NVO/0684-1
Distribution Category UC-90a

AN APPLICATION OF MHF TECHNOLOGY TO A TIGHT GAS SAND IN THE FORT WORTH BASIN

Final Report

Archie Crawford and Wesley Ellis

June, 1977

PREPARED FOR
THE ENERGY RESEARCH AND DEVELOPMENT ADMINISTRATION
BARTLESVILLE ENERGY RESEARCH CENTER
CHARLES H. ATKINSON, TECHNICAL PROJECT OFFICER
NEVADA OPERATIONS OFFICE
DORNER T. SCHUELER, CONTRACT ADMINISTRATOR

Dallas Production, Incorporated
Meadows Building
Dallas, Texas

ABSTRACT

This massive hydraulic fracturing treatment was performed on the Ferguson 1A, a marginal Bend Conglomerate gas producer, to test the feasibility of this technique which would be applicable to thousands of similar wells in the Fort Worth Basin.

The proposed treatment was to consist of 138,000 gallons 65 percent foam, 100,000 lb 100 mesh sand, 198,000 gallons gelled water-distillate emulsion and 667,000 lb 10-20 sand. The treatment was to be pumped into five individual zones between 5,957 ft and 6,794 ft. The treatment design called for 1,500 ft of conductive fracture per zone and an average PI contrast of 7.9 per zone.

The treatment commenced on September 14, 1976, and concluded on September 16, 1976. The casing ruptured on September 14, after placing 87,000 gal foam, 67,000 lb 100 mesh sand, 52,000 gal emulsion, and 151,000 lb 10-20 sand. Repair and clean up operations were completed on the 16th and an additional 51,800 gal of foam, 38,000 lb 100 mesh sand, 146,000 gal emulsion, and 250,000 lb 10-20 mesh sand were pumped.

The well has been recovering the frac load since September 17, 1976, and has recovered 3,426 bbl out of 7,144 bbl total load. Initial measured gas flow was 135 Mcf/D but has declined to 15 Mcf/D currently. It appears that this technique is probably not economically feasible.

INTRODUCTION

The Ferguson 1A is owned by Dallas Production, Incorporated and was drilled and completed in 1973. While this well was currently producing, its productive capacity was less than desirable considering the gross zone footage open for production. The pay zone for this well is the Bend Conglomerate which occurs widely in a four county area in the Fort Worth Geological Basin in Texas Railroad Commission Districts 9 and 7B. Except for specific wells where porosity development is unusual, this type well performance is quite common. Our experience in the Gas Finders Field in over sixty (60) wells indicates a stabilized production of less than 150 Mcf/D per well. In a group of seventy-nine (79) wells owned and operated in the Boonsville and Gas Finders Field in Denton and Wise Counties, forty-eight (48) of these wells had a productive capacity of less than 100 Mcf/D in February, 1976. In the Boonsville Field proper there are 1,400 wells producing from the Bend Conglomerate.

PROPOSED TREATMENT

Dallas Production Company, Inc.

Ferguson No. 1A
Gas Finders Field
Wise County, Texas

Pad Stages:

138,500 gal 65% quality foam (2% KCl water + N_2)
100,000 lb 100 mesh sand

Fracturing Stages:

198,000 gal Super K-Frac
132,660 gal crude oil
65,340 gal 2% KCl water
40 lb J-2/1000 gal
25 lb Aquaseal-2/1000 gal
5 gal E-15/1000 gal

667,000 lb 10/20 mesh sand

84 RCN ball sealers

Flush and Temperature Monitoring Fluid:

±30,000 gal
1 gal Aqua Flow/1000 gal
15 lb J-2/1000 gal

Anticipated Injection Rate:

15 BPM @ 4000 psi
±1500 HHP

FRACTURING PROCEDURE

1. Run base radioactive log.
2. Pump ±5,000 gallons at frac rates.
3. Run radioactive log to define zone and/or zones of interest.
4. Based on information in No. 2 above, select stage 1 volume based on:

Table 1

Zone	Estimated Gross Fracture Height	Pad (Foam)	Frac (Super K)	Proppant
1	10	7,500	8,000	25,000
2	30	23,000	30,000	101,000
3	40	31,000	42,500	148,000
4	40	31,000	42,500	148,000
5	70	56,000	75,000	245,000

(See individual zone sand schedules.)

5. Frac with first stage selected from No. 4 above based on radioactive survey.
6. Run ball stage equal to number of holes open in zone +20%. Place sealers in 2% KCl water, pump pipe capacity then slow injection rate to ±6 BPM and pump 60 bbl overflush.
7. Slow rate to between 1 and 2 BPM to keep sealers seated and run radioactive survey to define zone or zones of entry for second stage.
8. Pump second stage in accordance with information derived from radioactive survey and Table 1.
9. Repeat Step No. 6.
10. Repeat Step No. 7.
11. Pump third stage as per Table 1.
12. Repeat Step No. 6.
13. Repeat Step No. 7.
14. Pump fourth stage as per Table 1.
15. Repeat Step No. 6.
16. Repeat Step No. 7.
17. Pump fifth stage as per Table 1.
18. Flush with slick water + 1000 scf N_2.
19. Shut-in one (1) hour and commence load recovery.

SAND SCHEDULES

Sand Schedule

Zone 1

6,519 - 6,525 (Gross Fracture Height = 10 ft)

Pad stage to consist of 8,412 gal foam containing 5,880 lb 100 mesh sand staged as follows:

Six (6) stages of 912 gal each (319 gal water through blender).

Five (5) stages of 588 gal each containing 2 lb/gal 100 mesh sand (206 gal water through blender, sand concentration at blender 5.7 lb/gal).

Fracturing stage to consist of 8,000 gal Super K-Frac and 25,000 lb 10/20 mesh sand pumped as follows:

1. Pump 1,000 gal @ 1 lb/gal
2. Pump 1,000 gal @ 2 lb/gal
3. Pump 2,000 gal @ 3 lb/gal
4. Pump 4,000 gal @ 4 lb/gal

Sand Schedule

Zone 2

6,302 - 6,316 (Gross Fracture Height = 30 ft)

Pad stage to consist of 23,000 gal foam containing 16,667 lb 100 mesh sand staged as follows:

Six (6) stages of 2,444 gal each (855 gal water through blender).

Five (5) stages of 1,667 gal each containing 2 lb/gal 100 mesh sand (583 gal water through blender, sand concentration at the blender 5.7 lb/gal).

Fracturing stage to consist of 30,000 gal Super K-Frac and 181,000 lb 10/20 mesh sand pumped as follows:

1. Pump 3,000 gal @ 1 lb/gal
2. Pump 3,000 gal @ 2 lb/gal
3. Pump 4,000 gal @ 3 lb/gal
4. Pump 20,000 gal @ 4 lb/gal

Sand Schedule

Zones 3 and 4

6,786 - 6,794
5,957 - 5,982 (Gross Fracture Height = 40 ft)

Pad stage to consist of 31,000 gal of foam containing 21,740 lb 100 mesh sand staged as follows:

Six (6) stages of 3,355 gal each (1,174 gal water through blender).

Five (5) stages of 2,174 gal each containing 2 lb/gal 100 mesh sand (760 gal water through blender, sand concentration at blender 5.7 lb/gal).

Fracturing stage to consist of 42,500 gal Super K-Frac and 146,000 lb 10/20 mesh sand pumped as follows:

1. Pump 3,000 gal @ 1 lb/gal
2. Pump 4,000 gal @ 2 lb/gal
3. Pump 5,000 gal @ 3 lb/gal
4. Pump 30,000 gal @ 4 lb/gal

Sand Schedule

Zone 5

6,126 - 6,138 (Gross Fracture Height - 70 ft)

Pad stage to consist of 56,000 gal foam containing 40,580 lb 100 mesh sand staged as follows:

Six (6) stages of 5,951 gal each (2,083 gal water through blender).

Five (5) stages of 4,058 gal each containing 2 lb/gal 100 mesh sand (1,420 gal water through blender, sand concentration at the blender 5.7 lb/gal).

Fracturing stage to consist of 75,000 gal Super K-Frac and 245,000 lb 10/20 mesh sand pumped as follows:

1. Pump 5,000 gal @ 1 lb/gal
2. Pump 5,000 gal @ 2 lb/gal
3. Pump 10,000 gal @ 3 lb/gal
4. Pump 50,000 gal @ 4 lb/gal

TREATMENT DESIGN SUMMARY

Reservoir Parameters:

Avg. K = .25 md

ϕ = 10%

BHP = 1,283 psi (original)

Avg. BHFP = 3,700 psi

BHT = 135°F

Zone	Gross Frac Height feet	Perforation Interval feet	Number Perforations
1	10	6519 - 6525	12
2	30	6302 - 6316	14
3	40	6786 - 6794	16
4	40	5957 - 5982	16
5	70	6120 - 6138	12
	190		70

Assumed spacing = 320 A $\qquad r_e$ = 1867 ft

Estimated Reservoir Improvement
on
Original Stimulation Treatment

Zone	Penetration feet	L/r_e	Permeability Contrast inches	PI Contrast
1	1846	.98	33,600	6.2
2	659	.35	33,600	5.22
3	491	.26	33,600	3.8
4	491	.26	33,600	3.8
5	293	.16	33,600	3.1

Estimated Reservoir Improvement after Proposed Stimulation Treatment

Zone	Penetration feet	L/r_e	Permeability Contrast inches	PI Contrast
1	1500	.8	196,000	11.8
2	1500	.8	196,000	11.8
3	1500	.8	196,000	11.8
4	1500	.8	196,000	11.8
5	1500	.8	196,000	11.8

Average Productivity Increase from Original Treatment:

PI Contrast (Avg) = 3.9

Average Productivity Increase from Proposed Treatment:

PI Contrast = 11.8

Approximate Average Daily Production as of January 28, 1976:

Q_o = 50 Mcf/day

Predicted Post-Frac Production:

$$Q_a = (11.8 - 3.9)\ 50 \text{ Mcf}$$
$$= 395 \text{ Mcf/day}$$

Predicted Additional Production from Re-Stimulation:

$$Q_a - Q_o = 395 \text{ Mcf/day} - 50 \text{ Mcf/day}$$
$$= 345 \text{ Mcf/day}$$

Assuming a 10% decline per year for 5 years, the additional gas recovered by re-stimulation would be:

440,737.5 Mcf

DISCUSSION OF TREATMENT DESIGN

As a first step, a detailed study of the electrical log from the Ferguson 1 A was made for an estimate of the probable fracture heights during the original stimulation treatment as shown in Exhibit 1 and Exhibit 2. From this examination it was estimated that the individual zones had estimated gross fracture heights ranging from 10 to 70 feet. These detailed heights are listed in the Treatment Design section. Using the detailed inputs from Exhibit 2 and known or estimated formation parameters, a series of computer programs was run to predict the fracture length into each zone on the original treatment. From the measured conductivity of 20/40 frac sand at 3700 psi (Figure 1) and the pumping widths and correcting for spacing, a permeability contrast of 33,600 inches per zone was calculated. These computer runs are shown in detail and labeled Exhibit 3. Using the calculated lengths and the permeability contrast, the PI Contrast for each zone was calculated after the method of McGuire and Sikora (Figure 2). These PI Contrasts range from a high of 6.2 in the case of the 10 foot high fracture to 3.1 in the case of the 70 foot zone. The stabilized rate of ±47 Mcf/D for the Ferguson 1 A then represents the amount of stimulation improvement gained on the original treatment after flush production.

Now, in order to study the effects of massive fracturing, we have assumed a penetration of 1500 feet which by the generally accepted definition defines the minimum penetration necessary. Using preliminary programs for a width estimate and substituting 10/20 sand for 20/40 sand, the corrected permeability contrast is calculated as 196,000 inches. On this basis we can calculate that the productivity per zone, if these penetrations had been achieved, would be a PI Contrast of 11.8 if performed on an initial treatment. These projections are shown on the design summary.

This projection of improvement is the degree of improvement that could be expected from a new well. An average PI improvement for the original treatment was calculated by a ratio of zone height over total pay multiplied times the estimated PI Contrast per zone. The average PI Contrast calculated by this method was 3.9. Now, the net improvement expected will be the difference between the new PI Contrast of 11.8 and the old PI Contrast of 3.9. This would indicate a gain in productivity of 7.9 for a fracture length per zone of 1,500 feet and a 10/20 sand pack.

This net gain in PI Contrast when applied to an approximate stabilized flow of 50 Mcf/D should increase production to 395 Mcf/D for a net gain of 345 Mcf/D. Experience in tight gas sands shows that once stabilized production is achieved, as in this case, that further decline is very slow. A resonable figure for yearly decline, in this case, is estimated as 10% per year. This projection would indicate that an increase in recovery of 440,737 Mcf is possible in five (5) years if the massive fracturing effort is successful.

The factors necessary for successful re-stimualtion of the Bend Conglomerate are:

1. The fluids used must have extremely low leak-off characteristics.

2. The fluids must create sufficient fracture width to place large quantities of 10/20 mesh frac sand.

3. The fluid selected for sand placement must be capable of transporting the sand 1,500 feet from the wellbore.

4. They must be readily recoverable from the formation.

5. Positive control of fluid entry must be exerted so that each zone is stimulated to 1,500 feet.

In selecting the fluids, a decision was made to use a two-component treatment utilizing specialized fluids for pre-pad and sand placement. In this way the unique properties of each fluid can be utilized to perform its function.

The fluid selected for the pre-pad is a stable foam utilizing 35% by volume of 2% KCl water and 65% by volume N_2 gas. This product is widely used in fracturing, since a minimum of liquid is introduced into the formation and the gas portion helps purge the formation of this liquid quite rapidly. Among its properties are:

1. An extremely low leak-off coefficient for maximum fracture penetration.

2. Good viscosity for creating fracture width.

3. The ability to unload rapidly due to its gas lift and purging effect.

The foam's main drawback is its inability to place high proppant concentrations since the fluid portion only comprises 35% of the total volume and the sand must be added to this portion. Since the function of the pre-pad is to create penetration and width prior to sand placement, this limitation is overcome. The 100 mesh sand is added to the pad portion to seal any hairline fractures that are encountered and to contribute to the total fracture conductivity. This technique is widely used in fractured reservoirs where deep penetration is desired. Further details on foam are contained in the products section following this discussion.

The fluid proposed to place the proppant is known by The Western Company trade designation as Super K-Frac and consists of a gelled water external-oil internal emulsion in a ratio of 33% water to 67% oil. This well known fluid is marketed under various trade names by service companies and is a patented product of Exxon Production Research. It has been used widely in massive hydraulic fracturing efforts in various areas of the country. Its detailed properties are listed in the products section following the discussion. Previous experience in the Bend Conglomerate indicates that wells treated with this fluid respond significantly better than with other conventional fluids. This fluid exhibits all the attributes required to meet our design goals, namely low leak-off, excellent sand transport, long term stability and the creation of wide fractures. Experience in this area indicates a recovery of 50% to 60% of the oil phase pumped but it is felt that the foam pre-pad will result in a much higher recovery of the oil phase.

Exhibit 4 is a series of computer runs made for the purpose of selecting appropriate volumes of foam and Super K-Frac fluids. A program for each estimated fracture height was run with a requirement for 1,500 feet of penetration of the Super K-Frac fluid per zone. The following table shows the required fluid volumes and proppant amounts per zone:

Table 2

Zone	Frac Height	Interval	Perf's	Pad	Frac	10/20 Sand
1	10	6519-6525	12	7,500	8,000	25,000
2	30	6302-6316	14	23,000	30,000	101,000
3	40	6786-6794	16	31,000	42,500	148,000
4	40	5957-5982	16	31,000	42,500	148,000
5	70	6120-6138	12	56,000	75,000	245,000

If the fluid is distributed in the zones in the above manner then our 1,500 feet objective will be met and the projected improvements may be realized.

To achieve the selectivity requirement we propose to combine radioactive surveys to identify zone heights with stages of ball sealers in a continuous manner with each successive stage of sealers being held on the perforations by slow injection while successive surveys are run. While this procedure will be slow and tedious, it is within the state-of-the-art and is considered more desirable than the only available option; positive isolation with packers and bridge plugs. Using positive isolation, five separate treatments must be performed with the work spread out over a long period of time and the attendant expense of repeated equipment and rig charges.

Details of the proposed operations are contained in the fracturing procedure and proposal.

PRODUCT DESCRIPTION LIST

Name	Description	Purpose
Foamex	Blend of anionic and non-ionic surfactants.	Used to foam and aerate water to produce viscosity, reduce liquid volume and aid in recovery of load water.
J-2	Guar Gum (natural polymer).	Gelling agent for water.
Aqua Flow	Nonionic surfactant for water.	Demulsifier and surface tension reducer.
E-15	Liquid cationic emulsifier.	Emulsifier for Super K-Frac fluid system.
Aquaseal-2	Fluid loss additive for water.	Fluid loss control.
Super K-Frac	Gelled water external oil internal emulsion. Generally composed of 1/3 gelled water and 2/3 oil plus an emulsifier.	A high viscosity, stable fracturing fluid with low to moderate friction reduction. Good sand carrier. Very popular due to low cost for fluid properties achieved.
West-Foam	Fracturing fluid composed of 35%± water, 65%± N_2 plus foaming agent forming a stable foam.	Used where fast load recovery is important, where water sensitivity exists, or in low bottom hole pressure situations. Features good viscosity and low leak-off. Continuously mixed.
KCl	Potassium Chloride.	Used as a clay swelling preventative.

PRELIMINARY SURVEY

A flowing continuous survey was run by Schlumberger on September 3, 1976, to define the relative contribution of each zone treated. Since no back pressure was held at the surface the production rate to the atmosphere was 258 Mcf. The following table shows the flow from each zone.

Zone (ft)	Surface Production (Mcf)	% Total Production
5957 - 5982	0	0
6126 - 6138	57	22
6302 - 6316	86	33
6519 - 6525	115	45
6786 - 6794	0	0

The well was then shut in until September 7, 1976, and the survey rerun. Due to the unstable condition of the well, the surface flow varied from a high of 676 Mcf to a low of 211 Mcf toward the end. The following table shows the flow from each zone.

Zone (ft)	Surface Production (Mcf)		% Surface Production
	High	Low	
5957 - 5982	0	0	0
6126 - 6138	57	19	12 - 10
6302 - 6316	28	37	6 - 16
6519 - 6525	211	94	45 - 45
6786 - 6794	169	61	36 - 29

A temperature survey was run in conjunction with the spinner survey but no qualitative information could be gained due to poor definition of the logs.

The results of this survey seem contradictory since the flow from the zone at 6302 - 6316 ft has definitely decreased and after a flow period the flow from the zone at 6125 - 6138 ft has also decreased. This is possibly due to different pressure gradients in the other zones with the possibility of some cross flow occurring.

It is notable that the bottom zone at 6786 - 6794 ft shows appreciable flow on the second survey although it is covered with frac sand from the original treatment. This frac sand was removed from the well prior to the treatment.

In any event, the results of the second survey were not known prior to the treatment and therefore were not used in any subsequent decisions.

Details of the surveys are shown in Exhibit 5.

TREATMENT PERFORMANCE

The actual pumping operation began at 6:50 AM on September 14, 1976, by loading the casing with 2% KCl water and over-displacing 110 bbl at an injection rate of 15 BPM. The instantaneous shut-in pressure was 1100 psi after this stage. A radioactive trace tool was then run in the hole to the vicinity of the top perforation and pumping was started at 6 BPM. A burst of radioactive tracer material was ejected from the tool and the time required to pass both detectors was measured. In this way the percentage of fluid being taken by each zone was computed by the velocity decrease past each zone. Tool details and pertinent information on each run are shown in Exhibit 6.

The results of this initial survey showed the following distribution:

Zone Depth	Zone No.	Height (ft)	% Fluid	Rate/Zone BPM
5957 - 5982	4	40	30	1.8
6120 - 6138	5	70	54	3.24
6302 - 6316	2	30	1	.06
6519 - 6525	1	10	1	.06
6786 - 6794	3	40	14	.84

Based on this distribution it was decided to pump the required fluid and sand volumes for zones 4 and 5 (5957-82 and 6120-38). After these stages were pumped sufficient ball sealers were to be run to seal these zones (34 ball sealers) then another radioactive survey was to be run to determine the next stage volume depending on the new distribution.

The required volume for these two zones was as follows:

87,000 gal 65% quality foam
62,000 lb 100 mesh sand

117,500 gal emulsion
393,000 lb 10-20 mesh sand

This stage commenced at 9:50 AM and the foam was displaced at 15 BPM at 3400 psi without incident. The emulsion and 10-20 sand stage began at 12:01 PM with a sand concentration of 1 lb/gal at a pressure of 3000 psi and an injection rate of 20 BPM. Successive increments were pumped at 2 lb/gal sand and 3 lb/gal sand and 4 lb/gal sand was started at 12:46 PM with the pressure at 3400 psi and a rate of 19 BPM. From this point the pressure increased to 3900 psi and the rate was decreased to

10 BPM to stay under the 4000 psi allowable pressure. This occurred at 1:17 PM and since a screen-out seemed imminent an attempt was made to flush the casing with 2% KCl water. At 1:24 PM the pressure had increased to 4000 psi and the rate had declined to 7 BPM at which point the casing ruptured. It was decided to continue the flush since it was not known with certainty at this point that a rupture had occurred. When the flush was completed an ISIP of 1200 psi was observed which was consistent with the known bottom hole fracture pressure.

A radioactive velocity profile was run and a hole was found to be in the casing between 4000 and 5000 ft. It was decided to run 2 3/8 in. tubing to reverse circulate the sand from the hole and then to run 2 7/8 in. tubing and packer to serve as the conductor for the remaining treatment.

Before the screen-out and rupture occurred we had placed:

87,000 gal 65% quality foam
62,000 lb 100 mesh sand

52,000 gal emulsion
151,000 lb 10-20 mesh sand

Operations were suspended and the well allowed to flow the night of the 14th and into the morning of the 15th when the clean-out operation began.

Clean-out operations were completed during the night of September 15 and the tubing and packer were run on the morning of September 16. The packer was set at 5700 ft.

A radioactive velocity tool was run in the hole at 12:50 PM on September 16. It was found that during the night the bottom set of perforations (6786 - 6794 ft) were covered by sand. This survey also showed the following distributions:

Zone(ft)	Zone No.	% Total Rate	Rate/Zone BPM
5957 - 5982	4	15	.75
6120 - 6138	5	10	.5
6302 - 6316	2	65	3.25
6519 - 6525	1	9	.45
6786 - 6794	3	1	.05

Total surface rate was 5 BPM.

In view of events on September 14, our options seemed to be as follows:

1. To continue with the treatment as scheduled in the proposal and risk not only the stimulation treatment but possibly the well itself.

2. To redesign the sand addition schedule based on what we felt were the probable rock fracture situation and the demonstrated sensitivity of the formation to heavy concentrations of 10-20 mesh sand.

It was further speculated that, despite careful design of the stable foam pad, it had inadequately prepared the fractures for the heavy sand concentrations proposed. For this reason it was suggested that at least a portion of the Super K-Frac should be pumped without sand to further prepare the fractures for sand placement. A consensus judgment and decision was made for the second option and to settle for a more modest sand addition schedule.

