LABORATORY AND FIELD MEASUREMENTS IN SUPPORT OF FRACTURE TREATMENT IN THE COTTON VALLEY LIMESTONE FORMATION IN MUSE DUKE WELL NO. 1

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SUMMARY AND RECOMMENDATIONS

Laboratory and field measurements have been performed by Terra Tek to evaluate the massive hydraulic fracturing treatment on Mitchell Energy Corporation (MEC) Muse Duke No. 1 well.

Laboratory measurements were performed on samples from three distinct zones: Bossier Shale (11,116 - 11,207 footage); Cotton Valley Limestone (11,223 - 11,336 footage) and Anhydrite formation (11,505 - 11,510 footage). Pertinent mechanical properties determined were: Dynamic elastic properties including ultrasonic velocities, Poisson's ratio and elastic modulis; triaxial compression tests to evaluate static moduli, Poisson's ratio, maximum compressive strength and fracture toughness tests. The tests were carried out under *in situ* conditions of effective pressure and temperature (285°F). Some tests were also performed at standard conditions to delineate the effects of *in situ* conditions on the measured properties.

The effect of *in situ* conditions (pressure and temperature) on the measured ultrasonic velocities was very small. The static moduli were lower than the dynamic moduli, for samples tested, the difference was between 15 to 25 percent.

A series of three *in situ* stress measurements were scheduled in the Mitchell Energy Corp. Muse Duke No. 1 well. The first test was attempted at a depth of 11,456 feet. The packers on the testing tool failed during the first test and the program was subsequently cancelled. No *in situ* data was gained during the first test.

Although the attempt to measure the *in situ* stress did not produce the required results, the laboratory measurement program to determine the elastic properties of the various layers resulted in an overall evaluation of the possibility of fracture containment within Cotton Valley Limestone formation. The laboratory measurements indicate that the underlying zone (Anhydrite - Limestone sequence) appears to favor fracture containment, *i.e.*, downward migration of the induced fracture may be impeded by the higher moduli. On the other hand, the top Bossier Shale layer shows tendency NOT to contain upward fracture porpagation. However, laboratory determined dynamic elastic moduli indicate that the top 40 ft section of the Cotton Valley Limestone formation possesses higher elastic moduli than the middle section. This moduli contrast is favorable to limiting fracture growth upward if the top 40 ft section was not perforated. The prevention of early fracture initiation in the top limestone section would help produce a deep penetrating fracture with reduced fracture extension inside the upper Bossier shale zone. That is, eventually, the whole limestone formation would be fractured, since fracture migration upward cannot be entirely prevented. Furthermore, the use of heavy fracturing fluids (such as jelled water based fluids) would reduce the rate of upward fracture migration. Therefore, the use of foams in treating the Cotton Valley formation in Muse Duke No. 1 well should be avoided.

LABORATORY TEST RESULTS

A suite of mechanical property tests were conducted on specimens prepared from Muse Duke No. 1 cores. Samples chosen for testing were selected from the Bossier shale, Cotton Valley Limestone, and a layer of Anhydrite lying below the Cotton Valley Limestone. A graphical presentation of static and dynamic lab measurements of the moduli and Poisson's ratio is shown in Figure 1.

