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

Final Report

Archie Crawford
Wesley Ellis

June 1977

Work Performed Under Contract No. EY-76-C-08-0684

Dallas Production, Incorporated
Meadows Building
Dallas, Texas

ENERGY RESEARCH AND DEVELOPMENT ADMINISTRATION

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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 + N₂)
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 $\pm 5,000$ 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

<u>Zone</u>	<u>Estimated Gross Fracture Height</u>	<u>Pad (Foam)</u>	<u>Frac (Super K)</u>	<u>Proppant</u>
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

$\phi = 10\%$

BHP = 1,283 psi (original)

Avg. BHFP = 3,700 psi

BHT = 135°F

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

Assumed spacing = 320 A

$r_e = 1867$ ft

Estimated Reservoir Improvement on Original Stimulation Treatment

<u>Zone</u>	<u>Penetration feet</u>	<u>L/r_e</u>	<u>Permeability Contrast inches</u>	<u>PI Contrast</u>
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:

$$\text{PI Contrast (Avg)} = 3.9$$

Average Productivity Increase from Proposed Treatment:

$$\text{PI Contrast} = 11.8$$

Approximate Average Daily Production as of January 28, 1976:

$$Q_o = 50 \text{ Mcf/day}$$

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:

$$440,737.5 \text{ Mcf}$$

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 reasonable 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-stimulation 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 N₂ 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

<u>Zone</u>	<u>Frac Height</u>	<u>Interval</u>	<u>Perf's Pad</u>	<u>Frac</u>	<u>10/20 Sand</u>
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.

<u>Zone (ft)</u>	<u>Surface Production (Mcf)</u>	<u>% Total Production</u>
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.

<u>Zone (ft)</u>	<u>Surface Production (Mcf)</u>		<u>% Surface Production</u>
	<u>High</u>	<u>Low</u>	
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:

<u>Zone Depth</u>	<u>Zone No.</u>	<u>Height (ft)</u>	<u>% Fluid</u>	<u>Rate/Zone BPM</u>
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:

<u>Zone(ft)</u>	<u>Zone No.</u>	<u>% Total Rate</u>	<u>Rate/Zone BPM</u>
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 was 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:

<u>Zone (ft)</u>	<u>% Total Rate</u>
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:

	<u>BHFP (psi)</u>	<u>Fracture Gradient (psi/ft)</u>
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.....	<u>3,200.00</u>
	\$ 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.....	<u>896.58</u>
	\$ 178,390.35
Credit for Oil Salvage.....	<u>(7,592.20)</u>
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.....	<u>1,272.42</u>
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.....	<u>36,264.71</u>
TOTAL.....	\$ 51,314.81

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

	\$ 170,798.15
	22,821.32
	<u>51,314.81</u>
	\$ 244,934.28
Less Additional Oil Salvage.....	<u>(7,608.00)</u>
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.

<u>PI Contrast</u>	<u>Additional Gas/Day - Mcf</u>	<u>No. of Producing Days Required for Breakeven</u>
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_i/k)	Ordinate (J/J_o)
<u>For spacing shown and 3-inch wellbore radius.</u>			
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	$104 \sqrt{A}$	$\sqrt{40/A}$	$\frac{3.095}{\log(.472)(r_e/r_w)}$
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Schlumberger

INDUSTRIAL 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. Measured From KB

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

EXHIBIT		ONE	12-2-72						
Dr	Driller	7090							
De	-Logger	7091							
Blm	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
Source of Sample		MUDPIT							
Rm @ Meas. Temp.		2.30@ 78 °F		@		@		@	°F
Rm @ Meas. Temp.		2.20@ 78 °F		@		@		@	°F
Rmc @ Meas. Temp.		- @ - °F		@		@		@	°F
Source: Rmf Rmc		M -		@		@		@	°F
Rm @ BHT		1.32@ 135°F		@		@		@	°F
Time Since Circ.		3 HRS.							
Max. Rec. Temp.		135 °F							°F
Equip. Location		5662 WFS							°F
Recorded By		DELA							
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 SCALE CHANGES

Date	Sample No.	Type Log	Depth	Scale Up Hole	Scale Down Hole
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			

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

DETAIL LOG

5" = 100'

SPONTANEOUS-POTENTIAL MILLIVOLTS	DEPTHS	CONDUCTIVITY MILLIMHOS/M = $\frac{1000}{\text{OHMS. M}^2/\text{M}}$	
<div data-bbox="360 674 490 730" data-label="Text"> <p>- 20 +</p> </div>	1000	6FF40 INDUCTION	500
		1500	100
	0	RESISTIVITY OHMS. M ² /M	
		A - 16" - M SHORT NORMAL	
		0	50
	0	INDUCTION	
		0	50
	0	0	500

