KHAZAR UNIVERSITY

School: Engineering and Applied science

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MASTER THESIS

Title: Hydraulic Fracturing Methods in Stimulating Production from Oil and Gas wells

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ABSTACT

The Master Thesis is dedicated to the issued of "**Hydraulic fracturing methods in Stimulating production from oil and gas wells**"

The hydraulic fracturing methods and stimulation are studied in the thesis.

The well completion and stimulation process helps the completion engineer to design the well completion procedures used to plan completion design.

In the thesis, the fracture stimulation treatment is analyzed to improve the production rate of a well to more economically viable. All the derivatives and calculation is shown.

In the thesis, it's shown that fracture stimulation frequently causes actual productivity improvements, their structure, and mechanism and to be concluded, most of these wells would not be economically high investments without fracturing.

At the end of the thesis appropriate conclusions were obtained.

References of sources were shown.

XÜLASƏ

Bu maqistr tezisi **“Neft və qaz quyularında layın hidravlik parçalanması üsulu ilə hasilata təkan verilməsi**” məsələsinə həsr edilmişdir.

Tezisdə layın hidravlik parçalanması metodları və quyuya təkan vermə tədqiq edilmişdir. Quyunun tamamlanması və təkan verilməsi prosesi neft mühəndislərini quyunun tamamlanma layihələndirməsinə və bu layihənin icrası prosedurlarının hazırlanmasına cəlb edir.

Bu tezisdə quyunun iqtisadi səmərəliyinin təkmilləşdirilməsi üçün hasilatın artırılması hədəfə alan layı parçalayaraq təkan vermə üsulu analiz olunmuşdur.

Tezisdə göstərilmişdir ki layın hidravlik parçalanması üsulu ilə quyu hasilatına təkan verilməsi bir çox hallarda hasilatın artmasına səbə olmuşdur və müəyyən olunmuşdur ki struktur baxımından fərqli olan bu tip quyularda hasilatın layın hidravlik parçalanması üsulu ilə təkana gətirilməsi prosesi olmadan layihənin iqtisadi səmərəliyi mümkünsüz hesab olunur.

Tezisin yekununda uyğun nəticələr dərc olunmuşdur.

CONTENT

Proudly dedicated

TO MY FATHER MR.RAVISHANKER

INTRODUCTION

The objective of fracture stimulation treatment is to improve the production rate of the well in order to allow being more economically viable. It is essential that all well under consideration to be a candidate for a frac treatment should be completed in reservoir having sufficient recoverable reserves to justify the cost of development.

Fracture stimulation affects the rate at which production is withdrawn from the reservoir and it will not increase the total amount of petroleum that can be produced from the single reservoir, provided time and economics are not reverent facts, additionally, the total number of reserves produced by many individual wells prior to be substantially greater, since the abandonment pressure is often reduced as a result of fracturing. Considering several oil and gas wells that could be commercially produced as natural producers, total recoverable oil and gas reserves have been greatly increased by fracture stimulation. Its estimated over 25% of the all reserves in united states accounting over 8 billion bbl of oil. The future impact of fracturing on the commercial development of some now marginal world reserves is really expected to follow the trend as United States.

The effectively designed fracture stimulation program can reduce the total number of wells required to drain a reservoir. The further method and the benefits is a result of connecting several discontinuous reservoirs to a single wellbore. The results can be unpredictable, so this is not considered an appropriate application of hydraulic fracturing theory as discussed within the text.

The target of most Fracturing treatments is low-permeability reservoir. The low permeability necessarily varies from reservoir to other reservoir, depending on the net thickness of the pay zone and the properties of the fluid of the reservoir, Depending on the net thickness of the pay zone and the properties of the fluids. But reservoirs having an effective permeability of less than 1 md are generally considered to be the most likely candidates for successful fracture stimulation. Additionally some higher permeability reservoirs may be also considered as a source for fracture stimulation.

Frac treatment has gradually been found to range between 1.2 times the un-stimulated well's natural production level to about 8 times this value, depending upon the contrast in conductivity and frac length between the fracture and formation. The production efficiency of the individual wells can be even more favorably improved as a result of hydraulic fracturing. Increases in a well's productivity index can range from 1.2 to 14 folds.

The improvement in reservoir recovery rate realized for a specif pressure drawdown is frequently used by practicing engineers to quantify the effect of a stimulation treatment on the production efficiency of a well.

Fracture stimulation frequently causes actual productivity improvements in a large amount of these values if the fracture bypasses a damaged zone immediately adjacent to wellbore. If in such cases the improved productivity is a combination of negating the damage effect and the effect of the fracture on stimulating the undamaged productivity. It is a planned integral part of the completion program on approximately 35% to 40% of the well are completed in US. most of these wells would not be economically suggested business without the help of fracturing. Computer based simulation are frequently used to compare the un-stimulated well's income return with the theoretical return resulting from various fracture treatment programs. There is several interest on the part of the petroleum operator to be able to accurately evaluate the effect of changing each variable in fracture design.

The objective of this program is to provide background on hydraulic fracturing so that participants can evaluate the impact of each of the factors used in the design of hydraulic fracturing treatments, as well as the interrelationships of these factors and select the most appropriate fracture stimulation design for each situation.

CHAPTER 1.BASIC CONCEPTS OF HYDRAULIC FRACTURING

THEORY & MECHANICS OF HYDRAULIC FRACTURING

1.1 GENERAL FRACTURING THEORY:

The desired objective of an improved producing rate is achieved by creating a highly conductive, continuous flow path extending from the wellbore deep into the reservoir. The fracture conductivity is the product of the in-situ fracture permeability and the fracture width.

This high-conductivity flow path reduces the amount of pressure drawdown in moving the reservoir fluids through the reservoir, especially that energy required to flow the reservoir fluid through the critical radial flow zone located immediately adjacent to the well bore. Therefore, less reservoir pressure is required to move more fluid to the wellbore at higher rates.

Although Fracturing was originally developed to improve the productivity of oil wells, it has since been found to have significant application to gas wells. The magnitude of the fracturing operation required in tight gas reservoirs has led to the development of a special stimulation service termed massive hydraulic fracturing. The massive hydraulic fracturing treatment typically entails the pumping of exceptionally large volumes of frac fluid and prop pant in single treatment to create an exceptionally deep penetrating propped

Fracture. As a result of this type of treatment, the reservoir may be produced at much higher rates from a limited number of wells, thus avoiding the expense of extensive infill development drilling.

The formation permeability's fracture length varies with each well. Lower formation permeability's require a greater fracture length to acquire the desired increment in production. For example, the fracture half lengths in excess of 2000ft are routinely created in some tight gas reservoirs, although a frac half-length of about 200 to 500 ft normally adequate for most oil and gas wells. The fracture half length is the length of one wing of a fracture. In fracturing theory; it is assumed that two symmetrical frac wings are created simultaneously during a fracture operation, with the total overall frac length equal to twice the half length.

Fracture treatments for high-permeability zones are designed for a shorter frac length, sometimes as small as 20 to 50ft,but include a larger propped frac width to increase the conductivity ratio. The contrast in conductivity between an induced fracture and the original formation is typically about 100 to 10,000 fold. Higher permeability formations require that the induced fractures have much greater perm abilities to yield proportionate increases in production. Formation Conductivity, which is an indication of the natural producing capability of the formation, is the product of the relatives formation permeability and the net formation thickness. computer simulation studies, this ratio has been altered. The maximum conductivity that can be achieved with the use of conventional propping agents limits the applicability of the fracturing high permeability formations. Many successful Fracturing treatments are performed on high-permeability formation; the frac length is typically limited less than 50ft.

A conductive fracture is created by driving a “fluid wedge” through the rock and then placing a solid propping agent in the created void to provide the desired conductivity. Alternatively, the fracture conductivity is sometimes achieved by dissolving a portion of the rock on the fracture face using low-ph fluid. This technique is termed acid fracturing.

1.1.2 **FRACTURE INITIATION:**

In most cases, a fracture may be initiated by applying hydraulic pressure to an exposed formation. Prior to fracture initiation, a positive differential pressure will cause the fluid to enter the formation in a radial flow pattern, with the rate of fluid flow through the rock limited to a rate that is in compliance with Darcy’s law.

Maintaining the injection rate of a fluid above the maximum matrix flow capacity of the exposed formation are will continually increase the formation pore pressure at the wellbore.finally, the pore pressure will be increased to the point at which the tensile strength and the stress loading on the formation are exceeded and the rock will rupture in tension in a direction perpendicular to the least principal stress present in the formation. After breakdown, the predominant fluid leak off pattern will be into the exposed faces of the fracture in a linear flow regime.

FRACTURE GROWTH:

The Fracture will continue to be enlarged as long as sufficient hydraulic pressure is maintained and the injection rate is kept above the rate at which the injected fluid continues to leak off into the formation. The growth is generally confined to a single plane, continuing equally in all directions of the fracture plane until it encounters some barrier limiting the growth rate in that direction.

As injection continues, the fracture width at the wellbore continues to expand at a rate proportional to the length development and inversely proportional to the compressive strength, of the rock that is displaced by the fracture void.

1.1.3BARRIERS: FACTORS LIMITING FRACTURE GROWTH:

Fracture barriers may be defined as anything that limits the extension of a fracture in any direction. They may be overlying or underlying zones having significantly different properties of elasticity than the zone being fractured. Barriers may be rocks having a higher a higher tensile stress, high-stress loadings, or stress loading in which the least principle stress is in a different direction than at the wellbore. Barriers may also be rocks having a higher frac gradient, or zones having a lower pore pressure. Slippage planes unique bedding planes having no vertical bonding, in which the adjacent surfaces act almost as if they are lubricated-which dissipate the dynamic growth energy of a fracture may act as barriers. Barriers may also be physically intruded combinations of any or all of these factors, or additional growth extension may be simply stopped due to a reduction in hydraulic pressure at the fracture tip caused by frictional pressure losses along the plane of fracture extension.

The practical application of much of the theoretical knowledge about hydraulic fracturing that exists today is imprecise because there are so many factors that affect the geometrical growth of fractures. The continued application of the highest level of sophisticated fracturing technology available and the continued analysis of pre and post frac data will allow improved results to be attained, and will serve to make the task of predictive design more precise and practical.

FRACTURE ORIENTATION:

In order to design a fracture treatment properly, and correctly predict its benefit in increased production rates, it is necessary to first predict the orientation of the frac plane that is to be created. As mentioned previously, fracture orientation is directly related to the stress loading on the reservoir at the time of fracturing. The vertical stress loading is a function of the overburden pressures, which are normally about 1.0 to 1.1 psi/ft. The horizontal stresses are more complex. They are related to the rocks vertical stresses by means of the ability of the rock to deform and transmit pressure like a fluid, plus they include the effect of any geological movement that has taken place and not been fully dissipated. During core drilling and recovery operations these stresses are necessarily altered. Therefore accurate values for these stresses cannot be determined from laboratory testing procedures available at this time. However, use of these tests on oriented cores has proved to be extremely helpful in determining relative values and predicting the fracture azimuth.

The most accurate method for determining the least principle stress is in the field using pre-frac injection tests, which are commonly referred to as Mini fracs, micro fracs or data fracs.During these injection tests, pressure versus time and injection rate is accurately recorded and the results are carefully analyzed, generally with the aid of computer programs, to calculate the least principle stress, the frac gradient and the mathematical model most appropriate for use in the reservoir in question. This procedure may be used on the zone of interest as well as on the overlying and underlying zones, which may serve as barriers.

The general orientation of the fracture plane is frequently estimated by calculating the frac gradient from a small injection test performed on the zone of interest prior to the frac treatment. The frac gradient may also be estimated based on the frac gradient of offset wells,since it is typically the same for all wells in the same producing horizon of a single reservoir.

Rock stress measurement includes hydraulic fracturing with a straddle packer system as well as recording of the fracture trace on the borehole wall with an impression packer. Polymetra has developed a memory tool based on an electronic compass module and a data logger for measurement of the packer orientation-

sorces- http://www.polymetra.ch/index.php?id=18

1.2FORMATION-PROPERTIES AFFECTING THE ORIENTATION AND GROWTH PATTERN OF HYDRAULIC FRACTURE

Currently, most computer design programs are based on two-dimensional mathematical models that calculate the frac length and width only, and an assumed value is input for the frac height. Researchers are attempting to define a three-dimensional model that will accurately calculate the height growth simultaneously with the growth of the frac length and width. But for now, the prediction of the best value to input for the final height of a vertical fracture remains the single most important factor in the design of any frac treatment, and the one most difficult to calculate.

The method of solution currently employed by frac models essentially entails calculating the volume of the fracture void created by pumping a given volume of the fracture void created by pumping a given volume of fracturing fluid, after subtracting the volume of fluid that leaks off into the rock matrix during the total pumping time. By knowing this void volume and the frac height, and by using the appropriate fracture model, it is a fairly straightforward mathematical procedure to calculate the final fracture length and frac width.

The Formation properties that are known to influence the fracture growth pattern, including the height are,

A) Fracture gradient

B) Pore pressure

C) Young’s modulus

D) Poisson’s ratio

E) Compressive strength

F) Tensile strength

G) Bedding planes

H) Porosity

I) Permeability

J) Artificial barriers

1.2.1ROCK PROPERTIES:

Fracture gradient is a measure of the unit pressure required to hold open an induced fracture and is therefore proportional to the least principle stress in the reservoir. The least principle stress may be approximated by given Poisson ratio and the poroelastic constant are known. Its value is dependent on the pore geometry and the physical properties of the constituents of the fluid and solid systems. The larger the value of the value of the poroelastic constant, the easier it is compress the rock. When the compressibility of the dry rock (cb) is much greater than the intrinsic compressibility of the solid grains (cg),which is typical in many sedimentary rocks,then the poroelastic constant.

