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DETERMINATION OF THE OPTIMUM MASSIVE
HYDRAULIC FRACTURING DESIGN FOR THE
STIMULATION OF THE WASATCH AND
MESAVERDE FORMATIONS

Annual Report

By
Robert G. Merrill

July 1977

Work Performed Under Contract No. EY-76-C-08-0681

Gas Producing Enterprises, Incorporated
Denver, Colorado

MASTER

U. S. DEPARTMENT OF ENERGY

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P. O. Box 749
Denver, Colorado 80201

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PREPARED FOR
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U. S. ENERGY RESEARCH AND DEVELOPMENT ADMINISTRATION

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ANNUAL REPORT

Abstract

The MHF project in the Natural Buttes Unit, Bitter Creek Field, Utah has progressed through the first four phases of the scheduled program. Gas flow rates range from + 100 MCFD to 1.5+ MMCFD from the low permeability Mesa Verde-Wasatch formations after MHF treatments. MHF jobs have varied in size and in design of fluids and proppants. Thus far the results from the experiments are very encouraging.

Introduction

The experiment started in the Natural Buttes Unit with the fracturing of Natural Buttes Unit #18 as Phase I of the ERDA project. Phase II accomplished the treatment of Natural Buttes Unit #19. Phase III is the only one in which an existing well in the field prior to the beginning of the ERDA contract (an "old" well) was treated with MHF. Due to the success of this job, another "old" well is being studied for treatment. Phase IV was recently finished when Natural Buttes Unit #20 was put on production at 1.5+ MMCFD.

Discussion

Phase I: Natural Buttes Unit #18

The well was fraced with 9000 gallons of 15% HCl, 695,000 gallons of Versagel, 100,000 pounds of 40-60 sand and 1,380,000 pounds of 20-40 sand. The treatment was pumped in nine stages separated by ball sealers used as diverting agents. The well was placed on production on September 30, 1976 and made a total of 343 MMCF since the date of first sales, and is now producing at an average rate of 848 MCFD.

Frac fluid was a low residue guar gum derivative which had been cross linked to give the viscosity desired to hold the proppant in suspension. This suspension allows the proppant to be placed into the fracture in a vertical column and held there until the fracture closes thus trapping the sand grains. After a predetermined period of time, the gel breaks and may then be flowed back to the wellbore, leaving the sand distributed in a vertical column.

Phase II: Natural Buttes Unit #19

Gas production from this well has totaled 16.2 MMCF since it was treated by MHF. It is now producing at an average rate of 52 MCFD and is the only well that has been treated in two separate sections. The first section consisted of the lower nine zones treated with 363,000 pounds of 40-60 sand, 61,000 pounds of 100 mesh sand, 274,846 gallons of guar gum gel, 5000 gallons of 15% HCl and 485,000 SCF nitrogen. Please see text of the September, 1976 Monthly Report for details of this work.

The upper section from 7224-8676' was perforated and treated with the following: 6500 gallons of 15% MCl, 358,302 gallons of fluid, 72,000 pounds of 100 mesh sand, 712,000 pounds of 40-60 sand and 555,000 SCF of nitrogen. Please see test of the September, 1976 Monthly Report for details of this work.

The thin fluid used on this well was designed to create a fracture and then fill this fracture with sand using a technique known as the equilibrium bank method. This method has been used successfully in other areas and other formations and quite extensively throughout the industry. The purpose of using this method was to try to determine the ability of these fluids to obtain long frac wings and stay within the sand boundaries.

Phase III: Natural Buttes Unit #14

Since many old wells exist in the Rocky Mountain Basins that are completed in low permeability reservoirs, but which are only low volume producers, it was desirable to attempt an MHF on one of these types of wells to determine the feasibility of using this technique on other such wells. Natural Buttes Unit #14 was treated with 1,053,000 pounds of 20-40 sand, 40,000 pounds of 40-60 sand, 544,000 gallons of low residue cross linked gelled fluid, 32,000 gallons of prepad and 8000 gallons of 15% non-emulsifying acid. Natural Buttes Unit #14 was placed on initial production in October, 1974 and was fraced on March 15, 1977. Total production before fracing was 51 MMCF. The well has made 44.2 MMCF since the treatment.

Sandia Laboratories studied the MHF and took data by electrical potential methods. Sandia is evaluating this data to determine the direction of frac propagation and the length of the fracture.

Results from the frac treatment of Natural Buttes Unit #14 are so encouraging that another old well has been added to the program. It should be treated during the second year of the ERDA contract.

Phase IV: Natural Buttes Unit #20

MHF using the limited entry technique was performed on June 22, 1977 on Natural Buttes Unit #20 using the following materials: 2600 gallons 7-1/2° HCl, 10,000 gallons 2% KCl, 309,000 gallons YF4 PSD, 56,000 pounds 100 mesh sand, 745,000 pounds 40-60 sand and 25,000 pounds 20-40 glass beads and radioactive tracer sand. A Gamma-ray log was run and covered seven of the eight zones treated. All seven of the zones showed traces of radioactive sand indicating that the zones took fluid during the MHF treatment. Natural Buttes Unit #20 was placed on production in July, 1977 and is producing 1.5+ MMCFD.

Summary

The experiment is progressing according to schedule and the preliminary results are very encouraging. MHF has provided a means of producing gas from reservoirs having extremely low permeability. The economics of drilling and fracing these possible sources of energy for the future depends on how much of the calculated gas-in-place can be recovered due to these MHF treatments.

The objectives of the program are:

1. Determine the effect of fracture length of deliverability and ultimate recoverable reserves.
2. Determine the orientation of fractures.
3. The in situ fracture conductivity created by different combinations of fracture proppants and fluids is to be studied.
4. Evaluate the utility of fracture fluids in transporting sand, controlling frac height, avoiding formation damage and breaking gel strengths after the frac.
5. Determine the spacing for fraced wells.

These objectives are being pursued via experiments performed under actual field conditions.

Forecast of Work During the Second Year of the ERDA Contract

Phase V: Natural Buttes Unit #21

This well will be drilled and cores taken, completed and thoroughly tested. Detailed analyses will be made on the cores. Data takes from the cores may help determine the reliability of logs. Electric logs will be run by two companies to insure repeatability of logs and to compare output of data taken by competitive tools. Extensive production testing will be done on the cored intervals to enable us to better evaluate the log and core results.

Phase VI a: Natural Buttes Unit #22

Finish drilling operations and perform MHF.

Phase VI b: Natural Buttes Unit #9

Perform a MHF. A study is being made on the logistics of putting the desired materials for MHF on location. The well is an old one, and if successful, may provide a method for treating other old wells in the Natural Buttes Unit or other areas.

Monthly Report for September - Test Only

During September, 1976, the following work was accomplished:

- 1) Completed Phase I, the massive hydraulic fracturing of Natural Buttes No. 18,
- 2) Completed Phase II, the MHF of Natural Buttes No. 19.

Other wells in the field that have been previously stimulated by MHF include Natural Buttes No. 15, 16, and 17. This report includes a description of the MHF job done on each of the above wells. The results obtained from the MHF design applied to Natural Buttes No. 15, 16, and 17 will be used as a basis to compare the effectiveness of MHF designs applied to Natural Buttes No. 18, 19 and future wells.

Table No. 1 gives a summary of the MHF wells to date. In comparing the results of a MHF design on one well against another well, the following variables should be considered so that a valid comparison can be made between wells:

- 1) Number of zones perforated
- 2) Net feet of pay
- 3) Average porosity
- 4) Average water saturation
- 5) Average percent sand content

The "key" items that will be compared in establishing the effectiveness of a MHF design is to relate the fracture radius to the estimated first year average production rate. The results to date on Natural Buttes No. 15, 16, and 17 show no direct correlation of frac length to average first year production rate. It will take approximately three months of production history before an evaluation can be made on the effectiveness of the MHF design used on Natural Buttes No. 18 and 19.

Another item that has been investigated in the previous frac jobs is the ability to effectively treat the large number of zones (18 to 24 zones) in the wellhole. The temperature logs run immediately after the frac jobs have shown that a majority of the zones are being treated.

The following is a summary of the MHF jobs performed on previously fraced wells (Natural Buttes No. 15, 16, and 17) and the two wells fraced during the reporting period (Natural Buttes No. 18 and 19).

Natural Buttes No. 15 - Frac No. 1

Completion Data

The production casing was set at 8985' and consisted of 4½", 11.6# N-80, LTC casing. The casing was cemented with 730 sx of 50-50 Pozmix cement. The cement bond log showed good bonding.

The bottom six zones from 8535' to 8892' were perforated with a casing gun (See Table No. 2). Each zone was perforated in the middle of the sand with 1 shot per foot over a 4 ft. interval.

Pre-frac Test

The bottom six zones were not balled out after perforating. The zones tested 70 MCFD at a flowing pressure of 100 psi. A BHP build up on the well showed a pressure of 4497 psi after being shut-in 168 hrs. The build up gave an effective gas permeability of .00034 md.

Frac Design

The bottom six zones have 65 ft. of net pay with an average porosity of 10.5%, average water saturation of 40% and average sand content of 84% (see Table No. 12). A frac rate of 25 BPM was used in the frac design. Since the well was not balled out prior to fracing, it was assumed that the top zones would break down first. At a frac rate of 25 BPM, the perforation friction pressure drop through two zones (8 perfs) is sufficiently low that the next zone down the hole should not break down. Therefore, it is assumed that two zones are treated in each stage and the frac rate per zone is one-half of 25 BPM or 12½ BPM.

The stages were separated by ball sealers with 8 balls used in the early stages and additional balls dropped in the later stages to compensate for ball inefficiency downhole.

The frac height assumed was 26 ft. which includes 16 ft. of permeable sand and 5 ft. of shale above and below the sand.

The frac design used was a volume of 23,000 gal. per zone which gives a calculated frac length of 1035 ft.

Frac Job

The 6 zones were treated down the 4½" casing in three stages with the following proppant schedule per stage:

	<u>VOLUME (gal.)</u>	<u>RATIO (#/gal.)</u>	<u>MESH</u>	<u>SAND (lbs.)</u>
1.	1,000	15% NE Acid	----	----
2.	8,000	Pre-pad	----	----
3.	14,000	Pad	----	----
4.	4,000	1.0	40/60	4,000
5.	12,000	2.0	20/40	24,000
6.	16,000	3.0	20/40	48,000
7.	500	Pad	----	----
8.	1,000	15% NE Acid w/8 RCN balls in first part		
9.	Repeat steps (2) thru (8) two times.			

The average pumping rate during the job was 25 BPM and the average pressure was 5100 psi (see Table No. 7). Nitrogen was added in the last stage at the rate of 350 SCF/bbl. The ISIP was 3300 psi.