0400

6700

1360m

For Congl
Oil or Gas

9000

Sl: For Congl
Pass Oil
or Gas

Calibration before Survey

CALIBRATION RECORD

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

Log Analysis

Log Analysis

COMPANY DALLAS PRODUCTION CO. INC.										WELL FERGUSON NO. 1-A		
FIELD WILDCAT					COUNTY WISE					STATE TEXAS		
DEPTH	RT	RW	M	PG						% POROSITY	% WATER	REMARKS
6736-92	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	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

All interpretations are opinions based on inferences from electrical or other measurements and we cannot, and do not, guarantee the accuracy correctness of any interpretations, and we shall not, except in the case of gross or willful negligence on our part, be liable or responsible for a loss, costs, damages or expenses incurred or sustained by anyone resulting from any interpretation made by any of our officers, agents or employees. These interpretations are also subject to Clause 7 of our General Terms and Conditions as set out in our current Price Schedule.

DATE	LOCATION	ENGINEER
12-2-72	WICHITA FALLS	DELAY

SWS-1325-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

DATE

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

DOWELL DIVISION OF THE DOW CHEMICAL COMPANY

1-18-73

WELL NAME AND NUMBER

LOCATION

CUSTOMER REPRESENTATIVE

TREATMENT NUMBER

Ferguson #1

GN Doreline

Mr. [Signature]

5-11-8516

POOL

FORMATION

JOB DONE DOWN

ALLOWABLE PRESSURE

COUNTY

STATE

TUBING

TBS

W.C.

Cough

C

CSG:

TYPE OF SERVICE

TBS

OIL

WATER

B.D.A.

TBS

GAS

CIRC. BHT.

CUST. NAME

Dallas Prod. Co.

NEW WELL

TOTAL DEPTH

ADDRESS

Box 228

Casing Size

TUBING SIZE

CITY

Bowie Texas

Casing Depth

TUBING DEPTH

STATE & ZIP CODE

Bowie Texas

Liner Size

PACKER TYPE

REMARKS:

Bowie Texas

Liner Depth

PACKER DEPTH

OPEN HOLE

STATIC BHT.

CSG. OR ANRL. VOL.

TBS VOLUME

PERFORATED INTERVALS

TBS VOLUME

DEPTH

NO. OF HOLES

DEPTH

NO. OF HOLES

DEPTH

NO. OF HOLES

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DEPTH

NO. OF HOLES

FOR CONVERSION PURPOSES 24 BBLs EQUALS 1000 GALLONS

ARRIVED ON LOCATION: 12:15 P.M.

TIME	INJECTION		PRESSURE		SERVICE LOG
	RATE	BBLs IN	CSG.	TBG.	
12:35		0			Circ. Sand off Plug
1:04		76			Move Packer Plug
1:32			1500		Test Plug
1:49		0			B.D.A.
1:53		12			
1:53		0			Flush W. line 1 1/2 Gal. Flush
1:58		21			Set Packer
2:00	5		1950		
2:01	5	21.5	1450		
2:06	5	24	1350		
2:08	5	25	1200		
2:12	5.5	24	1950		
2:14	5.5	35	1950		

TIME LEFT LOCATION		AVG. LIQUID INJ. RATE		ADJ. RATE (SOLIDS INJ.)		TOTAL FLUID PUMPED		PROPS AND LIQUIDS INJECTED		
2:30 PM		1.5				OIL		WATER		
MAX. PRESSURE		AVG. PRESSURE		FINAL PUMP IN PRESSURE		SHUT IN PRESSURE		TYPE		SIZE OR PURPOSE
1950		1500		1950		IMMEDIATE		13. D. A.		500
15 MINUTES										
DOWELL LOCATION				DOWELL ENGINEER						
Gainesville				Harry Brown						
CALL BACK		DATE		CUSTOMER REP. CONTACTED		CUSTOMER CONSIDERED		PROD. BEFORE TREATMENT		PROD. AFTER TREATMENT
						☐ SATISFACTORY ☐ UNSATISFACTORY ☐ UNKNOWN		☐ TEST ☐ ALLOWABLE		☐ TEST ☐ ALLOWABLE
								DAYS		

STIMULATION TREATMENT REPORT

DWL-41 - 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

Ferguson A-1

Q.M. Deane

McCambridge

3-11-8518

POOL

FORMATION

JOB DONE DOWN

ALLOWABLE PRESSURE

W.C.

