KESHAVA DEVA MALAVIYA INSTITUTE OF PETROLEUM EXPLORATION
OIL & NATURAL GAS CORPORATION LTD.
DEHRADUN

"Design & Development of Fracturing Fluid For Hydraulic Fracturing"

Hydraulic Fracturing Project

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&
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B.Tech (Applied Petroleum Engineering)
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Major Project

On

"Design & Development of Fracturing Fluid for Hydraulic Fracturing"

A thesis submitted in partial fulfillment of the requirements for the Degree of

Bachelor of Technology

(Applied Petroleum Engineering)

By

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May 2010

UNIVERSITY OF PETROLEUM & ENERGY STUDIES

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CERTIFICATE

This is to certify that the work contained in this thesis titled "**Design & Development of fracturing fluid for Hydraulic fracturing**" has been carried out by Naval Kishore Dubey & Varun Nautiyal under my supervision and has not been submitted elsewhere for a degree.

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RESERVOIR GROUP, KDMIPE

Certificate

This is to certify that the work contained in this thesis titled "**Design & Development of fracturing fluid for hydraulic fracturing**" has been carried out by Mr Naval Kishore Dubey & Mr Varun Nautiyal, students of Applied Petroleum Engineering (APE) from University of Petroleum & Energy Studies, Dehradun under my supervision and has not been submitted elsewhere for a degree. During the work, they were found sincere, hard working, analytical and punctual. Their behaviour and conduct were very good and I am fully satisfied with their project work.

In my view this work will suffice the Project requirement of B.Tech Applied Petroleum Engineering Course.

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27th Feb 2010

NAVAL KISHORE DUBEY
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KDMIPE: AN INTRODUCTION

Keshava Deva Malaviya Institute of Petroleum Exploration (KDMIPE) is located in picturesque valley of Dehradun in the state of Uttarakhand. It was founded in 1962 with an objective to provide geo-scientific back up to the exploratory efforts of India's National oil company, ONGC. The Institute was rechristened as Keshava Deva Malaviya Institute of Petroleum Exploration (KDMIPE) on 19th December, 1981 by the then Prime Minister of India Late Mrs. Indira Gandhi in the memory of the Father of Indian Petroleum industry and first chairman of ONGC - Late Mr. Keshava Deva Malaviya.

FUNCTIONS OF KDMIPE:

- Absorption, up-gradation and development of the state-of-the-art exploration technologies for geo-scientific data acquisition, processing and interpretation.
- Synergetic geo-scientific research in the area of remote sensing, geology (Stratigraphic & sediment logy), geophysics, geo-chemistry, well logging & reservoir studies for proven and frontier basins.
- Basin studies for evaluation of hydrocarbon potential through integrated geo-scientific work for:
    1. Integration of exploration concepts, model to firm up prospects in different aspects for exploratory locations in proven, and frontier basin.
    2. Up-gradation of estimated resources with integrated-information and data management.
- Foreign basin studies for assessing equity oil prospects abroad.

- Co-ordination with regional exploration laboratories and with other institutes for integrated services.
- R & D work in alternate energy sources like geo-thermal, solar, & bio energy, alternate hydrocarbon sources like coal bed methane, and gas hydrates.
- Exploration effort reviews for short term strategic and long term perspective plans.
- Development for long & short-term investment strategies backed by exploration economies.
- Fostering interaction with national and international academics institutes and organizing collaborative research in emerging technology areas.
- HRD through information dissemination and organization of special management programmes and brainstorming sessions, workshops, seminars and conferences.

RESERVOIR GROUP – IN KDMIPE

It is one of the Groups of geo-science research under the pioneers of KDMIPE. Again this Group divided into many laboratories. The various laboratories under Reservoir Group are as follows:

- A) Reservoir performance \ Reservoir characterization Lab.

- B) Productivity Improvement Lab:
Well productivity enhancement: The section involves to revive sick wells and to enhance the productivity by stimulation techniques like acidizing, hydraulic fracturing and solvent treatment. Also devices technique to control the water production from coming inside the well along with the crude.

- C) Thermodynamics or PVT Lab:
Study the thermodynamics properties of reservoir fluids,

- D) Flow assurance Lab:
Study the properties of the crude oil such as viscosity, water content, pour point, gravity etc. Chemicals are identified to ensure the crude oil flow and transportation of waxy/heavy crudes.

CHAPTER - 1

(Fracturing Fluid Chemistry)

Introduction

Hydraulic fracturing has been established to be a very useful technique for enhancing the production of oil and natural gas from the reservoir. The technology was developed in the late 1940's, and has been improved continuously and applied in the oil and gas industry all over the world.

The wells are hydraulically fractured to connect many pre-existing fractures and flow pathways in the reservoir rock with an artificially larger fracture. This larger, man-made fracture starts at the well and extends out into the reservoir rock as much as several hundred feet. The fracture is created when a fluid is pumped down the well at high pressure for short period of time. The high pressure fluid (usually water with fluid additive to increase the viscosity) exceeds the tensile strength of the rock and initiates a fracture in the rock. A propping agent, usually sand carried by the viscous fluid, is pumped into the fracture to keep it from closing when the pumping pressure is released.

The viscous fluid pumped to propagate the fracture is converted into a low viscosity fluid in short time with the addition of breaker. The broken fluid flows back through the created fracture to the well and with no flow restrictions up to the surface once the well is put on production. The technique forms an open channel for the natural gas and oil which are trapped in the rock to flow to the surface.

In hydraulic fracturing treatments, a fracture is created from the wellbore by rupturing the formation at high pressure by means of a fracturing fluid. A propping material, carried by the fracturing fluid, is pumped into the induced fracture channel to prevent closure of the fracture after pressure has been released. Productivity improvement is mainly determined by the propped dimension of the fracture, which is in turn controlled by proppent transport and placement.

The fracturing fluid is a critical component of the hydraulic fracturing treatment. Its main functions are to open the fracture and to transport propping agent along the length of the fracture. Consequently, the viscous properties of the fluid are often considered the most important. However, successful hydraulic fracturing treatments require that the fluids have some other special properties. In addition to exhibiting the proper viscosity in the fracture, they should exhibit low friction pressure during pumping provide good fluid-loss control, break and clean up rapidly once the treatment is over and are as economical as is practice. Since, the reservoirs to be stimulated vary markedly in terms of temperature, permeability, rock composition and pore pressure, many different types of fluids have been developed to provide the properties described above. The first fracturing fluids were oil-base; in the late 1950s water-base fluids thickened with guar became increasingly more popular. In 1969, the first cross linked guar treatment was performed. By this time, only about 10% of the fracturing treatments were conducted with gelled oil. Concerns about damage led to the use of cleaner hydroxypropylguar in the 1970s. Currently, over 70 % of all fracturing treatments use guar or hydroxypropylguar-base aqueous fluids. Gelled oil treatments account for about 5 %. About 25 % of all treatments contain an energizing gas. Additives may be added to enhance the viscosity at high temperature, to break the viscosity at low temperature, or to help control leak off of the fluid to the formation. This chapter describes the chemistry of commonly used fracturing fluids and additives.

1.1 Hydraulic Fracturing: Concept and Application

The first hydraulic fracturing treatment was pumped in 1947 on a gas well operated by Pan American Petroleum Corporation in the Hugoton field The Kelpper Well No. 1 located in Grant County, Kansas was a low productivity well, even though it had been acidized. The well was chosen for the first hydraulic fracture stimulation treatment so that hydraulic fracturing could be compared directly to acidizing. Since that first treatment in 1947, hydraulic fracturing has become a standard treatment for stimulating the productivity of oil and gas wells.

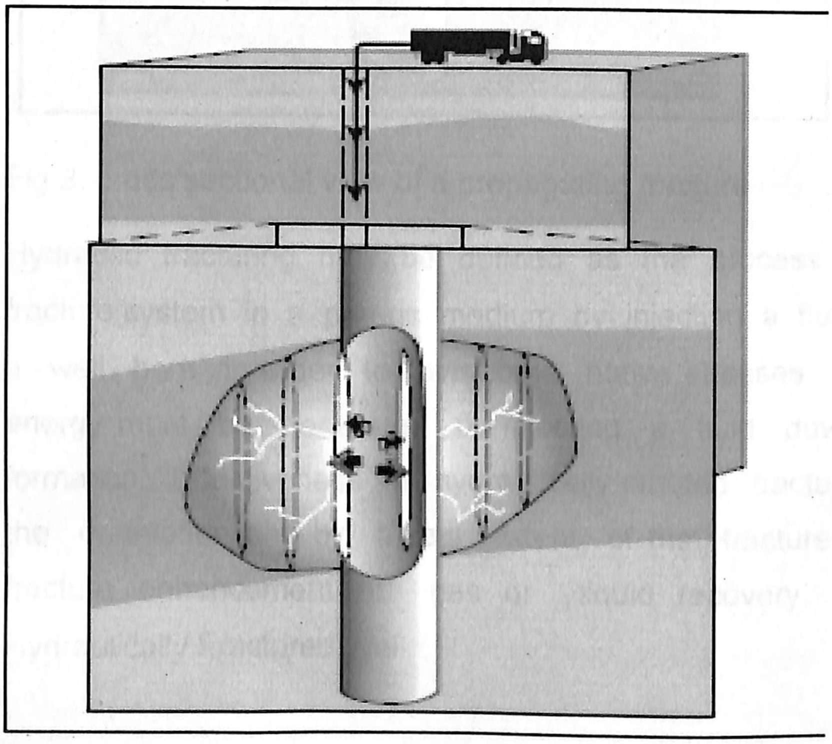


Fig 1: Internal pressure breaking a vertical wellbore

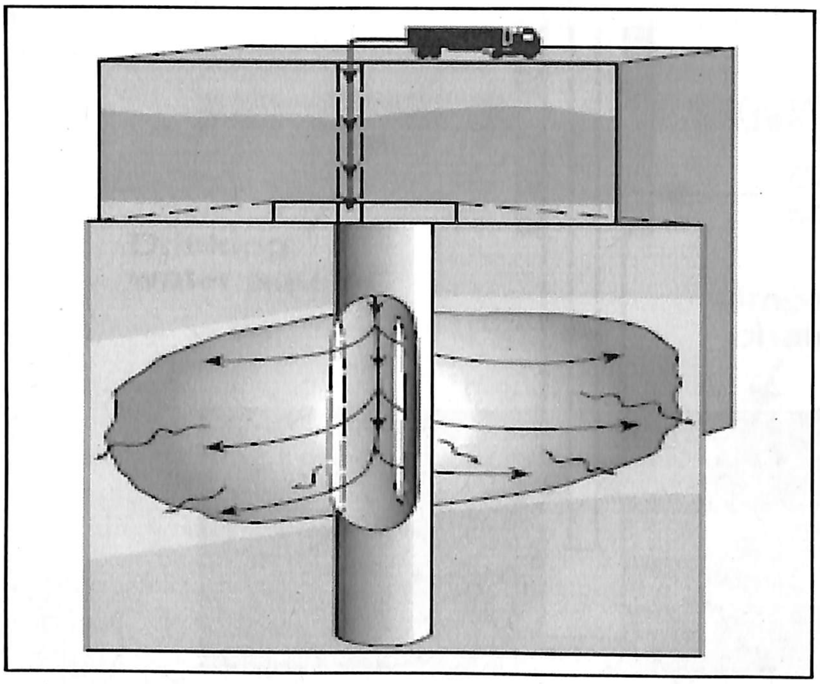


Fig 2: cross sectional view of a propagating fracture

Hydraulic fracturing may be defined as the process of creating a fracture or fracture system in a porous medium by injecting a fluid under pressure through a well bore in order to overcome native stresses. To fracture a formation, energy must be generated by injecting a fluid down a well and into the formation. Effectiveness of hydraulically created fractures is measured both by the orientation and by a real extent of the fracture system and by the post fracture enhancement of gas or liquid recovery. Figure 2 shows Typical Hydraulically Fractured Well.

In general, hydraulic fracture treatments are used to increase the productivity index of a producing well, or the injectivity index of an injection well. The productivity index defines the volumes of oil or gas that can be produced at a given pressure differential between the reservoir and the well bore. The injectivity index refers to how much fluid can be injected into an injection well at a given pressure differential.

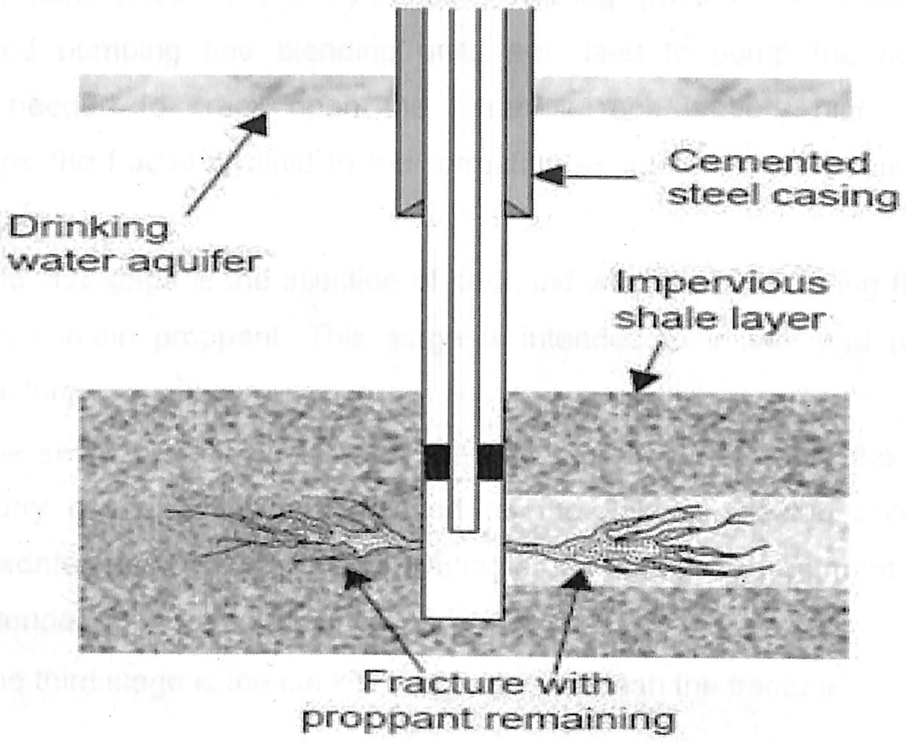


Figure 3: Hydraulically Fractured Well

There are many different applications for hydraulic fracturing, Such as

1. Increase the flow rate of oil and/or gas from low permeability reservoirs,
2. Increase the flow rate of oil and/or gas from wells that have been damaged
3. Connect the natural fractures and/or cleats in a formation to the wellbore,
4. Decrease the pressure drop around the well to minimize sand production,
5. Decrease the pressure drop around the well to minimize problems with Asphaltenes, and/or paraffin deposition
6. Increase the area of drainage or the amount of formation in contact with the well bore, and
7. Connect the full vertical ex tent of a reservoir to a slanted or horizontal well.

Obviously, there could b e other uses of hydraulic fracturing, but the majority of the treatments are pumped for these seven reasons.

The equipment used in the hydraulic fracturing process is shown in Fig. 4. Specialized pumping and blending units are used to pump the fluid since the pressure needed to crack open the reservoir rock is very high. The pumping unit pumps the fracturing fluid to the formation. A fracturing job usually consists of three stages.

A) The first stage is the injection of pad fluid which is a fracturing fluid that does not contain proppant. This stage is intended to initiate and propagate the fracture,

B) The second stage consists of injecting proppant slurry into the fracture. The slurry concentration is increased as the fluid is injected until reaching a predetermined value of solids loading at the end of the treatment. This stage is intended to prop the fracture open.

C) The third stage is the back flowing stage to clean the fracture.

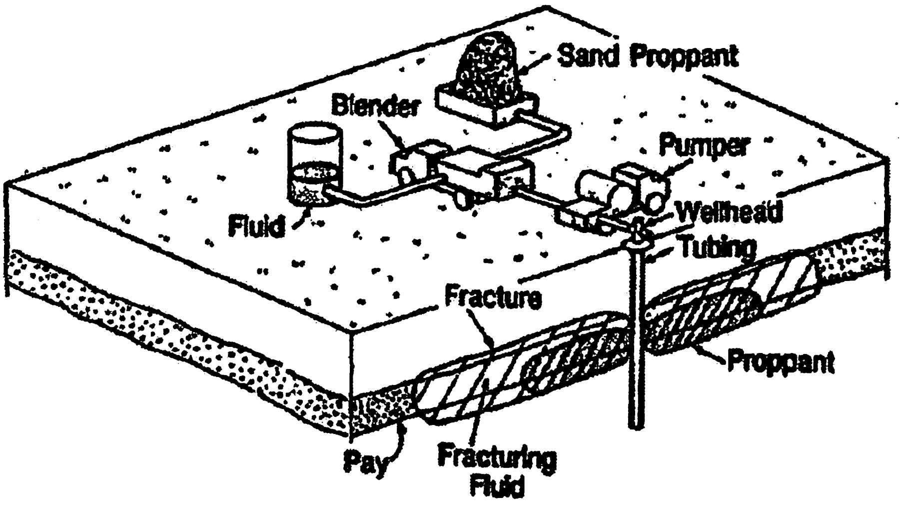


Figure 4: Hydraulic fracturing pumping unit

1.2 Fracturing Fluids

FUNCTIONS

The functions of fracturing fluids should be clearly understood by the fracture treatment designer.

The first function of a fracturing fluid is to transmit energy from the high pressure, positive displacement pumps of the fracturing trucks to the bottom of the well in order to cause a fracture to be initiated. Following crack initiation, the next function is to extend the fracture and to establish fracture width at the well bore. Once sufficient width has been established to accommodate the propping agent, the role of the fluid is enlarged to include carrying the proppant from the blender to the formation, and then transport and suspend the proppant particles within the fracture.

At the conclusion of the fracturing operation, when all of the proppant has been placed into the fracture, the next function of the fracturing fluid is to revert to a very low viscosity fluid with a very high fluid loss rate (leak off) which will enable the fracture to close quickly upon the proppant prior to total settlement of the suspended proppant. Occasionally, there is an additional function of the fracturing fluid. In some instances, the ability of the fracturing fluid to dissolve rock or certain rock constituents is used to advantage. In such cases, acids may be employed as the fracturing fluid.

1.3 PROPERTIES OF THE IDEAL FRACTURING FLUID

A) Reactions and Residues

One other aspect which we should remember is that, except in special cases, such as fracture acidizing, the fracturing fluid should be inert with respect to interaction with the formation rock or with the proppant. Ideally, every drop should be recovered from the formation and from the fracture. Also, the fracturing fluid should not react with the reservoir fluid, except perhaps, to reduce the surface tension, viscosity or to increase volatility. The most significant way in which fracturing fluids can reduce the effectiveness of the job is to cause plugging within the fracture itself due to residue. One of the worst causes of this effect is a guar gum gelling agent. Examples of extremely severe plugging, approaching 100%, have been reported as a result of laboratory testing under fully simulated in situ conditions. The same report indicated that there could also be considerable variation in the same type of product when obtained from different service companies. This is perhaps one of the most important but least understood factors, i.e. that one risks a considerable variation in quality when one specifies Brand X or equal. In the opinion of the writer, no product that is to be injected into a formation should be accepted for use by any oil company until either the oil company has tested the product under fully simulated down hole conditions in its own laboratory and passed on the product for the intended use, or else the supplier has provided sufficient evidence of adequate testing of the product to allay fears. Again, the test conditions are very important. While there exists API RP 39 that deals with evaluation of fracturing fluids, this procedure leaves much to be desired. Ideally, an improved industry standard testing procedure should be developed and used. In the absence of such, companies should consider establishing such a procedure for in-house use.

B) Fluid Loss

Another property of the ideal fracturing fluid is that it should exhibit a controlled, predictable fluid loss. This is extremely important because the rate of fluid loss determines a large number of other variables, such as fracture volume, and to some extent the length, width and height of the fracture.

The fracture geometry, in turn, is significant in terms of proppant placement and so forth. An under estimation of fluid loss rate may lead to a screen out near the beginning of the job due to inadequate fracture width, and complete job failure may result. Fluid loss may be controlled by any one of, or a combination of, three mechanisms of control; reservoir properties, fracturing fluid viscosity, or wall-building properties of the fracturing fluid itself. Due to the possibility of severe restriction to productivity that might be caused by plugging of the fracture bed, there is a trend away from the use of wall-building additives except for additives, which dissolve, in the produced fluids. These additives should be tested in the produced fluids.

Control of fluid loss by controlling the viscosity of the fracturing fluid augmented, if necessary, by soluble wall-building additives is the most popular approach. Even in very tight reservoirs this approach is widely used since long fractures are required and proppant transport becomes a very key factor.

Viscosity control is usually achieved in one of three manners; ultra viscous cross-linked gels, moderately viscous non-cross-linked (linear) gels, or very finely dispersed emulsions. These fluids tend to control fluid loss primarily due to their viscosity, but also due to the matting-out of the cross linked gel particles, which would impart a wall-building characteristic. In the case of emulsions, fluid loss control is due to the multiple phase and interfacial tension properties of the mixture.

There is room for controversy concerning fluid loss testing methods, dynamic versus static, and there is a certain amount of disagreement concerning the treatment of the first portion of the fluid loss, known as the spurt loss. There is also varying opinion on the seriousness of the effect of pressure on the fluid loss rate through filter cakes.

The role of fluid loss in fracture design is more critical in higher permeability reservoirs. It is vital to determine the fluid loss characteristics by careful laboratory testing using representative and multiple rock samples. The works of Nierode, Nolte and Smith provide us with ways of determining the correlation between laboratory and field determinations of fluid loss coefficient.

C) Proppant Transporter

The ideal fracturing fluid should be a "perfect transporter" of proppant. That is to say, the fluid should have the ability to carry the proppant in perfect suspension, with no settling, until such time as all of the proppant has been placed in the design location in the fracture. This implies that the fluid should exhibit an effective viscosity sufficient to resist the settling effect due to gravity, or that the specific gravity of the proppant and the fracturing fluid will be the same. Since we have very little choice concerning the density of the propping agent, the quality of the fracturing fluid becomes all-important.

The cross-linked water gels and some of the foamed materials are considered to be the better transporters. There is a certain amount of controversy in the industry concerning an acceptable laboratory method to determine the effective viscosity of the cross-linked gel systems, foams, and so forth. The traditional Power Law method of measuring shear stress at various shear rates and plotting on log-log paper has been found to be unsatisfactory due to the inadequacy of the laboratory instrumentation when testing cross-linked fluids having ultra-high viscosity.

These discussion on the proppant-fluid ratio, the ratio between injected fluid, fluid leak off and concentration of proppant in the fluid remaining in the fracture, as well as the relationship between fracture geometry and the velocity of the fracturing fluid moving in the fracture. All of these items and more are important factors in proppant transport. Also, and perhaps most important, after pumping stops, consideration must be given to the continuing tendency for the fracture to grow, the suspended proppant to settle and the simultaneous tendency for the fracture to close.

D) SEQUENTIAL DESCRIPTION

Let us first consider the concept of how the fracturing fluid creates the fracture.

As a volume of fluid is injected into the rock, one portion of the fluid, the fluid loss volume, leaks off and is lost from the fracture. The remaining portion stays in the fracture. Then, when the next volume enters the fracture, the portion remaining from the first volume is pushed ahead, opening up new fracture volume. As it does, a portion leaks off and a portion remains in the fracture. This process continues throughout the pumping operation. The fracture width at any specific distance from the well bore will increase from zero to some near equilibrium value as pumping continues. Consequently, after a period of pumping the width would become large enough to accept a particle such as propping agent.

