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MASSIVE HYDRAULIC FRACTURE TEST. COTTON VALLEY LIME, EAST TEXAS

Final Report for the Period August 8, 1978—July 31, 1980

By
Harry G. Kozik
Stephen A. Holditch
Atul Kumar

August 1980

Work Performed Under Contract No. AC08-78ET12150

Mitchell Energy Corporation
Houston, Texas

U. S. DEPARTMENT OF ENERGY

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A CASE HISTORY FOR MASSIVE HYDRAULIC FRACTURING THE COTTON VALLEY LIME MATRIX, FALLON AND NORTH PERSONVILLE FIELDS

LIMESTONE COUNTY, TEXAS

by

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ABSTRACT

This report summarizes the results of an active stimulation program on the Cotton Valley Lime as evaluated using reservoir production and pressure transient data.

Using standard economic parameters and reservoir permeabilities determined by history matching, a detailed study was made to determine the well spacing and fracture length radius necessary for optimum development of the Fallon and North Personville Fields.

In addition, the major details of designing and executing a super massive hydraulic fracture job are discussed in the appendix.

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INTRODUCTION

Considerable emphasis has been placed, in the last few years, on recovering gas from the "tight gas" basins. One step that shows promise towards unlocking that tight gas is massive hydraulic fracturing. A case in point is the evolution of the stimulation in the Cotton Valley Lime at Fallon and North Personville Fields, located about 10 miles southeast of Mexia in Limestone County, Texas. (Figure 1).

The Jurassic Cotton Valley group on the west flank of the East Texas Basin generally consists of succession of about 1,000 feet of terrestrial and marine sands and shales, 800 feet of dark shale (Bossier shale) and 300 to 500 feet of limestone known as the Cotton Valley Lime or Haynesville, at the bottom. The group covers over a quarter of a million square miles in the East Texas Basin and adjacent parts of Louisiana and Southeast Arkansas.

The Cotton Valley Lime in the Fallon and North Personville area has been a known gas area since its discovery in 1969. However, its poor permeability pay at the depth of 11,000+ feet had produced at rates too low for commercial development under the price schedules and technology of the past decade. Due to fractured porosity, beginning rates were moderately good, 1 to 4 MMCFGPD; but the natural fracture system was not sufficient to maintain the high rates of flow and consequently, the rates dropped to 0.500 to 0.200 MMCFPD in less than two years.

Lately, advancements in stimulation technology and improved economic incentives renewed interest in this area. Conventional acid stimulations and small frac jobs brought some improvement. Bigger frac jobs brought further improvement, but massive hydraulic fracturing looks like it is worthwhile.

The objectives of this report are to:

1. Document the evolution of stimulation technology of the Cotton Valley Lime at the Fallon and North Personville Fields.
2. Using a computer reservoir simulator, history match the production and pressure transient data of the Muse No. 1 Well before and after a massive hydraulic frac and determine the uniqueness of this solution.
3. History Match the production of the Muse-Duke No. 1 Well after a super-massive hydraulic fracture treatment.
4. Optimize the development of the Cotton Valley Lime reservoir with respect to fracture length and well density using reservoir data and economic guidelines.
5. Document the design of a super-massive hydraulic fracture job. (See Appendix.)

RESERVOIR CHARACTERISTICS

Rock Parameters: The Cotton Valley Lime formation is generally gray, massive, oolitic to pistolitic and finely crystalline to micritic. The better porosities appear to be related to the oolitic zones ranging from 2 to 12 percent with some local thin zones of 14 percent. Core analyses indicate that the average matrix permeabilities range about .01 to 0.7 md in the better rock and from .003 to .7 md when considering the total gross section. An occasional very thin streak of permeability may run up to 80-90 md.

Figure 2 shows histograms of the permeability and porosity of selected cores recovered from the Lawrence No. 1 and the Muse-Duke No. 1. From a total of 216 feet of core, 31 feet of the best reservoir rock were selected for a sample statistical analysis. The samples selected were those that had permeability measurements 90 degrees to horizontal of which the geometric mean was 0.10 md. and the harmonic mean was 0.06 md. The average porosity was 6.9 percent.

Net Pay: Net pay was determined as two categories, ie., the total porosity storage space available and the commercially producible porosity. The total porosity storage space was determined by counting porosity intervals of 2 percent and above because some permeability was beginning to develop at 2 percent. Commercially producible porosity was counted starting at 4 percent because 98 percent of the 4 percent porosity or better rock cored had permeabilities of 0.01 md. or more. The relationship of permeability to porosity is shown in Figure 3. Overall, the average producible net pay is running between 25 to 50 feet per well using 4 percent porosity as a cutoff.

Fracture Orientation: Figure 4 shows the distribution of fracture orientation of cores from the Muse-Duke No. 1. The density distribution of the orientated fractures indicated two major fracture strike trends bearing NW-SE. Using this information, the fracture strike distribution of the cores that were not oriented could be oriented in relation to true north. A comparison of the two density distributions of both oriented and non-oriented fracture strikes shows that the azimuth readings on the non-oriented fractures are equivalent to those readings represented by one of the major strike trends, and therefore, they were included in the plot. Also, histograms indicate that the majority of fractures occur in the 85-90 degree range with no fracture dip angles being noted less than 50 degrees.

Absolute Permeability: Absolute permeability measurements were made using a transient technique[3,15] which is well suited for permeabilities in the microdarcy range. The results are given in the following Table I. The test conditions of 8000 psi confining pressure, 6400 psi pore pressure and 285° F. temperature were commensurate with the in situ reservoir conditions. Application of simulated in situ conditions reduces permeability by an order of magnitude.

TABLE I

Absolute Permeability Measurements

MEC: Muse-Duke Well No. 1

Formation Sample Depth (ft.)	Confining Pressure (psi)	Pore Pressure (psi)	Temperature (°F)	Permeability (milli-darcy) md.
11313 A	100	0	75	.159
	8800	6400	285	.023
11313 B	100	0	75	.811
	8800	6400	285	.082
11313 C	100	0	75	.991
	8800	6400	285	.031

Effective Permeability: The transient technique mentioned above can also be used to measure effective permeability to gas at different water saturations by using partially saturated samples and keeping the pulsing pressure lower than the capillary pressure of water in the sample. In the tests performed, the pulsing pressure was always low compared to the expected capillary pressure of over 10 psi.

Table II lists the effective and relative permeability to nitrogen gas for samples from the 11,302 and 11,313 feet depth. The measurements were taken at in situ condition of 8800 psi confining pressure, 6400 psi pore pressure, 285° F temperature and at various water saturation levels. Figure 5 illustrates the variation of relative permeability to gas with increasing water saturation. Both the samples show similar trend. Up to 20 percent gas saturation, the relative permeability to gas is virtually unaffected by the presence of water. Thereupon, gas permeability decreases linearly with increasing water saturation and at about 85 percent water saturation, the relative permeability to gas approaches zero.

Ultrasonic Tests: Both the compression and shear wave velocities were measured on samples subjected to simulated in situ conditions. Sample axes were normal to the bedding plane and results are directly comparable, therefore, to the P-wave logs. Young's moduli and Poisson's Ratio derived from the measured densities and P (primary) and S (shear) waves assuming isotropic elastic material are compared with data derived from mechanical properties logs by Schlumberger in Figure 6. The results derived show very good agreement.

TABLE II

Effective Permeability Measurements

MEC: Muse - Duke Well #1

Core Sample (Ft)	Water Saturation %	Effective Permeability Kg (milli-darcy)	Relative Permeability (Krg)
11302	0	.0022	1.0
	20	.0021	0.95
	40	.0013	0.59
	60	.0008	0.36
	80	<.0001	-
	100	<.0001	-
11313	0	.0880	1.
	20	.0850	0.96
	40	.0450	0.51
	60	.0330	0.38
	80	.0150	0.17
	100	<.0001	-

STIMULATION HISTORY

Early Stimulations: The first six wells completed in the Cotton Valley Lime received either a light acid frac or a limited water-sand frac (under 50,000 gallons). The best well, Burleson No. 1, after a fracture treatment of 48,000 gallons of gelled water and 178,000 lbs. of sand, began producing 4.4 MMCFGPD which declined to 2.5 MMCFGPD in three months and to .500 MMCFGPD in two years.

The other five wells, after normal acid stimulation treatments, began at about 1 MMCFGPD per well which soon declined to .200 to .300 MMCFGPD. After the initial flush production, the decline rate for the Burleson Well was 45 percent for about the first two years, then dropped to 9 percent. The average of the other five wells declined at a rate of 57 percent and then dropped to 15 percent.

Massive Stimulations: The Muse No. 1 was the first well to receive a massive hydraulic sand fracture stimulation treatment. A total of 340,000 gallons of gelled water and 450,000 pounds of 20-40 mesh sand was pumped. An additional 48,000 pounds of 100 mesh sand was pumped ahead of the 20-40 sand to help control fluid loss. The initial after-frac rate was in excess of 4 MMCFPD and the rate has gradually declined to its present capability in excess of 1.1 MMCFPD after 28 months. After the initial flush production, its beginning decline was only 29% and its current decline rate is 13% as compared to the others above.

The super-massive hydraulic sand fracture stimulation treatment was done on the Muse-Duke No. 1. Following acid stimulation treatment, the well flowed in excess of 4 MMCFPD, dropping very quickly to 1.7 MMCFPD. Immediately after fracture stimulating with 2.8 million pounds of sand, the well flowed 6+ MMCFPD. Two months after fracturing it still had a 5+ MMCFPD deliverability. Six months later it was flowing 4 MMCFGPD and 22 months later it was still flowing 2.1 MMCFGPD with 700 psi flowing tubing pressure. Its initial decline rate began at 25 percent and its present rate is 5 percent.

Four other wells have been massively fracture treated with sand volumes ranging from that used on the Muse No. 1 to 1,000,000 pounds. Initial production indicates similar performances as the Muse No. 1.

Comparison Plots: Figure 7 shows a comparative plot of the daily rate vs the cumulative production of the representative wells just discussed. The bottom curve in the figure graphs the average cumulative production of the best three wells that were mainly acid treated. In eleven years the average cumulative production per well was just shy of a billion cubic feet of gas. The next curve above represents the cumulative performance of the Burleson No. 1 which was conventionally fracture treated. This well produced a cumulative of 2.4+ billion cubic feet of gas in 10+ years. The next curve above the Burleson No. 1 graphs the Muse No. 1 which had the first massive hydraulic fracture treatment. Its performance is much better. A cumulative of 1.9+ billion cubic feet of gas was produced in 2.7+ years. The top curve represents the performance of Muse-Duke No. 1 after its super-massive hydraulic fracture treatment. It is performing the best. Its cumulative production is 1.9+ billion cubic feet of gas in 1.8+ years.

RESERVOIR SIMULATION

A computer reservoir simulator[9,11] was used to history match the production and pressure transient data of the Muse No. 1 and the Muse-Duke No. 1. Basic formation permeability, fracture length, and fracture conductivity were varied to match the well performance and assess the sensitivity of project profit potential. Also, the study was made to optimize the development of the Cotton Valley Lime reservoir with respect to fracture length and well density.

History Match of the Muse No. 1: A history matching process was performed on the gas production and pressure buildup test data of the Muse No. 1. Inspection of the field data indicated that both the rate and flowing bottom hole pressure had declined with time. A numerical reservoir model was used to simulate the production history with a series of constant flow rates followed by constant pressure production as the well was pulled down toward line pressure. Figure 8 illustrates the production history for the Muse No. 1 and the line with the solid dots on Figure 9 represents the buildup data. The model was used to match the data in both these graphs. The following table presents the exact production values which were input into the model.

Time Period (Days)	Flow Rate (MMCF/D)	Flowing Bottomhole Pressure (PSI)
0-108	3210	Decreasing
108-231	2536	Decreasing
231-388	Decreasing	1080
388-398	-0-	Increasing (Buildup)
398-430	Decreasing	2000

In the first history matching of the Muse No. 1, the design fracture half length of 1500 feet was used. Several computer runs were necessary before an adequate history match was obtained. First, it was evident that using the average core derived permeability of .09 md., the shape of the buildup curve was not similar to the actual field data. The permeability had to be reduced and the fracture conductivity increased to match the field data. A successful match was finally obtained with a 1500 foot fracture half length, a permeability of 0.013 md. and a fracture conductivity of 450 md.-ft. (Run 1, Figure 9).

In an effort to test the uniqueness of this solution, additional computer runs were made. Using a 1000 foot fracture half length and a fracture conductivity of 450 md.-ft., an acceptable match was obtained with a permeability of 0.023 md. (Run 2, Figure 9).

Also, using a 500 foot fracture half length and a fracture conductivity of 450 md. ft., an acceptable match was obtained with a permeability of 0.0425 md. (Run 3, Figure 9).

Previous experience in history matching has led to the following conclusions:

1. Short-term production data can be adequately history matched using numerous combinations of fracture length and formation permeability.
2. Unique values of permeability and fracture length can be obtained only by history matching both the production data and the data from a long-term pressure buildup.

A unique history match was not obtained for the Muse No. 1 because of insufficient pressure buildup data. The buildup data presented in Figure 9 was completely dominated by linear flow into the fracture and the effects of fracture length had not been felt at the wellbore when the bombs were pulled.

To illustrate this point, consider the buildup data in Figure 10. These data were calculated by the numerical model using the three history match combinations.

History Match	Formation Permeability (md.)	Fracture Half-length (ft.)
1	.013	1500
2	.023	1000
3	.0425	500

Notice that for a 1 - 3 day buildup, the shape of the curves are essentially identical. It requires a buildup of 14 - 30 days before a unique history match can be obtained.

<u>Two Rate Test</u>: A two-rate test was also run on the Muse No. 1 prior to the pressure buildup. The two-rate test was included in all of our history match

runs. Figure 11 compares the pressures from the three history match runs to the actual field data.

The bottom hole pressures of the simulated cases following the rate change are smooth curves, due to the second flow rate being held precisely constant by the reservoir mode. The somewhat erratic behavior of the field data after the rate change is most likely due to the inability to maintain an exactly constant rate. The most important match point of the two-rate test was obtained, that being the pressure at the end of the second flow period.

History Match of the Muse-Duke No. 1: The Muse-Duke No. 1 was completed in the Cotton Valley Lime in September 1978. After the well was lightly acidized, the initial production was in excess of 4 MMCFPD at 4700 psi FTP, but the rate and pressure declined steadily to 3200 MCFPD and 3900 psi within 18 hours. The high initial rates and rapid decline are most likely due to the presence of natural fractures in communication with the wellbore. The Muse-Duke Well was tested for approximately three weeks at various rates and flowing tubing pressures. During this period, both flowing and shut-in bottom hole pressure surveys were obtained. At the end of the period the flow was down to 1700 MCFPD at 1800 psi FTP.

In November 1978, the well was massively fracture treated. The initial production at this time was in excess of 6 MMCFGPD. Six months later, it was flowing 4 MMCFPD and 22 months later it was still flowing 2.1 MMCFGPD at a line pressure of 700 psig.

An attempt was made to history match the Muse-Duke No. 1 after 50 days of production using the following parameters developed from the history match of the Muse No. 1:

Permeability	0.013 md.
Gas Porosity	0.036
Original Pressure	6750 psi
Bottom hole Temperature	286^{0} F.
Net Pay	50 feet
Fracture conductivity	450 md. ft.

Figure 12 shows that an acceptable match was obtained using the above described parameters. During the first twenty (20) days, the simulated flowing bottom hole pressure was considerably higher than the estimated flowing bottom hole pressure. This difference was probably due to the large volumes of frac water that were produced during the cleanup period. Therefore, the difference between the simulated and actual flowing bottom hole pressures are not as significant as depicted. The simulated case produced 290 million cubic feet during the 50 day period while the actual production was 270 million cubic feet.

The significance of the above history match is that by using, (1) the reservoir parameters as determined from the Muse No. 1 Well data, and, (2) the designed fracture half-length (2500 feet) for the Muse-Duke No. 1, the actual production history from the Muse-Duke No. 1 was successfully matched.

However, as discussed later, this fact does not prove that the designed 2500 foot fracture half length was created because the early life drawn down can be matched by numerous combinations of fracture length permeability and conductivity. It does point out, however, that a long fracture was created even though more data was needed to narrow down the above critical parameters. Therefore, the gas production from the Muse-Duke No. 1 was history matched again after 519 days of production. Table III presents a summary of the gas production. Also, these data have been presented in Figure 13 as flow rate and bottom hole pressure vs cumulative time. Furthermore, a post-frac pressure build up was run in August, 1979, after 256 days of production. These data are presented in Table IV and graphed in Figure 14 as the line connecting the open circles.

The results of the latest history match are illustrated as Cases I, II and III in Figure 14. These three cases on the graph were generated using the following data:

Case	Fracture Length (ft.)	Permeability (md)	Fracture Conductivity (md-ft)
I	750	.04	1000
II	1500	.022	1000
III	2500	.01	2000

For each of these cases, the correct cumulative production and flowing bottom hole pressure were computed by the model. Notice in Figure 14, however, that the 750 ft. fracture is too short, the 2500 ft. fracture is too long and only the 1500 ft. fracture adequately overlays the field buildup data.

Based upon the results of this computer model study, the following data best describe the Muse-Duke No. 1:

Average reservoir depth	11320 ft.
Original reservoir pressure	6750 psi
Current reservoir pressure	5635 psi
Formation gas permeability	.022 md
Formation gas porosity	3.6%
Net gas pay	50 ft.
Propped fracture half-length	1500 ft.
Average fracture conductivity	1000 md-ft.

Other Analyses: Other type curve pressure analysis methods were pursued to find a unique solution. An early attempt was made to curve match using Amoco's and S. A. Holditch and Associates, Inc.'s log-log plots for finite flow capacity fractures. The results[13] of these efforts indicated no unique solutions. The only significant observation that could be made at that time was that the buildup tests indicated a linear flow which increased from 12 to 360 hours and that the negative pressure loss, ΔP skin increased from 510 to 6220 psi, which yielded a wellbore improvement of approximately 1100 percent. However, if that observed long linear flow is applied to type curve analyses for infinite fracture flow conductivity, an acceptable solution emerges.

