NEW GENERATION OF FRAC FLUIDS

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INTRODUCTION

Since the advent of hydraulic fracturing as a well stimulation tool, a variety of fluids and treatment methods have been proposed and used to improve well productivity. Fluids used in this process over the years include water, lease oil, refined oil, water-oil emulsions, acid-oil emulsions, gelled oil, gelled water, and gelled acid.

A recent development has been the introduction of thick fluids with low pipe friction for hydraulic fracturing. The use of thick fluids can increase fracture conductivity by creating wider fractures, carrying larger and higher concentrations of propping agent and improving prop distribution. In many cases, the increased fracture conductivity will result in greater production increases.

This paper describes the new very-thick frac fluids and low-damage fluids to improve well productivity. Early attempts to increase fracture conductivity with thick fluid were only moderately successful. Acid-in-oil emulsions were used extensively in the 1950's.[1] These emulsions had excellent sand-carrying ability, but pipe frictional pressures developed during injection frequently prevented proper application for maximum productivity increase. The cost of the acid-oil emulsions was also a deterrent to widespread use as the size of treatments increased. Later, Khristianovich[2] renewed the interest in use of thick fluids to improve the fracturing process. The first successful application of thick frac fluids was the heavy, refined oil-water dispersions developed by Esso Production Research.[3] These fluids fulfilled the requirements of highly viscous fluids and established new fracturing technology. Increased friction pressures generated by this type fluid are overcome by special treating techniques in which a water ring is employed between the thick oil and the pipe wall. Although this type of fracturing fluid is still used in treating specific formations, handling difficulties have reduced its overall appeal.

The recently developed thick fluids described herein exhibit low friction pressure down tubular goods in addition to high viscosity in the fracture. These fluids generally provide relatively low formation damage and fracture conductivity damage. These are important factors in providing increased productivity where formation sensitivity or detrimental saturation changes are prevalent. The properties, application, and design of four new aqueous frac fluids and two new oil-based systems are described. These fluids are more expensive than conventional fluids; therefore the proper application is required.

PURPOSE OF NEW FLUIDS

Well conditions which may indicate the need for the highly viscous fluids are high overburdens, low reservoir pressure, soft formations, high permeability, high temperature, rapid decline in production, rate limitations which prevent optimum design with conventional fluids, or intervals where control of frac height is needed.

The key design factor in determining the effects of these conditions is fracture conductivity under existing fracture closure pressure. High overburden pressures, particularly with low reservoir pressure, give high fracture closure pressures which may result in low fracture conductivity. The proper choice of proppant and greater fracture width may be necessary at these high fracture closure pressures (above 4000 psi). With soft formations, prop embedment may reduce fracture conductivity. As will become evident in the following discussion, high permeability formations may require greater fracture conductivity for optimum stimulation. The low viscosity of conventional fluids at high temperatures may prevent obtaining fracture width for optimum fracture conductivity. A rapid production decline, where lower reservoir pressure is not responsible, may indicate fracture closure as a possible result of prop embedment or high closure pressures. The importance of fracture conductivity warrants a further discussion of this key factor.

FRACTURE FLOW CAPACITY

Fracture flow capacity, or conductivity, is defined as the product of effective fracture permeability and fracture width. (For this discussion, a filled fracture is assumed after fracture closure has taken place. The term "effective fracture permeability" is used here since there is some belief that an open area may exist in the fracture above the prop pack or through channels. If this is the case, then the permeability of the fracture may be greater than the permeability of the prop pack itself. Also, a partial monolayer does not apply to this discussion.) Thus, fracture conductivity will increase with increasing fracture width for a filled fracture at closure. The importance of this increased conductivity on productivity increase becomes apparent when folds of increase are plotted as a function of conductivity increase and penetration as in Fig. 1. Where conductivity ratios are low, as on the left of the curve, no amount of penetration will effect a large productivity increase. At higher conductivity ratios, as on the right, small increases in penetration bring about large increases in productivity. The effect of increased frac width then is to provide conductivity ratios that will permit taking advantage of increased penetration.

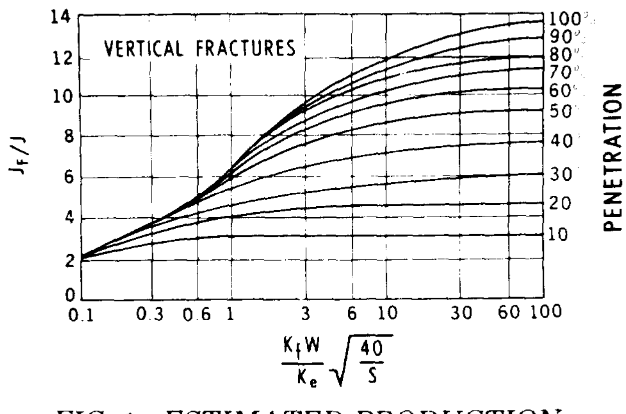

FIG. 1—ESTIMATED PRODUCTION INCREASE AFTER FRACTURING

From S. A. Khristianovich's[2] work, the following expression can be derived for fracture width from standard slot or fracture flow equations:

$$W_o = k\left(\frac{L}{A\,\Delta P_w}\right)^{1/3}$$

$$\text{where } k = \left(\frac{12W\mu}{h}\right)^{1/3}$$

The factors of interest here are injection rate, Q, and fracture fluid viscosity, μ. It is apparent that an increase of viscosity from perhaps 10 to 1000 cps would have a far greater effect on fracture width than an increase in injection rate from 10 to 20 BPM. Furthermore, increasing the injection rate quite often is not feasible due both to economics and mechanical well limitations. The new thick fracturing fluids provide greatly increased viscosity. Although the expression above is for Newtonian fluids, it serves to demonstrate the effect of viscosity. Actually, fracture width calculations become quite sophisticated when non-Newtonian fluids, fracture geometry, and the changing conditions of velocity and pressure are considered. It can be shown, however, that the thick, non-Newtonian fluids are much more efficient in continued and more rapid width development than the Newtonian fluids. Also, it is important to note that the term "viscosity" is meaningless when used to describe non-Newtonian fluids unless the conditions under which it is measured are stated. The rheology of these fluids will be discussed in more detail later in the paper.