The type of fluid used was My-T-Frac Gel and the following volumes were pumped:

3000 gal of 15% HCl
167000 gal of My-T-Frac gel
12000 lbs of 40/60 sand
216000 lbs of 20/40 sand

Post Frac Test

A temperature log run after the frac showed that probably 5 of the 6 zones were treated with the zones 8617-21', 8860-64', and 8888-92' taking a majority of the frac fluid.

The flow rate two weeks after the frac was 750 MCFD at a flowing casing pressure of 500 psi and 15 BWPD. A Bore Hole Audio Tracer Survey Log was run two weeks after the frac and showed the following:

<u>Perfs</u>	<u>% of Flow</u>
8535-39	7.1
8617-21	14.3
8765-69	13.3
8808-12	10.2
8860-64	9.2
8888-92	45.9
	<u>100.0%</u>

The flow rate three months after the frac was 445 MCFD at a flowing casing pressure of 550 psi.

Frac No. 2

Completion Data

After the lower 6 zones had been fraced and tested, a bridge plug was set at 8315' and 18 zones from 5571' to 8266' were perforated with a casing gun (see Table No. 2). Each zone was perforated in the middle of the sand with 1SPF over a 4 ft interval.

Pre-Frac Test

The upper 18 zones were not balled out after perforating. The zones tested 81 MCFD at a flowing pressure of 450 psi.

Frac Design

The upper 18 zones have 164' of net pay with an average porosity of 10.5%, average water saturation of 43%, and average sand content of 85% (see Table No. 2).

The frac design assumptions are the same as those used for Frac No. 1

The frac design used was a volume of 15500 gal. per zone which gives a calculated frac length of 786'.

Frac Job

The 18 zones were treated down the 4½" casing with the following proppant schedule per stage.

	<u>VOLUME (gal.)</u>	<u>RATIO (#/gal.)</u>	<u>MESH</u>	<u>SAND (lbs.)</u>
1.	1,000	15% NE Acid	----	----
2.	8,000	Pre-Pad	----	----
3.	8,000	Pad	----	----
4.	4,000	1.0	40/60	4,000
5.	7,000	2.0	20/40	14,000
6.	7,000	3.0	20/40	21,000
7.	5,000	4.0	20/40	20,000
8.	500	Pad	----	----
9.	1,000	15% NE Acid with 8 RCN Balls in first part		
10.	Repeat steps (2) thru (9) eight times.			

The average pumping rate during the job was 26 BPM and the average pressure was 3000 psi (see Table No. 8). Nitrogen was added in the last stage at the rate of 350 SCF/bbl. The ISIP was 2100 psi.

The type of fluid used was My-T-Frac Gel and the following volumes were pumped:

10,000 gal of 15% HCl
354,500 gal of My-T-Frac Gel
36,000 lbs. of 40/60 sand
495,000 lbs. of 20/40 sand

Post Frac Test

A temperature log was attempted after the frac but the tool failed.

The flow rate one month after the frac was 1688 MCFD with a flowing casing pressure of 550 psi.

The bridge plug at 8315' was drilled out and 2-3/8" tubing was hung-off open ended at 8878' and all 24 zones were produced.

Approximately 6 months after drilling out the bridge plug the flow rate was 893 MCFD with a flowing tubing pressure of 550 psi. A Bore Hole Audio Tracer Survey showed the following:

<u>Perfs.</u>	<u>% of Flow</u>
8862-66	6.8
8810-14	6.0
8767-71	5.3
8618-22	4.9
8536-40	4.5
8262-66	4.7
8232-36	4.7
8183-87	4.5
8022-26	4.4
7952-56	4.9
7930-34	5.1
7842-46	4.8
7759-63	4.7
7735-39	4.8

<u>Perfs.</u>	<u>% of Flow</u>
7632-36	4.7
7570-74	4.5
7415-19	4.0
7364-68	4.3
6657-61	2.7
6442-46	2.5
6365-69	2.5
5924-28	2.3
5770-74	2.4
	<u>100.0%</u>

It is estimated that the well have a first year average producing rate of 890 MCFD, (see Graph No. 1) which gives recoverable reserves of 2.45 BCF over a 20 year life. The decline rate used to determine the above reserves was 30% the first year, 20% the second year, 15% the third year, and 10% the fourth year, and 5% the remaining years.

Natural Buttes No. 16

Completion Data

The production casing was set at 9003' and consisted of 4½", 11.6#, N-80, LTC casing. The casing was cemented with 730 sx of 50-50 Pozmix cement. The cement bond log showed good bonding.

Twenty-four zones were perforated from 6517' to 8797' with a casing gun (see Table No. 3). Each zone was perforated in the middle of the sand with 1 shot per foot over a 4 ft. interval.

Pre-Frac Test

The well was not balled out after perforating. The well tested 9 MCFD at a flowing pressure of 225 psi. A BHP build-up on the well showed a pressure of 3494 psi after being shut-in 164 hrs. The build-up gave an effective gas permeability of .00000221 md.

Frac Design

The twenty-four zones have 290' of net pay with an average porosity of 8.6%, average water saturation of 45%, and average sand content of 75% (see Table No. 3).

A frac rate of 25 BPM was used in the frac design. Since the well was not balled out prior to fracing, it was assumed that the top zones would break down first. At a frac rate of 25 BPM, the perforation friction pressure drop through two zones (8 perfs.) is sufficiently low that the next zone down the hole should not break down. Therefore, it is assumed that two zones are treated in each stage and the frac rate per zone is one-half of 25 BPM or 12½ BPM.

The stages were separated by ball sealers with 8 balls used in the early stages and additional balls dropped in the later stages to compensate for ball inefficiency downhole.

The frac height assumed was 26 ft. which includes 16 ft. of permeable sand and 5 ft. of shale above and below the sand.

The frac design used was a volume of 23,500 gal. per zone, which gives a calculated frac length of 2055 ft.

Frac Job

The twenty-four zones were treated down the 4½" casing in the thirteen stages with the following proppant schedule per stage:

	VOLUME (gal.)	RATIO (#/gal.)	MESH	SAND (lbs.)
1.	1,000	15% Acid	----	----
2.	4,000	Pre-Pad	----	----
3.	10,000	Pad	----	----
4.	5,000	1.0	40/60	5,000
5.	11,000	2.0	20/40	22,000
6.	11,000	3.0	20/40	33,000
7.	10,000	4.0	20/40	40,000
8.	1,000	Pad with 8 balls		
9.	Repeat 1 thru 8 twelve (12) times.			

Due to only the bottom six zones (8041' to 8797') being inadvertently perforated, the frac job progressed as follows (see Table No. 9).

- 1) Three stages were pumped with 8 balls dropped between stages and the well balled out to 7000 psi.
- 2) A temperature log run showed that 5 of the 6 bottom zones were treated.
- 3) The upper 18 zones from 6517' to 7990' were perforated with a casing gun.
- 4) Fraced the upper 18 zones by first dropping 20 balls to cover the bottom 6 zones and then fracing the upper 18 zones in 10 stages. The average pumping rate was 25 BPM and the average pressure was 3900 psi. Nitrogen was not used. The ISIP was 2700 psi and in 15 min. was 2400 psi.

The type of fluid used was Versagel and the following volumes were pumped:

17,000 gals. of 15% HCl
 863,000 gals. of Versagel
 65,000 lbs. of 40/60 sand
 1,500,000 lbs. of 20/40 sand

Post Frac Test

A temperature log run after the frac found a sand bridge at 7120'. The log showed that all nine zones from 6517' to 7104' were treated.

The sand bridge was cleaned out with coil tubing. The coil tubing parted when attempting to pull out of hole and the tubing was left in the well.

The flow rate one month after the frac job was 1300 MCFD at a flowing casing pressure of 1200 psi.

It is estimated that the well will have a first year average producing rate of 870 MCFD (see Graph No. 2) which gives recoverable reserves of 2.40 BCF over a 20 year life. The decline rate used to determine the above reserves was 30% the first year, 20% the second year, 15% the third year, 10% the fourth year, and 5% the remaining years.

Natural Buttes No. 17

Completion Data

The production casing was set at 9010' and consisted of 4½", 13.5#, N-80, LTC casing. The casing was cemented with 1445 sx of 50-50 Pozmix cement. The cement bond log showed good bonding down to 8500' and fair bonding below 8500'.

Twenty-four zones were perforated from 6186 to 8960 with a casing gun (see Table No. 4). Each zone was perforated in the middle of the sand with 1 shot per foot over a 4 ft. interval.

The tubing was hung-off open ended at 5946'. A Plastron blast joint was installed in the top of the tubing string opposite the tubing head.

Pre-Frac Test

The well was not balled out after perforating. The zones would not flow after unloading the well with nitrogen. A BHP build-up showed a pressure of 3479 psi after being shut-in 161 hrs. The build-up gave an effective gas permeability of .00000379 md.

Frac Design

The twenty-two zones have 226 ft. of net pay with an average porosity of 9.7%, average water saturation of 44%, and average sand content of 78% (see Table No. 4).

A frac rate of 25 BPM was used in the frac design. Since the well was not balled out prior to fracturing, it was assumed that the top zones would break down first. At a frac rate of 25 BPM, the perforation friction pressure drop through two zones (8 perforations) is sufficiently low that the next zone down the hole should not break down. Therefore, it is assumed that two zones are treated in each stage and the frac rate per zone is one-half of 25 BPM or 12½ BPM.

The stages were separated by ball sealers with 8 balls used in the early stages and additional balls dropped in the later stages to compensate for all inefficiency downhole.

The frac height assumed was 26 ft. which includes 16 ft. of permeable sand and 5 ft. of shale above and below the sand.

The frac design used was a volume of 18,500 gal. per zone, which gives a frac length of 1039 ft.

Frac Job

The twenty-two zones were treated down the 2-3/8" tubing and the 2-3/8" x 4 1/2" annulus. The frac consisted of 11 stages with the following proppant schedule per stage:

	<u>VOLUME (Gal.)</u>	<u>RATIO (#/gal.)</u>	<u>MESH</u>	<u>SAND (lbs.)</u>
1.	1,000	15% NE Acid	----	----
2.	8,000	Pre-Pad	----	----
3.	10,000	Pad	----	----
4.	3,000	1.0	40/60	3,000
5.	8,000	2.0	20/40	16,000
6.	8,000	3.0	20/40	24,000
7.	4,000	4.0	20/40	16,000
8.	4,000	5.0	20/40	20,000
9.	1,000	Pad	----	----
10.	1,000	15% NE Acid with 8 RCN (SG=1.1) Balls in first part.		
11.	Repeat steps (2) thru (10) ten (10) times.			

The average pumping rate during the job was 23 BPM and the average pressure was 5500 psi (see Table No. 10). Nitrogen was added on the last stage at the rate of 350 SCF/bbl. The ISIP was 2800 psi and in 15 min. was 2630 psi.

