TREATMENT OF PROBLEM FORMATIONS IN THE PERMIAN BASIN

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ABSTRACT

Knowledge of rock properties can be a valuable tool in designing treatments for problem formations. All formations in the Permian Basin could be considered problem formations, but only the Delaware, San Andres, and Wolfcamp are discussed here. These rocks are of particular interest because of recent findings in core analysis and Scanning Electron Microscope (SEM) studies. The characteristics of these formations revealed by these studies have provided clues for improving treatment techniques. The new techniques are providing productivity increases many times greater than conventional treatment techniques.

This paper describes the studies of the three formations, the results of the studies, and the use of these results in the design of improved treatment techniques. Field results are used to support the success of improved treatment design in providing greater production increases.

INTRODUCTION

Successful treatments are dependent on the knowledge of rock properties within a formation. The treatment design for the Delaware, San Andres, and Wolfcamp formations in the Delaware Basin until recently were partly speculative. They were based on observational data from geological reports. With the utilization of the scanning electron microscope, we are now applying the exact data needed to design the proper formation treatments. The use of precise data in treatments has resulted in increased production over conventional methods.

GEOLOGY

The Permian Basin is a Paleozoic feature of West Texas. It is made up of Delaware Basin, a deep western trough, the Central Basin, a central uplifted area, and the shallower Midland Basin in the east. It is bounded on the north, east, and west by shelves. The Delaware Basin is bounded on the far west by the Diablo Platform and by the Val Verde Basin in the south. The Matador Arch, a long east-west fault zone, is in the northern section of the Permian Basin.

The Delaware formation is the Delaware Mountain Group, which is divided into the Brushy, Cherry, and Bell Canyons. They consist of sandstone, limestone, and shale. The porosities and permeabilities vary, depending on the facies.

The San Andres formation in West Texas is made up of limestone, dolomite, anhydrite, and sandstone. The lithologies of the San Andres vary according to facies. Reefal limestone is found on the western edge; on the platform proper are bedded limestones and dolomite; and the lower San Andres is porous and permeable throughout. Northward it becomes increasingly evaporitic, and in the southern Midland Basin it becomes sandy.

Porosities average 7 to 15 percent in the formation with permeabilities ranging from 0.04 to 500 millidarcies.

Rocks in the Wolfcamp formation, extensive throughout western Texas, consist of shale, limestone, and sandstone. Rocks of this formation attain 14,000 feet in thickness in the Delaware Basin and Val Verde trough. Due to their wide-spread nature, Wolfcamp rocks have varied lithologies. They vary from thick basinal shales to porous shelf and reefal limestones, to embedded limestones and sands. Reservoir rock properties are as variable as the facies within the Wolfcamp series. Porosities can range from less than 5 to more than 25 percent and permeabilities from less than 1 millidarcy to more than 1 darcy.

DESIGNING TREATMENTS: DELAWARE DESIGN

Fracture treatments in the past have used lease oil or gelled kerosene with usual sand concentrations of 1 pound per gallon of total treating fluid. Every type of sand grade was used, but the common size was 20-40 and 10-20 mesh. The oil-based fluid was used to prevent clay migration, since this formation contains some clay and acid-soluble products.

A new low pump rate treatment* using fluoboric acid has been designed to increase production without an increase in water. It has been developed to stimulate problem sandstone formations. The fluoboric acid slowly hydrolyzes to generate hydrofluoric acid, which acts to stabilize clays and other fines by chemically fusing them to each other and to sand grains. The control mechanism is illustrated by SEM studies, shown in Figure 1. The solutions used in treating this formation can be modified to overcome undesired characteristics found in the rock.

SEM analysis reveals the presence of layers of mixed clays. Increasing magnification 100 fold shows small sand grains cemented together (Figure 2). A magnification of 1000 fold reveals montmorillonite and illite covering the sand grain along with the presence of chlorite and calcite (Table 1). The numerous pore space indicates good porosity (Figure 3), which corresponds with the porosity and permeability test results shown in Tables 2 and 3.

