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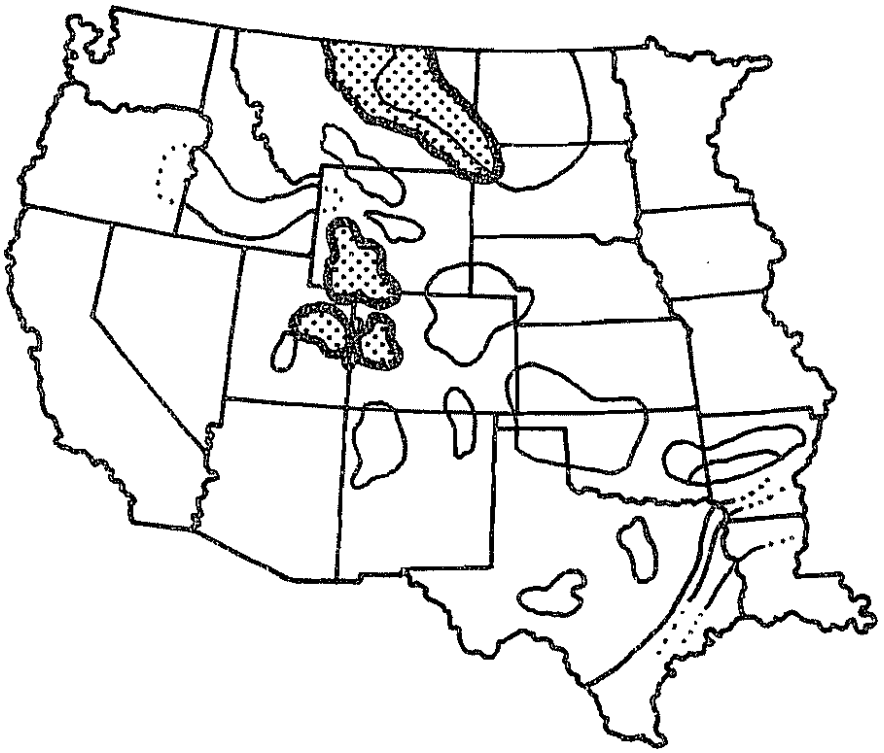
Morgantown' Energy Research Center
Morgantown, WV 26505

Western Gas Sands Project Status Report



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U.S. Energy Research
& Development Administration
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1. SUMMARY

This is the second issue of a Western Gas Sands Project Status Report compiled by CER Corporation for C. H. Atkinson, the Acting Project Manager.

The format may change as the reporting procedure becomes routine and an understanding of the content to be included is obtained. This issue compiles information of many of the pertinent activities which have been, and are being undertaken in the low permeability gas sands in the west and includes information which had not been received in time for the first issue. Hereafter, the status reports will only report new developments.

C. H. Atkinson, although continuing to report to Bartlesville Energy Research Center (BERC), has established an office at ERDA's Nevada Operations Office in Las Vegas, the project's primary contracting office.

The Western Gas Sands Project Plan, Project Implementation Plans and Project Plan Document FY 78 are in various stages of preparation. Several related studies are being conducted.

Resource assessment aot.Lvir.Les reported consist of those conducted by U.S.G.S. in Denver and the outcrop study of the eastern Uinta Basin conducted by CK Geoenergy Corporation.

Information gathering by U.S.G.S. of the initial data base for many of the project activities is nearing completion. Some base maps are complete and field investigations in the principal areas of interest are being conducted.

Laboratory R&D activities funded by ERDA have been directed toward new tools and instrumentation systems, rock mechanics experiments, mathematical modeling and data analysis. These activities to date have primarily been performed by the national laboratories, U.S.G.S. and ERDA's Energy Research Centers. Many items are arbitrarily reported in this category and in the section devoted to the Laboratories and Energy Research Centers even though they require considerable field experimentation.

The positive results of system development and data analysis teclmiques by Sandia and U.S.G.S. - Menlo Park in determining fracture orientation have been very encouraging.

The Field R&D section primarily reports on joint government/industry experiments.