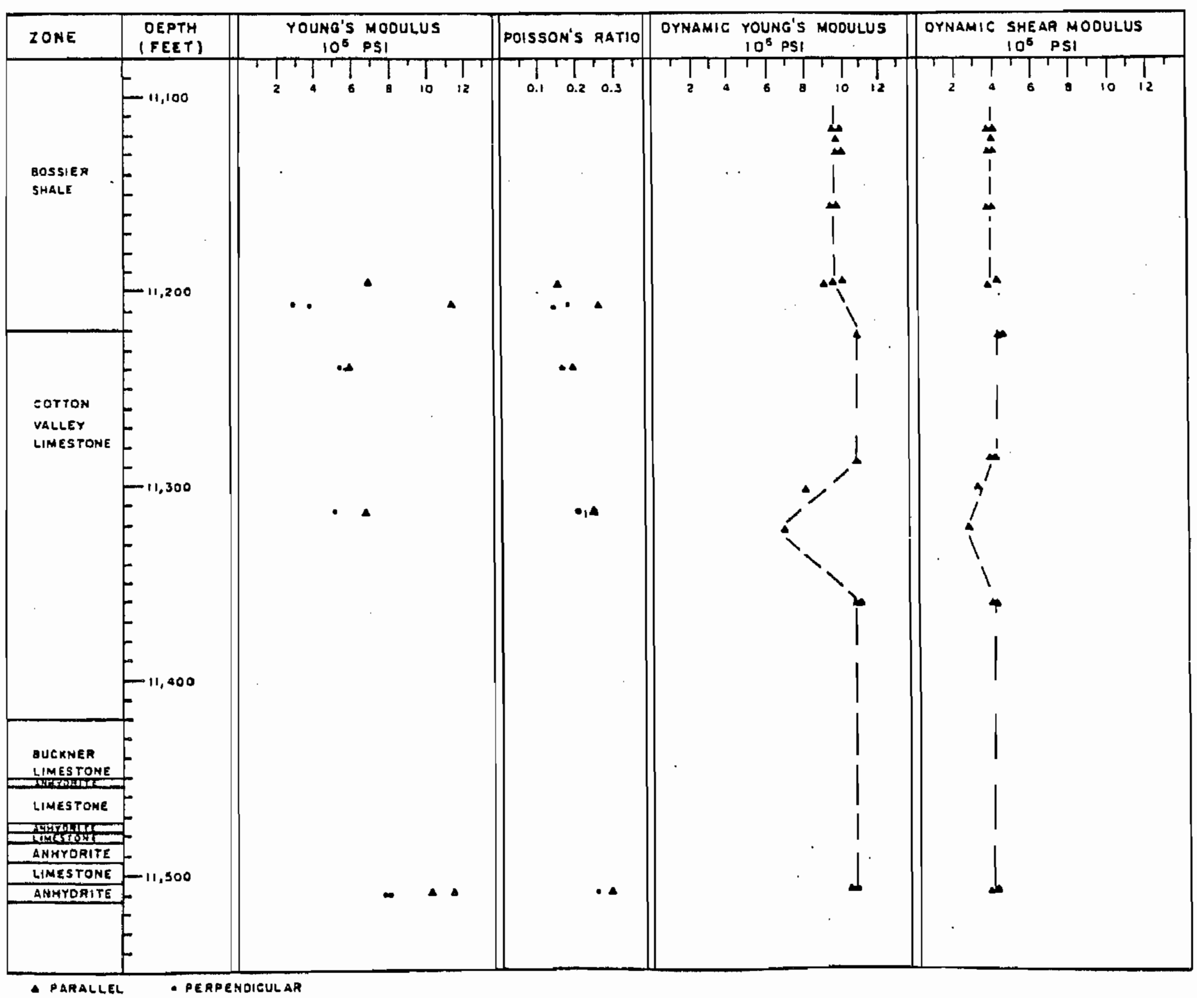

Figure 1. Moduli and Poisson's ratio versus depth for Muse Duke No. 1 core samples.

DYNAMIC ELASTIC PROPERTY TESTS

Ultrasonic velocities and bulk density have been determined in the laboratory on cores recovered from MEC Muse Duke Well No. 1. Measurements have been carried out on three formations: Bossier Shale (11,116 - 11,207 footage), Cotton Valley Limestone (11,223 - 11,336 footage) and Anhydrate formation (11,510 foot).

To determine the bulk dry density, the samples were dried at 110°F, weighted, then the total volume was measured in a mercury porosimeter.

Both the compression wave and shear wave velocities were measured on samples subjected to simulated *in situ* conditions (Effective pressure of 3200 psi and reservoir temperature of 285°F). Measurements were performed both in the axial (normal to bedding) and the horizontal (parallel to bedding) directions. This data, along with the measured bulk density, has been used to calculate the dynamic elastic moduli of the materials. The dynamic elastic properties are presented in Table 1.

