic FRACTURE to conduct fluid to the wellbore
= the fracture conductivity.

$k * L_f$ = formation permeability (k) * conductive fracture single wing length (L_f)
= ability of the FORMATION to deliver fluid to the hydraulic fracture.

These parameters are illustrated in Figure 5. It can be easily visualised that the objective of the propped hydraulic fracture treatment design process is to ensure that the pressure drop down the length of the fracture is low compared to the pressure drop across the formation. Thus, as much as possible of the well drawdown should be taken across the reservoir with the pressure drop within the fracture making a negligible contribution to the total value of the well drawdown. We will now consider these two factors in turn:

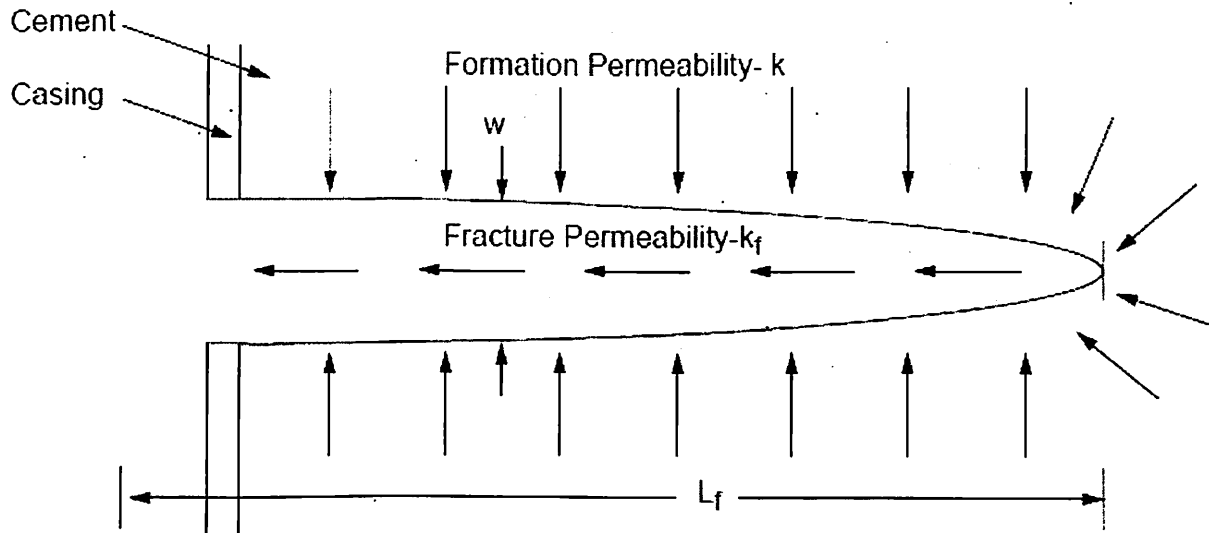


Figure 5 - Factors contributions to the dimensionless fracture conductivity

The fracture conductivity is **increased** by:

- (a) An **increased fracture width** (w),
- (b) An **increased proppant permeability** (large, more spherical, proppant grains have a higher permeability) and
- (c) **Minimising the permeability damage** to the proppant pack from the fracturing fluid.

Frequently the increased production achieved by carrying out a hydraulic fracturing treatment is represented by the "Folds of Increase" or FOI:

$$FOI = Q_f/Q_o \quad \dots\dots\dots (22)$$

Where,

$$Q_o = \frac{k \cdot h (P_e - P_{wf})}{\mu \cdot B_o \ln(r_e/r_w)} \quad \dots\dots\dots (23)$$

And

$$Q_f = \frac{k \cdot h (P_e - P_{wf})}{\mu \cdot B_o \ln(r_e/r'_w)} \quad \dots\dots\dots (24)$$

Q_o and Q_f are the well production under equivalent conditions before and after carrying out the hydraulic fracturing treatment. Thus:

$$FOI = \frac{\ln(r_e r_w)}{\ln(r_e r'_w)} \dots\dots\dots (25)$$

There have been several studies of the composite effect of fracture length, fracture conductivity and formation permeability on the well inflow performance (see Cinco- Ley, SPE 10043, 1982 for a review). A widely used correlation is that published by Cinco-Ley and Samaniego (JPT, 1981, 1749-1766) in which $\{r'_w/L_f\}$, or effective wellbore radius divided by conductive fracture length, is plotted against the dimensionless fracture conductivity (FCD). This is illustrated in Figure 5. This Figure shows that a FCD value of 15 is required to ensure that the well inflow is not being limited by the fracture conductivity. An alternative presentation (Figure 6) allows the (negative) skin effect due to the propped hydraulic fracture (S_f) to be calculated from the dimensionless fracture conductivity.

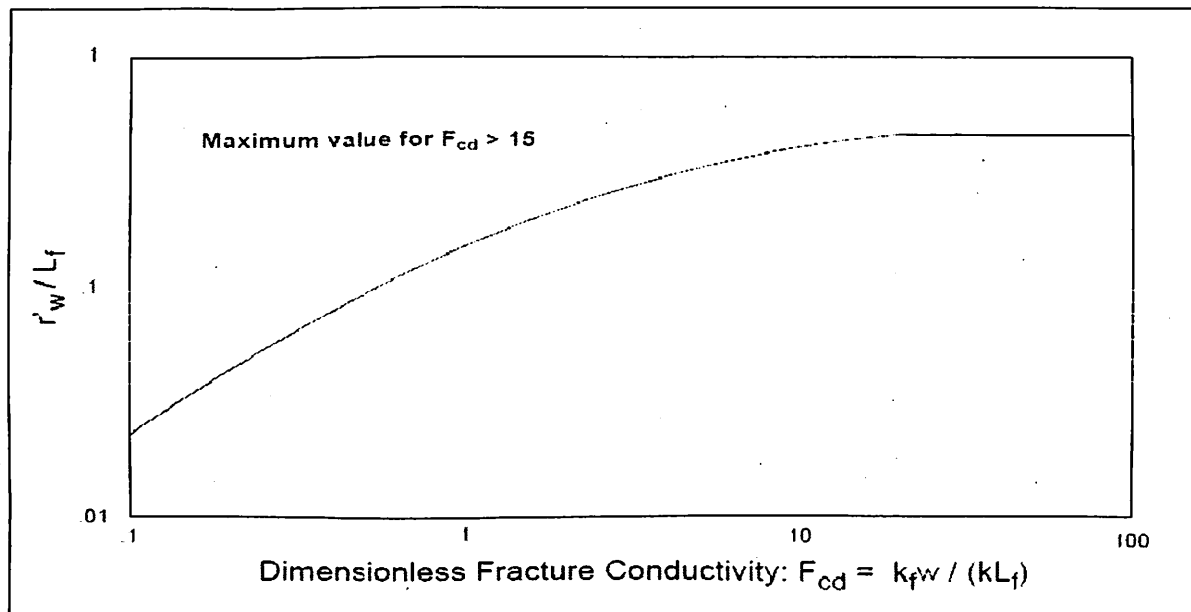


Figure 6 - Cinco-Ley and Samaniego's 1981 correlation between effective wellbore radius and fracture conductivity

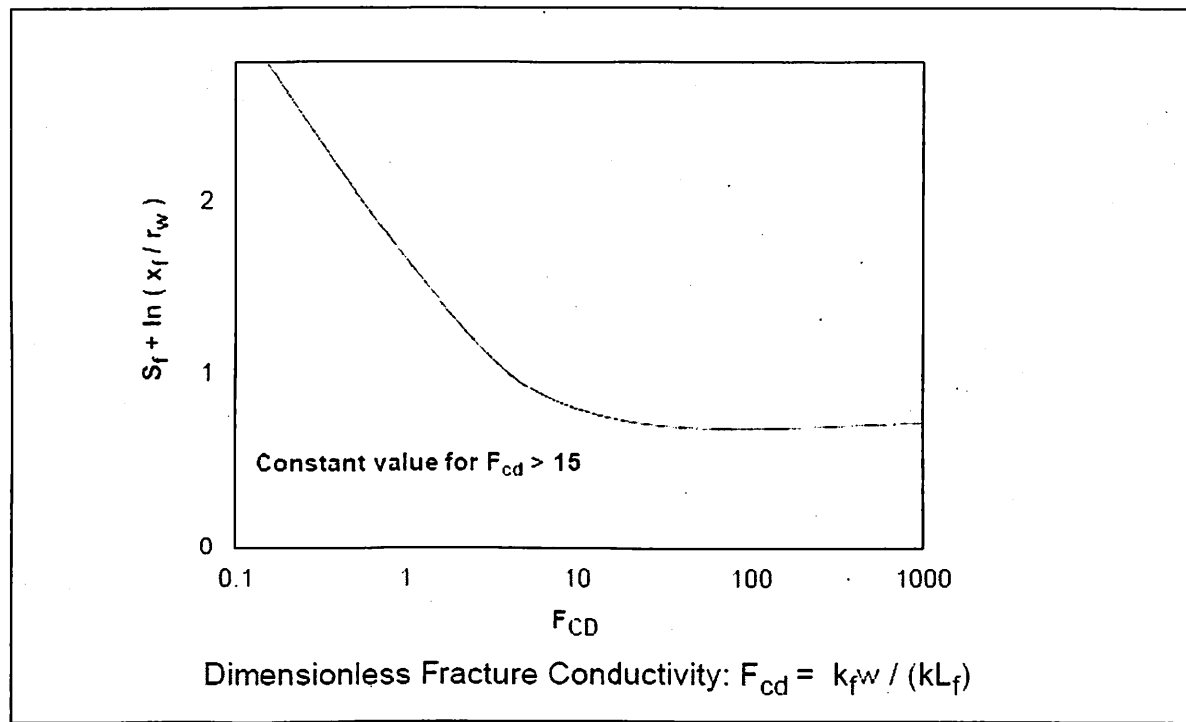


Figure 7 - Fracture skin effect varies with fracture conductivity

The above correlations and equations can be used to quantify the relationship between the increased production (FOI) as a function of the fracture length (L_f), formation permeability (k) and the fracture conductivity ($k_f w$) - see Figure 7. Figure 7 shows that for wells in *low permeability (0.1mD) formations*:

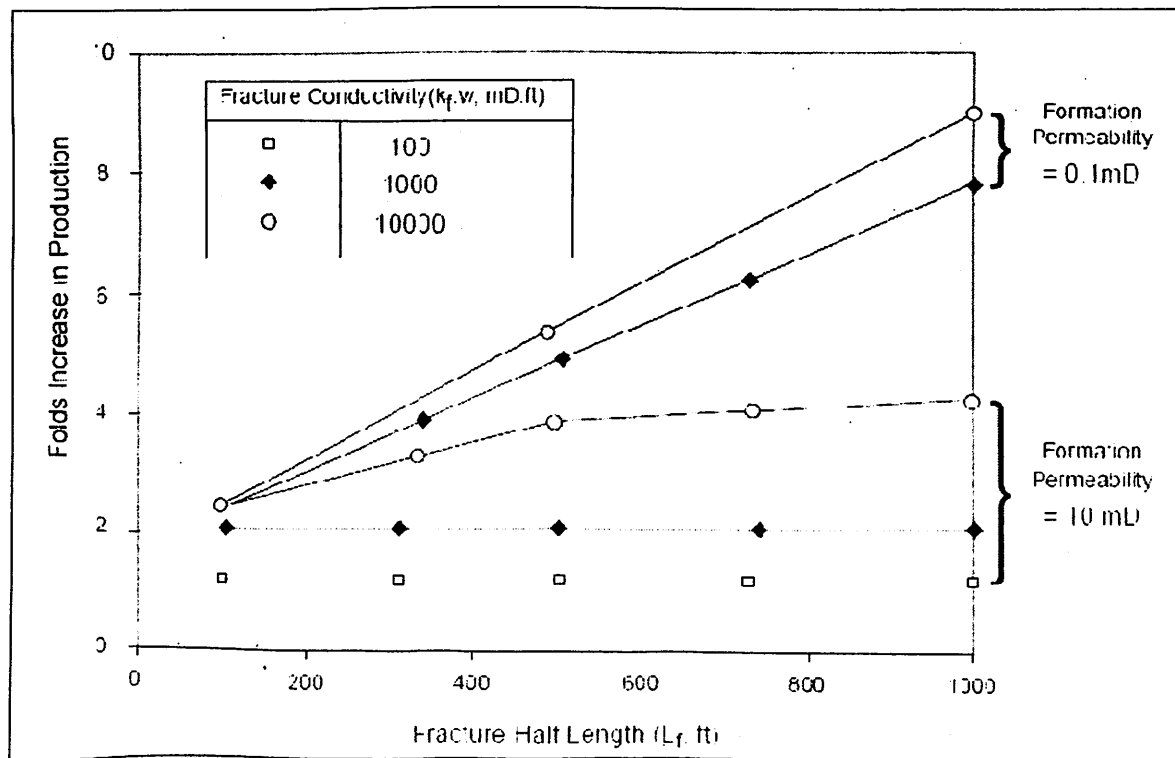


Figure 8 - Well productivity response to hydraulic fracturing

- (i) high values of the FOI are possible;
- (ii) FOI is related to fracture half length, while the fracture conductivity has a limited effect, providing its value is greater than a certain minimum.

The (low) formation permeability is controlling the well inflow and increased fracture conductivity does not improve well performance.

An increase in the formation permeability to 10 mD results in a different picture:

- (i) A fracture with a low conductivity (100 mD.ft) has essentially no effect on the well production;
- (ii) Increasing the fracture conductivity by a factor 10 (to 1,000 mD.ft) increases the well production (or FOI); but the FOI is still independent of fracture length for values greater than 100 ft;
- (iii) A further increase to 10,000 mD.ft is required before the inflow performance becomes sensitive to created fracture length i.e. the fracture conductivity is no longer the only limiting factor in well inflow.

Inflow from the formation *into* the fracture is no longer the controlling factor for this higher permeability reservoir. The above considerations will control the hydraulic fracture treatment design process since long and highly conductive fractures are more difficult to make and have a greater cost.

5. A BRIEF REVIEW OF ROCK MECHANICAL ISSUES RELATED TO HYDRAULIC FRACTURING

5.1 INSITU STRESS:

It is well known that there are three principle earth stresses oriented at right angles to one another (Figure 9). Below about 500 m, in a relaxed tectonic environment, the vertical stress (s_v) is normally the greatest. It can be quantified by integrating the density log from the point of measurement to the surface. An average value of 1.0 to 1.1 psi/ft is measured for wells at reasonable depth - though lower values are encountered in shallow, particularly offshore environments subject to rapid deposition.

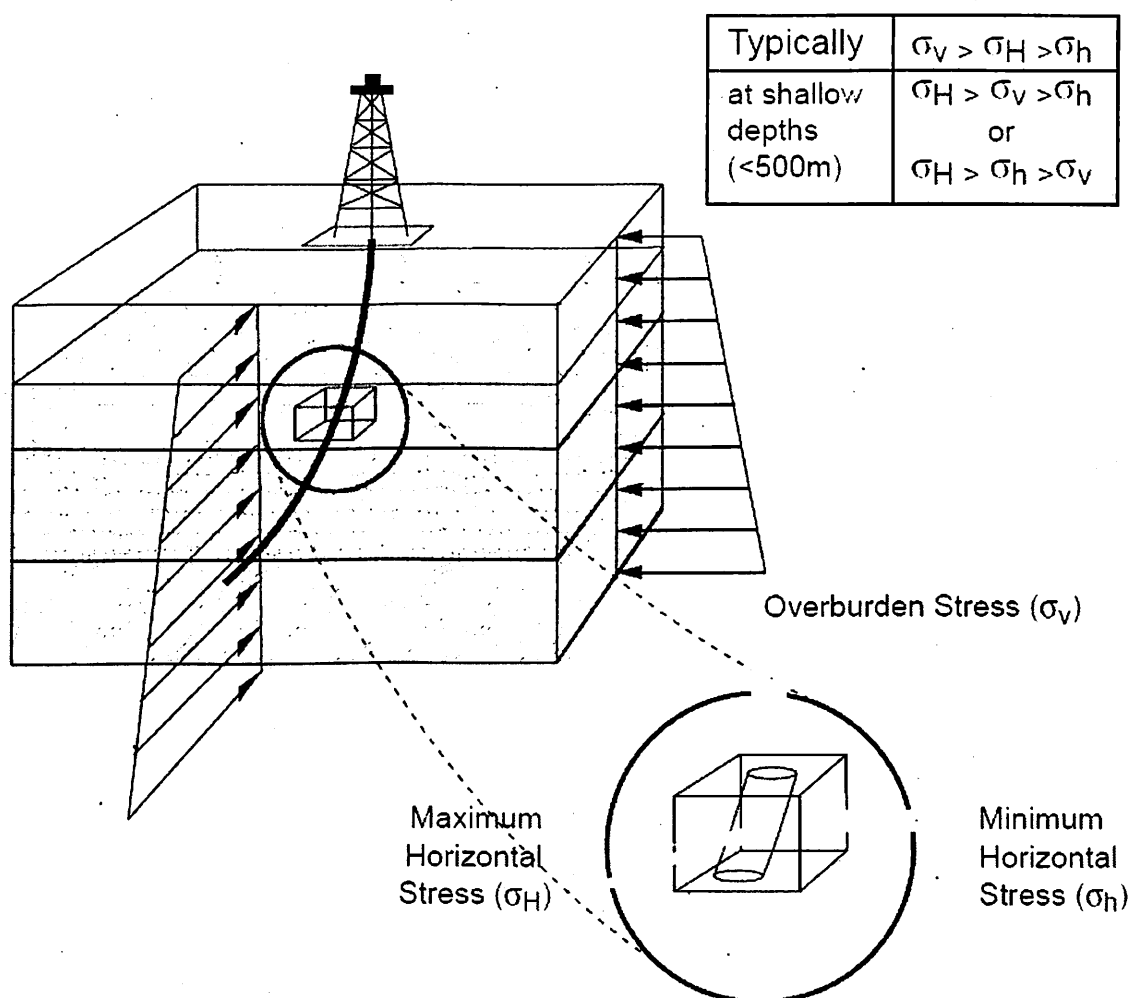


Figure 9 - Insitu stresses in the subsurface

The other two stresses - the maximum and minimum horizontal stresses are oriented at right angles to each other and at right angles to the vertical stress. The maximum horizontal stress is also referred to as the intermediate stress.

Note: In tectonically active areas e.g. in the foothills of mountain chains where mountain building is occurring; the maximum insitu stress may no longer be vertical. The orientation between the three insitu stresses remains the same - hence the minimum and intermediate stresses are also no longer horizontal. Propagation of a Hydraulic Fracture, involving the actual splitting apart the fabric of the formation. The split will propagate in the direction of least resistance i.e. will occur most easily in the direction perpendicular to the minimum insitu stress. Thus, in tectonically relaxed environments, we can assume that a hydraulic fracture will have a vertical orientation and will grow (propagate) in the direction intermediate (or maximum horizontal) of the insitu stress {at right angles to the minimum insitu stress}.

As discussed earlier, the vertical stress (s_v) can be measured or assumed with reasonable accuracy. The important rock property for predicting the other two stresses from the vertical stress is called Poisson's Ratio (ν), the ratio between Lateral Strain (ϵ_y) and the Longitudinal Strain (ϵ_x), i.e.

$$\nu = -\frac{\varepsilon_v}{\varepsilon_N} = \frac{-\text{Lateral Strain}}{\text{Longitudinal Strain}} \quad \dots\dots\dots (26)$$

Figure 10 explains how subjecting a rock sample to a vertical (the overburden) stress results in it shortening in the vertical direction and expansion in the horizontal direction. A similar effect occurs in a reservoir rock deposited in a sedimentary basin. The magnitude of the vertical stress at any depth is related to the weight of the overlying rock mass. This can often be estimated by integrating the density log from the depth under study to the surface (a default value of 1.0 - 1.1 psi/ft can be used if this log is not available).

