Hydraulic Fracturing - A Product of Industrial Research

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INTRODUCTION

Hydraulic fracturing is a prime example of the development of a stimulation process that is the result of industrial research. Perhaps Pan American Petroleum Corporation has derived the most benefit from a royalty-prestige standpoint, but it is doubtful that we have a preferred position over our competitors in the benefits obtained in terms of barrels of oil in the stock tank.

This paper is divided into four broad categories. The first is a brief background to establish the magnitude of the process. The second section briefly describes the growth era of fracturing with a review of many of the processes that have been used. The third section describes the engineering era of fracturing in which the whole process has become much more sophisticated. A large number of organizations have applied their technical know-how to determining what will happen when a well is fractured and just how to achieve, under optimized conditions, a certain result from fracturing. The fourth section suggests where fracturing will go from here and its future impact on the petroleum industry.

Hydraulic fracturing has progressed from an experimental process in the 40's to the most widely used stimulation procedure the industry has ever developed. The grand total of wells fractured by the process in the U. S. and Canada is approximately 450,000 with about 26,500 treatments currently being conducted each year.

Hydraulic fracturing had its initial introduction in the Hugoton, Kansas, gas field in the late 1940's. Figure 1 shows the equipment that was used in the initial field tests. It is interesting to note the care that was taken to separate the mixing tanks from the injection pump and the pump from the well before attempting treatments using gelled gasoline. The equipment you see pictured here was used in approximately 10 field trials of the fracturing process in Hugoton, Kansas; Frannie and Elk Basin Fields of Wyoming; Rangely and Winkleman Dome Fields of Colorado and the Sasakwa Field in Oklahoma. On the basis of the preliminary success in field testing, this process—hydraulic fracturing—was introduced to the oil industry as a commercial process in March 1949.

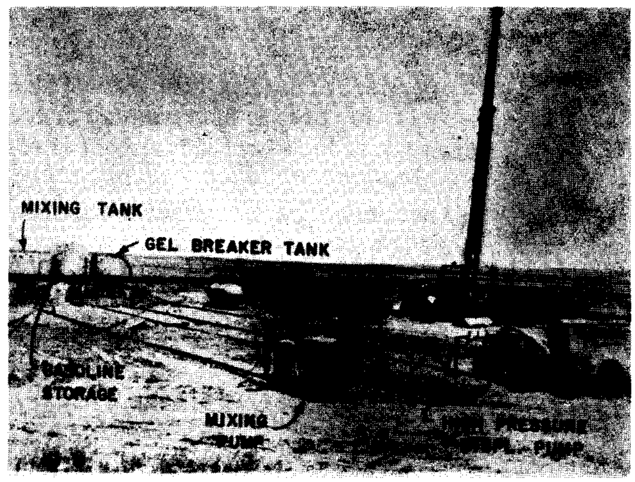


FIGURE 1

Fracturing has taken on many different forms over the past years—so many that the original form of fracturing in use during the period from 1949 to the mid-50's may have been forgotten by most people.

TYPES OF FRACTURING JOBS

Standard Hydrafrac

Fracturing in the late 1940's was conducted in a 3-step process. First, a thickened hydrocarbon, usually kerosene thickened with napalm gel, was pumped into a well to effect a breakdown of the formation. The fracturing liquid, transporting a closely graded sand, was displaced out into the formation to extend the fracture and place the propping agent away from the well bore. Next, a gel breaker was displaced into the fracture to break down the napalm gel and permit its return to the well bore. The third step then involved placing the well back on production and returning the broken napalm gel to the surface.

Hydrafrac Acid

In low solubility carbonate reservoirs, the first basic change in the hydraulic fracturing process involved following the gel with hydrochloric acid to break down the base gel and enlarge the fracture by means of reaction of the acid with the fracture surfaces. The third step involved returning the well to production and recovering the broken gel.

Acid Fracturing

The third innovation in the hydraulic fracturing process was the use of a thickened acid. This was accomplished by using a material such as batu gum to emulsify the acid in oil. The emulsion was then used as the fracturing medium and also to transport the propping agent away from the well bore to effect the necessary drainage channel in high solubility carbonate rock. The reaction of the acid with the reservoir rock effected a breakdown of the gel and the spent acid was then produced back to the well as a third step in the process.

Multiple Fracturing

Since many wells produce from long open hole sections, some of the order of 400 to 1500 ft or from multiple perforated zones, it appeared desirable in this type of reservoir to effect multiple fractures in a single treatment. This was accomplished by fracturing the formation in the same manner as has been described earlier using a gel, then following the original fracturing fluid with a gel containing an oil soluble granular material such as naphthalene or rock salt and repeating the process, forming as many additional fractures as desired. The fourth step was to inject a gel breaker material, if needed, to effect a breakdown of gel and the final step of returning the well to production.

To determine the effectiveness of this multiple fracturing technique on the permeability profile, injection surveys were conducted both before and after fracturing wells when the multiple fracturing method was used. It was found that multiple zones of permeability were produced.

At this stage of the development of hydraulic fracturing, the service companies recognized the need for equipment designed especially for the purpose of hydraulic fracturing and initiated a development program that resulted in mobile pumping equipment capable of handling large quantities of fluid at high pressures and high injection rates. This equipment made possible the hydraulic fracturing of formations utilizing what became known commercially as LVHIR (large volume high injection rate) treatments.

Viscous Fracturing Fluids

The first major change noted in using this equipment was to fracture formation with refined oils. This is still used in many areas with a high degree of success. The objective was to select oils, such as No. 5 residual fuel oil, that possessed reasonably good fluid loss characteristics and moderately high viscosities so that they could be pumped and handled by field equipment and still obtain long radius fractures at a reasonable cost. The next attempt was to use lease crude to accomplish this same objective. It was evident that if this type of fracturing fluid were to be used efficiently, it must be treated with an additive to reduce the high loss of the fracturing fluid to the formation during fracturing. It was at this point that the fluid loss additives became widely used in fracturing operations.

Water Fracturing

With the advent of large volume oil treatments, that is, 50,000 or more gallons, handled at high pressure and high rates, using several pumping units, there was an every increasing hazard to both well, equipment, and personnel due to the fire hazards involved in such a treatment. This, coupled with the fact that in many areas such as the San Juan Basin of New Mexico oil had to be transported long distances, made it desirable to attempt fracturing operations using water as the fracturing medium. Here, again, it was the ability of service companies to supply the equipment capable of handling water at high injection rates that permitted the successful application of this treating procedure to many areas.

In many areas the very nature of the formation, that is the action of fresh water on the clays in the matrix, made the fresh water fracturing fluid act as a low fluid loss material. In other areas, it was necessary to add materials to the water to both control its fluid loss and in some instances increase its viscosity.

Many of these fracturing methods are still being used. Obviously, those involving the simpler treating procedures, that is, the use of water or oil treated with a suitable additive, now predominate the field.

