PARTIAL MONOLAYER FRACTURING IN THE THREE BAR FIELD

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INTRODUCTION

Prior to 1971, the Devonian formation of the Three Bar Field, Andrews County, Texas was hydraulically fractured with a variety of conventional techniques. These treatments gave fair after-frac results, but sustained increases were small and sand backflow caused severe fill and pump problems. Much of the backflow material appeared to be finely crushed frac sand.

Core studies and computerized treatment evaluation indicated 12-20 glass beads placed in a partial monolayer with a high-viscosity fluid would yield better production increases, eliminate proppant crushing and minimize backflow problems.

Since January 1971, ten partial monolayer treatments have been performed in the Three Bar Field, which have resulted in more than two times the sustained production increase of conventional jobs, and proppant backflow problems have been eliminated. In addition, no proppant screen-out problems were encountered.

The partial monolayer frac technique appears to have particular application in hard rock formations where large fracture flow capacities are needed. Care should be taken in application and design of this technique to assure optimum results.

HISTORY

The Three Bar Field was discovered in 1945 and the Amoco-Operated Three Bar Unit, which comprises the major part of the field production, was formed in 1951. A line-drive water injection pattern was initiated in 1961 and several waterflood expansions were made up through 1971. The Three Bar Unit currently contains 44 producing wells and 17 water injection wells.

RESERVOIR

The Three Bar reservoir is a stratigraphic trap with an average permeability of 5 md and an average porosity of 20%. A typical well contains two 35-ft porous intervals at 8100 ft, which have relatively uniform pay characteristics. The formation is primarily a weathered chert with some lime. The average bottomhole pressure is 1500 psi, the bottomhole temperature is 130°F and the average productivity index in 0.25 BPD per psi drawdown.

FRAC TREATMENTS

Analytical Technique

The production ratio method was used to quantitatively compare the results of the highly successful partial monolayer fracturing technique with the other three major fracturing techniques used in the Three Bar Unit. Production ratio is defined as the ratio of total fluid production at any specific time to total fluid production prior to the frac stimulation.

Tables 1 through 3 and 5 through 6 list monthly well production from three months before to five months after the frac treatments. A set of ratio numbers was calculated for each well, and the ratio numbers were then averaged for each frac category.

This method gives equal weight to each frac job and prevents the results of one high capacity well from controlling the data of the entire category.

The average production ratio numbers for each technique are plotted on Figs. 1 through 3 and 5 through 6. By comparing the extrapolated decline trends prior to stimulation with production after stimulation, the net production gain is determined. The net production increase is shown as units-of-increase. One unit is equal to one production ratio sustained for 30 days. Assuming an average well production of 100 BFPD prior to stimulation, one unit would equal 3000 bbl incremental fluid.

Gelled Water and Sand

Prior to 1968, the primary stimulation was acid. Acidizing, even with hydrofluoric acid, was not very successful in this chert rock. In 1968 and 1969, 12 wells were hydraulically fractured with gelled water and sand. The average treatment consisted of 51,000 gal. gelled brine containing 60,000 lb 20-40 sand. Prior to the frac jobs, the performance was fairly constant. (See Table 1 and Fig. 1). Following the treatment, a production ratio of two was maintained for one month and then production rapidly declined. The incremental increase under the curve represents 3-1/2 units-of-increase.

TABLE 1—GELLED WATER WITH SAND

PRODUCTION PRIOR TO FRAC

	90 DAYS		60 DAYS		30 DAYS		0 DAYS	
WELL	BFPD	PR	BFPD	PR	BFPD	PR	BFPD	PR
A	77	.8	93	1	96	1	92	1
B	93	1.1	100	1.2	74	.9	83	1
C	75	.9	75	.9	75	.9	78	1
D	77	.8	99	1.1	93	1	93	1
E	133	1.0	128	1	111	.8	132	1
F	84	.9	102	1.1	102	1.1	94	1
G	26	1.1	24	1	17	.7	23	1
H	125	1.0	145	1.1	126	1	126	1
I	178	1.6	130	1.2	110	1	112	1
J	40	0.9	41	.9	21	.4	47	1
K	116	1.1	107	1	113	1	108	1
AVERAGE PR		1		1		.9		1

PRODUCTION AFTER FRAC

	30 DAYS		60 DAYS		90 DAYS		120 DAYS		150 DAYS	
WELL	BFPD	PR	BFPD	PR	BFPD	PR	BFPD	PR	BFPD	PR
A	135	1.5	131	1.4	134	1.5	127	1.4	94	1.0
B	161	1.9	328	4.0	234	2.8	150	1.8	170	2.0
C	231	3.0	209	2.7	158	2.0	150	1.9	142	1.8
D	147	1.6	146	1.6	128	1.4	124	1.3	100	1.1
E	215	1.6	321	2.4	265	2.0	188	1.4	222	1.7
F	327	3.5	200	2.1	163	1.7	102	1.1	126	1.3
G	64	2.8	31	1.3	42	1.8	18	.8	18	.8
H	86	.7	187	1.5	150	1.2	141	1.1	168	1.3
I	431	3.8	352	3.1	249	2.2	230	2.1	220	2.0
J	67	1.4	65	1.4	78	1.7	50	1.1	35	.7
K	164	1.5	158	1.5	169	1.6	152	1.4	162	1.5
AVERAGE PR		2.1		2.1		1.8		1.4		1.4