The linear flow equations indicate that pressure drop is directly proportioned to the $\sqrt{\text{time}}$ and early time pressure data plotted as a function of $\sqrt{\text{time}}$ should form a straight line, where fracture flow capacity is high, and wellbore storage and damage effects are minimal.[16] By the Square-Root Time Graph method, the slope of the line is related to the fracture length by the following equations:[16]

$$x_f = \frac{40.925\ QZT}{M_{vf}\ h} \sqrt{\frac{\mu}{k\phi C_t}}$$

When using this fracture flow equation, knowledge of the rock permeability must be known. Unfortunately, in this case, the permeability cannot be determined exactly. Figure 15 shows a plot of the well production of the Muse-Duke No. 1 prior to the fracture treatment. The quality of these data is poor because the well was cleaning up during this period, producing 150 to 200 barrels of water per day along with the gas. Figure 15 also shows a half slope line extending from 1.5 to 12 hours, indicating the presence of natural fractures on the formation. A formation 'kh' value of 4.0 md-feet was obtained by type curve matching these data with the natural unpropped fracture type curves[17] for natural fractured wells.

Figure 16 shows the post MHF production data for the Muse-Duke No. 1. Attempts to type curve match this data using 'kh' values of 4.0 md. feet were unsuccessful. This indicated that formation 'kh' value of 4.0 was probably incorrect, and it had to be less than 4.0 md. ft. Lower values of 'kh' were considered and these data were matched using the Finite Capacity fracture type curves of Agarwal, Carter & Pollock[16]. However, multiple matches were obtained. All these matches indicated very high fracture capacity ($k_f w$ / kx_f = 500).

Since very high fracture capacities were indicated for the Muse-Duke No. 1

fracture, the post MHF production was matched with the type curves for "infinite Conductivity fractures[17]. (Figure 17.) An acceptable match was obtained in this case with a type curve for $x_e/x_f = 1$. Here x_e is half the distance to the drainage boundary and x_f is half fracture length. Using the match point a formation 'kh' of 1.05 md feet and a half fracture length of 1814 feet was calculated.

In August 1979 (8 months after the MHF), a 25 day pressure buildup test was conducted on Muse-Duke No. 1. Using a formation 'kh' of 1.05 md feet, attempts were made to match this data using both the finite and infinite fracture capacity type curves. Match with the infinite capacity type curve was poor. An acceptable match was, however, obtained with the Cinco finite fracture capacity constant rate case type curve. (Figure 18.) A fracture length of 1764 feet and conductivity of 1100 md feet was obtained.

The fracture length obtained from the post MHF pressure buildup data is in close agreement with what was obtained from the well production data, the only difference being the fracture conductivity. The type curve match for the well production data was obtained with an infinite fracture conductivity type curve, whereas the pressure buildup data was matched with the finite fracture conductivity type curve.

The pressure buildup was run for 25 days whereas the production data is for 1.5 years. The production data has therefore been effected by a much larger reservoir area. A decrease in the formation permeability away from the wellbore and/or a gradual clearing of the fracture of the fracturing fluids or the fracture did not close as much as expected could cause the fracture conductivity to increase for the larger production times. In the case of the Muse-Duke No. 1, there is some evidence of a decreasing formation permeability away from the wellbore as well.

To summarize:

(1) No reliable formation 'kh' value could be obtained from the pre MHF data of Muse-Duke No. 1.

(2) Multiple matches were obtained using the post MHF production data with the Finite Fracture Capacity type curves. All the matches indicated very high fracture conductivity.

(3) An acceptable match of the post MHF production data was obtained with the Infinite Fracture Capacity type curve.

(4) Formation 'kh' of 1.05 md feet, fracture length of 1814 feet and the well drainage area of 300 acres was computed from this match.

(5) The above values appear to be reasonable since the field structure map and the location of the offset wells show the well drainage area to be around 300 acres.

(6) The post MHF pressure buildup data for the Muse-Duke No. 1 was matched with a Finite Fracture Capacity type curve. A fracture length of 1764 feet and conductivity of 1100 md feet was obtained.

(7) There is some evidence that the formation permeabilities are getting reduced away from the Muse-Duke No. 1 wellbore. Also, there is a possibility of an increase in the fracture permeability with time because of the cleaning out of the fracture fluids and/or the fracture closure is less than expected. All of these factors may be responsible for the Muse-Duke No. 1 fracture conductivity to increase with time.

(8) Wells in the Cotton Valley Lime formation with fractures similar to that in the Muse-Duke No. 1 could drain reservoir in excess of 300 acres.

OPTIMIZATION OF FRACTURE LENGTH AND WELL SPACING

Economic Parameters: The reservoir stimulation history matching analysis of the Muse No. 1 and the Muse-Duke No. 1 has defined the formation permeability to gas as being in the .01 - .04 md. range. Using the computer model FRACOP[9], a series of evaluations were made to determine the optimum fracture length and well spacing for a well of parameters similar to the Muse No. 1 and the Muse-Duke No. 1. Any evaluation which involves economic analyses is quite sensitive to each company's economic parameters, such as current product price, price escalation, operating costs, initial investment, net working interest, etc., which may not be the same as used here.

The following table lists the economic parameters used in this study:

Economic Parameters

Fixed Investment	$1,000,000
Product Price	$1.52/MCF Constant
Operating Expenses	$8,400/year Constant
Net Revenue Interest	79.7%
Production Tax Rate	13%
Federal Income Tax Rate	0.0%

Fracturing Costs

Designed Fracture Length (Radius) (Ft.)	Costs ($)
250	75,000
500	100,000
750	150,000
1000	200,000
1250	250,000
1500	300,000
1750	400,000
2500	700,000

Production Function: The FRACOP model uses input reservoir, well and fracture length parameters to generate a production function. This production function is then used to determine net cash flow and net present value for any desired discount rate.

Based upon the two permeabilities of .01 md. and .04 md., FRACOP runs were made using several fracture half-lengths and for 160, 320 and 640 acres drainage areas.

Figure 19 illustrates the effect of permeability upon the 30-year ultimate gas recovery (per well) as a function of fracture half-length. As would be expected, ultimate recovery increases as permeability, fracture length, and drainage area (well spacing) increase. Note, however, that for 160 acre spacing, increasing fracture half-length from 250 ft. to 1250+ ft. does not significantly influence the 30-year ultimate recovery. The effect of the higher permeability becomes more pronounced as the drainage area increases.

Figure 20 illustrates the effect of permeability upon the 30-year recovery per section as a function of fracture half-length. The table below summarizes the results for a 1000 ft. fracture half-length.

Well Spacing	Wells/ Section	Permeability (md.)	Ultimate Recovery (BCF/Sec.)	Recovery Efficiency (% of OGIP)
160	4	0.04	10.9	77.4
160	4	0.01	9.9	70.2
320	2	0.04	10.5	74.5
320	2	0.01	8.3	58.7
640	1	0.04	9.1	65.1
640	1	0.01	5.6	40.2

From a pure recovery basis, it appears that the best well spacing would be four wells per section since that well density results in the maximum recovery efficiency. However, to properly optimize the well spacing and fracture length from an economic viewpoint, the maximum discounted present value profit of each case must be determined. Figures 21 and 22 illustrate the 10% discounted profit per section for permeabilities of .01 and .04 md., respectively.

The table below summarizes the results of the FRACOP computer runs.

Permeability (md.)	Discount Factor (%)	Well Spacing (acres)	Optimum Fracture Half-Length (ft.)
0.01	0	320	1400-1600
0.04	0	640	1500
0.01	10	320	1500-1700
0.04	10	320	1400-1600
0.01	15	320	1700+
0.04	15	320	1400-1600

Based on the economic considerations listed earlier, the optimum well spacing and propped fracture half-length is 320 acres and 1500 feet, respectively.

CONCLUDING REMARKS

Based on the results of this study, no firm conclusions can be made as to the exact matrix permeability, fracture length and fracture conductivity for the wells that were massively hydraulic fracture treated.

However, even though a unique solution was not obtained, the important reservoir parameters were bracketed, i.e.: (1) a range of .01 to .04 md. for permeability and, (2) 500 to 1800 feet for the fracture half-length.

Furthermore, the optimum well spacing and propped fracture half-length appears to be 320 acres and 1500 feet.

Finally, and probably the most important, no unique solution can be obtained without adequate long-term pre frac buildup data to obtain the true formation capacity (kh).

NOMENCLATURE

B = Formation Volume Factor, RB/STB (m^3/m^3)

C or C_t = Total compressibility at initial reservoir conditions psi (Pa^{-1})

Cr = Relative fracture flow capacity, dimensionless

FcD = Fracture flow capacity, dimensionless

h = Formation thickness, ft (m)

k = Formation permeability, md ($10^{-3} \mu m^2$)

k_f = Fracture permeability, md($10^{-3} \mu m^2$)

m = Slope on a semi log plog, (psi^2/cp)/MCFD/cycle ($M\ Pa^2/Pa \cdot S$)/(m^3/d/cycle)

mp = Real gas pseudo-pressure, psi^2/cp ($M\ Pa^2/Pa \cdot S$)

$\Delta(m(p))$ = Difference in real gas pseudo pressures, psi^2/cp ($M\ Pa^2/Pa \cdot S$)

P = Pressure, psia (M Pa)

ΔP = Pressure drop, psia (M Pa)

Pi = Initial reservoir pressure, psi (M Pa)

PD = Dimensionless pressure or pressure drop

PwD = Well bore pressure, dimensionless

Pwf = Flowing bottom hole pressure, psia (M Pa)

q = Flow rate, MCF/day (m^3/d)

t = Flowing time, hours

tD = Dimensionless time

tDX_f = Dimensionless time based on X_f

Δt = Shut in time, hours

w = Fracture width, ft (m)

X_e = Distance from well bore to the reservoir boundary, ft (m)

x_f or L_f = Fracture half length, ft (m)

Z = Real gas deviation factor

ϕ = Total porosity, fraction

μ = Viscosity, cp (Pa·S)

M_{vf} = Slope in psi $\sqrt{\text{hour}}$ or psi$^2/\sqrt{\text{hour}}$

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APPENDIX

MECHANICS OF A "SUPER"-MASSIVE HYDRAULIC FRAC JOB

INTRODUCTION

One question that is always asked during the evolutionary process of fracturing is: "How big a job can be performed?" The answer is: "Just about as big a job as you would wish. The technology is available today." The real question is, "Will it be effective?"

The objective of this portion of the paper is to outline some of the major details in designing and executing a super-massive hydraulic frac job for the Muse-Duke No. 1.

PHYSICAL ROCK PROPERTIES

A very important factor in the basic design of a frac job is a knowledge of the in situ stresses[1,2,4] of the rock; not only of the objective formation, but also the bounding formations. The in situ rock stresses will control the behavior of the induced fracture away from a well bore.

In an attempt to determine these stresses, the following measurements were made:

Triaxial Tests: Triaxial compression tests were performed on core samples with the sample axis both perpendicular and parallel to the original core axis. Table V lists the results of the measurements as well as the simulated in situ environment under which the tests were run. The elastic moduli quoted were determined from the initial slopes of the stress-strain curves. As expected, the static moduli were lower than the dynamic moduli for the samples tested, shown by Figure 6, the difference being between 15 and 25 percent.

Fracture Toughness: Fracture toughness measurements were carried out on samples using the technique developed by Clifton et al.[4] In the technique, a core sample about 3 inches log is used. A small hole is drilled along the axis of the specimen and diametrically opposite pre-notches are placed at the internal wells 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. Tables VI and VII list the results of proportional and direct loading tests, respectively. The results are shown in Figure 23 illustrating the Cotton Valley Limestone formation to be more susceptible to fracturing in comparison to the bounding layers.

Containment Analysis: Final analyses of the laboratory measurement program indicates the possibility of fracture containment within the Cotton Valley Limestone formation. Variation in elastic moduli between the bounding Bossier Shale at 11,100 feet and the bounding limestone/anhydrite sequence at 11,500 feet to the Cotton Valley Limestone is about a factor of 2. Figure 6 presents the variation of moduli with depth. Lower moduli is observed between 11,280 feet and 11,340 feet associated with a higher porosity gas zone. Based on field experience, a modulus contrast of at least three is required for successful containment. Therefore, upper containment cannot be guaranteed for the Cotton Valley Limestone based on moduli data. However, critical stress intensity factor variation with depth (Figure 23) does indicate the Cotton Valley Limestone to be the more susceptible formation to fracturing in comparison to the bounding layers. Actual post frac pressure analyses have indicated that the majority of the induced fractures appear to be staying within the perforated zone.

FRACTURE DESIGN

Objective: The objective was to create a fracture in the Cotton Valley Lime to effectively drain 640 acres. Also, the fracturing fluid had to be pumped down 2-7/8 inch tubing under 9,600 psi maximum through 15 perforations from 11,235 to 11,418 feet. Basically, this comes down to programming a pumping schedule to create a 210+ foot high fracture with a radius of 2,500+ feet, keep it within the section, and pack it properly to keep it open.

The design details were developed by utilizing Halliburton's "Prop" computer programs, which integrates Danshey's[5,6,] concept of wide fracture development. Danshey's concept is more in keeping with our thoughts than an induced fracture in the Cotton Valley Lime would have to be wide in order to extend the fracture out any appreciable distance. This was also indicated by analysis of measured mechanical properties of the rock.

Fracture Containment: All frac designs, including the one shown for this well, are set up to create fractures in a homogenous rock having constant mechanical properties. Very little consideration is given to the bounding formations above and below the section to be fractured. For short fractures, the effect of the bounding formations on the vertical propagation of an induced fracture may be ignored, but for long fractures, it cannot be ignored. Consideration must be given to the vertical propagation[4,14] of the fracture into the bounding rock. Laboratory measurements indicate that the anhydrite limestone sequence of the Bucker formation below the Cotton Valley Lime would impede downward vertical migration of the fracture. On the other hand, the top bounding Bossier Shale is less apt to entirely contain a fracture initiated in the Cotton Valley Limestone.

Recent work[14] has demonstrated that the vertical propagation can be constrained by controlling the density of the fracturing fluid, the rates and the pumping pressure. High density fluids and low rates will tend to migrate a fracture downward and conversely a lighter fluid and high rates will tend to migrate a fracture upwards. Therefore, in order to minimize the upward migration of the fracture, the pumping program was modified to initiate the fracture by pumping a weighted pre pad (10 pounds per gallon salt water) followed by sand laden gelled water down 2-7/8 inch tubing. This was to be pumped at rates no greater than 24 barrels per minute at a maximum of 9600 psi pumping pressure. Whether these modifications were entirely successful is undecided since production history matches after the frac job indicated a propped 1500 to 1800 feet fracture radius instead of 2500 feet was created in the Cotton Valley Lime pay.

Well Data: The revelant well completion, formation, and treatment input data used in the program are listed in Table VIII. The location of the perforations in the section is shown in Figure 24.

Program Results: The results of the "Prop" program are listed in Tables IX through XI. These tables outline the calculated fracture dimensions, the pumping schedule, and the sand depositional profile. To capsulate, the program calculated that it would take 974,000 gallons of fluid and 2,965,200 pounds of 20-40 mesh sand to create and prop a 2,708 foot fracture. Also, it would take 5,182 hydraulic horsepower for 18 hours of pumping at 22 barrels per minute at 9,610 psi.

LOGISTICS

Bringing in and arranging the equipment for this job was a bit involved, but not unwieldy. After the location was enlarged to accomodate the equipment, it was placed as shown by Figure 25. All the equipment was trucked in and in place in ten days.

EXECUTION

Mechanically, the job went well. No breakdown of equipment happened in the 18 hours of pumping even after pumping 5 pounds of sand per gallon for 10 hours.

As shown by the pressure-rate chart of Figure 26, the pumping went smoothly without interruption except towards the end. About four hours after termination, the pressure dropped slightly and then began to rise gradually while the rates began to drop. We are not sure exactly what caused this behavior. We suspect the fracture penetrated a zone of deeper permeability which increased the fluid loss to the formation and the fracture began to close thereafter. Even so, 2.8 million pounds of sand (a record amount) was in place before screening out. A comparison of the design job and the actual performance is made in the Treatment Summary of Table XII.

SUMMARY

The design and execution of a "super" massive hydraulic fracture job is within the bounds of practicality with today's technology. The gel chemistry and the equipment have been developed to the state that almost any of the tight gas reservoirs can be physically fractured. The question remains .... "HOW EFFECTIVELY WILL THE FRACTURE PRODUCE THE GAS?"

TABLE III

MUSE-DUKE PRODUCTION

Month	Month Production (MCF)	Producing Days	Average Rate (MCFD)	Cumulative Production (MCF)	Cumulative Days
Oct - 1978	16,544	10	1654	16,544	10
Nov	21,950	10	2195	38,494	20
Dec	171,000	28	6107	209,494	48
Jan - 1979	149,500	31	4822	358,994	79
Feb	121,260	26	4664	480,254	105
Mar	121,150	29	4178	601,404	134
Apr	139,650	30	4655	741,054	164
May	106,850	30	3561	847,904	194
June	100,200	29	3455	948,104	223
July	85,600	26	3292	1,033,704	249
Aug	18,700	7	2671	1,052,404	256
Sept	55,000	12	4583	1,107,404	268
Oct	70,725	19	3722	1,178,129	287
Nov	60,425	29	2083	1,238,554	316
Dec	96,775	30	3225	1,335,329	346
Jan - 1980	81,075	31	2615	1,416,404	377
Feb	68,975	28	2463	1,485,379	405
Mar	69,150	27	2561	1,554,529	432
Apr	69,575	30	2319	1,624,104	462
May	60,650	28	2166	1,684,754	490
June	63,050	29	2174	1,747,804	519

Shut-in August 8, 1979 for PBU

Cumulative Production = 1,052,404 MCF
Cumulative Days = 256 Days
Last Rate = 2671 MCFD

$$\text{Horner Time} = \frac{1{,}052{,}404\ \text{MCF}}{2671\ \text{MCFD}} = 394\ \text{Days}$$

TABLE IV

DATA FOR PRESSURE BUILDUP TEST ANALYSIS

OPERATOR:	Mitchell Energy
WELL NAME:	Muse-Duke No. 1
DEPTH TO TOP OF FORMATION (FT.):	11220.
PERFORATED INTERVAL:	11220-11420
TOTAL NET PAY (FT):	50.
PERFORATED NET PAY (FT):	50.
WELL BORE RADIUS (FT):	0.3300
PRODUCTION TIME (HR):	9456.0
PRESSURE AT SHUT-IN (PSI):	1262.0
INITIAL RESERVOIR PRESSURE (PSI):	6750.0
BOTTOM HOLE TEMPERATURE (DEG F):	286.
DRY GAS FLOW RATE (MCF/D):	2671.
WET GAS FLOW RATE (MCF/D):	2672.
TOTAL POROSITY (FRACTION):	0.03600
WATER SATURATION (FRACTION):	0.50000
GAS POROSITY (FRACTION):	0.01800
SEPARATOR GAS GRAVITY:	0.65000
GAS-CONDENSATE RATIO (SCF/STB):	900000.
CONDENSATE GRAVITY (DEG API):	55.0
GAS EQUIVALENT OF CONDENSATE (SCF/STB):	820.
WET GAS SPECIFIC GRAVITY:	0.65327

GAS PROPERTIES AT INITIAL PRESSURE AND TEMPERATURE

GAS VISCOSITY (CP):	0.02700
GAS COMPRESSIBILITY (PSI-1):	0.0000892
Z-FACTOR:	1.15117
GAS FORMATION VOLUME FACTOR (RB/MCF):	0.64053

PRESSURE BUILDUP TEST ANALYSIS RESULTS

HORNER SLOPE (PSIA**2/CP-CYCLE):	0.39801E 09
PRESSURE AT ONE HOUR (PSIA**2/CP):	-0.48940E 09
FORMATION GAS PERMEABILITY (MD):	0.16346
APPARENT SKIN FACTOR:	-6.7011
RADIUS OF INVESTIGATION (FT):	
END OF PRODUCTION PERIOD:	6134.
END OF HORNER STRAIGHT LINE:	1652.
END OF BUILDUP TEST:	1652.

