FRACTURE TREATMENTS IN THE ABO FORMATION
PECOS SLOPE FIELD

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ABSTRACT

This paper focuses on the various stimulation designs and treatments performed during the development of the Pecos Slope Field in eastern New Mexico. Information collected from over 125 wells has been categorized and studied in an attempt to determine the best possible stimulation technique for this formation.

The Abo sand is a noncontinuous, lenticular, "tight gas" formation which has made evaluation of treatments difficult due to the manner in which these sands were deposited. The evaluation of various stimulation techniques has been summarized by means of calculated skin factors, K, Kh, CAOF and percent decline in the first three months of production.

This evaluation will help to determine the preferred fluids, volumes, sand concentrations, rates and other aspects which may or may not play a role in the success of stimulation treatments in this area.

INTRODUCTION

The Pecos Slope Field in eastern New Mexico is one of the most recent areas to be designated for "tight gas" classification in the Permian Basin area. Current activity is centered in Chaves County, New Mexico, although the field could eventually extend into DeBaca, Guadalupe and Lincoln counties.

Drilling activity in this area in earlier years had been concentrated on the shallower, more conventional San Andres oil wells bordering the Pecos River. This was due to the fact that the Abo Formation was once shunned as being uneconomic at the time when operators began exploring for the Abo in this area. Interest in the Abo Formation was not generated until 1977 when an independent operator reentered an abandoned well and made a successful gas well in the Abo, although their primary target was a deeper formation. At that time, it was recognized that the Abo Formation was productive; however, due to the large stimulation treatments required to commercially produce these wells, the Section 102 gas price of $2.81/MCF as outlined by the Federal Energy Regulatory Commission (FERC) guidelines at that time provided at best only marginal rates of return on investments and, in many cases, less than desirable return on investments.

Mesa Petroleum Company played a key role in having the "tight gas" classification designated for all gas produced from the Abo Formation lying under 1.536 million acres in Chaves and DeBaca counties. Mesa had originally filed a joint application with Yates Petroleum Corporation in the area for 5.76

million acres to be designated "tight gas" under the initial request for land in DeBaca, Chaves, Guadalupe, Lincoln and Torrance counties. The FERC's designation of the area in Chaves and DeBaca counties (Figure 1) increased the maximum ceiling price for gas in the Abo Formation to that of Section 107 which was $4.92/MCF in June 1981 when the ruling went into effect. This was a 75% increase in the price which an operator could receive for gas produced from the Abo. This ruling caused rapid acquisitions of unleased acreage which sent lease prices soaring. It also triggered an exploration and development program by several operators which has resulted in more than 450 wells drilled over the last one and one-half years. Activity has decreased recently in the Pecos Slope Field due to lower pipeline demands and the increasing difficulty of obtaining a pipeline connection due to the currently depressed gas market. There still remains a large amount of undeveloped acreage in this field and the development is expected to increase again as the gas market gains strength.

Wells in this area will typically produce only 50 MCFD or less prior to any type of stimulation. After acidizing and fracturing, an average well will flow 400 to 600 MCFD and some wells may initially produce over 1,000 MCFD. The purpose of this paper is to discuss the various treatment designs in the Pecos Slope Field and their effects on productivity.

GEOLOGY

The principal producing formation in the Pecos Slope Field is the Abo. The Abo Formation, a member of the Leonardian series of the Lower Permian age, is a grouping of low-permeability sands dipping downward from northwest to southeast. Producing depths range from 2,500 ft in the northwest to 4,800 ft in the southeast portion of the field. Gross pays range from 200 to 1,000 ft. Within this section, there are 1 to 24 individual zones varying in total net pay from 5 to 80 ft.