Based on the wire line survey, a decision was reached to pump the volume required to the thin zone from 6302-6316 ft with 7500 gal of foam, 5888 lb of 100 mesh sand, 8000 gal of Super K-Frac and a revised schedule calling for 12,000 lb of 10-20 mesh sand. After this stage, 15 ball sealers were to be run and the remaining pad, consisting of 44,000 gal containing 33,000 lb of 100 mesh sand followed by 138,000 gal of Super K-Frac containing 238,000 lb of 10-20 mesh sand was to be pumped. This judgment was based on the fact that when the zone receiving 65% of the injection rate was shut off, the remaining three (3) zones would receive approximate equal increments of injection rate, since both upper zones had received some portion of the frac on September 14 and theoretical distribution per zone could be met except for the bottom zone. Since the bottom zone should have been allocated 148,000 lb of sand, and it wad doubtful that it received any significant portion of fracturing fluid on September 14, then the remaining 4 zones would receive 80% of this allotted sand concentration. In any event, the 10-20 sand concentration, considering all five (5) zones and ignoring the 100 mesh sand, would be in excess of 7/10 lb per square ft of fracture area. This sand concentration is more than adequate to meet the conductivity needs of low permeability rock such as occurs in the Ferguson 1A.

Pumping of the foam pad on September 16 commenced at 3:05 PM and the Super K-Frac/10-20 mesh sand stage was completed at 3:45 PM with an average injection rate of 14 BPM at 7600 psi. At this point, 15 ball sealers and 750 gal of acid were run and the second foam pad stage begun. Pumping of the foam pad was completed at 5:01 PM with an average pressure of 6500 psi and average injection rate of 15 BPM.

The final stage of Super K-Frac was begun at 5:02 PM and pumping continued until 11:58 PM. At this point injection rate varied between 11 and 15 BPM with an average pressure of 7500 psi. The immediate shut down pressure was 4600 psi.

A final radioactive velocity survey was run beginning at 1:30 AM on September 17. The logging tool touched sand at 6128 ft with the following distributions into the open perforations:

Zone (ft)	% Total Rate
5957 - 5982	82
6120 - 6124	18

Since fill-up already existed to ±6730 ft then during the course of the treatment sand had built up 602 ft in the casing. There is no evidence that from the pressure rate chart that any pumping period could account for the build-up. It can be noted that there was a small but finite loss to the sand fill-up that covered the bottom set of perforations. At 15 BPM this loss would amount to .15 BPM and the sand already in place would act as a filter causing still further build-up of sand. At 9:00 PM pumping operations were suspended for 11 minutes with sand left in the casing due to a blender malfunction and some significant fill could have occurred during this period. Neither of these factors alone could account for the total fill present but the combination of the two added to a very slow fill that could occur during the 8 hour and 45 minute pumping period would easily account for the total fill.

Due to the fill-up, however, it is impossible to predict the final fluid distribution per zone. It is reasonable to say that the top two zones received more than their proportionate share of the total treatment volume. It is also reasonable to assume that the bottom perforations (6786 - 6794 ft) received very little of the total and far less than called for in the original design.

The entire performance of this treatment was complicated by a grossly wrong assumption of bottom hole fracture pressure. Since the zones had been previously isolated and fractured individually, it was felt that the average bottom hole fracture pressure as reflected by the treatments was reasonable for fracturing design. This assumption was probably grossly in error. It appears that the bottom hole fracturing pressure during the treatments steadily increased from the original estimate to a maximum value and then stabilized.

The following illustrates this fact:

	BHFP (psi)	Fracture Gradient (psi/ft)
Estimate based on original treatments	3700	.56
September 14 recorded after wire line survey	3960	.61
September 16 recorded after wire line survey	4760	.73
September 16 post treatment	7460	1.14

In retrospect, it seems improbable that the treatment could have been conducted via the 4 1/2 in. casing on September 14, at pressures below 4000 psi even with a revised sand addition schedule calling for maximum concentrations of under 3 lb/gal.

The unusual sensitivity of these zones to the placement of 10-20 sand is difficult to explain since the computer programs predicted more than adequate width and more than enough fracture volume to accept this quantity of sand. It seems probable that insufficient fracture width played at least some part in the problem. One likely cause of insufficient width might be that our original estimate of fracture height was grossly in error. Although the logs on this well showed good lithological barriers to fracture growth, it seems likely that these barriers were broken which resulted in lower fluid velocity in the fracture which in turn led to significant narrower fractures. The original treatments were performed with gelled water with apparent viscosities on the order of 30 cp whereas the fluid used on this treatment has an apparent viscosity of 150 cp. This five-fold increase in viscosity could place undue stress on the zone boundary causing the fracture to grow out of the zone.

Details of pressure injection rate and volume for events on September 14, 15, and 16 are presented in Exhibit 7.

POST FRACTURING PERFORMANCE

Load recovery commenced at 2:00 AM on September 17, flowing at approximately 10 bbl load per hour. By September 22, the flow had decreased to less than 100 bbl/day and continued to decrease until September 30, at which time total recovery amounted to 1136 bbl. At this point a decision was made to clean the sand fill-up from the hole to uncover the bottom perforations. This operation was completed on October 1, and the tubing and packer were run on October 2. Swabbing operations commenced on October 4, with 240 bbl load being swabbed on this date. Swabbing was discontinued on October 6, and the well flowed 60 bbl of load.

Flow had declined by October 25 to less than 10 bbl per day and by November 1, a decision was made to set a pumping unit and pump the load back. On November 11 the pump and rods were run and preparations were made to begin pumping. Bad weather delayed operations until November 18 when the pump was started. Pump problems developed and the pump failed to pump.

A decision was made to squeeze the hole in the casing in order to allow the load to be pumped via the tubing while allowing the gas to flow via the annulus. It was felt that this would allow faster recovery of the load while some stabilized gas flow could be measured.

These operations were commenced on December 2, 1976, and the hole was located at 4813 ft. A squeeze operation was conducted on December 4 using 100 sacks of cement to a squeeze pressure of 2000 psi. The squeeze packer was pulled and cement was drilled out to the bridge plug by December 8. The bridge plug became stuck at 5440 ft while pulling. Fishing operations were commenced but were unsuccessful, so on December 19 it was decided that the plug would have to be milled over. Subsequent milling and fishing operations continued until January 15, 1977. Tubing and rods were run and pumping started on January 19. See the Daily Operations Report for details of the repair operations.

Initial load production was 40 bbl/D with a gas flow rate of 135 Mcf/D. Since that time through March 25, 1977, recovery has declined to 4 bbl/D with a gas flow of 15 Mcf/D.

Prior to pumping, the well had flowed an estimated 2158 bbl and has since pumped 1268 bbl out of a total load of 7144 bbl. This indicates that approximately 48% of the load has been recovered if fluid lost during the milling and fishing operations is ignored.

It is obvious at this point that the treatment was ineffective in producing reservoir improvement. Also, at this point, the well is nearing the economic limit and may have to be abandoned in the near future. While the exact reasons for this lack of response will never be known for certain, the probable causes would include:

A. An uncontrolled vertical fracture growth during the treatment.

B. A limited reservoir since the Bend is a discontinuous reservoir with erratic development across the trend.

C. Bottom hole pressure was too low to furnish sufficient energy to expel the load even with the aid of N_2.

D. Severe mechanical problems that interfered with both the treatment and subsequent load recovery.

It would appear that this type reservoir is a poor candidate for further utilization of MHF technology. The reasons for this probably involve the geology of the region and reservoir limits rather than the mechanical problems that plagued this operation.

ECONOMIC ANALYSIS

The total estimated cost of performing this treatment, ignoring any salvage value of the oil used to make the emulsion, was $175,536.52.

A breakout of these cost factors is as follows: (See Exhibit 9)

The Western Company of North America	$ 93,917.52
Nitrogen Oil Well Service Company	23,200.00
Schlumberger Well Service	12,540.00
Water and Hauling	2,679.00
Oil Purchase (3200 bbl)	40,000.00
Pulling Unit	3,200.00
	$ 175,536.52

The total actual expenditures were:

Nitrogen Services		
Nitrogen Oil Well Service Co.................	$	23,200.00
Water		
Geer Tank Trucks.............................		3,137.74
Pulling Rig		
Wise Well Service............................		2,775.00
Wise Well Service............................		520.00
Oil		
The Permian Corp.............................		42,444.40
Logging		
Schlumberger Well Service....................		3,946.20
Schlumberger Well Service....................		3,725.89
The Western Company..........................		3,826.52
Fracturing		
The Western Company..........................		93,918.02
Dowell.......................................		896.58
	$	178,390.35
Credit for Oil Salvage.....		(7,592.20)
TOTAL EXPENDITURE..........	$	170,798.15

Additional expenditures as a result of the ruptured pipe and the necessity to clean out the casing and fracture down tubing and under a packer were:

Geer Tank Trucks................................	$	1,359.60
W. H. Dodson - Backhoe Loader.....................		75.00
Bowie Dozer - Dig Pits............................		125.00
Bowie Dozer - Clearing Location...................		100.00
Norvell Trucking - Rock for Entrance..............		380.44
Wise Supply Co. - Stripper Rubber.................		197.69
Wise Supply Co. - 5625 ft 2 3/8 in. Tubing........		17,458.09
Wise Supply Co. - Tubing Head 2 in. Choke and Fittings......................		1,238.08
Scott Construction - Rocking Road.................		240.00
Oilfield Service - Haul Connections and Tubing....		375.00
Baker Oil Tools...................................		1,272.42
TOTAL ADDITIONAL EXPENDITURE.......	$	22,821.32

Additional expenditures incurred as a result of the squeeze and subsequent fishing and milling operations were:

Parts and Connection............................	$	1,963.78
Pulling Unit....................................		5,021.74
Pumping Unit....................................		668.50
Squeeze...		7,396.08
Fishing and Milling.............................		36,264.71
TOTAL.........	$	51,314.81

The total cost of the treatment and subsequent mechanical operations were:

	$ 170,798.15
	22,821.32
	51,314.81
	$ 244,934.28
Less Additional Oil Salvage.....	(7,608.00)
TOTAL EXPENDITURE.......	$ 237,326.28

It was clear that if a reasonable return on this investment was to be gained, then a significant proportion of the projected production increases would have to be met. At a favorable gas price of $2.13/Mcf, we needed a substantial improvement before treatments of this size could become commonplace. The following table illustrates the need for substantial improvement at a total cost of $237,000.00.

PI Contrast	Additional Gas/Day - Mcf	No. of Producing Days Required for Breakeven
7.9 (predicted)	276	403
7	240	463
6	200	556
5	160	695
4	120	927
3	80	1,390
2	40	2,781

If the treatment could have been performed at the estimated cost of $175,536.00, the rate of payout would range between 298 days and 2,060 which still shows the need for substantial increases before this technique would be economically sound.

Since the treatment not only failed to increase production, but actually reduced it to the point where abandonment is being considered, it is clear that this project was an economic failure. Considering replacement well cost at $175,000.00 plus total cost associated with the treatment of $237,000.00, this total investment has only resulted in an indication that this area is not favorable for the application of massive treatments. Considering the potential benefits if the attempt has been successful, we feel that it was still worthwhile.

FIGURE 1

Permeability - Closure stress curves for Heart of Texas sand

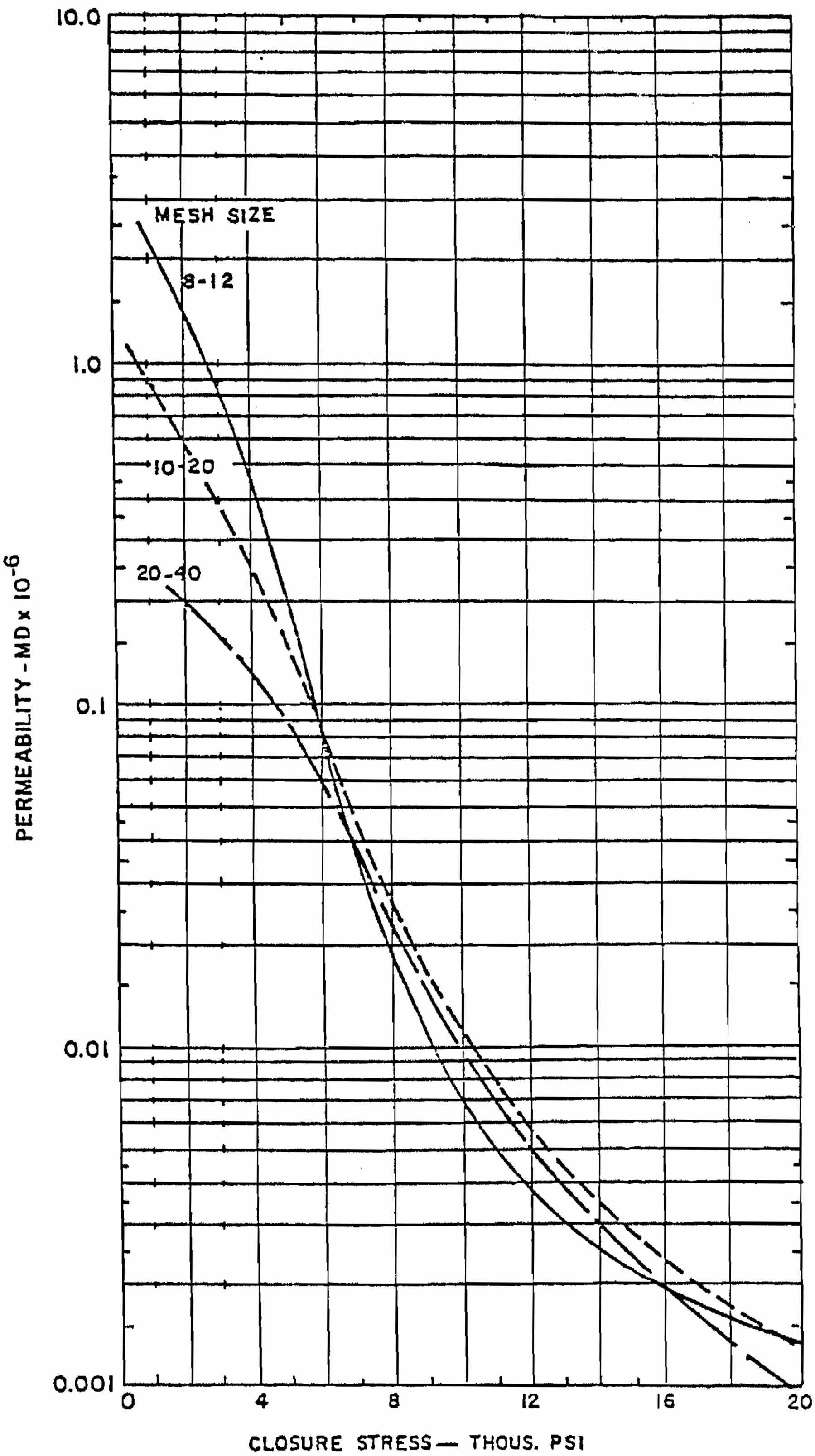
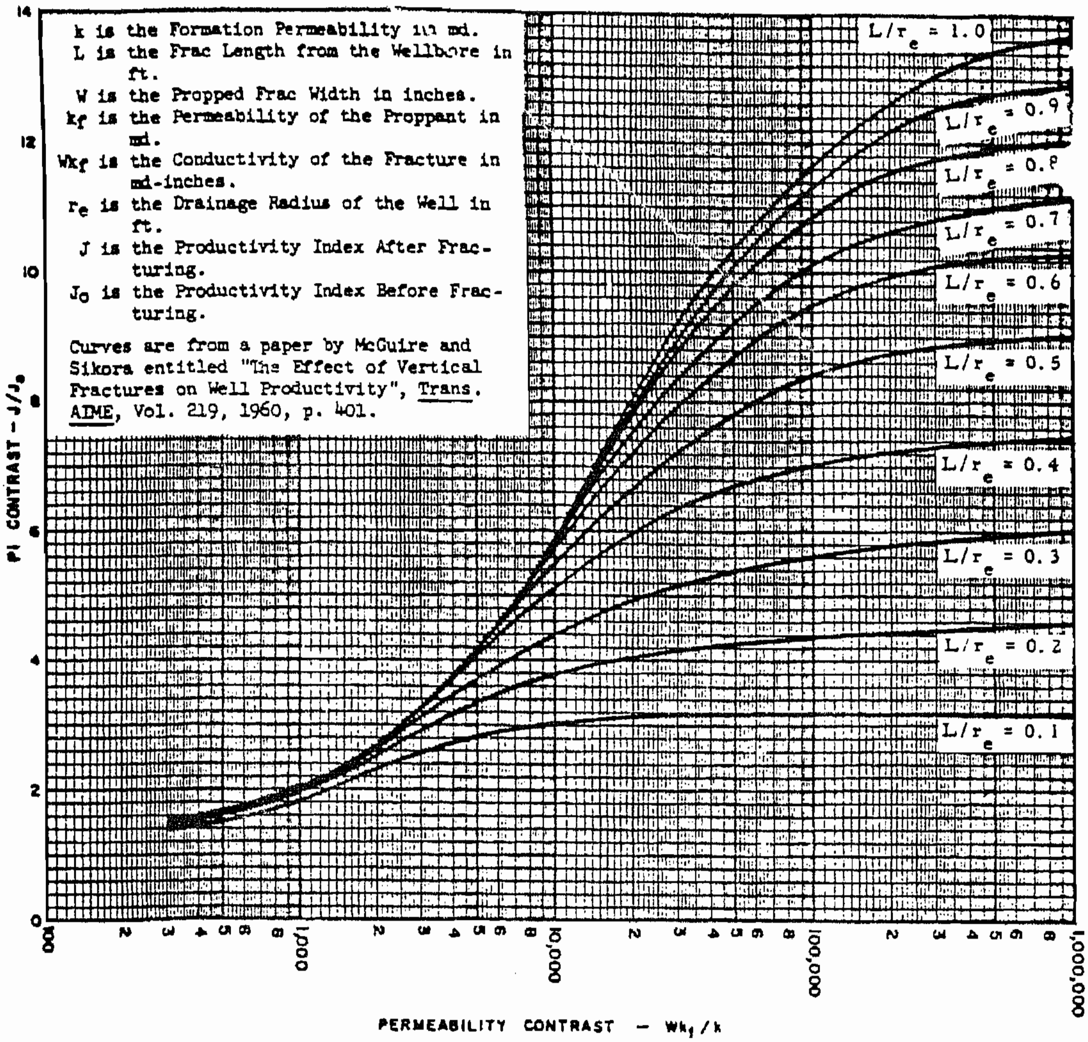


FIGURE 2



INCREASES IN PRODUCTION FROM VERTICAL FRACTURES

Note: This graph is based on a well spacing (A) of 40 acres and a wellbore radius (r_w) of 3 inches. It can be converted to other well spacing and wellbore radii by use of the following scaling factors:

Well Spacing	Drainage Radii	Scaling Factors for Abscissa (Wk_f/k)	Scaling Factors for Ordinate (J/J_o)
For spacing shown and 3-inch wellbore radius.			
10 Acres	330 ft	2.00	1.11
20 Acres	467 ft	1.42	1.05
40 Acres	660 ft	1.00	1.00
80 Acres	933 ft	0.71	0.95
160 Acres	1320 ft	0.50	0.91
320 Acres	1867 ft	0.35	0.87
640 Acres	2640 ft	0.25	0.84
For other spacing (A) and wellbore radii (r_w).			
A	$104\sqrt{A}$	$\sqrt{40/A}$	$\frac{3.095}{\log(.472)(r_e/r_w)}$

Schlumberger INDUCTION-ELECTRICAL LOG

COUNTY	WISE
FIELD or LOCATION	WILDCAT
WELL	FERGUSON NO. 1-A
COMPANY	DALLAS PROD.

COMPANY DALLAS PRODUCTION CO. INC.

WELL FERGUSON NO. 1-A

FIELD WILDCAT

COUNTY WISE STATE TEXAS

LOCATION 1320' FNL, 1320' FEL, BEN D. SMITH SURVEY A-779

Sec.___ Twp.___ Rge.___

Other Services: FDC-ML

Permanent Datum: GROUND LEVEL, Elev. 807

Log Measured From KB, 11 Ft. Above Perm. Datum

Dri[illegible] Measured From KB

Elev.: K.B. 818 D.F. 817 G.L. 807

EXHIBIT 1

Da[te]	12-2-72			
Ru[n No.]	ONE			
De[pth] -Driller	7090			
De[pth] -Logger	7091			
Btm. Log Interval	7090			
Top Log Interval	322			
Casing—Driller	8 5/8@ 308	@	@	@
Casing—Logger	322			
Bit Size	7 7/8"			
Type Fluid in Hole	FGM			
Dens. | Visc.	9.5 | 210			
pH | Fluid Loss	- | - ml	ml	ml	ml
Source of Sample	MUDPIT			
R_m @ Meas. Temp.	2.30@ 78 °F	@ °F	@ °F	@ °F
R_{mf} @ Meas. Temp.	2.20@ 78 °F	@ °F	@ °F	@ °F
R_{mc} @ Meas. Temp.	- @ - °F	@ °F	@ °F	@ °F
Source: R_{mf} | R_{mc}	M | -			
R_m @ BHT	1.32@ 135°F	@ °F	@ °F	@ °F
Time Since Circ.	3 HRS.			
Max. Rec. Temp.	135 °F	°F	°F	°F
Equip. | Location	5662 | WES			
Recorded By	DELAY			
Witnessed By	MR. CRAWFORD, MARTINEAU			

FOLD HERE — The well name, location and borehole reference data were furnished by the customer.

CHANGES IN MUD TYPE OR ADDITIONAL SAMPLES

Date | Sample No.				
Depth - Driller				
Type Fluid in Hole				
Dens. | Visc.				
ph | Fluid Loss		ml		ml
Source of Sample				
Rm @ Meas. Temp.	@	°F	@	°F
Rm @ Meas. Temp.	@	°F	@	°F
Rm @ Meas. Temp.	@	°F	@	°F
Source: Rmf | Rmc				
Rm @ BHT	@	°F	@	°F
Rm @ BHT	@	°F	@	°F
Rm @ BHT	@	°F	@	°F

SCALE CHANGES

Type Log	Depth	Scale Up Hole	Scale Down Hole

EQUIPMENT DATA

Run No.	ONE			
Panel No.	H 434			
Cart. No.	F 376			
Sonde No.	M 334			
Mem. Panel No.	B 123			
G.R. Cart. No.				
G.R. Panel No.				
TTR No.				
Cent. Device	USED			
Stand off - Inches	1.5"			
Time Const - Sec.				
Speed - F.P.M.				