The Uinta Basin in Utah and Piceance Basin in Colorado have had seven massive hydraulic fracture (MHF) experiments in the Upper Cretaceous tight gas formations. These are:

Austral Oil Company	Federal 3-94
CER Corporation	MHF-3
Gas Producing Enterprises	Natural Buttes No. 14, 18, 19, 20
Mobil oil	F-31-13G
Pacific Transmission	Sand Ridge II Federal No. 23-25
Rio Blanco Natural Gas	498-4-1
Texas American Oil and Western Oil Shale	No. 1 Home Federal

In addition, Dallas Production has performed a MHF in No. 1-A Ferguson, completed in the Bend Conglomerate of Pennsylvanian age in Wise County, Texas. Colorado Interstate Gas Company has recently been awarded a contract to determine if productivity in low permeability reservoirs can be improved by reducing the interstitial water saturation. They are using two wells, the Sprague No. 1 and Miller No.1, completed in the Dakota J formation in the Wattenberg Field in north central Colorado.

All of the massive hydraulic fracture wells, with the exception of the Pacific Transmission well, have been fractured in the scheduled target formations. The Mobil and GPE No. 14 and 18 wells show significant improvement as compared to the original flow rates. The Mobil well is being tested for additional MHF treatments.

Proposals from Rio Blanco Natural Gas Company and Mitchel Energy Company concerning MHF experiments have been received and are being evaluated.

Sandia Laboratories have had an active research program in hydraulic fracturing underway at ERDA's Nevada Test Site to study the behavior of hydraulically induced cracks in an in situ environment. To do this several hydraulic fracturing experiments employing various colored grouts as fracturing fluid and sand proppant of different colors have been performed. By mining back and coring, the results of each individual fracture experiment can be delineated.

Results from the mineback investigation have demonstrated how different geological features affect fracture growth. In a uniform media, the fractures are vertical with a consistent dip and bearing. When faults or bedding planes are present, the fracture growth may be retarded or reoriented. Additional in situ stress measurements and material property data are being obtained to further quantify the observed fracture behavior in these experiments.

2. PROJECT MANAGEMENT

A Western Gas Sands Project (WGSP) has been established with C. H. Atkinson designated as the Acting Project Manager. Although continuing to report to Bartlesville Energy Research Center (BERC), he has recently established an office at ERDA's Nevada Operations Office, the project'sprimary contracting office.

Several defining documents are being prepared for the Western Gas Sands Project. These are:

Project Plan
Project Implementation Plan
Project Plan Document FY 78.

A draft of the Project Plan has undergone "in-house" review and has been circulated to selected industrial companies and universities for comment. The response received to date has been very favorable to the project although there are specific tasks which need additional consideration.

The Project Implementation Plan is in the early stages of preparation. The framewcrkhas been established and it will be completed by the end of FY 77. The preliminary work completed on the Project Plan Document FY 78 is being revised to accommodate the substantial reduction in funding from that previously anticipated. The detailed tasks contemplated in FY 78 will be reviewed to insure efficient utilization of the funds available for maximum impact on task activities. Hopefully, in future years, there will be funds available for significant field R&D.

Two intense, short term studies being conducted which will result in documents relevant to the project are:

"Enhanced Gas Recovery Management Plan (EGRMP)" by Lewin & Associates, and

"Market Oriented Program Planning Study Number 2 (MOPPS #2)" by Booze-Allen.

These studies have been heavily supported by project personnel from various sources on a priority basis. The resulting diversion of effort has delayed some activities.

Another document which has relevance is the recently completed but not yet published by the Federal Power Commission:

"Report to Supply Technical Advisory Task Force - Nonconventional Natural Gas Resources Sub-Task Force IV: Gas in Tight Formations."

An unsolicitated proposal, received from Rio Blanco Natural Gas Company regarding an additional MHF treatment in their 498-4-1 well has been reviewed

and contract modification is pending. A proposal from the Mitchell Energy Company regarding MHF tests in the Cotton Valley Trend in East Texas is being **reviewed.**

A draft report by C. R. Boardman on the geologic study of the Uinta Basin has been submitted for review. This report is part of Contract No. EY-76-C-08-0683 between Texas American Oil Corporation, Western Oil Shale corporation and ERDA.

3. RESOURCE ASSESSMENT

3.1 GENERAL ACTIVITIES OF THE U.S.G.S. TO DATE

Technical Assistance and advice on tight gas sands was provided to Lewin & Associates, Sandia Laboratories, Booze-Allen, CER, Industry personnel and representatives of the Canadian Government. Computer processing requests have been submitted to Petroleum Information (PI) and the compiling of all available geological and engineering data for all basins is underway.

Various meetings were attended with a paper prepared for the Third ERDA Symposium and an informal talk on U.S.G.S. programs given at LLL in July.