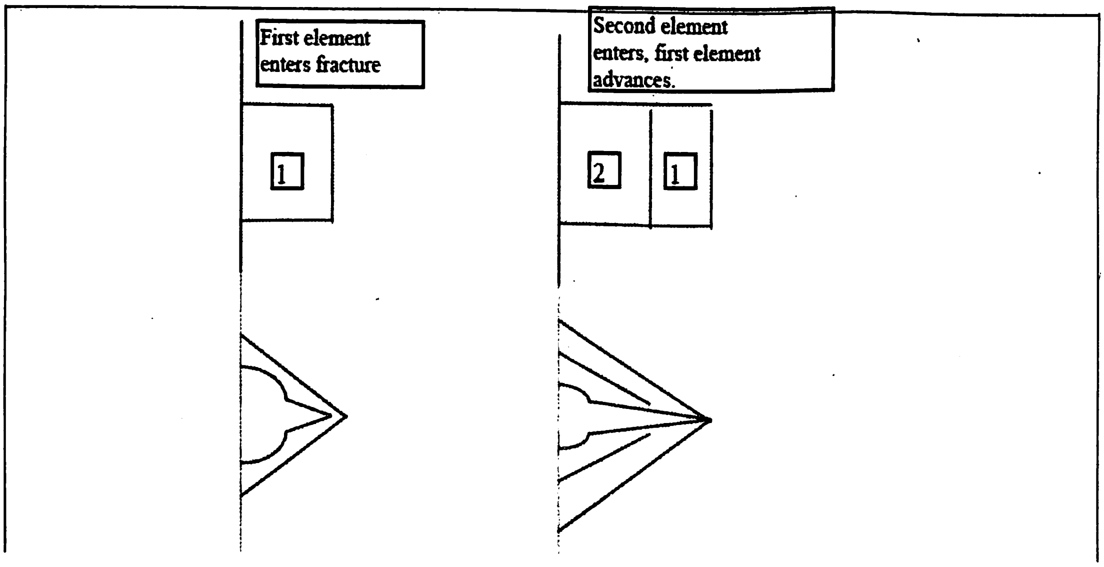


Fig 5: concept of fluid loss

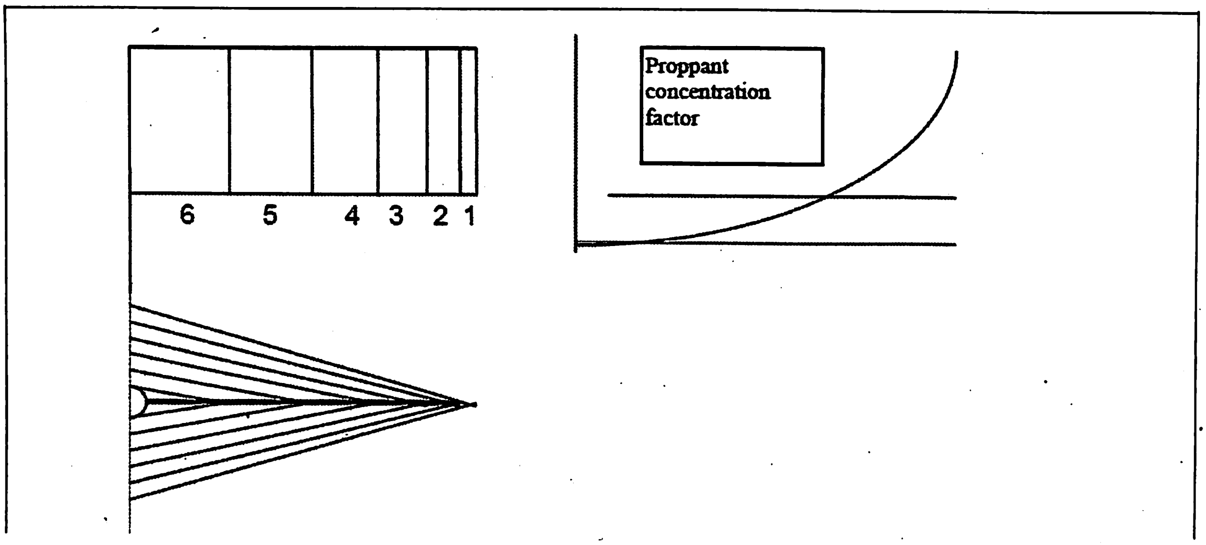


Fig 6: proppant Concentration Factor

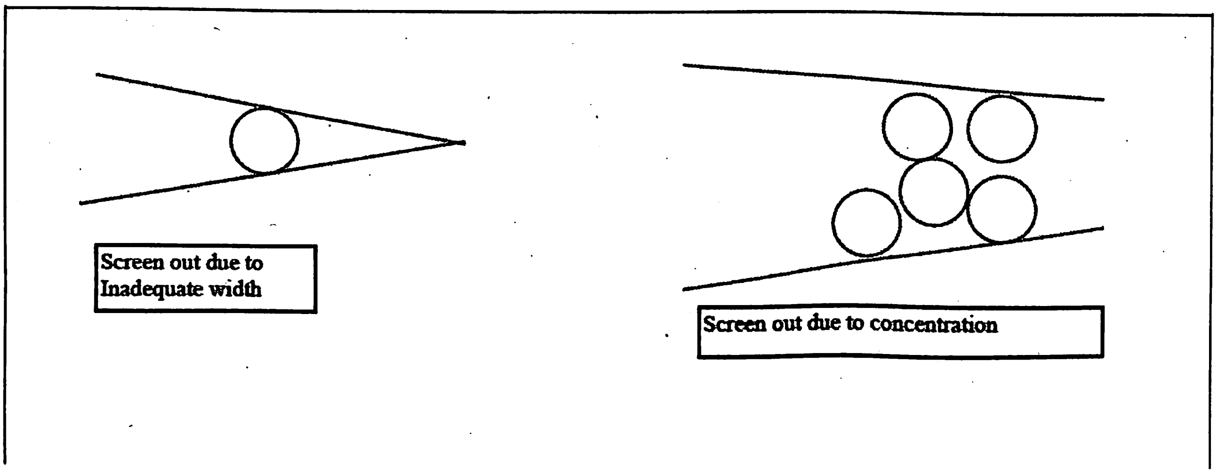


Fig 7: Screen-out Schematics

One can visualise that an element of fluid into which proppant has been introduced would tend to lose some of its fluid phase but none of its proppant as it travelled along the fracture. Therefore, the proppant concentration increases as the fluid element moves through the fracture. A screen out (or sand-off, this text uses the two terms interchangeably) will occur if either the fracture width at the leading edge of the moving proppant is too small or the concentration of proppant at the leading edge becomes too high. In order to help avoid this scenario of a screen out, a volume of fluid, known as the pad volume, is added at the beginning of the job. (Sometimes a special pre-treatment fluid is pumped ahead of the pad volume. This is called the pre-pad.) The pad volume consists of high quality fracturing fluid containing all of the appropriate additives but no propping agent. The purpose is to generate sufficient fracture width ahead of the propping agent and to provide a pad of fluid at the leading edge to help condition the faces of the fracture so that fluid losses will be controlled by the time the proppant arrives at a given point in the fracture. If the proper basic information is available this volume may be calculated and this is usually done with the aid of a computer.

E) PARTICLE VELOCITY

Once the pad volume has been pumped, the addition of propping agent can begin. If we imagine the propping agent particle moving away from the well bore, carried by an element of fluid, there are two directional components to its velocity. Horizontally, the particle has been observed experimentally (Daneshy, 1975) to move with the fluid slug without significant slippage. Some observers (Clark et al, 1977) dispute this claim, and say that the horizontal velocity of the proppant particle is only 70 to 90% of the velocity of the fluid. Again, we remind readers to also consider the contribution of convection by Cleary and Fonseca (1992).

The second component of the particle velocity is the vertical (downward) direction. This portion is termed the settling velocity. It has been shown by Daneshy to be affected by the following variables:

- Flow properties of the fracturing fluid, (n' and k' modified).

- Particle diameter, d

- Particle density, ρ_{sd}

- Fracturing fluid density, ρ_f

Daneshy provided an equation that relates these variables as follows:

$$V = \frac{[2n+1]d}{108n}\left[\frac{[\rho_{sd}-\rho_f]d}{72\,k_a}\right]^{n^{-1}}$$

$$V_h = V\,\frac{f_{vsl}}{10^{1.82}[1-f_{vsl}]}$$

Where:

f_{vsl} = the volume fraction of the slurry occupied by the fluid.

He also showed that when there was more than one particle, and if there was any interference between particles, the effect of this interference was to hinder the settling velocity. To account for this he provided an additional equation to correct the settling rate.

F) Rheological Characteristics

The ability to control and predict the "viscosity" of a fracturing fluid is very important due to the role that viscosity plays in transport, fluid loss, friction in the pipe and friction in the fracture. Friction in the fracture is in turn very important in respect to fracture height and fracture width, and therefore, in containment.

As mentioned, treatment of "viscosity" of non-Newtonian fluids, particularly cross-linked water gels and foams, is a very complex subject and much more work must be done before an industry consensus is reached.

Naturally, one of the more important and desirable characteristics of a fracturing fluid is its ability to be pumped at high rates with low frictional pressure loss. The service companies have made very significant contributions in this respect, so it is now possible to pump fluids at high rates with a fraction of the horsepower formerly required. The ability to efficiently transfer energy from the surface to the formation has been a huge contribution. It is important when planning treatments to realise that not all friction reducers are compatible with all other additives and it is well to remind ourselves that when there is an incompatibility between two additives, there is a good possibility that neither will function. Field measurements of the actual value of friction due to pumping are very easy to obtain, and this determination should be made routinely on fracturing jobs to verify the performance of service company additives. It should be noted that the frictional pressure loss that is recorded just prior to the instantaneous shut down pressure is actually a combination of frictions. These include pipe, perforation, near wellbore and fracture friction. It cannot be assumed that all of the friction is due to pipe friction. In fact, it is possible that an indication as to a restricted number of perforations open or excessive near wellbore friction may come from analysis of this part of the recording. This is especially true if there is an unusually high pressure loss, and if a Newtonian fluid is being pumped during the flushing of the pipe at the end of the job. Fracturing fluids are generally not run 'neat'. The base fluid is usually treated with at least one or two additives of one kind or another to increase the viscosity, prevent emulsions, and so forth.

One of the most common additives is a gelling agent to increase the ability of the fluid to carry proppant in suspension, and to resist leaking off into the formation. However, once the last of the proppant has been displaced out of the casing and into the formation, a very important combination of events occurs. This period can have enormous influence on the success or failure of the job.

It is necessary for fluid loss to occur before the pressure in the fracture can fall in order to allow the fracture to begin to close. The faster the pressure is reduced, the faster the fracture closes.

However, in order for fluid loss to occur, some finite time is required. If the proppant remains held in perfect suspension, the amount of time is of no consequence. In the real world, we seldom, if ever, achieve perfect transport with materials presently in use. That is to say, some settling of the proppant occurs, both during pumping and after pumping has stopped. In view of this, closure time becomes critically important. Unless there is sufficient loss of fluid after pumping stops (and before complete settling of the proppant) to enable the fracture to close sufficiently to prevent further settling, then all of the proppant will settle to the bottom. This could leave a large portion, or perhaps the entire top portion of the fracture unpropped. Some people, who have conducted diagnostic computer simulations on instances of job failures, are claiming that there is strong indication that this may be occurring in more instances (the figure 90% has been mentioned) than was previously suspected. However, it can be very dangerous to generalise and it would be very easy to draw the wrong conclusions unless all of the facts of individual cases are examined very carefully. The diagnostic technique does not result in a unique solution unless several questionable assumptions are made.

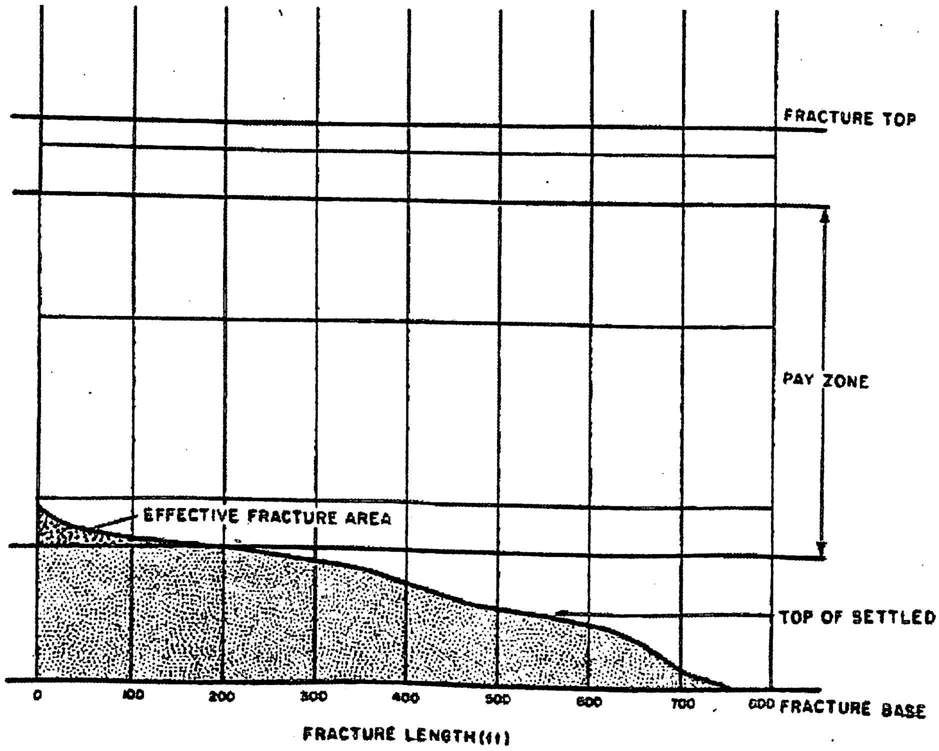


Fig 8 : History match of proppant distribution at closure

The manner in which the fluid loss and viscosity characteristics change at the end of the pumping is very important, and much more development work needs to be done in this area. Service companies should be asked for data on this aspect of their fluids. In the meanwhile, a very reasonable approach to the problem would be to develop a pressure-time-rate schedule for bleeding off pressure at the surface in a very controlled manner, immediately after the cessation of pumping, in order to deliberately reduce the internal fracture pressure and allow fracture closure to take place. Some engineering record keeping and analysis of volume, rate and pressure relationships for this operation, along with produced proppant volumes should allow rules of thumb to be developed for particular fields.

G) Gas Reservoirs with Low Level Water Saturation

An earlier version of this present course pointed out in 1984 that gas reservoirs may exist that is, at the present time, under-saturated with regard to water. In other words, the current level of formation water saturation is less than would be the case if a sample of the rock was flooded with formation water and then displaced with humidified formation gas to an irreducible saturation level.

The implication of such a situation, were it to exist, is that treatment of the formation with a water base fracturing fluid would likely semi-permanently raise the water saturation, thereby reducing the relative permeability to gas, and consequently resulting in lower gas production than would be the case if the water saturation had remained undisturbed. It is expected that this would not be the case if the relative permeability problem could have been avoided by using a non-wetting, highly recoverable phases.

If such a highly under-saturated condition is detected by log analysis or other means, such as preserved-core analysis, laboratory work to evaluate the resultant relative permeability to gas during various clean-up stages following treatment by various base fracturing fluids may be justified.

Some production companies have conducted a number of treatments on dry gas wells using hydrocarbon fracturing base fluids that are highly volatile at reservoir temperatures.

The significance of low treatment fluid recovery is far greater where short or low conductivity hydraulic fractures are prevalent. This can occur even when very large quantities of proppant are placed. The important aspect is the final location and geometry of the propped fracture; not how many tonnes were placed. If the fracture geometry is such that the fracture is adequately propped for only a very short distance in the productive part of the zone, retention of the wetting phase can be devasting.

Most people are familiar with the effect of saturation on relative permeability curves. Papers by Jones et al, and by Holditch have effectively discussed the role of capillary pressure and how it relates to clean up of an invaded reservoir, with particular emphasis on low pressure reservoirs that have been fractured. A case for the use of surface and interfacial tension reduction additives can be easily made for such instances.

A product has been introduced to attack the problem from a wettability point of view by changing the contact angle between the water and the sand grain surface. Normally this angle is about 0°. The product is designed to change the contact angle to between 90° and 180°. The effect is to completely eliminate or reverse capillary pressure.

The capillary pressure equation is

$$P_{cap} = \frac{2\gamma \cos\theta}{r}$$

Where: γ = liquid-vapour interfacial tension

θ = contact angle between the liquid and the solid

r = capillary radius

The value of cos θ = 1 for $\theta = 0^\circ$

= 0 or negative for $\theta = 90^\circ$ to 180°

H) Chemical Compatibility

Fracturing fluids ideally should be compatible with special purpose chemicals and additives, in order that the same base fracturing fluid may have its applicability extended over a large area of the field operation. Such additives include friction reducers, gelling agents, foaming agents, gel breakers, fluid loss additives, emulsion preventers, clay stabilizers and so forth. Incompatibility of chemicals run together due to lack of or inappropriate laboratory testing can lead to very poor or even disastrous results. If chemicals combine to form precipitates, neither of the chemicals will be available to perform its function, and in addition a potential for plugging will have been created. Don't mix cationic materials with anionic materials without first ensuring that there will be no loss of effectiveness or detrimental effects (serious precipitation). Mutual solvents, and/or dispersants can sometimes help "make it work" if the mixing of the two cannot be avoided.

I) Range Of Application

The ideal fracturing fluid should be applicable over a wide range of conditions. The advantage of this, of course is that a single base fluid could be used in very broad application, and field personnel for both the service and producing companies would become more expert in handling and preparing the product. Ideally, there would be capability to fine-tune the properties to meet specific job requirements. Many people believe that the ideal base fluid is clear water, and with careful testing, adequate modification may be made to provide a near perfect fluid. In most cases, water is readily available and may be filtered to provide a standard base fluid that is relatively constant, compared to crude oil for instance, in its properties from one geographical area to the next.

J) Ease of Preparation

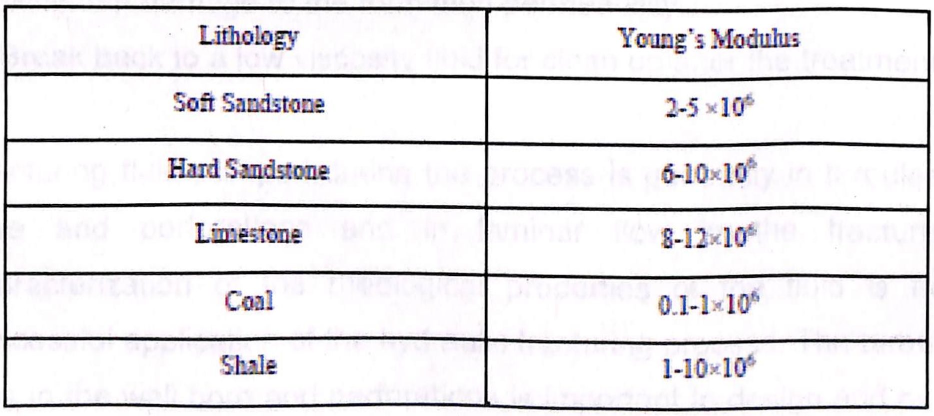
The ideal base fluid should be easy to prepare on location, and it should not be difficult to maintain control over the quality of the fluid. Some materials may be added to the base fluid entirely `on the-fly,' and no re-circulation of fluid is required before the job in order to mix all components thoroughly. Other fluids require batch mixing and re-circulation before the job. In some instances, several stages of pre mixing are required in order to mix all the chemicals in the proper manner. This requires substantial time on location, and in some cases starts the clock running on the life of the fluid if it has internal breakers, or if it has been formulated for a time break. One of the serious disadvantages of the batch mix approach is that if the job must be postponed, or terminated early after the preparation of the chemicals has begun, the entire chemical batch must be paid for, and it may not be reclaimable. On-the-fly mixing has a clear advantage in this respect.

However, batch mixing does have one very distinct advantage. Quality control is much easier to exercise when each stage of preparation can be checked prior to starting the next stage, and the final properties may be verified before pumping to the well. Also the averaging and thorough mixing effect of re-circulation tends to make for much more thorough blending.

FRACTURING FLUIDS PROPERTIES

The types and use of fracturing fluids have evolved greatly over the past 60 years and continue to evolve. To select the fracturing fluid for a specific well, it is necessary to understand the properties of the fluid and how these properties may be modified to accomplish desired effects.

Table 2.1 : Ranges of Young's Modulus for Various Lithologies [9].



Lithology	Young's Modulus
Soft Sandstone	$2\text{-}5 \times 10^6$
Hard Sandstone	$6\text{-}10 \times 10^6$
Limestone	$8\text{-}12 \times 10^6$
Coal	$0.1\text{-}1 \times 10^6$
Shale	$1\text{-}10 \times 10^6$

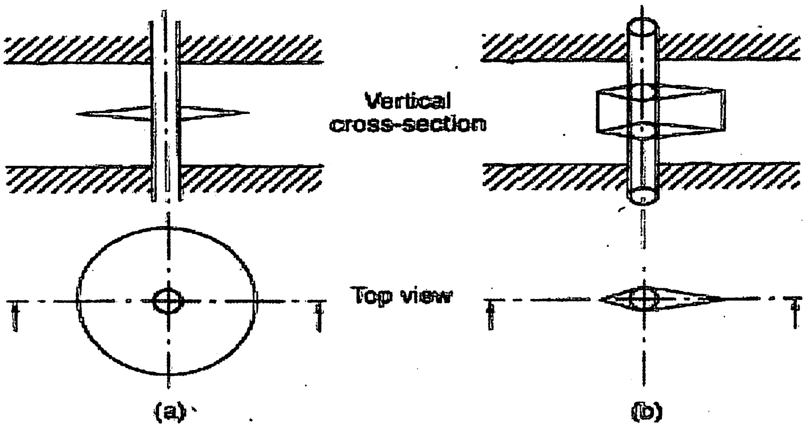


Figure 2.4 : Fracture configuration [4].
a. Horizontal fracturing. b. Vertical fracturing

Fig 9: Fracture Configuration

The properties that a fracturing fluid should possess are :

1- Low leak-off rate
2- Ability to carry the propping agent,
3- Low pumping friction loss,
4- easy to remove from the formation,
5- Compatible with the natural formation fluids,
6- Minimum damage to the formation permeability,
7- Break back to a low viscosity fluid for clean up after the treatment.

Fracturing fluid pumped during the process is generally in turbulent flow in the well bore and perforations and in laminar flow in the fracture. The accurate characterization of the rheological properties of the fluid is necessary for the successful application of the hydraulic fracturing process. The turbulent flow frictional loss in the well bore and perforations is important to design and perform a fracturing treatment. The frictional losses are used to predict the surface treating pressure and injection rate. The laminar flow behaviour of the fluid in the fracture is critical to the design of proppant transport and fracture geometry. The fracture geometry and extension during the treatment depends to a high degree on the rheological properties of the clean as well as proppant-laden fluid. Fracturing fluids are generally classified into three types: aqueous based, oil, and foam fluids. Aqueous-based fracturing fluids have been widely used in the oil and gas wells because of their low cost, high performance, greater suspending power, environmentally acceptable and ease of handling. Aqueous-based fracturing fluids are classified based on the amount of polymer (gelling agent) per gallon of water. For example a 20-pound fracturing fluid mix consists of a ratio of 20 pounds of gelling polymer per 1000 gallons of base fluid. Various mixes of these gelling agents are used in hydraulic fracturing treatments, depending on the type of formation being stimulated.

Guar is the most popular polymer for preparing aqueous-based fracturing fluid. The guar polymer has a very high affinity for water. The guar polymer easily dissolves in water and readily establishes hydrogen bond with the water molecules and gets hydrated.

The hydration of the polymer particle causes it to swell, exposing more sites on the guar to establish more hydrogen bonds with the water molecule. The hydration of the polymer continues till each guar molecule is well bonded with water molecule. The hydration rate is monitored with guar solution viscosity which varies as an exponentially with time for hydration. When no further increase in the viscosity is observed, the guar hydration is considered to be complete.

Oil-based fracturing fluids are primarily used for water sensitive formation. They normally employ gelled kerosene, diesel, distillates, and many crude oils. Aluminium salts of organic phosphoric acids are generally used to raise viscosity, proppant carrying capability, and improve temperature stability. Compared to aqueous-based fluids, they are more expensive and more difficult to handle. Oil-based fluids are more hazardous because of flammability and also possess environmental concerns.

Foam fracturing fluids are used in low pressure and fluid sensitive formations to aid in clean-up and reduce fluid contact. They are gas and liquid dispersions. Foams can use nitrogen and/or CO_2 as the internal phase and water-methanol mixtures used as the external phase for the formation of foam fracturing fluids. The disadvantages associated with foam fluids are: they cannot be loaded with high proppant concentration, the cost of foam fluid systems including field equipment is very high, and they are very uneconomical as compared to aqueous and oil-based fracturing fluids. Furthermore the rheological characterization of foams is not easy because of the many variables involved. The viscosity of the fracture fluid is important. The fluid should be viscous enough (normally 50–1000 cp) to create a wide fracture (normally 0.2–1.0 in) and transport the propping agent into the fracture (normally 10 to 100 sec/feet). The density of the fluid is also important. Water based fluids have densities near 8.4 ppg. Oil base fluids, although never used to fracture treat coal seam reservoirs, will have densities that are 70-80% of the water based fluids. Foam fluids can have densities that are 50% or less that of water based fluids. The density affects the surface injection pressure and the ability of the fluid to flow back after the treatment. In low pressure reservoirs, low density fluids, like foam, can be used to assist in the fluid clean up.