TABLE 1 MINERALOGICAL ANALYSIS OF DELAWARE SANDSTONE

Mineral	Approximate Weight Percent
Quartz	25 to 100
Feldspars	10 to 30
Calcite	1 to 15
Dolomite	1 to 15
Mixed Clay	1 to 15

TABLE 2—CLAY ANALYSIS IN PERCENT

Particle Size	Kaolinite	Chlorite	Illite
4 to 5	3 to 5	3 to 5	0.5 to 1

TABLE 3

(md) Permeability	Percent Porosity	Percent Soluble Iron	Percent Acid Solubility
1.3 to 2.65	22.8	0.13 to 0.22	5 to 9.5

*Patents pending

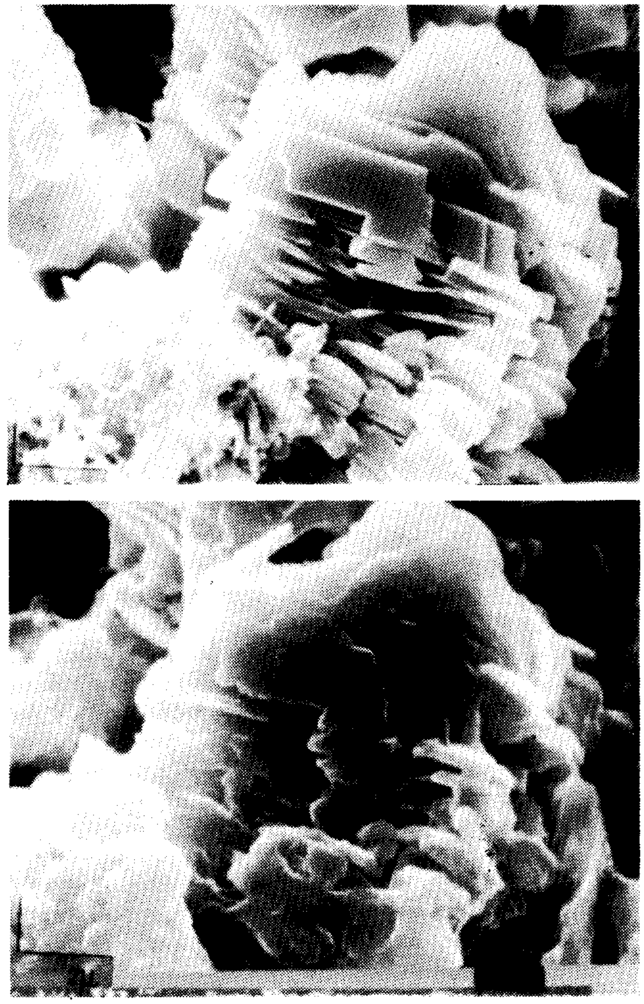

FIGURE 1 SEM PHOTOGRAPH OF A ROCK IN THE DELAWARE FORMATION.

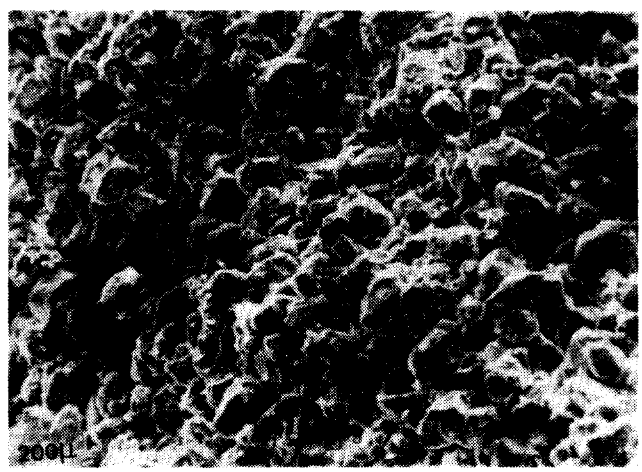

FIGURE 2—SEM PHOTOGRAPH (100x) OF A ROCK IN THE DELAWARE FORMATION SHOWING SAND GRAINS CEMENTED TOGETHER FOLLOWING A CLAY ACID TREATMENT.

FIGURE 3 SEM PHOTOGRAPH OF A ROCK IN THE DELAWARE FORMATION MAGNIFIED 1000 TIMES, SHOWING CLAY MINERALS COVERING THE SAND GRAINS.

Typical Treatment Employing Fluoboric Acid

One-hundred gallons of 15 percent HCl per ft of zone is injected at 3 BPM. The purpose of the HCl treatment is to dissolve any calcite or feldspar in the fractures. This could be natural dolomite and limestone present in most sandstones. An iron-sequestering agent is used to prevent precipitation of iron. A liquid diverting agent is used so that the total zone will be covered. A surfactant is also added.