Many of the wells which were fractured with this technique have had repeated problems with sand backflow, causing fill and pump problems. Finely crushed sand has been recovered from the pump barrels. Although the gelled water fracs were economic successes, the sand backflow was causing repeated mechanical problems. Also, the high treatment costs ($11,000) required very long payouts.

Gelled Lease Crude with Sand and Glass Beads

During 1970, four gelled lease crude fracs yielded much better results than the gelled water treatments, (see Table 2 and Fig. 2). The treatments resulted in five units-of-increase (versus 3-1/2 for gelled water), while the treatment cost averaged $7500.

The treatment consisted of 30,000 gal. gelled lease crude containing 40,000 lb 20-40 sand and 2800 lb 12-20 glass beads. It was hoped that the 0.1 ppg glass beads would give enough added strength to the propped fracture to prevent sand crushing and backflow. Crushed frac sand has not occurred in these wells, but some sand backflow and fill problems have occurred. It appears that the high-strength beads prevented sand crushing but allowed the smaller sand particles to be washed out.

TABLE 2—GELLED LEASE CRUDE WITH SAND AND GLASS BEADS

PRODUCTION PRIOR TO FRAC

	90 days		60 days		30 days		0 days	
WELL	BFPD	PR	BFPD	PR	BFPD	PR	BFPD	PR
Q	328	1.4	265	1.1	228	.9	241	1
R	118	1.4	88	1.1	84	1.0	82	1
S	100	3.1	92	2.9	71	2.2	32	1
T	322	1.1	330	1.1	300	1.0	294	1
AVERAGE PR		1.8		1.6		1.3		1

PRODUCTION AFTER FRAC

	30 days		60 days		90 days		120 days		150 days	
WELL	BFPD	PR	BFPD	PR	BFPD	PR	BFPD	PR	BFPD	PR
Q	368	1.5	353	1.5	341	1.4	334	1.4	324	1.3
R	78	.9	72	.9	85	1.0	78	.9	71	.9
S	68	2.1	53	1.7	36	1.1	52	1.6	37	1.2
T	515	1.8	412	1.4	474	1.6	421	1.4	423	1.4
AVERAGE PR		1.6		1.4		1.3		1.3		1.2