1.3 YOUNG'S MODULUS:

The elastic properties of a rock are identified by two different terms. One in young's modulus, E, which is defined as the modulus of elasticity of a rock. It is essentially an index regarding the stiffness of a rock. It is essentially an index regarding the stiffness of a rocked is defined as the ratio of the applied stress required to cause a proportional increment of displacement. In other words, it is a co-efficient of proportionally indicating the ability of a rock to deform under given loading condition. Its value is determined as

$$E \equiv \frac{\text{tensile stress}}{\text{tensile strain}} = \frac{\sigma}{\varepsilon} = \frac{F/A_0}{\Delta L/L_0} = \frac{FL_0}{A_0 \Delta L}$$

Higher value of young modulus indicates a greater stiffness. Therefore fracture width growth will be minimal, resulting in the formation of a greater farc length or height to accommodate a given volume of fracture void. Adjacent formations having a young's modulus appreciably larger than the pay zone will tend to contain the fracture propagation within the pay zone.

1.3.1 POISSON'S RATIO:

The second elastic property of the rock is Poisson's ratio, which is defined as the ratio, which is defined as the ratio of the lateral expansion demonstrated by a rock when subjected to the longitudinal load, divided by the amount of longitudinal deformation caused by the same loading. its an important value in fracturing design work because it affects the fracture propagation pressure. It is also useful in estimating the detrimental effects of impediment or crushing of the pro=pant, which could occur after the fracture closes on the prop ant, it is typically derived from the shear stress versus shear strain values as determined by induction logs or measured in laboratories.

SHEAR MODULUS RELATIONSHIP:

$$E= 2G (1+v)$$

Some typical measured values for these elastic properties for various formations.

COMPRESSIVE STRENGTH:

The higher the compressive strength of the formation, the thinner the width of the fracture that will be formed. A thin fracture width can cause linear growth to be maximized, presuming that the fluid efficiency is identical in both cases.

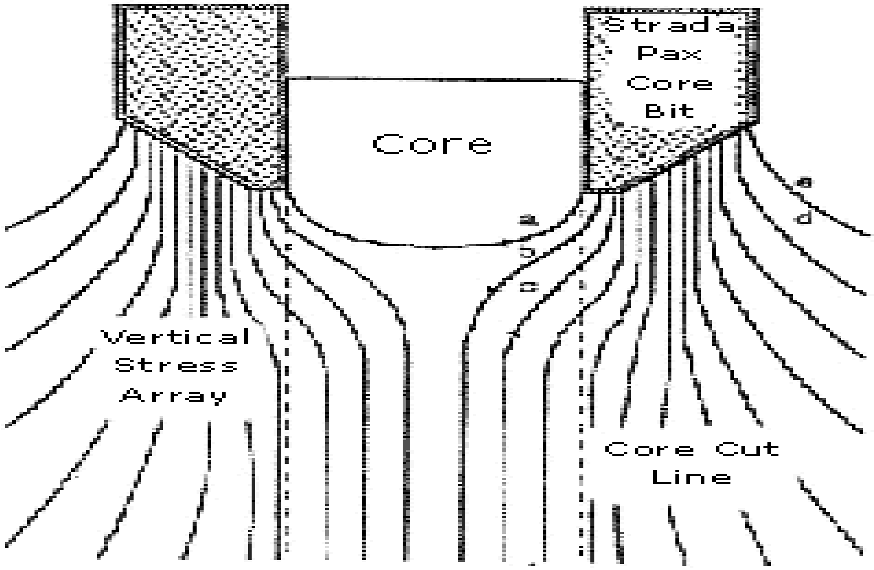
TENSILE STRENGTH:

Although the effect of the tensile strength is minimal, an increase in tensile strength will tend to inhibit additional fracture growth.

Bedding planes slippage that occurs along the bedding planes tends to dissipate the energy required for the fracture propagation, and thus reduce fracture growth in that direction. This phenomenon is particularly significant when considering the KG model. The presence of intersecting fractures or planes of weakness hinders further fracture growth in that direction, even if growth is not stopped completely. The vertical growth was relatively constant until an un-cemented bedding plane was contacted by the fracture. As the fracture crossed the bedding plane, it quickly shifted a small lateral distance before resuming its original vertical growth pattern at a reduced velocity. The reduced velocity was theorized to be the result of energy loss caused by changes in fracture direction.

1.3.2 STRESSES:

The least principal stress present in a reservoir rock has major impact on the geometric fracture growth. This in-situ stress is the combined result of the original gravity loading of the overburden, as translated laterally as per Poisson's ratio, and the lateral directional stress caused by tectonic activity that has taken place since deposition. The presence of a higher in-situ stress would serve to limit additional fracture growth in that direction.



Induced Fracture of vertical stress and Core cut line

Sources used: www.corias.com/**induced_fractures**.htm

1.3.3 PORE PRESSURE:

Another component of this in-situ horizontal formation stress is the pore pressure, corrected to compensate for the poro elastic constant.

The presence of higher pore pressure in an adjacent formation acts to increase the tensile forces present in that zone, thereby requiring a lower internal hydraulic pressure to initiate failure caused by rupturing, which can actually cause a fracture to grow into adjacent formation.conversely,an adjacent low-pressure zone or an area of lower pressure within the reservoir, such as that surrounding an old producing well, will put that formation in compression and cause it to serve as a fracture barrier and stop continued growth, or possibly divert fracture growth in another direction. An accurate analysis of the pore pressures in the zone of interest and the surrounding formations is essential to allow accurate predictions of the height containment of vertical fractures.

ARTIFICIAL BARRIERS:

The deposition of the propping agent or other solid particles may cause a differential pressure loss that will cause further fracture growth in that direction to be limited.

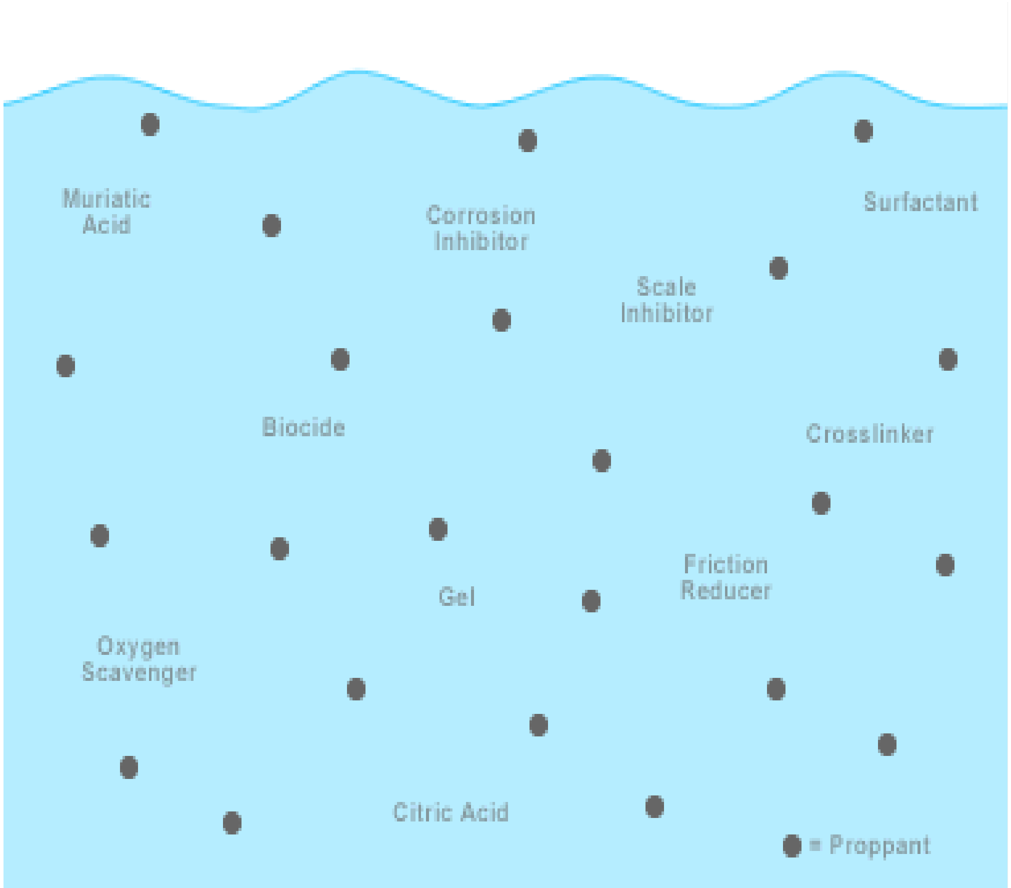
CHAPTER 2.HYDRAULIC FRACTURING FLUIDS

2.0 HYDRAULIC FRACTURING FLUIDS:

Early fracture treatments entailed pumping a single viscous oil-base fluid throughout the entire treatment. With the advent of improved alternative fluid systems, more consideration was given to the role of the fluid in each phase of the operation, and consequently of several fluids is now frequently employed in a single treatment.

The requirements of the fracturing fluids are unique and extreme. The frac fluid must, at various times, function to

a) Initiate the fracture
b) Propagate or extend the fracture
c) Carry the prop pant where required
d) Retrovert to the wellbore without enclosing reservoir flow



Source for this picture: http://geology.com/energy/hydraulic-fracturing-fluids/

A several chemical additives are used in hydraulic fracturing fluids. They include: dilute acids, biocides, breakers, corrosion inhibitors, cross linkers, friction reducers, gels, potassium chloride, oxygen scavengers, pH adjusting agents, scale inhibitors and surfactants. These chemical additives typically might make up just 1/2 to 2 percent of the fluid. The remaining 98 to 99 1/2 percent of the fluid is water. Prop pants such as sand, aluminum shot or ceramic beads are frequently injected to hold fractures open after the pressure treatment is completed.

2.1 **FRACTURE INITIATION:**

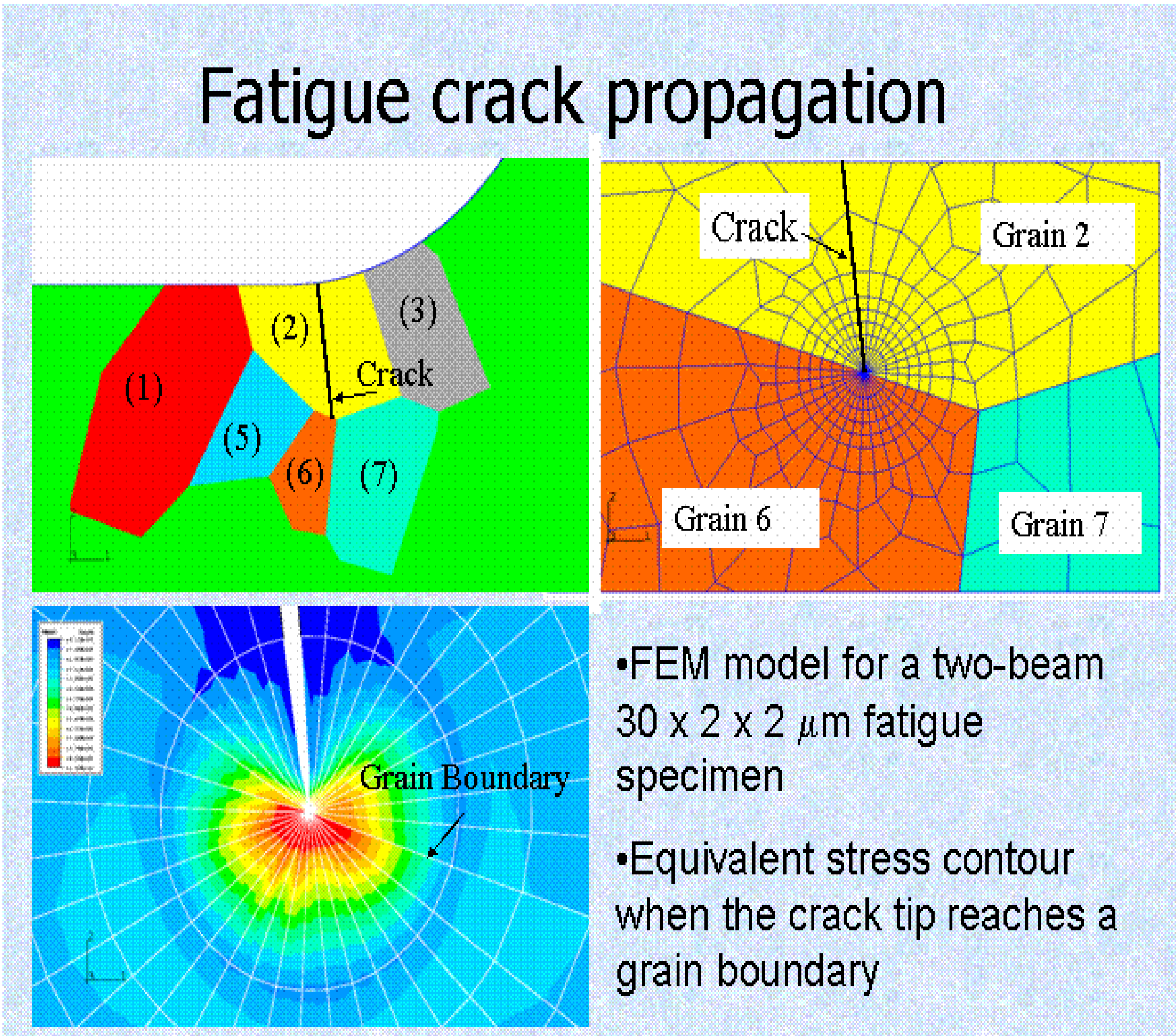
The primary requirement of the first fluid pumped is to initiate the fracture. Fracture initiation is accomplished by increasing the pore pressure in the rock to the point where the rock is ruptured because the tensional stress limit is exceeded.Thus, the primary performance criterion for this fluid is a high rate of leakoff, allowing it to enter the pores and increase the pore pressure as well as overcome artificially high stress concentrations present around the wellbore. These high stress concentrations are the result of drilling a hole into the formations .In the order to satisfy this requirement, the fluid must be what is termed a "penetrating fluid." Acid with no fluid-loss control is an example of an excellent penetrating fluid. Use of a non penetrating fluid to initiate a fracture would cause higher than normal breakdown pressure. This is because the only energy available to cause the formation to rupture comes from the hydraulic pressure within the wellbore acting on the available surface area. Since only the area of the perforation tunnel is upright to the direction of least principal stress could be available for the fluid to act upon to create a conventional hydraulic fracture, the resulting, pressures at the wellbore would be relatively high. The same phenomenon is noted in open hole completions, since the only surface area available for fracture initiation is the wall of the open hole. The theoretical pressure required to rupture the formation in a open hole with a non-penetrating fluid is equal to that pressure required to rupture a thick-walled cylinder. However, the actual pressure required to initiate breakdown of an open hole section is normally lower than this because of fluid leak off into natural fractures or because of naturally occurring planes of weakness that intersect the wellbore.

