SOCIETY OF PETROLEUM ENGINEERS OF AIME
6300 North Central Expressway
Dallas, Texas 75206

PAPER NUMBER SPE 1134

THIS IS A PREPRINT --- SUBJECT TO CORRECTION

DESIGN OF TREATMENT FOR STIMULATION OF LOW PERMEABILITY FORMATIONS

By

Bill F. Halepeska, Member AIME, The Western Co., Midland, Tex.

INTRODUCTION

Numerous low permeability reservoirs, most of which cover long vertical sections, have been developed commercially in the last few years as a result of advancements in the field of stimulation technology. Many of these had been tested previously and unsuccessful completion attempts made. Lithologically, these formations include cherty limestones of Devonian age, silty limestones from the Mississippian and limey sands of Canyon age, as well as others. Measured formation permeabilities range from 0.01 to about 0.4 md. with some naturally fractured sections indicating greater values as fracture permeability. Gross vertical thicknesses vary from 100 feet in some more homogeneous lime sections to 1,000 feet or more in highly broken sand and shale sections. Most of these occur at depths below 6,000 feet, and some in excess of 10,000 feet.

For some time, stimulation techniques which were then considered applicable failed to provide flow systems necessary for commercial production. Based upon past experience, stimulation programs were designed and completion practices altered where practical to meet treatment demands. Industry's willingness, even in an atmosphere of increasing cost consciousness, to spend greater amounts than ever before for stimulation has contributed to the development of such programs.

Research provided through field operations, supported by mathmatical analyses and laboratory experimentation, has contributed to improved techniques. To date, hydraulic fracturing appears to be the only method which will affect the desired results in these low permeability formations.

ELEMENTS OF DESIGN FOR STIMULATION TREATMENT

The elements of treatment design are numerous and difficult to define unless associated with plans for stimulation of a specific well. Consideration must be given to both materials and technique of application in light of individual well conditions and formation characteristics. Design of treatment for low permeability reservoirs is essentially the same as for any other, with some modifications providing greater vertical coverage and radial extent of fracture system. This is usually reflected in greatly increased fracture volumes and/or injection rates.

A brief general discussion of several major factors in treatment design is presented.

Fluid Type

Choice of treating fluid, as always, depends to some extent upon formation characteristics. Often, this is the prime consideration. Determination of fluid efficiency as a function of permeability, porosity and other variables, continues to be a factor in selection. Formation solubility, determined through routine carbonate solubility analysis, and the presence of clays subject to hydration are also considered.

Some of the first work of significance performed in low permeability reservoirs utilized acid base frac fluids in deep limestone formations. These fluids were prepared as high viscosity acid-kerosene emulsions which offered exceptional sand carrying properties along with good retarded acid characteristics. In spite of very high fluid costs involved, the results achieved seemed to justify its use.

Continued development of stimulation programs for low permeability reservoirs has, however, focused much more attention on mechanical and economic factors. There has, in many respects, been a transition period during which interest has been shifted from oil base to aqueous base frac fluids. This latter group includes fresh water, brine and weak acid (3 to 7-1/2 per cent).

From a mechanical standpoint, these fluids offer more effective surface treating pressure control through increased hydrostatic head and lower friction losses. All of these fluids can be altered through the use of special additives to provide friction reduction which exceeds 70 per cent under some conditions. The improved hydraulic horsepower utilization resulting from these properties is an obvious economic advantage also. In addition, cost of supplying the fluid itself becomes quite significant when considering the very large volumes used.

The use of special additives to improve fluid fracture efficiency has not been as widespread in low permeability formations as in those exhibiting higher permeabilities. Lower efficiencies have generally been compensated for by increased volume and/or injection rate.

Treatment Volume

In order to achieve optimum fracture area and satisfactory productivity in low permeability formations, volume requirements have increased tremendously. Long intervals and large well spacing are two important factors influencing volume determination. Treatments in the 75,000 to 100,000 gallon range have become commonplace, with many exceeding twice that amount. In at least one area, frac operations using volumes in excess of 12,000 barrels are performed. The trend toward these larger treatments reflects the need for an extensive drainage system to compensate for extremely low formation capacity.