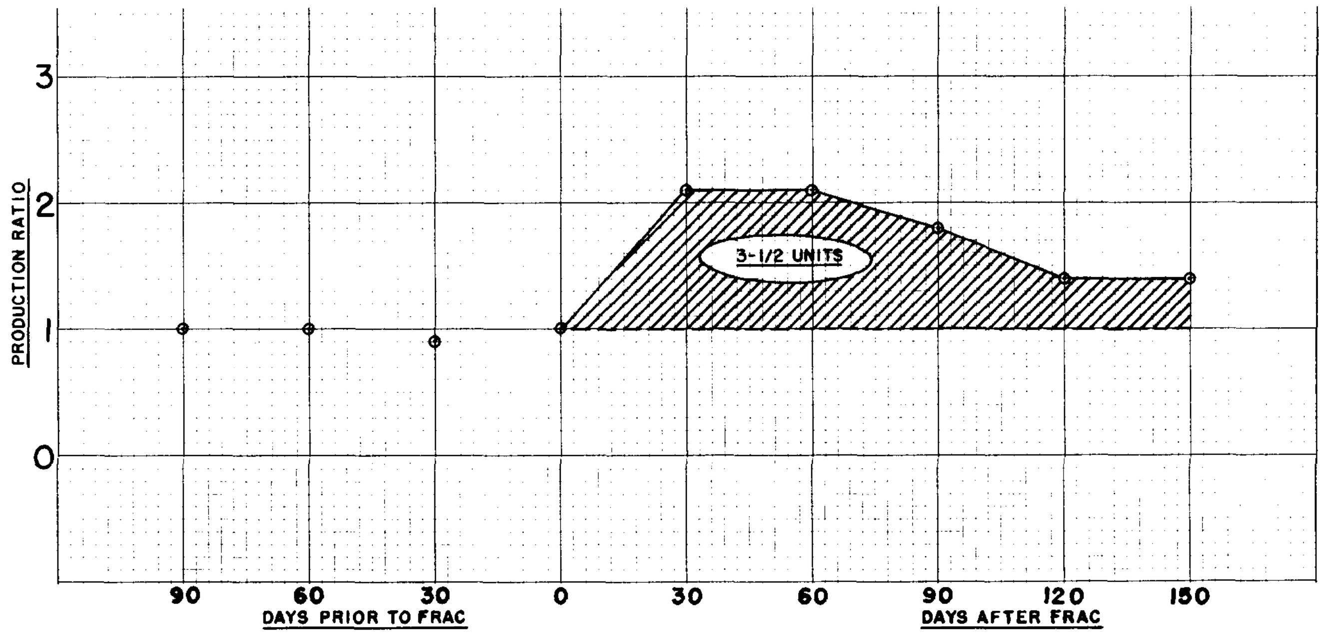

FIG. 1—CHANGE IN AVERAGE PRODUCTION RATIOS USING GELLED WATER WITH SAND

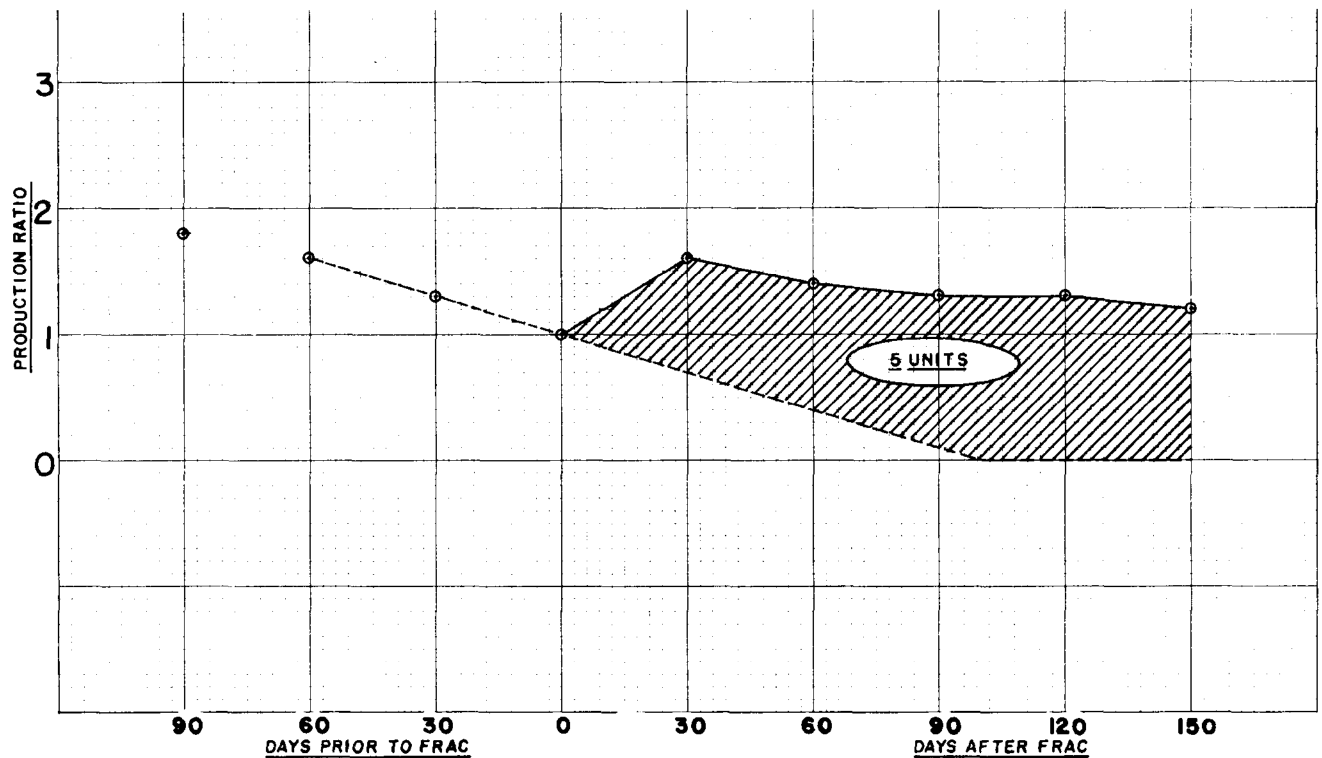

FIG. 2—CHANGE IN AVERAGE PRODUCTION RATIOS USING GELLED LEASE CRUDE WITH SAND AND GLASS BEADS

Multilayer—"Zero" Sand Fall Rate Fluids with Sand

Five multilayer treatments were also performed during 1970. These treatments consisted of high-viscosity cross-linked fluid containing 2 to 3 ppg 10-20 sand. The treatment was designed to pack multilayers of sand throughout the created fracture height and length. The results (see Table 3 and Fig. 3) indicated not as good results (4-1/2 units-of-increase) and a higher treatment cost ($8000) than gelled oil fracs with sand and glass beads but much better results than gelled water with sand treatments. Also, some sand backflow and fill problems occurred following the treatments.

