ALTERED STIMULATION TECHNIQUE AND FLUID SHOWS IMPROVED CANYON SAND PRODUCTION IN FLOWERS WEST AND GUEST UNITS, STONEWALL COUNTY, TEXAS

VITHAL J. PAI
The Western Company of North America

ABSTRACT

In order to combat falling productivity and increased water production in the West Flowers and Guest (Canyon Sand) fields, a new approach to stimulation technique and fluid had to be initiated. It was suspected that many pre-1975 frac jobs probably were lost into unproductive zones resulting in very little stimulation of the actual pay section. To combat this situation, the frac fluid was changed to a very high viscosity cross-linked CMC-based polymer gel. The base fluid was 2% KCl water treated with de-emulsifiers. A detailed computerized study was conducted to determine a near optimum treatment design. Fluid volumes were selected based on frac lengths, which provided the most economically feasible productivity increase ratios (J/J_0), and proppant concentrations were analyzed so as to afford the optimum permeability contrasts. Sand concentrations were increased, and 10-20 mesh sand was used.

The perforations are acidized and broken down. This is followed by a base temperature survey. A 2,000-gal dummy stage (slick water) is pumped to determine the zone taking fluid. If channeling is observed, a stage of a calculated amount of benzoic acid flakes is run to divert the fluid into the pay section. A 2,000-gal dummy stage is next pumped. Based on the results of a temperature and radioactive survey, the fraction of the pay section taking fluid is determined. A proportional amount of frac is pumped followed by a calculated amount of block. This is followed by a shut-in period of 20 minutes to let the fracture heal and the surface pressure fall about 500 psi. The above steps are repeated until all or most of the zone is fractured.

INTRODUCTION

The Flowers West, Flowers, and Guest (Canyon Sand) fields are located in southeastern Stonewall County, Texas, approximately 3 miles southwest of the city of Aspermont. These fields are contiguous, as shown in Figure No. 1, and produce from the Canyon Sand of Pennsylvanian age. Although these are separate fields, they have a common reservoir.

These fields were discovered in 1951. Getty's Flowers No. 1, completed in January, 1951, was the

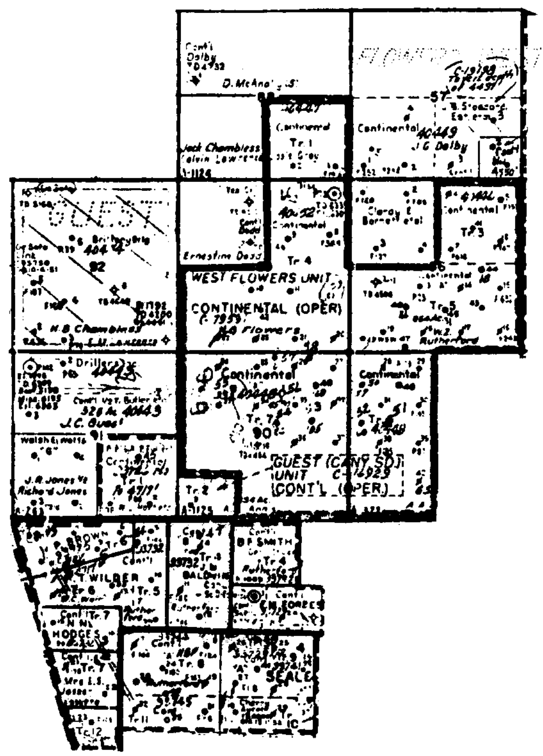

FIGURE 1—FLOWERS WEST AND GUEST FIELDS

Flowers discovery well. Continental's Flowers No. 1, Section 89, completed in February, 1952, was the discovery well in the Flowers West field. The majority of the wells in these fields are operated by Continental, Getty, and Texas Pacific. It would be fair to say that these fields are at present in an advanced state of depletion.