The type of fluid used was My-T-Frac Gel and the following volumes were pumped:

11,000 gal. of 15% HCl
506,000 gal. of My-T-Frac Gel
33,000 lbs. of 40/60 sand
836,000 lbs. of 20/40 sand

Post Frac Test

A temperature log run after the frac found a sand bridge at 7460'. The log showed that all 10 zones from 6186' to 7204' were treated.

The sand bridge was cleaned out with coil tubing. The flow rate one month after the frac job was 1500 MCFD at a flowing tubing pressure of 1040 psi. A Bore Hole Audio Tracer Survey run one month after the frac showed the following results:

<u>Perfs.</u>	<u>% of Flow</u>
6179-83	.4
6683-87	.3
6761-65	.6
6792-97	.6
6821-25	.7
6904-12	3.7
6977-81	.7
7066-70	.7
7168-72	.8
7196-7200	.8
7446-50	1.2
7598-7602	.5
7770-74	.3

<u>Perfs.</u>	<u>% of Flow</u>
7822-26	.8
7868-72	4.8
8110-14	3.2
8175½-79½	7.1
8329-33	11.9
8453-57	22.4
8485-89	30.6
8642-46	8.6
	<u>100.0</u>

It is estimated that the well will have a first year average producing rate of 740 MCFD (see Graph No. 3) which gives recoverable reserves of 1.97 BCF over a 20 year life. The decline rate used to determine the above reserves was 30% the first year, 20% the second year, 15% the third year, 10% the fourth year, and 5% the remaining years.

The well is currently loading up with water and has to be unloaded with nitrogen. A temperature log is being evaluated, and a workover will probably be attempted in the near future to shut-off the water influx.

Natural Buttes No. 18

Completion Data

The production casing was set at 9140' and consisted of 4½", 13.5#, N-80, LTC casing. The casing was cemented with 1600 sx of 50-50 Pozmic cement. The cement bond log generally showed good bonding with some intervals of fair bonding.

Eighteen zones were perforated from 6490' to 8952' with a casing gun (see Table No. 5). Each zone was perforated in the middle of the sand with 1 shot per foot over a 4 ft. interval.

The tubing was hung-off open ended at 6092'. A Plastron blast joint was installed in the top of the tubing string, opposite the tubing head.

Pre-Frac Test

The well was not balled out after perforating. The zones would not flow after unloading the well with nitrogen. A BHP build-up showed a pressure of 3970 psi after being shut-in 336 hrs. The build-up gave an effective gas permeability of .0000845 md.

Frac Design

The eighteen zones have 224 ft. of net pay with an average porosity of 10%, average water saturation of 48%, and average sand content of 88% (see Table No. 5).

A frac rate of 25 BPM was used in the frac design. Since the well was not balled out prior to fracing, it was assumed that the top zones would break down first. At a frac rate of 25 BPM, the perforation friction pressure drop through two zones (8 perforations) is sufficiently low that the next zone down the hole should not break down. Therefore, it is assumed that two zones are treated in each stage and the frac rate per zone is one-half of 25 BPM or 12½ BPM.

The stages were separated by ball sealers with 8 balls used in the early stages and additional balls dropped in the later stages to compensate for all inefficiency downhole.

The frac height assumed was 26 ft. which includes 16 ft. of permeable sand and 5 ft. of shale above and below the sand.

The frac design used was a volume of 37000 gal. per zone, which gives a frac length of 2314 ft.

Frac Job

The eighteen zones were treated down the 2-3/8" tubing and the 2-3/8" x 4-1/2" annulus. The frac consisted of 9 stages with the following proppant schedule per stage:

	<u>VOLUME (gal.)</u>	<u>RATIO (#/gal.)</u>	<u>MESH</u>	<u>SAND (lbs.)</u>
1.	1,000	15% NE Acid	----	----
2.	4,000	Pre-Pad	----	----
3.	19,000	Pad	----	----
4.	9,000	1.0	40/60	9,000
5.	10,000	2.0	20/40	20,000
6.	26,000	3.0	20/40	78,000
7.	10,000	4.0	20/40	40,000
8.	1,000	Pad with 8 RCN Balls		
9.	Repeat (1) through (8) eight (8) times.			

The average pumping rate during the job was 29.5 BPM and the average pressure was 6000 psi (see Table No. 11). Nitrogen was not used. The ISIP was 3100 psi and in 15 min. was 2650 psi.

The type of fluid used was Versagel and the following volumes were pumped:

9,000 gal. of 15% HCl
695,000 gal. of Versagel
100,000 lbs. of 40/60 sand
1,380,000 lbs. of 20/40 sand

Post Frac Test

A temperature log run after the frac found a sand bridge at 7436'. The depth of the sand bridge is the same depth the sand laden frac fluid was displaced to. The log showed that all eight zones from 6490' to 7050' were treated.

The sand bridge was cleaned out with coil tubing. The coil tubing was run to 7985' and had to be pulled because of mechanical problems. Therefore, the five zones from 8614' to 8952' are covered with sand. The sand will be removed at a later date by lowering the 2-3/8" tubing and circulating out the sand with foam.

The well was fraced on 9/22/76, and was turned to sales on 9/30/76. The following is a list of flow rates and flowing tubing pressures since the well was turned to sales:

<u>Date</u>	<u>FTP</u>	<u>Flow Rate</u>
9/30	1650	1944 MCFD
10/1	1300	1943
10/2	1400	1508
10/3	1045	1790
10/4	cleaned out sand bridge	
10/5	895	1000 flow of frac water increased
10/6	1149 psi	1410 MCFD

Natural Buttes No. 19 - Frac No. 1

Completion Data

The production casing was set at 9697' and consisted of 4½", 13.5#, N-80, LTC casing. The casing was cemented with 1975 sx of 50-50 Pozmix cement. The cement bond log showed fair to poor bonding.

The bottom nine zones from 8909 to 9664 were perforated with a casing gun (see Table No. 6). Each zone was perforated in the middle of the sand with 1 shot per foot over a 4 ft. interval.

Pre Frac Test

The bottom nine zones were not balled out after perforating. The zones would not flow after unloading the well with nitrogen.

Frac Design

The bottom nine zones have 94 ft. of net pay with an average porosity of 9.2%, average water saturation of 45% and average sand content of 88% (see Table No. 6).

A frac rate of 25 BPM was used in the frac design. Since the well was not balled out prior to fracing it was assumed that the top zones would break down first. At a frac rate of 25 BPM, the perforation friction pressure drop through two zones (8 perfs.) is sufficiently low that the next zone down the hole should not break down. Therefore, it is assumed that two zones are treated in each stage and the frac rate per zone is one-half of 25 BPM or 12½ BPM.

The assumed frac height was 15 ft. The frac height was less than the 26 ft. used on previous frac designs because a less viscous fluid was being tested. The fluid used to carry the sand was 1½% KCl with 20 to 40 lbs. of Guar Gum per 1000 gal.

Frac Job

The nine zones were treated down the 4½" casing in five stages with the following proppant schedule per stage:

<u>Type Fluid</u>	<u>Fluid Volume, Gal.</u>		<u>Sand Rate, Lbs./Gal.</u>		<u>Total Sand, Lbs.</u>	
	<u>Per Interval</u>	<u>Cumulative Total</u>	<u>40-60</u>	<u>100</u>	<u>40-60</u>	<u>100</u>
Pad	4,000	4,000	-	3/4	-	3,000
Pad	4,000	8,000	-	1-1/2	-	6,000
Frac	4,000	12,000	3/4	3/4	3,000	3,000
Frac	8,000	20,000	1-1/2	-	12,000	-
Frac	8,000	28,000	1-3/4	-	14,000	-
Frac	12,000	40,000	2	-	24,000	-
					53,000	12,000

The frac job progressed as follows (See Table No. 12):

1. Stage No. 1 - Pumped 1,000 gals. of 15% HCl and followed with a "stage" of pad and sand laden fluid as detailed above.
2. Stage No. 2 - Pumped 1,000 gals. of 15% HCl. Distribute (1) 10 perforation ball sealers, (2) 100 lbs. of Unibeads (50 lbs. fine and 50 lbs. wide range) and (3) one quart (3 mc/qt.) of 100 mesh radioactive tracer sand in the first 500 gals. and follow the acid with a "stage" of fluid and sand.
3. Stage No. 3 - Pumped 1,000 gals of 15% HCl. Distribute (1) 10 perforation ball sealers, (2) 100 lbs. of Unibeads (50 lbs. fine and 50 lbs. wide range) and (3) one quart (3 mc/qt.) of 100 mesh radioactive tracer sand in the first 500 gals. and follow the acid with a "stage" of fluid and sand. Displace to the top of the perforations at 8913' with untreated water.
4. Flow back period - Flowed well back immediately, wide open, for about 3½ hours, recovering about 2000 bbls. of treating fluid.
5. Stage No. 4 - Pumped 1,000 gals. of pad fluid containing (1) 30 perforation ball sealers and (2) 200 lbs. of Unibeads (100 lbs. fine and 100 lbs. wide range). Followed with 1000 gals of 15% tracer sand in the first 500 gals. Followed with a "stage" of fluid and sand.
6. Stage No. 5 - Pumped 1000 gals. of 15% HCl. Distribute (1) 10 perforation ball sealers, (2) 100 lbs. of Unibeads (50 lbs. fine and 50 lbs. wide range) and (3) one quart (3 mc/qt.) of 100 mesh radioactive tracer sand in the first 500 gals. and follow the acid with a "stage" of fluid and sand. Displaced to the top of the perforations at 8913' with untreated water.

The first three stages used 40 lb. per 1000 gal. Guar Gum and average 1.6 lb. per gal. of sand, with a maximum of 3 lb. per gal. of 40/60 sand. The maximum rate was 17 BPM at a pressure of 5700 psi. The ISIP was 3100 psi and in 10 min. was 2900 psi.

The last two stages used 20 lb. per 1000 gal. Guar Gum and averaged 1.4 lb. per gal. of sand, with a maximum of 2 lb. per gal. of 40/60 sand. The maximum rate was 25 BPM at a pressure of 6600 psi. The maximum pressure was 7450 psi. The ISIP was 4100 psi and in 5 min. was 3200 psi.

The following volumes were pumped:

5,000 gal. of 15% HCl
 274,846 gal. of fluid
 61,000 lbs. of 100 mesh sand
 363,000 lbs. of 40/60 sand
 485,000 SCF of nitrogen

Post Frac Test

A temperature and radioactivity log run after the frac found a sand bridge at 9624'. The temperature and radioactivity log showed that all seven zones from 8909' to 9576' were treated.

The bottom nine zones were fraced on 9/21/76 and turned to sales on 9/26/76.

The flow rate for the one day test was 170 MCFD at a flowing casing pressure of 450 psi and with approximately 200 bbls. of frac water per day.

