DEVELOPMENT, DESIGN, AND RESULTS OF HIGH SAND CONCENTRATION FRACTURING TREATMENTS

John E. (Chick) Smith
Consultant

ABSTRACT

Marked advancements have been made during the past four decades since the first commercial hydraulic fracturing treatment was performed in 1948. The high sand concentration fracturing process is one of the most dramatic of the advancements that have been realized. The central thesis of this paper is the evolution of the high sand concentration fracturing process, and the paper is composed of the following three catagories.

1. Development. The high sand concentration fracturing process is presented from its conception in 1960, thru the first experimental treatment in 1972 and the first complete successful treatment in 1976, to the present status of the process.

2. Design. An overview of the procedures and mechanics required to design and perform a successful high sand concentration fracturing treatment is presented.

3. Results. Initial and long term production increases are presented for high sand concentration fracturing treatments, and where possible, they are compared to conventional sand concentration treatments.

INTRODUCTION

Since the formal introduction of hydraulic fracturing to the petroleum industry in 1948, the technique has increased in prominence each succeeding year until it is now the most popular method of well stimulation. In many areas, it is the only technique which will substantially increase production and make commercial wells. Other than the major application of the creation of fractures to improve the producing rate of oil and/or gas from low permeability formations, the process of hydraulic fracturing of underground formations has found additional widespread geotechnical applications during the past 20 to 30 years. The additional applications are as follows:

1. Fracture stimulation of water wells. This includes production, injection, supply, and liquid waste disposal (both toxic and nontoxic) wells. If the disposal waste is toxic, it is essential to know the shape of the fracture to avoid contact with nearby permeable formations.

2. Fracture production and injection wells in secondary recovery projects to increase performance and recovery by controlling sweep efficiencies.[1-5]

3. Fracture production and injection wells in geothermal energy reservoirs in hot, dry rock formations.[6] This consists of injecting water down the inlet wells to be heated in the rock mass and then produced back at the surface through the outlet wells. Prediction of fracture growth behavior is essential in determining the performance and efficiency of the reservoir.

4. Mini fracturing prior to performing a massive fracturing treatment is effective in determining the actual stress gradients in the formation to be fractured and the surrounding formations.[7-12]

5. Mini fracturing prior to designing and installing mines or large underground structures is serviceable in determining the actual stress gradients in the rock and soil surrounding the mines, dams, structure (bridge and building) footings, etc.[13]

6. Mini fracturing prior to performing in-situ leach, solution mining, etc. projects is a useful tool in determining the actual stress gradients of the formation to be leached or mined and the surrounding formations. This process was used by the writer in uranium in-situ leach projects in Northern New Mexico and South Texas.

During the last 10 to 15 years, the history of hydraulic fracturing illustrates that dramatic progress has been made in the process.[64] The ability to develop concepts that produced improvement in design techniques grouped with laboratory developments gave considerable insight into what was required to achieve maximum economic efficiency in fracturing operations. Development of polymer chemistry coupled with parallel developments in mechanical technology allowed the service companies to meet the demands of the petroleum industry for treatments of greater magnitude. In some areas treatments as large as over two million gallons of fluid and over three million pounds of sand have been performed. Injection rates from 5 to 100 bbl/min are not only common but are performed with a minimum amount of difficulty.

Part of the progress that has been realized in hydraulic fracturing theory and performance is known as high sand concentration fracturing treatments. This fracture stimulation procedure takes advantage of the sand carrying capacity of modern crosslinked polymers and modern sophisticated storing, transporting, blending, pumping, and metering equipment. Currently, it is not infrequent with proppant concentrations averaging 5 to 8 lb/gal that a low concentration of 1 lb/gal is used at the start of a treatment; and toward the end of the treatment, the concentration may be increased to 14-16 lb/gal. Fracturing equipment became extremely sophisticated in order to meet the need for proportioning a large number of dry and liquid additives, then properly blending them into the base fluid as well as adding the various concentrations of frac sand or other propping agents. Often sand concentrations as high as 20 lb/gal are mixed. In order to handle large volumes of frac sand, special storage facilities and transporting equipment have been developed to facilitate getting the sand delivered at the right rate to the fluid in the blender. Proportioning and mixing of gelling agents, fluid loss agents, breakers, surfactants, and complexing agents have also become a highly sophisticated procedure. It is necessary to blend them in a very uniform method to give the maximum yield.

Another facet of the recent technology increase in the process of hydraulic fracturing is in the systems of energized frac fluids which includes mixtures of frac fluids and CO_2 or N_2. Frac fluid - CO_2 energized fluids pass through phase changes that range from (1) liquid - liquid mixtures of frac fluid and CO_2, (2) to CO_2 in frac fluid emulsions, (3) to comingled CO_2 gas dispersed in frac fluid. Mixtures of frac fluid and CO_2 range from 25% to 50% depending on the presssure required to fracture the formation. In the past, sand concentrations of CO_2 frac jobs were 1-3 lb/gal, where they now are 7-10 lb/gal. The other energized frac fluid is composed of frac fluid and N_2. Frac fluid - N_2 energized fluid differs considerably from frac fluid - CO_2 energized fluid principally due to the different phase behavior of N_2 and CO_2. Under most fracture treatment conditions, N_2 is a gas throughout the treatment. Energization comes from both comingled and finely dispersed foams, but the greatest benefit is realized when the frac fluid - N_2 energized fluid is a true foam of 65-90 quality. In the past, sand concentrations of N_2 fracturing treatments were 1-2 lb/gal, where they now are 4-5 lb/gal.

The purpose of this paper is not to clarify the turbid waters of hydraulic fracturing theory, but to present how the innovation of high sand fracturing treatments evolved, and how the author and his associates utilized the technique to more effectively employ the fracturing process. A certain amount of equating will be required; however, the development and discussion of theory will be confined to only that which is necessary to clarify the method of analysis.

DEVELOPMENT

In 1960, shortly after the completion of Crittendon's classic hydraulic fracture treatment design methods and procedures[14,15], it became apparent to the author that high conductivity in the propped portion of the created fracture would produce higher initial and longer lasting production increases, which would, in turn, play a major role in maintaining a better position in recovering more producible hydrocarbon reserves. At that time, fracturing fluid and equipment were insufficient to perform high sand concentration fracturing treatments. Generally, hydraulic fracturing treatments consisted of the following:

1. Gelled water treatments composed of 9-10 lb/gal brine water containing 25 lb/1,000 gal of guar gum, 20 lb/1,000 gal of silica flour, carrying 1-2 lb/gal of 20-40 mesh frac sand, and pumped at 40-50 BPM.

2. Lease oil treatments composed of 30° API lease oil containing 25 lb/1,000 gal of Adomite Mark II, carrying 1-3 lb/gal of 20-40 mesh frac sand, and pumped at 30-40 BPM.

3. Refined oil treatments composed of 20° API refined oil containing 25 lb/1,000 gal of Adomite Mark II, carrying 1-5 lb/gal of 20-40 mesh frac sand, and pumped at 15-20 BPM.

In June, 1972, a program of controlled screen out fracturing treatments was undertaken by Mobil Oil Corporation in West Texas and Eastern New Mexico, and the results of the program was reported by the writer.[16,17] This program, even though designed and conducted to eliminate proppant voidage at the wellbore, initiated and furnished much of the basic data for the methods and procedures employed in high sand concentration fracturing treatments.

The first high sand concentration fracturing treatment designed and performed by the writer and his associates was in July, 1976, in the South Blanco Field, Mesa Verde Formation (approximate depth = 5,000-6,000 ft), Rio Arriba County, New Mexico. Six high sand concentration fracturing treatments were performed on two wells. Each treatment was very similar and in general consisted of the following:

1. Fracturing fluid - 120,000 gal crosslinked fluid

    A. Prepad - 10,000 gal
    B. Pad - 20,000 gal
    C. Proppant carrying fluid - 90,000 gal
    D. Gelling agent - 40 lb/1,000 gal guar gum
    E. Fluid loss additive - 30 lb/1,000 gal Adomite Aqua
    F. Crosslinker - 0.4 gal/1,000 gal (titanate)

2. Proppant - 270,000 lb 20-40 mesh Brady sand

    A. Minimum sand concentration - 1.0 lb/gal
    B. Maximum sand concentration - 8.0 lb/gal
    C. Average sand concentration - 3.0 lb/gal

3. Rate - 50 bbl/min

    A. Minimum rate - 20 bbl/min
    B. Maximum rate - 60 bbl/min
    C. Average rate - 50 bbl/min

Each of the high sand concentration fracturing treatments was conducted with very little trouble, and each of the wells responded very favorable to the treatments.

All of the previous high sand fracturing treatments were performed using essentially the same type of gelled, crosslinked fracturing fluid (50 lb/1,000 gal gelling agent and 50 lb/1,000 gal fluid loss agent), and 20-40, 16-30, and 12-20 mesh Brady sand was used singularly and in mixtures as the propping agent, with 20-40 mesh sand being more frequently utilized. Depending on the conditions, a solid scale inhibitor and/or solid paraffin inhibitor were sometimes added to the frac sand. Crosslinking was accomplished through the use of both high pH (titante) and low pH (antimonate) crosslinking agents. Injection rates ranged from 30 to 100 BPM with an average of 50 BPM, and sand concentrations ranged from 6 to 12 lb/gal with an average of 10 lb/gal. Sand concentrations as high as 23 lb/gal were obtained; however, the extremely high concentration was not actually required in obtaining the best results from the high sand concentration fracturing treatments. The high sand concentration was done in an effort to determine equipment limitations and to test the hydraulic fracture treatment design methods and procedures. A prepad and pad were used on all but the first four treatments on which no prepad was used. The prepad was used primarily as a carrier for liquid chemicals which were employed to combat bacteria, oxygen enrichment, iron sulfide, and paraffin.

Possibly the most controversial issue in this paper is the height containment of induced hydraulic fractures. Of the numerous (200-300) high sand fracturing treatments performed by the writer and his associates, only two treatments have been out of zone. These two treatments were performed on up the hole recompletions in older deep wells down 9-5/8 in. casing, where the quality of the cement job was not known and later proved to be bad.

Radioactive coated frac sand was employed on each high sand concentration fracturing treatment. This sand provided a source for an after frac gamma ray survey. The gamma ray log provided the necessary data for determining fracture height, which established fracture height containment. In addition, fracture height obtained from the gamma ray log was used in after frac draw down pressure analysis. Figs. 1-6 are typical after frac gamma ray logs ran on wells that were fractured using the high sand concentration fracturing treatment process. These logs were run on wells completed in different formations (Grayburg, San Andres, Strawn, Spraberry, and Dean) at various depths (approximately 3,000-9,000 ft). Examination of Figs. 1-6 shows the fracture treatment on each well was properly contained and remained in zone. Some of the first high sand concentration fracture treatments were performed using what is now known as "stairstep staging".[18] It soon became apparent that a much quicker method of staging was needed to arrive at high sand concentrations faster. What is now known as "ramp staging"[18] was employed on the remainder of the treatments. This allowed sand concentrations of 8 to 10 lb/gal to be reached in 2 to 5 min, which, in turn, allowed most of the treatment to be pumped at high sand concentrations. This resulted in less fluid being used to place the sand in the fracture, which was the first and most important step in fracture height containment.

The productivity of a fractured well is dependent upon the conductivity of the propped fracture, and the fracture conductivity is controlled by varying the type and/or amount of proppant used during the fracturing treatment. Fig. 7 presents a graph which was generated by Halliburton Services.[19] Illustrated in Fig. 7 is the proppant concentration levels of a 20-40 mesh Brady sand which would result in a partial monolayer, a full monolayer, and a multilayer. A partial monolayer occurs at proppant concentrations of approximately 0.025 to 0.200 lb/ft^2, a full monolayer occurs at proppant concentrations of approximately 0.200 to 0.500 lb/ft^2, and a multilayer occurs at a proppant concentration of approximately 0.500 lb/ft^2 and above. A partial monolayer provides the maximum flow capacity through a fracture. As more proppant is added, where a full monolayer exists, the fracture flow capacity reaches a minimum. As even more proppant is introduced, where multiple layers of proppant occur, the fracture flow capacity is increased. Under most conditions, partial monolayer propping is not practical because it is extremely difficult to achieve the required proppant placement geometry in the fracture; therefore, multiple layers of proppant are preferred and utilized. When multiple layers of proppant are obtained, the outer layers of proppant can embed and/or crush with the inner layers of the proppant remaining open to provide a permeable path for fluid flow. This phenomena is one of the primary reasons why the high sand concentration fracturing treatment process was developed and why past treatment results were so successful. In previous high sand concentration fracturing treatments, design was based on sand concentration of a minimum of 2.0 lb/ft^2 whenever possible. Work by Coulter and Wells[20] on sand concentration (lb/ft^2) is presented in Figs. 8 and 9. This data, although performed under specific test conditions, indicated a minimum sand concentration of 1.0 lb/ft^2 was needed to increase fracture conductivity significantly; and at a sand concentration of 2.0 lb/ft^2, fracture conductivity leveled off slightly but was not reduced greatly.

Presented in Fig. 10[21] is the effect of dimensionless fracture conductivity (C_{fD}) on the dimensionless fracture flux density (q_{fD}) along a fracture. Examination of Fig. 10 shows for a highly conductive fracture, the flux density is high at the portions of the fracture farthest from the wellbore. As the fracture conductivity is decreased, the flux density changes so the flow entering the portion of the fracture close to the wellbore becomes high. For example, for a low conductivity fracture, approximately 70% of the flow comes from the half of the fracture nearest to the wellbore; and for a high conductivity fracture, approximately 70% of the flow comes from the half of the fracture farthest from the wellbore. Findings published by van Poollen[22] agree with the results of Cinco et al[21] presented here. All the data emphasizes the importance of creating highly conductive fractures.

Fig. 11[21] presents a plot of the effect of dimensionless fracture conductivity (C_{fD}) on the dimensionless fracture pressure drop (Δp_{fD}) along a fracture. The pressure drop is the difference between the pressure at any point along the fracture and the pressure at the leading edge of the fracture. The curves on Fig. 11 show for a highly conductive fracture that the pressure drop along the fracture is small, and as the fracture conductivity decreases, the pressure drop along the fracture becomes greater. Also, presented in Fig. 11 is the results published by Pratts[23] which are in excellent agreement with the results by Cinco et al[21] presented here. All this information accentuates the gravity of creating highly conductive fractures.

Presented in Fig. 12[21] is pseudo skin factor (S_f) function of dimensionless fracture conductivity (C_{fD}) for a system where r_e/r_w = 2,000 and r_e/L_f = 10. Pseudo skin factor is defined as the difference between the dimensionless pressure drop for a fractured well and that for an unfractured well. Fig. 12 shows that the skin factor is negative, indicating an increase in well productivity. Also shown in Fig. 12 is that initially there is a rapid decrease of skin factor for a small increase in fracture conductivity, and as fracture conductivity increases farther, skin factor approaches a stabilized value. Data by McGuire and Sikora[24] and Pratts[23] agree extremely well with the results of Cinco et al[21] presented here. All of this data points up the significance of creating highly conductive fractures.

Fig. 13[20] presents the effect of fines on the conductivity of 20-40 and 12-20 mesh Brady sand at a closure stress of 3,500 psi on a Canyon Sand core. The fines used in the tests were crushed Brady sand in the 60-100 mesh screen range. Although the test results are applicable only to the specific test conditions, they are indicative of the decrease in fracture flow capacity that can result after fines enter the proppant bed. Examination of Fig. 13 shows that as few as 5% fines result in a 60% decrease in fracture flow capacity for 1.0 lb/ft^2 of 20-40 mesh sand and a 30% decrease in fracture flow capacity for 3.0 lb/ft^2 of 20-40 mesh sand. This work by Coulter and Wells[20] is in agreement with the findings of van Poollen et al[25], and all of the data emphasizes the importance of high sand concentration in reducing fines and increasing fracture flow capacity.

When a fracturing slurry (propping agent mixed with gelled, crosslinked, aqueous fluid containing a fluid loss additive) is employed in the creation of a hydraulic fracture in a formation, a portion of the fluid leaks into the matrix of the formation and is stripped of the gelling agent and fluid loss additive. The stripped material is deposited on the face of the fracture, concentrated by the action of filtration, and forms a tough, leathery layer referred to as the filter cake. Fig. 14 presents a schematic of this fluid loss mechanism. The filter cake has desirable properties during the fracturing treatment operation in that it minimizes fluid loss and aids in fracture propagation. When the fracture heals, part of the filter cake is forced into the formation pores, and the remaining portion of the filter cake plugs the proppant flow channels in proximity of the fracture face. This results in reduced fracture flow capacity. If the filter cake can be contacted, a filter cake solvent fluid has recently been developed to convert the filter cake to a thin, non-viscous fluid with very little residue. In addition, high proppant concentration will aid in the prevention of the filter cake problem in that final proppant concentration in the fracture has a large influence on how much polymer concentration takes place during fracture closure. If the proppant concentration is low, the increase in polymer concentration is high. When the proppant concentration is high, such that the fracture width is just wide enough to contain the proppant, the fracture closes very little and the polymer concentration is not greatly affected. Fig. 15[26] illustrates both pictorally and graphically the phenomena of proppant concentration on final polymer concentration.

A phenomena that can reduce fracture conductivity is deviation from Darcy's law by high flow rates. Darcy's law describes laminar flow through porous media, and simply put, it states that if the resistance to flow remains constant, the pressure gradient is proportional to the velocity of the fluid. When fluid velocity is increased to a point where flow no longer is laminar, the pressure drop increases more than proportionately, and non-Darcy flow occurs. Conductivity and permeability measurements on proppants are usually made at flow rates low enough to avoid non-Darcy flow. Non-Darcy flow will reduce the productivity of a fractured well below what is expected from productivity increase curves by increasing the expected pressure drop required to produce at a given rate. The production of low viscosity oil wells at high rates will be significantly lowered, and gas well production will be greatly reduced if non-Darcy flow exists. When designing a hydraulic fracture treatment, the effect of non-Darcy flow should be considered, and if necessary, fracture conductivity should be adjusted to compensate for the effect of non-Darcy flow on the permeability of the fracture. Several methods can be employed to overcome the effects of non-Darcy flow. They are:[26]

1. Increasing proppant concentration.

2. Changing to a higher performance (higher permeability) proppant.

3. Combination of both of the above.

All of the discussion and explanation of the information and data presented in this section (Development) of this paper emphasizes the importance of creating highly conductive fractures, which is one of the main reasons for performing high sand concentration fracturing treatments.

DESIGN

The hydraulic fracturing process consists of mixing special chemical additives (gelling agent, fluid loss agent, friction reducing agent, clay stabilizing agent, iron control agent, pH control agent, crosslinking agent, etc.) with a base fluid (fresh water, NaCl water, KCl water, formation water, etc.) to make the desired fracturing fluid. A propping agent (sand, sintered bauxite ceramic proppant, intermediate density/intermediate strength ceramic proppant, curable and precurable resin coated proppants, etc.) is blended with the fracturing fluid forming a viscous fluid proppant slurry. The slurry is then pumped down the wellbore into the formation at sufficiently high rates and pressures to create a crack in the reservoir rock of narrow width and large areal extent. When pumping is stopped and the pressure is relieved, the formation closes on the propping agent leaving behind a highly permeable proppant bed for oil and/or gas to flow easily from the formation extremities into the wellbore.

In summary, hydraulic fracture treatments are composed of a fracturing fluid and a propping agent. In the design of hydraulic fracture treatments, the primary consideration is usually the selection of the fracturing fluid; however, the only part of the fracture treatment which remains and controls the productivity of the well is the propping agent that was placed in the fracture during the fracturing treatment. Examination of the previous statements concerning fracturing fluid and propping agent illustrates the importance of the propping agent in a hydraulic fracture treatment, which, in turn, shows the importance of high sand concentration treatments. It is essential that the correct type, size, and concentration of frac sand be chosen so productivity and ultimate recovery from the well are maximized. As long as sand concentration is low, hydraulic fracture treatment design is fairly simple and straight forward. If sand concentration is high, design of hydraulic fracture treatments becomes more complicated.

Design of high sand concentration fracturing treatments begins with the description of the transient three dimensional problem of determining the shape of the fracture at any time during the fracturing treatment and determining the shape of the trapped proppant bed upon closure of the fracture. This is an extremely complex three dimensional problem and involves the coupling in time of solutions to the following:

1. Problems in fluid mechanics involving slurry and fluid flow in the fracture and fluid flow into the formation.

2. Problems of in-situ material and in-situ stress properties involving the formation and the pressured fracture.

3. Problems in heat transfer between the slurry and/or fluid and the formation.

4. Problems in the rheological response of the slurry and fluid.

The basic methods and procedures used in the design of high sand concentration fracturing treatments have been reported, discussed, and explained fully in detail.[27-30] The design method solves simultaneously equations for fracture flow, reservoir flow, and fracture mechanics. The design approach has been generally accepted by the industry and dealt with by the author in an acceptable manner. Since it is beyond the scope of this paper, the writer will not attempt to review or expand on the techniques given in the above cited literature except where drastic changes in design methods have been made. Fig. 16 presents four graphs that are computer generated and plotted to explain the treatment size of a high sand concentration fracturing treatment.

In today's world of computers, many sophisticated hydraulic fracture treatment design programs are available for designing the treatment, predicting post treatment production, and estimating future revenue from the treatment. The programs often predict fracture flow capacities and productivity increases that are much higher than actual results. This discrepancy cannot be attributed to a single input error but rather a combination of input data and/or calculations, including but not limited to rheology and leakoff parameters and permeability and conductivity of the proppant pack.