The creation of wide fractures permits the use of large size prop materials. Here again, viscosity becomes important since it provides good prop suspension and prop transport characteristics to the fracture fluid. The thick fluids are capable of transporting high concentrations of large props into a fracture to establish a highly permeable prop pack.[4, 5, 6] These same characteristics enable the thick fluids to carry the prop a greater distance into the reservoir than is possible with more conventional fluids.

DAMAGE

Potential damage to the formation or fracture conductivity is indicated in wells showing slow or poor return of frac fluids, a lower productivity increase than expected, or inconsistent response from well to well in the same area. These problems may result when encountering formations containing water-sensitive clays or formations extremely sensitive to saturation changes of water (oil wells) or oil or water (gas wells). In these cases, careful selection of frac fluid is required to minimize decreases in productivity. The new generation of frac fluids was designed to minimize potential damage.[4, 5] Two new systems have been developed to be used where saturation changes or formation sensitivity are a major problem. One is a gelled oil[7] fluid which has been very effective in oil wells as discussed later. A second system, primarily for gas wells, is unique.[8] Liquefied gases are mixed in such a ratio that they remain a liquid and behave as liquids as long as they are under adequate pressure and below the critical temperature for the mixture (e.g., during the fracturing treatment). The fluid is designed so that after the job, its critical temperature is exceeded in the reservoir as the liquid heats up. This allows the liquid to revert to a gas which results in extremely rapid clean-up and no residual liquefied gases are left in the formation. This process is discussed in greater detail in another paper presented in this Proceedings.[9]

GENERAL PROPERTIES OF NEW FLUIDS

Several criteria are common to all the new fluids. In addition to the main themes of high viscosity, low pipe friction and loss damage, low fluid loss and positive gel breakdown were also developed in these new fluids.

Low fluid loss coupled with higher prop concentrations makes these fluids highly efficient, and smaller volumes can achieve the same volume of fracture as larger volumes of conventional fluids. The high viscosity of the fluid may allow lower rates, reducing horsepower costs. The reduced horsepower costs and smaller volumes can improve the economics of the treatment even though the per gallon cost of the new fluids is higher. However, in many instances, the greatest economic gain can be to use these highly efficient fluids to achieve greater fracture penetration. This is particularly true where the viscous fluids give significant increases in fracture conductivity and hence greater productivity increases (Fig. 1). In many cases, the fluid loss efficiency of these fluids allows treatment of higher permeability formations than when using conventional fluids.

The fluid loss of these fluids is controlled to some degree by both the viscosity and the wall-building characteristics of the fluid itself.

The success of any highly viscous frac fluid is dependent on how well it breaks down following a treatment. Positive breakdown of gel must occur in order to have good well clean-up. Breakdown of the viscous gels is assured because an internal breaker is incorporated into all fluids. Additional breakers are used when faster breakdown is desired. In many cases, formation water or oil and thermal degradation aid in the viscosity decrease.

All of the fluids discussed herein have low fluid loss (Table 1) and positive gel breakdown.

TABLE 1—GUIDELINES FOR SELECTION OF VISCOUS AQUEOUS FLUIDS

		FLUID PROPERTIES			
		Crosslinked Guar	Crosslinked Cellulose	High Temp Cellulose	Synthetic Polymer
THICKENER CONCENTRATION (lb/1000 gal)					
Conc Range Available		40 to 80 lb	40 to 80 lb	60 to 150 lb	40 to 150 lb
Conc for Data Below		60 lb	60 lb	100 lb	100 lb
BRINE TOLERANCE (make-up water required)		Good	Fresh water required	Excellent	Fresh water required
FRICTION PRESSURE in 2⅞" Pipe (psi/1000 ft)					
Q	Water				
10 BPM	500 psi	270 psi	303 psi	128 to 230 psi	230 psi
20 BPM	1700 psi	410 psi	570 psi	330 to 550 psi	400 psi
APPARENT FRACTURE VISCOSITY (cps) at Intermediate Flow Conditions (160 sec^{-1})					
Fluid Temp (°F)	30 Weight Motor Oil				
80	400 cps	1865 cps	654 cps	200* cps	(*)
150	—	1751 cps	172 cps	300 cps	217 cps
200	15 cps	1388 cps	(**)	244 cps	185 cps
300	—	(**)	(**)	77 cps	103 cps
FLUID LOSS					
C_w $(10^3)(ft/(time)^{0.5})$		1 to 3	2 to 3	1 to 2	(Viscosity controlled, generally as good as others)
Spurt (gal/100 ft^2)(3)		1 to 2**	0**	10 to 15**	
MINIMUM FORMATION AND FRACTURE DAMAGE					
		Fair	Good	Excellent	Excellent

(*) Outside temperature range
(**) For recommended temperature range

FLOW OF VISCOUS FLUIDS - RHEOLOGY

The importance of viscosity in creating wider fractures, in carrying prop efficiently and in reducing fluid loss has been amply shown. However, these viscous fluids have a variable viscosity depending on the flow conditions.[10] The study of fluid flow behavior is termed "rheology".

A technical discussion of rheology has been included in the Appendix. At this point, a more practical discussion in terms of the fracturing process seems in order.

Except for water and oil, essentially all thickened frac fluids show a decrease in viscosity: (1) with increased velocity (flow rate); (2) for smaller pipe size or frac width; and (3) for lower frac height. This effect is even more pronounced with the more viscous fluids. Although the viscosity changes, it is reversible. That is, a change in flow condition will change the viscosity; but on reestablishing the initial flow condition, the initial viscosity will be restored.

During a fracturing treatment, the frac fluid is exposed to a wide range of flow conditions and will exhibit different viscosities. The three particular points of interest are: (1) in the pipe; (2) in the fracture; and (3) in the pores of the formation. As an illustration, the viscosity of a thick fluid was calculated at these points as shown in Fig. 2. Going down the 2⅞ in. tubing, the fluid is being sheared and less viscosity is exhibited. After the fluid enters the 0.4-in. fracture with a height of 30 ft, less shearing occurs and the viscosity goes up. High initial shear occurs as the fluid enters the pores of a formation. This is indicated by the spurt loss. Then, as the fluid leaks off into the pores, the viscosity increases as the job proceeds because the velocity is decreasing.