2.2 **FRACTURE PROPAGATION:**

The second requisite of the fluid is that it leads or spreads the fracture after it has been originated. As mentioned previously, Fracture propagation continues until the fluid leak off rate equals the total injection rate.Therefore, in order to increase the size of a fracture that may be created by pumping a given volume of fluid, it is necessary to either increase the fluid injection rate or to improve the fluid effect which fluid leaks efficiency (reduce the rate at which fluid leaks off into the rock matrix). A fluid's efficiency is defined as the percentage of the total volume of pumped fluid that remains in the fracture void and does not leak off into the matrix.

The fluid leak off rate may be visualized by application of Darcy's law based on a linear flow regime. As such, it is obvious that fluid efficiency may be improved either by increasing the fluid viscosity or by artificially reducing the permeability of the formation relative to the fluid being injected. Both of these techniques are commonly used today and will be discussed in more detail later.

As the essential properties of the first fluid pumped differ markedly from the requirements for the main body of frac fluid, it is apparent that two completely different fluids are required to perform an efficient fracturing treatment.



Source for this picture: me.berkeley.edu

2.3 PROPPANT TRANSPORT:

With the objective of a fracturing being the creation of a high-conductivity flowpath, the next requirement of a frac fluid is to ensure that the created fracture is wide enough to accept the injected solid material and transport that propping agent to the desired location. Propping agents characteristically have a higher specific gravity then the carrier frac fluid and therefore have a tendency to settle to the bottom of the fracture. Various mathematical models, such as stokes' law; have been utilized to predict the deposition pattern for various prop pants in various fluid systems.

Stokes's law states that the differences in fluid/solid specific gravity, the size of the solid particle, and the fluid viscosity are the key factors used to calculate the settling rate and time. High fluid viscosities assist in transporting propping agents deeper into the fracture before the propping agent settles to the bottom of a vertical fracture. The use of high-viscosity fluids also improves the fluid efficiency (by reducing leak off) and possibly creates wider fractures.

2.3.1 CLEANUP:

Thus far it has been demonstrated that the first fluid pumped should have penetrating properties, the main body of frac fluid should have a low leak off rate, and that portion of the fluid used to transport prop pant should have high viscosity. With these three idealized characteristics, It would be possible to create a satisfactory propped fracture. But a fracture is ultimately satisfactory only if the prop pant remains in place and the fluid that is used to transport it may be easily removed from the formation so as to allow formation fluids to flow into and through the induced fracture. Therefore, the final requirement of frac fluid(s) is to revert to a low-viscosity, nondamaging system that will easily return to the wellbore without hindering the placement of the prop pant or causing formation damage.

A major consideration regarding fluid return is compatibility of the frac fluid with formation fluids and rock. Sometimes the frac fluid with has a tendency to emulsify with the formation fluid, or it may be dissolve some minerals from the rock that will interfere with the complex chemistry of the viscosifiers or breaker. The high viscosity of an emulsion makes it extremely High

2.3.2 FLUID-LOSS CONTROL:

Fluid efficiency can be improved by the addition of gelling agents, special fluid-loss additive, and specially formulated fluid systems. Viscosifier added to base fluids increase the fluid viscosity, thereby reducing the fluid leak off rate. Insoluble or slowly soluble fluid-loss additives that create a thin skin of filter cake can also reduce the leak off rate. Concerns exist that this solid fluid-loss material may permanently damage the conductivity of the matrix and fracture

Another technique frequently utilized to reduce the leak off rate is the use of multiphase fluid systems as the base frac fluid. This has the advantage of reducing any permanent damage to the flow capacity of the formation and the fracture that could be caused by the use of solid fluid-loss additives. Laboratory and field experience has shown that the use of five percent diesel oil dispersed in a water-base frac fluid significantly reduce the fluid leak off rate.

The term that are used to describe the fluid leak off characteristics are referred to as “fracturing fluid coefficients.”The three coefficients commonly considered are viscosity, wall building and compressibility controlled factors. Cv is the term used to describe control resulting from the viscosity of the frac fluid.

2.4 VISCOSITY:

The fluid viscosity affects both the rate of fluid leak off and the transporting capability of the frac fluid. The fluid leak off is one of the major controlling factors in determining the size of the created fracture area, therefore viscosity is an important factor in the ultimate fracture length. Furthermore, this term affects the fracture width, which, in turn, affects the length. When taking into account that this property may be altered considerably by the addition of viscosifiers,it is readily apparent that viscosity is the single most important controllable variable in fracture fluid design.

Considerable research into the rheological properties of fracturing fluid systems and the effects of other controllable parameters on the fluid viscosity has been under taken.

Today's fracturing fluids are much more complex than the gelled napalm used in the industry's first fracturing experiment. Modified water-base systems are used to fracture more than 85% of the more than 25,000 fracturing treatments performed annually in the United States, and similar usage is estimated inter-nationally. The viscosity of these systems varies considerably, from 1 cp formation water to a cross linked fluid having an apparent viscosity of several million centipoises.

Viscosity may be simply defined as the resistance of a fluid to a motion of its molecules among themselves.Vicosity can also be defined as ratio of the shear stress to the rate of shear strain.

In order to correctly depict the viscosity of a fluid under a specified condition of shear, it is first necessary to know which type of fluid system it is; e.g., it is a true (Newtonian) fluid or is it a non-Newtonian fluid? If it is a simple Newtonian fluid, the shear stress is directly proportional to the rate of shear, as shown in fig 2.5, and the viscosity is a unique constant value. A very few low viscosity frac fluids appear to execute likewise to pure Newtonian fluids, nor they are merely used because of their lack of viscosity.

If the fluid is non Newtonian, the viscosity varies depending on the rate of shear. Note that for a Bingham plastic fluid, of which drilling fluid is an example, the slope of the log-log plot of shear stress versus shear strain is a straight line with a positive intercept of the y-axis (fig-2.6) this indicates that a large positive stress is required to initiate movement. The straight line results from plotting only two data points. The same plot for the power law model shows somewhat similar relationship between shear stress and shear rate, but, since it depends on several data points it is a curve rather than a straight line and may intercept eh y-axis at or near the origin. Most high viscosity frac fluids are so complex as to require the use of power model to describe their viscosity performance. Consequently, the power-law model is used almost exclusively in frac fluid work because of its greater accuracy over a large rate of shear.

What this means is terms of hydraulic fracturing is that the demonstrated fluid viscosity varies depending on the shear velocity to which the fluid is being subjected. It will exhibit a different viscosity when subjected to lower rates of shear (eg,while it is flowing through the proportion process)than it does when moving down the wellbore at a high velocity.frac fluids are generally shear thinning in that they demonstrate a lower viscosity when subjected to a high rate of shear

.2.5 RHEOLOGY:

As stated above, expressions to describe the rheological behavior of fracturing fluids are typically based on power law fluid relation. a rotating viscometer, such as fann model 50,is used to measure the viscosity exhibited at different shear rates. Then the power law model is applied to determine the consistency index (k”) and behaviors index (n”) of the fluid. These power-law model indicators are defined as follows.

N=log slope of the shear stress and shear rate curve dimensionless

K”=shear stress at sec”-1; units are expressed as lb f sec”n1/ft2

Values for the apparent viscosity of the fluid at shear rates corresponding to fann viscometer measurements at 100 rpm and 300 rpm (shear rates of 170 sec”-1 511 sec”-1, respectively)are typically reported and used by the industry. Their ease and relative accuracy of measurement and their ready availability make them useful for comparing various fluids. Most printed references to apparent viscosity are at one of these shear rates. These apparent viscosities are frequently taken to be representative of the viscosity of a fluid in an open fracture (170 sec”-1) for 100 rpm on the fann viscometer)and in the tubular(511 sec for 300 rpm on the fann viscometer)

Apparent Viscosity (cp) =47880 k’/ (shear rate) $^{1-n}$

The viscosity of all fracturing fluids is highly dependent on temperature, and, as started previously, many fracturing fluids are extremely shear-sensitive. This is especially true for those fluids viscosified using complex polymers that have been chemically crosslinked.when subjected to extended periods of high shear, the cross linking bond appears to be physically destroyed. Some fluids are capable of healing or recrosslinking, while others are permanently damaged. Therefore, special tests that duplicate the conditions of shear and temperature to which a fluid is exposed during an actual fracturing treatment have been found to be useful design aids for comparing the performance of different fluid systems.

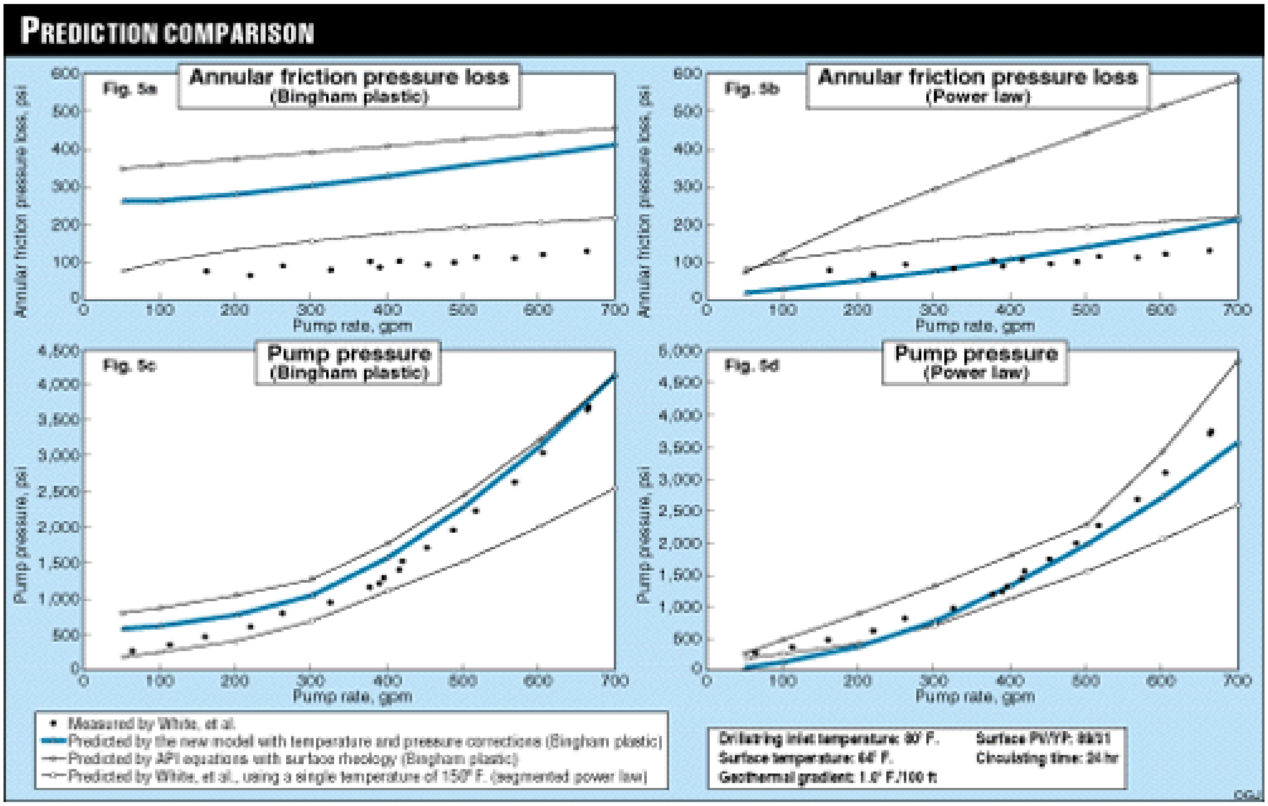
In addition to determining the effect on the rate at which a frac fluid leaks off into the matrix, knowledge of the fluid viscosity is important for two other reasons:(1) To allow calculation of the fracture width development, and to determine the prop ant deposition pattern.

FRACTURE WIDTH DEVELOPMENT:

Viscosity plays an important role in the width development in both models, although it has a slightly greater impact on the KGD model, compared to the PKN model, shows that a wider fracture is created by pumping a given volume of fluid of a given viscosity. This also means that calculation based on the KGD model give a shorter fracture half-length.

2.6 FRICTION LOSS:

The high viscosity is a desirable characteristic for fracturing fluid, one of the consequences of this feature can be friction loss during the pumping of fluid at high rates through the wellbore tubular.