Injection Rate

Conductor size and depth with corresponding surface fracturing pressures and horsepower costs are the principle limiting factors in determining applicable rates. With the development of effective aqueous base friction reducing agents, treating pressures have been reduced considerably. Horsepower requirements can be accurately anticipated and the loss due to friction pressure minimized. Rates in the vicinity of 50 BPM have become very common, even at well depths greater than 10,000 feet. Much greater rates are routinely achieved at shallower depths.

Injection rate, as an element of treatment design, serves a multiple function. Initially, it will influence to some degree the relative effectiveness of total frac volume in terms of fracture area created. The rate-volume relationship determines pumping time and thus total leak-off of frac fluid to the formation. Second, it provides the necessary energy for transportation of propping agent through the created fractures. Quite often, the fluids used during these operations exhibit poor sand carrying properties for effective distribution in such extensive fracture systems. These fluids must rely more upon the turbulence and drag produced by high rates for transportation of propping agent.

More recently, injection rate has been effectively utilized as a direct factor in fluid control and selectivity. The limited-entry method of selective stimulation described by Lagrone, et al[1], uses rate to provide a predetermined perforation restriction and thus assure treatment distribution over the total pay interval. In addition, high injection rates alone have been credited with providing satisfactory vertical distribution where other means are relatively ineffective.

Injection rate and total treatment volume are more closely related in some instances when acid is employed as frac fluid. In order to achieve maximum benefit from the acid and prevent displacement of large volumes of spent acid further into the formation, optimum rates are determined. In instances involving large volume acid fracturing operations without propping agent, maximum rates are desirable.

Propping Agent

Much research has been conducted and results published describing propping agents and the fracture capacity requirements for adequate formation drainage[2, 3, 4]. Formation capacity, hardness and depth (reflected in estimated overburden) are some of the more important factors in determining these requirements. The indicated reservoir capacity in the average low permeability formation is extremely low, and fracture flow capacity is usually adequately provided using common frac sand. Most treatments in these formations utilize 20-40 mesh frac sand.

The special techniques and propping agents for obtaining high capacity fractures have been used infrequently in treatment of these reservoirs. Although there are instances where these practices are at least theoretically necessary for adequate drainage, there is a lack of significant field results to bear out this need. In addition, cost has become a factor of no little importance influencing their use in view of the very large fluid volumes pumped and propping materials required.

In some instances large volume frac operations have been conducted where no propping agent is used at all. For certain low solubility carbonate formations being fractured with acid base fluids, this practice is at least theoretically justifiable. Conductivity tests run with core samples indicate that acid etched fracture faces provide excellent flow characteristics. Good results have also been achieved using fresh water without propping agent in treatment of certain dense carbonate formations. Reason for success here is believed to be the removal of salt from an extensive natural fracture system.

Selectivity

A majority of the low permeability reservoirs considered here produce from a substantial gross interval. Fluid control and distribution is a very important element in stimulation design, especially in instances involving multiple productive zones scattered over a long interval. Developments in selective treatment techniques now afford maximum control in such cases.

Most significant of these developments is the limited-entry technique which utilizes perforation restriction in sufficient magnitude to assure fluid exit through each of a limited number of holes. The mechanical simplicity of this technique and the degree of volume distribution which it affords are its greatest advantages. Modified versions of the limited-entry technique, one of which is described by Webster, et al[5], provide additional versatility in treatment selectivity.

The need for fluid control and the method selected depend primarily upon the characteristics of the formation. Gross vertical interval, net pay thickness, homogeneity and rock parting pressure over the entire interval are among those factors to be considered. Often to a lesser degree, mechanical limitations and cost are also factors in the method selected.

The limited-entry technique is combined with bridge plugs in a two-stage operation in one area where two fairly distinct formation fracture pressures are indicated. The section encountered covers 400 to 600 feet. In yet another area, a gross vertical interval of 500 to 700 feet containing numerous sand lenses is successfully stimulated in a one-stage treatment utilizing a pure limited-entry design.

DESIGN EFFECTS ON COMPLETION PROGRAM

Design of treatment for stimulation of low permeability reservoirs frequently necessitates re-evaluation of the completion program. The perforating program, for instance, now serves a more significant role than that of simply providing a means of access from or into the production casing string. The importance of properly planned perforating to the overall completion success has been explored and discussed by Cocanower[6].

