MASTER

MASSIVE HYDRAULIC FRACTURING EXPERIMENT
NO. 1 HOME FEDERAL WELL, UINTAH COUNTY, UTAH

FINAL REPORT

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Western Oil Shale Corporation
3662 Mountcrest
Las Vegas, Nevada 89121

July 1977

PREPARED FOR
THE
UNITED STATES ENERGY RESEARCH AND DEVELOPMENT ADMINISTRATION
NEVADA OPERATIONS OFFICE

Under Contract No. EY-76-C-08-0683

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Printed in the United States of America

Available from

National Technical Information Service

U. S. Department of Commerce

5285 Port Royal Road

Springfield, VA 22161

Price: Printed Copy \$; Microfiche \$3.00

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THE
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ABSTRACT

Two massive hydraulic fracturing experiments were performed on two separate gas-bearing intervals of Mesaverde sandstones in the No. 1 Home Federal well located in Uintah County, Utah. Water-base gel carrying sand proppant was used as the frac medium and the limited entry technique was used for injection.

The first experiment was carried out on an interval containing 112 ft. of net pay between 10,014 and 10,202 ft. Pre-frac production capacity was estimated to be 60+ MCF/D. Post-frac production capacity was significantly less, presumably attributable to a limited lateral extent of inherent formation permeability.

The second experiment was carried out on an interval containing 85 ft. of net pay between 7,826 and 9,437 ft. Pre-frac production capacity of 33 MCF/D was increased by MHF to an initial 500 MCF/D and to a relatively stabilized 155 MCF/D within four months following the treatment.

I INTRODUCTION

Western Oil Shale Corporation and Texas American Oil Corporation performed two massive hydraulic fracturing experiments on the No. 1 Home Federal Well located in Sec 34, T10S, R19E, Uintah County, Utah. The first MHF was carried out on Oct. 1, 1976 and the second on Dec. 21, 1976. Both treatments were applied to low permeability, gas-bearing sands in the Mesaverde formation.

A. Well Description

The No. 1 Home Federal Well was spudded on December 11, 1975, was drilled with KCl water to total depth of 10,780 on January 13, 1976, and was cased to total depth on January 15, 1976.

Hole Specifications:

Conductor: 18" Dia., 60' depth
Intermediate: 11" Dia., 3032' depth
Final: 7 7/8" Dia., 10708' depth

Casing and Tubing Specifications:

Conductor Pipe: 13 3/8" OD, J-55, 48#/ft. set at 51' depth, cemented to bottom of cellar.
Intermediate Casing: 8 5/8" OD, J-44, 1129.75' of 32#/ft. and 1888.25 ft. of 24#/ft., set at 3017' depth, cemented to surface.
Production Casing: 5 1/2" OD, N-80, 23#/ft., set at depth of 10,780', cemented to 6900' depth.
Production Tubing: 2 3/8" OD, J-55 - 76 joints and N-80 - 245 joints, 4.5#/ft., set at 9,768 ft. depth.

Logs

Compensated Density
Contact Caliper
Sidewall Neutron
BHC Sonic with Caliper
Gamma Guard

B. Fracture Design Basis

The fracture design for both treatments was based primarily upon the finding that KCl water did not appear to damage the permeability of Mesaverde sandstone cores from another well in the Uinta Basin. Both treatments therefore utilized KCl water-based gel along with appropriate additives applied by the limited entry technique.

C. Reservoir Description

The two intervals treated were located between the depths 10,014-10,202 ft. (Interval #1/MHF#1) and between 7,826 - 9,437 ft. (Interval

Prepared for the Energy Research and Development Administration
under Contract No. EY-76-C-08-0683

#2/MHF#2). Individual zone depths, net pay thicknesses, average water saturations, and porosities based on log analysis are presented as follows for these two intervals:

INTERVAL #1 (MHF#1)

<u>Zone Depth, ft.</u>	<u>Net Pay, ft.</u>	<u>Average Water Saturation, %</u>	<u>Average Porosity, %</u>
10,014 - 038	22	33	12.7
10,044 - 062	18	40	12.3
10,088 - 100	12	42	9.7
10,136 - 148	10	34	11.0
10,142 - 202	50	43	11.0
	112 Total	41 Avg	11.8 Avg

INTERVAL #2 (MHF #2)