It is estimated that 78% of the 6600 bbls. of frac water was recovered over the 6 day flow period.

Frac No. 2

Completion Data

After the lower nine zones had been fraced and tested, 10 zones from 7224' to 8676' were perforated with a 2-1/8" scallop gun (See Table No. 6). Each zone was perforated in the middle of the sand with 1 SPF over a 4 ft. interval.

Pre-Frac Test

The upper 10 zones were not balled out after perforating. The upper zones would not be tested due to the lower nine zones being open.

Frac Design

The upper 10 zones have 100 ft. of net pay with an average porosity of 9.9% average water saturation of 48%, and average sand content of 86% (see Table No. 6).

The frac design assumptions are the same as those used for Frac No. 1. A volume of 25,000 gal. per zone was used which gives a frac length of 2900'.

Frac Job

The 10 zones were treated down the 4½" casing in 7 stages with the following proppant schedule per stage:

<u>Type Fluid</u>	<u>Fluid Volume</u>		<u>Sand Rate, Lbs./Gal.</u>		<u>Total Sand, Lbs.</u>	
	<u>Per Interval</u>	<u>Cumulative Total</u>	<u>40-60</u>	<u>100</u>	<u>40-60</u>	<u>100</u>
Pad	4,000	4,000	-	3/4	-	3,000
Pad	4,000	8,000	-	1-1/2	-	6,000
Frac	4,000	12,000	3/4	3/4	3,000	3,000
Frac	8,000	20,000	1-1/2	-	12,000	-
Frac	8,000	28,000	2	-	16,000	-
Frac	8,000	36,000	2-1/2	-	20,000	-
Frac	19,000	50,000	3	-	42,000	-
					93,000	12,000

The frac job progressed as follows:

1. Stage No. 1 - Pumped 1500 gals. of pad fluid containing (1) 60 perforation ball sealers and (2) 200 lbs of Unibeads (100 lbs. fine and 100 lbs. wide range). Followed with 1000 gals. of 15% HCl containing one quart (2mc/qt.) of 100 mesh radioactive tracer sand in the first 500 gals. Follow with a "stage" of fluid and sand.
2. Stage No. 2 - Pumped 1000 gals. of 15% HCl. Distribute (1) 10 perforation ball sealers, (2) 100 lbs. of Unibeads (50 lbs. fine and 50 lbs. wide range) and (3) one quart (3 mc/qt.) of 100 mesh radioactive tracer sand in the first 500 gals. and follow the acid with a "stage" of fluid and sand.
3. Stage No. 3 - Pumped 1000 gals. of 15% HCl. Distribute (1) 10 perforation ball sealers, (2) 100 lbs of Unibeads (50 lbs. fine and 50 lbs. wide range) and (3) one quart (3 mc/qt.) of 100 mesh radioactive tracer sand in the first 500 gals. and follow the acid with a "stage" of fluid and sand.
4. Stage No. 4 - Pumped 1000 gals. of 15% HCl. Distribute (1) 10 perforation ball sealers, (2) 100 lbs. of Unibeads (500 lbs. fine and 50 lbs. wide range), (3) one quart (3 mc/qt.) of 100 mesh radioactive tracer sand in the first 500 gals. and follow the acid with a "stage" of fluid and sand.
5. Stage No. 5 - Pumped 1000 gals. of 15% HCl. Distribute (1) 10 perforation ball sealers, (2) 100 lbs. of Unibeads (50 lbs. fine and 50 lbs. wide range) and (3) one quart (3 mc/qt.) of 100 mesh radioactive tracer sand in the first 500 gals. and follow the acid with a "stage" of fluid and sand.
6. Stage No. 6 - Pumped 1000 gals. of 15% HCl. Distribute (1) 10 perforation ball sealers, (2) 100 lbs. of Unibeads (50 lbs. fine and 50 lbs. wide range) and (3) one quart (3 mc/qt.) of 100 mesh radioactive tracer sand in the first 500 gals. and follow the acid with a "stage" of fluid and sand.
7. Stage No. 7 - Pumped 1000 gals of 15% HCl. Distribute (1) 10 perforation ball sealers, (2) 100 lbs. of Unibeads (50 lbs. fine and 50 lbs. wide range) and (3) one quart (3 mc/qt.) of 100 mesh radioactive tracer sand in the first 500 gals. and follow the acid with a "stage" of fluid and sand. Displace to the top of the perforations at 7224' with untreated water. Note: In the later stages, the volumes of sand fluid and diverting agents were modified as per the attached service company treating report (Table No. 12) which contains additional details.

The seven stages used 30 lb. per 1000 gal. Guar Gum and averaged 1.9 lb. per gal. of sand, with a maximum of 5.5 lb. per gal. The maximum rate was 26 BPM at a pressure of 45000 psi. The maximum pressure was 5500 psi. The ISIP was 3000 psi and in 5 min was 2800 psi.

The following volumes were pumped:

6,500 gal. of 15% HCl
358,302 gal. of fluid
72,000 lbs. of 100 mesh sand
712,000 lbs. of 40/60 sand
555,000 SCF of nitrogen

Post Frac Test

Two days after the frac a wireline was run in the well and the top of the sand was tagged at 8674'. An attempt was made to wash out the sand with coil tubing, but the coil tubing became stuck while washing at 8913'. The coil tubing pulled apart at 1657' from the surface. A work-over rig is presently rigging up on the well to recover the coil tubing, wash out the sand with foam, and hang off the 2-3/8" tubing open-ended opposite the bottom perforations.

The well is presently flowing to the pit through two 2" lines. The well is unloading slugs of water at an estimated rate of 350 BWPD.

General Comments on Treatment

It is to be noted that this is the first time 40/60 sand has been used on a large frac job in the Natural Buttes area and there was very little data on the usage of this sand in other areas to be used as a guideline. The first part of the frac job was modified during the actual treatment, the second part was redesigned based on the results of the first part and during the actual fracturing procedure in the second part, additional modifications were made. Various pertinent items regarding the treatments, etc., are as follows:

1. In the first part of the frac which treated the lower and presumably harder, tighter sands, it was determined that 3 lbs. of 40/60 sand per gallon could be pumped with a fluid containing 40 lbs. of Guar Gum per 1000 gallons. It was also determined that 2 lbs. of 40/60 sand per gallon could be pumped with a fluid containing 20 lbs. of Guar Gum per 1000 gallons. In the second part of the frac job it was determined that 5½ lbs. of 40/60 sand could be pumped with a fluid containing 30 lbs. of Guar Gum per 1000 gallons. It is to be further noted that these sand volumes do not necessarily represent the upper limit since the well did not screen out and it is therefore assumed that higher concentration (lbs. per gallon sand volumes) could be used although it appears doubtful at this time if there will be justification for using concentrations in excess of 5 lbs. per gallon.
2. There was no apparent relationship between sand concentration and pressure increases as the different concentrations of sand were pumped into the formation. As an example, in some cases the higher sand concentrations would enter the formation without any appreciable pressure increase (pumping) and a low concentration might cause a minor pressure increase (200-400 psi).
3. There were no apparent appreciable pressure changes when larger size sand (40/60) entered the formation behind the smaller mesh sand (100). In one stage the 100 mesh sand was omitted and 40/60 sand was used throughout the stage, including in the pad fluid. This indicates that consideration should be given to designing future jobs using only a single mesh sand (40/60). This would simplify the overall design and performance of the job.
4. It appears that the concentration of 40/60 sand can be increased more rapidly as compared to the larger sand sizes. For example, in one case the 40/60 sand concentration was increased from 1 lb. per gallon to 3 lbs. per gallon with no noticeable pressure increase when the higher concentration of sand entered the formation. Conventionally, 20/40 sand

concentrations are increased in $\frac{1}{2}$ to 1 lb. gallon increments. This should permit establishing a higher sand concentration earlier in the job.

5. The frac job was performed in two parts primarily because it was unknown as to how the Wasatch-Mesaverde sands would accept 40/60 sand with a thin fluid. The results of the two treatments indicate that the 40/60 sand can be pumped satisfactorily and future jobs should be done in one operation.
6. In the first part of the frac three stages were pumped followed by a flow back period. In the second part of the frac seven stages were pumped before flowing back. In all cases, the well was flowed back at a maximum rate (1-3" and 2-2" openings). No appreciable sand recoveries were observed during any flow back periods. Since large volumes of fluid were recovered over a relatively short time interval (example - 2,000 bbls. in $3\frac{1}{2}$ hrs.), it definitely appears that this type of a flow back is justified for wells fraced with the thinner gelled fluids. Where all zones in a well are to be fraced in one operation, there is some question as to whether an intermediate flow back period should be used. When the lower zones in No. 19 were stimulated, an intermediate flow back period was used and the upper section was treated in seven stages without an intermediate flow back period. Overall fluid recoveries were apparently better after treating the lower zones, where a flow back period was used, as compared to treating the upper zones where no intermediate flow back was used. If the flow back period is omitted, possible additional damage to the fracture face due to exposing the fracture to the excess pressure must also be evaluated. This requires additional consideration and investigating.
7. Several days after the second frac job was completed, the top of the sand was checked in the well at 8674' which indicated part of the perforations were covered. This is not considered to be significant when comparing using 40/60 sand in a thin gel to a frac job using the cross linked KCl polymer with 20/40 sand since the same phenomenon occurs with the thick gel fluids and larger size sand.
8. As noted earlier, the initial frac design on this well was based on a 15' high fracture. Since the job was modified appreciably during the actual fracing operation, fracture depths should be recalculated. It appears reasonable to use a fracture height of 15' with the thin fluid as compared to using a fracture height of 26' for the thicker fluid, however, this should be investigated further.
9. Nitrogen was used in this job to facilitate flow back similar to initial fracing procedures with the thick fluid (Natural Buttes No. 15, etc.). In future jobs, it may be possible to omit using nitrogen. However in this case, additional consideration should be given to using at least one intermediate flow back period.
10. Good ball action was observed in both jobs with somewhat better ball action in the second part. However in the second part successively higher pressures were not always observed as succeeding stages were pumped and as would normally be expected. For example, assuming the bottom zones were balled off, the frac of the upper section included seven stages designed to stimulate 14 zones when theoretically only ten zones should have been open (again assuming the lower zones were balled off). This could indicate that either the lower zones were not adequately balled off and/or the actual stage efficiency is lower than estimated and additional stages should be included in the design.

