DE 549

MASSIVE HYDRAULIC FRACTURE CONTAINMENT AND PRODUCTIVITY ANALYSES OF MEC MUSE-DUKE WELL #1

by

U. Ahmed, A. S. Abou-Sayed,
L. M. Buchholdt, A. H. Jones
TERRA TEK, INC.
420 Wakara Way
Salt Lake City, Utah 84108
and
H. G. Kozik
MITCHELL ENERGY CORPORATION
3900 One Shell Plaza
Houston, Texas 77002

ABSTRACT

Recently, a massive hydraulic fracture (MHF) treatment was performed in Mitchell Energy well Muse-Duke #1. The fracture is intended to stimulate gas production from the Cotton Valley Limestone formation. Almost 900,000 gallons of fracturing fluid and 2.8 million pounds of sand proppant were pumped in the fracture. It was estimated that a fracture 210 feet high by 5400 feet long (2700 feet each wing) would be generated. The treatment is intended to drain 640 acres of reservoir. As part of a DOE/Mitchell Energy joint project, Terra Tek has provided laboratory and field measurements in support of the design of this stimulation treatment. Furthermore, the post stimulation treatment has been predicted based on various measured parameters. This report presents the data obtained in the laboratory and field program and their implications on the economics of MHF stimulation of tight gas formations at the Cotton Valley, Texas fields.

Laboratory mechanical properties and field *in situ* stress measurements were performed to evaluate the containment of a MHF treatment. To assess productivity of the MHF treated well, laboratory tests were performed to determine the interaction between various fracturing fluids, proppant concentration and the limestone cores. All the laboratory tests were performed under simulated *in situ* conditions and treatment schedule.

From the containment analysis it appears that a MHF treatment will vertically extend to cover the entire Cotton Valley Limestone formation and that it will be contained downward by the limestone/anhydrite sequence and

Prepared for DOE under Contract No. EG-78-C-08-1547

upward by the upper portion of limestone formation and the Bossier shale. Analysis of the fracturing fluid interaction (the damage caused) has shown that when the damage is incorporated in the stimulation ratio calculations, precise post fracturing prediction can be made. The results implied that damage to fracture conductivity has limited post stimulation production increase to the equivalent of an effective fracture length of 800 feet. Consideration of the damage to fracture faces, resultant fracture conductivity and drainage radius, also, shows benefits for the economics of fracturing stimulation by delineating the optimum fracture length. Based on the study, the incremental revenue from gas sales can defray the cost of the treatment in six months.

INTRODUCTION

Acreage in the Fallon and Personville Fields in the Limestone County, Texas is being actively developed by Mitchell Energy Corporation (MEC) of Houston. Recovering gas from the "tight basins" like the Cotton Valley Limestone formation requires the promise of Massive Hydraulic Fracturing (MHF) towards unlocking that tight gas. In support of a successful MHF treatment in the MEC Muse-Duke Well #1, Terra Tek Incorporated of Salt Lake City has provided laboratory and field tests in their program.

Results to date of Massive Hydraulic Fracturing (MHF) vary from extremely successful to extremely disappointing failures[1]. Studies over the years and a recent one[2] of some 500 MHF treatments suggest that the majority of the MHF failures result from not achieving the "necessary propped fracture geometry". In an earlier study[3] by the authors it has been identified that there are three aspects which impair the achievement of "the necessary propped fracture geometry": (a) fracture deviation from the zone of gas concentration (fracture containment analysis), (b) productivity damage due to the fracturing fluid interaction with host rock face (swelling, flocculation, release of fines, embedment, etc.) and, (c) fracture conductivity damage due to the fracturing fluid interaction with the propped bed. The present status of the fracture containment analysis is well presented in the literature[1, 4-5]. A recent study[3] elaborately documents the damaging effect of fracturing fluid on the productivity of hydraulically fractured wells. These studies[1, 3-6] show the use of laboratory tests on cores at simulated *in situ* conditions (stress, temperature, saturation and fracture treatment procedure) to delineate the extent of the above mentioned three aspects. This paper presents the analyses of the three aspects in respect to the MHF treatment performed in Mitchell Energy Well Muse-Duke #1 in the Cotton Valley limestone formation. Their implication on economics of the MHF stimulation treatment is also presented.

BACKGROUND

The Cotton Valley Limestone formation (pay zone) is mostly gray, massive, oolitic to pisolitic and finely crystalline to micritic[10]. In the Muse-Duke Well #1 the pay formation ranges from about 11,220 feet to about 11,420 feet.

Above it lies a massive layer of the Bossier Shale. Below it is the Buckner Limestone followed by alternate thin sections of Limestone and anyhydrite. Figure 1 is a drillers log identifying the different formation in the reservoir and boundary layers.

The pay zone permeability to gas is low (mostly 0.01 to 0.04 md) with locally enhanced permeability areas (0.03 md to 0.1 md) due to the presence of natural fractures. The matrix porosity ranges between 2 to 12 percent with local thin zones up to 14 percent[10].

The MHF treatment is intended to stimulate gas production from the pay zone by draining 640 acres of the reservoir. Almost 900,000 gallons of fracturing fluid and 2.8 million pounds of sand proppant were pumped in the fracture. It was estimated that a fracture 210 feet high by 5400 feet long (2700 feet each wing) would be generated. As part of the DOE/Mitchell Engery joint project, Terra Tek has provided laboratory and field measurements in support of the design of this stimulation treatment. Furthermore, the post stimulation production and economics of the treatment has been predicted based on various measured parameters.

This report first presents the fracture containment analysis followed by fracturing fluid damaging nature, productivity assessment and finally the economics.

FRACTURE CONTAINMENT ANALYSIS

Laboratory and field measurements have been performed to evaluate the MHF containment in the Cotton Valley Limestone formation of MEC Muse Duke No. 1 well.

Laboratory measurements were performed on samples from three distinct zones: Bossier Shale, Cotton Valley Limestone and Anhydrite formation. Pertinent mechanical properties determined were: Dynamic elastic properties including ultrasonic velocities, Poisson's ratio and Young's moduli; 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^{0}F). Description of the experimental procedure can be found in earlier work[1, 4-6]. 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 field *in situ* stress measurements (Bossier Shale, Cotton Valley Limestone and Anydrite formation) were scheduled. The first test was attempted at a depth of 11,456 feet. It was conducted using a Lynes straddle inflatable testing and treating tool with an eight foot straddle section. Detailed description of the test is described elsewhere[11]. Failure in the packer resulted at a shut-in pressure of 7980 psi and the bottom hole peak pressure reached 9380 psi. Further evidence against a successful test is found in the results of the MHF

treatments conducted by Mitchell Energy on Wells Muse A No. 1 and Quinn Estate No. 1[12]. Further field *in situ* stress measurements was subsequently cancelled.