1.4 Fracture Fluid Additives

In most low permeability reservoirs, fracture fluid loss and efficiency is controlled by the formation permeability. In high permeability formations, a fluid-loss additive must be added to the fracture fluid to reduce leak-off and improve fluid efficiency.
Typical additives for a water based fluid are briefly described below.

- Polymers – used to viscosity the fluid
- Cross linkers – used to change the viscous fluid to a pseudo-plastic fluid
- Biocides – used to kill bacteria in the mix water
- Buffers – used to control the pH of the fracture fluid
- Surfactants – used to lower the surface tension
- Fluid loss additives – used to minimize fluid leak-off into the formation
- Stabilizers – used to keep the fluid viscous at high temperature
- Breakers – used to break the polymers and crosslink sites at low temperature

Formation temperature is one of the main factors concerning the type of additives required to mix the optimum fracturing fluid. In deep, hot reservoirs (>250^{0}F), more additives are required than in shallow, low temperature reservoirs. The owner of the oil or gas well normally does not own the equipment or the additives required to pump a fracture treatment. The operator will hire a service company to pump the fracture treatment. Each service company has their own research department for developing fracture fluids and additives. Each service company obtains their additives from various suppliers. As such, there is no set of rules one can use to select the proper additives for a fracture fluid, without first consulting with the service company that will mix and pump the fluid into the well. Many times, pilot tests of the fracture fluids must be conducted to be certain all the additives will work properly at the temperature in the reservoir and for the duration of the treatment.

Selection of the fracture fluid is a critical decision for the design engineer of fracture treatment. Economides *et al.* developed a flow chart that can be used to select the category of fracture fluid on the basis of factors such as reservoir temperature and pressure, the expected value of fracture half-length, and a determination if the reservoir is water sensitive.

1.4.1 Polymer

Various materials are used to thicken water, oil or acid for fracturing. The primary purpose is to improve proppant transport characteristics,. but fluid loss control may also be improved. A wide range of residue content remaining after the gel has `broken' is possible, depending upon the particular type of gelling agent used. This is a very important consideration. It is also very important to have accurate readings of the reservoir temperature to give to the service company in order to formulate the proper mixture.

1.4.1.1 Increase Viscosity of Oil-Based Fracturing Fluids

The viscosity of oil based fracturing fluids using polymer technology occurs by forming a polymer *in situ* by the formation of an "association polymer". An organic acid or organic phosphoric acid and a base are reacted in the liquid hydrocarbon to form the associated polymer. The most common chemicals being used for the gelation of oils are the aluminium phosphate type products for the formation of primary association polymers. Recent developments allow the addition of solid aluminium phosphate to the pre-gelled oil, which acts as a secondary gelling agent yielding higher down hole viscosity and better temperature stability.

The uses of soap-type viscosifiers for oil based fracturing fluids are rarely used today. These area mixture of caustic and toll oil fatty acids producing a high viscosity gel that has excellent sand carrying capability. Higher friction pressures are observed than when using aluminium phosphate systems.

1.4.1.2 Increase Viscosity of Water-Based Fracturing Fluids

The general classes of gelling agents commonly used to prepare base (linear) gels include the following:

A) Guar Gum

This material, a naturally occurring polymer coming from the guar bean, is available in several formulations. It is normally the least expensive gelling agent but is relatively highly damaging, having a residue of 8-14%. It is easy to cross-link and can be used in brines. (Cost Factor of 1.0)

B) Refined (Modified) Guar

Same properties as guar gum but possibly only one-third the residue.

C) Hydroxy Propyl Guar Gum (HPG) (Derivatized guar)

The main advantage for this product is its relatively low residue, 1 to 3%, thereby making it less damaging. It is typically more expensive than guar but less expensive than other water-based gelling agents. It is easy to cross-link and can be used in brines. (Cost factor of 1.4)

D) Carboxy Methyl Hydroxy Propyl Guar (CMHPG) (Double derivatized)

Used primarily in cross-linked systems because its high cost takes it out of the running in linear systems, CMHPG typically has lower residue than HPG, although still in the range of 1 to 3%. It is easier to cross-link than HPG and can be used in brines. (Cost Factor 1.4)

E) Hydroxy Ethyl Cellulose (HEC)

This is the cleanest, least damaging of the water-based gelling agents, having a residue of almost zero. It is not usually cross-linked, but can be used in brines. (Cost Factor 1.7)

F) Carboxy Methyl Cellulose (CMC)

This material is rapidly hydrating and while stated to be suitable for both continuous and batch mix operations, it typically is difficult to mix to a lump-free fluid. It is sensitive to even low salt concentrations (2% NaCl or KCl; 0% CaCl2) and is seldom used. (Cost Factor 1.6)

G) Carboxy Methyl Hydroxy Ethyl Cellulose (CMHEC) (Double derivatized)

Higher tolerance for salt makes this a more widely used additive than CMC. It is popular for low temperature applications. It is easy to cross-link. (Cost Factor 1.7)

H) Xanthan Gum

This product is used mainly in the drilling industry. It is relatively expensive and hence has limited current use for hydraulic fracturing but has good proppant transport capabilities. There is a 3%residue using hypo chlorate oxidizing breaker but the break is unpredictable. It can be cross-linked. It is good for gelling hydrochloric acid up to 15% concentration. (Cost Factor 2.0)

I) Polyacrylamide and Copolymers

These chemicals are rarely used for hydraulic fracturing gelling agents but are used as friction reducers in prepad and flush fluids. They are often used at concentrations of 0.2 to 0.5 kg/m^3 of fluid. The material can be degraded, it is residue free, it is usually ionic in nature but cationic, anionic and non-ionic forms are available. (Cost Factor 1.8)

1.4.2 CROSS-LINKING AGENTS

A large percentage of fracturing fluids are cross-linked using a variety of chemicals. These chemicals, used in very small concentrations, (0.1 to 0.5 % liquid vol/vol) can produce very large increases in apparent viscosity of the base gel. The chemicals work by chemically linking the linear polymers in the base fluid together limiting the ability of the water molecules to move.

Some common cross-linkers are:

- Borates
- Aluminium
- Titanium
- Zirconium
- Antimony.

Selection of the proper cross-linking agent is based upon the type of gelling agent being used, the pH of the system, the predicted fluid temperatures, plus other factors. When using borates the pH of the base fluid should be above 8.5. When using the other metallic cross-linkers the pH will usually be in the range of 2 to 8 and will depend upon the gelling agent being used.

One of the concerns when using cross-linked fluids is the shear stability of the fluid while it is being pumped down the tubular and through the perforations. Following shear, the cross-linked fluid should reheal rapidly under down-hole conditions so the propping agents will be transported and not dropped from the fluid near the wellbore. The stability and rehealing properties of a cross-linked fluid system should be verified in the laboratory under down-hole conditions using some kind of shearing device and the reheal time determined.

To minimise the effect of shear in the surface equipment and tubular goods the use of delayed reacting cross-linkers is now standard practice. The cross-link time is controlled so the cross linking occurs near the perforations or after the fluid enters the fracture. This result in a higher viscosity fluid in the fracture than if the fluid was subjected to shear after cross-linking occurred.

1.4.3 BREAKERS

Gel breakers are an important part of most gelled liquid systems. They enable the gels to revert to low viscosity fluids in the formation. Various systems and mechanisms are used to break gels and almost all of them are very temperature sensitive. Some are very pH sensitive. An important development has been encapsulated breakers. These chemicals permit the fracturing fluid to be placed into the formation before the gel breaking activity begins. This provides several advantages. The gel loading can be less because the designer doesn't have to account for the immediate action of the gel breaker. Also the encapsulated, solid gel breaker will probably stop in the fracture and filter cake before it dissolves, rather than passing into the matrix. This means that sufficient population of breaker will be present within the gel-rich filter cake to help degrade all of the cake. This was not always the case until such breakers were available.

For all cross-linked fluids, other than borates, the breaker chemical degrades the polymer into short chains reducing the viscosity. For borate cross-linked fluids the cross-link itself is broken. The breakers used for oil gels are usually either acids or bases and they work by interfering with the association polymers.

1.4.4 BUFFERS

Buffers are sometimes required to help adjust the pH within certain narrow ranges required by some systems. If pH buffers are employed, you should be aware of the effect of that pH on the formation. A pH of less than 7 is preferred from a formation-fluid compatibility stand point.

However, because of other factors involved, it may be necessary to override this to obtain other desired properties of the fracturing fluid.

By proper pH control, polymer hydration rate, polymer temperature stability, cross-linking characteristics, gel break, and clay control may be obtained.

Common pH control chemicals used are:

- Monosodium phosphate
- Sodium acetate (acetic acid)

- Fumaric acid
- Citric acid
- Formic acid
- Sodium bicarbonate
- Sodium carbonate
- Magnesium oxide.

1.4.5 FRICTION REDUCERS

While some of the gel systems have inherently low friction properties, others are enhanced by the addition of friction reduction additives. They are also used, of course, in non-gelled systems, where they may be mandatory. The effect is to conserve pumping energy and enable the job to be conducted at much higher injection rates than would otherwise by possible.

1.4.6 FLUID LOSS ADDITIVES

In some cases, it is necessary to control the fluid loss rate from the fracture by employing additives that tend to build impervious filter cakes. The use of such additives can be crucial to job success in some cases. However, it is most important to select very carefully from additives that will not cause permanent plugging. Again, know what you are using.

Commonly used fluid loss agents are:

- Silica flour
- Polymers (e.g. guar, starch)
- Silica flour and polymer
- Oil soluble resin
- Oil soluble resin and natural polymer
- Emulsions
- Insoluble gases
- Hydrocarbon phase.

1.4.7 CLAY STABILIZERS

Potassium Chloride

Potassium chloride is the most widely used salt to help prevent clay swelling. It is usually used at two to three per cent by weight in fresh water. Due to environmental concerns and regulations, on-chloride salts of potassium or ammonium are becoming more common. Potassium sulphate has been used.

Polymers

In recent years, products have been developed which may be added to fracturing or acid systems to help `stabilise' clays in place in the formation and thereby prevent them from being set free to migrate to other locations where they might act as restrictions to flow. The additives are best applied either ahead of, or in conjunction with, the very first fluid to enter the formation at time of completion. The chemicals are preventive in nature and generally will be ineffective in curing an existing problem. There is a wide range of effectiveness among the various products and laboratory testing of effectiveness of the chosen product is suggested. Some are significantly damaging to low permeability formations and prudence suggests laboratory testing before such use.

1.4.8 OTHER ADDITIVES

Other additives are mostly employed on an as-needed basis. In all instances, it is very important to remember what we have been preaching about compatibility of additives.

The list of other additives includes surface tension reducers, non-emulsifiers, biocides, iron sequestering agents, anti-sludge additives, paraffin inhibitors, water scale inhibitors and many others. Be receptive to new concepts but be careful.

1.4.9 ENERGIZING GASES

Carbon dioxide and nitrogen are widely used to help provide gaseous energy to recover liquid fracturing fluids after the treatment. Their use helps eliminate the need for swabbing and also helps to reduce the fluid retention time in the formation. Quantities to use can be calculated from gas lift charts or software available from the service companies. The ratio to use depends on formation pressure, depth, hydrostatic head of fracturing fluid and temperature.

A) Nitrogen

Nitrogen is ordinarily employed in the field as a gas. However, it is more conveniently transported as a liquid. The liquid, at very cold (cryogenic) temperatures, is pumped with a high-pressure cryogenic pump through a heat exchanger where it is converted to a gas and then is injected into the treating lines.

B) Carbon Dioxide

Carbon dioxide is ordinarily pumped as a liquid (at about -10 to 0 °C), and in many cases, is carried through the length of the tubing in liquid state, only to vaporise as it enters the formation. Since it can be transported in liquid state, it has the ability to cause significant cooling. The effects of this have to be considered. The application of liquid carbon dioxide as a stand-alone fracturing fluid was discussed earlier.

	N_2	CO_2
Critical Temp °C	-147	31
Critical Pressure kPa abs	3400	7385
°C (at 1 atm)	Normal Boiling Point -196	Sublimation Temperature -78
Volume Ratio gas/liquid (std conditions)	696	547
Liquid Density	0.808 (at 1 atm)	1.10 (at -25 °C, 1700 kPa)

Fig 10: Comparision of ENERGIZING GASES N_2 & CO_2

1.5 Fluid Rheological Models

The science of rheology by definition is the study of the deformation and flow behaviour of materials. Materials in this context can be solids, liquids or gases .Rheology describes the relationship between force, deformation and time and comes from the Greek word “rheos” means to flow. The rheological characteristics of fluid are important in evaluating its ability to perform a specific function. In the petroleum industry, fluids are used to transport and suspend solids, reduce friction pressure and also to control fluid loss. Fluids can be broadly classified into two categories:

Newtonian and Non-Newtonian fluids.

Newtonian Fluids

Newtonian fluids are fluids in which the ratio between applied shear stress, and the rate of shear is constant with respect to time and shear history. The relationship characterizing Newtonian fluids is expressed mathematically as follows:

t=mg...(1)

Where,

t = shear stress

m = viscosity

g= shear rate

Eq.1 is commonly known as Newton's law of viscosity. Fluids which exhibit such a linear relationship between shear stress and shear rate are known as Newtonian fluids. Examples of Newtonian fluids are water, light hydrocarbons, and all gases.

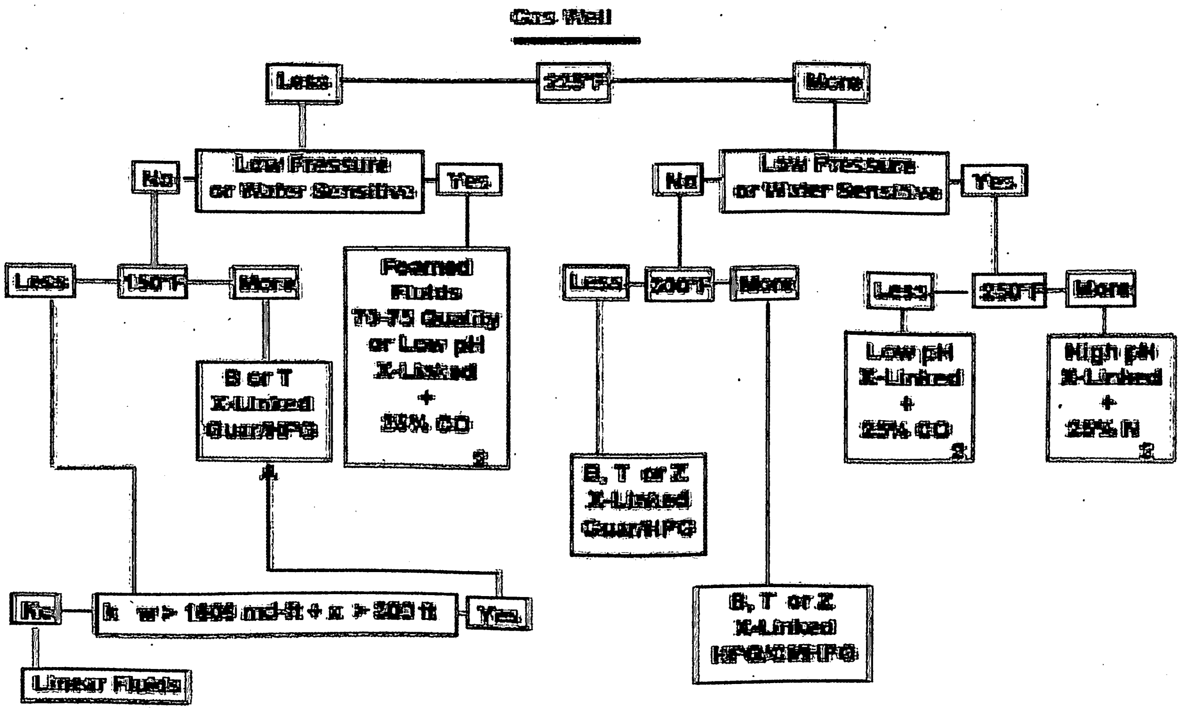


Fig 10: selecting a fracture fluid

Non-Newtonian Fluids

A non-Newtonian fluid is one whose rheogram (shear stress versus shear rate) is nonlinear or does not pass through the origin. Most of the fluids used in the petroleum industry are non-Newtonian fluids. Non-Newtonian fluids are further classified into:

a) Fluids for which the rate of shear is determined by the shear stress at that point or instance and are called 'time independent' purely viscous or inelastic fluids.

b) More complex fluids whose relationship between shear stress and shear rate depends upon the duration of shearing and their kinematic history. They are called time-dependent fluids.

c) Fluids that are partially elastic and recover after deformation are known as Viscoelastic fluids.

Figure 11 shows the flow behaviour curves for time independent fluids on a linear scale. Linear flow behaviour, a typical characteristic of a Newtonian fluid is also included in the Figure.

The following are the rheological models that described the various types of non-Newtonian fluids.

1) Bingham Plastic Model

The Bingham plastic model is a two-parameter time-independent rheological model that accounts for the stress required to initiate fluid flow in viscous fluids. This initial stress is referred to as the yield stress. Once the yield stress is overcome, the fluid is represented as a Newtonian fluid, which is shown by the linear relationship between the applied stress and the rate of shear. The constitutive equation for the Bingham plastic model is given as follows.

$$\tau=\tau_0+\gamma_p.g \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots \quad (2)$$

Where,

τ_0 = yield stress

γ_p = plastic viscosity

2) Power Law Model

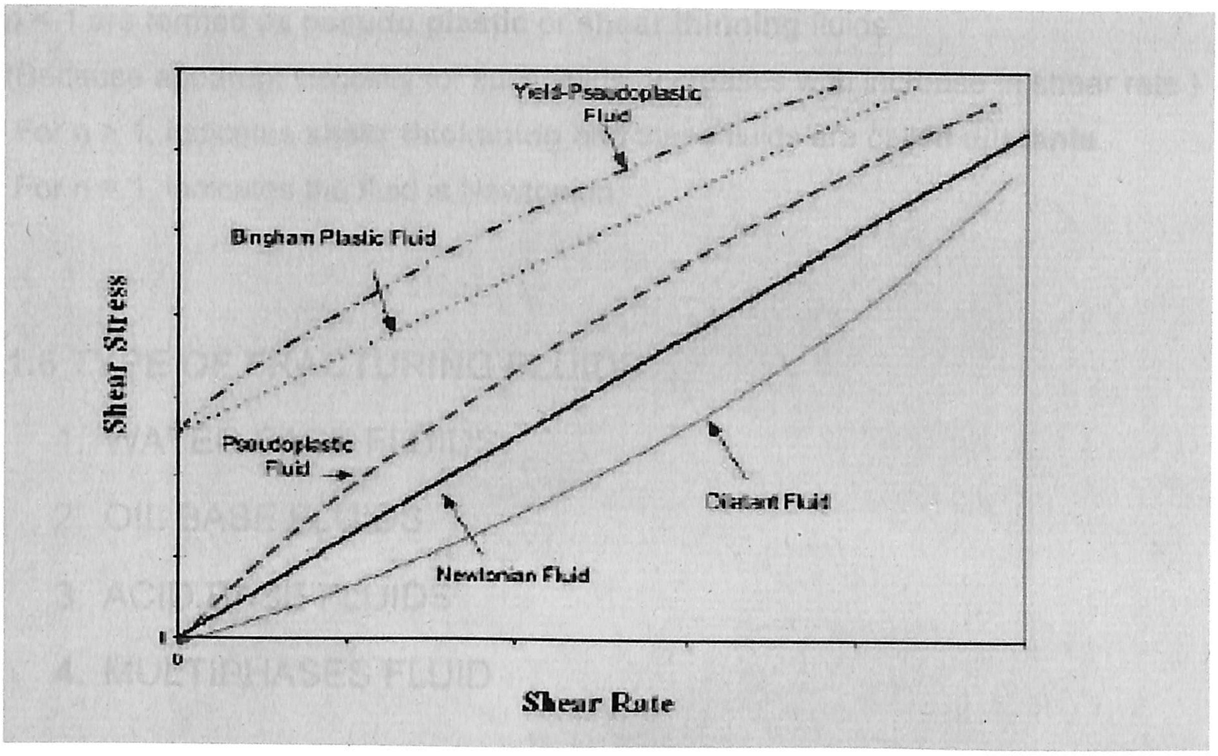


Fig 11: Types of time independent fluid flow behaviour

The power law model is also a time-independent two parameter rheological model like the Bingham plastic model. However, where the Bingham plastic model expresses a linear relationship between shear stress and shear strain, the power law model uses a nonlinear relationship which can better characterize the shear-thinning characteristics of most common drilling fluids. The following is the constitutive equation for the power law model.

t = k (g)n .... (3)

Where,

n and k are the flow behaviour index and consistency index respectively.

$$K=\frac{511^{1-n}\times\varnothing_{300}}{100\times4.788}$$

$$n=3.32\log(\varnothing_{600}/\varnothing_{300})$$

Fluids for which

$n < 1$ are termed as **pseudo plastic** or **shear thinning** fluids

(Because apparent viscosity for such fluids decreases with increase in shear rate.)

For $n > 1$, indicates **shear thickening** and these fluids are called **dilatants**.

For $n = 1$, indicates the fluid is Newtonian.

1.6 TYPE OF FRACTURING FLUIDS

1. WATER BASE FLUIDS
2. OIL BASE FLUIDS
3. ACID BASE FLUIDS
4. MULTIPHASES FLUID

1.6.1 WATER-BASE FLUIDS

Because of their low cost, high performance, and easeof handling, water-base fluids are the most widely used fracturing fluids. Potential problems with water-base fluids are formation damage of water-sensitive zones and pack damage caused by unbroken polymer and additives.

One of the first polymers used to viscosify water for fracturing applications was guar gum. Guar is a long-chain polymer composed of mannose and galactose sugars (Whistler, 1959). Polymers composed of sugar units are called polysaccharides. Guar gum comes from the endosperm of guar beans, which are grown mainly inPakistan and India, but also in the southwestern United States. The beans are removed from the bean pod, processed to separate the endosperm from the bean hull and embryo (splits), and ground into a powder.