TABLE I
DYNAMIC ELASTIC PROPERTIES
MITCHELL ENERGY CORPORATION WELL
MUSE DUKE NO. 1

DEPTH	SAMPLE ORIENTATION*	PORE PRESSURE (psi)	CONFINING PRESSURE (psi)	DENSITY (gm/cc)	P-WAVE (ft/sec)	S-WAVE (ft/sec)	POISSON's RATIO	MODULI ($psi \times 10^6$)			
								CONSTRAINED	SHEAR	BULK	YOUNG's
11,116	Parallel	0	3200	2.71	17,674	10,528	0.225	11.42	4.05	6.02	9.92
11,121	Parallel	0	3200	2.72	17,542	10,377	0.231	11.25	3.94	6.00	9.69
11,128	Parallel	0	3200	2.68	19,047	10,454	0.284	13.13	3.96	7.86	9.69
11,157	Parallel	0	3200	2.68	17,159	10,376	0.216	10.66	3.86	5.51	9.39
11,194	Parallel	0	3200	2.68	19,665	10,786	0.285	13.98	4.21	8.37	10.81
11,195	Parallel	0	3200	2.60	16,875	10,320	0.225	9.98	3.73	5.01	8.97
11,195	Parallel	0	3200	2.66	13,051	7,756	0.227	6.09	2.15	3.22	5.28
11,207	Perpendicular	0	3200	2.62	16,247	9,908	0.204	9.33	3.47	4.70	8.35
11.223	Parallel	0	3200	2.69	20,976	10,882	0.316	15.95	4.29	10.23	11.30
11,288	Parallel	0	3200	2.68	19,975	10,384	0.315	14.43	3.90	9.23	10.25
11,302	Parallel	0	3200	2.60	16,729	9,539	0.259	9.82	3.19	5.56	8.04
11,323	Parallel	0	3200	2.58	15,268	8,966	0.237	8.10	2.79	4.37	6.91
11,363	Parallel	0	3200	2.68	20,035	10,474	0.312	14.46	3.95	9.19	10.37
11,336	Parallel	0	3200	2.69	19,879	10,541	0.304	14.29	4.02	8.93	10.49
11,336	Perpendicular	0	3200	2.68	20,102	10,994	0.287	14.60	4.37	8.78	11.24
11,510	Parallel	0	3200	2.92	19,313	10,345	0.301	14.80	4.21	9.18	10.96
11,510	Perpendicular	0	3200	2.89	18,622	10,354	0.276	13.51	4.18	7.94	10.66

STATIC MECHANICAL PROPERTY TESTS

Samples from three selected zones from MEC Muse-Duke Well #1 were used in the mechanical and physical properties tests. The zones are 11,195 - 11,207 footage intervals in the Bossier Shale Formation; the 11,239 - 11,313 footage in the Cotton Valley Limestone formation and 11,510 ft in the Anhydrite formation. Samples used in the triaxial compression tests were cylinders 0.75 inch in diameter by 1.5 inches in length and were obtained both perpendicular and parallel to the core axis, *i.e.*, parallel and perpendicular to the bedding plane respectively. Table II lists the results of the measurements (Young's Modulus, Poisson's ratio and Maximum Compressive Strength) and the confining pressures at which the tests were run. Tests were run at downhole temperature of 285°F.