TABLE IV
(Continued)

OPERATOR: Mitchell Energy
WELL NAME: Muse-Duke No. 1
TYPE OF STIMULATION: Post MHF

SHUT-IN TIME HOURS	BHP PSIA	HORNER TIME	PSEUDO PRESSURE PSIA**2/CP	DELTA PSEUDO PRESSURE
0.00000	1262.0	0.00000	0.11257E 09	0.00000
0.25000	1406.0	24577.	0.13963E 09	0.27065E 08
0.50000	1446.0	12289.	0.14715E 09	0.34583E 08
0.75000	1467.0	8193.0	0.15110E 09	0.38530E 08
1.0000	1494.0	6145.0	0.15617E 09	0.43604E 08
1.5000	1528.0	4097.0	0.16337E 09	0.50796E 08
2.0000	1556.0	3073.0	0.16943E 09	0.56861E 08
2.5000	1580.0	2458.6	0.17463E 09	0.62059E 08
3.0000	1599.0	2049.0	0.17874E 09	0.66174E 08
4.0000	1633.0	1537.0	0.18611E 09	0.73537E 08
6.0000	1684.0	1025.0	0.19715E 09	0.84583E 08
8.0000	1727.0	769.00	0.20647E 09	0.93896E 08
10.000	1761.0	615.40	0.21412E 09	0.10155E 09
12.000	1791.0	513.00	0.22141E 09	0.10885E 09
16.000	1840.0	385.00	0.23333E 09	0.12076E 09
20.000	1886.0	308.20	0.24451E 09	0.13194E 09
24.000	1923.0	257.00	0.25351E 09	0.14094E 09
33.000	1963.0	187.18	0.26323E 09	0.15066E 09
41.000	2045.0	150.85	0.28429E 09	0.17172E 09
49.000	2091.0	126.39	0.29663E 09	0.18406E 09
53.000	2112.0	116.92	0.30226E 09	0.18969E 09
61.000	2154.0	101.72	0.31352E 09	0.20095E 09
69.000	2189.0	90.043	0.32290E 09	0.21033E 09
77.000	2224.0	80.792	0.33229E 09	0.21972E 09
85.000	2257.0	73.282	0.34130E 09	0.22873E 09
93.000	2284.0	67.065	0.34918E 09	0.23661E 09
101.00	2315.0	61.832	0.35822E 09	0.24565E 09
109.00	2339.0	57.367	0.36522E 09	0.25265E 09
112.00	2352.0	55.857	0.36901E 09	0.25644E 09
121.00	2379.0	51.777	0.37689E 09	0.26432E 09
133.00	2415.0	47.195	0.38739E 09	0.27482E 09
145.00	2450.0	43.372	0.39760E 09	0.28503E 09
157.00	2481.0	40.134	0.40664E 09	0.29407E 09
169.00	2510.0	37.355	0.41532E 09	0.30275E 09
181.00	2539.0	34.945	0.42440E 09	0.31183E 09
193.00	2563.0	32.834	0.43192E 09	0.31935E 09
205.00	2588.0	30.971	0.43975E 09	0.32718E 09
217.00	2616.0	29.313	0.44852E 09	0.33595E 09
229.00	2640.0	27.830	0.45604E 09	0.34347E 09
241.00	2668.0	26.494	0.46481E 09	0.35224E 09
253.00	2689.0	25.285	0.47139E 09	0.35882E 09
265.00	2711.0	24.185	0.47828E 09	0.36571E 09
277.00	2732.0	23.180	0.48486E 09	0.37229E 09
289.00	2754.0	22.260	0.49182E 09	0.37925E 09
301.00	2775.0	21.412	0.49879E 09	0.38622E 09
313.00	2794.0	20.629	0.50510E 09	0.39253E 09
325.00	2812.0	19.905	0.51108E 09	0.39851E 09
337.00	2830.0	19.231	0.51705E 09	0.40448E 09
349.00	2852.0	18.605	0.52436E 09	0.41179E 09
360.00	2864.0	18.067	0.52834E 09	0.41577E 09
374.00	2915.0	17.428	0.54527E 09	0.43270E 09
398.00	2909.0	16.437	0.54328E 09	0.43071E 09
422.00	2932.0	15.559	0.55092E 09	0.43835E 09
446.00	2955.0	14.776	0.55855E 09	0.44598E 09
470.00	2975.0	14.072	0.56519E 09	0.45262E 09
494.00	3005.0	13.437	0.57523E 09	0.46266E 09
518.00	3024.0	12.861	0.58185E 09	0.46928E 09
542.00	3044.0	12.336	0.58881E 09	0.47625E 09
566.00	3065.0	11.855	0.59613E 09	0.48356E 09
602.00	3092.0	11.206	0.60553E 09	0.49296E 09
614.00	3101.0	11.007	0.60867E 09	0.49610E 09
638.00	3124.0	10.630	0.61668E 09	0.50411E 09
662.00	3139.0	10.281	0.62190E 09	0.50933E 09
686.00	3155.0	9.9563	0.62747E 09	0.51490E 09

TABLE V

TRIAXIAL COMPRESSION TEST DATA

MEC: MUSE-DUKE NO. 1

Formation	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	Perpendicular	2.66	3200	0	6.85	0.15	23,879
	11,207	Perpendicular	2.67	3200	0	2.50	0.35	21,491
	11,207	Along	2.67	3200	0	3.68	0.18	21,405
	11,207	Along	2.68	3200	0	2.81	0.14	23,440
COTTON VALLEY LIMESTONE	11,239	Along	2.70	3200	0	5.30	0.16	---
	11,239	Perpendicular	2.69	3200	0	5.84	0.18	37,023
	11,313	Along	2.51	8800	5600	5.15	0.22	29,014
	11,313	Perpendicular	2.52	8800	5600	6.67	0.23	23,146
ANHYDRITE	11,510	Along	2.95	3200	0	7.69	0.23	24,949
	11,510	Along	2.94	3200	0	7.94	0.25	26,004
	11,510	Perpendicular	2.93	3200	0	10.20	0.29	27,000
	11,510	Perpendicular	2.93	3200	0	11.40	0.23	27,530

*Orientation with respect to the core axis.

TABLE VI

PROPORTIONAL LOADING CRITICAL STRESS INTENSITY FACTOR (K_{Ic})

MEC: MUSE-DUKE WELL NO. 1

ZONE	DEPTH (feet)	CONFINING PRESSURE (psi)	BURST (psi)	TEMPERATURE °F	CRITICAL STRESS INTENSITY FACTOR (K_{Ic}) (psi inch)
BOSSIER SHALE	11,121	415	3360	285	580
	11,195	235	1960	285	415
	11,207	170	1400	285	296
COTTON VALLEY LIMESTONE	11,239	390	3105	285	657
	11,336	290	2300	285	397
	11,374	315	2525	285	534
ANHYDRITE	11,510	315	2375	285	410

TABLE VII

DIRECT LOADING CRITICAL STRESS INTENSITY FACTOR (K_{Ic})

MEC: MUSE-DUKE WELL NO. 1

ZONE	DEPTH (feet)	BURST PRESSURE (psi)	TEMPERATURE °F	CRITICAL INTENSITY FACTOR (K_{Ic}) (psi inch)
BOSSIER SHALE	11,207	1850	75	568
COTTON VALLEY LIMESTONE	11,313	1640	75	503
ANHYDRITE	11,505	2340	75	718

TABLE VIII:FRACTURING PROCESS INPUT DATA

WELL COMPLETION DATA

Depth of Formation (Ft.)---------11,200
Depth of Packer (Ft.)------------11,130
Tubing, ID ----------------------2.441
Casing, ID ----------------------4.778
No. Perforations-----------------15
Perforation Dia. (In.)-----------.38

TREATMENT DATA

Type of Gel-----------Versagel
Gel Concentration-----1500-1600
Injection Rate --------22.0 BPM
Treatm't Fl. SP GR----1.020
N---------------------0.5100
K (SLOT)--------------0.037000 LBF/Sec N/SQFT
CW-Fluid Loss COEFF---0.00260 FT/SQRT(MIN)
Spurt Volume----------0. GAL/SQFT
CVC-Spurt Loss COEFF--0.00029 FT/SQRT(MIN)
Spurt Time------------0. MIN.
Damage Ratio----------1.0
Apparent Viscosity--869. CP @ 0.995 IN.WIDTH

FORMATION DATA

Young's Modulus---------------5.76+06 PSI
Permeability------------------0.09 Millidarcys
Porosity----------------------8.5 Percent
Reservoir Fl. Compres'blty----1.66E-04 1/PSI
Reservoir Fl. Viscosity-------0.02 CPS
BHTP -------------------------8607. PSI
Reservoir Fl. Pressure--------6350. PSI
Closure Pressure--------------7100. PSI
Gross Fracture Height---------210. FT
Net Fracture Height-----------36. FT
Wellbore Diameter-------------5.50 IN
Drainage Radius---------------2640. FT
Well Spacing------------------640 ACRES

TABLE IX:CALCULATED FRACTURE DIMENSIONS

DESIGN NO.	VOLUME Total GAL	VOLUME PAD / 1000	Created Length Ft.	Width Avg. In.	Prop Length Ft.	Prop Height Ft.	PROP Total Sx.	PROP Capacity Ft.	RELATIVE Incr. (T)	PROD Eff. %
1	974.3	200.0	3522.2	0.995	2708.4	199.7	29652.	5.53	4.5	94

TABLE X: PUMPING SCHEDULE

95,000 Gallons Treated Water Prepad*
70,000 Gallons Versagel 1525 Pad
70,000 Gallons Versagel 1525, 1#/Gal. Oklahoma #1
60,000 Gallons Versagel 1525 Spacer
15,000 Gallons Versagel 1524, 1#/Gal. 20-40 R/A Sand
15,000 Gallons Versagel 1524, 2#/Gal. 20-40 R/A Sand
20,000 Gallons Versagel 1524, 3#/Gal. 20-40 R/A Sand
90,000 Gallons Versagel 1524, 4#/Gal. 20-40 R/A Sand
180,000 Gallons Versagel 1622, 5#/Gal. 20-40 R/A Sand
200,000 Gallons Versagel 1621, 5#/Gal. 20-40 R/A Sand
120,000 Gallons Versagel 1600, 5#/Gal. 20/40 R/A Sand
2,850 Gallons Treated Water Displacement*

*The Treated Water will utilize 10#/Gal. brine water as the base fluid.

TABLE XI: DEPOSITIONAL PROFILES

AT THE END OF PUMPING:

CARRY DISTANCE	2708.4 FT.
Max. BED Height	3.9 FT.
Avg. BED Height	2.2 FT.
% Prop Deposited	4.1 %

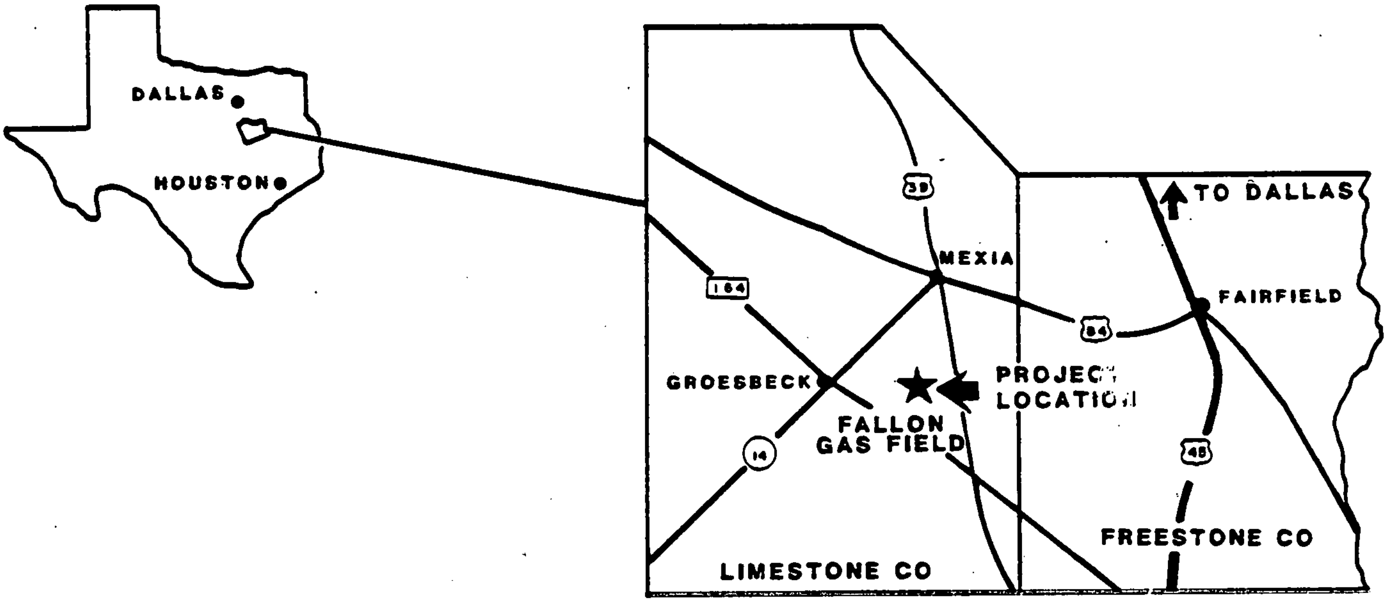
DISTANCE FROM WELL	DEPOSITED PROP BED HEIGHT FT.		SUSPENDED PROP	
	END OF PUMPING	FINAL	HEIGHT/FT.	CONC.#/GAL.
12.1	3.6	62.1	210.0	5.0
109.3	3.6	61.9	209.3	5.0
206.5	3.8	61.9	208.7	5.0
303.6	3.7	61.8	208.1	5.0
400.8	3.6	61.7	207.4	5.1
498.0	3.4	62.6	206.4	5.1
655.9	3.3	63.0	205.4	5.1
813.7	3.1	63.1	204.4	5.1
971.6	2.9	63.3	203.3	5.1
1129.5	2.7	63.7	202.3	5.2
1287.4	2.5	63.1	201.4	5.2
1433.2	2.3	63.3	200.5	5.2
1278.9	2.1	64.2	199.6	5.3
1724.7	1.8	61.7	198.8	5.3
1882.5	1.5	61.6	197.9	5.3
2040.4	1.3	51.2	194.5	4.3
2125.5	1.1	47.5	194.0	4.3
2210.5	1.0	48.3	193.5	4.3
2295.5	0.8	49.3	193.0	4.4
2380.5	0.5	50.3	192.5	4.4
2465.5	0.4	37.9	187.7	3.3
2502.0	0.3	34.1	187.5	3.3
2538.4	0.3	33.7	187.2	3.3
2574.8	0.2	27.2	180.6	2.2
2611.3	0.1	25.5	180.3	2.2
2647.7	0.1	15.7	170.9	1.1
2684.1	0.0	12.4	170.5	1.1

EQUIVALENT BED

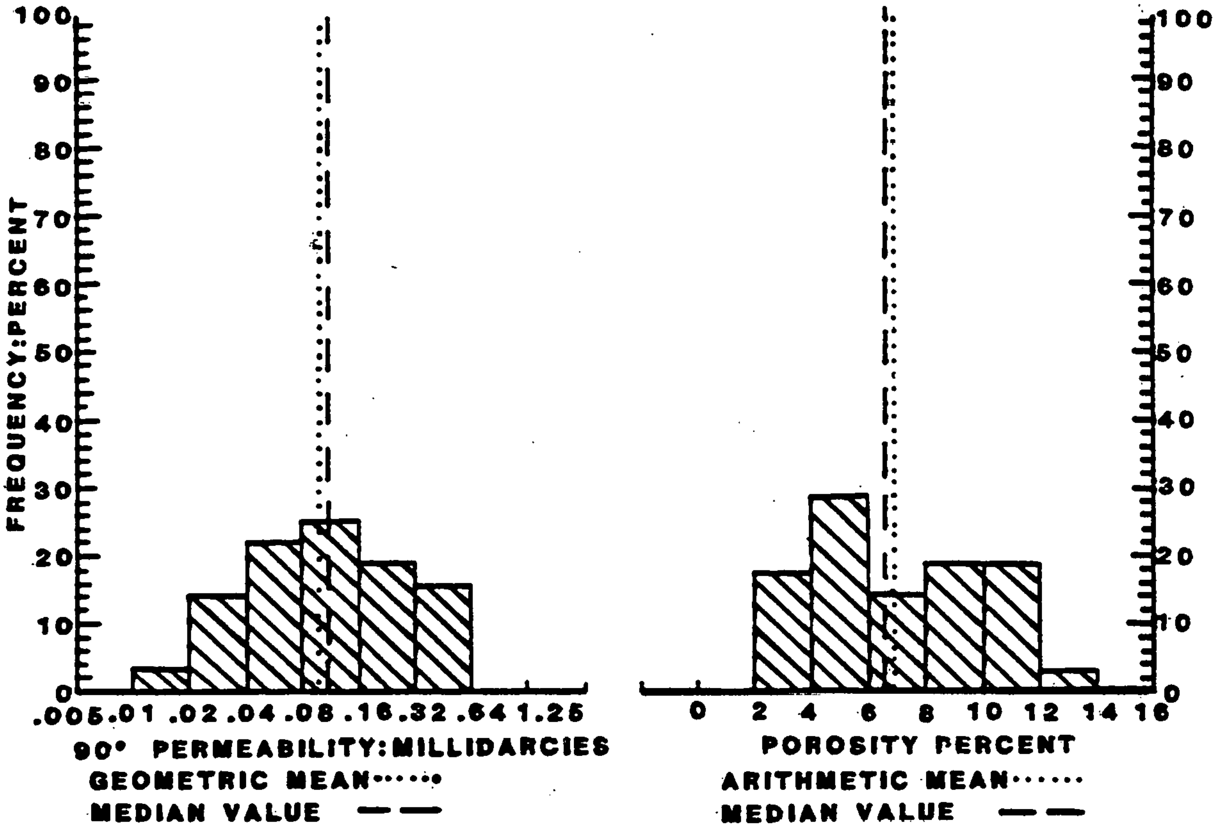
Length = 2708. FT.
Height = 199.7 FT.
BED Concentration = 2741. LB/1000 SQ. FT.