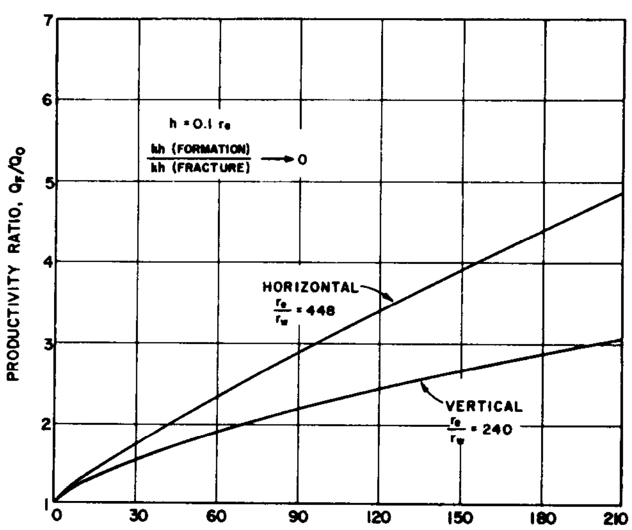
No discussion of fracturing can ignore the orientation of fractures. It is general knowledge that there are widely divergent opinions on this subject. We believe that horizontal fractures can be initiated under certain conditions and also can be extended at less than overburden pressure under some conditions. Some maintain that vertical fractures are usually formed and that horizontal fractures are never made and extended at less than overburden pressure. It is beyond the scope of this paper to attempt to explain fracture orientation and propagation. Many people and organizations have or are in the process of studying this very important facet of fracturing.

FACTORS CONTROLLING FRACTURE EXTENSION

To understand the factors controlling fracture extension, analytical and electrical model studies were made to show the effect of fracture radius or penetration on both the flush and stabilized production that may be obtained from a given reservoir with a given fracture system.

FIGURE 2

EFFECT OF FRACTURE PENETRATION ON PRODUCTIVITY



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Post Fracturing Production

Figure 2 is a plot of productivity ration (productivity after fracturing divided by productivity before fracturing) versus fracture extent and shows the effect (for conditions specified) of increased fracture extent on well production for a single horizontal fracture in the center of the pay and a vertical fracture, the plane of which bisects the bore of the hole and extends the same distance into the reservoir as the horizontal fracture. It may be observed that an increase in the extent of either a horizontal or vertical fracture will result in an increase in well productivity.

From these considerations and field results, it has been demonstrated that well productivity is increased as the fracture length increases and the total production from a given reservoir can be obtained in a shorter length of time.

Calculation of Fracture Penetration

Having seen the importance of fracture length on well productivity, it is necessary to consider the effects of fracturing fluid characteristics and reservoir fluid and rock characteristics on the areal extent of a fracture. The effect of these variables may be illustrated by considering mathematically how they affect the calculations of the areal extent of a fracture.

The general fracture area calculation equation, presented below, shows that the injection rate is equal to the rate of leak off plus the rate of fracture growth.

$$Q=2\int_0^t V(t-\lambda)\,\frac{dA}{d\lambda}\,d\lambda + W\frac{dA}{dt}$$

Injection rate = Rate of leak off + Rate of fracture growth

The integrated form of this equation is shown below.

$$A=\frac{QW}{4\pi C^2}\left(e^{X}\cdot \mathrm{erfc}\,(X)+\frac{2X}{\sqrt{\pi}}-1\right)$$

$$\text{Where } X=\frac{2C\sqrt{\pi t}}{W}$$

This equation shows that the area is equal to the injection rate times the fracture width divided by 4 times π times a C factor squared times an expression which involves a function X which is equal to 4 times this same factor C times the square root of πt divided by W where

C is the fracture fluid coefficient, W is fracture clearance or width and t is the injection time.

Fracture Fluid Coefficient "C"

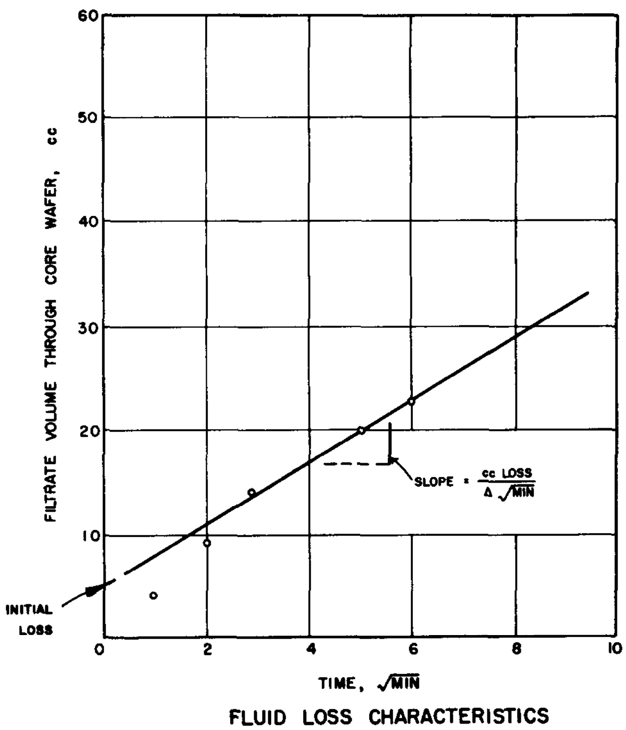
The fracturing fluid coefficient is defined in terms of three characteristics. The first is in terms of the viscosity of the fracturing fluid. The second is in terms of the effect of the reservoir fluid, and the third is in terms of the wall building characteristics of the fracturing fluid.

Viscosity - $C_I = 0.0469\sqrt{\dfrac{K\ \Delta P\ \phi}{\mu}}$

Reservoir Fluid - $C_{II} = 0.0374\ \Delta P\sqrt{\dfrac{K\ \phi\ C_f}{\mu}}$

Wall Building - C_{II} = Determined experimentally

The first two can be calculated using the formulas shown here. The third, which is the one which is the most used, is determined experimentally. Experimental determination of the wall building coefficent is obtained using a high pressure filter press in which the filter medium is a core wafer. Typical data for such an experiment are shown on Fig. 3. On the basis of these data, the C factor is calculated based on the slope of the fluid loss versus square root of the time curve.