REMARKS

Service Order No. - 73026

API Serial No. -

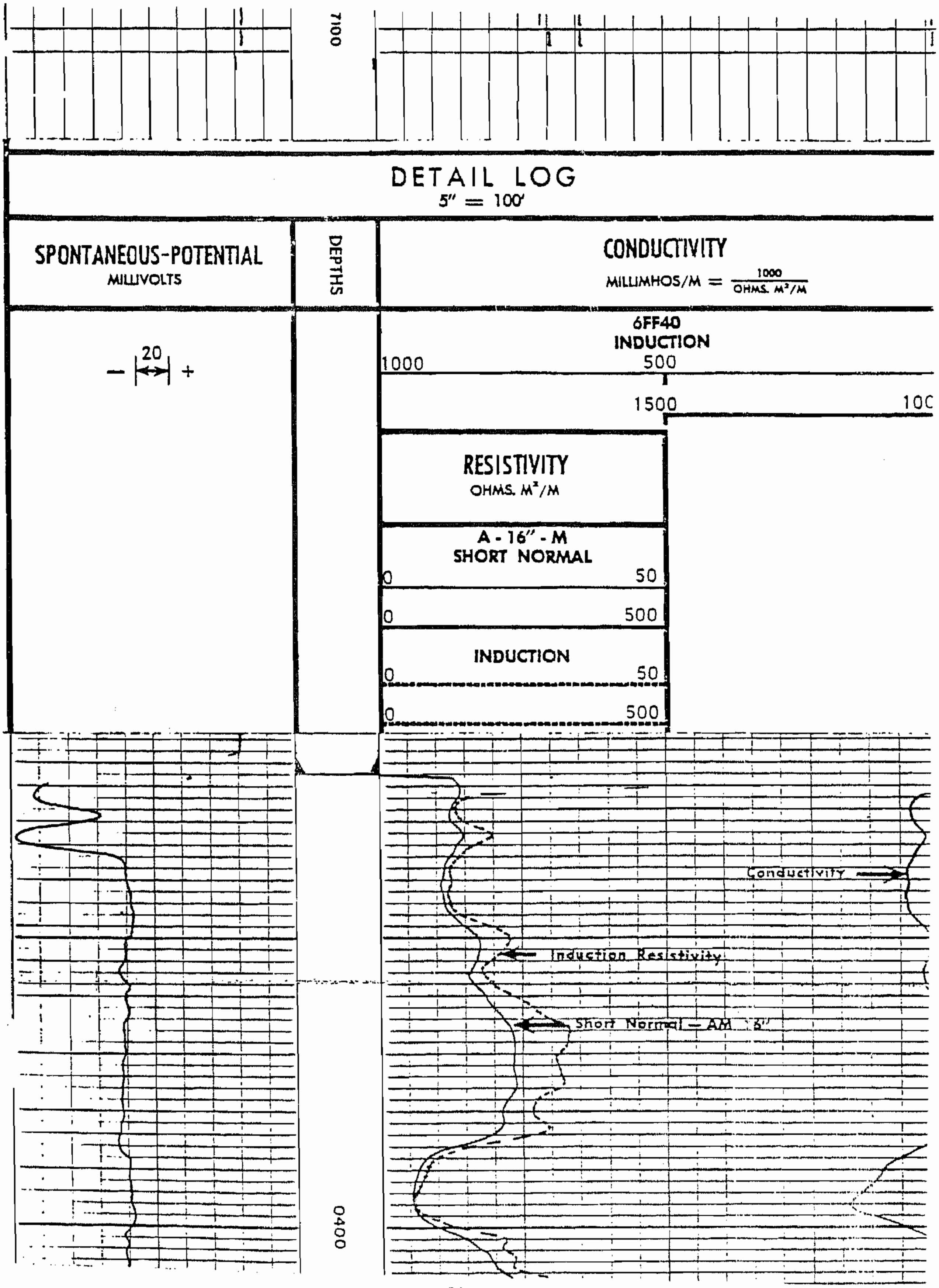
☒ Surface determined sonde errors used for 6FF40.

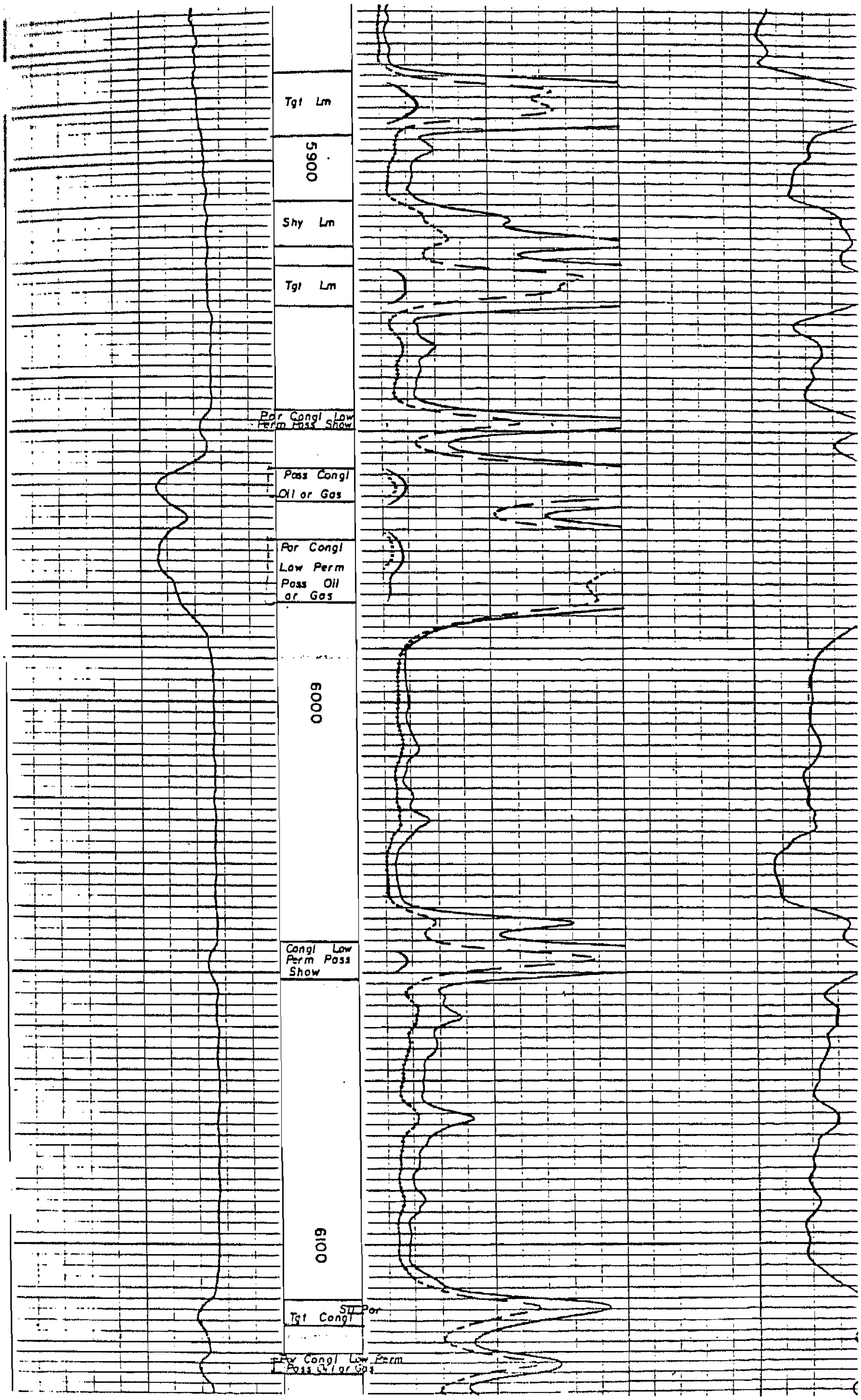
☐ 6FF40 sonde error corrected for ___ inch borehole signal at Rm =

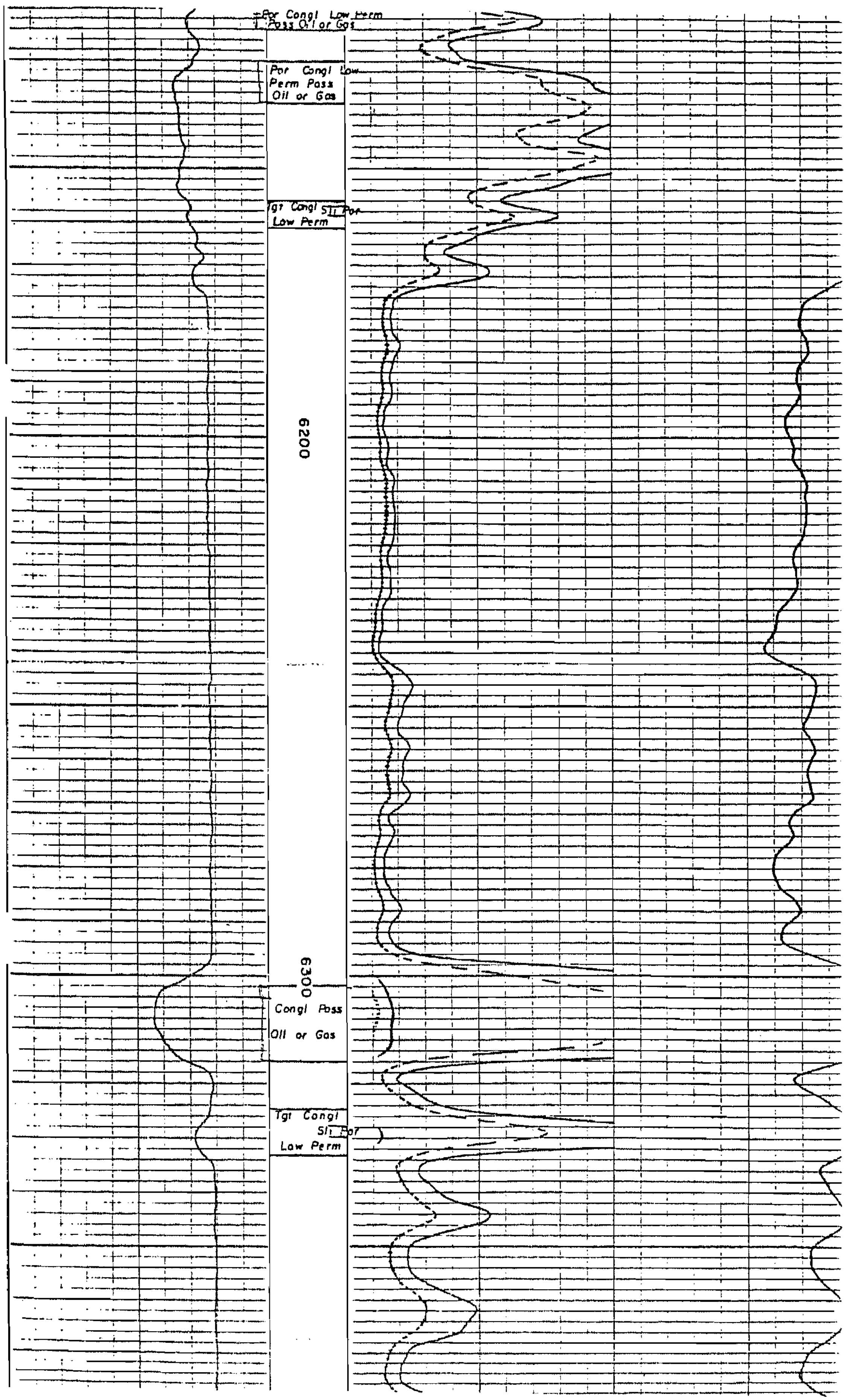
☐ 6FF40 zero set in hole at depth of ___ feet.

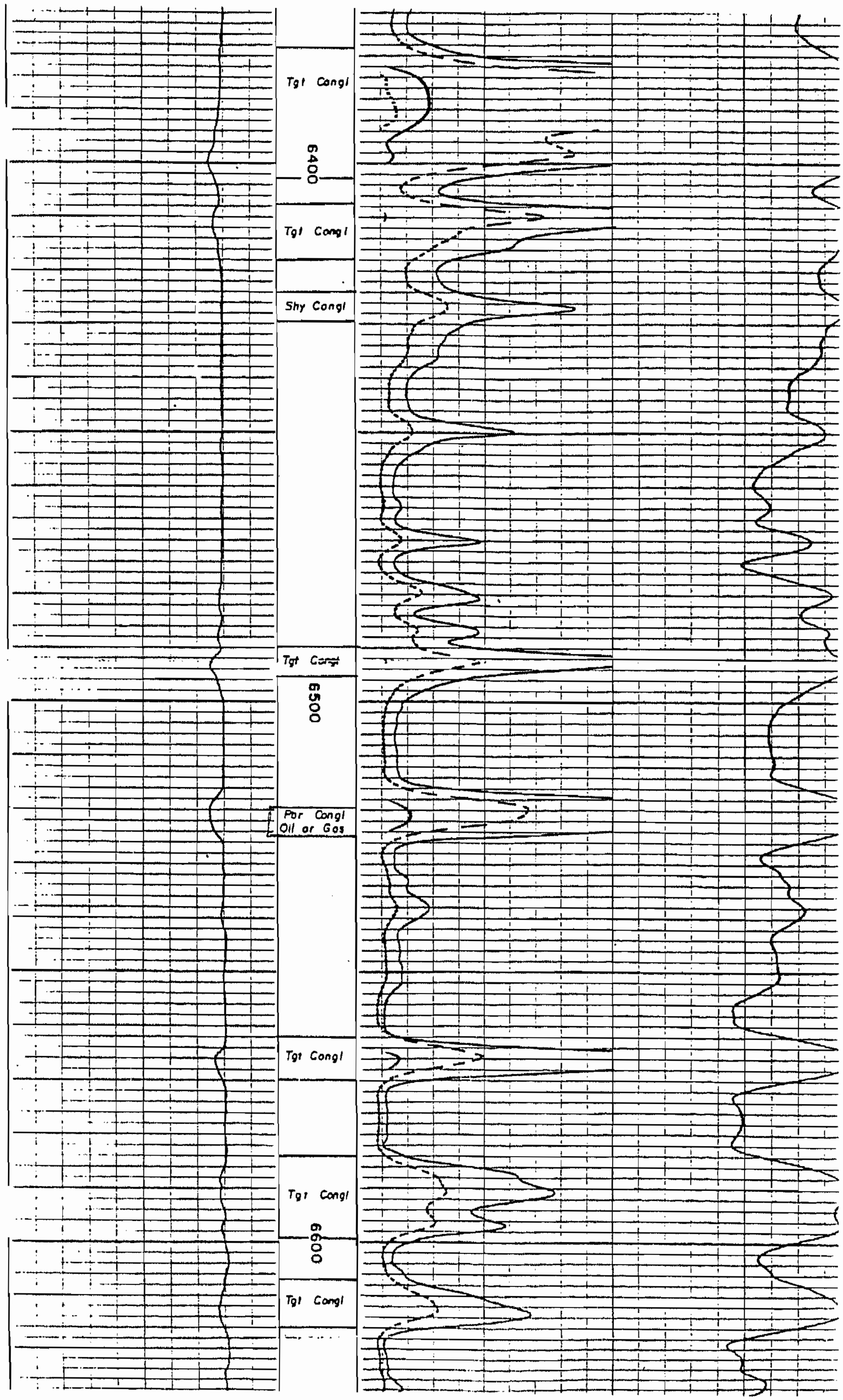
CALIBRATION DATA

CALIBRATION:	BACKGND. CPS.	SOURCE CPS.	GALV. INCR. DIVISION	SENS. TAP (FOR CAL.)	SENS. TAP (RECORD)	TIME CONST.
GAMMA RAY:						

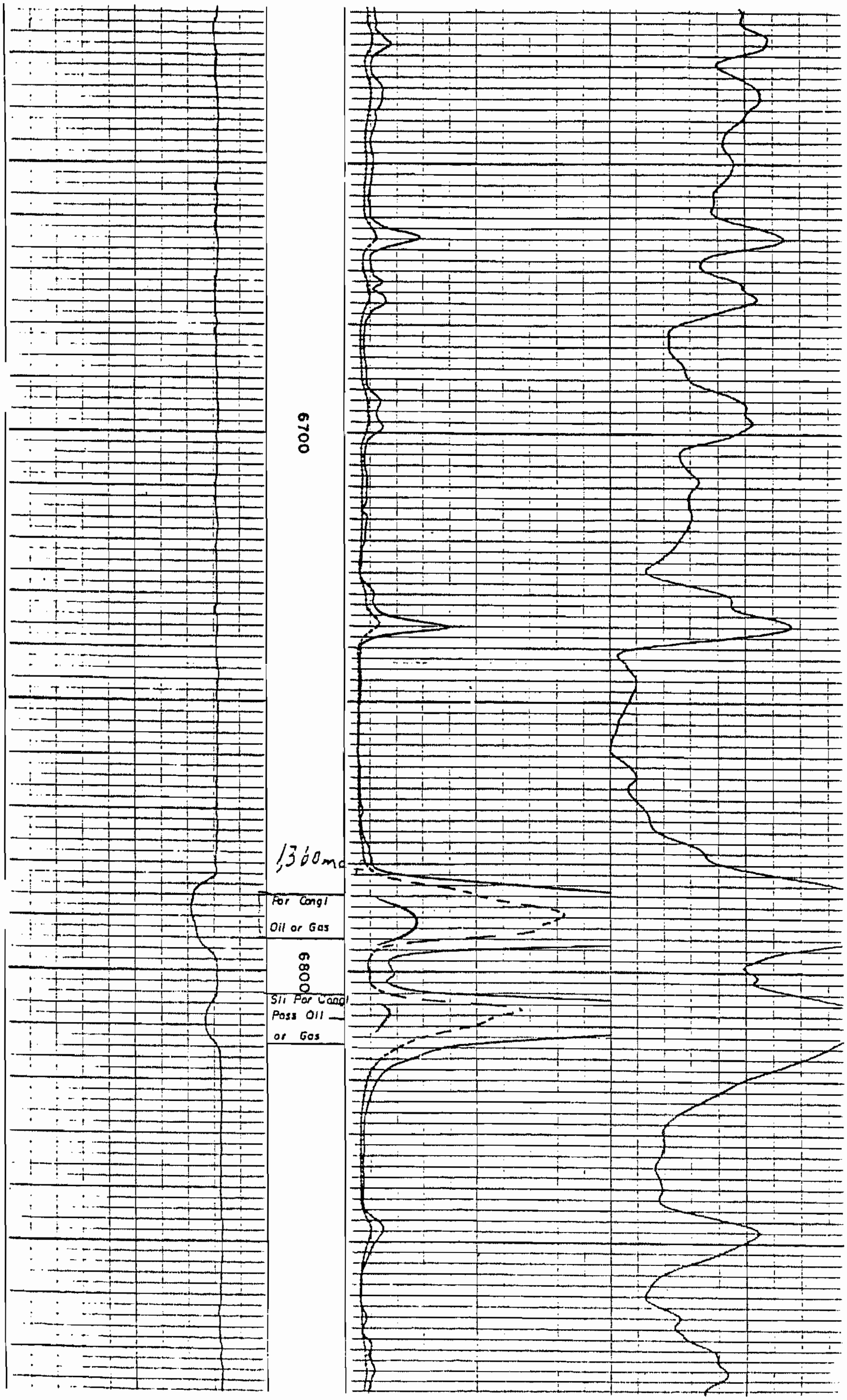

DETAIL LOG
5" = 100'
SPONTANEOUS-POTENTIAL
MILLIVOLTS
DEPTHS
CONDUCTIVITY
MILLIMHOS/M = 1000 / OHMS. M²/M
6FF40
INDUCTION
1000
500
1500
100
RESISTIVITY
OHMS. M²/M
A - 16" - M
SHORT NORMAL
0
50
0
500
INDUCTION
0
50
0
500
20
− +
Conductivity
Induction Resistivity
Short Normal — AM 16"


Tgt Lm
5900
Shy Lm
Tgt Lm
Por Congl Low Perm Poss Show
Poss Congl Oil or Gas
Por Congl Low Perm Poss Oil or Gas
6000
Congl Low Perm Poss Show
6100
Sl Por
Tgt Congl
Por Congl Low Perm Poss Oil or Gas

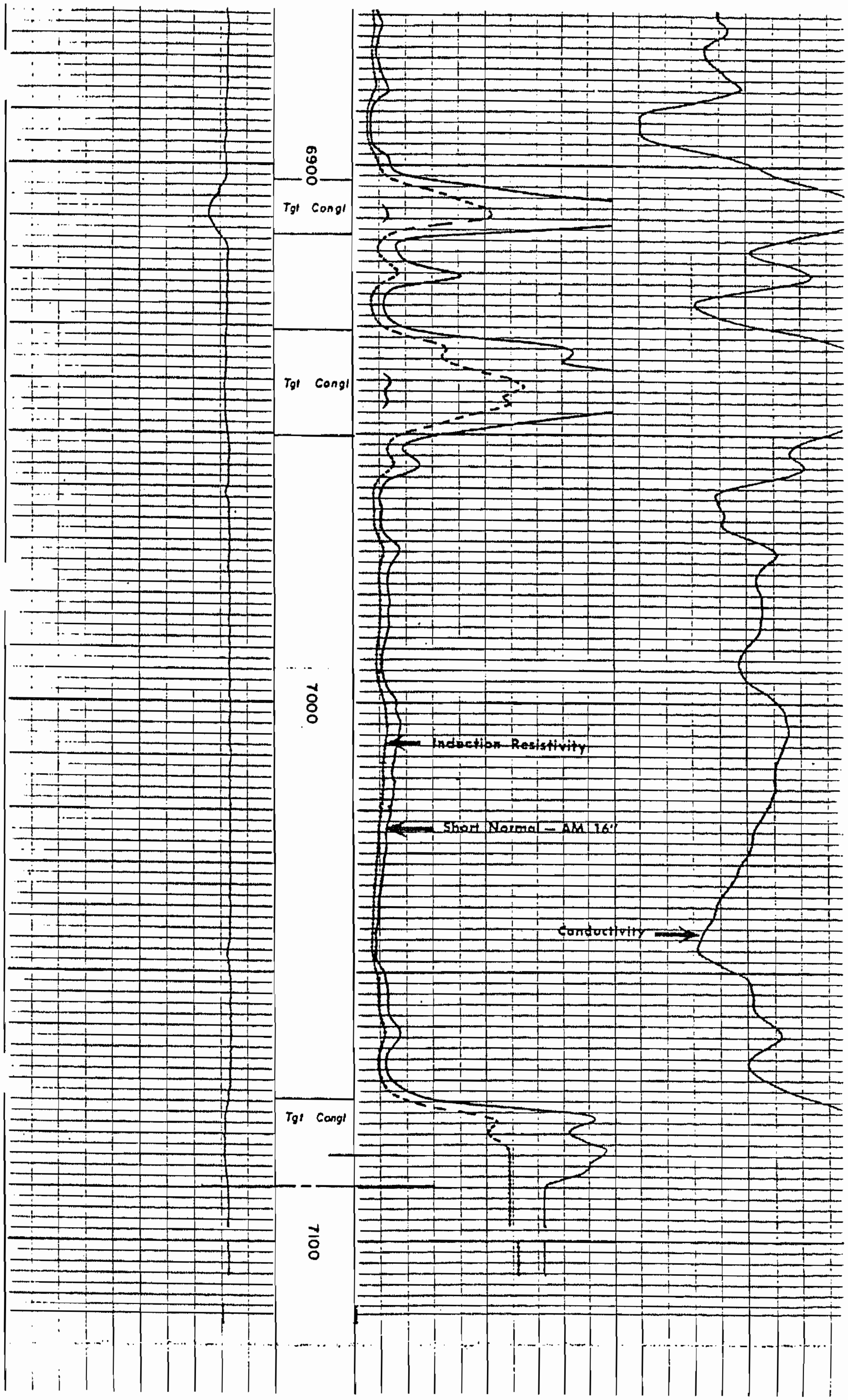

Por Congl Low Perm Poss Oil or Gas
Por Congl Low Perm Poss Oil or Gas
Tgt Congl Sli Por Low Perm
6200
6300
Congl Poss Oil or Gas
Tgt Congl Sli Por Low Perm