The early wells were acidized with 1,500 to 3,000 gal of 15% HCl acid and fractured,[1] depending on the need, with gelled lease crude oil or with gelled brine containing 30 to 35 lb of guar gum per 1,000 gal of brine. The frac fluid volumes ranged from 10,000 to 20,000 gal and proppant concentrations averaged 1 lb/gal. The discovery well drilled flowed nearly 300 BOPD and no water. As more wells were drilled in 1956 and 1957, the average potential fell to 130 BOPD and some 20 BWPD. By 1961 these fields were depleted considerably, and new wells had to be put on pumps. These wells potentialled on an average 20 to 30 BOPD and some 20 BWPD. Low potentials and rapidly declining production led to curtailment in drilling activity.

In early 1967, secondary recovery was begun by installing a waterflood project. Increased demand for crude oil and higher oil prices due to the energy crisis caused a resurgence of drilling activity in 1973. These wells potentialled between 13 to 90 BOPD and an average of 120 BWPD on pumps.

Since 1974, higher energy costs have made the economics of production, even production at lower rates, more lucrative. But it was necessary to design a new stimulation technique to improve frac efficiency and enhance production. In early 1975, 13 wells drilled were completed using an altered stimulation program and fluid. The results from this approach were encouraging and led to more drilling in 1976 and 1977. The average potential of these wells is 101 BOPD and 109 BWPD. These results are outstanding considering the advanced stages of depletion in these fields.

From extensive work done with temperature surveys and gamma-ray logs in conjunction with dummy stages tagged with radioactive sand, it was observed that there was considerable channeling of frac fluid behind the pipe. The channel went up the hole as high as 500 ft above the Canyon pay section. Surveys also indicated fluid entry into wet sand stringers, such as the Gunsight Lime and also the Coleman Junction. It is suspected that many of the pre-1975 frac jobs were probably lost in these unproductive zones, resulting in very little stimulation of the primary pay section. The higher production in earlier completions in spite of channeling was probably due to a much lower state of depletion of the reservoir.

PURPOSE

This paper deals with the analysis of the channeling problem and the design of the altered stimulation program that resulted in enhanced oil recovery and a decrease in water production. Since 1974, over 80 wells were stimulated in this area. A random sample of 16 wells treated was selected for study. This data has been presented in Table 1.

TABLE 1 STIMULATION VOLUMES & INITIAL POTENTIAL IN FLOWERS WEST & GUEST UNITS

WELL NAME	DATE COMPLETED	TREATMENT TYPE & VOLUME	INITIAL POTENTIAL PER DAY
West Flowers #41	10-16-73	1,500 gal Mud Acid 10,000 gal Lease Crude 10,000 lb 20-40 Mesh Sand	93 BO + 23 BW
West Flowers #42	10-28-73	1,500 gal Mud Acid 6,000 gal Lease Crude 6,000 lb 20-40 Mesh Sand	13 BO + 76 BW
West Flowers #44	10-31-75	1,500 gal Acid 19,000 gal CMC Gel 30,000 lb 20-40 Mesh Sand	48 BO + 120 BW
West Flowers #45	10-07-75	1,500 gal Acid 44,000 gal CMC Gel 59,000 lb 20-40 Mesh Sand	31 BO + 106 BW
West Flowers #46	10-23-75	500 gal Acid 26,000 gal CMC Gel 40,000 lb 20-40 Mesh Sand	26 BO + 91 BW
West Flowers #47	10-28-75	1,700 gal Mud Acid 20,000 gal CMC Gel 48,000 lb 20-40 Mesh Sand	27 BO + 101 BW
West Flowers #48	11-8-75	1,000 gal 15% Acid 48,000 gal CMC Gel 67,500 lb 20-40 Mesh Sand	130 BO + 40 BW (flowing)
West Flowers #49	11-8-75	1,000 gal 15% Acid 63,000 gal CMC Gel 77,000 lb 20-40 Mesh Sand	160 BO + 180 BW (flowing)
West Flowers #50	2-9-76	1,000 gal 15% Acid 9,000 gal CMC Gel 5,600 lb 10-20 Mesh Sand 9,600 lb 20-40 Mesh Sand	57 BO+ 23 BW
West Flowers #55	4-2-76	1,000 gal 15% Acid 11,500 gal CMC Gel 12,700 lb 20-40 Mesh Sand 24,800 lb 10-20 Mesh Sand	335 BO+ 118 BW
Guest #40	5-8-75	1,000 gal 15% Acid 11,500 gal Gelled Prod. Water 35 lb Guar Gum/1,000 20,000 lb 20-40 Mesh Sand	13 BO + 6 BW
Guest #41	5-9-75	2,500 gal 15% Acid 13,000 gal Gelled Water 24,000 lb 20-40 Sand	42 BO+ 24 BW
Guest #42	4-29-75	1,000 gal 15% Acid 12,000 gal Gelled Water 20,000 lb 20-40 Sand	35 BO + 38 BW
Guest #43	5-23-76	1,000 gal 15% Acid 34,000 gal CMC Gel 47,600 lb 20-40 Sand 43,000 lb 10-20 Sand	145 BO + 65 BW
Guest #46	6-15-76	1,000 gal 15% Acid 29,400 gal CMC Gel 49,980 lb 20-40 Sand 45,570 lb 10-20 Sand	72 BO + 160 BW
Guest #47	7-21-76	1,000 gal 15% Acid 15,100 gal CMC Gel 14,100 lb 10-20 Sand 15,470 lb 20-40 Sand	80 BO + 200 BW