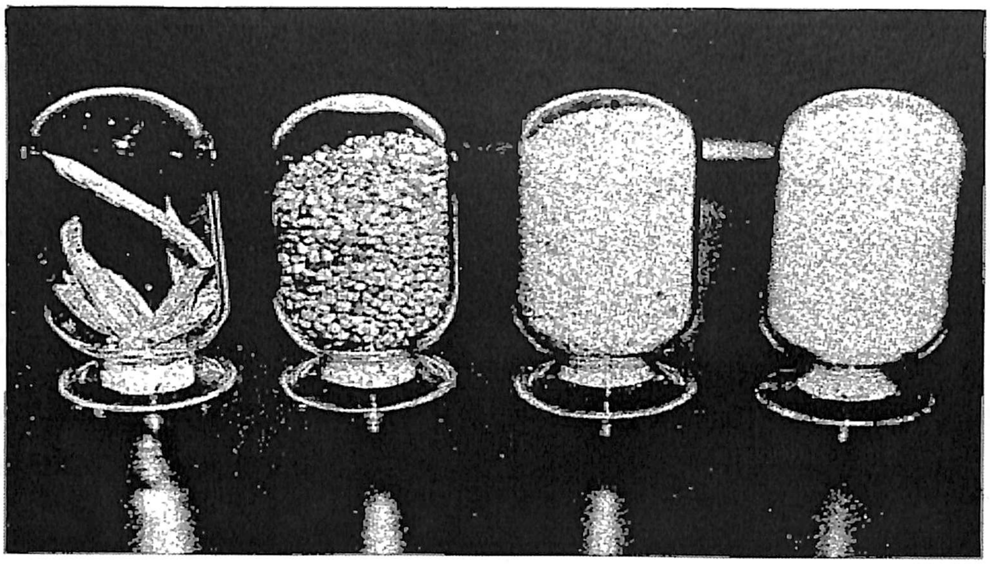


Fig 12: Photo of guar pods, beans, splits, and powder

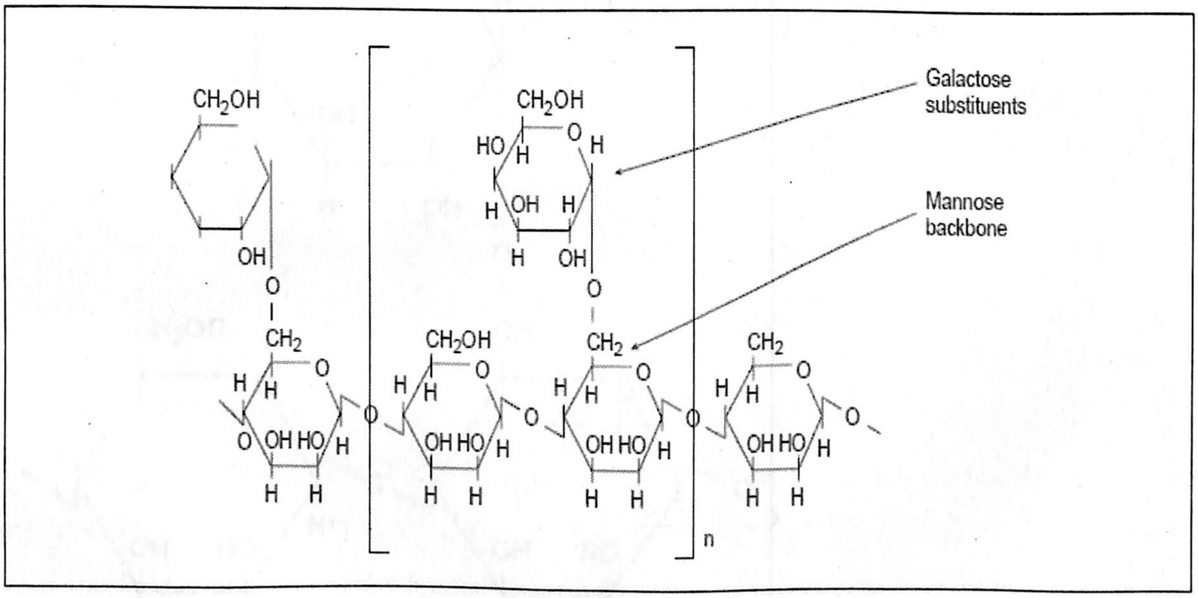


Fig 13: Structure of guar

The guar polymer has a very high affinity for water. When the powder is added to water, guar particles "swell" and "hydrate," which means the polymer molecules become associated with many water molecules, unfold, and extend out into the solution. The guar solution on the molecular level can be pictured as long, bloated strands suspended in water. The strands tend to overlap and hinder motion, which causes an increase in the viscosity of the solution. Recent studies indicate that the arrangement of galactose units may be more random, with galactose appearing on two or three consecutive mamrose units (Henkel, 1986). Also, the ratio of mannose to galactose may range from 1.6: I to 1.8: I instead of 2:1. Guar is a natural product. The process used to produce guar powder does not completely separate the guar from other plant materials, which are not soluble in water. Consequently, as much as 6 to 10% of the guar powder will not dissolve and may cause damage to the formation face or proppant pack. To minimize this problem, guar can be derivatized with propylene oxide to produce hydroxypropylguar (HPG). The reaction changes some of the -OH sites to -0-CHZ-CHOH-CH3.

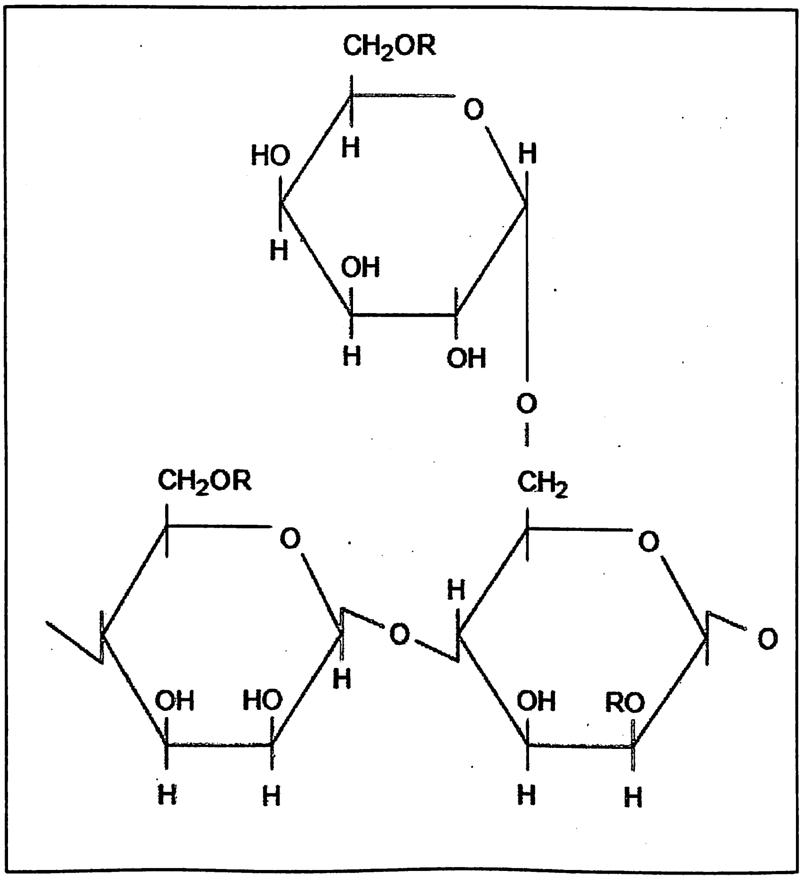


Fig 14: Repeating unit structure of hydroxypropylguar R-CH_2-CHOH-CH_3

HPG typically contains only about 2 to 4 % insoluble residue. It has generally been considered to be less damaging to the formation face a proppant pack than is guar, although recent studies (Almond et al., 1984) have indicated that guar and HPG cause about the same degree of pack damage. Hydroxypropylguar substitution makes HPG more stable at an elevated temperature than guar; therefore HPG is better suited for use in high-temperature wells. The addition of the less hydrophilic HP substituent also makes- the HPG more soluble in alcohol. A common quality assurance check is to add an equal volume of methanol to the polymer solution. Another guar derivative which is carboxy methyl Hydroxypropyl guar (CMHPG). This "double derivatized" guar contains the hydroxypropyl functionality of HPG as well as a carboxylic acid substituent. CMHPG is usually used for low-temperature wells (Almond and Garvin 1984). Hydroxyethylcellulose (HEC) or hydroxypropylcellulose (HPC) is used when a very clean fluid is desired. These polymers have a backbone composed of glucose sugar units which appears to be similar to the mannose backbone of guar, but there is a significant difference. Guar contains hydroxyl pairs which are positioned on the same side of the sugar molecule (cis orientation) In HEC, the –OH groups are on adjacent carbons, but they are on opposite sides of the ring (tram orientation). The cis arrangement is easily cross linked, while the Trans is not. HEC can be cross linked at a pH of 10 to 12 with Zr(IV) . To crosslink HEC under milder conditions, the carboxymethyl group can be added, which makes cross linking with metal ions such as Al(III), Ti(IV), and Zr(IV) possible at a pH of approximately 4 to 6. Still another type of polymer is Xanthan gum (Fig. 16).Xanthan is a biopolymer, produced metabolically by the microorganism Xanthonwnus campesttis (Lipton and Burnett, 1976). Xanthan solutions behave as Power Law fluids even at very low shear rates (Kirkby and Rockefeller, 1985), while HPG solutions become Newtonian. Clark et al. (1985) showed that at shear rates less than 10 sec^{-1}, xanthan solutions suspend sand better than does HPG. These properties may increase the use of xanthan in the future, but for now xanthan is more expensive than guar or cellulose derivatives and it is used less frequently.

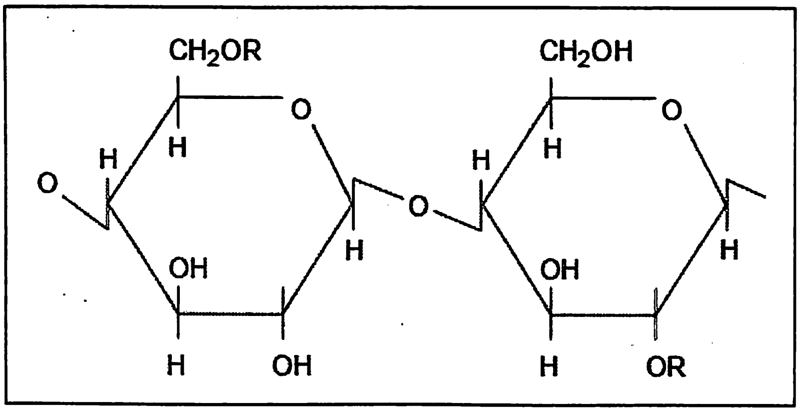


Fig 15: Repeating unit structure of hydroxy ethyl cellulose, R-CH_2CH_2OH

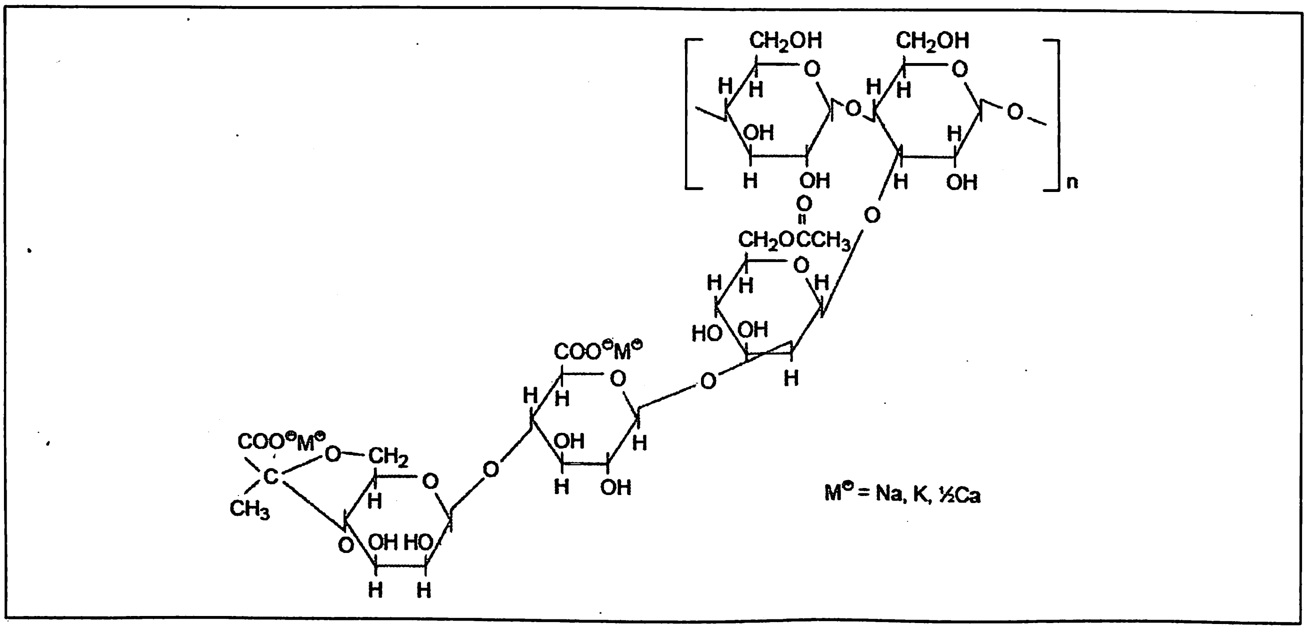


Fig 16: Repeating unit structure of Xanthan gum

The most damaging fluids are guar polymers the poorer ones of which can leave as much as 30%residue. The cellulose derivatives are believed to be essentially non-residue producing, and the synthetic polymers also produce little or no residue.

The common water gelling agents are:

- Guar gum,
- Hydroxypropyl guar (HPG) gum,
- Hydroxyethyl cellulose (HEC),

- Carboxymethyl cellulose (CMC), and
- Carboxymethyl hydroxyethyl cellulose (CMHEC)
- Carboxymethyl hydroxypropyl guar (CMHPG).

When selecting a gelled and/or cross-linked system, it is very important to design the correct breaker type and concentration for the proper temperature, in order to obtain the desired break time.

Cross linkers cross linking agents are used to dramatically increase the effective molecular weight of the polymer, thereby increasing the viscosity of the solution. A number of metal ions have been used to crosslink water-soluble polymers (Conway et al., 1980). Borate, Ti(IV), and Zr(IV) are by far the most popular. Al(IJI) is sometimes used to crosslink CMHPG and CMHEC because of the ion's affinity for cross linking carboxyl groups at low pH. Antimony (V) has been used to crosslink guar and HPG for low-temperature applications. Inorganic species such as borate salts (Deuel and Neukern, 1949) and transition-metal complexes (Chrisp, 1967) react with guar and HPG through the cis -OH pairs. A complex such as the one in Figure is formed. When the polymer solution is concentrated. Enough that the molecules overlap (for HPG, at least 0.25 % by wt), the complex in Fig 14 a can react with an overlapping polymer so that the two are linked together (Fig.17) (Menjivar, 1984). A species is created which has two times the molecular weight of the polymer alone. Because each polymer chain contains many cis-hydroxyls, the polymer can be cross linked at more than one site. Very high molecular-weight networks develop, especially under static conditions, resulting in highly viscous solutions. Boric acid and borate salts are used to produce cross linked gels with guar and HPG which are stable to 200 to 225 ^{O}F. At a pH above eight, borate forms an extremely viscous gel in a matter of seconds. High pH is required for cross linked gel stability, with a pH of 9 to 10 as an optimum. The borate ion is believed to be the cross linking species; a high pH is required to shift the equilibrium between a boric acid and a borate ion (shown in Eq.) toward high borate concentration.

H_3B0_3 + OH- + B (OH);

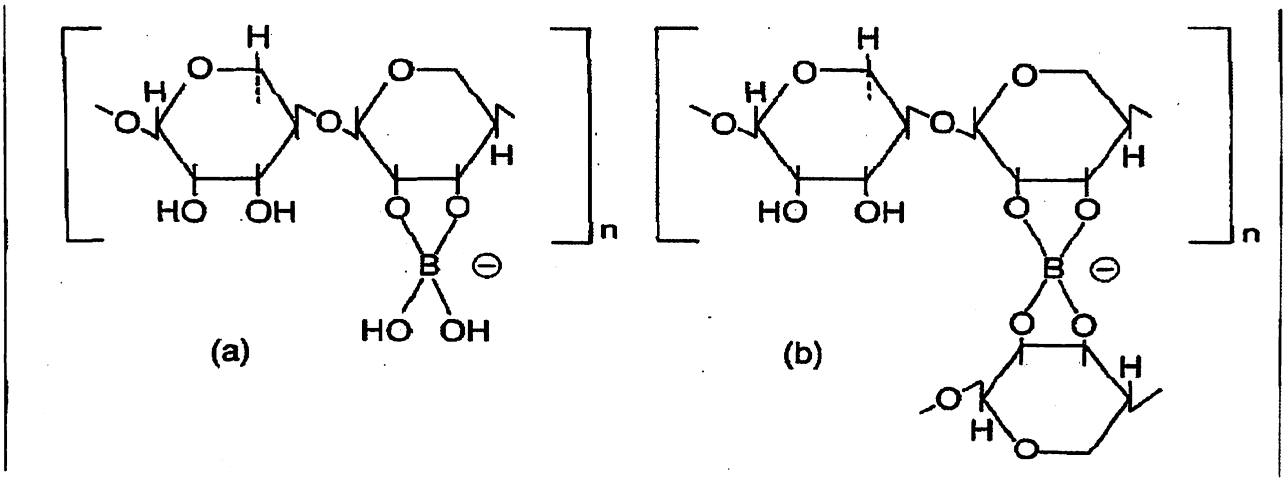


Figure 17: Effect of temperature and cross linker on the viscosity of HPG solutions.

Although the gel is very viscous, it will thin with shear and heat, but it will return to its original state once shear or heat is removed. Heating the fluid above 2O°F will cause some irreversible loss of viscosity due to polymer degradation. The borate crosslink is reversible; crosslink form and then break, only to form again (Deuel and Neukern, 1949). The rapid rate of cross linking for standard systems and the viscous nature of the gel cause high friction pressure during pumping. This drawback, as well as the loss of viscosity above 200 to 225 °F, limits the use of borate cross linked fluids to relatively shallow, cool wells. The characteristics of this commonly used cross linked fluid are summarized in Table

Borate	**Ti and Zr Complexes**
Fast crosslinking	Controlled crosslinking rate
Crosslinking reversible	Crosslinking permanent
No shear degradation	Shear-sensitive
Upper temperature limit: 200° to 225°F	Upper temperature limit: 300° to 325°F
High friction pressure	Friction pressure reduced by delayed crosslinking
pH 8 to 10 required concentration	Variable pH

Transition-metal cross linkers have been developed for fracturing deep, hot wells. Titanium and zirconium complexes have been used most frequently because of their affinity for reacting with oxygen functiontities (cis-OH), stable +4 oxidation states (Cotton and Wilkinson, 1972), and their low toxicity. The bond formed between the titanium or zirconium complex and the polymer is very thermally stable. The upper temperature limit for these gels is about 325 ^{O}F. It appears that the stability of the polymer backbone, rather than of the polymer-metal ion bond, is the limiting factor. Very hot wells (> 400 F) can be fractured with these fluids, if the treatments are designed to provide adequate cool down. The transition-metal polymer bond is very sensitive to shear. High shear irreversibly degrades transition-metal cross linked fluids (Craigie, 1983). Unlike the borate cross linker, once the bond between transition-metal cross linker and polymer is broken, it does not re-form. Thus, it is not desirable to have cross linking occurring in the high shear region of the tubing, because this results in an irreversible loss of viscosity. A number of factors affect the rate .before cross linking. These include fluid temperature and pH; shear conditions, cross linker type, and the presence of competing ligands. For example, increasing temperature & pH will usually accelerate the cross linking reaction. Fortunately, some of these parameters can be controlled to slow down the cross linking. Many different organic molecules (ligands) are capable of reacting with the metal ion, and they strongly affect the properties of the ion. Cross linkers are delayed because of competition for the metalion between the polymer and other ligands. Picture a hypothetical titanium complex laving two ligands (L) capable of binding at two sites (bidentate), and two ligands (A) capable of binding at one site (monodentate). For cross linking to occur, two polymer molecules must displace the ligands at four coordination sites. If the ligands are easy to displace, reaction so that it does not occur in the high shear region (generally 500 to 1500 sec^{-1}) of the tubing, but that it does occur in the low shear region (generally 10 to 200 sec^{-1}) of the fracture. By manipulating the chemistry, shear degradation of the fluid can be minimized. Curves B and C in Figure below illustrate the effect on high-temperature viscosity of reducing the crosslinking rate.

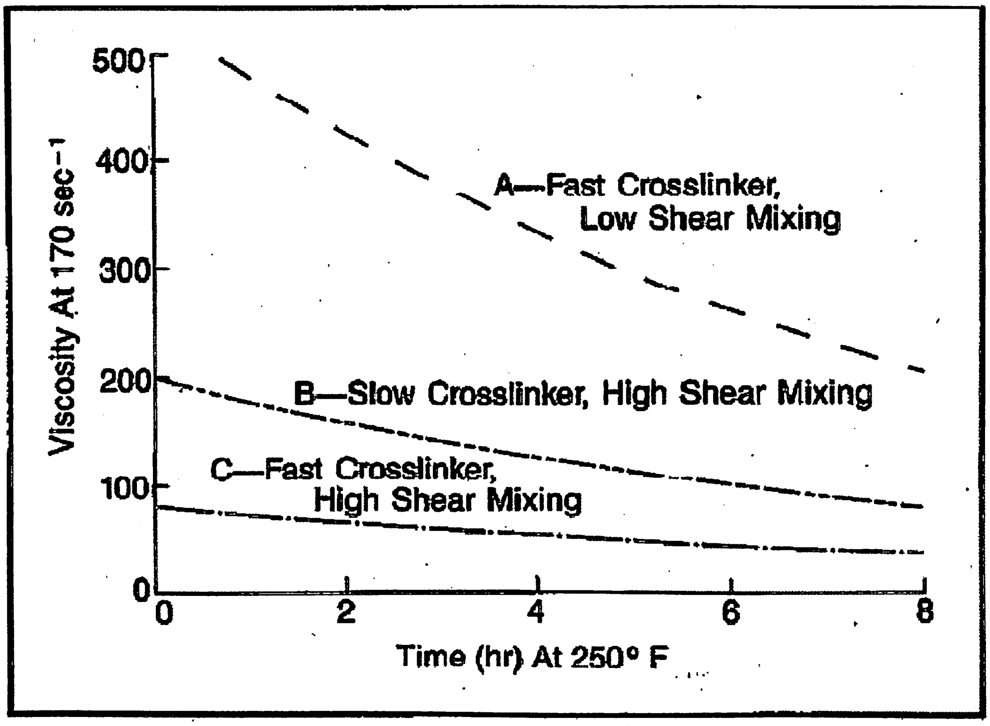


Fig 18: Graph between viscosity and time showing cross linking variation

For cross linking to occur, two polymer molecules must displace the ligands at four coordination sites. If the ligands are easy to displace cross linking occurs rapidly. If the ligands are difficult to displace (inherent delay), cross linking occurs more slowly. Alternately, a competing ligands may be added to a fast cross linker to effect a delay (Payne and Harms, 1984; Rummo, 1982). Some ligands used in transition-metal cross linkers are tri ethanolamine, acetyl acetone, and ammonium acetate. Viscosity should be building as the fluid leaves the tubing, although total cross linking is not necessary at this point. If cross linking occurs too rapidly, high friction pressure and shear degradation may result. If cross linking occurs too slowly, proppant may settle out in the fracture near the wellbore. There is considerable interest to use fluid having a crosslink time similar to the time the fluid will spend in the tubing. Unfortunately, as pointed out by Baranet and Ainley (1985) and Hodge and Baranet (1987), commonly used field methods for determining crosslink time may not be reliable. One way to get around the perceived need for precise control of crosslink time is to use a dual cross linker system (Baranet and Ainley, 1985; Royce et al., 1984) in which a fast and a slow cross linker are used in combination. The fast cross linker ensures that there is adequate viscosity at the perforations. The slow cross linker, which is accelerated by the heating of the fluid in the fracture, ensures there will be a viscous, temperature-stable fluid in the fracture. There are many benefits to a delayed cross linking fluid system. Use of a delayed cross linker system produces fluids with better long-term stability at elevated temperature. Reduced friction pressure permits higher injection rates and reduces horsepower requirements.

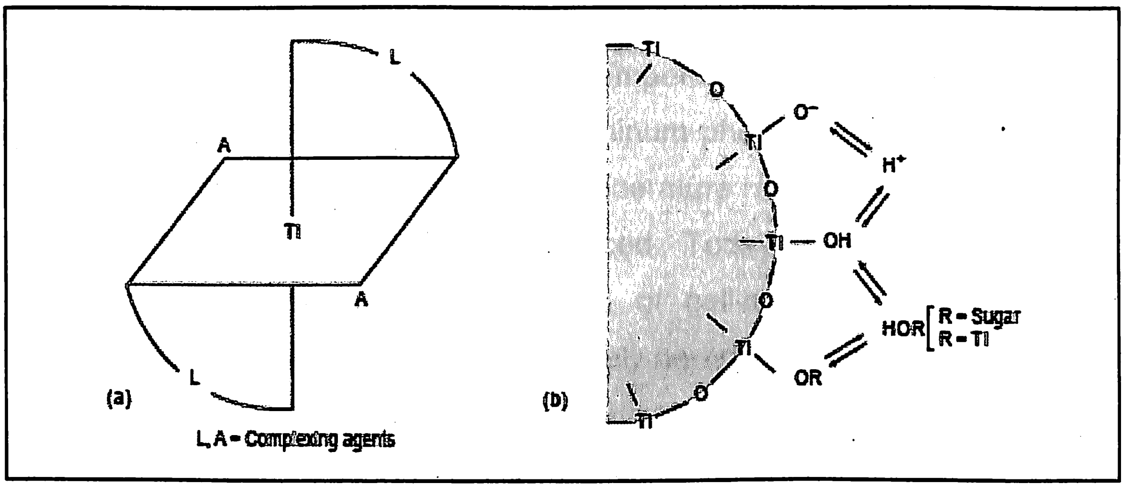


Fig 19: Hypothetical titanium complex a) hydrolyzed to a colloidal titanium dioxide particle and (b) providing polymer crosslinking on the particle surface

1.6.2 OIL-BASE FLUIDS

Oil based fluids can be categorised as crude oils, blends of crude, condensates, refinery products, gelled oil, emulsions and polyemulsions.

With all of the above fluids, it is important to check the compatibility of the fluids with the reservoir fluids. Even crude from the same reservoir may be altered considerably so as to cause problems if pumped back into the reservoir. A simple example is that paraffin or Asphaltenes may tend to come out of solution as solids at temperatures slightly below reservoir temperature. In some instances, they will not go back into solution at reservoir temperature. Therefore, it is possible to plug a well by injecting crude from the same reservoir. Blends of crude oil have been used to produce a composite with the desired viscosity. This is not a recommended practice due to the compatibility uncertainties.