Through the limited-entry principle, a specific number of holes of a given size is used in conjunction with regulated injection rate to provide fluid distribution. In addition, the higher injection rates achieved necessitate that sufficient access from the casing be available to prevent horsepower waste due to excessive pressure loss through perforations.

The average casing string is designed for a two-fold function. It must meet treatment conductor requirements as well as production requirements. Anticipated treating pressures and desired injection rates are two of the main considerations. Very few successful completions in low permeability reservoirs are cased with pipe of less than 4-1/2" diameter. With injection rates often approaching 100 BPM, larger conductors as well as those with greater internal yield properties are necessary.

CASE HISTORIES

Azalea Devonian Field

The Azalea Field is located in northeast Midland County, Texas (Figure 1). Discovery of the Devonian reservoir here occurred in 1957, with early field development being rather slow. The initial well was completed as a high ratio oil producer, but the field was later classified as a retrograde condensate reservoir. A majority of the wells were completed during 1960 and 1961. As of January 1, 1965, there were 114 producing gas condensate wells in the Azalea Field proper, indicating a productive area in excess of 30,000 acres. Total production from the Devonian reservoir as of that date was 63,913,532 MCF of gas and 7,243,665 barrels of condensate.

The Devonian Formation here consists of 400 to 600 feet of limestone, cherty limestone and chert. Productive interval occurs as a light gray, semi-crystalline, cherty limestone and is encountered near the Devonian top at approximately 11,400' (-8600), noted in Figure 2. Net pay varies in thickness from 20 to 100 feet. Average porosity is between 4 and 5 per cent with a maximum of 8 per cent. Permeability range is from 0.01 to 0.40 md. The average solubility in acid indicated here is 80 per cent.

Slow rate of development during the field's early history is attributed in part to the poor results obtained from stimulation methods used. Initial treatments used acid and were conducted via tubing at slow rates. Rate of acid reaction at bottom hole temperature limited the effectiveness of such treatments. Early frac operations were performed using refined (frac) oil and were not entirely satisfactory. Friction pressures created with this fluid at these depths presented surface pressure problems. In addition, clean-up difficulties resulted from the heavy refined oil residuals.

Several treatments using gelled water were conducted with little better results than those realized using oil; however, the water provided minimum treating pressures at higher rates and maximum safety. The pessimism with which these jobs were viewed was not entirely warranted, as most were conducted under adverse mechanical conditions.

The first truly significant results were achieved using an acid-kerosene emulsion as frac fluid. Such a program utilized high capacity fracturing in effective combination with deep penetration acidizing. Most subsequent completion stimulation programs utilized the same fluid. Acid strength was reduced from the standard 15 per cent to 10 and 7-1/2 per cent. Volumes gradually increased to a maximum of 150,000 gallons with maximum rates around 50 BPM. Common frac sand (20-40 mesh) was used as propping agent in most instances. Propping agent was omitted entirely in some treatments with the theory that acid etched fracture faces provided adequate flow capacity. Results from these treatments were comparable to those where sand was used.

Normal drilling program for the area called for setting an intermediate casing string (9-5/8") at about 9500 feet with the 5-1/2" or 7" production string set at total depth. This practice was later altered to include 7-5/8" N-80 run to approximately 10,000 feet with a 5-1/2" liner to total depth. This provided a conductor which made it possible to achieve injection rates around 50 BPM at pressures of 5000 p.s.i. or greater with the heavy emulsions used as frac fluid.

An example of a typical completion in the Azalea Field may be as follows:

7-5/8"-29# @ 10,193'; 5-1/2"-20# @ 10,050-11,407'
Perforations: 2/ft. 11,250-62'; 11,272-296'
Breakdown with 1,000 gal. 15% Mud Acid
Frac via casing with:
  150,000 gal. Acid-Kero Emulsion (7-1/2%)
  150,000# 20-40 Sand
  46.0 BPM @ 3950 p.s.i.
IPCAOF: 4,000 MCF; GLR 4820-1

A tabulation of production in barrels of condensate and MCF of gas per month versus treatment fluid type and volume was made during development in the area. Figure 3 indicates the results of this study.