These sands were deposited as lenses and stringers as a result of the deltaic process of river drainage into the Permian Sea and the erosion of an early mountain range which is roughly the same as the existing Sacramento and Capitan mountain ranges to the west of this field. The top of the Abo Formation is overlain by an anhydrite section which forms the impermeable trap for the reservoir. This anhydrite is characterized by "three fingers" on the gamma-ray section of the GR-CNL-FDC log (Figure 2). The referenced figure shows a typical log from the west side of this field and the "crossover" effect as shown on the compensated neutron-formation density portion of the log indicating the presence of hydrocarbon-bearing zones. All potential gas-producing zones are easily recognizable due to this crossover effect. Typical open-hole logging consists of running a GR-CNL-FDC log combined with an open-hole caliper log to determine the gas-bearing Abo zones. Resistivity logs are generally only run in areas known to have formation water production problems and in all wildcat wells.

These lenticular sands are not easily correlated on a well-to-well basis except in certain localized sections of the field. This is due largely to the meandering river system by which these sands were deposited. This lack of correlation over the field is the main reason for not being able to establish any one correct method to stimulate these wells.

Coring is difficult due to the vertical separation and discontinuity of the Abo sands which make it difficult to anticipate the depths at which these sands will be encountered. Therefore, coring operations can be a costly, time-consuming procedure in this field since the entire Abo Formation should be cored in order to ensure that adequate core samples are recovered. Core analysis results have shown the Abo Formation to be a light-gray or reddish-brown sandstone with fine, angular grains. The permeability is less than 0.1 md and some indication of both horizontal and vertical natural hairline fractures has been detected through magnification of the available core samples by the scanning electron microscope (SEM). Figure 3 shows one such natural fracture to a magnification of 200X. Mineral composition indicates the Abo to be made of approximately 70% quartz, 15% feldspar, 10% calcite and dolomite, and 4% to 5% clays. The composition of the clay particles is equally split between chlorite and illite. The modulus of elasticity was measured to be 13 x 10^6 psi, or very hard. Solubility in 15% hydrochloric acid was measured at 9% to 13% and 28% to 34% in 12-3% mud acid.

STIMULATION TECHNIQUES

During the development of this field, stimulation techniques have undergone various transition phases as production history began to develop and operators became more familiar with the characteristics of the Abo Formation. Several different methods are currently being practiced as each operator in the area has tried to achieve the "ideal" treatment, and mixed feelings still remain as to which of these methods is best. The following discussion will describe the various transitions including their benefits as well as their limitations.

Acidizing

The principal reasons for acidizing the Abo sand are to open perforations prior to fracturing and to remove any immediate damage in the vicinity of the wellbore. A secondary reason would be to remove calcareous cementing materials present in the formation. A good acid breakdown is essential to provide proper distribution of the fracturing treatment.

Few changes have been made in acidizing techniques during the development of the field. One key change is the fact that nitrogen is no longer used as an energizing agent in acid treatments as it was once. The early wells were perforated, treated and tested by means of isolating individual intervals with a bridge plug and packer. The use of nitrogen allowed rapid recovery of the acid load water to enable testing of the individual zones as quickly as possible.

It was soon learned that the entire Abo interval could be perforated at one time and still be acidized effectively. This was performed by spotting acid across the desired intervals, raising the tubing above the top perforation and treating down 2-3/8-in. open-ended tubing in one stage. Generally, 100% excess ball sealers are evenly spaced throughout the acid in an attempt to open all perforations. More effective ball action is obtained when the tubing is set approximately 100 ft above the top perforation during acidizing. This allows the ball sealers sufficient time to slow down after leaving the tubing and entering the reduced velocity in the 4-1/2-in. production casing. The type of acid most commonly used is 7-1/2% hydrochloric acid containing a corrosion inhibitor and clay stabilizer.

Core analysis indicates a difference in solubility between hydrochloric and mud acid of approximately 20%. This might indicate that a mud acid treatment would be a better approach toward the completion of these wells; however, since the acid is used only as a breakdown fluid and these wells must be fractured in order to sustain production, there is no economic reason to use the more expensive mud acid.

Fracturing

Hydraulic fracturing is necessary to achieve sustained production rates over the life of these wells. This is really the key to economic success in this field due to the extremely low permeability and the low bottom-hole pressures. A tremendous increase over the natural flow capacity of the formation is achieved by creating a sand-propped extension of the wellbore as provided by the hydraulic fracturing process.