Much of the error in post treatment production results from applying erroneous laboratory data to the permeability and conductivity of the proppant pack. Laboratory data is not what is achieved in actual downhole conditions. Laboratory permeability and/or fracture conductivity is measured in linear, rectangular stainless steel test cells which are dominated by edge and wall effects. In actual downhole conditions, there are minimal edge and wall effects because the fracture area is extremely large in comparison to that of the laboratory test equipment. In addition, fractured formations are usually softer than the proppant so some slight degree of embedment is normal. This embedment aids in the reduction of the edge and wall effects. Depending on the type and method of laboratory testing, laboratory measured permeability and conductivity data should be reduced by a factor of 50% to 80% under normal conditions, and under certain circumstances, the reduction could be as high as 95%. Fig. 17 presents a plot illustrating the effect of compaction pressure on the permeability of 20-40 mesh Brady and Ottawa sands. Additional plots are available for various mesh sizes (16-30, 10-20, 12-20, etc.); however, they are not presented here for the sake of brevity. The data obtained from the plots agree extremely well with that obtained from actual field operations.

Fluids encountered in the petroleum industry may be classified as Newtonian and non-Newtonian. In Newtonian fluids, the relationship between shear stress and shear rate is linear. In non-Newtonian fluids, there is a nonlinear relationship between shear stress and shear rate, except for non-Newtonian Bingham plastic fluids where the shear stress and shear rate relationship is linear. Non-Newtonian fluids may be subdivided into three general categories - Bingham plastic, pseudoplastic, and dilatant. Fig. 18 presents a typical shear stress-shear rate diagram for Newtonian and non-Newtonian fluids.

Newtonian fluids are extremely common and easily dealt with in the petroleum industry. The most common examples of Newtonian fluids in the oil and gas industry are oil, water, and gases.

Bingham plastic fluids are probably the simplest non-Newtonian fluid type because they differ from Newtonian fluids only in that their linear relationship between shear stress and shear rate does not go through the origin. Examples of Bingham plastic fluids commonly encountered in the petroleum business are drilling mud and cement slurry.

Pseudoplastic fluids are very common in the petroleum industry and are referred to as power law non-Newtonian fluids. Examples of pseudoplastic fluids are gelled oil, water, and acid.

Dilatant fluids are extremely rare in the oil and gas industry and are of very little interest. Examples of dilatant fluids are starch, quicksand, and beach sand.

In high sand concentration fracturing treatments, the rheology of the fracturing slurry changes as the sand concentration (lb/gal) is increased. The slurry rheology passes through three general regimes as the sand concentration is increased from 0 to 24 lb/gal. The three rheology regimes are as follows:

1. For frac sand concentrations from 0 to 4-6 lb/gal, the slurry rheology is non-Newtonian, pseudoplastic, and perfect transport.
2. For frac sand concentrations from 4-6 to 14-16 lb/gal, the slurry rheology is non-Newtonian, pseudoplastic, and not perfect transport.
3. For frac sand concentrations from 14-16 to 22-24 lb/gal, the slurry rheology is non-Newtonian, Bingham plastic, and not perfect transport.

Fig. 19 illustrates a schematic of the hypothesis just presented. Practically all high sand concentration fracturing treatment designs fall into the category of sand concentrations of 4-6 to 14-16 lb/gal.

The degree of proppant concentration in the fracturing fluid has a definite effect on the rheology of the fracturing slurry. Although much more research needs to be done with fracturing slurries, the general industry feeling is that fracturing slurry rheology is substantially influenced by proppant concentration; however, very few design programs take this into account.[26] The industry's inability to accurately measure the rheology properties of the fracturing slurry is probably the reason why it is not incorporated in the design programs.

The author has devised a method for predicting the rheology properties of the fracturing slurry, and the method has been employed in the design of many of the high sand concentration fracturing treatments discussed in this paper. An effort to acquaint the reader with the method will be presented, and an endeavor to be thorough and complete without resorting to excessive theory and mathematical development will be followed. The method employs the following equations and Figs. 20-23.

$$SR = \frac{(40.3)(Q)}{(W_t^2)(H_f)} \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots \quad (1)$$

$$\mu_a = \frac{(47{,}880)(K')}{SR^{1-n'}} \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots \quad (2)$$

The high sand concentration fracturing treatment is first designed using the rheology properties of the fracturing fluid. Employing data from the first design (Q, H_f, and W_t), Equation 1 (Fig. 20), Equation 2 (Fig. 21), Fig. 22, and Fig. 23, the rheology properties of the fracturing slurry are determined. The fracturing treatment is then redesigned utilizing the slurry rheology properties. When the treating fracture width of two consecutive fracturing treatment designs agree within acceptable limits, the fracturing treatment design is complete. This requires a trial and error solution if performed on a calculator and an iteration solution if performed on a computer.

The volume added to the fracturing fluid with varying concentrations of sand is shown in Table I.[31] Examination of Table I shows for a sand concentration of 10 lb/gal that the fracturing slurry is composed of 69% fluid and 31% sand. High sand concentrations affect fluid loss in that the fluid portion of the fracturing slurry leaks off, and the sand portion of the fracturing slurry does not leak off. The fluid loss data for the fracturing slurry can be estimated fairly accurately on a fluid-sand percentage basis from the fluid loss data of the fracturing fluid; however, fluid loss data should be obtained from laboratory measurements performed on the fracturing slurry.

LOGISTICAL AND OPERATIONAL PROBLEMS

Problems associated with performing high sand concentration fracturing treatments are numerous and varied; however, they may be grouped into two main categories - logistical and operational. Logistical problems involve the preparation of the well and location to accommodate the stimulation equipment and materials necessary to perform the stimulation treatment in a safe and efficient manner. Operational problems are those which occur during the actual performance of the stimulation treatment, and include such things as equipment malfunctions and failures, rate and pressure variations, sand quality and concentration variations, gel quality and concentration variations, etc.

Logistical and operational problems of high sand concentration fracturing treatments are similar to those of massive hydraulic fracturing treatments. Several excellent papers[32,33] have been written and published which present how the logistical and operational problems of massive hydraulic fracturing treatments were handled.

This section of this paper was prepared to identify some major problem areas that have been encountered while preparing for and performing high sand concentration fracturing treatments. How the problems were solved, avoided, or at least minimized is presented in hopes that it will be useful to others who have the responsibility of conducting high sand concentration fracturing treatments.

LOGISTICAL PROBLEMS

Location Design And Preparation

Adequate location size and accessibility is essential in performing a high sand concentration fracturing treatment. It is more economical to build the location before drilling operations begin than to modify the location prior to stimulation operations. Ideally, the stimulation portion of the location should be approximately 200 by 200 ft; however, location size is actually dictated by stimulation equipment requirements, frac tank requirements, sand quantity, and auxilliary equipment needs such as logging equipment, pressure recording equipment, and CO_2 or N_2 equipment. The location should be of sufficient size to allow from 50 to 100 ft between the pumping equipment and the wellhead, and the wellhead should be accessible without having to cross any high pressure lines.

Drilling And Production Equipment And Materials Problems

Equipment and materials left on location from the drilling operation and premature delivery and/or installation of production equipment such as pumping units, tank batteries, pits, etc. often become obstacles that result in improper placement of stimulation equipment and materials. This results in the stimulation equipment and materials being handled awkwardly, hazardously, and improperly. If too many items are left on location, the size of the stimulation treatment may be reduced and/or limited which could result in a sacrifice in job quality and possibly imperil the desired results. Every effort should be made to keep the location as unobstructed as possible until the high sand concentration fracturing operations are completed.

Frac Tank Preparation And Installation

The author has performed high sand concentration fracturing treatments where the frac tanks have been set both level and inclined. The writer personally believes it is beneficial to slope the frac tanks toward the pumping equipment with the rear of the tanks from 6 to 12 in. higher than the front. Inclining the frac tanks will minimize the waste of gel which is left in the bottom of the tanks; however, it will result in slightly erroneous gauging of the tanks. If the frac tanks are set flat or lower at the rear of the tanks, from 25 to 75 bbl of gel will be left in each frac tank, depending on the severity of the backward slope and the height of the suction manifold of the tank. In high sand concentration fracturing treatment job designs, it is good practice to assume useful frac tank capacity to be 95% of the actual capacity. It is also good practice to have approximately 5% over the job design of gel to compensate for gauging errors, calibration errors, human errors, tank and manifold leakage, etc.

Adequate space should be left behind the frac tanks to allow emptying contaminated tanks and refilling without having to remove equipment already in place. The area behind the frac tanks has to be sufficiently competent to support water hauling equipment.

The frac tanks should be set so none of the blenders will be more than approximately 75 ft from the fartherest tank. This is extremely important especially when suction can pose a problem as the result of a very viscous base gel being pumped.

All frac tanks should be numbered. The quality control engineer and chemist should have a layout of the frac tanks with each tank clearly numbered. They should be aware of the tank that is being pumped out of at anytime, and they should catch samples of the gel and/or slurry that is being pumped during the fracturing operations for inspection and analysis. The quality control vans should be placed near the frac tanks for use in inspection and analysis of the quality of the gel and/or slurry.

Water Hauling Preparation And Transportation

As with frac tanks, water hauling trucks should be very clean. Trucks that have been used recently for hauling extraneous fluids such as oil, tank bottoms, drilling mud, spent acid water, workover load water, salt water disposal fluid, etc. should not be employed without being thoroughly cleaned. Steam cleaning and flushing with fresh water will usually be satisfactory. Water hauling personnel should be shown the exact location of the water source. They should be instructed that any other source of water could jeopardize the success of the fracturing treatment, is not acceptable, and will not be tolerated.

Gel Preparation

Gel preparation should begin with cleaning the frac tanks. It is essential that all frac tanks be extremely clean. Most modern crosslinked gel systems are sensitive to fluid pH and other chemical contaminants such as reducing agents, sulfates, iron, etc. that can prevent gel hydration and/or interfere with the crosslinking mechanism. Steam cleaning and flushing the frac tanks with fresh water will usually yield the best results.

Bacterial contamination is one of the major sources of gel problems, and to control the bacterial growth, a bacteriacide should be placed in the frac tanks before they are filled with water. The most common bacterial contamination is caused by sulfate reducing bacteria which gives the gel a black coloration and a strong hydrogen sulfide odor. In the cooler months when water temperatures are 60°F or less, bacterial contamination is not too severe.

If the treating fluid temperature is 40°F or less, most crosslinking mechanisms are greatly slowed down, and crosslinking time can increase from 10 to 20 fold depending on the gel system, the crosslinker used, and the ambient temperature. To accelerate the crosslinking process and shorten the crosslinking time, all cold treating fluid has to be heated to 60°F or higher.

Due to the uneven heat absorption in a frac tank, the temperature that exists in the tank is often stratified. Temperature variations of 5°F to 20°F are quite common. While this temperature variation has little effect on the time necessary to gel the fluid, it will have a pronounced effect on the time required to crosslink the gel.

Prior to hauling and placing any water in the frac tanks, the water source should be thoroughly tested to insure compatibility with the processed gel system to be used in the fracturing treatment. The amount of attention to this detail cannot be overemphasized. This will avoid a loss of time and money as a result of placing incompatible water in the frac tanks. After the frac tanks are filled with approved water, each frac tank should be checked to verify the water quality. If any of the frac tanks contain unsuitable water, they can be emptied and refilled with acceptable water before gelling operations are initiated.

Gelling operations should not be started until the well is completely ready to be fractured. Numerous unexpected delays such as perforating problems, acidizing problems, swabbing and testing problems, weather problems, delay of materials, etc. can postpone a job indefinitely. If the delay is long enough, the gel can deteriorate to the point where it is unusable resulting in a loss of several thousands of dollars.

OPERATIONAL PROBLEMS

Multiple Blender Systems

When pumping high sand concentrations, the capacity of the blenders can be exceeded or required to operate at near 100% efficiency. Two types of equipment arrangements are available to solve the problem. Two blenders are used in each case, and the pumping requirements are split between each blender, thus allowing each blender to operate within its optimum range.

In the first arrangement, the fracturing equipment is set up into two separate units as if two fracturing treatments were being performed. Each unit contributes equally to the total injection rate and sand output. The shortcoming of this method is that the fluid and sand of each unit is isolated, and if one unit develops problems that can not be corrected, the fracturing treatment will be substantially compromised and possibly aborted.

In the second arrangement, two blenders are set up side by side. Both blenders are fed by the same sand source through the use of a conventional conveyor belt and a T belt conveyor with dual blender feed. This allows routing all the sand through either blender if one or the other fails. This will allow the fracturing treatment to continue to completion by using only one blender. Each blender should be set up in such a manner that will allow either blender to be replaced by a standby unit. The standby blenders should be hooked in line ready to pump with minumum time loss during changeover.

Standby Equipment

The cost of the fracturing equipment is 15% to 25% of the total fracturing treatment cost. The integrity and success of the fracturing treatment should not be jeopardized by the added expense of adequate standby equipment. The cost of refracturing a well is much higher than the expense of the standby equipment. The success of refracturing a well as initially desired is very poor due to proppant pack geometry and mobility, fracture height growth, etc.; and the further the fracturing treatment has progressed, the more difficult it is to refracture the well.

Fluid And Sand Rate Monitoring

There are three methods of measuring fluid injection rate - turbine flowmeters, counting pump strokes, and frac tank gauging. All three methods should be used as a counter check for each other. A visual record of the fluid injection rate is usually accomplished by a turbine flowmeter and recorded on a fracture monitor. Counting pump strokes is a fairly reliable source of measuring fluid injection rate if the displacement capacity and pump efficiency of the pump are known. By measuring the volume of fluid pumped from a frac tank in a given length of time, the fluid injection rate can be determined.

There are three methods of measuring sand injection rate - radioactive densimeters, sand screws, and sand storage units. All three methods should be used in conjunction to counter check each other. Sand injection rate is usually achieved very accurately through the use of a radioactive densimeter and recorded on a fracture monitor. The sand screw method of measuring sand injection rate is reasonably accurate if the sand screw displacement volume is known and wear and tear on the sand screw is minimized. By gauging the sand storage units, the sand injection rate can be determined.

Continuous and accurate monitoring of the fluid and sand injection rates will allow problem areas to be detected early in the fracturing treatment. Modifications can then be made to correct the problems and continue the fracturing treatment.

Erosion Failures In Surface Treatment Lines And Wellhead

When high sand concentrations are being pumped, it is necessary to closely monitor the erosion problems in the surface treatment lines and wellhead. Erosion problems become more severe as sand concentration and fracturing slurry velocity are increased. Changes in the diameter of the surface lines and sharp changes in the direction of flow in the surface lines are critical erosion areas. Singular flow of the fracturing slurry into the wellhead should be directly down, and varied flow of the fracturing slurry into the wellhead should directly oppose each other. All surface treatment lines should be anchored or staked, and the treatment lines connected directly to the wellhead should be chained to the well where possible.

Popoff Valve

During a high sand concentration fracturing treatment the treatment variables (injection rate, slurry density, and pressure) change quite rapidly with time so no coherent picture of bottom hole pressure behavior is possible without some means of sensing and calculating the data quite rapidly. A turbine flowmeter, radioactive densiometer, and on site computer provide the most meaningful way to account for changes in the treatment variables. Even with the data from the computer, very little time is available if a pressure increase problem occurs. Without data from the computer, it is impossible to detect a pressure increase problem before it occurs because the slurry head overshadows the other pressure parameters. People cannot react fast enough to avert disaster, and for this reason, a popoff valve is essential in high sand concentration fracturing treatments. The popoff valve should be set near the wellhead, and a line from the popoff valve to the pit should be laid and staked down. The popoff valve should be set 300 psi below the burst pressure of the treating string and tested to ensure that the popoff valve will not leak and will blow at the proper pressure.

FRACTURE HEIGHT CONTAINMENT

Factors which affect fracture containment and geometry are:

1. In-situ material properties (Poisson's ratio, Young's modulus, shear modulus, and bulk modulus).

2. In-situ stress properties (maximum horizontal in-situ stress, minimum horizontal in-situ stress, overburdened vertical stress, and in-situ stress gradients).

3. Fracture toughness.

4. Fracturing slurry density properties.

In-situ Material Properties

The material barrier concept, including interface theory, has been thoroughly discussed, fully explained, and accurately reported by several authors[34-45]. Theoretically, the material barrier concept provides a basis for retarded vertical growth of a hydraulic fracture that approaches the interfaces between the pay zone and the above and below bounding formations with stronger material properties than the pay zone. The effectiveness of such containment is negated by the high probability of intersecting pre-existing flaws near the interfaces.

Idealized material property fracture barrier theory predicts that the stress intensity factor approaches zero as a fracture nears an interface with a layer of higher material properties than the fractured zone.[41] The effect is a decrease in the stress intensity factor by the higher material barrier zone, which, in turn, assists in the vertical containment of the fracture. In addition, differences in the material properties within a layered formation are important in controlling fracture height, not as a containment barrier per se, but in the manner in which the variations in the material properties affect the vertical distribution of the magnitude of the minimum horizontal stress in the layered formation.[43] The material property contrast between the formation layers also has an influence on the overall stress field in and around the fracture, which, in turn, has an effect on controlling the vertical height of the fracture.[41]

While in-situ material properties do not stop the vertical growth of a fracture, they do provide an aid in controlling the vertical height of the fracture. For this reason, in-situ material properties should be examined while determining the vertical containment of fractures. In-situ material properties can be obtained from the following equations, and the information necessary to solve the equations can be obtained by utilizing log data from acoustic logs, wave train logs, and density logs. These equations were determined from formulations by Kithas[34], Anderson and Walker[46], and Nations[47].

$$\upsilon = \frac{(0.5)(\Delta t_s/\Delta t_c)^2 - 1}{(\Delta t_s/\Delta t_c)^2 - 1} \quad \text{(3)}$$

$$E = \frac{(2.6928 \times 10^{10})(\rho_b)(\upsilon + 1)}{\Delta t_s^2} \quad \text{(4)}$$

$$G = \frac{(1.3464 \times 10^{10})(\rho_b)}{\Delta t_s^2} \quad \text{.......... (5)}$$

$$K = [1.3464 \times 10^{10}][\frac{\rho_b}{\Delta t_c^2} - \frac{(4)(\rho_b)}{(3)(\Delta t_s^2)}] \quad \text{.......... (6)}$$

All of the in-situ material properties are interrelated, and each one affects the other. By inserting and equating like terms in the above equations, the following expressions are obtained. These expressions show the relationship between Poisson's ratio, Young's modulus, and shear modulus.

$$\upsilon = [\frac{(0.5)(E)}{G}] - 1 \quad \text{.......... (7)}$$

$$E = (2)(G)(\upsilon + 1) \quad \text{.......... (8)}$$

$$G = \frac{(0.5)(E)}{(1 + \upsilon)} \quad \text{.......... (9)}$$

In the application of Equations 3, 4, 5, and 6, compressive travel time is obtained from conventional acoustic logs and shear travel time is obtained from full wave train logs. The relationship between compressive and shear travel time as a function of lithology is shown in Table II. This data in part is by Kithas[34] and Picket[48] with the remaining portion by the writer.

A plot of the maximum elongation of a hydraulic fracture in a three layer system as a function of shear modulus contrast is presented in Fig. 24.[41] Examination of Fig. 24 shows to obtain an elongated fracture that a shear modulus contrast of 16 or higher is required. This is in agreement with the data reported in the literature[40,49]; whereas, it was found that material property differences of factors of 5 to 15 did not contain fractures.

The criterion for fracture extension by Sneddon[50] can be stated as follows:

$$\Delta p = \sqrt{\frac{(\pi)(E)(\tau)}{(2)(R_f)(1 + \upsilon^2)}} \text{ — Radial Fracture} \quad \text{....... (10)}$$

$$\Delta p = \sqrt{\frac{(2)(E)(\tau)}{(\pi)(L_f)(1 + \upsilon^2)}} \text{ — Linear Fracture} \quad \text{........ (11)}$$

In the above equations, τ denotes the specific fracture surface energy of the formation and is defined[51] as the amount of energy needed to break the molecular bond between the particles of the formation and create a unit surface area. Approximate values of the specific fracture surface energy along with approximate values of Poisson's ratio, Young's modulus, and shear modulus for carbonate and clastic formations are presented in Table III. The numbers in Table III give some idea of the magnitude and variance of each of the material properties listed.

Equations 10 and 11 show there is a specific relationship between the formation material properties (Young's modulus, specific fracture surface energy, and Poisson's ratio), fracture radius and/or length, and the pressure required for fracture propagation. An increase in pressure beyond what is predicted from the equations results in fracture propagation, which is the exact mechanism employed in the propagation of a fracture in all hydraulic fracture treatments.