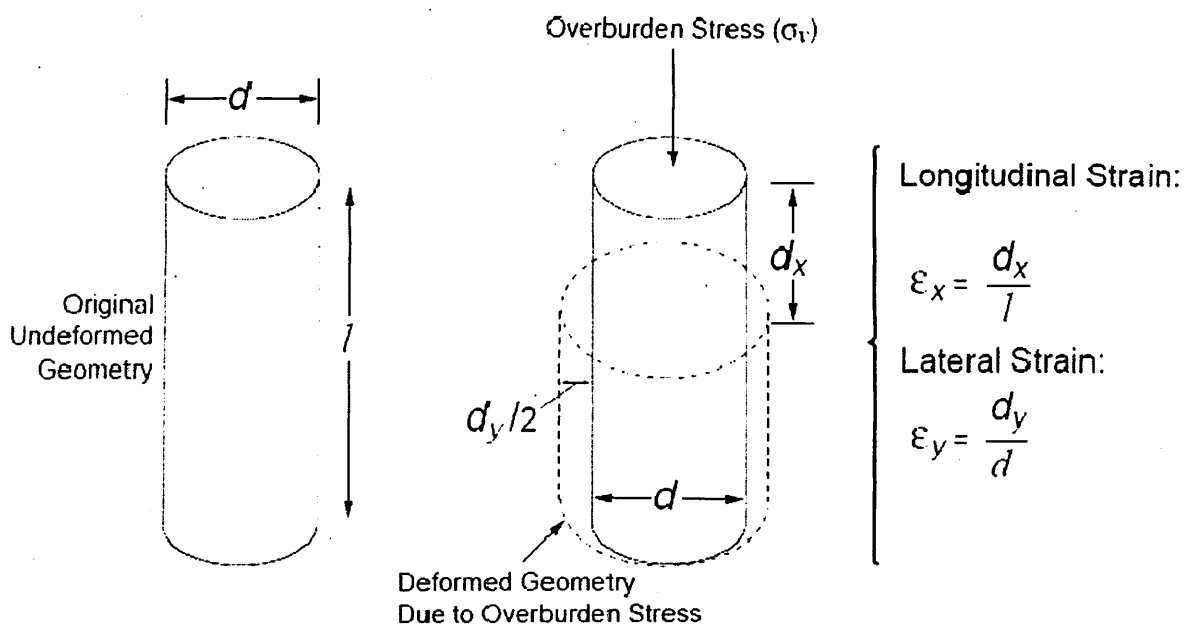


Figure 10 - Measurement of Rock properties: Poisson's Ratio (ν)

If we assume that the horizontal stress depends only on the elastic behaviour of the rock, the overburden load can be related to the horizontal stresses via the above Poisson effect together with assumptions about the lateral boundary conditions. In a tectonically relaxed area, the two horizontal stress components will have the same value within a specific lithology:

$$\sigma_h = \sigma_H = \left(\frac{\nu}{1-\nu} \right) \sigma_v \approx \frac{1}{3} \sigma_v \quad \text{if } \nu = 0.25 \quad \dots\dots\dots (27)$$

Variations in lithology, and hence variations in Poisson's Ratio, thus lead to abrupt changes in horizontal stresses with depth.

The above is a simplified picture of the behaviour of rock formations but it does allow the derivation of a first estimate of the potential horizontal stress changes between layers. Figure 11 illustrates the resulting stresses from deposition of a formation with constant lithology.

Here tectonic forces resulting from movement of the earth's crust have induced a stress component (σ_{tec}), so that the two horizontal components are no longer equal.

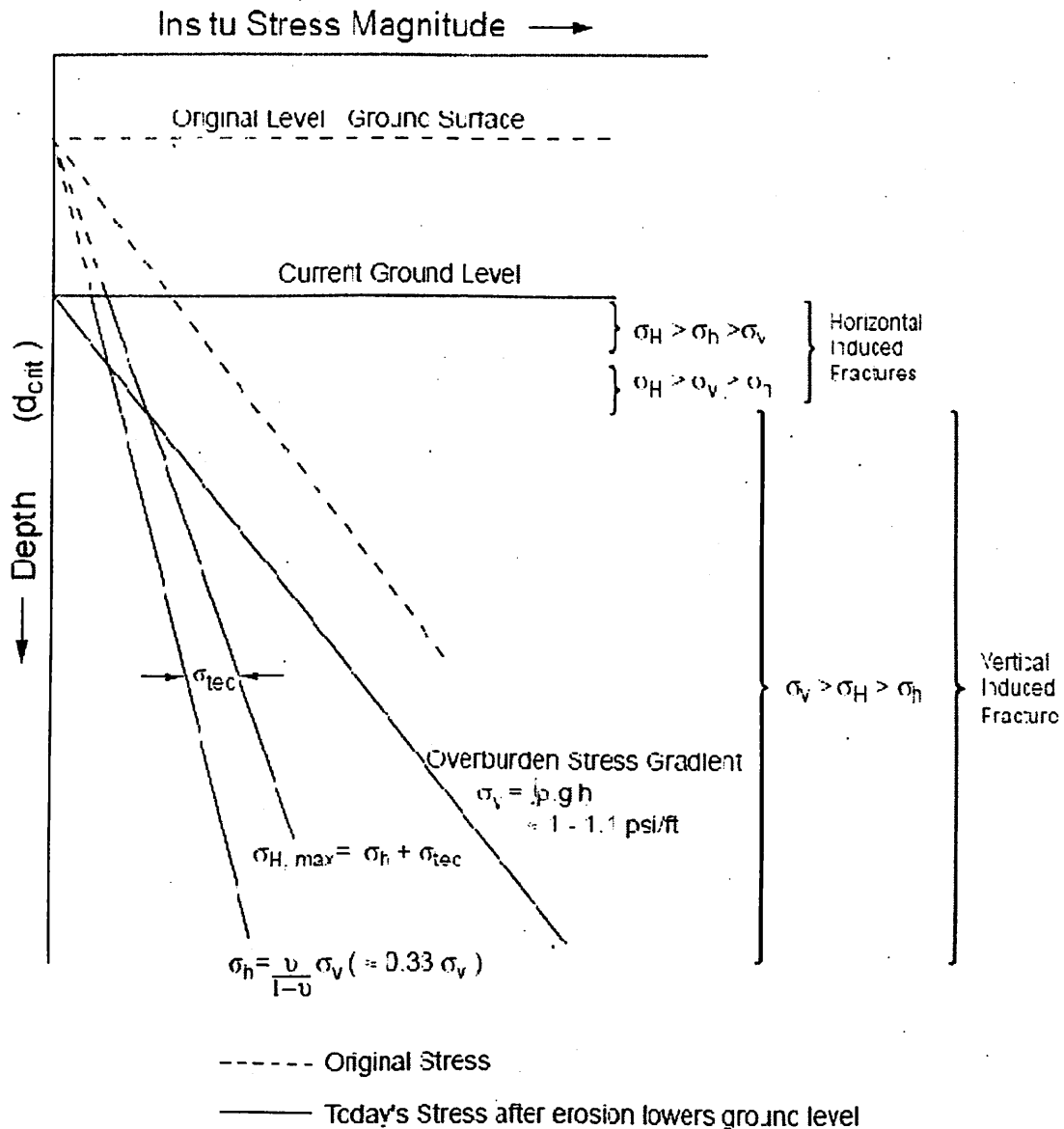


Figure 11 - Magnitude of insitu stress

Surface elevations change over geologic time. Figure 11 shows how surface erosion has changed the vertical stress profile while the horizontal stresses have remained "locked-in" due to, for example, inelastic rock deformation. This explains why the vertical stress is normally not the largest one at shallow depths. Other geological processes, such as burial and uplift, also lead to similar anomalous stress patterns. The presence of a minimum horizontal stress implies that there will be a preferred direction of fracture propagation. The fracture will grow in "easiest" direction (requires the least amount of energy) i.e. as a vertical fracture perpendicular to the minimum horizontal stress below the critical depth (d_{crit} in Figure 11) and as a horizontal fracture at shallower depths.

5.2 EFFECTIVE STRESSES:

The pore fluids present within the rock matrix will support a proportion of the total applied stress. This means that effective stress (s') carried by the rock matrix grains is smaller than the total stress. This was quantified by Terzaghi as:

$$s' = s - P \quad \dots\dots\dots(28)$$

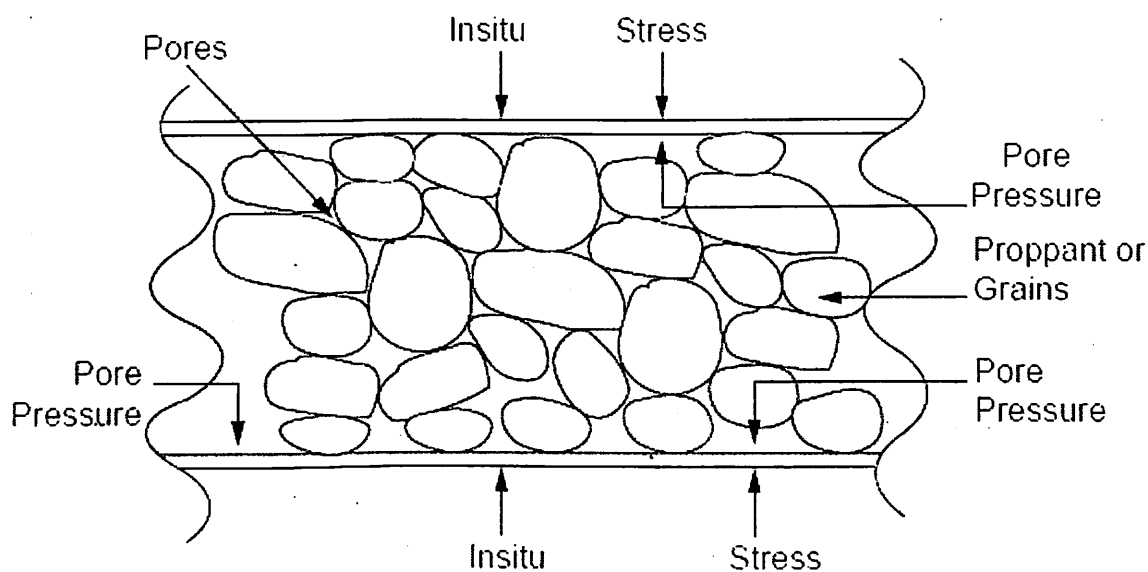


Figure 12 - Effective stress acting on a propped fracture.

Where, s is the total stress, p is the pore pressure and s' the effective stress which will govern the failure of the material. This is illustrated in figure 12. It was later recognised by Handin that the intergrain cementation does not allow the pore pressure to completely counteract the applied load. A correction factor, the poroelastic constant a was introduced:

$$s' = sa - P \quad \dots\dots\dots(29)$$

Where a can vary between 0 and 1 but has a typical value of 0.7 for petroleum reservoirs.

One important conclusion from these equations is that the values of the stresses which control fracture propagation can change as the reservoir pressure depletes during the life of a petroleum reservoir. Hence the stress profile measured early in a field's lifetime may become invalid as the field matures. E.g. A hydraulic fracture created later in the life of a field will tend to be more confined to the pay zone than a similar treatment carried out early in field life. This occurs because the pay zone reservoir pressure will have decreased due to oil or gas production, while the pressure and hence the insitu stress in the bounding shale will be unchanged.

6. CREATION OF A PROPPED HYDRAULIC FRACTURE

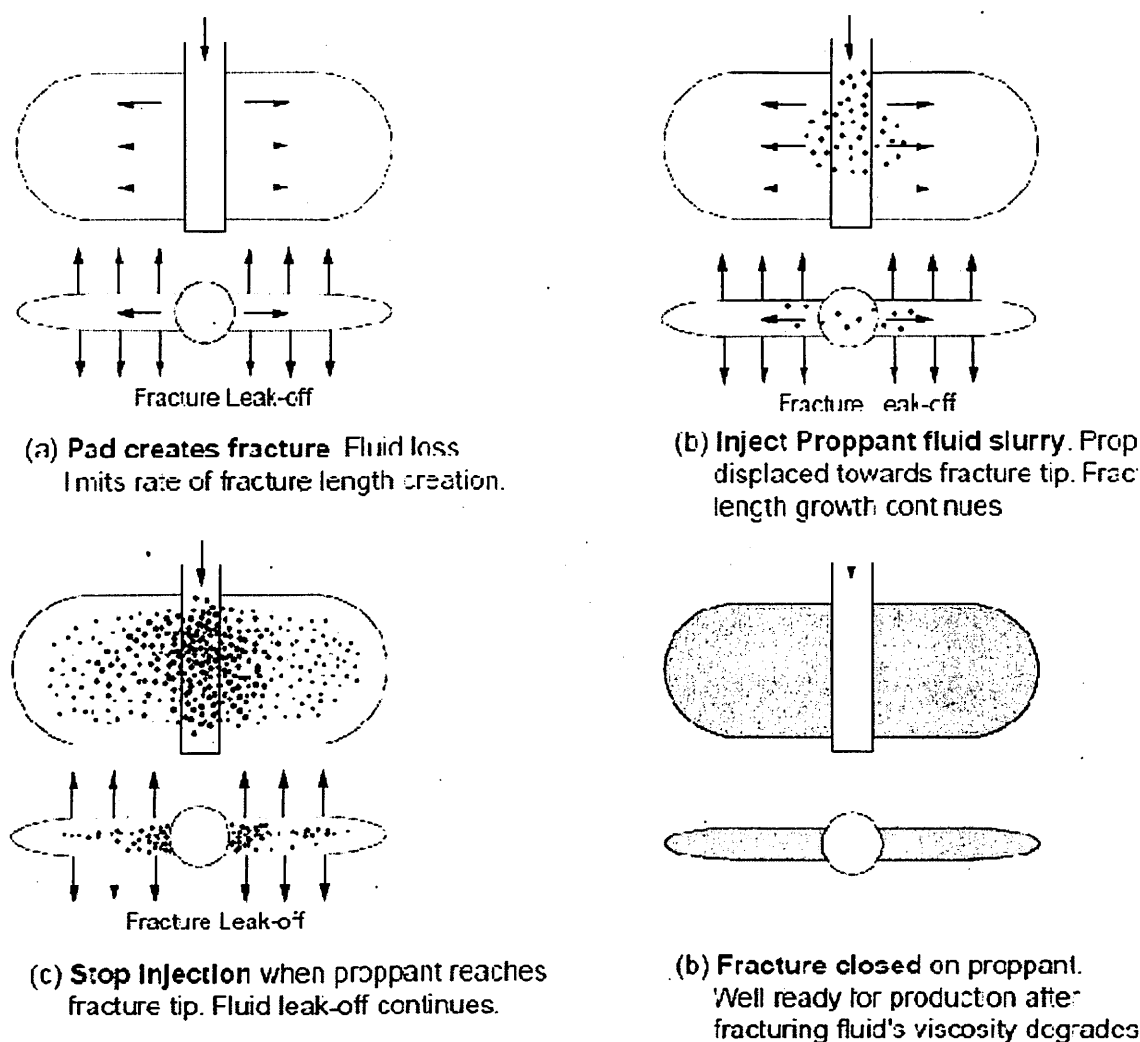


Figure 13 - Creation of a propped hydraulic fracture

Figure 13 summarises the main stages in the process involved in creation of a propped hydraulic fracture:

- (i) An initial fracture of appropriate length and width is created by pumping fracture fluid called the pad. The most common fracturing fluids are water based, cross-linked, polymer solutions (or gels) - which exhibit highly non-Newtonian rheological properties and appropriate fluid loss properties. This is often preceded by a sacrificial pre-pad (a low viscosity fluid which satisfied part of the fluid loss from the fracture at a reduced cost). Typically, about 50-80% of the total fluid volume pumped leaks off to the formation while only 20-50% creates useful fracture volume.
- (ii) Proppant and Gravel Pack Sand are of similar size and the same material may be used for both applications. Proppant particles are added at low concentration to the fracturing fluid once:

- a. The fracture width is sufficient to admit the proppant without causing a screen out and
- b. The created fracture is nearing its design length. The concentration of proppant is increased towards the end of the job with proppant concentrations as high as 40% vol being pumped {(Figure 14(a))}. This ensures that a more uniform, final proppant concentration in the fracture is achieved. This occurs because the low proppant concentration in the slurry pumped initially will become more concentrated as it is displaced towards the fracture tip as the fracturing fluid leaks off into the formation. "Slumping" of the denser proppant will also occur due to the influence of gravity. This process will continue until fracture closure is complete. These processes are illustrated in figure 14(b).

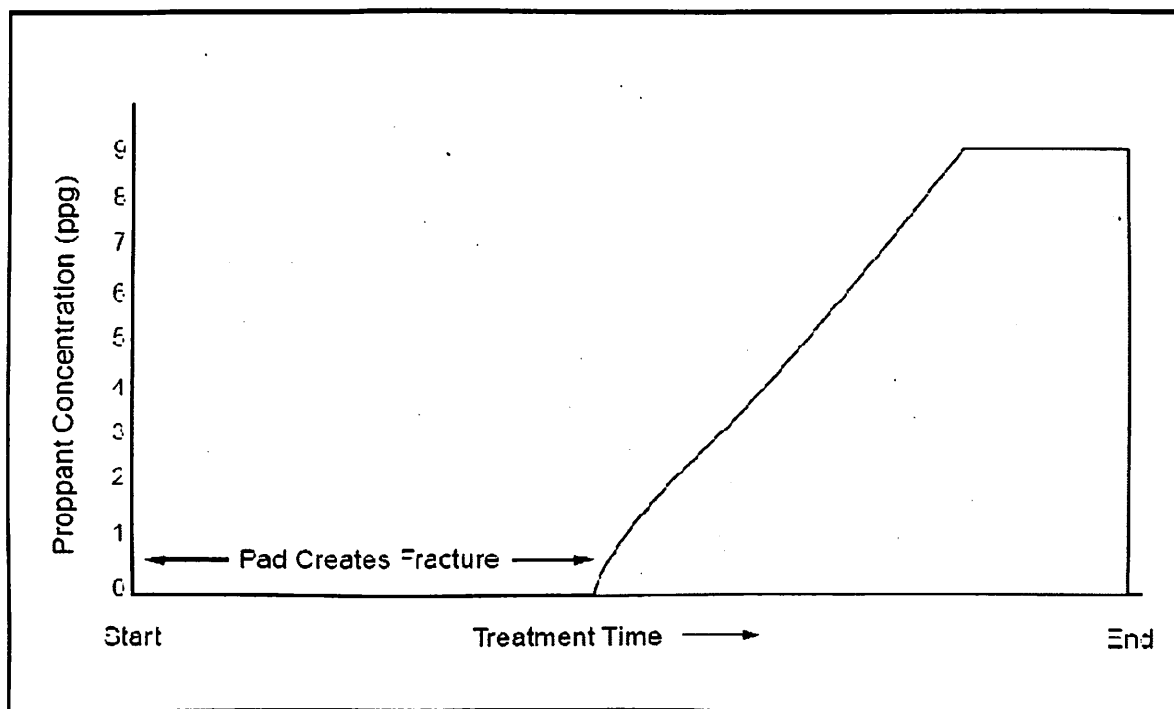


Figure 14(a) - Hydraulic fracturing proppant concentration schedule during an hydraulic fracturing treatment

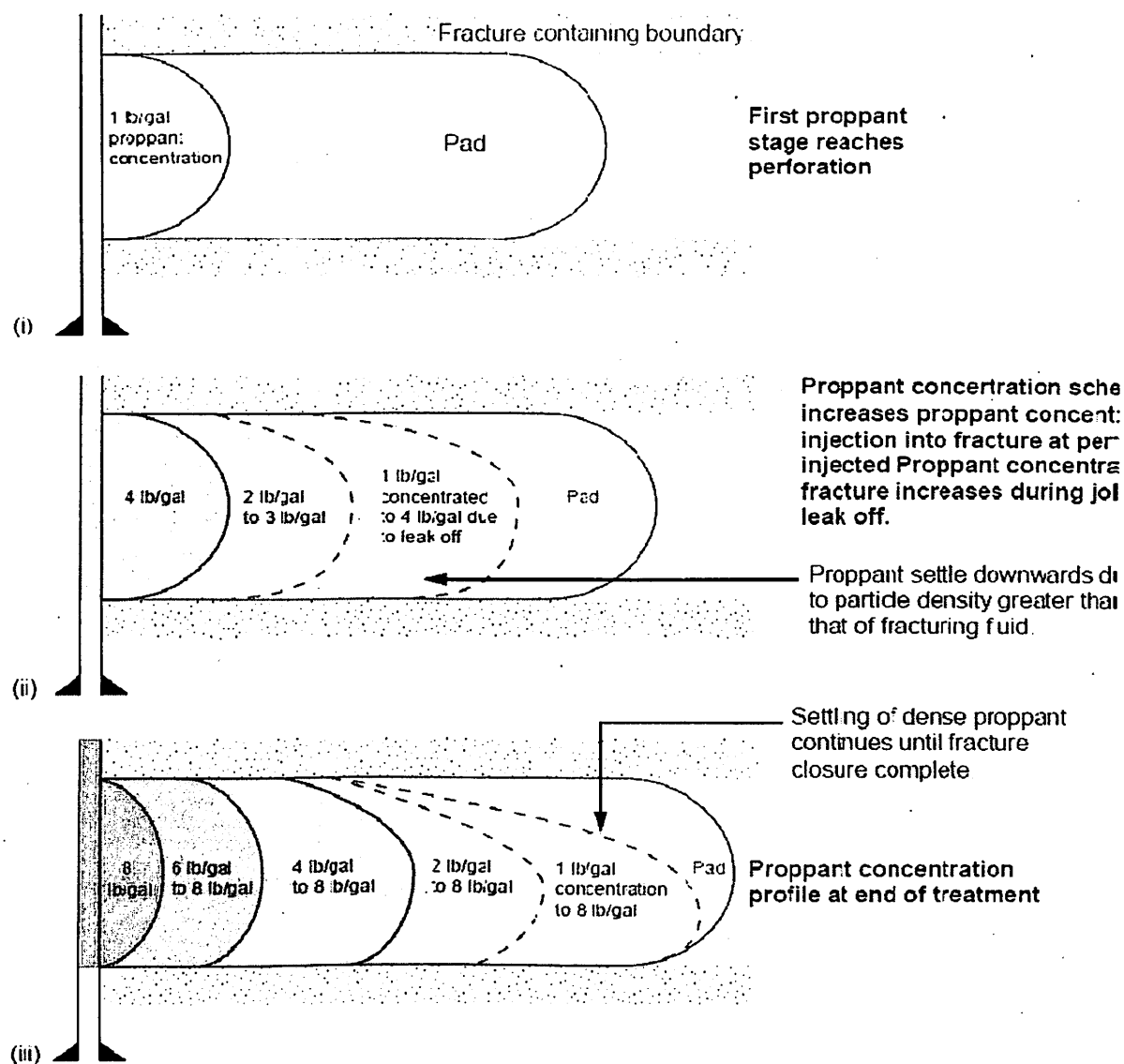


Figure 14(b) - Proppant profile development during a hydraulic fracture treatment.