FLUID LOSS CHARACTERISTICS

FIGURE 3

$$C = 0.0164\ \frac{m}{a} \qquad m = \frac{V}{\sqrt{t}}$$

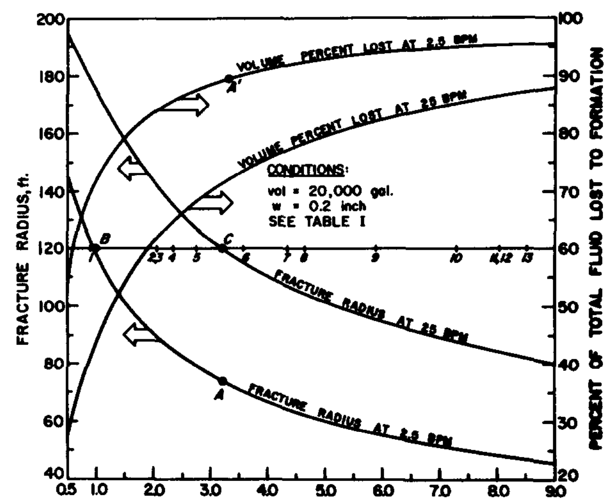
a = area of filter media

Where m = slope of the line
V = filtrate volume

The effect of the fracturing fluid coefficients is summarized on Fig. 4 where it may be seen that a decreasing coefficient (resulting from increased fracturing fluid viscosity, increased reservoir fluid viscosity and compressibility or decreased fluid loss) markedly increases the fracture area obtained. Also shown on this figure is the effect of increasing pump rate which always tends to increase the fracture penetration obtained for any set of conditions.

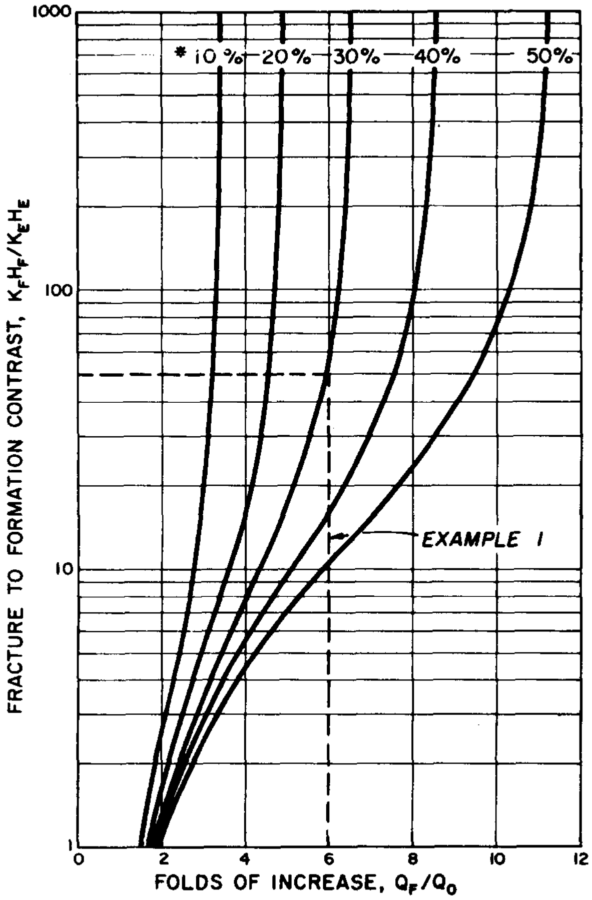
FIGURE 4

EFFECT OF FRACTURING FLUID COEFFICIENT AND PUMP RATE ON FRACTURE EXTENT



Deriving Maximum Profit

In order to engineer a fracturing job, that is, obtain the best return on the money spent for treatment, it is necessary to know the effect of fracture penetration on production obtained. Figure 5 shows that increasing fracture penetration increases the production obtained from a given formation.



APPROXIMATE PRODUCTION INCREASE
FROM FRACTURING

*PENETRATION = HORIZONTAL FRACTURE RADIUS OR DEPTH OF PENETRATION OF ONE OF A PAIR OF VERTICAL FRACTURES AT 180°, EXPRESSED AS PERCENT OF DRAINAGE RADIUS.

Q_F = PRODUCTION AFTER FRACTURING, BOPD
Q_O = PRODUCTION BEFORE FRACTURING, BOPD
H_E = NET PAY THICKNESS, FEET
K_E = EFFECTIVE HORIZONTAL PERMEABILITY, MD
K_FH_F = EFFECTIVE FRACTURE CAPACITY, MD-FT