The laboratory measurement program to determine the elastic properties of the various layers resulted in an overall evaluation of possibility of fracture containment within Cotton Valley Limestone formation. Figure 2 presents the variation of dynamic and static moduli with depth. Figure 3 presents the variation of the critical stress intensity factor with depth.

The laboratory measurements indicate that the underlying zone (Anydrite-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 to contain upward fracture propagation. However, laboratory determined dynamic elastic moduli indicate that the top 40 foot 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 foot 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 and high sand concentration) 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 would not work.

FRACTURING FLUID DAMAGE

From the fracture containment analysis it appears that a massive hydraulic fracture will vertically extend to cover the entire Cotton Valley Limestone formation and that it will be contained downward by the limestone/anhydrite sequence and upward by the upper portion of limestone formation and the Bossier Shale. Even if the fracture with right orientation and dimension is created the ultimate productivity of the fractured well will depend on the flow of gas into the fracture and the conductivity of the fracture to transport the gas to the wellbore. Fracturing fluid can considerably affect the resulting conductivity.

Three fracturing fluids were used to determine their damaging nature to the pay zone fracture face permeability and the propped fractured conductivity. The three fracturing fluids are basically the same - cross-linked refined guar gum water gelled. They were supplied by Halliburton, Dowell and Western Companies and are hereby referenced (respectively) as Water-gelled I, Water-gelled II and Water-gelled III.

The system used to measure permeability and propped fracture conductivity of the tight reservoir rocks at varying stress levels and *in situ* temperature conditions is shown schematically in Figure 4. A detailed description

of the testing procedure can be found in Reference 3. For the convenience of the reader, a brief description of the experimental procedure is presented here. Figure 5 illustrates the simulation of the pressure distribution and effective pressures used in the experiment for four phases (fracturing, clean-up, shut-in and production). Figures 6 and 7 are the sample assembly schematics for matrix permeability and fracture conductivity tests respectively. During testing, the sample assembly is placed in the high pressure high temperature vessel of the system.

The transient technique for permeability determination[13, 14] is used because of the very low permeability of the cores (μdarcy range). Horizontal permeability at bench conditions for core at *in situ* saturation was first determined. After the samples have been subjected to *in situ* effective pressure (stress) and temperature conditions, permeability was again determined. The *in situ* effective pressure used is the difference between the confining pressure and pore pressure of the formation when the well is produced after the MHF job. While the confining pressure, pore pressure and temperature were maintained constant, the fracturing fluid was then flowed across one face of the sample for four hours at an appropriate injection pressure (the particular fracture-fluid flow time and pressure used simulated the field fracture job conditions). Shut-in time of twelve hours was allowed (to closely simulate field shut-in) to assure the fracturing fluid was completely broken before backflow. On termination of shut-in, permeability measurements were taken to assess the amount of damage. Clean up was simulated by introducing nitrogen at pressure equivalent to the pore pressure at the sample back face and reducing pressure at the fracture face. The "pressure reduction" is essentially the differential pressure available in the well. Tests were stopped upon reaching the specific "reduction pressure" of the well even if 100 percent damage was not recovered. At the termination of tests, samples were visually inspected to determine whether or not the fracturing fluid had completely penetrated the core.

Fracture conductivity was measured by using fluid flowrate low enough to avoid non-Darcy flow inside the fracture or by extrapolating measurements to zero flowrate. The core samples were saw cut and propped with 20-40 mesh Ottawa sand. Proppant concentrations used were similar to field concentrations. Initially the cores were subjected to confining pressures of 0.7 Mpa (100 psi) for the proppants to settle in place. By flowing dry nitrogen gas through the propped channel, conductivity measurements were taken. The change in conductivity with effective pressure was determined by keeping the pore pressure constant and varying the confining pressure. This approach provided proof of the dependence of fracture conductivity on the effective stress and eliminates the Klinkenberg effect from the results. To simulate fracturing time, fracturing fluids were subsequently flowed through the propped fracture for four hours. Afterward, nitrogen gas was flowed at *in situ* stress conditions to simulate opening of the well and conductivity measurements were taken until it stabilized. After each sequence of tests ended, the fracture faces were examined with an optical microscope to assess the degree of sand embedment, sand crushing, fracture face chipping, clay flocculation and chemical reaction at the fracture face.

The permeability and the clean-up data on the cores from the pay zone

are presented in Table 1 and Figure 8. The initial *in situ* permeabilities of the samples interacted by Water-gelled I and II were in the neighborhood of 25 μd, whereas, the sample interacted by Water-gelled III was much higher (83 μd). The damaged permeability of all the samples at initiation of clean up were in the tenths of micro-darch range, irrespective of the initial permeability of the sample and fluid used. There was no evidence of the fracturing fluid flowing totally through the sample.

A differential pressure of 500 psi was adequate for the clean-up of the samples damaged by Water-gelled I and II. The sample damaged by Water-gelled III cleaned up about 50 percent on a 500 psi differential pressure; permeability appeared to stabilize at this level even after three hours of backflow. Upon increasing the differential up to 2000 psi there was a 10 percent increase in damage recovery.

The various levels of permeability reduction are attributed to the fact that different fracturing fluids leave different types of solid and liquid residue in the sample pores[3]. Nitrogen backflow helps remove some residues. However, varying amounts of damage remains even after backflowing for unrealistically high differential pressures.

Figure 9 illustrates the effect of *in situ* conditions (stress and temperature) and three different water-gelled fracturing fluids (Water-gelled I, Water-gelled II and Water-gelled III) on the fracture conductivity of samples from Cotton Valley Limestone formation. The fractures were fully packed (4 lb/ft^2) with 20-40 mesh Ottawa sand. The curve for the virgin samples are the fracture conductivity to nitrogen-effective stress relationship at *in situ* temperature. Point A represents fracture conductivity at effective *in situ* stress. The gentle slope of these curves indicate that the reduction in fracture conductivity with stress is principally due to the packing of the proppants. The other curves represented by individual reacting fracturing fluids have two points at *in situ* effective stress and temperature. Points B', C' and D' represent the lowest fracture conductivity values at maximum damage. The stabilized values of fracture conductivity upon nitrogen flow clean-up procedure are shown as points B, C and D. These values represent the expected fracture conductivity in the field after the well has been opened and flowed to clean-up. The remainder of the curves show the conductivity-effective stress relationship at virgin condition. After interaction, the three different fracturing fluids damaged the fracture conductivity in different amounts. At *in situ* conditions of stress and temperature the fracture conductivity reduction ranges between one and two orders of magnitude depending on the fracturing fluid.