Crngl.

TUBING ☒ CASING ☐ ANNULUS ☐

TBC 4300 CSG: —

COUNTY Winn

STATE Texas

TYPE OF WELL

OIL ☐ GAS ☒ WATER ☐ INJ. ☐

TYPE OF SERVICE

AGE OF WELL

NEW WELL ☒ REWORK ☐

Water Force

CASING SIZE

TOTAL DEPTH

CUST. NAME

Dallas Prod. Co.

CASING DEPTH

TUBING SIZE

ADDRESS

Box 228

LINE SIZE

TUBING DEPTH

CITY

Bowie Texas

OPEN HOLE

PACKER TYPE

STATE & ZIP CODE

CSG. OR ANRL. VOL.

TBC VOLUME

REMARKS:

PERFORATED INTERVALS

DEPTH NO. OF HOLES

FOR CONVERSION PURPOSES 24 BBLs EQUALS 1000 GALLONS

ARRIVED ON LOCATION: 2:30 PM

TIME	INJECTION		PRESSURE		SERVICE LOG
	RATE	BBLs IN	CSG.	TBG.	
<u>3:26</u>				<u>3100</u>	<u>Test Line</u>
<u>3:27</u>		<u>0</u>			<u>W f. 100 Pail</u>
<u>3:30</u>	<u>13</u>	<u>31</u>	<u>41200</u>		<u>L L L</u>
<u>3:33</u>	<u>14</u>	<u>72</u>	<u>41600</u>		<u>L L L</u>
<u>3:33</u>	<u>14</u>	<u>0</u>	<u>41600</u>		<u>L L L 2# 20/42</u>
<u>3:37</u>	<u>14</u>	<u>36</u>	<u>41600</u>		<u>L L L on line</u>
<u>3:39</u>	<u>15</u>	<u>100</u>	<u>41500</u>		<u>L L L</u>
<u>3:43</u>	<u>15</u>	<u>180</u>	<u>43500</u>		<u>L L L</u>
<u>3:46</u>	<u>15</u>	<u>200</u>	<u>43000</u>		<u>L L L</u>
<u>3:50</u>	<u>15</u>	<u>230</u>	<u>43000</u>		<u>L L L</u>
<u>3:50</u>	<u>15</u>	<u>0</u>	<u>43000</u>		<u>L L L Flush</u>
<u>3:53</u>	<u>15</u>	<u>50</u>	<u>43000</u>		<u>L L L</u>

TIME LEFT LOCATION <u>5:15 PM</u>	AVG. LIQUID INJ. RATE <u>14</u>	ADJUST. RATE (SOLIDS INC.)	TOTAL FLUID PUMPED OIL WATER	PROPS AND LIQUIDS INJECTED TYPE SIZE OR PURPOSE AMOUNT
MAX. PRESSURE <u>4600</u>	AVG. PRESSURE <u>4400</u>	TRIAL PUMP IN PRESSURE <u>4300</u>	SHUT IN PRESSURE IMMEDIATE 15 MINUTES <u>1050</u> <u>950</u>	<u>12</u>
DOWELL LOCATION <u>Gladwin No</u>	DOWELL ENGINEER <u>Thermon</u>	CUSTOMER CONSIDERED SERVICE	SATISFACTORY UNSATISFACTORY UNKNOWN	PROD. BEFORE TREATMENT TEST ALLOWABLE
CALL BACK	DATE	CUSTOMER REP. CONTACTED	PROD. AFTER TREATMENT TEST ALLOWABLE	DAYS

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

Ferguson A-1

LOCATION

9th District

CUSTOMER REPRESENTATIVE

McCrumb

TREATMENT NUMBER

3-11-8509

POOL

W.C.

FORMATION

Coastal

JOB DONE DOWN

TUBING A ☒ CASING B ☐ ANNULUS C ☐

ALLOWABLE PRESSURE

TBC 4,300 CSG: —

COUNTY

Wise

STATE

Texas

TYPE OF WELL

OIL A ☐ GAS B ☒ WATER C ☐

TYPE OF SERVICE

Water Free

AGE OF WELL NEW WELL A ☒ REWORK B ☐

TOTAL DEPTH

CIRC. BHT.

CUST. NAME

Dallas Prod. Co.

Casing Size

4 1/2

Casing Depth

—

Tubing Size

2 1/2

Tubing Depth

6075

Liner Size

—

Liner Depth

—

Packer Type

Dowell Inc

Packer Depth

6075

Open Hole

—

CSG. OR ANRL. VOL.