Sources for this picture: ogj.com

One of the major expenses of the fracture treatment is the cost of renting the high horsepower pumping equipment, and high friction losses necessitate additional horsepower and higher expense. Early fracturing treatments used viscous, low-gravity crude oil to transport the propant.this type of fluid has very high friction properties, and injection rates necessarily kept quite low. As water-base fluids were introduced, it was found that the friction losses were lower and injection rates could be increased to maintain the same fluid performance in the fracture. It's also found that water base gelling agents, when used at a concentration sufficient to viscosify the fluid to a viscosity roughly equivalent to that of the crude oils used for fracturing, would actually reduce the friction loss since suppression of turbulence. Utilizing long chain water soluble polymers allowed friction losses to be reduced to less than half that of those caused by the use of ungelled water, even when used at very low concentrations. The same concept is currently used to chemically viscosify oil-base fluids.

COMPATIBILITY:

Since early fracturing treatments used petroleum-based fluids exclusively, primarily to ensure compatibility with the reservoir and fluids contained, the use of water as a fracturing fluid was employed in light of the difficulty in alternating the properties of crude oil, the reduced fire hazard in the use of water, and the lower cost of using viscosified water as compared to crude oil. It was found, in almost all instances, the complete compatibility could be reasonably ensured by use of the proper additive.

- Bacteria control agents
- Breakers for reducing viscosity
- Clay stabilizing agents
- Chelating agents
- Demulsifying agents
- Dispersing agents

- Forming agents
- Gypsum inhibitors
- Nitrogen and carbon dioxide gases
- Potassium chloride
- Scale inhibitors
- Sequestering agents
- Sludge inhibitors
- Surfactants
- Temperature-stabilizing agents
- Water-blockage-control agents

Considering reservoir compatibilities, the author should must also take into account the overall mutual compatibility of all essential additives. The highly complex fluid systems typically used today, especially the cross linked frac fluid, are very sensitive to even minute concentrations of many of the additives listed above.

TYPES OF FLUIDS:

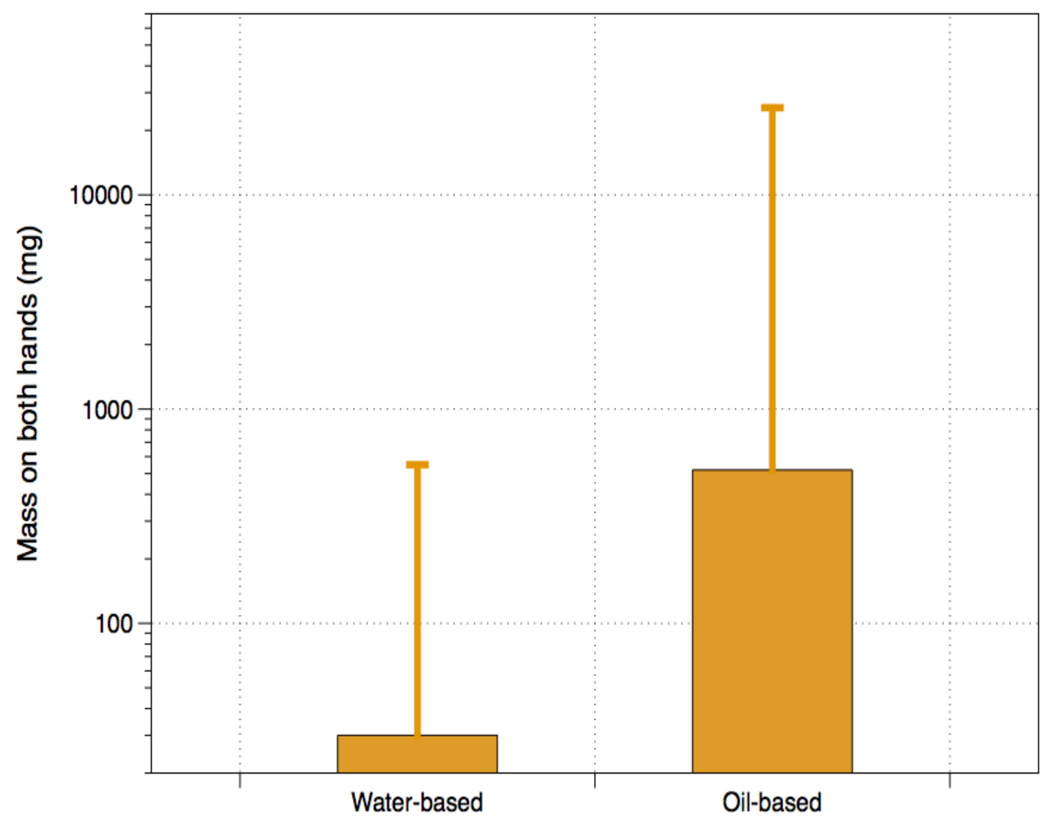
There a many different types of fluids that may be considered for use in fracture stimulation. Early fracture treatments almost exclusively used crude oils or special reined oils to ensure complete compatibility with the reservoir. Water-base systems, the safest and easiest to use, are currently the most common thing.

Water may be used in a wide range of formation types, over a wide range of temperature and pressure, and is generally available at a low cost. The fluid properties may also be easily modified for an additional moderate expense. The viscosity of water is increased by the addition of gelling agents.

- Natural guar gum
- Hydroxypropyl guar
- Hydroxyethyl cellulose
- Carboxymethyl hydroxyethyl cellulose

A linear gel that is, one that does not incorporate cross linking the chemistry is prepared using 10 to 100 pounds of gelling agent per 1000 gallons of water, with the usual concentration level between 25 to 60 pounds per 1000 gallons. This gives viscosity sufficient to carry prop pants through the surface equipment and tubular goods when pumped at normal injection rate, but still classified as a dropout-type fluid in terms of bottom hole performance.

Oil-based fluids lease crude oil is still used for some fracturing treatments because of its relatively low cost and compatibility. It is very inefficient prop pant transport medium and has poor fluid loss control; though like water the performance of crude oil can also be improved with the use of additives. Fluid loss additives can reduce the leak off rate to reasonable values and new generation viscosifiers allow pro-pant transport capabilities on a par with cross linked water caution is advised.



Sources of this picture: johncherrie.blogspot.com

The friction loss of gelled oil is much lower than that of the gelled water, but the surface treating pressures for oils still generally remain higher because of the lower hydrostatic pressure of a column of oil. Lease oil and gelled oils are used primarily in formations that are extremely sensitive to water.

ACID BASE FLUIDS: when fracturing limestones or dolomite formation, acids are sometimes used in conjunction with the fracturing fluids to each flow channels on the formation face.

> The resultant fracture conductivity is quite high, as it is proportional to the width of the etched fracture raised to the third power. Acids having retarded spending rates extent the applicability of this teqnique, but the comparative cost of acid versus prop ants further limits the oppturtunity to realize an economic benefit.

EMULSIONS: Mixtures of oil and an aqueous material are sometimes emulsified and used as fracturing fluids. One such system, commonly referred to as k-1 emulsion, consists of two parts crude oil emulsified in one part of water. This system is an economical alternative, particularly when the cost of crude oil is low. The high viscosity of an emulsion creates wider fractures than does an aqueous linear gel, and assists in reducing fluid leak off and in transporting the proppants.emulsion are especially effective in controlling fluid loss because the fluid that leaks off from fracture is a multiphase mixture. The relative permeability to a multiphase system is always lower than either single phase.Mixures containing as little as 5% volume of a second discrete fluid phase have been effective in limiting leak off.

GAS OR FOAM FLUIDS: Specialized emulsions using nitrogen or carbon-dioxide gas as the inner phase of an aqueous mixture have been commercialized in recent years. These emulsified foams typically contain 70% to 90% gas at bottom hole fracturing conditions. This large volume of gas expands even more during cleanup to supplement the reservoir energy and help with the recovery of injection fluids. The high viscosity of the foam fluid allows it to transport prop pants very efficiently and is especially beneficial in reducing fluid loss. The multiphase composition of the leak off fluid satisfactorily improves the fluid efficiency. The use of foams is especially effective in highly water-sensitive gas reservoirs where the use of oil is impractical. The relatively small volume of water included in foam, coupled with the normally rapid fluid recovery fluid recovery rate, minimize the deter mental effect of using water in a water-sensitive reservoir.

PROPANT AND FRACTURE CONDUCTIVITY:

The most important material used in hydraulic fracturing is the one that remains in the well after the invoice has been paid: the propping agent. And the most important part of the fracturing operation is the placement of this prop pant. All aspects of treatment design should be considered from this viewpoint.

In the previous sections, discussions concerning fracture geometry and how to create a hydraulic fracture void by injecting an efficient fluid system were presented. This section will deal with how to prop open this void and realize the optimum benefit from fracturing treatment.

In order to optimize the impact of a fracture stimulation treatment on the long-term productivity of a reservoir, it is essential that both deep fracture penetration and adequate fracture conductivity are achieved. Design optimization further entails achieving the correct balance between conductivity and fracture length in order to realize the maximum benefit from each. When fracturing very low permeability reservoirs, very long fractures must be created, but it is critical to provide sufficient conductivity to utilize most of the fracture length that is created. When dealing with higher permeability reservoirs, it is equally important to adequately prop the short fracture in order to realize the maximum benefit from the created fracture width.

2.6.1 FACTORS AFFECTING PRODUCTIVITY IMPROVEMENT:

The main documents that determine the extent of productivity progress resulting from the fracture stimulation are

- The geometry of the propped fracture
- The fracture conductivity
- The contrast between the fracture conductivity and the conductivity of the un-stimulated reservoir
- The propped fracture length in relation to the drainage radius of the wall.

PROPPING AGENT:

The purpose of the propping agent is to prop open the fracture after it has been created. It must be capable of holding the fracture faces apart to allow formation fluids to flow through the fracture with a minimal loss of energy, and it must be long lasting.practically,it should be capable of being placed using pumping equipment and a fluid system that are currently available. Preferably it should be readily available. Safe to handle and relatively inexpensive. The propping agent qualities that have proven effective in achieving a consistently high-permeability performance are

- Small, rounded particles
- Uniform size
- High degree of sphericity
- High compressive strength
- High degree of roundness
- Consistent density
- Insolubility in reservoir fluids
- Stability at reservoir temperature.

PROPANT PERMEABILITY:

The prop ant permeability is a measure of the capability of the propant to allow flow to occur; similar in concept to formation permeability. This permeability of the propant is determined in the laboratory by measuring the flow rate through a proppant-filled test cell of finite dimensions at several flowing pressure differentials until steady state flow is achieved the test cell is configured such that elevated temperature and uniaxial loading to stimulate fracture closure may be applied. The cross=sectional area of the test cell is then used in Darcy's linear flow equation to determine the propant permeability. The permeability is generally plotted permeability. The permeability is generally plotted versus the applied stress loadings. It is then possible to calculate the conductivity of this proppant in a fracture of any specific cross=sectional area under actual condition of closure. Standardized API test specification has been accepted by the industry and are presented in API RP 56 "Recommended Practices for Testing Sand Used in Hydraulic Fracturing Operations,"

FRACTURE CONDUCTIVITY:

The fracture conductivity is a measurement of how well the propped fracture is able to conduct produced fluids. Since pressure differential is required to move fluid through the length of an induced fracture, a propped fracture having an insufficient the capacity will limit a well's potential production rate.

Fracture conductivity is determined by the prop pant properties and the resulting permeability of the packed fracture, the effective propped fracture width, and the distribution of the prop pant, the closure stress in the fracture, the rate of pressure drawdown, and the formation properties. In order to select the ideal prop pant for a fracture treatment, it is necessary to understand how these various properties and factors are interrelated.

PROP PANT PROPERTIES AFFECTING PERFORMANCE:

The API has established specifications and testing procedures to ensure that essential proppant properties are met. These standards will be discussed in detail in this selection.
No API standard has been established for defining the minimum permeability performance for each grade of frac sand. But since standards regarding the testing procedures for frac sands have been adopted, the test results for several proppants may be compared to determine which is the most suitable proppant to use in a treatment design.

ROUNDNESS AND SPHERICITY:

Particle roundness essentially refers to lack of angularity. In fracturing proppants, it is determined visually and reported as a Krumbein Roundness factor on a scale of 0.1 to 1.0. A value of 0.1 indicates the presence of acute angles as compared to 0.9 roundness indicating irregular but smooth grain curvature.

Sphericity is measured and reported on a similar basis with 0.01 sphericity indicating the presence of either or both highly convex and concave surface variances, and 1.0 sphericity indicating an almost perfect sphere.

A perfectly smooth sphere would have roundness of 1.0 and a sphericity of 1.0. No naturally occurring proppant has this idealized characteristic. A manufactured proppant having this characteristic is glass beads formed by dropping molten glass through a cool atmosphere.

A well-formed proppant such as Northern white Sand. Its permeability performance curve. The less rounded sand has a slightly superior performance under conditions of low stress because the irregular particles do not fit together quite as closely as the rounded particles. However, as the stress is increased, the loss in permeability is more rapid in the less rounded material because of a higher incidence of particle failure caused by the angularity. After the amount of residue present in the fracture (from the crushed proppant) reaches a critical level, the permeability drops off very quickly.

This particle failure by crushing is believed to be caused. Mainly by small imperfections in the particle sphericity and the resultant random but highly concentrated point-to-point loading that increases as the stress load is increased. These sub rounded points may be easily broken off or may actually “chisel” into adjacent particles, scratching the surface. Like window glass, silica prop pants, especially man-made glass bead proppants, tend to fail at the point where the surface has been scratched. Opportunities abound for the prop pants to be scratched during the handling and pumping operation. But the most likely time for this to happen is during the final moments of fracture closure when the proppant pack is squeezed into a minimum volume and forced to conform to any irregularities in the face of the fracture.