RESERVOIR CHARACTERISTICS & LITHOLOGY

The producing interval is the Canyon Sand of the Pennsylvanian age. The pay occurs as clean to shaley sands at depths of 3,950 ft on the east side of the Flowers field to 4,500 ft on the west side of the Flowers West field (a typical log is shown in Figure No. 2). The pay in most wells exists as several sand stringers from two to several feet in thickness. These pay stringers are separated by shale beds or beds of shaley sand or sandy shales. In some few instances, the pay appears as a well-developed sand body up to 35 ft thick. X-ray diffraction analysis showed the formation to be a quartz sandstone, with quartz concentration ranging from 70% to 85%. There was also considerable pyrite by visual inspection. Feldspar was 5% by weight and illite ranged from 10% to 20% by weight. There was 0% to 5% of kaolinite and slight traces of chlorite.

The quartz sandstone has shale partings ranging from paper-thin to greater than half an inch in thickness. The partings probably act as permeability barriers causing large variations in permeability. The clays present did not appear to be expandable or swellable. In a few instances the sands are clean; however, the majority of them contain shale. Permeabilities are low and average at 14 md, but the presence of shale causes rapid variations in permeability. The presence of quartz grains affords cementation without the aid of any interstitial carbonates. Although the clays present are not swellable, there appears to be a tendency toward sloughing and subsequent particle migration.

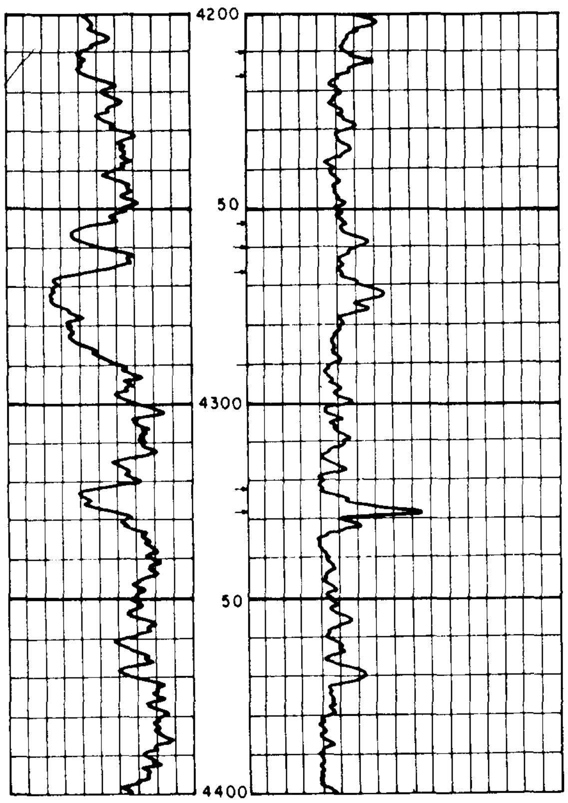

FIGURE 2—TYPICAL CANYON SAND LOG

The Canyon Sand dips from east to west across the Flowers field. This dip is generally correlative with the regional dip. The weighted average porosity in the Flowers field is 15.7%, and the average water saturation as calculated from electric logs is 40%. Produced water is primarily connate water. The original reservoir pressure was around 1,500 psig. The average frac gradient is 0.78 psi/ft indicating vertical fracturing.