Dora Roberts Field

The Dora Roberts Devonian Field is located in the west central portion of Midland County, Texas (Figure 4). Discovery of the Devonian reservoir in this field occurred in 1955, and steady development continued for the next two years. From 1957 until 1962, however, only four or five wells were completed, for a total of twenty producers. Activity increased in 1962 and by December, 1964, there were forty-seven active wells reported. A repressuring project commenced during 1963, and RRC field status was changed from oil to gas condensate.

The Devonian Formation in the Dora Roberts area consists essentially of 600 to 800 feet of limestone, cherty limestone and chert with the productive interval covering some 400 feet. The upper portion (100-150') is usually less cherty, having an acid solubility of 85 to 90 per cent. An average porosity of 7 per cent is indicated, and permeability is low except where scattered natural fracturing occurs. The lower portion becomes somewhat more siliceous, and exhibits an average solubility of about 60 per cent. Porosity here is lower, averaging less than 4 per cent. Cores show that this more dense section contains numerous zones of natural vertical fracturing. Productive interval is topped at approximately 11,700 feet.

An investigation of treatment shut-in pressures shows that a significant difference in fracture pressures exists between the upper and lower zones. This variation has been as much as 2000 p.s.i. on one well, with an average difference of 800 p.s.i. The more highly fractured lower zone consistently exhibits the lower pressure value.

Some earlier completions were acidized only, but later programs used fracturing as stimulation means. Refined oil was employed as frac fluid, with some treatments using volumes to 75,000 gallons. Surface treating pressures experienced were high and injection rates restricted down the usual string of 5-1/2" casing. Average gross interval covered in these completions was less than 200 feet.

With the increased activity in 1962, completion program was altered to include a greater gross interval, now averaging 350 feet. In order to provide effective fluid distribution, perforating program was changed from long intervals shot with two and four shots per foot to widely spaced groups containing six to twelve holes each (Figure 5). In most instances stimulation was provided by two separate treatments, with separation between upper and lower zones accomplished using a bridge plug.

Gelled brine water was employed as frac fluid. This fluid exhibits excellent friction characteristics, and is an effective sand transporting medium. Volumes vary from 50,000 to 155,000 gallons per zone, with the larger volumes normally being used in the lower zone. Propping agent used in all instances is 20-40 frac sand, with an average concentration of 1-1/2 pounds per gallon. Total sand volumes in excess of 700,000 pounds have been used during some stimulation programs in the Devonian here. Pumping rates normally achieved vary from 45 to 65 BPM.

A typical completion in the Dora Roberts Devonian would be as follows:

5-1/2"-17 & 20# csg. set to T.D.
Lower Devonian
Perforations: 11,950-53'; 11,972-75'; 11,997-12,000'; 12,023-26'; 12,046-49' 60 Holes
Treatment: 155,000 gal. Gelled Brine, 225,000# 20-40 Sand, 63 BPM @ 5000 p.s.i.
Upper Devonian
Perforations: 11,724-27'; 11,750-53'; 11,775-78'; 11,800-03'; 11,830-33'; 60 Holes
Treatment: 55,000 gal. Gelled Brine, 5,000 gal. 15% Acid, 75,000# 20-40 Sand, 51 BPM @ 4900 p.s.i.
IPCAOF: 3,350 MCFPD; GLR 4400-1

Ozona Canyon Trend

The Ozona Canyon area is located in Crockett County, Texas (Figure 6). Discovery well in the Canyon reservoir was completed as a gas-condensate producer in March, 1962. Most earlier ventures in the area used conventional drilling muds and had bypassed the Canyon section in search of deeper Ellenburger reservoirs. Several had, during the course of drilling, tested this section for 300 to 500 MCF/D and considered it insignificant. One company had earlier unsuccessfully treated and tested a small Canyon section in an Ellenburger failure.

Initial development in the area following discovery was slow due to the lack of a pipeline outlet for the gas, but increased substantially during 1963 and 1964. The installation of a gas processing facility, which began operation about January 1, 1964, has prompted much of the increased activity. There were 60 Canyon gas producers indicated in the area as of January 1, 1965. Most wells completed during the first 1-1/2 to 2 years were widely scattered over an extensive area as part of a program[7] to develop information concerning the extent and characteristics of the reservoir.