SIZE CONSIDERATIONS: Proppant size is specified as a mesh range, such as 20/40 or 12/ 20. The diameters of the largest and smallest particles in API standard mesh ranges.

The larger the proppant diameter, the greater the permeability will be—up to a point. Compare the perm abilities for 20/40 and larger sands. Even though large particles provide high flow capacities at low closure stress, they are more sensitive to increases in closure stress,

PARTICLE DIAMETER (IN.)

API mesh size	Largest	Smallest
6/12	0.1320	0.0661
8/16	0.0937	0.0469
12/20	0.0661	0.0331
16/30	0.0469	0.0232
20/40	0.0331	0.0165
30/50	0.0232	0.0117
40/70	0.0165	0.0083
70/140	0.0083	0.0041

and the permeability of various sizes of proppants at high closure stresses is essentiality the same, and in some cases even low , than the smaller –sized proppants,. However, this is not true for premium man-made prop pants, which typically have high higher compressive strengths. They show similar proportionate losses in permeability regardless of size.

Another important consideration in selecting the correct size of propend to use is the fracture width required to allow placement of the prop. A hydraulic width equal to 2 1 / 2 times the diameter of the largest particle is considered by many in the industry to be the minimum width that will allow free movement of the prop pant through the fracture. Other engineers consider the minimum width to be three times the diameter of the largest particle. The largest particle in the 20 /40 mesh range has a diameter of 0.0331 in. is required. The larger 12 /20 mesh prop as a maximum fracture width of 0.165 in. , almost double that for the 20 / 40 mesh.

Although the calculated width is theoretically not a function of the formation depth, it has been the experience of the author that the use of large prop pants is more likely to cause near-wellbore screen outs in deep wells than in shallow wells. Furthermore , analysis of the short-term performance of different size prop pants under conditions in which the closure stress is in excess of about 4000 psi confirms that a higher proportionate loss in permeability is realized when using large prop pants. As reported by Montgomery and Sternson, the actual fracture conductivity as seen in the field is considerably less than that calculated from laboratory test. Thus it would seem reasonable to limit the use of large-sized particles to shallow applications.

The use of prop pants larger than 20 / 40 mesh is, for the most part, limited to situations in which the closure stress is below about 6000 psi. More than 85% of all prop pants used today are 20/ 40 mesh or smaller.

Mesh Distribution Grain-size distribution is as important as the grain size. Many pumping service companies have established strict purchasing standards that call for specific distribution of the particle sizes included within a mesh range. The mix is important to allow the maximum permeability to be realized while limiting the point-to-point loading as well as minimizing the invasion of fines. Table 3.2 lists the typical mesh range distribution for a sample of 20/40 proppant.

Proppant permeability is maximized by the use of a narrow range of particle sizes. By controlling the variance in particle size within a mesh range, the particles within the pack are separated by a maximum distance, thus providing the highest possible permeability. Mesh distribution is controlled by the proppant suppliers by passing all the proppant through a stack of vibrating sieves and blending proportionate amounts of each cut. Manufactured proppants are typically sorted to more closely adhere to individual mesh-distribution specification standards, with the discarded off-size material frequently recycled through the manufacturing process.

Chemical/Temperature-Stability:

Extended exposure to high temperatures has been found to adversely affect the performance of most proppants, including man-made materials.

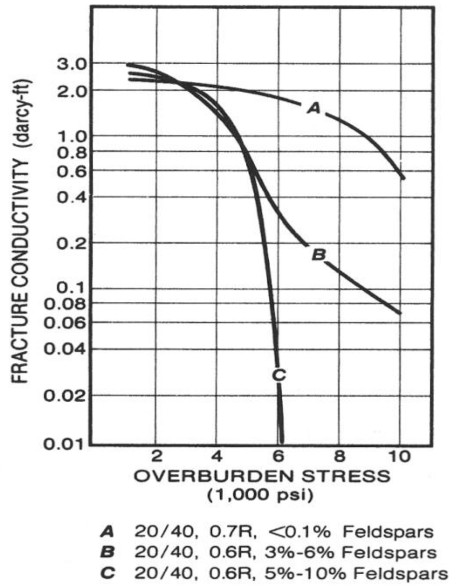
The API standards include a guality control test to measure the solubility of a proppant in hydrofluoric acid. This ensures that sands used as fracturing proppants have minimal impurities, especially feldspars (alumina silicates). Feldspars not only reduce the compressive strength of the proppant, but are sensitive to some formation waters, which causes additional strength degradation after exposure to high temperatures for long periods of time. The maximum amount of feldspars allowed is 2%.

temperature reservoir fluids are currently underway in an attempt to quantify the effects of temperature and time on prop- pant properties. Figure 3.3 shows the effects of feldspars on short-term fracture conductivity.

Density:
Knowledge of the proppant density is essential in order to predict the most probable depositional pattern of the proppant. The manufactured proppants have higher densities than sand and therefore settle faster. This is not a serious concern unless a mixture of different density proppants is used together, in which case they would tend to segregate by density. 'When high density proppants are used, it is recommended that crosslinked (good prop transport) fluids be used to ensure proper placement of the proppant.

Other Proppant Properties:
A strong quality assurance program is practiced by most proppant suppliers and service companies to ensure the proppants used meet the specified standards. This is extremely important when considering that the source of the most commonly used proppant—sand—is open mining excavations.

The practice of utilizing local sand sources because of possible freight savings can prove to be quite costly in terms of potential losses in post-treatment productivity. It is strongly recommended that thorough investigations regarding adherence to all performance standards be undertaken prior to considering a local purchasing program.



3 Effect of proppant quality on conductivity (Courtesy of Dowell Schlumberger.)

Objectives of increased productivity will be achieved. The choice of fracturing fluid influences the performance of the proppants in two distinctly different ways. The insoluble material in the fluid and proppant may damage some of the prop- pant permeability. The viscosity and velocity of the carrier fluid directly affects the final distribution of the proppant within the fracture as the fracture is closed.

Proppant Damage:

The amount of insoluble material present in the frac fluid gradually increases as the fluid moves through the fracture and some of the fluid leaks off into the matrix, filtering out the insoluble material. The insoluble gel residue in guar gum adds to the plugging action of solid fluid-loss additive. Much of this insoluble material is flowed from the well during cleanup and post-treatment production. Even though the particles in question are minute in size and can be flowed through the proppant pack, some particles remain in a tightly compacted mass similar to the filter cake formed during the treatment, and others bridge due to velocity and direction changes throughout the pack. These blockages can restrict formation fluid from entering the fracture or hinder its movement through the packed fracture. This is the main reason that guar gum is being replaced by the cleaner HPGs, and liquid fluid-loss additives are replacing the traditional solid fluid-loss additives (FLAs).

Fracturing fluids that are not compatible with the formation could aggravate the migration of formation fines, which would also inhibit prop pant permeability. Highly incompatible fluid systems occasionally dislodge large-sized pieces of the fracture face. These pieces can crumble, and thereby greatly reduce the proppant permeability. The use of large volumes of acid in formations with minimal solubility would be an example of this problem. Or, surfactants included in the frac fluid may alter the wet ability of the formation and/or the prop- pants, thereby affecting the relative permeability of the fluid. Emulsions forming between the frac fluid and the reservoir fluids could also be detrimental to the productivity of the fractured well. This could be the result of not running the correct emulsion checks prior to a frac treatment. Care is required to ensure the frac fluid selected is compatible with the formation and the reservoir fluids, thus minimizing the occurrence of these problems.

In order to account for this indeterminate amount of damage, a correction factor of 0.30-0.5 times the laboratory permeability value is typically applied to the published proppant data.

This range is generally accepted by the industry as reasonable to account for the combined effects of gel residue, formation fines, and long-term proppant degradation.

Proppant Distribution:

The flow rate through the proppant pack at the extreme tips of the fracture wings is only about 10% to 15% of the total flow rate through the fracture immediately adjacent to the wellbore (Figure 3.4). Therefore much lower fracture conductivity is actually required at the frac tip, and ideally the conductivity would taper evenly to a maximum at the wellbore.

A positive improvement in well performance could still be realized if the proppant concentration were equally distributed from the tip to the wellbore, and not tapered. Even though this is a relatively inefficient use of the proppant, many fracture treatments are designed to provide a constant proppant concentration over the entire propped length. In order to achieve this equal distribution of proppant from fracture tip to wellbore, the concentration of the proppant added to the fluid at the surface during the treatment is incrementally increased to compensate for fluid leakoff. Table 3.3 is an example of a pumping schedule using increasing proppant concentration.

Placement of Proppants:

The productivity ratio of a fracture treatment depends on the distribution pattern of the proppant. The final distribution of the propping agents in a packed vertical fracture depends primarily on the type and viscosity of frac fluid used (a dropout-type versus a transport-type fluid), the flow velocity of the frac fluid, and the size, density, and concentration of the propping agent carried by the fluid.

When using a low-viscosity dropout-type fluid, the proppant will continually settle toward the bottom of the fracture as the fluid moves away from the wellbore due to the low viscosity of the fluid and its resulting poor proppant-suspension properties. A bed of proppant will then be deposited on the bottom of the fracture, gradually building up in a dune-type deposi- tional pattern. The dimensions of this proppant bed will be dictated by the hydraulic frac geometry near the wellbore.

Pump the following treatment at 12 bpm via 2 7/8 in. tubing with an anticipated surface treating pressure of 10,750 psi, observing a maximum wellhead pressure of 14,000 psi.

1000 gallons 15% HC1 as breakdown fluid
6000 gallons linear gelled pre-pad
16,000 gallons cross linked pad fluid
7000 gallons cross linked fluid + 1.0 ppg 20/40 proppant
8000 gallons cross linked fluid + 2.0 ppg 20/40 proppant
9000 gallons cross linked fluid + 2.5 ppg 20/40 proppant
9000 gallons cross linked fluid + 3.0 ppg 20/40 proppant
4180 gallons slick flush.

Pack width will be equal to the dynamic hydraulic width, the pack height will be determined by the critical velocity required to move proppant laterally over the top of the proppant pack, and the propped length will be a function of the total volume of proppant pumped. The pack height will continue to increase after pumping has stopped, since those proppants still in suspension at that point will continue to settle. Settling will continue until the fracture has closed to a width equal to the diameter of the suspended particles, resulting in a significantly different after-closure pack.

Also, as stated earlier, when using this type of fluid, the first proppant pumped is deposited near the wellbore, and the proppant pumped later in the treatment is transported deeper into the fracture.

It shows a potential problem that could result from the use of a dropout-type fluid when no lower frac barrier is present. In this schematic, extensive fracture growth has taken place outside the zone of interest and the final distribution of the proppant pack is largely outside the zone of interest, yielding little improvement in productivity.

When the more viscous sand-transport type of fluid is used, the proppant particles settle only slightly during pumping and the height of the settled proppant pack deposited at the bottom of the fracture during pumping is be very small. Only this small volume of the propped fracture would have a width equal to the original hydraulic width, and it is generally assumed to be identical to the average propped width in calculating the fracture conductivity. The dimensions of the final main prop pack will depend almost exclusively on the amount of proppant that is distributed throughout the fracture at the time pumping is stopped and equilibrium is finally reached. The width of the final prop pack will typically be much smaller than the dynamic hydraulic width and will depend on the unit volume of proppant contained in the fracture void per unit of frac area at the time pumping is stopped. The propped fracture length will depend on how far the leading edge of proppant-carrying fluid has penetrated laterally at the time equilibrium is reached.

The final propped fracture height will be a function of the settling effect taking place during the pumping operation, and continuing afterward until the fracture has completely closed on the proppant, holding it in place.

This capability to suspend solid particles for long periods of time would appear to be extremely useful in designing unique proppant distribution patterns, such as a partial-monolayer placement. This distribution pattern has a much higher flow capacity than a fracture completely filled with proppant and would appear to be an idealized proppant distribution pattern, provided the proppant particles are strong enough to withstand the closure stresses. However, a partial-monolayer placement pattern has thus far proven to be impossible to achieve, particularly in a vertical fracture, due to particle aggregation. Therefore, further discussion will be limited to the performance of a more conventional multilayered proppant pack.

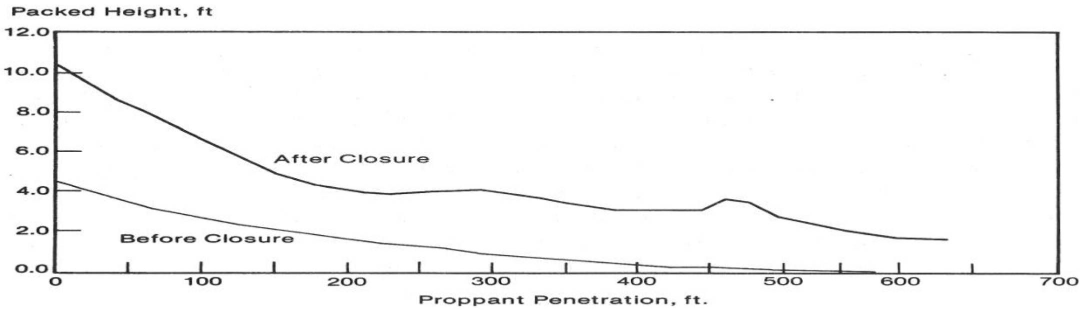


Fig. 3.5 Proppant distribution in fracture.

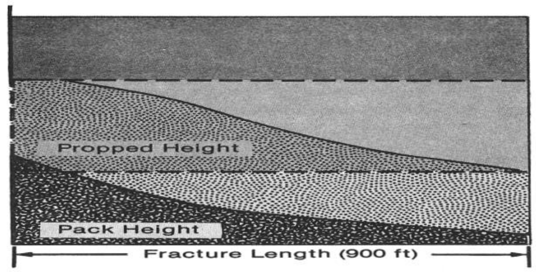


Fig. 3.6 Proppant settling.