—

TBC VOLUME

36

STATIC BHT.

1400

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	INJECTION		PRESSURE	
	RATE	BBLs IN	CSG.	TBC.
1:38				4000
1:39		0		
1:42	19	35		3000
1:44	19	72		3030
1:44	19	0		3050
1:44	19	36		3100
1:50	19	100		3150
1:56	19	200		3200
1:59	19	260		3200
1:59	19	0		3700
2:02	19	50		3300

SERVICE LOG

1:38				4000	Test Line
1:39		0			W.F. 60 Ppd
1:42	19	35		3000	— — —
1:44	19	72		3030	— — —
1:44	19	0		3050	— — — 2# 20/140
1:44	19	36		3100	— — — on line
1:50	19	100		3150	— — —
1:56	19	200		3200	— — —
1:59	19	260		3200	— — —
1:59	19	0		3700	— — — Flush
2:02	19	50		3300	— — —

TIME LEFT LOCATION	AVG. LIQUID INJ. RATE	ADAPL RATE (SOLIDS INC)	TOTAL FLUID PUMPED	PROPS AND LIQUIDS INJECTED		
3:15 PM	19		OIL 323 WATER 323	TYPE	SIZE OR PURPOSE	AMOUNT
MAX. PRESSURE	AVG. PRESSURE	FINAL PUMP IN PRESSURE	SHUT IN PRESSURE			
3300	3700	3300	IMMEDIATE 1000 15 MINUTES 1000	J-209		650
				J-89		250
				4000		10
				20/140		20,000
DOWELL LOCATION	DOWELL ENGINEER	PROD. BEFORE TREATMENT				
Grienerville	Harvey Moore	TEST ALLOWABLE				
CALL BACK	CUSTOMER REP. CONTACTED	CUSTOMER CONSIDERED SERVICE	SATISFACTORY	PROD. AFTER TREATMENT	TEST ALLOWABLE	
			UNKNOWN			

STIMULATION TREATMENT REPORT

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

DOWELL DIVISION OF THE DOW CHEMICAL COMPANY

DATE

12-23-72

WELL NAME AND NUMBER

Ferguson A-1

LOCATION

G.M. Decker

CUSTOMER REPRESENTATIVE

McConnell

TREATMENT NUMBER

3-11-8425

Boonsville Bend

Congl.

TUBING A ☒ CASING B ☐ ANNULUS C ☐

ALLOWABLE PRESSURE

TBG 4500 CSG: —

Wise

Texas

TYPE OF WELL

OIL A ☐ GAS B ☒ WATER C ☐ INJ. D ☐

Water Frac

AGE OF WELL NEW WELL A ☒ REWORK B ☐

CUST. NAME Dallas Prod. Co.

Casing Size 4 1/2 Casing Depth — Tubing Size 2 1/2 Tubing Depth 6770

ADDRESS Box 228

Liner Size — Liner Depth — Packer Type Down 11 m-6 Packer Depth 6770

CITY, STATE & ZIP CODE

Bowie

Open Hole — CSG. OR ANRL. VOL. 550 TBG VOLUME 39 Static BHT. 140'

REMARKS:

PERFORATED INTERVALS

DEPTH	NO. OF HOLES	DEPTH	NO. OF HOLES	DEPTH	NO. OF HOLES
6786					
6794					

FOR CONVERSION PURPOSES 24 BBLs EQUALS 1000 GALLONS

ARRIVED ON LOCATION 9:00 AM

TIME	INJECTION		PRESSURE		SERVICE LOG
	RATE	BBLs IN	CSG.	TBG.	
1036		0			W.F. 600 Cio Hole
1106		94			✓ ✓ ✓ ✓
1120			4500		✓ ✓ Test Line
1121	14	0	3500		✓ ✓ Prod
1124	18	30	4100		✓ ✓ ✓
1124	18	0	4100		✓ ✓ 2nd 20'
1126	18	39	4100		✓ ✓ ✓ ✓ ✓ ON PC
1129	19	100	4700		✓ ✓ ✓ ✓
1134	19	200	4700		✓ ✓ ✓ ✓
1138	19	260	4700		✓ ✓ ✓ ✓
1138	19	0	4700		✓ ✓ Flue
1140	19	50	4200		✓ ✓ ✓