- (iii) The proppant slurry in the wellbore is displaced to the perforations and fluid injection halted. This normally occurs at about the same time as the first proppant reaches the fracture tip. There will be minimal stimulation from the fracturing treatment if the final proppant slurry volumes are over displaced away from the wellbore i.e. the well loses (direct) communication with the hydraulic fracture. However, excessive under displacement of the slurry will leave large amounts of proppant in the wellbore at the end of the treatment. This would then have to be removed by a special cleanout trip made with a coiled tubing or work over unit prior to returning the well to production.
- (iv) Leak-off continues and the fracture closes on the proppant. Viscosity degradation from the action of the chemical breaker added to the fracturing fluid aids in the back production of the degraded fracturing fluid followed by hydrocarbon production.

A complex computer program is required for treatment design since, in addition to the complexities of fracture shape prediction described earlier; it must also optimise the transport of the proppant within the fracture.

7. MODELLING THE SHAPE OF THE INDUCED FRACTURE:

Several (commercial) programmes are available to predict the shape (height, length and width) of the induced hydraulic fracture. They fall into one of three classes:

- (i) **2D**: these models use two dimensional, analytical equations where the fracture height is required to be input.

This class is used extensively in engineering programs, requiring a reduced data set to the others, as well as limited computing requirements.

- (ii) **P3D**: or pseudo three dimensional programs. This combination of analytical and numerical routines will predict the fracture height and width to vary somewhat independently.

This class is used by fracturing specialists and has moderate computing requirements.

- (iii) **Fully 3D**: these fully three dimensional programs are complex numerical modelling programs with extensive input data and high end computing requirements. The fracture height, width, length and shape can all vary completely independently.

This class of program is normally only found in the research laboratories. Realistic predictions from any of these programs depends on accurate input data being available. This includes:

- (i) Geological data (formation boundaries etc.)
- (ii) Rock mechanical properties from sonic and density logs and core measurements (Young's modulus, Poisson's Ratio etc.)

The extent of data provision required for specific case studies often limits the application of fully 3D programs to more generic studies evaluating the effects of changes in a given treatment or formation parameter.

7.1 2D FRACTURE MODELS:

The complexity of hydraulic fracturing models derives from the need to simultaneously satisfy two sets of laws:

- (i) conservation of momentum, mass and energy;
- (ii) Fracture propagation criteria that control the advance of the fracture tip.

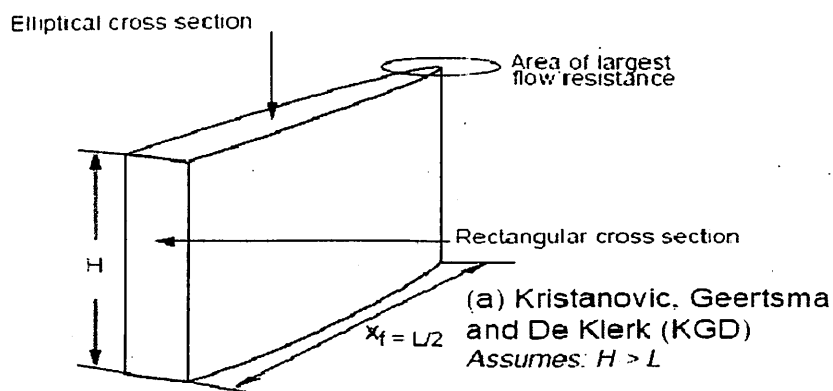
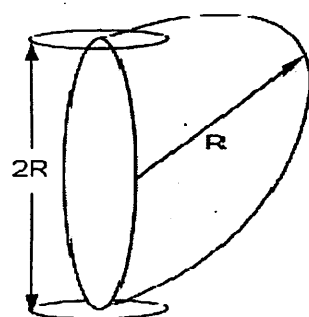
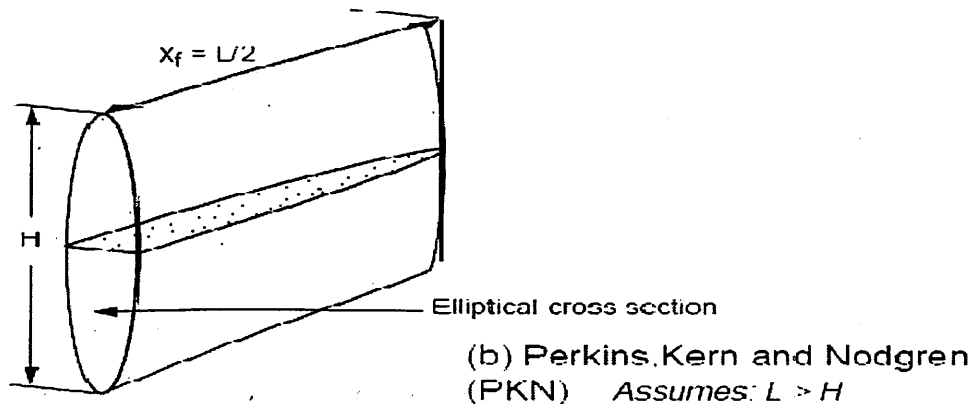


Figure 15a - Fracture shapes predicted by two dimensional hydraulic fracturing models(KGD)



(c) Radial Model
Assumes: $L = H = 2R$

Key

H (or $2R$) is fracture height at wellbore.
 x_f (or $L/2$ or R) is fracture half length.

Figure 15(b,c) - Fracture shapes predicted by two dimensional hydraulic fracturing models(PKN & Radial)

We will look at the class (i) or 2D models in greater detail:

- (i) The simplest solution available is when the fracture height is greater than the fracture length and free slippage occurs at the upper and lower boundary giving a rectangular shape at the wellbore. The fracture shape will not depend on the

vertical position in the fracture (see Figure 24a). This model was introduced by Kristianovic, Geerstma and de Klerk (KGD).

- (ii) A second situation is when the fracture is confined by boundary layers-it has an elliptical shape at the wellbore and the length is much greater than the height.
- (iii) A limiting case between the two is the radial one when the fracture height equals the fracture length (Figure 24c).

As mentioned earlier, they require a value for the fracture height to be input. Within this constraint and when used in the correct application area (i.e. L/H ratio), they give results which agree well with the more complex models.

7.1.1 2D FRACTURE MODELS:

7.1.1.1 CONSTANT HEIGHT FRACTURE MODELS:

Since the wellbore is often fractured at a great depth ($> 5,000$ ft) where the minimum in-situ stress is in the horizontal plane, the fracture is a vertical fracture whose plane is perpendicular to the minimum in-situ stress. There are two factors that control the vertical growth of a hydraulic fracture. They are (1) the contrast in material properties, and (2) the contrast in vertical distribution of in-situ stress. Warpinski and his co-authors have made detailed studies of these factors both in the laboratory and in the field. They have found that the contrast in in-situ stress is the predominant factor that influences the height growth of hydraulic fractures and that the contrast in material properties, unless very large (five times or larger), is not a dominant factor in fracture containment. Laboratory experiments have demonstrated that an in-situ stress contrast of 400 psi is sufficient to contain the vertical growth of a hydraulic fracture.

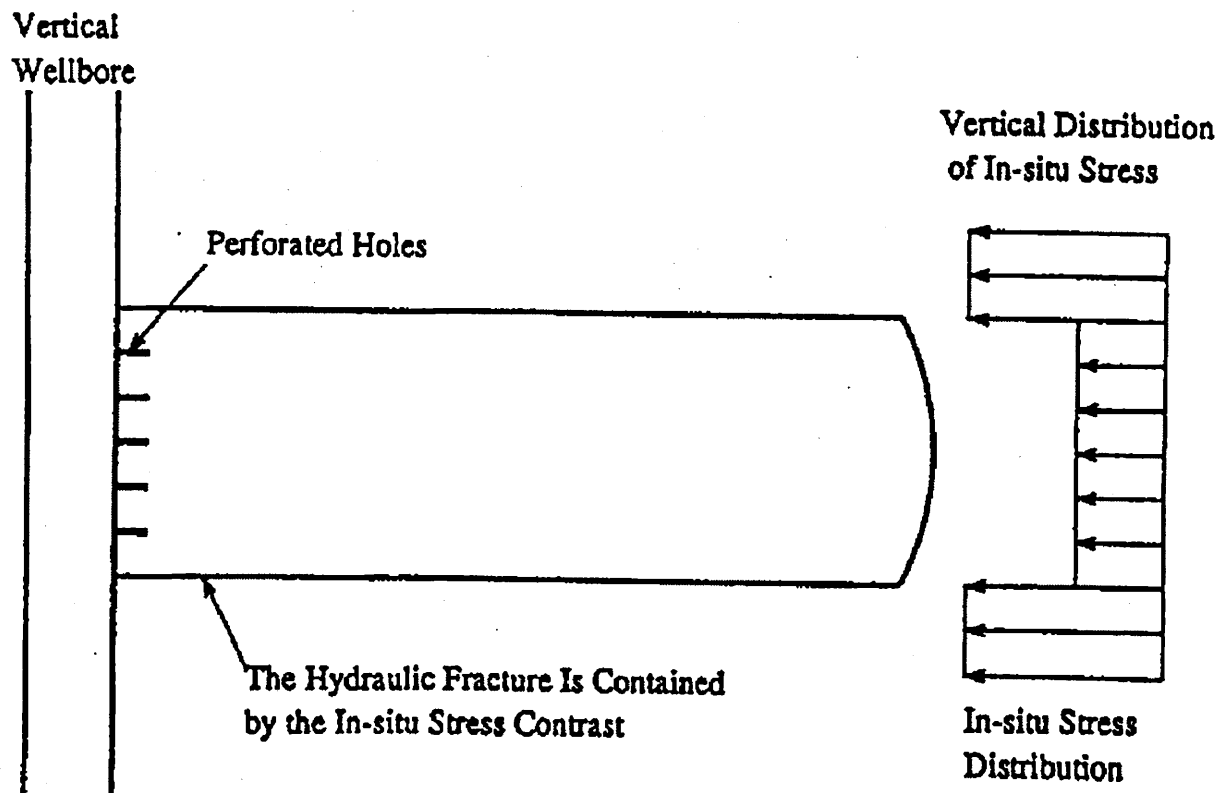


Figure 16 - The vertical growth of hydraulic fracture is contained by the contrast in in-situ stresses.

Since the plane of hydraulic fracture is perpendicular to the minimum horizontal in-situ stress, the growth of fracture height is controlled by the vertical distribution of the horizontal minimum in-situ stress. When the contrast of stresses between adjacent stress zones is large, the growth of fracture height is expected to be contained as shown in Fig. 16.

There are two basic constant height models: the Khristinaovic-Geertsma Klerk, KGD model, and the Perkins-Kern-Nordgren, PKN model. Most of the early hydraulic fractures were designed by applying one of these models. The underlying mechanics of these two models differs significantly.

7.1.1.1.1 THE KHRISTIANOVIC-GEERTSMA-DE KLERK (KGD) MODEL:

One wing of the KGD fracture is shown in Fig. 17(a). In addition to the constant height assumption, two other assumptions are (1) the fracture is at a plane strain condition in the horizontal plane; and (2) the fracture tip is a cusp-shaped tip as proposed by Barenblatt. This assumption of a cusp-shaped tip removes the stress singularity at the fracture tip which would otherwise be predicted by the elasticity analysis.

Following Geertsma-de Klerk, the fracture is approximated as a channel of opening width w . The pressure distribution for the flow of a viscous fluid (Newtonian fluid) inside the fracture can be written as

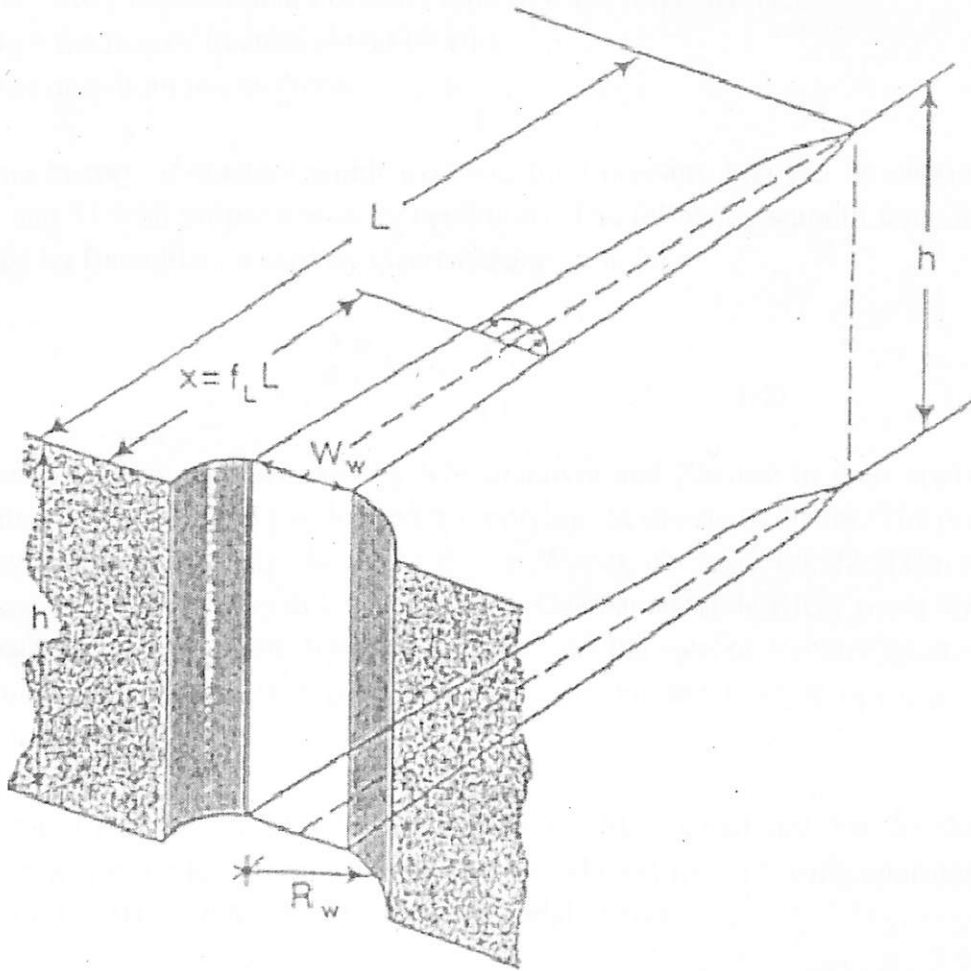


Figure 17(a) - The KGD constant height fracture model

$$p_w - p = \frac{12\mu QL}{h} \int_{f_{L,w}}^{f_L} \frac{df_L}{w^3}, \quad \dots\dots\dots (30)$$

h = fracture height,
 L = total length of the fracture,
 p = local fluid pressure,
 p_w = fluid pressure at wellbore,
 Q = fluid injection rate,
 r_w = wellbore radius,
 w = local fracture width,
 μ = frac-fluid viscosity.

The above equation has two unknowns, p and w . England and Green's solution for a plane fracture in an infinite elastic medium provides another relationship between p and w as

$$w = \frac{4(1-\nu)L}{\pi G} \left[\int_{f_L}^1 \frac{f_2 df_2}{\sqrt{f_2^2 - f_L^2}} \int_0^{f_2} \frac{p(f_1) df_1}{\sqrt{f_2^2 - f_1^2}} - \frac{\pi}{2} \sigma_{\min} \sqrt{1 - f_L^2} \right], \quad (1-5) \quad \dots\dots\dots (31)$$

Where

G and ν = shear modulus and Poisson's ratio of rock, respectively,

f_1 and f_2 = fraction of fracture extent ($= x/L$),

$s_{\min}$ = the minimum in-situ stress.

The time history of fracture width $w(t)$ and fluid pressure $p(t)$ can be obtained by solving Eqs.30 and 31 with proper boundary conditions. The following smooth fracture tip condition proposed by Barenblatt is used by Geertsma and de Klerk:

$$\left(\frac{dw}{df_1}\right)_{f_1=1} = 0. \quad \dots\dots\dots (32)$$

The same condition is also used by Khristianovic and Zheltov in their study of hydraulic fracturing. Note that Eq. 31 is derived by applying the elasticity theory. The proper boundary condition at the fracture tip should be $f_L = 1$, $W = 0$, not as in Eq. 32. Therefore, there is a mathematical inconsistency at the fracture tip. Geertsma and de Klerk argue that since the tip is a local singularity of the fracture, its effect on the overall fracture geometry should be small and their solution is a good approximation for the fracture opening width and the overall fracture length.

By assuming that the dry zone in front of fracture tip is small and that the shape of the wet portion in a fracture can be approximated by an ellipse, the following approximate solutions (no fluid leak off) are obtained by Geertsma and de Klerk:

Fracture length:

$$L = 0.48 \left[\frac{8GQ^3}{(1-\nu)\mu} \right]^{1/6} t^{2/3} \quad \dots\dots\dots (33)$$

Maximum fracture opening width

$$w_o = 1.32 \left[\frac{8(1-\nu)Q^3\mu}{G} \right]^{1/6} t^{1/3} \quad \dots\dots\dots (34)$$

Wellbore pressure

$$p_w = \sigma_{\min} + 0.96 \left[\frac{2G^3Q\mu}{(1-\nu)^3L^2} \right]^{1/4} \quad \dots\dots\dots (35)$$

One sees that the fracture opening width increases in proportional to $t^{1/3}$ and the wellbore pressure decreases with the increase of fracture length and approaches to in-situ $s_{\min}$ for large value of L . Since the fracture is assumed to be at a plane strain condition in the horizontal plane, the KGD model is best suited for fractures whose length/height ratio is near unity or less.

7.1.1.1.2 THE PERKINS-KERN-NORDGREN (PKN) MODEL:

Figure 17(b) is a sketch of a PKN fracture. In addition to the assuming a constant fracture height, the other two assumptions are

(1) The fracture is at a state of plane strain in the vertical plane and the vertical fracture cross-section is elliptical and

(2) The fracture toughness has no effect on the fracture geometry, i.e., the K_{IC} of the rock medium is assumed to be zero.

Following Nordgren, the continuity equation for flow of an incompressible fluid inside the fracture can be written as

$$\frac{\partial q}{\partial x} + q_l + \frac{\partial A}{\partial t} = 0 \quad \dots\dots\dots (36)$$

Where

$q(x,t)$ = volume rate of flow through a cross-section of the fracture,

$q_l(x, t)$ = volume rate of fluid leak off per unit fracture length,

$A(x,t)$ = cross-sectional area of the fracture.

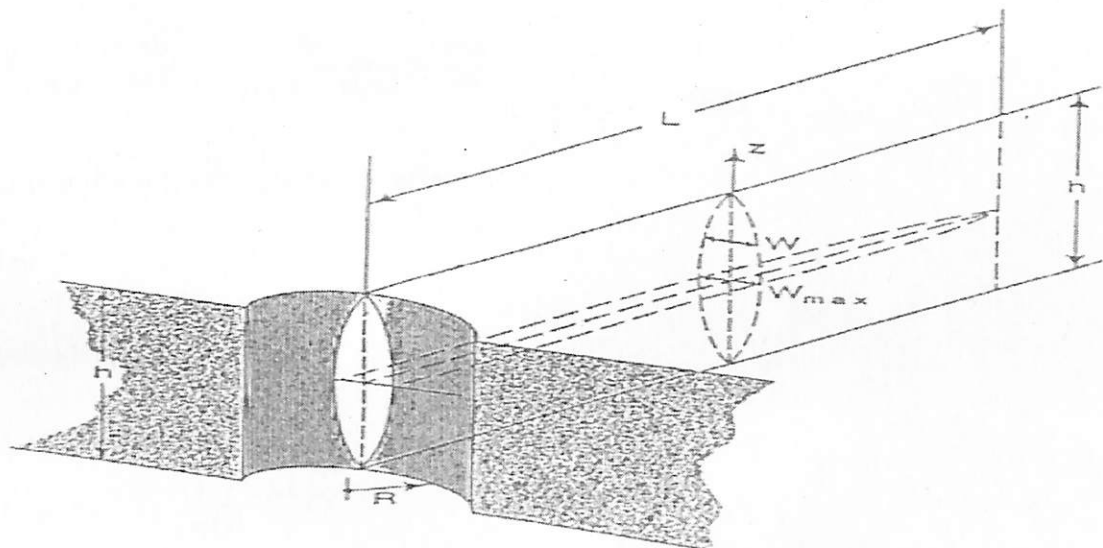


Figure 17(b) - The PKN constant height fracture model

The elliptical fracture opening width w is directly related to the net pressure p by equation

$$w = \frac{(1 - \nu)}{G} (h^2 - 4z^2)^{1/2} p \quad \dots\dots\dots (37)$$

Knowing the fracture geometry, the fracture cross-sectional area can be written as

$$A = \int_{-h/2}^{h/2} w dz = \frac{\pi}{4} Wh \quad \dots\dots\dots (38)$$

Where,

$W = W_{\max}$ is the maximum fracture opening width.