<u>Zone Depth, ft.</u>	<u>Net Pay, ft.</u>	<u>Average Water Saturation, %</u>	<u>Average Porosity, %</u>
7,826 - 29	3	53	8.5
7,852 - 81	27	51	8.5
7,974 - 80	6	40	8.5
8,042 - 46	4	35	8.5
9,225 - 37	12	51	8.0
9,308 - 14	6	40	7.0
9,410 - 37	27	40	9.5
	85 Total	45 Avg	8.5 Avg

II MHF #1 EXPERIMENT

MHF #1 consisted of 411,640 gallons of frac fluid and 600,000 pounds of sand. Injection rate varied between 19 and 46 BPM. Wellhead injection pressures varied between 6,400 and 7,000 psi.

A. Pre-frac Treatment

On March 31, 1976 Wellex perforated the target interval with 23 1/4"-diameter holes with Sidewinder jet charges between the depths of 10028 and 10200 feet. No gas showed at the surface after the perforating job was completed. Perforation depths were as follows:

10,028	10,091	10,137	10,167	10,179	10,192
10,032	10,093	10,140	10,171	10,182	10,196
10,058	10,096	10,143	10,174	10,185	10,200
10,062	10,098	10,163	10,176	10,188	

The perforations were broken down using acid, KCl water and ball sealers on April 4, 1976. Total fluid used in the breakdown was 380 barrels. Most of the breakdown fluids were recovered by April 13.

B. Pre-frac Production and Testing

Cumulative production into the wellbore prior to shut-in for pressure

buildup monitoring is estimated to be 716 MCF. Volumes produced from the well are listed as follows:

DATE	VOLUME, MCF
Prior to 4/12	144
4/12	167
4/13	12.7
4/14	40
5/5	<u>322.7</u>
TOTAL	696.4

An additional volume of 19.5 MCF is estimated to have flowed into the wellbore but was not produced during the last 16 1/2 hours of the 24-hour production period. These volumes were measured or calculated utilizing wellhead and bottom hole pressure data, the volume of void inside the wellbore of 1308 cubic ft., and an average temperature inside the wellbore of 150° F.

Bottom hole pressures were measured with a 72-hour pressure bomb by Cable Engineering Company of Roosevelt, Utah prior to, during, and subsequent to the 24-hour production period commencing May 5, 1976. These bottom hole pressure data are presented in the Cable Engineering Company data sheets in Appendix A. The pressure data show that the stabilized pressure at a depth of 10,114 ft. was 6,631 psi just prior to the 24-hour production period. This pressure was reduced to 2,091 psi by flowing the well for approximately 7 1/2 hours. At 7 1/2 hours the flow rate was held at 40+ MCF/D with the bottom hole pressure rising at a rate of about 20 psi per hour. At 15 hours into the production period, the flow rate was stabilized at 40 MCF/D. At the end of the flow test (24 hours) the production rate was still 40 MCF/D while the bottom hole pressure was rising at a rate of 13.5 psi per hour. Flowing tubing pressure was 775 psig and flowing casing pressure, 350 psig. The bottom hole pressure at shut-in was 2,387 psig.

Final flow capacity is estimated to have been 62 MCF/D, considering the observed flow rate and the pressure buildup rate.

The well was shut in after removing the pressure bomb until August 26, at which time gas was produced on a 20/64" choke into the Mountain Fuel line located north of the well. Production was intermittent because of the well loading up with water.

Observed pressures and flow rates prior to September, 1976 were:

DATE	FTP, psig	FCP, psig	FLOW RATE, MCF/D
8/27	1375	490	40
8/28	1725	490	40
8/29	1925	490	40
8/30	2175	490	40
8/31	2340	425	40

A temperature survey was run on September 27. The results are depicted on Figure 1 along with the perforation locations. As indicated by the static log in this figure, slight cooling (indicating gas influx) appeared to have occurred over zones 1, 2, 4 and 5. Zone 3 does not appear to exhibit any significant cooling.

C. MHF Treatment Description

Halliburton Services had all equipment and materials in place and ready to frac by September 28. There were twenty-one 500-barrel tanks of 2% KCl water, two blender trucks (only one truck was needed for the frac job; the additional truck was on standby only), ten pump trucks each capable of achieving 1,000 hydraulic horsepower, three sand tanks with capacities of 2,560 cubic ft. each, two chemical trucks, a control van, and a number of ancillary pieces of equipment such as headers, valves and lines. Three flow lines were attached to the well, two connected to the casing and one connected to the tubing.