The original fracturing fluids were oil-base(Heavy oils), primarily because these fluids were perceived to be less damaging to the hydrocarbon-bearing formation than were water-base fluids. Their inherent viscosity also made them more attractive than water (Howard and Fast, 1970). Oil-base fluids are expensive to use and operationally difficult to handle. Therefore, they are now used only in formations which are known to be extremely water-sensitive or suffer permeability reduction when exposed to aqueous fluids. In the 196Os, the industry used aluminum salts of carboxylic acids (e.g., aluminum octoate) to raise the viscosity of hydrocarbon fracturing fluids (Burnham et al.1980). This improved the temperature stability and proppant-carrying capability of the fluids. In the 197Os, aluminum phosphate ester salts replaced the aluminum carboxylate salts. Again, the temperature range of the fluids was extended and the proppant transport was enhanced. Today, aluminum phosphate ester chemistry remains the preferred method of gelling hydrocarbons for fracturing purposes. Both methods of thickening oil rely on an “associative” mechanism (Baker et al., 1970). As suggested in Figure interactions between the aluminum complexes and phosphate ester molecules produce a long polymer chain (Burnham, 1980)

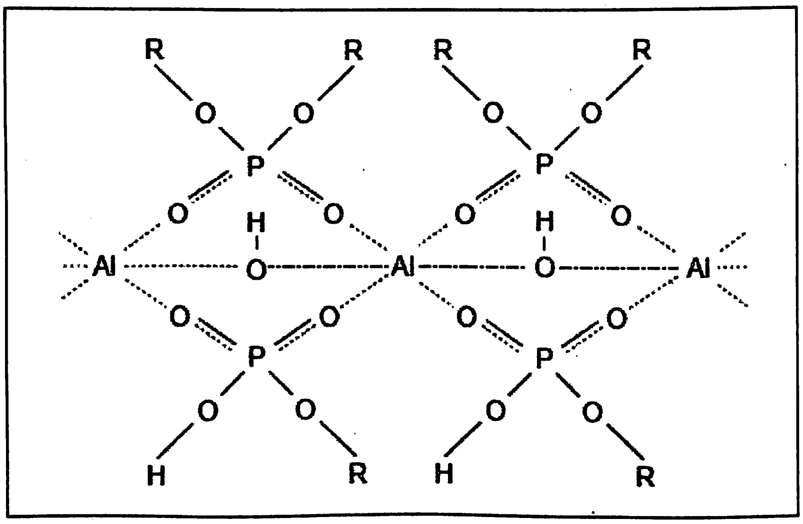


Fig 20: Proposed structure of the aluminum phosphate ester polymer chain (Bumham et al., 1980)

The R groups shown in Fig. 20 are hydrocarbon chains which must be soluble in the oil to be gelled. The soluble R group kept aluminum phosphate ester polymer in solution. Generally, the R groups are hydrocarbon chains containing 1 to 18 carbon atoms (Crawford et al., 1973). The R groups have a high affinity for oils such as kerosene and diesel which are comprised of 12-carbon to 18-carbon (and somewhat higher) chains. Crude oils are composed of a larger number of different organic compounds and may contain paraffin and Asphaltenes. Some of the high-molecular-weight compounds, especially the paraffin and Asphaltenes are not compatible with the aluminum phosphate ester gelling system. Many crude oils may be gelled, but it is good practice to test them prior to attempting to gel on location. The R groups can be pictured as forming an oil compatible shield around the polar core of aluminum ions (McKenzie, 1980). Polar species (such as water, acids, bases or salts) will be incorporated into the polar core, and will affect the association of the aluminum ions and phosphate ester groups. These materials can make the gel structure more rigid or they can destroy the gel structure. The viscosity of the standard aluminum phosphate ester gel is controlled by varying the quantities of aluminum compound and phosphate ester. To improve high-temperature performance, t he viscosity of the gel can be increased by increasing the amount of polymer however; this results in very high viscosities on the surface, which make it difficult to draw the fluid out of the tanks to the pumps.

1.6.3 Acid-based fluids

In some cases, operators have found that employing acid as the fracturing fluid is the best choice. These applications would normally be in carbonate formations that have rather high solubility, unless the acid-soluble material is present primarily as the lining of existing crevices or fractures, a viscous fingering technique is used.

In this application, the objective is to pump a pad or pre-flush of highly viscous material, such as cross-linked water ahead of the acid. The thinner acid will then tend to finger through the gel and create unevenly etched channels for production. The channels would be held open (hopefully) by the undissolved portion of rock that was not contacted by the acid.

Another approach has been to use a highly viscous gelled acid, and Xanthan gum (Crowe et al,1980) has been reported to be a good gelling agent. It also tends to retain some of its viscosity after spending, and may therefore be beneficial in aiding the recovery of insoluble fines that have been released as a result of the acid.

One of the great disadvantages to the use of hydrochloric acid where deeply penetrating treatments are required is that it tends to react very quickly. The result is that unreactive material (spent acid) is pumped as the leading edge of the fracturing fluid for a large part of the job.

Consequently very little, if any, etching will be done any distance from the well bore. If a viscous material had been used, a wider fracture would result and the more favourable surface area to volume relationship would allow the live acid to penetrate more deeply into the formation. Deeper penetration of reactive fluid is also achieved by means of retarded or slow-acting acids. Acid fracturing is a well stimulation process in which acid, usually hydrochloric acid (HCl), is injected into a carbonate formation at a pressure sufficient to fracture the formation or to open existing natural fractures. As the acid flows along the fracture, portions of the fracture face are dissolved. Because flowing acid tends to etch in a non uniform manner conductive channels are created that usually remain when the fracture closes. The effective length of the fracture is determined by the etched length, which depends on the volume of acid used, its reaction rate and the acid fluid loss from the fracture into the formation. The effectiveness of the acid fracturing treatment is determined largely by the length of the etched fracture. In some cases, especially in carbonates, a choice exists between acid and propped fracturing treatments.

Operationally, acid fracturing is less complicated because no propping agent is employed. Also, the danger of proppant screen out and the problems of proppant flow back and cleanout from the wellbore after the treatment are eliminated. However, acid is more expensive than most nonreactive treating fluids. The major barrier to effective fracture penetration by acid appears to be excessive fluid loss (Nierodeand Kruk, 1973). Fluid loss is a greater problem when using acid than when using a nonreactive fluid.

The constant erosion of fracture faces during treatment makes it difficult to deposit an effective filtercakebarrier. In addition, acid leak off is extremely non uniform & results in wormholes and the enlargement of natural fractures. This greatly increases the effective area from which leak off occurs & makes fluid-loss control difficult.

1.6.4 Multiphase fluids

There are situations in which the properties of standard water-base, oil-base or acid-based fluids can be enhanced by incorporating a second phase into the fluid. Foams are created by adding gas to the fluid.

Emulsions are created by mixing oil and water together. The different systems are described in this section.

1.6.4.1 ADDITIVES

A fracturing fluid is generally not simply a liquid and viscosifying material, such as water and HPG polymer or diesel oil and aluminum phosphate ester polymer. Various additives are used to adjust pH, control bacteria, improve high-temperature stability, break the fluid once the job is over, minimize formation damage, and/or control fluid loss. Buffers are pH-adjusting chemicals which are added to aqueous fracturing fluids to maintain a desired pH. The buffers, weak acids, bases, or both, are used in sufficient quantity to maintain the pH at the desired level even if an extraneous acid or base is introduced through contaminated water or proppant. Buffers are used to promote hydration of the polymer. For example, guar and HPG are usually treated to be dispersible and non hydrating at high pH. Water pH should be high initially to allow dispersion, but then should be lowered to permit hydration. The pH can be lowered by adding the acidic buffer after the polymer is dispersed. Another approach is to combine a slowly soluble acid with the dry polymer. The polymer disperses before the acid. Can dissolve and lower the pH. Some chemicals used as buffers are acetic, adipic, formic, and fumaric acids (Henkel, 1986). Buffers also are used to maintain the proper pH for cross linked fluids. Cross linked systems are generally formulated to work best in a narrow pH range such O.5 pH units from the optimum. Guar, HPG, and CMHPG can be cross linked at pH 3 to 10, depending on the cross linker used. The acids mentioned previously can be used in the low-pH systems, and sodium bicarbonate and/or sodium carbonate can be used for high-pH fluids.

1.6.4.2 Bactericides

Bactericides are added to polymer-containing aqueous fracturing fluids to prevent viscosity loss due to bacterial degradation of the polymer. The polysaccharides (sugar polymers) used to thicken water are a great food source for bacteria. Bacteria will not only ruin gel by reducing the molecular weight of the polymer, but also they can be turn sweet wells into sour ones. Once introduced into the reservoir, some bacteria survive and reduce sulfate ions to H_2S, the extremely dangerous gas with the characteristic "rotten-egg" odor. Usually the materials kill the bacteria, but they do not always inactivate the enzymes they have produced which are responsible for breaking down the polysaccharides. For this reason, it is common practice to add bactericide to the fracture tanks before water is added, to ensure that the bacterial enzyme level is kept low. A variety of bactericides is available. Bactericides are not necessary in oil-base fracturing fluids.

1.6.4.3 Foams

The use of foam as a fracturing fluid was reported by Bullen and Bratrud, in 1975; and by Wendorffand Ainley, in 1981.Nitrogen and carbon dioxide have been utilised in oil and gas production operations for many years. However, the use of nitrogen and water foam as a fracturing fluid is much more recent.

Several advantages for foam are claimed over conventional liquid fracturing fluids. Since foam consists of at least 75% nitrogen by volume, at down hole conditions, a condition referred to as `75% quality,' the amount of liquid introduced to the reservoir is very small. This is more clearly understood when one realises that the amount of nitrogen is actually more than 75%at surface conditions. Often, quality is reduced towards the end of the treatment to permit higher proppant concentrations. Foam is a stable mixture of liquid and gas. To make the mixture stable, a surface-active agent (surfactant) is used. The surfactant concentrates at the gas/liquid interface and lowers the interfacial tension.

The surfactant stabilizes thin liquid films and prevents the cells from coalescing. Pressurized gas (nitrogen or carbon dioxide) in foam expands when the well is flowed back and forces liquid out of the fracture. Foams accelerate the recovery of liquid from a propped fracture and thus are excellent fluids to use in low-pressure reservoirs.

Also, the liquid phase is minimal because foams contain up to 95% by volume gas. In the case of a water-base fluid, foaming the fluid significantly decreases the amount of liquid in contact with the formation. Therefore, foams perform well in water sensitive formation (Ward, 1984; Ainley, 1983).Foams yield pseudo plastic fluids with good transport Properties (King, 1982; Reidenbach *et al.*, 1986).

They provide good fluid-loss control in low-permeability formations where the gas bubbles are approximately the size of the rock pore openings (Harris,1985).

Foams are described by their quality:

$$foam\ quality = \frac{gas\ volume}{foam\ volume} \times 100 .$$

Originally, foam quality was considered to range from 52% to 95%. Above 95%, the foam usually changes to a mist, with gas as the continuous phase. Below 52%, stable foam does not exist because There are no bubble/bubble interactions to provide resistance to flow or to gravity separation (Mitchell,1969). Above 52% gas, the gas concentration is high enough that the bubble surfaces touch.

Stable dispersions of gas in liquid can be prepared with qualities less than 52% (Watkins *et al.*, 1983). It may not be appropriate to call them foams, but they can be used effectively as energized fluids. Viscosifying the liquid phase with a polymer is an effective method for increasing the stability of foams. The thicker the continuous phase, the more difficult it is for the gas bubbles to move together and coalesce. Guar, HPG and Xanthan gum have been used as stabilizers. Still, a relatively high quality, although not as high as 52%, is required to maintain dispersion of the gas phase. A further improvement in foam stability can be achieved by cross linking the polymer in the aqueous phase (Watkins *et al.*, 1983). The liquid phase then becomes viscous enough to maintain dispersion of the gas bubbles, even at foam quality less than 40%.Thickening the liquid phase also improves foam rheology and fluid-loss control. Proppant concentrations in the foamed fluid are generally lower than the concentration achieved with single-phase, liquid treatments.

Therefore, a larger volume of foam may be required to place the desired amount of proppant. Nitrogen and carbon dioxide are used as energizing gases. N_2 is less dense than CO_2. CO_2 creates a denser foam and, consequently, lower surface treating pressures because of the increased hydrostatic head in the wellbore. Lower treating pressures reduce pumping costs. On the other hand, because CO_2 is much more soluble in oil and water than N_2, it takes moreCO_2 to saturate the liquid and to create the foam.

Reductions in pumping costs may be offset by increases in material costs. An important point is that the liquid phase of the foam can be treated to help prevent emulsions from forming or clays from swelling.

The characteristics of the foam are such that it tends to remain rather stable in the fracture until flow back causes a pressure drop. This pressure drop, if it is great enough, acts as the triggering mechanism to cause the foam structure to begin to break down. The materials should return in the form of a mist rather than foam.

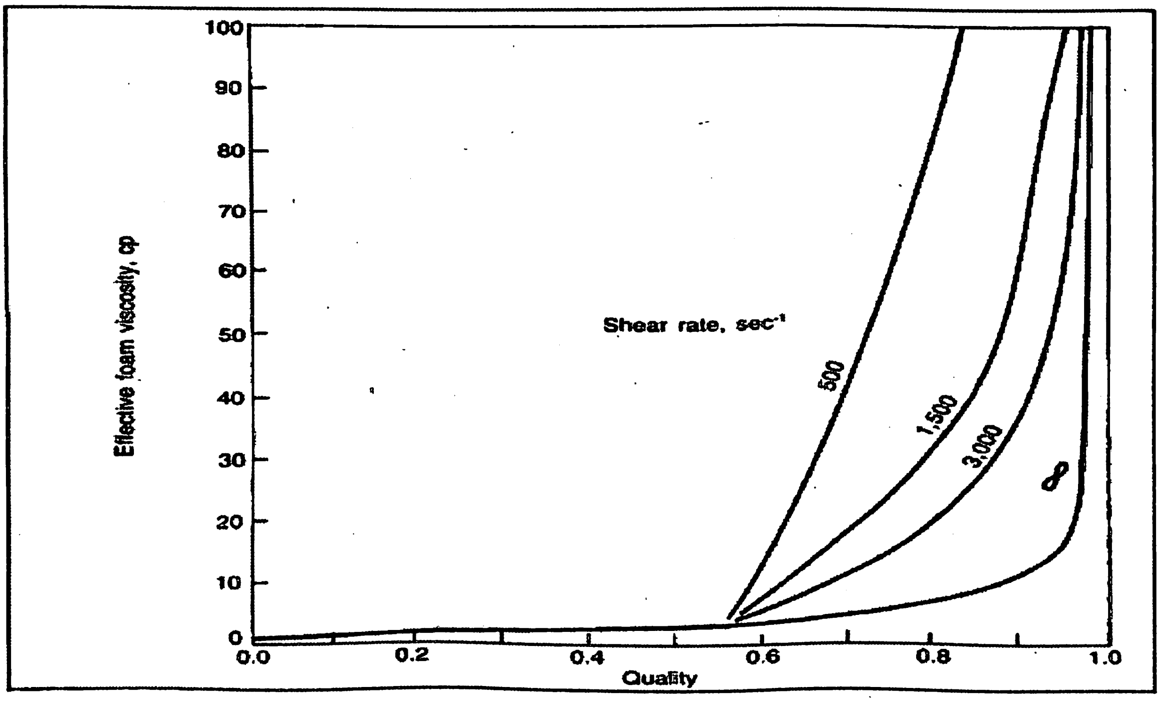


Fig 21: Foam Viscosity Vs Quality

The proponents of foam as a fracturing fluid claim very low leak off characteristics, particularly in low permeability reservoirs. The combination of low leak off and stable viscosity provides good proppant transport characteristics. A very significant advantage of foam is the improved fire safety, due to the inert nature of the components.

Foam fracturing jobs are more difficult to design than conventional fracturing jobs, because the properties of the foam change significantly as pressure changes due to the compressibility of the nitrogen. This means that both hydrostatic head and frictional pressure loss vary with pressure and must be calculated by computer.

A further point to remember when considering foam as a fracturing fluid is that since the foam has a very low density, and consequently a low hydrostatic head, much higher surface pressures are required in order to initiate and extend a fracture than would be required with a liquid system.

A great advantage to the use of foam is the ease with which flow back is initiated following the treatment. This rapid flow back minimises contact time between the liquid phase and any sensitive formation materials and can potentially result in less damage and more complete clean up. Foamed acid provides much greater formation coverage for a given volume of acid, the ratio being about four to one, and much better clean up of acid-insoluble fines or mud particles.

Foamed hydrocarbons are generally applied to water-sensitive, low pressure formations that require fracturing to be commercial. Its lower surface tension properties also make it advantageous over methanol/water foams or straight water foams.

1.6.4.4 Emulsions

An emulsion is a dispersion of two immiscible phases such as oil in water or water in oil stabilized with a surfactant. Emulsion-based fracturing fluids are highly viscous solutions with good transport properties. The higher the percentage of the internal phase, the more resistance there is to droplet movement, resulting in a higher viscosity.

Emulsion-based fracturing fluids have been used for a number of years (Kiel, 1971). The most common fluid, termed polyemulsions, is composed of 67% hydrocarbon internal phase, 33% viscosified brine external phase and an emulsifying surfactant.

Viscosifying the aqueous phase improves the emulsion stability and significantly reduces friction pressure during pumping because the polymer acts as a friction reducer. The polymer concentration used is generally 20 to 40 lbm/1000 gal, so the fluid contains only one-sixth to one-third as much polymer as a standard water-base fracturing fluid. The emulsion usually breaks because of adsorption of the emulsifier onto the formation rock; because so little polymer is used, this type of fluid is known for causing less formation damage and cleaning up rapidly (Roodhart *et al.*, 1986).

Disadvantages of polyemulsions are high friction pressure and high fluid cost (unless the hydrocarbon is recovered). Polyemulsions also thin significantly as the temperature increases, which limits their use in hot wells.

1.6.4.5 Breakers

Relatively high viscosity fluids are used to transport proppant into the fracture. Leaving a high-viscosity fluid in the fracture would reduce the permeability of the proppant pack to oil and gas, limiting the effectiveness of the fracturing treatment (Penny, 1987;Brannon and Pulsinelli, 1992). Gel breakers are used to reduce the viscosity of the fluid intermingled with the proppant. Breakers reduce viscosity by cleaving the polymer into small-molecular-weight fragments. It has been estimated that fluid loss during the treatment and during closure increases the polymer concentration in the fracture after closure 5–7 times(Penny, 1987) to as much as 20 times (Hawkins,1988) higher than the surface concentration. The increased polymer concentration causes a major increase in viscosity. Ideally, a gel breaker put into the fluid at the surface should have minimal effect on the gel until pumping ceases(and the fracture closes) and then should react rapidly with the gel. The viscosity of the gel and the molecular weight of the polymer should be significantly reduced to allow rapid cleanup of the sand pack(Almond *et al.*, 1984; Gall and Raible, 1985).

The most widely used fracturing fluid breakers are oxidizers and enzymes. The most common oxidative breakers are the ammonium, potassium and sodium salts of peroxyndisulfate ($S_2O_8^{2-}$). Thermal decomposition of peroxydisulfate (persulfate) produces highly reactive sulphate radicals that attack the polymer, reducing its molecular weight and its Viscosifying ability:

$O_3S - O{:}\,O - SO_3^{2-} \rightarrow \cdot SO_4^{-} + \cdot SO_4^{-}$

Free-radical breakers have the potential to create free radicals on the polymer and produce a chain reaction that increases breaker efficiency. Decomposition of persulfate, and therefore reactivity, is very temperature dependent, as is typical of chemical reactions. Thermal decomposition is too slow below about 125°F for persulfate to be used alone, but free-radical generation can be accelerated by the addition of amines (Hinkel, 1981). When the fluid temperature exceeds 125°F, sulphate radical generation occurs more rapidly. With increased temperature, the breaker becomes too reactive. As little as 0.1 lbm/1000 gal of dissolved persulfate causes rapid viscosity loss above 180°F [80°C]. At high temperatures, the reaction of dissolved persulfate with the polymer generally occurs during pumping rather than after placement of the proppant and closure of the fracture. Certain enzyme breakers of the class hemi cellulose are also used to reduce the viscosity of water-base fluids. Enzymes have been in use for some time, but prior to 1994 their use was thought to be limited to a relatively mild environment: pH range of about 3.5 to 8 and temperatures less than about 150°F. Because they are active at ambient temperature, enzymes begin to degrade the polymer immediately upon mixing and under some conditions can be too reactive, like per sulphates.

Encapsulated breakers were developed to allow high concentrations of breaker to be used without compromising fluid viscosity during pumping (Gulbis *et al.*, 1992). In an encapsulated breaker, the active breaker is coated with a film that acts as a barrier between the breaker and the fracturing fluid.

The breaker may be released as a result of crushing (Nolte, 1985), osmotic rupture (Walles *et al.*, 1988) or diffusion of the breaker chemical (Gupta andCooney, 1992) through the barrier polymer. Any type of breaker including enzymes and acids, can been capsulated. Encapsulation is usually expensive, so mixture of dissolved and encapsulated breakers can be used to achieve the desired level of breaker at the lowest cost. Because temperature has a significant effect on breaker activity and coating permeability, a single encapsulated breaker cannot cover the temperature range of 70° to 300°F [20° to 150°C]. A higher temperature usually requires that the breaker have a less permeable coating, which is achieved by increasing the coating thickness or by using a different barrier polymer. The breaker chemical itself may have to be changed for high-temperature applications.

For example, the half-life of persulfate at160°F [70°C] is about 6.8 hr, but at 200°F it is only about 15 min. Thus, even encapsulated persulfate breakers have limited utility above 200°–225°F [90°–110°C].

Enzymes are biocatalysts, meaning they are not used up when they react with guar. Theoretically, a single enzyme molecule can react with many different guar molecules (i.e., turnover rate) so polymer degradation might go on for a longer time and be more complete than with an oxidizer.

These enzymes are globular proteins with three-dimensional (3D) structures.

1.6.4.6 Surfactants

A surface-active agent, or surfactant, is a material that at low concentration adsorbs at the interface between two immiscible substances. The immiscible substances may be two liquids, such as oil and water, a liquid and a gas, or a liquid and a solid. The surfactant becomes involved in the interface and lowers the amount of energy required to expand the interface (Rosen, 1972).

They are necessary ingredients in foams to promote the formation of stable bubbles. They are used in polyemulsions fluids to stabilize the oil-in-water emulsion. In addition, they are used as surface-tension-reducing agents and formation-conditioning agents (Penny *et al.*, 1983) to promote cleanup of the fracturing fluid from the fracture.

Some bactericides and clay-control agents are surfactants.

1.6.4.7 Viscoelastic Fluids

Fatty amine quaternary ammonium salts are called Viscoelastic surfactants and are a class of compounds that form micelles in aqueous systems that contain certain cations producing Viscoelastic properties to the liquid (Brown et al 1996). These salts have been used for many years to thicken consumer products such as bleach and liquid dishwasher detergent. The deformation of these fluid systems is time dependent when shear is applied. When the system deforms its rheological behaviour is almost Newtonian. The texture of these fluids when static is similar to gelatine and therefore has excellent particle suspension properties. These fluids have been used for many years for gravel packing applications. The concentration of surfactant used to provide suspension varies from 2.5% to 6%by volume of common completion brines. These fluids are very easy to prepare in the field requiring no internal breakers or polymer hydration. More recently, Viscoelastic (VES) fluids are finding use as fracturing fluids for high permeability formations. The leak-off behaviour of VES fluids is less dependent upon differential pressure than HEC fluids and at fracturing pressures the fluid-loss rates of VES fluids are lower than those observed with HEC fluids. The principal advantage of the VES fluid is that very little residue is left after breaking, unlike polymer-based systems such as HEC or guar.

The viscosity of VES fluids can be reduced by two mechanisms: (1) contact with oil or condensate and reduction of the salt concentration. Since one or both situations usually occur during cleanup after stimulation, no additional breaker chemicals are usually required.VES fluids have been used for the fracturing of high-permeability formations and when frac packing in particular.

These materials are promoted to be cleaner than polymer based fluids. The products are available with breakers that function in the leak-off (matrix) fluid or in the proppant pack fluid.

Natural dilution also assists in the reduction of viscosity.

1.7 Proppant

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

- Proppant composition
- Physical properties of the proppant
- Proppant-pack permeability
- Effects of post closure polymer concentration in the fracture
- Movement of formation fines in the fracture
- Long-term degradation of the proppant.