Forecast of Work for October, 1976

During October, 1976 the following work is planned:

- 1) Phase I - Natural Buttes No. 18
 - a. Move in workover rig
 - b. Lower 2-3/8" tubing and wash out frac sand to PBTD
 - c. Hang off tubing (open-ended) opposite the bottom perforations
- 2) Phase II - Natural Buttes No. 19
 - a. Move in workover rig
 - b. Recover coil tubing lost in hole
 - c. Go in hole with 2-3/8" tubing and wash out frac sand to PBTD
 - d. Hang off tubing (open-ended) opposite the bottom perforations
- 3) Phase III - Natural Buttes No. 14
 - a. Move in workover rig
 - b. Pull 2-3/8" tubing
 - c. Run casing inspection log to determine the condition of the 4½", 11.6#, N-80 casing. The casing inspection is required prior to fracing, because the field has a history of a corrosive water zone at approximately 4000 ft. creating holes in the production casing. After the casing inspection log is evaluated, a decision will be made on the suitability of the well for fracing.

Monthly Report for October - Text Only

During October, 1976, the following work was accomplished:

- 1) Coil tubing was fished from Natural Buttes No. 19, frac sand was washed from wellbore, and well was flowing in order to recover all of remaining frac fluid before putting on production test.
- 2) Natural Buttes No. 18 flowed an average of 1412 MCFD. Natural Buttes 18 was restricted all month due to line capacity. An attempt to wash out sand from 7408' to PBTD was made with coil tubing and using nitrogen foam. The coil tubing became stuck in the frac sand, but was pulled free and retrieved from the hole.
- 3) Ran a borehole audio tracer survey log and differential temperature log on Natural Buttes No. 17 in order to determine the source of the water production.

Graphs Nos. 1, 2, 3, and 4 give up-dated production curves on four of the wells that have been stimulated by massive hydraulic fracturing. These curves are being used to determine the economics of the MHF treatments. So far, the results still do not show a direct relationship of frac length to average first year production. A discussion of frac lengths, heights and proppants will follow later in this report.

The following is a discussion of the work accomplished during October, 1976:

Natural Buttes No. 19

1) Cleaning of the Wellbore

After flowing the well to the pit and recovering 3290 barrels of water, a wireline was run and tagged sand at 8674'. A coil tubing unit was rigged up and an attempt to washout the frac sand using nitrogen foam was made. The attempt to wash out the sand failed, and the coil tubing became stuck at 8922'. The 1" coil tubing parted 1657' from surface. Then a workover rig was moved in and 2-3/8" tubing was used to wash over the coil tubing inside the 4-1/2" casing. The coil tubing was recovered in this manner, and then the frac sand was washed from the wellbore with 2% KCl water and soap. The 2-3/8" tubing was then hung off at the bottom of the perforations, 9656', and the well started flowing to the pit to clean up at an estimated rate of 250 BWPD. At that time there was still 5646 barrels of water left to recover. All of the frac fluid will have to be recovered before an accurate measurement of produced reservoir fluids can be made. Approximately three months of production history will be needed to evaluate and compare the MHF design used on this well with the MHF design used on Natural Buttes No. 18.

2) Discussion of Frac Treatment

As noted in last month's report, 40/60 sand as well as 100 mesh sand was used in the second part of the stimulation treatment. There were no appreciable pressure changes when larger (40/60) size sand entered the formation behind the smaller mesh (100) sand.

In post treatment analysis, we realized from pressure-drop calculations that the zone heights ranged from as little as 15' to as much as 35'. Because two different sand sizes were used in this treatment, we have attempted to determine where the two "sands" are located in the fracture. There are many variables which have an effect on the distribution of the sand, some of which are as follows: viscosity of frac fluid, proppant support capacity, fluid velocity in the fracture, sand concentrations, frac heights, frac widths, etc., and the list is endless.

To simplify our calculations, we calculated our sand placements for the minimum 15' frac height and the maximum 35' frac height. Thus, for frac heights covered by this range, we may assume the placement of sand in the fracture will be a combination or modification of the two extremes (see Figures 1, 2, 3, 4, and 5).

According to our computer calculations, we have a fracture length of 3228' (Point A to Point D; Point A' to Point D' in figure 1). As discussed previously frac heights created while pumping will range from 15' to 35' (see Figures 2 and 3).

It is doubtful that production will enable us to determine actual sand placement in the created fractures. Natural Buttes No. 19 should be on production about the 15th of November. Performance of the 40% Guar Gum fluid and smaller frac proppant design will be determined by production history in approximately the next three months.

Natural Buttes No. 18

This well flowed at an average rate of 1412 MCFD for the month of October. This is not the maximum capacity of this well as the capacity of the sales line is limited. Some other wells in the field had to be pinched back in order to allow this rate. A procedure is being prepared and studied for use in cleaning out remaining frac sand in the wellbore. Fishing jobs such as the one on Natural Buttes No. 19 are very expensive and add to the payout of the MHF treatment and also detract from the economics.

Natural Buttes No. 17

A borehole audio tracer survey and temperature log were re-run on this well because it was determined that the method used before was faulty. In order to be able to analyze the BATS log and temperature log inside of the tubing, the flow of produced fluids must be up the tubing-casing annulus. After listening to the production from the various perforations, we determined that all of the water production was coming from two sets of perforation. The two water zones are between 8100' and 8200'. These water sources will have to be squeezed off before the well will be able to produce. A procedure is being prepared for the purpose of shutting off the flow of water from the two zones between 8100' - 8200'. This work is expected to be done during the first quarter of next year. After studying Table No. 2, there does not appear to be any correlation from the log data to water production. The two water zones are Numbers 16 and 17 on the table.

Also noted on the BATS log and the temperature log was the fact that no production was coming from below an obstruction of 8600' (see Table No. 3 for BATS log results).

Natural Buttes No. 15

The BATS log and temperature log that were run August 6, 1976, were run with the production coming up through the tubing; thus, those results are erroneous. In order to properly utilize the borehole audio tracer survey inside of tubing, the produced fluids must flow up the tubing-casing annulus. If the produced fluids flow down the annulus and then up the tubing, there are several changes taking place and all create noise which travels up and down the tubing. If the flow is up the annulus, there is a measurable noise level above and below the producing intervals, and since the flow is upward, any increase in noise above a producing interval must be produced in the annulus. Thus, it can be attributed to the producing interval as gas or water which is determined by the frequency of the noise.

Forecast of Work for November, 1976

During November, 1976, the following work is planned:

1) Phase III - Natural Buttes No. 14

- a. Move in workover rig
- b. Pull 2-3/8" tubing
- c. Run casing inspection log to determine the condition of the 4-1/2", 11.6#, N-80 casing. The casing inspection log is required prior to fracing because the field has a history of corrosive water zone at 4000' creating holes in the production casing. An electro-magnetic caliper log will also be run in order to determine if the loss of metal is on the inside or outside of the pipe. After the casing inspection and caliper are evaluated, a decision will be made on the suitability of the well for fracing.

Monthly Report for November - Text Only

Introduction

During November, 1976 the following work was accomplished:

I Phase III - Natural Buttes No. 14:

A casing inspection log and an electromagnetic caliper log were run; also run in the well was a Schlumberger TDT-K log.

II Frac Length and Width:

Halliburton Services recently developed a new, more advanced computer program. The new program calculates considerably shorter frac lengths compared to the old computer program.

III Items to be tested as per contract with ERDA:

Phase I: Natural Buttes No. 18

Phase II: Natural Buttes No. 19

IV Flow Testing Natural Buttes No. 19

V Flow testing Natural Buttes No. 15, 16, 17, and 18

Discussion of Work Performed

I Phase III - Natural Buttes No. 14

A. Completion Data:

Production casing was set at 8,063' on August 25, 1974, and consisted of 4-1/2", 11.6#, N-80, LT&C, 8rd casing. The casing was cemented with 580 sacks of 50-50 pozmix with 2% gel, 12.5 pounds gilsonite per sack. The cement bond log showed the top of cement to be at about 6,250'.

The casing was perforated October 10, 1974 at the following intervals and are measured from Gamma Ray-CBL depths.

1.	6826-30'	4 shots
2.	6874-78'	4 shots
3.	6952-56'	4 shots
4.	6970-74'	4 shots
5.	7084-88'	4 shots
6.	7261-65'	4 shots
7.	7407-13'	4 shots
8.	7572-76'	4 shots
9.	7724-28'	4 shots
10.	7790-94'	4 shots
11.	8967-71'	4 shots
12.	8000-04'	4 shots

The well was acidized October 11, 1974, with 10,000 gallons of 15% acid with standard additives in stages of 500 gallons followed by 15 barrels of 2% KCl water and four perf ball sealers and 50 pounds of Benzoic acid flakes. Averaged 10 BPM at 6200 psi. Maximum pressure - 6800 psi with good ball action throughout the job. Initial shut-in pressure = 3200 psi, 15 minutes shut-in pressure = 3200 psi. Flowed well back wide open, began making acid gas in one hour, 30 minutes.

See Graph #5 for Production Decline Curve.

B. Pre Frac Evaluation:

A casing inspection log and caliper log were run November 4, 1976. Careful evaluation of the logs show that some light weight pipe was run in the well. The string of pipe appears to have some 9.5# pipe included. A minimum wall thickness was taken from the casing inspection log and a burst strength of 5911 psi was calculated, assuming N-80 grade. However, since 9.5# pipe must have been included accidentally in the string, the burst of 9.5# J-55 pipe is the maximum that can be used which is 4380 psi.

The pipe in the well does not appear to be in bad condition (corroded, pitted, worn, etc.); however, the light weight pipe will have lower burst pressure tolerances than the pipe that was supposed to be in the well. It is felt that at this time, a frac treatment can be designed with the limitations in mind, due to the 9.5# pipe being located below the top of the cement behind pipe.

Schlumberger ran their TDT-K log on the well on November 29, 1976. This log was run to help evaluate the zones that are perforated and also to help determine if there are any other zones which should be perforated prior to MHF. The accuracy of this log can be increased ten-fold by making a statistical analysis of data collected by making five passes of the formation. It will be determined from examining the results of the log made using data from a conventional one pass and comparing it to a log made using the best statistical data gathered from the five pass technique. It is hoped to develop a better method of determining the best sands to perforate and frac in the Mesaverde and Wasatch formations. Full evaluation of this log will not be made until December as the calculations and final prints of the logs have not been received.

II Frac Lengths and Widths

Halliburton had developed a new computer program that incorporates the latest information in rock mechanics, fluid dynamics (proppant transport geometry, and job characteristics such as different sand sizes, actual sand concentrations and volumes instead of averages, etc. See Table #7-2 for a comparison of the calculated frac lengths derived from the old and new computer programs. Also see Table No. 1

In general, the new program calculated shorter propped frac lengths on the order of one-third the old program. The width of the created frac is considered to be much wider than previously calculated using the old program. This has the effect of shortening the fracture. However, the folds of increase calculated from both programs are approximately equal.

III Items to be tested as per contract with ERDA:

A. Phase I: Natural Buttes Unit No. 18 (Section 10, T10S, R22E)

1. New Fluid Design

Halliburton's Versa-Gel, a cross-linked, KCl water-based fluid, continuously mixed with minimum viscosity was used for the MHF treatment. This fluid performed well. No problems were encountered with sanding out or excessive friction pressure. This fluid appears to have carried the sand in "perfect" transport as designed.