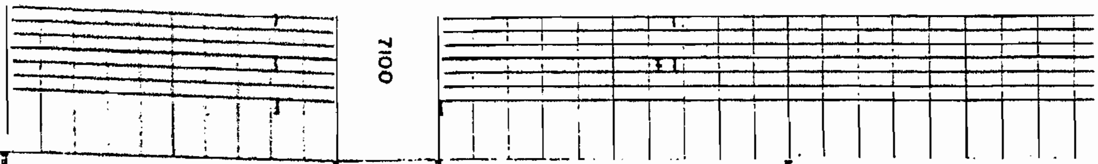


Tgt Congl
6400
Tgt Congl
Shy Congl
Tgt Congl
6500
Por Congl
Oil or Gas
Tgt Congl
Tgt Congl
6600
Tgt Congl



6700
1360 md
Por Congl
Oil or Gas
6800
Sli Por Congl
Poss Oil
or Gas


6900
Tgt Congl
Tgt Congl
7000
Induction Resistivity
Short Normal — AM 16"
Conductivity
Tgt Congl
7100



A - 16" - M
SHORT NORMAL
0 50
0 500

INDUCTION
0 50
0 500

RESISTIVITY
OHMS. M^2/M

6FF40
INDUCTION
1000 500
1500 1

20
– |←→| +

SPONTANEOUS-POTENTIAL
MILLIVOLTS

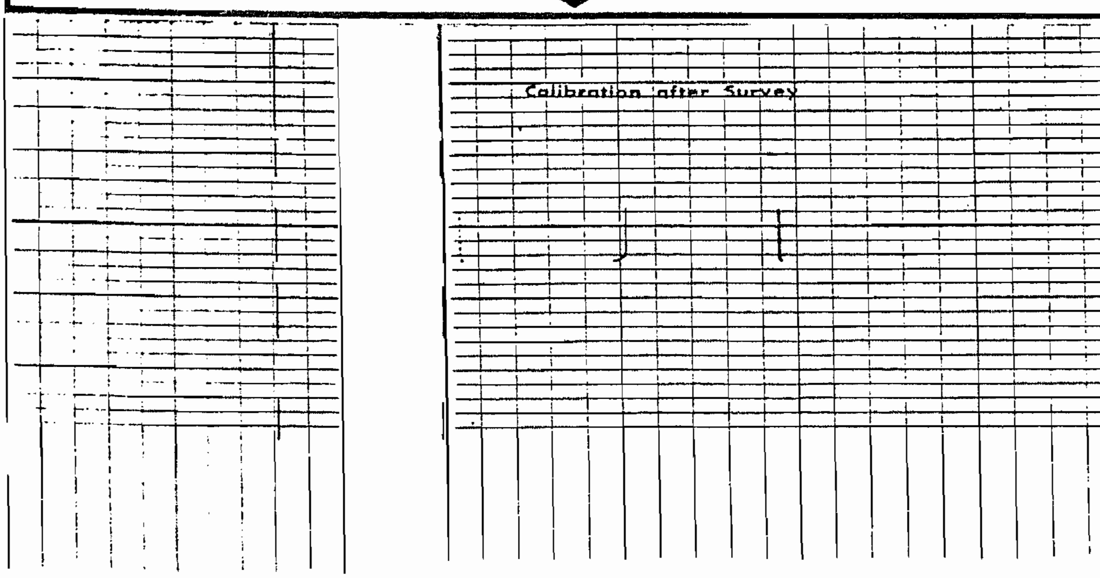
DEPTHS

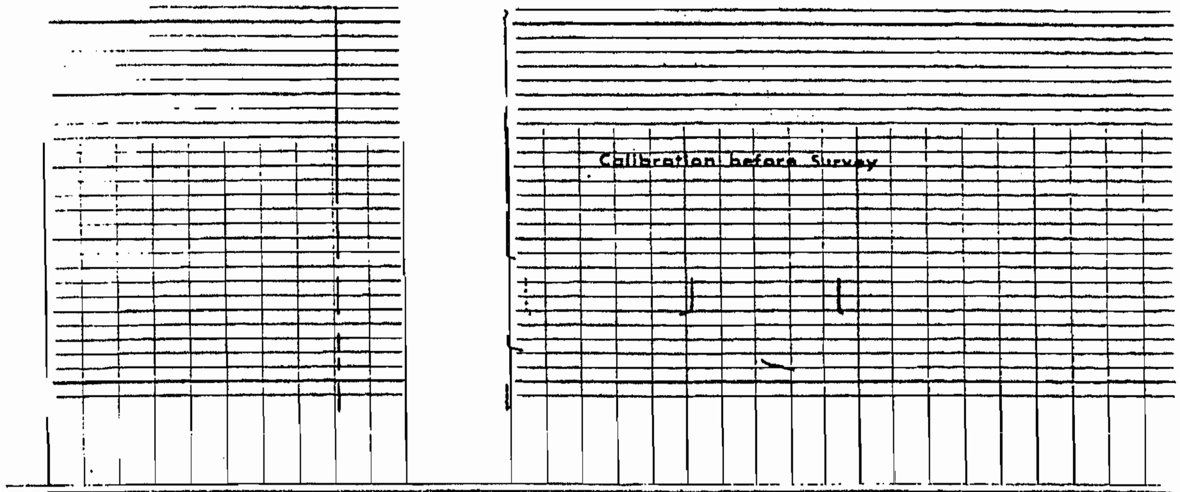
CONDUCTIVITY
MILLIMHOS/M = $\frac{1000}{\text{OHMS. } M^2/M}$

COMPANY DALLAS PRODUCTION CO. INC.
WELL FERGUSON NO. 1-A
FIELD WILDCAT
COUNTY WISE STATE TEXAS

SCHL. FR 7090
SCHL. TD 7091
DRLR TD 7090
Elev:
KB 818
DF 817
GL 807

CALIBRATION RECORD





CALIBRATION RECORD

COMPANY DALLAS PRODUCTION CO. INC.

WELL FERGUSON NO. 1-A

FIELD WILDCAT

COUNTY WISE STATE TEXAS

SCHL FR 7090
SCHL TD 7091
DRLR TD 7090
Elev:
KB 818
DF 817
GL 807

Log Analysis

COMPANY		WELL
DALLAS PRODUCTION CO. INC.		FERGUSON NO. 1-A
FIELD: WILDCAT	COUNTY: WISE	STATE: TEXAS

DEPTH	RT	RW	M	PG	% POROSITY	% WATER	REMARKS
6786-92	41	.035	H	2.68	14	19	OIL OR G.
6792-94	24-35				8-10	35	OIL OR G.
6520-25	33				8-10	33	OIL OR G.
6302-16	60				14-16	15	OIL OR G.
6130-38	37				10-12	26	LOW PERM OIL OR G.
6120-24	33				12-14	23	" "
6044-50	44				8-10	29	LOW PERM OIL OR G.
5980-82	45				10	26	" "
5975-78	47				10	26	" "
5973-75	65				9	24	" "
5970-73	55				13	16	" "

Log Analysis

COMPANY	WELL
DALLAS PRODUCTION CO. INC.	FERGUSON NO. 1-A

FIELD	COUNTY	STATE
WILDCAT	WISE	TEXAS

DEPTH	RT	RW	M	PG	% POROSITY	% WATER	REMARKS
6786-92	41	.035	H	2.68	14	19	OIL OR G.
6792-94	24-35				8-10	35	OIL OR G.
6520-25	33				8-10	33	OIL OR G.
5302-16	60				14-16	15	OIL OR G.
6130-38	37				10-12	26	LOW PERM OIL OR G.
6120-24	33				12-14	23	" "
6044-50	44				8-10	29	LOW PERM OIL OR G.
5980-82	45				10	26	" "
5975-78	47				10	26	" "
5973-75	65				9	24	" "
5970-73	65				13	16	" "
5957-63	75				11-13	17	OIL OR G.
5946-50	30				9	35	LOW PERM OIL OR G.
3924-44	2.5	.04		2.65	11	90	WTR

DATE	LOCATION	ENGINEER
12-2-72	WICHITA FALLS	DELAY

SWS-1329-C

EXHIBIT 2

WELL COMPLETION PROGNOSIS

Ferguson "A" No. 1
Wise County, Texas

1. Move in Well Service Unit, 6900' of 2½" tubing, and drilling equipment. Run 3 7/8" bit and scraper on tubing and drill out DV tool at 780'.

2. Run Gamma-ray correlation and collar log and perforate the 4½" casing as follows:

Zone 1	6786'-94'	w/16 holes
Zone 2	6519'-25'	w/12 holes
Zone 3	6302'-16'	w/14 holes
Zone 4	6120'-6124' & 6130'-38'	w/12 holes
Zone 5	5957'-62' & 5970'-82'	w/16 holes

3. Run a retrievable bridge plug and retrievable packer on 2½" tubing, and treat and test the five zones as follows:

Zone 1 6786' - 6794'

a. Set plug at 6810' and packer at 6770'
b. Swab down.
c. Treat w/500 gallons bda.
d. Swab down.
e. Treat w/20,000# 20/40 sand in gelled calcium chloride water at the rate of 2# sand per gallon.
f. Shut-in minimum 36 hours for gels to break.
g. Swab in, clean up & test.
h. After satisfactory testing release packer, pick up bridge plug and move up to zone 2.

Zone 2 6519' - 6525'

a. Set plug at 6550' and packer at 6500'. Repeat steps b through h.

Zone 3 6302' - 6316'

a. Set plug at 6330' and packer at 6290'. Repeat steps b through h.

Zone 4 6120' -24' & 6130'-6138'

a. Set plug at 6150' and packer at 6100'. Repeat steps b through h.

Zone 5 5957'-62' & 5970'-82'

a. Set plug at 6000' and packer at 5940'. Repeat steps b through h.

4. Pull 2½" tubing and run 2" tubing for completion.

STIMULATION TREATMENT REPORT

DOWELL

DWL-404-J PRINTED IN U.S.A.

DOWEL DIVISION OF THE DOW CHEMICAL COMPANY

DATE	1-18-73
WELL NAME AND NUMBER	Fergerson A-1
LOCATION	9N Decatur
CUSTOMER REPRESENTATIVE	McCausland
TREATMENT NUMBER	5-11-8516
POOL	W. C.
FORMATION	Congl.
PIPE SENT DOWN	Tubing A ☑ / Casing B ☐ / Annulus C ☐
ALLOWABLE PRESSURE	TBG: 3500 CSG:
COUNTY	Wise
STATE	Texas
TYPE OF WELL	Oil A ☐ / Gas B ☑ / Water C ☐ / Inj. D ☐
TYPE OF SERVICE	B.D.A.
AGE OF WELL	New Well A ☑ / Rework B ☐
TOTAL DEPTH	—
CIRC. BHT.	
CASING SIZE	4 1/2
CASING DEPTH	—
TUBING SIZE	2 1/2
TUBING DEPTH	5972
LINER SIZE	—
LINER DEPTH	—
PACKER TYPE	Dowell M-6
PACKER DEPTH	5972
OPEN HOLE	—
CSG. OR ANNL. VOL.	—
TBG VOLUME	34
STATIC BHT.	140°

CUST. NAME: Dallas Prod. Co.

ADDRESS: Box 228

CITY, STATE & ZIP CODE: Bowie Texas

REMARKS:

PERFORATED INTERVALS

DEPTH	NO. OF HOLES	DEPTH	NO. OF HOLES	DEPTH	NO. OF HOLES
5950					
62					
5970					
82					

FOR CONVERSION PURPOSES 24 BBLS EQUALS 1000 GALLONS

ARRIVED ON LOCATION: 12:15 P.M.

TIME P.M.	INJECTION RATE	INJECTION BBLS IN	PRESSURE CSG.	PRESSURE TBG.	SERVICE LOG
12:35		0			Circ. Sand off Plug
1.04		26			← ← ← ← Move Packer + Plug
1.32			1500		Test Plug
1.49		0			B.D.A.
1.53		12			← ← ←
1.53		0			Fresh Water 1% Kcl Flush
1.58		21			← ← ← Set Packer
200	.5	—		1950	← ← ←
2.01	.5	21.5		1450	← ← ←
2.06	.5	24		1350	← ← ←
2.08	.5	25		1200	← ← ←
2.12	5.5	24		1950	← ← ←
2.13	5.5	35		1950	← ← ←

TIME LEFT LOCATION	2.30 P.M.
AVG. LIQUID INJ. RATE	1.5
ADJUSTED RATE (SOLIDS INCL.)	
TOTAL FLUID PUMPED	OIL: WATER: 35
MAX. PRESSURE	1950
AVG. PRESSURE	1500
FINAL PUMP IN PRESSURE	1950
SHUT IN PRESSURE	IMMEDIATE: 800 15 MINUTES:
DOWELL LOCATION	Gainesville
DOWELL ENGINEER	Harry Brown

PROPS AND LIQUIDS INJECTED

TYPE	SIZE OR PURPOSE	AMOUNT
B.D.A.		500

CALL BACK: DATE | CUSTOMER REP. CONTACTED | CUSTOMER CONSIDERED SERVICE ☐ SATISFACTORY ☐ UNSATISFACTORY ☐ UNKNOWN | PROD. BEFORE TREATMENT ☐ TEST ☐ ALLOWABLE | DAYS | PROD. AFTER TREATMENT ☐ TEST ☐ ALLOWABLE

STIMULATION TREATMENT REPORT

DWL-41 -J PRINTED IN U.S.A. DOWELL DIVISION OF THE DOW CHEMICAL COMPANY

DATE	1-19-73
WELL NAME AND NUMBER	Fergerson Ail
LOCATION	9 M Decatur
CUSTOMER REPRESENTATIVE	McCrawford
TREATMENT NUMBER	3-11-8518
POOL	W. C.
FORMATION	Congl.
JOB DONE DOWN	TUBING A ☑ CASING B ☐ ANNULUS C ☐
ALLOWABLE PRESSURE	TBG 4300 CSG —
COUNTY	Wise
STATE	Texas
TYPE OF WELL	OIL A ☐ GAS B ☑ WATER C ☐ INJ. D ☐
TYPE OF SERVICE	Water Frac
AGE OF WELL	NEW WELL A ☑ REWORK B ☐
TOTAL DEPTH	—
CIRC. BHT.	—

CUST. NAME Dallas Prod. Co.

ADDRESS Box 228

CITY, STATE & ZIP CODE Bowie Texas

REMARKS:

CASING SIZE	CASING DEPTH	TUBING SIZE	TUBING DEPTH
4 1/2	—	2 1/2	5922
LINER SIZE	**LINER DEPTH**	**PACKER TYPE**	**PACKER DEPTH**
—	—	Dowell m.l.	5922
OPEN HOLE	**CSG. OR ANNL. VOL.**	**TBG VOLUME**	**STATIC BHT.**
—	—	34	1400

PERFORATED INTERVALS

DEPTH	NO. OF HOLES	DEPTH	NO. OF HOLES	DEPTH	NO. OF HOLES
5957					
67					
5970					
82					

FOR CONVERSION PURPOSES 24 BBLS EQUALS 1000 GALLONS

ARRIVED ON LOCATION: 2:30 P.M.

TIME P.M.	INJECTION RATE	INJECTION BBLS IN	PRESSURE CSG.	PRESSURE TBG.	SERVICE LOG
3.26				3600	Test Line
3.27		0			W.F. 60 Pad
3.30	13	31		4200	" " "
3.33	14	72		4600	" " "
3.33	14	0		4600	" " " 2# 20/40
3.35	14	36		4600	" " " on Pen
3.39	15	100		4450	" " "
3.43	15	150		4350	" " "
3.46	15	200		4300	" " "
3.50	15	250		4300	" " "
3.50	15	0		4300	" " Flush
3.53	15	50		4300	" " "

15 1/2 4

Kal 12

TIME LEFT LOCATION	AVG. LIQUID INJ. RATE	ADJ. INJ. RATE (SOLIDS INC.)	TOTAL FLUID PUMPED OIL	TOTAL FLUID PUMPED WATER
5:15 P.M.	14			
MAX. PRESSURE	**AVG. PRESSURE**	**FINAL PUMP IN PRESSURE**	**SHUT IN PRESSURE IMMEDIATE**	**SHUT IN PRESSURE 15 MINUTES**
4600	4400	4300	1050	950

DOWELL LOCATION Gainesville

DOWELL ENGINEER [illegible]

PROPS AND LIQUIDS INJECTED

TYPE	SIZE OR PURPOSE	AMOUNT
J-209		650
J-84		250
Sand	20/40	20,000
Adomall		10

CALL BACK DATE	CUSTOMER REP. CONTACTED	CUSTOMER CONSIDERED SERVICE	PROD. BEFORE TREATMENT	PROD. AFTER TREATMENT
		☐ SATISFACTORY ☐ UNSATISFACTORY ☐ UNKNOWN	☐ TEST ☐ ALLOWABLE	DAYS ☐ TEST ☐ ALLOWABLE

STIMULATION TREATMENT REPORT

DWL-494-J PRINTED IN U.S.A. DOWELL DIVISION OF THE DOW CHEMICAL COMPANY

DATE: 1-15-73

WELL NAME AND NUMBER	LOCATION	CUSTOMER REPRESENTATIVE	TREATMENT NUMBER
Fergeson A-1	9 N [illegible]	McCrawford	3-11-8509

POOL: W.C.
FORMATION: Cong/.
COUNTY: Wise
STATE: Texas
TYPE OF SERVICE: Water Frac

JOB DONE DOWN: TUBING A ☑ CASING B ☐ ANNULUS C ☐
ALLOWABLE PRESSURE: TBG: 4500 CSG: —
TYPE OF WELL: OIL A ☐ GAS B ☑ WATER C ☐ INJ. D ☐
AGE OF WELL: NEW WELL A ☑ REWORK B ☐
TOTAL DEPTH: — CIRC. BHT.:

CASING SIZE	CASING DEPTH	TUBING SIZE	TUBING DEPTH
4 1/2	—	2 1/2	6025
LINER SIZE	**LINER DEPTH**	**PACKER TYPE**	**PACKER DEPTH**
—	—	Dowell [illegible]	6025
OPEN HOLE	**CSG.OR ANRL.VOL.**	**TBG VOLUME**	**STATIC BHT.**
—	—	36	140°

CUST. NAME: Dallas Prod. Co.
ADDRESS: Box 228
CITY, STATE & ZIP CODE: Bowie Texas
REMARKS:

PERFORATED INTERVALS

DEPTH	NO. OF HOLES	DEPTH	NO. OF HOLES	DEPTH	NO. OF HOLES
6120					
24					
6130					
38					

FOR CONVERSION PURPOSES 24 BBLS EQUALS 1000 GALLONS

ARRIVED ON LOCATION: 10:00 A.M.

TIME P.M.	INJECTION RATE	BBLS IN	PRESSURE CSG.	TBG.	SERVICE LOG
1.38				4000	Test Line
1.39		0			W.F. 60 Pad
1.42	19	35		3000	← ← ←
1.44	19	72		3050	← ← ←
1.44	19	0		3050	← ← ← 2# 20/40
1.46	18	36		3100	← ← ← ← ← on [illegible]
1.5[illegible]	19	100		3150	← ← ← ← ←
1.56	19	200		3200	← ← ← ← ←
1.59	19	260		3280	← ← ← ← ←
1.59	19	0		3280	← ← Flush
2.02	19	50		3300	← ← ←

TIME LEFT LOCATION	AVG. LIQUID INJ. RATE	ADJ. INJ. RATE (SOLIDS INCL.)	TOTAL FLUID PUMPED OIL	WATER
3:15 P.M.	19			322

MAX. PRESSURE	AVG. PRESSURE	FINAL PUMP IN PRESSURE	SHUT IN PRESSURE IMMEDIATE	15 MINUTES
3300	3200	3300	1200	1200

DOWELL LOCATION: Graham [illegible]
DOWELL ENGINEER: Harvey Moore

PROPS AND LIQUIDS INJECTED

TYPE	SIZE OR PURPOSE	AMOUNT
Kcl		10
J-209		650
J-84		250
[illegible]		10
Sand	20/40	20,000

CALL BACK DATE	CUSTOMER REP. CONTACTED	CUSTOMER CONSIDERED SERVICE	PROD. BEFORE TREATMENT	PROD. AFTER TREATMENT
		☐ SATISFACTORY ☐ UNSATISFACTORY ☐ UNKNOWN	☐ TEST ☐ ALLOWABLE	DAYS ☐ TEST ☐ ALLOWABLE

STIMULATION TREATMENT REPORT

DWL-494-J PRINTED IN U.S.A. — DOWELL DIVISION OF THE DOW CHEMICAL COMPANY

DATE: 12-23-72

WELL NAME AND NUMBER: Fergerson A-1
LOCATION: 9 M. Decatur
CUSTOMER REPRESENTATIVE: McCrawford
TREATMENT NUMBER: 3-11-8925

POOL: Boonsville Bend
FORMATION: Congl.
JOB DONE DOWN: TUBING A ☒ | CASING B ☐ | ANNULUS C ☐
ALLOWABLE PRESSURE: TBG 4320 | CSG: —

COUNTY: Wise
STATE: Texas
TYPE OF WELL: OIL A ☐ | GAS B ☒ | WATER C ☐ | INJ. D ☐

TYPE OF SERVICE: Water Frac
AGE OF WELL: NEW WELL A ☒ | REWORK B ☐
TOTAL DEPTH: —
CIRC. BHT.:

CUST. NAME: Dallas Prod. Co.

ADDRESS: Box 228

CITY, STATE & ZIP CODE: Bowie

REMARKS:

CASING SIZE	CASING DEPTH	TUBING SIZE	TUBING DEPTH
4 1/2	—	2 1/2	6770

LINER SIZE	LINER DEPTH	PACKER TYPE	PACKER DEPTH
	—	Dowell m-L	6770

OPEN HOLE	CSG.OR ANNL.VOL.	TBG VOLUME	STATIC BHT.
—	36	39	140'

PERFORATED INTERVALS

DEPTH	NO. OF HOLES	DEPTH	NO. OF HOLES	DEPTH	NO. OF HOLES
6986					
6994					

FOR CONVERSION PURPOSES 24 BBLS EQUALS 1000 GALLONS

ARRIVED ON LOCATION 9:00 A.M.