Experimentally, the specific fracture surface energy is measured by several methods, some of which are the cleavage test, beam test, Brazilian test, ring test, and double ring test[51]. All of these tests basically employ the same testing method, where a rock sample is subjected to a force in such a manner that the rock sample fails in tension. There are variations in testing results arising mainly from the natural differences in the rock samples. Usable rock samples are expensive and scarce since they are obtained from cores. In the absence of rock samples, the specific fracture surface energy can be approximated from Fig. 25 which is a plot of experimental data[52] showing the specific fracture energy as a function of Young's modulus for carbonate and clastic formations. In addition, the effective fracture surface energy can also be calculated from the following equations which are rearrangements of Equations 10 and 11.

$$\tau = \frac{(0.6366)(R_f)(1+\upsilon^2)(\Delta p^2)}{E} \text{ — Radial Fracture .. (12)}$$

$$\tau = \frac{(1.5708)(L_f)(1+\upsilon^2)(\Delta p^2)}{E} \text{ — Linear Fracture .. (13)}$$

With the exception of Δp, all of the data necessary to solve the above equations are readily available and easily obtained. The source of energy in a hydraulic fracture treatment is the pressure of the slurry inside the fracture. The magnitude of this pressure is equal to the sum of two terms; one to balance the least principal stress, and the other to provide the energy for fracture propagation. Care should be exercised in the selection of Δp, since in reality, it is some average value over the entire area of the fracture. Δp can vary from near zero to well over 1,000 psi as the result of varying rock properties and fluctuating fracture treatment variables.

Theoretically, Daneshy[51] has shown that the magnitude of the expression $(E\tau/1-\upsilon^2)$ for different formations is an indicator of their relative fracturability. Using the expression as a means of determining the relative fracturability of various formations shows that the formation with the smallest term requires the lowest pressure for fracture extension and is the easiest formation to be fractured. For this reason, the term is referred to as the fracturability index. A plot of the fracturability index contrast of a hydraulic fracture in a three layer system as a function of stiffness contrast is presented in Fig. 26. Based on past experience of the writer, vertical fracture containment is possible to a degree when the fracturability index contrast is above a range of approximatly 2.5 to 4.5. The variance in fracturability index contrast is primarily the result of formation lithology with clastic formations in the lower portion and carbonate formations in the upper portion of the spread.

In-situ Stress Properties

The extent to which the adjacent formation layers will control the vertical growth of a hydraulic fracture being propagated in a pay zone is dependent on the contrasts in the in-situ stress action of the fractured formation and the adjacent formation layers. The development of both quantitative and qualitative predictions of hydraulic fracture growth and geometry is based on numerous intricate factors including knowledge of fracture height impedence which encompasses the in-situ stress fields of the fractured formation and the adjacent formation layers. Two dimensional analyses of the problem[35] show that as a growing fracture within the pay zone approaches the interfaces between the pay zone and the above and below adjacent formation layers, the vertical growth of the fracture will be hindered if the minimum in-situ stress of the adjacent formation layers is greater than the minimum in-situ stress of the pay zone.

Vertical fracture height growth is a complex function of fluid rheology, injection rate, fracture treating pressure, and containment mechanisms. Fluid rheology, injection rate, and fracture treating pressure are controllable treatment variables, and containment mechanisms are rock mechanics variables which are controlled by formation and fracture mechanics. Containment mechanisms which are different, interrelated, and often discussed simultaneosly are as follows:

1. In-situ stress contrast of the fractured formation and the adjacent formation layers.

2. Material property contrast of the fractured formation and the adjacent formation layers.

There are important differences between[44] the in-situ stress contrast and the material property contrast. They are:

1. In-situ stress contrast is a stronger fracture height containment mechanism than material property contrast.

2. In some cases, in-situ stress contrast can possibly stop vertical fracture growth.

3. Fracture height growth cannot be completely arrested by material property contrast.

4. In-situ stress contrast does not act until the fracture reaches a barrier formation with different stress than the fractured formation.

5. The effect of a barrier formation with different material properties than the fractured formation is felt at a distance before the fracture penetrates the barrier formation.

The strength of the fractured formation and the formation layers above and below the fractured formation is measured by means of the stress intensity factor, and the value of the stress intensity factor depends on fracture geometry, fracturing slurry rheology, injection rate, and fracture treating pressure. There are four types of stress intensity factors. They are:

1. Stress intensity factor at the front and/or leading edge of the fracture (K_1).

2. Stress intensity factor at the upper (K_{1u}) and lower (K_{1l}) boundaries of the fractured zone.

3. Critical stress intensity factor (K_{1c}) is a material property (fracture toughness and/or fracturability) that controls horizonal fracture propagation. Measured values of critical intensity factor are contained in Table IV.[41] All of the values in Table IV were measured under low confining pressure, and undoubtably, if measured under downhole conditions, the values would be higher, possibly by a factor of two to four. The main point of the values in Table III is their range is fairly narrow, meaning the actual critical stress intensity factors for the various formations are fairly close, whether they are equal to or higher than the values in the table.

Stress intensity factor at the fracture front and/or leading edge for round shaped fractures of radius $H_f/2$ and rectangular shaped fractures can be obtained from Equation 14 and 15, respectively.[41]

$$K_I = (0.80)(\Delta p_I)(\sqrt{H_f}) \text{ — Radial Fracture} \quad (14)$$

$$K_I = (1.00)(\Delta p_I)(\sqrt{H_f}) \text{ — Linear Fracture} \quad (15)$$

In Equations 14 and 15, Δp_I is the pressure at the wellbore minus the sum of fracture friction and the minimum horizonal stress.

The stress intensity factor at the upper and lower edges of a rectangular fracture can be obtained from Equations 16 and 17, respectively.[41]

$$K_{Iu} = (1.25)(\Delta p_{Iu})(\sqrt{H_f}) \text{ — Upper} \quad (16)$$

$$K_{Il} = (1.25)(\Delta p_{Il})(\sqrt{H_f}) \text{ — Lower} \quad (17)$$

In Equations 16 and 17, Δp_{Iu} and Δp_{Il} are the pressure at the wellbore minus some average value over the entire area of the fracture of fracture friction and the minimum horizonal stress.

Examination of Equations 15, 16, and 17 shows if the slurry overpressure in the fracture was constant over the entire fracture area that the stress intensity factor at the upper and lower tips of the fracture would be 25% higher than at the fracture front. This results in a ratio of the stress intensity factor at the upper and lower boundaries of the fracture to the stress intensity factor at the fracture front to be 1.25. Work by Cleary[53] predicts the ratio of stress intensity factors to be both much smaller and larger than the 1.25 stated above. His work showed the stress intensity factor ratio could vary from approximately 0.3 to 20.

Fracture Toughness

Research programs, theoretical studies, and operational designs on fracture propagation including fracture height and geometry originated in the theory of tensile cracks by Griffith[54,55] and later was expanded for pressurized cracks by Sneddon[50,56]. Based on the energy criterion, a relationship of fracture shape, material properties, and the external force needed for fracture propagation was developed. In hydraulic fracturing, the energy source is the pressure inside the fracture, and the horizontal fracture extension is controlled by the material properties of the formation characterized by fracture toughness, specific energy, or critical stress intensity factor. A fracture propagates when the stress intensity factor reaches a value equal to the critical stress intensity factor (fracture toughness or fracturability) of the formation. The effect of an increase in fracture toughness is to increase frac pressure; therefore, fracture toughness is only important in controlling fracture height for fractures created with a low viscosity fluid such as injection water in a waterflood[44,57]. Fracture toughness by itself does not constitute a barrier to the vertical growth of a fracture created by viscous fluids at high pump rates.

Idealized linear elastic fracture theory predicts that the stress intensity factor decreases when a fracture crosses into a formation layer of higher ductility and/or lower permeability.[41] In principle, a ductile material such as shale may impede fracture height growth by dissipation of energy in the zone of plasticity around the upper and lower tips of the fracture. This phenomenon may be incorrectly interpreted as an increase in fracture toughness; when in actuality, it is absorption of energy in the zone of plasticity.

Fracturing Slurry Density Properties

Various degrees of vertical fracture containment are possible by knowing the in-situ material properties, the in-situ stress properties, and the fracture toughness of the fractured formation and the adjacent formation layers to the fractured formation; however, the most dominant component of the mechanism of vertical fracture containment is the retardation of vertical fracture growth by the impedance to fluid flow into the narrow upper and lower fracture tips. This fluid flow impedance mechanism can easily be implemented by blocking flow in both narrow fracture tips with proppant. This is accomplished through the use of high proppant concentration in a perfect transport fluid. For instance, proppant mixed with a perfect transport fluid in high concentration will gather in both the upper and lower narrow fracture tips and effectively reduce the transmissivity or permeability wherever it congregates. Fluid which flows in the wide central channel of the fracture may not penetrate into either the upper or lower proppant packed narrow fracture tips. Fig. 27 presents a schematic of this fluid flow impedance mechanism. It is possible to form a protective upper and lower barrier which greatly, if not completely, enhances vertical fracture containment. High sand concentration in a perfect transport fluid of the right gel concentration and fluid loss concentration produces extremely viscous fracturing slurry, when pumped at the correct injection rate and fracture treating pressure result in a slight compaction of the fracture faces. Fig. 14 presents a schematic of this elastic rock mechanism which was first reported, explained, and discussed by Cleary[58].

This rock compactability will make the treating fracture width slightly broader than it would be for lower sand concentration slurries, and lead to enhanced flow down the central channel of the fracture. Compaction of the fracture faces, even though very small, does also help in retarding fluid loss to the formation, which in turn helps to reduce fracturing fluid formation damage.

Even with the existence of formation face compaction and employing the correct type and amount of fluid loss additive, some leakoff does occur. In addition to the formation damage that leakoff causes, leakoff results in two other pronounced affects. They are:

1. Seepage of the leakoff effluent requires additional energy and fracturing fluid to that necessary for obtaining the desired fracture area.

2. Leakoff causes some formation swelling due to the chemical action of the leakoff effluent on the rock which provides an effect like elastic rebound of the formation.[36,58] The formation swelling effect can help in retarding vertical fracture height growth by reducing the size of the fracture apertures available to flow for the spreading of the fracture perimeter.

The presence and flow of pore fluids (oil, water and gas) affect the deformation (compaction and/or swelling) response of the porous formation surrounding the fracture. The in-situ material properties of an undrained formation are often appreciably higher than in-situ material properties of a drained formation; a feature which must be considered whenever in-situ material properties are employed in predicting vertical fracture height growth. The in-situ stress properties surrounding the fracture are also influenced by the presence of pore fluids.

Since proppant blockage in the upper and lower fracture tips provides a protective encirclement that controls vertical fracture height, which, in turn, results in more rapid flow down the main avenue of the fracture, the desired fracture penetration can be achieved without fracturing out of zone. In addition, rate does not have to be reduced to restrain pressure in an attempt to restrict fracture height. Employing the correct rate results in the proppant being properly placed and the fracture being fully packed in length as well as in width and height. This results in a highly conductive fracture from the desired length to the wellbore which is precisely why industrial hydraulic fracture treatments are conducted.

A plot of the dimensionless fracture height growth rate (R_{fg}) versus dimensionless fracture tip size (S_{ft}) as a function of viscosity ratio (VR) for both Newtonian (n'=1.0) and non-Newtonian (n'=0.5) fluids is generated in Fig. 28.[44] Viscosity ratio is defined as the contrast of the altered viscosity in the fracture tip to the viscosity in the main portion of the fracture. Typically, viscosity ratio is 1.0 or greater as a result of the proppant effect in the fracture tip.

Examination of Fig. 28 shows for a viscosity rátio greater than 1.0 that the reduction in fracture height growth rate is rapid for small increases in fracture tip size; therefore, even a small proppant bank in the fracture tip will result in a significant reduction in fracture height growth rate. Theoretically, the increase in the viscosity of the slurry in the fracture tip compared to the viscosity of the slurry in the main aisle of the fracture is on the order of 100[11]; however, if bridging of the proppant occurs such that the fluid must flow through it, a much higher viscosity ratio would be appropriate. If the viscosity ratio for a non-Newtonian fluid is increased from 1.0 to 40 and the proppant bank height reaches only 5% of the fracture height, fracture height growth rate will decrease from approximately 0.905 to 0.25, a decrease of 74%.

To obtain a viscosity ratio of less than 1.0 in Fig. 28, heat up of the slurry in the fracture tip is necessary. If this happens, fracture height growth rate is very slow and considerable increase in fracture tip size is required before a significant decrease in fracture height growth rate can be achieved; therefore, temperature changes at the fracture tip are not likely to increase fracture height growth rate seriously.[11] If viscosity ratio for a non-Newtonian fluid is decreased from 1.0 to 0.1 and the proppant bank height reaches 5% of the fracture height, fracture height growth rate will increase only from approximately 0.95 to 0.99, a 4% increase.

Simonson et al[35] suggested that the magnitude of the in-situ stress gradient could be used to control vertical fracture height growth, and by examining the stress intensity factors for the upper and lower sections of the fracture, they[35] generated the following expression.

$$K_{Il} - K_{Iu} = (0.8862)(g_{fs} - g_{ms})(H_f)(\sqrt{H_f}) \quad \text{.................. (18)}$$

Fracture propagation in the horizontal direction begins when the fracture leading edge stress intensity factor (K_I) becomes greater than the critical stress intensity factor (K_{Ic}), and the upper and lower fracture tip stress intensity factors (K_{Iu} and K_{Il}) are greater than the fracture leading edge stress intensity factor (k_I) by a factor of 1.25 or greater. With this in mind, examination of Equation 18 shows that the downward or upward fracture height growth will be favored if the pressure gradient of the fracturing slurry (g_{fs}) is greater or less than the gradient of the minimum in-situ stress(g_{ms}). This result shows that fracturing slurry density can help contain vertical fracture height growth. The existence of the flow impedance mechanism has been previously pointed out by several authors[35,42,44,58], but the phenomena has not been delved into in any detail. These authors pointed out that heavy/light proppant particles when mixed with frac fluid will settle/rise to the bottom/top of the fracture tips and effectively reduce the transmissivity (permeability) wherever they collect. The flow impedance mechanism can be generalized to include any feature which acts to block flow in narrow fracture apertures such as spalled rock particles (Kiel frac), slugs of proppant separated by spacers of frac fluid (tip frac and pillar frac), etc.

RESULTS

It has been theoretically determined, well established by field results, and fully documented in the petroleum engineering literature that high sand concentration in an induced fracture has many advantages.[17,20,59-70] The referenced literature is cited here to show development of ideas and performance results rather than to present a scholarly listing of references. The advantages of high sand concentration in a created fracture relate to the following:

1. More complete fracture fill-up, both vertical and horizontal.

2. Less sand crushing and more resistant to the effects of fines.

3. Less damage to the fracture faces and proppant bed.

4. Forms the easiest, least expensive, strongest upper and lower fracture containment mechanism to completely arrest fracture height growth by providing upper and lower sand bridging barriers to vertical fracture propagation. This, in turn, results in maximizing the fracture area in contact with the productive reservoir rock with respect to volume injected and other treatment parameters; consequently, productivity is greater, abandonment pressure is lowered, and additional reserves are recovered.

5. Greater initial and sustained fracture flow capacity.

6. Higher initial production increase and higher sustained production, thus recovery of more reserves and higher initial and sustained profits.

High sand concentration fracturing treatments have been performed at depths of 2,000 to 12,000 ft and in numerous formations, some of which are the Yates, Seven Rivers, Queen, Grayburg, San Andres, Glorieta, Clearfork, Spraberry, Dean, etc.

The high sand concentration fracturing process is a stimulation procedure that takes advantage of the sand carrying capacity of modern crosslinked polymers. Sand concentrations of 12 to 14 lb/gal are routinely pumped and 20 lb/gal can be pumped if necessary. The result is high conductivity in the propped portion of the fracture. High sand fracturing treatments vary with formation characteristics; however, a typical high sand fracturing treatment might be composed of a 5,000-10,000 gal prepad, a 5,000-10,000 gal pad, and 20,000-40,000 gal of gelled, crosslinked, fracturing fluid (50 lb/1,000 gal polymer gelling agent and 50 lb/1,000 gal fluid loss agent) and could be expected to place 200,000-400,000 lb of 10-20, 12-20, 16-30, and/or 20-40 mesh sand in the created fracture at approximately 50 BPM. The usual result of the afore mentioned high sand fracturing treatment is that production will be enhanced by an increase of approximately 4 to 5, and the increase in production will have a low decline rate and be sustained for several years. Examples of production increases, low decline rates, and sustained production of high sand treatments are presented in Figs. 28-31. The production decline curves presented in Figs. 28-31 are for wells in West Texas, and are representative of most of the high sand concentration fracturing treatments that have been performed by the author and his associates. Other production data and decline curves showing similar results are available; however, for the sake of brievity, they are not included. Examination of Figs. 28-31 shows the high sand concentration fracture treatment wells to have a high initial producing rate, a low decline rate, and sustained production.

In order to show that high sand concentration fracturing treatments are successful in other areas, additional production data is presented in Tables V and VI. Presented in Table V is the production data for 20 high sand concentration fracturing treatments performed in Oklahoma at depths of approximately 3,000 to 8,500 ft. Presented in Table VI is the production data for 11 high sand concentration fracturing treatments performed in South Texas at a depth of approximately 9,800 ft. Examination of the data in Tables V and VI shows the high sand concentration treatments to be very successful.

SUMMARY AND CONCLUSIONS

Based on what has gone before, an attempt has been made to express as simply as possible the major factors that affect the success of the design, performance, and results of high sand concentration fracturing treatments. Each major factor has been discussed in turn and its pros and cons examined. Little, however, has been said about the realities which will be forcibly brought to the attention of the design engineer when he or she first attempts the actual design and performance of a high sand concentration fracturing treatment. This omission was deliberate. It would require a much larger volume than this paper to present a comprehensive explanation and discussion of the complexities of the data, design, and performance of high sand concentration fracturing treatments. The aim of this paper is to show what can be accomplished if the correct data, proper design, and adequate performance of high sand concentration fracturing treatments are selected for the conditions encountered. It is the basic philosophy of the paper that high sand concentration fracturing treatments are difficult only when the data, design, and performance have not been adequately tailored to produce the best results. Thus, the tone of the paper is intended to suggest, at least broadly, a system which appears to be generally applicable at this time. This is not to imply that simpler systems of hydraulic fracture treatment design may not prove, in many cases, to be more convenient to use. It is always much easier to favor the easy approach and use the simplest method. A method of hydraulic fracture treatment design is required that is both theoretically sound and practically tractable. High sand concentration fracturing treatments are designed and performed by methods that are both theoretically sound and practically tractable, and each method is both quantitive and qualitative. Quantitive results without qualitive results is only of academic importance in evaluating the results of a hydraulic fracturing treatment. Both the initial production increase (quantitive) and the sustained production increase (qualitive) should be used in evaluating the results of a hydraulic fracture treatment.

By no means are high sand concentration fracturing treatments the final and only answer to well stimulation and petroleum recovery problems; however, they do offer a technological field that has potentials of yielding large rewards.

NOMENCLATURE

C_{fD} = dimensionless fracture conductivity

E = Young's modulus, psi

E_f = Young's modulus of the fractured formation, psi

E_l = Young's modulus of the lower barrier formation, psi

E_u = Young's modulus of the upper barrier formation, psi

G = shear modulus, psi

G_f = shear modulus of the fractured formation, psi

G_l = shear modulus of the lower barrier formation, psi

G_u = shear modulus of the upper barrier formation, psi

g_{fs} = fracturing slurry gradient, psi/ft

g_{ms} = minimum in-situ stress gradient, psi/ft

H_f = fracture height, ft

K = bulk modulus, psi

K_l = stress intensity factor at the front and/or leading edge of the fracture, psi-in.$^{0.5}$

K_{lc} = critical stress intensity factor, psi-in.$^{0.5}$

K_{ll} = stress intensity factor at the lower tip of the fracture, psi-in.$^{0.5}$

K_{lu} = stress intensity factor at the upper tip of the fracture, psi-in.$^{0.5}$

K_f = fracture permeability, md

K_r = reservoir permeability, md

K' = consistency index, lb/sec n'/ft^2

K'_v = Fann viscometer consistency index, lb/Sec n'/ft^2

L_f = fracture length, ft

n' = flow behavior index, dimensionless

Q = injection rate, BPM

q_f = fracture flux density, BPD-ft

q_{fD} = dimensionless flux density

R_f = fracture radius, ft

R_{fg} = dimensionless fracture growth rate

r_e = drainage radius, ft

r_w = wellbore radius, ft

S.G. = specific gravity, dimensionless

SR = shear rate, sec^{-1}

S_f = pseudo skin factor

S_{ft} = dimensionless fracture tip size

W_h = healed fracture width, in.

W_t = treating fracture width, in.

Δp = pressure differential across the fracture face, psi

Δp_{fD} = dimensionless pressure differential across the fracture face

Δp_f = pressure differential across the fracture face to the front and/or leading edge of the fracture, psi

Δp_{fu} = pressure differential across the fracture face to the upper tip of the fracture, psi

Δp_{fl} = pressure differential across the fracture face to the lower tip of the fracture, psi

Δt_c = compressive travel time, microsec/ft

Δt_s = shear travel time, microsec/ft

μ_a = apparent viscosity, cp

μ_{a170} = apparent viscosity at 170 sec^{-1}, cp

υ = Poisson's ratio, dimensionless

υ_f = Poisson's ratio of the fractured formation, dimensionless

υ_l = Poisson's ratio of the lower barrier formation, dimensionless

υ_u = Poisson's ratio of the upper barrier formation, dimensionless

ρ_b = bulk density, gm/cc

τ = effective fracture surface energy, ft-lb/in.^{2}

τ_f = effective fracture surface energy of the fractured formation, ft-lb/in.^{2}

τ_l = effective fracture surface energy of the lower barrier formation, ft-lb/in.^{2}

τ_u = effective fracture surface energy of the upper barrier formation, ft/in.^{2}

ACKNOWLEDGEMENTS

The author wishes to express his appreciation for the professional manner and method exercised by Alpha & Omega, Qualidraft-Qualitype, and Graphics Interpretations in the typing, drafting, and computer work of this paper.