2. 20/40 Mesh Sand Conductivity

The 20/40 mesh sand used in the concentrations and volumes of the Natural Buttes No. 18 MHF is providing sufficient fracture capacity. The conductivity provided by the 20/40 mesh sand is more than the formation's ability to utilize. This is the ideal situation because the pressure drop needed to move the gas to the well bore is at the optimum.

3. Fracture Length

As discussed previously, the new computer program is calculating frac lengths in the range of 450' to 950' for the Natural Buttes wells #15, 16, 17, 18, and 19. Results from Sandia Laboratories work concerning frac length and orientation indicates that the length of the frac wings are not equal in the Wamsutter Area.

4. Best Zones

No water is being made from the Natural Buttes #18 well. However, the same criteria used to select the zones for perforating in No. 18 did not predict the "best" zones for Natural Buttes #19. There does not appear to be any way of consistently predicting which zones may or may not produce water.

B. Phase II: Natural Buttes Unit No. 19 (Section 21, T10S, R21E)

1. Light Gelled Frac Fluid

A 40# gel made from water and a guar-gum gelling agent was used and performed as designed. The fluid carried the sand without problems or excessive friction pressure. Concentrations of 5-1/2 pounds of 40/60 mesh sand per gallon of frac fluid were pumped during the MHF treatment.

2. Frac Height Control

A temperature log was not run immediately after the frac treatment due to the decision to flow the well back as soon as possible. A temperature log was run three days after the frac treatment to determine which zones were giving up the production. All but one zone were giving up some production. A radioactive log run at the same time showed that all of the zones had taken at least some fluid during the frac job.

Mechanical properties calculated from electric logs on Natural Buttes #25 indicate sand frac gradients of .7 to .8 psi per foot and shale frac gradients of .8 to .9 psi per foot. This indicates that the fractures will be contained within the sand formations.

3. Fracture Conductivity of 40/60 Mesh Sand

The 40/60 mesh sand theoretically has enough fracture conductivity for use in these tight formations. However, since the well is loading up with water, a determination cannot be made of the effective frac conductivity.

4. Fracture Lengths

Using Western Company's computer program, the frac length calculated is 3228'. However, using Halliburton's new program as discussed previously, we obtain a calculated length of 848'.

IV Flow Testing of Natural Buttes No. 19

After completing the clean out operation of the well bore, the well was flowed to the pit in order to recover the remaining frac fluids. Due to high water production, this well will require remedial work to shut off water production.

V Flow testing of Natural Buttes No. 15, 16, 17, and 18

See Tables 3, 4, 5, and 6 for monthly production as well as Graphs No. 1, 2, 3, and 4 for decline curves.

Forecast of Work for December, 1976:

- I Clean out frac sand in Natural Buttes #18. The top of the frac sand was tagged at 8290' with a wireline. The perforated interval is from 6490' to 8952'.
- II Continue to try to clean up the Natural Buttes #19 so the well will flow continuously and a Borehole Audio Tracer Survey log can be run to determine what zones are producing water.
- III Design MHF for Natural Buttes No. 14 and coordinate with Sandia Laboratories on performing frac orientation work.

Monthly Report for December - Test Only

Introduction

During December, 1976, the following work was accomplished:

- I A workover rig moved in and cleaned out the remaining frac sand in Natural Buttes Unit No. 18
- II Natural Buttes Unit No. 19 continued to flow heads of water and gas while flowing to the pit.
- III Design for Natural Buttes Unit No. 14 MHF was completed. TDT log analyzed.
- IV Natural Buttes Unit No. 20 was staked and drilling permit submitted to the U.S.G.S.

Discussion of Work Performed

I Phase I - Natural Buttes Unit No. 18

A workover rig was moved in, rigged up, and 2-3/8" tubing worked to the top of the frac sand at 8,290'. Frac sand was cleaned out to PBTD - 9,108', and the well turned to pit. The well will have to flow for several days to clean up before being put on the sales line. Production results for January and February should be indicative of the cleanout operation opening up the additional five zones previously covered by frac sand. (See Table No. 7, Graph No. 5).

II Phase II - Natural Buttes Unit No. 19

A BATS log and temperature log will be run in January if production can be sustained for several days. (See Table No. 8, Graph No. 6). Natural Buttes Unit No. 19 will make formation water at the rate of 200-300 BWPD until it loads up and kills itself. After analysis of the BATS log and temperature log, steps will be taken to shut off water if economical to do so.

III Phase III - Natural Buttes Unit No. 14

Design for Natural Buttes Unit No. 14 was completed. Casing will be tested to 6,000 psig surface pressure with 2% KCl water in the well. A CIBP will be set above the top set of perforations.

The CIBP and casing test are being run due to the casing inspection log results. The log shows either several light weight joints of pipe or pipe of a higher grade such as P-110 instead of N-80. Due to the lower pressure rating which will have to be given this string of casing and the increased friction pressure for fracture orientation equipment, it will be recommended that the fracture orientation work be done on a new well with new casing. New casing will have a higher pressure rating, thus allowing for the increased friction pressure caused from the necessary string of 1-1/4" tubing to house Sandia's equipment and the dropping of ball sealers down the annulus.

Three additional zones were recommended for perforating from the TDT log on Natural Buttes Unit No. 14. No additional benefit was derived from running the TDT log five times over the interval from 6,000' to 8,000'. One conventional pass over the interval is sufficient.

Bids for the proposed MHF will be mailed in January, and it is expected that the frac will be performed in mid-February.

The MHF of Natural Buttes Unit No. 14 was moved to the first quarter of 1977 from the fourth quarter of 1976 to provide additional time to consider all of the casing test results and formation log results. Also, during this time Gas Producing Enterprises, Inc. tried to schedule fracture orientation work on this well, but as mentioned previously, the pressure rating of the casing string in Natural Buttes Unit No. 14 prohibits such work.

IV Phase IV - Natural Buttes Unit No. 20

Drilling permit submitted to the U.S.G.S. for approval. A 12-Point Surface Use Plan was submitted along with the drilling permit.

Forecast of Work for January, 1977

I Phase I - Natural Buttes Unit No. 18

Flow testing after cleaning frac sand from well bore.

II Phase II - Natural Buttes Unit No. 19

Run a bore hole audio tracer survey and temperature survey to determine gas and water sources. Depending on survey results and if economical, work will be performed to shut off the water zones.

III Phase III - Natural Buttes Unit No. 14

Obtain bids for the MHF of Natural Buttes Unit No. 14.

IV Phase IV - Natural Buttes Unit No. 20

Prepare drilling procedures, Surface Use Plans, etc., for the drilling of Natural Buttes Unit No. 20.

Monthly Report for January - Text Only

Introduction

During January, 1977, the following work was accomplished:

- I Natural Buttes Unit No. 18 was flow tested for 25 days during January.
- II Natural Buttes Unit No. 19 was logged with a Borehole Audio Tracer Survey and Temperature Survey.
- III Bids for the MHF of Natural Buttes Unit No. 14 were mailed and U.S.G.S. permits were applied for.
- IV U.S.G.S. application for a permit to drill Natural Buttes Unit No. 20 has been filed and verbal approval received.

Discussion of Work Performed

I Phase I - Natural Buttes Unit No. 18

In December, frac sand was washed off the bottom five zones. 31,083 MCF was produced over a period of 25 days for an average rate of 1,243 MCF. See Production Curve and Daily Production Table.

II Phase II - Natural Buttes Unit No. 19

The BATS Log and Temperature Log indicate that water is being made from two sets of perforations (7,728-32' and 7,632-36'). An AFE is being prepared for proposed isolation work to eliminate these water sources. The BATS Log and Temperature Log were run three times at different flow rates in order to better identify the sources of gas and water production. No production was recorded for January.

III Phase III - Natural Buttes Unit No. 14

Bids are being solicited for the MHF treatment of Natural Buttes Unit No. 14, and will then be submitted to ERDA for approval. U.S.G.S. permits have been applied for and upon approval of these, Gas Producing Enterprises, Inc. will begin the construction necessary for the MHF treatment. See Decline Curve for production history. Sandia Laboratories may try to determine the orientation of the fractures using the electric potential method.

IV Phase IV - Natural Buttes Unit No. 20

Necessary permits and applications have been applied for on Natural Buttes Unit No. 20. Verbal approval has been received from the U.S.G.S. for drilling the subject well. Drilling procedures have been prepared for Natural Buttes Unit No. 20 and work should begin on schedule.

Forecast of Work for February, 1977

I Phase I - Natural Buttes Unit No. 18

Continue flow testing

II Phase II - Natural Buttes Unit No. 19

Move in workover equipment and isolate water producing intervals.

III Phase III - Natural Buttes Unit No. 14

Prepare to MHF. Build lined pit for frac fluids, etc. Survey and stake electric potential locations for Sandia Laboratories fracture orientation work.

IV Phase IV - Natural Buttes Unit No. 20

Move in rotary equipment. Prepare to drill well.

Monthly Report for February - Text Only

Introduction

During February, 1977, the following work was accomplished:

- I Natural Buttes Unit No. 18 produced an average of 1065 MCFD for 28 days during the month of February, 1977.
- II Natural Buttes Unit No. 19 was worked over. Packers were set to isolate the two water producing zones.
- III Natural Buttes Unit No. 14 - preparing to MHF on March 15, 1977.
- IV Natural Buttes Unit No. 20 - location built and waiting on rotary tools after setting 13-3/8" casing.

Discussion of Work Performed

- I Phase I - Natural Buttes Unit No. 18

Produced well for 28 days.

- II Phase II - Natural Buttes Unit No. 19

Isolation packers were set at 7,596' and 7,785' to seal off water production from perforations 7,632-36' and 7,728-32'. Production from the 12 zones before 7,785' is about 190 MCFD. The five zones above 7,596' are producing to the pit at zero pressure and gas rate is TSTM. There was a scale build-up in the casing that had to be cleaned out prior to setting the packers. The scale is presently being analyzed.

- III Phase III - Natural Buttes Unit No. 14

Three additional zones were perforated (6,297-6,031'; 6,382-86' and 6,642-46'). MHF is set up to be performed on March 15, 1977 consisting of 1,048,000 pounds of 20/40 sand; 40,000 pounds of 40/60 sand; 544,000 gallons of gelled fluid; 32,000 gallons of pre-pad; and 8,000 gallons of 15% non-emulsifying acid. Maximum allowable pressure is 6,000 psi; design frac rate is 25 BPM at 4,500 psi. The designed frac radius per zone is 780'. Sandia will measure fracture length and orientation using the electrical potential method.