TABLE 3—MULTILAYER—HIGH VISCOSITY FLUID AND SAND

PRODUCTION PRIOR TO FRAC

WELL	90 days BFPD	90 days PR	60 days BFPD	60 days PR	30 days BFPD	30 days PR	0 days BFPD	0 days PR
L	1	.05	5	.23	10	.50	21	1
M	10	1.00	10	1.00	10	1.00	10	1
N	147	1.00	200	1.40	180	1.20	147	1
O	14	.30	20	.40	36	.70	50	1
P	14	1.40	12	1.20	10	1.00	10	1
AVERAGE PR		.70		.80		.90		1

PRODUCTION AFTER FRAC

WELL	30 days BFPD	30 days PR	60 days BFPD	60 days PR	90 days BFPD	90 days PR	120 days BFPD	120 days PR	150 days BFPD	150 days PR
L	18	.9	42	2.0	24	1.1	25	1.2	23	1.1
M	22	2.2	7	.7	7	.7	11	1.1	10	1.0
N	208	1.4	252	1.7	153	1.0	151	1.0	104	.7
O	58	1.2	64	1.3	92	1.8	168	3.4	195	3.9
P	44	4.4	66	6.6	53	5.3	68	6.8	18	1.8
AVERAGE PR		2.0		2.5		2.0		2.7		1.7

Partial Monolayer—"Zero" Sand Fall Rate Fluids with Glass Beads

From the results of the above frac techniques, it was apparent that glass beads and high viscosity fluids had advantages over other techniques in the Three Bar Unit. The first partial monolayer treatment was done in the Three Bar Unit in January, 1971.

The fracturing fluid used is a cross-linked guar gum, water-base gel with an apparent viscosity, under static conditions, greater than 20,000 cp. This fluid possesses thixotropic-like properties; therefore, its apparent viscosity is somewhat shear-dependent. The energy induced by the pumps and tubular goods during the treatment shears the fluid to a flowable state with friction properties that are often much less than those of water. Upon leaving the wellbore and entering the fracture, the fluid reverts from turbulent to laminar flow, and the degree of shear being applied to the fluid is greatly reduced. The fluid responds to this reduction of shear by increasing its apparent viscosity to a point where it affords almost perfect proppant transport. The significance of this is that the effective fracture may be very similar to the created fracture, particularly so in respect to fracture height.

This treatment was designed from core information which indicated a flow capacity of approximately 30,000 md-ft at a proppant concentration of 80 lb 12-20 UCAR Props per 1000 ft of fracture area. These tests were run at a closure pressure of 3500 psi. This was calculated to be a concentration of 0.3 ppg under the treatment conditions.

The fracture height at 25 BPM had been determined from temperature surveys on previous fracture treatments. It was determined to be 100 ft at this rate. The permeability and damage ratio was calculated from pressure buildup tests run on the well. There was no damage indicated by these tests.

A computer design (Table 4) was run using the criteria above. A design was selected which gave a three-fold increase (see Design Number 3, Table 4).

TABLE 4—COMPUTER DESIGN

AMOCO PRODUCTION CO., THREE BAR 60, ANDREWS CO., TEXAS

1% KCL, 20 LBS WAC-9 AND 1 GAL. 15N PER 1,000, DEVONIAN 8290-8377

INJECTION RATE - BBL/MIN		25.0
ASSUMED FRACTURE HEIGHT - FT		100.0
NET FORMATION THICKNESS - FT		56.0
ELASTIC MODULUS - PSI		0.50E+07
FORMATION PERMEABILITY - MD		0.50
FORMATION POROSITY		0.20
BHTP - PSI		5020.
RESERVOIR PRESSURE - PSI		1500.
RESERVOIR FLUID VIS - CP		0.60
CW - FLUID LOSS COEF. - FT/SQRT (MIN)		0.00190
SPURT LOSS - GAL/SQFT		0.
TYPE OF GEL		MY-T-GEL
GEL CONCENTRATION		80 LBS
N-PRIME		0.3000
K-PRIME (SLOT) - LBF-SEC**N/SQFT		1.010000
WELL SPACING - ACRES		80.
DRAINAGE RADIUS - FT		933.
WELLBORE RADIUS - FT		0.200
DAMAGE RATIO		1.0
TYPE & CONC NO 1 PROP	12-20 UCAR	0.30 LB/GAL AVG

DESIGN NO	PROD INCREASE (T)	TOTAL VOL GAL/1000	PAD VOL GAL/1000	PROPPED FRAC LN FT	PROPPED FRAC HT FT	VIS CPS	FRAC WIDTH IN	PROP 1ST SX	PROP 2ND SX
1	2.4	10.0	3.5	144.	100.0	3369.	0.474	20.	0.
2	2.7	15.0	5.2	191.	100.0	3924.	0.529	29.	0.
3	3.0	20.0	7.0	233.	100.0	4372.	0.571	39.	0.
4	3.2	25.0	8.7	273.	100.0	4754.	0.606	49.	0.
5	3.4	30.0	10.5	310.	100.0	5091.	0.637	59.	0.