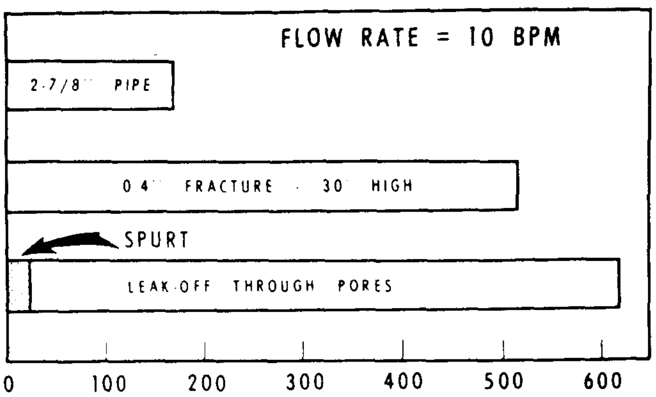

FIG. 2—THE APPARENT VISCOSITY OF A VISCOUS GEL AT DIFFERENT LOCATIONS DURING A FRAC JOB

The variable viscosity requires at least two values to describe the flow behavior. The flow behavior index (n′) and the consistency index (K′) are the values commonly used. The value n′ is mathematically defined as the slope on a log-log plot of shear stress ($W\Delta P/2L$ for a fracture) versus shear rate ($6Q/Hw^2$ for a fracture), where w = frac height. K′ is the intercept on this same plot at one reciprocal second and is the apparent viscosity of the fluid, usually in British units of $lb_f\text{-}sec^{n'}/ft^2$, at one reciprocal second. For a given fracture width and length, this log-log plot is basically a pressure drop vs flow rate relationship. The value n′ usually has values from 0.2 to 0.8 for thickened frac fluids. As n′ is lowered, the more rapidly the apparent viscosity decreases with the same change in flow rate. As the concentration of a thickener is increased, n′ decreases while K′ increases. The effect of a temperature increase is to increase n′ and lower K′. The viscous frac fluids generally have low n′ and high K′ (Table 2).

TABLE 2—APPARENT VISCOSITY OF WATER AND OIL-BASE GELS IN FRACTURES

				Apparent Viscosity (cps)	
System	Temp (°F)	K′	n′	50 sec^{-1}	500 sec^{-1}
Crosslinked Guar:					
(water)	80	0.860	0.56	7350	2660.0
	150	0.500	0.56	4270	1545.0
Crosslinked Cellulose:					
(water)	80	0.490	0.29	1465	286.0
	150	0.081	0.39	360	87.5
(1% KCl)	80	0.290	0.23	680	116.0
	150	0.041	0.44	218	60.5
Synthetic Polymer:					
(water)	150	—	—	—	—
	200	0.180	0.26	476	86.4
	300	0.140	0.24	346	59.5
(0.5% KCl)	150	0.077	0.42	380	100.0
	200	0.051	0.44	294	85.0
	300	0.031	0.43	159	43.0
Gelled Kerosene:					
	80	0.150	0.30	463	93.0

The pipe friction pressure of the viscous fluids does not increase with rate near as much as the base unthickened fluid (water or oil). This is partly a result of the rapid decrease in viscosity at high rates but it is also a result of the unique ability of the thickener to reduce friction in turbulent flow. At frac rates generally used, all the viscous fluids will have a pipe friction pressure approaching only one-third that of oil or water. In many cases, this low pipe friction will allow a frac job that would not be possible with either water or oil alone. Examples of the friction properties in pipe are shown in Table 1 and Fig. 3. The flow behavior of these viscous fluids in the fracture can best be handled by a computer program which is available. However, hand calculations can be made using the procedure outlined in the Appendix.

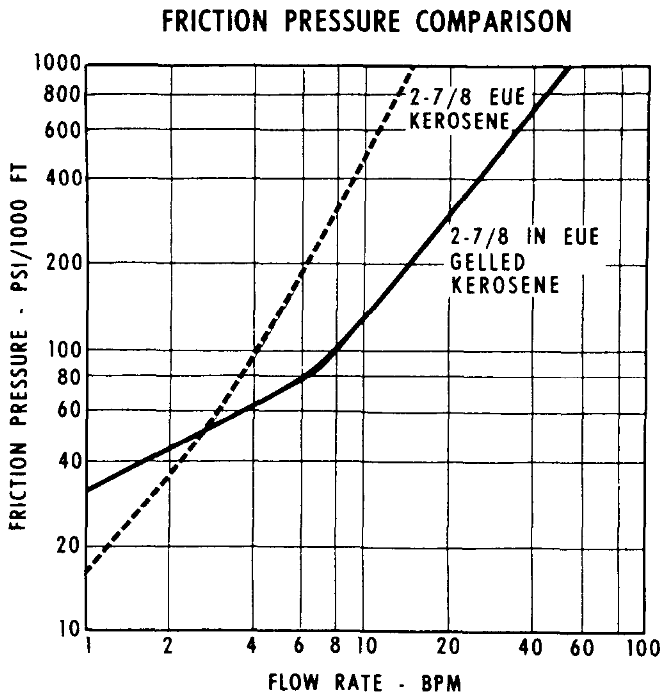

FIG. 3—FRICTION PRESSURE COMPARISON OF KEROSENE TO GELLED KEROSENE

WATER-BASE GELS

There are three basic materials used to prepare water-base thickened fluids. These are guar gum, cellulose derivatives, and a synthetic polymer. All are "water-swellable" polymers, which have been used in fracturing for some time. Each has its own advantages and imparts different fluid characteristics when used as a thickener for water. Guar is a naturally occurring polymer refined from the guar bean. The cellulose derivative is prepared by reacting a naturally occurring cellulose material with synthetic chemicals to form a remarkably pure polymer. The synthetic polymer is made by reacting only synthetic chemicals to again produce a high purity polymer.

The high viscosity of these fluids is achieved either by crosslinking or using high concentrations of polymers that impart good viscosity and friction reducing properties. Polymers can be tied together (crosslinked) to produce very high viscosities. A viscosity increase in the magnitude of eight to ten-fold can be achieved by crosslinking.

There are four viscous water-base fluids now available which cover a wide temperature range. The type of gelling agent used for obtaining the viscous water-base gel is dependent on well conditions. The four new fluids are a crosslinked guar gum, a crosslinked cellulose derivative, a high-temperature cellulose, and a high concentration of synthetic polymer. Each of these is available in fairly broad concentration range to achieve the desired viscosity under reservoir conditions. Typical viscosity values for these four systems are shown in Table 1.

The crosslinked guar fluids develop higher viscosities than the other fluids (Table 1), but this high viscosity drops sharply at fluid temperatures above 200°F. This system is usable where fluid temperatures are from 50-225°F. Also, some residue remains when the guar fluids break down. In some cases, formation damage or reduction in fracture conductivity might result from this residue.