TIME LEFT LOCATION	AVG. LIQUID INJ. RATE	ADJ. RATE (SOLIDS INC)	TOTAL FLUID PUMPED	PROPS AND LIQUIDS INJECTED
1230 A.M.		18	OIL 1382	TYPE SIZE OR PURPOSE AMOUNT
MAX. PRESSURE	AVG. PRESSURE	FINAL PUMP IN PRESSURE	SHUT IN PRESSURE	
4100	4100	4200	IMMEDIATE 15 MINUTES 1800 1700	1-209 600
DOWELL LOCATION	DOWELL ENGINEER			J-84 250
Boonsville	McConnell			Kel 12
CALL BACK	CUSTOMER REP. CONTACTED	CUSTOMER CONSIDERED SERVICE	PROD. BEFORE TREATMENT	PROD. AFTER TREATMENT
			TEST ALLOWABLE	DAYS TEST ALLOWABLE

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

DATE _____

12-19120-72

WELL NAME AND NUMBER <i>Ferguson A-1</i>		LOCATION		CUSTOMER REPRESENTATIVE <i>Mr. Crawford</i>		TREATMENT NUMBER <i>3-11-8415</i>	
POOL		FORMATION		JOB DONE DOWN TUBING ☒ CASING ☐ ANNULUS ☒		ALLOWABLE PRESSURE	
COUNTY <i>Wisc</i>		STATE <i>Texas</i>		TYPE OF WELL OIL ☒ GAS ☐		TBO: CSG:	
TYPE OF SERVICE <i>Rental</i>				AGE OF WELL NEW WELL ☒ REWORK ☐		TOTAL DEPTH CIRC. BHT.	
CUST. NAME <i>Dallas Production</i>				CASING SIZE CASING DEPTH <i>4 1/2</i>		TUBING SIZE TUBING DEPTH	
ADDRESS <i>Box 945</i>				LINER SIZE LINER DEPTH		PACKER TYPE PACKER DEPTH	
<i>Bowie, Texas</i>				OPEN HOLE CSG. OR ANRL. VOL.		TBO VOLUME STATIC BHT. <i>2 1/2</i>	
CITY, STATE & ZIP CODE				PERFORATED INTERVALS			
REMARKS:				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

[illegible]

TIME LEFT LOCATION 12 N		AVG. LIQUID INJ. RATE		ADJ. INJ. RATE (SOLIDS INC.)		TOTAL FLUID PUMPED OIL WATER		PROPS AND LIQUIDS INJECTED					
MAX. PRESSURE		AVG. PRESSURE		FINAL PUMP IN PRESSURE		SHUT IN PRESSURE IMMEDIATE 15 MINUTE		TYPE		SIZE OR PURPOSE		AMOUNT	
DOWELL LOCATION				DOWELL ENGINEER									
CALL BACK		DATE		CUSTOMER REP. CONTACTED		CUSTOMER CONSIDERED SERVICE		☐ SATISFACTORY ☐ UNSATISFACTORY ☐ UNKNOWN		PROD. BEFORE TREATMENT ☐ TEST ALLOWABLE		PROD. AFTER TREATMENT ☐ TEST ALLOWABLE	

STIMULATION TREATMENT REPORT

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

DOWELL DIVISION OF THE DOW CHEMICAL COMPANY

DATE	DESCRIPTION	AMOUNT	BALANCE
1950			
1951			
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1-1-23

WELL NAME AND NUMBER		LOCATION		CUSTOMER REPRESENTATIVE		TREATMENT NUMBER	
Ferguson A-1		GN Deatur		McCracken		5-11-8430	
POOL		FORMATION		JOB DONE DOWN		ALLOWABLE PRESSURE	
Boonsville Bond		Coagl		TUBING A ☒ CASING B ☐ ANNULUS C ☐		TBC: 4500 CSG: —	
COUNTY		STATE		TYPE OF WELL			
Wise		Texas		OIL A ☐ GAS B ☒ WATER C ☐ INJ. D ☐			
TYPE OF SERVICE				AGE OF WELL		TOTAL DEPTH	
B.D.A.				NEW WELL A ☒ REWORK B ☐		CIRC. BHT.	
CUST. NAME				CASING SIZE		TUBING SIZE	
Dallas Prod. Co.				4 1/2		2 1/2	
ADDRESS				CASING DEPTH		TUBING DEPTH	
Box 228				—		6265	
CITY				LINER SIZE		PACKER TYPE	
Bowling Texas				—		Dowell m-6	
STATE & ZIP CODE				OPEN HOLE		TBC VOLUME	
REMARKS:				—		37	
				CSG. OR ANNL. VOL.		STATIC BHT.	
				—		1402	
PERFORATED INTERVALS							
DEPTH		NO. OF HOLES		DEPTH		NO. OF HOLES	