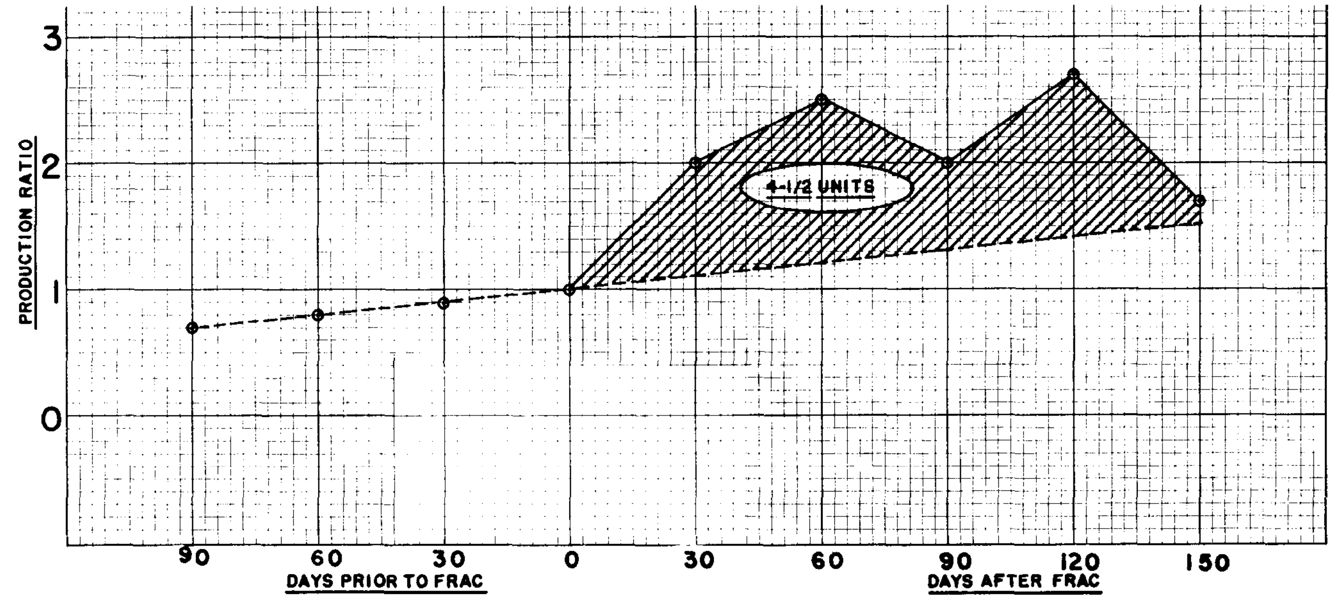

FIG. 3—CHANGE IN AVERAGE PRODUCTION RATIOS USING MULTILAYER-HIGH VISCOSITY FLUID WITH SAND

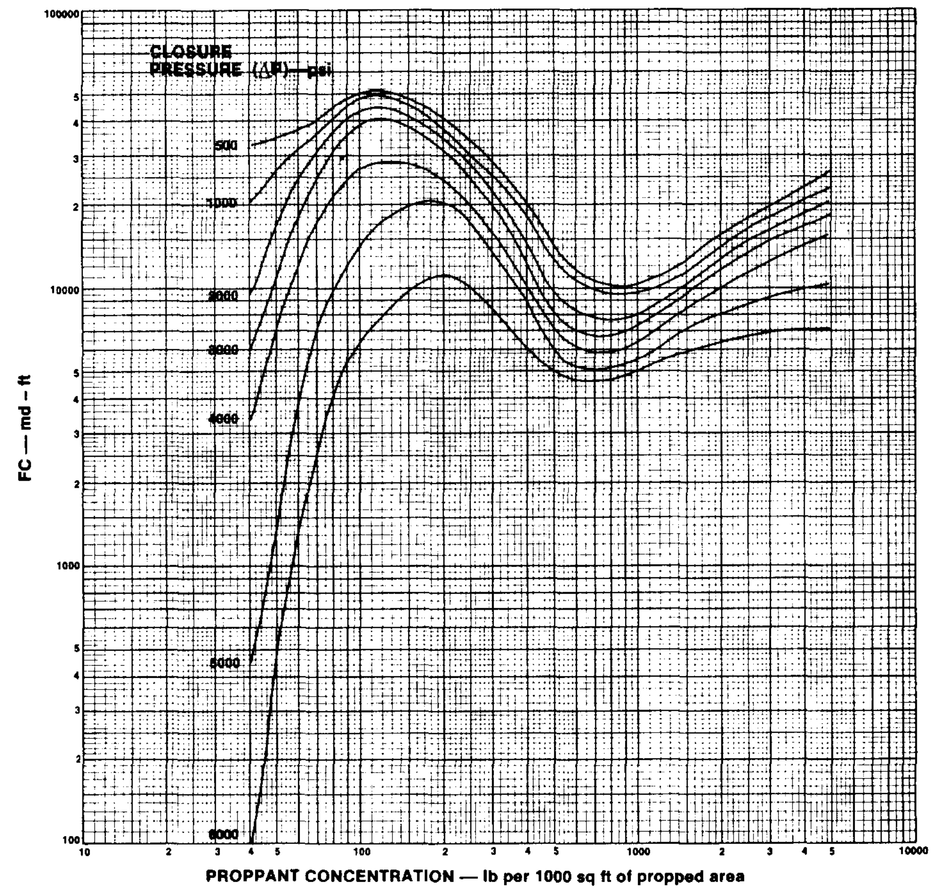

FIG. 4—FRACTURE FLOW CAPACITY VS