TABLE XII: TREATMENT SUMMARY

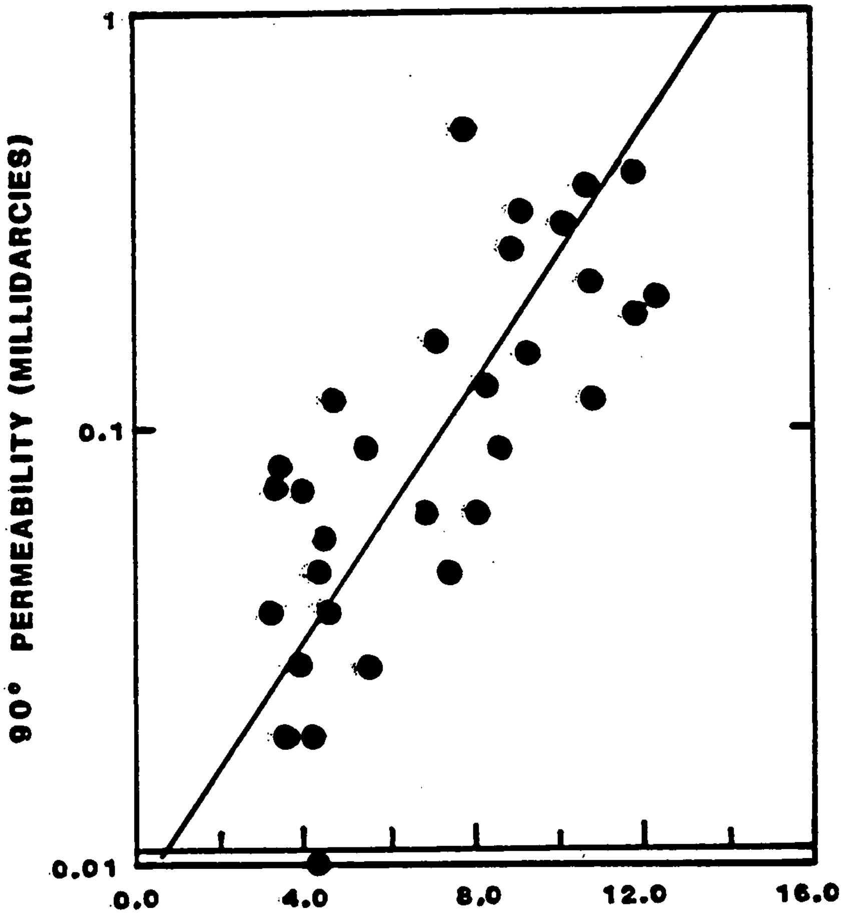
	DESIGN	ACTUAL
Hydraulic Horsepower (HHP)	5,182	5,085
Surface Injection Pressure (PSI)	9,610	9,100
Injection Rate (BPM)	22	22.8
Pipe Friction (PSI)	5,785	--
Total Versagel (Gal.)	840,000	793,000
Total 20-40 Ottawa Sand (Lbs.)	2,965,000	2,730,000
Total Oklahoma #1 (Lbs.)	70,000	70,000
Total Water Required (Bbls.)	22,500	21,223
Propped Fracture Length (Ft.)	2,708	1,500
Gel Pumping Time (Hrs.)	16.1	17



WELL SIGHT LOCATION
FIGURE 1

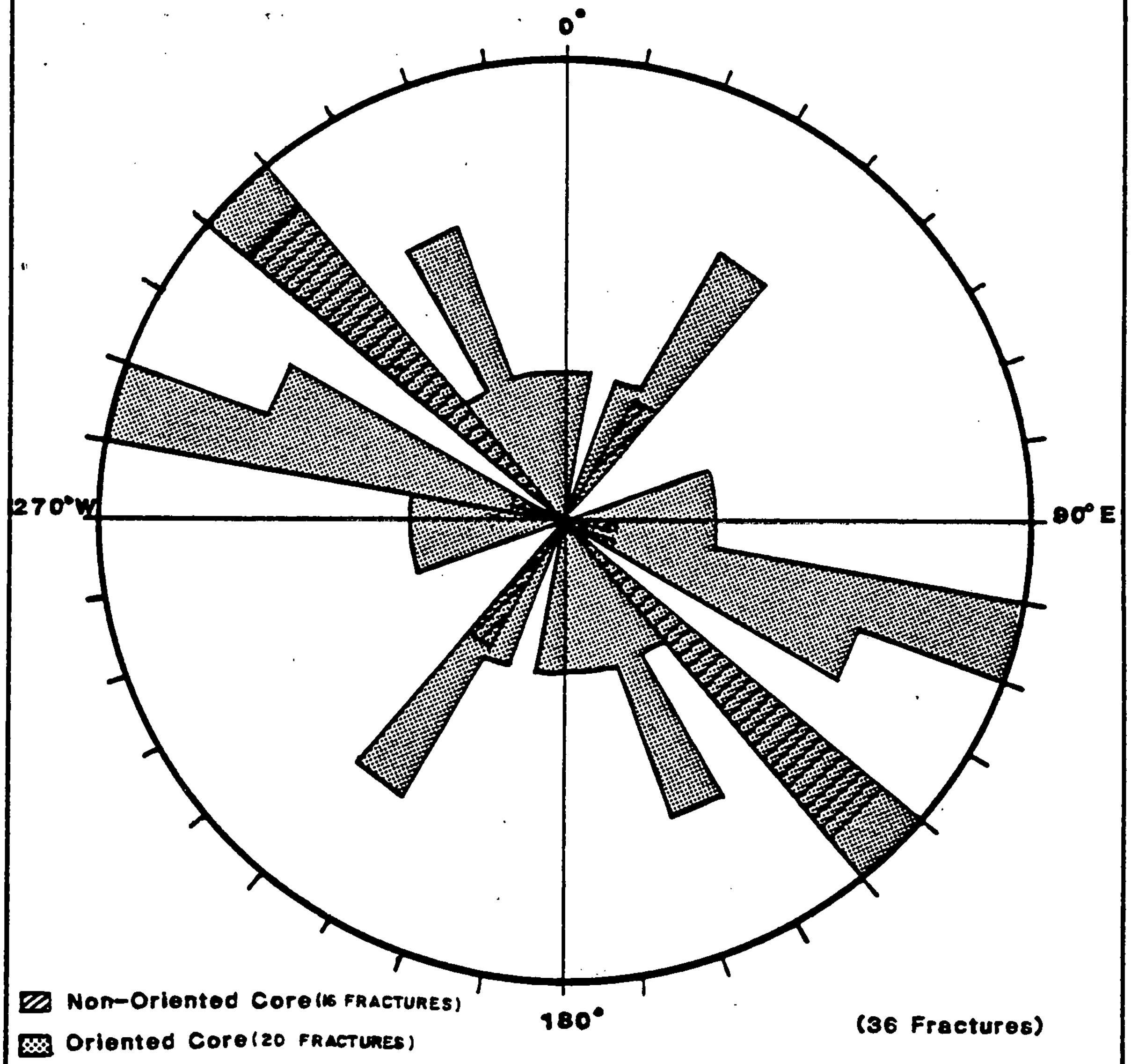


PERMEABILITY AND POROSITY HISTOGRAMS
MITCHELL ENERGY CORPORATION
LAWRENCE NO.1 & MUSE-DUKE NO.1 COMBINED
LIMESTONE COUNTY, TEXAS
FIGURE 2

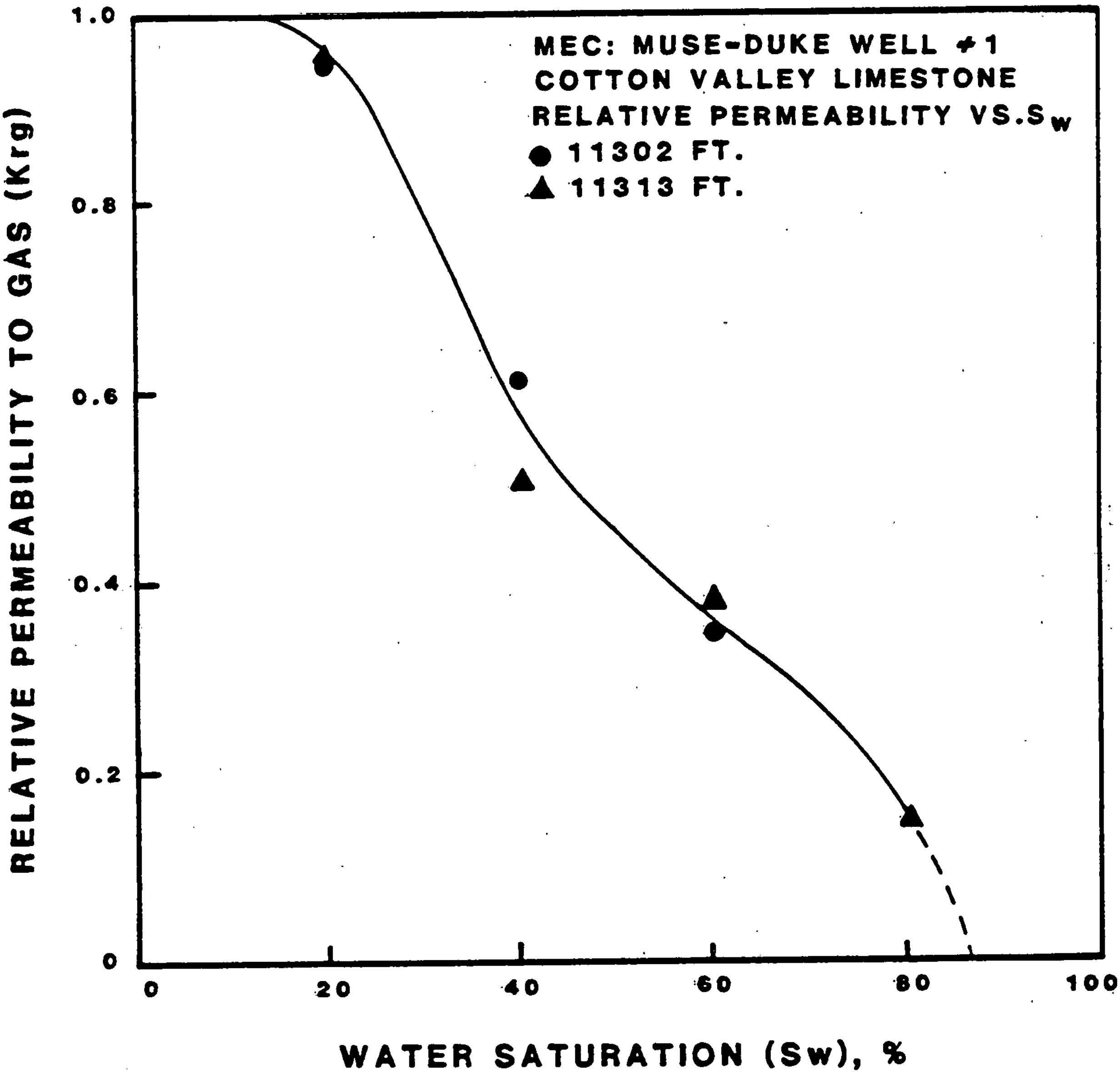


PERMEABILITY VS. POROSITY

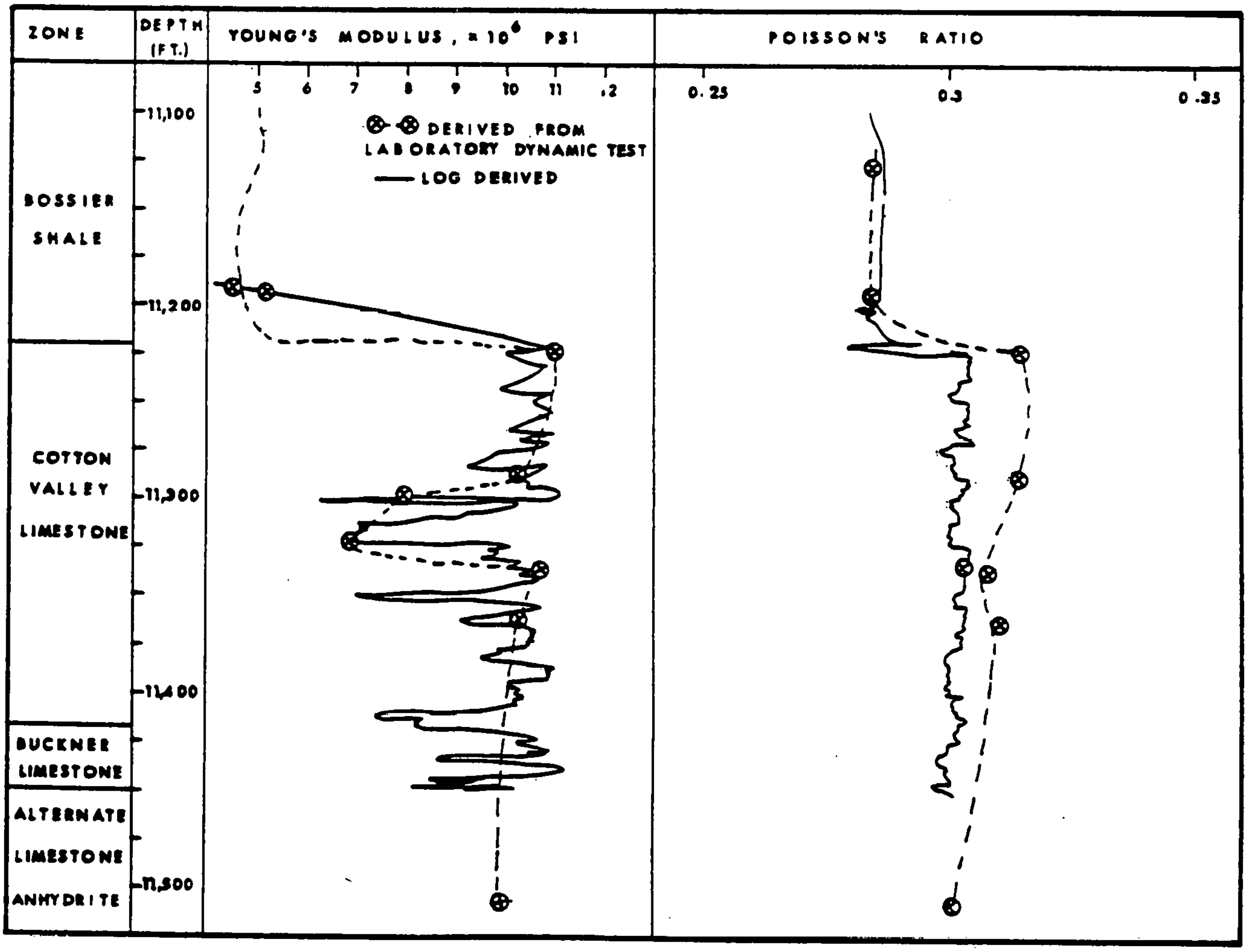
MITCHELL ENERGY CORPORATION
LAWRENCE NO.1 & MUSE-DUKE NO.1
COMBINED
LIMESTONE COUNTY, TEXAS
FIGURE 3



DISTRIBUTION OF FRACTURE ORIENTATION
COTTON VALLEY LIMESTONE
MITCHELL ENERGY CORPORATION
NO.1 MUSE-DUKE
NORTH PERSONVILLE FIELD
LIMESTONE COUNTY, TEXAS
FIGURE 4