FIGURE 5

FIGURE 6

EFFECT OF PERMEABILITY AND FRACTURE RADIUS ON RELATIVE SAVINGS

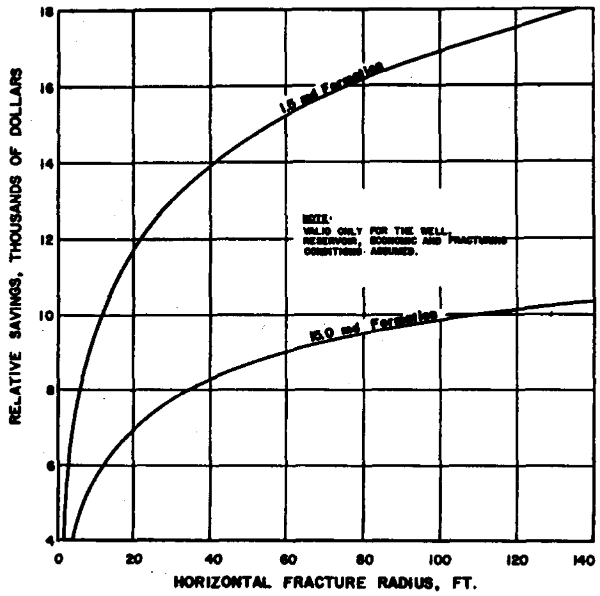


FIGURE 7

TYPICAL FRACTURE RADIUS VS PUMP RATE CURVES

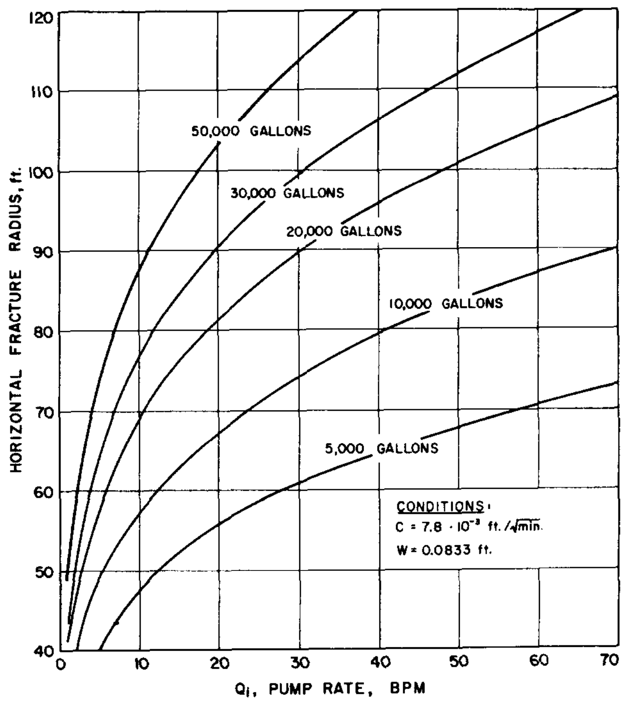


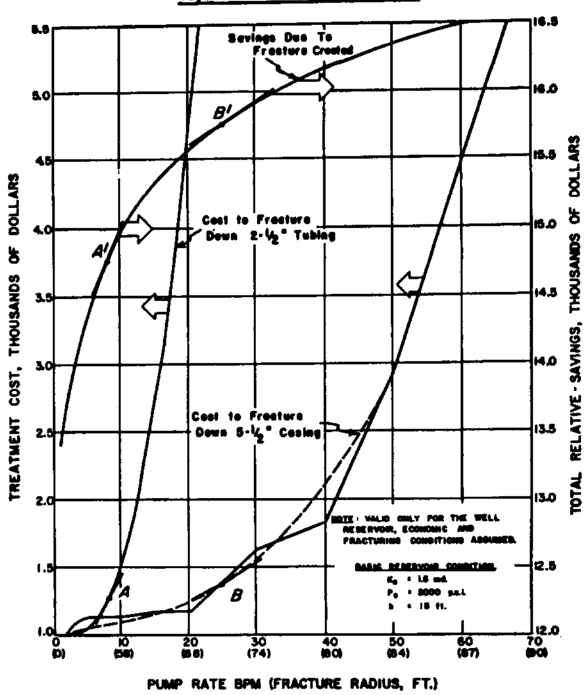
Figure 6 illustrates the effect of horizontal fracture radius on dollars saved in producing a given quantity of oil where savings is defined as the difference between the cost of producing an **unfractured** well to the economic limit and producing the same well after a fracturing treatment to the same economic limit, i.e., getting the same amount of oil quicker.

Having determined the effect of fracture radius on production rate and the effect of fracture radius on relative savings, Fig. 7 shows what volumes and pump rates are required to obtain various fracture radii with a LFL oil having a C factor .003 ft/ $\sqrt{\text{min}}$.

The next step in designing an optimum fracturing treatment is that of combining savings and treatment cost. Figure 8 was prepared to show the treatment cost and total savings as a function of pump rate—fracture radius for a 10,000 gal. treatment conducted down 2½-in. tubing in one case and 5½-in. casing in another. From this plot, it may be noted that the slope of the relative savings curve decreases with increasing pump rates, while the slope of the treatment cost curves for both the tubing and casing jobs increases rapidly with increasing pump rates. The points at which the slope of the treatment cost and savings curves are equal represent the pump rate where the rate of spending equals the rate of return. At higher or lower pump rates, the rate of spending exceeds or fails to equal the rate of return and, of course, the net profit is less. For example, the point at which the slope of the fracture treating cost curve equals the slope of the total savings curve occurs at points labeled A and A' for the 2½-in. tubing job and at point B and B' for the treatment down 5½-in. casing. These points represent the optimum treating conditions for a 10,000-gal. job. Deducting the treatment cost from the total savings at the optimum point gives the maximum net profit to the operator under the conditions specified.

FIGURE 8

TREATMENT COST VS. SAVINGS FOR A 10,000 GALLON TREATMENT*

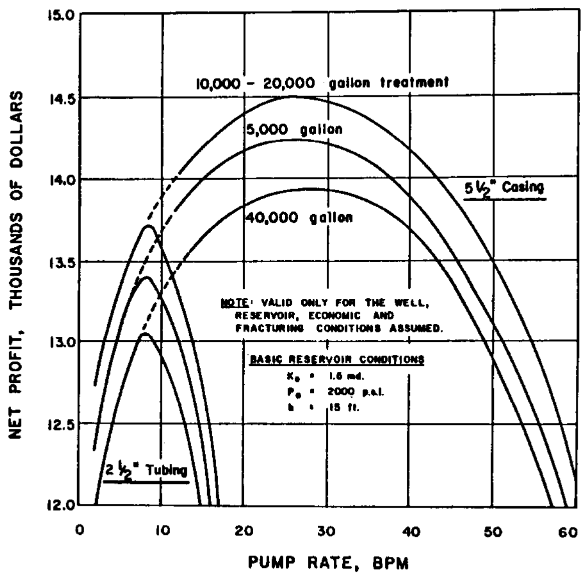


* FRACTURING FLUID - SAND AND OIL WITH FLUID LOSS AGENT.

The determination of the net profit to be derived from fracturing then involves a careful analysis of the savings versus treating costs. This permits a plotting of the data as illustrated on Fig. 9.

FIGURE 9

NET PROFIT DERIVED FROM FRACTURING WITH OIL



*FRACTURING FLUID-SAND AND OIL WITH FLUID LOSS AGENT.

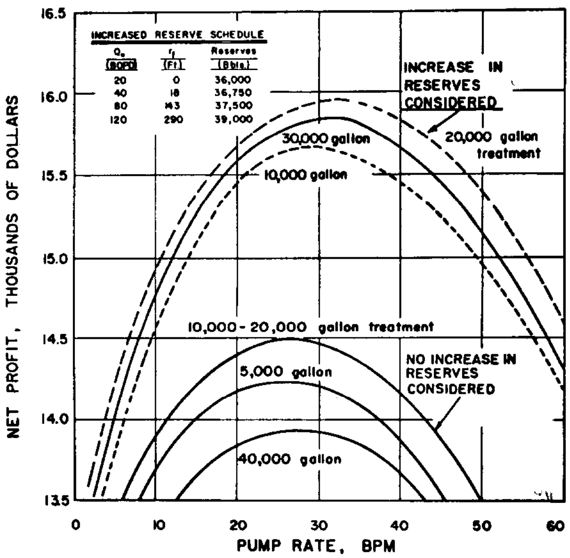
Optimization of Frac Job

The interesting thing to note here is that the largest volume, highest pump rate job does not necessarily produce the maximum net profit. For the conditions shown here, a 10,000 to 20,000 gal. job returns more net profit than does a 40,000 gal. treatment pumped at a higher rate. These data are based on using a low fluid loss oil with a .003 C factor and no additional recoverable reserves were attributed to fracturing.

The effect of an increase in recoverable reserves (1000 bbl.) is illustrated on Fig. 10 for the 5½-in. casing job. The lower set of curves are the same as shown on the previous slide where no increase in reserves was assumed. The upper curves illustrate the effect of increased reserves and show that net profit is increased appreciably if the treatment increases the recoverable reserves.

FIGURE 10

EFFECT OF INCREASED ULTIMATE RECOVERY ON NET PROFIT AND TREATMENT DESIGN*



NOTE: VALID ONLY FOR THE WELL, RESERVOIR, ECONOMIC AND FORMATION CONDITIONS ASSUMED.

BASIC RESERVOIR CONDITIONS

K_o = 1.5 md.

P_e = 2000 psi

h = 15 ft.