TABLE II
TRIAXIAL COMPRESSION TEST DATA
MITCHELL ENERGY CORPORATION WELL
MUSE DUKE NO. 1

	Depth (ft.)	Sample Orientation*	Sample Density (gm/cm^3)	Confining Pressure (psi)	Pore Pressure (psi)	Young's Modulus (10^6 psi)	Poisson's Ratio	Maximum Compressive Strength(psi)
BOSSIER SHALE	11,195	Parallel	2.66	3200	0	6.76	0.17	23,879
	11,207	Parallel	2.67	3200	0	11.36	0.26	21,491
	11,207	Perpendicular	2.67	3200	0	3.68	0.18	21,405
	11,207	Perpendicular	2.68	3200	0	2.81	0.14	23,440
COTTON VALLEY LIMESTONE	11,239	Parallel	2.69	3200	0	5.84	0.18	37,023
	11,313	Parallel	2.52	8800	5600	6.67	0.23	23,146
	11,239	Perpendicular	2.70	3200	0	5.38	0.16	---
	11,313	Perpendicular	2.51	8800	5600	5.15	0.22	29,014
ANHYDRITE	11,510	Parallel	2.93	3200	0	10.20	0.29	27,000
	11,510	Parallel	2.93	3200	0	11.40	0.23	27,530
	11,510	Perpendicular	2.95	3200	0	7.69	0.23	24,949
	11,510	Perpendicular	2.94	3200	0	7.94	0.25	26,004

* Orientation with respect to the bedding plane.

FRACTURE TOUGHNESS TESTS

Fracture toughness measurements were carried out on cylindrical samples using the burst technique developed by Clifton, *et al.*, (1976). In this technique, a core sample about three inches long is used. A small hole is drilled along the axis of the specimen and two opposite prenotches are placed at the internal walls to specify the fracture initiation points. A bladder is placed in the hole to prevent fluid from entering the sample or the notches and then pressure is applied in the bladder until the sample bursts. Tests were carried out on samples from the Bossier Shale formation (11,121 - 11,207 footage), Cotton Valley Limestone formation (11,239 - 11,374 footage) and Anhydrite formation (11,505 - 11,510 footage). Confined burst tests to evaluate proportional loading critical stress intensity factor were performed at *in situ* temperature of 285°F and are presented in Table III. Unconfined burst tests to evaluate direct loading critical stress intensity factor were performed at room temperature of 75°F and are presented in Table IV.

TABLE III
PROPORTIONAL LOADING CRITICAL STRESS INTENSITY FACTOR (K_{Ic})
MITCHELL ENERGY CORPORATION WELL
MUSE DUKE NO. 1

ZONE	DEPTH (feet)	CONFINING PRESSURE (psi)	BURST PRESSURE (psi)	TEMPERATURE °F	CRITICAL STRESS INTENSITY FACTOR (K_{Ic}) (psi $\sqrt{inch}$)
BOSSIER SHALE	11,121	415	3360	285	580
	11,195	235	1960	285	415
	11,207	170	1400	285	295
COTTON VALLEY LIMESTONE	11,239	390	3105	285	655
	11,336	290	2300	285	400
	11,374	315	2525	285	535
ANHYDRITE	11,510	315	2375	285	410

TABLE IV
DIRECT LOADING CRITICAL STRESS INTENSITY FACTOR (K_{Ic})
MITCHELL ENERGY CORPORATION WELL
MUSE DUKE NO. 1

ZONE	DEPTH (feet)	BURST PRESSURE (psi)	TEMPERATURE °F	CRITICAL INTENSITY FACTOR (K_{Ic}) ($psi\sqrt{inch}$)
BOSSIER SHALE	11,207	1850	75°	570
COTTON VALLEY LIMESTONE	11,313	1640	75°	615
ANHYDRITE	11,505	2340	75°	880

APPENDIX

FIELD TEST

IN SITU STRESS MEASUREMENT BY HYDRAULIC FRACTURING

Background

Determining *in situ* stresses from field measurements by hydraulic fracturing has undergone several stages of theoretical evolution (cf., Hubbert and Willis, 1957; Kehle, 1964; Haimson and Fairhurst, 1976; and Abou-Sayed, *et al.*, 1978). Laboratory studies (Lamont and Jensen, 1963, and Haimson and Fairhurst, 1967) and field experiments (Raleigh, *et al.*, 1972; Haimson, *et al.*, 1974, and Bredehoeft, *et al.*, 1976, among others) have been used to verify theory. Since the experimental techniques are presented elsewhere (Haimson, 1968), only a brief description will be presented here.