The Canyon section consists of numerous lensing sands interspersed with shale. Total formation thickness varies substantially over the area, with an approximate maximum of 1,000 feet. Productive lenses consist of gray, well consolidated, fine grained sand. Even when clean, these sands are tight, having an average permeability of less than 0.30 md. and average porosity near 11 per cent. Most of these sands contain 3 to 5 per cent acid soluble carbonates. Canyon completions have indicated from 40 to 130 feet of net pay, covering a maximum gross vertical interval of approximately 700 feet. Average depth of productive zones is 6300 feet.

Discovery well in the Canyon section had 5-1/2" casing set at total depth for attempted Ellenburger completion. No selectivity was attempted, and a single Canyon interval (6413-39') was perforated using 4 shots per foot. Stimulation consisted of treatment using 15,000 gallons 15% acid injected at 12 BPM. No propping agent was used.

Subsequent stimulation programs utilized sand as propping agent in addition to increasing fluid volume and rate. For a time, perforating programs continued to include only the major zones (1 to 3 in number) using 4 shots per foot. In these cases, the large number of holes generally minimized fluid control and many of the potentially productive sands were not treated.

Adoption of the limited-entry technique into stimulation practices provided a satisfactory solution in most instances, and made it more feasible to treat all the significant sands encountered (Figure 7). Weak acid (5 to 7-1/2 per cent) continued to be the most common frac fluid used. This fluid provided some permeability improvement adjacent to fractures by removal of carbonate material and offered some protection against possible damage due to presence of clays. Brine water use is becoming more common, and will possibly replace the acid entirely. Friction reducing agents are employed to improve horsepower utilization and increase rates.

Most casing programs in the area utilize 4-1/2" or 5-1/2" N-80 pipe to provide an adequate conductor for rates required. Some surface treating pressures exceed 6000 p.s.i. Of the Canyon completions to date, five (5) are cased with pipe of less than 4-1/2" diameter. The average AOF/D for these wells in just over 1,700 MCF.

An example completion in the Ozona Canyon is as follows:

5-1/2"-17# N-80 set to total depth
24 - 0.50" holes 6264-6897'
Fractured With:
75,000 gal. 7-1/2% Slick Acid
112,000# 20-40 Sand
72 BPM @ 5500 p.s.i.
IPAOF: 4,250 MCF; GLR 39,800-1

A compilation of potentials versus treatment volumes does not reveal any particular trend. The extreme scattering of completions to date, combined with the lack of lateral continuity of many of the sand lenses, will render any such comparison invalid at this time. The average potential for the area, however, exceeds 3000 MCF/D with a low of 125 MCF and a respectable high of 9500 MCF.

Mississippian Trend
Central Oklahoma

The area of interest here includes a portion of Garfield, Alfalfa and Major Counties, Oklahoma (Figure 8). The reservoir or reservoirs included are found in that portion of the Mississippian system referred to as the "solid Mississippi," which is understood to be the Meramec and Osage limestones. The productive history of this area is relatively short, most development having occurred within the past two years. The Meramec is composed essentially of sandy, silty limestone with occasional stringers of chert and cherty limestone. Thickness varies widely over the area, from a few feet (10-20) to as much as 140-150 feet. Average porosity is around

7 per cent, with little permeability of significance except where natural fracturing occurs. Fracture systems are thought to be the primary reservoir in the Meramec Formation.

The Osage occurs essentially as a very dense cherty limestone. Chert is present as both individual beds and as a siliceous intermix with the limestone. Natural fracturing may be found at any point throughout the 500 to 600 feet of the Osage zone encountered. Porosity is indicated in a rather narrow range from 3 to 7 per cent. As with the overlying Meramec, primary reservoir is thought to be within the extensive natural fracture system.

Completion stimulation programs vary widely in detail, but most embrace the more fundamental practices common to the area. Few completions produce from open hole, and casing size is normally 4-1/2" or larger. Most operators have utilized some form of the limited-entry technique to provide selective treatment of the interval, but method of application, placement of holes and pressure differential maintained vary widely.