TIME A.M.	INJECTION RATE	INJECTION BBLS IN	PRESSURE CSG.	PRESSURE TBG.	SERVICE LOG
10.36		0			W.F. On Circ Hole
11.06		94			″ ″ ″ ″
11.20				4500	″ ″ Test Line
11.21	14	0		3500	″ ″ Pad
11.24	18	30		4100	″ ″ ″
11.24	18	0		4100	″ ″ 2# 20/40
11.26 1/2	18	39		4100	″ ″ ″ ″ on Perf
11.29 1/2	19	100		4200	″ ″ ″ ″
11.34 1/2	19	200		4200	″ ″ ″ ″
11.38	19	260		4200	″ ″ ″ ″
11.38	19	0		4200	″ ″ Flush
11.40 1/2	19	50		4200	″ ″ ″

Sand 20/40 20,000

TIME LEFT LOCATION	AVG. LIQUID INJ. RATE	ADJ. RATE (SOLIDS INC.)	TOTAL FLUID PUMPED
12.30 A.M.		18	OIL: — WATER: 382

MAX. PRESSURE	AVG. PRESSURE	FINAL PUMP IN PRESSURE	SHUT IN PRESSURE IMMEDIATE	SHUT IN PRESSURE 15 MINUTES
4200	4100	4200	1800	1750

DOWELL LOCATION: Gainesville
DOWELL ENGINEER: Henry Moore

PROPS AND LIQUIDS INJECTED

TYPE	SIZE OR PURPOSE	AMOUNT
L-209		650
J-84		250
Kcl		12
Adomall		10

CALL BACK: DATE | CUSTOMER REP. CONTACTED | CUSTOMER CONSIDERED SERVICE ☐ SATISFACTORY ☐ UNSATISFACTORY ☐ UNKNOWN

PROD. BEFORE TREATMENT: TEST ☐ ALLOWABLE ☐
PROD. AFTER TREATMENT: DAYS ☐ TEST ALLOWABLE ☐

STIMULATION TREATMENT REPORT

DWL-464-J PRINTED IN U.S.A. DOWELL DIVISION OF THE DOW CHEMICAL COMPANY

DATE	1-2-72
WELL NAME AND NUMBER	Ferguson A-1
LOCATION	9 N Decatur
CUSTOMER REPRESENTATIVE	M. Crawford
TREATMENT NUMBER	3-11-8431
POOL	Boonsville Bend
FORMATION	Congl.
JOB DONE DOWN	TUBING A ☑ CASING B ☐ ANNULUS C ☐
ALLOWABLE PRESSURE	TBG: 4500 CSG: —
COUNTY	Wise
STATE	Texas
TYPE OF WELL	OIL A ☐ GAS B ☑ WATER C ☐ INJ. D ☐
TYPE OF SERVICE	Water Frac
AGE OF WELL	NEW WELL A ☑ REWORK B ☐
TOTAL DEPTH	—
CIRC. BHT.	
CASING SIZE	4 1/2
CASING DEPTH	—
TUBING SIZE	2 1/2
TUBING DEPTH	6265
LINER SIZE	—
LINER DEPTH	—
PACKER TYPE	Dowell [illegible]
PACKER DEPTH	6265
OPEN HOLE	—
CSG. OR ANRL. VOL.	—
TBG VOLUME	37
STATIC BHT.	140°

CUST. NAME: Dallas Prod. Co.

ADDRESS: Box 228

CITY, STATE & ZIP CODE: Bowie Texas

REMARKS:

PERFORATED INTERVALS

DEPTH	NO. OF HOLES	DEPTH	NO. OF HOLES	DEPTH	NO. OF HOLES
6302					
16					

FOR CONVERSION PURPOSES 24 BBLS EQUALS 1000 GALLONS

ARRIVED ON LOCATION: 8:00 A.M.

TIME A.M.	INJECTION RATE	BBLS IN	PRESSURE CSG.	PRESSURE TBG.	SERVICE LOG
11:25				5300	Test Line
11:27		0			Wf. 60 Pad
11:29	18	32		3200	
11:31	18	72		3200	
11:31	18	0		3200	2 # 20/40
11:33	18	37		3250	O/C [illegible]
11:36	18	100		3300	
11:42	17	200		3500	
11:45	17	230		3600	
11:45	17	0		3600	Flush
11:48	17	50		3700	

Kcl 12

TIME LEFT LOCATION	AVG. LIQUID INJ. RATE	ADJUSTED RATE (SOLIDS INCL)	TOTAL FLUID PUMPED OIL	WATER
12:30 PM		17		372

MAX. PRESSURE	AVG. PRESSURE	FINAL PUMP IN PRESSURE	SHUT IN PRESSURE IMMEDIATE	15 MINUTES
3700	3500	3700	1200	1000

DOWELL LOCATION: Graysville

DOWELL ENGINEER: [illegible]

PROPS AND LIQUIDS INJECTED

TYPE	SIZE OR PURPOSE	AMOUNT
Sand	20/40	20,000
J-209		650
J-84		250
Adomite		70

CALL BACK: DATE | CUSTOMER REP. CONTACTED | CUSTOMER CONSIDERED SERVICE ☐ SATISFACTORY ☐ UNSATISFACTORY ☐ UNKNOWN | PROD. BEFORE TREATMENT: TEST ALLOWABLE | PROD. AFTER TREATMENT: DAYS TEST ALLOWABLE

TREATMENT REPORT
DWL-494-1 PRINTED IN U.S.A.

DOWELL DIVISION OF THE DOW CHEMICAL COMPANY

DATE	TREATMENT NUMBER
12-19-20-72	3-11-8415

WELL NAME AND NUMBER	Fergerson A-1
LOCATION	
POOL	
FORMATION	
COUNTY	Wise
STATE	Texas
TYPE OF SERVICE	Rental
CUSTOMER REPRESENTATIVE	Mr. Crawford
JOB DONE DOWN	TUBING A ☒ CASING B ☐ ANNULUS C ☒
ALLOWABLE PRESSURE	TBG: CSG:
TYPE OF WELL	OIL A ☒ GAS B ☐ WATER C ☐ INJ. D ☐
AGE OF WELL	NEW WELL A ☒ REWORK B ☐
TOTAL DEPTH	
CIRC. SHT.	

CUST. NAME: Dallas Production
ADDRESS: Box 945
Bowie, Texas
CITY, STATE & ZIP CODE:
REMARKS:

CASING SIZE	CASING DEPTH	TUBING SIZE	TUBING DEPTH
	4 1/2		

LINER SIZE	LINER DEPTH	PACKER TYPE	PACKER DEPTH

OPEN HOLE	CSG. OR ANRL. VOL.	TBG VOLUME	STATIC SHT.
		2 1/2	

PERFORATED INTERVALS

DEPTH	NO. OF HOLES	DEPTH	NO. OF HOLES	DEPTH	NO. OF HOLES

FOR CONVERSION PURPOSES 24 BBLS EQUALS 1000 GALLONS

ARRIVED ON LOCATION: 2:00 P.M 12-19-72

TIME	INJECTION RATE	INJECTION BBLS IN	PRESSURE CSG.	PRESSURE TBG.	SERVICE REMARKS
					Rig up to Circulate Hole
3:00					Try to circulate Hole while Drilling DV tool
					Bit would plug-
					Kept reverse & try Direct.
					Shut Down 6:30 P.M. 12-19-72
					9:00 A.M on loc 12-20-72
10:00					start Drilling- Circulate water
12:00					DV tool Drilled-
					shut Down-
					Left loc.

TIME LEFT LOCATION	AVG. LIQUID INJ. RATE	ADJ. INJ. RATE (SOLIDS INC.)	TOTAL FLUID PUMPED OIL	TOTAL FLUID PUMPED WATER
12 N				

MAX. PRESSURE	AVG. PRESSURE	FINAL PUMP IN PRESSURE	SHUT IN PRESSURE IMMEDIATE	SHUT IN PRESSURE 15 MINUTE

PROPS AND LIQUIDS INJECTED

TYPE	SIZE OR PURPOSE	AMOUNT

DOWELL LOCATION | DOWELL ENGINEER

CALL BACK	DATE	CUSTOMER REP. CONTACTED	CUSTOMER CONSIDERED SERVICE	PROD. BEFORE TREATMENT	PROD. AFTER TREATMENT
			☐ SATISFACTORY ☐ UNSATISFACTORY ☐ UNKNOWN	☐ TEST ☐ ALLOWABLE	DAYS ☐ TEST ☐ ALLOWABLE

STIMULATION TREATMENT REPORT

DWL-484-J PRINTED IN U.S.A.

DOWELL DIVISION OF THE DOW CHEMICAL COMPANY

DATE	12-27-7[illegible]
WELL NAME AND NUMBER	Ferguson A-1
LOCATION	9 M. Decatur
CUSTOMER REPRESENTATIVE	McCaslin[illegible]
TREATMENT NUMBER	3-11-8921
POOL	Boonsville Bend
FORMATION	Congl.
JOB DONE DOWN	TUBING A ☑ CASING B ☐ ANNULUS C ☐
ALLOWABLE PRESSURE	TBG: 4500 CSG: —
COUNTY	Wise
STATE	Texas
TYPE OF WELL	OIL A ☐ GAS B ☑ WATER C ☐ INJ. D ☐
TYPE OF SERVICE	B.D.A.
AGE OF WELL	NEW WELL A ☑ REWORK B ☐
TOTAL DEPTH	—
CIRC. BHT.	

CUST. NAME: Dallas Prod Co

ADDRESS: Box 228

CITY, STATE & ZIP CODE: Bowie Texas

REMARKS:

CASING SIZE	CASING DEPTH	TUBING SIZE	TUBING DEPTH
4 1/2	—	2 1/2	6485
LINER SIZE	LINER DEPTH	PACKER TYPE	PACKER DEPTH
—	—	Dowell mh	6485
OPEN HOLE	CSG. OR ANNL. VOL.	TBG VOLUME	STATIC BHT.
—	—	37.5	140°

PERFORATED INTERVALS

DEPTH	NO. OF HOLES	DEPTH	NO. OF HOLES	DEPTH	NO. OF HOLES
6519					
6525					

FOR CONVERSION PURPOSES 24 BBLS EQUALS 1000 GALLONS

ARRIVED ON LOCATION: 12:00 P.M.

TIME P.M.	INJECTION RATE	INJECTION BBLS IN	PRESSURE CSG.	PRESSURE TBG.	SERVICE LOG
1.06		0			Cir Sand 1% Kcl Water
2.17		152			← ← ← ←
2.59		0			B.D.A.
303		12			← ← ←
303		0			1% Kcl Water Flush
3.11		25			← ← ← ← Set Packer
3.14	.5	—		800	← ← ← ←
3.15	.5	25.5		1050	← ← ← ← ←
3.17	.5	26.5		1300	← ← ←
3.19	.5	27.5		1400	← ← ← ←
3.20	.5	28		1100	← ← ← ←
3.21	5.5	31.5		2200	← ← ← ← Increase Rate
3.28	5	38		2450	← ← ← ←

TIME LEFT LOCATION	AVG. LIQUID INJ. RATE	ALLOW. RATE (SOLIDS INCL)	TOTAL FLUID PUMPED OIL	TOTAL FLUID PUMPED WATER
4.00 P.M.	1.25			38

MAX. PRESSURE	AVG. PRESSURE	FINAL PUMP IN PRESSURE	SHUT IN PRESSURE IMMEDIATE	SHUT IN PRESSURE 15 MINUTES
2450	1500	2450	1200	0

PROPS AND LIQUIDS INJECTED

TYPE	SIZE OR PURPOSE	AMOUNT
Kcl		2
B.D.A.		500

DOWELL LOCATION: Gainesville

DOWELL ENGINEER: Lloyd Moore

CALL BACK DATE	CUSTOMER REP. CONTACTED	CUSTOMER CONSIDERED SERVICE	PROD. BEFORE TREATMENT	PROD. AFTER TREATMENT
		☐ SATISFACTORY ☐ UNSATISFACTORY ☐ UNKNOWN	☐ TEST ☐ ALLOWABLE	DAYS ☐ TEST ☐ ALLOWABLE

STIMULATION TREATMENT REPORT

DWL-494-J PRINTED IN U.S.A. — DOWELL DIVISION OF THE DOW CHEMICAL COMPANY

DATE	1-1-73
WELL NAME AND NUMBER	Fergerson A-1
LOCATION	9N Decatur
CUSTOMER REPRESENTATIVE	McCrawford
TREATMENT NUMBER	5-11 8430
POOL	Boonsville Bend
FORMATION	Congl
JOB DONE DOWN	TUBING A ☑ CASING B ☐ ANNULUS C ☐
ALLOWABLE PRESSURE	TBG: 4500 CSG: —
COUNTY	Wise
STATE	Texas
TYPE OF WELL	OIL A ☐ GAS B ☑ WATER C ☐ INJ. D ☐
TYPE OF SERVICE	B.D.A.
AGE OF WELL	NEW WELL A ☑ REWORK B ☐
TOTAL DEPTH	—
CIRC. BHT.	

CUST. NAME: Dallas Prod. Co.

ADDRESS: Box 228

CITY, STATE & ZIP CODE: Bowie Texas

REMARKS:

CASING SIZE	CASING DEPTH	TUBING SIZE	TUBING DEPTH
4 1/2	—	2 1/2	6265
LINER SIZE	**LINER DEPTH**	**PACKER TYPE**	**PACKER DEPTH**
—	—	Dowell m-l	6265
OPEN HOLE	**CSG. OR ANRL. VOL.**	**TBG VOLUME**	**STATIC BHT.**
—	—	37	140°

PERFORATED INTERVALS

DEPTH	NO. OF HOLES	DEPTH	NO. OF HOLES	DEPTH	NO. OF HOLES
6302					
16					

FOR CONVERSION PURPOSES 24 BBLS EQUALS 1000 GALLONS

ARRIVED ON LOCATION: 8:00 AM

TIME	INJECTION RATE	BBLS IN	PRESSURE CSG.	PRESSURE TBG.	SERVICE LOG
905		0		400	Kill Well
9.37		55		0	← ←
10.20		0			Circ. Sand off B.P
10.46		48			← ← ← ←
11.31		0			B.D.A.
11.35		12			← ← ←
11.35		0			Fresh Water Flush
11.45		24			← ← ← Set Packer
11.47	.5	—		500	← ← ←
11.50	.5	25.5		900	← ← ←
11.51	.5	26		750	← ← ←
11.55	.5	28		750	← ← ←
11.56	6	—		2000	← ← ← Increase Rate
11.57	6	38		2000	← ← ←

TIME LEFT LOCATION	AVG. LIQUID INJ. RATE	ADJ. INJ. RATE (SOLIDS INCL.)	TOTAL FLUID PUMPED OIL	TOTAL FLUID PUMPED WATER
12:15 PM	1.25			39
MAX. PRESSURE	**AVG. PRESSURE**	**FINAL PUMP IN PRESSURE**	**SHUT IN PRESSURE IMMEDIATE**	**15 MINUTES**
2000	1700	2000	800	

DOWELL LOCATION: Gainesville

DOWELL ENGINEER: Henry Moore

PROPS AND LIQUIDS INJECTED

TYPE	SIZE OR PURPOSE	AMOUNT
B.D.A.		500

CALL BACK DATE	CUSTOMER REP. CONTACTED	CUSTOMER CONSIDERED SERVICE	PROD. BEFORE TREATMENT	PROD. AFTER TREATMENT
		☐ SATISFACTORY ☐ UNSATISFACTORY ☐ UNKNOWN	TEST ☐ ALLOWABLE ☐	DAYS TEST ☐ ALLOWABLE ☐

STIMULATION TREATMENT REPORT

DWL-494-J PRINTED IN U.S.A.

DOWELL DIVISION OF THE DOW CHEMICAL COMPANY

DATE: 2-28-72

WELL NAME AND NUMBER	LOCATION	CUSTOMER REPRESENTATIVE	TREATMENT NUMBER
Fergeson A-1	9 N. Decatur	McCrawford	3-11-8427

POOL	FORMATION	JOB DONE DOWN	ALLOWABLE PRESSURE
Boonsville Bend	Congl.	TUBING A ☑ CASING B ☐ ANNULUS C ☐	TBG: 4500 CSG: —

COUNTY	STATE	TYPE OF WELL
Wise	Texas	OIL A ☐ GAS B ☑ WATER C ☐ INJ. D ☐

TYPE OF SERVICE: Water Frac

AGE OF WELL: NEW WELL A ☑ REWORK B ☐

TOTAL DEPTH	CIRC. SHT.
—	

CUST. NAME: Dallas Prod. Co.

ADDRESS: Box 228

CITY STATE & ZIP CODE: Bowie Texas

REMARKS:

CASING SIZE	CASING DEPTH	TUBING SIZE	TUBING DEPTH
4 1/2	—	2 1/2	6485

LINER SIZE	LINER DEPTH	PACKER TYPE	PACKER DEPTH
—	—	Dowell m. 6	6485

OPEN HOLE	CSG. OR ANNL. VOL.	TBG VOLUME	STATIC BHT.
—	—	37.5	140°

PERFORATED INTERVALS

DEPTH	NO. OF HOLES	DEPTH	NO. OF HOLES	DEPTH	NO. OF HOLES
6519					
6525					

FOR CONVERSION PURPOSES 24 BBLS EQUALS 1000 GALLONS

ARRIVED ON LOCATION: 10:15 AM.

TIME PM.	INJECTION RATE	BBLS IN	PRESSURE CSG.	TBG.	SERVICE LOG
1224				4500	Test Lines
1226		0		500	W.f. 60 Pad
1228	16	35		3700	✓ ✓ ✓
1230 1/2	16	72		3750	✓ ✓ ✓
1230 1/2	16	0		3750	W.f. 60 2# 20/40 Sand
1232 1/2	16	38		3800	✓ ✓ ✓ ✓ on fm.
1236	16	100		3950	✓ ✓ ✓ ✓
1242 1/2	16	200		3900	✓ ✓ ✓ ✓
1246	16	260		3900	✓ ✓ ✓ ✓
1246	16	0		3900	✓ ✓ Flush
1249 1/2	16	50		3900	✓ ✓ ✓

TIME LEFT LOCATION	AVG. LIQUID INJ. RATE	ADJ. INJ. RATE (SOLIDS INCL.)	TOTAL FLUID PUMPED OIL	WATER
1:45 PM		16		262

MAX. PRESSURE	AVG. PRESSURE	FINAL PUMP IN PRESSURE	SHUT IN PRESSURE IMMEDIATE	15 MINUTES
3900	3900	3900	1250	1050

DOWELL LOCATION: Graham(?)ville

DOWELL ENGINEER: [illegible]

PROPS AND LIQUIDS INJECTED

Kal 12

TYPE	SIZE OR PURPOSE	AMOUNT
Sand	20/40	20,000
J-209		650
J-94		250
Adomall		10

CALL BACK: DATE | CUSTOMER REP. CONTACTED | CUSTOMER CONSIDERED SERVICE: ☐ SATISFACTORY ☐ UNSATISFACTORY ☐ UNKNOWN

PROD. BEFORE TREATMENT: ☐ TEST ☐ ALLOWABLE

PROD. AFTER TREATMENT: DAYS ☐ TEST ☐ ALLOWABLE

EXHIBIT 3

N PRIME	=	.37	K PRIME	=	.0160000
SPURT	=	7.5 CC	FLUID LOSS	=	.0013 FT/SQR(MIN)
HEIGHT	=	40 FT	YOUNGS MOD.	=	3.00E+06 PSI
INJECTION RATE	=	15 BPM			

VOLUME (GAL)	LENGTH (FT)	WIDTH (IN)
10500	364	.139
11500	390	.143
12500	416	.146
13500	442	.149
14500	466	.152
15500	491	.155 - 5957 - 5982

N PRIME	= .37		K PRIME	=	.0160000
SPURT	= 7.5 CC		FLUID LOSS	=	.0013 FT/SQR(MIN)
HEIGHT	= 70 FT		YOUNGS MOD.	=	3.00E+06 PSI
INJECTION RATE	= 19 BPM				

VOLUME (GAL)	LENGTH (FT)	WIDTH (IN)
10500	217	.135
11500	233	.139
12500	248	.142
13500	264	.145
14500	279	.148
15500	293	.151 - 6120 - 6138

N PRIME	=	.37	K PRIME	=	.0160000
SPURT	=	7.5 CC	FLUID LOSS	=	.0013 FT/SQR(MIN)
HEIGHT	=	30 FT	YOUNGS MOD.	=	3.00E+06 PSI
INJECTION RATE	=	17 BPM			

VOLUME (GAL)	LENGTH (FT)	WIDTH (IN)
10500	488	.148
11500	523	.151
12500	558	.155
13500	592	.158
14500	626	.162
15500	659	.165 - 6302 - 6316

N PRIME = .37		K PRIME = .0160000	
SPURT = 7.5 CC		FLUID LOSS = .0013 FT/SQR(MIN)	
HEIGHT = 10 FT		YOUNGS MOD. = 3.00E+06 PSI	
INJECTION RATE = 16 BPM			

VOLUME (GAL)	LENGTH (FT)	WIDTH (IN)
15000	1846	.185 - 6519 - 6525

N PRIME	=	.37	K PRIME	=	.0160000	
SPURT	=	7.5 CC	FLUID LOSS	=	.0013	FT/SQR(MIN)
HEIGHT	=	40 FT	YOUNGS MOD.	=	3.00E+06	PSI
INJECTION RATE	=	18 BPM				

VOLUME (GAL)	LENGTH (FT)	WIDTH (IN)
16000	514	.162 - 6784 - 6799

EXHIBIT 4

THE WESTERN COMPANY

MAXI FRACTURING DESIGN STUDY

OPERATOR - ERDA
WESTERN REPRESENTATIVE - HANNAH (03/22/76)
FIELD - ---- FORMATION - BEN CONGLOMERATE
COUNTY - WISE STATE - TEXAS
WELL - ----

ANALYSIS - A PAD VOLUME IS PUMPED SUCH THAT A FRACTURE IS CREATED OUT TO THE DESIRED PENETRATION AND THEN FRACTURING FLUID IS PUMPED OUT TO THIS PENETRATION

WELL AND RESERVOIR PROPERTIES:

WELL DEPTH = 6600 FT CASING DIAMETER = 4.00 IN
DRAINAGE RADIUS = 2000 FT FRACTURE HEIGHT = 10 FT
WELLBORE RADIUS = 3.2 IN POROSITY = 10.0 PER CENT
VISCOSITY = .1 CPS COMPRESSABILITY = 1.00E-03 1/PSI
PERMEABILITY = .25 MD YOUNGS MODULUS = 3.00E+06 PSI
TEMPERATURES: EARTH = 70 F; FLUID = 70 F; FORMATION = 120 F
BOTTOM HOLE PRESSURE: STATIC = 1000 PSI; FRACTURING = 3700 PSI
OVERBURDEN PRESSURE = 2700 PSI

PAD FLUID PROPERTIES:

TYPE - FOAM
VISCOSITY = 150.0 CPS PERMEABILITY = .10 MD
SPECIFIC GRAVITY = .35 SPURT LOSS = 1.0 CC
N PRIME = 1.0000 K PRIME = .001580
CI = .000629 CII = .050490 CIII = .000269
COMBINED C = .000188 FT/SQRT(MIN) BASED ON COMBINED CI-CII-CIII

FRACTURING FLUID PROPERTIES:

TYPE - SUPER-K
VISCOSITY = 150.0 CPS PERMEABILITY = .10 MD
SPECIFIC GRAVITY = .92 SPECIFIC HEAT = 1.0 BTU/LB-F
N PRIME = .4000 K PRIME = .085000
CI = .000629 CII = .050490 CIII = .000269
COMBINED C = .000188 FT/SQRT(MIN) BASED ON COMBINED CI-CII-CIII

PROPPANT DATA:

SAND MESH - 20-40 MAXIMUM DIAMETER = .0787 IN
TRUE DENSITY = 22.1 LBS/GAL
PUMPING RATE = 15 BPM CONDUCTIVITY = 10.00 DARCY-FT
AVERAGE CONCENTRATION: WELLBORE = 0.833 LB/SQ-FT
FRACTURE TIP = 0.833 LB/SQ-FT

PENETRATION = 1000 FEET = 50 PER CENT OF DRAINAGE RADIUS

PAD FLUID REQUIRED = 4412 GAL
PAD PUMPING TIME = 7 MIN
PUMPING FRACTURE WIDTH CREATED BY PAD = 0.302 IN

FRACTURING FLUID REQUIRED = 4581 GAL
FRACTURING FLUID PUMPING TIME = 7.3 MIN
PUMPING FRACTURE WIDTH AT END OF TREATMENT = 0.355 IN

SAND SCHEDULE IS AS FOLLOWS:

PUMP 3524 GAL. AT 4.000 LB/GAL FOR 6.6 MIN.
PUMP 341 GAL. AT 5.000 LB/GAL FOR .7 MIN.