Examination of the samples after each test under an optical microscope and scanning electron microscope (SEM) revealed that clogging of channels due to the residue from fracturing fluids is the predominant reason for the reduction in fracture conductivity. Figure 10 and 11 shows the residue left by Water-gelled I and II in the packed samples respectively. Other pertinent reasons identified was the packing of proppants, proppant embedment due to the softening of the fracture face, proppant crushing and release of fines.

PRODUCTIVITY ASSESSMENT

Based on the fracture containment analysis, a massive hydraulic fracture initiated vertically at the middle of the Cotton Valley Limestone formation is expected to be contained within the formation. The lower limestone/anhydrite sequence will act as the lower barrier and the upper portion of the Cotton Valley Limestone formation and Bossier Shale will act as the upper barrier. Because of a less stronger upper barrier the use of heavy fracturing fluids (such as the water-gelled fracturing fluids) would reduce the rate of upward fracture migration. The experimental data concerning the heavy fracturing fluid show considerable reduction in fracture conductivity due to the residue left behind by the fracturing fluid and the damages to the fracture face (softening, swelling, release of fines, etc.) by the fracturing fluid. The reduced fracture conductivity is the expected conductivity in the field and it needs to be incorporated in the evaluation of the particular MHF stimulation treatment. It is seen that there is considerable damage to the formation permeability by the fracturing fluid. However, numerical study[15] has shown that 95 percent permeability damage up to a depth of six inches is a prerequisite for any significant reduction in well productivity. In calculating the actual stimulation ratio the lab measured damaged *in situ* fracture conductivity should be used along with *in situ* formation permeability, predicted fracture dimensions (fracture length and width) based on the volume of sand and fracturing fluid to be pumped, well data and spacing.

Table 2 presents the relevant reservoir and laboratory measured properties used in the following productivity assessment study.

The field MHF job in which pretreatment laboratory analysis has been performed is presented here. The benefits of using the lab-derived actual data in assessing the post fracture production of the well is shown.

Here post-treatment production is determined. It is predicted based on both damaged and undamaged fracture conductivities and compared with predictions that, at present, are widely used in the industry. The field job consisted of pumping fracturing fluid (refined guar gum cross-linked Water-gelled I) and 20-40 mesh Ottawa sand through tubing performations at 11,220 - 11,430 feet. The laboratory data presented earlier concerns the core samples from the same formation depths.

The formation has an overall matrix permeability of 90 μdarcy. Figure 9 shows that the fracture conductivity at *in situ* conditions of stress and temperature of the Cotton Valley formation core material (using same proppant and proppant concentration as used in the field job) at undamaged condition is 2500 md ft (Point A) and 59 md ft (Point C) after clean-up of the Water-gelled I fracturing fluid. Figure 12 shows a comparison of fracture conductivity-effective stress relationship of the sample before and after the interaction with Water-gelled I at *in situ* conditions. Also included in the figure are some results presented by the Service Company[16]. Their work dealt with proppant embedment in formations characterized as soft to hard. Data from work by Cook[17] are shown in the figure as well. The data deals with interaction of brine with soft to hard formations at *in situ* stress and temperature condition.

Table 3 presents a list of data used to calculate stimulation ratio using the equation presented by McGuire and Sikora[18] for vertically fractured wells for the four different approaches: Cooke[17], Service Company[16], Terra Tek (undamaged data), Terra Tek (damaged data). Actual well spacing and well data, formation permeability and fracture dimensions are used. Pretreatment production trend is used with the calculated stimulation ratio to predict the post fracturing production. Figure 13 presents the actual field production data of the well before and after the fracturing stimulation. Post stimulation predicted production data are also presented for all four stimulation ratios. Curve D represents the anticipated production based on the laboratory data for damaged permeability and fracture conductivity. There is a close agreement with the actual field data with a deviation of only about 6 percent. Curves A, B and C are substantially different from the actual field data since damage was not considered. Again curves B (Service Company[16]) and C (Terra Tek, undamaged tests) are very close to each other due to the similarity of fracture conductivity measurement by flowing nitrogen only. One needs to note that the relationship presented by McGuire and Sikora[18] is applied to semi-steady state situation. For this system, the reservoir reaches semi-steady state after 69 days and Figure 13 presents prediction beyond 69 days.

Figure 14 shows the dependency of stimulation ratio on fracture radius for various fracture conductivity values for this particular reservoir well spacing, wellbore radius and formation permeability values (damaged and undamaged). When the actual fracture conductivity value is in the 10-100 md ft range, fracture longer than 0.3-0.4 of the drainage radius does not significantly affect the stimulation ratio. Holditch[15] has shown similar results in his numerical study. It is important to note that for the measured fracture conductivity value (59 md ft) of this particular well, production associated with a 2700 foot fracture is essentially identical to a 600-800 foot fracture. When estimated fracture flow capacity values are in thousands of md-ft range, fracture radius does have a very significant impact on the stimulation ratio. This further strengthens the issue that knowledge of realistic fracture conductivity can economize the MHF job size.

ECONOMICS

The post fracturing production trends seen in Figure 13 and the following parameters have been used to present discussion on the economics of the MHF treatment:

Gas Price:	$1.84/MCF escalating 10% per year
Discount Rate:	12 percent
Production Taxes:	10 percent
Federal Income Tax:	Not Included
Production Rate Level Line after five years:	3000 MCF/day

It is imperative to caution that production trend used in the calculation is based on very limited data. Ninety days of post fracturing production trend has been used to predict cumulative production for five years.

Figure 15 shows the trend of the calculated cumulative production of gas over the period of five years following the MHF treatment. Three cases have been considered with assumed fracture conductivity of 59 md-ft (as measured in the laboratory) 2500 md-ft and 400 md-ft. Cumulative production trend for the unfractured reservoir is also included for reasons of illustrative comparison. The undamaged cases where fracture conductivity of 2500 and 4000 md-ft is assumed, steep increase in cumulative production is seen at early time. It finally, levels off with the trend of the actual case (59 md-ft) at about five years. Over the course of five years the actual case shows a steady increase in cumulative production.

Figure 16 illustrates the present worth revenues that can be collected over a period of five years from the incremental gas production available from the fracturing treatment. Here also the three fracture conductivity cases are presented. It is seen that had the fracture conductivity not been damaged a higher amount of revenue can be collected in the earlier years of production. In one and one-half years a fracture with conductivity of 2500 md-ft would generate twice the amount of revenue as opposed to the actual damaged situation of 59 md-ft. Nevertheless, the damaged well has a high enough productivity potential to defray the one million dollar MHF treatment cost from the incremental revenue over a period of six months.

CONCLUSION

The experimental and field results presented here give insight into aspects of the massive hydraulic fracture containment and productivity analysis of MEC Muse-Duke Well #1. Laboratory measured values of elastic moduli are important in delineating a fracture containment and the measured values of permeability and fracture conductivity indicate that the amount of formation damage is dependent on the interaction of fracturing fluid, the host rock and proppant bed design.