1. The acid is followed with a 3 percent NH_4Cl spacer to avoid mixing of fluoboric acid with the hydrochloric acid. A surfactant is used to aid in cleanup after the treatment.
2. Fluoboric acid is overflushed to dissolve clays and other fines deep in the formation and to stabilize fines.
3. A 3-percent NH_4Cl solution is used to displace the fluoboric acid to the perforations.
4. The well is then shut in for the prescribed period of time to allow spending of the acid and stabilization of formation fines.

Field Results

Treatments using HBF_4 have shown very good results with little production decline in months following the treatment. The wells were treated at 3 BPM with tracers in the spacer fluids to determine complete zone penetration. The tracers revealed that for each BPM a 10 foot vertical height was achieved.

Case History

An oil well producing from a 30 ft zone of Delaware sandstone had an average production of 7 BOPD. Production immediately after fluoboric acid treatment was 180 BOPD. Two months following treatment, the well was choked to 120 BOPD.

Although gelled oil or kerosene has been a useful fluid system to treat the Delaware with varying results,

1. HBF_4 treatments are designed to remove all damage to flow channels.
2. Complete zone coverage can be accomplished at a low pump rate.
3. HBF_4 treatment can be as effective in increasing production as gelled oil or kerosene at a lower cost.
4. A shut-in period is required following the treatment to allow spending of the acid and stabilization of the fines.

DESIGNING TREATMENTS: SAN ANDRES DESIGN

The San Andres formation has been treated in the past with acid, gelled oil, gelled kerosene, and gelled water. Various types and amounts of sand have been used up to a 2 pound-per-gallon average. The success from treatments has ranged from good to poor.

A pad and acid treatment has been used in the past two years with very good results. A new treatment using gelled water with a 4 pound-per-gallon average sand concentration has yielded outstanding results.

SEM analysis has revealed that the San Andres is highly fractured dolomite containing a varying amount of calcium sulfate (Figure 4).

Results of a core analysis shown in Table 6 indicates the presence of soluble iron and a small amount of mixed clays. The clays do not seem to be a problem in treating this formation.

Treatment Design

The following is a typical treatment employing a pad and acid system.

1. A small volume of acid is pumped.
2. A medium viscosity fracture fluid is pumped.
3. A medium viscosity fracture fluid containing 100-mesh sand at 3 ppg is pumped.

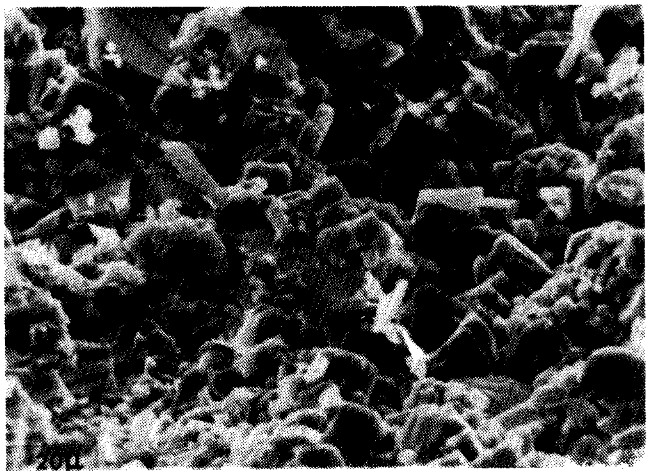

FIGURE 4—SEM PHOTOGRAPH OF A ROCK IN THE SAN ANDRES FORMATION, SHOWING HIGHLY FRACTURED DOLOMITE AND CALCIUM SULFATE.

4. A volume of acid at least 100 gallons more than the first volume of acid is pumped.
5. A medium viscosity fracture fluid, 1000 gallons more than the first volume, containing 3 ppg of 100-mesh sand is pumped.
6. A volume of acid, 1000 gallons more than the second volume of acid is pumped.
7. A medium viscosity fracture fluid, 1000 gallons more than the second volume, containing 3 ppg of 100-mesh sand is pumped.
8. A volume of acid, 1000 gallons more than the third volume of acid is pumped.
9. An overflush of at least 2000 gallons of medium viscosity fracture fluid is pumped.
10. Water containing a friction-reducing agent displaces to the perforations.