3.1.1 Specific Area Activities

Resource assessment activities are proceding in the Uinta, Piceance and Greater Green River Basins and the Northern Great Plains Province.

Base maps of the Greater Green River Basin were prepared for publication and enhanced LANDSAT photos were ordered for the lineament study. The lineament map for South Dakota has been completed.

Cores were obtained for study and samples were prepared and submitted for Geo-chemical, SEM, X-ray, Micropaleo age determination and other analyses.

Maps were obtained from Petroelum Information (PI) computer file with a plot of all well penetrations, Tertiary and Cretaceous cores, DSTs, shows, and preliminary pressure gradients for the Greater Green River Basin. Regional structure and temperature maps have not yet been received.

A computer listing of all well data with a separate listing of cores and DSTs for both Tertiary and Cretaceous formations for the Uinta and Piceance Basins has been obtained from Petroleum Information.

Regional Stratigraphic log sections are being constructed for all the study areas with well test and core data being posted to the log sections.

A comprehensive bibliography of all available literature, reference card files, etc. on low permeability reservoirs is being prepared.

3.1.2 Reports Issued

Bibliography of low permeability natural gas reservoirs of the Northern Great Plains by D. D. Rice, USGS Open-File Report 77-391 (1977).

Preliminary Chart Showing Distribution of Rock Types, Lithologic Groups, and Depositional Environments for Some Early Tertiary and Late Cretaceous Rocks from Outcrops at Willow Creek-Indian Canyon through the Subsurface of the Duchesne and Altamont Oilfields, Southwest to North-Central Parts of the Uinta Basin, Utah, by T. D. Fouch, USGS Open File Report 77··509 (1977), in press.

Geological Programs to Provide a Characterization of Tight, Gas-Bearing Reservoirs in the Rocky Mountain Region, by C. W. Spencer, T. D. Fouch, and D. D. Rice, Third ERDA Symposium on Enhanced Oil and Gas Recovery Proceedings, Vol. 2-Gas (1977), in press.

3.2 OUTCROP STUDY

An outcrop study of fracture and sandstone geometries in the Mesaverde and adjacent formations was made around the periphery of the eastern uinta Basin, Utah.

The objective of the study was to:

1. Determine sandstone geometries for the various rock types, by measuring rock outcrops around the eastern margin of the basin and develop the characteristic distribution of height/length/width (H/L/W) ratios in each major genetic non-marine rock type (deltaic plain and alluvial plain deposits).

2. Determine trend directions of the sandstone bodies by evaluating the orientation of the H/L/W data and the directional sedimentary features in the individual sandstone bodies.

3. Determine the fracture/joint orientation of the individual sandstone bodies.

4. Determine the relationship between the fracture/joint density and the characteristics of the sandstone bodies.

5. Model the reservoir geometry of the major genetic sandstone types.

The surface fracture phenomena observed on outcrop fracture surfaces are those typical of tension failures and may well correlate with the tensile failures of hydraulic fracturing. This may well provide an informative model for MHF design and evaluation.

It has been observed that fracture density is highest in the non-reservoir rocks, while the lowest fracture densities are found in the plastic mudstones and shales and the massive sandstone reservoir rocks. The fluvial sandstones of the Farrer interval display the lowest continuity and the marine margin sandstones of the Castlegate and Sego intervals display the greatest continuity.

The effective reservoir volume of the discontinuous Nelsen and Farrer facies is strongly dependent on the sandstone/shale ratio of the interval. The higher sandstone/shale ratios generally are interconnected sand lens systems and the lower ratios generally are systems or isolated channels with little interconnection.

The fluvial massive reservoir sandstones are generally interbedded with the easily fractured brittle siltstones and thin, very fine-grained sandstones. The marine margin sandstones are frequently associated with coals. Thus, the reservoir rocks in the Mesaverde Group and adjacent strata may be interbedded with layers more susceptible to fracturing than the reservoirs. The subsurface model developed from the outcrop study would suggest that:

1. The hydraulic fracture be initiated within the reservoir rock with no opportunity to start in the adjacent non-reservoir material.

2. The fracture sizes should be based on sand continuity and fracture/sandstone orientation, e.g.,

   a. Continuous sandstones bounded by plastic shales should receive massive treatments if other factors are favorable to this type of treatment.

   b. Sandstone beds with suspected continuity that are bounded by brittle siltstones, silty shales, or thin, fine-grained (non-reservoir) sandstones should receive fracture treatments designed to minimize propagation of fracture wings beyond the probable extent of the reservoirs, since it appears that under these circumstances, conventional hydraulic fractures, once passing out of the less easily fractured reservoir rock, will continue to propagate in the non-reservoir layers.