The crosslinked cellulose derivative fluids are classed as clean fluids in that they leave essentially no residue on breakdown. These fluids are used where a light amount of formation damage might be objectionable. These fluids are applicable where fluid temperatures range from 50-150°F. The crosslinked cellulose derivative suspends sand better than any of the viscous fluids within this temperature range.

For deep, hot wells, a different, clean cellulose system was developed using high concentrations. To avoid confusion with the crosslinked cellulose system, we will refer to this system as "HC", standing for high temperature cellulose. The "HC" can be used for fracturing fluid temperatures from 200-350°F. With normal cooldown by the pad fluid, this will allow treating of wells with bottomhole static temperatures in excess of 450°F. The basic component of "HC" is a cellulose derivative with fast hydrating characteristics to provide early viscosity and low friction pressure, and with delayed hydration that provides additional viscosity in the fracture. This technique permits low friction pressure with high gel concentrations to yield high viscosity in the fracture. The viscosity of the fluid actually increases with increasing temperature as shown in Fig. 4, whereas with most fluids viscosity decreases. A varied range of viscosities is possible to meet different well conditions. Since the basic components of the "HC" are totally water-soluble, there is no residue after breakdown of the gel. The salt tolerance of this system is very good, which should broaden its use.

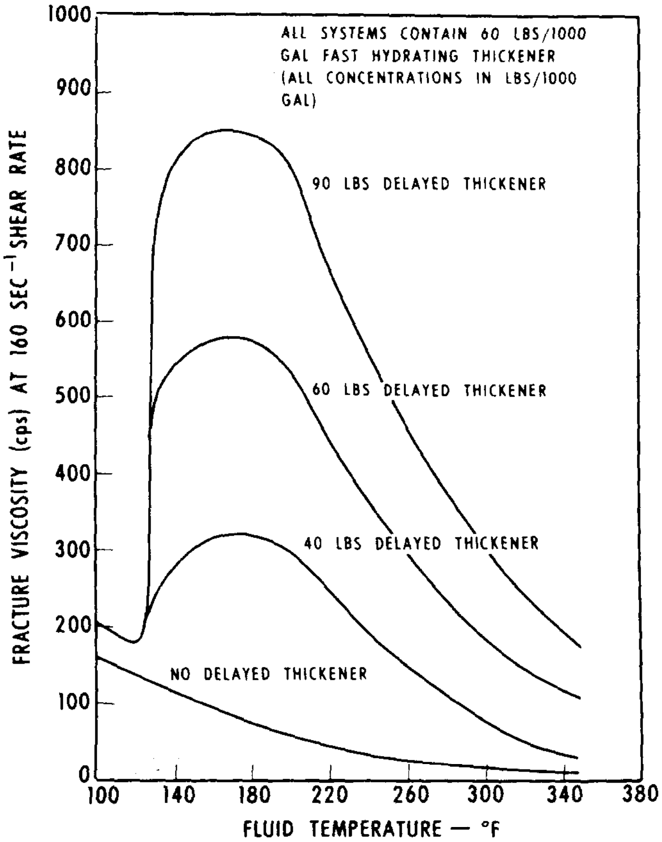

FIG. 4—APPARENT VISCOSITY (FRACTURE) VS TEMPERATURE FOR HIGH TEMPERATURE CELLULOSE SYSTEM

The synthetic polymer fluids are designed for treating oil and gas wells in sandstone formations where the fluid temperatures are from 125-350°F. Special precautions must be taken in limestone formations. High viscosities are achieved by use of high concentrations of this very efficient thickener. The synthetic polymer is a clean fluid system which provides good stability at high temperatures. The viscosity decreases very little with increases in temperature which is not true of many thickeners and particularly viscous oils. Fresh water must be used with the synthetic polymer fluids to obtain optimum results.

We will not attempt to relay all the physical properties of these new fluids because of the large volume of information required for varied well conditions. Also, the properties of these fluids are well-defined but will vary with the service company. However, we have attempted to summarize the properties of these fluids in Tables 1 and 3 to serve as guides for selection. "Typical", expected conditions are used and therefore, cannot cover the full range of fluid properties available. Only the values for intermediate concentrations are shown.

TABLE 3—GUIDELINES FOR SELECTION OF VISCOUS AQUEOUS FLUIDS

	RESERVOIR CONDITIONS			
	Crosslinked Guar	Crosslinked Cellulose	High Temp Cellulose	Synthetic Polymer
Fluid Temp Range:	50-225°F	50-150°F	200-350°F	125-350°F
May be used in:				
Sandstone	Yes	Yes	Yes	Yes
Limestone	Yes	Yes	Yes	Sometimes
Oil Wells	Yes	Yes	Yes	Yes
Gas Wells	Fair	Good	Excellent	Excellent
Water Injection	Fair	Good	Excellent*	Excellent*

* For appropriate temperature range

OIL-BASE FLUIDS

A lot of research and development during the past 12 to 15 years has been devoted to water-base fluids; there have been some advancements in oil-base fluids. The oil-base fluids are particularly needed to treat water-sensitive formations. Injection of aqueous fluids into some formations may fail to provide stimulation benefits and can result in a productivity decrease. Even the use of clay control agents, like the commonly used potassium chloride or calcium chloride, has not been successful in fracturing some formations. Available oil-base frac fluids and crude oils often did not provide satisfactory response and, in many cases, sandstone formations which failed to respond to aqueous fluids were simply set aside as poor candidates for fracturing. Kiel's[3] development of the hot viscous oil-water dispersions renewed interest in oil-base fracturing fluids for such formations. As a result, a new oil gel[7] has been developed which meets the requirements for viscous frac fluids.

This system is prepared by addition of the gelling agent to diesel oil, kerosene or in some cases crude oil, followed by an activator. A breaker is added to this gelled oil system as it is pumped into the well. Most crude oils will also destroy the gel, thus providing an additional means of breaking the gel after it enters the formation. The breaker is designed so that it works slowly, thus minimizing the danger of premature destruction of the gel.

One of the most important advantages of using the gelled oil system is that it does not create a "water block" nor damage water-sensitive formations. Many formations tend to accumulate or imbibe water by capillary action within the pore spaces immediately surrounding the wellbore. In time, this capillary-held water may accumulate to such an extent that it seriously restricts admission of oil into the wellbore. The gelled oil, being free of water, will not complicate or add to this blocking problem.