PROPPANT CONCENTRATION (EXAMPLE COMPUTER DESIGN PROBLEM)

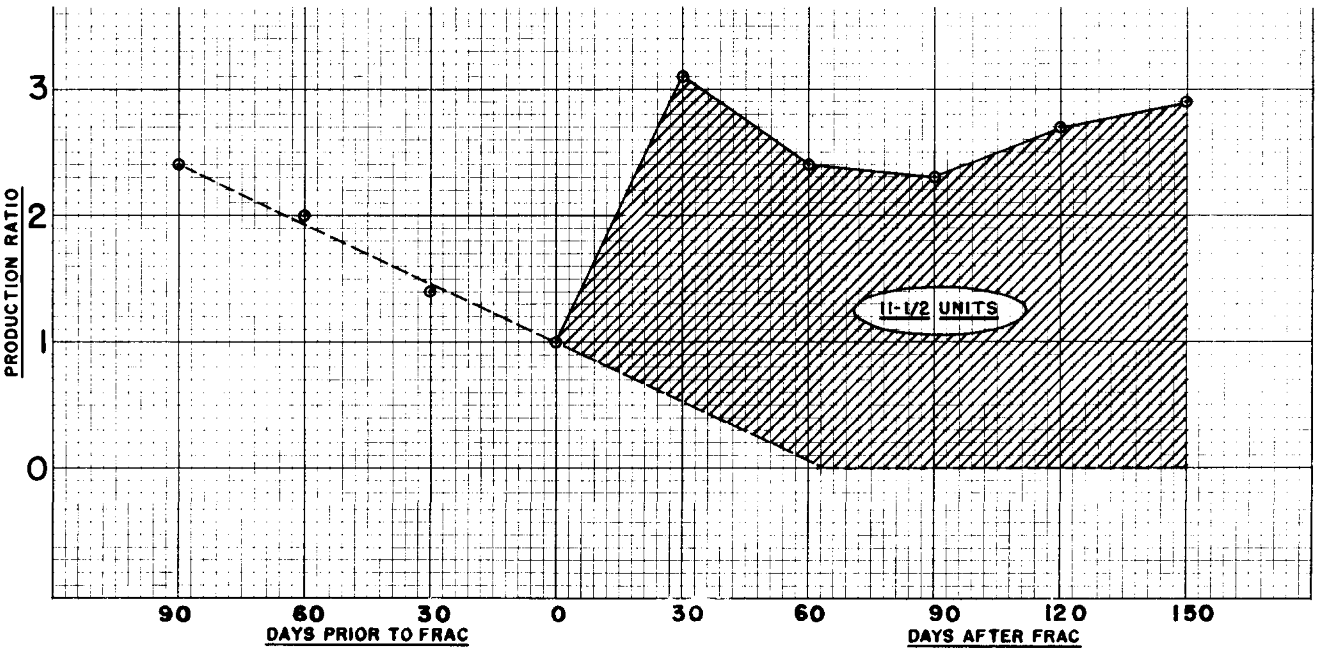

FIG. 5—CHANGE IN PRODUCTION RATIOS USING PARTIAL MONOLAYER-HIGH VISCOSITY WATER WITH GLASS BEADS EXAMPLE ONE.