*FRACTURING FLUID - OIL AND SAND WITH FLUID LOSS AGENT TREATMENT DOWN 5½" CASING

JOB MECHANICS

Fracture Placement

The mechanics of doing the job is also important. For example, the placement of fractures at a desired depth in a well is often necessary to achieve maximum productivity and oil recovery. It is also necessary in reservoirs near depletion to attain an increased gravity drainage rate in order to make the wells produce commercial quantities of oil. Water or gas coning can often be reduced by the placement of horizontal fractures at appropriate locations in the formation.

Liquid-Sand Jetting

The method that has been most successfully used to selectively place horizontal fractures involves jetting of sand and liquid at high rates to circumferentially notch the formation. In laboratory tests conducted in a 3-ft. diameter concrete test drum, the casing, cement, and formation were penetrated 10-in. after rotating a jetting tool while pumping sand and water through it at 2000 psi. This technique has been very successful in the field.

Single Plane Multiple Shaped Charges

Another method used to achieve horizontal fracture placement and minimize screenout possibilities is the use of a multi-charge, single-plane shaped-charge gun. Nearly all perforating companies offer these charges which produce ¾-in. to 1-in. diameter holes and several inches of penetration.

Penetrating Fluid

A third method of fracture placement that has been used is the employment of a non-penetrating fluid to restrict fluid egress from the well, and the use of a penetrating fluid placed at the selected elevation to effect a fracture. The key to fracture placement, vertically or horizontally, is to restrict fluid egress to the plane and elevation desired and if possible weaken the formation in the desired direction.

FRACTURE CAPACITY

The fluid carrying capacity of the created fracture has a major effect on a productivity increase that may be obtained from a fracturing treatment. Figure 5 shows the effect of fracture to formation flow capacity contrast on well productivity (or folds of increase) plotted as a function of the drainage area penetrated. It may be noted that contrasts greater than 10 for short fractures (10 per cent of the drainage radius) and contrasts greater than 50 for moderate (30 per cent) fractures, or greater than 100 for deep penetrating fractures are not justified. Therefore, careful study of the required fracture capacity is indicated. It may be observed from these data that the productivity from fracturing can be increased by increasing the fracture capacity. This is particularly true for the higher capacity formations.

Having looked at the effect of fracture capacity on well productivity, now let us examine the factors controlling fracture capacity. These are well depth, rock hardness, propping agent characteristics, and propping agent distribution. All of these factors are inter-related so that the selection of the optimum propping agent requires careful consideration.

The proppant required for a given job depends on three factors: (1) type of rock in which fracturing is to be done, (2) well depth or overburden pressure, and (3) the capacity required.

The type of formation or rock in which fracturing is being accomplished has been categorized by defining them in terms of embedment pressure or the pressure required to embed a ball of a given dimension into the rock a fixed distance.

Selection of Proppant

To illustrate the selection of propping materials, the first step is to determine the fracture flow capacity required to achieve the desired production following fracturing. This capacity depends upon the flow capacity of the producing formation and the penetration of the fracture into the reservoir. The relationship of fracture-formation capacity ratio to the production increase ratio with fracture penetration as a parameter is shown on Fig. 5. Along the abscissa are the folds of increase which is simply the production after fracturing divided by the production before fracturing. The ordinate is scaled for fracture to formation capacity contrast which is the fracture capacity divided by the formation capacity. Five curves are shown —one for each of five fracture penetrations— expressed as per cent of the drainage radius.

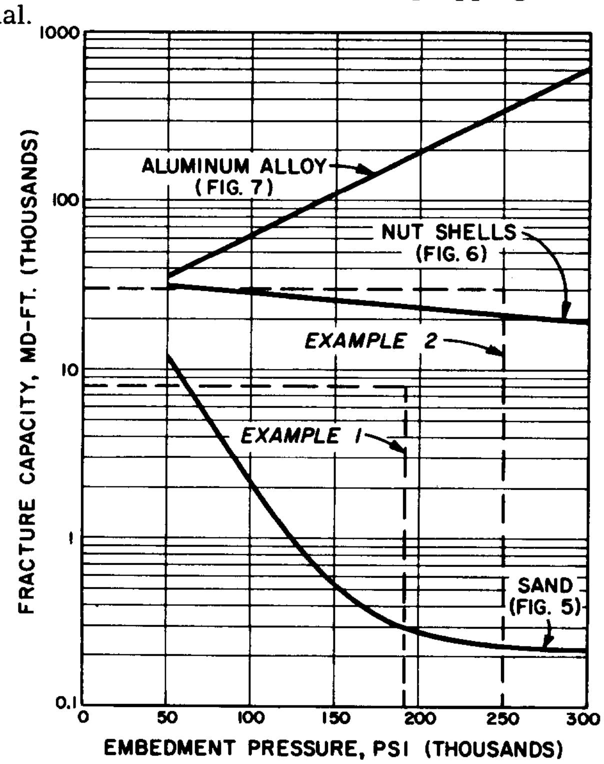
It may be seen from these curves that a high fracture to formation flow capacity contrast is required to obtain the maximum benefit from fracturing and that where fracture penetration is deep and formation flow capacities are high, fractures with high capacity are more advantageous.

Example Problem

To illustrate the use of this chart, assume a 7000 ft well in the San Andres formation with a formation capacity of 160 md-ft, that it is desired to increase productivity six-fold, and that we plan to make a fracture penetrating 30 per cent of the drainage radius of the well. Using the curve, follow the six-fold increase line straight up until it intersects the 30 per cent fracture penetration curve. From this intersection go horizontally to the left margin where we read that a fracture to formation contrast of 50 to 1 is required to achieve a six-fold production increase. This means that the fracture capacity must be 50 times the formation capacity. Simple multiplication tells us that the fracture capacity required is 160 x 50 or 8000 md-ft.

The second step in the selection of propping agents is the determination of embedment pressure as previously described. The embedment pressure for the San Andres formation used in this example is 193,000 psi.

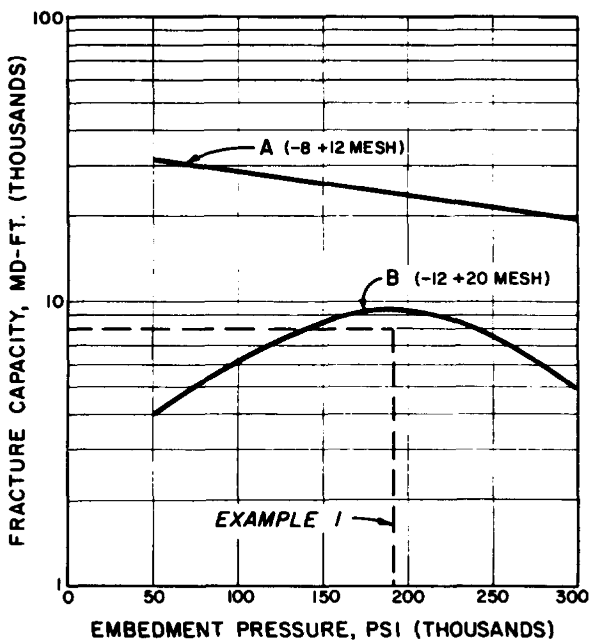
The third step involves selection of the type propping agent required. For this purpose a generalized propping agent selection chart shown on Fig. 11 was prepared with curves for maximum fracture capacity obtainable for sand, rounded nutshells and aluminum alloy proppants for a well depth of 7000 ft. On these curves fracture capacity is plotted against embedment pressure. Taking the known values from the previous two steps and starting at the lower margin with 193,000 psi embedment pressure and going vertically till the horizontal line for 8000 md-ft is intersected puts us at a point between the curves for sand and nutshells. This tells us that a sand propped fracture will not give us the desired capacity and rounded nutshells will have to be used for propping material.