Fresh water containing few additives is the universally accepted frac fluid. Dissolution of salt, which occurs in the formation, is one of the major functions of the treating fluid and is performed most effectively with fresh water. Earlier treatments employed 2,000 to 2,400 barrels per zone, with some more recent treatments using as high as 12,000 barrels per zone. Injection rates cover a wide range, from a low of 20 BPM to a high near 100 BPM. Low fracture pressures characteristic of these formations, coupled with efficient friction reducing additives, make these higher rates easily attainable. The method of selectivity employed and injection rate achieved are closely related.

The use of propping agents in treatments here is rather unusual compared to the average fracturing program elsewhere, with numerous operations conducted using none at all. Even where used, the amount of sand in relation to total volume of frac fluid is small indeed. Dissolution of salts, thought to occur as linings in the fractures, is believed to provide considerable flow capacity without benefit of propping agent.

An example of completion in the Mississippian Trend would be as follows:

5-1/2"-15.50# casing to Total Depth
71 Perforations in 2 Zones
Fractured in 2 Stages With:
20,980 bbl. Fresh Water
52,500# Sand
77 BPM
IP: 480 BOPD; GOR: 809-1

Relative importance of the various treatment factors and completion techniques employed in this area have been discussed fully[8]. For purposes of this paper, however, it suffices to note only that treatment volume appears to have the most direct bearing upon results. Degree of selectivity is probably of secondary importance, with injection rate next and propping agent of least importance.

CONCLUSIONS

Few of the stimulation techniques employed during development of these low permeability formations are entirely new, but represent slight modifications and refinements in the older basic methods. Most significant of these techniques deal with selectivity and fluid control.

Of the various factors which collectively constitute a successful treatment program, fluid volume appears to be the most important single factor. Of secondary importance, injection rate and selectivity must be considered together in light of the respective effect each has upon the other. The use and selection of propping agent would seem to be a variable of lesser importance in many instances.

The practices employed in these programs obviously have not reached the ultimate in refinement which will provide commercial means of developing other very low permeability reservoirs in the future.

REFERENCES

1. Lagrone, K. W. and Rasmussen, J. W.: "A New Development in Completion Methods-The Limited-Entry Technique", J. Pet. Tech., Vol. 15, No. 7, 695 (July, 1963).

2. Rixe, F. H.; Fast, C. R. and Howard, G. C.: "Selection of Propping Agents for Hydraulic Fracturing", Paper No. 875-17-L, Spring Meeting of Rocky Mountain Dist. API (April, 1963).

3. Huitt, J. L. and McGlothlin, B. B., Jr: "The Propping of Fractures in Formations Susceptible to Propping Sand Embedment", 115, Drilling and Production Practice (1958).

4. Huitt, J. L.; McGlothlin, B. B., Jr. and McConald, J. F.: "The Propping of Fractures in Formations in Which Propping Sand Crushes", 120, Drilling and Production Practice (1959).

5. Webster, K. R.; Goins, W. C., Jr. and Berry, S. C.: "A Continuous Multi-Stage Fracing Technique", Paper No. 977, Fall Meeting SPE (1964).

6. Cocanower, R. D.: "Perforating Assumes New and Greater Importance in Well Stimulation", Paper No. 799, Mech. Eng. Aspects of Drilling Production Symposium (1964).

7. Kubitz, John R. and Shearin, H. M.: "Producer-Engineer-Purchaser...A Case History", Journal Pet. Tech. (July, 1964), Vol. 16, 719.