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	LENGTH	WIDTH
(GAL)	(FT)	(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	LENGTH	WIDTH
(GAL)	(FT)	(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 YOUNG'S 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	COMPRESSIBILITY = 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 <u>WISE</u> FIELD or LOCATION <u>WALDCAT</u> WELL <u>FERGUSON NO. 1-A</u> COMPANY <u>DALLAS PROD., INC.</u>	COMPANY <u>DALLAS PRODUCTION, INC.</u>		
	WELL <u>FERGUSON NO. 1-A</u>		
	FIELD <u>WALDCAT</u>		
	COUNTY <u>WISE</u> STATE <u>TEXAS</u>		
LOCATION <u>1320' FNL, 1320' FEL</u> <u>BEN D. SMITH SURVEY</u> <u>A-779</u>		Other Services: <u>HRT</u>	
Sec. _____ Twp. _____ Rge. _____			
Permanent Datum: <u>GROUND LEVEL</u> , Elev. <u>807</u>		Elev.: K.B. <u>818</u>	
Log Measured From <u>K.B.</u> , <u>11</u> Ft. Above Perm. Datum		D.F. <u>-</u>	
Drilling Measured From <u>K.B.</u>		G.L. <u>807</u>	
Date	<u>9-7-76</u>	Production Method	<u>FLOWING</u>
Run No.	<u>TWO</u>	Prod. Rate (Surface)	
Depth — Driller	<u>6820</u>	for: Choke size	<u>FULL</u>
Depth — Logger	<u>6782</u>	: BH Pressure	
Btm. Log Interval	<u>6781</u>	: Tbg. Hd. Press.	<u>250# - 75#</u>
Top Log Interval	<u>5900</u>	: % Water Cut	<u>-</u>
Casing — Driller		: G.O.R.	
Casing — Logger	<u>6820</u>	Produced Fluids (Type)	
Casing size	<u>4 1/2"</u>	GAS: Cu. ft/day @ STP	
Casing Wt.	<u>10.5#</u>	: BH Density	
Tubing — Driller	<u>-</u>	: BH Viscosity	
Tubing — Logger	<u>-</u>	OIL: Bbls/day	
Tubing size	<u>-</u>	: API Grav. @ _____ °F	
Tubing Wt.	<u>-</u>	: Surf. Density @ _____ °F	
Bit Size (Open hole)	<u>7 7/8"</u>	: 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.	<u>168</u>		
Truck & Locn.	<u>3868/GRM</u>		
Recorded by	<u>PRIDDY</u>		
Witnessed by	<u>MR. CRAWFORD</u>		

10-01-76 PMO586721

Schlumberger Depths

WELL SKETCH

Driller Depths

FOLD HERE

Indicate : Depth datum
Deviation in production zone
Open hole diameter
Diameter and weight of casing and tubing
Position and nature of perforations (bullet, conventional shaped charges, capsules, etc.)

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. 4 1/2
UP-FLOW ASSY. ☐
DOWN-FLOW ASSY. ☒
CENTRALIZERS ☒

COMPANY DALLAS PRODUCTION, INC.WELL FERGUSON NO. 1-AFIELD WILDCAT COUNTY WISEDate 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	
<u>5957-82</u>	<u>0</u>	<u>0</u>	<u>0%</u>
<u>6125-38</u>	<u>57 MCF</u>	<u>19 MCF</u>	<u>12% - 10%</u>
<u>6302-16</u>	<u>28 MCF</u>	<u>37 MCF</u>	<u>6% - 16%</u>
<u>6519-25</u>	<u>211 MCF</u>	<u>94 MCF</u>	<u>45% - 45%</u>
<u>6786-94</u>	<u>169 MCF</u>	<u>61 MCF</u>	<u>36% - 29%</u>

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 STABILIZED. 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 4½" - 10.5# PIPE

Z(GAS COMPRESSIBILITY FACTOR) = .93

BHF = 617PSI

BHT = 168°

1/BG SCF/CUFT (GAS VOLUME FACTOR = 37.37

All interpretations are opinions based on inferences from electrical or other measurements and we cannot, and do not, guarantee the accuracy or correctness of any interpretations, and we shall not, except in the case of gross or willful negligence on our part, be liable or responsible for any loss, costs, damages or expenses incurred or sustained by anyone resulting from any interpretation made by any of our officers, agents or employees. These interpretations are also subject to Clause 7 of our General Terms and Conditions as set out in our current Price Schedule.