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Screen-out Problems:

Regardless of what type of fluid is used, the proppant concentration will gradually increase as the fluid moves away from the wellbore because of fluid leakoff into the formation matrix. A plot of the proppant concentration versus distance from the wellbore, such as that shown in Figure 3.7, is a very useful output option from a computerized frac model.

When the proppant/fluid slurry becomes very concentrated or the frac width is too small to allow the proppant to be displaced further, a screen out will occur.

A screen out condition may occur at any point within the fracture or, infrequently, within the wellbore. A wellbore screen out, generally the result of trying to pump too high a concentration of proppant with a fluid of too little viscosity or at too low an injection rate, causes an instantaneous increase in surface pressure because of the proximity of the blockage to the pumping equipment. A tip screen out, which takes place at or near the extremity of the fracture, differs in that the pressure increase is much slower because of the large volume of fluid between the blockage and the pumps, and because the large open fracture opens even wider as the pressure increases; also, fluid leak off continues over the entire exposed fracture face.

A true tip screen out is usually caused by insufficient fracture width at the fracture tip, which may result from using a not- large-enough pad volume or a pad fluid sufficiently viscous to open the fracture ahead of the proppant-laden slurry. A near tip, or intermediate, screen out could also be caused by a greater-than-anticipated leak off rate of the pad fluid or the carrier fluid, which would reduce the fracture width and, therefore, the volume of the fracture void that is available to accept the proppant. In the author's opinion, excessive leak off is the most common cause for a screen out. The Inordinate fluid leak off can be the result of common factors, including

o A formation permeability greater than that of the design o a gross fracture height greater than that of the design o the presence of unexpected natural hairline fractures intersecting with the induced fracture o a greater-than-anticipated differential pressure o a higher-than-anticipated temperature, which reduces fluid efficiency

o An injection rate lower than that of the design o inattentiveness to fluid specifications during mixing

These critical factors should be reviewed carefully when designing a frac treatment, and taken into consideration continually throughout the treatment.

Tip screen outs may be prevented by using a sufficient volume of efficient pad fluid. Enough pad fluid should be pumped to create a fracture width at the leading edge of the proppant slurry adequate to allow two proppant particles to be carried side by side. A general rule for this value is 2 1/2 to 3 times the width of the largest particle. A proppant concentration exceeding 18 lb of sand per gallon of slurry volume is generally considered unpumpable. These values may be considered design limits.

If a tip screen out occurs, the pressure may increase slowly enough to allow enough solids-free flush fluid to be pumped to clear the wellbore before the maximum pressure limit is reached. Clearing the wellbore in this manner may make it unnecessary to move a rig back in later just to remove the proppant from the wellbore; plus, it will allow the frac fluid to be recovered in a timely manner as per the design program. However, extreme caution should be exercised and the previously established pressure limit should be closely observed. The pressure limit is established to prevent rupturing the wellbore tubular goods and/or to prevent vertical fracture growth through an adjacent formation barrier. Uncontrolled vertical fracture growth could be especially damaging if nearby formations contain undesirable fluids or low pressures that could dissipate the target reservoir's producing energy. Provided the proppant-blending schedule has been followed correctly and excessive vertical growth has not taken place, the well performance should be greatly improved.

As a general rule, the proppant slurry volume should not be over flushed, nor should the proppant addition be stopped and restarted during a fracturing operation, especially when using a frac fluid that has excellent proppant-suspension properties.

Reservoir Dimensions Causing Prop-pant Performance:

After the correct proppant has been placed according to the design plan, several reservoir characteristics must be taken into account before predicting the in-situ permeability of the proppant pack.

Formation Effects:

The formation properties are important not only because some of them determine the hydraulic fracture width, but because some soft formations may actually be crushed or deformed by the propping agent and become embedded in the proppant pack.

If the frac fluid is non-reactive and no proppant is used, the induced fracture will slowly "heal" due to the elasticity of the formation, and lose conductivity. Similarly, if proppant is used but is over flushed away from the wellbore at the end of the treatment, the same healing process can occur in the near- wellbore fracture area and the productivity improvement will be nonexistent, or at best short-lived. This effect is most pronounced in softer formations having lower module of elasticity. When predicting the expected productivity improvement from a conventional fracturing treatment, it is essential to consider only that portion of the fracture geometry that is effectively propped and connected to the wellbore.

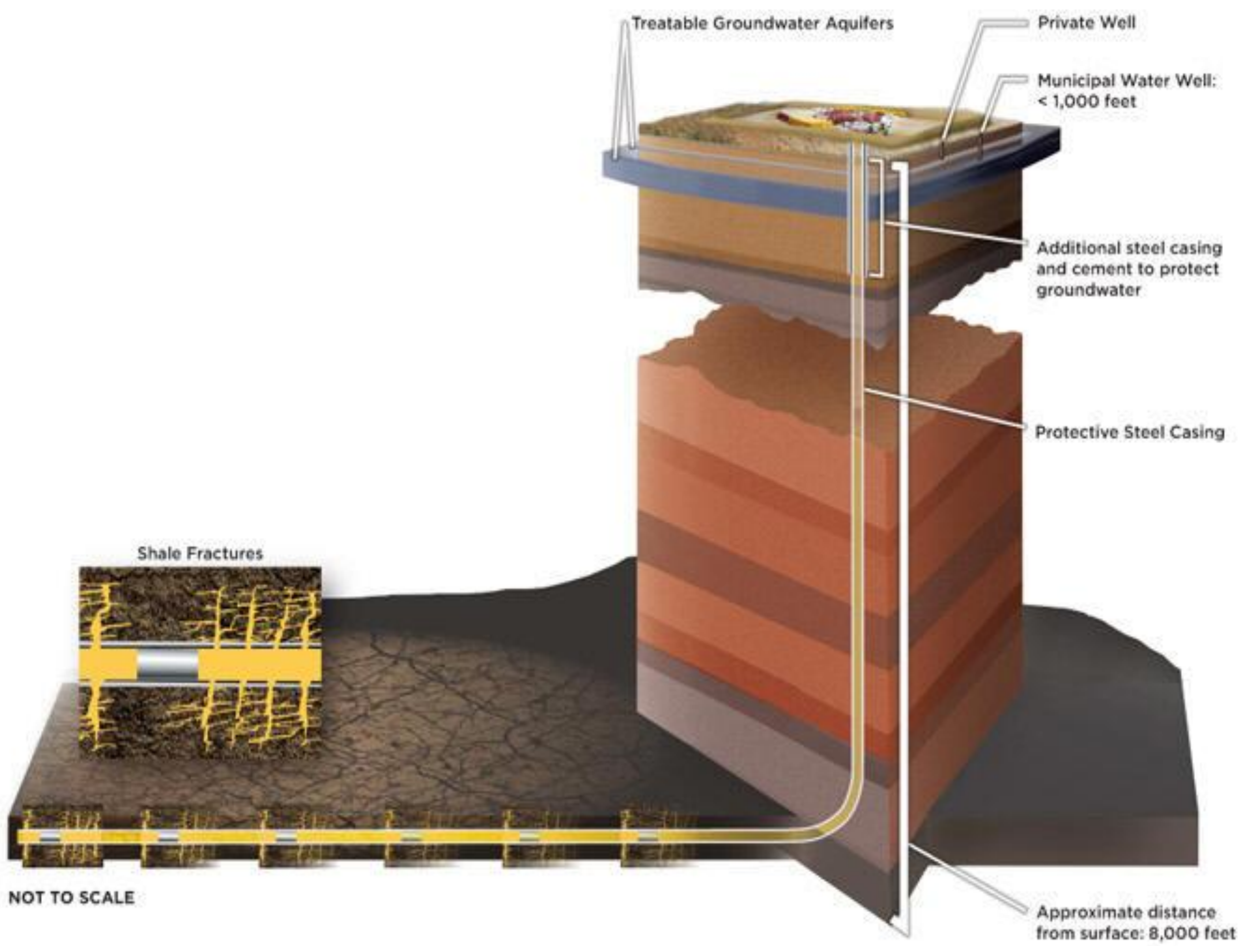
The Formation permeability is used to calculate the dimensionless fracture conductivity (F_{CD}):

$$F_{CD} = \frac{K\,w}{K\,x_f} \qquad (3\text{-}D$$

This is the key equation used in matching the fracture permeability and an associated fracture length required to realize a maximum benefit from a fracture treatment of a formation having a known permeability. The dimensions of an idealized fracture that would satisfy these conditions could vary greatly, but by assigning realistic values for one or two of these dimensions, the value of the remaining unknowns can be easily determined graphically, to solve for the necessary design dimensions.

SAFETY LIMITATION:

Safety is of paramount importance throughout the fracture treatment. All pumping service companies have stringent standards that must be adhered to regarding pumping operations. The standards may differ depending on the type of fluid being pumped.



Source image from: http://www.energyindustryphotos.com

COST CONSIDERATION: To determine which is the most economical fluid for a fracturing treatment, it is necessary to evaluate several different complete fluid systems. It is also necessary to consider the rate at which the expenses are recovered and the total returns on the fracture treatment investment.

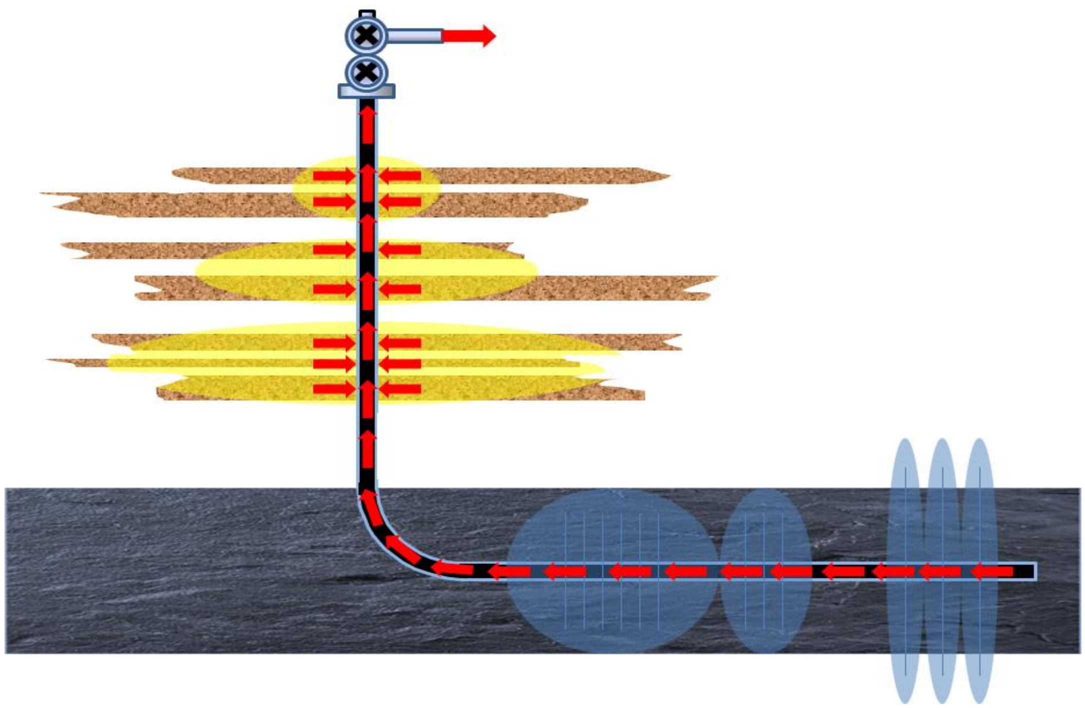
FRACTURING ADDITIVES: Most of the fracturing additives used today are designed for use in water-base fluid, since this type of fluid is used for most fracturing treatments. The most commonly used additive is a viscosifier.A great many commercial water-base viscosifiers are currently in use, but the most falls into one of the categories are Guar gum has been available in several forms for many years and is still one of the most commonly used viscosifiers.this material is processed from the commercially grown guar bean. During the rather crude refining process, some of the insoluble husk is ground and mixed in with the desired end product. This insoluble material, accounting for about 9-13% of the total solids content, serves to supplement the fluid-loss additives, thereby improving the efficiency of the frac fluid. There is concern in the industry regarding the possibly detrimental effect to these insoluble materials on the conductivity of the prop pants.

This high solids content is the primary reason that alternative gelling agents have been developed.Hydroxypropyl guar product is a manufactured material that has total insoluble solids content accounting for less than 3% of its total weight. The viscosity development and fraction loss properties of guar and HPG are about the same. Most water base fracs use one of these two viscosifiers.

Cleaner viscosifiers,namely hydroxyethyl cellulose (HEC) and carboxymethyl hydroxyethyl cellulose (CMHEC),contain less than 1% insoluble materials.

CHAPTER 3. DESIGNING FRACTURE TREATMENT

Several fracturing treatment designed today utilize complex computer simulators and sophisticated mathematical models to determine the optimum treatment design. a few of the expensive fracturing operations that are performed today do not apply either of these design aids, but simply use a carbon copy of the frac program pumped into another well at another time, with the optimistic attitude that "if it work once, it should work again."



Sources of image: phoenix-sw.com

3.1OPERATIONAL CONSIDERATIONS: It may impose limits on the hypothetically optimum treatment defined by a computer simulator. Take these factors into account prior to undertaking a job design in order to avoid unnecessary work and embarrassment. Operating conditions encountered on offshore locations frequently impose additional economical and unique logistical consideration on fracturing program design. Special equipment, however, has been developed for offshore use, including completely self-contained frac boats and continuous-mix fluid systems, so offshore limitations are primarily those of economics rather than operational logistics.