REFERENCES

1. Smith, John E.: "Prediction Of The Orientation And Azimuthal Direction Of Induced Fractures," Fourteenth Annual Southwestern Petroleum Short Course Proceedings (April 20-21, 1967) 13-26.

2. Smith, John E.: "Hydraulic Fracture Treatment Evaluation - Shafter Lake San Andres Unit - Shafter Lake (San Andres) Field," Eighteenth Annual Southwestern Petroleum Short Course Proceedings (April 15-16, 1971) 39-52.

3. Perkins, T. K. And Gonzales, J. A.: "The Effect Of Thermoelastic Stresses On Injection Well Fracturing," Soc. Pet. Eng. J. (Feb., 1985) 78-88.

4. Britt, L. K. And Bennett, C. O.: "Determination Of Fracture Conductivity In Moderate - Permeability Reservoirs Using Bilinear Flow Concepts," SPE Paper 14165 Presented At The 60th Annual Technical Conference And Exhibition Of The SPE Of AIME, Las Vegas, Nev. (Sept. 22-25, 1985).

5. Britt, L. K.: "Optimized Oilwell Fracturing Of Moderate - Permeability Reservoirs," SPE Paper 14371 Presented At The 60th Annual Technical Conference And Exhibition Of The SPE Of AIME, Las Vegas, Nev. (Sept. 22-25, 1985).

6. Katagiri, Kunio And Ott, William K.: "Frac Treatment Boosts Geothermal Well Production," World Oil (Sept., 1983) 64-67.

7. Nolte, K. G.: "Determination Of Fracture Parameters From Fracturing Pressure Decline," SPE Paper No. 8341 Presented At The 54th Annual Technical Conference And Exhibition Of The SPE Of AIME, Las Vegas, Nev. (Sept. 23-26, 1979).

8. Nolte, K. G. And Smith, M. F.: "Interpretation Of Fracturing Pressures," J. Pet. Tech. (Sept., 1981) 1767-1775.

9. Nolte, K. G.: "Fracturing Design Considerations Based On Pressure Analysis," SPE Paper 10911 Presented At The SPE Cotton Valley Symposium, Tyler, Tex. (1982).

10. Nolte, K. G.: "Basic Frac Concepts And Frac Design," SPE Hydraulic Fracturing Symposium, Texas Tech Chapter Of The SPE Of AIME, Lubbock, Tex. (April 7, 1982).

11. Veatch, R. W. And Crowell, R. F.: "Joint Research Operations Programs Accelerate Massive Hydraulic Fracturing Technology," J. Pet. Tech. (Dec., 1982) 2763-2775.

12. Veatch, Jr., R. W.: "Overview Of Current Hydraulic Fracturing Design And Treatment Technology - Part 1," J. Pet. Tech. (April, 1983) 677-687.

13. Mendelsohn, D. A.: "A Review Of Hydraulic Fracture Modeling - Part I: General Concepts, 20 Models, Motivation For 3D Modeling," Journal Of Energy Resources Technology (Sept., 1984) 369-376.

14. Crittendon, Bob C.: "Hydraulic Fracture Treatment Design Manual," Magnolia Petroleum Company (July 25, 1958).

15. Crittendon, Bob C.: "The Mechanics Of Design And Interpretation Of Hydraulic Fracture Treatments," J. Pet. Tech. (Oct., 1959) 21-28.

16. Smith, John E.: "Effect Of Incomplete Fracture Fill-Up At The Wellbore On Productivity Ratio," SPE Paper No. 4677 Presented At The 48th Annual Fall Meeting Of The SPE Of AIME, Las Vegas, Nev. (Sept. 30-Oct. 3, 1973).

17. Smith, John E.: "Effect Of Incomplete Fracture Fill-Up At The Wellbore On Productivity Ratio," Twenty-Second Annual Southwestern Petroleum Short Course Proceedings (April 17-18, 1975) 135-144.

18. Handke, Wayne And Watson, Eddie: "Microprocessor Controlled Blender Used To Provide Ramping Sand Concentration Schedule During Fracturing Jobs In West Texas," Thirty-fourth Annual Southwestern Petroleum Short Course Proceedings (April 22-23, 1987) 95-101.

19. Halliburton Services: "The Fracbook Design/Data Manual For Hydraulic Fracturing," A Halliburton Company (1971).

20. Coulter, G. R. And Wells, R. D.: "The Advantages Of High Proppant Concentration In Fracture Stimulation," J. Pet. Tech. (June, 1972) 643-650.

21. Cinco, L. Heber, Samaniego, V. F., And Dominguez, A. N.: "Transiet Pressure Behavior For A Well With A Finite-Conductivity Vertical Fracture," Soc. Pet. Eng. J. (Aug., 1978) 253-264.

22. van Poollen, H. K.: "Productivity Vs Permiability Damage In Hydraulically Produced Fractures," API Drilling And Production Practice (1957) 103-110.

23. Pratts, M.: "Effect Of Vertical Fractures On Reservoir Behavior - Incompressible Case," Soc. Pet. Eng. J. (June, 1961) 105-118.

24. McGuire, W. J. And Sikora, V. J.: "The Effect Of Vertical Fractures On Well Productivity," Trans. AIME (1960), Vol. 219, 401-403.

25. van Poollen, H. K., Tinsley, J. M., And Saunders, C. D.: "Hydraulic Fracturing; Fracture Flow Capacity Vs Well Productivity," SPE Paper No. 890-G Presented At 32nd Annual Fall Meeting Of The SPE Of AIME, Dallas, Tex. (Oct. 6-9, 1957).

26. Norman, Michael E. And Fast, C. Robert: "Proppant Monograph," General Abrasive Division Of Dresser Industries (1985).

27. Craft, B. C., Holden, W. R., And Graves, Jr., E. D.: "Well Design: Drilling And Production," Prentice-Hall, Inc. (1962) 483-535.

28. Smith, John E.: "Hydraulic Fracture Treatment Design," Twelfth Annual Southwestern Petroleum Short Course Proceedings (April 22-23, 1965) 65-86.

29. Smith, John E.: "Design Of Hydraulic Fracture Treatments," SPE Paper No. 1286 Presented At The 40th Annual Fall Meeting Of The SPE Of AIME (Oct. 3-6, 1965).

30. Howard, G. C. And Fast, C. R.: "Hydraulic Fracturing," SPE Of AIME Monograph Volume 2 Of The Henry L. Doherty Series (1970) 40, 42, 43, 150.

31. Ely, John W.: "Stimulation Treatment Handbook - An Engineer's Guide To Quality Control," PennWell Publishing Company (1985).

32. Parker, Cecil D.: "Logistic And Operational Considerations For Massive Hydraulic Fracturing," J. Pet. Tech. (July, 1981) 1189-1195.

33. Pai, Vithal J., Garbis, Sam J., And Hall, Howard: "MHF - From Concept To Execution," Thirtieth Annual Southwestern Petroleum Short Course Proceedings (April, 27-28, 1983) 100-129.

34. Kithas, Bill A.: "Lithology, Gas Detection, And Rock Properties From Acoustic Logging Systems," SPWLA Paper No. 7005 Presented At The SPWLA 17th Annual Logging Symposium, Denver, Colo. (June 9-12, 1976).

35. Simonson, E. R., Abou-Sayed, A. S., And Clifton, R. J.: "Containment Of Massive Hydraulic Fractures," Soc. Pet. Eng. J. (Feb., 1978) 27-32.

36. Daneshy, A. A.: "Hydraulic Fracture Propagation In Layered Formations," Soc. Pet. Eng. J. (Feb., 1978) 33-41.

37. Cleary, M. P.: "Primary Factors Governing Hydraulic Fractures In Heterogeneous Stratified Porous Formations," ASME Paper No. 78-PET-47 Presented At The 1978 ASME Energy Technology Conference, Houston, Tex. (Nov. 5-9, 1978).

38. Advani, S. H. et al: "Hydraulic Fracture Modeling For The Eastern Gas Shales Program," 1982 Eastern Gas Shales Symposium, 1, DOE/METC, Pittsburg, Pa.

39. Hanson, M. E., Anderson, G. D., Shaffer, R. J., And Thorson, L. D.: "Some Effects Of Stress, Friction, And Fluid Flow On Hydraulic Fracturing," Soc. Pet. Eng. J. (June, 1982) 321-332.

40. Warpinski, Norman A., Clark, James A., Schmidt, Richard A., And Huddle, Clarence W.: "Laboratory Investigation On The Effect Of In-Situ Stress On Hydraulic Fracture Containment," Soc. Pet. Eng. J. (June, 1982) 333-340.

41. van Eekelen, H. A. M.: "Hydraulic Geometry: Fracture Containment In Layered Formations," Soc. Pet. Eng. J. (June, 1982) 341-349.

42. Voegle, M. D., Abou-Sayed, A. S., And Jones, A. H.: "Optimization Of Stimulation Design Through The Use Of In-Situ Stress Determination," J. Pet. Tech. (June, 1983) 1071-1081.

43. Teufel, Lawrence W. And Clark, James A.: "Hydraulic Fracture Propagation In Layered Rock: Experimental Studies Of Fracture Containment," Soc. Pet. Eng. J. (Feb., 1984) 19-32.

44. Settari, A.: "Quantitative Analysis Of Factors Influencing Vertical And Lateral Fracture Growth," SPE/DOE Paper No. 13862 Presented At The 1985 SPE/DOE Joint Symposium On Low Permeability Reservoirs, Denver, Colo. (May 19-22, 1985) 117-134.

45. Blanton, T. L. And Teufel, L. W.: "In-Situ Stress Determination From Wellbore Elongation," SPE/DOE Paper No. 13877 Presented At The 1985 SPE/DOE Joint Symposium On Low Permeability Reservoirs, Denver, Colo. (May 19-22, 1985) 279-292.

46. Anderson, Terry And Walker, Terry: "Log Derived Rock Properties For Use In Well Stimulation Design," SPE Paper Presented At The SPE 47th Annual Fall Meeting, San Antonio, Tex. (Oct. 8-11, 1972).

47. Nations, J. F.: "Lithology And Porosity From Acoustic Shear And Compressional Wave Transit Time Relationships," SPWLA Paper Presented At The SPWLA 15th Annual Symposium, McAllen, Tex. (June 2-5, 1974).

48. Pickett, G. R.: "Acoustic Character Logs And Their Applications In Formation Evaluation," SPE Paper No. 452 Presented At The SPE 37th Annual Fall Meeting, Los Angeles, Calif. (Oct. 7-10, 1962).

49. Warpinski, N. R., Schmidt, R. A., And Northrop, D. A.: "In-Situ Stresses: The Predominant Influence On Hydraulic Fracture Containment," SPE Paper No. 8932 Presented At The 1980 SPE/DOE Symposium On Unconventional Gas Recovery, Pittsburgh, Pa. (May 18-20, 1980).

50. Sneddon, I. N.: "The Distribution Of Stress In The Neighborhood Of A Crack In An Infinite Solid," Proc., Roy. Soc. London, Series A (Oct.-Dec., 1946), 187, 229.

51. Daneshy, A. A.: "Rock Properties Controlling Hydraulic Fracture Propagation," SPE Paper No. 5752 Presented At The 1976 SPE European Spring Meeting, Amsterdam, Netherlands (April 8-9, 1976).

52. Perkins, T. K. And Bartlett: "Surface Energies Of Rocks Measured During Cleavage," Soc. Pet. Eng. J. (Dec., 1963) 307-313.

53. Cleary, M. P.: "Primary Factors Governing Hydraulic Fractures In Heterogenenous Stratified Porous Formations," ASME Paper No. 78-Pet-47 Presented At The ASME Energy Technology Conference And Exhibition, Houston, Tex. (Nov., 1978).

54. Griffith, A. A.: "The Phenomena Of Rupture And Flow In Solids," Phil. Trans. , Royal Society, London (1921) Vol. A221, 163-198.

55. Griffith, A. A.: "The Theory Of Rupture," Proc., Int. Cong. Appl. Mech. (1924).

56. Sneddon, I. N. And Elliot, H. A.: "The Opening Of A Griffith Crack Under Internal Pressure," Quart. Appl Match. 4 (1946) 262-267.

57. Perkins, T. K. And Gonzalez, J. A.: "The Effect Of Thermoelastic Stresses On Injection Well Fracturing," Soc. Pet. Eng. J. (Feb., 1985) 78-88.

58. Cleary, Michael P.: "Analysis Of Mechanisms And Procedures For Producing Favorable Shapes Of Hydraulic Fractures," SPE Paper No. 9260 Presented At The SPE 56th Annual Fall Meeting, Dallas, Tex. (Sept. 21-24, 1980).

59. Seidel, W. R. And Stahl, Jr., E. J.: "Gas Well Stimulation With A Viscous Water-Base Fracturing Fluid," J. Pet. Tech. (Nov., 1972) 1385-1390.

60. Coulter, G. R., Matthews, B. A., Seglem, R. L., And Smith, J. E. "Chick": "The Theoretical And Mechanical Aspects Of Ultra High Sand Concentrations In Hydraulic Fracturing," Proceedings Of The Twenty-Seventh Annual Meeting, Southwestern Petroleum Short Course, Texas Tech University, Lubbock, Tex. (April 17-18, 1980) 97-104.

61. Wright, Jr., T. R., Pankonien, Laura J., And Leonard, J. G.: "Well Completion Practices In Active U.S. Areas," World Oil (May, 1980) 9, 78.

62. Pitts, John Paul: "Unique Spraberry Frac Sparks New Hopes," Drill Bit (July, 1980) 20-24.

63. Mickey, Vernetta: "Chick Frac Utilizes High Sand Concentrations," Drill Bit (Feb., 1981) 62-66.

64. Waters, A. B.: "History Of Hydraulic Fracturing," SPE Hydraulic Fracturing Symposium, Texas Tech SPE Chapter Of AIME, Texas Tech University, Lubbock, Tex., (April 7, 1982).

65. Garvin, Tom: "Present Fracturing Practices (West Texas)," SPE Hydraulic Fracturing Symposium, Texas Tech SPE Chapter Of AIME, Texas Tech University, Lubbock, Tex. (April 7, 1982).

66. Petzet, G. A.: "High Sand Fracs Hike Output In Oklahoma Wells," Oil & Gas J. (Oct. 11, 1982) 90-92.

67. Shah, S. N., Smith, D. R., And Donaldson, D. E.: "Ultra-High Sand Concentration In Hydraulic Fracturing - A Case History," SPE Paper No. 11578, Proceedings Of The Third SPE National Production Operations Symposium, Oklahoma City SPE Section Of AIME, Oklahoma City, Okla. (Feb. 27-March 1, 1983) 261-270.

68. Smith, John M.: "Ultra High Sand Concentration Hydraulic Fracturing Treatments," Texas Tech University Petroleum Engineering Department Seminar Report (Fall, 1983).

69. Gregorcyk, William A., Pauls, Richard, Holtmeyer, Marlin, Venditto, J. J., And Chisholm, Pat: "High Frac Sand Concentrations Boost Production In Texas' Olmos Formation," Oil & Gas J. (Sept. 17, 1984) 105-108.

70. Shaw, Subhash N. And Smith, David R.: "Ultrahigh Sand Concentrations Boost Oklahoma Production," Pet. Eng. Int. (Jan., 1985) 50-58.

TABLE I
Sand-Fluid Fracturing Slurry Properties*

Sand-Fluid Ratio Lb Sand/Gal Fluid	Sand-Slurry Ratio Lb Sand/Gal Slurry	Fluid-Slurry Ratio Gal Fluid/Gal Slurry	Slurry-Fluid Ratio Gal Slurry/Gal Fluid	Slurry Density Lb/Gal
0.5	0.489	0.978	1.022	8.743
1.0	0.957	0.957	1.045	9.034
1.5	1.404	0.936	1.068	9.304
2.0	1.834	0.917	1.090	9.573
2.5	2.245	0.898	1.112	9.824
3.0	2.643	0.881	1.135	10.079
3.5	3.024	0.864	1.158	10.316
4.0	3.388	0.847	1.180	10.537
4.5	3.740	0.831	1.202	10.754
5.0	4.080	0.816	1.225	10.967
5.5	4.406	0.801	1.248	11.166
6.0	4.728	0.788	1.270	11.379
6.5	5.023	0.773	1.294	11.547
7.0	5.315	0.759	1.317	11.721
7.5	5.601	0.747	1.339	11.906
8.0	5.872	0.734	1.362	12.067
8.5	6.137	0.722	1.385	12.231
9.0	6.399	0.711	1.407	12.400
9.5	6.641	0.699	1.430	12.541
10.0	6.890	0.689	1.452	12.705
10.5	7.119	0.678	1.475	12.841
11.0	7.348	0.668	1.498	12.986
11.5	7.567	0.658	1.520	13.121
12.0	7.776	0.648	1.543	13.245
12.5	7.988	0.639	1.566	13.381
13.0	8.190	0.630	1.588	13.507
13.5	8.381	0.621	1.611	13.622
14.0	8.571	0.612	1.633	13.736
14.5	8.755	0.604	1.656	13.853
15.0	8.935	0.596	1.679	13.965
15.5	9.110	0.588	1.701	14.073
16.0	9.281	0.580	1.724	14.176
16.5	9.445	0.572	1.747	14.273
17.0	9.610	0.565	1.769	14.381
17.5	9.766	0.558	1.792	14.476
18.0	9.923	0.551	1.814	14.576
18.5	10.071	0.544	1.837	14.665
19.0	10.215	0.538	1.860	14.753
19.5	19.361	0.531	1.882	14.846
20.0	10.499	0.525	1.905	14.930
20.5	10.633	0.519	1.928	15.011
21.0	10.769	0.513	1.950	15.097
21.5	10.897	0.507	1.973	15.176
22.0	11.028	0.501	1.995	15.259

* Based on sand having a true density of 22.1 lb/gal (specific gravity = 2.65) and 2% KCl water having a density of 8.44 lb/gal at 60°F (specific gravity = 1.011).

TABLE II
Velocity Ratio As A
Function of Lithology

Formation Type	Velocity Ratio* (Dimensionless)
Limestone	1.90
Limey Dolomite	1.85
Dolomite	1.80
Sandy Dolomite	1.75
Soft Sandstone	1.70
Medium Sandstone	1.65
Hard Sandstone	1.60

$$* \text{ Velocity Ratio} = \frac{\text{Compressive Travel Time}}{\text{Shear Travel Time}}$$

TABLE III
Values of Formation Properties

Formation Property	Limestone & Dolomite		Sandstone	
	Range	Average	Range	Average
Poisson's Ratio (Dimensionless)	0.26- 0.31	0.29	0.18- 0.24	0.21
Young's Modulus (Psi x 10^6)	8.0 -13.0	10.5	0.5 - 7.5	4.0
Shear Modulus (Psi x 10^6)	3.0 - 5.0	4.0	0.2 - 3.0	1.6
Specific Fracture Surface Energy (Ft-Lb/In.^{2})	0.004-0.020	0.010	0.005-0.070	0.040

TABLE IV
Critical Stress Intensity Factors

Formation Type	Critical Stress Intensity Factor (Psi-In.$^{0.5}$)		
	Maximum	Minimum	Average
Siltstone	1,650	950	1,300
Sandstone	1,600	400	1,000
Limestone	950	400	675
Shale	1,200	300	750
Average	1,350	513	931

TABLE V
High Sand Concentration Fracturing Treatment Results*
Oklahoma

Well No.	Depth (Ft)	Maximum Sand Conc. (Lb/Gal)	Initial Production After Conventional Treatment (BOPD)	Production After High Sand Concentration Treatment: Oil Production Initial (BOPD)	Oil Production 1 Year (BOPD)	Gas Production Initial (MCFPD)	Gas Production 1 Year (MCFPD)
1	3,024	18	1-2	50	21	NA	35
2	3,003	16	1-2	32	10	NA	18
3	3,022	16	1-2	17	10	NA	21
4	3,056	19	1-2	42	18	NA	35
5	2,976	16	1-2	22	9	NA	33
6	3,004	14	1-2	23	9	72	54
7	3,002	14	1-2	22	8	NA	46
8	2,954	14	New	22	8	NA	32
9	3,104	16	1	8	16	Trace	Trace
10	3,204	15	New	24	15	Trace	Trace
11	3,304	16	New	6	3	127	159
12	3,242	16	3	15	8	100	94
13	3,256	15	New	16	13	169	102
14	3,272	16	New	7	4	226	182
15	3,280	14	New	24	8	136	66
16	3,348	12	New	6	5	76	77
17	3,230	14	New	None	None	180	127
18	4,572	16	New	6	18	Trace	Trace
19	8,300	14	0	140	100	Trace	Trace
20	8,500	12	10	50	40	Trace	Trace
Average		15	2	28	17	84	54

* Fluid Type:	Crosslinked, Gelled (40 Lb/1,000 Gal)Water
Pad Volume:	10,000 Gal
Fracturing Fluid Volume:	30,000 Gal
Sand Type:	10-20 Mesh Sand
Sand Quantity:	322,000 Lb
Sand Concentration:	2-18 Lb/Gal
Sand Concentration:	3.4 Lb/Ft^2
Injection Rate:	35 BPM

TABLE VI

High Sand Concentration Fracture Treatment Results
AWP (Olmos Sand) Field - 9800 Ft
McMullen County, Texas

Well No.	Well Type	Frac Fluid Type	Stimulation Fluid Volume (Gal)	Proppant Quantity (Lb)	Average Proppant Conc. (Lb/Gal)	Maximum Proppant Conc. (Lb/Gal)	Average Pump Rate (BPM)	Oil Production Before/After (BPD)	Gas Production Before/After (MCFD)	Oil (Bbl)	Time (Days)	Gas (MMCF)	Time (Days)
1	Oil	Oil/Water Emulsion	33,000	50,000	3.0	4.0	Unk	Heading Oil/26	0/10	1,948	180	0.8	180
2	Oil	Gelled Condensate	40,000	70,000	3.0	4.0	13.4	Swabbing/20	0/10	2,537	180	1.3	180
2 (Refrac)	Oil	Gelled Diesel	177,000	1,500,000	12.0	15.0	12.5	10-14/255	0/357	32,000	180	45.0	180
3	Oil	Gelled Diesel	120,000	403,000	7.5	9.5	12.5	Swabbing/110	0/75	16,290	180	11.1	180
4	Gas	Gelled Diesel	150,000	815,000	10.0	17.0	17.0	2/134	150/1100	10,250	180	178.0	180
5	Oil	Gelled Diesel	206,000	1,250 000	14.0	14.5	12.5	Swabbing/180	0/150	23,600	180	19.7	180
6	Oil	Gelled Water	180,000	1,550,000	8.6	14.8	12.5	TSTM/115	TSTM/200	7,306	66	11.1	65
7	Oil	Gelled Water	181,000	1,185,000	6.5	15.5	12.5	12/80	TSTM/260	4,223	60	15.2	60
8	Oil	Gelled Water	190,000	1,570,000	8.3	14.5	12.6	10/130	10/160	6,377	56	8.8	54
9	Oil	Gelled Water	188,000	1,550,000	8.2	14.3	12.5	11/135	TSTM/90	6,642	49	4.0	45
10	Gas	Gelled Water	200,000	1,650,000	8.3	16.0	12.6	TSTM/70	20/1100	1,920	36	20.1	36
Average			151,000	1,054,000	8.1	12.6	13.1	7/114	16/319	88 BOPD		241 MCFPD	

FIG. 1

FRAC EVALUATION LOG

COMPANY: TAEL
LEASE & WELL NO.: BNSY NO. 1-301
FIELD: SAND HILLS
FORMATION & DEPTH: JUDKINS - 3120 FT
COUNTY & STATE: CRANE CO., TEX.