In general, the following conclusion can be drawn from results of the reported work.

1. It appears that a MHF treatment will vertically extend to cover the entire Cotton Valley Limestone formation and that it will be contained downward by the limestone/anhydrite sequence and upward by the upper portion of the Limestone formation and the Bossier Shale.

2. Different types of fracturing fluid used in this study can cause as much as 100 percent matrix permeability damage. The damage clean-up is dependent not only on high differential pressure but also on the fracturing fluid causing the damage.

3. Fracture conductivity reduction as much as 89 to 9[illegible] percent for fully packed proppant beds following fracturing fluid flow is seen.

4. The pronounced reason for fracture conductivity reduction at *in situ* condition has been the residue left behind by the fracturing fluid. Other pertinent reasons were proppant packing, proppant embedment due to softening of fracture face, and release of fines from the fracture face.

5. The use of damaged fracture face and fracture conductivity (measured at *in situ* condition) in the stimulation ratio calculation provided a better method to predict post fracturing production realistically.

6. Knowledge of the fracturing fluid damaging nature can be useful for careful planning of fracture design optimization. Depending on the fracture conductivity there exists a upper bound on fracture length beyond which productivity does not increase significantly. For the well in question, the bound appears to be 800 feet.

7. The laboratory measured values show that the revenue from the incremental gas sales has a potential of defraying the stimulation cost in about six months.

ACKNOWLEDGEMENTS

The authors would like to express their appreciation to the United States Department of Energy for the financial support of this work.

Close cooperation from Halliburton, Dowell and Western Service Companies is appreciated.

REFERENCES

1. Simonson, E. R., Abou-Sayed, A. S., and Jones, A. H.: "Containment of Massive Hydraulic Fractures," Society of Petroleum Engineers Journal, (February, 1978), Vol. 14, No. 1, pp. 27-32.

2. Murphy, D. L. and Carney, M. J.: "Massive FRAC-A Second Look," Proceedings of the Massive Hydraulic Fracturing Symposium, University of Oklahoma, (February, 1977), pp. 57-75.

3. Ahmed, U., Abou-Sayed, A. S., and Jones, A. H.: "Experimental Evaluation of Fracturing Fluid Interaction with Tight Reservoir Rocks and Propped Fractures," paper SPE 7922, Proceedings of the 1979 SPE Symposium on Low Permeability Gas Reservoirs, Denver, Colorado, May 20-22, 1979, pp. 109-126.

4. Brechtel, C. E., Abou-Sayed, A. S., and Jones, A. H.: "An Evaluation of Fracture Containment within the Castlegate Sand," Terra Tek Report TR 77-24, (March, 1977).

5. Brechtel, C. E., Abou-Sayed, A. S., and Jones, A. H.: "Fracture Containment Analysis Conducted on the Benson Pay Zone in Columbia Well 20538-T," Second Eastern Gas Shales Symposium, Vol 1., U.S. Department of Energy (METC), Morgantown, W. Va., (October, 1978), pp. 264-272.

6. Abou-Sayed, A. S., Brechtel, C. B., and Clifton, R. J.: "In Situ Stress Determination of Hydrofracturing - A Fracture Mechanics Approach," Journal of Geophysical Research, Vol. 83, No. B6, (June, 1978).

7. Cleary, M. P.: "Primary Factors Governing Hydraulic Fractures in Heterogeneous Stratified Porous Formations," ASME paper 78-PET27, (July 1978).

8. Daneshy, A. A.: "Hydraulic Fracture Propagation in Layered Formations," Journal of Petroleum Technology, (February, 1978), pp. 33-41.

9. Advani, S. H., GangaRao, H. V. S., Chang, H-Y, Komar, C. A., and Khan, S.: "Hydraulic Fracture Modeling for the Eastern Gas Shales Program" Second Eastern Gas Shales Symposium, Vol. 1, U.S. Department of Energy (METC), Morgantown, W. Va., (October, 1978), pp. 84-98.

10. Kozik, H. G., Bailey, B. G., and Holditch, S. A.: "A Case History for Massive Hydraulic Fracturing the Cotton Valley Lime Matrix Fallon and Personville Fields - Limestone County, Texas," paper SPE 7911, Proceedings of the 1979 SPE Symposium on Low-Permeability Gas Reservoirs, Denver, CO, May 20-22, 1979, pp. 15-32.

11. Brechtel, C. E., Ahmed, U., and Abou-Sayed, A. S.: "Laboratory and Field Measurements in Support of Fracture Treatment in the Cotton Valley Limestone Formation in Muse-Duke Well No. 1," Terra Tek Report, TR 78-6, (November, 1978).

12. Field data, Mitchell Energy Corporation, Houston, Texas.

13. Brace, W. F., Walsh, J. B., and Frangos, W. T.: "Permeability of Granite Under High Pressure," Journal of Geophysical Research, (1968), Vol. 69, pp. 259-273.

14. Yamada, S. E. and Jones, A. H.: "Analysis of Pulse Technique for Permeability Measurement," Terra Tek Report, TR 79-8, (January, 1979), (in preparation for publication).

15. Holditch, S. A.: "Factors Affecting Water Blocking and Gas Flow from Hydraulically Fractured Gas Wells," paper SPE 7561 presented at SPE 53rd Annual Fall Meeting, Houston, Tx, Oct. 1-3, 1978.

16. Halliburton: The Fracbook - Design/Data Manual for Hydraulic Fracturing, Halliburton Services, Duncan, Oklahoma, (1971), p. 92.

17. Cooke, C. E., Jr.,: "Conductivity of Fracture Proppants in Multiple Layers," Journal of Petroleum Technology, (September, 1973), pp. 1101-1106.

18. McGuire, W. J., and Sikora, V. J.: "The Effect of Vertical Fractures on Well Productivity, Trans., AIME, 219, (1960), pp. 401-403.