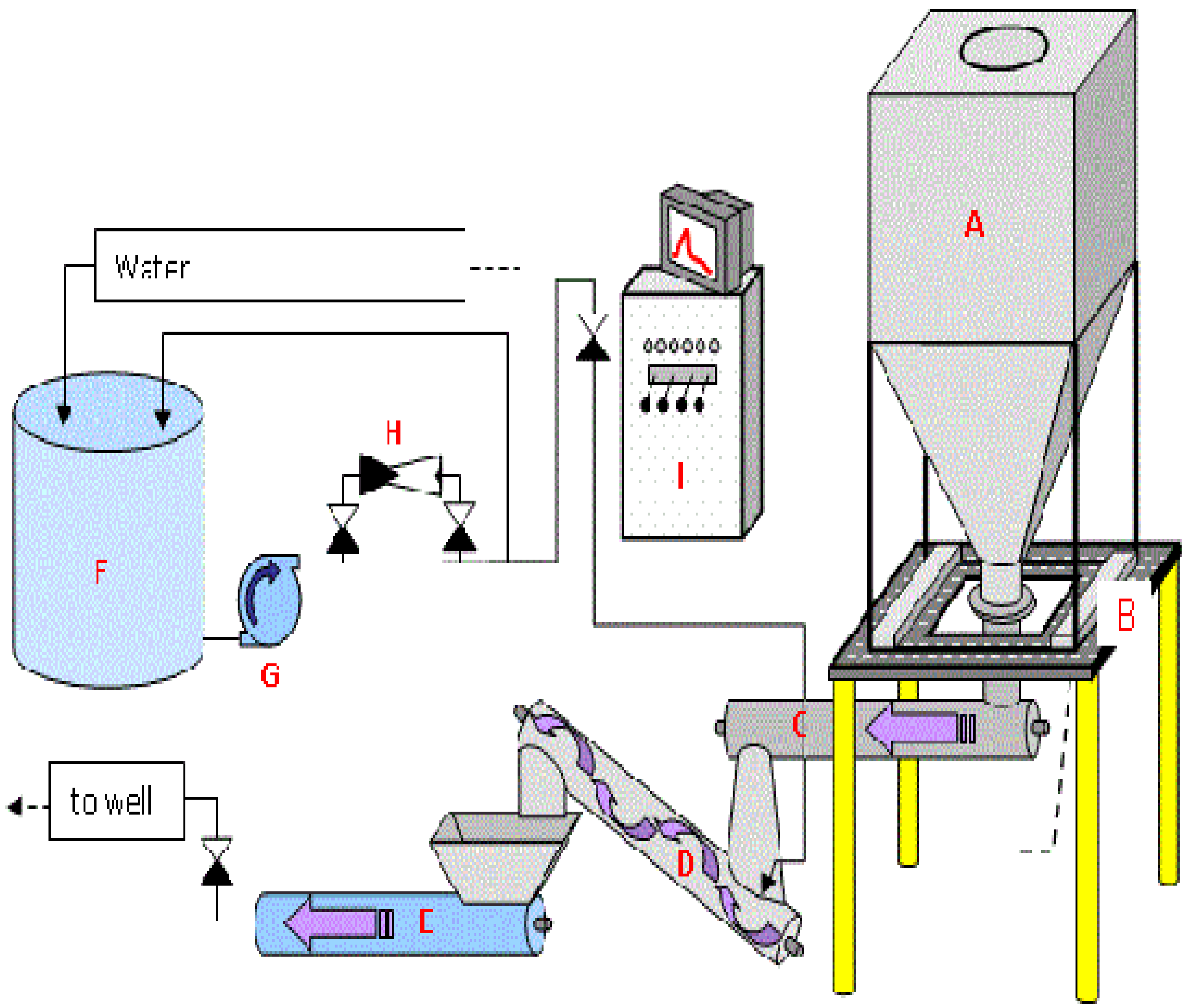
3.1.1 SURFACE LOCATION: The size needed to drill and shape of a surface location required for a fracturing treatment is quite different from that needed to drill the well. Although generally the drilling locations required for deep wells are large enough to accommodate all the frac pumps and associated equipment.

Source image from: http://fracfocus.org

Small shallow hole locations frequently impose severe space restrictions, especially if the rig is still on location. The rig should be moved off the location, whenever practical, to make more room during a frac treatment. Alternatively, it should be shut down during the pumping operation for safety purposes.

The safety standards used by the industry to protect personal and equipment define the minimum distances that should be maintained between the wellhead and potential ignition sources. They specify that the storage facilities for treating fluids should be located a safe distance from the wellhead and from potential ignition sources if the frac fluid is flammable.

Sufficient space must be available to spot the blender, the prop ant storage facilities, frac pumps, and the pumping manifold and recording centre. And leave enough room for personal to move among the equipment. The equipment that will be in operation during the treatment should be located cross-wind to the wall to further minimize the possibility and potential severity of fire in the event of an accident. More room must be reserved for logging equipment involved in overall structures. Sometimes it's necessary to enlarge the location prior to frac treatment, or to use space adjacent to the hard pad.the cost of any special preparation as well as other eventualities must be taken into account when finalizing the treatment costs.



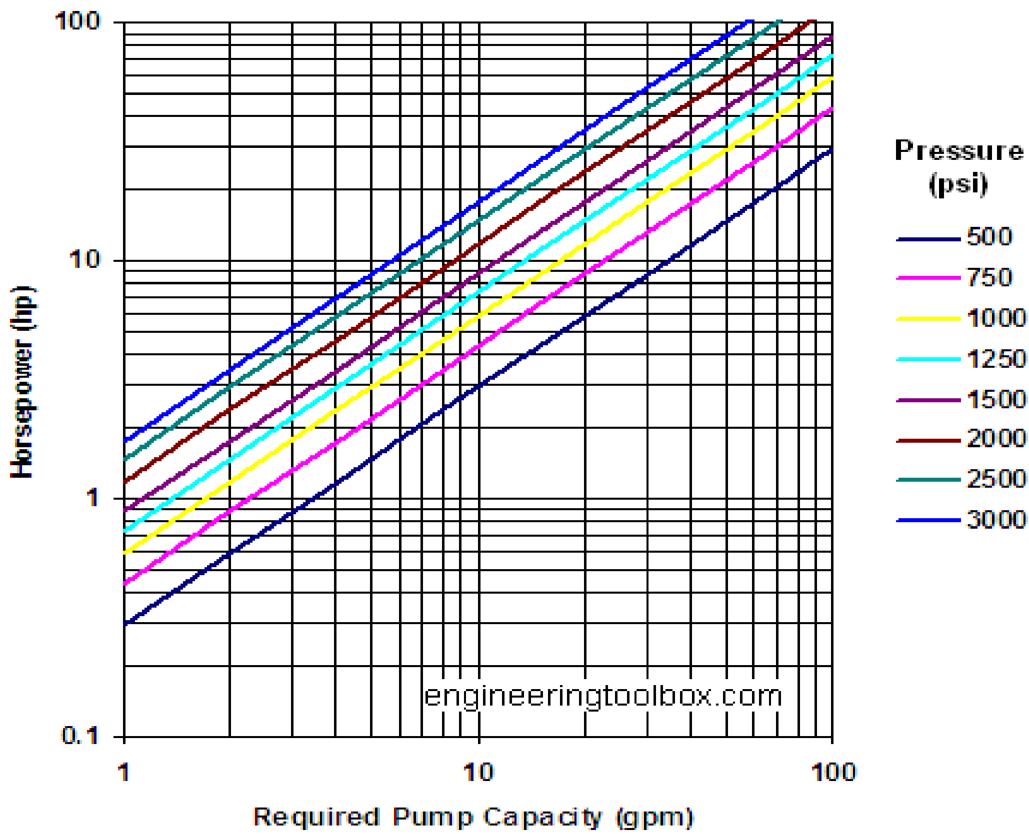
Typical process flow schematic, Major components: A. Solids Hopper, B. Load Cell, C. Solids Metering Auger, D. Mixer Auger, E. Injection Pump, F. Gel Tank, G. Gel Transfer Pump, H. Educator (for gel preparation), and I. Control Stand with data acquisition equipment.

Source image from: http://www.frx-inc.com

3.1.2 Wellhead Equipment and well configuration

Source image from: http://kazpetromac.kz

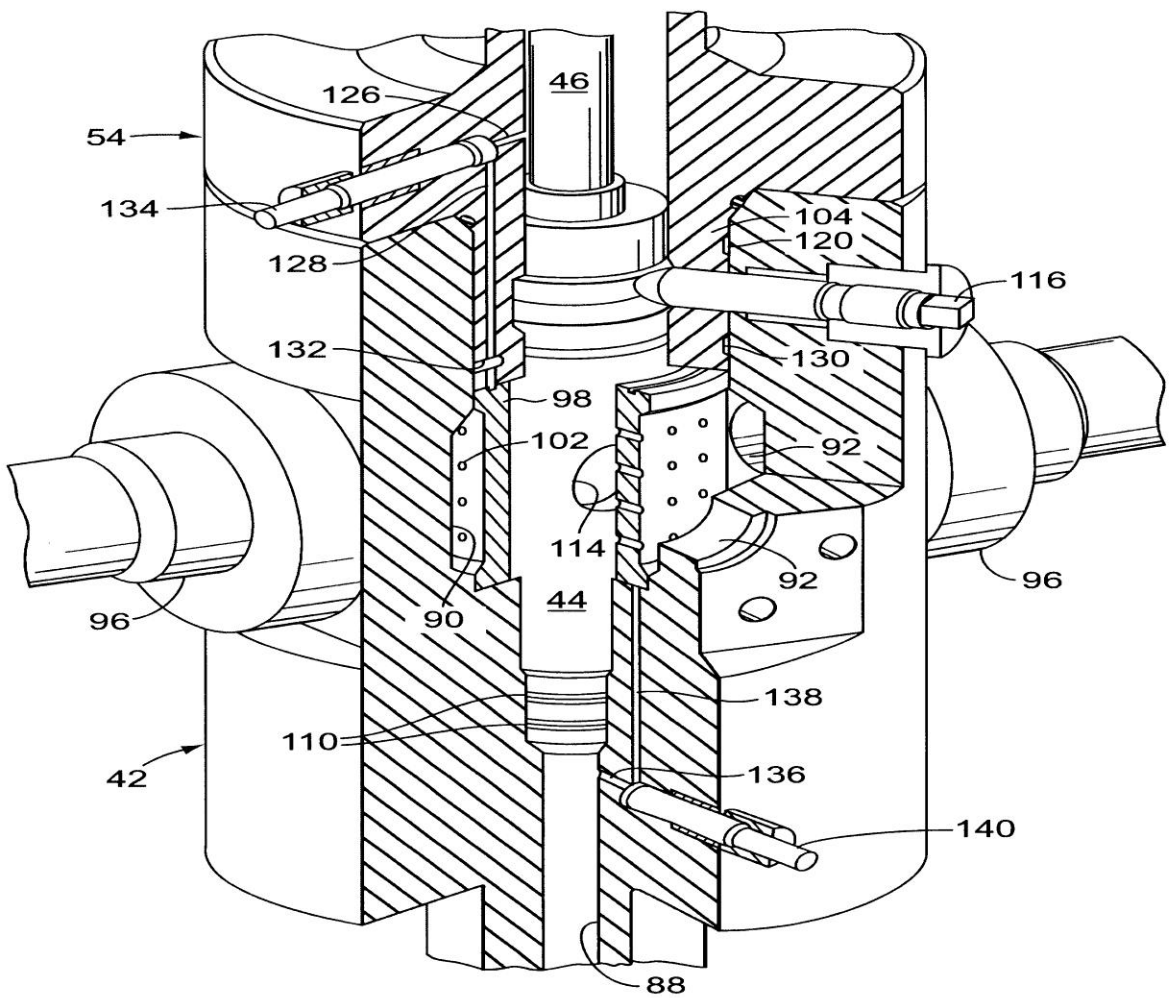
A Fracturing treatment is normally pumped at high surface pressure, with the actual pressure predicted by the formula. The effect of possible pressure variances during the treatment should also be taken into account. A maximum treating pressure that will protect the tubular goods and prevent fracture growth through defined barriers should be established. The actual treating pressure cannot be accurately predicted when the program is written, the maximum pressure increase owing o fracture extension that can be accommodated prior to breaking down these barriers should be readily available at the job site. It can then be used to finally calculate the maximum pressure limit.



3.1.2 Source of the image: engineeringtoolbox.com

A graph such shown in the fig 3.1.2 can be used to select possible rate and pressure combinations available with a prescribed amount of horsepower,or to determine the probable impact of losing some horsepower during the treatment.

The fracturing pressure will probably be the highest pressure to which the wellhead will ever be subjected. The wellhead equipment selected must have a pressure rating adequate to accommodate the anticipated fracturing pressure plus a significant margin for error. It may be necessary to install a special wellhead just for the fragment and change it later,or use special high pressure wellhead isolation tools.



3.1.3 Well head isolation tool

Source image from: freepatentsonline.com

Well head isolation tool is used to protect the production equipment from high pressures and excessive erosion during the fracturing operation.

The size of the tubing string in a well is a critical factor in fracturing operations as well as in production. The production tubing should be specially designed to handle a frac if such a treatment is being considered in the well completion. If the tubing is too small, the friction losses would be excessive, therefore by increasing horsepower requirements or restricting injection rate. Either these conditions could increase the total fluid volume required or could possibly even lead to a screen out because of the tremendous pressure losses incurred. The minimum recommended tubing size for a frac job is 2 7/8inches. pressure sometimes held on the annulus above a packer to provide a tubing-burst safety factor.

$$\Delta F = (Ap - A_i)\,\Delta p_i - (Ap - A_o)\,\Delta p_o \qquad \text{(eqn 3.1.4)}$$

Using this equation we can calculate the upward force acting on the packer. The use of a hydraulic hold down is recommended to prevent this. The buoyant tubing weight set down on the packer also acts to reduce this force.