The volume rate of fluid flow q is related to the pressure gradient by the solution for laminar flow of Newtonian fluid in an elliptical tube, i.e.,

$$q = -\frac{\pi W^3 h}{64\mu} \frac{\partial p}{\partial x} \quad \dots\dots\dots (39)$$

The fluid leak off rate q_l is expressed as

$$q_l = \frac{2c_l h}{\sqrt{t} \tau(x)} \quad \dots\dots\dots (40)$$

Where

c_l = fluid loss coefficient,

$t(x)$ = time at which fluid leak-off begins at position x .

Substitution of Eqs. 38, 39, and 40 into Eq. 36 gives the governing equation for the propagation of a hydraulically induced fracture.

$$\frac{G}{64(1-\nu)\mu h} \frac{\partial^2 W^4}{\partial x^2} = \frac{8c_l}{\pi\sqrt{t} \tau(x)} + \frac{\partial W}{\partial t} \quad \dots\dots\dots (41)$$

The initial condition for the above equation is

$$W(x,0) = 0$$

And the boundary conditions are

$$W(x,t) = 0, \text{ at } x > L(t)$$

$$\left[\frac{\partial W^4}{\partial x} \right]_{x=0} = -\frac{256(1-\nu)\mu}{\pi G} Q \quad \dots\dots\dots (42)$$

The above equations are solved numerically by Nordgren. It is interesting to note that the wellbore pressure predicted by the PKN model, in contrast to the KGD model, increases as the fracture length increases.

In the extreme cases of small and large fluid leak off, an analytical solution can be derived from Eq. 41 as follows

For a large fluid leak-off:

Fracture length

$$L = \frac{Q}{\pi c_e h} t^{1/2} \quad \dots\dots\dots (43)$$

Fracture opening width

$$w_o = 4 \left[\frac{2(1-\nu)\mu Q^2}{\pi^3 G c_e h} \right]^{1/4} t^{1/8} \quad \dots\dots\dots (44)$$

Wellbore pressure (net)

$$p_w = 4 \left[\frac{2G^3 \mu Q^2}{\pi^3 (1-\nu)^3 c_e h^3} \right]^{1/4} t^{1/8} \quad \dots\dots\dots (45)$$

For no fluid leak-off:

Fracture length

$$L = 0.68 \left[\frac{GQ^3}{(1-\nu)\mu h^4} \right]^{1/5} t^{4/5} \quad \dots\dots\dots (46)$$

Fracture opening width

$$w_o = 2.5 \left[\frac{(1-\nu)\mu Q^2}{Gh} \right]^{1/5} t^{1/5} \quad \dots\dots\dots (47)$$

Wellbore pressure (net)

$$p_w = 2.5 \left[\frac{G^4 \mu Q^2}{(1-\nu)^4 h^6} \right]^{1/5} t^{1/5} \quad \dots\dots\dots (48)$$

Due to the assumption of a plane strata condition in the vertical plane, the PKN model has been generally regarded to be best suited for fractures whose length/height ratio is large.

7.1.1.2 CIRCULAR FRACTURES:

When the vertical distribution of the minimum in-situ stress is uniform, the hydraulic fracture is expected to take the shape of a circle. Geometrically, a circular fracture is a 3-D fracture; however it is mathematically a 2-D fracture similar to the constant height fractures discussed in the previous section. Geertsma and de Klerk have shown that the governing equations for their constant height fracture can be readily converted to that for a circular fracture as follows:

$$p_w - p = \frac{6\mu Q}{\pi} \int_{f_{rw}}^{f_l} \frac{df_r}{f_r w^3},$$

$$w = \frac{4(1-\nu)R}{\pi G} \left[\int \frac{df_2}{\sqrt{f_2^2 - f_r^2}} \int \frac{f_1 p(f_1) df_1}{\sqrt{f_2^2 - f_1^2}} - \sigma_{\min} \sqrt{1 - f_r^2} \right], \quad (49)$$

Where, $f_r = r/R$, $f_{rw} = r_w/R$, and r_w and R are the radii of wellbore and circular fracture, respectively.

The approximate solution for the above equation is as follows:

Fracture radius:

$$R = 0.548 \left[\frac{GQ^3}{\mu} \right]^{1/9} t^{4/9} \quad (50)$$

Maximum fracture opening width

$$w_o = 2 \left[\frac{\mu^2 Q^3}{G^2} \right]^{1/9} t^{1/9} \quad (51)$$

Wellbore pressure

$$p_w = \sigma_{\min} - \frac{5}{4\pi} \frac{Gw_o}{R} \ln\left(\frac{r_w}{R}\right) \quad (52)$$

The same problem has been studied by Abe, Mura, and Keer with a rigorous treatment of fracture tip. Referring to Fig. 18 and noting that R is the radius of the domain wetted by the fluid, the governing equations for the propagation of a circular hydraulic fracture can be written as follows:

The continuity equation for fluid:

$$\frac{\partial(\rho w)}{\partial t} + \frac{1}{r} \frac{\partial(rq)}{\partial r} = 0 \quad (53)$$

The equation of motion for fluid:

$$\frac{\partial p}{\partial r} = - \frac{12\mu q}{\rho w^3} \quad (54)$$

The fracture opening equation:

$$w = \frac{8(1-\nu^2)}{\pi E} \int_r^R \frac{r_1 dr_1}{\sqrt{r_1^2 - r^2}} \int_{r_w/r_1}^1 \frac{x}{\sqrt{1-x^2}} [p(x, r_1) - \sigma_{\min}] dx \quad (55)$$

The stress intensity factor K at fracture tip:

$$\pi \left(\frac{R}{2} \right)^{1/2} K = \int_{r_w}^R \frac{[p(r) - \sigma_{min}] r dr}{\sqrt{R^2 - r^2}} \quad \dots\dots\dots (56)$$

The global fluid conservation equation:

$$\int_{r_w}^R \rho r w dr = \int_0^t Q r_w dt \quad \dots\dots\dots (57)$$

The boundary conditions for the above equations are

$$p = p(r, t), R_0 = r = R_1$$

$$p = 0, \quad R_1 = r = R$$

$$p(R_1, t) = 0, \text{ at } r = R_1.$$

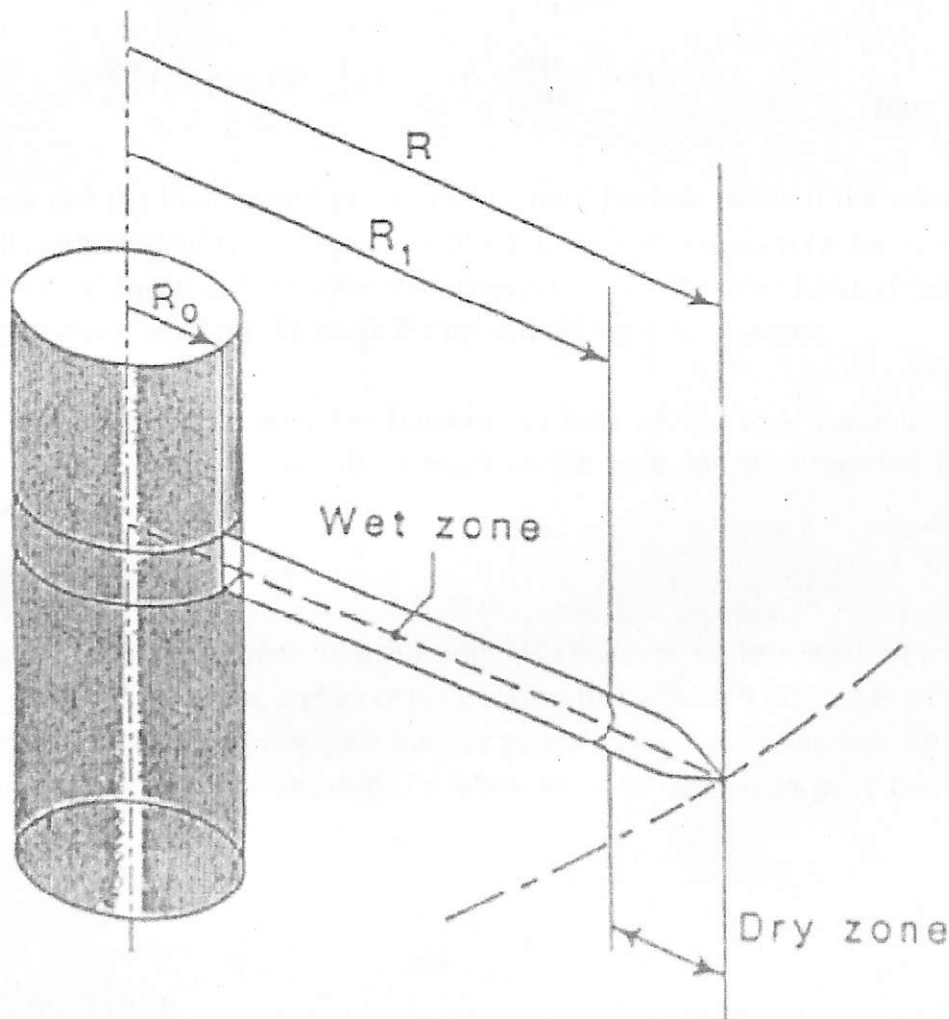


Figure 18 - A circular fracture with dry zone

The above equations are solved numerically by the authors and the results are generally in agreement with those from the KGD model. Their analysis of singularity at the fracture tip is instructive. The results are summarized in the following paragraphs:

At fracture tip, $w = 0$, the right-hand side of Eq. 54 is singular. It follows from the theory of elasticity that the width w near fracture tip can be expressed by

$$w = C(r - r)^{\gamma}, \gamma \geq 1/2 \quad (58)$$

Where C is a non-vanishing constant.

Barenblatt's theory requires that the opposite faces of the fracture close smoothly at its edge, so that $\gamma > 1$. If this condition is satisfied, the integration of Eq. 54 in finding the pressure p will not converge if the tip of fracture is included. This leads to the conclusion that Eq. 54 is applicable only in the wetted region, $R_0 < r < R_1 < R$, where the fracture width w is not zero.

Let $u_a = dR_1/dt$ be the fluid velocity at tip $r = R_1$ (or the moving velocity of the wet zone), the flow rate can be written as $q = \gamma w u_a$. Then, at $r = R_1$, the right-hand of Eq. 54 can be written as

$$-\frac{12\mu}{\rho} \frac{1}{w^2} \frac{dR_1}{dt} = \frac{dR_1}{dt} O\left(\frac{1}{w^2}\right) \quad (59)$$

Therefore,

$$\left(\frac{\partial p}{\partial r}\right)_{r=R_1} = O\left(\frac{1}{w^2}\right) \quad \text{if} \quad \frac{dR_1}{dt} \neq 0 \quad (60)$$

This implies that the fluid cannot penetrate the entire fracture radius if the velocity u , is not zero, and its impenetrability is characterized by Eq. 60. The condition for the wet radius R_1 is given by the third equation of the boundary conditions. On the other hand, if there is no fluid flow in the fracture, the fluid can reach the tip and fill the entire fracture.

In the KGD and PKN models, the fracture stiffness of the rock medium is neglected. According to Barenblatt, the tensile strength of the rock can be neglected for large-size fractures by the condition

$$1 \gg \frac{\pi}{\sqrt{2R}} \frac{K_{IC}}{\sigma_{min}} \quad (61)$$

This condition has been adopted by many authors. However, in their study of propagation of circular fractures, Abe, Mura, and Keer have shown that although the length of dry zone ($R - R_1$) is indeed very small, its effect on fracture geometry cannot be ignored. An approximate formula for the average fluid pressure p_a when the R/r_w ratio is large is derived by these authors as follows:

$$\frac{p_a - \sigma_{min}}{\sigma_{min}} = \frac{1}{1 - \sqrt{1 - \left(\frac{R_1}{R}\right)^2}} \left[\sqrt{1 - \left(\frac{R_1}{R}\right)^2} + \frac{\pi}{\sqrt{2R}} \frac{K_{IC}}{\sigma_{min}} \right] \quad (62)$$

The second term in the bracket reflects the fracture strength of the rock. It is seen that this term can not be neglected in the fracture growth problem. The fracture opening width is established mainly by the net pressure (i.e., $p_a - \sigma_{min}$) inside the fracture. To obtain an approximate solution, the following condition should be used instead of Eq. 61:

$$\sqrt{1 - \left(\frac{R_1}{R}\right)^2} \gg \frac{\pi}{\sqrt{2R}} \frac{K_{IC}}{\sigma_{min}} \dots\dots\dots (63)$$

The ratio R_1/R is an increasing function of R and it is almost equal to unity for large fractures. However, it is practically impossible to satisfy inequality 63. Therefore, the effect of dry zone and the fracture toughness must be taken into consideration in the analysis of fracture propagation. The same conclusion has also been reached by Jeffrey and by Yew and Liu using the KGD model.

8. Fluid Systems:

The fracturing fluid is a vital part of the fracturing process. It is used to create the fracture, to carry the proppant into the fracture, and to suspend the proppant until the fracture closes. On a more basic level, the fluid system is the vehicle that allows us to transfer mechanical energy (in the frac pumps) into work performed on the formation. In order to carry out these tasks efficiently, the ideal fluid must have a combination of the following properties.

- (i) Low cost.
- (ii) Ease of use.
- (iii) Low tubing friction pressure.
- (iv) High viscosity in the fracture, to suspend the proppant.
- (v) Low viscosity after the treatment, to allow easy recovery.
- (vi) Compatibility with the formation, the reservoir fluids and the proppant.
- (vii) Safe to use.

Some of these properties are not easy to combine in the same fluid. Usually, the process of selecting a fracturing fluid is a trade off. It is up to the Engineers to decide which properties are most important and which properties can be sacrificed. In order to make this choice easier, there are a number of fluid systems available for fracturing.

8.1 Water-Based Linear Systems:

The first fracturing fluid, used in Kansas in 1947, was gasoline gelled with war surplus napalm. Obviously this was a highly dangerous fluid, and it wasn't long before water based systems were available. The first of these systems used starch as the gelling agent, but by the early 1960's guar was introduced and soon became the most common polymer for fracturing. Today, polymers derived from the guar bean are used in most fracturing treatments - the other main source of polymers being cellulose and its derivatives.

Before the dry polymer is added to the water, the individual molecules are tightly curled up on themselves. As the polymer molecule hydrates in water, it straightens out – which is why these fluids are referred to as linear gels – as illustrated in Figure 19:-

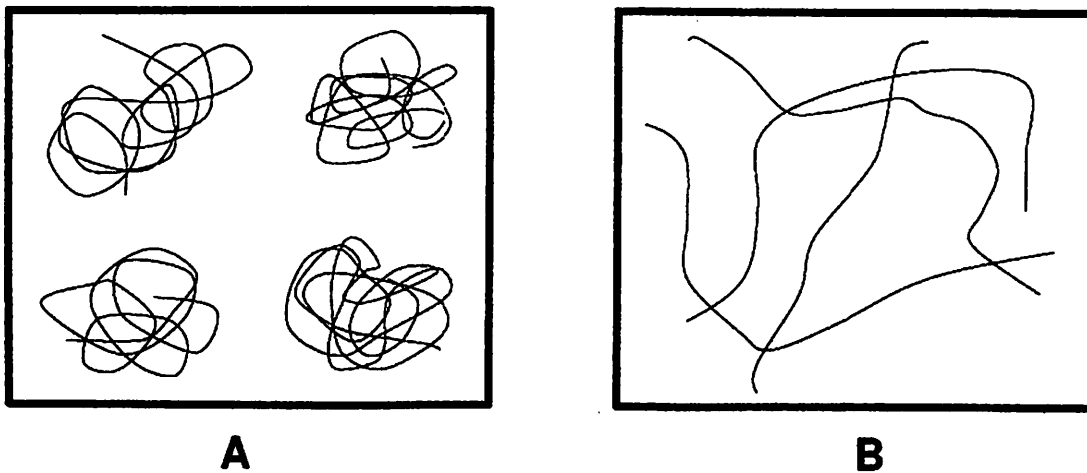


Figure 19 – Hydration of polymer gels in water. 'A' shows a polymer molecule before hydration in water, whilst 'B' shows a polymer molecule after hydration in water.

It is these long, linear molecules that produce the increase in viscosity. However, it should be remembered that this hydration only occurs at a specific pH range. Outside this range, the hydration rate can be very slow and sometimes almost non-existent. Different polymers have different pH ranges, and buffers may have to be used to make the polymer hydrate. If a polymer that hydrates at a neutral pH is added to water, it may start to hydrate very rapidly. This leads to the formation of “clumps” of non-hydrated polymer, surrounded by partially hydrated polymer, surrounded in turn by hydrated polymer. These are known as *fish-eyes* and are a sign that the gel has been poorly mixed.

Several techniques can be employed to prevent the formation of fish-eyes.

- i) Buffer the water so that the pH will prevent hydration. Once the polymer powder is thoroughly dispersed in the water, a different buffer is used to change the pH to a point where the polymer will hydrate.
- ii) Add the polymer through a high shear device (such as a jet mixer) to ensure that the polymer does not form clumps.
- iii) Circulate the hydrating gel through a high shear device, such as a choke, to break up any fish eyes.
- iv) Slurry the polymer into a hydrocarbon-based fluid (such as diesel, kerosene or even methanol).

The slurry is then added to the water, allowing the polymer to disperse before it hydrates.

A combination of these methods can also be used.

Common polymers used for linear gels include:-

- (i) Starch
- (ii) Guar
- (iii) Hydroxypropyl Guar (HPG)
- (iv) Carboxymethyl Hydroxypropyl Guar (CMHPG)
- (v) Carboxymethyl Guar (CMG)
- (vi) Cellulose
- (vii) Hydroxyethyl Cellulose (HEC)

The most commonly used polymers for fracturing are Guar, HPG and CMHPG, mostly as the basis for crosslinked systems (see below). HEC is probably the most widely used polymer for linear gel fracturing, due to its popularity for fracturing low temperature, high permeability formations.

8.2 Water-Based Crosslinked Systems:

The majority of hydraulic fracturing treatments are carried out using water based crosslinked gels. These systems offer the best combination of low cost, ease of use, high viscosity and ease of fluid recovery. Generally, water based crosslinked gels will be used unless there is a specific reason not to use them – they are the default option. The starting point for a crosslinked system is a linear gel, as described above in Section 8.1.

When used for crosslinked systems, linear gels are often referred to as base gels. The most commonly used linear gels are guar and its derivatives; HPG, CMG and CMHPG. A crosslinked gel, as illustrated in Figure 20, consists of a number of hydrated polymer molecules, which have been joined together by the crosslinking chemical. This series of chemical bonds between the polymer molecules greatly increases the viscosity of the system, sometimes by as much as 100 times. In order for an efficient crosslink to occur, two separate things need to happen. First, the base gel needs to be buffered to a pH which will allow the crosslinking chemical to work. Usually, this is at a different pH to that required for polymer hydration, so a different pH buffer has to be used. Secondly, the crosslinking radical needs to be present at sufficient concentration. If both these conditions occur, the gel will experience a dramatic increase in viscosity.

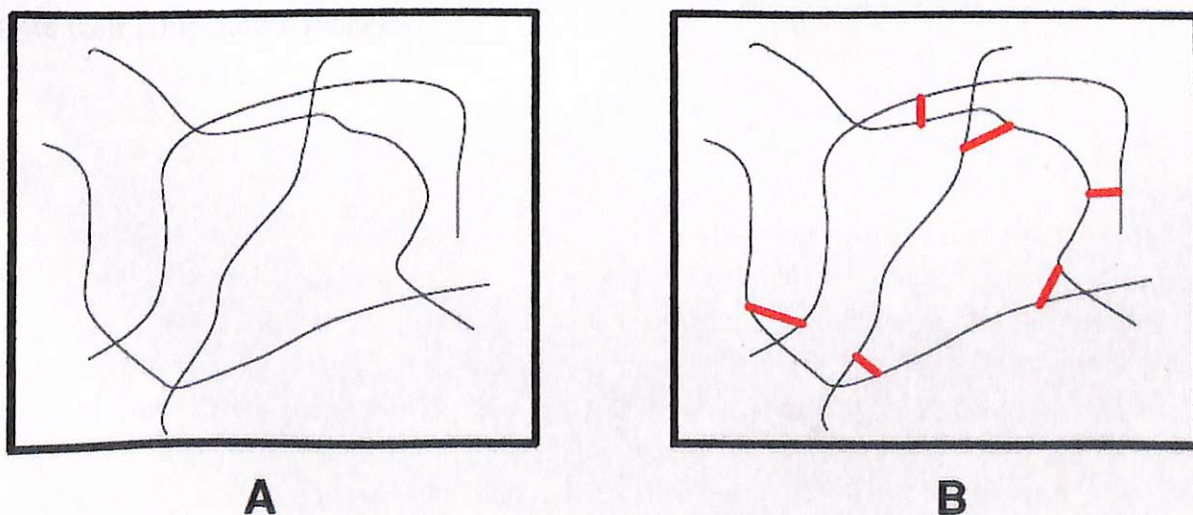


Figure 20 – A crosslinked polymer. 'A' shows the hydrated polymer prior to addition of the

Crosslinker. 'B' shows the crosslink chemical bonds between the polymer molecules.

Obviously, a fully crosslinked polymer is extremely viscous, and can result - under the wrong conditions - in a high level of fluid friction as it is pumped downhole. To counter this, it is quite common to use a delayed crosslinker. A delayed crosslinker can take anything up to 10 minutes before the gel is fully hydrated, depending upon the temperature, initial pH and shear that the fluid experiences. The ideal crosslink delay system would delay the onset of crosslink as long as possible, but would still have the fluid fully crosslinked by the time it reaches the perforations.