TABLE 1

FRACTURING FLUID/ROCK INTERACTION
MEC.: Muse-Duke Well No. 1
11,313'

Fracturing Fluid	Permeability at *in situ* conditions, Before Fracturing Fluid Flow, K_i μd	Permeability after Fracturing Fluid Flow, K_d, μd	Time of Nitrogen Backflow hrs. Δp of 500	1000	1500	2000	Final Permeability K_f, μd	Estimated 100% Recovery Time, hrs
Water-Gelled I	31	0.3	1.5	--	--	--	25	1.7
Water-Gelled II	23	0.2	2	--	--	--	22	2.2
Water-Gelled III	83	0.1	3	0.5	--	0.5		Inconclusive

TABLE 2

MEC MUSE-DUKE WELL #1
Reservoir and Lab Measured Properties

Reservoir Pressure	6400 psi
Effective Stress	2400 psi
Reservoir Temperature	285°F
Gas Porosity	0.036
Well Spacing	640 acres
Wellbore Radius	0.25 feet
Fracture Geometry	210 feet in height with 800 to 2700 ft. of each wing in the Cotton Valley Limestone formation.
Range of Undamaged Formation Permeability	23 to 90 μdarcy
Range of Damaged Formation Permeability	20 to 48 μdarcy
Undamaged Fracture Conductivity	2500 md-ft
Range of Damaged Fracture Conductivity	59 to 280 md-ft

TABLE 3

STIMULATION RATIO CALCULATION

DATA SIMILAR TO ALL PREDICTION METHODS					VARIABLE DATA SOURCE	VARIABLE DATA			STIMULATION[18] RATIO	REPRESENTATIVE CURVE ON FIGURE 24
r_w ft.	r_e ft.	r_f ft.	K_o μdarcy	w ft.		K_d μdarcy	Kw md-ft	r_d ft.		
0.25	2979	2700	90	0.04	Cooke[17]	90	7200	-	15.2	A
0.25	2979	2700	90	0.04	Service Company[16]	90	4000	-	13.9	B
0.25	2979	2700	90	0.04	Terra Tek (undamaged)	90	2500	-	13.2	C
0.25	2979	2700	90	0.04	Terra Tek (damaged)	22	59	0.08	3.4	D

r_w = wellbore radius; r_e = drainage radius; r_f = created fracture radius; K_o = undamaged formation permeability; w = created fracture width; k_d = damaged formation permeability; Kw = fracture conductivity ; r_d = radius of formation penetration of fracturing fluid

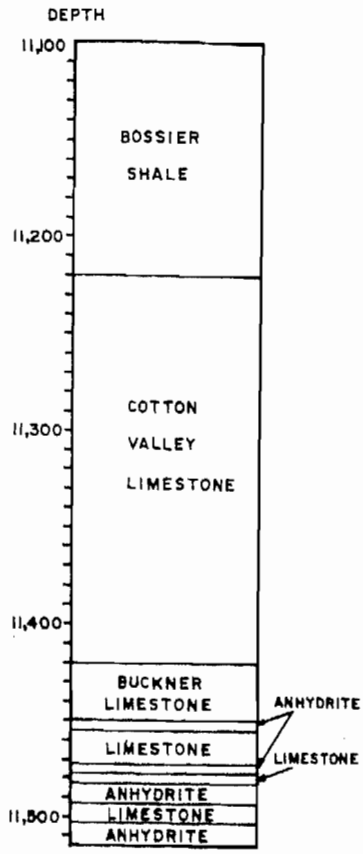

Figure 1. Drillers Log. MEC Muse-Duke Well #1

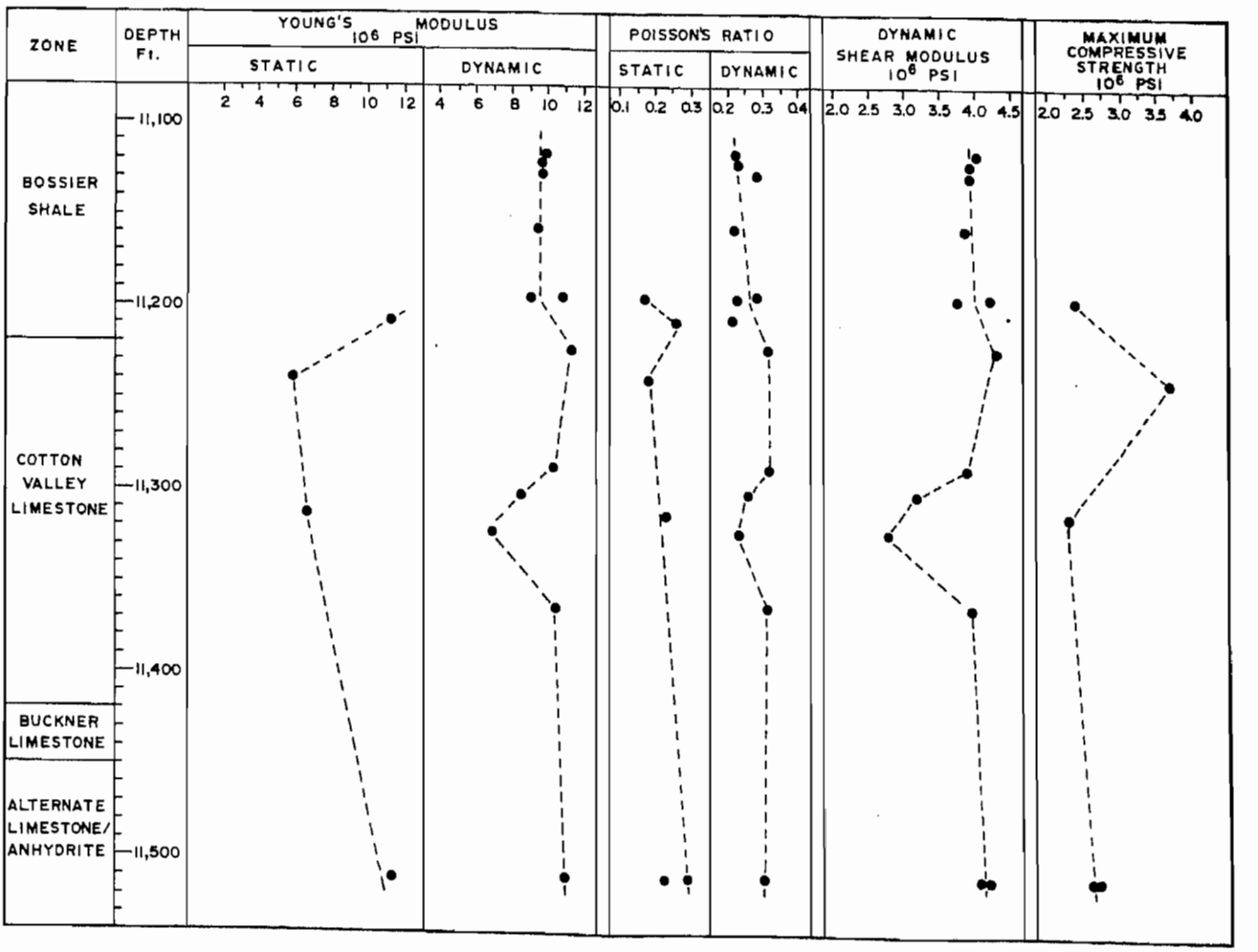

Figure 2. Variation of Moduli and Mechanical Properties with Depth
MEC Muse-Duke Well #1