3.3 STUDY OF BASIN ACTIVITIES

3.3.1 Northern Great Plains Province Activity

There are primarily four units that have been receiving attention throughout areas of Montana. All four are Upper Cretaceous units. The Judith River and Eagle Formations represent the youngest production. These units have been most actively drilled on the Bearpaw Arch of Blaine, Chouteau, and Hill Counties. Both units can be drilled through at less than 2,000 ft. These sands are not normally fractured. Initial production may vary from less than 100 to more than 1,000 MCFD. Major operators in the area are Fuelco, Wise Oil, Montana Power Company and Tricentral U.S. Inc. In 1975, the Montana Oil and Gas Commission listed over 200 wells drilled in the Bearpaw Arch area, of which 150 were development and 50 were exploratory. In 1976 production from Tiger Ridge, the large field to the north of the arch, was over 14.7 billion cubic ft. The other major Judith River-Eagle producing area is the Cedar Creek anticline in which many of the wells are quite old. Pacer Resources Inc. (Calgary, Canada) drilled a 1976 Eagle test. Again, drilling depths are very shallow. Cumulative production to 1974 is over 132 billion cubic ft of gas.

The Carlile (Bowdoin Sands) and Greenhorn (Phillips Sands) are older than the Judith River and Eagle units. These sands are predominately productive in the Bowdoin Field of Phillips and Valley Counties. Again, drilling depths are shallow, ranging from 1,500 to 2,000 ft. Frac treatments, while not as significant in the more permeable sands to the south and original field area, are practically always necessary to the north and northwest. They are quite small, averaging about 40,000 lbs. Initial production may range from less than 100 to well over 2,000 MCFD. Major operators are Kansas-Nebraska Natural Gas Co. (Midlands Gas Corp.), Joseph Paine and Associates, Miami Oil Producers, and Odessa Natural Corp. Cumulative production to 1974 for the Bowdoin Field is 128 billion cubic ft of gas. Most of the recent wells (150) to the north are shut in pending pipeline completion. These wells will substantially increase total production when they are put on stream.

3.3.2 Greater Green River Basin Activity

Within the last few years, tight gas sands of the Lewis and Mesaverde formations in the Wamsutter area and the Frontier Formation of the Moxa Arch area have become interesting to oil and gas operators. Both areas seem to be large stratigraphic traps. Amoco is the most active operator in these areas and probably the most experienced in developing this type of play with their Wattenberg (Denver Basin) expertise. In 1976 Amoco had 269 completions in the Rocky Mountain states.

The Almond and Ericson Formations of the Mesaverde have been the most common pay zones at depths ranging from 9,000 to 16,000 ft. The average cost of drilling and completing a well has been about $1 million. Frac tratements have varied from 50,000 lbs to 1,000,000 lbs. Although the area has been sparsely drilled, some of these wells have been excellent, producing more than 10 MMCFD. Amoco has completed or tested 40 wells in the Wamsutter area with an average initial potential of 1 MMCFD. They plan to drill 27 more wells in 1977.

The Moxa Arch area Frontier gas sands are very similar in character to those of the Mesaverde in the Wamsutter area. Amoco has completed 16 wells in that area with another B wells planned for 1977. The best production appears to be from the top of the arch with little success on the western side. The Rock springs Uplift to the east has objectives ranging from Wasatch (Tertiary) to the Paleozoics. There have been some discoveries there during the past few years.

3.3.3 Uinta Basin Activity

There has been limited activity in the Uinta Basin with most drilling taking place west of the Chapita Wells gas field. Major operators are Gas Producing Enterprises (GPE), Belco Petroleum, and Mapco Inc. Primary objectives are the tight Wasatch and Mesaverde units at depths from 5,000 to 9,000 ft. Initial production varies from about 500 to over 1,000 MCFD. Frac treatments for the units vary from 50,000 to 200,000 Ibs of sand with the Wasatch getting the larger frac treatments.

The southern part of Uintah County has seen recent activity by various operators for Castlegate, Ferron and Dakota production. These units at 2,000 to 5,000 ft are relatively shallow in this area.