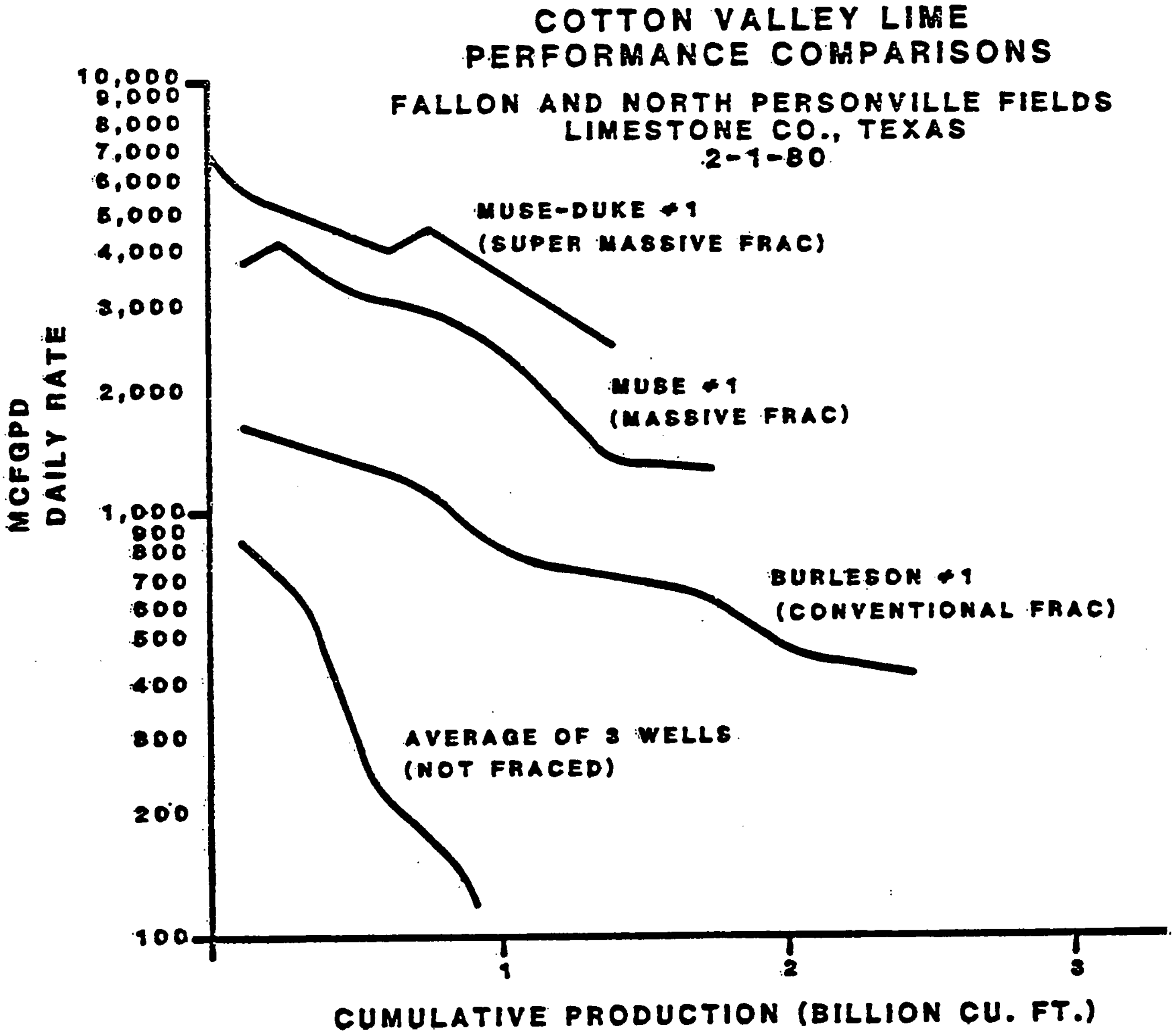


RELATIVE PERMEABILITY TO GAS AS A FUNCTION OF WATER SATURATION.
MEC: MUSE-DUKE WELL No.1
FIGURE 5



DYNAMIC PROPERTY VARIATION WITH DEPTH

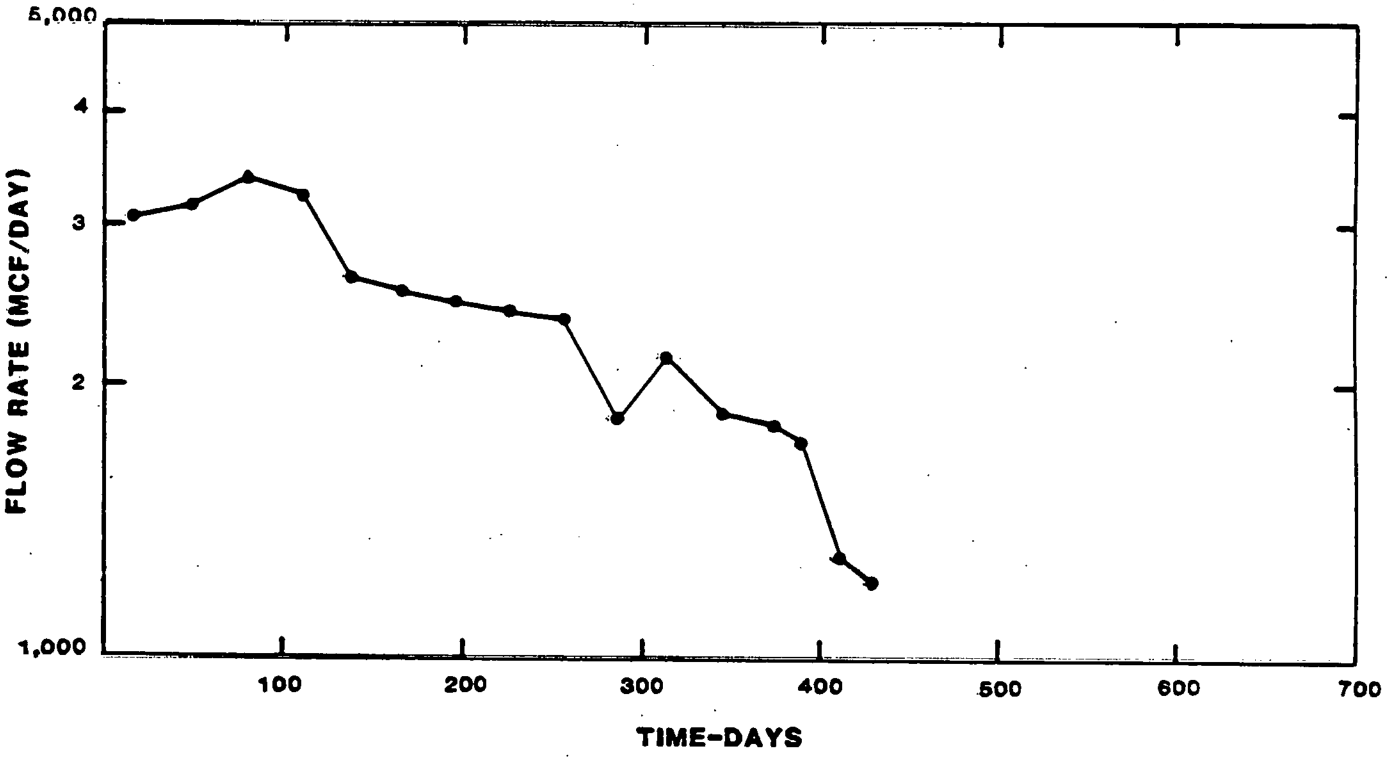
MITCHELL ENERGY CORPORATION
MUSE-DUKE WELL NO. 1
FIGURE 6



COTTON VALLEY LIME PERFORMANCE COMPARISONS

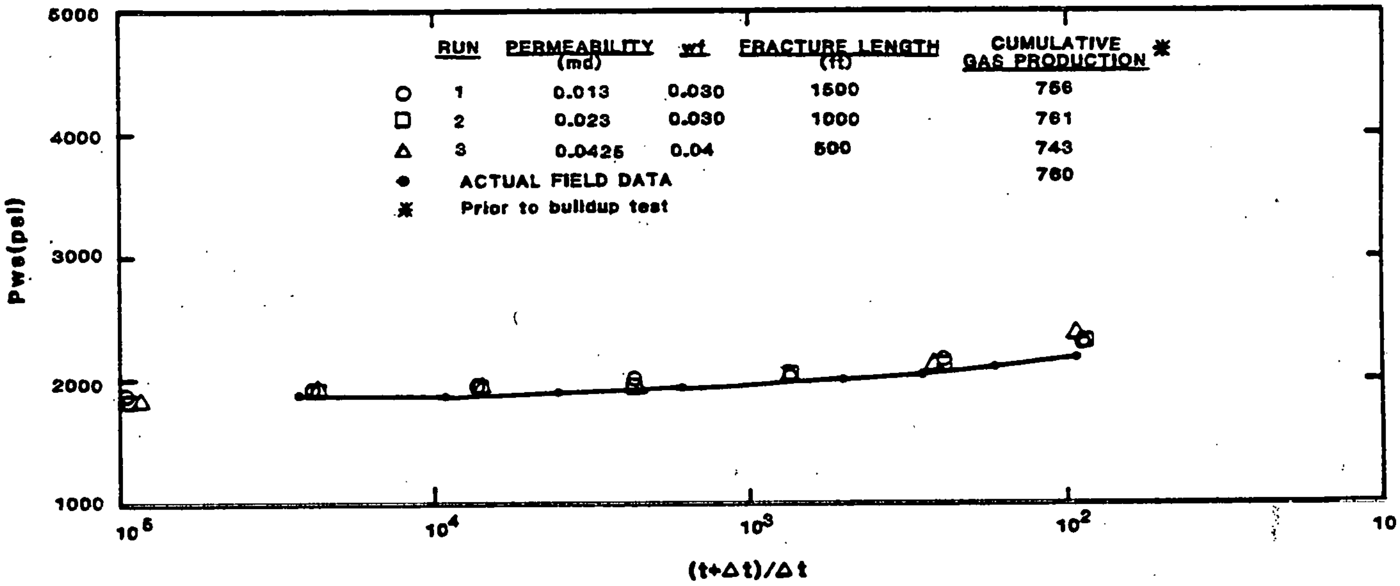
FALLON AND NORTH PERSONVILLE FIELDS
LIMESTONE CO., TEXAS
2-1-80

FIGURE 7



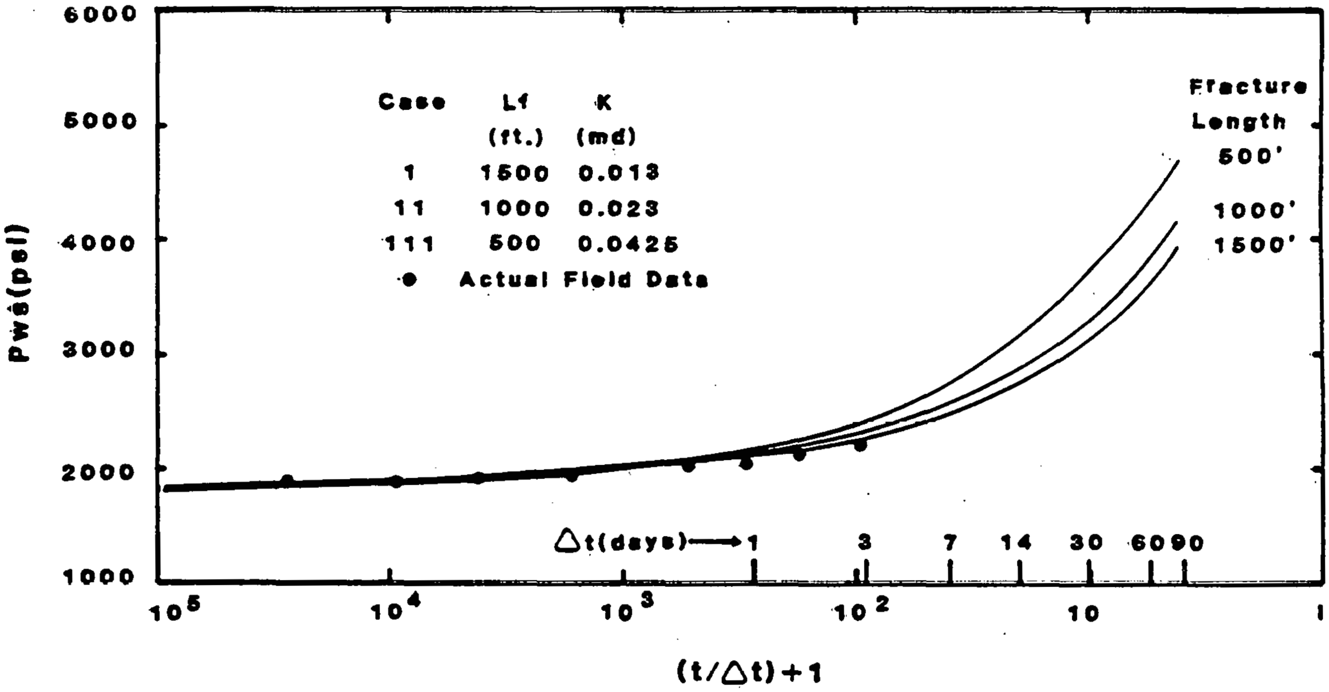
PRODUCTION DECLINE CURVE - #1 MUSE

FIGURE 8



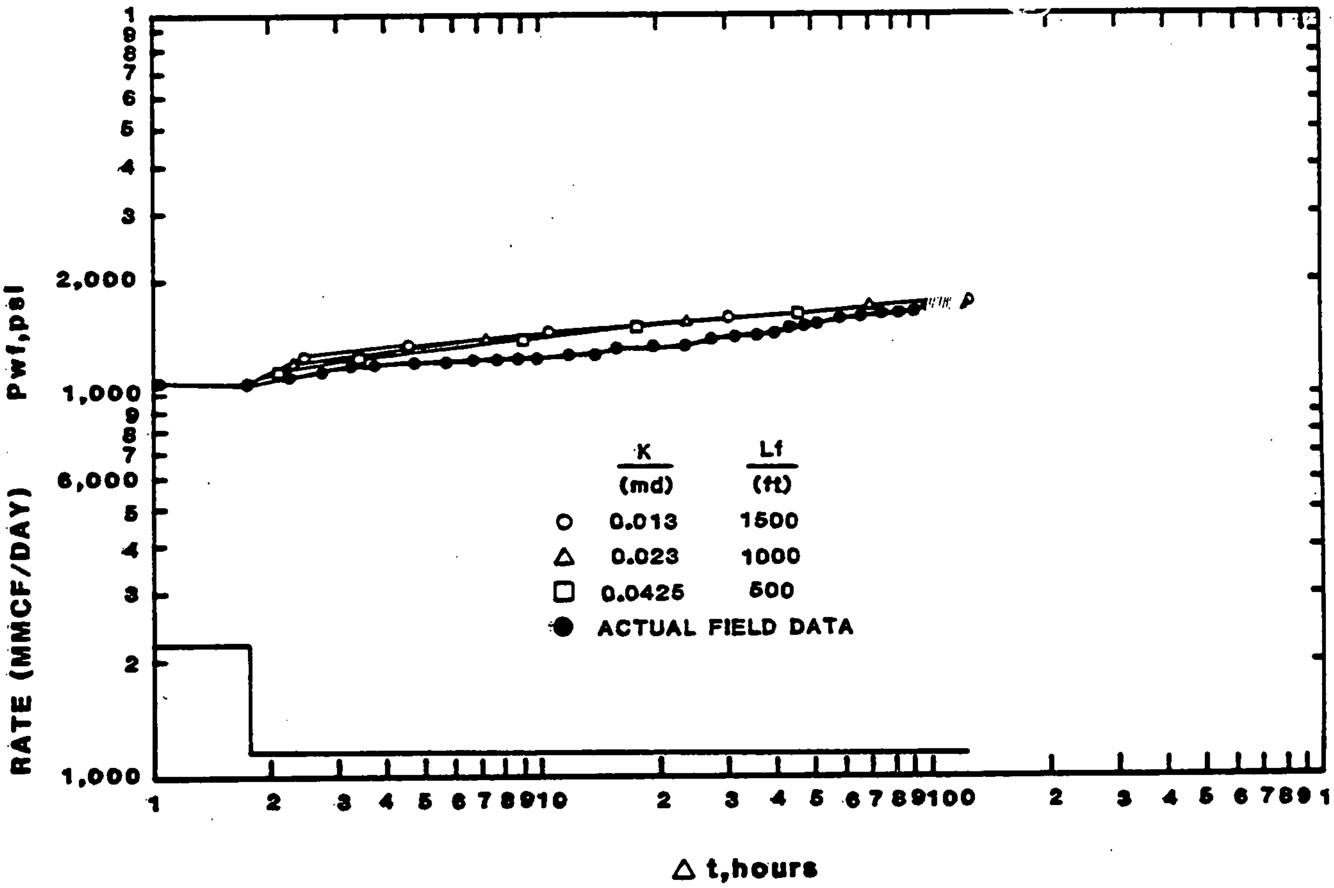