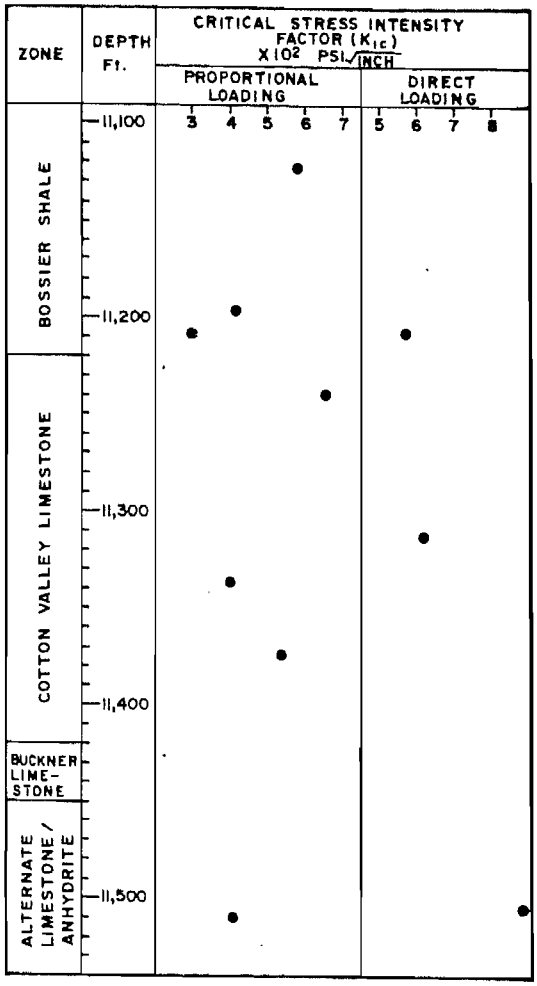

Figure 3. Variation of Critical Stress Intensity Factor with Depth MEC Muse-Duke Well #1