The *in situ* stress measurement follows procedures similar to those used in all hydraulic fracturing; however, the hole is left open so that fracture orientation can be determined. The test section is isolated by a packer pressurized against the wall of the borehole. This packer may be in a straddle configuration (see Figure A1) for tests conducted away from the hole bottom, or a single packer for tests conducted in the bottom ten to twenty feet of the hole (Figure A2). "Fracturing fluid" is injected into the section sealed by the packer(s) and the pressurization of the section is monitored by surface and, if possible, downhole pressure gages. Pressure is raised slowly until the breakdown pressure (P_b) is reached, and a fracture is formed in the rock surrounding the hole. Providing the flow rate remains constant after breakdown, the pressure will drop to a constant level, known as the extension pressure (P_f) as the fracture propagates out into the formation. If the fluid flow is stopped, the entire system will

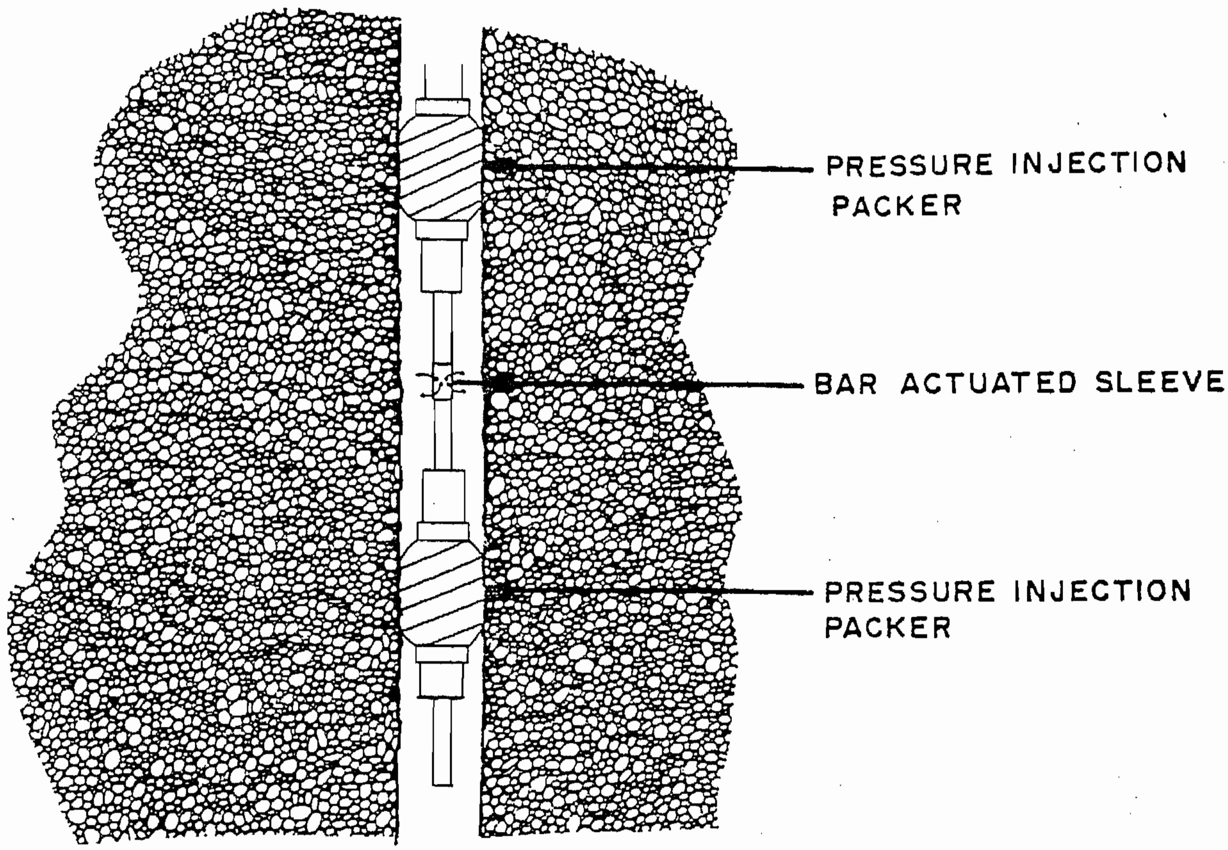

Figure A1. Configuration of a straddle packer test.