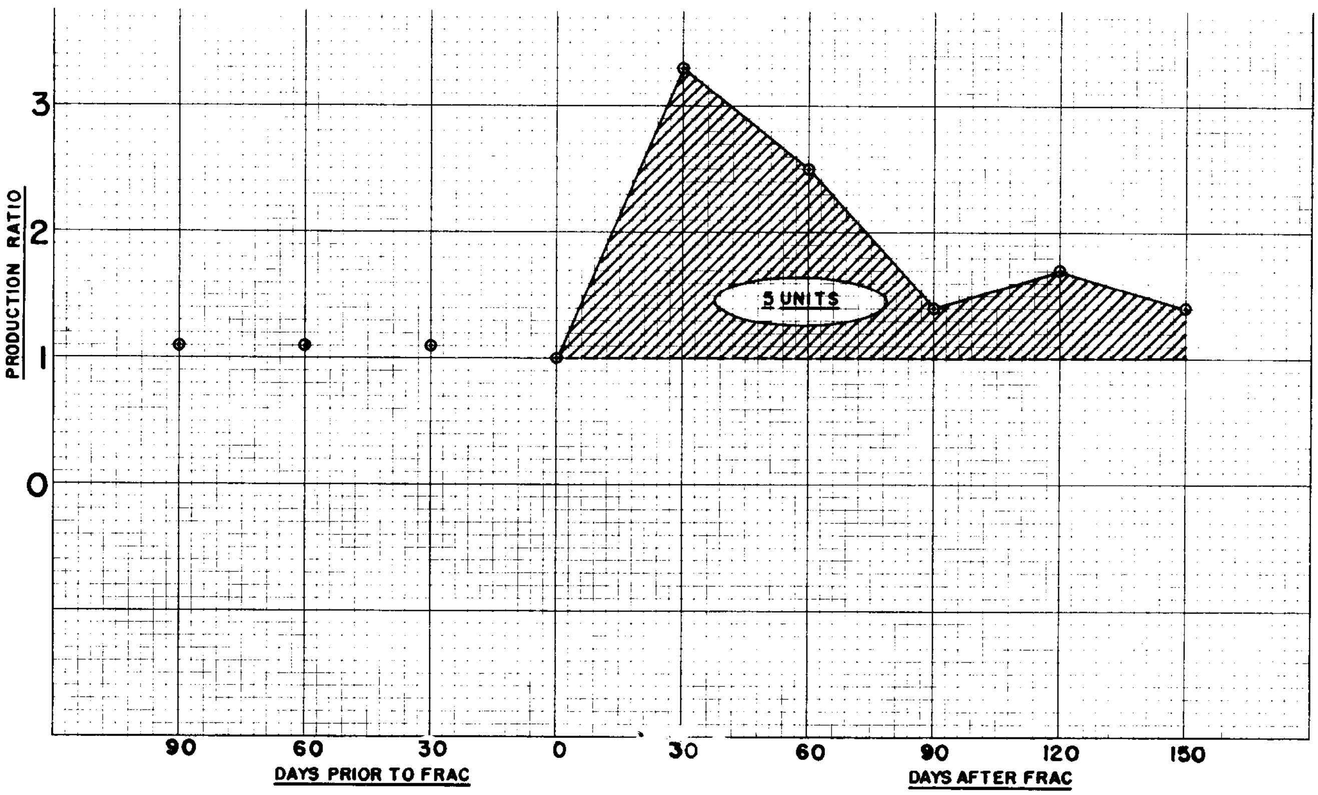

FIG. 6—CHANGE IN PRODUCTION RATIOS USING PARTIAL MONOLAYER-HIGH VISCOSITY OIL AND GLASS BEADS, EXAMPLE TWO

The job was performed as follows:

Average Rate - 24 BPM
Average Pressure - 2300 psi
Job Size - 20,000 gal. Complexed Guar Gum
Propping Agent - 3900 lb 12-20 UCAR Props
Base Fluid - fresh water with 2% potassium chloride

Operation Procedure:

1. 10,000 gal. 2% KCl pre-pad with 500 lb fluid-loss agent
2. 7000 gal. cross-linked guar gum pad
3. 13,000 gal. cross-linked guar gum with 0.3 ppg 12-20 UCAR Props
4. Flush to perforations with 2% KCl (no overflush).
5. Close well in for 24 hours.

The treatment results from this first well were as predicted, and led to further work in the field and general area.

From 1971 through mid-1972, 10 partial monolayer treatments have been performed in which a high-viscosity fracturing fluid was used for placement of a partial monolayer. These jobs resulted in twice the sustained production increase (11.5 units-of-increase) of conventional treatments.

To date there has been no evidence of bead backflow, or any sandout problems on the highly viscous water jobs. Clean-out problems have been eliminated, and more rapid cleanup has been attained with the partial monolayer system than with other jobs. The cost of these jobs has been approximately $8500.

The three partial monolayer treatments using highly viscous oil gave results very similar to the oil fracs (five units-of-increase) but far short of the results of the partial monolayer using water. Apparently, these cross-linked oil-base fluids did not maintain the proper viscosity to place the beads in a partial monolayer. See Tables 5 and 6 and Figs. 5 and 6.