The pay sands of Guest Unit are of the Canyon series of the Pennsylvanian age. The pays are low permeability argillaceous sands and are probably deltaic depositions. There are basically three producing sands ("A," "B," and "D"). The sands dip in a westerly direction and range from 4,300 to 4,700 ft. Water saturations are gradational laterally and are probably due to capillary forces and the presence of argillaceous clay within the matrix of the sands. The average porosity for "A," "B," and "D" sands is 15.4%, 13.8%, and 15.7% respectively. The average permeabilities are 5 md, 32.3 md, and 10.8 md respectively. Average water saturation is 42% in all three sands.

ALTERED STIMULATION APPROACH

In order to combat the earlier mentioned channeling problem, the stimulation program was altered in 1975. The frac fluid used was 2% KCl water gelled with cross-linked CMC-based polymer. The gel was treated with de-emulsifier. The properties of the frac fluid will be discussed later. Sand concentrations were increased to 2 lb/gal or more. Larger mesh sand (10-20 mesh) was used at the tail end of the frac treatment to improve the permeability contrast of the sand pack.[2] The perforations were acidized and broken down. This was followed by a base temperature and radioactive survey. A 2,000-gal slick water dummy stage tagged with radioactive sand was pumped at 15 BPM (average) to determine which zone was taking fluid.