3.3.4 Piceance Basin Activity

Activity in the Piceance Basin is centered around three areas. One area is in the western part of Rio Blanco County where several operators are drilling for the Upper Cretaceous Mancos "B" (Emery) production. American Resources is active in the Trail Canyon Field of Rio Blanco County where the Mancos "B" is reached at 3,200 ft. Frac treatments are about 100,000 lbs of sand. Fuel Resources, Northwest Exploration and Chandler and Associates are actively drilling for the Mancos "B" to the north in the Dragon Trail area.

Another major activity center is in the Plateau Field of eastern Mesa County. Major operators here include Flying Diamond Oil, Apache Corp., and Adolph Coors. The primary objectives are the Upper Cretaceous Cozette, and Corcoran Sands. Depths to these sands range from 3,000 to 5,000 ft.

Mobil has an active drilling program to develop Wasatch sand production on the Piceance Creek Dome.

4. LABORATORY RESEARCH AND DEVELOPMENT

4.1 INTRODUCTION

Many of the tasks applicable to this category as reported in the Western Gas Sands Project Plan arc contained in Section 6, entitled NATIONAL LABORATORIES AND ENERGY RESEARCH CENTERS. Brief mention is made of pertinent activities not reported there and expanded coverage is anticipated in succeeding months.

4.2 PRESSURE CORING SYSTEM

Bartlesville Energy Research Center (BERC) initiated a study by Maurer Engineering to determine the feasibility of designing and fabricating a coring system which will allow cores to be taken and subsequentiy analyzed under as close to in situ conditions as possible. A final report has been issued which generates optimism that such a system can be built. Sandia has reviewed the engineering requirement and has proposed a course of action which combines their capabilities with those of Maurer Engineering for a prototype tool. BERC has authorized Sandia to proceed.

4.3 MOBILE DATA COLLECTION SYSTEM

The mobile data collection system to collect production test information has been authorized and the basic design has been completed. Sandia has solicited bids for the fabrication and two responses were received. Procurement has been initiated with Gearhart-Owen Industries Inc. of Fort Worth, Texas.

4.4 BOREHOLE GRAVITY METER

USGS is currently fielding a borehole gravity meter on an experiment for the Eastern Shale Project. It is anticipated that the meter will be available for use i.n the Western Gas Sands Project; however, it has severe temperature and size limitations. The instrument has housings for both low and high pressures. The low pressure housing is good to approximately 2,000 psi, and the high pressure housing is good to approximately 12,000 psi. The low pressure housing has an OD of 5.9 in., and the high pressure housing has an aD of 6.25 in. The maximum temperature limitation is 95°C.

A new instrument is being fabricated having a housing good to 11,000 psi and an OD of 4.06 in. Its designed maximum temperature limitation is 125°C. USGS has contracted with Lecoste for the fabrication of the tool and the USGS is designing the electronics. It is anticipated that the USGS will get the tool some time in August and go through a laboratory checkout and subsequent field shakedown during September and October.

4.5 FRACTURE ORIENTATION SYSTEM DEVELOPMENT

Considerable effort has been expended in FY 75, 76 and 77 on the development of systems capable of determining fracture orientation. Three systems have been extensively investigated for MHF completions (two by Sandia and one by USGS, Menlo Park) and a considerable amount of field experimentation, modeling and

data analysis has taken place. A fourth system using downhole seismic sensors may prove useful if Los Alamos Scientific Laboratory (LASL) experience with fracture diagnostics in the hot dry rock program can be made applicable to the western gas sands. Sandia is investigating this possibility. Table 4-1 is a tabulation of the field experiments to date. Note that many experiments have included both the electrical potential and tiltmeter systems and generally there seems to be fair agreement. More details are found under the section describing Sandia's efforts. The chronological history of USGS effort on the tiltmeter followsin Sub Section 4.7.

4.6 SPECIAL CORE ANALYSIS AND FRAC ORIENTATION EVALUATION

Special core analyses and fracture orientation measurements have been performed by TerraTek Inc., Salt Lake city, Utah, on core taken from Federal No. 23-25 Well, drilled by Pacific Transmission under contract with ERDA. The objectives were to determine in situ stress direction in gas bearing sands. The methods employed were surface measurements of oriented core relaxation, preferential fracture orientation from mini-breakdowns, followed by impression packers in the well to visually detect fractures at the wellbore. In addition, laboratory investigation of fracture direction on core wafers was determined by application of point loads.