GENERALIZED SELECTION CHART
MAXIMUM FRACTURE CAPACITY OBTAINABLE
WELL DEPTH 7000 FEET

FIGURE 11

Having determined the type propping material, the final step is the selection of the size and concentration of nutshells that will produce the desired fracture capacity. This is determined from the curves for rounded nutshells shown on Fig. 12. The point where a vertical line through the 193,000 psi embedment pressure point intersects the horizontal line for 8000 md-ft is just below the curve for $-12+20$ mesh nutshells. This indicates that a 0.1 monolayer of $-12+20$ mesh rounded nutshells should be used to make an 8000 md-ft fracture resulting in a six-fold production increase. This 0.1 monolayer is equivalent to a concentration of 30 lb/1000 sq ft. When designing a fracturing job, the fracture area can be calculated if the fluid characteristics and the volume and the pumping rate of the treatment are known. The total amount of propping agent can be calculated by multiplying the fracture area by the concentration. The fracture area is information which most service companies will supply to the customer.



PROPPING MATERIAL SELECTION CURVE FOR ROUNDED NUTSHELLS

WELL DEPTH 7000 FEET
A. 0.033 lb/sq ft, 0.1 MONOLAYER
B. 0.024 lb/sq ft, 0.1 MONOLAYER

FIGURE 12

Fracture Capacity vs. Distribution and Embedment Pressure

Propping agent distribution has a great influence on the fracture capacity. For example, if the propping agent is placed so that the individual particles are widely separated, high fracture capacities will result even if the propping agent reforms. If the propping agent is closely packed, the fracture capacity will be less. For example, in a well 7000 ft deep in a formation with an embedment pressure of 200,000 lbs, a fracture with a ¼ monolayer distribution of $-12+20$ mesh nutshell proppant will have a flow capacity of approximately eight times that of a full monolayer.

Propping Agent Spacers

If the propping agent deforms or crushes and forms a low permeability mass, low capacity will result unless open channels are flushed through the propping agent.

The attainment of optimum distribution is a difficult problem. One method commercially available is the use of a material soluble in well fluids, such as an oil soluble petroleum resin, for example, Amoco 506 (1.1 specific gravity), or a water soluble spacer, for example, urea (1.3 specific gravity), which is placed with the propping agent.

The spacer material subsequently dissolves in the produced oil and leaves a properly distributed propping agent. Another method involves programming the injection of the propping agent to correlate its movement into the fracture with a loss of fracturing fluid so that the proper wide distribution will be achieved.

The cost of these spacer materials is equal to or less than the cost of the propping agent with which the spacer is generaly used. Urea, for example, is one-third to one-fifth the cost of nutshells, and resin spacer is about equal to the price of rounded nutshells.

In designing a fracturing treatment, the quantity of proppant and spacer used should be equivalent to that required for a full monolayer. The amount of proppant should be determined as outlined above and the spacer would occupy the remaining volume to make a full layer. The ratio of proppant to spacer will vary with the type of material used. A one to four volume ratio of deformable propping agent to spacer is generally considered suitable and a one to one ratio of non-deformable, brittle proppant to spacer usually gives the best results. Pre-blending the spacer and proppant is recommended. However, a satisfactory field mixing procedure has been devised.

Spacer Field Test Results

About 100 propping agent spacer treatments have been conducted. Most of the treatments used hydrocarbon resin and about 10 or 12 used prilled urea to space nutshells. The initial potential after fracturing 35 wells in 12 different formations using Amoco 506 resin to space nutshells was 261 BOPD or 44 BOPD higher than the average initial potential of 217 BOPD for 16 conventional jobs.

The average daily production of 18 wells fractured on completion using resin to space nutshells was 32 BOPD higher than the average production of 18 wells fractured on completion without spacer.

Data obtained on the production history of 33 wells fractured using Amoco 506 resin spacer showed that 21 of these wells were better than conventionally treated offset wells after periods of time varying up to 14 months.

Fifteen gas condensate wells in the Farmington, New Mexico, area were fractured using resin spacer. Initial potentials of the wells fractured with spaced props averaged 5358 MCFD which was 19 per cent more than the average of 4487 MCFD from offset wells fractured with unspaced props.

WELL MECHANICS

Long radius fractures are often necessary to take advantage of high fracture capacity. These can generally be best achieved by high injection rates and low fluid losses; however, fracturing pressures and tubular goods strength often limit the pump rate.

HHP to Overcome Friction

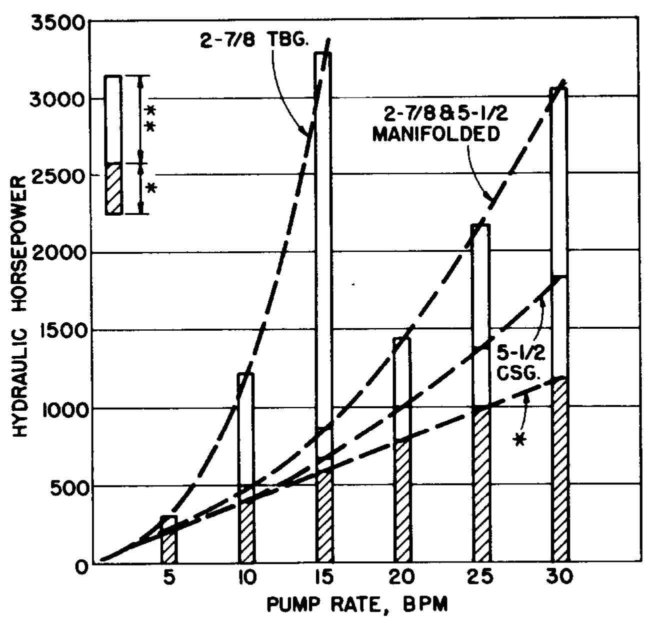
The hydraulic horsepower expended in overcoming friction losses is often a major portion of the total horsepower used in pumping liquids into a well. The effect of different sizes of tubular goods on the hydraulic horsepower is shown graphically on Fig. 13.