Halliburton started the massive frac with a KCl water prepad stage on September 29 at 1000 hrs. Maximum injection rate achieved was 12 BPM at 7,000 psig wellhead pressure (target rate was 42 BPM). The frac was stopped and 50 ball sealers were dropped, along with 3,000 gallons of acid in an attempt to increase the injection rate. The prepad stage was then restarted and a rate of 16 BPM was achieved. The prepad stage of 43,400 barrels was completed at approximately this injection rate.

On September 29, 1976 another temperature survey was run to determine appropriate locations for additional perforations. The results of this survey are presented in Figure 2 along with the original perforation locations.

Based upon the analysis of this temperature log and Halliburton calculations, 32 new 1/4" perforations were added to the target interval on September 30, 1976. The depths of the new perforations are as follows:

ZONE 1	10,027		10,144
	10,029		10,145
	10,030		10,146
	10,032		
ZONE 2	10,059	ZONE 5	10,165
	10,060		10,169
	10,061		10,172
			10,175
ZONE 3	10,090		10,178
	10,092		10,180
	10,094		10,184
	10,095		10,187
	10,097		10,189
	10,098		10,194
ZONE 4			10,195
	10,139		10,197
	10,141		10,199
	10,142		

After perforating, Halliburton spotted 3,000 gallons of acid and dropped 75 ball sealers. The fracture treatment was then reinitiated with another prepad stage of KCl water at 1503 hrs. Maximum initial injection rate was 15 BPM at 7,000 psi. The frac was stopped after a few minutes and restarted at 1530 hrs. At this point an injection rate of 27 BPM at 6900 psi was achieved. The prepad stage was finished at 1628 hrs. and the wellhead was secured for the night.

The fracture treatment was recommenced at 1118 hours and was completed at 1542 hours on October 1, 1976. The following frac conditions prevailed:

Average Injection Pressure: 6850 psi

Average Injection Rate: 29 bbls/min.

Average Hydraulic Horse Power: 4,869

Maximum Injection Pressure: 7,000 psi

Maximum Injection Rate: 46 bbls/min.

The injection pressure, flow rate and sand concentration are plotted as a function of time in Figure 3. This is an idealized plot taken from the detailed log in the subcontractor's report.

Total volume of fluid injected prior to the October 1, 1976 operation was 96,920 gals. On October 1, the treatment was started with pad volume of 90,000 gals. followed by the stages listed below:

STAGE 1	10,000 gals. with 1 lbs/gal 40-60 sand
STAGE 2	35,000 gals. with 2 lbs/gal 40-60 sand
STAGE 3	40,000 gals. with 3 lbs/gal 40-60 sand
STAGE 4	30,000 gals. with 2 lbs/gal 20-40 sand
STAGE 5	60,000 gals. with 3 lbs/gal 20-40 sand
STAGE 6	40,000 gals. with 4 lbs/gal 20-40 sand

These six stages were followed by a 1,000-gal. Versagel spacer and 9,240 gal. displacement for a total volume injected of 315,340 gallons during the October 1, 1976 operation. By including the pre-pad and break down treatments on September 29 and 30, 1976 a total of 411,640 gallons were injected.

The materials used and their concentrations during the fracturing treatment are listed in Table 1.

D. Post-frac Production and Testing

Immediately following the fracturing treatment a temperature survey was run, the results of which are shown in Figure 4. The well was then opened on a 26/64" choke at 1225 hours with a wellhead pressure of 3400 psi. On October 2, the choke size was reduced to 20/64". Load water was recovered via a 20/64" choke until October 9 at which time a 26/64" choke was inserted. The cumulative load water recovery is shown as a function of time in Figure 5.

On October 7 at 1245 hours, the well was hooked up to the gas pipeline and gas was produced to sales. The well died at 2400 hours on this date. It was opened to the air and the pressure bled down to 0 in three minutes. It was shut in at 1400 hours on October 8. On October 9, NOWSCO pumped 93 MCF of nitrogen into the casing and the well started flowing again. The well was shut in on October 12 by the automatic shutdown valve. The well was opened to the air and a gas flow rate of 21 MCF/D was observed. On October 13 the well was shut in at 0800 hours. From October 21 through November 11 the well was shut in for pressure buildup. This pressure buildup is plotted in Figure 6.