Example pad and acid treatment:

A. The perforations are acidized.
B. 5000 gallons of Waterfrac pad.
C. 6000 gallons of Waterfrac plus 3 lb/gal 100-mesh.
D. 5000 gallons of 28 percent acid.
E. 6000 gallons of Waterfrac plus 3 lb/gal 100-mesh.
F. 7000 gallons of 28 percent acid.
G. 7000 gallons of Waterfrac plus 3 lb/gal 100-mesh.
H. 8000 gallons of 28 percent acid.
I. 6000 gallons of Waterfrac overflush.
J. The casing or tubing is flushed.

Three stages each of acid and pad are used so that maximum penetration may be achieved with the live acid. The extended penetration is accomplished by preventing the acid from leaking off into the fractures before it can extend out into the reservoir. After the initial fracture has been created, the natural fractures and hairline fractures are filled to prevent acid leakoff. The pads function as a mechanical retarder for the acid. The acid will slowly penetrate the gel but not before acid penetration in the reservoir is complete. Chemical additives are added to the pad and acid to prevent secondary reactions. Based on the lithology of this rock, 1 percent KCl is added to the pad to prevent clay migration. A surfactant is added to reduce surface tension and provide for faster cleanup following the job. In certain instances, characteristics of the well may call for the use of a bactericide, silt suspender, friction-reducing agent, or iron-sequestering agent.

Results

Analysis of the results of a treatment can explain how it works. Figure 5 shows the results of 100-mesh sand controlling fluid leakoff into the rock matrix. Pressure analysis shows that when a fluid leaks off a pressure drop takes place. The pad fluid will fill up the fractures, controlling leakoff, causing the pressure to increase. Figure 5 shows the pressure drop after each acid stage and buildup after a pad stage. The pressure analysis indicates that more than 1 lb/gal of 100-mesh is required to control the fluid leakoff.

After the job starts, 2 lbs/gal of 100-mesh sand is injected at 6 minutes and acid is injected at 10 minutes. One minute later, the pressure increases. One lb/gal of 100-mesh sand is injected at 14 minutes followed by acid at 19 minutes, causing the pressure to decrease until the pad is injected. 100-mesh sand builds the pressure up at 27 minutes and fluid loss is controlled until acid leaks off at 34 minutes. More pad is used until 100-mesh sand is started at 38 minutes. Acid is started at 42 minutes with leakoff controlled, resulting in a buildup of pressure. One lb/gal of 100-mesh is added at 48 minutes and acid at 53 minutes. The final acid stage leaked off as before. A pad is used for overflush to remove all the acid from the wellbore.

Figure 6 shows the results from a conventional fracture treatment using a cross-link gel system

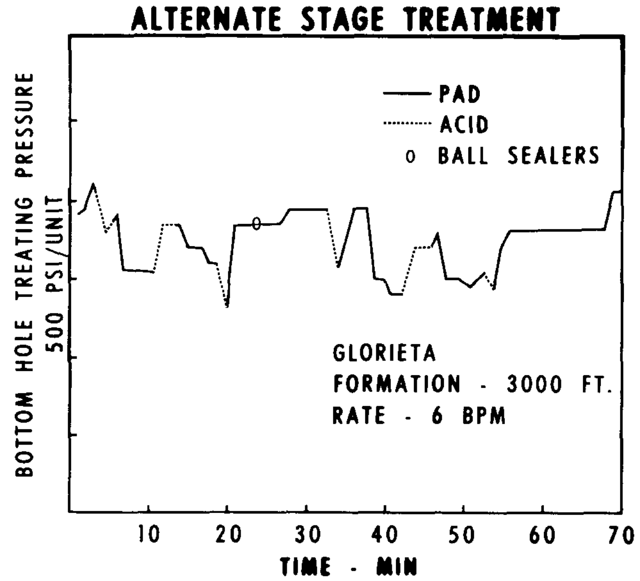

FIGURE 5 GRAPH SHOWING LEAKOFF CONTROL USING 100-MESH SAND.

employing 1 lb/gal average sand concentration. Results from a subsequent well test reveal that water production dropped from 190 to 68 BPD and oil from 32 to 11 BPD.