8. Mississippian Trend--Garfield, Major and Alfalfa Counties, Oklahoma, A Western Company Report (Jan., 1965).

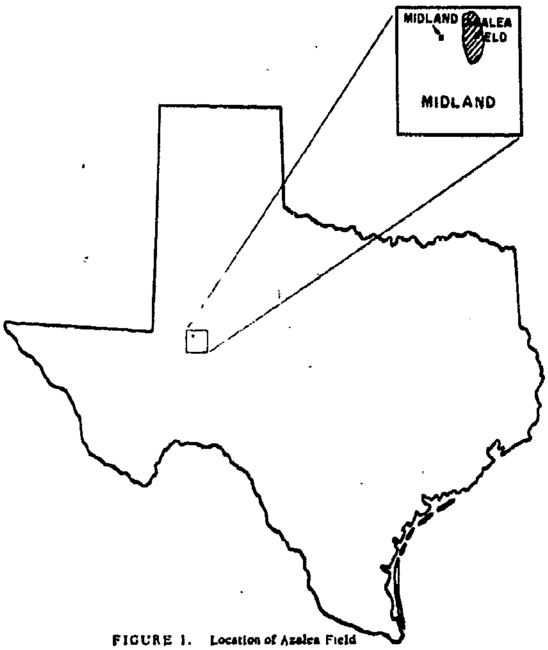

FIGURE 1. Location of Azalea Field

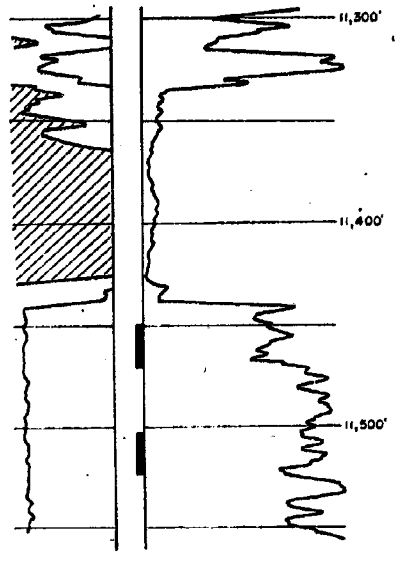

FIGURE 2. Type Log from Azalea Devonian Field Showing Perforated Intervals

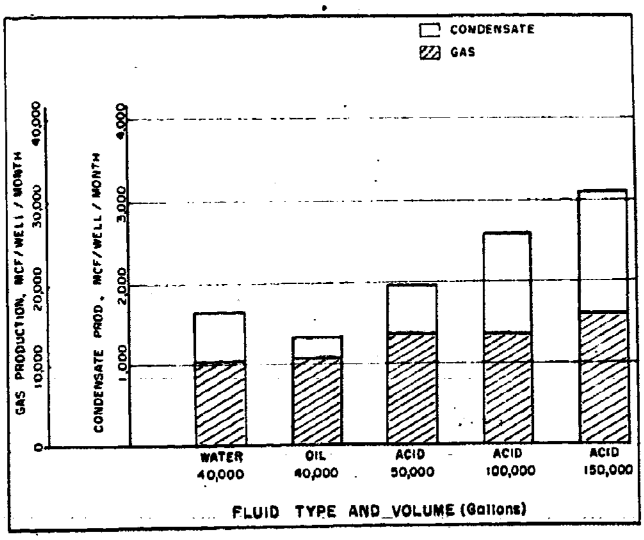

FIGURE 3. Production in Barrels Condensate and MCF Gas per well/month Versus Treatment Type and Volume