Post-frac gas production prior to the pressure buildup is shown graphically in Figure 7. Also shown are the flowing tubing and casing pressures. As indicated in this figure, cumulative gas production was 325 MCF over a period of 5 1/2 days for an average of 59 MCF/D.

Shut-in bottom hole pressures were measured on November 1, 1976. The shut-in casing pressure as measured at the wellhead was 2775 psi just prior to running the down hole pressure bomb. Down hole pressures measured were as follows:

<u>DEPTH, ft.</u>	<u>PRESSURE, psi</u>
6400	3102
9500	4392
9700	4471
9900	4557
*10,114	4649

*Middle of perforations

The fluid level in the well was found to be 3,000 ft. during these measurements.

On November 11 the tubing was opened and the well flowed water to the pit. At 12:30 p.m. gas was produced into the pipeline at the rate of 393 MFC/D on a 12/64" choke, after unloading approximately 35 barrels of water.. On November 12 the choke became plugged and approximately 250 barrels of water were unloaded. After unloading, gas was produced into the pipeline

at the rate of 699 MCF/D on a 16/64" choke. On November 13 gas flow rate dropped to 129 MCF/D and after unloading ten barrels of water the rate increased to 550 MCF/D. On November 14 the well was shut-in and attempts were made thereafter to unload the water with nitrogen. On November 17 the well was producing at a rate of 731 MCF/D on a 16/64" choke. Thereafter the well died and only traces of gas were produced. The total volume of gas produced during November was only 60 MCF.

III MHF #2 EXPERIMENT

MHF #2 consisted of 247,500 gallons of frac fluid and 450,000 pounds of sand. Injection rate varied between 17 and 36 BPM. Wellhead injection pressure varied between 5,500 and 7,000 psi.

A. Pre-frac Treatment

The isolation of the first MHF zone was completed by pumping 12,000 pounds of sand into the wellbore. Top of the sand was found to be 9,922 ft. upon completion of the zone isolation.

The tubing was pulled to allow the remainder of the Mesaverde pay zones to be perforated with a Welex 3-1/2" casing gun. On December 2 the well casing was perforated with single .34" perforations at each of the following depths:

7768 ft.	7975 ft.	9227 ft.
7827 ft.	7979 ft.	9233 ft.
7855 ft.	8044 ft.	9311 ft.
7860 ft.	9045 ft.	9415 ft.
7869 ft.	9050 ft.	9420 ft.
7877 ft.	9223 ft.	9425 ft.
		9433 ft.

The top of the sand was found at a depth of 9872 ft. after perforating.

The well was killed with brine and a bridge plug was emplaced at a depth of 9460 ft. The tubing was then pulled back to a depth of 7750 ft. and the well was acidized with 2,500 gal. of 15% HCl with a non-emulsifier. 35 ball sealers were used and good ball action was observed. The well was opened to the pit after acidizing. It flowed back approximately 15 barrels and died. 34 barrels of 3% KCl water were then pumped down the tubing, and the bridge plug was retrieved.

B. Pre-frac Production and Testing

On December 5 a flow rate of approximately 200 MCF/D was observed. After a brief shut-in period for pressure build-up the tubing was run into the well along with 144 barrels of brine to kill it. The bottom of the tubing was set at a depth of 9359.75 ft. The hole was circulated with 200 barrels of 3% KCl water prior to shut-in.

The well was shut in from December 6 to December 10. On December 10 a

trace of load water and gas were flowed and a bottom hole pressure bomb was run to a depth of 9430 ft. at 12:15 p.m. The tubing was left open to the pit overnight. A trace flow of gas was observed along with an estimated 50 barrels of water per day. The bottom hole pressure bomb was pulled on December 11. The data from these pressure measurements are presented in the Cable Inc. report in Appendix B. As indicated by these data, the average reservoir pressure is estimated to be 4,264 psig, and reservoir temperature 186° F.

After the bomb was pulled, nitrogen was injected to unload water from the tubing and casing. The well was then left open to the pit and flowed a trace of gas and more than 100 barrels of water.

On December 14 a 180 hr. pressure bomb was run into the well by Cable Inc. The bomb was on bottom at 6:35 p.m. During the first 41 hrs. and 45 min. of the pressure measurements, the well was open to the pit to unload the water prior to a gas flow test which was begun at 12:30 p.m. on December 16 (41 hrs. and 45 min. after the pressure bomb was on bottom). The flow test was conducted for 22 hrs. and 15 min., ending at 10:45 a.m. on December 17. Average flow rate was 33 MCF/D. Thereafter the well was shut-in for pressure build-up. The bottom hole pressure data are presented in the Cable Inc. report in Appendix C.