A good evaluation of treatments performed in this formation is difficult due to the nature of the reservoir. The following information based on a study of 126 wells is an attempt to evaluate the various fracturing fluids, volumes, sand concentrations, rates and techniques which have been used. This evaluation is made keeping cost effectiveness in mind.

Fracturing Fluids

The base for all fracturing fluids used in this area is 2% KCl water which helps prevent excess formation damage. A clay stabilizer is added to prevent clay migration and flocculation during and after stimulation. Surfactants are added to lower capillary forces which restrict fluid flow within the formation matrix.

Treatments in the Pecos Slope have been performed with one of the following types of fluid.

- Foam
- Noncrosslinked Gelled 2% KCl Water
- Noncrosslinked Gelled 2% KCl Water Energized
- Crosslinked Gelled 2% KCl Water Energized

Foam is considered to be the most ideal fluid of those listed due to the smaller amount of liquid placed in the formation. This reduces the possibility of formation damage and also provides a more rapid cleanup after stimulation. The major disadvantage of foam treatments is the smaller concentrations of sand which may be transported. The lower sand concentrations are believed to be a contributing factor to the more rapid declines noted in the earlier foam-fractured wells.

Energized fluids (those using CO_2 or N_2) have been noted to clean up more rapidly and, in most cases, more efficiently than the nonenergized fluids. At the same time, by using energized fluid, the total amount of load water to be recovered is reduced without sacrificing the increased sand concentrations which may be transported by gelled fluids. Additional cost incurred by energizing fluids is small compensation for the advantage of increased load water recovery efficiency and the reduced amount of liquid placed in the formation.

Although this area has relatively few fluid leakoff problems due to the low formation permeability, fluids are often crosslinked in order to aid in fluid-loss control and to combat potential screenouts particularly at the lower pumping rates. Proppant distribution in a noncrosslinked gelled fluid is more effective when increased rates are used to promote proppant suspension because of the increased velocity of the fluid. A comparison was made on equivalent volume treatments for a 36-net-ft interval pumped at 50 BPM using the same design parameters. The results indicate that crosslinked gelled 2% KCl water does a better job of more evenly distributing the sand throughout the fracture where the noncrosslinked gelled 2% KCl treatment leaves a larger amount of the sand near the wellbore (Figure 4). This is due to the better transporting characteristics of the crosslinked system. The study also indicates a deeper penetration of the propped fracture created by the noncrosslinked gelled fluid. The deeper penetration is a result of a narrower fracture width. In this study, the noncrosslinked fluid treatment resulted in a hydraulic fracture width of 0.501 in. and the crosslinked fluid treatment created a hydraulic fracture width of 0.783 in. The more uniformly packed fracture is believed to be more important in sustaining production rates over the life of these wells than the less uniform, deeper penetrating fractures created by a noncrosslinked system. This has yet to be proved since insufficient production data are available at this time.

Volumes

A comparison of the wells studied indicates the size of fracture treatment in the Pecos Slope Field has an influence on the productivity increase. Treatments performed with less than 1,000 gal/net-ft of pay have shown rapid production declines during the early life of these wells and decreased absolute open-flow potential tests (CAOF). A marked improvement in production decline was seen in the wells where 1,000 to 1,500 gal/net-ft of pay were pumped. The lowest skin effects, greatest calculated fracture permeabilities and higher CAOFs have been observed in the wells where a volume of 2,000 gal/net-ft was pumped. The key to the observed productivity increase is the ability to place more sand in the formation with the larger fluids volumes; however, economics must be considered on a well-to-well basis to determine the best possible treatment volume for the money spent.

Sand Concentrations

Various concentrations of sand, mesh sizes and design methods have evolved with treating experience in the field. In the earlier treatments, 100-mesh sand was used as a fluid-loss additive. This may have been effective in preventing premature screenouts in areas where natural fracturing may have existed; however, indications of such fracturing were rarely observed. Since fluid leakoff was determined to be an insignificant problem, the use of 100-mesh was discontinued.