Unlike conventional oil-base fracturing fluids, the gelled oil system is not extremely temperature-sensitive as it maintains approximately 90% of its original viscosity at elevated temperatures. The graph in Fig. 5 illustrates the small viscosity reduction under moderate shear over the present treating temperature range.

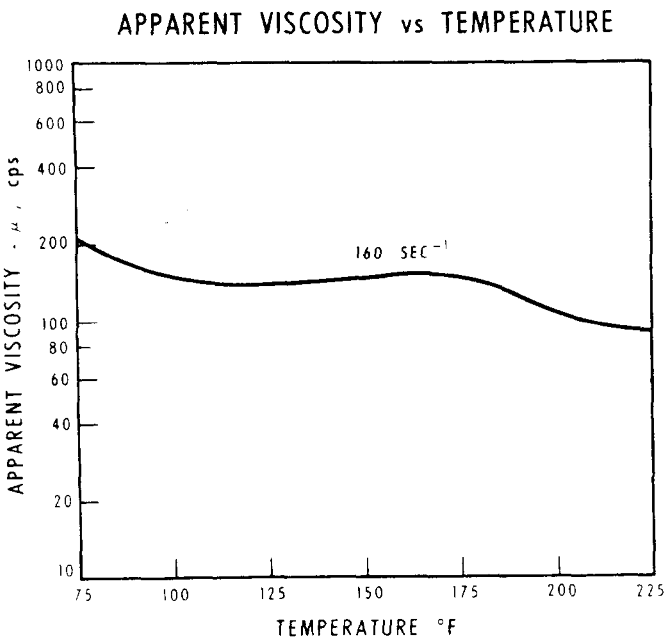

FIG. 5—APPARENT VISCOSITY OF GELLED KEROSENE VS TEMPERATURE

As in the case of the water-base gels, friction pressures generated by the oil system are considerably less than for the oil used to prepare the gel. This is illustrated in Fig. 3. Such friction reduction allows treatments to be performed down small diameter tubing. Conventional oil-base materials could not have been used in many cases where the new gelled oil system was quite satisfactory.

The fluid loss of the oil gel is controlled by three means. First, the viscosity in the pore structure is maintained. The breaker also functions as a fluid-loss control agent and, where the formation is highly permeable, additional bridging solids can be added.

JOB DESIGN

Proper job design is important in obtaining maximum benefit from the viscous frac fluids. As discussed, the key to job design is fracture conductivity and penetration. The viscous fluids should be used only when these factors indicate an improved well productivity over conventional fluids. In the early use of the viscous fluids, poor design practices were not uncommon. In several instances, equal volume comparisons were made for similar rate treatments which meant the penetration of the more viscous frac fluids would be less than that of conventional fluids because of the greater frac width. Hence, the value of increased conductivity was not utilized. For this type of comparison, the rate should have been decreased so equal frac widths were compared. Even better, the design should consider even greater penetrations than with conventional fluids to utilize the greater conductivity with increased frac width. The increased volume of viscous fluid required must be justified economically by a productivity increase. In deep, hot wells, particularly for large volume treatments, the cool-down of the well is an important design consideration as discussed by Sinclair.[11]

No special treating techniques are required with the "thick" frac fluids. Because of their low friction pressures, they can be used in the same manner as the more conventional fluids. Injection rates, volume, and prop size and concentrations are based on computer design for each well. The major deviation from conventional techniques is the use of Frac Conditioner. This is a volume of lightly gelled fluid containing a fluid-loss additive used ahead of the pad volume. The purpose of the frac conditioner is to: (1) open and establish a fracture pattern; and (2) establish initial leak-off control and lay down a filter cake with an inexpensive fluid. The frac conditioner is followed by a pad volume of "thick" frac fluid, to establish frac width, followed by the prop-laden frac fluid.

CASE HISTORIES

Case histories of both the water-base and oil-base "thick" frac fluids are presented in Tables 4, 5 and 6. The water-base fluids using guar gum as the gelling agent have been in general use much longer than those using polymers. Field results of the guar fluids are, therefore, more readily available. The examples shown in Table 4 are from an area where the problem was confinement of the fracture to the producing interval while obtaining enough conductivity and penetration to provide the desired productivity increase. Due to rapid growth of fracture height, high rate-high volume treatments often went out of zone and were ineffective from a stimulation standpoint. Controlled-height fracturing at the more modest rates shown in the

TABLE 4—FIELD RESULTS - GELLED WATER (CROSSLINKED GUAR)

Muddy Sand - Highlight Field, Wyoming, Depth - 9400-9800 ft, pump rate - 8-10 BPM down 2⅞" pipe

	Production	
Materials*	Before	After
31,000 G. W.** 19,250 20-40 4,000 12-20 beads	4 BOPHS	11 BOPHF
18,000 G. W. 11,250 20-40 2,250 12-20 beads	½ BOPHS	480 BOPDF
32,000 G. W. 20,000 20-40 4,000 12-20 beads	½ BOPHS	168 BOPDF
32,000 G. W. 20,000 20-40 4,000 12-20 beads	1 BOPHS	10 BOPHF
32,000 G. W. 24,000 20-40	144 BOPDS	408 BOPDF

* All wells used approximately 8000 gal. lightly gelled water containing 20 lb per 1000 gal. fluid loss additive as a conditioner and a pad volume of 1000 gal. viscous frac fluid.

** Gel Water - Guar

table have been highly successful with production increases ranging from two to more than tenfold. Low friction pressure of the frac fluids has permitted treating down tubing and has drastically reduced the volume of fluid required.

The more recently developed cellulose and polymer-gelled fluids are applicable in wells where there is a need to reduce formation damage to a minimum. Although they have not yet had the wide application of the guar fluids, they have been particularly successful in some areas. Table 5 shows results of treatments in Oklahoma and in the North Louisiana-Texas area. In this latter area, the polymer gel has shown good production increases where it has not previously been possible to initiate and propagate a fracture.