C. MHF #2 Description

Halliburton conducted the massive hydraulic fracturing of the well on December 21. The job was begun at 10:15 a.m. and was completed at 1:42 p.m. The average injection pressure was 6500 psi; the average injection rate 35 barrels per minute; and the average hydraulic horse power used was 5,576. Total fluid volume used was 247,500 gal. This included a pad of 40,000 gal., a treatment of 200,000 gal. and displacement of 7,500 gal. The frac fluid was Halliburton's 'Versagel'. 50,000 lbs. of 40-60 sand and 450,000 lbs. 20-40 sand were used to prop the fracture. The frac fluid additives are listed in Table 2 and the frac pressures and injection rates are plotted in Figure 8.

D. Post-frac Production and Testing

The load water was flowed back beginning at 7:15 p.m. on December 21. Sand flowed back in sufficient quantities to erode holes in the flow line. The sand stopped flowing back at 5:00 a.m. on December 22.

On December 27 the well was hooked up to the treating unit and gas sales were commenced at a rate of 477 MCF/D. The production rates as a function of time from December 27, 1976 through June 30, 1977 are depicted in Figure 9. As indicated in this figure, the rate had essentially stabilized at about 155 MCF/D in April and remained at this average level throughout May and June.

Cumulative water production from the start of flowback throughout June, 1977 is shown in Figure 10. As indicated by this figure, the water production rate stabilized in March at about 20 BPD.

IV CONCLUSIONS AND RECOMMENDATIONS

Both MHF treatments clearly resulted in non-economic production rates. Because of the limited success achieved by MHF #2 on Interval #2, it is believed that the reason for the disappointing MHF #1 results was the inherent inadequacy of Interval #1 to release its gas; probably because of an extremely limited radial extent of permeability. Assuming this to be the case, it follows that KCl water-based gel is compatible with the Mesaverde sands at least to an extent, and therefore, may prove to be an acceptable, inexpensive frac fluid for this formation.

MHF #2 enabled Interval #2 production rate to increase from 33 MCF/D to an initial 500 MCF/D and to a somewhat stabilized 155 MCF/d. at approximately 4 months following the frac.

It is recommended that MHF experimentation be continued with water-base frac fluid and limited entry injection in the Uinta Basin. Improved methods obviously need to be developed to 1) identify all sands amenable to successful MHF treatment in a given well and 2) identify those areas in a given basin that are most likely to contain sufficient thicknesses of sands amenable to successful treatment. It is recommended that developmental work on these improved methods be given at least as high a priority as is given to carrying out experimental MHF treatments.

Date of Survey May 4, 7, 1976

BH Temp. 173 °F at 10,114 ft.
4:00 PM 4-14 76

Well Shut In 9:00 A M. 5-6 1976

Bomb On Bottom 6:13 PM. 5-4 1976

BOMB NO. 32494 CALIB NO. 5-1-76

72 HRS. = 5 INCHES

BUILDUP					
PT. NO.	PRES. DEF.	PRES. (PSIG)	TIME	TBG. PRES.	CSG. PRES.
1	1.233	6631	482 hours 13 Min		
2	"	"	483 "		
3	"	"	490 "		
4	"	"	497 "		
5	1.233	6631	0		
6	0.823	4439	30 Min		
7	0.824	4444	1 Hour		
8	0.820	4422	2 "		
9	0.777	4193	3 "		
10	0.745	4021	4 "		
11	0.747	4032	5 "		
12	0.749	4043	6 "		
13	0.388	2102	7 "		
14	0.386	2091	8 "		
15	0.394	2134	10 "		
16	0.401	2172	12 "		
17	0.412	2231	15 "		
18	0.431	2333	20 "		
19	0.441	2387	24 "		

Well shut
in 4:00 P
4-14-76

Well open
for flow
8/64
Choke

BUILDUP					
PT. NO.	PRES. DEF.	PRES. (PSIG)	TIME	TBG. PRES.	CSG. PRES.
20	0.441	2387	0		
21	0.446	2414	30 Min		
22	0.452	2446	1 Hour		
23	0.462	2500	2 "		
24	0.472	2554	3 "		
25	0.482	2608	4 "		
26	0.492	2661	5 "		
27	0.501	2710	6 "		
28	0.511	2763	7 "		
29	0.520	2812	8 "		
30	0.537	2903	10 "		
31	0.554	2995	12 "		
32	0.579	3129	15 "		
33	0.617	3333	20 "		
34	0.686	3704	30 "		
35	0.704	3801	33 "		

Shut
in for
BU

Date of Survey May 10, 16, 1976

BH Temp. 173 °F at 10.114 ft.