SAND REQUIRED = 15804 LBS

PRODUCTIVITY INCREASE = 9.84

MULTIPLIERS FOR THEORETICAL SOLIDS CONCENTRATION PROFILE
(BASED ON DISTANCE FROM WELLBORE):

DISTANCE (FEET) -	0	200	400	600	800	1000
MULTIPLIER -	1.00	1.01	1.03	1.04	1.06	1.07

WELLBORE SAND CONCENTRATION

LBS/GAL	LBS/SQ-FT
.125	.0275
.250	.0547
.500	.1083
.750	.1606
1.000	.2118
1.500	.3110
2.000	.4061
2.500	.4973
3.000	.5848
4.000	.7499
5.000	.9028
6.000	1.0448

PENETRATION = 1500 FEET = 75 PER CENT OF DRAINAGE RADIUS

PAD FLUID REQUIRED = 7313 GAL
PAD PUMPING TIME = 11.6 MIN
PUMPING FRACTURE WIDTH CREATED BY PAD = 0.334 IN

FRACTURING FLUID REQUIRED = 7945 GAL
FRACTURING FLUID PUMPING TIME = 12.6 MIN
PUMPING FRACTURE WIDTH AT END OF TREATMENT = 0.408 IN

SAND SCHEDULE IS AS FOLLOWS:

PUMP 6727 GAL. AT 4.000 LB/GAL FOR 12.6 MIN.

SAND REQUIRED = 26911 LBS

PRODUCTIVITY INCREASE = 12.44

MULTIPLIERS FOR THEORETICAL SOLIDS CONCENTRATION PROFILE
(BASED ON DISTANCE FROM WELLBORE):

DISTANCE (FEET) -	0	300	600	900	1200	1500
MULTIPLIER -	1.00	1.02	1.03	1.05	1.06	1.08

WELLBORE SAND CONCENTRATION

LBS/GAL	LBS/SQ-FT
.125	.0317
.250	.0630
.500	.1245
.750	.1847
1.000	.2436
1.500	.3577
2.000	.4671
2.500	.5720
3.000	.6727
4.000	.8625
5.000	1.0384
6.000	1.2017

PENETRATION = 2000 FEET = 100 PER CENT OF DRAINAGE RADIUS

PAD FLUID REQUIRED = 10481 GAL
PAD PUMPING TIME = 16.6 MIN
PUMPING FRACTURE WIDTH CREATED BY PAD = 0.359 IN

FRACTURING FLUID REQUIRED = 11748 GAL
FRACTURING FLUID PUMPING TIME = 18.6 MIN
PUMPING FRACTURE WIDTH AT END OF TREATMENT = 0.451 IN

SAND SCHEDULE IS AS FOLLOWS:

PUMP 10343 GAL. AT 3.000 LB/GAL FOR 18.6 MIN.

SAND REQUIRED = 31031 LBS

PRODUCTIVITY INCREASE = 14.2

MULTIPLIERS FOR THEORETICAL SOLIDS CONCENTRATION PROFILE
(BASED ON DISTANCE FROM WELLBORE):

DISTANCE (FEET) -	0	400	800	1200	1600	2000
MULTIPLIER -	1.00	1.02	1.03	1.05	1.07	1.09

WELLBORE SAND CONCENTRATION

LBS/GAL	LBS/SQ-FT
.125	.0350
.250	.0695
.500	.1375
.750	.2040
1.000	.2690
1.500	.3950
2.000	.5158
2.500	.6316
3.000	.7428
4.000	.9525
5.000	1.1467
6.000	1.3270

THE WESTERN COMPANY

MAXI FRACTURING DESIGN STUDY

OPERATOR - ERDA
WESTERN REPRESENTATIVE - HANNAH (03/22/76)
FIELD - ---- FORMATION - BEN CONGLOMERATE
COUNTY - WISE STATE - TEXAS
WELL - ----

ANALYSIS - A PAD VOLUME IS PUMPED SUCH THAT A FRACTURE IS CREATED OUT TO THE DESIRED PENETRATION AND THEN FRACTURING FLUID IS PUMPED OUT TO THIS PENETRATION

WELL AND RESERVOIR PROPERTIES:

WELL DEPTH = 6600 FT CASING DIAMETER = 4.00 IN
DRAINAGE RADIUS = 2000 FT FRACTURE HEIGHT = 30 FT
WELLBORE RADIUS = 3.2 IN POROSITY = 10.0 PER CENT
VISCOSITY = .1 CPS COMPRESSABILITY = 1.00E-03 1/PSI
PERMEABILITY = .25 MD YOUNGS MODULUS = 3.00E+06 PSI
TEMPERATURES: EARTH = 70 F; FLUID = 70 F; FORMATION = 120 F
BOTTOM HOLE PRESSURE: STATIC = 1000 PSI; FRACTURING = 3700 PSI
OVERBURDEN PRESSURE = 2700 PSI

PAD FLUID PROPERTIES:

TYPE - FOAM
VISCOSITY = 150.0 CPS PERMEABILITY = .10 MD
SPECIFIC GRAVITY = .35 SPURT LOSS = 1.0 CC
N PRIME = 1.0000 K PRIME = .001580
CI = .000629 CII = .050490 CIII = .000269
COMBINED C = .000188 FT/SQRT(MIN) BASED ON COMBINED CI-CII-CIII

FRACTURING FLUID PROPERTIES:

TYPE - SUPER-K
VISCOSITY = 150.0 CPS PERMEABILITY = .10 MD
SPECIFIC GRAVITY = .92 SPECIFIC HEAT = 1.0 BTU/LB-F
N PRIME = .4000 K PRIME = .085000
CI = .000629 CII = .050490 CIII = .000269
COMBINED C = .000188 FT/SQRT(MIN) BASED ON COMBINED CI-CII-CIII

PROPPANT DATA:

SAND MESH - 20-40 MAXIMUM DIAMETER = .0787 IN
TRUE DENSITY = 22.1 LBS/GAL
PUMPING RATE = 15 BPM CONDUCTIVITY = 10.00 DARCY-FT
AVERAGE CONCENTRATION: WELLBORE = 0.833 LB/SQ-FT
FRACTURE TIP = 0.833 LB/SQ-FT

PENETRATION = 1000 FEET = 50 PER CENT OF DRAINAGE RADIUS

PAD FLUID REQUIRED = 13720 GAL
PAD PUMPING TIME = 21.8 MIN
PUMPING FRACTURE WIDTH CREATED BY PAD = 0.302 IN

FRACTURING FLUID REQUIRED = 17261 GAL
FRACTURING FLUID PUMPING TIME = 27.4 MIN
PUMPING FRACTURE WIDTH AT END OF TREATMENT = 0.436 IN

SAND SCHEDULE IS AS FOLLOWS:

PUMP 13478 GAL. AT 3.000 LB/GAL FOR 24.3 MIN.
PUMP 1654 GAL. AT 4.000 LB/GAL FOR 3.1 MIN.

SAND REQUIRED = 47052 LBS

PRODUCTIVITY INCREASE = 9.84

MULTIPLIERS FOR THEORETICAL SOLIDS CONCENTRATION PROFILE
(BASED ON DISTANCE FROM WELLBORE):

DISTANCE (FEET) -	0	200	400	600	800	1000
MULTIPLIER -	1.00	1.02	1.04	1.07	1.09	1.12

WELLBORE SAND CONCENTRATION

LBS/GAL	LBS/SQ-FT
.125	.0338
.250	.0673
.500	.1331
.750	.1974
1.000	.2604
1.500	.3823
2.000	.4992
2.500	.6113
3.000	.7189
4.000	.9218
5.000	1.1098
6.000	1.2843

PENETRATION = 1500 FEET = 75 PER CENT OF DRAINAGE RADIUS

PAD FLUID REQUIRED = 22878 GAL
PAD PUMPING TIME = 36.3 MIN
PUMPING FRACTURE WIDTH CREATED BY PAD = 0.334 IN

FRACTURING FLUID REQUIRED = 30038 GAL
FRACTURING FLUID PUMPING TIME = 47.6 MIN
PUMPING FRACTURE WIDTH AT END OF TREATMENT = 0.502 IN

SAND SCHEDULE IS AS FOLLOWS:

PUMP   9406 GAL. AT 2.500 LB/GAL FOR   16.6 MIN.
PUMP 17228 GAL. AT 3.000 LB/GAL FOR   31.0 MIN.

SAND REQUIRED = 75203 LBS

PRODUCTIVITY INCREASE = 12.44

MULTIPLIERS FOR THEORETICAL SOLIDS CONCENTRATION PROFILE
(BASED ON DISTANCE FROM WELLBORE):

DISTANCE (FEET) -	0	300	600	900	1200	1500
MULTIPLIER -	1.00	1.03	1.05	1.08	1.11	1.14

WELLBORE SAND CONCENTRATION

LBS/GAL	LBS/SQ-FT
.125	.0389
.250	.0774
.500	.1531
.750	.2271
1.000	.2995
1.500	.4398
2.000	.5742
2.500	.7032
3.000	.8270
4.000	1.0604
5.000	1.2766
6.000	1.4774

PENETRATION = 2000 FEET = 100 PER CENT OF DRAINAGE RADIUS

PAD FLUID REQUIRED = 32947 GAL
PAD PUMPING TIME = 52.3 MIN
PUMPING FRACTURE WIDTH CREATED BY PAD = 0.359 IN

FRACTURING FLUID REQUIRED = 44521 GAL
FRACTURING FLUID PUMPING TIME = 70.6 MIN
PUMPING FRACTURE WIDTH AT END OF TREATMENT = 0.554 IN

SAND SCHEDULE IS AS FOLLOWS:

PUMP 39996 GAL. AT 2.500 LB/GAL FOR 70.6 MIN.

SAND REQUIRED = 99991 LBS

PRODUCTIVITY INCREASE = 14.2

MULTIPLIERS FOR THEORETICAL SOLIDS CONCENTRATION PROFILE
(BASED ON DISTANCE FROM WELLBORE):

DISTANCE (FEET) -	0	400	800	1200	1600	2000
MULTIPLIER -	1.00	1.03	1.06	1.09	1.12	1.15

WELLBORE SAND CONCENTRATION

LBS/GAL	LBS/SQ-FT
.125	.0430
.250	.0855
.500	.1690
.750	.2507
1.000	.3307
1.500	.4856
2.000	.6340
2.500	.7764
3.000	.9131
4.000	1.1708
5.000	1.4095
6.000	1.6312

THE WESTERN COMPANY

MAXI FRACTURING DESIGN STUDY

OPERATOR - ERDA
WESTERN REPRESENTATIVE - HANNAH (03/27/76)
FIELD - ---- FORMATION - BEN CONGLOMERATE
COUNTY - WISE STATE - TEXAS
WELL - ----

ANALYSIS - A PAD VOLUME IS PUMPED SUCH THAT A FRACTURE IS CREATED OUT TO THE DESIRED PENETRATION AND THEN FRACTURING FLUID IS PUMPED OUT TO THIS PENETRATION

WELL AND RESERVOIR PROPERTIES:

WELL DEPTH = 6600 FT CASING DIAMETER = 4.00 IN
DRAINAGE RADIUS = 2000 FT FRACTURE HEIGHT = 40 FT
WELLBORE RADIUS = 3.2 IN POROSITY = 10.0 PER CENT
VISCOSITY = .1 CPS COMPRESSABILITY = 1.00E-03 1/PSI
PERMEABILITY = .25 MD YOUNGS MODULUS = 3.00E+06 PSI
TEMPERATURES: EARTH = 70 F; FLUID = 70 F; FORMATION = 120 F
BOTTOM HOLE PRESSURE: STATIC = 1000 PSI; FRACTURING = 3700 PSI
OVERBURDEN PRESSURE = 2700 PSI

PAD FLUID PROPERTIES:

TYPE - FOAM
VISCOSITY = 150.0 CPS PERMEABILITY = .10 MD
SPECIFIC GRAVITY = .35 SPURT LOSS = 1.0 CC
N PRIME = 1.0000 K PRIME = .001580
CI = .003446 CII = .050490 CIII = .000269
COMBINED C = .000249 FT/SQRT(MIN) BASED ON COMBINED CI-CII-CIII

FRACTURING FLUID PROPERTIES:

TYPE - SUPER-K
VISCOSITY = 150.0 CPS PERMEABILITY = .10 MD
SPECIFIC GRAVITY = .92 SPECIFIC HEAT = 1.0 BTU/LB-F
N PRIME = .4000 K PRIME = .085000
CI = .000629 CII = .050490 CIII = .000269
COMBINED C = .000188 FT/SQRT(MIN) BASED ON COMBINED CI-CII-CIII

PROPPANT DATA:

SAND MESH - 20-40 MAXIMUM DIAMETER = .0787 IN
TRUE DENSITY = 22.1 LBS/GAL
PUMPING RATE = 15 BPM CONDUCTIVITY = 10.00 DARCY-FT
AVERAGE CONCENTRATION: WELLBORE = 0.833 LB/SQ-FT
FRACTURE TIP = 0.833 LB/SQ-FT

PENETRATION = 1000 FEET = 50 PER CENT OF DRAINAGE RADIUS

PAD FLUID REQUIRED = 19128 GAL
PAD PUMPING TIME = 30.3 MIN
PUMPING FRACTURE WIDTH CREATED BY PAD = 0.302 IN

FRACTURING FLUID REQUIRED = 24485 GAL
FRACTURING FLUID PUMPING TIME = 38.8 MIN
PUMPING FRACTURE WIDTH AT END OF TREATMENT = 0.461 IN

SAND SCHEDULE IS AS FOLLOWS:

PUMP 21558 GAL. AT 3.000 LB/GAL FOR 38.8 MIN.

SAND REQUIRED = 64675 LBS

PRODUCTIVITY INCREASE = 9.84

MULTIPLIERS FOR THEORETICAL SOLIDS CONCENTRATION PROFILE
(BASED ON DISTANCE FROM WELLBORE):

DISTANCE (FEET) -	0	200	400	600	800	1000
MULTIPLIER -	1.00	1.02	1.05	1.08	1.11	1.13

WELLBORE SAND CONCENTRATION

LBS/GAL	LBS/SQ-FT
.125	.0357
.250	.0710
.500	.1405
.750	.2085
1.000	.2749
1.500	.4037
2.000	.5270
2.500	.6454
3.000	.7591
4.000	.9733
5.000	1.1717
6.000	1.3561

PENETRATION = 1500 FEET = 75 PER CENT OF DRAINAGE RADIUS

PAD FLUID REQUIRED = 32137 GAL
PAD PUMPING TIME = 51 MIN
PUMPING FRACTURE WIDTH CREATED BY PAD = 0.334 IN

FRACTURING FLUID REQUIRED = 42658 GAL
FRACTURING FLUID PUMPING TIME = 67.7 MIN
PUMPING FRACTURE WIDTH AT END OF TREATMENT = 0.53 IN

SAND SCHEDULE IS AS FOLLOWS:

PUMP 30672 GAL. AT 2.500 LB/GAL FOR 54.1 MIN.
PUMP 7497 GAL. AT 3.000 LB/GAL FOR 13.5 MIN.

SAND REQUIRED = 99175 LBS

PRODUCTIVITY INCREASE = 12.44

MULTIPLIERS FOR THEORETICAL SOLIDS CONCENTRATION PROFILE
(BASED ON DISTANCE FROM WELLBORE):

DISTANCE (FEET) -	0	300	600	900	1200	1500
MULTIPLIER -	1.00	1.03	1.06	1.09	1.12	1.16

WELLBORE SAND CONCENTRATION

LBS/GAL	LBS/SQ-FT
.125	.0411
.250	.0817
.500	.1616
.750	.2398
1.000	.3163
1.500	.4644
2.000	.6063
2.500	.7425
3.000	.8732
4.000	1.1197
5.000	1.3480
6.000	1.5600

PENETRATION = 2000 FEET = 100 PER CENT OF DRAINAGE RADIUS

PAD FLUID REQUIRED = 46564 GAL
PAD PUMPING TIME = 73.8 MIN
PUMPING FRACTURE WIDTH CREATED BY PAD = 0.359 IN

FRACTURING FLUID REQUIRED = 63300 GAL
FRACTURING FLUID PUMPING TIME = 100.4 MIN
PUMPING FRACTURE WIDTH AT END OF TREATMENT = 0.585 IN

SAND SCHEDULE IS AS FOLLOWS:

PUMP 18459 GAL. AT 2.000 LB/GAL FOR 31.9 MIN.
PUMP 38782 GAL. AT 2.500 LB/GAL FOR 68.5 MIN.

SAND REQUIRED = 133875 LBS

PRODUCTIVITY INCREASE = 14.2

MULTIPLIERS FOR THEORETICAL SOLIDS CONCENTRATION PROFILE
(BASED ON DISTANCE FROM WELLBORE):

DISTANCE (FEET) -	0	400	800	1200	1600	2000
MULTIPLIER -	1.00	1.03	1.06	1.10	1.14	1.17

WELLBORE SAND CONCENTRATION

LBS/GAL	LBS/SQ-FT
.125	.0454
.250	.0903
.500	.1785
.750	.2649
1.000	.3493
1.500	.5129
2.000	.6696
2.500	.8200
3.000	.9644
4.000	1.2366
5.000	1.4888
6.000	1.7229

THE WESTERN COMPANY

MAXI FRACTURING DESIGN STUDY

OPERATOR - ERDA
WESTERN REPRESENTATIVE - HANNAH (03/22/76)
FIELD - ---- FORMATION - BEN CONGLOMERATE
COUNTY - WISE STATE - TEXAS
WELL - ----

ANALYSIS - A PAD VOLUME IS PUMPED SUCH THAT A FRACTURE IS CREATED OUT TO THE DESIRED PENETRATION AND THEN FRACTURING FLUID IS PUMPED OUT TO THIS PENETRATION

WELL AND RESERVOIR PROPERTIES:

WELL DEPTH = 6600 FT CASING DIAMETER = 4.00 IN
DRAINAGE RADIUS = 2000 FT FRACTURE HEIGHT = 70 FT
WELLBORE RADIUS = 3.2 IN POROSITY = 10.0 PER CENT
VISCOSITY = .1 CPS COMPRESSABILITY = 1.00E-03 1/PSI
PERMEABILITY = .25 MD YOUNGS MODULUS = 3.00E+06 PSI
TEMPERATURES: EARTH = 70 F; FLUID = 70 F; FORMATION = 120 F
BOTTOM HOLE PRESSURE: STATIC = 1000 PSI; FRACTURING = 3700 PSI
OVERBURDEN PRESSURE = 2700 PSI

PAD FLUID PROPERTIES:

TYPE - FOAM
VISCOSITY = 150.0 CPS PERMEABILITY = .10 MD
SPECIFIC GRAVITY = .35 SPURT LOSS = 1.0 CC
N PRIME = 1.0000 K PRIME = .001580
CI = .000629 CII = .050490 CIII = .000269
COMBINED C = .000188 FT/SQRT(MIN) BASED ON COMBINED CI-CII-CIII

FRACTURING FLUID PROPERTIES:

TYPE - SUPER-K
VISCOSITY = 150.0 CPS PERMEABILITY = .10 MD
SPECIFIC GRAVITY = .92 SPECIFIC HEAT = 1.0 BTU/LB-F
N PRIME = .4000 K PRIME = .085000
CI = .000629 CII = .050490 CIII = .000269
COMBINED C = .000188 FT/SQRT(MIN) BASED ON COMBINED CI-CII-CIII

PROPPANT DATA:

SAND MESH - 20-40 MAXIMUM DIAMETER = .0787 IN
TRUE DENSITY = 22.1 LBS/GAL
PUMPING RATE = 15 BPM CONDUCTIVITY = 10.00 DARCY-FT
AVERAGE CONCENTRATION: WELLBORE = 0.833 LB/SQ-FT
FRACTURE TIP = 0.833 LB/SQ-FT

PENETRATION = 1000 FEET = 50 PER CENT OF DRAINAGE RADIUS

PAD FLUID REQUIRED = 33474 GAL
PAD PUMPING TIME = 53.1 MIN
PUMPING FRACTURE WIDTH CREATED BY PAD = 0.302 IN

FRACTURING FLUID REQUIRED = 48500 GAL
FRACTURING FLUID PUMPING TIME = 76.9 MIN
PUMPING FRACTURE WIDTH AT END OF TREATMENT = 0.512 IN

SAND SCHEDULE IS AS FOLLOWS:

PUMP 26790 GAL. AT 2.500 LB/GAL FOR 47.3 MIN.
PUMP 16446 GAL. AT 3.000 LB/GAL FOR 29.6 MIN.

SAND REQUIRED = 116316 LBS

PRODUCTIVITY INCREASE = 9.84

MULTIPLIERS FOR THEORETICAL SOLIDS CONCENTRATION PROFILE
(BASED ON DISTANCE FROM WELLBORE):

DISTANCE (FEET) -	0	200	400	600	800	1000
MULTIPLIER -	1.00	1.03	1.06	1.10	1.14	1.17

WELLBORE SAND CONCENTRATION

LBS/GAL	LBS/SQ-FT
.125	.0397
.250	.0790
.500	.1563
.750	.2318
1.000	.3058
1.500	.4489
2.000	.5862
2.500	.7178
3.000	.8442
4.000	1.0825
5.000	1.3032
6.000	1.5082

PENETRATION = 1500 FEET = 75 PER CENT OF DRAINAGE RADIUS

PAD FLUID REQUIRED = 56239 GAL
PAD PUMPING TIME = 89.2 MIN
PUMPING FRACTURE WIDTH CREATED BY PAD = 0.334 IN

FRACTURING FLUID REQUIRED = 73662 GAL
FRACTURING FLUID PUMPING TIME = 116.8 MIN
PUMPING FRACTURE WIDTH AT END OF TREATMENT = 0.51 IN

SAND SCHEDULE IS AS FOLLOWS:

PUMP 43868 GAL. AT 2.500 LB/GAL FOR 77.4 MIN.
PUMP 21863 GAL. AT 3.000 LB/GAL FOR 39.4 MIN.