POST FRACTURE BOTTOM HOLE PRESSURE BUILDUP - #1 MUSE

FIGURE 9



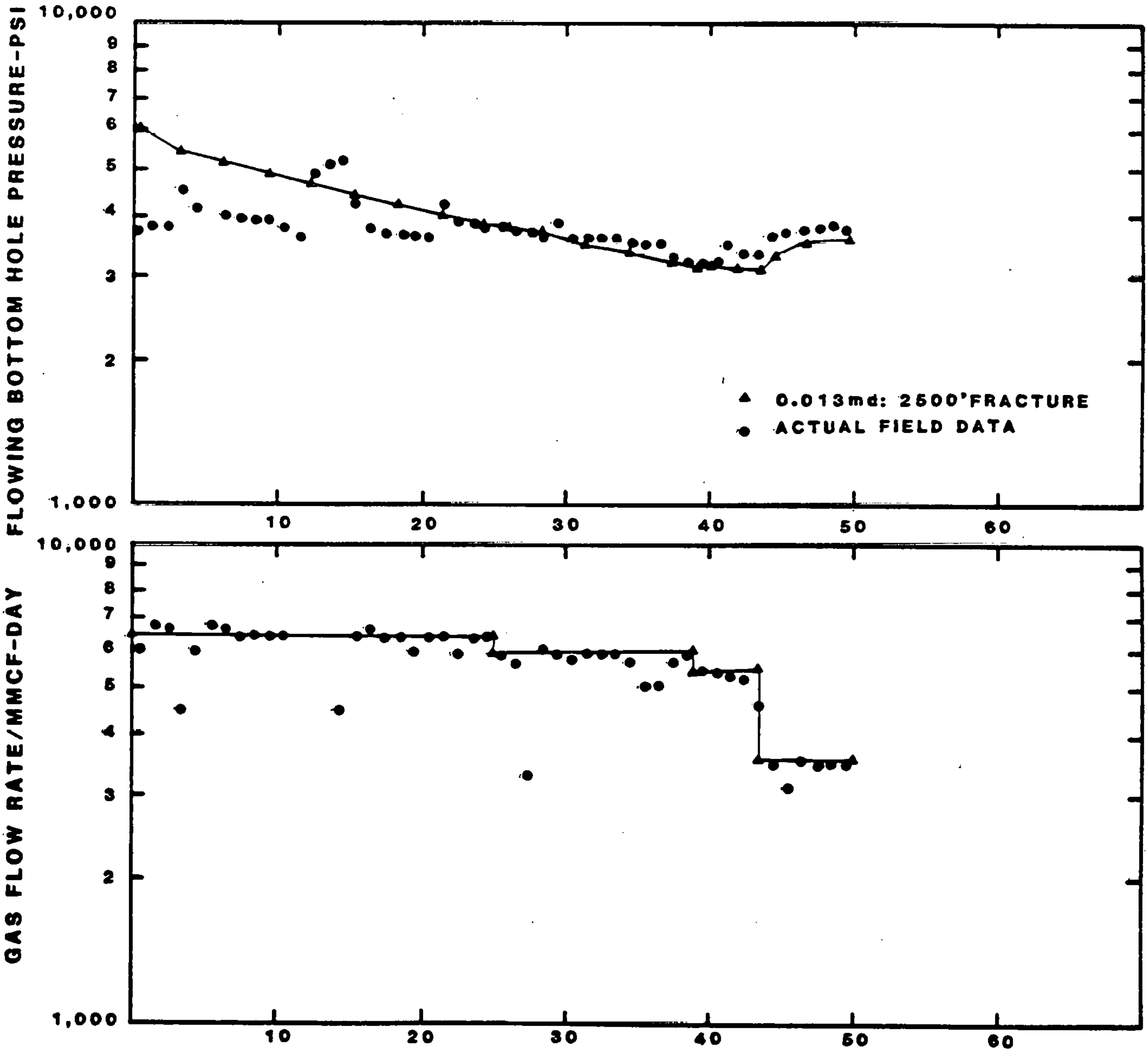
POST FRACTURE BOTTOM HOLE PRESSURE BUILDUP TEST - #1 MUSE

FIGURE 10



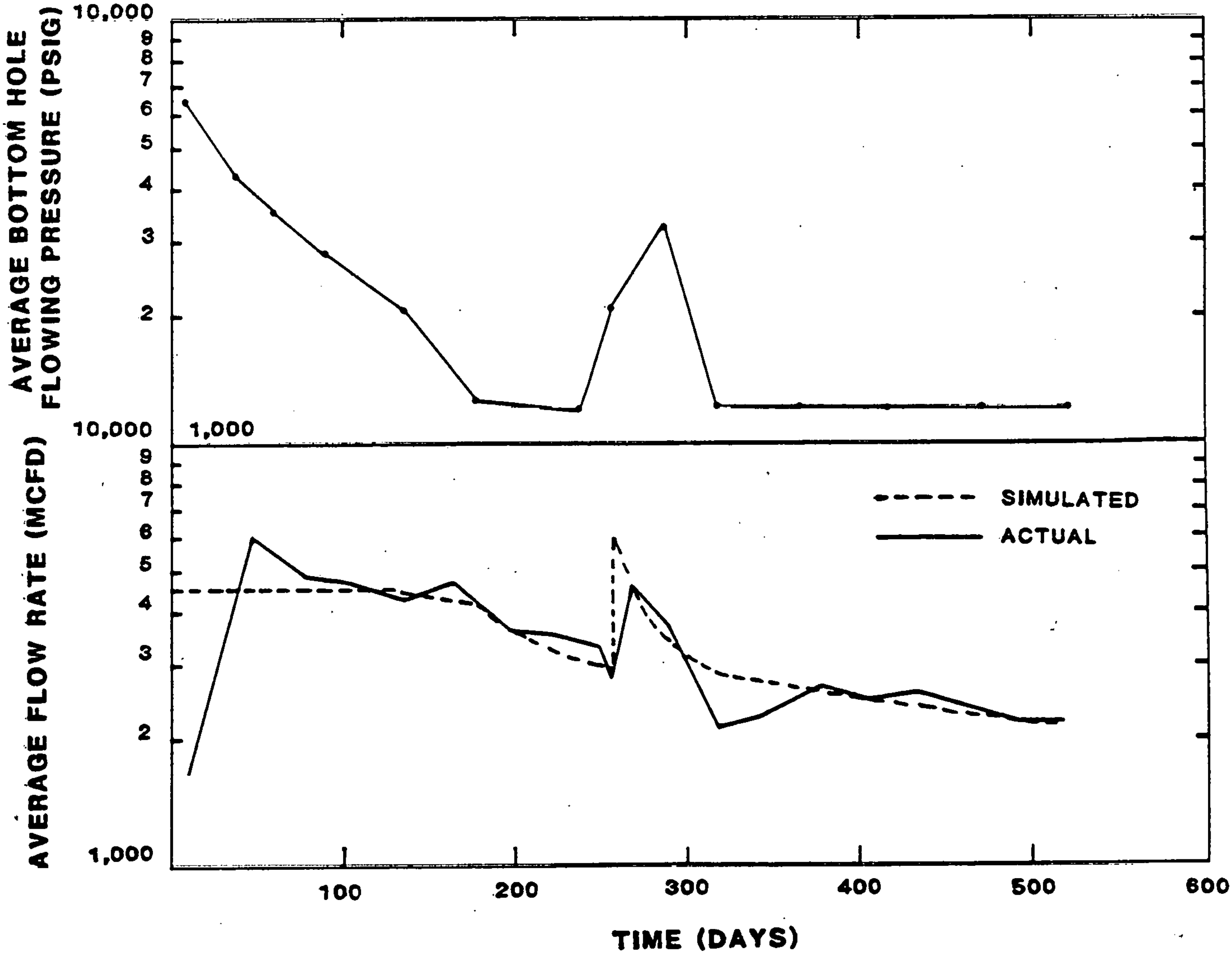
HISTORY MATCH OF TWO RATE TEST - #1 MUSE

FIGURE 11

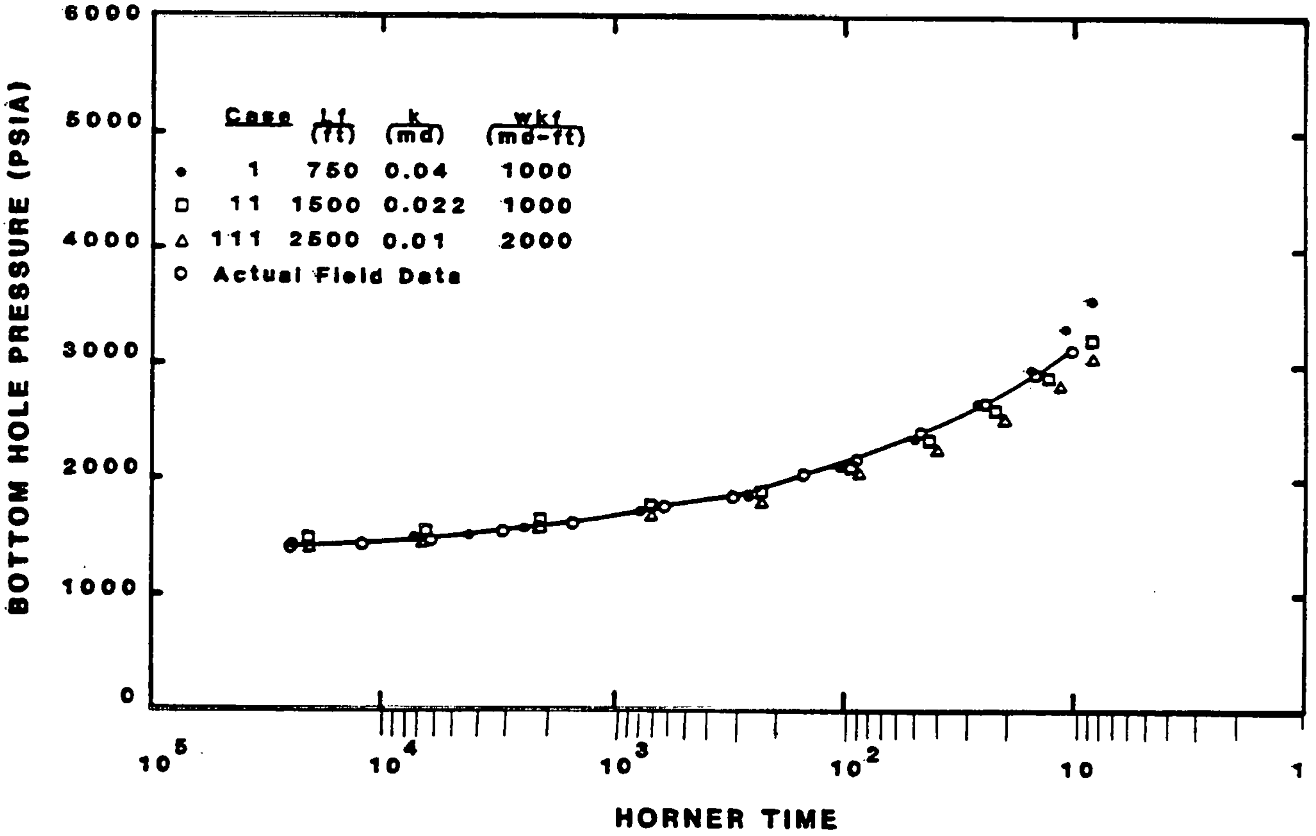


HISTORY MATCH OF FIRST DRAWDOWN - #1 MUSE-DUKE

FIGURE 12



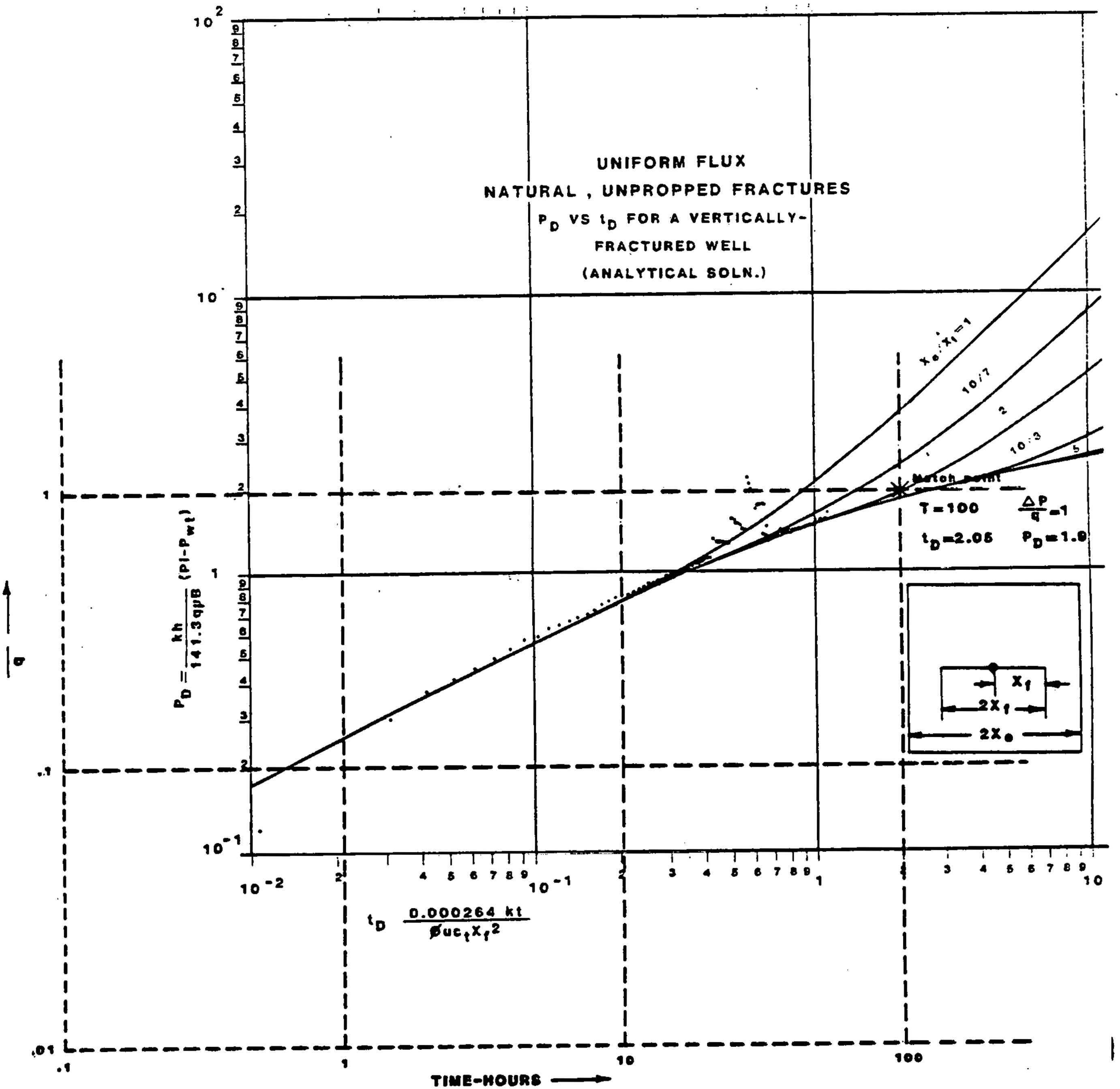
AVERAGE FLOW RATE (MCFD) AND BHFP (PSIG)
VS TIME (DAYS)
MITCHELL ENERGY CORPORATION
MUSE-DUKE WELL NO. 1
LIMESTONE COUNTY, TEXAS
FIGURE 13