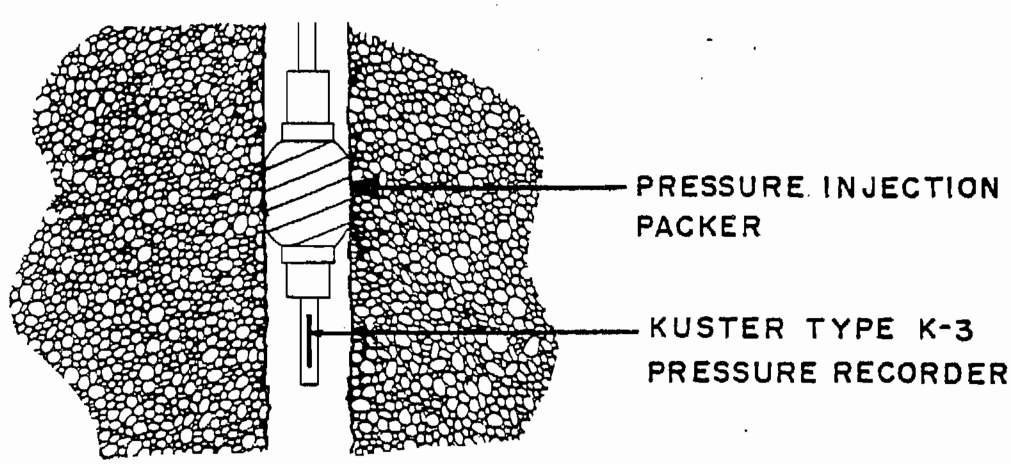

Figure A2. Configuration of a single packer test.

come to an equilibrium where the *in situ* stress acting to close the fracture equals the fluid pressure; this equilibrium pressure is the shut-in pressure (P_s).

Fracture orientation is determined by an impression packer. The soft rubber membrane on the outside of the packer is extruded into the crack under pressure, thereby forming a permanent trace of the fracture. A downhole compass correlated with a reference mark on the outside of the packer provides absolute orientation of the fracture.

Analysis of Hydraulic Fracture Data

In situ stress measurements of this type (undertaken in a vertical well bore) generally assume that the axis of the borehole is aligned with a principal stress direction. This assumption, then fixes the remaining two principal directions in the horizontal plane, and leads directly to formulations for the vertical and minimum principal stresses (assuming that the vertical direction can be estimated by integrating density logs to the test depth. The minimum *in situ* stress (σ_{HMIN}) is obtained directly from the pressure records generated during the hydraulic fracture and is equal to the shut-in pressure.

Although it has always been accepted in hydrofracturing that the minimum principal stress was equal to the shut-in pressure, the first analytical proof of this relationship was shown by Abou-Sayed, *et al.*, in 1978. Abou-Sayed showed that the fracture must be aligned with a principal stress direction, and that this direction is parallel to the maximum principal stress for an isotropic media. In this case, if the crack is long and held open by a static fluid pressure, the fluid pressure must be equal to the minimum principal *in situ* stress acting to close the fracture.

The determination of the maximum principal *in situ* stress (σ_{HMAX}) is considerably more complicated and is based upon both the pressure record generated during the field test and properties of the rock that are obtained in the laboratory. The equation for the calculation of the maximum principal stress, derived by plane strain analysis of the initiation and propagation of a crack in a linear elastic media using the method of fracture mechanics is (see Abou-Sayed, *et al.*, 1978):

$$\sigma_{HMAX} = \frac{G}{(G-F)} p_s - \frac{F}{(G-F)} p_b + \frac{K_{Ic}}{\sqrt{\pi L}\ (G-F)} \qquad (1)$$

where

p_s = shut-in pressure

p_b = break down pressure

K_{Ic} = critical stress intensity factor

L = length of the crack

G and F = numerically determined constants that depend on the ratio of crack length to borehole radius