TABLE 5—FIELD RESULTS - GELLED WATER (POLYMER)

		Production	
Formation	Materials*	Before	After
Cotton Valley Arkansas	10,000 G. W.** 30,000 20-40	4 BOPDF	40.0 BOPDF
Vicksburg Texas	70,000 G. W. 5,000 20-40 108,000 10-20 16,000 12-20 beads	500 MCFD	4.0 MMCFD
Travis Peak Texas	1[illegible],000 G. W. 49,000 20-40	500 MCFD	2.7 MMCFD
Osborne Oklahoma	70,000 G. W. 70,000 20-40 ? 10-20 beads	Show	1.5 MMCFD

* All wells used gelled water conditioner and a pad volume of viscous frac fluid ahead of sand-laden fluid. Pump rate ranged from 6-18 BPM down 2⅜" or 2⅞" pipe.

** Gelled Water - Polymer

The gelled-oil system is one of the newest of the "thick" fluids and has not had the wide application of the water-base gels. Its use is increasing rapidly, however. Results in Table 6 show productivity increases of five to tenfold.

TABLE 6—FIELD RESULTS - GELLED OIL

Formation	Depth	Materials*	Production Before	Production After
Muddy Wyoming	8640	27,000 G. O.** 23,000 sand 1,500 beads	8 BOPD	483 BOPD
Marchand Oklahoma	9940	52,000 G. O. 105,000 sand	385 BOPD	1500 BOPD
Viking Canada	4890	14,000 G. O.	1.7 MMCFD	12 MMCFD
San Andres Texas	5010	16,500 G. O. 19,000 sand	19 BOPD 35 BWPD	73 BOPD 23 BWPD

* All wells used a volume of frac conditioner and a pad of gelled oil.
** Gelled oil

ACID FRACTURING

A recent development closely related to the viscous frac fluids is the Frac Pad and Acid technique. This technique, developed primarily for massive low permeability zones, has found many applications in carbonate formations. It consists basically of establishing fracture area with a less expensive fracture fluid and using acid to etch the fracture for conductivity. The greater frac width achieved by the viscous frac fluids provides greater live acid penetration through lower fracture-area to acid-volume ratio. The recent advances in this technique consist of a highly sophisticated computer design program and the use of the new frac fluids as pad fluids.

While computer acid design has been available for some time, recent laboratory work has shown that much of that used in computer programming can be improved. For example, much past data was obtained with static tests or with slot flow tests which were not properly controlled; acid coefficients for many concentrations and acid mixtures were not available; and many of the variables of acidizing were not recognized and programmed.

Currently a new computer design is being introduced which combines new data and many of the parameters relevant to the reaction of pad fluids and the acid in the formation. Among these factors are:

1. The geometry of the fracture created by the pad fluid
2. The temperature profile of the acid in the fracture
3. Relative change in reaction rates at incremental distances along the fracture
4. The leak-off of pad fluid and the acid
5. The displacement of the pad fluid by the acid, may be taken to complete depletion of the pad fluid if desired
6. Changes in the hydraulic fracture width during the displacement of all fluids
7. The increase in fracture width caused by acid etching
8. The volume of overflush fluid required to displace the acid
9. The effect of increased pump rates during injection of the acid stage
10. The ultimate conductivity of the etched fracture, used to predict folds of increased production.

It is felt that this new acid design will provide better answers and greatly improve fracture acidizing from the standpoint of economy as well as better stimulation results.

CONCLUSIONS

Recent trends in hydraulic fracturing have been a return to viscous fracturing fluids and somewhat more moderate injection rates than have been prevalent during the past decade. Although viscous fluids are not new, fluids, both oil and water-base, have been developed recently which overcome the primary disadvantage of high friction loss, even at viscosities much higher than those exhibited by early fluids.

The new viscous fluids are applicable in the following situations:

1. Where mechanical or pressure limitations prevent the use of high-rate, high-volume treatments
2. In high permeability reservoirs where high-conductivity fractures are required
3. In retreatment
4. In treatments where control of fracture height is needed. In some instances, limited frac height is desired. This dictates low rates where only the viscous fluids can achieve adequate conductivity and penetration of the prop pack. In other cases, a large frac height is desired, but depth may limit the rate necessary with conventional fluids. The new fluids may provide sufficient viscosity to allow satisfactory treatment in this case also.
5. In fracturing of relatively soft reservoir rock where fracture healing is a problem
6. Where slow or poor clean-up and inconsis-

tent production results indicate the need for a low-damage fluid.

The new gels provide positive and rapid breakdown to facilitate clean-up and reduce formation damage to a minimum.

More sophisticated computer programs are also a recent development indicating a continuing trend toward more carefully planned and engineered stimulation treatments. While computer programs are being improved almost daily, the greatest advancements have been in fracture acidizing design. All data in these programs have been revised and factors can now be calculated which previously could not be considered. Field results indicate that computer-designed treatments can provide effective and economical stimulation in reservoirs where many types of treatments had proved unsuccessful in the past.

NOMENCLATURE

A = Cross-sectional area (ft^2)
D = Diameter, ID, (inches)
du/dr = Absolute shear rate (sec^{-1})
h = Fracture height (ft)
J = Productivity index before fracturing
J_F = Productivity index after fracturing
K′ = Consistency index (lb_f-$sec^{n'}/ft^2$)
K_e = Effective horizontal formation permeability (md)
K_F = Fracture permeability (Darcies)
L = Fracture length or penetration (ft)
n′ = Flow behavior index (dimensionless)
P_w = Pressure differential at wellbore (psi)
Q = Flow rate (BPM)
S = Well spacing (acres)
w = Fracture width (inches or feet)
μ_a = Apparent viscosity (cps)
τ = Shear stress (lb_f/ft^2)

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APPENDIX

Rheology

The physical properties of the "thick" fracture fluids influence their usefulness and method of application. Special consideration is given to describing their viscosity behavior under varying flow conditions. The term viscosity is sometimes misused in describing the physical characteristics of fluids such as drilling muds, cement slurries, and many fracturing fluids. Unfortunately, these fluids do not behave as Sir Isaac Newton predicted. These non-Newtonian fluids are in sharp contrast to water, sugar solutions, alcohol, refined materials, glycerine, and many low molecular weight liquids and gases. The rheology of Newtonian fluids is classically shown by the proportionality between shear stress and shear rate on arithmetic coordinates as in Fig. 6. In the case of non-Newtonian fluids, such as those mentioned earlier, the shear stress is not proportional to the shear rate. The term "apparent viscosity" is applied to these fluids. This is the viscosity the fluid has at a specific shear rate. If the shear rate isn't specified, then the viscosity of a non-Newtonian fluid is meaningless.