An ideal proppant should produce maximum permeability in a fracture. Fracture permeability is a function of proppant grain roundness, proppant purity, and crush strength. Larger proppant volumes allow for wider fractures, which facilitate more rapid flow back to the production well. Over a period of 30 minutes, 4,500 to 15,000 gallons of fracturing fluid will typically transport and place approximately 11,000 to 25,000 pounds of proppant into the fracture. The ideal propping agent will be strong, resistant to crushing, resistant to corrosion, have a low density, and readily available at low cost.

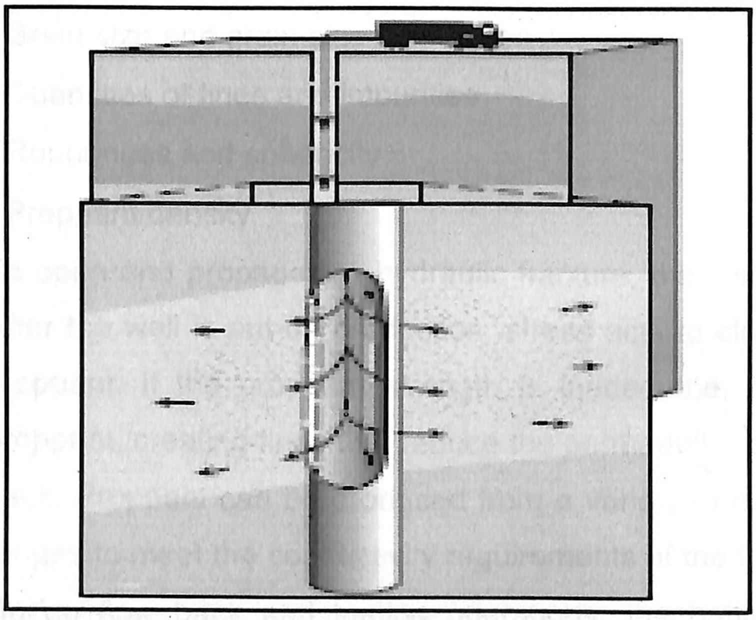


Fig 22: Introducing proppant into the fracture

The products that best meet these desired traits are silica sand, resin-coated sand, and ceramic proppants. Generally, sand is used to prop open fractures in shallow formations. For coal seam reservoirs, sand is usually the best choice for a propping agent and virtually every fracture treatment in a coal seam reservoir uses sand. Sand is much less expensive per pound than the resin-coated sand or the ceramic proppants. Resin-coated (epoxy) sand is stronger than sand and is used where more compressive strength is required to minimize proppant crushing. Some resins can be used to form a consolidated sand pack in the fracture, which will help to eliminate proppant flow back into the wellbore. Resin coated sand is more expensive than sand. Ceramic proppants consist of sintered bauxite, intermediate strength proppant (ISP), and light weight proppant (LWP). The strength of the proppant is proportional to its density. Also, the higher strength proppants, like sintered bauxite, cost more than ISP and LWP. Ceramic proppants are used to stimulate deep (>8,000 ft) wells where large values of *in-situ* stresses will apply large forces on the propping agent.

1.7.1 Physical properties of proppant

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

- Proppant strength
- Grain size and grain-size distribution
- Quantities of fines and impurities
- Roundness and sphericity
- Proppant density.

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

During flow back and testing operations, the bottom hole producing pressure is usually held constant and at a low value to maximize the production rate. The potential for maximum crushing can occur during flow back and testing operations, when the flowing pressure at the perforations may be low, or initially in the production of a well because the fracture gradient is at its Maximum. However, if the well is initially completed and produced at a higher bottom hole pressure and with a nearly constant production rate, the maximum effective stress on the proppant is less. By producing well in this manner, the stress on the proppant can increase with time, but it never exceeds the bottomhole fracturing pressure. Because the producing pressure is lowest at the well, the effective closure stress is highest at the well, and higher strength proppant can be used as a tail-in segment after the fracture has been packed with a lower strength proppant.

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

- Sand—closure stresses less than 6000 psi
- Resin-coated proppant (RCP)—closure stresses less than 8000 psi
- Intermediate-strength proppant (ISP)—closure stresses greater than 5,000 psi but less than10,000 psi
- High-strength proppant—closure stresses at or greater than 10,000 psi.

Proppant type and size should be determined by comparing economic benefits versus cost. Proppants with larger grain sizes provide a more permeable pack because permeability increases as the square of the grain diameter; however, their use must be evaluated in relation to the formation that is propped and the increased difficulties that occur in proppant transport and placement. Dirty formations, or those subject to significant fines migration, are poor candidates for large proppants. The fines tend to invade the proppant pack, causing partial plugging and a rapid reduction in permeability. In these cases, smaller proppant, which resist the invasion of fines, are more suitable. Although smaller proppant offer less initial conductivity, the average conductivity over the life of the well is higher and more than offsets the initial high productivity provided by larger proppant (which is usually followed by a rapid production decline).

Larger grain sizes can be less effective in deeper wells because of greater susceptibility to crushing resulting from higher closure stresses (as grain size increases, strength decreases). Larger proppant have more placement problems. Placement problems are twofold—a wider fracture is required for the larger grains, and the particle settling rate increases with increasing size. If the grain-size distribution is such that the mesh range contains a high percentage of smaller grains, the proppant-pack permeability and therefore conductivity are reduced to about that for a pack of the smaller grains. The roundness and sphericity of a proppant grain can have a significant effect on fracture conductivity.

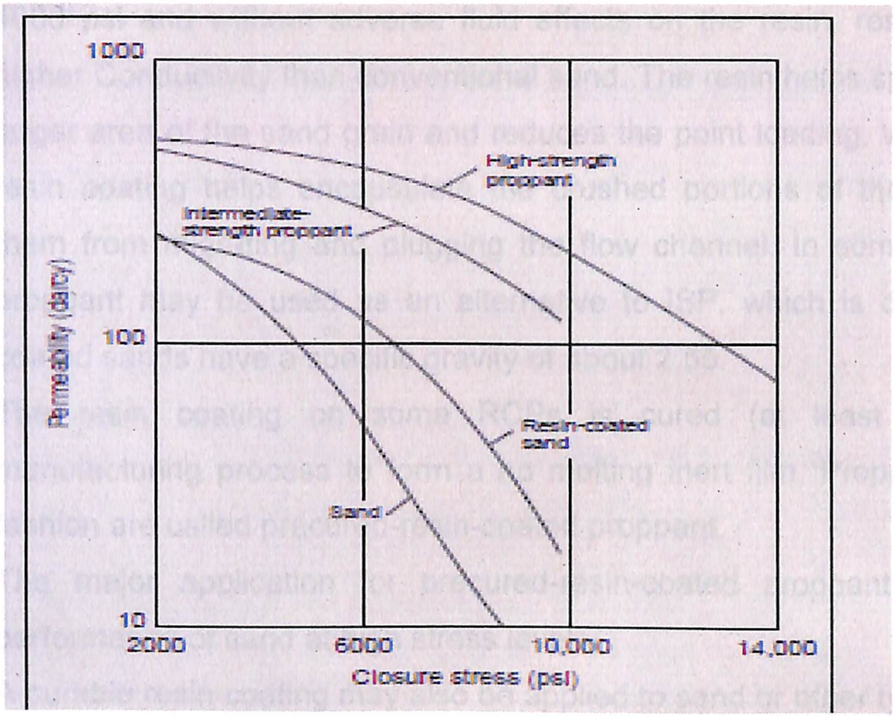


Fig 23: Strength comparison of various types of proppants

1.8 Classes of proppant

Sand is the most commonly used proppant. It is the most economical, is readily available and generally provides sufficient fracture conductivity for closure stresses less than 6000 psi. Its specific gravity is about 2.65. Depending on the overall balance of physical properties, sand can be subdivided into groups:

- Northern white sand
- Texas brown sand
- Colorado silica sand
- Arizona silica sand.

American Petroleum Institute (API) standards can be used to similarly qualify and group any sand source.

Resin coatings are applied to sand (usually northern white sand) to improve proppant strength and to reduce flow back during production. Resin-coated sand is stronger than conventional sand and may be used at closure stresses less than 8000 psi, depending on the type of resin-coated sand. At closure stresses greater than

4000 psi and without adverse fluid effects on the resin, resin-coated sand has a higher Conductivity than conventional sand. The resin helps spread the stress over a larger area of the sand grain and reduces the point loading. When grains crush, the resin coating helps encapsulate the crushed portions of the grains and prevents them from migrating and plugging the flow channel. In some cases, resin coated proppant may be used as an alternative to ISP, which is discussed next. Resin-coated sands have a specific gravity of about 2.55.

The resin coating on some RCPs is cured (at least partially) during the manufacturing process to form a no melting inert film. Proppant processed in this fashion are called precured-resin-coated proppant.

The major application for precured-resin-coated proppants is to enhance the performance of sand at high stress levels.

A curable resin coating may also be applied to sand or other types of proppants. The major application of curable-resin-coated proppant is to prevent the flow back of proppant near the wellbore. The curable-resin-coated proppants are mixed and pumped in the later stages of the treatment, and the well is shut in for a period of time to allow the resin to bind the proppant particles together. Theoretically, the RCP cures into a consolidated, but permeable, filter near the wellbore.Fibertechnology, is an alternative technique for proppant flow back problems that introduces no chemical compatibility issues or special curing requirements for time and temperature. Guidelines for minimizing the undesirable effects of RCPs are listed in Sidebar 7C.

ISP is fused-ceramic (low-density) proppant or sintered-bauxite (medium-density) proppant. The sintered-bauxite ISP is processed from bauxite ore containing large amounts of mullite. This is in contrast to a high-strength proppant, which is processed from bauxite ore high in corundum. ISP is generally used at closure stresses greater than 5,000 psi, but less than 10,000 psi. The specific gravity of ISP ranges from 2.7 to 3.3.High-strength proppant is sintered bauxite containing large amounts of corundum, and it is used at closure stresses greater than 10,000 psi. High-strength proppant is the most costly proppant. Its specific gravity is 3.4 or greater.

Specifications of Low Strength Proppant (ONGC/WS/26/97)

1 Physical State	The material as received, shall be in the form of single grains.			
2 Sieve Analysis	Type -I	Type-II	Type-III	
(a) Size designation, ASTM or equivalent.		12/20	20/40	40/70
(b) Retention between the designated sieve sizes, percent by mass.		90(min)	90(min)	90(min)
(c).Retention onASTM sieve No. 8, % by mass.	0.1(Max)	NA	NA	
(d) Retention on ASTM sieve No. 16, % by mass.	NA	0.1(Max)	NA	
(e) Retention on ASTM seive no.30, % by mass.	NA	NA	0.1(Max)	
(f) Passing through ASTM sieve No. 30, % by mass.		1.0(Max)	NA	NA
(g) Passing through ASTM sieve No. 50, % by mass.		NA	1.0(Max)	NA
(h) Passing through ASTM sieve No.100, % by mass.		NA	NA	1.0(Max)
3. Proppant grain clusters, percent by count.		Less than one		
4 Krumbein Sphericity		0.6(min)	0.6(min)	0.6(min)
5 Krumbein Roundness	0.6(min)	0.6(min)	0.6(min)	
6. Acid solubility in 12% w/w HCl + 3% w/w HF ,on dry basis % by mass. (i) 5gm of sample in 100 ml ofAcid. (ii) Temperature 65°C- 66°C (iii) Time 30 minutes. (iv) Filtration through. G-4 crucible	2.0(Max)	2.0(Max)	3.0(Max)	

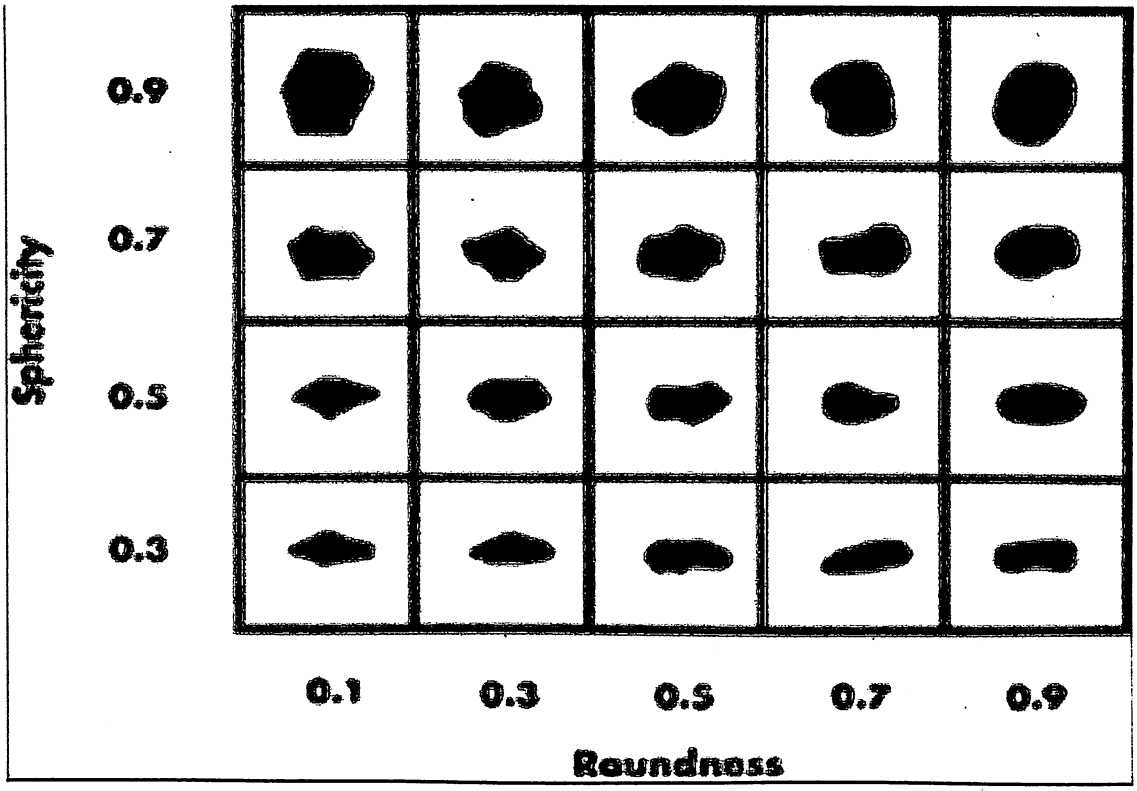


Fig 24: Sphericity and roundness of Proppant Sand particle

CHAPTER – 2

(Physical Rock Properties)

2.1 Fracture Mechanics & In-Situ stress

Rock mechanics is the theoretical and applied science of the mechanical behaviour of rock, the branch of mechanics concerned with the response of rock to the force fields of its physical environment. In hydraulic fracturing, rock mechanics is important in the determination of mechanical properties and the in-situ stress state of reservoir rock, the calculation of deformation and failure behaviour of the rock mass caused by the treatment, and the determination of the fracture's final geometry.

Mechanical properties usually, of concern for treatment design and analysis, are

(1) Elastic properties, such as Young's modulus (or shear modulus) and Poisson's ratio;

(2) Strength properties, such as fracture toughness and tensile and compressive strength;

(3) Poroelastic parameters describing the compressibility of the rock matrix compared with the compressibility of the bulk rock under specific fluid flow (or migration) conditions. Stress not only controls or influences most aspects of fracture behaviour, but also influences the values of both reservoir properties and mechanical properties of the rock.

For example, increased confining stress will generally result in increased strength decreased permeability and porosity, and mixed results for Young's modulus and Poisson's ratio.

In-situ Stresses

Underground formations are confined and under stress. Fig. 25 illustrates the local stress state at depth for an element of formation. The stresses can be divided into 3 principal stresses. In Figure 25, σ1 is the vertical stress, σ2 is the maximum horizontal stress, while σ3 is the minimum horizontal stress, where σ1>σ2>σ3. This is a typical configuration for reservoirs. However, depending on geologic conditions, the vertical stress could also be the intermediate (σ2) or minimum stress (σ3). These stresses are normally compressive and vary in magnitude throughout the reservoir, particularly in the vertical direction (from layer to layer). The magnitude and direction of the principal stresses are important because they control the pressure required to create and propagate a fracture, the shape and vertical extent of the fracture, the direction of the fracture, and the stresses trying to crush and/or embed the propping agent during production.

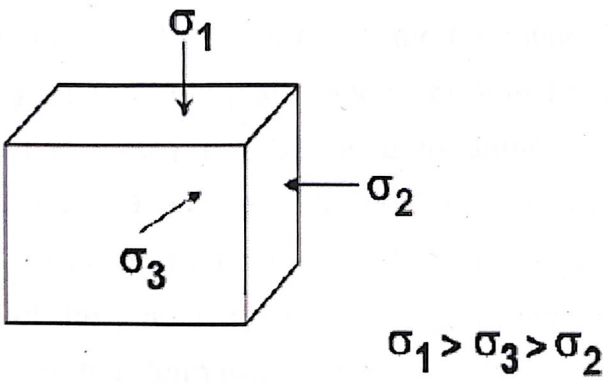


Fig 25: Local in situ stress at depth

A hydraulic fracture will propagate perpendicular to the minimum principal stress (σ3).If the minimum horizontal stress is σ3, the fracture will be vertical. Minimum horizontal stress profile with depth can be computing the using Eq. 1.

$$\sigma_{min} = \frac{\upsilon}{1-\upsilon}(\sigma_{ob} - \alpha\ \sigma_p) + \alpha\ \sigma_p + \sigma_{ext} \text{ ....}(1)$$

Where,

σ_{min} = the minimum horizontal stress (*in-situ* stress)

υ = Poissons' ratio

σ_{ob} = overburden stress

α = Biot's constant

σ_p = reservoir pore pressure

σ_{ext} = tectonic stress

Poisson's ratio can be estimated from acoustic log data or from correlations based upon lithology. The overburden stress can be computed using density log data. Normally, the value for overburden pressure is about 1.1 psi per foot of depth. The reservoir pressure must be measured or estimated. Biot's constant must be less than or equal to 1.0 and typically ranges from 0.5 to 1.0. The first two terms on the right hand side of Eq.1 represent the horizontal stress resulting from the vertical stress and the poroelastic behaviour of the formation. The tectonic stress term is important in many areas where plate tectonic or others forces increase the horizontal stresses. Poroelastic theory can be used to determine the minimum horizontal stress in tectonically relaxed areas. It combines the equations of linear elastic stress-strain theory for solids with a term that includes the effects of fluid pressure in the pore space of the reservoir rocks. The fluid pressure acts equally in all directions as a stress on the formation material. The "effective stress" on the rock grains is computed using linear elastic stress-strain theory. Combining the two sources of stress results in the total stress on the formation, which is the stress that must be exceeded to initiate a fracture.

2.2 Basic Rock Mechanics

In addition to the *in-situ* or minimum horizontal stress, other rock mechanical properties are important when designing a hydraulic fracture. Poisson's ratio is defined as "the ratio of lateral expansion to longitudinal contraction for a rock under a uniaxial stress condition". The value of Poisson's ratio is used in Eq. 1 to convert the effective vertical stress component into an effective horizontal stress component. The effective stress is defined as the total stress minus the pore pressure. The theory used to compute fracture dimensions is based upon linear elasticity. To apply this theory, the modulus of the formation is an important parameter. Young's modulus is defined as "the ratio of stress to strain for uniaxial stress". The modulus of a material is a measure of the stiffness of the material. If the modulus is large, the Material is stiff. In hydraulic fracturing, a stiff rock will result in more narrow fractures. If the modulus is low, the fractures will be wider. The modulus of a rock will be a function of the lithology, porosity, fluid type, and other variables.

2.2.1 Fracture Orientation

Usually the hydraulic fracture propagates perpendicular to the least principle stress. In some shallow formations the least principal stress is the overburden stress; thus, the hydraulic fracture will be horizontal. In reservoirs deeper than 1000 ft or so, the least principal stress will likely be horizontal; thus, the hydraulic fracture will be vertical.

The azimuth orientation of the vertical fracture will depend upon the azimuth of the minimum and maximum horizontal stresses.

2.2.2 STRESS

When a force is applied to an object, the stress that is induced is the force divided by the area over which the force acts. In that sense, it is analogous to pressure. But, whereas a pressure is exerted equally in all directions, a stress has a single direction.

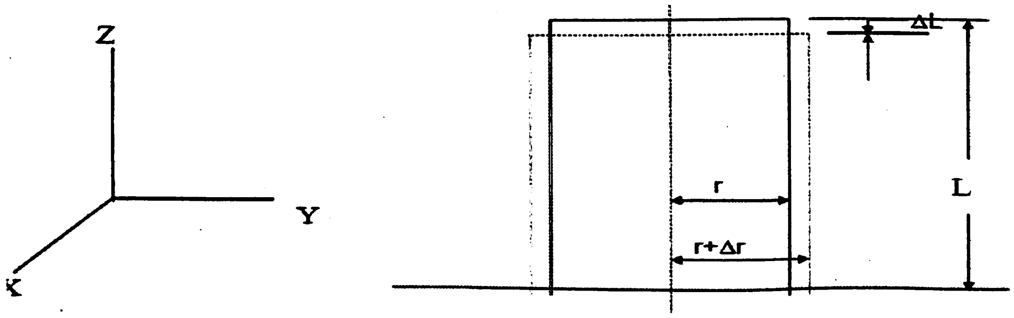


Fig 26: Deformations caused by an applied force

Let F be force acting compressively on a cylinder of radius r. The effect of F is to induce a stress σ, with magnitude.

$$\sigma = \frac{F}{\pi r^2}$$

Since σ acts parallel to the z-axis of a three-dimensional system, it should be properly labelled σ_z.In this case, there are no forces acting in the x and y directions so we may say that

$$\sigma_x = \sigma_y = 0.$$

Stresses may be compressive or tensile; in this case σ_z is a compressive stress. Usually, in rock mechanics, compressive stresses are given positive values and tensile stresses are given negative values.

2.2.3 STRAIN

When a stress exists in a body it produces a deformation. For example, in the present case, the force F induces a stress, σ_z, which produces a reduction in the length of the cylinder from L to L -ΔL. This is expressed in terms of the ratio of the change in length to the original length. This is

Known as the strain, ε_z.

$$\varepsilon_z = \frac{[L - \Delta L] - L}{L} = \frac{-\Delta L}{L}$$

The negative sign indicates shortening rather than a lengthening. Similarly, the strain evidenced by the change of radius from r to r + Δr is expressed as:

$$\varepsilon_x = \varepsilon_y = \frac{[r + \Delta r] - r}{r} = \frac{\Delta r}{r}$$

2.2.4 YOUNG'S MODULUS

A material that behaves elastically, stresses and strains are related linearly in the following manner:

$$\varepsilon_z = \left[\frac{1}{E}\right] \sigma_z$$

In this relationship, E is known as Young's Modulus or the modulus of elasticity of the material, and has the units of psi or GPa. The relationship is known as Hooke's law.