If the crack length is small compared to the borehole radius, Equation (1) reduces to

$$\sigma_{HMAX} \cong 3p_s - 2p_b + \frac{K_{Ic}}{\sqrt{\pi L}\ (G-F)} \qquad (2)$$

The application of this equation is not simple and is based primarily on the assumptions that K_{Ic} can be accurately determined and that an accurate range of the crack length (L) is known. The result is best presented as upper and lower bounds on σ_{HMAX} and is generated by the following procedure. First, an estimate is obtained using the equation that describes the elastic state of stress at the borehole wall (see Haimson and Fairhurst, 1967). This equation is written as

$$\sigma_{\theta\theta} = 3p_s - p_b - \sigma HMAX - p_o \tag{3}$$

where

$\sigma_{\theta\theta}$ = the tangential stress of the borehole wall

p_s = shut-in pressure

p_b = break down pressure

σ_{HMAX} = maximum principal stress

p_o = formation pore pressure

The propagation of a small pre-existing flaw or fracture cannot begin until the tangential stress ($\sigma_{\theta\theta}$) at the borehole wall moves from a state of compression to tension. Therefore, the value of σ_{HMAX} cannot be less than the value determined when $\sigma_{\theta\theta}$ is set equal to zero, or

$$\sigma_{HMAX} \geq 3p_s = p_b - p_o \tag{4}$$

A second estimate of σ_{HMAX} is generated by assuming a characteristic crack length (L) and performing the calculation indicated by Equation (2). The uncertainty in crack length (L) has a very strong effect on the value of σ_{HMAX} hence the upper and lower bounds. It is felt, however, that a reasonable range in the crack length can be obtained by examining the core recovered from the well.

Another estimate of σ_{HMAX} can be achieved by cyclic repressurization of the test zone after the hydraulic fracture has been created. If the test zone is repressurized slowly at a constant flow rate, in some cases the reopening of the fracture can be detected by a reduciton in the rate of pressurization. The opening of the fracture corresponds to a change in the state of tangential stress ($\sigma_{\theta\theta}$) from compression to tension or a close estimate of the point at which $\sigma_{\theta\theta}$ at the well bore is zero. The opening pressure and shut-in pressure are substituted into Equation (4) and σ_{HMAX} can be calculated with greater precision.

THE FIELD TEST AND RESULTS

The field test was conducted using a lynes straddle inflatable testing and treating tool with an eight foot straddle section. The packer assembly was tripped into the hole on the drill pipe and the length of each stand of pipe was measured before attaching it to the drill string. The test depths had been selected by examining a density and caliper log generated the previous night. The caliper log indicated that most of the hole was washed out to some extent. Three zones were selected for testing and the tool lowered to the deepest zone at 11,456 feet. When the tool had been lowered to this depth, a gamma ray probe was lowered inside the pipe to assure that the tool was located at the correct depth. The attempt to generate a gamma log failed because the wireline attached to the probe was defective. The tool was then located by using the pipe fully, with the center of the straddle section at 11,456 feet.

The fracturing fluid was the water based 10-11 lbs/gal drilling mud ~~that had been~~ used during the drilling of the hole. This was pressurized at the surface by injecting fresh water at a rate of roughly 2.5 gpm. Both flow rate and pressure were measured at the surface by two strain gage type pressure transducers and a turbine flowmeter. An additional pressure record was generated by a Kuster K-3 pressure recorder that was inserted in the drill pipe immediately above the packers.

The packers were inflated to 1350 psi above the hydrostatic pressure at the 1st depth (6480 psi). The straddle tool was then moved from the inflate position to a blocked out position, which sealed the individual packers. The pressure in the drill pipe was released and the tool moved to the open between position so that fluid pressure could be applied to the formation isolated by the two inflated packers.