Well Shut In 9:00 A. M. May 6 1976

Bomb On Bottom 12:40 P. M. May 10 1976

BOMB NO. 3249A CALIB NO. 5-1-76
12673N

72 HRS. = 5 INCHES

BUILDUP					
PT. NO.	PRES. DEF.	PRES. (PSIG)	TIME	T&G. PRES.	CSG. PRES.
36	1.060	5436	99 Hours 40 Min.		
37	1.061	5441	100 "		
38	1.080	5538	105 "		
39	1.097	5626	110 "		
40	1.113	5708	115 "		
41	1.125	5769	120 "		
42	1.134	5815	125 "		
43	1.142	5856	130 "		
44	1.149	5893	135 "		
45	1.154	5918	140 "		
46	1.158	5938	145 "		
47	1.162	5959	150 "		
48	1.165	5974	155 "		
49	1.168	5990	160 "		
50	1.170	6000	165 "		
51	1.172	6010	168 "		
52	1.175	6026	171 " 50 Min.		
53	1.176	6031	175 "		
54	1.178	6041	180 "		

BUILDUP					
PT. NO.	PRES. DEF.	PRES. (PSIG)	TIME	T&G. PRES.	CSG. PRES.
55	1.180	6051	185 Hours		
56	1.182	6061	190 "		
57	1.184	6072	195 "		
58	1.186	6082	200 "		
59	1.188	6092	205 "		
60	1.189	6097	210 "		
61	1.190	6103	215 "		
62	1.192	6113	220 "		
63	1.193	6118	225 "		
64	1.194	6123	230 "		
65	1.195	6128	235 "		
66	1.197	6138	241 " 35 Min.		

Date of Survey — Dec. 10, 11, 1976 —

BH Temp. — 186 — °F at — 9430 — ft.

Well Shut In — M. — 19 —

Bomb On Bottom 12:15 P. M. 12-10 — 1976

BOMB NO. — 3790 — CALIB NO. 12-1-76 —

— 72 — HRS. = — 5 — INCHES

DRAWDOWN					
PT. NO.	PRES. DEF.	PRES. (PSIG)	TIME	TBG. PRES.	CSG. PRES.
1	1.393	4264	0		
2	1.389	4252	30 Min.		
3	1.387	4245	1 Hour		
4	1.384	4236	2 "		
5	1.381	4227	3 "		
6	1.379	4221	4 "		
7	1.377	4215	5 "		
8	1.376	4212	6 "		
9	1.375	4209	7 "		
10	1.374	4206	8 "		
11	1.374	4206	10 "		
12	1.373	4202	12 "		
13	1.373	4202	14 "		
14	1.376	4212	16 "		
15	1.381	4227	20 "		
16	1.378	4218	25 " 15 Min.		

APPENDIX B CABLE ENGINEERING BHP DATA FOR DEFINITION
OF RESERVOIR PRESSURE - INTERVAL #2

Date of Survey Dec. 14, 20, 1976

BH Temp. 186 °F at 9430 ft.
Approx.

Well Shut In 12:20 P. M. 12-16 19 76

Bomb On Bottom 6:35 P. M. 12-14 19 76

BOMB NO. 3789 CALIB NO. 12-1-76

120 HRS. = 5 INCHES

BUILDUP					
PT. NO.	PRES. DEF.	PRES. (PSIG)	TIME	TBG. PRES.	CSG. PRES.
1	0.686	2101	0		
2	0.697	2135	30 Min.		
3	0.711	2177	1 Hour		
4	0.728	2229	2 "		
5	0.760	2327	3 "		
6	0.788	2413	4 "		
7	0.813	2489	5 "		
8	0.836	2560	6 "		
9	0.833	2550	7 "		
10	0.854	2615	8 "		
11	0.882	2700	10 "		
12	0.891	2728	12 "		
13	0.911	2789	15 "		
14	0.943	2887	20 "		
15	0.967	2960	25 "		
16	0.966	2957	30 "		
17	0.946	2896	35 "		
18	0.646	1979	40 "		
19	0.362	1110	41 " 45 Min.		