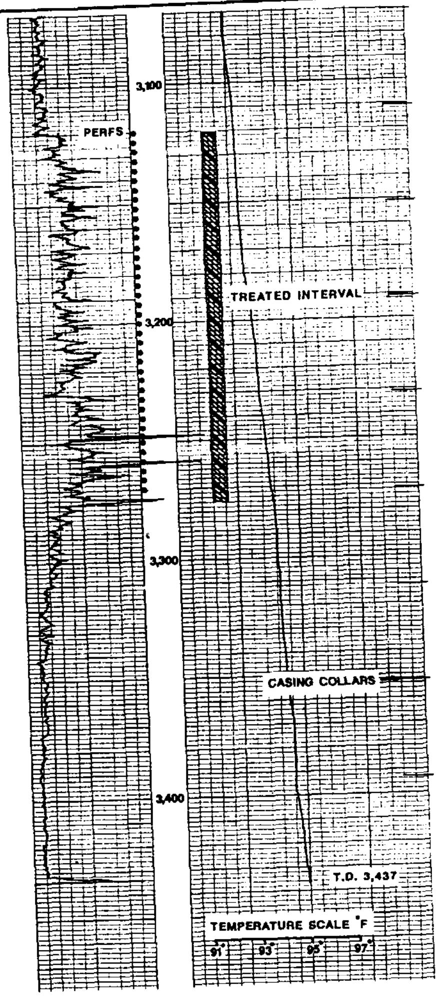


FIG. 2

FRAC EVALUATION LOG

COMPANY: MHI
LEASE & WELL NO.: U 19 W NO. 1
FIELD: EMMA
FORMATION & DEPTH: SAN ANDRES - 4320 FT
COUNTY & STATE: ANDREWS CO., TEX.

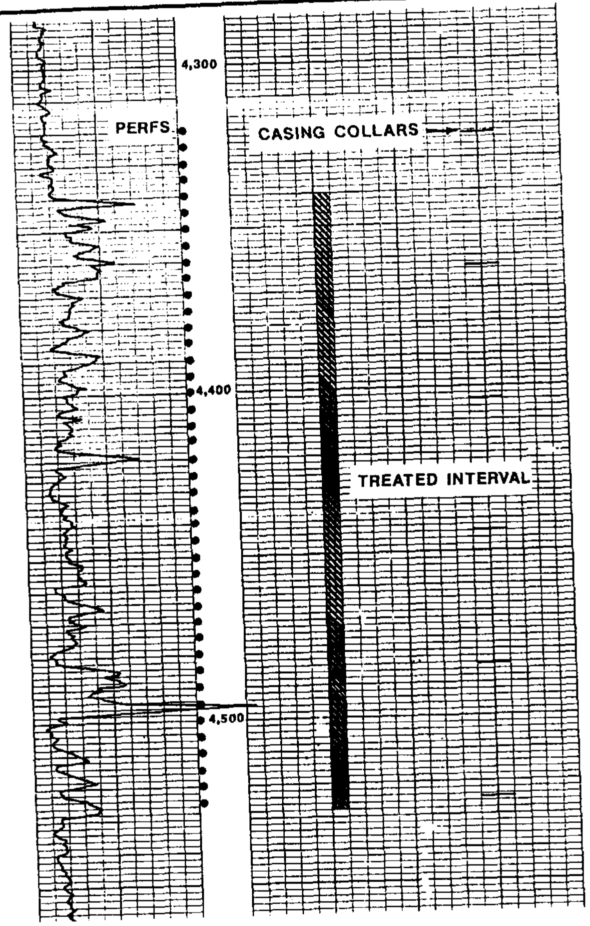


FIG. 3

FRAC EVALUATION LOG

COMPANY: PVI
LEASE & WELL NO.: T NO. 13-5
FIELD: FUHRMAN MASCHO
FORMATION & DEPTH: SAN ANDRES - 4398 FT
COUNTY & STATE: ANDREWS CO., TEX.

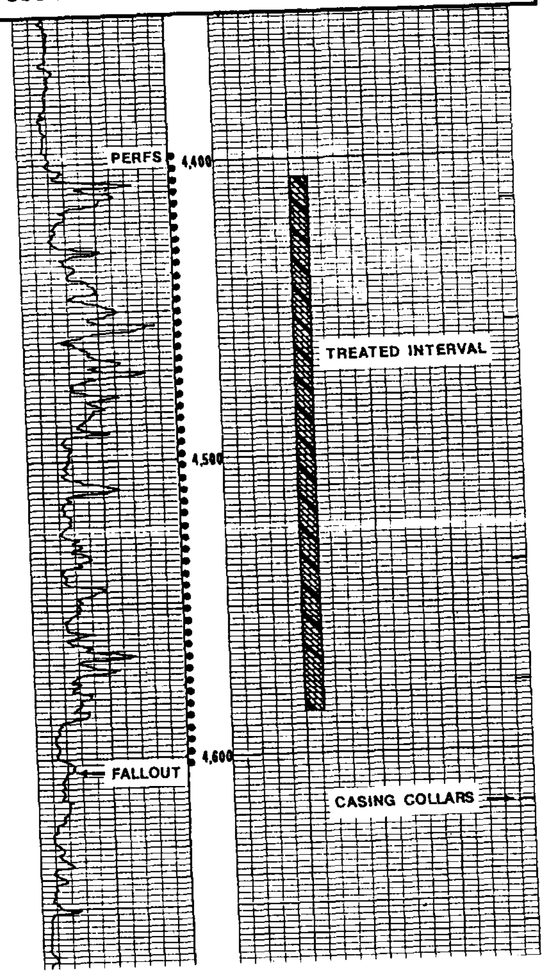


FIG. 4

FRAC EVALUATION LOG

COMPANY: ROC
LEASE & WELL NO.: JEC "C" NO. 7
FIELD: JAMESON
FORMATION & DEPTH: STRAWN – 6584 FT
COUNTY & STATE: COKE CO., TEX.

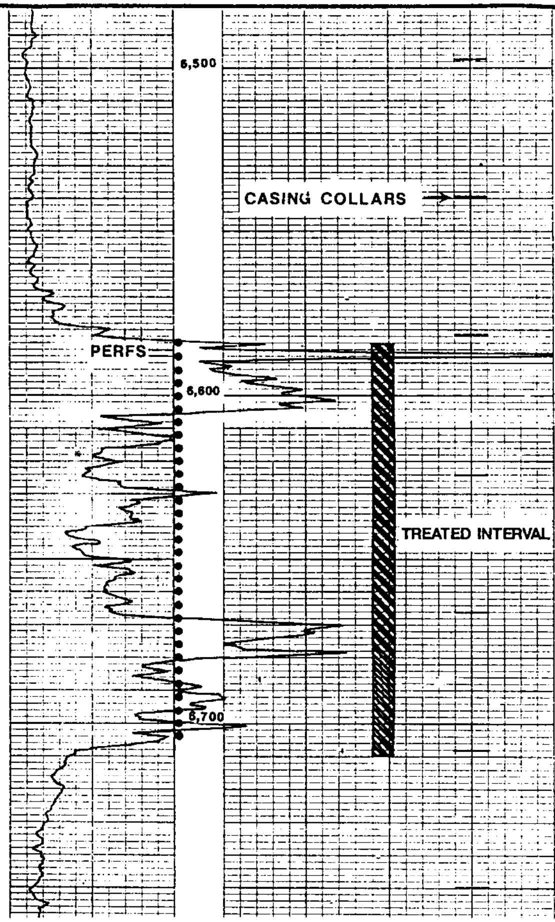


FIG. 5

FRAC EVALUATION LOG

COMPANY: D&CEC
LEASE & WELL NO.: CE "B" NO. 1
FIELD: BIG WHEEL
FORMATION & DEPTH: LOWER SPRABERRY – 8530 FT
COUNTY & STATE: DAWSON CO., TEX.

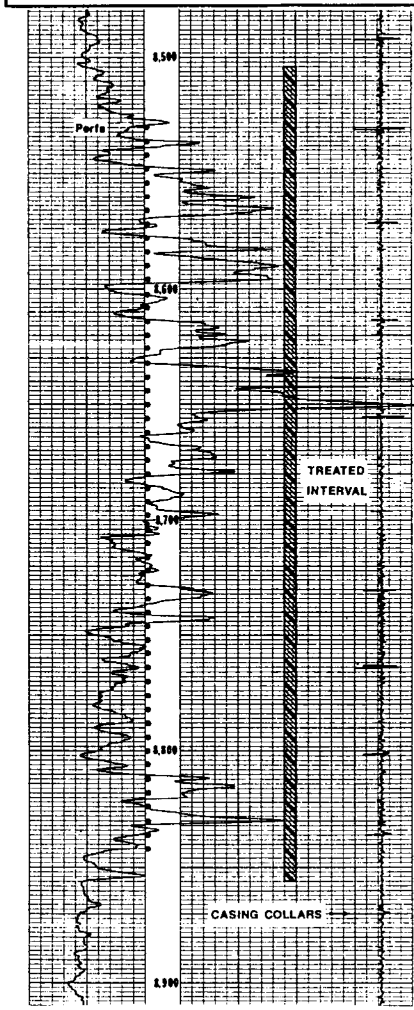
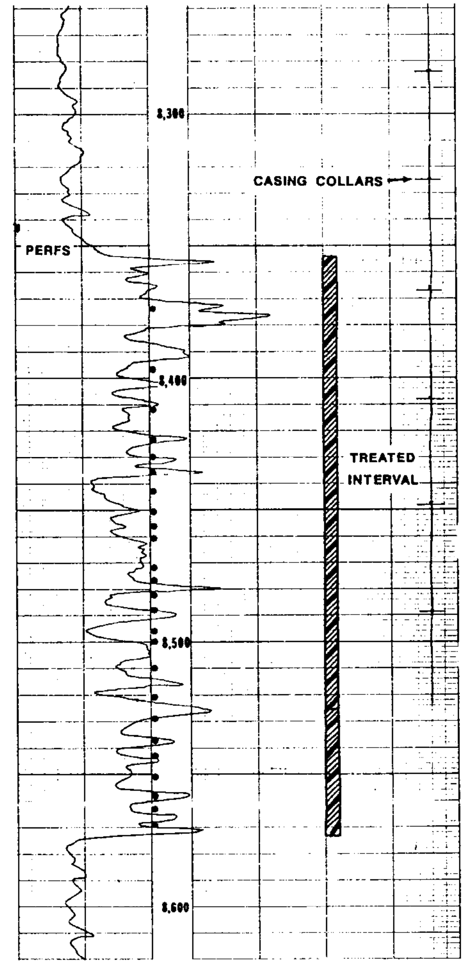


FIG. 6

FRAC EVALUATION LOG

COMPANY: MOC
LEASE & WELL NO.: NOC NO. 1
FIELD: J.L.M.
FORMATION & DEPTH: DEAN – 8374 FT
COUNTY & STATE: MARTIN CO., TEX.



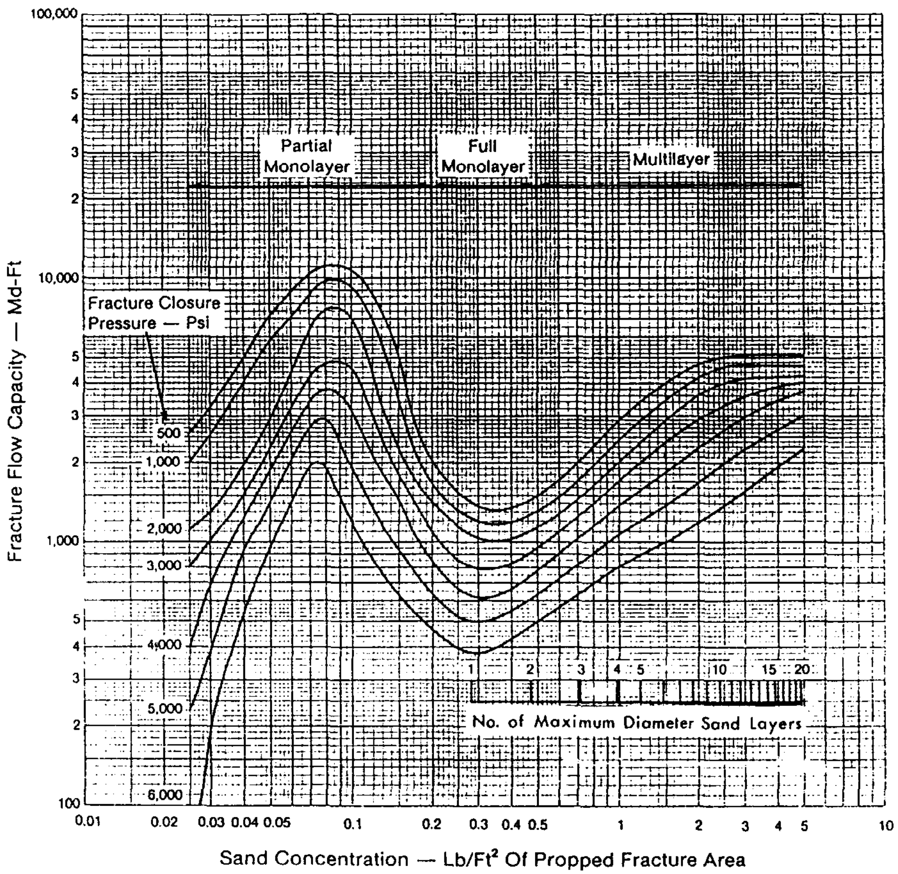


Fig. 7
Effect Of 20-40 Mesh Brady Sand Concentration
At Various Fracture Closure Pressures On
Fracture Flow Capacity

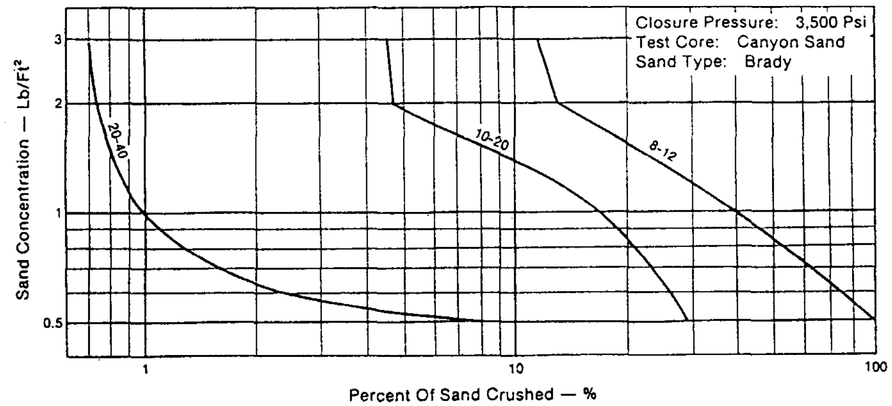


Fig. 8
Effect Of Sand Concentration On The Percentage Of Sand
Crushed For Various Mesh Sizes Of Brady Sand

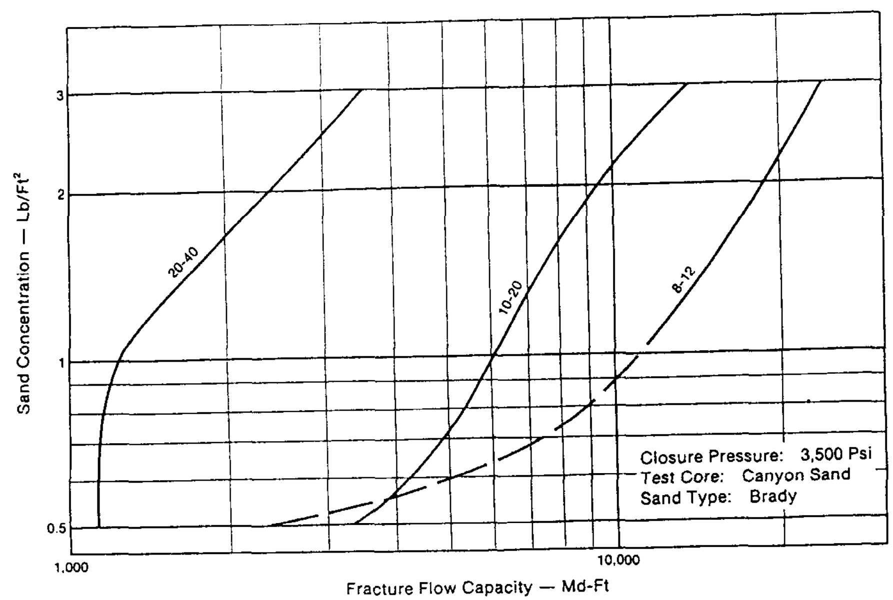


Fig. 9
Effect Of Sand Concentration On Fracture Flow Capacity
For Various Mesh Sizes Of Brady Sand

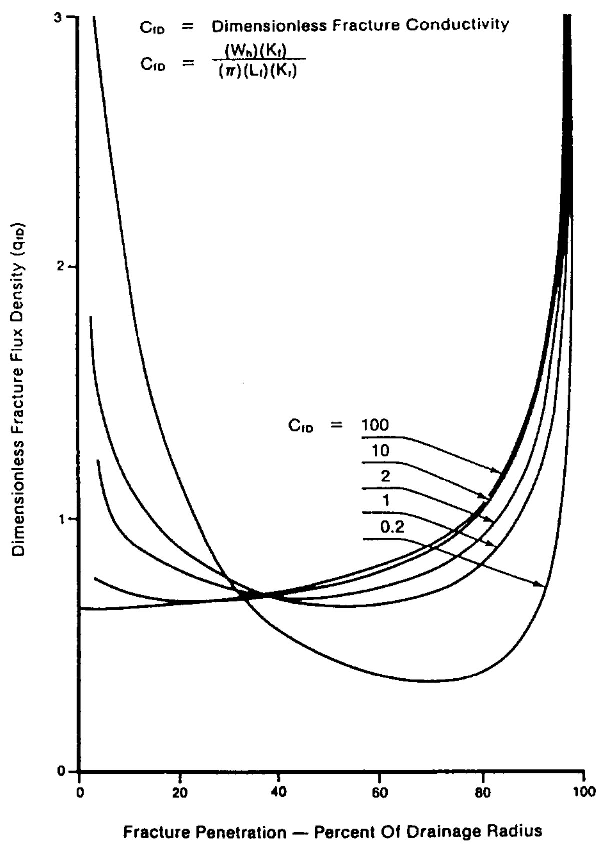


Fig. 10
Effect Of Dimensionless Fracture Conductivity
On Dimensionless Fracture Flux Density Along A Fracture