MITCHELL ENERGY CORPORATION

MUSE-DUKE WELL NO.1
LIMESTONE COUNTY, TEXAS

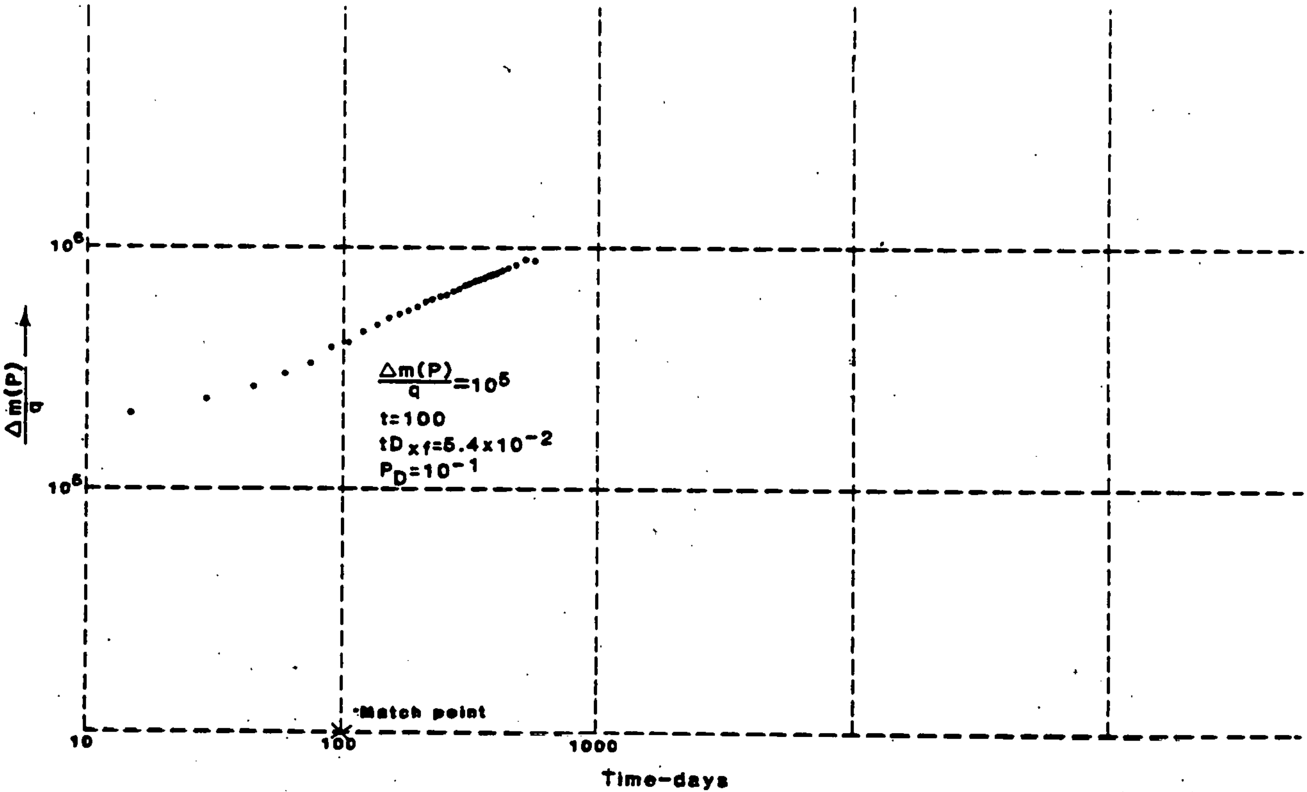
FIGURE 14



PRE MHF PRODUCTION DATA

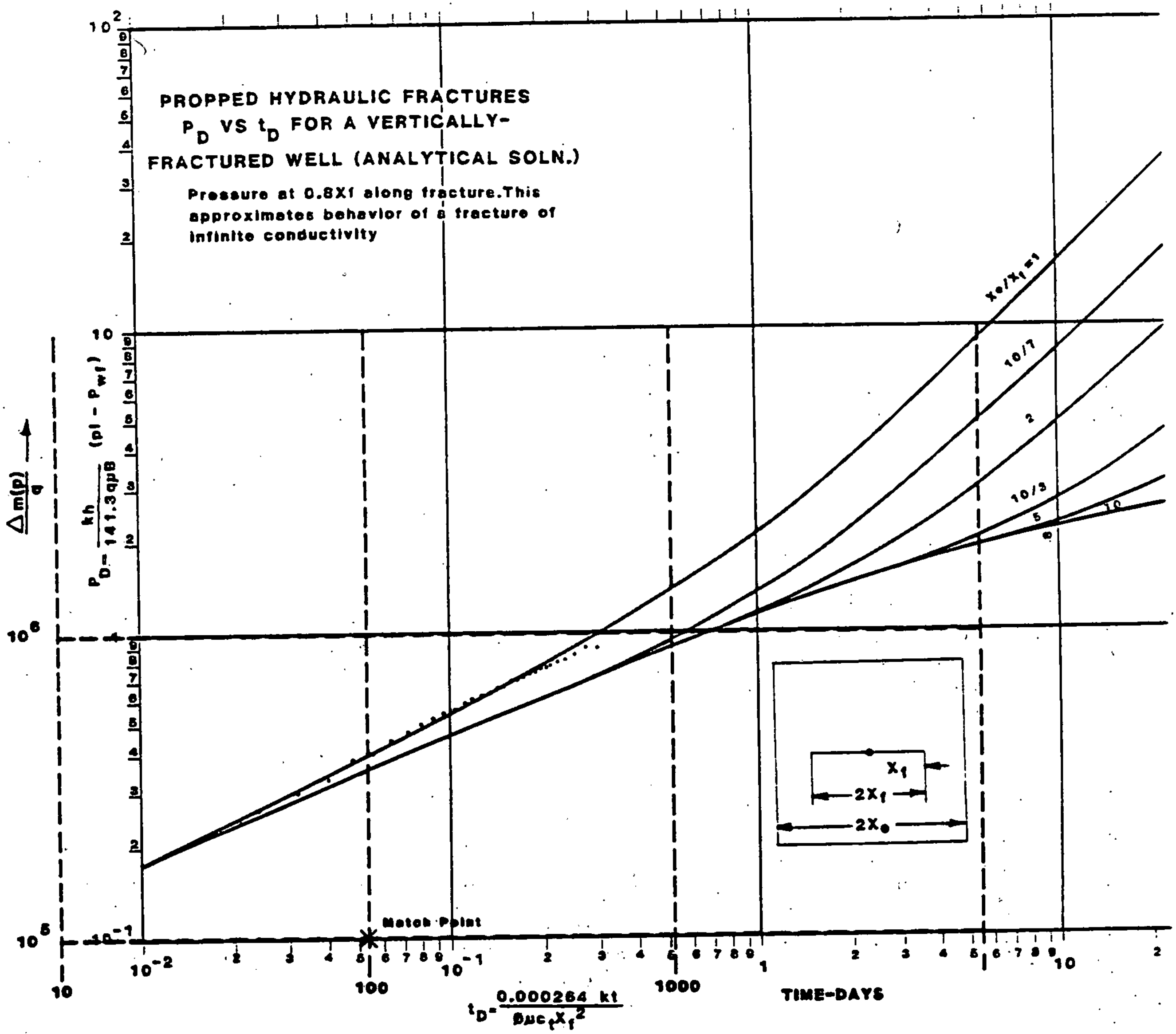
MUSE DUKE - 1

FIGURE 15

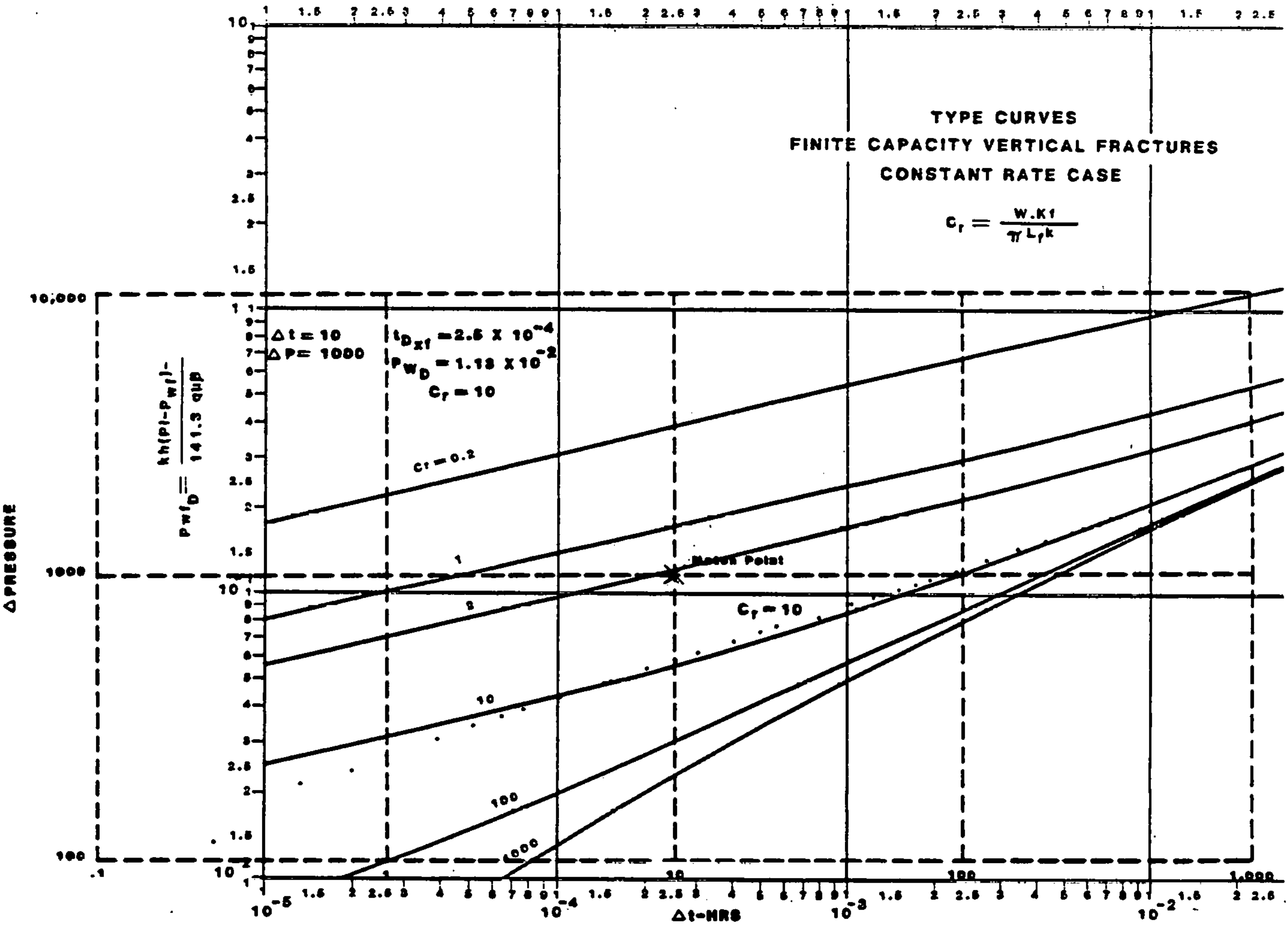


POST MHF PRODUCTION DATA

MUSE DUKE-1
FIGURE 16



MUSE DUKE-1
POST MHF PRODUCTION DATA
FIGURE - 17

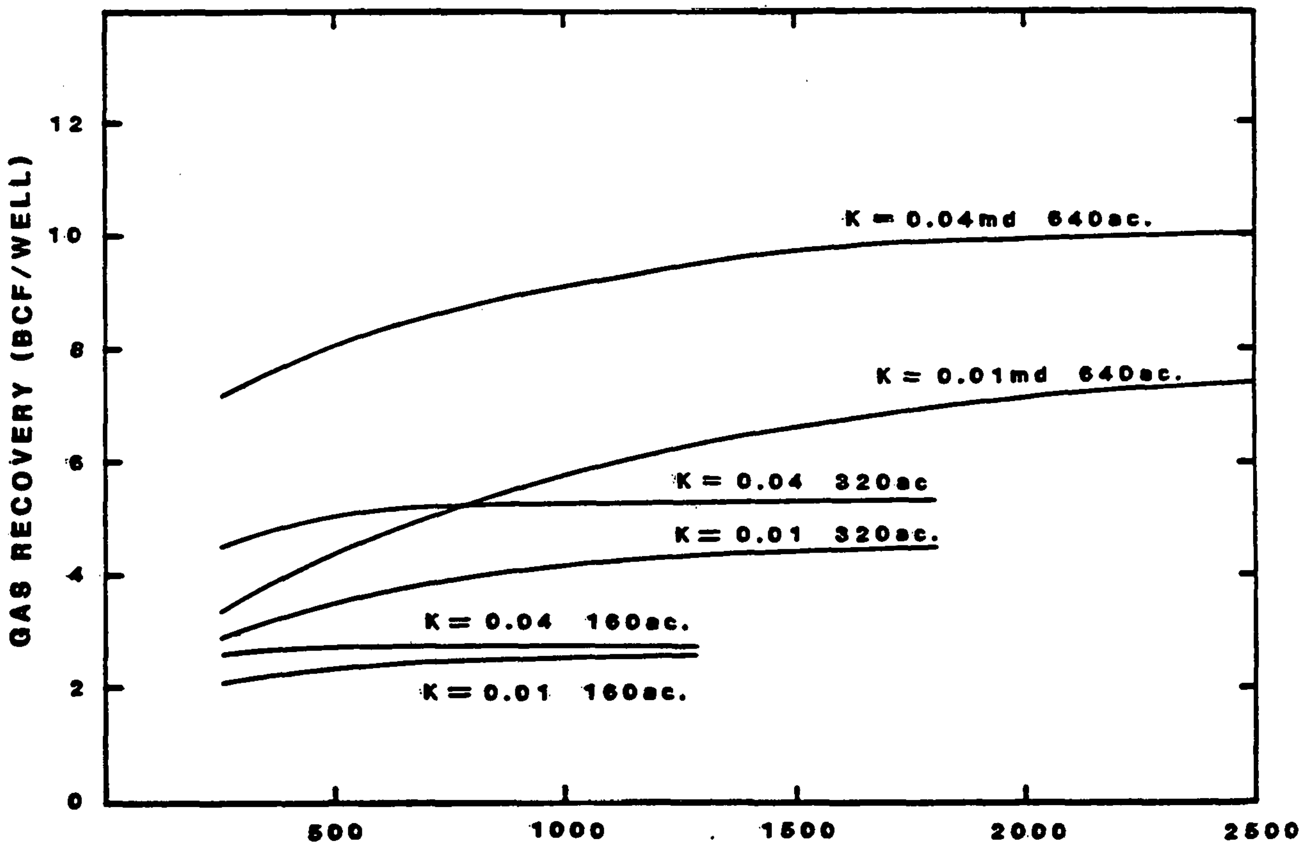


POST MHF PRESSURE BUILD-UP DATA

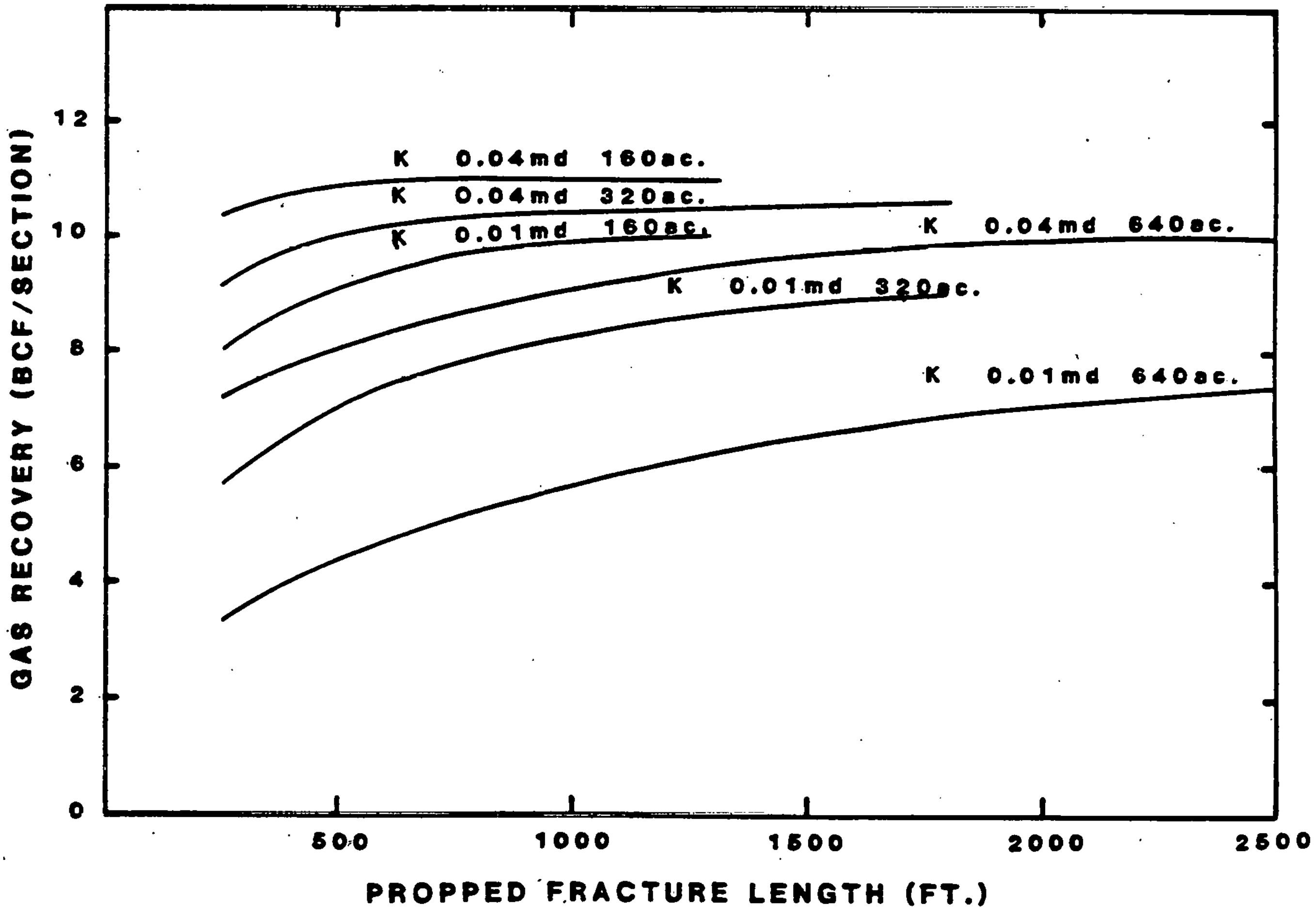
MUSE DUKE - 1

FIGURE 18

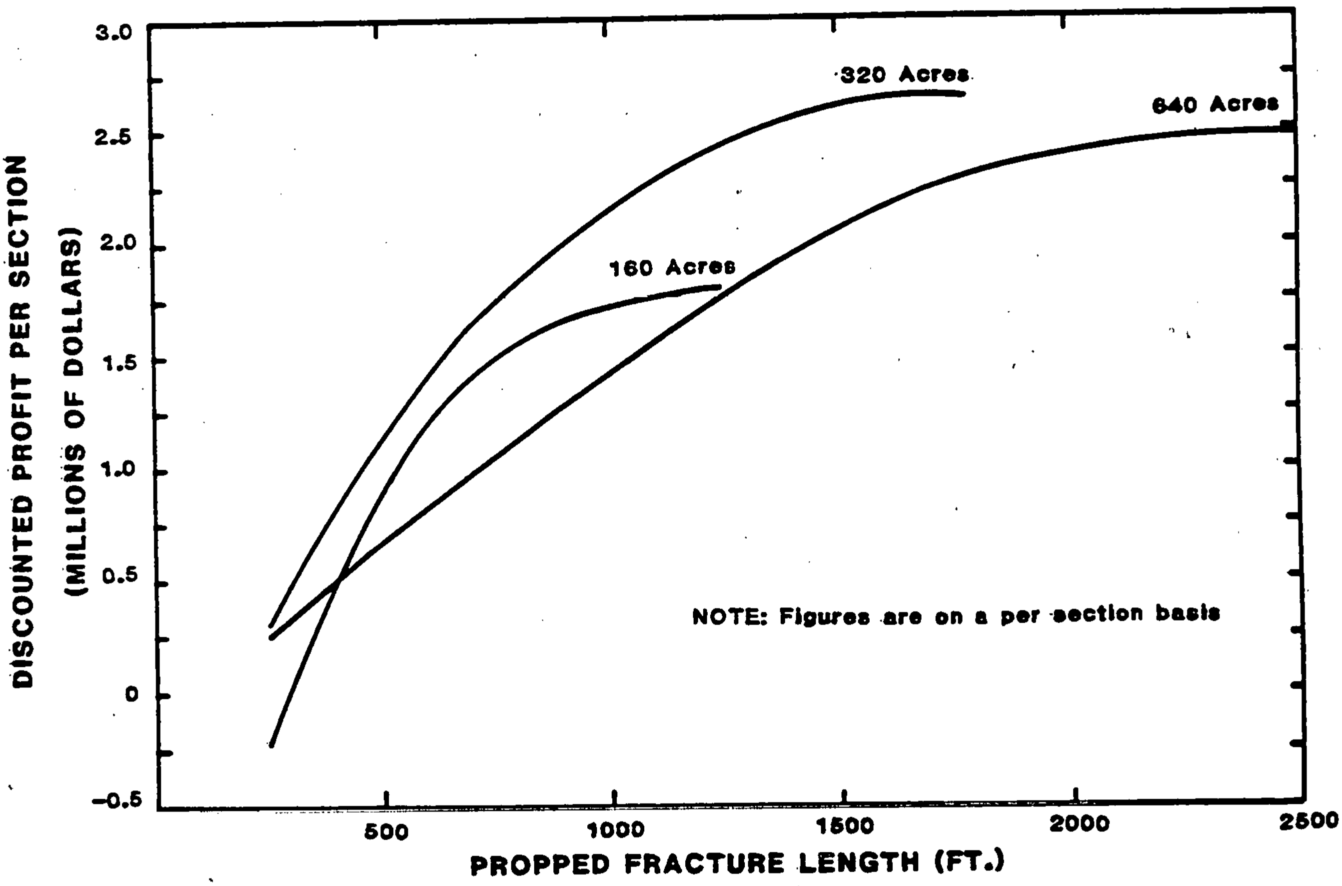
$$t_D = \frac{0.000264\ kt}{\phi \mu C\ L_f^2}$$