By: PRIDY & SCHNORR

SCHLUMBERGER**PRODUCTION LOGGING
CONTINUOUS FLOWMETER****SCHLUMBERGER WELL SURVEYING CORPORATION**
Houston, Texas

COUNTY <u>WISE</u> FIELD or LOCATION <u>WILDCAT</u> WELL <u>FERGUSON</u> NO. <u>1-A</u> COMPANY <u>DALLAS PROD., INC.</u>	COMPANY <u>DALLAS PRODUCTION, INC.</u>		
	WELL <u>FERGUSON NO. 1-A</u>		
	FIELD <u>WILDCAT</u>		
	COUNTY <u>WISE</u> STATE <u>TEXAS</u>		
LOCATION <u>1320'FNL, 1320'FEL</u> <u>BEN D. SMITH SURVEY, A-779</u>		Other Services: <u>HRT</u>	
Sec. _____ Twp. _____ Rge. _____			
Permanent Datum: <u>GROUND LEVEL</u> , Elev. <u>807</u>		Elev.: K.B. <u>818</u>	
Log Measured From <u>K.B.</u> , <u>11</u> Ft. Above Perm. Datum		D.F. <u>7</u>	
Drilling Measured From <u>K.B.</u>		G.L. <u>807</u>	
Date	<u>9-3-76</u>	Production Method	<u>FLOWING OUT CSG.</u>
Run No.	<u>ONE</u>	Prod. Rate (Surface)	<u>45-50 MCF</u>
Depth — Driller	<u>6820</u>	for: Choke size	<u>FULL</u>
Depth — Logger	<u>6782</u>	: BH Pressure	<u>-</u>
Btm. Log Interval	<u>6781</u>	: Tbg. Hd. Press.	<u>53 PSI</u>
Top Log Interval	<u>5900</u>	: % Water Cut	
Casing — Driller	<u>6820</u>	: G.O.R.	
Casing — Logger	<u>-</u>		
Casing size	<u>4 1/2"</u>	Produced Fluids (Type)	
Casing Wt.	<u>10.5#</u>	GAS: Cu. ft/day @ STP	
Tubing — Driller	<u>-</u>	: BH Density	
Tubing — Logger	<u>-</u>	: BH Viscosity	
Tubing size	<u>-</u>	OIL: Bbls/day	
Tubing Wt.	<u>-</u>	: API Grav. @ _____ °F	
Bit Size (Open hole)	<u>7 7/8"</u>	: Surf. Density @ _____ °F	
		: BH Viscosity	
SI Tbg. Hd. Press.	<u>53 PSI</u>	WATER: Bbls/day	
SI BH Press (Res.)		: Water Salinity	
Productivity Index	<u>45-50K/D</u>	: Surf. Density @ _____ °F	
Form. Volume Factor		: BH Viscosity	
Max. Rec. Temp.			
Truck & Locn.	<u>3868/GRM</u>		
Recorded by	<u>PRIDY</u>		
Witnessed by	<u>MR. CRAWFORD</u>		

SWSC-1305

10-01-76WNO58672

Schlumberger Depths

WELL SKETCH

Driller Depths

FOLD HERE

PERFORATIONS

5957-82

6126-38

6302-16

6519-25

6786-94

5 1/2" CSG.

FILLUP 6782

T.D. 6820

Indicate : Depth datum
Deviation in production zone
Open hole diameter
Diameter and weight of casing and tubing
Position and nature of perforations (bullets, conventional shaped charges, capsules, etc.)

FOLD HERE

CONDITIONS OF PRODUCTION DURING SURVEY

EQUIPMENT

Panel: N°
Plug in unit N°
Sonde N°
SPINNER DIA. 4 1/2 FB
UP-FLOW ASSY. ☐
DOWN-FLOW ASSY. ☐
CENTRALIZERS ☐

with choke of:
Casing:

Production rate:
Head pressures: Tubing
Time of production prior survey:
Time of stabilization prior survey:

REMARKS: BOTTOM SET PLUGGED OFF DUE TO SAND PRODUCTION 6786-94

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 5-3-97

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:

ZONE	WELL FLOWING	WELL STABLE
	<u>SURFACE PRODUCTION</u> <u>FR EACH ZONE</u>	<u>% SURFACE PRODUCTION</u>
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

If interpretations are opinions based on inferences from electrical or other measurements and we cannot, and do not, guarantee the accuracy or correctness of any interpretations, and we shall not, except in the case of gross or willful negligence on our part, be liable or responsible for any loss, costs, damages or expenses incurred or sustained by anyone resulting from any interpretation made by any of our officers, agents or employees. These interpretations are also subject to Clause 7 of our General Terms and Conditions as set out in our current Price Schedule.