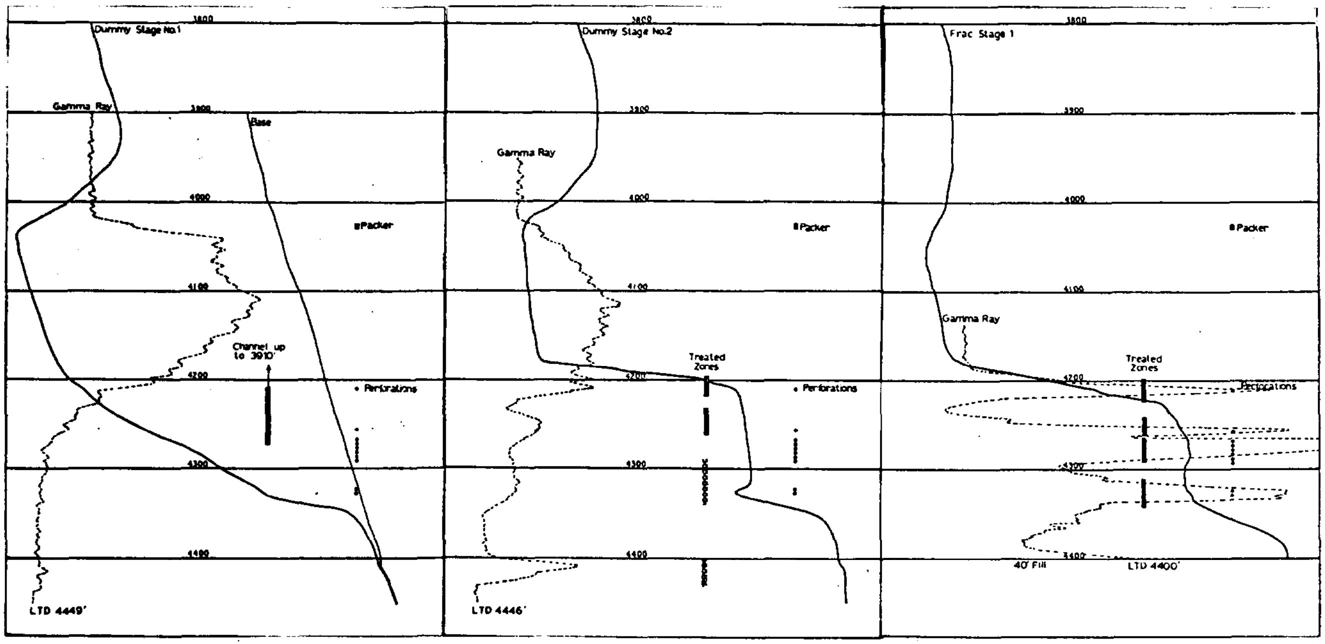

FIGURE 3—DUMMY STAGE-1 FIGURE 4—DUMMY STAGE-2 FIGURE 5—FRAC STAGE—1

TEMPERATURE AND RADIOACTIVE SURVEYS

A temperature and radioactive survey was run, and if channeling was observed, a stage of calculated amount of benzoic acid flakes was run to block the channels and divert the fluid into the desired section. A 2,000-gal dummy stage was next pumped to determine if the desired zone was taking fluid. Based on the results of the temperature and radioactive survey, the fraction of the pay section taking fluid was determined. A proportional amount of frac was then pumped at 15 BPM, followed by a calculated amount of block (Figure Nos. 3-5). This is followed by a shut-in of 20 minutes to let the fracture heal and surface pressure fall about 300 to 500 psi. These steps were repeated until all or most of the zone was fractured. The actual treatment procedure is listed under "Sample Treatment Procedure." The sample of frac treatments selected is presented in Table 1.

SAMPLE TREATMENT PROCEDURE

1. Perforate the Canyon Sand as desired, down casing.
2. Run in hole with tubing and packer to bottom perforation.
3. Spot ± 250 gal (6 bbl) double inhibited 15% acid across the perforated interval.
4. Pick up and set packer at ± 60 ft above top perforation. (Apply 500 psi on annulus.)
5. Run a base temperature and radioactive log to determine the prestimulation temperature and radioactive profile.
6. Break down and pump 2,000 gal slick treated 2% KCl water containing 1/2 can of radioactive sand (dummy stage) (surface treating pressures as shown in Figure No. 6).
7. Flush the dummy stage to bottom perforation.
8. Run temperature and radioactive log to determine the zone and the height of the zone taking the fluid. In the event of fluid entry into an unproductive zone, run block as per Step 9.
9. Calculate the amount of benzoic acid flakes required to block the zone taking fluid, based on the interpretation of temperature and radioactive log.
10. Run the calculated amount of benzoic acid flakes in slick 2% KCl water (about 20 to 40 lb block/ft of zone).
11. Pump another dummy stage consisting of 2,000 gal slick treated 2% KCl water containing 1/2 can radioactive sand.
12. Repeat Step 8 to determine if the previous zone of fluid entry is blocked and the vertical extent of the zone taking fluid.
13. Based on the interpretation of the log, calculate the volume of the frac fluid to be pumped. From the computer runs, sufficient frac fluid volume is required to obtain a frac

length of approximately 500 ft.

14. Repeat Steps 10 through 13 two more times or until the desired zones are fractured. Run a final evaluation log if desired.
15. Flush with slick 2% KCl water.
16. Observe overnight shut-in. Open to recover load.

Note: It would be desirable to pump ± 250 bbl 15% acid prior to each frac stage. For 10,000-gal frac stage, schedule sand as follows:

a) Pump 2,000 gal as pad.
b) Pump 1,000 gal with 1 ppg 20-40 mesh sand.
c) Pump 2,000 gal with 2 ppg 20-40 mesh sand.
d) Pump 2,000 gal with 3 ppg 20-40 mesh sand.
e) Pump 1,000 gal with 2 ppg 10-20 mesh sand.
f) Pump 2,000 gal with 2.5 ppg 10-20 mesh sand.