FIGURE 13

HORSEPOWER DISTRIBUTION DURING A FRACTURING TREATMENT

CONDITIONS: WELL DEPTH 7000'; BOTTOM HOLE TREATING GRADIENT 0.7 PSI/FT.
OPEN HOLE COMPLETION (NO PERFORATION FRICTION)
WATER BASE FRACTURING FLUID

* HORSEPOWER REQUIRED TO PUMP INTO FORMATION (NO FRICTION LOSS)
** TUBULAR GOODS FRICTION HORSEPOWER



This graph is a plot of the hydraulic horsepower required to pump water into a typical 7000-ft well when various arrangements of tubular goods are used. It will be noted that the total hydraulic horsepower has been divided into two components. These are the horsepower necessary to inject fluids into a formation, cross hatched portion, and the additional horsepower to overcome friction for the various tubular goods combinations.

The horsepower required to inject liquids into a formation after the fracture is initiated varies directly with the injection rate and cannot be controlled by the operator. The friction horsepower portion of the total horsepower, or upper portion of the bar graphs, increases exponentially with the injection rate; however, it can be reduced by using larger size tubing, treating down the casing or manifolding the tubing and casing, and using friction-reducing additives.

These curves show that the friction horsepower can be the major cost item in some treatments, particularly with smaller size tubular goods and higher pump rates.

Hydraulic Horsepower Cost

Assuming that the cost of renting equipment is \$1/hydraulic horsepower, and using the horsepower data from the preceding figure, the cost of the hydraulic HP lost to friction in a 7000-ft well with a treating pressure gradient of 0.7 psi/ft while pumping water at 15 BPM through 2⅞-in. tubing would be \$2700. The friction HP is 82 per cent of the total horsepower used. If the fluid is pumped through manifolded 2⅞-in. tubing and 5½-in. casing, the cost is reduced to \$270 which is 32 per cent of the total horsepower required. If the treatment is conducted down casing then the friction HP would cost only \$95 and only 14 per cent of the total HP would be lost to friction.

The economics of using a friction-reducing additive in the stimulating fluid will depend on well depth, efficiency and cost of the additive, quantity of fluid to be used, injection rate required, size tubular goods used, allowable casing working pressure, and cost of the pumping equipment.

Manifolding Tubing and Casing

The potential horsepower cost reduction

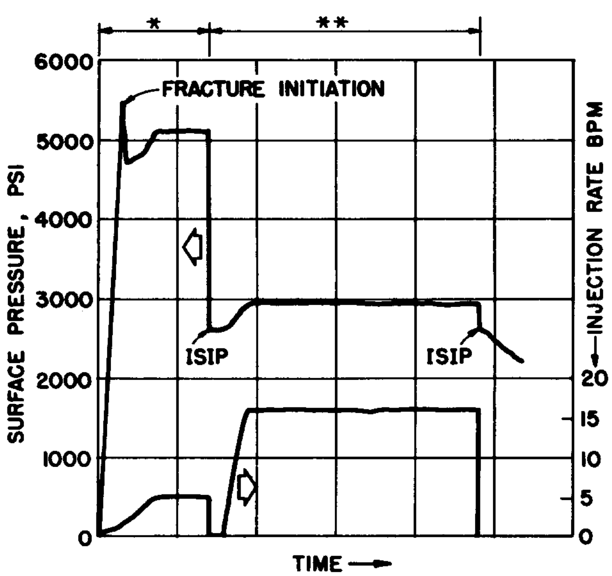
that will result from treating down manifolding tubing and casing in lieu of tubing alone is often not obtained in wells where the surface pressure required to initiate the fracture exceeds the working pressure of the casing. However, after the fracture is initiated, the surface pressure often declines and is within the working pressure of the casing throughout the remainder of the job.

The plot shown on Fig. 14 shows a surface pressure and injection rate record for a stimulation treatment where a water base fluid was used in a typical well 7000-ft deep.

FIGURE 14

SURFACE PRESSURE AND INJECTION RATE WHILE FRACTURING

* INJECTING THROUGH TUBING
** INJECTING THROUGH MANIFOLDED TUBING AND CASING



It may be observed that approximately 5500 psi surface pressure was required to initiate the fracture in this well. After the fracture was initiated, the surface injection pressure through tubing was about 5100 psi at a pump rate of five BPM. When injection was suddenly stopped, the pressure dropped to 2600 psi.

This instantaneous shut-in pressure, marked ISIP, is the surface pressure, exclusive of friction losses, required to inject into the formation after breakdown. The 5100 psi injection pressure while pumping at 5 BPM through tubing includes 2500 psi friction loss. That is, 5100 minus 2600 ISIP.

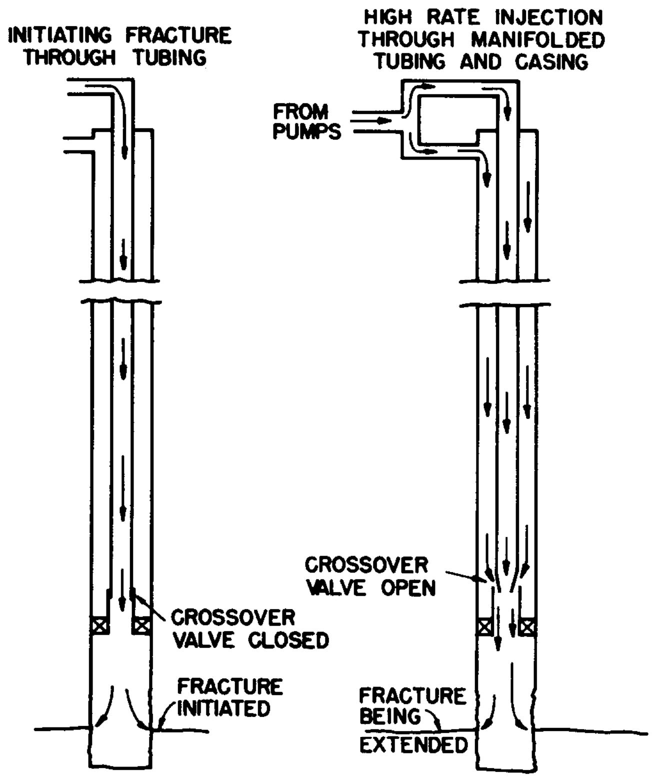
After the formation was broken down through the tubing, it was possible to increase the injection rate into the formation through the manifolded tubing and the tubing casing annulus to 16 BPM yet the surface pressure required was only 3000 psi which was below the 3500 psi casing working pressure.

Cross-Over Valve Assembly

These pressure-injection rate characteristics ultimately resulted in the development of a cross-over valve and packer arrangement, shown on Fig. 15. This arrangement isolates the casing during the time the fracture is being initiated and then permits simultaneous injection through the tubing and annulus during the remainder of the treatment.