Sand concentrations and mesh sizes have changed with the transition of fracturing fluids used in this field. The original foamed fracture treatments used 20/40-mesh sand at maximum sand concentrations of 2-1/2 to 3 lb/gal. The switch to gelled 2% KCl water was followed by an increased maximum sand concentration of six to seven pounds per gallon of 20/40-mesh sand and the sand concentration for the entire treatment would average 2 to 2-1/2 lb/gal. The next change involved the use of 10/20-mesh sand to tail-in after the 20/40-mesh sand. This allows greater flow capacity near the wellbore where it is most critical and prevents the 20/40-mesh sand from flowing back into the wellbore. Along with the addition of 10/20-mesh sand, average sand concentrations were increased to three pounds per gallon while maintaining a maximum sand concentration of six pounds per gallon. Thus, the sand-to-fluid ratio was increased, resulting in greater flow capacities with no increased potential damage to the formation.

Pump Rates

Treatment pumping rates have varied dramatically from initial jobs to the present-day designs. Initial treatments performed on isolated intervals were pumped at lower rates due to surface treating pressure limitations created by treating down 2-3/8-in. tubing. In an effort to cut stimulation costs and save time, it was determined that all intervals could be treated effectively at one time. This was performed by treating at a rate high enough to create a limited entry technique. This required a pressure differential of approximately 350 psi across the perforations. This could be achieved by pumping at rates of 1.5 to 1.8 BPM/perforation. By pumping at these rates, a natural pressure diversion of the treating fluid could be achieved. Excessive rates have been determined to cause the fracture to treat out of zone and the slower rates do not achieve the pressure differential required to treat in a limited entry technique.

Techniques

Stimulation techniques have changed as pump rates were altered to confirm to the developing technology of the area. Earlier treatments performed down 2-3/8-in. tubing were pumped at 12 to 18 BPM. As the need for larger volumes and high sand concentrations became evident, the resultant rate increases raised surface treating pressures near the maximum limitation.

To reduce the surface treating pressure and attain the desired rates to achieve the limited entry technique, the next step was to treat "triple entry." This meant pumping down the tubing and tubing/casing annulus. Hydraulic horsepower charges were reduced due to lower treating pressures.

In an attempt to lower hydraulic horsepower requirements and surface treating pressures even more, treatments were performed down 4-1/2-in. casing. An initial concern with this method was the fact that the wells usually had to be killed with 2% KCl water prior to running the tubing back in the well. This was thought to be a source of irreparable damage to the formation; however, potential tests run prior to and after killing the well showed no indication of additional damage. Due to this fact, fracturing down 4-1/2-in. casing is the most commonly practiced stimulation technique in the Pecos Slope at this time.

CONCLUSIONS

Due to the low bottom-hole formation pressure and low matrix permeability, the Abo Formation must be stimulated to be commercially productive.

This evaluation of the various stimulation techniques which have been performed during the development of this field is an effort to find a relationship between fracture treatment procedures and production results. From the evaluation, the following conclusions have been made.

1. Crosslinked fluids gave the best overall results. Load water recovery is quicker and more efficient when fluids are energized.

2. In most wells, fracture treatment volumes of 2,000 gal/net-ft of pay will provide adequate proppant distribution and fracture penetration.

3. Sand concentrations should be based on an average of 2.5 to 3.0 lb/gal.

4. Natural pressure diversion is obtained at pump rates of 1.5 to 1.8 BPM/perforation to provide treating fluid entry through all perforations.

5. Fracturing down 4-1/2-in. casing has provided the desired rates with lower hydraulic horsepower resulting in a more cost effective treatment.