The most commonly used crosslinking systems are as follows:-

- (i) Borates
- (ii) "Exotic" Borates
- (iii) Zirconates
- (iv) Aluminates
- (v) Titanates

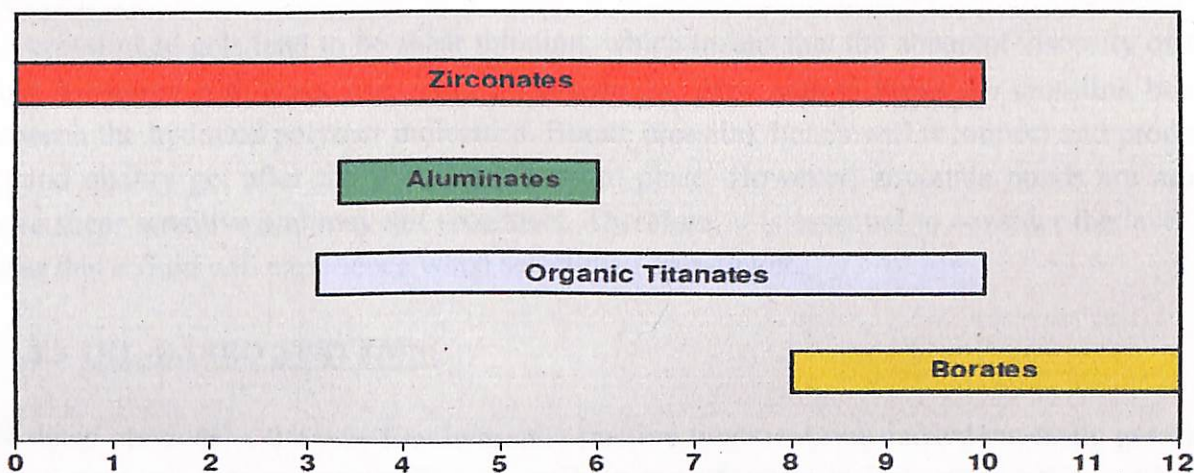


Figure 21 – pH ranges for crosslinkers

Of these, the borates and "exotic" borates are by far the most commonly used, followed by the zirconates. Figure 21 illustrates the pH ranges of these crosslinkers, whilst Figure 22 shows their temperature ranges:-

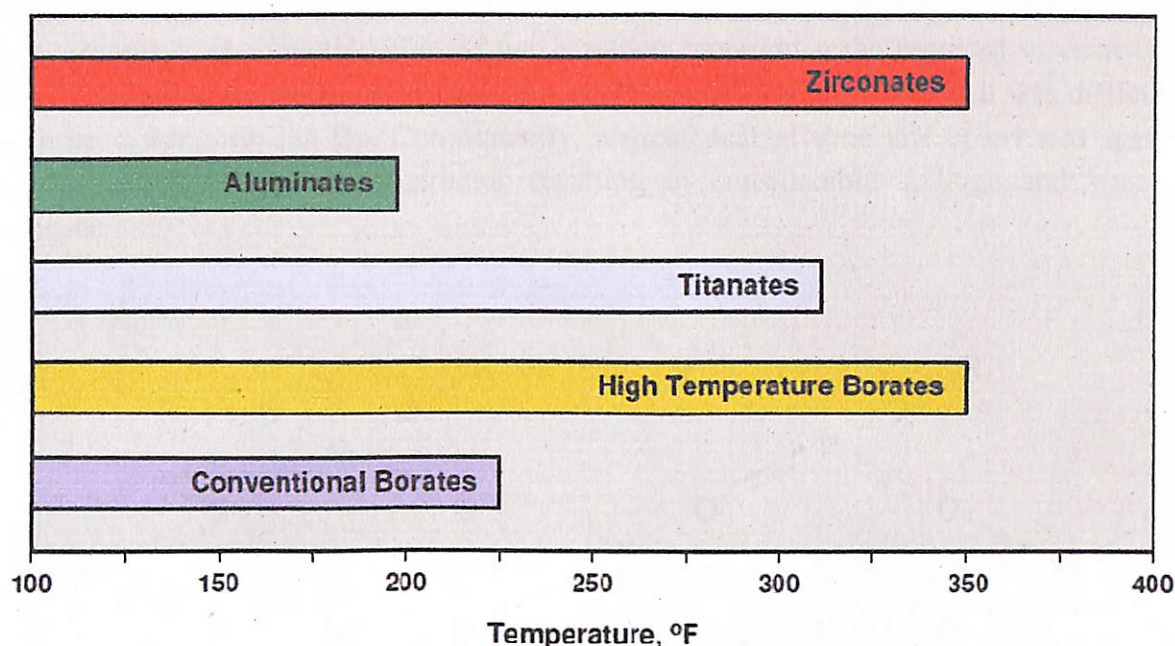


Figure 22 – Temperature range for crosslinkers

All crosslinked gels tend to be shear thinning, which means that the apparent viscosity of the fluid decreases with shear rate. This is because the shear acts to break the crosslink bonds between the hydrated polymer molecules. Borate crosslink bonds will reconnect and produce a good quality gel after the shearing has taken place. However, zirconate bonds are much more shear sensitive and may not reconnect. Therefore, it is essential to consider the level of shear that a fluid will experience when selecting a crosslinker.

8.3 OIL-BASED SYSTEMS:

As stated previously, the very first hydraulic fracture treatment was carried out using gasoline gelled with war surplus napalm. The operation was performed on Pan American Petroleum's Klepper No 1 well, Grant county, Kansas, (part of the Hugoton gas field) in 1947. The treatment was aimed at 4 gas bearing limestone formations, at about 2500 ft. The gasoline based fluid was selected, as it was perceived to be more compatible with the formation. This continues to be the primary reason for selecting an oil-based fluid. For the record, the treatment on Klepper No 1 failed to produce a significant production increase, and it was decided that the "Hydrafrac" process would never compete successfully with acidizing in this type of formation.

The first widely-used oil-based fluid system was based on the reaction of an acidic material (tallow fatty acid) and basic material (caustic) to form a polymeric salt, in a process similar to the manufacture of soap. These fluids provided viscosity, but were very unstable at elevated temperatures. As time progressed, this system was replaced by others based on the use of aluminium phosphates, which were able to provide significantly increased viscosity and more stability at elevated temperatures. In the early 70's, the aluminium phosphate systems were replaced by the aluminium ester systems. The association of aluminium and phosphate esters is illustrated in Figure 23.

These systems used a combination of two products to produce the required viscosity. The relative ratio of these two products was extremely critical – so critical that it was difficult to mix these systems on the fly. Consequently, a great deal of time and effort was spent in pregelling tanks full of hydrocarbons, resulting in considerable spillage and waste of chemicals.

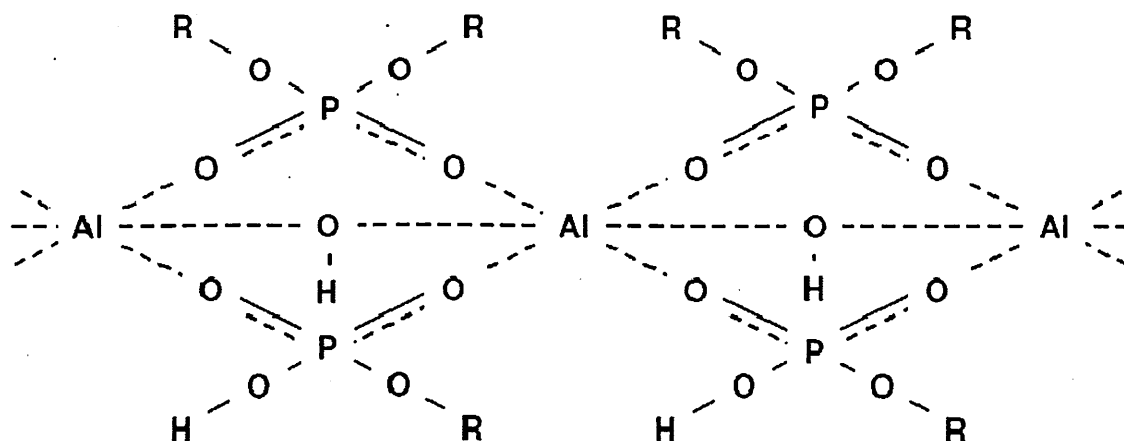


Figure 23 – Aluminium phosphate association polymer

8.4 EMULSIONS:

In general, emulsions are only rarely used in fracturing operations, but in some parts of the world they have been found to have an ideal combination of fluid loss characteristics, formation compatibility and downhole viscosity. As a result, in these areas their use is common.

Most of these systems are oil-in-water emulsions and operate in a similar fashion. Water is gelled with a standard gelling agent and held in a tank(s). During the job, water and oil are mixed together at the ratio of 2 parts oil to one part gel. An emulsifier is either pre-blended in the water phase (the gel) or added on the fly. The fluids very quickly form a brown emulsion, the viscosity of which is largely proportional to the initial viscosity of the water phase. Some systems require an external breaker in order to destroy the emulsion and allow the fluids to be recovered. However, in most systems, the emulsion quickly falls apart after exposure to the formation.

8.5 VISCO-ELASTIC SURFACTANT FLUIDS:

Visco-elastic surfactant (VES) systems are water-based fluids that employ a completely different method from all other water-based fluid systems for obtaining viscosity. They do

not rely upon the hydration of a polymer. Instead, they use the unique properties of certain surfactants when mixed at certain concentrations in brine-based fluids.

In aqueous fluids, surfactants will tend to expel their lipophilic (water-repelling) tails out from the surface of the fluid. As the concentration of the surfactant increases, close packing occurs and no more surfactant molecules can expel their tails. At this point, the surfactant molecules will start to form spherical aggregates (or micelles) with the lipophilic tail facing inwards, and the hydrophilic head facing outwards. The concentration at which these micelles start to form is called the critical micelle concentration (CMC), and is often around 0.5% by volume of surfactant. The CMC will decrease as the molecular weight of the surfactant increases.

As the surfactant concentration increases further, and in the presence of a suitable counter ion (such as those produced by brines), these micelles can come together to form worm- or rod-shaped aggregates or micelles. It is these rod-shaped micelles that impart viscosity to the water.

VES fluids have some rather unique properties, as follows:-

1. VES fluids are extremely shear thinning, with the property to quickly re-heal after the shear is removed. This means that the fluids have an extremely low friction pressure, whilst at the same time retaining excellent proppant transport characteristics.
2. VES fluids are very easy to mix. Simply start with the base brine and add the surfactant on the fly.
3. VES fluids can be made to be very environmentally friendly, depending upon the combination of surfactant and brine used.
4. VES fluids often require no breaker system, as micelles can be disrupted by changes in pH, high temperatures, and dispersion in formation waters or by contact with hydrocarbons.
5. The VES system is as formation and proppant pack friendly as the base brine used to mix it. The systems contain no polymers, and therefore produce no polymer residue.

Therefore, these fluids are capable of providing zero formation damage and 100% regained proppant pack permeability.

9. PROPPANTS:

The word proppant comes from the abbreviation of two words - "propping agent". Proppants are granular materials, which are placed inside the fracture in order to "prop" the fracture open as the pressure falls below closure. The conductivity of the fracture is directly related to the quantity of proppant within the fracture, the type of proppant, the producing conditions and the size of the proppant grains.

The purpose of hydraulic fracturing is to place the right amount of the right kind of proppant in the right place. When this is done correctly, the well is effectively stimulated.

9.1 PROPPANT PACK PERMEABILITY AND FRACTURE CONDUCTIVITY:

As discussed earlier, one of the major factors affecting post-treatment well performance is the fracture conductivity. This is the product of the proppant pack permeability and the width of the fracture. In other words, the fracture conductivity is a function of the type of material holding the fracture open and the amount of this material within the fracture.

The permeability of the proppant pack is controlled by several factors:-

- i) **Proppant Substrate.** The material that the proppant is made from obviously has a big effect on the permeability of the proppant pack. Some materials are stronger than others and are better able to withstand the enormous forces trying to crush the proppant as the fracture closes. The weaker the material, the more the proppant grain will deform. Proppant deformation reduces the porosity of the pack and reduces the overall fracture width. The more brittle the proppant is, the more likely it is that the proppant will produce fines as the grains are pushed together in a series of point to point contacts. Any fines will significantly reduce the proppant pack permeability.
- ii) **Proppant Grain Size Distribution.** A normal sedimentary formation has a wide variety of grain sizes, depending upon how well "sorted" the individual rock grains are. In general, any sandstone will be a mixture of small, medium and large grains. The mixture of grain sizes acts to reduce the formation's permeability and porosity, as the smaller grains will occupy the pore spaces between the larger grains and will also tend to plug up the pore throats. However, if a set of particles are of almost identical size, then there will be no fines to block up the pore spaces and pore throats, so that the porosity (and hence the permeability) are maximised. This is why proppants are generally produced within a specific grain size distribution. This uniformity of grain size is one of the main reasons why proppant is usually several orders of magnitude more permeable than the formation, and also one of the main reasons why so much effort is spent in ensuring this uniformity of size.

This is illustrated in Figure 24, below;

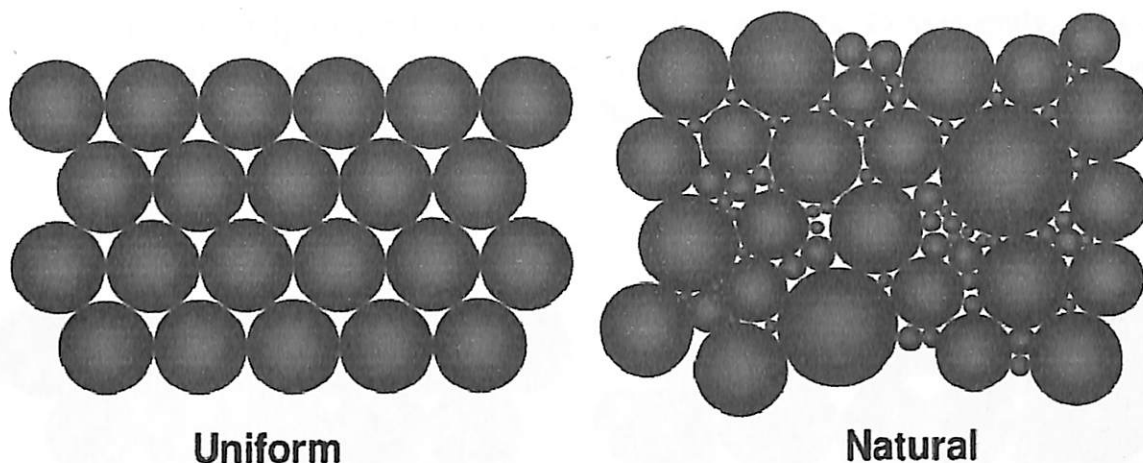


Figure 24 – The effect of uniform and natural grain size distribution on porosity

Proppants are supplied within a specific grain size range. This grain size refers to the size of sieve used to sort the proppant. For instance, 20/40 size means that the vast majority of the proppant will fit through a size 20 sieve (20 holes per square inch), but will not fit through a size 40 sieve (40 holes per square inch). This is sometimes confusing, as larger grain sizes correspond to smaller mesh numbers. Common proppant sizes are 8/12, 12/20, 16/30, 20/40 and 40/60, although theoretically any combination of sizes can be produced.

- iii) **Average Proppant Grain Size.** Generally, the larger the average proppant grain size is, the higher the permeability of the proppant (provided the grain size distribution is reasonably uniform). This is because larger grains produce larger pore spaces and pore throats, allowing an increased flow rate for a similar porosity. However, the larger grains are more susceptible to producing permeability reducing fines than are the smaller grain sizes. This is because larger grains distribute the closure pressure across fewer grain-to-grain points of contact and so the point contact loads tend to be greater.

This is illustrated in Figure 25;

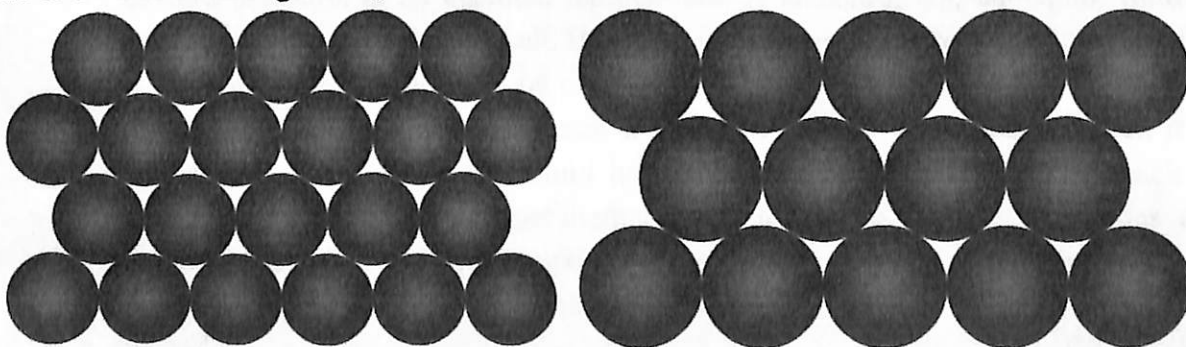


Figure 25 – Diagram illustrating how larger grains have larger pore spaces and hence greater permeability.

- iv) **Sphericity and Roundness.** These quantities define how spherical the proppant grains are and how many sudden, sharp edges the grains have. Obviously, the smoother and more spherical the proppant grain is, the higher the pack permeability. There are standard API procedures for checking these quantities, but

unfortunately they rely on some subjective analysis. Consequently, it is often difficult to see a clear trend between one proppant type and another. However, in general, artificial proppants will have better sphericity and roundness than naturally occurring types.

This is illustrated in Figure 26;

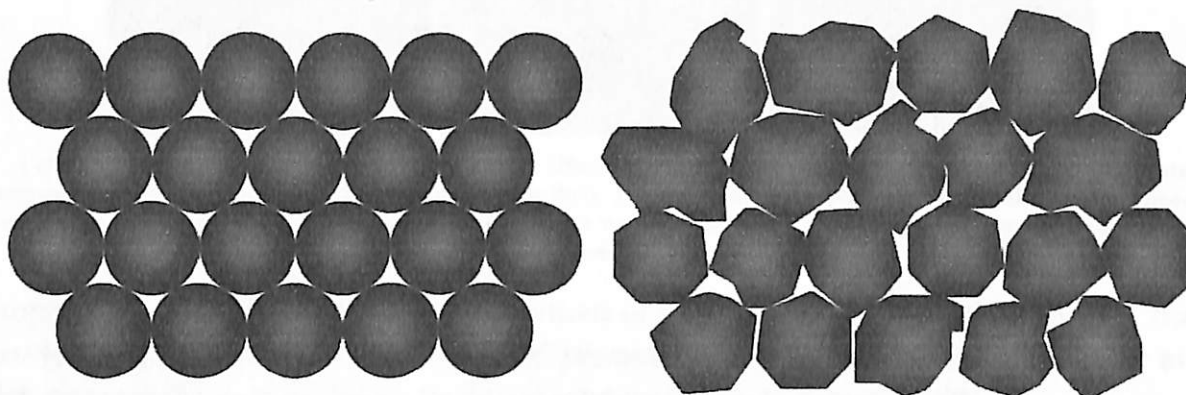


Figure 26 – Diagram illustrating the difference between a proppant with good sphericity and roundness (left), and a proppant with poor sphericity and roundness (right).

Coarse, angular grains also tend to produce more fines, as corners and edges tend to get broken off as compressive stress is applied. Therefore, proppants with good sphericity and roundness also tend to retain greater permeability at high stresses. In addition, because proppant with low sphericity and roundness will produce a more convoluted flow path for the produced fluids, non-Darcy pressure losses tend to be greater in these materials (see Section 10.9), leading to decreased effective proppant pack permeability.

- v) **Frac Fluid Quality.** The amount of residue left by the fracturing fluid can also have a big influence on the permeability of the proppant pack. In order to assess the effect of these fluids, a quantity called *Regained Permeability* is measured. Put simply, a sample of the proppant is put into a load cell and is subjected to a closure pressure, at an elevated temperature. A standard, non-damaging fluid is then flowed through the test cell. By analysing the pressure drop and flow rate, the permeability of the pack can be calculated. Next, the frac fluid is flowed through the test cell, and allowed to remain there for a specific time, during which it is designed to break. Once the fluid has broken, the permeability of the pack is measured again, by the same method as before. The two permeabilities are compared and the result (the regained permeability) is given as the percentage of the original permeability that remains after the test.