3.1.4 TIMING: A successful frac treatment is the result of detailed planning and though pretreatment organization. The key element is good communication between involved participants, including the pumping service, rig supervisor, trucking contractors,downhole tool service company, supplier of frac tanks, logging company, and the company representative.

Flow Rate (gph)	Tubing size (inch)	Loss of Head (inch per 10 ft. of tubing)
475	3/4 inch	14.4 inch
800		38.4 inch
800	1 inch	9.6 inch
1200		22.8 inch
1600		40.8 inch
1600	1.25 inch	13.2 inch
2400		25.2 inch
1600	1.5 inch	3.6 inch
2400		8.4 inch
3200		14.4 inch
4000		18 inch
3200	2 inch	4.8 inch
4000		7.2 inch
4800		9.6 inch
5600		12 inch
6400		16.8 inch
7200		20.4 inch

Source image from:pondusa.com

Total Head

The higher the pump must push the water, the less water will be pumped. The terms head or lift are used to indicate the rise, measuring how high the water must be pumped for a particular application.

The time required for each facet of the operation depends on the size and complexity of the job, and on local conditions. The freshly cleaned fluid storage tanks are the first pieces of the equipment to be set on location. They should be spotted by the fracturing supervisor in a level area of the location that meets the company safety standards and allows the proper set up for the prop pant and pumping equipment. They should be filled with type of fluid recommended by the fracturing service company. Making sure that there is enough for an extra stage of flush or for other unplanned contingencies for treatments involving large amounts of prop pants, the prop storage facilities will be large portable tanks that are filled after being set on the location. On small treatments, the prop ant is usually transported to the location in trucks along with the pumping equipment, and poured from these trucks directly in to the blender for mixing, the pumping equipment is normally brought to the location on the morning of the job and hooked up in a few hours while the frac fluid premix is underway, exceptionally large treatments or critical operations may require an extra day to set up all the equipment. The actual pumping operation may require only few minutes or few hours, but preparing for the frac job may take several days or week.

4.0 CONCLUSION AND RESULTS

AFTER THE TREATMENT: one of the most important portions of the frac treatment is the cleanup operation after the job to remove the frac fluids from the reservoir. This is frequently a laborious efficiency of gas well, where the low displacement efficiency of gas does not push the fluid from the well at a high rate. These results in exceptionally long clean-up periods and may cause undue production restrictions. The use of an appropriate surface tension reducer helps to minimize these problems.

The well should be shut in the specified period of time after pumping is stopped to allow the fracture to close on the prop-pant and the fluid viscosity to reduce. Closure time is the time required for the fracture to heal and hold the proppant securely in place. Closure time can also be observed on a highly sensitive surface pressure recording as the time when the slope of the pressure decline curve changes.gel and cross linked fluids incorporate a breaker that causes the fluids incorporate a breaker that causes the fluid viscosity to deteriorate so it will flow back to the wellbore more easily. The breaker concentration can be varied throughout the job to provide faster breaking action for the last fluid pumped, with the idealized objective to match the break times for all the frac fluid pumped and trigger the break to occur about an hour or so after the fracture has closed. For large treatment, a larger safety margin is required and the break time may be set for several hours after the planned closure time.

Very soon after the fluid is broken it should be flowed from the well, using a small surface choke to control the fluid production rate and minimize the pressure drawdown through the packed fracture. The fluid velocity through the fracture should be kept low, but the fluid should be effectively recovered in as short a time as possible. Flowing the frac fluid back too fast could cause excessive drawdown, which can be crushing the prop ant near the wellbore. The formation in the vicinity of the created fracture will be temporarily pressurized because of the frac fluid leakoff.short shut in times allow this induced energy to be used during flowback.rapid fluid recovery is also advisable because excessive shut in time allows the fluid to migrate further into the reservoir.unrecoved frac fluid can restrict productivity. The major uses of surfactant in the fracture fluid, in conjunction with a small shut in time, appear to be helpful in shortening this effect.

An energizing gas may be included in the frac treatment to hasten the fluid recovery time. If the use of gases is impractical, a swabbing unit should be available.

Shutting in a well during the cleanup period, even temporarily should be avoid when possible. The use of a variable choke the critical cleanup period is recommended to avoid having to close in the well to change chokes. This is especially important for acid fracturing treatments in low-permeability gas wells because the un-dissolved solids can fall out and block the etched flow channels.

DESIGN PARAMETERS:

The information about the reservoir and the individual well under consideration must be gathered before an attempt is made to design the optimum fracture stimulation treatment for the particular well. An example of the type and amount of information that should be considered for job design purposes is given in the sample input data sheet. This example computer data sheet lists all the information currently required for application of an experimental three dimensional mathematical fracturing design model.

RESERVOIR CHARACTERISTICS:

Drill stems tests or other pressure transient tests should be run on a reservoir prior to fracturing a well. The information derived from these tests is invaluable in determining the static reservoir pressure and the actual reservoir permeability effective to the produced fluids. a test on a flank or edge well is especially useful because the results confirm whether the well is located within the established reservoir or in a separate, limited reservoir. In addition, the producing capability of the well.

EQUIPMENT SELECTION:

The basic equipment components required to perform a frac treatment are high-pressure pump trucks, blender, and storage equipment. Most frac treatmentments also involve the use of a wide array of auxiliary support equipment, which makes the job easier. For an offshore situation in which the equipment must be temporarily installed on a flat barge, the equipment should be skid-mounted rather than mounted on trucks, to keep the centre of gravity as low as possible.

Fracture Pump Truck

Sources for this image: sjpetro.en.china-ogpe.com

BLENDER TRUCK

source for this picture: fracturing.ru

PUMP TRUCKS:

The pump trucks used for fracturing include a high-horsepower prime mover driving one or more positive dis-placement high-efficiency triplex pumps mounted on a heavy duty oil field chassis. The fluid end of the pump is designed to operate over a sizable pressure range with the transmission system giving a relatively constant horsepower performance. The fluid end of the pumps can easily be changed to extent the performance range of the pumps. Some pumping equipment is operated from remote control panels to facilitate overall treatment control and improve safety conditions. The output performance of these units is typically in the 800-1500 horse power range, with some units having two prime mover/pumps installed on the same truck chassis.

Because these specialty units are unique to the oil industry, most of them are manufactured by the pumping service companies themselves. The pump truck is high pressure equipment is normally rented for each treatment on an hourly basis with the total pumping charges determined from the total hydraulic horsepower (HHP) developed .the extreme operating conditions encountered when pumping prop ant/fluid slurries at high pressures,atleast one extra unit should be available as a standby for most work. For some work with long pumping times, as much as 100% excess horsepower should be kept in reserve.

$$HHP = 0.0245 \times P \times Q$$

BLENDER:

The most critical piece of equipment in fracture stimulation is the blender. This unit transfers the frac fluid from the storage tanks, blends the proportionate amount of prop-pant and chemical additives with the fluid, and pressurizes the suction of the high-pressure pumps with this slurry. Since all the fluid and prop-pant must go through this single unit, its continuous operation is essential to the success of every frac treatment.

PROP-PANT SELECTION: The prop pant selection process may be handled manually by use of the procedure using type curves.

The first step in this procedure I to decide on the treatment objective. The prop pant design for a fracture intended to give a high initial productivity level with minimal regard for the long-term productivity of the well could differ considerably from the design intended to accomplish long-term stable productivity. The dimensionless time function corresponding to the critical time and then either the desired cumulative production or production rate may be used to calculate the appropriate dimensionless terms,

Precious fracture optimization includes determining the optimum value for the dimensionless fracture conductivity (fcd) that will give the desired objective.

Service company data regarding the permeability performance of various proppants versus closure can then be used to calculate the resulting fracture conductivities, after applying an appropriate permeability correction factor believed representative for that formation, the fluid type and reservoir conditions .The results of using several different prop pants should be considered for various frac widths in multiples of 0.1 in. The practicality of attaining the required fracture width must also be considered when determining the best proppant choice. Then this information may be used to select the most economical proppant to use. Sources

t_{Dxf}	F_{CD}
1.0	3
0.01	10
0.01	30
0.001	50
0.0001	100
0.00001	500

Evaluating the fracture treatment all information related to a fracturing treatment should be routinely collected and analyzed in order to improve subsequent treatments in the same field. The effect of each fracturing treatment should be evaluated periodically in relation to those of other wells in the field so that the predicated results can be compared with actual post-frac performance .In this way, improvements may be incorporated into subsequent treatments in the same or similar fields to prevent recurrence of identical problems.

Post-Treatment Fracture Height Determination One of the most useful tools commonly used in conjunction with fracture stimulation is a temperature survey to determine the fracture height at the well bore .This survey is conducted shortly after pumping has ceased; it measure the change in bottom hole temperature that ha taken place because of the large volume of fluid injected into the formation. This method is sometimes replaced or supplemented with a radioactive tracer log to detect the presence of some special proppant that has been coated with a radioactive isotope. Both of these logging surveys used to assist in the evaluation of a frac treatment. Both techniques have been successfully utilized in determining the fracture height, although they are both subject to errors in interpretation. The determination of the fracture height is essential for use in the fracture length determination methods discussed below.

POST-TREATMENT FRACTURE LENGTH DETERMINATION:

Deals with use of type curves to compare as well's post frac production data with a family of type curve that have been prepared for a specific field or application using a mathematical simulator. In the study discussed in this paper, they used a special simulator for massive hydraulic fracturing (MHF) applications to analyze low-permeability gas wells fractured with large treatment. A unique aspect of this investigation was the derivation of type curves representing fractures having the derivation a finite flow capacity, the determination of fracture geometry with the use of type curves involves finding curve having an identical shape as the subject well data plot at the sane dimensionless time.

In addition to good post-treatment production data and confirmation of the actual fracture height, type of analysis requires good pretreatment information about the formation pressure and permeability. The utilization of the various tools available to analyze fracturing results is one of the most important factors in improving the science of hydraulic fracturing.

COMPUTER SIMULATION IN FRACTURE TREATMENT DESIGN:

The effective design of a fracturing treatment deals with the comparative analyses of several complex subjects frequently requiring simultaneous solution of mathematical relationships. The use of computer programs is almost imperative is the design engineer is to have sufficient time to be involved in other projects. All pumping service companies and several operators have developed their own software programs that, although somewhat different, are useful in fracturing treatment design. Until a method has been devised to more closely evaluate the performance of fracturing treatments, and until this same technology can be incorporated into the design model, it will be impossible to say which model is most accurate.

PROBLEMS:

1)Assume that the reservoir described in the preceding problem is bounded above by a very small shale zone and a 40ft thick formation having a pressure of 3000 psi,instead of having the described Effectiveness upper barrier .All other formation properties of this upper zone are essentially the same as the same as the target reservoir. What would be the effect of this change on the resultant frac height?

- Even though the shale barrier may not be an effective barrier(due to its thinness),the low=pressure formation would be more difficult to fracture than the target zone, so frac height would be identical to before:130ft,with 50ft of the frac growth in the lower zone.
- If the pore pressure in the upper zone were equal to or greater than the target zone, then frac growth would continue to extent up into this zone as well, and the total frac height would be at least 170 ft,assuming the treatment rate would cover this much open fracture. If the next zone above was not a suitable barrier,even greater vertical height growth would take place initially…

2) Estimating the frac gradient for a well 7800 ft deep with a reservoir pressure of 3600 psi.

Pfg =X + (1.1- x) Po/D assuming X=0.5 Psi/ft

Pfg=0.5 +0.6 x 3600/7800

Pfg=0.777 Psi/Ft.

3) A preliminary datafrac treatment on an 8000ft well had the following pressure record when pumping slick fresh water down 27/8 tubing:

BPM=barrel per minute

PSI=per square inch

1) Surface treating pressure at 5 bpm -3300 PSI

2) Surface treating pressure at 10bpm-3900 PSI

3) Surface treating pressurre at 15bpm-4500PSI

4) Surface treating pressure at 20bpm-2800PSI

15 minute shut in pressure - 2200PSI

a. What is exact fracture incline for this well?

b.Estimate the surface treating pressure to treat this well at 20bpm using a water-base farc fluid.

Solution:

a.FRAC GRADIENT=Pfg=ISIP+Ph÷D

$2800+(0.433\times8000)/8000=6264/8000$

Pfg=0.783 psi/ft

b. The surface treating pressure at 20 bpm would be approximately the same as during the data-frac when pumping at 20 bpm; therefore it would be about 5000 psi

3) What general Conditions would it be advisable to consider using the following proppants?

- A.SAND?
- B.ISP?
- C. Bauxite?
- D. Acid?

Sand is always used for logging at depts. of 8000ft or less, with the closure stress is less than 6000 psi.

ISP: Used at any depth where high conductivity is essential but is most generally considered for use under conditions where the closure stress is between 6000 and 9000 psi, assuming it is the most economical choice.

Bauxite: eventually considered only when a change occurs, in which the closure stress reach excess of 9000 psi.

Acid: fracturing is a given primary consideration when the target zone is a severely damaged, soluble formation where prop pants have typically given some operational problem although local economical and logistical considerations typically have a very large impact on final decision.

SUMMARY:

Proper design of the fracturing treatment requires that the design engineer investigate all aspects of the reservoir and individual well, taking each potential problem into consideration. Compromises are mandatory, since all solution cannot be compatible. It is here that experience and knowledge must be used to determine which potential problem is most likely to occur, in which would be most damaging. Research of previous similar direction is very useful and the dissection of successes.

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