The record of the test is shown in Figure A3. The fluid was injected at a rate of approximately 2.5 gpm for roughly 21 minutes. The pressure built up to 9,380 psi (2,900 psi surface) then dropped abruptly to 7,980 psi (1500 surface). The fluid flow was stopped and the system shut-in. The pressure stabilized at 7,980 psi (1,500 psi surface). At the point which appeared to be formation breakdown (p_b = 9,380 psi), the drill pipe moved upwards in the slips approximately 6 inches. The slips were removed, and the drill pipe had to be raised 10 feet before any weight was taken by the elevators. This indicated that the lower packer had ruptured and that the fluid pressure acting upward against the upper packer had pushed the tool up the hole.

The pressure was released at the surface, and then fluid flow into the drill pipe was resumed. Flow rates as high as 9 gpm would not produce a pressure increase. Furthermore, fluid began to return through the annulus at the surface. This indicated that the upper packer had also ruptured.

DISCUSSION AND CONCLUSIONS

Careful interpretation of the test results suggest that no hydraulic fracture was created during this test. The peak pressure reached was 9380 psi and the shut-in pressure was 7980 psi. The apparent "breakdown" was caused by the packer failure depicted in Figure A4. The lower element pulled off of the mandrel, and established communication with the open hole below. During this process the upper element failed and was forced uphole by the over balance of fluid pressure acting in the test section. As the pressure dropped the pipe weight forced the element downwards, causing it to squash out (Figure A4) and reseal the section of open hole below the packer. The pressure that would be generated by the pipe weight acting on the squashed out packer would be roughly 2000 psi. This value compares well with the shut in pressure, 1500 psi (differential), if one considers the effects of packer and fluid friction.

Further evidence against a successful test is found in the results of the MHF's conducted by Mitchell Energy on wells Muse A No. 1 and Quinn Estate No. 1. Instantaneous shut in pressures recorded in these two wells were 9000 psi (Kozik, 1978) significantly higher than this test indicates:

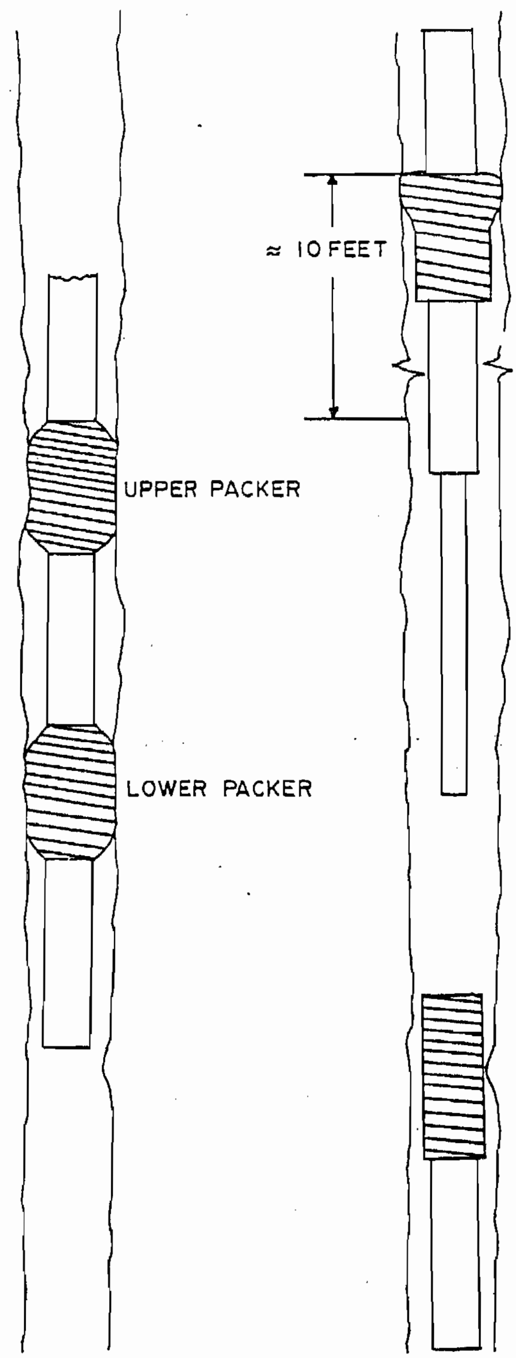

Figure A4. Schematic of packer failure