Design of the MHF is based on the following criteria:

- 1. 12.5 BPM per zone - fracing two zones per stage
- 2. 26' frac height per zone
- 3. Formation permeability = 0.05 md
- 4. Formation porosity = 8%

A differential temperature survey will be run over the fraced interval to determine the number of zones treated and the frac height per zone.

IV Phase IV - Natural Buttes Unit No. 20

Drilled rat hole and mouse hole and set 13-3/8" casing at 62'.
Presently waiting on rotary drilling equipment.

I Phase I - Natural Buttes Unit No. 18

Continue production testing.

II Phase II - Natural Buttes Unit No. 19

Continue to production test. Analyze scale problem. May co-mingle tubing and annulus, depending upon results of scale analyses.

III Phase III - Natural Buttes Unit No. 14

MHF on March 15, 1977. Measure fracture length and orientation by the electrical potential method. Begin production testing.

IV Phase IV - Natural Buttes Unit No. 20

Move in rotary drilling equipment. Rig up and drill ahead.

Monthly Report for March - Text Only

Introduction

During March, 1977, the following work was accomplished:

- I Natural Buttes Unit No. 18 produced an average of 1,090 MCFD for 31 days.
- II Natural Buttes Unit No. 19 was produced for 31 days at an average rate of 166 MCFD.
- III Natural Buttes Unit No. 14 was fraced March 15, 1977.
- IV Natural Buttes Unit No. 20 is drilling ahead below 5,600'.
- V Drilling programs are being prepared for Natural Buttes Units Nos. 21 and 22.

Discussion of Work Performed

- I Phase I - Natural Buttes Unit No. 18

Produced well for 31 days.

- II Phase II - Natural Buttes Unit No. 19

Produced well for 31 days. Scale was analyzed as BaSO_4 . Water analysis did not disclose the source of the scale; therefore, the scale problem is still under investigation.

- III Phase III - Natural Buttes Unit No. 14

- A. The MHF treatment was performed on March 15, 1977, and consisted of the following: 1,053,000 pounds of 20/40 sand; 40,000 pounds of 40/60 sand; 544,000 gallons of low residue cross-linked gelled fluid; 32,000 gallons of pre-pad; and 8,000 gallons of 15% non-emulsifying acid. Average treating pressure was 2600 psi with a maximum recorded pressure of 3,600 psi. The Dowell treatment report is attached.

Sandia Laboratories (Albuquerque, New Mexico) studied the MHF treatment with the intent to determine the direction of propagation of the fracture wings. The data collected by Sandia had not been tabulated at the time of this report.

The MHF performed on Natural Buttes Unit No. 14 was the first in our ERDA program performed on an "old" well. At this time, the well is producing an estimated 150 MCFD and 150 BWP, and the gas is still too wet to burn. A spinner survey, fluid density log and BAT's log will be run before running tubing in the hole.

A temperature survey was run to try to determine fracture heights, but was not successful in getting all the way down to the bottom six sets of perforations. Radioactive sand was pumped in the last part of the first stage. The purpose for the radioactive sand was to establish the sequence in which the perforations took fluid. A radioactive survey run did not show any trace of the radioactive sand in the upper nine sets of perforations; therefore, at this time, we still do not know where the first stage was placed.

A workover rig will be moved in and the fracture sand cleaned out of the wellbore. At that time, another radioactive survey should be run to try to determine the placement of the radioactive material.

B. Completion Data for Natural Buttes Unit No. 14

The production casing was set at 8,063' and consisted of 4-1/2", 11.6#, N-80, LT&C casing. The casing was cemented with 580 sacks of 50-50 Pozmix cement. The bond log showed fair to good bonding. The bottom 12 zones were perforated in 1974 with a thru-tubing gun, and produced a total of 49.2 MMCF to October 1, 1976. Then in December, 1976, a Schlumberger TDT-K log was run to try and pick additional zones. Three more sets of perforations were added with a 3-3/8" casing gun.

The first 12 zones were balled out on October 10, 1974, with 10,000 gallons of 15% HCl in 500 gallon stages (20 stages) with four ball sealers and 50 pounds Benzoic acid flakes between stages. Average injection rate was 10 BPM at 6,200 psi. Maximum pressure = 6,800 psi. Balled out on 16th stage. ISIP = 3,200 psi, 15 minutes, ISIP = 3,200 psi.

The three sets of perforations that were added were not broken down prior to the frac job.

A 51 hour build-up was run on the well on November 8, 1975. The extrapolated BHP was 3,100 psig; the effective gas permeability was 0.00441 millidarcies, and skin damage was -1.02.

A McCullough Casing Inspection log was run. Evaluation of the inspection log indicated a bridge plug should be set and a pressure test conducted.

A test of burst strength was performed on December 29, 1976, to determine the strength of the 4-1/2" casing. Pressure was applied at 6,000 psi and held for 30 minutes above a bridge plug set at 6,805'.

C. Frac Design and Job on Natural Buttes Unit No. 14

The eight* stages consisted of the following:

1,000 gallons	15% HCl
4,000 gallons	Pre-Pad
20,000 gallons	Pad
5,000 gallons	Gel + 1 ppg 40/60
1,000 gallons	Gel + 2 ppg 20/40
17,000 gallons	Gel + 4 ppg 20/40
1,000 gallons	Pad + 7/8" RCN balls (SG = 1.1)

*On the eighth stage, the last 5,000 gallons of sandladen fluid was raised to 5 ppg. All seven previous stages were pumped at a continuous 25 BPM rate; however, the eighth stage was slowed to a rate of 5 BPM to flush to the bottom of the perforations. This slow pump rate supports the theory of "perfect transport" due to the fact that no screenout occurred; however, when running the logging tools, a bridge was encountered at 7,300'. The bridge could have been caused by sand settling out at the lower pump rates; but, it is probably due to sand returning to the wellbore due to cross flows of fluid from one set of perforations to another after the frac treatment was stopped. This phenomenon is seen on the temperature logs by way of temperature reversals.

The MHF was designed for calculated fracture lengths of 879', assuming 26' fracture heights which include 16' of permeable sand and 5' of shale above and below the sand, and fracture widths of 0.4716" for a treatment volume of 24,500 gallons per zone. See attached Dowell Computer Output.

Surface equipment was placed around the lined pit and wellbore as per attached sketch. No equipment breakdowns were encountered throughout the entire 11 hours of pumping.

D. Post Fracture Test

Temperature and radioactive logs were run to 7,300' where they encountered sand bridges. The well was turned to the pit at 1:00a.m. on March 16, 1977, on a 19/64" choke. A spinner survey will be run to determine the rates of gas and volumes of water coming from each set of perforations open above the frac sand. Then a workover rig will be moved in to clean out frac sand to 8,048'. As of March 31, 1977, a total of 9,800 barrels of frac fluid were recovered, leaving 4,080 barrels of fluid to be recovered.

IV Phase IV - Natural Buttes Unit No. 20

Natural Buttes Unit No. 20 was spudded February 9, 1977. 13-3/8" casing was set at 62' KB. 8-5/8" casing was set at 2,499' KB. Natural Buttes Unit No. 20 is presently drilling ahead below 5,600'.

V & Phase V &
VI Phase VI Natural Buttes Unit No. 21 and Natural Buttes Unit No. 22

The drilling programs for Natural Buttes Unit Nos. 21 and 22 are presently being designed. Actual programs may change due to increased scope of project.

Forecast of Work for April, 1977

I Phase I - Natural Buttes Unit No. 18

Continue production testing.

II Phase II - Natural Buttes Unit No. 19

Continue production testing.

III Phase III - Natural Buttes Unit No. 14

Production test. Clean out frac sand. Tabulate frac orientation data from Sandia Laboratory experiment.

IV Phase IV - Natural Buttes Unit No. 20

Finish drilling. Complete and perforate. Pre-frac production test.

V & Phase V &

VI Phase VI - Natural Buttes Unit No. 21 and Natural Buttes Unit No. 22

Finalize drilling programs.

Monthly Report for April - Text Only

Introduction

During April, 1977, the following work was accomplished:

- I Natural Buttes Unit No. 18 produced at an average rate of 957 MCFD for 29 days.
- II Natural Buttes Unit No. 19 produced 30 days at an average rate of 139 MCFD.
- III Natural Buttes Unit No. 14 was flowing frac fluids to the pit for 18 days. Well #14 was then put through the separator and dehydration unit and produced at 317 MCFD measured rates for 7 days. See production curves and tables.
- IV Natural Buttes Unit No. 20 was drilled to a total depth of 9807', logged, and completed.
- V Natural Buttes Unit No. 21 is being scheduled for drilling after completion of Natural Buttes Unit No. 26.
- VI Natural Buttes Unit No. 22 has been designed and should be spudded after Natural Buttes No. 21, but may be spudded prior to Natural Buttes No. 21 due to permitting, drilling program changes, etc.

Discussion of Work Performed

- I Phase I - Natural Buttes Unit No. 18

Produced well for 29 days.

- II Phase II - Natural Buttes Unit No. 19

Produced well for 30 days.

- III Phase III - Natural Buttes Unit No. 14

Frac sand was cleaned out of the casing and put on production to recover frac fluids. The well produced for 7 days and then the dehydrator had to be cleaned out, as frac sand had plugged it up. The well will be back on production after the dehydrator is put back into operation.

- IV Phase IV - Natural Buttes Unit No. 20

This well was drilled to a total depth of 9807' and casing was set at 9807'. Logs were taped and Saraband computations were made. The well is being stuided for MHF and a frac program will be designed within the next month.

- V Phase V - Natural Buttes Unit No. 21

Coring and testing programs have been completed and should be implemented into the drilling and completion operations.

VI Phase VI - Natural Buttes Unit No. 22

This well has been staked and permits should be received in the near future.

Forecast of Work for May, 1977

During May, the following work is planned:

I Phase I - Natural Buttes Unit No. 18

Continue to flow.

II Phase II - Natural Buttes Unit No. 19

Continue to produce.

III Phase III - Natural Buttes Unit No. 14

Production test.

IV Phase IV - Natural Buttes Unit No. 20

MHF treatment.

V Phase V - Natural Buttes Unit No. 21

Begin drilling operations.

VI Phase VI - Natural Buttes Unit No. 22

Begin drilling operations.

Monthly Report for May - Text Only

Introduction

During May, 1977, the following work was accomplished:

- I Natural Buttes Unit No. 18 produced at an average rate of 810 MCFD for 31 days.
- II Natural Buttes Unit No. 19 produced at an average rate of 82 MCFD for 31 days.
- III Natural Buttes Unit No. 14 produced 30 days at an average rate of 698 NCFD. Gamma Ray log was run.
- IV Natural Buttes Unit No. 20 was tested to 8000 psi and then perforated to provide limited entry technique to be used on the frac job.
- V Natural Buttes Unit No. 21 is still waiting on approval of the recommended research work.
- VI Natural Buttes Unit No. 22 was spudded and 13-3/8" casing set and cemented at 85' KB.