FORM 3-64

Well
open for
flow

BUILDUP					
PT. NO.	PRES. DEF.	PRES. (PSIG)	TIME	TBG. PRES.	CSG. PRES.
20	0.362	1110	0		
21	0.382	1171	30 Min.		
22	0.417	1278	1 Hour		
23	0.485	1486	2 "		
24	0.546	1673	3 "		
25	0.591	1810	4 "		
26	0.634	1942	5 "		
27	0.672	2058	6 "		
28	0.704	2156	7 "		
29	0.738	2260	8 "		
30	0.785	2404	10 "		
31	0.819	2508	12 "		
32	0.873	2673	15 "		
33	0.926	2835	20 "		
34	1.024	3135	30 "		
35	1.071	3278	40 "		
36	1.101	3370	50 "		
37	1.123	3437	60 "		
38	1.141	3492	70 "		
39	1.162	3557	80 "		
40	1.194	3654	95 " 10 Mn.		

Well
shut
in
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<u>MATERIAL</u>	<u>AMOUNT</u>	<u>CONCENTRATION, Amt/1,000 gal.</u>
Proppant 40-60 Sand	200,000 lbs.	1,000, 2,000, 3,000 lbs.
Proppant 20-40 Sand	400,000 lbs.	2,000, 3,000, 4,000 lbs.
Anti-Foaming Agent (NF-1)	365 gal.	1 gal.
Crosslinker (CL-11)	250 gal.	.6 gal.
Surfactant (Super-Flo)	365 gal.	1 gal.
Non Emulsifier (3N)	18 gal.	3 gal.
Fluid Loss Additive (WAC-11)	1,000 lbs.	50 lbs.
HCl Acid	1,000 lbs.	--
Gelling Agent (WG-2)	21,000 lbs.	60 lbs.
Friction Reducing Agent (FR-2)	250 lbs.	5 lbs.
Bactericide (Adocide)	185 gal.	.5 gal.
Breaker (AP)	250 lbs.	.1 - .25 lbs.
Breaker (GBW-3)	300 lbs.	.5 - 1.5 lbs.
KCl	77,000 lbs.	166 lbs.
Corrosion Inhibitor (HAI-50)	30 gal.	5 gal.

TABLE 1. MATERIALS INJECTED - MHF #1

ADDITIVE	TRADE NAME	CONCENTRATION UNITS SHOWN/ 1000 gal.	TOTAL USED
Non Foaming Agent	NF-1	1 lb.	248 lb.
Surfactant	TRI-5	1 lb.	248 lb.
Crosslinker	CL-11	0.5 gal.	121 gal.
Gelling Agent	WG-12	50 lb	124,000 lb.
Friction Reducer	FR-20	3 lb.	25 lb.
Breaker	AP-6BW-3	.25 lb, .5-1 lb.	61 lb., 86 lb.
Bactericide	Adocide	.5 gal	124 gal.
KCl		250 lb. (3%)	650 SKS

TABLE 2. HALLIBURTON FRAC FLUID ADDITIVES - MHF #2

FIGURE 1. STATIC AND DIFFERENTIAL TEMPERATURE SURVEYS - 9/27/76
INTERVAL #1

FIGURE 2. TEMPERATURE SURVEYS, 9/29/76 - INTERVAL # 1

FIGURE 3. INJECTION PRESSURES, RATES, AND SAND CONCENTRATIONS
OCT. 1, 1976 - MHF #1

FIGURE 4. TEMPERATURE SURVEY - 10/1/76, POST MHF #1

FIGURE 5. CUMULATIVE VOLUME OF LOADWATER RECOVERED VERSUS TIME - MHF #1

FIGURE 6 WELLHEAD PRESSURE BUILDUP FOLLOWING POST MHF #1 FLOW TESTING

FIGURE 7. POST MHF #1 GAS PRODUCTION AND ASSOCIATED WELLHEAD PRESSURES

FIGURE 8. INJECTION PRESSURES AND RATES - MHF #2

FIGURE 9. GAS PRODUCTION RATE VS TIME FOLLOWING MHF #2

FIGURE 10. CUMULATIVE WATER PRODUCTION FOLLOWING MHF #2 VS TIME