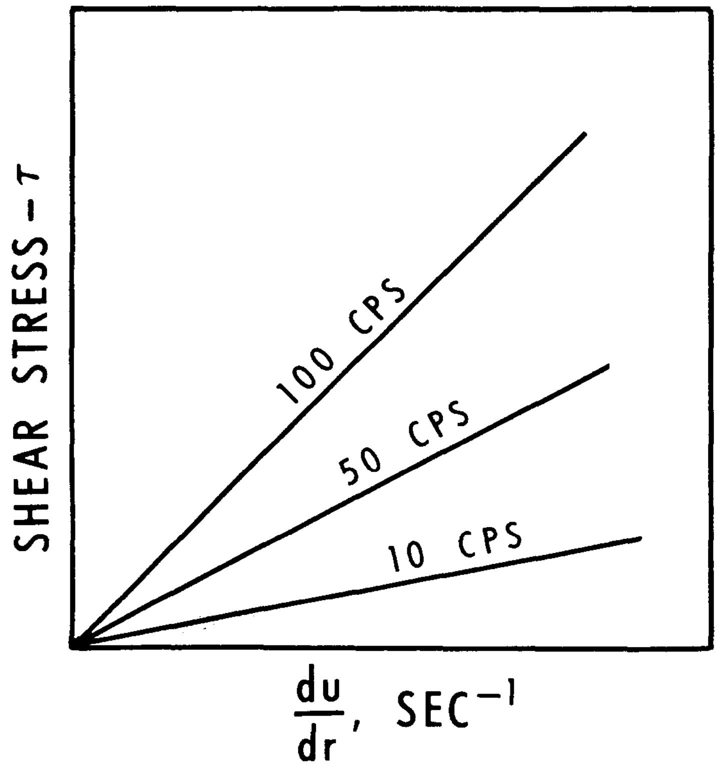

FIG. 6—VISCOSITY PLOT OF NEWTONIAN FLUIDS

Solutions of high molecular weight polymeric materials are invariably non-Newtonian except when unusually dilute. Such fluids are grouped into classes depending upon their behavior. The classes are Bingham plastics, dilatant, and pseudoplastic. A plot of their typical shear stress vs shear rate behavior is shown in Fig. 7. By far, the greatest number of non-Newtonian fluids fall into the pseudoplastic class. These exhibit a decrease in apparent viscosity with an increase in shear rate.

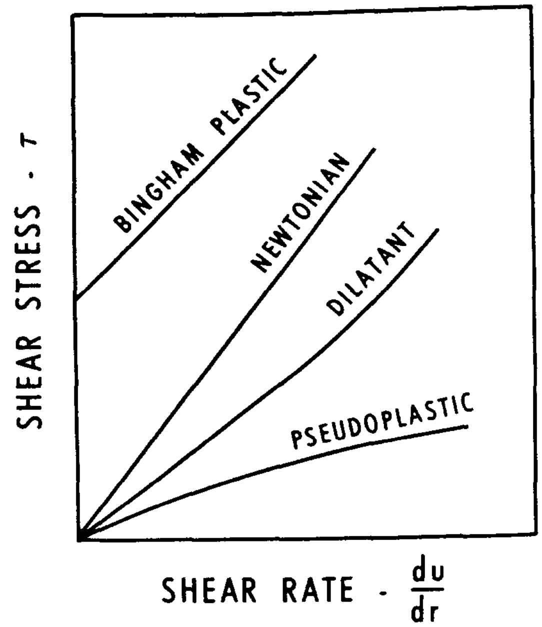

FIG. 7—FLUID-FLOW CURVES, ARITHMETIC

Many fluids form a straight line over a portion of the shear-rate range of interest in fracturing when their flow curves are plotted on logarithmic coordinates as shown in Fig. 8. The equation for any straight-line segment can be written as $\tau = K\,(du/dr)^n$, where K becomes the intercept at a shear rate of one sec^{-1}, and n is the slope of the line. This has become known as the Power-Law Model.[12]

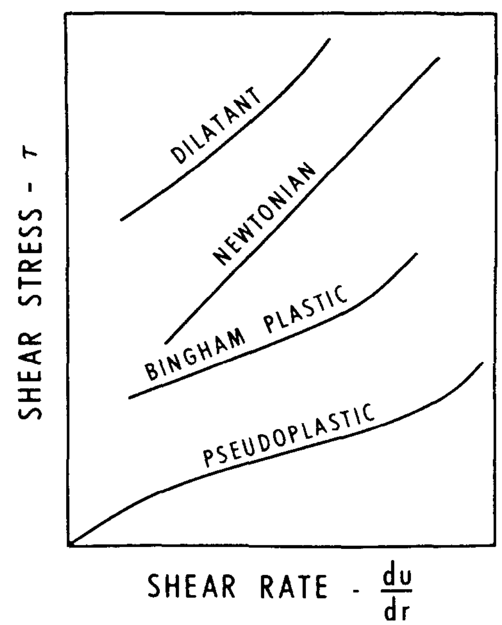

FIG. 8—FLUID-FLOW CURVES, LOGARITHMIC

In the case of Newtonian fluids, where shear stress is proportional to shear rate, the equation becomes one of the first order and n = 1.0. All Newtonian fluids, then, have a slope of unity on a log-log plot. The intercept, K, varies with the consistency of the fluid. By using the "Power-Law Model," the flow properties of many non-Newtonian fluids may be readily compared with Newtonian fluids. K is the viscosity of the fluid at one reciprocal second shear rate and is called the "consistency index." The larger the value of K, the more viscous the fluid is for a specific "n" value. The parameter, n, is referred to as the "flow-behavior index." A pseudoplastic fluid will have an "n" value of less than 1.0 while a dilatant fluid would have a value greater than 1.0. The parameter, n, measures the deviation from a Newtonian fluid.

The apparent viscosity, μ_a, is the ratio of shear stress to shear rate.

$$\mu_a \text{ (centipoise)} = \frac{\tau}{(du/dr)} = \frac{47{,}880 \text{ K}}{(du/dr)^{1-n}}$$

Rotational viscosimeter data can be used with the above formula. It is possible, of course, to study the rheological properties of a fluid by measuring its laminar flow properties in a pipe. The equation for fluid-flow in a pipe in the Power-Law form is:

$$\frac{D\Delta P}{4L} = K' \left(\frac{8V}{D}\right)^{n'}$$

where $D\Delta P/4L$ is the shear stress and $8V/D$ is the shear rate.