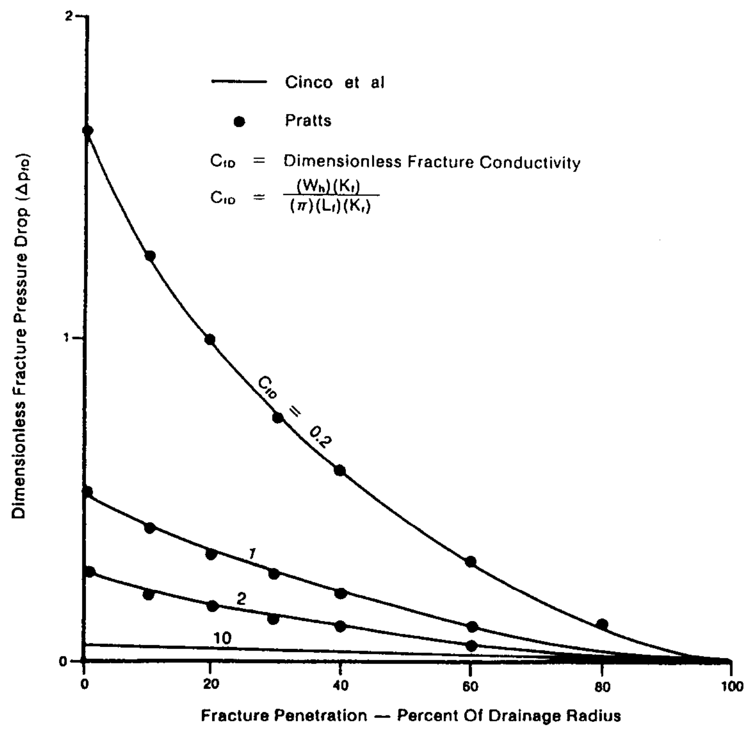


Fig. 11
Effect Of Dimensionless Fracture Conductivity
On Dimensionless Fracture Pressure Drop Along A Fracture

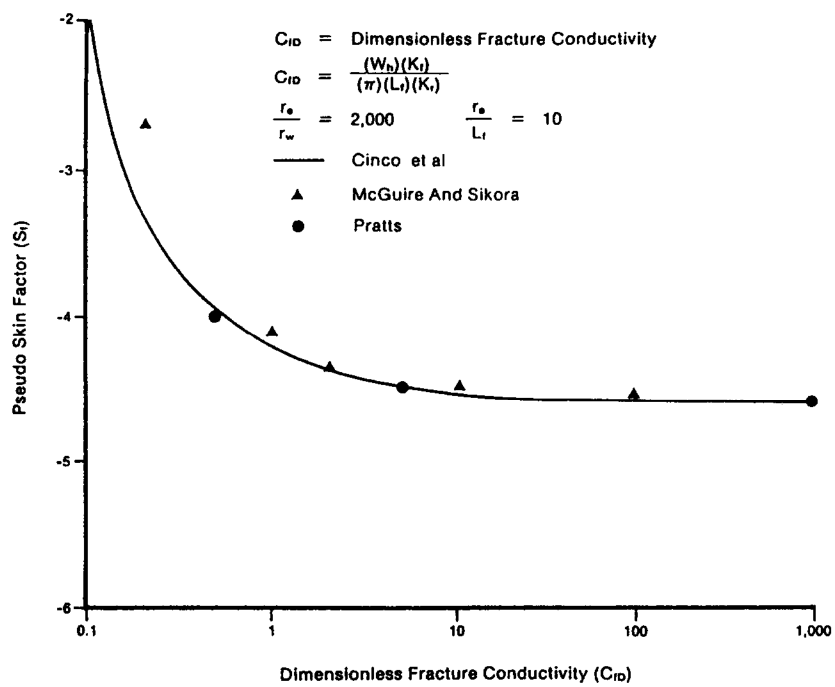


Fig. 12
Effect Of Dimensionless Fracture Conductivity
On Pseudo Skin Factor For A Vertical Fracture

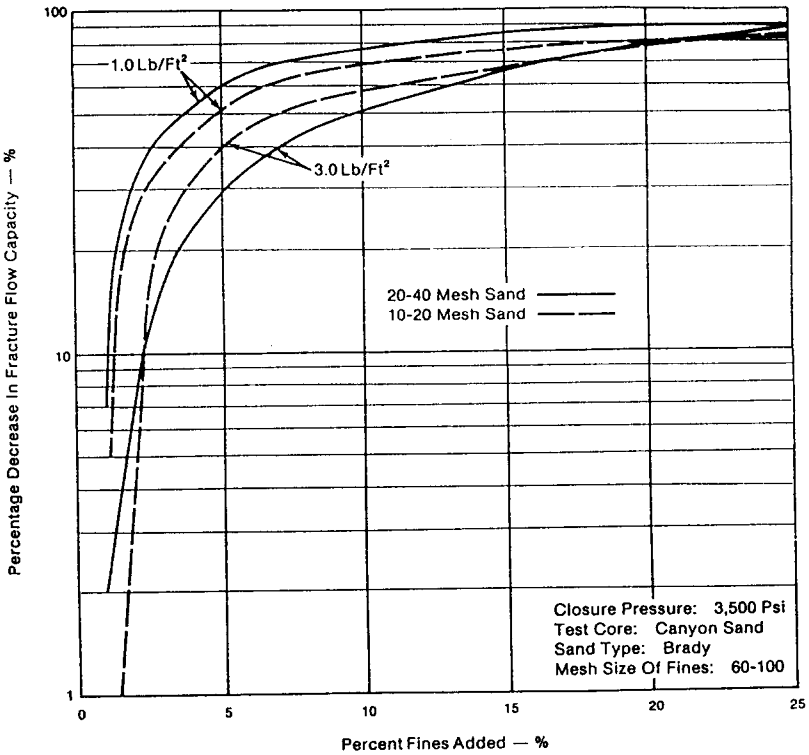


Fig. 13
Effect Of Fines On Fracture Flow Capacity For Various Sand Concentrations Of Various Mesh Sizes Of Brady Sand

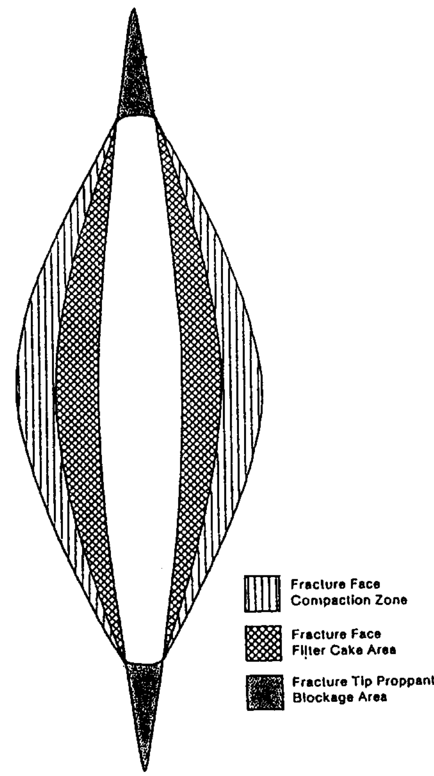
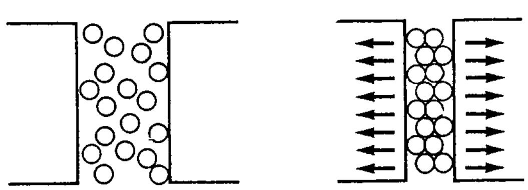


Fig. 14
Fracture Schematic Showing Fracture Face Compaction, Fracture Face Filter Cake, And Fracture Tip Proppant Blockage Mechanisms

Low Proppant Concentration

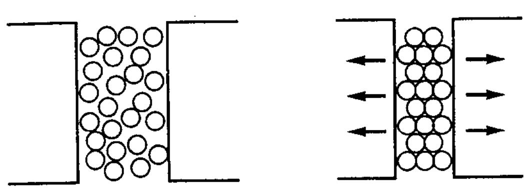
Before Fracture Closure | After Fracture Closure



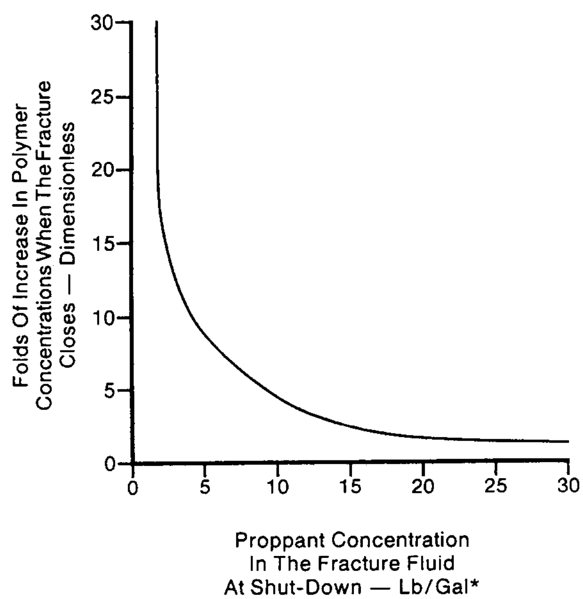
Large Amounts Of Fluid Leak Off, Leading To Large Increases In Polymer Concentration.

High Proppant Concentration

Before Fracture Closure | After Fracture Closure



Little Fluid Leaks Off Before The Fracture Closes, Resulting In Smaller Increases In Polymer Concentration.



$$^{*}\text{Lb/Gal} = \frac{\text{Lb/Ft}^2}{\left(\frac{W_f}{12} \times 7.48\right) - \left(\frac{1}{\text{S.G.} \times 8.34} \times \text{Lb/Ft}^2\right)}$$

Fig. 15
Effect Of Proppant Concentration On Final Polymer Concentration

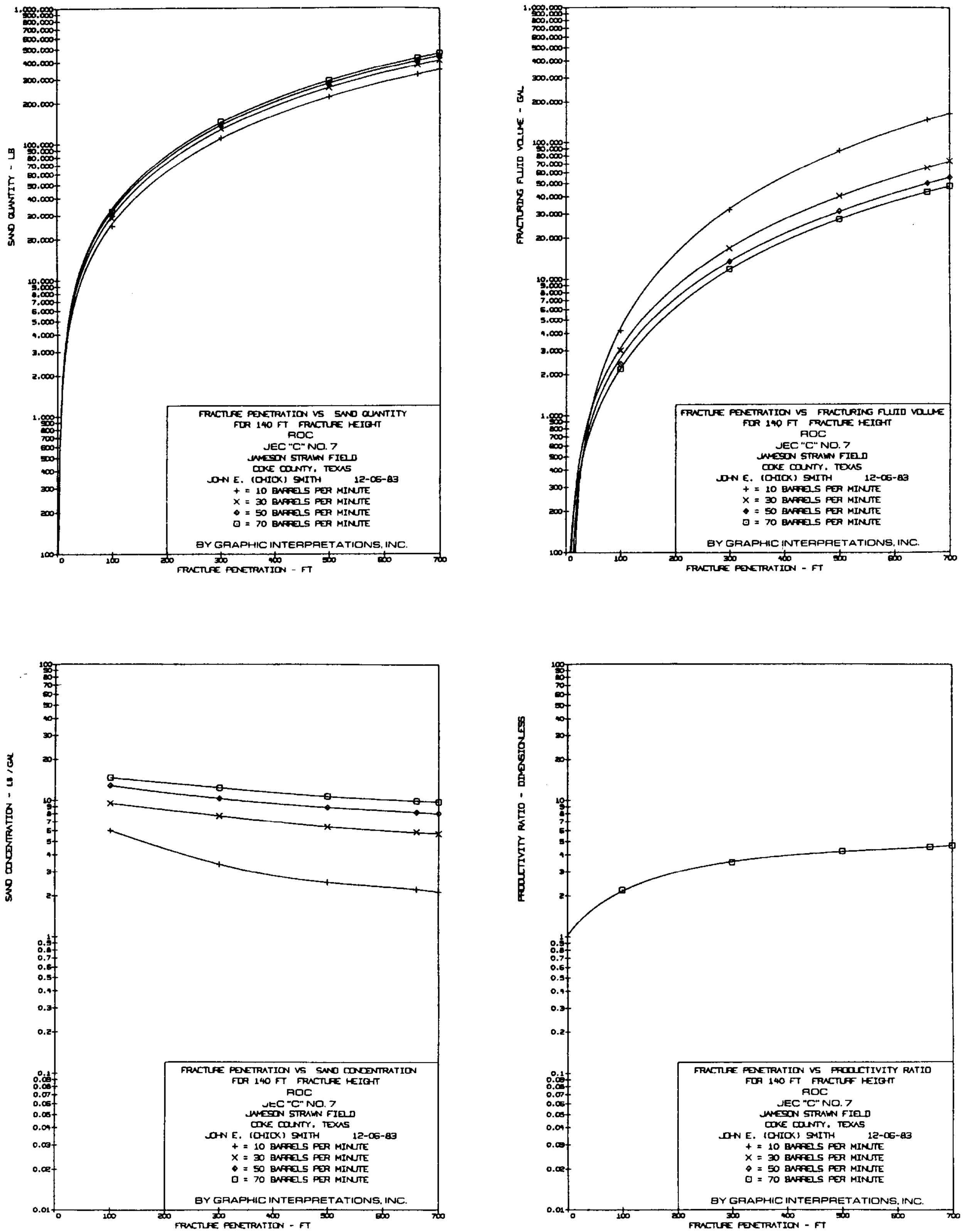


Fig. 16
Graphs Illustrating Fracture Treatment Parameters For A Typical High Sand Concentration Fracturing Treatment

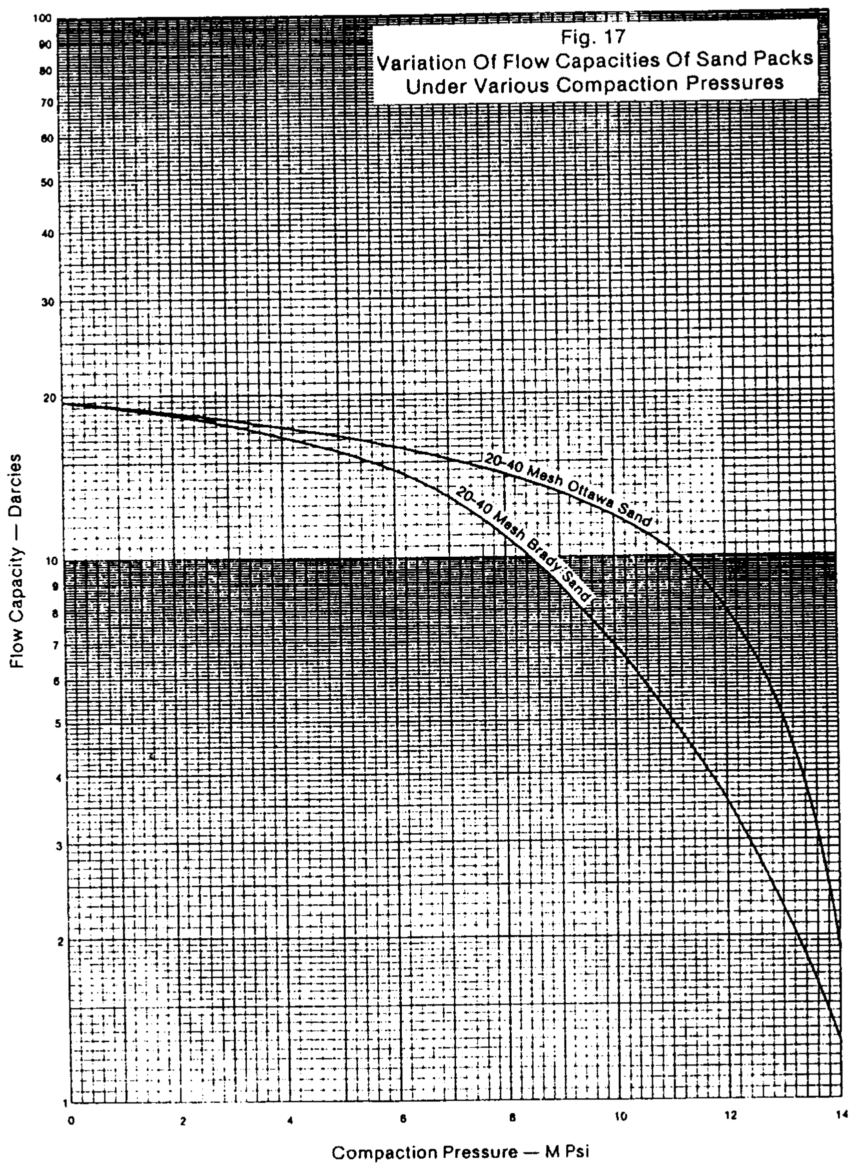


Fig. 17
Variation Of Flow Capacities Of Sand Packs
Under Various Compaction Pressures

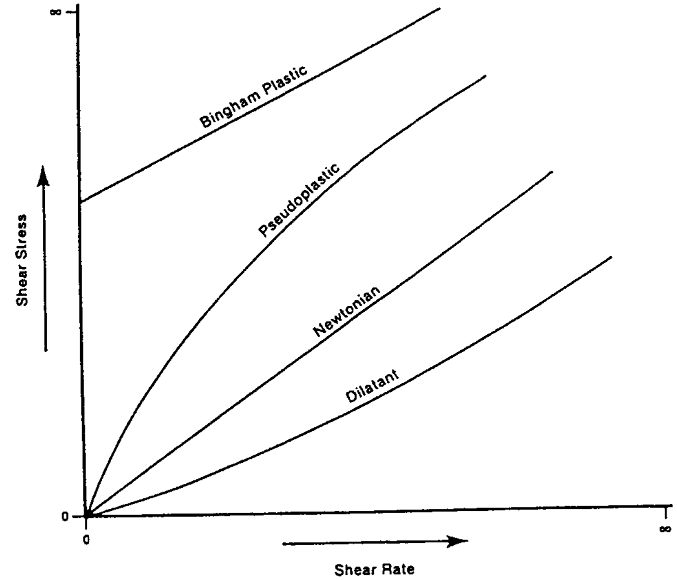


Fig. 18
Typical Shear Stress — Shear Rate Diagram
For Newtonian And Non-Newtonian Fluids