Simulated in situ permeability is being measured on selected samples and an investigation on the effect on permeability under simulated in situ conditions of invasion from various fracturing fluids is being conducted.

Results of this work will be reported in detail in future monthly summaries. Similar core analyses by TerraTek are planned in conjunction with the evaluation of individual sand members in CIGE No. 21 well add-on experiments to characterize reservoir properties.

4.7 U.S.G.S. TILTMETER

May 1975 Rio Blanco	Good correlation of tilt response to pumping pressure and rate variations. Poor definition for determination of azimuth and extent based on instrument geometry and amplitude of signal.
Aug 1975 Wattenberg	MUddy-J Sandstone approximately 9,000 ft -- still too few instruments to provide confidence on azimuth and extent of fracture. Excellent correlation between pressure and rate changes associated with temporary 1 hr shut-in. Too few instruments to test model.
Nov 1975 Wattenberg	Muddy-J.- Instrumentation doubled -- poor SiN. All instruments placed at theoretically poorest position for receiving tilt signal to test model.

Dec 1975	Wattenberg	Muddy-J - All instruments placed at theoretically optimum positions for signal reception. Good definition on azimuth and extent. In agreement with Sandia's electric potential results.
Jan 1976	Wattenberg	Muddy-J - Signal quality about same as December at same depth. Azimuth and extent well defined for one wing. Instrument geometry designed to test model resulted in positioning half the instruments at an inner arc the same as the November experiment and the remaining ones at the optimum positions associated with the December frac. Results in good agreement with resistivity. Model for a simple well defined biwinged frac confirmed.
Jun 1976	W. Virginia	Devonian Shale depth approximately 4,000 ft. Poor SiN. Instrument, array geometry, recording gain, etc. based on design frac and past experience conclusion: Fracture failed to attain length sufficient to be detected.
Aug 1976	W. Virginia	Devonian Shale - Well approximately 5,000 ft from frac. Poor SiN except during periods of extreme pressure and/or rate variations. Conclusions: Frac failed to attain design. Signatures similar to electric potential results.
May 1977	W. Virginia	Devonian Shale same well as August frac. Exceptionally low background noise -- still poor SiN. Interpretation: Frac failed to attain design length.
Nov 1976	Oklahoma	Shallow (80 ft) frac -- combined experiment to test model with electric potential, tilt, rock mechanics experirnent,borehole television monitoring, cycling experiment to test observations of good SiN when pressure changes and rate are extreme. Excellent definition of azimuth and extent -- even deduction that wings were unequal in length. Excellent agreement with electric potential and other observations. Final confirmation made when frac was drilled near its extreme.
Jun 1977	Rock Springs, Wyoming	Green River Shale depth at 200 ft. Exceptional results. Detailed response between pumping parameter variations and tilt response. Sufficient detail in record to suggest significant deviations from a simple symmetric horizontal fracture .-later confirmed by other evidence.

TABLE 4-1 FRACTURE ORIENTATION EXPERIMENTS

PARTICIPANT	FRACTURE DATE	LOCATION	SANDIA SEISMIC	SANDIA ELECTRIC POTENTIAL	USGS TILTMETER
ERDA	Spring '74	NTS, Nevada	X		
EPNG	Summer '75	**San Juan Basin**	X	X	
CER (MHF-3. third frac)	May "2, '75	Rio Blanco, CO			X
EPNG (Pinedale #7)	Sept, '75	Pinedale, WY	X	X	
EPNG (Pinedale #5)	Jul 2. '75	Pinedale. WY	X	X	
AMOCO	Aug, '75	Wattenberg, CO			X
EPNG (Pinedale #5)	Oct, 20. ' 75	Pinedale, WY	X	X	
AMOCO (Martin Hart "En No.1)	Nov,lS, '75	Wattenberg, CO		X	X
AMOCO (Salazer G. U. No. 11	Dec, 16, ,75	Wattenberg, CO		X	X
AMOCO (UPRR-22Pl	Jan,27,'76	Wattenberg, CO	X	X	X
COLUMBIA GAS	Jun, '76	W. Virginia			X
COLUMBIA GAS	Aug,4, '76	W. Virginia		X	X
COLUMBIA GAS	May, '77	W. Virginia			X
ERDA (NTS-2)	Jul, '76	NTS, Nevada	X		
AMOCO (Mini-Frac)	Nov,4, '76	Tulsa, OK		X	X
GPE (natural Buttes No. 14)	Mar,15, '77	Vernal, UT		X	
CONOCO	Mar,22,'77	Casper, WY		X	
GPE (Natural Buttes No. 20)	**Jun!22,! 77**	**Vernal**, UT		X	
LERC/SANDIA	Jun, '77	Rock Springs, WY			X

FUTURE EXPERIMENTS

Aug 10, 1977 Rock Springs, Wyoming -- Phase II of June experiment. Similar conditions at same well.