An acid and pad treatment was performed in July 1976. Oil production climbed from 15 BPD to 20 BPD over a 3-month period. Water production dropped from 52 BPD to 40 BPD. After 11 months passed, oil production was at 100 BPD and water at

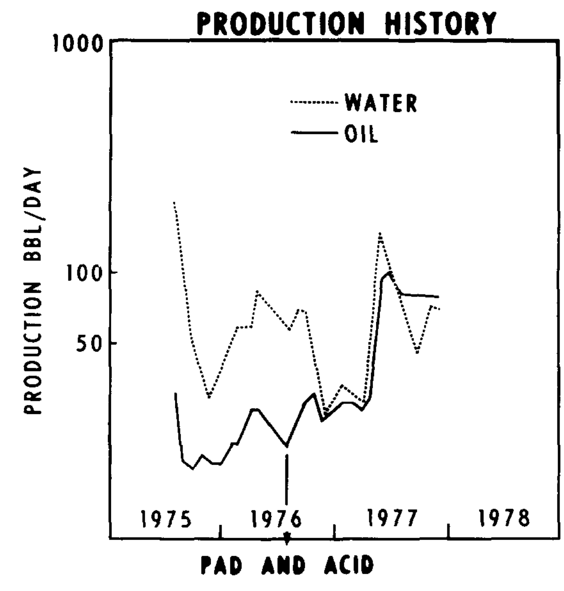

FIGURE 6 -RESULTS OF A FRACTURE TREATMENT USING CROSS-LINKED GEL AND 1 LB GAL AVERAGE SAND CONCENTRATION.

150 BPD. The most significant result is that oil production will only show a slow decline.

If a well is going to be fractured without acid, a fracture treatment using more sand than conventional treatments is recommended. The following is a typical treatment employing gelled water and 4-ppg average sand concentration.

1. A small volume of acid is pumped.
2. A cross-linked water base fluid to establish the fracture is pumped.
3. The same fluid with 2 lb/gal 100-mesh sand is pumped.
4. A volume with 3 lb/gal 100-mesh sand is pumped.
5. A volume with 4 lb/gal 100-mesh sand is pumped.
6. A volume with 4 lb/gal 20/40-mesh sand is pumped.
7. A volume with 5 lb/gal 20/40-mesh sand is pumped.
8. A volume with 6 lb/gal 20/40-mesh sand is pumped.

*9. A volume with 6 lb/gal 10/20-mesh sand is pumped.

10. The casing is flushed to perforations.

*On the last 12 bbls of fluid the cross-link system is cut and the pump rate is slowed to screen out the 10/20-mesh sand at the wellbore.

Designing this type of treatment incorporates several fracture techniques.

1. 100-mesh sand effectively controls fluid loss into hairline fractures and natural fractures.
2. Injection rates can be designed to control fracture height.
3. A packed fracture has better conductivity than one in which sand settles to the bottom and allows the top portion of the fracture to close.
4. The controlled screen-out treatments are better than nonscreen-out treatments.

The chemical additives are to be used according to the results of the analysis shown in Table 5, 6, and 7.

The fluid must contain KCL to prevent clay problems and a surfactant to lower surface tension and aid in faster cleanup after the treatment. In some areas a bactericide must be used for bacteria problems.

TABLE 4 EXAMPLE TREATMENT

Use 20,000 gallons of total fluid with a total of 76,000 lbs of sand.

1. 1000 gal of acid.
2. 1000 gal of Waterfrac.
3. 1000 gal of cross-link.
4. 2000 gal of cross-link with 2 lb/gal 100-mesh sand.
5. 3000 gal of cross-link with 3 lb/gal 100-mesh sand.
6. 3000 gal of cross-link with 4 lb/gal 100-mesh sand.
7. 3000 gal of cross-link with 4 lb/gal 20/40-mesh sand.
8. 3000 gal of cross-link with 5 lb/gal 20/40-mesh sand.
9. 3000 gal of cross-link with 6 lb/gal 20/40-mesh sand.
10. 1000 gal of cross-link with 6 lb/gal 10/20-mesh sand*.
11. Flush.

*Cut cross-link on last 500 gal and slow pump rate to screen out 10/20 mesh sand in the wellbore.

Results

Analysis of Figure 7 shows how 100-mesh sand controls fluid leakoff with the Mini-Massive frac.