FRAC FLUID SELECTION

The frac fluid selected[3] is a medium duty complexed CMC-based (synthetic polymer) gel. The gel is complexed on the acidic side, and the pH of the finished product lies between 4 and 5. The low pH prevents any possible reprecipitation of hydratable iron oxides and also affords protection against damage from swellable clays. The gel is complexed and exhibits perfect proppant support under both static and dynamic conditions and is capable of carrying high proppant concentrations. A controlled breaking mechanism, contained within the gel, produces a return fluid with a viscosity slightly higher than the base water within 8 hours at bottom-hole conditions. The gel is treated with a de-emulsifier and a chemical to prevent sloughing caused by migrating clay particles. The complexed gel allows for maximum prop penetration and assures propping of the entire fracture. It also eliminates the tendency of the proppant to "bank" at the wellbore. The synthetic polymer leaves no residue; any formation damage can be caused only by addition of fluid loss control additives.

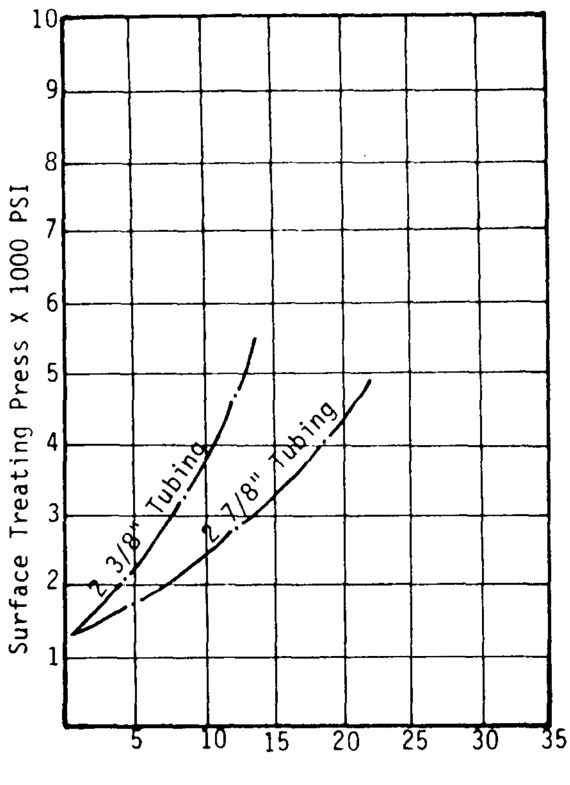

FIGURE 6—CMC GEL TREATMENT

COMPUTER AIDED STIMULATION DESIGN

A computerized study[4,5] was conducted to determine the fluid volumes required to optimize the productivity increase contrast (J/J_o). The fracture heights were varied from 10 to 50 ft. The proppant concentrations (Figure No. 7) were maintained at levels which provide maximum conductivity.[2] The use of 10-20 mesh sand at high concentrations at the

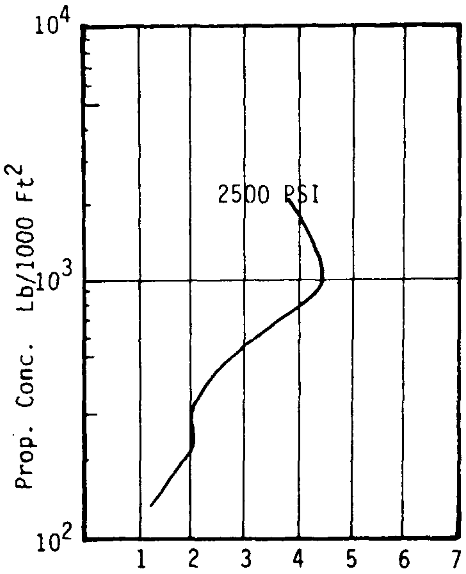

FIGURE 7—10-20 MESH SAND CONDUCTIVITY

tail end of the fracturing operation seems to provide the best results. The following parameters were assumed for purposes of the study.