DESIGN PARAMETERS

Type and Competence of the Formation

The formation must resist embedment of the propping agent, as severe embedment can cause the fracture to close completely. A multilayer or packed fracture would be recommended in this case. The other extreme would be a formation which would be so hard as to completely crush the propping agent in a partial monolayer. Laboratory tests can be run to determine if the core is competent to support a partial monolayer.[1]

TABLE 5—PARTIAL MONOLAYER — HIGH VISCOSITY WATER AND GLASS BEADS

PRODUCTION PRIOR TO FRAC

	90 DAYS		60 DAYS		30 DAYS		0 DAYS	
WELL	BFPD	PR	BFPD	PR	BFPD	PR	BFPD	PR
U	100	3.6	74	2.6	15	.5	28	1
V	23	2.9	18	2.3	10	1.3	8	1
W	24	1.3	17	.9	20	1.1	19	1
X	138	1.1	122	1.0	123	1.0	121	1
Y	40	4.0	30	3.0	20	2.0	10	1
Z	60	2.3	66	2.5	67	2.6	26	1
AA	120	1.6	100	1.4	79	1.1	73	1
AVERAGE PR		2.4		2.0		1.4		1

PRODUCTION AFTER FRAC

	30 DAYS		60 DAYS		90 DAYS		120 DAYS		150 DAYS	
WELL	BFPD	PR	BFPD	PR	BFPD	PR	BFPD	PR	BFPD	PR
U	32	1.1	33	1.2	17	.6	17	.6	15	.5
V	69	8.6	36	4.5	30	3.8	31	3.9	24	.3
W	37	1.9	32	1.7	22	1.2	34	1.8	33	1.7
X	276	2.3	258	2.1	243	2.0	207	1.7	203	1.7
Y	37	3.7	31	3.1	41	4.1	61	6.1	94	9.4
Z	49	1.9	66	2.5	70	2.7	72	2.8	72	2.8
AA	160	2.2	108	1.5	122	1.7	124	1.7	79	1.1
AVERAGE PR		3.1		2.4		2.3		2.7		2.9

TABLE 6—PARTIAL MONOLAYER—HIGH VISCOSITY OIL AND GLASS BEADS

PRODUCTION PRIOR TO FRAC

	90 DAYS		60 DAYS		30 DAYS		0 DAYS	
WELL	BFPD	PR	BFPD	PR	BFPD	PR	BFPD	PR
BB	145	.9	140	.9	135	.9	151	1
CC	5	1	5	1	5	1	5	1
DD	134	1.5	123	1.4	110	1.3	87	1
AVERAGE PR		1.1		1.1		1.1		1

PRODUCTION AFTER FRAC

	30 DAYS		60 DAYS		90 DAYS		120 DAYS		150 DAYS	
WELL	BFPD	PR	BFPD	PR	BFPD	PR	BFPD	PR	BFPD	PR
BB	223	1.5	244	1.6	213	1.4	167	1.1	152	1.0
CC	38	7.6	24	4.8	9	1.8	14	2.8	11	2.2
DD	76	.9	92	1.1	92	1.1	92	1.1	92	1.1
AVERAGE PR		3.3		2.5		1.4		1.7		1.4

Selection of the Propping Agent

The selection of the propping agent must be determined from the crushing and embedment tests. Theoretically, the largest diameter propping agent will give the best fracture flow capacity, and field results have indicated this to be true. A careful study to determine the required flow capacities along with laboratory tests should be made for any partial monolayer design.[1]

Fracture Concentration of the Propping Agent

The proppant concentration required is a function of three parameters[1]: (1) closure pressure, (2) strength of the propping agent, and (3) hardness of the formation. (See Fig. 4)

The fracture closure pressure is related to the BHTP and reservoir pressure. It is readily seen from Fig. 4 that at higher closure pressure, crushing and embedment severely affect fracture flow conductivity. Again, a careful study of the reservoir to be fractured is required for partial monolayer designs; crushing and embedment may dictate that a multilayer treatment be performed.[2]

Selection of Fracture Fluid

The fracture fluid must be compatible with the formation and reservoir fluids. The fluid must have the ability to suspend the propping agent in almost perfect transport. It must also have sufficient supporting strength to hold the propping agent in suspension until the fracture closes on the proppant. These are the properties exhibited by the high-viscosity cross-linked fluids.

CONCLUSIONS

1. The Three Bar Unit Devonian formation partial monolayer treatments have proven superior to conventional packed fracture systems, (from a production and economic standpoint).
2. The partial monolayer system and high-strength glass beads have reduced sand backflow problems.
3. A partial monolayer can be placed with high-viscosity cross-linked water-base gels.
4. Partial monolayer treatments can eliminate many sandout problems due to lower concentrations of proppant in the carrying fluid.

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