A pad fluid is injected causing an initial fracture followed by fluid leakoff. Two lbs/gal of 100-mesh sand is injected after 5 minutes followed by 3 lbs/gal of 100-mesh at 8 minutes. Leakoff is controlled at 10 minutes. Four lbs/gal of 100-mesh sand is injected at 11 minutes with leakoff being maintained until 4 lbs/gal of 20/40 mesh is injected. Penetration occurs as the job progresses to point of where 6 lbs/gal of 10/20-mesh sand is injected at 25 minutes into the treatment. The increase in pressure at this point shows the intended screen-out at the wellbore. Pumping is stopped at 26 minutes.

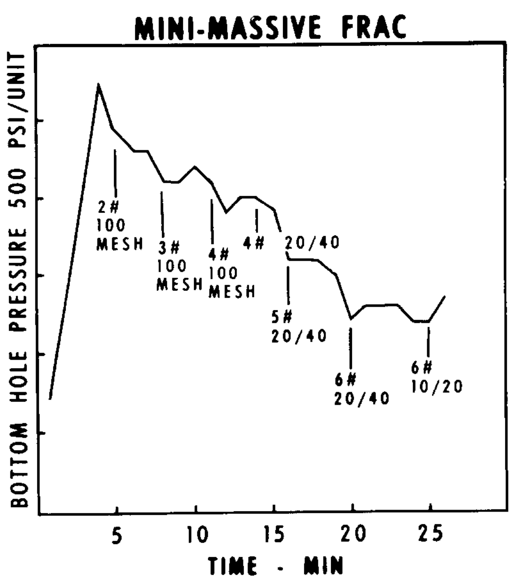

FIGURE 7 -RESULTS OF 100-MESH SAND CONTROLLING LEAKOFF WITH THE ACID AND PAD SYSTEM.

TABLE 5 MINERALOGICAL ANALYSIS OF SAN ANDRES LIMESTONE.

Mineral	Approximate Weight Percent
Dolomite	25 to 100
Quartz	1 to 15
Feldspars	1 to 15
Anhydrite	1 to 15

TABLE 6 CLAY ANALYSIS IN PERCENT.

Particle Size	Kaolinite	Chlorite
3	3	3

TABLE 7

(md) Permeability	Percent Porosity	Percent Soluble Iron	Percent Acid Solubility
0.03 to 0.04	5.5 to 12.1	0.08	85 to 95

Figure 8 shows the production history after a high sand concentration treatment. Water production went from an initial 720 BPD to 400 BPD three months later. The oil production reduced from 175 BPD to 135 BPD during the same time span.

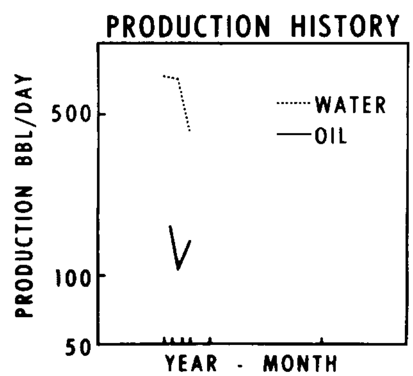

FIGURE 8 PRODUCTION HISTORY OF A WELL AFTER A HIGH SAND CONCENTRATION TREATMENT.

DESIGNING TREATMENTS: WOLFCAMP DESIGN

The Wolfcamp formation consists of an upper sandstone containing quartz, mixed clays, iron and dolomite (Table 7), and a lower limestone containing dolomite, sandstone and iron. Its solubility in acid increases as depth increases. Because of unexpected results, the Wolfcamp is, and always has been, a difficult formation to treat. Previous treatments either used gelled kerosene, or they were acid cleanup jobs. Gelled kerosene treatments used 1 to 2 lbs/gal of 20/40-mesh sand at various pump rates. Acid concentrations in the cleanup jobs ranged from 5 to 28 percent and were pumped at various rates.

Using the SEM, we have gained enough knowledge about the Wolfcamp formation to design a more precise treatment to achieve better production results (Figure 9).