Reservoir Properties

Bottom-Hole Temperature:	120° F
Fracture Heights Considered:	10, 20, and 50 ft
Formation Permeability:	14 md (average)
Formation Porosity:	15% (average)
Bottom-Hole Pressure:	1,000 psi (average)
Young's Modulus:	6.5×10^6 psi
Well Depth:	4,500 ft (average)
Reservoir Fluid Viscosity:	3 cps
Bottom-Hole Frac Pressure:	3,510 psi
Drainage Radius:	660 ft
Formation Permeability to Reservoir Oil & Frac Fluid:	4 md (estimated)

Frac Fluid Properties at Bottom-Hole Conditions[3]

Leak-Off Viscosity:	1.0 cp
Spurt Loss:	0.0 cc
n′:	0.36
k′:	$0.14\ lb_f \times sec^{n'}/ft^2$
Specific Gravity:	1.02
Specific Heat:	1.00 BTU / lb_f
Fluid Leak-Off Coefficient:	0.0023 ft / min

The results of the computer study are presented in Table 2 and plotted in Figure No. 8. Figure No. 9 shows productivity increase contrast as a function of penetration.[6] It can be seen from Figure No. 9 that L/r_e ratios in excess of 0.7 provide very little P.I. contrast increase. The frac treatment, therefore, should be designed to provide a fracture length of 462 ft (0.7 x 660-ft drainage radius). The actual treatments were designed for fracture lengths of approximately 500 ft. From Figure No. 7 it can be seen that frac conductivity is maximized at sand concentrations of 1,000 lb/1,000 ft.[5] Amount of sand to be pumped is calculated as follows.

Sand (lb) = Frac Height (ft) x Frac Length (ft) x 2

All frac treatments should be designed using the above guidelines. Both 20-40 mesh and 10-20 mesh sand have been used as proppant; however, due to high formation permeability, it is recommended that 10-20 mesh sand be used to provide a higher permeability contrast.

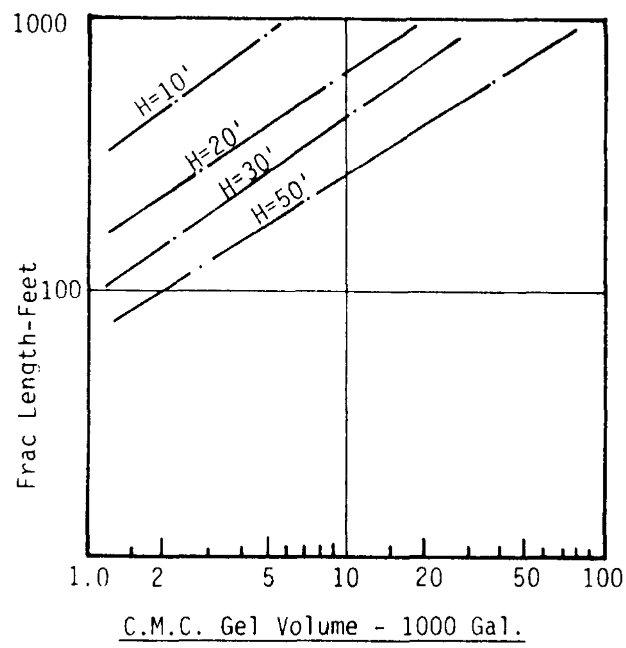

FIGURE 8—VOLUME VS. PENETRATION

TABLE 2—FRAC FLUID VOLUME VS. J/J_o

Frac Height Feet	Fluid Volume Gal	Frac Length (L) Feet	Frac Width Inches	L/r_e	PI Contrast* $x10^4$	J/J_o
10	300	132	.109	.2	1.35	3.90
10	549	198	.127	.3	1.35	4.60
10	840	264	.141	.4	1.35	5.40
10	1,588	396	.164	.6	1.35	6.05
10	2,018	462	.173	.7	1.35	6.20
10	2,487	528	.182	.8	1.35	6.25
20	798	132	.128	.2	1.35	3.90
20	1,494	198	.149	.3	1.35	4.60
20	2,346	264	.166	.4	1.35	5.40
20	4,473	396	.193	.6	1.35	6.05
20	5,734	462	.204	.7	1.35	6.20
20	7,119	528	.214	.8	1.35	6.25
30	1,444	132	.141	.2	1.35	3.90
30	2,736	198	.164	.3	1.35	4.60
30	4,334	264	.183	.4	1.35	5.40
30	8,377	396	.212	.6	1.35	6.05
30	10,797	462	.224	.7	1.35	6.20
30	13,471	528	.236	.8	1.35	6.25
50	3,068	132	.159	.2	1.35	3.90
50	5,930	198	.185	.3	1.35	4.60
50	9,531	264	.206	.4	1.35	5.40
50	13,833	330	.239	.5	1.35	5.90
50	18,700	396	.242	.6	1.35	6.05
50	24,210	462	.248	.7	1.35	6.20