FIGURE 15

CROSSOVER VALVE TECHNIQUE

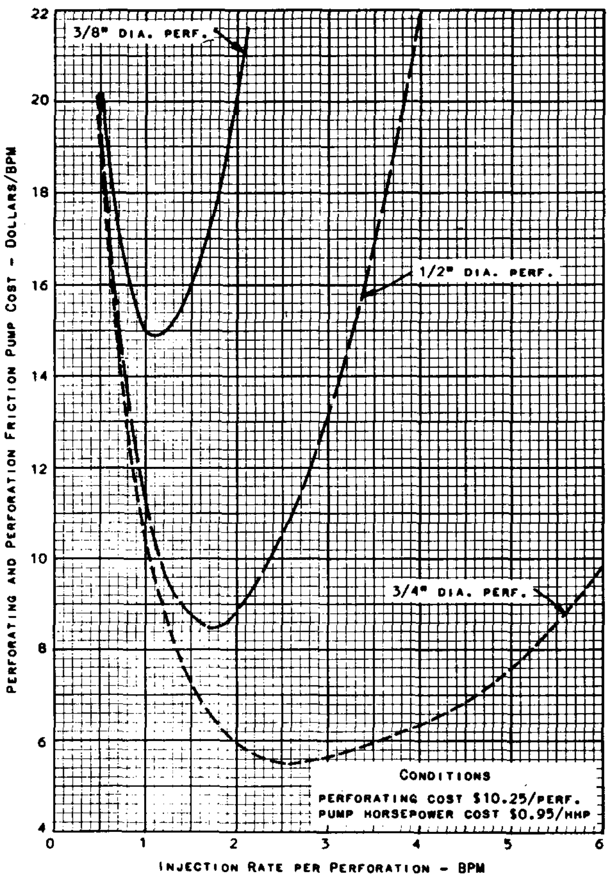


Perforation Friction

The cost of perforations must be correlated with the friction horsepower cost required to pump the stimulating fluid through the perforations if minimum costs are to be obtained. This correlation is shown by the curves on Fig. 16 which are based on an assumed perforating cost of \$9/perforation and a pump charge of \$1/hydraulic horsepower. The cost of perforating and perforating friction in dollars per barrel per minute is plotted against injection rate per perforation with perforation diameter as a parameter.

FIGURE 16

EFFECT OF PERFORATING PROGRAM ON TREATMENT COST



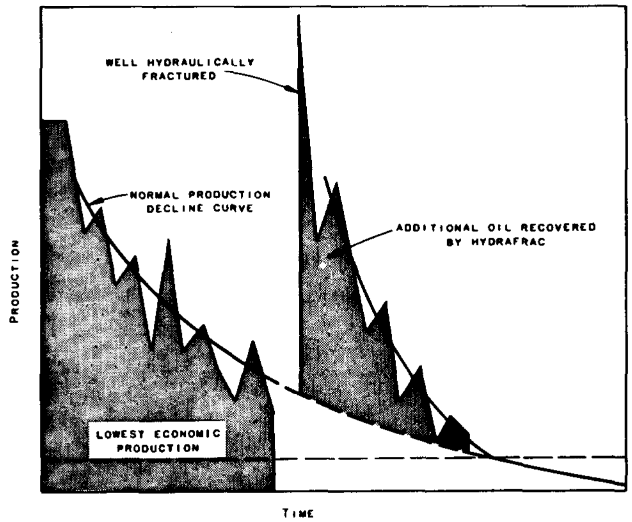
These curves show that using competitively priced equipment that produces the largest diameter perforation will normally result in the lowest combined perforation and pump cost.

RESULTS OF HYDRAULIC FRACTURING

The question is frequently asked by operators, "What is the overall effect of hydraulic fracturing on a well's productive history?" Figs. 17 and 18 illustrate what we believe are typical results from successful hydraulic fracturing jobs. Figure 17 shows a situation where the well responded to hydraulic fracturing but after a period of time returned essentially to the same decline curve as would have been extrapolated from the well production history prior to fracturing. The area shown under the upper curve is interpreted as representing the additional oil recovered as a result of hydraulic fracturing.

FIGURE 17

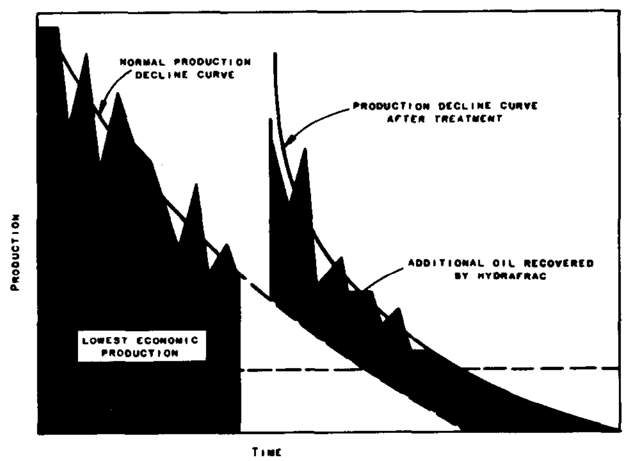
ADDITIONAL OIL RECOVERY BY HYDRAULIC FRACTURING



More typical of the results obtained from fracturing is shown on the curve on Fig. 18 in which both additional oil is recovered from fracturing and the production decline curve is at a higher level than would have been anticipated from prefracturing production history.

FIGURE 18

ADDITIONAL OIL RECOVERY BY HYDRAULIC FRACTURING



It is very difficult to obtain an overall average industry figure on the number of wells that are successfully fractured. Estimates based on data obtained from all sources indicate that between 80 to 90 per cent of all wells respond successfully to hydraulic fracturing.

Future

Normal fracturing as we have seen it practiced over the past 10 or 15 years essentially overcomes well bore completion damage and places a high capacity flow channel within a few hundred feet of the well. This type of treatment will undoubtedly continue to find wide usage.

Very definitely in the future hydraulic fracturing picture is what we term reservoir fracturing, that is, the creation of extremely deep penetrating fractures to effect drainage of large areas by hydraulic fracturing. If our predictions are correct, we would anticipate that this type of fracturing operation can well result in a marked reduction in the number of wells required to drain a reservoir. As we see it now, we have the technical know-how to put this type of fracturing operation into use.

CONCLUSION

Perhaps this paper can best be concluded by considering the estimated increase in oil reserves that have resulted from hydraulic fracturing. More than 450,000 fracturing jobs have been conducted in the United States and Canada with the overall estimated increase in the recoverable reserves of seven billion barrels. It is obvious that hydraulic fracturing has markedly affected everyone in the petroleum industry. It should also be noted that developments of this type would not have been possible without the wholehearted cooperation of oil producing and service company personnel. This process is truly a product of industrial research.