Figure 27, below, illustrates the difference between fluids with a high and low regained permeability;

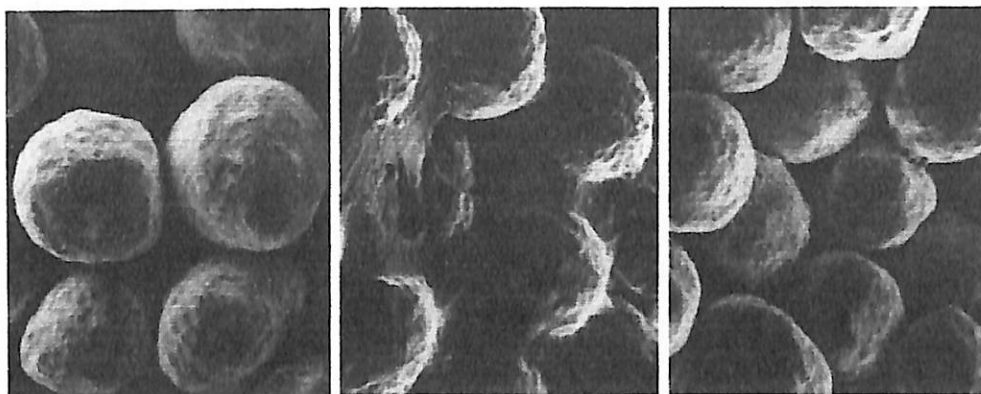


Figure 27 – Three SEM micrographs showing the effects of frac fluid residue. The micrograph on the left shows undamaged proppant before the addition of the frac fluid. The center micrograph shows the residue left by a poorly designed crosslinked system. The final micrograph shows the same proppant pack after an enzyme breaker has been used.

Proppant packs can lose significant proportions of their permeability to fluid damage. Cheap, poorly designed fluids can cause regained permeabilities to be as low as only 30% or even less, whereas the state-of-the-art fluids can produce values in excess of 90%.

- vi) **Closure Stress.** As the proppant is crushed by the closure of the formation, it will start to produce fines. As discussed above, these fines will reduce the permeability of the pack. The stronger the proppant, the fewer fines are produced - nevertheless, all proppant types experience a decrease in permeability as closure stress increases, to a greater or lesser extent. In addition, most proppants also have a “maximum” stress, above which whole-scale disintegration of the proppant substrate starts to occur, rather than simple fines production. At this point, pack permeability falls dramatically.

It should be noted that the reservoir pressure has an influence on the closure stress experienced by the proppant. The relationship between reservoir pressure and closure pressure is dependent upon a number of factors - there are circumstances under which a decrease in reservoir pressure can result in an increase in closure stress. Additionally, there can be localised areas of low reservoir pressure (such as near the wellbore during drawdown) where once again the proppant experiences higher closure pressure. This potential increase in stress with the life of the well must be allowed for when selecting a proppant.

- vii) **Non-Darcy Flow.** As the flow rate through the proppant pack increases, the pressure drop will increase at a rate faster than that predicted by Darcy’s law. This is due to the effects of inertial energy losses, as the fluid rapidly changes direction as it moves through the pore spaces. As the fluid velocity increases, the pressure drop due to inertial flow effects increases with the square of the velocity. So at low flow rates, (such as in a reservoir rock), non-Darcy effects can safely be ignored, whilst at high rates (such as in a proppant pack), the effective proppant permeability has to be reduced to reflect this effect. The phenomenon is particularly significant in high rate gas completions.

- viii) **Multi-Phase Flow.** Multi-phase flow has a similar effect upon proppant pack permeability as it does on formation permeability. It reduces it, by an amount that is dependent upon the absolute permeability, and the relative saturation of each phase. As it is very rare for a reservoir to produce a single phase (with the exception of some gas reservoirs), it is also very rare for proppant to conduct only a single phase. Therefore, the actual effective permeability of the proppant pack may be significantly less than the published data, which is generally produced for single-phase flow only (although this situation is improving).

10. OVERVIEW OF EQUATIONS AND METHODS USED IN CASE STUDY

The equations used in the case study are shown below

For PKN model:

$$L = 0.48 \left[\frac{8GQ^3}{(1-\nu)\mu} \right]^{1/6} t^{2/3}$$

$$w_o = 1.32 \left[\frac{8(1-\nu)Q^3\mu}{G} \right]^{1/6} t^{1/3}$$

Where:

L – Half length of the fracture

G- Modulus of elasticity

Q- Flow Rate

T – Time of pumping

μ - Viscosity of fracturing fluid

ν - Poissons ratio

For KGD model:

$$L = 0.68 \left[\frac{GQ^3}{(1-\nu)\mu h^4} \right]^{1/5} t^{4/5}$$

$$w_o = 2.5 \left[\frac{(1-\nu)\mu Q^2}{Gh} \right]^{1/5} t^{1/5}$$

Where:

L – Half length of the fracture

G- Modulus of elasticity

Q- Flow Rate

T – Time of pumping

μ - Viscosity of fracturing fluid

?- Poissons ratio

For Radial Model:

$$R = 0.548 \left[\frac{GQ^3}{\mu} \right]^{1/9} t^{4/9}$$

$$w_o = 2.1 \left[\frac{\mu^2 Q^3}{G^2} \right]^{1/9} t^{1/9}$$

Where:

R – Radius of the fracture

G- Modulus of elasticity

Q- Flow Rate

T – Time of pumping

μ - Viscosity of fracturing fluid

?- Poissons ratio

11. CASE STUDY ANALYSIS:**HYPOTHETICAL CASE STUDY:****RESERVOIR DATA:**

Porosity	3.50 %
Gross Height	11 ft
Surface (0 ft)	70 °F
Ratio Net/Gross Height	0.6814
Bottom Hole (3062 ft)	130 °F
Young's Modulus	1320000 psi
Poisson' Ratio	0.26
Permeability	0.050 md
Total Compressibility	0.0001742 1/psi
Fluid Viscosity	0.02 cp
Reservoir Pressure	1377 psi

FRACTURING FLUID PROPERTIES:

Density	8.30 lb/gal
Thermal Conductivity Btu/(hr*ft*°F)	0.381
Specific Heat Btu/(lbm*°F)	0.988
Surface Fluid Temp	75 °F
?	0.69

K'	0.000992 lb*s^n'/ft ²
Foam Type	None
Gel Stability	Low Degradation
Ct and Cp Source	Program Defaults
Ct (Thermal Expansion)	0.0008112 1/°F
Cp (Fluid Compressibility)	0.0000029 1/psi

DRILLING/WELLBORE INFORMATION:

Injection Path:	Casing
Measured Depth:	3066 ft
True Vertical Depth:	3066 ft
Casing outside Diameter:	5.500 in
Casing inside Diameter:	4.892 in
Wellbore Volume:	2984 gal
Tubing outside diameter:	2.375inch, N80, ID 1.995 inch, 4.7lb/ft, 3040 ft mD
Casing outside diameter: lb/ft,	3066 ft MD, OD=5.5 inch, ID= 4.892inch, 17
Perforation interval	3050.2ft – 3054.3 ft 6 shots/ft diameter 0.4 inch
Perforation interval	3057.9 ft- 3061.5 ft 6shots/ft diameter 0.4 inch
Pumping flowrate	25 bbl/min

Assume the following design considerations to compare the fracture properties for the various models.

Flowrate=25 bbl/min, total proppant =21000 lbs, total pumping time =20 min, total clean fluid volume =13400 gals, pad volume = 30% total fluid volume. Assume water fracs are preferred and simple sand may be used to prop open the fracture.

Formation Properties:

NAME	TVD	TYPE	GROSS HT	LKOFF HT	NET HT	PERFS	PRF DIA	FRAC GRAD	IN SITU STRESS	YM	POISSON	RESVR PRESS K	POROSITY	
CLEAN-SANDSTONE	1550	CLEAN-SANDSTONE	1000	1000	1000	0	0.4	1.01	2070	9.09E+06	0.26	1377	0.05	3.5
SHALE	2550	SHALE	500.2	500.2	500.2	0	0.4	0.91	2548	1.32E+06	0.35	1377	0.001	1
CLEAN-SANDSTONE	3050.2	CLEAN-SANDSTONE	4.1	4.1	4.1	25	0.4	0.77	2350	9.09E+06	0.26	1377	0.05	3.5
SHALE	3054.3	SHALE	3.6	3.6	3.6	0	0.4	0.83	2537	1.32E+06	0.35	1377	0.001	1
CLEAN-SANDSTONE	3057.9	CLEAN-SANDSTONE	3.6	3.6	3.6	22	0.4	0.77	2356	9.09E+06	0.26	1377	0.05	3.5
SHALE	3061.5	SHALE	4.5	4.5	4.5	0	0.4	0.83	2543	1.32E+06	0.35	1377	0.001	1
CLEAN-SANDSTONE	3066	CLEAN-SANDSTONE	100	100	100	0	0.4	0.78	2430	9.09E+06	0.26	1377	0.05	3.5

Table 2: Formation Properties

Objectives: (i) To compare the fracture properties for the various 2D models and the P3D model theoretically and compare the theoretical results with the results obtained using the simulator.

(ii) To select the best fracture models using the given fluid properties.

THEORETICAL SOLUTION:

The fracture properties using the analytical equations for the 2D models are given below.

(i) KGD Model: For KGD model the length of the fracture is given as

$$L = 0.48 \left[\frac{8GQ^3}{(1-\nu)\mu} \right]^{1/6} t^{2/3}$$

So, the length comes out to be $L = 729.11$ ft.

And the width is given as

$$w_o = 1.32 \left[\frac{8(1-\nu)Q^3\mu}{G} \right]^{1/6} t^{1/3}$$

So, the width comes out to be $W = 0.86$ ft.

(ii) PKN Model: Since the sands are laminated therefore the zones are to be connected using the fracture. So, the fracture height is set at $h = 11$ ft. Now for the PKN model the length of the fracture is given as

$$L = 0.68 \left[\frac{GQ^3}{(1-\nu)\mu h^4} \right]^{1/5} t^{4/5}$$

So, the length comes out to be $L = 433.15$ ft

And the width is given as

$$w_o = 2.5 \left[\frac{(1-\nu)\mu Q^2}{Gh} \right]^{1/5} t^{1/5}$$

So, the width comes out to be $W = 0.178$ ft.

(iii) Radial Model: For the radial model the length is given as

$$R = 0.548 \left[\frac{GQ^3}{\mu} \right]^{1/9} t^{4/9}$$

So, the length comes out to be $R = 55.58$ ft.

And the width of the fracture is given as

$$w_o = 2 \left[\frac{\mu^2 Q^3}{G^2} \right]^{1/9} t^{1/9}$$

So, the width comes out to be $W = 1.02$ ft.

Simulated Results using FracCade 5.1 (Schlumberger):

Now the fracture properties will be evaluated using the simulator (FracCade 5.1). The fracture thus obtained will be compared with the theoretical results.

The sands are laminated, hence the best solution to have a fracture that connects both the sands. So, for these models the height is fixed to be 11 ft.

- (i) **Radial Model:** For the radial model the simulator predictions are given in the table given below:

PropFRAC Placement Simulator Predictions:	
Initial Fracture Top TVD	3050.2 ft
Initial Fracture Bottom TVD	3061.5 ft
Propped Fracture Half-Length	100.4 ft
Propped Width at Well	0.042 in
Average Propped Width	0.025 in
Average Gel Concentration	134.2 lb/mgal

Average Fluid Retained Factor..	 1.00
Max Hydraulic Fracture Half-Length.....	 171.8 ft
EOJ Hydraulic Fracture Half-Length...	 98.2 ft
EOJ Hydraulic Width at Well.....	 0.153 in
EOJ Hydraulic Height at Well....	 343.6 ft
EOJ Net Pressure.....	 651 psi
Efficiency.....	 0.406
Estimated Closure Time...	 14.4 min
Equivalent Leakoff.....	 2.7E-3 ft/min0.5
Effective Conductivity....	 1851 mD.ft
Effective F_{cd}	 368.9

Table 3: PropFRAC Placement Simulator Predictions

Fracture Conductivity and ACL Propped Length Per Zone Data:

Zone Nbr	Zone Name	Top TVD ft	Gross Height ft	Fracture Conductivity md.ft	ACL Propped Length ft
1	CLEAN-SANDSTON	1550.0	1000.0	0	0.0
2	SHALE	2550.0	500.2	920	99.9
3	CLEAN-SANDSTON	3050.2	4.1	1851	100.4
4	SHALE	3054.3	3.6	1851	100.4
5	CLEAN-SANDSTON	3057.9	3.6	1851	100.4
6	SHALE	3061.5	4.5	1842	100.4
7	CLEAN-SANDSTON	3066.0	100.0	1204	100.4

Table 4: Fracture conductivity and ACL propped length Per Zone Data

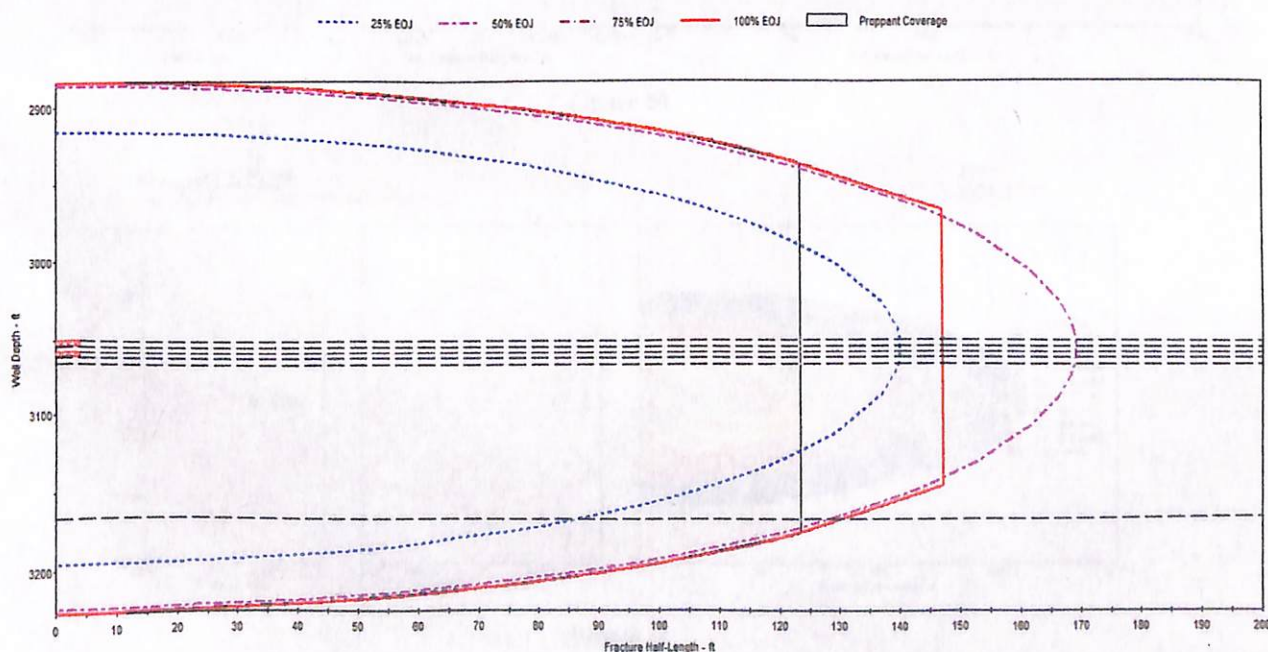


Figure 28

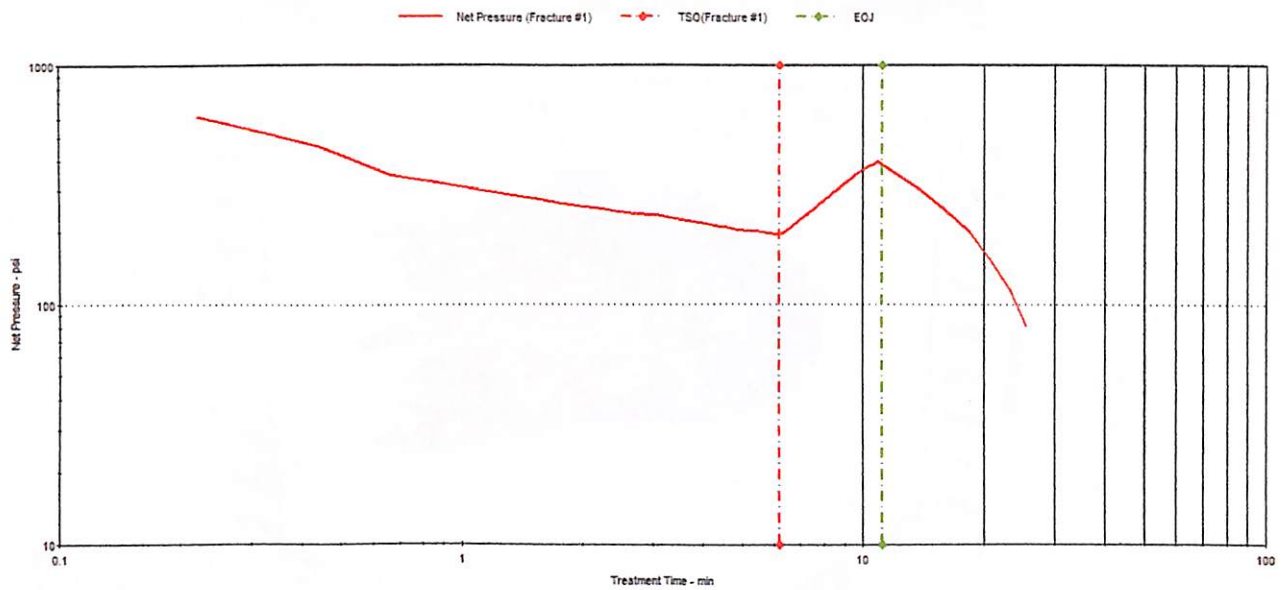


Figure 29

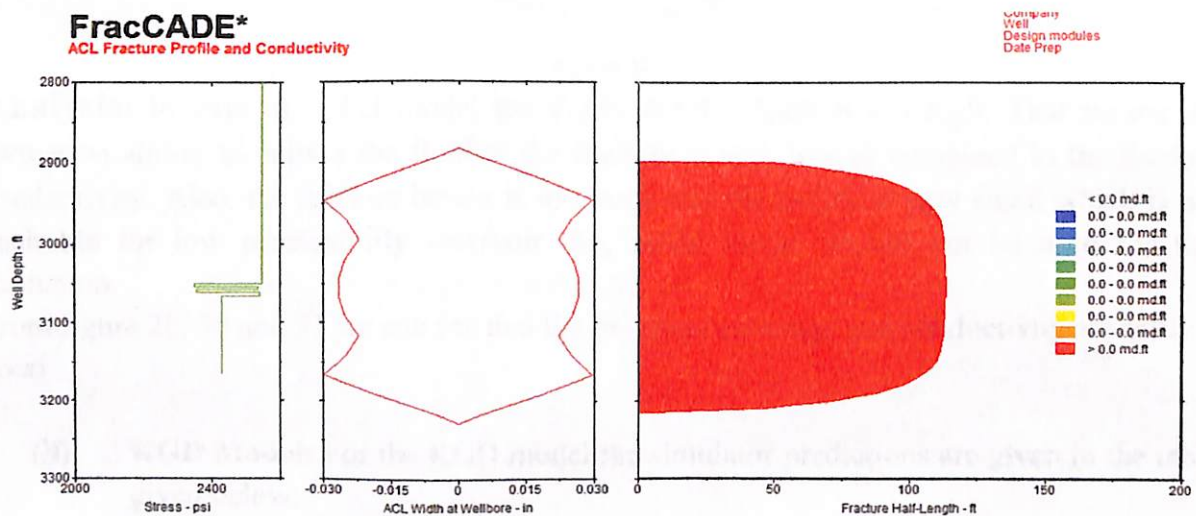


Figure 30

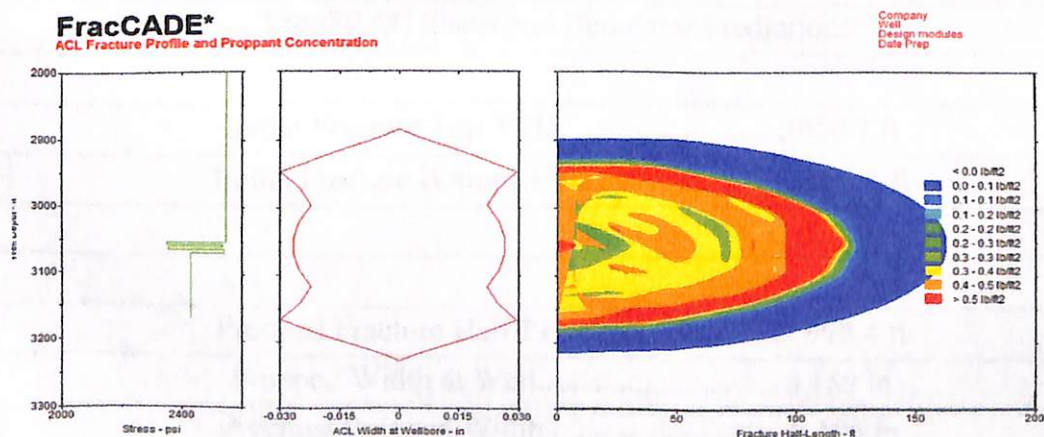


Figure 31

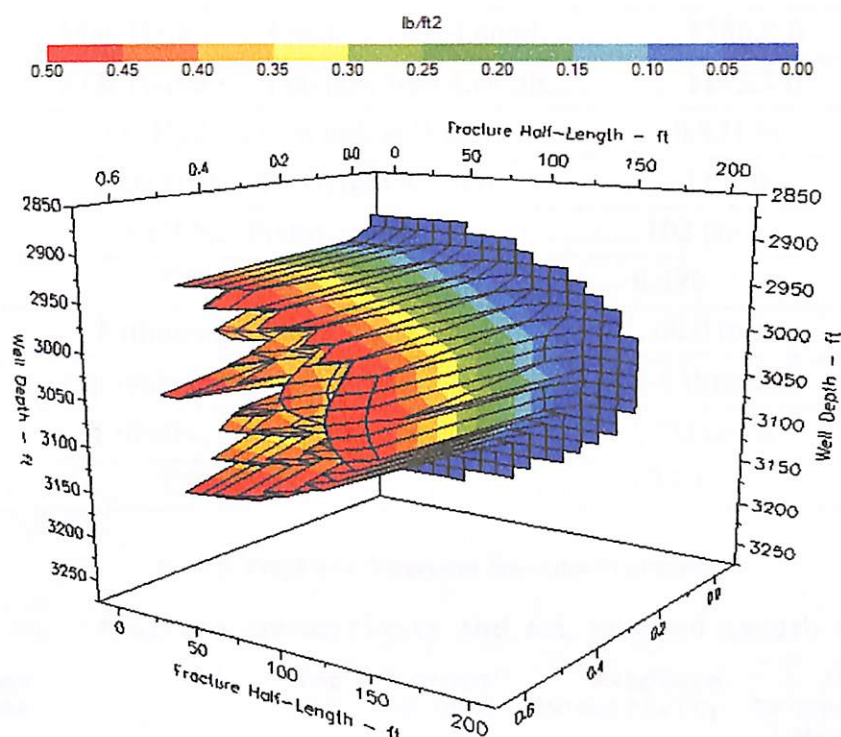


Figure 32

Analysis: In case of radial model the F_{cd} is 368.9, which is too high. That means the formation ability to deliver the fluid to the fracture is very low as compared to the fracture conductivity. Also, the fracture height is too large and the length is very small which is not desirable for low permeability reservoir. So, radial model should not be used for this formation.