SAND REQUIRED = 175261 LBS

PRODUCTIVITY INCREASE = 12.44

MULTIPLIERS FOR THEORETICAL SOLIDS CONCENTRATION PROFILE
(BASED ON DISTANCE FROM WELLBORE):

DISTANCE (FEET) -	0	300	600	900	1200	1500
MULTIPLIER -	1.00	1.04	1.08	1.12	1.17	1.21

WELLBORE SAND CONCENTRATION

LBS/GAL	LBS/SQ-FT
.125	.0396
.250	.0787
.500	.1557
.750	.2310
1.000	.3046
1.500	.4473
2.000	.5840
2.500	.7151
3.000	.8410
4.000	1.0784
5.000	1.2983
6.000	1.5025

PENETRATION = 2000 FEET = 100 PER CENT OF DRAINAGE RADIUS

PAD FLUID REQUIRED = 81486 GAL
PAD PUMPING TIME = 129.2 MIN
PUMPING FRACTURE WIDTH CREATED BY PAD = 0.359 IN

FRACTURING FLUID REQUIRED = 126000 GAL
FRACTURING FLUID PUMPING TIME = 199.8 MIN
PUMPING FRACTURE WIDTH AT END OF TREATMENT = 0.651 IN

SAND SCHEDULE IS AS FOLLOWS:

PUMP 113273 GAL. AT 2.000 LB/GAL FOR 195.9 MIN.
PUMP 2223 GAL. AT 2.500 LB/GAL FOR 3.9 MIN.

SAND REQUIRED = 232106 LBS

PRODUCTIVITY INCREASE = 14.2

MULTIPLIERS FOR THEORETICAL SOLIDS CONCENTRATION PROFILE
(BASED ON DISTANCE FROM WELLBORE):

DISTANCE (FEET) -	0	400	800	1200	1600	2000
MULTIPLIER -	1.00	1.04	1.08	1.13	1.18	1.23

WELLBORE SAND CONCENTRATION

LBS/GAL	LBS/SQ-FT
.125	.0505
.250	.1004
.500	.1986
.750	.2946
1.000	.3886
1.500	.5706
2.000	.7450
2.500	.9123
3.000	1.0729
4.000	1.3758
5.000	1.6562
6.000	1.9168

EXHIBIT 5

SCHLUMBERGER

PRODUCTION LOGGING CONTINUOUS FLOWMETER

SCHLUMBERGER WELL SURVEYING CORPORATION
Houston, Texas

COUNTY WISE
FIELD or LOCATION WILDCAT
WELL FERGUSON NO. 1-A
COMPANY DALLAS PROD., INC.

COMPANY DALLAS PRODUCTION, INC.

WELL FERGUSON NO. 1-A

FIELD WALDCAT

COUNTY WISE STATE TEXAS

LOCATION 1320'FNL, 1320'FEL
BEN D. SMITH SURVEY
A-779
Sec. Twp. Rge.

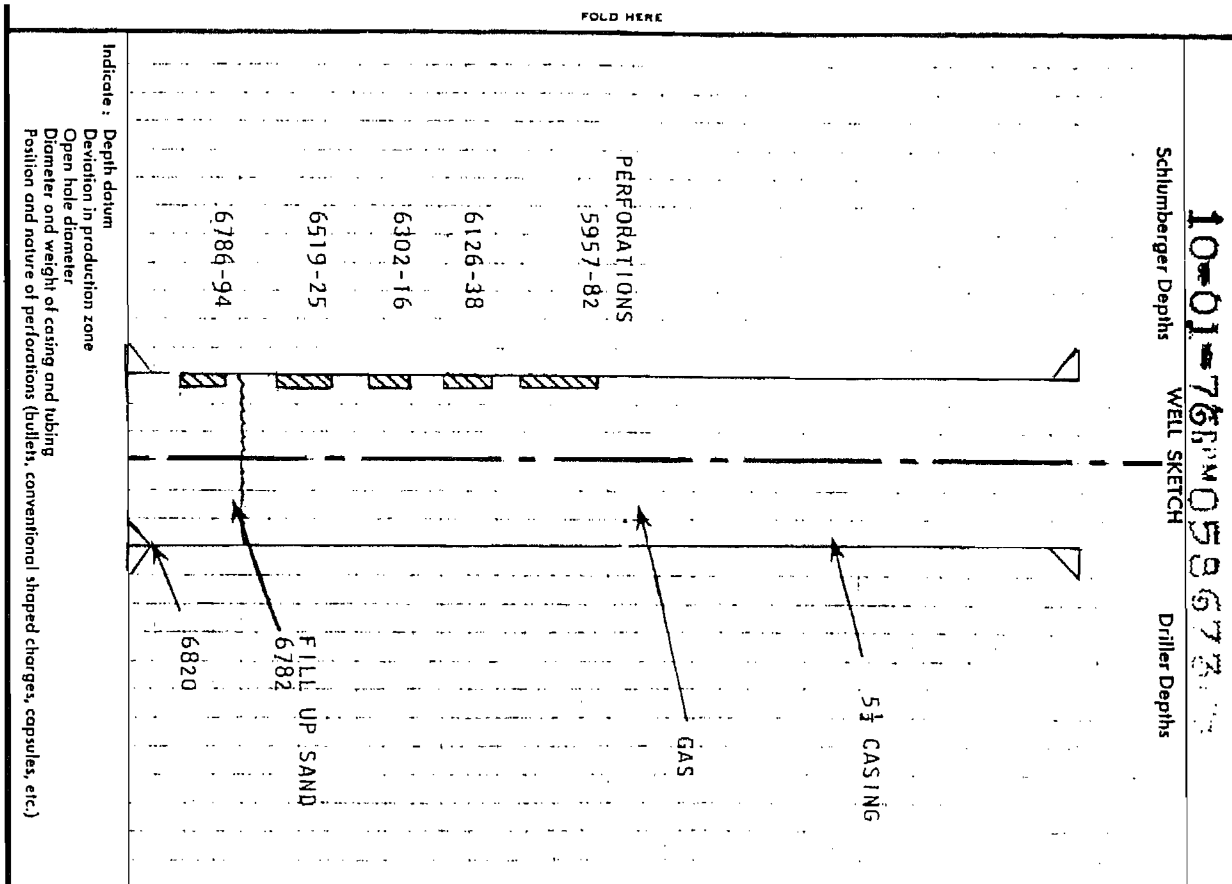
Other Services:
HRT

Permanent Datum: GROUND LEVEL, Elev. 807
Log Measured From K.B., 11 Ft. Above Perm. Datum
Drilling Measured From K.B.

Elev.: K.B. 818
D.F. -
G.L. 807

Date	9-7-76	Production Method	FLOWING	
Run No.	TWO	Prod. Rate (Surface)		
Depth — Driller	6820	for: Choke size	FULL	
Depth — Logger	6782	: BH Presure		
Btm. Log Interval	6781	: Tbg. Hd. Press.	250# - 75#	
Top Log Interval	5900	: % Water Cut		
		: G.O.R.	-	
Casing — Driller				
Casing — Logger	6820			
Casing size	$4\frac{1}{2}$"	Produced Fluids (Type)		
Casing Wt.	10.5#	GAS: Cu. ft/day @ STP		
Tubing — Driller	-	: BH Density		
Tubing — Logger	-	: BH Viscosity		
Tubing size	-	OIL: Bbls/day		
Tubing Wt.	-	: API Grav. @ °F		
Bit Size (Open hole)	7 7/8"	: Surf. Density @ °F		
		: BH Viscosity		
SI Tbg. Hd. Press.		WATER: Bbls/day		
SI BH Press (Res.)		: Water Salinity		
Productivity Index		: Surf. Density @ °F		
Form. Volume Factor		: BH Viscosity		
Max. Rec. Temp.	168			
Truck & Locn.	3868/GRM			
Recorded by	PRIDDY			
Witnessed by	MR. CRAWFORD			

FOLD HERE



FOLD HERE

CONDITIONS OF PRODUCTION DURING SURVEY	
Production rate: UNKNOWN	with choke of:
Head pressures: Tubing 250# DOWN TO 75#	Casing:
Time of production prior survey: SHUT IN	
Time of stabilization prior survey:	
REMARKS:	

EQUIPMENT		
Panel:	PPB-CB	N° 738-A
Plug in unit	PRN-C	N° 732-A
Sonde		N°
SPINNER DIA.	F.B.	4½
UP-FLOW ASSY.		☐
DOWN-FLOW ASSY.		☒
CENTRALIZERS		☒

COMPANY DALLAS PRODUCTION, INC.
WELL FERGUSON NO. 1-A
FIELD WILDCAT **COUNTY** WISE **Date** 9-7-76

Schlumberger

PROBLEM: DETERMINE THE PRODUCTION PROFILE- WHAT PERFORATED ZONES ARE PRODUCING AND HOW MUCH GAS IS COMING FROM EACH ZONE.

TECHNIQUE:
THE FULLBORE FLOWMETER WAS RUN AT DIFFERENT CABLE SPEEDS TO DETERMINE THE FLOW PROFILE WHILE THE WELL WAS PRODUCING.

INTERPRETATION:

WELL FLOWING

WELL UNSTABLE

ZONE	SURFACE PRODUCTION FR. EACH ZONE		%SURFACE PRODUCTION
	HIGH	LOW	
5957-82	0	0	0%
6125-38	57 MCF	19 MCF	12% - 10%
6302-16	28 MCF	37 MCF	6% - 16%
6519-25	211 MCF	94 MCF	45% - 45%
6786-94	169 MCF	61 MCF	36% - 29%

WHEN WELL STABLE - ONLY THREE ZONES ARE PRODUCING AS INDICATED ON THE 9-3-76. ON 9-7-76 THE WELL WAS UNSTABLE BECAUSE IT HAD NOT BEEN PRODUCED LONG ENOUGH TO STABLIZED. AFTER BEING SHUTIN THE RUN 1 ON 9-7-76 DOES INDICATE THAT THERE IS SOME PRODUCTION COMING FR ZONE 6786-94, BUT AFTER FLOWING FOR SOME TIME IT PRESSURE DRAWS DOWN-LIKE A ZONE THAT HAS A "HIGH POSITIVE SKIN FACTOR." FRACING SHOULD HELP THIS ZONE.

MAIN PRODUCING ZONES ARE 6126-38, 6302-16 &6519-25.

THE FLOW METER SURFACE PRODUCTION IS BASED ON THE FOLLOWING PARAMETERS.
44.7 FT/MIN = 1000 BBL/DAY FOR $4\frac{1}{2}$" - 10.5# PIPE
Z(GAS COMPRESSIBILITY FACTOR) = .93
BHF= 617PSI
BHT= 168°
1/BG SCF/CUFT (GAS VOLUME FACTOR = 37.37

By: PRIDDY & SCHNORR

SWS-1428-C

SCHLUMBERGER

PRODUCTION LOGGING CONTINUOUS FLOWMETER

SCHLUMBERGER WELL SURVEYING CORPORATION
Houston, Texas

COUNTY WISE
FIELD or LOCATION WILDCAT
WELL FERGUSON NO. 1-A
COMPANY DALLAS PROD., INC

COMPANY DALLAS PRODUCTION, INC.

WELL FERGUSON NO. 1-A

FIELD WILDCAT

COUNTY WISE STATE TEXAS

LOCATION 1320'FNL, 1320'FEL
BEN D.SMITH SURVEY, A-779.

Sec. ______ Twp. ______ Rge. ______

Other Services:
HRT

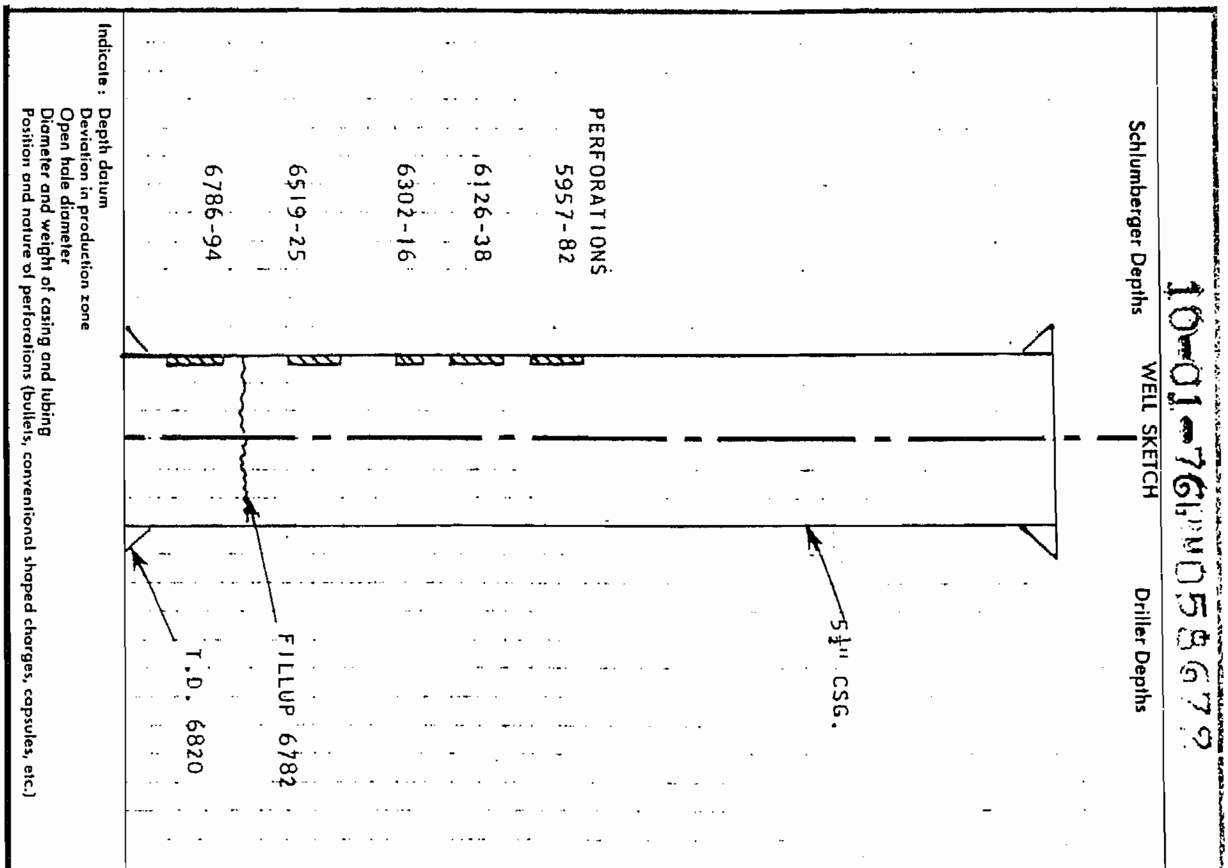
Permanent Datum: GROUND LEVEL, Elev. 807
Log Measured From K.B., 11 Ft. Above Perm. Datum
Drilling Measured From K.B.

Elev.: K.B. 818
D.F. -
G.L. 807

Date	9-3-76	Production Method	FLOWING OUT CSG.	
Run No.	ONE	Prod. Rate (Surface)	45-50 MCF	
Depth — Driller	6820	for: Choke size	FULL	
Depth — Logger	6782	: BH Presure	-	
Btm. Log Interval	6781	: Tbg. Hd. Press.	53 PSI	
Top Log Interval	5900	: % Water Cut		
		: G.O.R.		
Casing — Driller	6820			
Casing — Logger	-			
Casing size	$4\frac{1}{2}$"	Produced Fluids (Type)		
Casing Wt.	10.5#	GAS: Cu. ft/day @ STP		
Tubing — Driller	-	: BH Density		
Tubing — Logger	-	: BH Viscosity		
Tubing size	-	OIL: Bbls/day		
Tubing Wt.	-	: API Grav. @ °F		
Bit Size (Open hole)	$7\frac{7}{8}$"	: Surf. Density @ °F		
		: BH Viscosity		
SI Tbg. Hd. Press.	53 PSI	WATER: Bbls/day		
SI BH Press (Res.)		: Water Salinity		
Productivity Index	45-50K/D	: Surf. Density @ °F		
Form. Volume Factor		: BH Viscosity		
Max. Rec. Temp.				
Truck & Locn.	3868/GRM			
Recorded by	PRIDDY			
Witnessed by	MR. CRAWFORD			

SWSC-1305

FOLD HERE



FOLD HERE

CONDITIONS OF PRODUCTION DURING SURVEY		EQUIPMENT	
Production rate:	with choke of:	Panel:	N°
Head pressures: Tubing	Casing:	Plug in unit	N°
Time of production prior survey:		Sonde	N°
Time of stabilization prior survey:		SPINNER DIA. 4½ FB	
		UP-FLOW ASSY.	☐
REMARKS: BOTTOM SET PLUGGED OFF DUE TO SAND PRODUCTION 6786-94		DOWN-FLOW ASSY.	☐
		CENTRALIZERS	☐
PERFORATIONS @ 6786-94, 6519-25, 6302-16, 6126-38			
5957-82			

COMPANY DALLAS PRODUCTION, INC.
WELL FERGUSON NO. 1-A
FIELD WILDCAT **COUNTY** WISE **Date** 9-3-97

Schlumberger

PROBLEM: DETERMINE THE PRODUCTION PROFILE-
WHAT PERFORATED ZONES ARE PRODUCING
& HOW MUCH GAS IS COMING FR. EACH ONE.

TECHNIQUE:
THE FULLBORE FLOWMETER WAS RUN @ DIFFERENT CABLE SPEEDS TO DETERMINE THE FLOW PROFILE WHILE THE WELL WAS FLOWING.

INTERPRETATION:

	WELL FLOWING	WELL STABLE
ZONE	SURFACE PRODUCTION FR EACH ZONE	% SURFACE PRODUCTION
5957-82	0	0%
6126-38	57 MSCF	22%
6302-16	86 MSCF	33%
6519-25	115 MSCF	45%
6786-94	0	0%

TOTAL SURFACE PRODUCTION 258 MCF

By: [illegible]

SWS-1428-C

THE WESTERN COMPANY

WL-75 (Rev.11/75)

EXHIBIT 6 **Profile**

FILING NO. 9-76-179-L	COMPANY Dallas Production Co., Inc.
	WELL Ferguson #1-A
	FIELD Wildcat
	COUNTY Wise STATE Texas
JOB NO.	LOCATION 1320' FNL & 1320' FEL Ben D. Smith Survey A-779 SEC. TWP. RGE.
	OTHER SERVICES:

PERMANENT DATUM: Ground Level, ELEV. 807'	ELEV.: K.B. 818'
LOG MEASURED FROM Kelly Bushing 11 FT. ABOVE PERM. DATUM	D.F. 817'
DRILLING MEASURED FROM Kelly Bushing	G.L. 807'

DATE	9-14-76		
RUN NO.	One		
TYPE LOG	Velocity Profile		
DEPTH—DRILLER			
DEPTH—LOGGER	6793'		
BOTTOM LOGGED INTERVAL	6792'		
TOP LOGGED INTERVAL	5700'		
TYPE FLUID IN HOLE	Water		
SALINITY, PPM CL.			
DENSITY			
LEVEL	Full		
MAX. REC. TEMP., DEG. F.			
OPERATING RIG TIME	Portable Mast		
RECORDED BY	Ray		
WITNESSED BY	Mr. Crawford,	Mr. Ellis, & Mr.	Atkinson

RUN	BORE-HOLE RECORD			CASING RECORD			
NO.	BIT	FROM	TO	SIZE	WGT.	FROM	TO
				4.5"	10.50#	Surface	T.D.

Date Injection Started ____________

Cumulative Injection ____________ BW to ____________

Time Drive 1.88 & .46 seconds per Log Division

Customer pressure ________ Western pressure Sur. #1 - 1200#
Sur. #2 - 2900#

Customer Flow Rate ________ BPD Western Rate Sur. #1 - [illegible] 3PM
q
Sur. #2 - 5 BPM
Sur. #3 - 1.5 BPM

Perforations 5957' - 62', 5970'-82', 6120'-24', 6130'-38', 6302'16', 6519'-25', 6786'-94'.

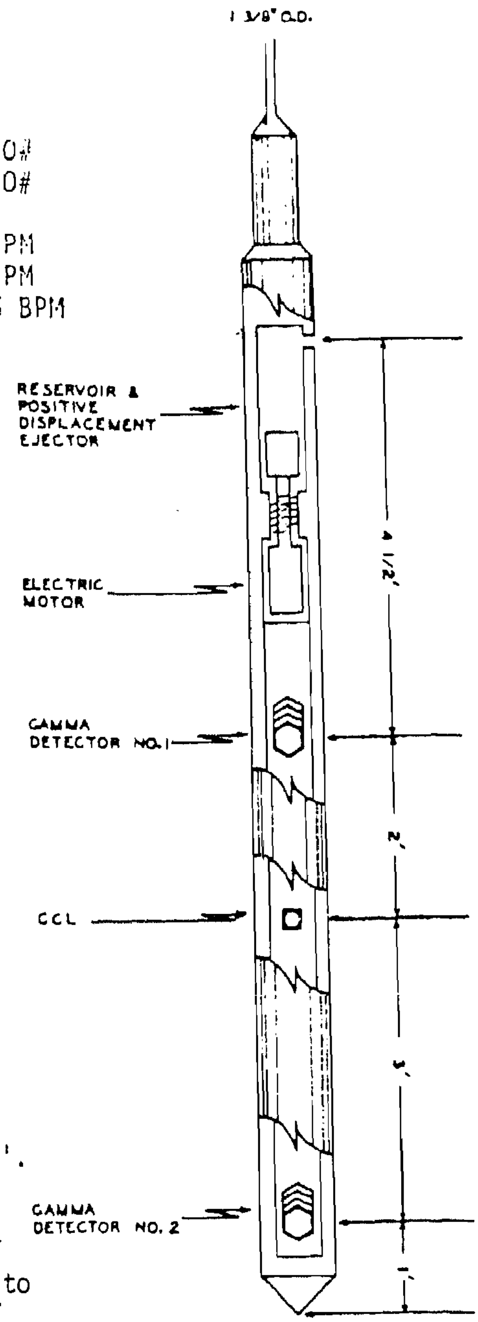
Channeling Indications No Yes From ______ to ______
______ to ______
______ to ______

Remarks: 9-14-76 - Initial Survey #1 indicates 30% of fluid being lost to 5957'-62', and 5970'-82'. 54% being lost to 6120'-24' and 6130'-38'. 1% to 6302'-16'. 1% to 6519'-25', and 14% to 6786'-94'. Went Back in hole after frac began and found hole in casing to be between 4000' and 5000'.

9-15-76 - Tagged fill-up @6392'.

9-16-76 - Survey #2 indicates 15% of fluid being lost to 5957'-62' and 5970' - 82'. 10% to 6120'-24' and 6130'-38'. 65% to 6302'-16'. 9% to 6519'-25' and 1% to 6786'-94'.

Survey #3 (after frac) indicates 82% of fluid being lost to 5957'-62' and 5970'-82' with remaining 18% going to 6120'-24'. T.D. after frac was 6128'.