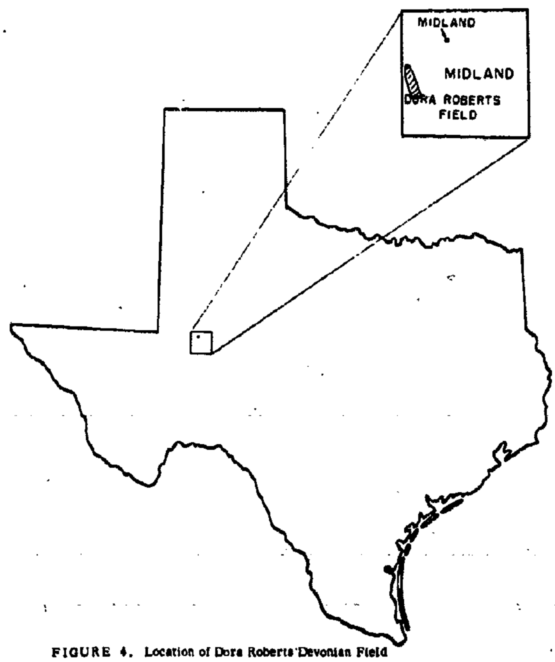

FIGURE 4. Location of Dora Roberts Devonian Field

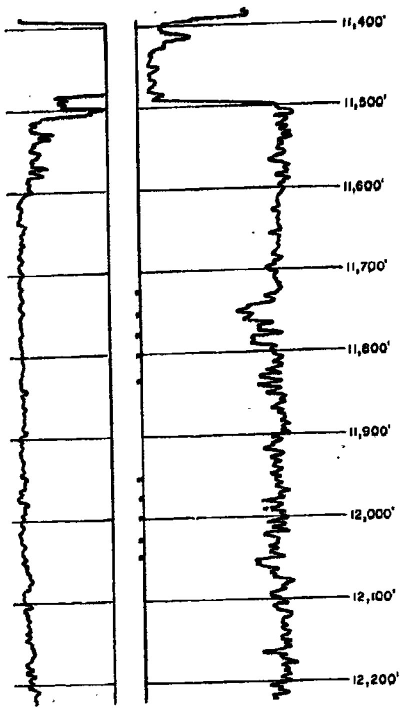

FIGURE 5. Type Log from Dora Roberts Devonian Field Showing Perforated Intervals

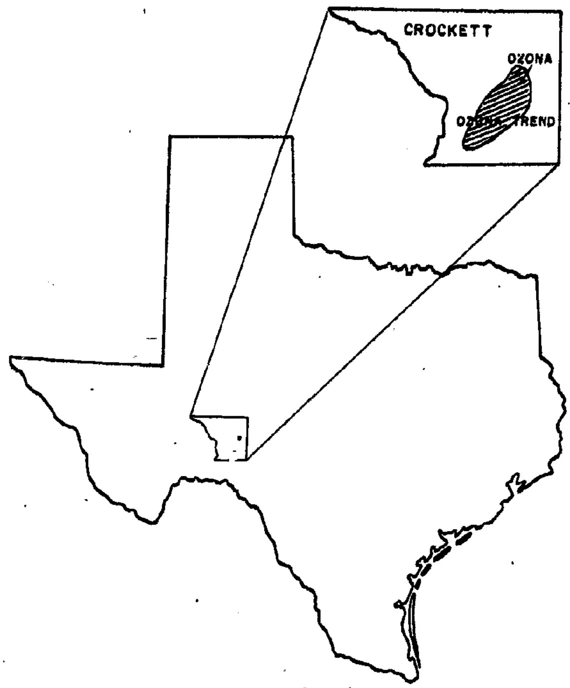

FIGURE 6. Location of Ozona Canyon Area

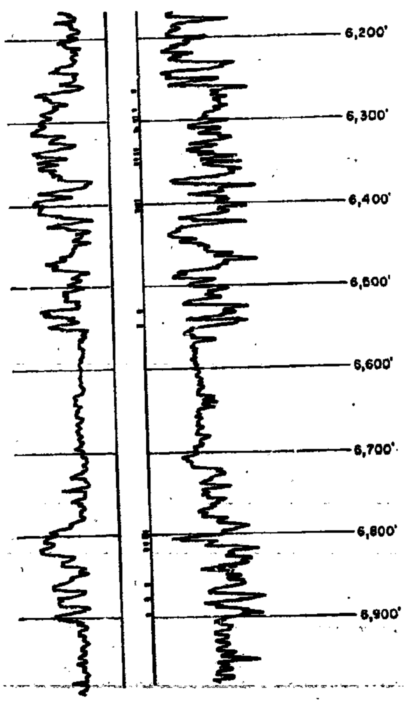

FIGURE 7. Type Log in the Ozona Canyon Trend Indicating Perforated Points

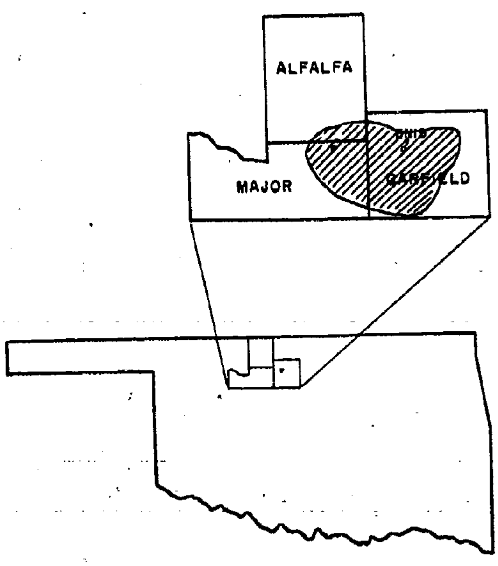

FIGURE 8. Location of Mississippian Trend Area