Values for K′ and n′ are determined by plotting the shear rate vs the shear stress on logarithmic coordinates. K′ and n′ values are usually reserved for pipe flow rheology while K and n are used in discussing rotational viscosimeter data.

Similarly, an equation for fluid flow in a fracture in the Power-Law form can be written as:

$$\frac{W\Delta P}{2L} = K'_F \left(\frac{6V}{w}\right)^{n'}$$

For convenience, a nomograph (Fig. 9) for obtaining apparent viscosities from n′ and K′ values is included. In addition, the graphs in Figs. 10 and 11 correlate injection rate and shear rate for flow through tubing and fractures respectively. Thus, the apparent viscosity of a fracturing fluid under dynamic conditions can be determined rather easily.

The following example illustrates the use of Figs. 9 and 11 for determining apparent viscosity. Determine the viscosity in the fracture for a fluid with n′ = 0.3, K′ = 0.20 at the fluid temperature in the fracture. Flow rate is 10 BPM, the frac height (h) is 50 feet and average frac width is 0.3 inch. Q/h is then 0.2 BPM/ft. From Fig. 11, we find this value for a 0.3 inch fracture gives a shear rate of 0 about 90 sec^{-1}. On nomograph, Fig. 9, we connect (1) SR = 90 sec^{-1} to (2) n′ = 0.3 for the pivot point (3). Then drawing a line from pivot point (3) through K′ = 0.2 on (4) gives an apparent viscosity of 400 cps on (5) μ_a.

The apparent viscosities at fracture shear rates for the gels described in this paper have been experimentally determined using the high temperature, high pressure Fann Viscosimeter, Model 50. These new data are presented in Table 3. Use of this new Fann Viscosimeter has provided information at relatively high temperatures demonstrating the effectiveness of these gels for treatments.

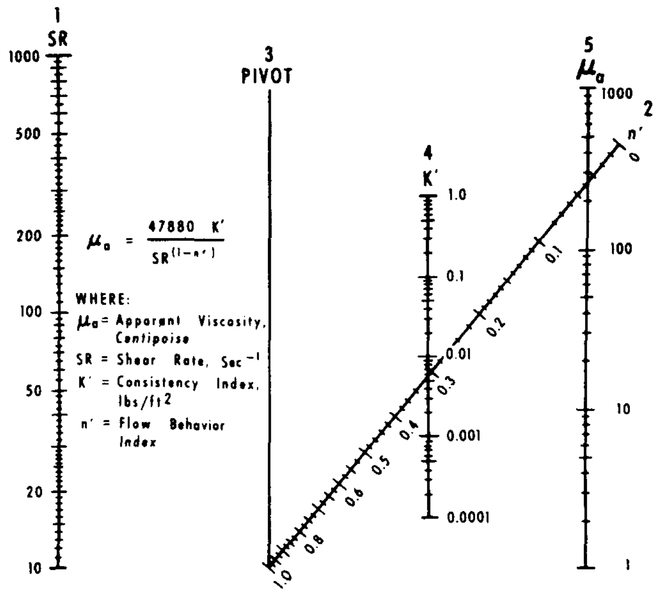

FIG. 9—NOMOGRAPH FOR CALCULATING APPARENT VISCOSITIES

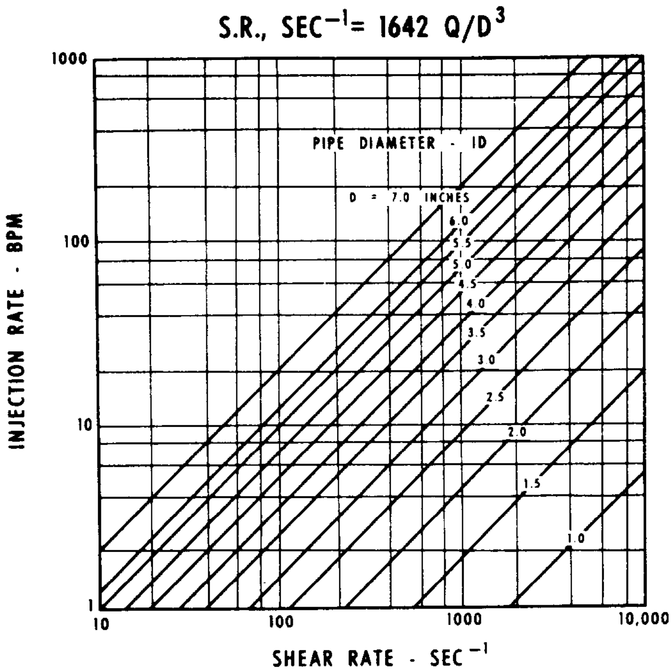

FIG. 10—SHEAR RATE FOR FLOW THROUGH PIPES

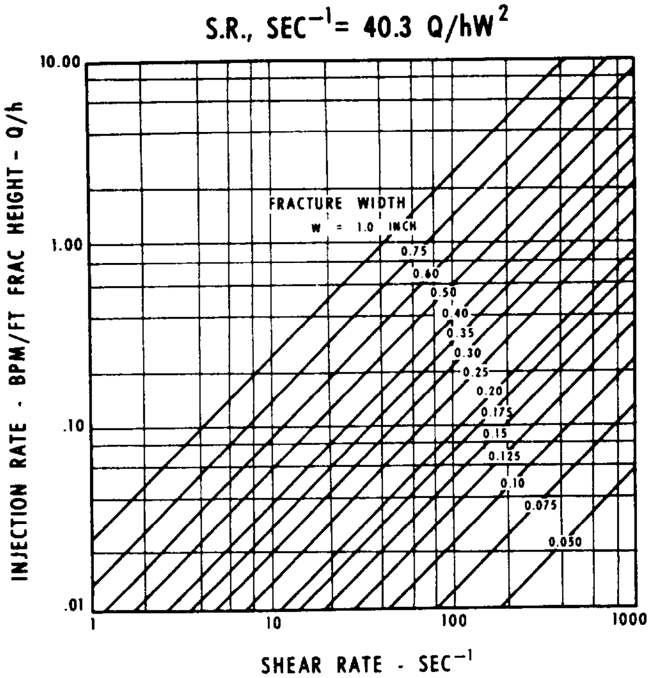

FIG. 11—SHEAR RATE FOR FLOW THROUGH FRACTURES