*Permeability Contrast = Wk_f/k =

$$\frac{4.5 \times 12 \times 10^3}{4}$$

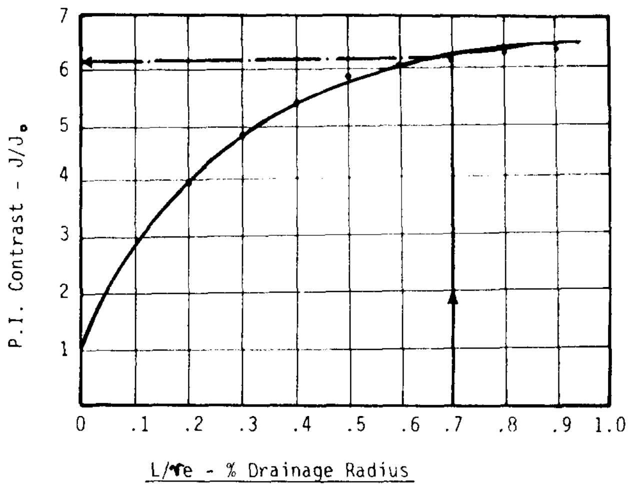

FIGURE 9—P.I. CONTRAST VS. PENETRATION

CONCLUSIONS

1. It is possible to improve productivity in semi-depleted reservoirs by enhancing the efficiency of the stimulation program systematic usage of tempeature surveys in conjunction with radioactive logs. In many of the wells investigated, this technique revealed channeling, causing extensive loss of expensive frac fluids into unproductive zones.
2. Use of benzoic acid flakes to divert frac fluids out of the channels and into the pay section has helped improve productivity 3 to 4 fold. Also, water production has been decreased to some extent.
3. The use of residue free synthetic polymer (CMC) as a gelling agent has helped prevent formation damage.
4. The CMC-based cross-linked polymer complexes at acidic pH between 4 and 5, thereby preventing reprecipitation of hydratable iron oxides and also providing protection against formation damage due to clay swelling.
5. The use of larger mesh (10-20 mesh) sand seems to improve production, possibly due to higher sand pack permeability contrast.
6. The use of cross-linked fluid enables high concentrations of sand to be pumped at relatively low rates. This improves conductivity of the sand pack.

NOMENCLATURE

H = Frac height, ft
J = Productivity Index after fracturing
J_o = Productivity Index before fracturing
k = Formation permeability to reservoir fluid, md
k_f = Proppant pack permeability to reservoir fluid, md
L = Frac length from the wellbore, md
r_e = Drainage radius of the well, ft
W = Propped frac width, in.
Wk_f = Conductivity of the fracture, md-in.

REFERENCES

1. Clark, J. B.: "A Hydraulic Process for Increasing the Productivity of Wells," *Trans.* AIME, Vol. 186 (1949) 1-8.
2. Western Company Experimental Fracture Conductivities Study (December 1968).
3. Western Company Stimulation Services Product Bulletin No. 380. OWG, "Titan 1 Gel," (December 1975).
4. Western Company Stimulation Program Library.
5. Craft, B. C., Holden, W. R., & Graves, E. D., Jr.: *Well Design Drilling and Production*, Prentice-Hall, Inc., Englewood Cliffs, N.J. (1962) 483-533.
6. McGuire, W. J. & Sikora, V. J.: "The Effect of Vertical Fractures on Well Productivity," *Trans.* AIME, Vol. 219 (1960) 401.