From figure 28, 30 and 31 we can see that the proppant coverage and conductivity are fairly good.

- (ii) **KGD Model:** For the KGD model the simulator predictions are given in the table given below:

PropFRAC Placement Simulator Predictions:	
Initial Fracture Top TVD.....	3050.2 ft
Initial Fracture Bottom TVD.....	3061.5 ft
Propped Fracture Half-Length.....	998.4 ft
Propped Width at Well.....	0.159 in
Average Propped Width.....	0.106 in
Average Gel Concentration.....	301.5 lb/mgal
Average Fluid Retained Factor.....	1.00

Max Hydraulic Fracture Half-Length.....	1586.8 ft
EOJ Hydraulic Fracture Half-Length.....	1192.3 ft
EOJ Hydraulic Width at Well.....	0.821 in
EOJ Hydraulic Height at Well.....	11.3 ft
EOJ Net Pressure.....	102 psi
Efficiency.....	0.896
Estimated Closure Time.....	60.0 min
Equivalent Leakoff.....	7.9E-4 ft/min ^{0.5}
Effective Conductivity.....	1703 md.ft
Effective Fcd.....	34.1

Table 5: PropFRAC Placement Simulator Predictions

Fracture Conductivity and ACL Propped Length Per Zone Data:

Zone Nbr	Zone Name	Top TVD ft	Gross Height ft	Fracture Conductivity md.ft	ACL Propped Length ft
1	CLEAN-SANDSTON	1550.0	1000.0	0	0.0
2	SHALE	2550.0	500.2	603	998.4
3	CLEAN-SANDSTON	3050.2	4.1	1541	998.4
4	SHALE	3054.3	3.6	1755	998.4
5	CLEAN-SANDSTON	3057.9	3.6	1887	998.4
6	SHALE	3061.5	4.5	1489	998.4
7	CLEAN-SANDSTON	3066.0	100.0	0	0.0

Table 6: Fracture conductivity and ACL propped length Per Zone Data

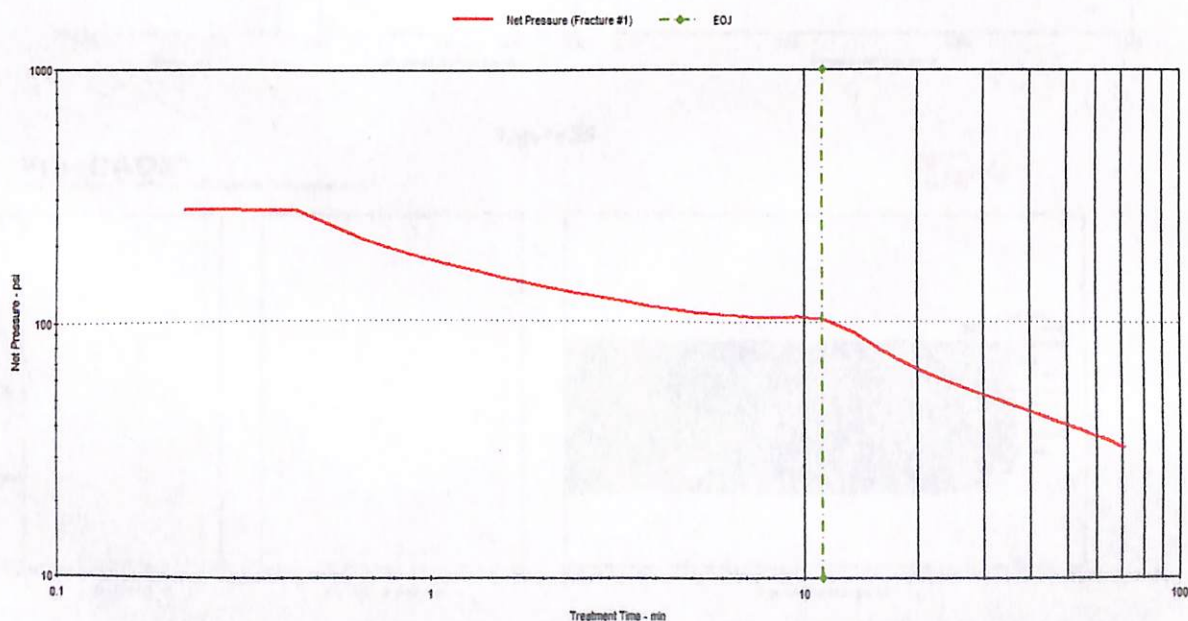


Figure 33

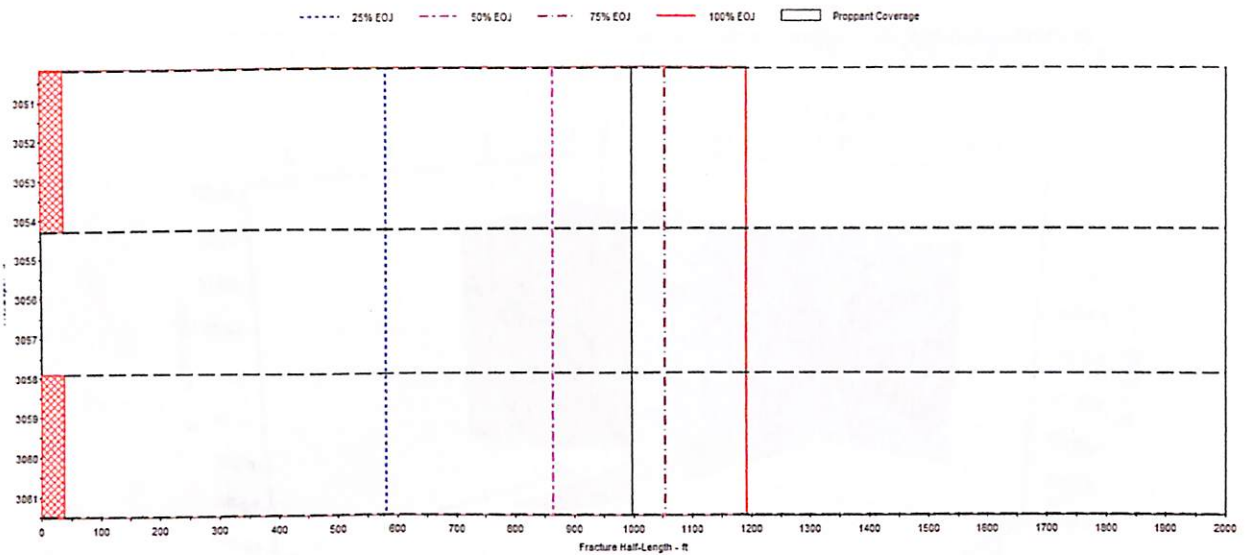


Figure 34

FracCADE*
ACL Fracture Profile and Conductivity

Company
Well
Design modules
Date Prep

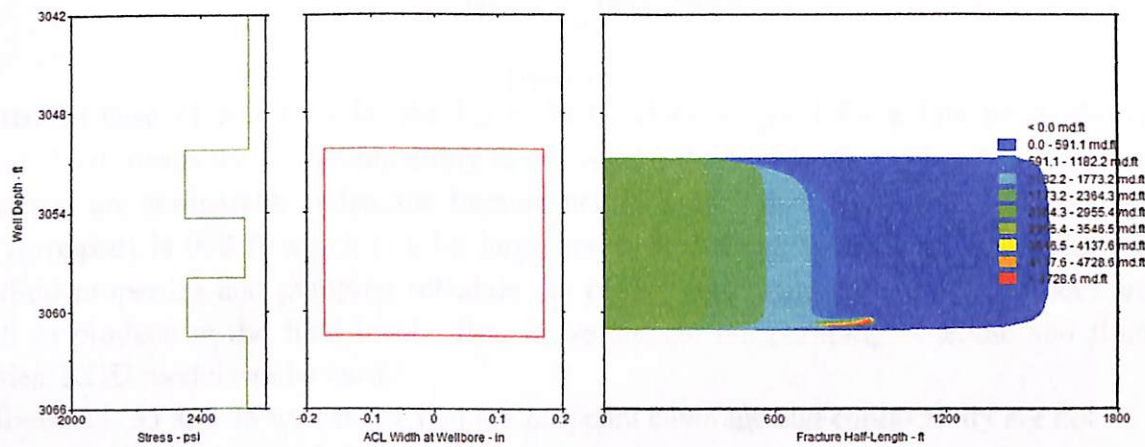


Figure 35

FracCADE*
ACL Fracture Profile and Proppant Concentration

Company
Well
Design modules
Date Prep

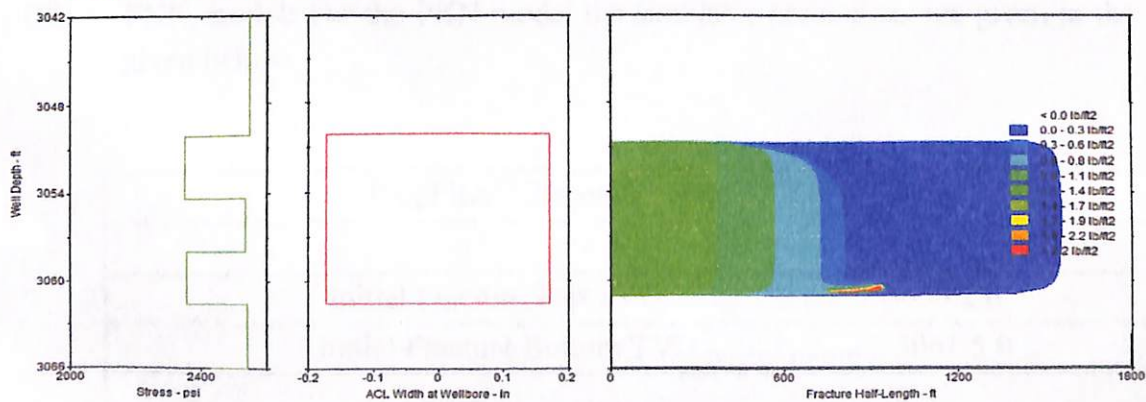


Figure 36

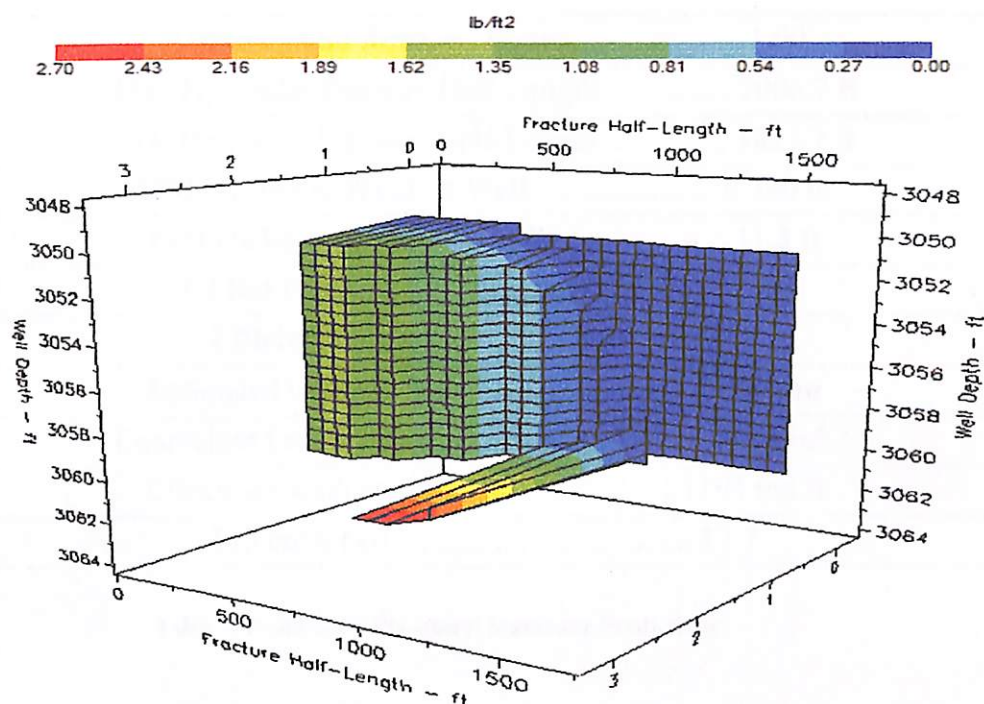


Figure 37

Analysis: In case of KGD model the F_{cd} is 34.1, which is good for a low permeability reservoir. That means the formation ability to deliver the fluid to the fracture and the fracture conductivity are comparable. Also, the fracture height is 11.3 ft which is good but the half length (propped) is 998 ft which is a bit large and thus difficult to produce. So, under the given fluid properties and pumping schedule the properties obtained from KGD model are difficult to produce at the field level. But, if we change the pumping schedule and fluid properties, KGD model can be used.

From figure 34, 35 and 36 we can see that the proppant coverage and conductivity are not good. Around 600 ft of length is unpropped.

- (iii) **PKN model:** For the PKN model the simulator predictions are given in the table given below:

PropFRAC Placement Simulator Predictions:	
Initial Fracture Top TVD.....	3050.2 ft
Initial Fracture Bottom TVD.....	3061.5 ft
Propped Fracture Half-Length.....	1347.9 ft
Propped Width at Well.....	0.111 in
Average Propped Width.....	0.072 in
Average Gel Concentration.....	1631.4 lb/mgal

Average Fluid Retained Factor.....	1.00
Max Hydraulic Fracture Half-Length.....	2006.7 ft
EOJ Hydraulic Fracture Half-Length.....	1827.7 ft
EOJ Hydraulic Width at Well.....	0.390 in
EOJ Hydraulic Height at Well.....	11.3 ft
EOJ Net Pressure.....	12872 psi
Efficiency.....	0.743
Estimated Closure Time.....	60.0 min
Equivalent Leakoff.....	1.3E-3 ft/min ^{0.5}
Effective Conductivity.....	1194 md.ft
Effective Fcd.....	17.7

Table 7: PropFRAC Placement Simulator Predictions

Fracture Conductivity and ACL Propped Length Per Zone Data:

Zone Nbr	Zone Name	Top TVD ft	Gross Height ft	Fracture Conductivity md.ft	ACL Propped Length ft
1	CLEAN-SANDSTON	1550.0	1000.0	0	0.0
2	SHALE	2550.0	500.2	236	1347.9
3	CLEAN-SANDSTON	3050.2	4.1	1175	1347.9
4	SHALE	3054.3	3.6	1582	1347.9
5	CLEAN-SANDSTON	3057.9	3.6	1216	1347.9
6	SHALE	3061.5	4.5	1040	1347.9
7	CLEAN-SANDSTON	3066.0	100.0	0	0.0