ULTIMATE GAS RECOVERY (PER WELL) VS.
PROPPED FRACTURE LENGTH
FIGURE 19

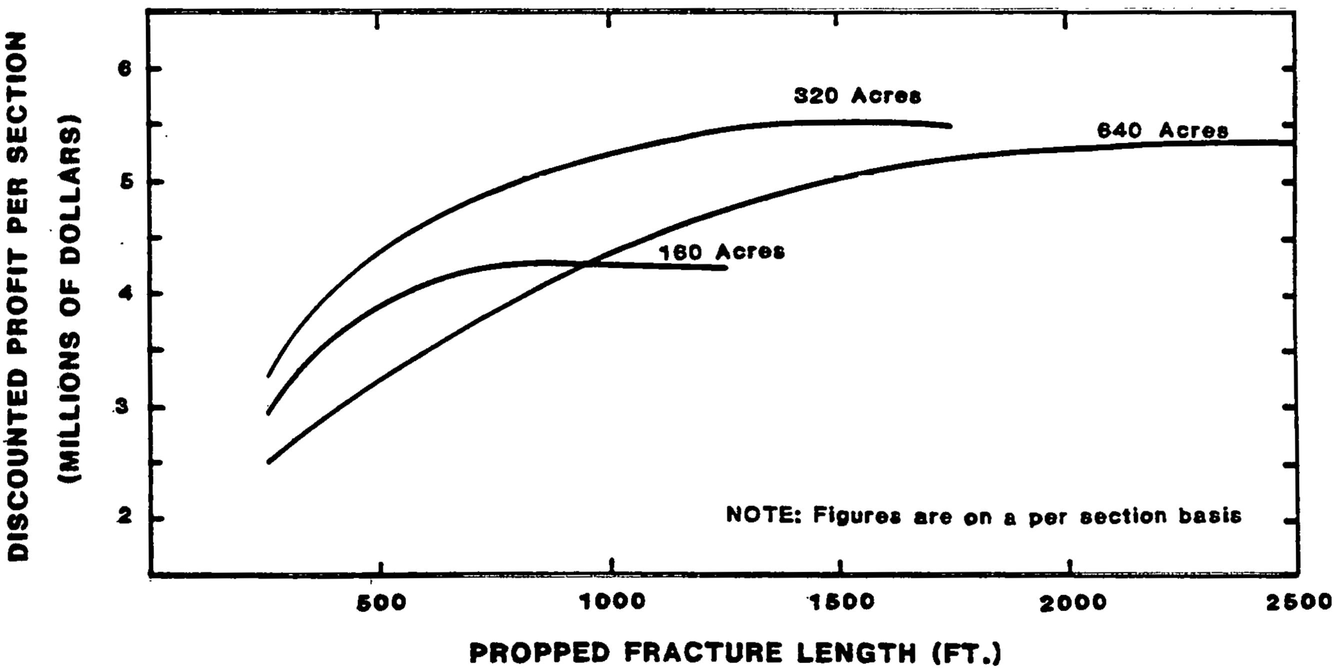


ULTIMATE GAS RECOVERY (BCF/SECTION)
VS. FRACTURE LENGTH
FIGURE 20



PERCENT DISCOUNTED PRESENT VALUE PROFIT
VS. FRACTURE LENGTH (FEET)
0.01 md PERMEABILITY, 10% DISCOUNTED

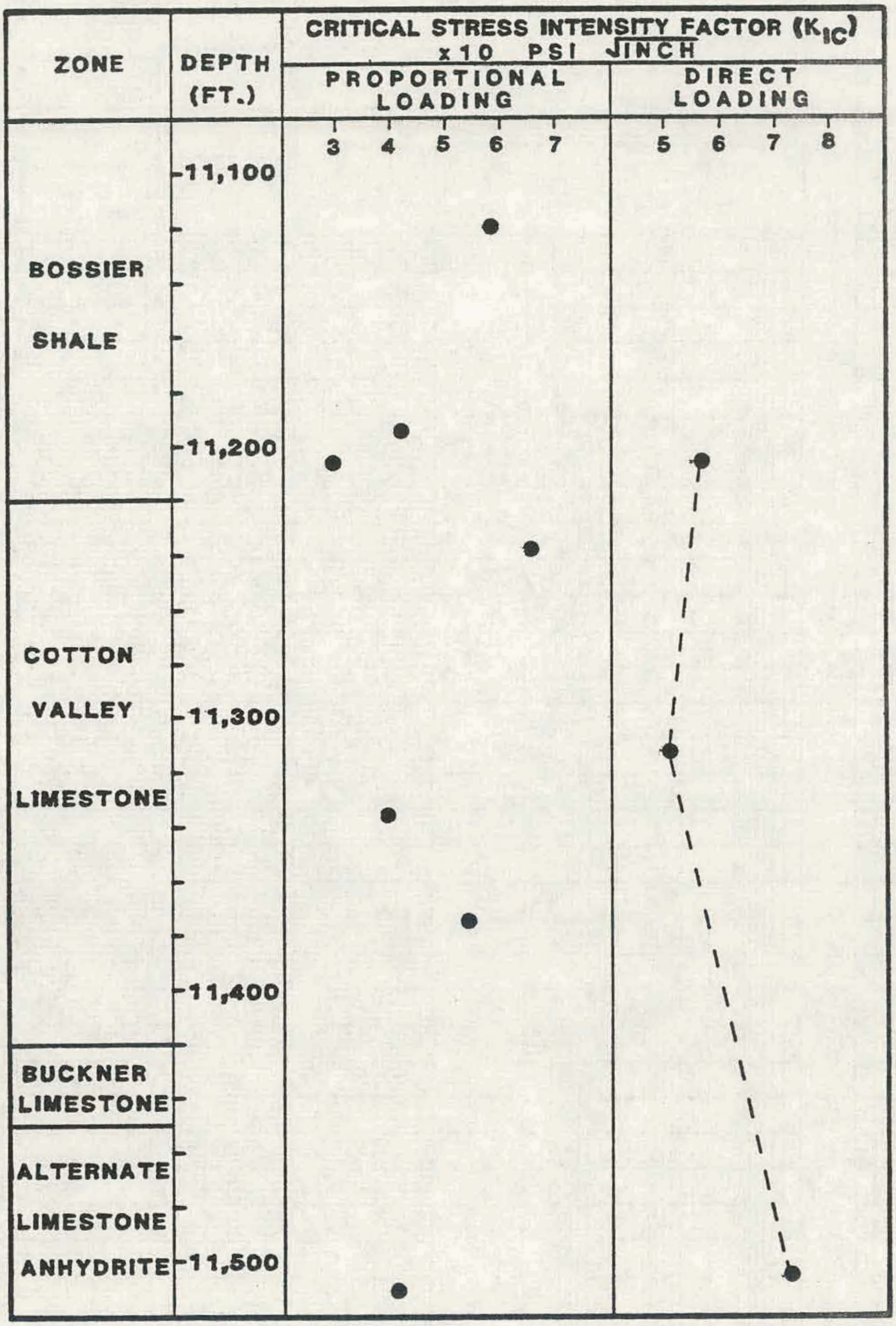
FIGURE 21



PERCENT DISCOUNTED PRESENT VALUE PROFIT VS. FRACTURE LENGTH (FEET)

0.04 md PERMEABILITY, 10% DISCOUNTED

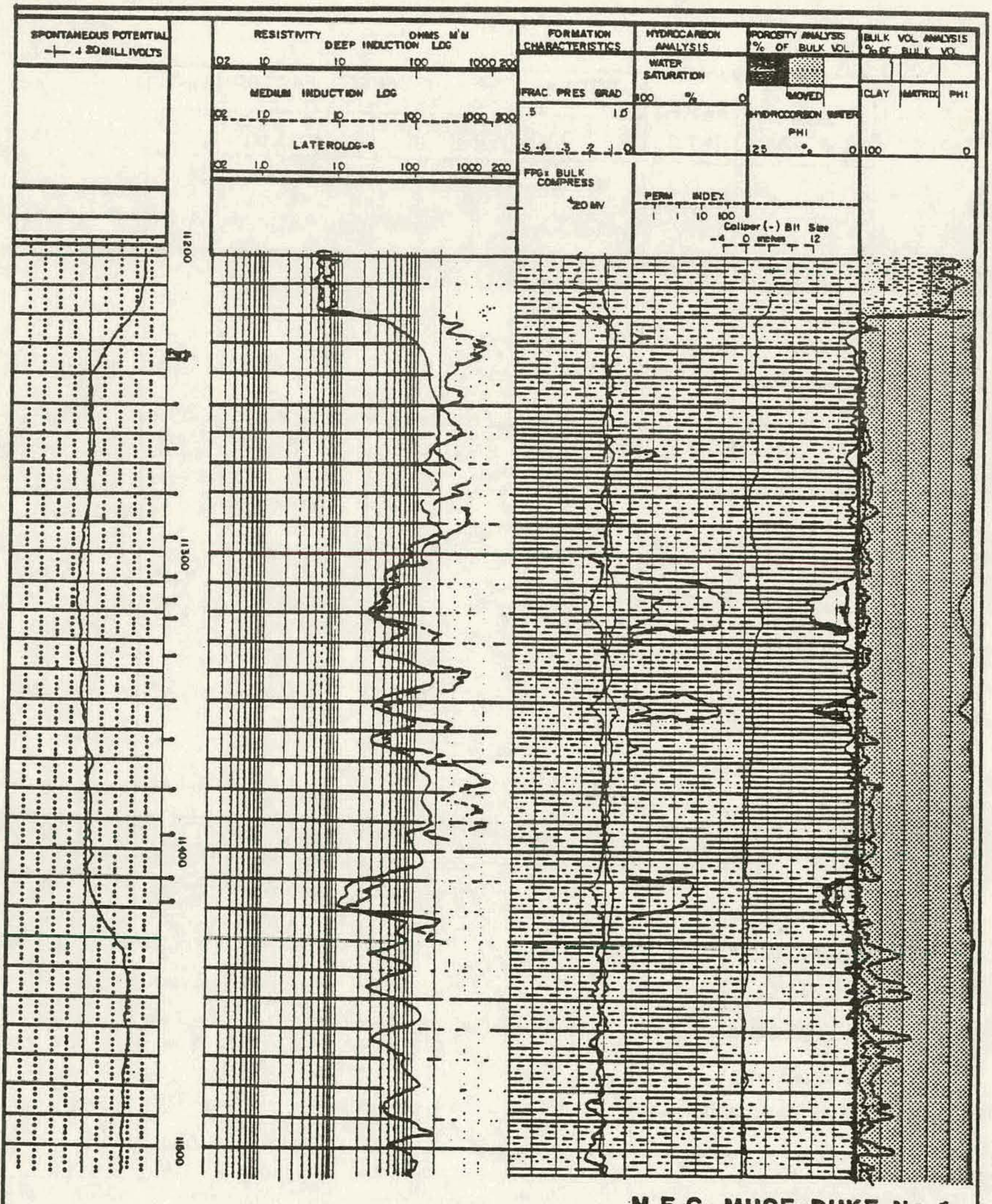
FIGURE 22



CRITICAL STRESS INTENSITY FACTOR VARIATION WITH DEPTH

MEC: MUSE-DUKE WELL NO. 1

FIGURE 23

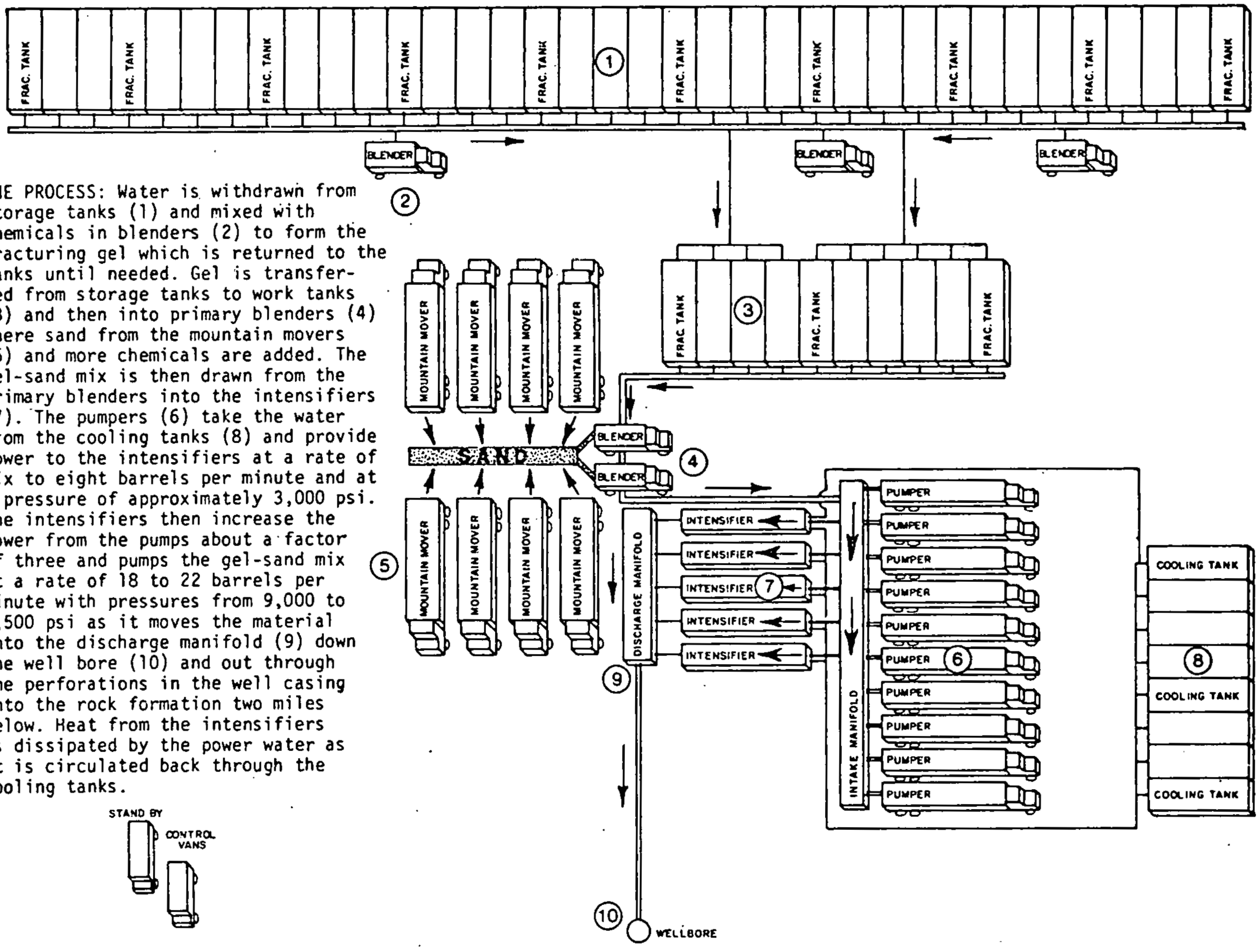


M.E.C. MUSE-DUKE No. 1
COTTON VALLEY LIME
LIMESTONE CO., TEXAS

LOG SHOWING PERFORATIONS IN COTTON VALLEY LIME

#1 MUSE-DUKE

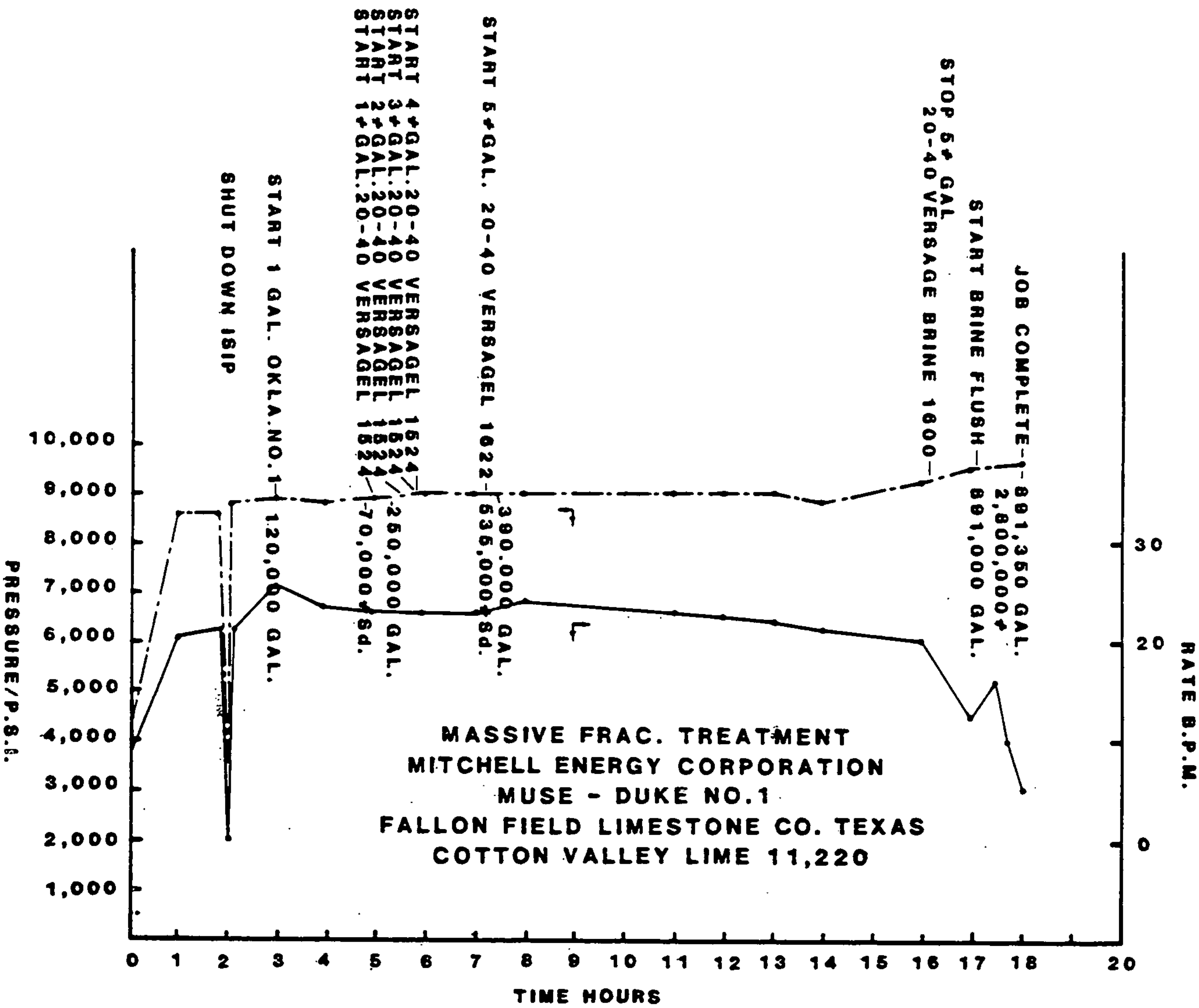
FIGURE 24



THE PROCESS: Water is withdrawn from storage tanks (1) and mixed with chemicals in blenders (2) to form the fracturing gel which is returned to the tanks until needed. Gel is transferred from storage tanks to work tanks (3) and then into primary blenders (4) where sand from the mountain movers (5) and more chemicals are added. The gel-sand mix is then drawn from the primary blenders into the intensifiers (7). The pumpers (6) take the water from the cooling tanks (8) and provide power to the intensifiers at a rate of six to eight barrels per minute and at a pressure of approximately 3,000 psi. The intensifiers then increase the power from the pumps about a factor of three and pumps the gel-sand mix at a rate of 18 to 22 barrels per minute with pressures from 9,000 to 9,500 psi as it moves the material into the discharge manifold (9) down the well bore (10) and out through the perforations in the well casing into the rock formation two miles below. Heat from the intensifiers is dissipated by the power water as it is circulated back through the cooling tanks.

EQUIPMENT LAYOUT FOR FRAC JOB - #1 MUSE-DUKE

FIGURE 25



PRESSURE - RATE RECORDINGS DURING FRAC JOB #1 MUSE-DUKE
FIGURE 26

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