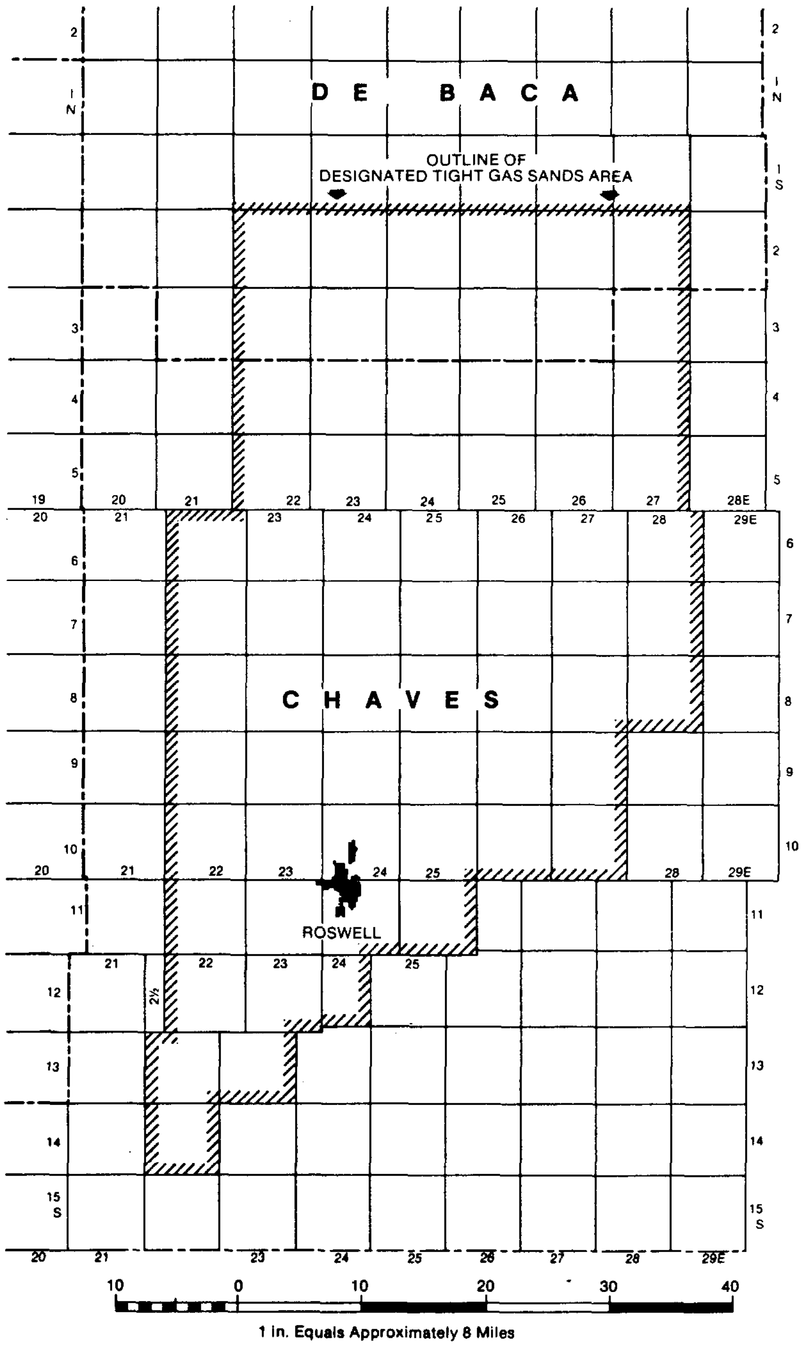

FIGURE 1 — DESIGNATED "TIGHT GAS SANDS" AREA FOR THE PECOS SLOPE FIELD.