By: PAUL - SCHWORE

THE WESTERN COMPANY

EXHIBIT 6

Profile

WL-75 (Rev. 11/75)

FILING NO. 9-76-179-L	COMPANY <u>Dallas Production Co., Inc.</u>						
	WELL <u>Ferguson #1-A</u>						
	FIELD <u>Wildcat</u>						
	COUNTY <u>Wise</u> STATE <u>Texas</u>						
JOB NO.	LOCATION <u>1320' FNL & 1320' FEL</u> <u>Ben D. Smith Survey A-779</u>					OTHER SERVICES:	
	SEC. _____ TWP. _____ RGE. _____						
PERMANENT DATUM: <u>Ground Level</u> ELEV. <u>807'</u>							
LOG MEASURED FROM <u>Kelly Bushing 11</u> FT. ABOVE PERM. DATUM							
DRILLING MEASURED FROM <u>Kelly Bushing</u>							
ELEV.: K.B. <u>818'</u>							
D.F. <u>817'</u>							
G.L. <u>807'</u>							
DATE	<u>9-14-76</u>						
RUN NO.	<u>One</u>						
TYPE LOG	<u>Velocity Profile</u>						
DEPTH-DRILLER							
DEPTH-LOGGER	<u>6793'</u>						
BOTTOM LOGGED INTERVAL	<u>6792'</u>						
TOP LOGGED INTERVAL	<u>5700'</u>						
TYPE FLUID IN HOLE	<u>Water</u>						
SALINITY, PPM CL.							
DENSITY							
LEVEL	<u>Full</u>						
MAX. REC. TEMP., DEG. F.							
OPERATING RIG TIME	<u>Portable Mast</u>						
RECORDED BY	<u>Ray</u>						
WITNESSED BY	<u>Mr. Crawford, Mr. Ellis, & Mr. Atkinson</u>						
RUN	BORE-HOLE RECORD				CASING RECORD		
NO.	BIT	FROM	TO	SIZE	WGT.	FROM	TO
				<u>4.5"</u>	<u>10.50#</u>	<u>Surface</u>	<u>I.D.</u>

ate Injection Started _____
 Cumulative Injection _____ BW to _____
 Time Drive 1.88 & .46 seconds per Log Division
 Customer pressure _____ Western pressure _____
 Customer Flow Rate _____ BPD Western Rate _____
 Sur. #1 - 1200#
 Sur. #2 - 2900#
 Sur. #1 - 0 BPM
 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'.

BURST SHEET

THE WESTERN COMPANY

Burst Number	Depth (Feet)	Time		Diameter Hole (Inches)	Dia. Small Hole (In.)	Dist. From Chg. (Feet)	Western Flow Rate (BPD)	Percent Fluid In Hole	Remarks
Units		Sec.							
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

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 ☒ This Well ☒

WELL DATA: OG ☒ 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 ☒ No ☐ Pad Type Foam Frac & Super K
 Treating Fluid Type: Oil ☐ Water ☐ Acid ☐ Misc. ☐ Foam ☒ Emulsion ☐
 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 ☒ 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 ☒ Casing ☒ 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 Aquaflo
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		Barrels Fluid Pumped	Inj. Rate BPM	REMARKS—
	Tubing	Casing			
6:50		100		15	Run pad
6:57		1400	110	14	Hole loaded
7:05		1500	220	14	All pad shut down run log TSDP 1100
7:50		1200		6	Run pad and log
8:22		1200	205	6	All pad TSDP 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	1287	11	All flush TSDP 1200
2:10		1300	180	5	Run pad and log
	9/15/76				Circulate sand run 2 7/8 tubing with Baker packer
					and set at 5700 - tubing cap. 33 casing cap 18
	9/16/76				Test lines 9000 psi; Max psi 8500
					Load hole and check rate
10:37	6000		50	13	Shut down check TSDP 3100
10:44	8500		50	20	Resume water
10:50	7700		140	17	Shut down TSDP 2600
12:50				5	Start pad and log
1:25	2700		153	5	All pad and log TSDP 1900

[illegible]

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 perms 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 perms.

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
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 retrieving 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

ERDA Cost Estimate

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	<u>20,133.75</u>	
Sub-Total		\$ 92,321.73
Super-K Frac License Fee Base	139.00	
198,000 gal	1,102.86	
Multiple Zone Royalty	<u>353.93</u>	
Sub-Total		<u><u>1,456.79</u></u>
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
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WATER

3,572 bbl	2,679.00
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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