Table 8: Fracture conductivity and ACL propped length Per Zone Data

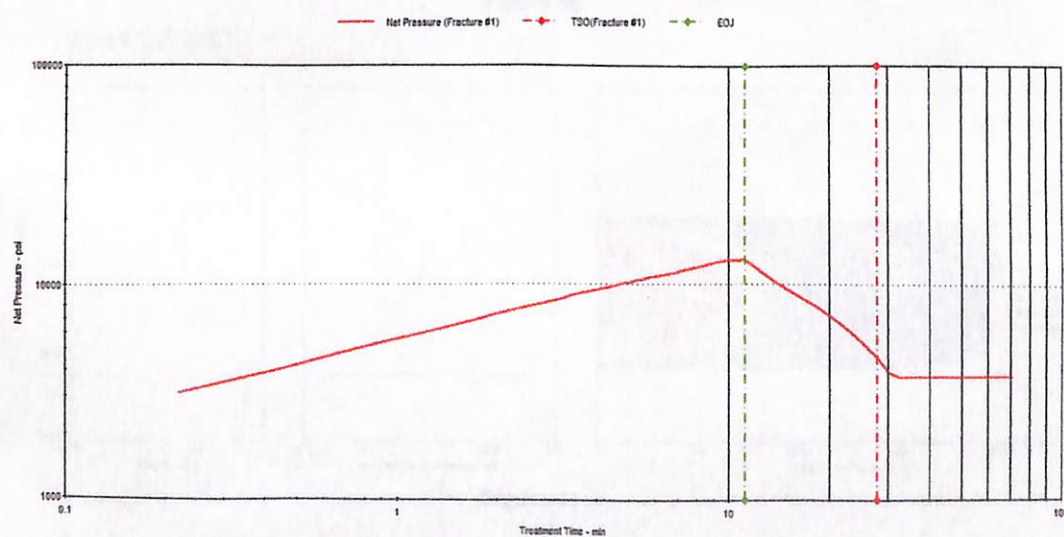


Figure 38

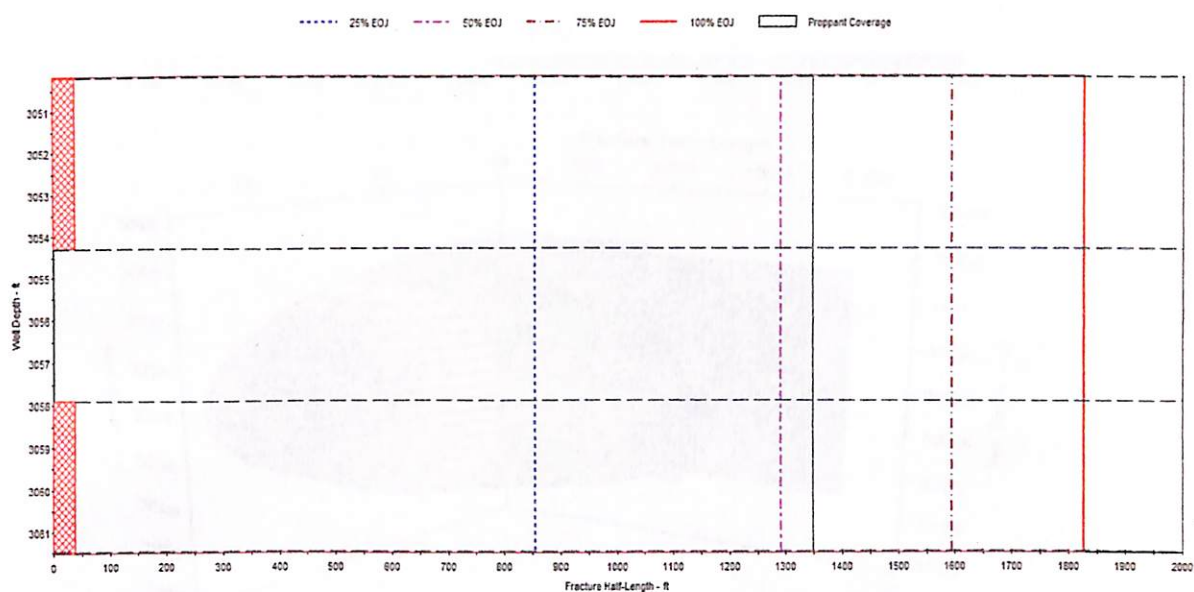


Figure 39

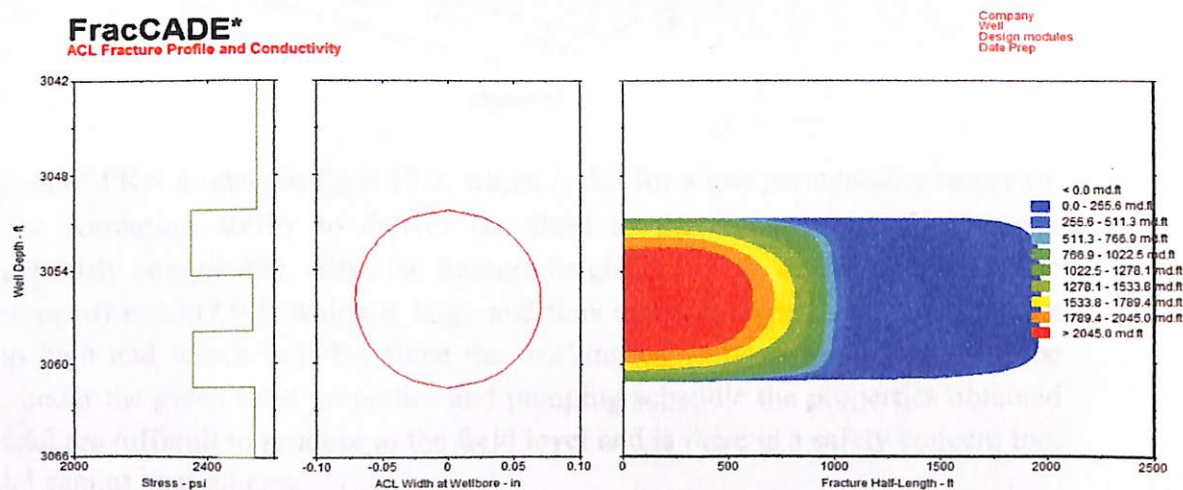


Figure 40

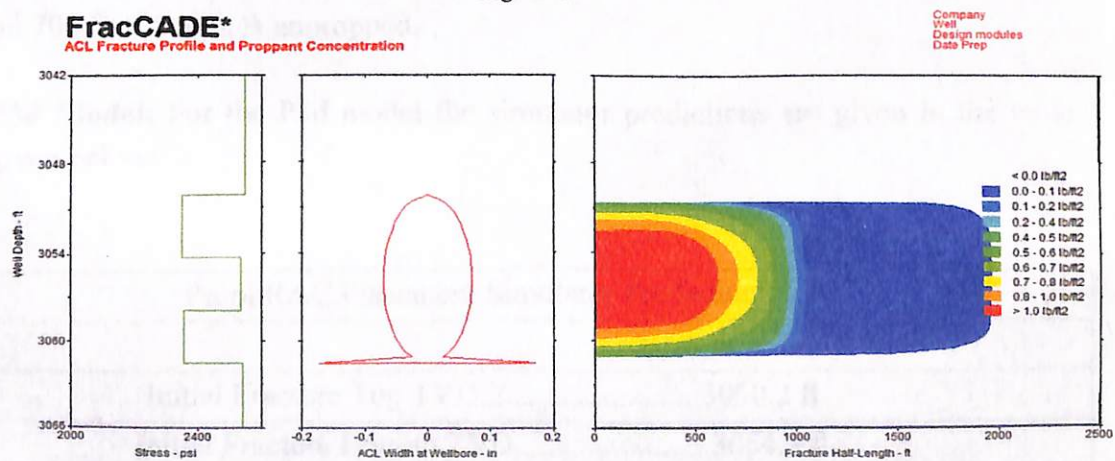


Figure 41

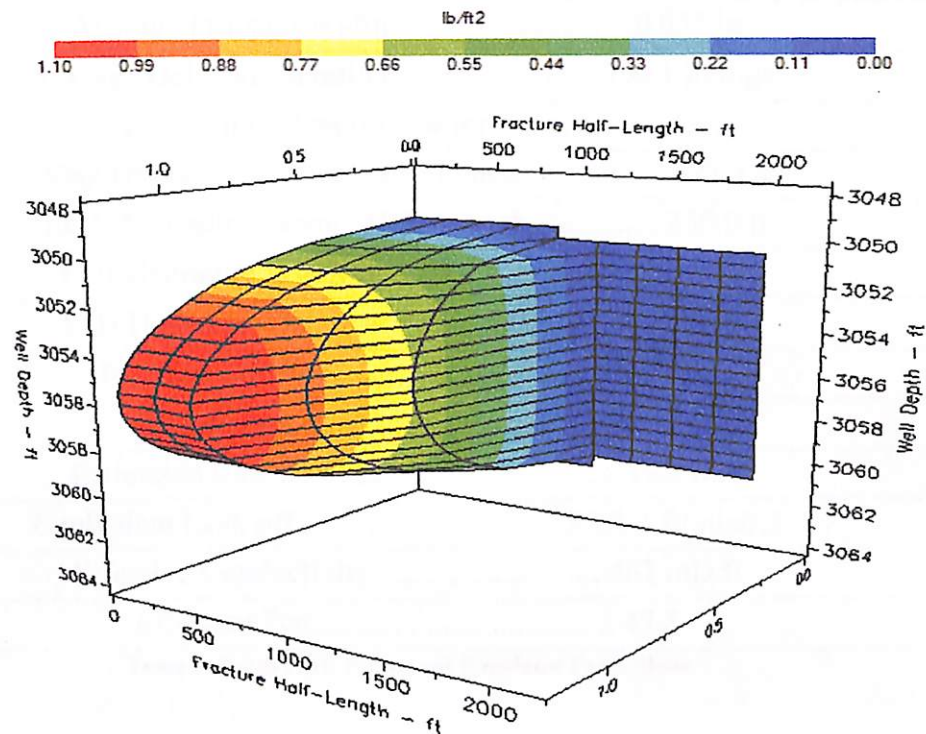


Figure 42

Analysis: In case of PKN model the F_{cd} is 17.7, which is fair for a low permeability reservoir. That means the formation ability to deliver the fluid to the fracture and the fracture conductivity are fairly comparable. Also, the fracture height is 11.3 ft which is good but the half length (propped) is 1347.9 ft which is large and thus difficult to produce. The EOJ net pressure is too high and which is risky, since the working capacity of the tubulars can be exceeded. So, under the given fluid properties and pumping schedule the properties obtained from PKN model are difficult to produce at the field level and is there is a safety concern too. So, PKN model cannot be used here.

From figure 39, 40 and 41 we can see that the proppant coverage and conductivity are not good. Around 700 ft of length is unpropped.

- (iv) **P3d Model:** For the P3d model the simulator predictions are given in the table given below:

PropFRAC Placement Simulator Predictions:	
Initial Fracture Top TVD.....	3050.2 ft
Initial Fracture Bottom TVD.....	3054.3 ft
Propped Fracture Half-Length.....	194.5 ft
Propped Width at Well.....	0.043 in

Average Propped Width.....	0.031 in
Average Gel Concentration.....	300.1 lb/mgal
Average Fluid Retained Factor.....	1.00
Max Hydraulic Fracture Half-Length.....	350.0 ft
EOJ Hydraulic Fracture Half-Length.....	350.0 ft
EOJ Hydraulic Width at Well.....	0.170 in
EOJ Hydraulic Height at Well.....	258.3 ft
EOJ Net Pressure.....	368 psi
Efficiency.....	0.469
Estimated Closure Time.....	19.2 min
Equivalent Leak off.....	5.3E-4 ft/min ^{0.5}
Effective Conductivity.....	462 mD.ft
Effective Fcd.....	47.5

Table 9: PropFRAC Placement Simulator Predictions

Fracture Conductivity and ACL Propped Length Per Zone Data:

Zone Nbr	Zone Name	Top TVD ft	Gross Height ft	Fracture Conductivity md.ft	ACL Propped Length ft
1	CLEAN-SANDSTON	1550.0	1000.0	0	0.0
2	SHALE	2550.0	500.2	170	178.1
3	CLEAN-SANDSTON	3050.2	4.1	421	194.5
4	SHALE	3054.3	3.6	472	194.5
5	CLEAN-SANDSTON	3057.9	3.6	507	194.5
6	SHALE	3061.5	4.5	543	194.5
7	CLEAN-SANDSTON	3066.0	100.0	734	194.5

Table 10: Fracture conductivity and ACL propped length Per Zone Data

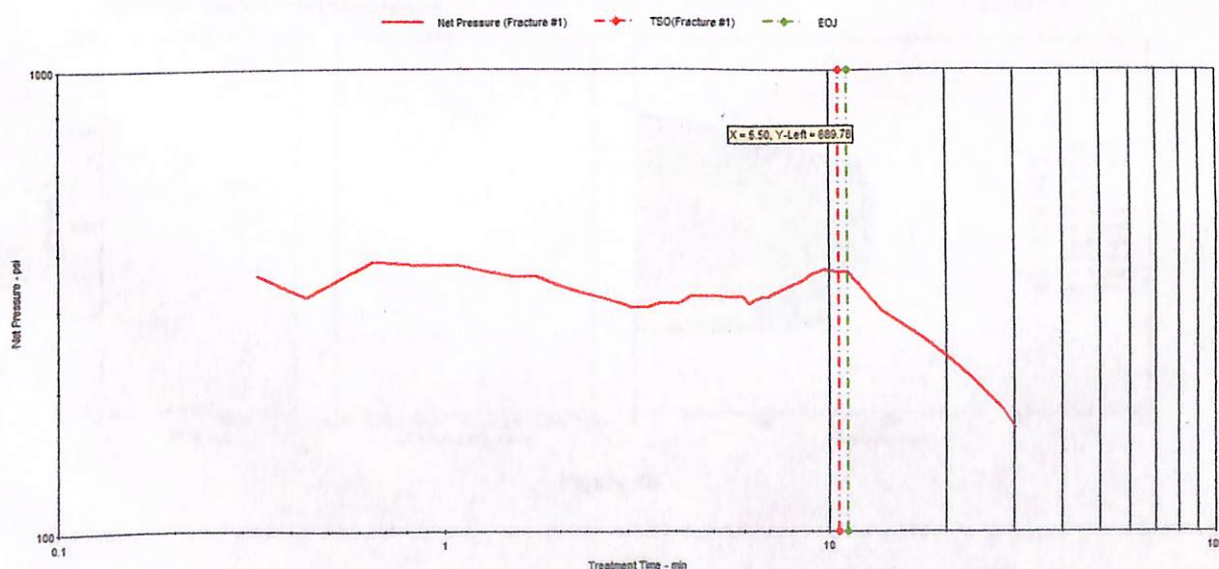


Figure 43

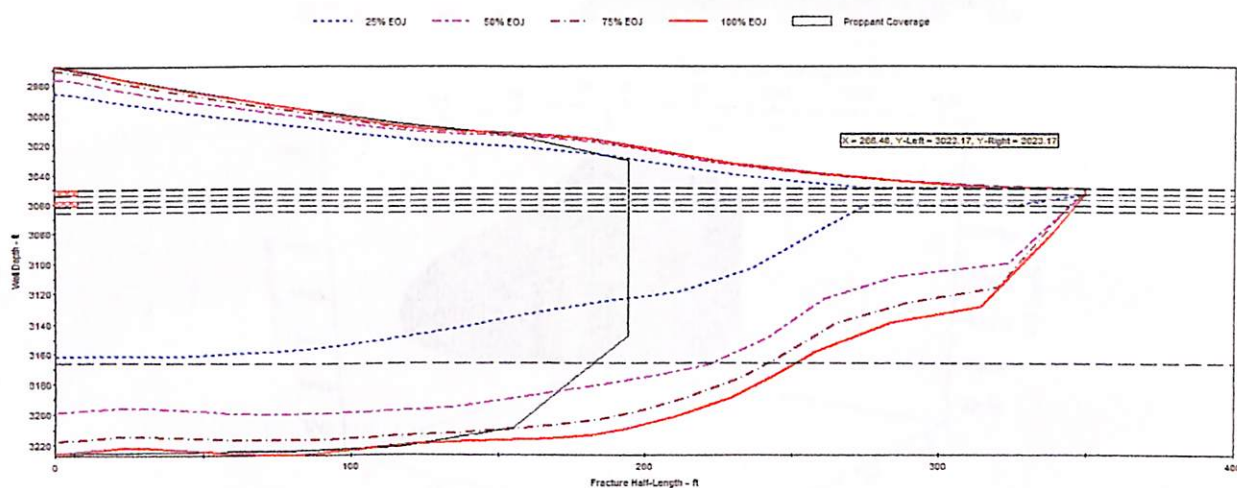


Figure 44

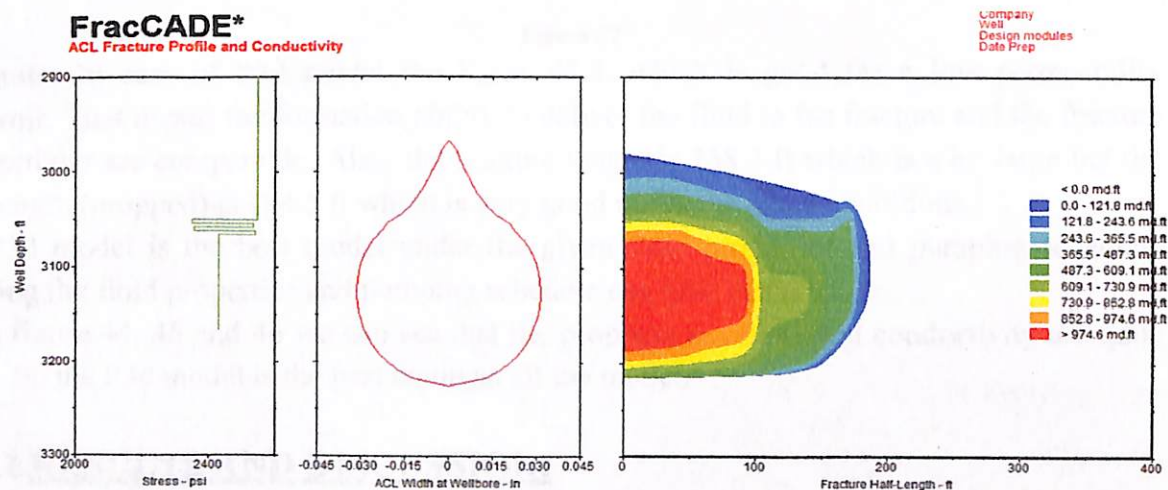


Figure 45

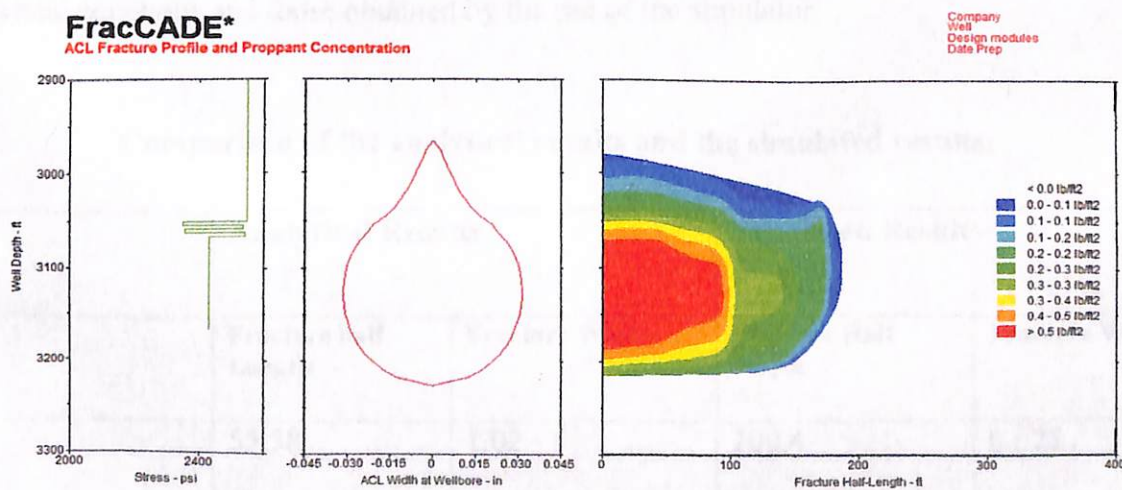


Figure 46

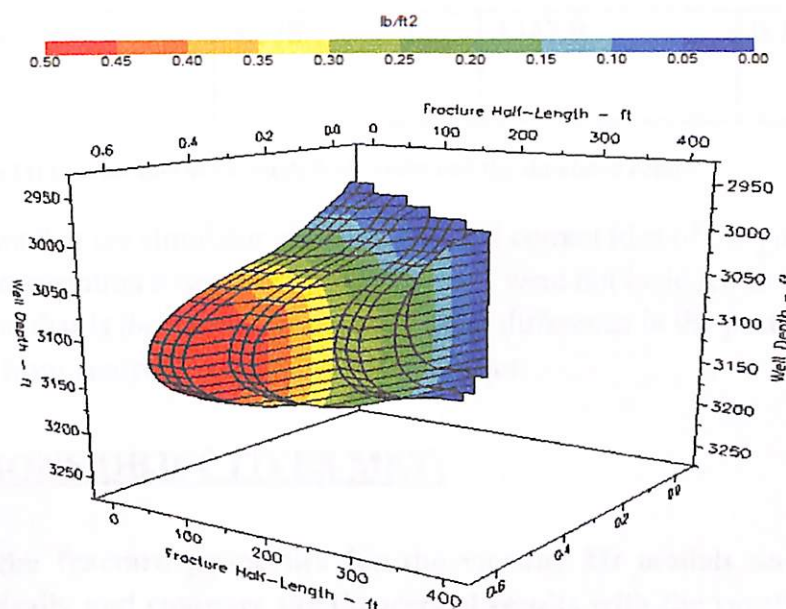


Figure 47

Analysis: In case of P3d model the F_{cd} is 47.5, which is good for a low permeability reservoir. That means the formation ability to deliver the fluid to the fracture and the fracture conductivity are comparable. Also, the fracture height is 258.3 ft which is a bit large but the half length (propped) is 194.5 ft which is very good under the given conditions.

So, P3d model is the best model under the given fluid properties and pumping schedule. Altering the fluid properties and pumping schedule can give better results.

From figure 44, 45 and 46 we can see that the proppant coverage and conductivity are quite good. So the P3d model is the best amongst all the model.

12. RESULTS AND DISCUSSION:

The table below shows the comparison between the results that were obtained using the analytical equations and those obtained by the use of the simulator.

Comparison of the analytical results and the simulated results:

	Analytical Results		Simulated Results	
	Fracture half Length	Fracture Width	Fracture Half length	Fracture Width
Radial	55.58	1.02	100.4	0.025
KGD	729.11	0.86	998.1	0.106

PKN	433.15	0.178	1347.9	0.111
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Table 11: Comparison of the analytical results and the simulated results

The above results shows that the simulator gives a better and correct idea of the picture down hole as it takes into consideration a few more properties that were not included in the analytical equations and that is the reason for getting a wide difference in the post stimulation properties as obtained from analytical equations and simulator.

13.CONCLUSIONS/OBJECTIVES MET:

- 1 To compare the fracture properties for the various 2D models and the P3D model theoretically and compare the theoretical results with the results obtained using the simulator**

From the comparison between the results obtained using analytical equations and the simulator predictions, it is quite clear that there is a bit difference between both the results. This can be because the equations behind the simulator's predictions differ from the one used in this text.

- 2 To select the best fracture models using the given fluid properties.**

Comparing the fracture dimensions, fracture conductivities and other parameters it is quite clear that the P3D model is the best model under the given fluid properties and pumping schedule.

REFERENCES

- (i) Economides, M.J. and Nolte, K.G. (March 2000). *Reservoir Stimulation*. NY and Chichester: Wiley.
- (ii) Herriot Watt University: *Production Technology-II*(pp 311- 364)
- (iii) Robert S Schechter. (2000). *Oil Well Stimulation*.

APPENDIX:

FracCade* simulation program

Fracturing treatment designs are developed using the advanced Schlumberger FracCade simulation program. This highly specialized software allows detailed optimal design, monitoring, recording and analysis of the stimulation treatment to ensure the resulting fracture performance is matched to the formation deliverability.

CADE for Windows (CFW) applications are used in the oilfield service industry to evaluate services and propose the most cost-effective, highest yield service treatment.

CFW is the framework upon which the Computer Assisted Design applications (CADEs) are built. This framework can be used with other similar Schlumberger products. CFW offers flexibility in data exchange between modules and applications. A single set of data can be entered and several applications can use it to create output.

PropFRAC Placement module:

The PropFRAC Placement module is a numerical hydraulic fracture simulator that uses a different fracture geometry model. It provides the capability to model fracture growth into layers above and below the pay zone along with fracture extension and recession. The simulation is based on the coupling of fluid flow into fracture and rock mechanics that allow screenouts and slurry dehydration to be simulated. The simulation can continue even after proppant bridging or slurry dehydration occurs.

The Pump Schedule Generator (PSG) is designed for WS engineers involved in hydraulic fracture design who need to get a pump schedule for a proppant fracture treatment. PSG will generate a pump schedule for the treatment based on the design of fracture geometry and proppant distribution. It is more efficient to use the PSG instead of manually adjusting the pump schedule and running the fracture simulator again until the desired fracture geometry is achieved. Even though PSG automatically generates a pump schedule, engineering judgement is still needed to examine the results and setting the input parameters.

With the new release of FracCADE, the added customer benefits are the following:

- Obtain the pump schedule for a fracture treatment more efficiently because the pump schedule is automatically generated based on fracture design parameters.
- Optimize the pump schedule by controlling the distance between the fracture tip and slurry front to prevent premature screen-out.
- Learn about fracture growth features for design parameters because the liquid only schedule shows the relationship between fracture geometry and pumped volume.
- Learn about the reasons for achieving or not achieving required fracture design because the ideal schedule shows the effects of operational constraints.
- Obtain the pump schedule for tip-screen-out treatment with more control and convenience by selecting the three available criteria: net pressure limit, average propped width, and total mass limit.

With the new design methodology, FracCADE gives you the following three different types of design capabilities:

- Liquid Only
- Non Tip-Screen-Out
- Tip-Screen-Out