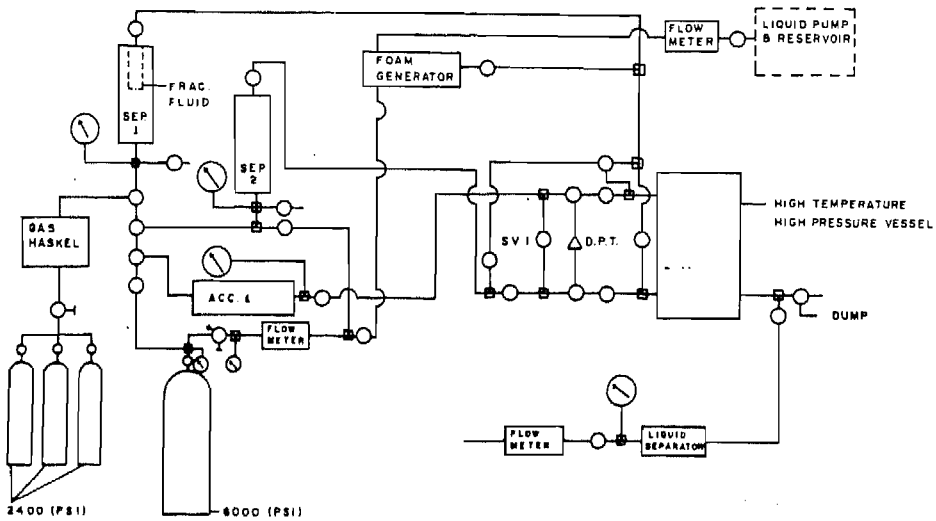

Figure 4. Schematic of the Laboratory System

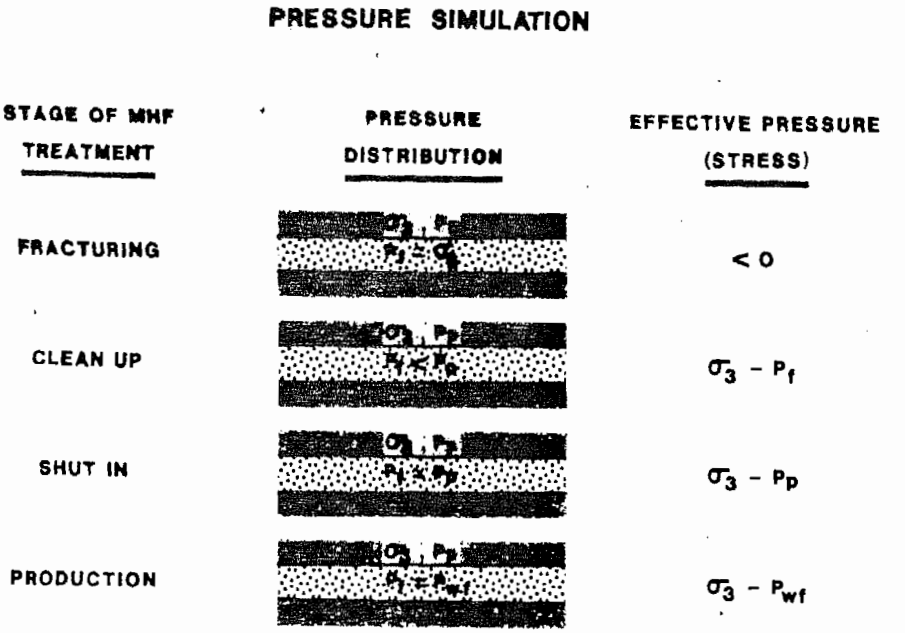

Figure 5. Four Stages of Pressure Simulation

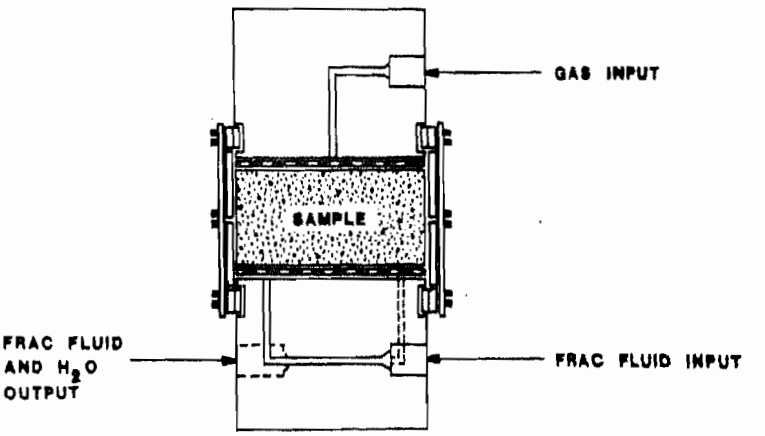

Figure 6. Fracture Face Permeability Measurement Sample Assembly

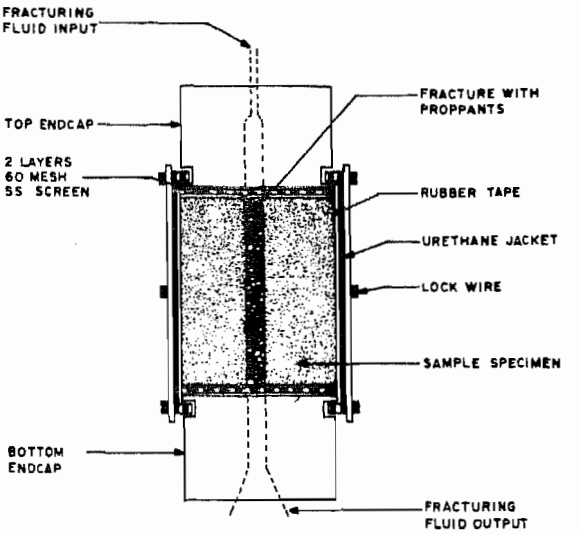

Figure 7. Fracture Conductivity Measurement Sample Assembly

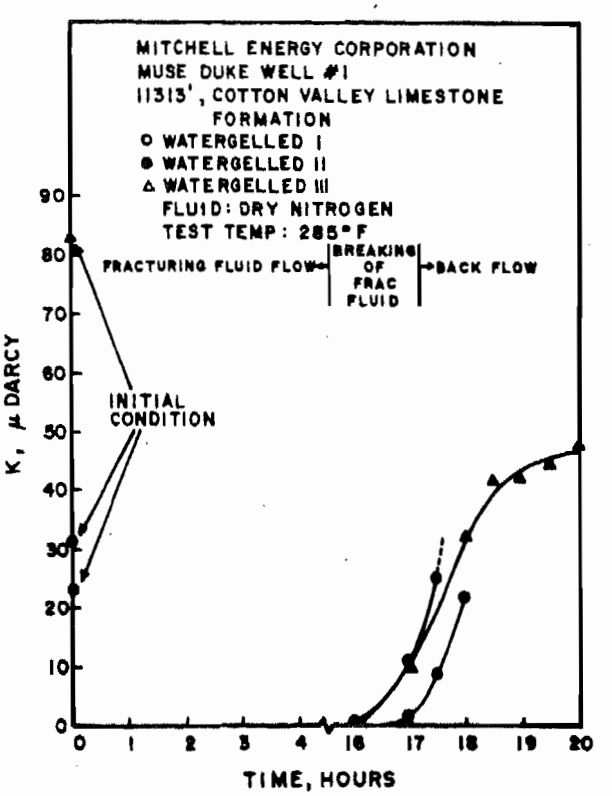

Figure 8. Changes in Permeability During Damage and Clean Up
MEC Muse-Duke Well #1

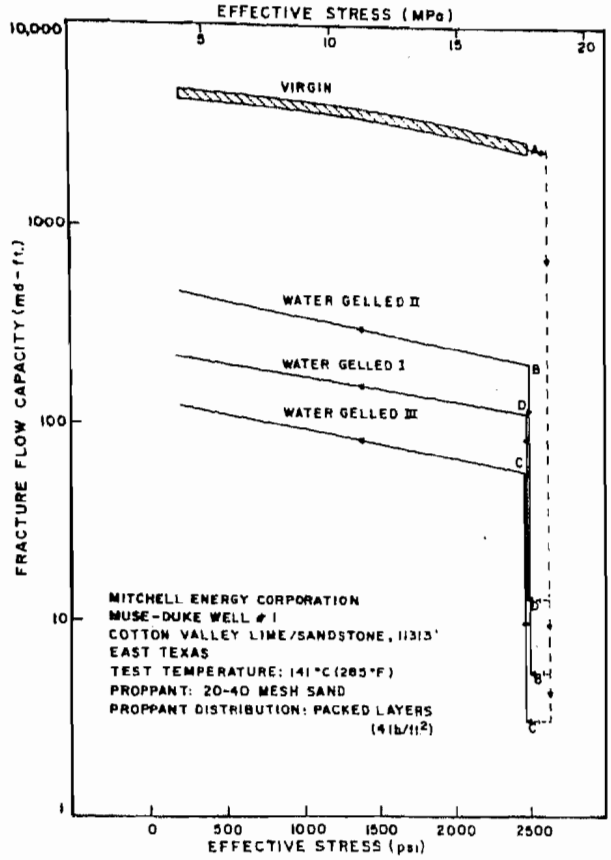

Figure 9. Fracture Conductivity - Effective Stress Relationship. Packed Layers of 20-40 Mesh Ottawa Sand. MEC Muse-Duke Well #1

Figure 10. Residue Left by Water-Gelled I in the Proppant Bed. MEC Muse-Duke Well #1. Magnification 50x.

Figure 11. Residue Left by Water-Gelled II in the Proppant Bed. MEC Muse-Duke Well #1. Magnification 50x.

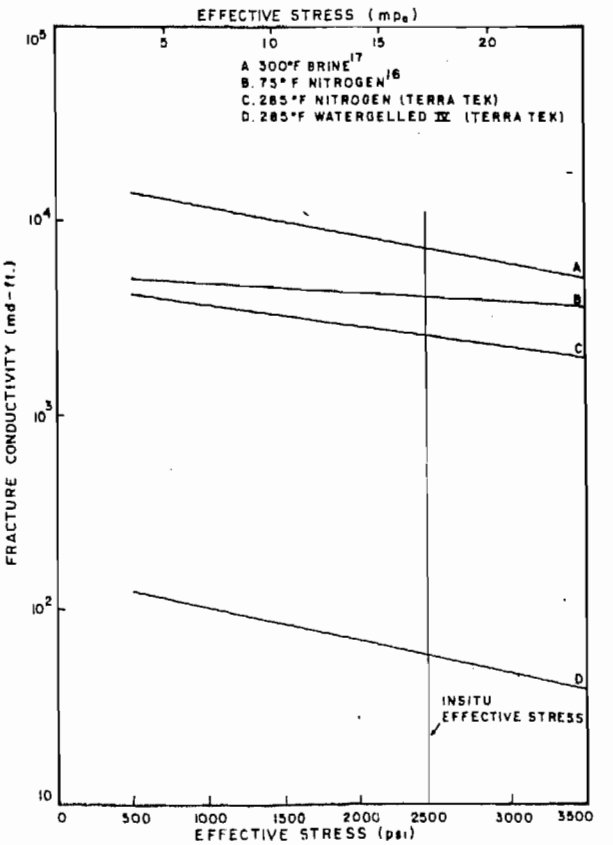

Figure 12. Fracture Conductivity - Effective Stress Relationship for Four Different Prediction Methods