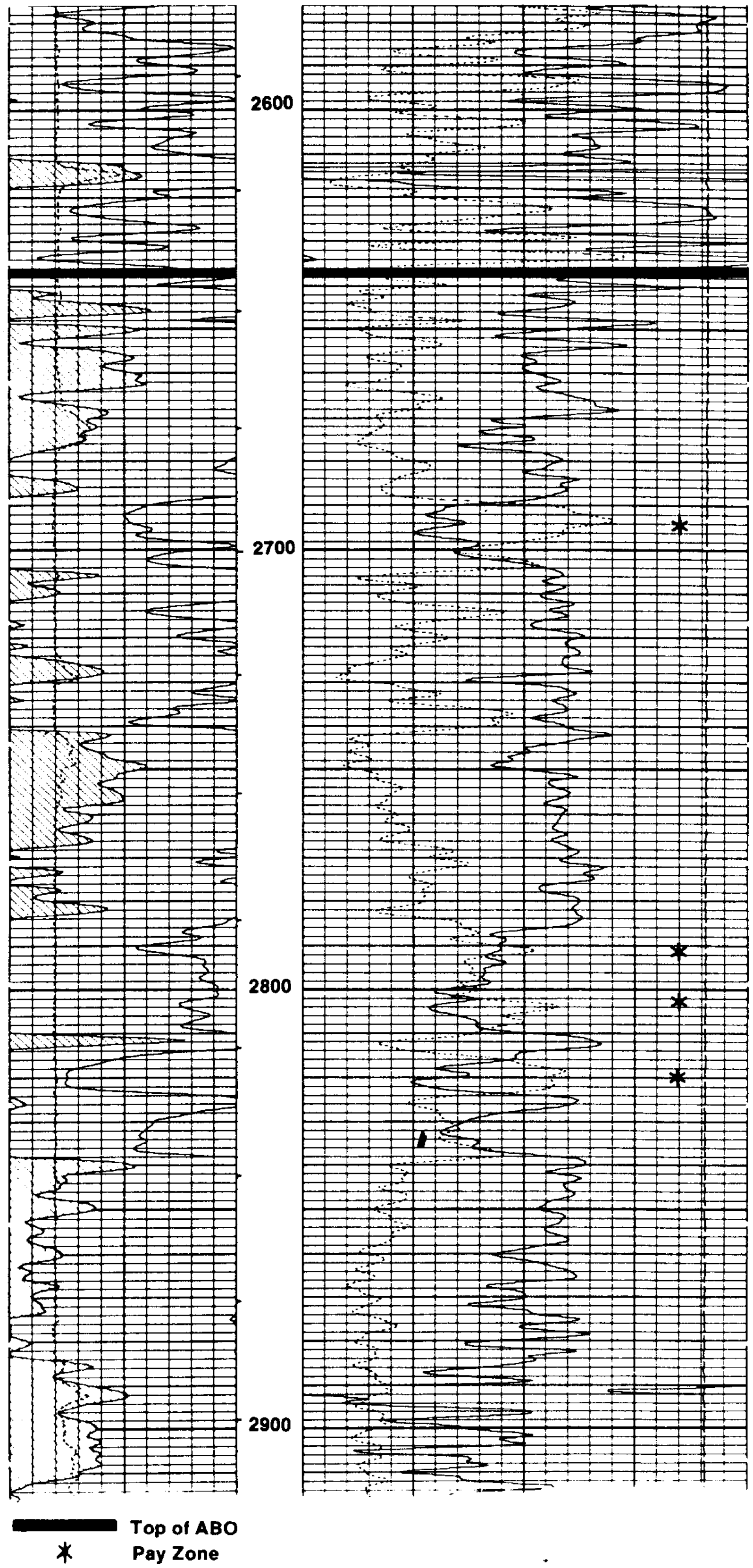

FIGURE 2 — GR-CNL-FDC LOG OF TYPICAL WELL ON THE WEST SIDE OF THE PECOS SLOPE FIELD.