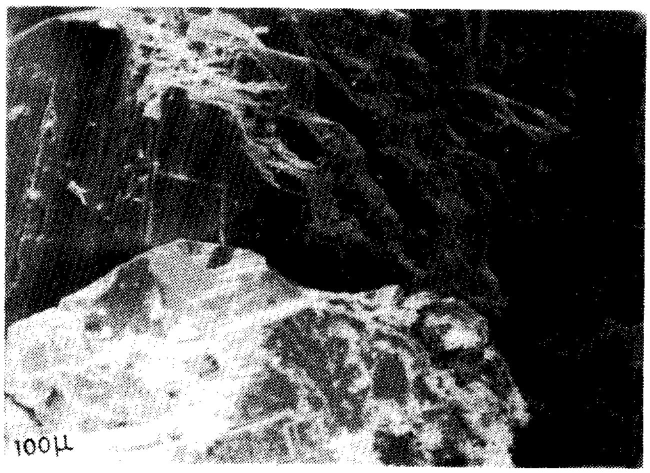

FIGURE 9 SEM PHOTOGRAPH OF A WOLFCAMP FORMATION ROCK.

The lower Wolfcamp can be treated with the pad and acid technique employing 100-mesh sand. The acid must contain surfactants and iron sequestering agents. Clean gelling agents and surfactants must be incorporated into the pad. Treating the upper Wolfcamp can be a little more difficult. Gelled kerosene that contains fluid-loss agents and large sand concentrations are still being used.

This zone can be treated with fluoboric acid to remove the clays and stabilize the fines. After this, a cross-linked water-base gel system can be used with great success.

The treatment in Table 8 is based on the clay properties shown in Table 11. The high clay content could not be controlled with a water base system. Gelled kerosene was used along with a fluid-loss additive and a high sand concentration.

TABLE 8 GELLED KEROSENE TREATMENT.

Volume Fluid (bbl)	Sand and Mesh Type (lb/gal)	Sand (lb)
60	Pad	None
144	2 lb 20/40	12,100
24	200 lb diverting agent	None
60	Pad	None
144	2 lb 20/40	12,100
24	200 lb diverting agent	None
60	Pad	None
144	2 lbs 20/40	12,100
24	200 lb diverting agent	None
60	Pad	None
144	2 lbs 20/40	12,100
72	Flush	None

This treatment was performed on a new well with initial oil production of 880 BPD and very little water. Two months later, oil production decreased to 100 BPD. The results might have been better if more sand had been used. Sand concentrations will be increased in subsequent treatments to improve results.

The treatment in Table 9 is shown to evaluate water base treatments. The well was acidized with a mud and silt removal acid* before the fracture treatment. This acid aids in the removal of fines. A large pad was used to establish an initial fracture. Sand 100-mesh was then injected to help control fluid leakoff in the natural and induced fractures. Another pad was used to separate the 100-mesh sand from the larger 20/40-mesh sand. The 20/40-mesh sand concentration was tapered from 1/2 lb/gal to 1 1/2 lb/gal. After ball sealers were dropped for diversion, steps 1 to 7 were repeated. The tubing was then flushed with 100 bbl of water.

Results of this type treatment are still being evaluated, but the water base treatment is very effective if the clays are dealt with before the fracture treatment.

*Patent pending.

TABLE 9—CROSS-LINK TREATMENT.

Volume Fluid (bbl)	Sand & Mesh Type (lb/gal)	Sand (lb)
1. 120	Pad	None
2. 48	1 lb 100	2,000
3. 72	2 lb 100	6,000
4. 72	Pad	None
5. 48	1/2 lb 20/40	1,000
6. 72	1 lb 20/40	3,000
7. 288	1 1/2 lb 20/40	12,100
8. 120	Pad ball sealers	None
9. Repeat Steps 1-7		
10. 100	Flush	None

TABLE 10—MINERALOGICAL ANALYSIS OF WOLFCAMP SANDSTONE.

Mineral	Approximate Weight Percent
Quartz	25 to 100
Dolomite	10 to 30
Feldspars	1 to 15
Mixed Clay	1 to 15

TABLE 11—CLAY ANALYSIS IN PERCENT.

Particle Size	Illite	Montmorillonite
3.8 to 5.9	3.8 to 4.7	Trace to 1.2

TABLE 12

(md) Permeability	Percent Porosity	Percent Soluble Iron	Percent Acid Solubility
0.04 to 0.05	11.7 to 12.5	30 to 118	16.4 to 21.5

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ACKNOWLEDGMENTS

The author wishes to express his appreciation to Dowell Division of the Dow Chemical Company U.S.A. for permission to publish and present this paper.