Discussion of Work Performed

- I Phase I - Natural Buttes Unit No. 18
Produced well for 31 days.
- II Phase II - Natural Buttes Unit No. 19
Produced well for 31 days.
- III Phase III - Natural Buttes Unit No. 14
Produced well for 30 days. A gamma ray log was run to try and locate the radioactive sand. There was no trace of radioactive sand in the wellbore. The radioactive sand was probably pushed too far from the wellbore to detect on the gamma log.
- IV Phase IV - Natural Buttes Unit No. 20
A mechanical properties log was made from data collected by the open hole logs. Perforations were picked over a total of eight zones; the number of perforations was limited to allow the frac job to be accomplished using the limited entry technique. The frac is scheduled for June 22, 1977.
- V Phase V - Natural Buttes Unit No. 21
Waiting on approval of recommended program for Natural Buttes Unit No. 21.

VI Phase VI - Natural Buttes Unit No. 22

This well has been spudded and 13-3/8" casing was set at 85' KB.
Drilling out below the 13-3/8" is expected to start in early
June, 1977.

Forecast of Work for June, 1977

I Phase I - Natural Buttes Unit No. 18

Continue to flow.

II Phase II - Natural Buttes Unit No. 19

Continue to flow.

III Phase III - Natural Buttes Unit No. 14

Production test.

IV Phase IV - Natural Buttes Unit No. 20

MHF treatment.

V Phase V - Natural Buttes Unit No. 21

Initiate drilling operations, with coring, etc., as per the
recommended program as soon as the drilling operations on Natural
Buttes Unit No. 22 are completed, subject to receiving approval on
Natural Buttes Unit No. 21.

VI Phase VI - Natural Buttes Unit No. 22

Finish drilling operations.

Monthly Report for June - Text Only

Introduction

During June, 1977, the following work was accomplished:

- I Natural Buttes Unit No. 18 produced at an average rate of 848 MCFD.
- II Natural Buttes Unit No. 19 produced 30 days at an average rate of 52 MCFD
- III Natural Buttes Unit No. 14 produced 30 days at an average rate of 646 MCFD.
- IV Natural Buttes Unit No. 20 was fraced using the limited entry technique.
- V Natural Buttes Unit No. 21 is still waiting on approval of the recommended research work.
- VI Natural Buttes Unit No. 22 is drilling ahead at 8000'. 8-5/8" casing was set at 2513' KB.

Discussion of Work Performed

- I Phase I - Natural Buttes Unit No. 18
Produced well for 25 days.
- II Phase II - Natural Buttes Unit No. 19
Produced well for 30 days.
- III Phase III - Natural Buttes Unit No. 14
Produced well for 30 days.
- IV Phase IV - Natural Buttes Unit No. 20

*MHF was performed as per the attached treatment report on June 22, 1977. Perforations were acidized and balled out with 3000 gallons 15% acid and the well was allowed to clean up and flow test to pit. The well would make about 75 MCFD and no water after the acid job. Sandia Laboratories monitored the frac treatment to determine fracture orientation. The data is being analyzed.

The MHF was designed for the limited entry technique. The entire job was performed satisfactorily. After the well was treated, a wireline was run in the wellbore to 9010' where it stopped on an obstruction. This obstruction was probably a small sand bridge, since it was removed by flowing the well back. The temperature log only covered one set of perforations before reaching the sand bridge and they showed a cooling effect which indicates that the perforations took fluids during the frac treatment.

Natural Buttes No. 20 was turned to the pit 12 hours after fracing to clean up. The well has almost cleaned up and should be ready to flow to sales by mid-July.

V Phase V - Natural Buttes Unit No. 21

Waiting on approval of the recommended program.

VI Phase VIa - Natural Buttes Unit No. 22

Drilling below 8000' KB.

Phase VIb - Natural Buttes Unit No. 9

Design work for MHF is in progress. The casing will be tested for strength (6000 psi) sometime in July.

Forecast of Work for June, 1977

I Phase I - Natural Buttes Unit No. 18

Continue flowing well to sales.

II Phase II - Natural Buttes Unit No. 19

Continue to produce well. May run a BHP build up.

III Phase III - Natural Buttes Unit No. 14

Allow well to produce to sales.

IV Phase IV - Natural Buttes Unit No. 20

Put well on production.

V Phase V - Natural Buttes Unit No. 21

Initiate drilling operations, with coring, etc., as per the recommended program as soon as approval is received.

VI Phase VIa - Natural Buttes Unit No. 22

Finish drilling operations. Design MHF, completion program, etc.

Phase VIb - Natural Buttes Unit No. 9

Finalize design on MHF and obtain bids on proposed work.

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TABLE NO. 9

COMPLETION ZONES

NATURAL BUTTES NO. 14

	Perforation TDT Depths	Pay Interval	NET FT. OF PAY	AVERAGE		
				<u>Ø</u>	<u>Sw</u>	<u>%Sd</u>
1	6826-30	6825-33	8	7.5	65	40
2	6874-78	6867-94	27	10	50	55
3	6952-56	6950-66	16	8.5	50	50
4	6970-74	6970-84	14	10	50	50
5	7082-86	7080-93	13	8.5	55	45
6	7261-65	7285-74	16	11.0	45	70
7	7409-13	7406-22	16	8.0	53	50
8	7572-76	7562-98	36	7.5	55	40
9	7724-28	7710-48	38	12.5	40	97
10	7790-94	7788-7802	14	15.0	38	92
11	7967-71	7960-76	16	8.0	42	--
12	8000-04	7995-8010	15	--	--	--

(Not Available)

An additional three zones will be added:

13	6297-6301	6294-6304	10	11.5	55	66
14	6382-86	6366-90	24	10.0	52	60
15	6642-46	6640-48	<u>8</u>	<u>10.0</u>	<u>56</u>	<u>63</u>
271' (18' per zone)				9.9	49.2	65.0

TABLE NO. 5

COMPLETION ZONES

NATURAL BUTTES NO. 18

	<u>Perforation Interval Saraband Depths</u>	<u>* Pay Interval</u>	<u>NET FT. OF PAY</u>	<u>AVERAGE</u>		
				<u>Ø</u>	<u>Sw</u>	<u>%Sd</u>
1	6490-94	6488-95	7	10	50	90
2	6644-48	6640-55	15	11	50	92
3	6668-72	6666-73	7	12	57	83
4	6698-6702	6694-6706	12	11	50	90
5	6740-44	6734-49	15	12	39	90
6	6780-84	6777-96	19	8	50	79
7	6954-58	6936-60	24	9	60	80
8	7046-50	7040-60	20	10	56	90
9	7438-42	7430-51	21	9	54	91
10	7728-32	7724-35	11	10	50	95
11	7852-56	7848-59	11	12	40	97
12	7886-90	7885-92	7	8	50	88
13	7924-28	7918-30	12	10	50	90
14	8614-18	8614-18	4	8	35	77
15	8846-50	8840-52	12	9	38	90
16	8872-76	8868-78	10	8	45	75
17	8900-04	8893-8903	10	11	39	99
18	8948-52	8946-53	<u>7</u>	<u>9</u>	<u>48</u>	<u>90</u>
224' (12-1/2')				10%	48%	88%

*Criteria used to select the pay interval was:
Percent sand greater than 80%
Porosity greater than 8%
Water saturation less than 55%

TABLE NO. 6

COMPLETION ZONES

NATURAL BUTTES NO. 19

	Perforation Interval Saraband Depths	* Pay Interval	NET FT. OF PAY	AVERAGE		
				$\emptyset$	Sw	% Sd
1	7224-28	7224-44	14	9	55	85
2	7351-55	7351-55	4	12	45	90
3	7405-09	7405-26	12	10	52	85
4	7444-48	7444-49	5	10	55	85
5	7478-82	7477-89	12	10	50	82
6	7632-36	7628-38	10	9	50	85
7	7728-32	7727-39	12	11	40	95
8	8108-12	8108-26	11	9	45	85
9	8369-73	8365-77	10	9	53	82
10	8672-76	8672-86	10	11	38	90
11	8909-13	8906-16	10	11	35	95
12	8991-95	8990-99	9	10	40	85
13	9142-46	9142-49	7	10	65	90
14	9231-35	9230-39	9	10	55	95
15	9402-06	9403-06	3	12	55	92
16	9478-82	9480-91	11	9	45	80
17	9572-76	9570-82	12	9	35	90
18	9630-34	9630-63	33	8	45	85
19	9660-64					
			194 (10.2')	9.5%	47%	87%

*Criteria used to select pay interval:
Percent sand greater than 80%
Porosity greater than 8%
Water saturation less than 55%

TABLE NO. 2

COMPLETION ZONES

NATURAL BUTTES NO. 20

	Perforation Interval Saraband Depths	* Pay Interval	NET FT. OF PAY	AVERAGE		
				<u>Ø</u>	<u>Sw</u>	<u>%Sd</u>
1	8498-8501	8497-8501	4	10	50	88
2	9184-86	9181-89	8	8	55	80
3	9218-28	9216-35	19	11	40	92
4	9264-79	9264-79	15	10	45	88
5	9305-16	9304-18	14	9	44	88
6	9335-36	9335-36	1	8	50	84
7	9380	9379-80	1	10	40	88
8	9471-76	9473-76	<u>3</u>	<u>11</u>	<u>28</u>	<u>95</u>
			65' (8.1')	9.9%	44%	88.5%

*Criteria used to select pay interval:

Percent sand greater than 80%

Porosity greater than 8%

Water saturation less than 55%

Table 1 Summary of MHF Wells												
Well	No. of Zones Perf.	Net Ft. of Pay	Average				Frac Job Size			Frac Length Ft.	Est. 1st Yr. Avg. Prod. Rate MCFD	Rec. Reserve 30 Yrs. BCF
			Net Ft Per Zone	ϕ	SW	% Sd	Type of Fluid	Gals of Gel	Pounds of Sand			
NATURAL BUTTES #18	18	224	12.5	10	48	88	VERSA FRAC	695,000	1,480,000	882	1200	4.12
NATURAL BUTTES #19	19	194	10.2	9.5	47	87	40# GUAR GUM	655,000	1,237,000	950		
NATURAL BUTTES #14	15	271	18.0	9.9	49	65	YF4-PSD	544,000	1,082,000	879		

NOTE: Frac lengths have been changed according to the calculations made from Halliburton's new computer program.

NATURAL BUTTES NO. 14

NATURAL BUTTES NO. 18

4 1/2" @ 9140
 2 3/8" @ 8,969'
 PERFS: 6490-8954 (18 zones)
 FRAC: 695,000 GAL Versagel &
 1,480,000# SD
 Frac Length = 950'

NATURAL BUTTES NO. 19