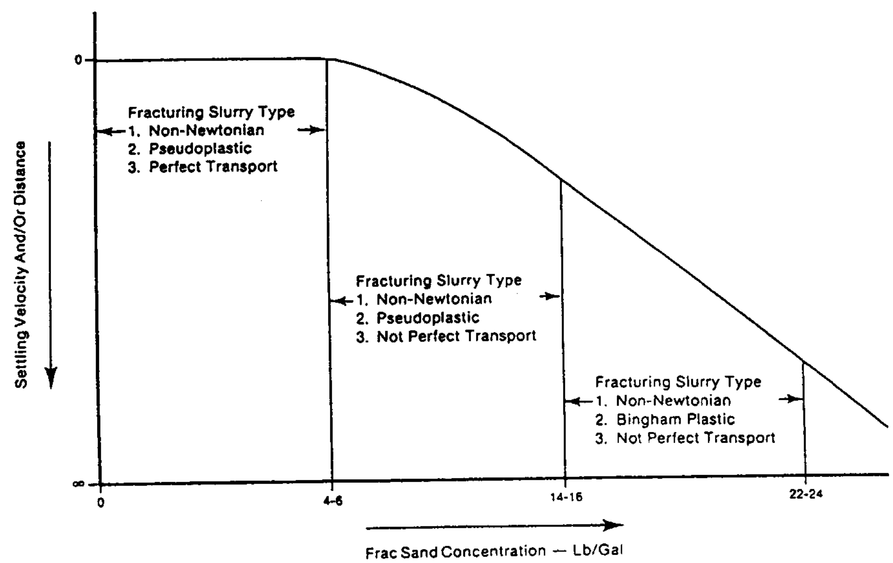


Fig. 19
Effect Of Frac Sand Concentrations
On Fracturing Slurry Rheology

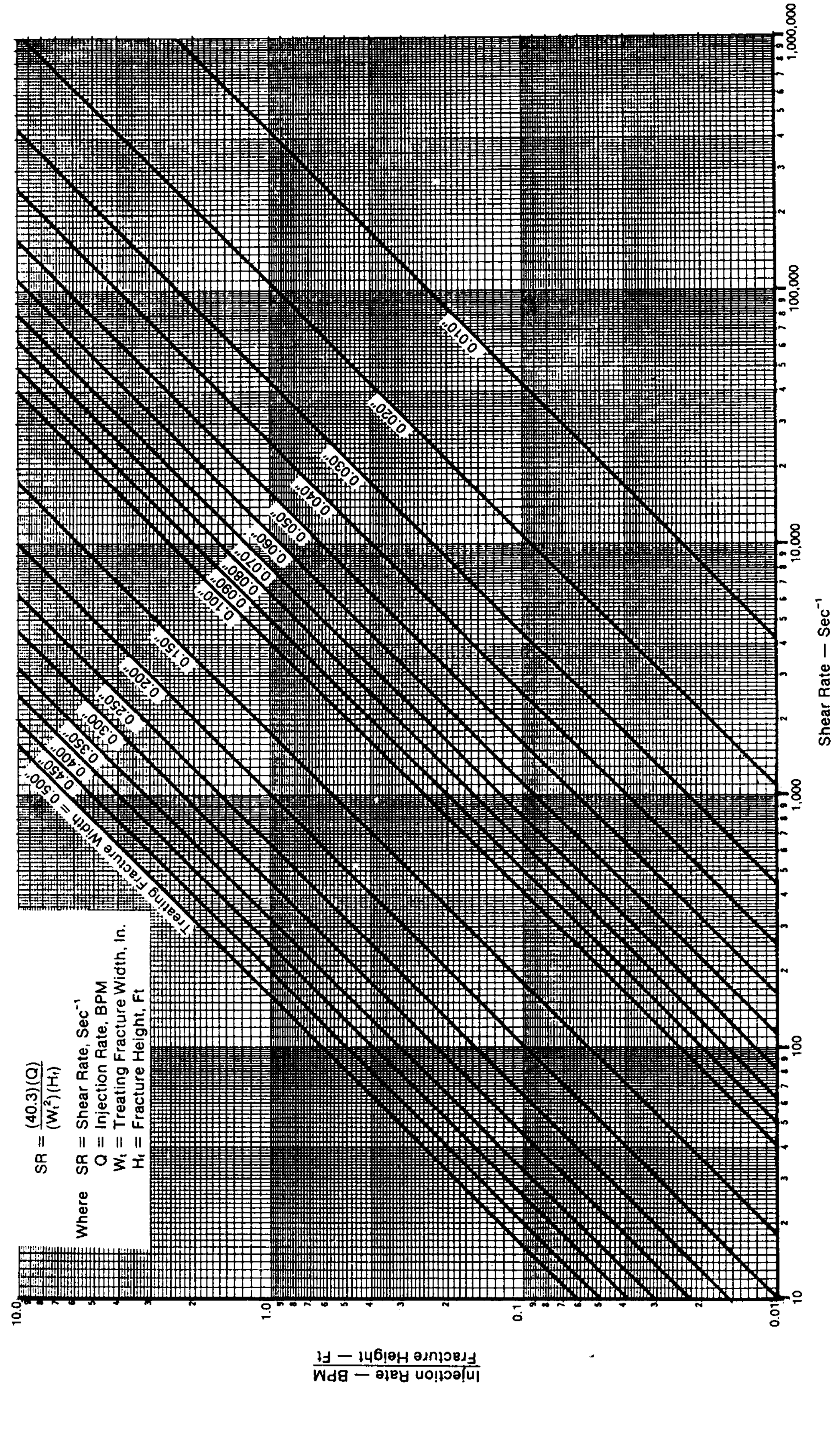


Fig. 20
Shear Rate For Flow Through Fractures

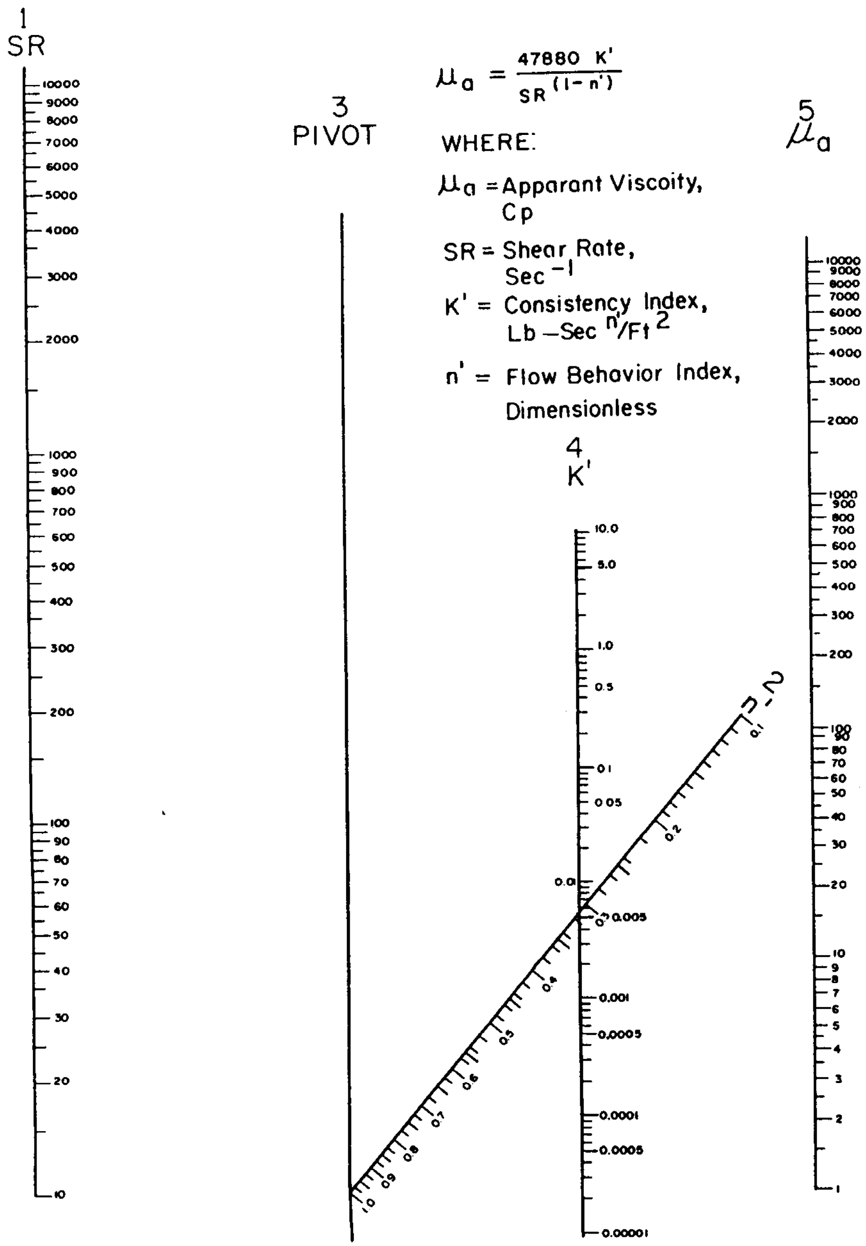


Fig. 21
Nomograph For Calculating Apparent Viscosities

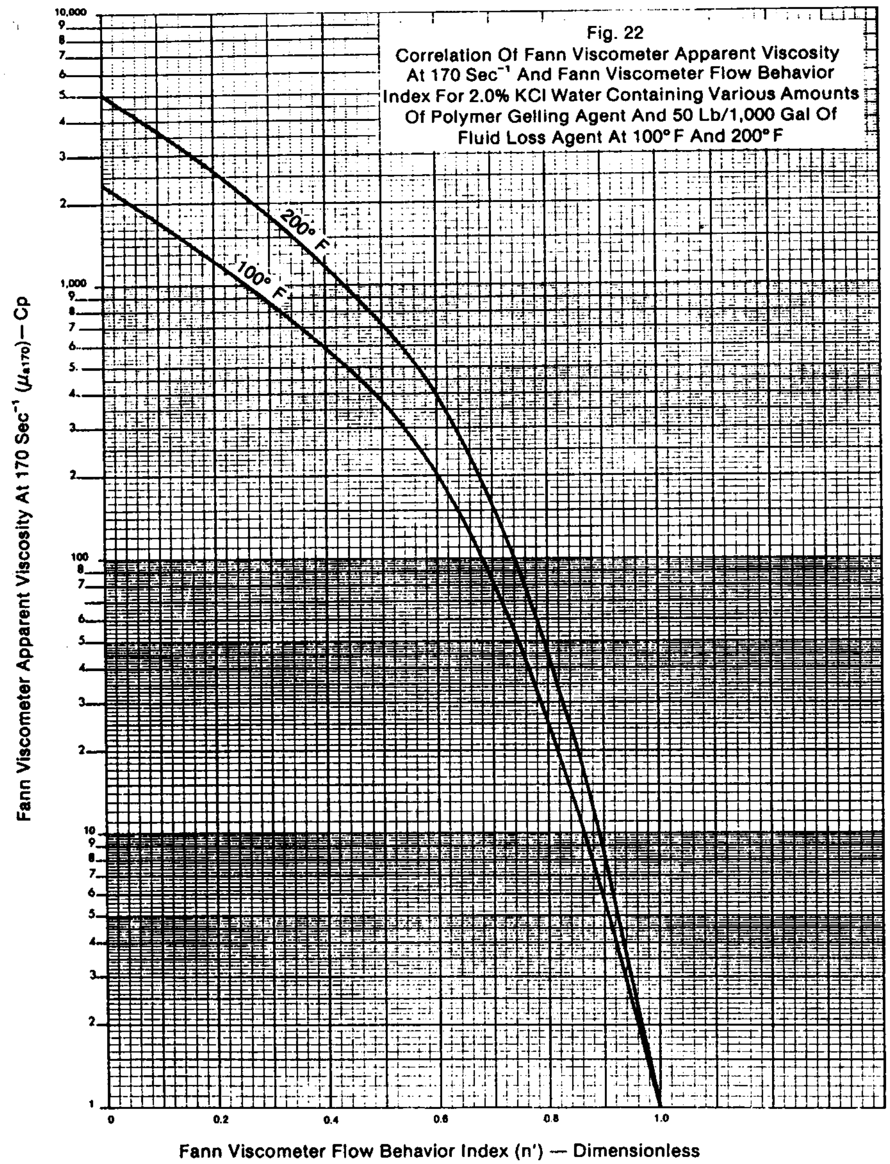


Fig. 22
Correlation Of Fann Viscometer Apparent Viscosity At 170 Sec^{-1} And Fann Viscometer Flow Behavior Index For 2.0% KCl Water Containing Various Amounts Of Polymer Gelling Agent And 50 Lb/1,000 Gal Of Fluid Loss Agent At 100° F And 200° F

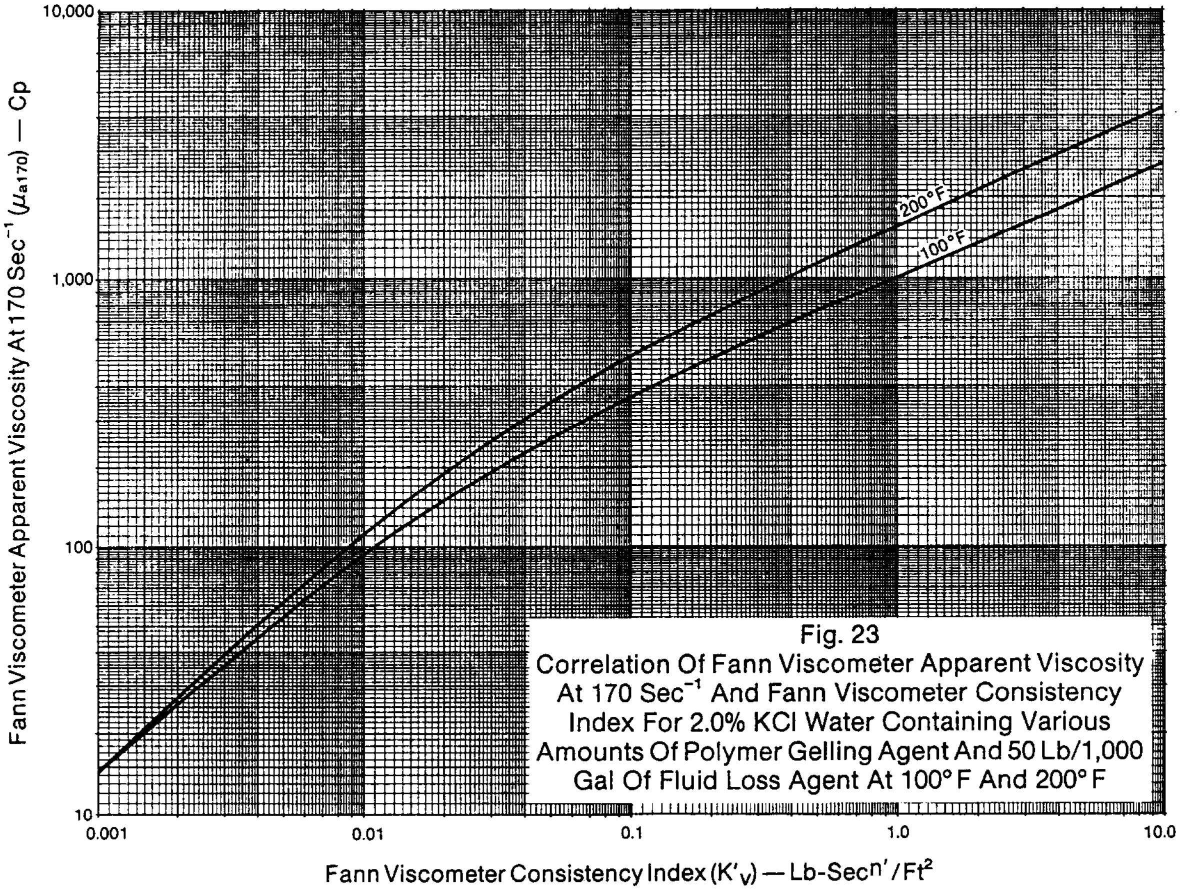


Fig. 23
Correlation Of Fann Viscometer Apparent Viscosity At 170 Sec^{-1} And Fann Viscometer Consistency Index For 2.0% KCl Water Containing Various Amounts Of Polymer Gelling Agent And 50 Lb/1,000 Gal Of Fluid Loss Agent At 100° F And 200° F