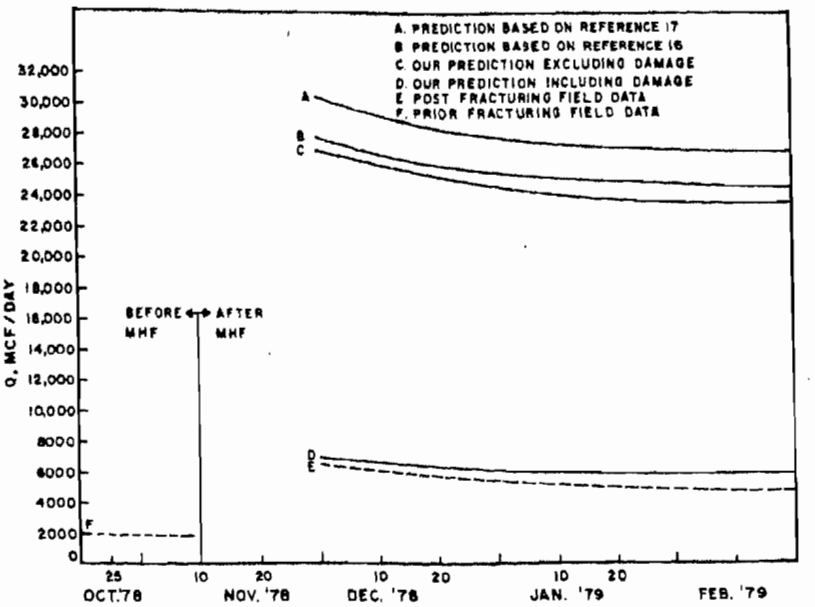

Figure 13. Production Decline Curve Prediction
MEC Muse-Duke Well #1

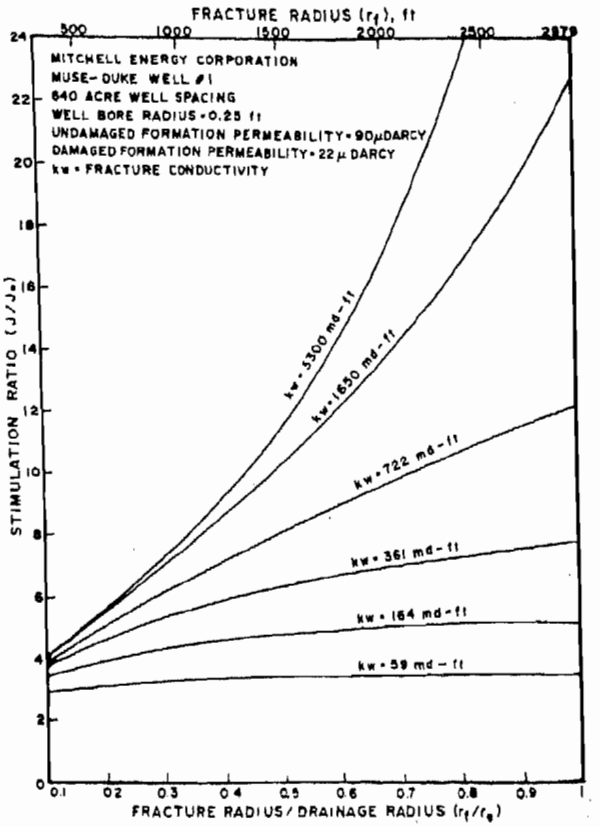

Figure 14. Relationship Between Stimulation Ratio and Fracture Length for Different Fracture Conductivity

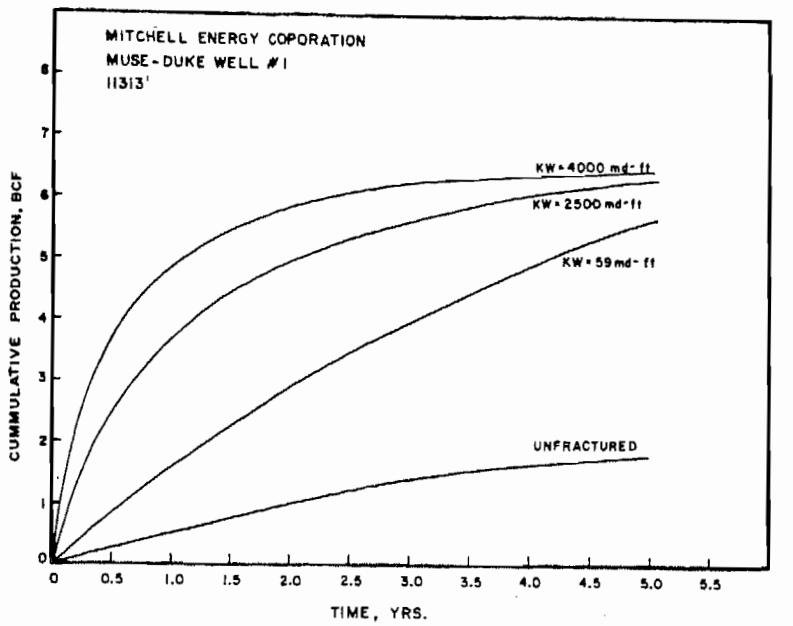

Figure 15. Cumulative Production Prediction with Time. MEC Muse-Duke Well #1

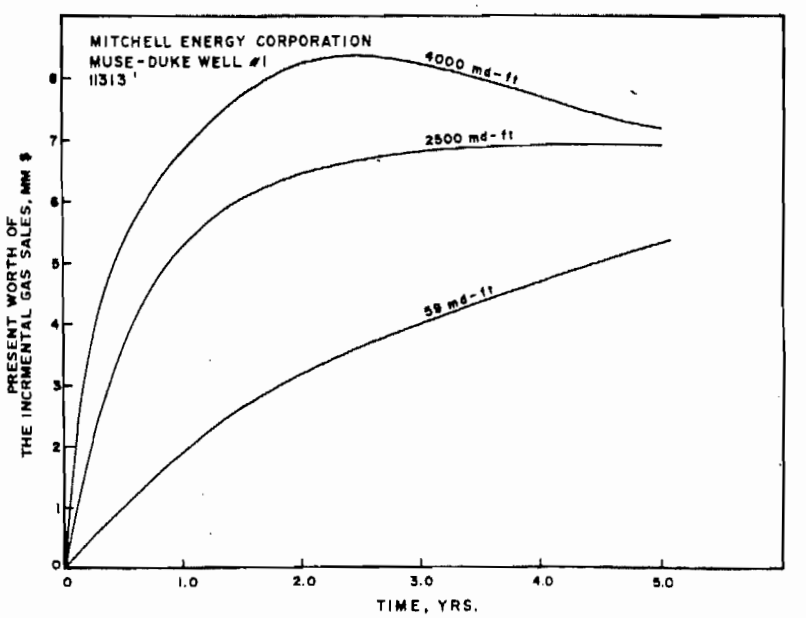

Figure 16. Prediction of Present Worth of the Incremental Gas Sales with Time. MEC Muse-Duke Well #1