WL-49 WESTERN CO. (Rev. 5-72)

BURST SHEET

THE WESTERN COMPANY

Burst Number	Depth (Feet)	Time Units	Time Sec.	Diameter Hole (Inches)	Dia. Small Hole (In.)	Dist. From Chg. (Feet)	Western Flow Rate (BPD)	Percent Fluid In Hole	Remarks
		Velocity Survey #1 - Run 9-14-76							
		20 ft. Spacing Between Detectors							
1	6160'-6180'	21	19.74	4.052			995	14	
2	6510'-6530'	21	19.74	4.052			995	14	
3	6495'-6515'	20	18.8	4.052			1038	15	
4	6300'-20'	20	18.8	4.052			1038	15	
5	6275'-95'	18	16.92	4.052			1161	16	
6	6125'-45'			4.052					Erratic Rate
7	6130'-50'			4.052					Erratic Rate
8	6275'-95'	18	16.92	4.052			1161	16	
9	6230'-50'			4.052					Erratic Rate
10	6130'-50'	18	16.92	4.052			1161	16	
11	6095'-6115'	4	3.76	4.052					Erratic Rate
12	6095'-6115'	17	3.91	4.052			5039	70	Fast Time Drive
13	5970'-90'	17	3.91	4.052			5039	70	Fast Time Drive
14	5930'-50'	12	2.76	4.052			7157	100	Fast Time Drive
15	5920'-40'	12	2.76	4.052			7157	100	Fast Time Drive
		Velocity Shots Taken To Locate Hole in Casing							
		20 ft. Spacing Between Detectors							
16	5930'-50'	214		4.052					
17	5930'-50'	158	148.5	4.052			107		
18	5010'-30'	48	45.12	4.052			432		
19	4010'-30'								
20	4010'-30'	15	3.45	4.052			5742		Fast Time Drive
21	3010'-30'	15	3.45	4.052			5742		Fast Time Drive
		Velocity Survey #2 Run 9-16-76							
		10 ft. Spacing Between Detectors							
22	6720'-30'	110	103.4	4.052			76	1	
23	6505'-15'	14	13.16	4.052			730	10	
24	6285'-95'	2	1.88	4.052					
25	6285'-95'	8	1.84	4.052			5368	75	Fast Time Drive
26	6105'-15'	7	1.61	4.052			6097	85	Fast Time Drive
27	5940'-50'	6	1.38	4.052			7157	100	Fast Time Drive
28	5930'-40'	6	1.38	4.052			7157	100	Fast Time Drive
		Velocity Survey #3 Run 9-16-76							
		10 ft. Spacing Between Detectors							
29	6105'-15'	27	25.38	4.052			361	18	
30	5940'-50'	21	4.83	4.052			2058	100	Fast Time Drive

Form PS-8 (Rev. 6/75)

EXHIBIT 7

The Western Company
of North America
TREATMENT REPORT

Date 9/14/76 Western District Snyder F. Receipt 149350
Operator Dallas Production Co. Inc.
Lease Ferguson Well No. 1-A
Field Gas Finder Location Snyder District
County Wise State Texas
Stage Number 1, This Zone [x] This Well [x]

WELL DATA: OG [x] NG [ ] NO [ ] OO [ ] WD [ ] IW [ ] Misc. [ ] Depth TD/PB 6793 Formation Ben Conglomerate
Size Tubing — Tubing Perf. — Type Packer — Set At —
Size Casing 4.5 Wt. 9.5 Set From surface To thru Size Liner — Wt. —
Liner Set From — To — Open Hole: Size — From — To —
Casing Perforations: Size .41 Holes Per Foot -- Intervals 6519-6525; 6786-6794; 5957-5982
6126-6138; 70 holes
Previous Treatment N/A Prior Production N/A

TREATMENT DATA: Pad Used: Yes [x] No [ ] Pad Type Foam Frac & Super K
Treating Fluid Type: Oil [ ] Water [ ] Acid [ ] Misc. [ ] Foam [x] Emulsion [x]
Treating Fluid Volume Gals. 336,500 Fluid Description 198,000 gals Super K
138,500 gals Foam; 1500 gals 15% DS 30
Total Prop Quantity 501,000 Lbs. Prop Type: Sand [x] Beads [ ] Special [ ] None [ ]
Prop Mesh Sizes, Types and Quantities 100,000# 100 mesh; 401,000# 10/20
Hole Loaded With Water and Gas Treat Via: Tubing [x] Casing [x] Anul [ ] Tubing & Anul. [ ]
Ball Sealers: 15 In 1 Stages of 15
Types and Number of Pumps Used Two Fracmasters and Two Titans
Auxiliary Materials 30,000# KCL; 250 gals Adofoam; 600# B-5; 5220 gals Aquaflow
4100# J-2; 3100# Aquaseal; 440 gals E-15;
Procedure Treat casing via casing burst casing; run tubing and packer and
treat via tubing below packer

FLUID PUMPED AND CAPACITIES IN BBLS.
Tubing Cap. —
Casing Cap. 110
Annular Cap. —
Open Hole Cap. —
Fluid to Load —
Pad Volume 1784
Treating Fluid 5230
Flush 110
Overflush 20
Total to Recover 7144

Time AM/PM	Treating Pressure-Psi Tubing	Treating Pressure-Psi Casing	Barrels Fluid Pumped	Inj. Rate BPM	REMARKS—
6:50		100		15	Run pad
6:57		1400	110	14	Hole loaded
7:05		1500	220	14	All pad shut down run log ISDP 1100
7:50		1200		6	Run pad and log
8:22		1200	205	6	All pad ISDP 100
9:50				5.3	Run foam pad
10:03		3200	70.4	5.3	Run 2# 100 mesh sand
10:13		3100	122.4	5.3	Run Foam pad
10:26		3300	192.8	5.2	Run 2# 100 mesh sand
10:36		3200	244.8	5.2	Run Foam pad
10:49		3400	315.2	5.2	Run 2# 100 mesh sand
11:00		3200	367.2	5.2	Run Foam pad
11:13		3400	437.6	5.2	Start 2# 100 mesh sand
11:21		3300	489.6	5.2	Start pad
11:39		3300	560	5.2	Start 2# 100 mesh sand
11:48		3300	612	5.2	Start pad: Total Foam Frac 62,000# 100 mesh sand
					682.4 total water
12:01		3400		18	Run Super K with 1# 10/20 sand
12:14		3000	190	21	Run 2# 10/20 sand
12:25		3100	404	18	Run 3# 10/.20 sand
12:46		3500	764	18	Run 4# 10/20 sand burst casing
1:17		4000	1237	6	Cut sand start flush
1:41		1600	1387	11	All flush ISDP 1200
2:10		1300	180	5	Run pad and log
	9/15/76				Circulate sand run 2 7/8 tubing with Baker pakcer
					and set at 5700 - tubing cap. 33 casing cap 18
	9/16/76				Test lines 9000 psi; Max psi 8500
10:30					Load hole and check rate
10:34	6000		50	13	Shut down check ISDP 3100
10:37	8500		50	20	Resume water
10:44	7700		140	17	Shut down ISDP 2600
12:50				5	Start pad and log
1:25	2700		153	5	All pad and log ISDP 1900

3:05					Run 750 gals acid
3:14	4300		18	3.7	Start foam frac
3:15	4300		24		Shut down fix leak
3:19	4300		28	3.7	Resume foam frac with 2# 100 mesh sand
3:20	4300		32	3.7	Run pad
3:21	4300		36	3.7	Run 2# 100 mesh sand
3:23	4400		40	3.7	Run pad
3:24	4500		44	3.7	Run 2# 100 mesh sand
3:25	4500		48	3.7	Run pad
3:27	4500		52	3.7	Run 2# 100 mesh sand
3:28	4500		56	3.7	Run pad
3:29	4500		60	3.7	Run 2# 100 mesh sand
3:30	4500		64	3.7	Run pad
3:34	4000			13	Start super K pad
3:37	5000		48	15	Run 1# 10/20 sand
3:41	6700		96	11	Run 2# 10/20 sand
3:45	7300		144	14	Run 3# 10/20 sand
3:49	7600		192	14	Cut sand run water
3:54	5000		212	6	Start acid and balls
4:00	4500			3.7	Run pad foam frac
4:06	6600		24	3.7	Run 2# 100 mesh sand
4:11	6700		58	3.7	Run pad
4:16	6700		92	3.7	Run 2# 100 mesh sand
4:20	6700		116	3.7	Run pad
4:25	6600		150	3.7	Run 2# 100 mesh sand
4:30	6500		174	3.7	Run pad
4:35	6500		208	3.7	Run 2# 100 mesh sand
4:40	6500		232	3.7	Run pad
4:45	6500		266	3.7	Run 2# 100 mesh sand
4:50	6500		290	3.7	Run pad
5:01	6200		338	3.7	All foam Foam Frac 38,000# 100 mesh sand
5:02	6200			15	Start Super K pad
5:53	7500		480	15	Run 1# 10/20 sand
7:20	7500		1440	10	Run 2# 10/20 sand
9:10	7500				Packing out on blender shut down
					Start flush
9:50	6000			10	Resume Super K
10:20	6500		2640	10	Run 3# 10/20 sand 250,000# 10/20 sand
11:50	7000		3544	9	All frac start flush
11:58	7000		3614	9	All flush
	9/17/76				
1:30				1.5	Run pad and log
1:43			19	1.5	All pad shut down

Treating Pressure: Min. 3200 Max. 7500 Avg. 6000

Inj. Rate on Treating Fluid 12.0 Rate on Flush 10.0

Avg. Inj. Rate 11.0 I.S.D.P. 4200 Flush Dens. lb/gal 8.5

Final Shut-in Pressure 3800 in 10 Minutes.

Operator's Maximum Pressure 4000-9000

Customer Representative Crawford & Ellis

Western Representative Cumbie and Barnes

Distribution

Bill Matson, P. O. Box 186, No. 50

Fort Worth, Texas 76101.

Snyder District 79549 No. 4

Job Number

502338

EXHIBIT 8

DAILY OPERATIONS REPORT
Ferguson "A"-1
Wise County, Texas

1976

8/26/76 - Rig up WSU. Well flowing 40 MCF gas day. TP 60#, Bled off pressure, Ran swab, no fluid in well bore. Pull tubing, turned well back into line flowing thru 4 1/2" casing.

8/27/76 - Well flowing 40 MCF day WHP 60#
8/28/76 - Well flowing 40 MCF day WHP 60#
8/29/76 - Well flowing 40 MCF day WHP 60#
8/30/76 - Well flowing 40 MCF day WHP 60#
8/31/76 - Well flowing 40 MCF day WHP 60#
9/1/76 - Well flowing 40 MCF day WHP 60#
9/2/76 - Well flowing 40 MCF day WHP 60#
9/3/76 - Schlumberger Well logging ran Velocity Profile logs. Found lower most set of perfs covered by sand.
9/4/76 - Well shut in
9/5/76 - Well shut in
9/6/76 - Schlumberger well logging ran 2nd Velocity Survey.
9/7/76 - Blew well down into pipeline
9/8/76 - Rig up WSU, and pumped all sand out of 4 1/2" casing
9/9/76 - Well shut in
9/10/76 - Well shut in, moving in frac equipment
9/11/76 - Well shut in
9/12/76 - Well shut in
9/13/76 - Well shut in
9/14/76 - Ran tracer survey. Massive frac pumping began @ 9:40 a.m., pumped 62,000# 100 Mesh sand, 87,000 gallons foam, 52,000 gallons Super K frac fluid and 151,000# 10/20 Mesh sand. The pump pressure increased to 4000# @ pump rate of 10 bpm and the casing ruptured @ the depth of 4500'. Began bleeding pressure to run tubing.
9/15/76 - Ran 2 3/8" tubing and circulated sand out of the well bore. Pulled 2 3/8" tubing.
9/16/76 - Ran 2 7/8" tubing and Baker Packer and set @ 5800'. Continue frac treatment down 2 7/8" tubing, finished treatment at midnight. (See letter in file for detail).
9/17/76 - Ran tracer survey and found approximately 600' sand fill up in well bore. Began flowing back @ 2:00 a.m. Flowing @ approximate rate of 10 bph.
9/18/76 - Continue flowing frac fluid, flowed 230 bbls.
9/19/76 - Continue flowing frac fluid, flowed 190 bbls.
9/20/76 - Continue flowing frac fluid, flowed 158 bbls.
9/21/76 - Continue flowing frac fluid, flowed 105 bbls.
9/22/76 - Continue flowing frac fluid, flowed 80 bbls.
9/23/76 - Continue flowing frac fluid, flowed 70 bbls.
9/24/76 - Continue flowing frac fluid, flowed 70 bbls.
9/25/76 - Continue flowing frac fluid, flowed 60 bbls.
9/26/76 - Continue flowing frac fluid, flowed 60 bbls.
9/27/76 - Continue flowing frac fluid, flowed 43 bbls.
9/28/76 - Continue flowing frac fluid, flowed 40 bbls.
9/29/76 - Continue flowing frac fluid, flowed 30 bbls.
9/30/76 - Rig up WSU, pull 2 7/8" tubing, run 2" tubing, prep to wash out sand.
10/1/76 - Washed sand out of casing to plug below all perfs.
10/2/76 - Pull tubing & pick up packer, ran packer and set @ 5800' w/tail pipe to 6600'.
10/3/76 - Down Sunday
10/4/76 - FL 1500' from Surface. Swabbed 240 bbls frac fluid, began showing gas.
10/5/76 - FL 1200', swabbed 216 bbls frac fluid, gas increasing.
10/6/76 - FL 2500', swabbed down and well began flowing, spray frac fluid and gas.
10/7/76 - Flowed 60 bbls frac fluid w/fair show gas in 24 hours, 1/2" choke TP 10#.

10/8/76 - Flowed 40 barrels frac fluid
10/9/76 - Flowed 20 barrels frac fluid
10/10/76 - Flowed 10 barrels frac fluid and well died
10/11/76 - Well began flowing without swab, flowed 40 barrels frac fluid
10/12/76 - Flowed 17 barrels frac fluid
10/13/76 - Flowed 11 barrels frac fluid
10/14/76 - Flowed 3 barrels frac fluid
10/15/76 - 10/17/76 SI
10/18/76 - SIP after 3 days 770#, open to tanks, flowed 3 barrels frac fluid and died
Ru swab unit, FL 3000', swab down and left open, well flowing into tank.
10/19/76 - Flowed 21 bbls frac fluid
10/20/76 - Flowed 18 bbls frac fluid
10/21/76 - Flowed 14 bbls frac fluid
10/22/76 - Flowed 8 bbls frac fluid
10/23/76 - Flowed 14 bbls frac fluid
10/24/76 - Flowed 10 bbls frac fluid
10/25/76 - Flowed 8 bbls frac fluid
10/26/76 - Flowed 5 bbls frac fluid
10/27/76 - Flowed 5 bbls frac fluid
10/28/76 - Flowed 5 bbls frac fluid
10/29/76 - Flowed 7 bbls frac fluid
10/30/76 - Flowed 5 bbls frac fluid
10/31/76 - Flowed 6 bbls frac fluid
11/1/76 - Flowed 5 bbls frac fluid
11/2/76 - Setting pumping unit - Flowed 3 bbls frac fluid
11/3/76 - Flowed 5 bbls frac fluid, awaiting WSU to run rods
11/4/76 - Awaiting WSU
11/5/76 - Flowed 3 bbls frac fluid, awaiting WSU to run rods
11/6/76 - Flowed 3 bbls frac fluid
11/7/76 - Flowed 4 bbls frac fluid
11/8/76 - Flowed 8 bbls frac fluid
11/9/76 - Flowed 3 bbls frac fluid, awaiting unit to run rods
11/10/76 - Flowed 5 bbls frac fluid
11/11/76 - RUWSU, haul in and unload rods, prep to run rods
11/12/76 - Ran pump & rods, prep to start pumping
11/13/76 - Down due to weather
11/14/76 - Down due to weather
11/15/76 - Down due to weather
11/16/76 - Down due to weather
11/17/76 - Rigging up pumping unit and connecting separator and test tank
11/18/76 - Rig up Pumping unit, start well to pumping
11/19/76 - Failed to pump
11/20/76 - Failed to pump
11/21/76 - Awaiting WSU to repair
11/22/76 - Awaiting well service unit to pull pump
11/23/76 - Awaiting well service unit
11/24/76 - Awaiting well service unit
11/25/76 - Down for holiday
11/26/76 - Down for holiday
11/27/76 - Down for holiday
11/28/76 - Down for holiday
11/29/76 - Awaiting WSU to pull pump
11/30/76 - RUWSU
12/1/76 - RUWSU, attempt to pull rods, pump stuck, prep to pull tubing and rods
12/2/76 - Attempt to pull tubing, Stuck @ packer, backed off rods and pulled
12/3/76 - Unseated Pkr. & pulled tubing, ran Ret BP & squeeze pkr.
12/4/76 - Located hole in Csg @ 4813', set BP @ 5500', Pkr @ 4750' squeeze w/100 sks to /2000#
12/5/76 - Sunday

Ferguson "A" # 1 DAILY OPERATIONS REPORT Wise County, Texas

12/7/76 - Pull squeeze pkr, ran bit, prep to drill cement.
12/8/76 - Drill out cement, POH w/bit, ran retrieving tool and recovered BP
12/9/76 - Bridge plug became stuck while pulling, attempting to loose
12/10/76 - Unable to loose BP, cut off tubing 6' above plug @ 5440' POH w/tbg, running tubing w/overshot and jars to fish plug
12/11/76 - Ran overshot, jars and tubing, caught fish, unable to pull BP
12/12/76 - Down due to weather
12/13/76 - Down Sunday
12/14/76 - Released and pulled overshot, ran wash pipe, washed over to plug catcher
12/15/76 - Ran 2" tubing w/60' 1 3/8" tail pipe, washed thru fish to top of plug
12/16/76 - Pull tbg w/1" tail pipe, run overshot and caught fish, pulled free and started out of hole
12/17/76 - POH w/tbg, overshot had pulled loose, no fish, re-ran overshot and caught fish, worked with bumper and hydraulic jars, failed to free BP
12/18/76 - Continue working & jaring on plug, failed to free
12/19/76 - Released overshot & pulled, ran wash pipe and mill shoe, prep to mill over plug
12/20/76 - Down Sunday
12/21/76 - Mill over top collar on BP retreiving head and pull mill, prep to run overshot and attempt to pull.
12/22/76 - Fish out, cut off tubing and top of retrieving head, ran shoe and wash pipe, continue milling
12/23/76 - Milling over retrieving head and bridge plug
12/24/76 - Milling over retrieving head & bridge plug
12/25/76 - Down for Holiday
12/26/76 - Down for Holiday
12/27/76 - Down for Holiday
12/28/76 - Milled over bridge plug, ran overshot and caught, now pulling out of hole
12/29/76 - Pulled bridge plug up to 1500' and became stuck, attempting to free
12/30/76 - Unable to free bridge plug @ 1500', now milling over
12/31/76 - Milling over bridge plug @ 1500'
1/ 1/77 - Milling over bridge plug
1/ 2/77 - Down Holiday
1/ 3/77 - Down Holiday
1/ 4/77 - Milling over bridge plug
1/ 5/77 - Milling over bridge plug
1/ 6/77 - Finish milling over plug and pushed to bottom, pulling tubing
1/ 7/77 - POH w/tbg, and fishing tool, ran tubing and checked bottom @ 6810', no sand in well bore. Picked tbg up and landed @ 6780', now running pump and rods
1/ 8/77 - Ran pump & rods and put well to pumping
1/ 9/77 - Pumping, will drop from daily report and give weekly production report each Tuesday
1/26/77 - Pumping @ rate of 40 bbls frac fluid per day and flowing 135 MCF gas per day from the casing into the pipeline
2/9/77 - Pumping at rate of 6 bbls frac oil & 10 bbls water per day. Flowing 70 MCF gas day from the casing annulus to pipeline
2/17/77 - Pumping 6 bbls frac oil, 10 bbls frac water & flowing est 56 MCF gas day from casing annulus to pipeline
2/23/77 - Pumping 6 bbls frac water & 4 bbls oil per day. Flowing est 50 MCF gas thru csg.
3/2 /77 - Pumping 4 bbls frac water & two bbls oil & flowing est 35 MCF gas day thru csg.
4/1/77 - Pumping 2 bbls oil, 1 bbl water per day, flowing 15 MCF thru casing

EXHIBIT 9

ERDA
COST ESTIMATE

WESTERN

West-Foam Service Mixing Charge	$ 6,925.00
138,500 gal	
West-Foam Service Sand Pumping Charge	
138,500 gal	4,155.00
Sand Pumping Charge	
100,000 lb 100 mesh	100.00
667,000 lb 10-20 mesh	3,001.50
Aquaseal-2	
1,650 lb	1,650.00
J-2	
3,090 lb	5,871.00
E-15	
330 gal	5,197.50
KCl	
27,000 lb	3,915.00
West-Foam	
242.5 gal	2,121.88
Aqua Flow	
30 gal	450.00
Sand	
100,000 lb 100 mesh	2,880.00
667,000 lb 10-20 mesh	19,209.60
Ball Sealers	
84	105.00
Acidmaster	
First 4 hours	350.00
6 hours	240.00
Hydraulic Horsepower	
First 4 hours, 1500 HHP	2,475.00
6 hours	2,970.00
Master Mixer	
First 4 hours, 15 BPM	357.50
6 hours	429.00
Ball Injector	65.00
Frac Tanks	
18	3,780.00

WESTERN (continued)

Mileage Charges		
3 Pumps		
2 Blenders		
26 Sand Trucks		
3 Stake Beds		
1 Frac Monitor		
1 Iron Truck		
36 - 150 miles	$ 5,940.00	
Transport Charges		
767,000 lb sand - 150 miles	20,133.75	
Sub-Total		$ 92,321.73
Super-K Frac License Fee Base	139.00	
198,000 gal	1,102.86	
Multiple Zone Royalty	353.93	
Sub-Total		1,456.79
TOTAL - Western		$ 93,917.52

NOWSCO

65% quality 138,500 gal 15 BPM 2.53 MMscf	23,200.00

SCHLUMBERGER WELL SERVICE

Wire Line Services	12,540.00

WATER

3,572 bbl	2,679.00

OIL

3,200 bbl @ $12.50/bbl = $40,000.00 less 1,600 bbl recovered @ $12.00/bbl = ($19,200.00)	20,800.00 net

ERDA Cost Estimate

PULLING UNIT	$ 3,200.00
TOTAL - Western plus Other Services (OIL - net)	$156,336.52
TOTAL - Western plus Other Services (OIL - gross)	$175,536.52

Bill Matson
June 22, 1976

ERDA Cost Estimate

PULLING UNIT	$ 3,200.00	
Sub-Total (OIL - Net)		$ 62,419.00
TOTAL - Western plus Other Services		$156,336.52
Sub-Total (OIL - Gross)		$ 81,619.00
TOTAL - Western plus Other Services		$175,536.52

Bill G. Matson
June 22, 1976

☆U.S. GOVERNMENT PRINTING OFFICE: 1977-740-094/263