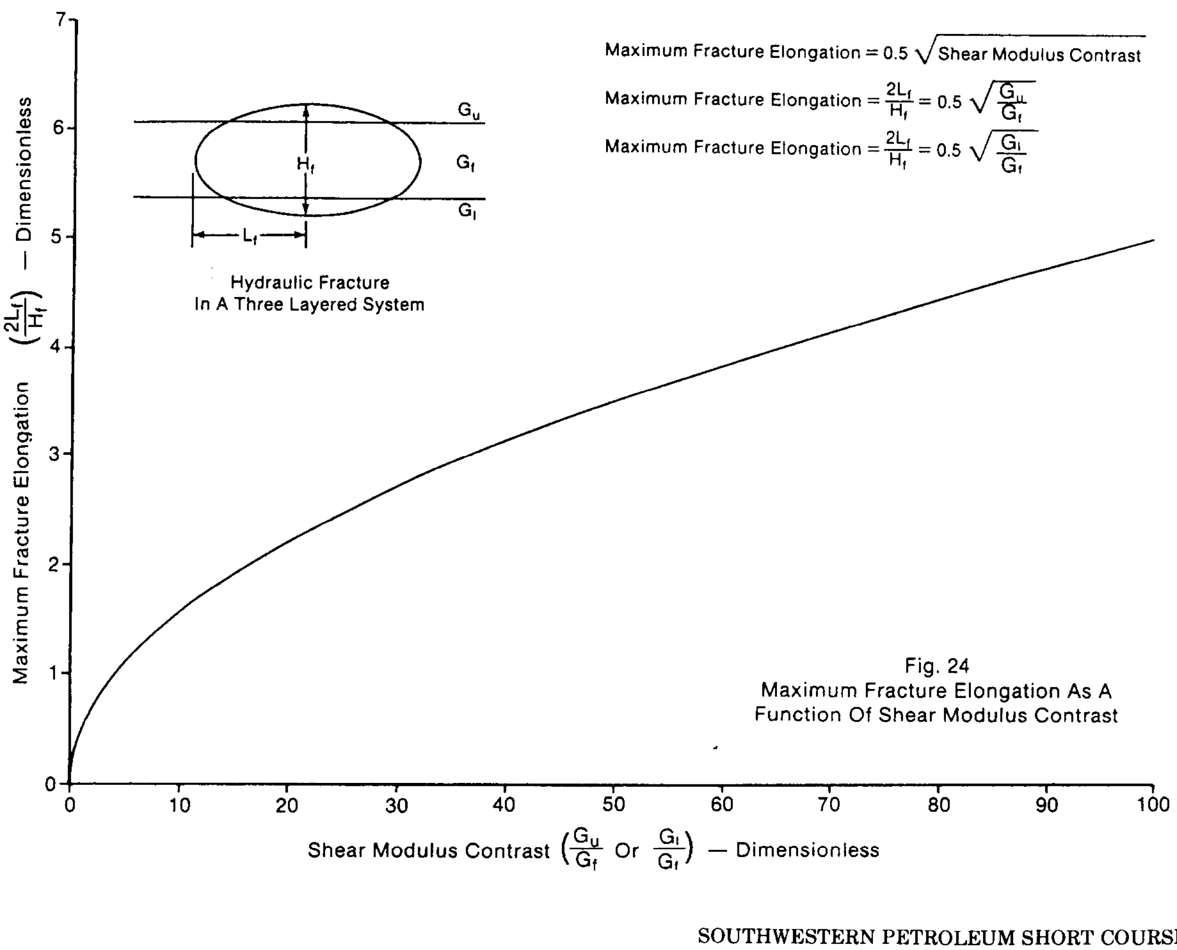


Fig. 24
Maximum Fracture Elongation As A Function Of Shear Modulus Contrast

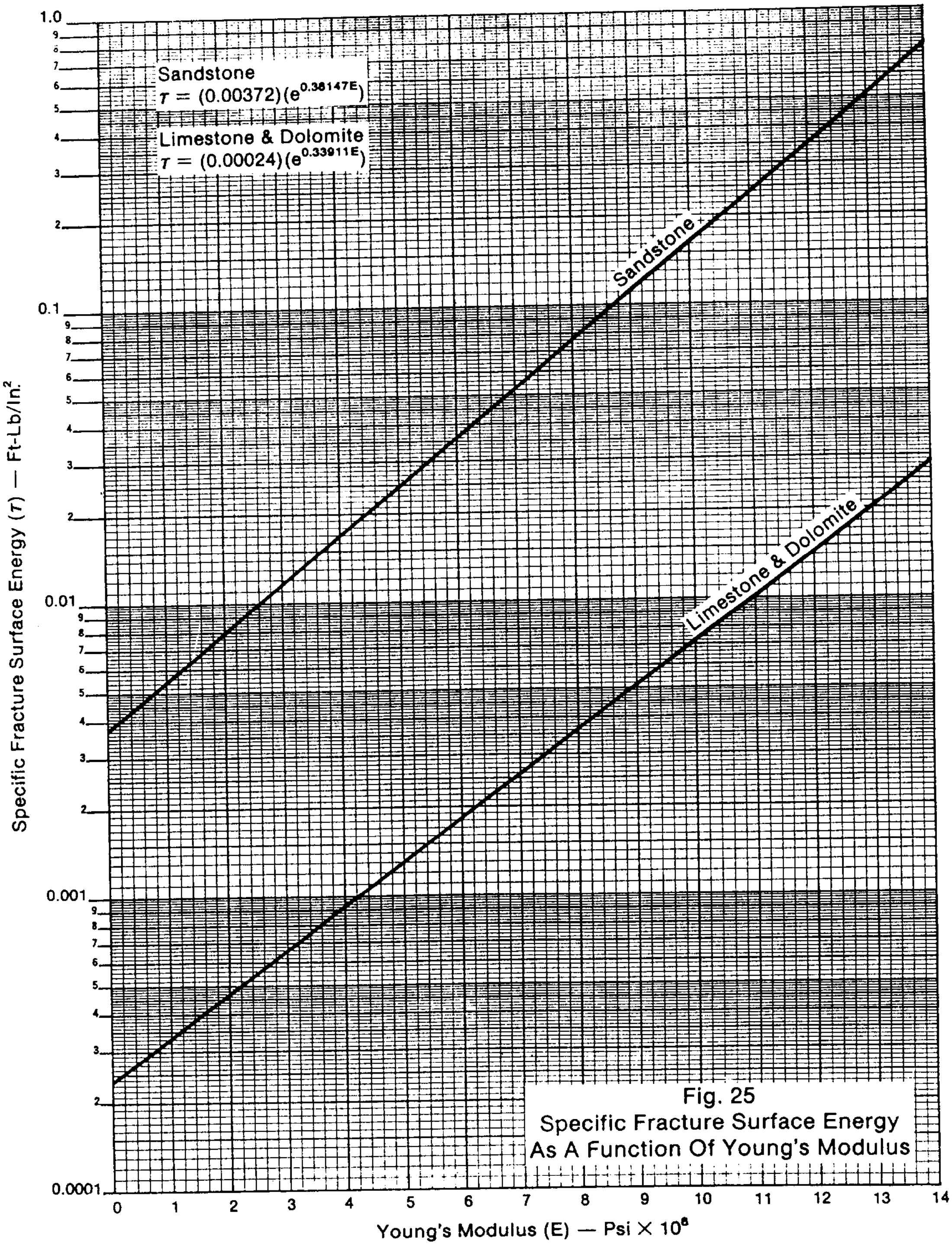


Fig. 25
Specific Fracture Surface Energy As A Function Of Young's Modulus

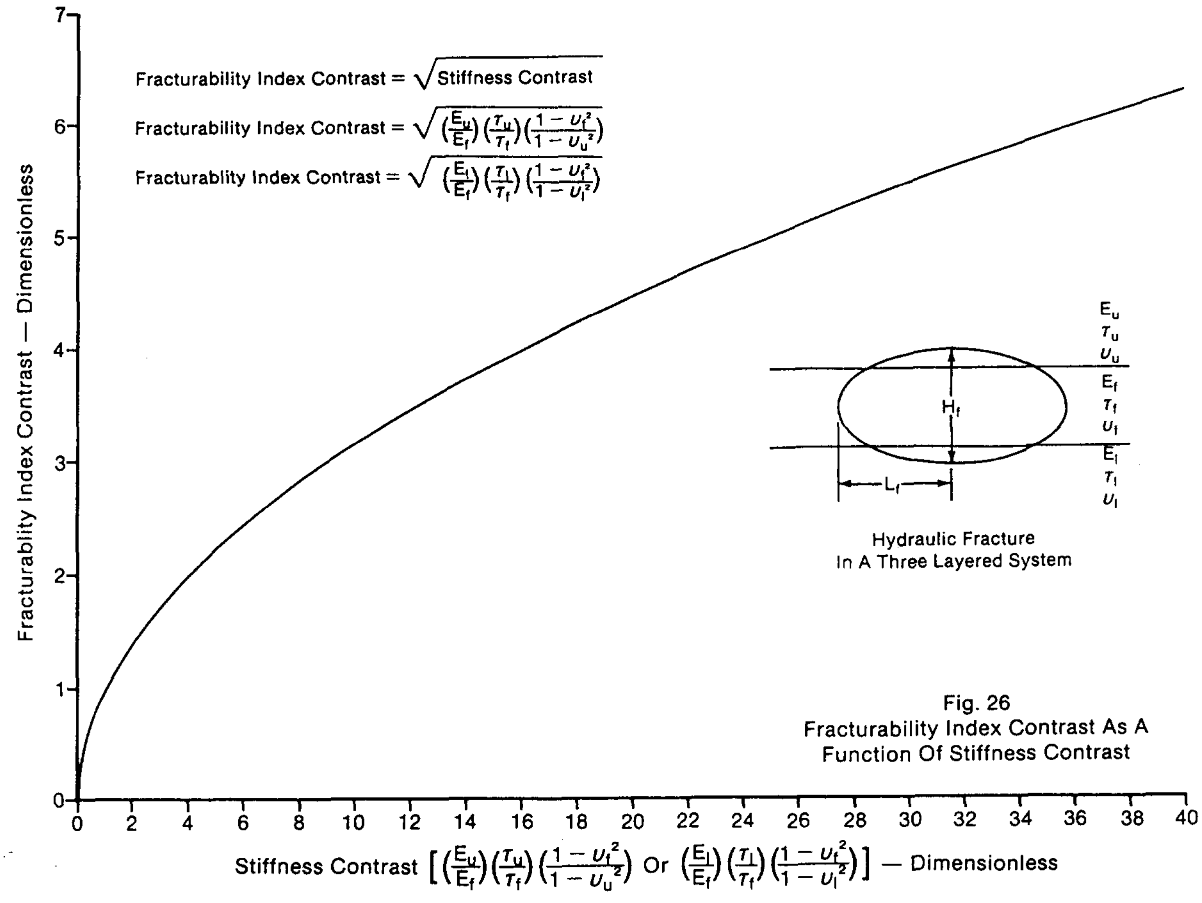


Fig. 26
Fracturability Index Contrast As A Function Of Stiffness Contrast

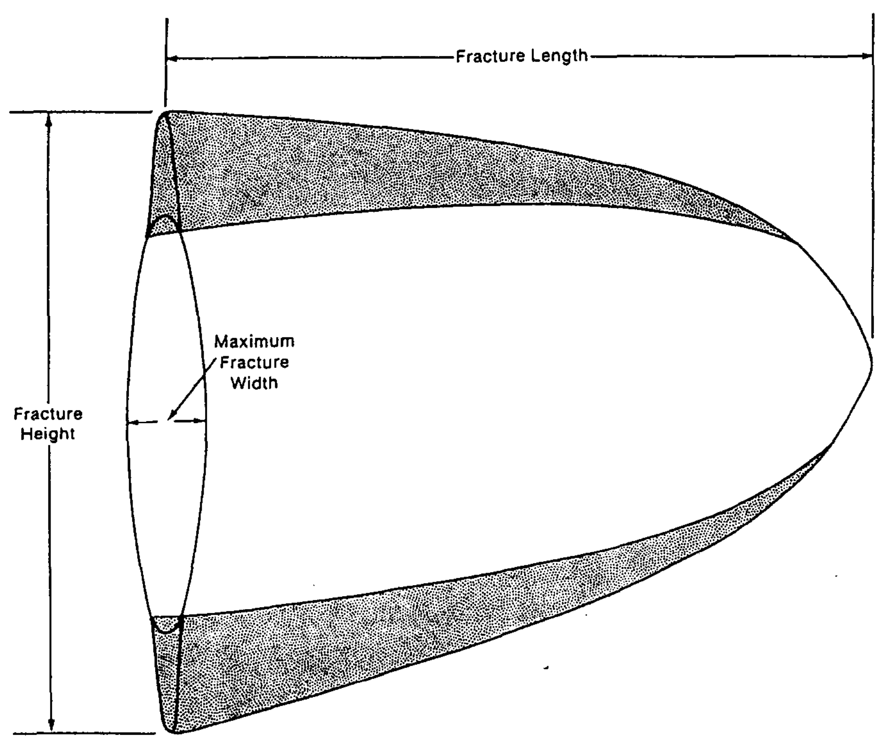


Fig. 27
Fracture Containment Through Flow Impedance Mechanisms

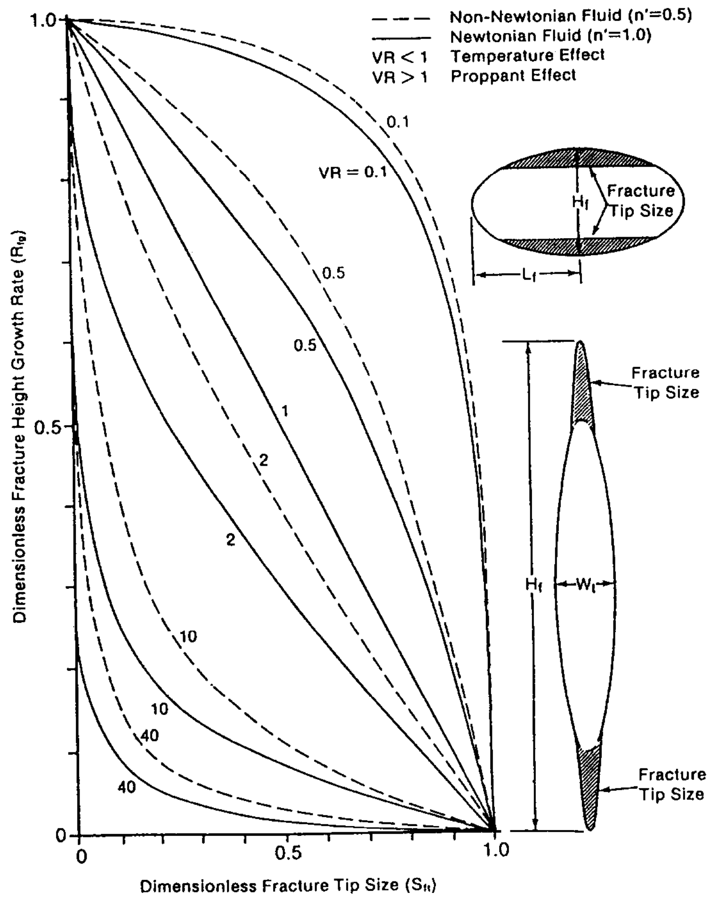
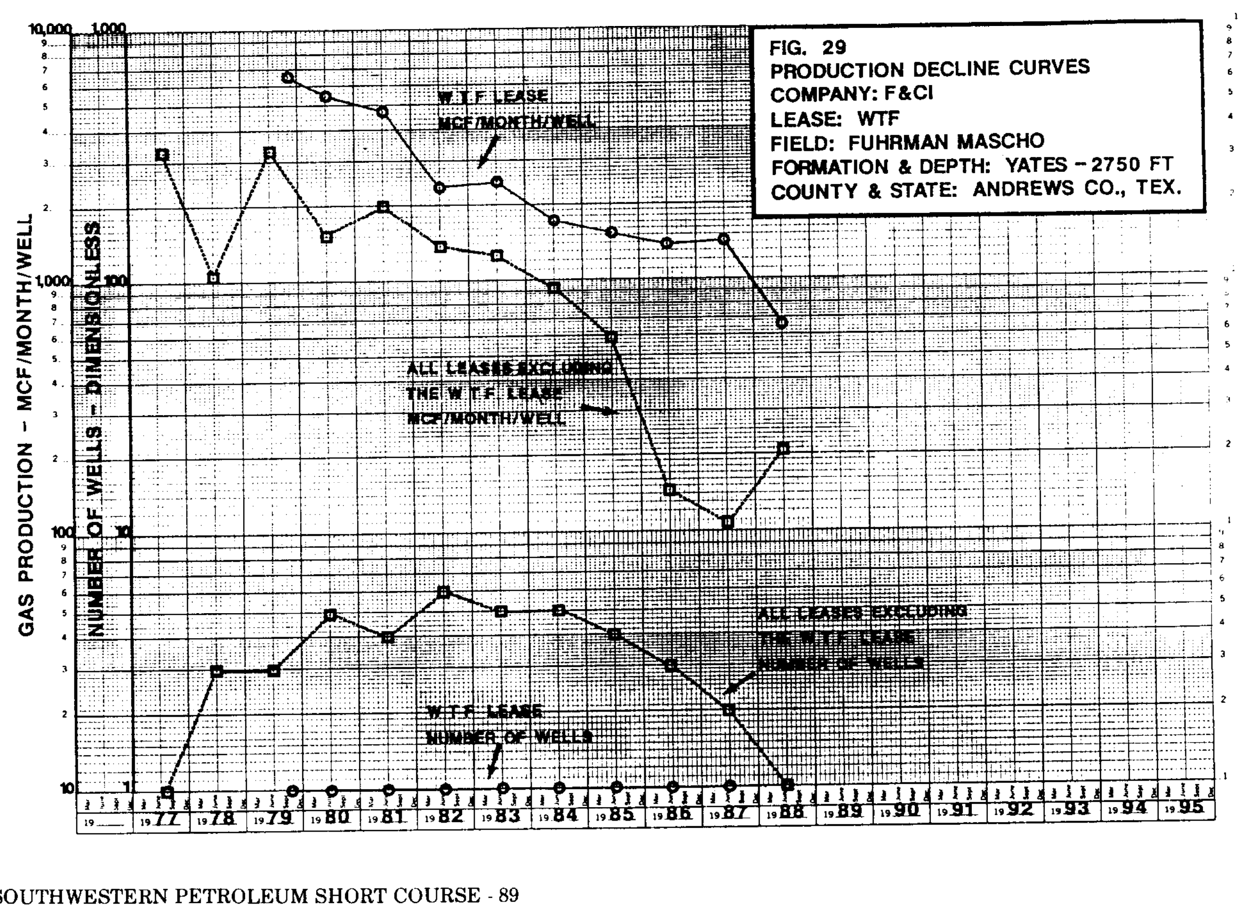


Fig. 28
Dimensionless Fracture Height Growth Rate Versus
Dimensionless Fracture Tip Size As A Function Of Viscosity Ratio



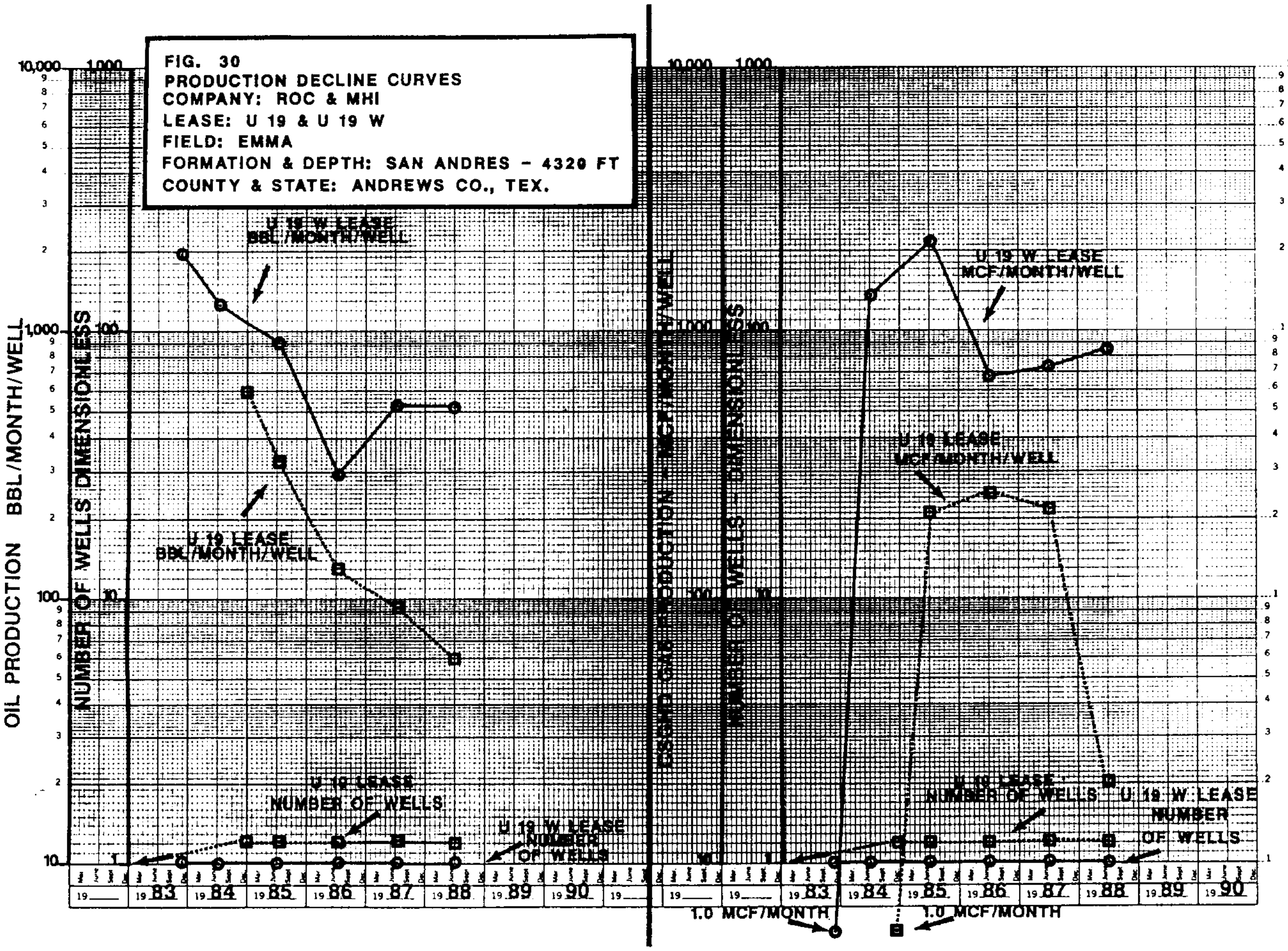


FIG. 30
PRODUCTION DECLINE CURVES
COMPANY: ROC & MHI
LEASE: U 19 & U 19 W
FIELD: EMMA
FORMATION & DEPTH: SAN ANDRES - 4320 FT
COUNTY & STATE: ANDREWS CO., TEX.
OIL PRODUCTION BBL/MONTH/WELL
NUMBER OF WELLS DIMENSIONLESS
U 19 W LEASE
BBL/MONTH/WELL
U 19 LEASE
BBL/MONTH/WELL
U 19 LEASE
NUMBER OF WELLS
U 19 W LEASE
NUMBER
OF WELLS
U 19 W LEASE
MCF/MONTH/WELL
U 19 LEASE
MCF/MONTH/WELL
U 19 LEASE
NUMBER OF WELLS
U 19 W LEASE
NUMBER
OF WELLS
1.0 MCF/MONTH
1.0 MCF/MONTH

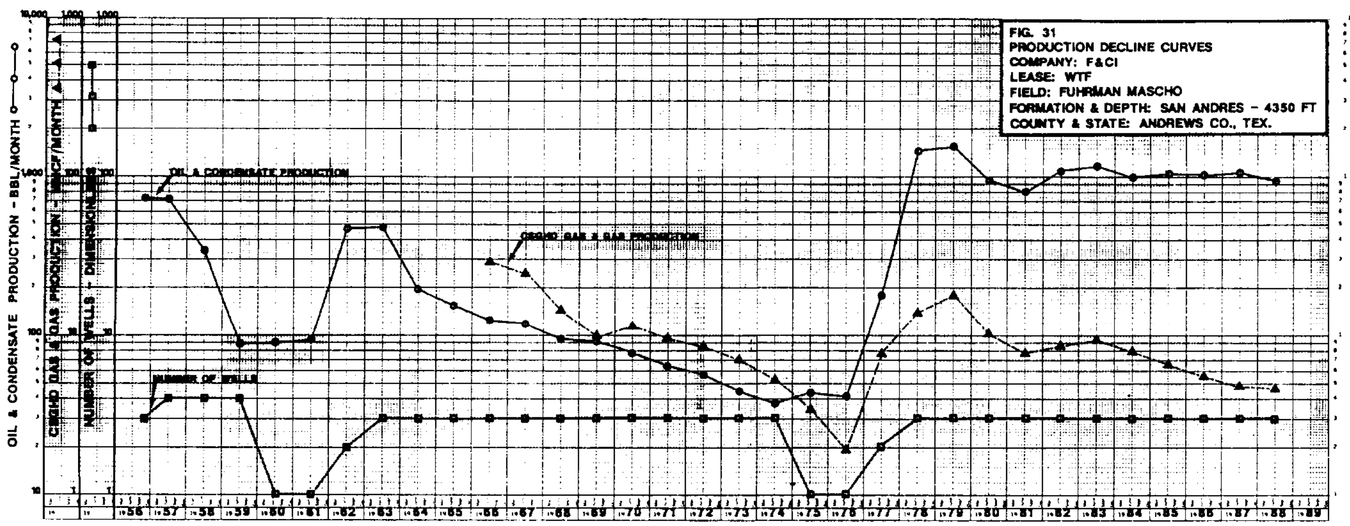


FIG. 31
PRODUCTION DECLINE CURVES
COMPANY: F&CI
LEASE: WTF
FIELD: FUHRMAN MASCHO
FORMATION & DEPTH: SAN ANDRES - 4350 FT
COUNTY & STATE: ANDREWS CO., TEX.
OIL & CONDENSATE PRODUCTION
CSGHD GAS & GAS PRODUCTION
NUMBER OF WELLS

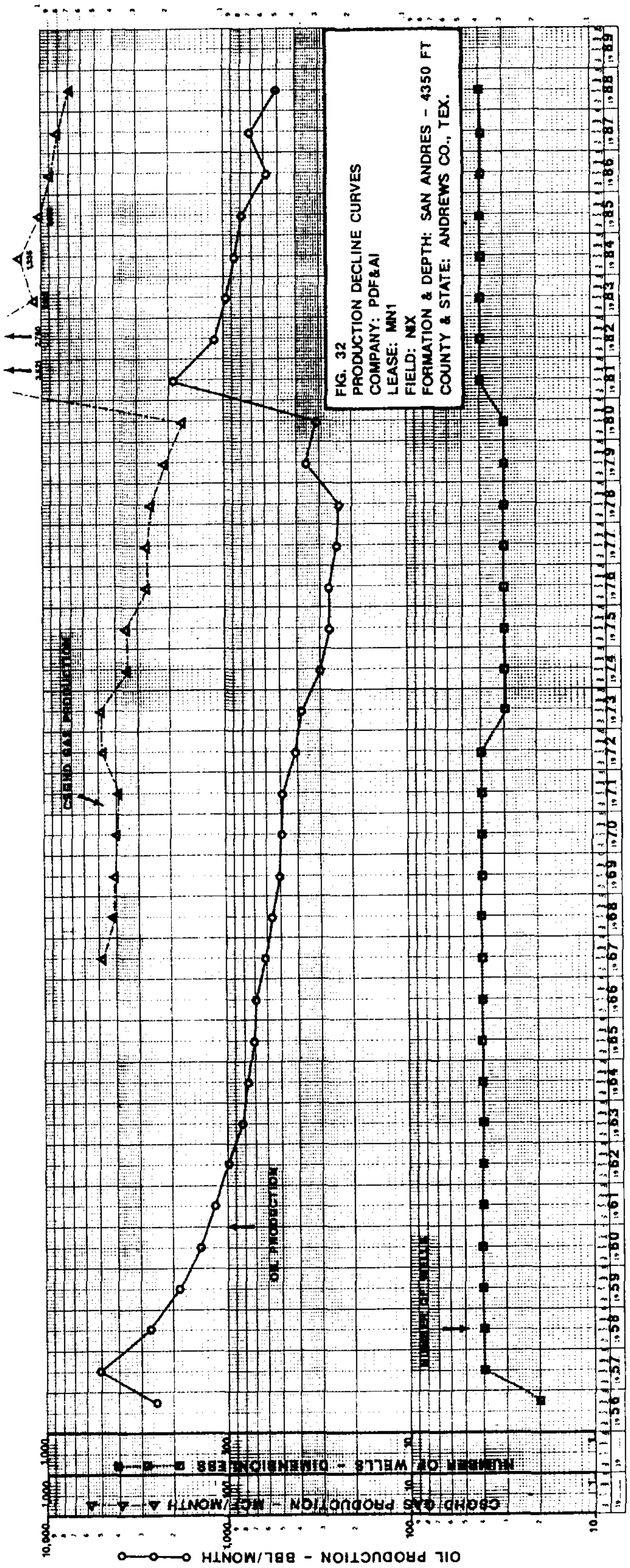


FIG. 32
PRODUCTION DECLINE CURVES
COMPANY: PDF&AI
LEASE: MN1
FIELD: NX
FORMATION & DEPTH: SAN ANDRES - 4350 FT
COUNTY & STATE: ANDREWS CO., TEX.
CSGHD GAS PRODUCTION
OIL PRODUCTION
NUMBER OF WELLS
OIL PRODUCTION - BBL/MONTH
CSGHD GAS PRODUCTION - MCF/MONTH
NUMBER OF WELLS - DIMENSIONLESS