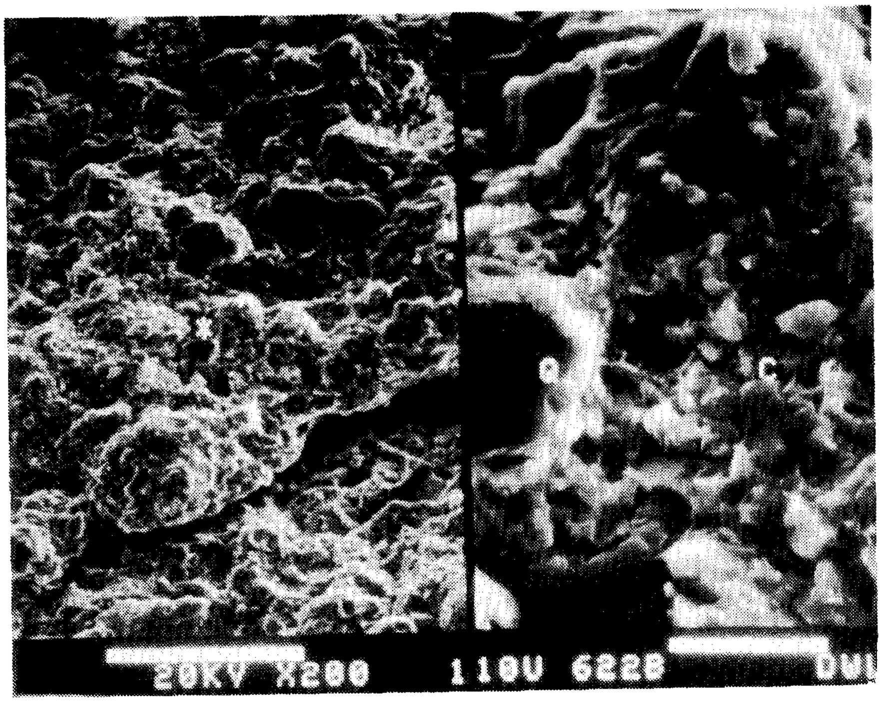

FIGURE 3 — THIS SPLIT SCREEN VIEW SHOWS ONE OF THE SMALL FRACTURES OCCASIONALLY FOUND IN THE ABO FORMATION OF THIS AREA. FRACTURES SUCH AS THESE (APPROXIMATELY 10 μ WIDE) PROBABLY PROVIDE ONE OF THE FEW CHANNELS FOR FLUID TO FLOW THROUGH THIS ROCK. THE STARRED (*) AREA ON THE LEFT IS SHOWN AT HIGHER MAGNIFICATION ON THE RIGHT. QUARTZ (Q) AND CALCITE (C) ARE MIXED WITH FELDSPARS. MAGNIFICATION 200X/2000X.

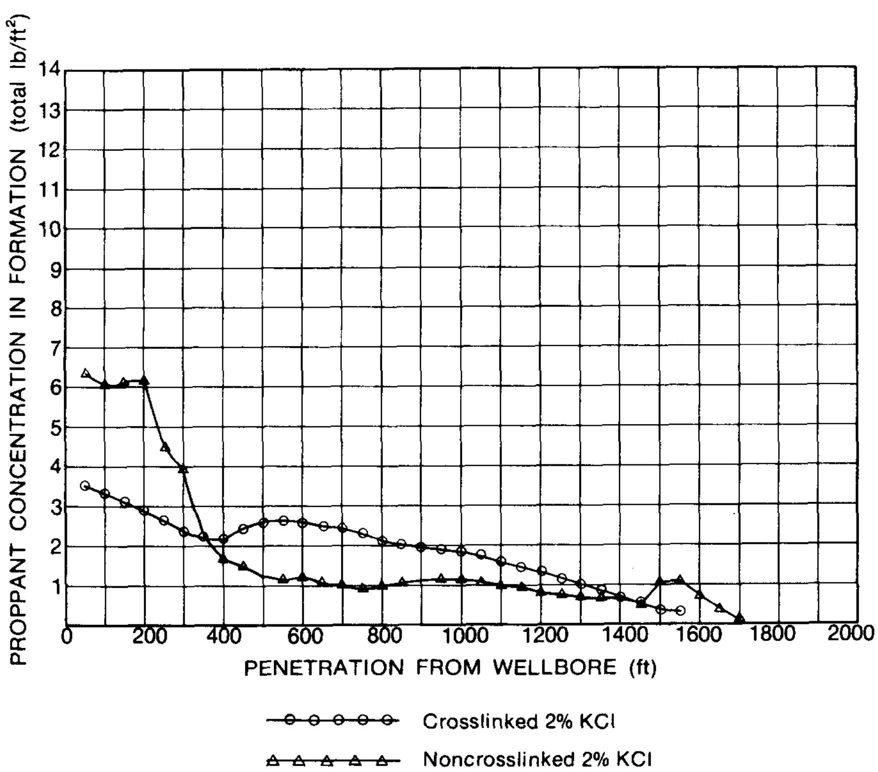

FIGURE 4 — COMPARISON OF PROPPANT DISTRIBUTION IN SIMILAR SIZE TREATMENTS OF CROSSLINKED VS NONCROSSLINKED GELLED FRACTURING FLUIDS.