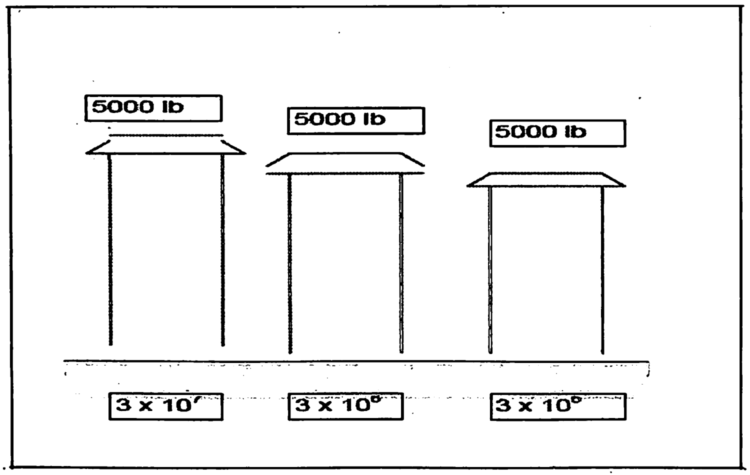


Fig 27: Effect of varying young's Modulus (courtesy Halliburton)

2.2.5 POISSON'S RATIO

Another important relationship in the properties of homogeneous, isotropic materials is the relationship between the longitudinal and the radial deformations. This relationship is known as Poisson's Ratio, v. which is dimensionless

$$v = \frac{\varepsilon_x}{-\varepsilon_z}$$

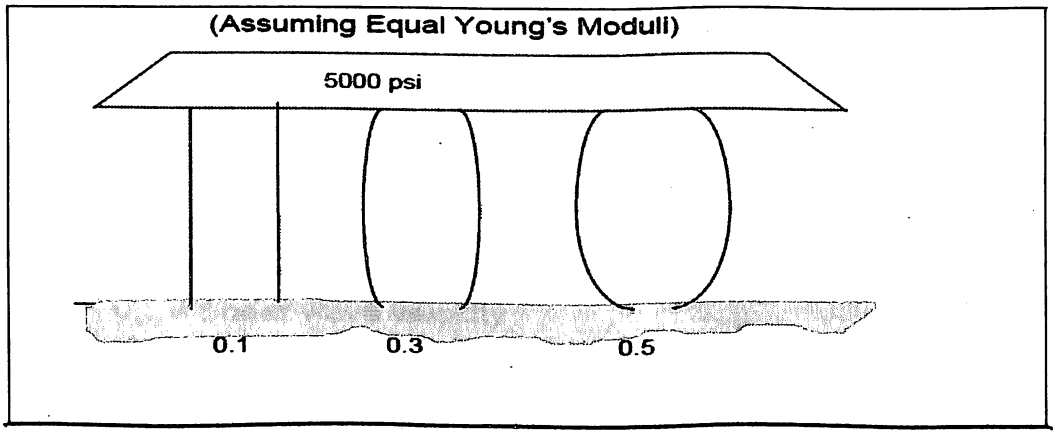


Fig 28: demonstrates schematically the effect of varying Poisson's ratio

2.3 PRINCIPAL STRESSES

Another term that requires definition results from the fact that all of the stresses acting on a body may be resolved into their directional effects as expressed in three mutually perpendicular directions. The stresses acting in these three mutually perpendicular directions are termed the principal stresses. When the treatment of rock mechanics problems assumes that the rock is isotropic, elastic, and homogeneous, the two properties of the material that must be identified are Young's modulus, E and Poisson's ratio, v .These are usually determined by a compressive measurement in the laboratory in which loads and deformations are measured. However, the properties are sometimes deduced from sonic determinations. The relationships for the velocities of the compression and shear waves respectively are given by the following equations:

$$V_c = \sqrt{\left[\frac{E[1-v]}{\rho[1+v][1-2v]}\right]}$$

$$V_{sh} = \sqrt{\frac{E}{2\rho[1+v]}}$$

where:

ρ = density of the rock,

V_c = Compressional wave velocity

V_{sh} = Shear wave velocity

IN-SITU PRINCIPAL STRESSES

The system of stresses acting at a given point in a formation is impossible to define in detail due to its extreme complexity. However, it is possible to resolve the entire network into three mutually perpendicular stresses, which are termed the in situ principal stresses. This greatly simplifies the prediction of the mechanical behaviour of the formation.

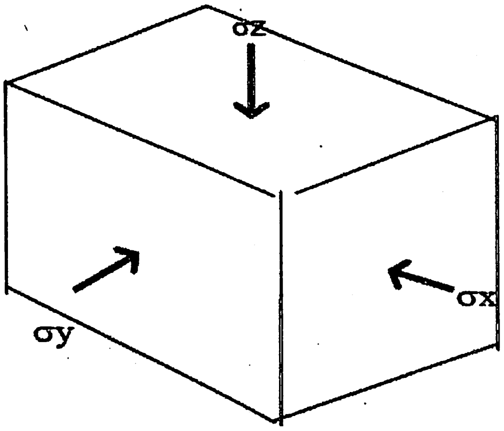


Fig 29: Representation of Principal stresses

If the only force acting on a formation were due to the weight of the overburden, then the vertical stress σ_z would be:

$$\sigma_z = \rho g h$$

And, the horizontal stress would be

$$\sigma_x = \sigma_y = \left[\frac{\nu}{1-\nu}\right] \sigma_z$$

where: σ_z = vertical stress

and σ_x = σ_y = horizontal stress

ρ = density of the overburden

h = depth of the overburden

ν = Poisson's ratio for the formation

g = acceleration due to gravity

This is an unreal case since there are always horizontal forces of some magnitude. The example is for illustrative purposes only.

It should also be pointed out that, although we generally make the assumption that in rock mechanics the vertical stress is a principal stress, this is not necessarily accurate, since for each situation there is only one true set of principal stresses. It is not ordained that one of these should be vertical.

2.4 FRACTURE EXTENSION PRESSURE GRADIENT

It has also been shown that the fracture extension pressure gradient is fairly constant for a given formation in a given area and is generally expressed as fracturing pressure gradient, BHTP/D,where D is the depth of the formation in question. For most situations the gradient will vary from about 15 to 25 kPa/m (0.66 to 1.11 psi/ft). The lower range generally would represent vertical fractures, while the higher numbers have been shown to generally be associated with horizontal fractures.

Therefore, if we know the gradient, based on even one fracturing treatment, we should be able to calculate the surface pumping pressure required to conduct a fracturing treatment on almost any other well in the same formation in the same area.

The shut in pressure recording period should (ideally) be at least twice as long as the pumping period, or at least until closure has occurred.

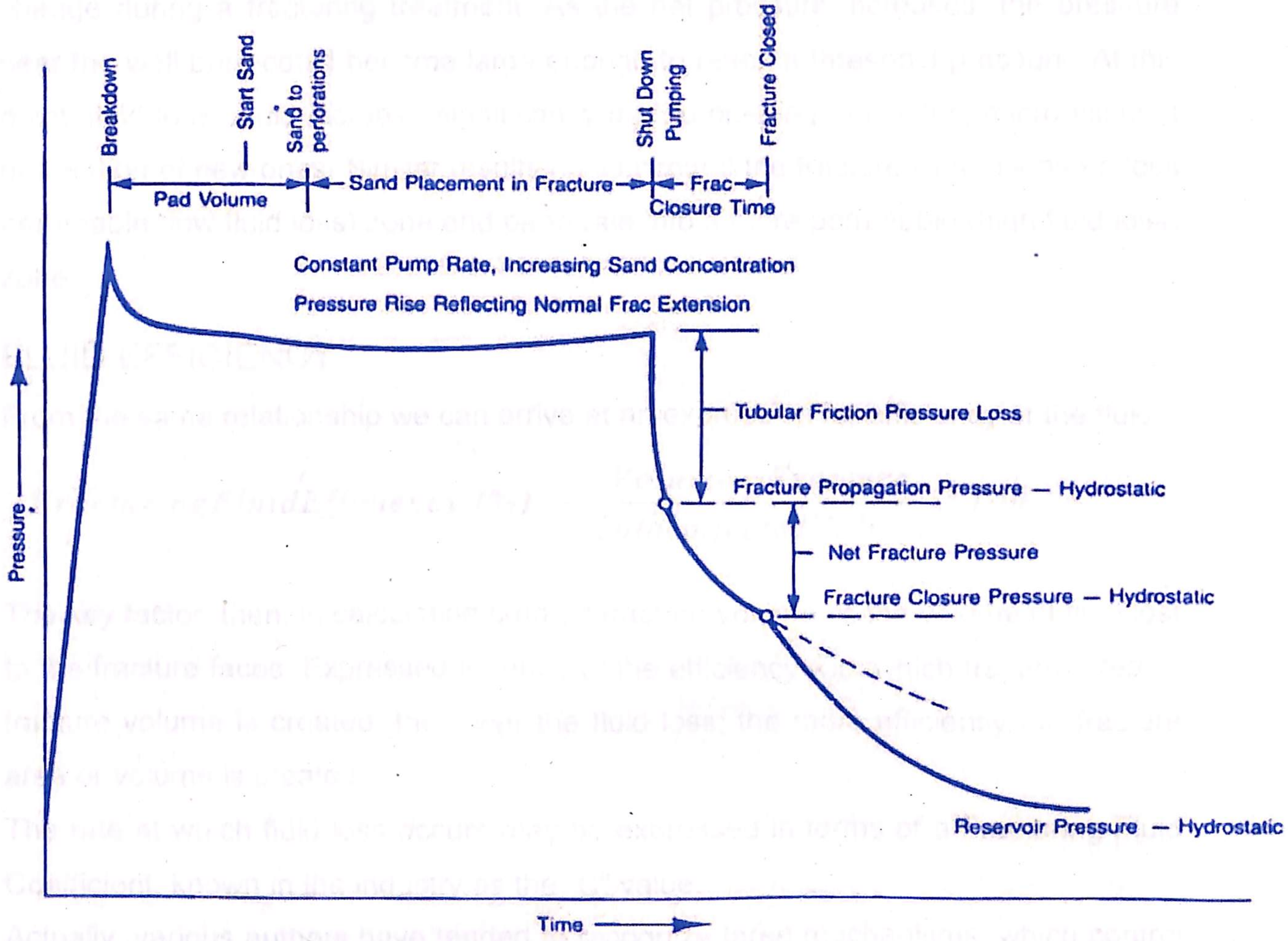


Fig 30: Schematic time chart of pressure and time

2.5 FLUID LOSS

The basic relationship in respect to fracture area calculations was expressed by Carter of Pan American (now Amoco) in the appendix to the classic Howard and Fast paper. Expressed simply, the relationship states that the total volume of fluid injected into a fracture is the sum of the volume that leaks off into the fracture faces (termed fluid loss volume) and the volume of the created fracture.

The relationship may also be expressed in terms of rate so that the rate of growth of the volume of the fracture is equal to the total injection rate minus the rate at which fluid is lost to the fracture faces.

Since fluid loss is of first order importance in the generation/propagation of a fracture, it is important to understand the difference in values of fluid loss determined under differing conditions. One of the least understood issues is that fluid loss can change during a fracturing treatment. As the net pressure increases, the pressure near the well bore could become large enough to reach a threshold pressure. At this point, fluid loss could increase significantly due to opening of existing micro fissures or creation of new ones. Similar results could occur if the fracture was to leave a less permeable (low fluid loss) zone and penetrate into a more permeable (high fluid loss) zone.

FLUID EFFICIENCY

From the same relationship we can arrive at an expression for efficiency of the fluid:

$$FracturingFluidEfficiency\ (\%) = \frac{VolumeofFracture}{TotalInjectedVolume} * 100$$

The key factor, then, in calculating created fracture volume, is the volume of fluid lost to the fracture faces. Expressed in terms of the efficiency with which fracture area or fracture volume is created, the lower the fluid loss, the more efficiently the fracture area or volume is created.

The rate at which fluid loss occurs may be expressed in terms of a Fracturing Fluid Coefficient, known in the industry as the "C" value.

Actually, various authors have tended to recognize three mechanisms, which control the rate at which fracturing fluids leak off to a formation during a hydraulic fracturing treatment.

2.6 EQUIPMENT AND OPERATIONS OVERVIEW

Fracturing Equipment:

The equipment required to conduct a fracturing operation consists of certain core items as well as a number of ancillary pieces of equipment that may be required for special applications.

-Tank trucks to haul fluid,

-Tanks for fluid – specs,

-Preheating equipment,

-Filtering equipment, Tank manifold with hoses in and out,

-Blender, Chemical concentrate trailer with synchronized proportioning system &

-field laboratory equipment,

-Hydration/conditioning unit to process diluted gel concentrate,

-Proppant transportation/storage/transfer equipment,

-Nitrogen or carbon dioxide transportation and pumping units,

-Pumping unit to pump additives, acid, or hold pressure on the annulus for packer,

Completions,

-Two tiered manifold for pressurized suction & high-pressure discharge with hoses &

-High-pressure steel line in and out,

-Tree-saver or fracturing well-head,

-Check-valves,

-Pressure-relief valves,

-Isolation valves,

-High pressure line for bleeding off well pressure to a safe location,

-Crane truck for transporting and handling heavy equipment items,

-Instrumentation/data acquisition/processing unit,

-Sensing/sending equipment with signal lines to instrumentation/data centre,

-Data acquired includes clean and proppant-laden fluid density, tubing-head &

-Casing- head pressures,

-Injection rate

-Wireless communication equipment for onsite communications

-Fire-protection and ambulances (depending upon circumstances).

Operations Overview Diagram:

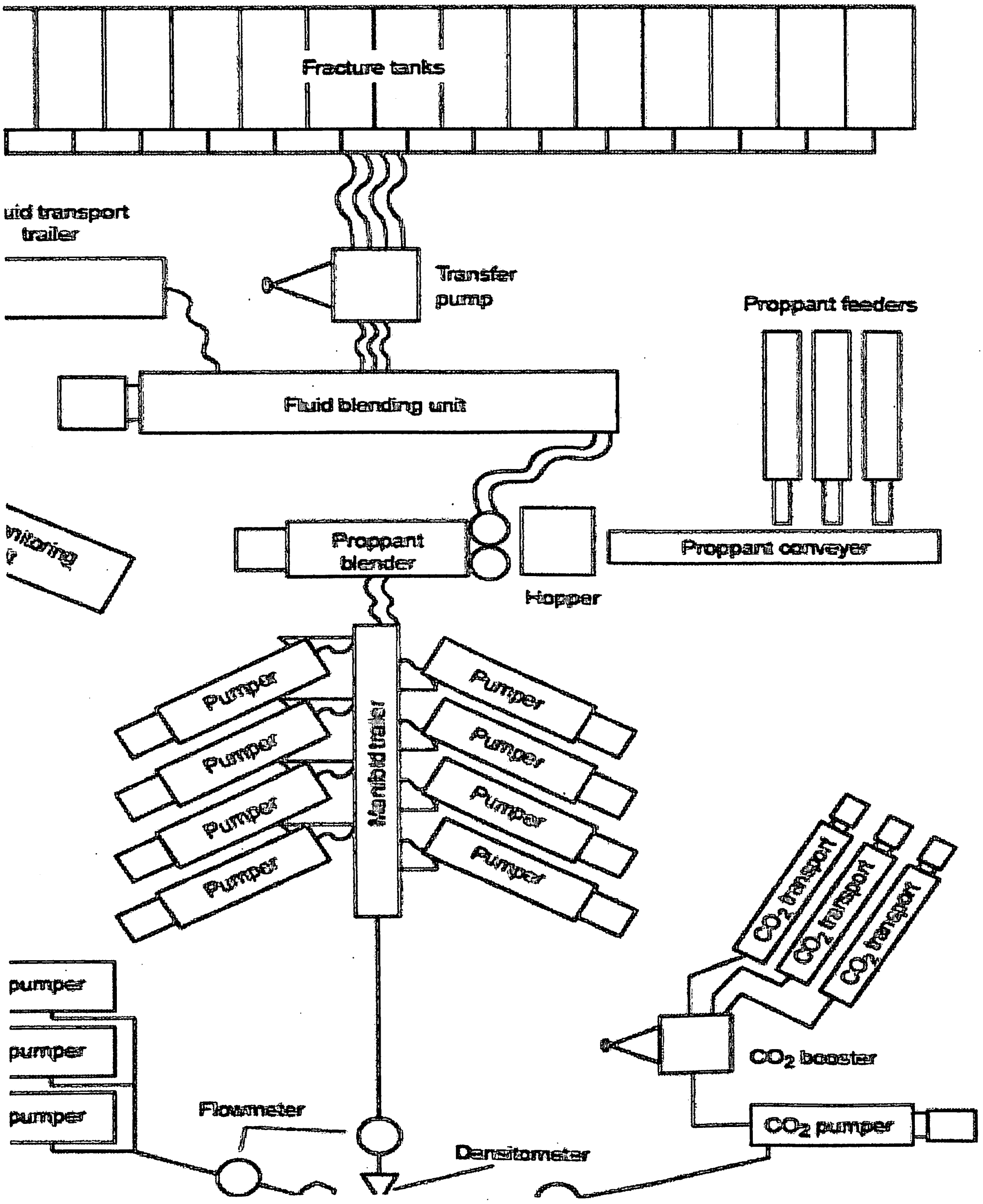


Fig 31: Overview of Field Fracturing Unit

To organize the equipment so that no equipment movement is required once pumping operations commence. Timing, order of delivery to location, and possibly storage requirements of equipment and materials. Inspection of equipment and materials and verification of readiness according to a suitably detailed checklist.

Review of the specific program in the field to be certain that all involved understand the overall operational objective, the order of operations and the individual responsibilities both in the planned program and in plausible "what-if" situations. Command authorities within the Oil Company and for Service Company should be very clear here. Safety details should be elaborated during a tailgate meeting for all on location.

An important item is the detailed manner in which pumping equipment will be shut down as required to avoid over-pressuring of the tubular equipment.

CHAPTER-3

(EVALUATION OF FRACTURING FLUID PROPERTIES)

EXPERIMENT NO. 1

AIM: To calculate the fluid properties like viscosity and pH of the water base fracturing fluid.

Sample 1: HPG Gel

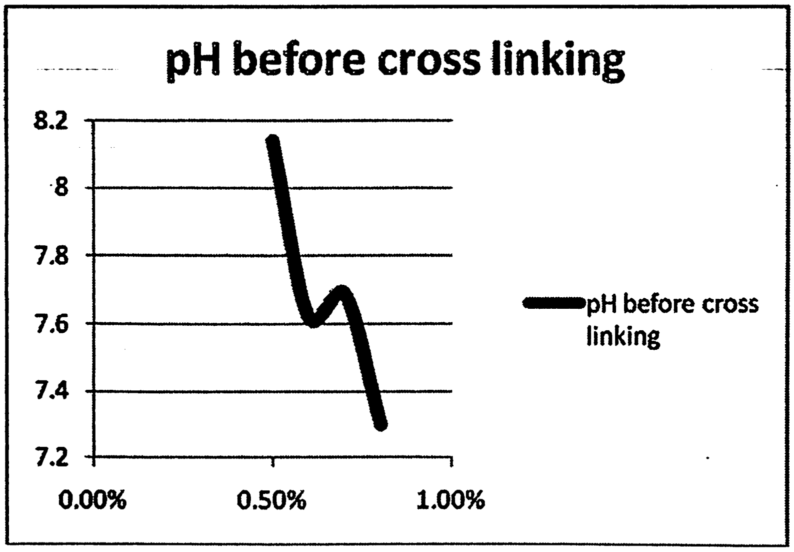
S.N	HPG gel concentration (wt/v)	0.5%	0.6%	0.7%	0.8%
1	pH before cross linking	8.14	7.62	7.69	7.3
2	pH when cross linked	8.48	8.38	8.29	8.26
3	pH after breaking	8.3	8.29	8.18	7.9
4	Viscosity before cross linking (Brookfield Viscometer at 100 rpm)	131.7cp@ 24 °C	216.9cp@ 24 °C	475cp@ 24 °C	1440cp@ 24 °C
5	Viscosity when cross linked	2639cp@ 24 °C	5111cp@ 24 °C	13437cp@ 24 °C	30953cp@ 24 °C
6	Viscosity after breaking	12 cp@ 90 °C	16 cp@ 90 °C	19 cp@ 90 °C	30 cp@ 90 °C

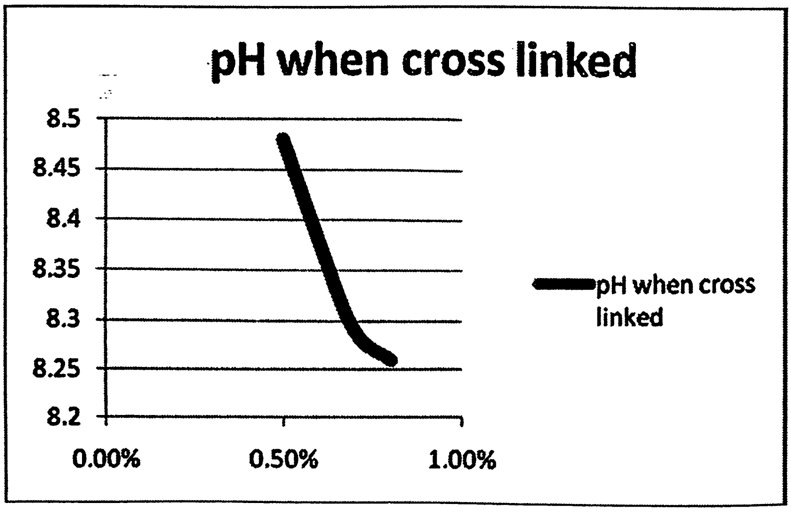
Procedure for making HPG gel

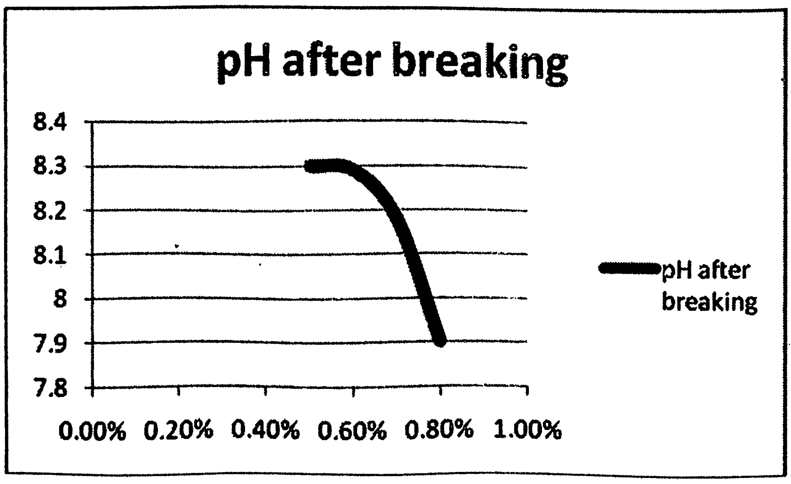
Gel making process

- 200 ml H_2O+4 gm KCl+0. X% of HPG
- This solution is stirred for 45 minutes.
- PH and viscosity of the solution is measured.
- 6.5 ml borax solution of 1% stock is added for cross linking
- Again measure, x-linking behaviour, pH and viscosity.

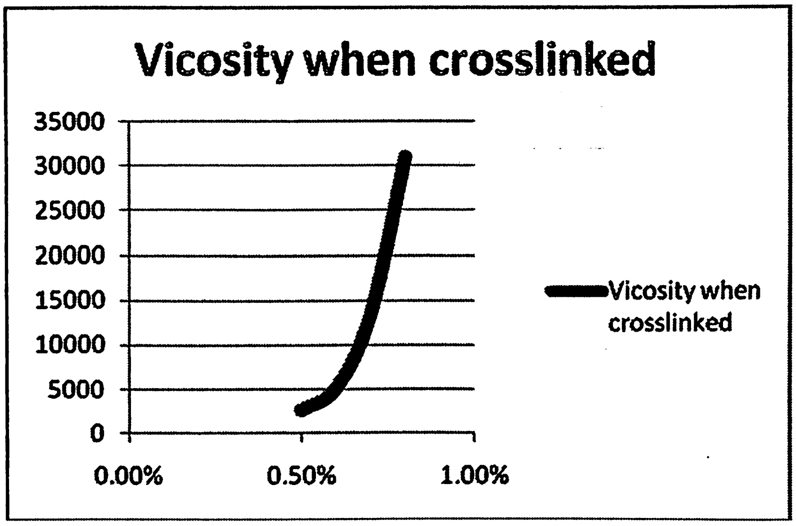
Graph: Sample-1 pH Vs Wt% of HPG gel under experiment no. 01

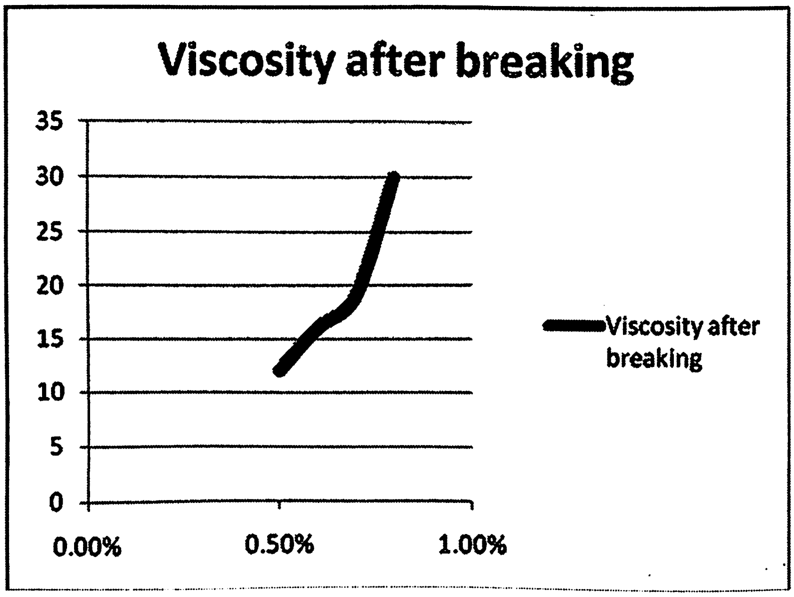






Graph:Sample-1 Viscosity Vs Wt% of HPG gel under Experiment no 01





Crosslink check

Gel breaking process

- The above solution + 2ml APS(ammonium per sulfate) solution from !% stock solution
- This is then put in a oven for 3-4 hours @90^{0}C for gel breaking
- Measure the viscosity and fluidity of gel.

Sample 2: HEC gel

Serial number	HEC gel concentration (wt.)	0.5%
1	pH before cross linking	8.04
2	pH when cross linked	8.54
3	pH after breaking	8.09
4	Viscosity before cross linking (Brookfield Viscometer at 100 rpm)	136.3cp@ 24 ^{0}C
5	Viscosity when cross linked	156.8cp@ 24 ^{0}C
6	Viscosity after breaking	24 cp@ 90 ^{0}C

Procedure for making HEC gel

Gel making process

- 200 ml H_2O+4 gm kcl+0 .X% of HEC powder
- This solution is stirred for 45 minutes.
- PH and viscosity of the solution is measured.
- 6.5 ml borax solution of 1% stock is added for cross linking
- Again measure, x-linking behaviour, pH and viscosity

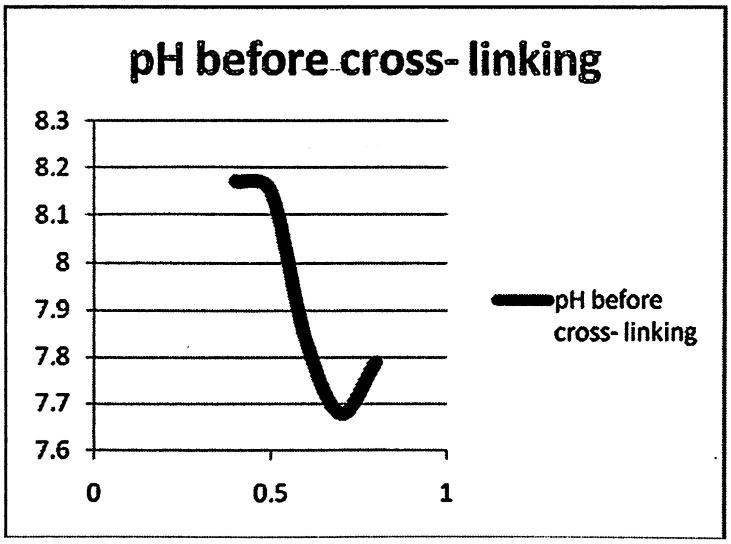
Gel breaking process

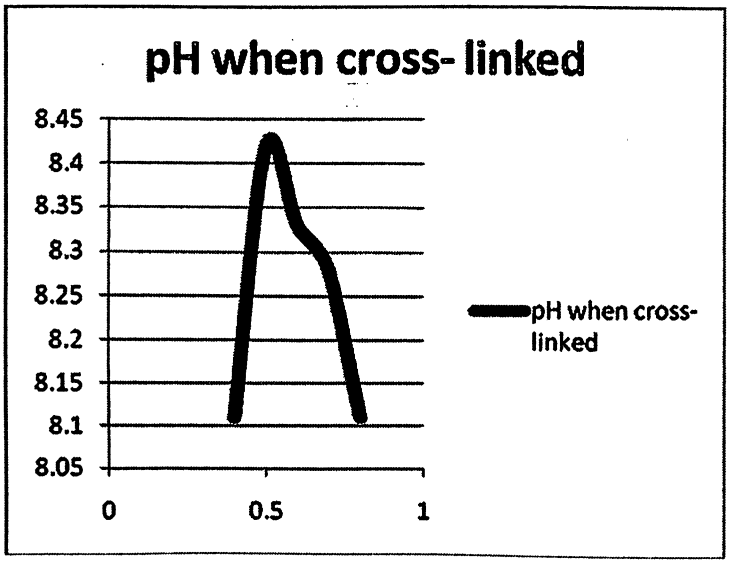
- The above solution + 2ml APS(ammonium per sulfate) solution from !% stock solution
- This is then put in a oven for 3-4 hours @90^{0}C for gel breaking
- Measure viscosity and fluidity

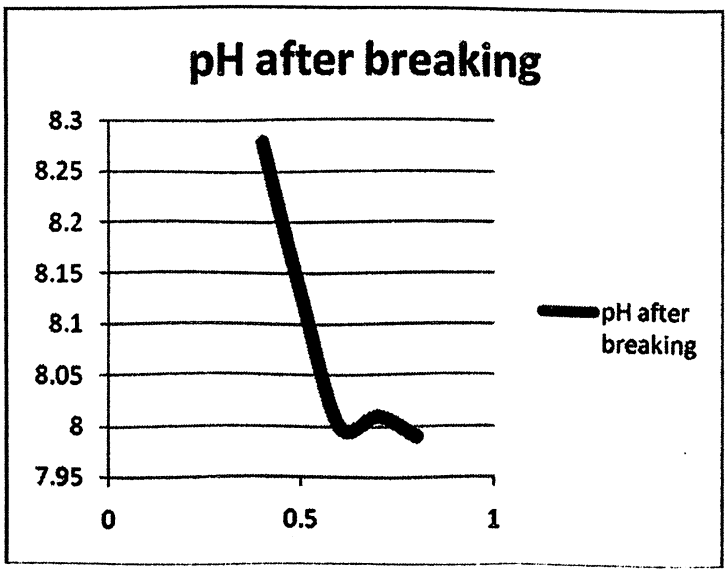
Sample 3: Gelling Agent – Gd-II

S. N	GA - II gel concentration (w/V.)	0.4%	0.5%	0.6%	0.7%	0.8%
1	pH before cross-linking	8.17	8.15	7.84	7.68	7.79
2	pH when cross-linked	8.11	8.42	8.33	8.28	8.11
3	pH after breaking	8.28	8.13	8.00	8.01	7.99
4	Viscosity before cross linking (Brookfield Viscometer at 100 rpm)	61.5cp @24 ^{0}C	148.5cp @24 ^{0}C	231cp @24 ^{0}C	284cp @24 ^{0}C	926cp @24 ^{0}C
5	Viscosity when cross linked	29500cp @24 ^{0}C	44200cp @24 ^{0}C	46291cp @24 ^{0}C	62187cp @24 ^{0}C	101e3cp @24 ^{0}C
6	Viscosity after breaking	7.20cp @90 ^{0}C	15.51cp @90 ^{0}C	18.6cp @90 ^{0}C	30cp @90 ^{0}C	50cp @90 ^{0}C

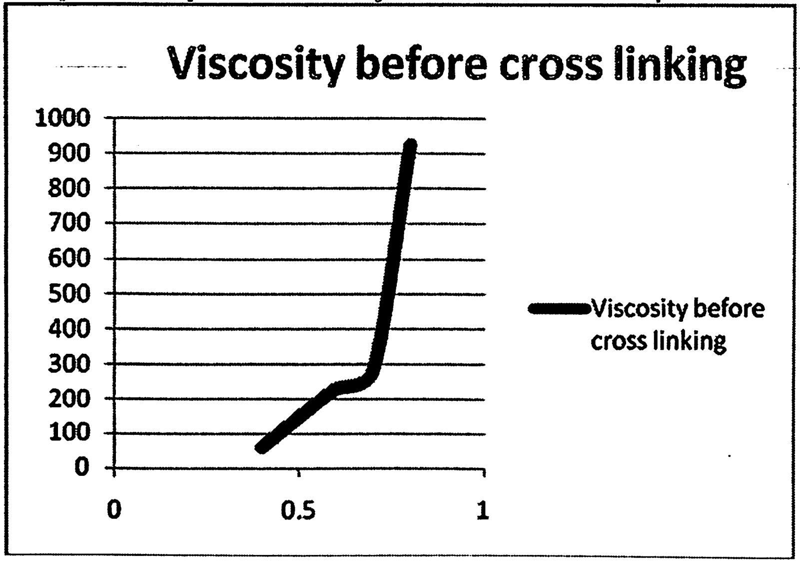
Graph: Sample-3 pH Vs Wt % of GA-2 under Experiment no. 01

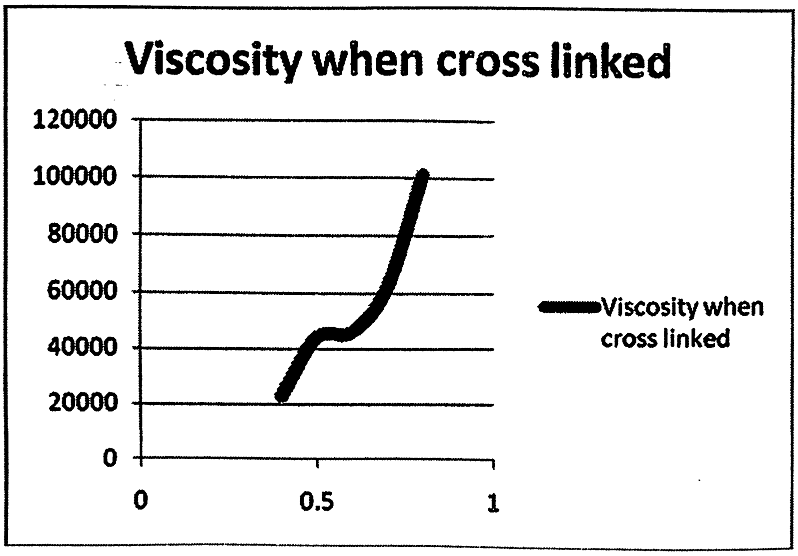


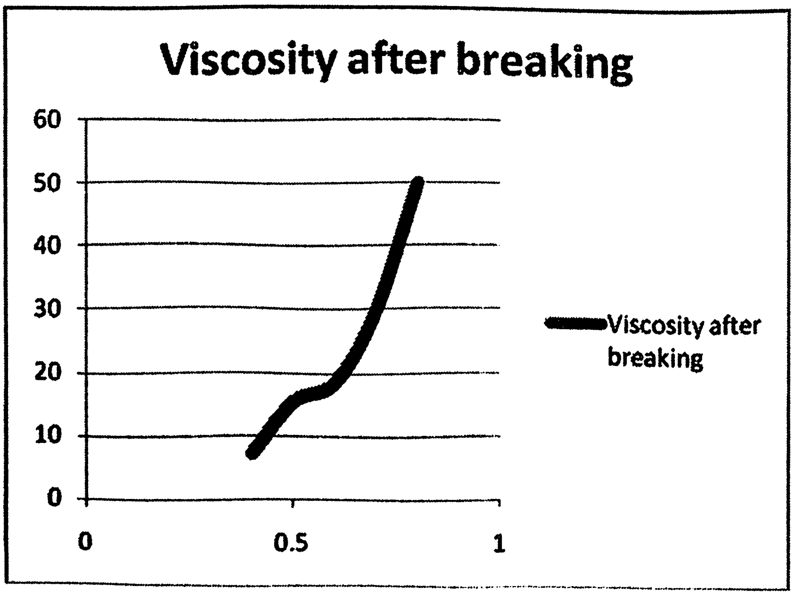




Graph: Sampe-3 Viscosity Vs Wt% under Experiment No 01







Procedure for making GA- II gel

Gel making process

- 200 ml H_2O+4 gm kcl+0.X% of GA -2
- This solution is stirred for 45 minutes.
- Ph and viscosity of the solution is measured.
- 6.5 ml borax solution of 1% stock is added for cross linking
- Again measure, x-linking behaviour, pH and viscosity

Gel breaking process

- The above solution + 2ml APS(ammonium per sulfate) solution from !% stock solution
- This is then put in a oven for 3-4 hours @90^{0}C for gel breaking
- Measure viscosity and fluidity

EXPERIMENT NO.2

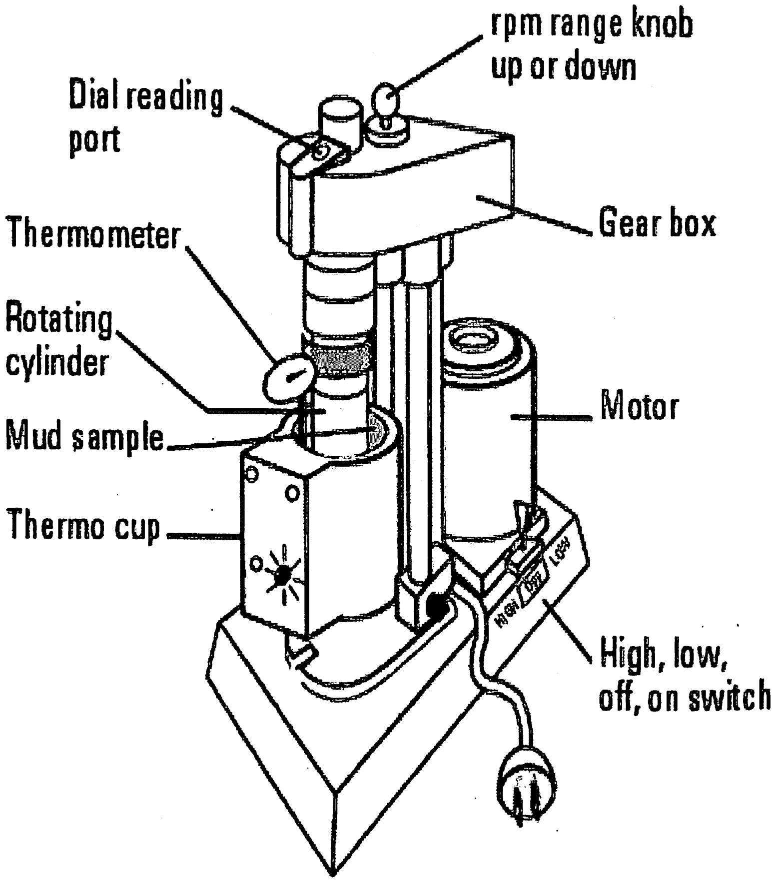
AIM: To determine the consistency index and flow behavoiur index of GA-II.

Materials required:

GA-II Powder, glass beaker, Sartorius weighing balance, magnetic stirrer, Fann Viscometer (Six Speeds)

Experimental setup:

Fann viscometer setup is carried out.



Preparation of Gel Solution:

3% KCl + diff conc. of gelling agent - Stirred for 45 min

Measured viscosity in Fann viscometer

Observation:

Table 1:

S.N	GA- II (% w/v)	Dial reading Ø600 rpm (at 1022sec-1 shear rate)	Dial reading Ø300 rpm (at 511 sec-1 shear rate)
1	0.6	58	45
2	0.7	74	60
3	0.8	90	73
4.	0.9	113	93
5.	1.0	134	111

Calculation:

1. Apparent viscosity $= Ø_{600}/2$
2. Plastic viscosity $= Ø_{600} - Ø_{300}$ = in cp
3. Viscosity at 511 shear rate $^{-1}$ = in cp
4. Flow behaviour index ,n' = 3.32 log $(Ø_{600} / Ø_{300})$
5. Consistency index, k' = $(511^{(1-n)} \times Ø_{300}) / (100 \times 4.788)$

   = in lb-sec / 100 sq. Ft

Table 2:

Sr No	Conc. of GA-II (w/v)	App Viscosity cps	Plastic viscosity cps	Viscosity at 511 sec-1 shear rate	n'	K' (in lb-sec/100 sq. ft)
1	0.6	29	13	45	0.36	4.90
2	0.7	37	14	60	0.30	9.71
3	0.8	45	17	73	0.30	11.86
4.	0.9	56.5	20	93	0.28	17.22
5.	1.0	67	23	111	0.27	21.79

EXPERIMENT NO. 3

AIM 1: To determine the gel breaking time studies and rheology of water base frac fluid at 90 ^{0}C.

Fluid Parameters:

Breaker –> ammonium per sulphate

Gelling agent –> GA-II (0.6%) x-linked with borax

Breaker Conc. –> 0.01% (w/v)

Temperature **->90 ^{0}C**

Equipment:

Fann Viscometer

Table:

Time in Minutes	Viscosity at 300 rpm	n’
Initial	x-linked	-
30	65	0.2994
60	34	0.4358
90	32	0.4592
120	22	0.5403
180	16	0.7000
240	6	0.999

AIM 2: To determine the gel breaking time studies and rheology of water base frac fluid at 80 ^{0}C.

Fluid Parameters:

Breaker – ammonium per sulphate

Gelling agent – GA-II (0.6%) x-linked with borax

Breaker Conc. – 0.03% (w/v)

Temperature - **80 ^{0}C**

Equipment:

Fann Viscometer

Table:

Time in Minutes	Viscosity at 300 rpm	n’
Initial	x-linked	-
30	40	0.3783
60	18	0.6371
90	13	0.5846
120	10	0.7651
180	6.5	0.8926
240	5	0.9994

EXPERIMENT NO. 4

AIM: To measure the effect of residue content of fracturing fluid in terms of permeability damage.

METHODOLOGY:

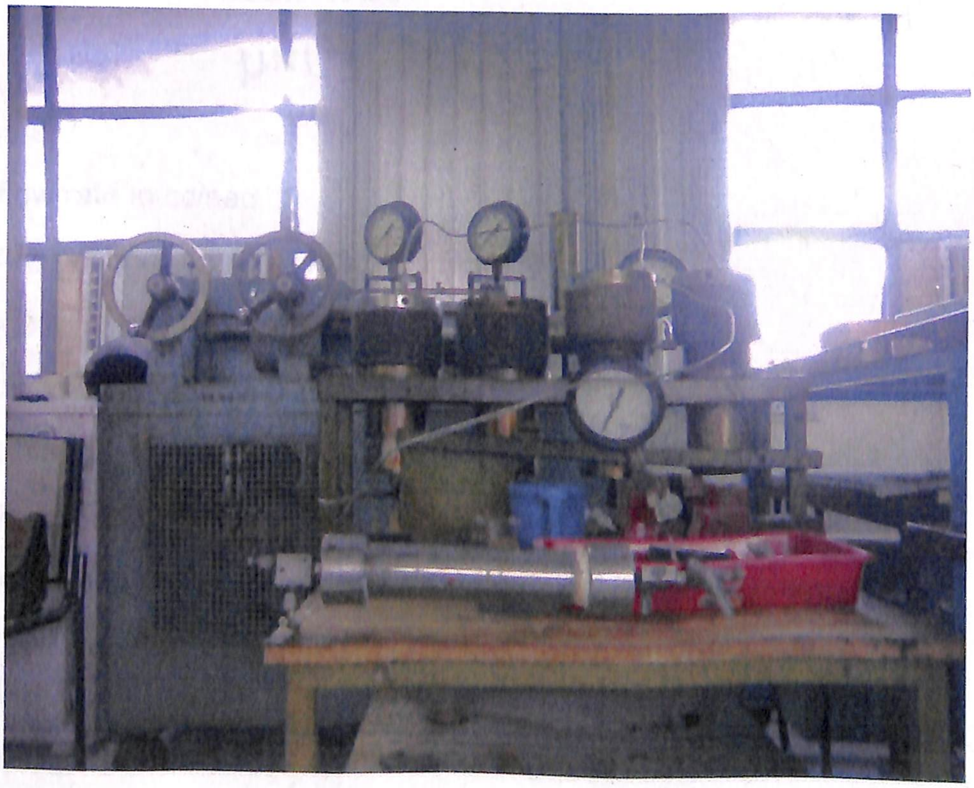
After preparation and conditioning of sand pack, permeability with respect to brine (3% KCl solution) was calculated. Then passed the fracturing fluid through the sand pack and placed the sand pack in hot air oven at 90°C for four hrs. Bring out the sand pack holder and flowed again 3 % brine from it. Record the permeability again. Calculate the reduction in permeability by using both the permeability.

MATERIALS REQUIRED:

Ruska positive displacement pump, accumulator unit, sand pack holder, pressure gauge, Sand 20/40 mesh size, laboratory glassware, Electronic balance, Stop watch, Magnetic stirrer, KCl, gelling agent , APS and hot air oven.

Experimental setup:

Experiment is done with the help of Ruska positive displacement pump, accumulator unit and sand pack holder and the experimental setup is as below:



Preparation of Sand Pack:

Take the 20/40 mesh size sand. Wash the sand granules thoroughly with clean brine (3% KCl) to wash out the dirt and fines. At the same time low density impurities were also washed out. Placed the fine sieve at one end of sand pack holder and put the sand gradually in the holder. Through out the packing process the sand pack holder was vibrated to allow for maximum sand settlement. Finally the top end fittings were screwed by keeping a fine sieve on the top.

Saturation and porosity estimation:

Porosity of sand packs was determined from the weight difference before and after saturation with brine.

THEORY:

The Ruska positive displacement pump (above diagram) is used to compress the required fluid in the core. Once the core is fully saturated with the given fluid, we start measuring the flow rate then by using Darcy's law, permeability can be calculated.

Formula used:

$$Q = \frac{k \times A \times \Delta P}{\mu \times L}$$

Where,

Q=flow rate in cc/sec

A=Area of core pack in cm2

ΔP=Differential Pressure in atm

μ=Viscosity of given fluid in cp

L= length of core pack in cm

K=Permeability of core pack in Darcy

This formula is well known by Darcy equation

For this experiment, the given data as follows.

Length of sand core pack= 30 cm

Diameter of Sand Core = 3.8 cm

Area of core holder=11.3354 cm2

Porosity: **Approx 40%**

PROCEUDRE:

1. We made the sand core pack with the help of filling water continuously.
2. All the connections (inlet & outlet) are checked.
3. Pressure taps are installed and checked.
4. All the connections are made and brine is allowed to fully saturate the core of sand pack.
5. Meanwhile the permeability of sand pack is calculated.
6. Now gel is prepared and allow to, corresponding permeability is calculated.
7. Then gel with breaker APS (ammonium per sulfate) is flowed and corresponding permeability is calculated.

Observation 1: with 100% brine (3% KCl) saturation (Absolute)

Table 1:

VOLUME (CC)	TIME (SEC)	FLOW RATE (CC/SEC)	PRESSURE (PSI)	P (KG/CM^2)	K (mD)
6	2.64	2.272727	5.2	0.365605	**16452.03**
9	2.84	3.169014	7.2	0.506222	**16567.89**
12	2.98	4.026846	9.4	0.660901	**16125.48**
15	3.2	4.6875	10.8	0.759333	**16337.78**
20	3.8	5.263158	11.8	0.829642	**16789.59**

OBSERVATION 2: with GA-II (0.6%) and breaker - Ammonium Per Sulfate.

Table 2:

VOLUME (CC)	TIME (SEC)	FLOW RATE (CC/SEC)	PRESSURE (PSI)	P (KG/CM^2)	**K (mD)**
2.5	53.63	0.046616	7.5	0.527315	**233.9627**
5	105	0.047619	7.5	0.527315	**238.9984**
15.5	120	0.129167	15	1.05463	**324.1416**
15	120	0.125	15	1.05463	**313.6854**

Remarks: Viscosity of gel, 50 cps is not incorporated in the perm calculation

Observation 3: With Brine after gel breaking at 90 ^{0}C

Table 3:

VOLUME (CC)	TIME (SEC)	FLOW RATE (CC/SEC)	PRESSURE (PSI)	P (KG/CM^2)	**K (mD)**
5	1.5	3.333333	12.5	0.878858	**10037.93**
6.5	3	2.166667	7.5	0.527315	**10874.43**
12	17.5	0.685714	2.5	0.175772	**10324.73**

Observation 4: Reduction in overall Permeability damage.

Table 4:

Avg. K with 3% KCl Before gel pumping	**Avg. K with 3% KCl after gel breaking**	**Reduction in Permeability**	**% Reduction**
16454.55	**10412.36**	**6042.191**	**36.72048**

Results & Discussions

It has been concluded from the above studies that-

1. Water base fracturing fluids are most commonly used for hydro fracturing. Besides economy and safe in operation, it has the following excellent properties like minimum damage to formation, ability to carry high volume of proppant, low pumping friction loss, easy flow back from the formation, compatibility with formation fluid etc.
2. In case of water sensitive formations, oil base frac fluid is being used.
3. HPG based polymer gel is very good viscosifier as it has a good thermal stability above 90 deg C with zero residue content.
4. Indigenous Gelling Agent Gd-II can be used up to 90 deg c. It has low residue content of around 4%.
5. Borax alone is an effective cross linker up to 90 Deg C. However above this temperature, the x-linking can be delayed by addition of additive.
6. Break-time studies with Ammonium per sulphate shows the Newtonian behaviour of gel like water after four hrs at 90 deg C. This way, flow back of broken gel after the hydro fracturing job is assured.
7. Experiment with HEC shows the inability to form x-link gel because of its chemical structure. It is a clean residue free high viscosity and is used in work over operations.
8. Presence of residue in the gelling agent reduces the permeability of proppant pack up to 35% as the core flooding experiment results show the effect of GA-II having 4% residue content. Breaking of complete fluid with maximum flow back from the formation is essential to avoid the permeability impairment.
9. HPG is a residue free gel with least damage to the formation provided with economic considerations.

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