Aug 1977 Test Site	Support for Sandia's mineback experiment. Part of array at surface injection point -- remainder of array split between two tunnels oblique at the same depth of the fracture initiation level.
Sep 1977 Laredo, Texas	Gas field at 5,000 ft depth with Sandia and Shell.
Next Fiscal Year:	Tentatively: Wattenberg field at one-half previous depths -- in Sussex formation approximately 5,000 ft. A three-well experiment sequence. CIGE unit 21 in connection with GPE sand characterization (Utah). Remainder of year open.

4.8 LOGGING TOOLS

Logging tools which are currently operational and which show promise for tight gas sands location and evaluation include:

4.8.1 Nuclear

4.8.1.1 Natural Radioactivity by Decay Gamma Rays

The total natural gamma count rate is calibrated in reference to a standard-mix pit on University of Houston campus. Generally, clay fraction in sands, silts, and shales varies with the ratio of radioactivity in a given sediment (in excess of that in a clean sand) to the difference between a thick shale and a thick clean sand. Total activity consists of U^{238}, Th^{232}, and K^{40} decay.

PotassilUU 40 is fixed in the crystal structure of illite clays and micas. Hence it should be a better indicator of clay fraction than U or Th (which are absorbed in irregular amounts). Dresser-Atlas has a spectral gamma log showing relative concentrations of all three major isotopes (K40, Th^{232}, and U238) daughters. Schlurnberger Corporation has the tool in a semi-research capability. Clay fraction is necessary for correction of resistivity readings in shaly sands.

4.8.1.2 Thermal Neutron Capture

Dresser-Atlas and Schlurnberger both have pulsed neutron tools which detect prompt rays of thermal capture (binding energy is released whenever e.g. Cl35 absorbs a neutron and becomes C136). Dresser-Atlas has a fixed gate at about 300 microseconds after pulsing which lasts 300 microseconds; Schlurnberger has a variable gate with two near and far detectors. Both printout sigma, or macroscopic cross section, and count rate at some time where count rate decays exponentially with time. Schlurnberger also prints count ratio. These

tools are mainly sensitive to C135 and highly absorbing materials such as Boron or Samarium. Schlumberger suggest that far count is sensitive to low density gas in an uninvaded zone due to the lower H-moderation of fast neutrons.

4.8.1.3 Neutron Capture Energy Selective

Dresser and Schlumberger have neutron activation-gamma measurement capabilities, using slow logging rates or using stationary tools in boreholes so that the prompt gammas from particular reactions may be measured. It is possible to measure Ca in a window from 5-6 Mev providing there is a low Cl^{35} present. Interference from degraded higher energy gammas makes this technique insensitive to small quantities or small cross-section elements.

4.8.1.4 Inelastic Scattering Gamma Rays

High energy scattering of neutrons is significant in rock, due to 0, C, si, and Fe. The resulting inelastic gammas may be counted for neutron fluxes of 10^8 or greater. C is noted in the 3-4 Mev range and o in the 5-6 Mev range. C is useful in locating oil but is interfered with by degraded oxygen gammas. The ratio of C/O is used to eliminate this interference, but the tool is useful only for oil or large fraction (to total fluid) in sands with no CaC03'

4.8.1.5 Thermal and Epithermal Neutron Population Comparisons

Combinations of a steady neutron source and separate logs of thermal and epithermal populations yield a discernable difference in neutron disappearance due to clay. The two logs work above and below the cadmium resonance, consequently measure hydrogen moderation and moderation plus capture. Clays in fresh water cause additional capture, partly due to Boron and are seen only by the Thermal Neutron log. The difference between logs should be a measure of clay.

4.8.1.6 Activation Logging

Aluminum in clays can be activated by thermal neutrons to yield a decay gamma (9 minute half life). This requires very slow logging speeds or stationary tools, for good statistics. Clays are aluminosilicates with somewhat variable aluminum fraction.

4.8.2 Practical Utility of Nuclear Tools in Tight Gas Sandstones

A plot of $\phi_n - \phi_d$ versus clay fraction yields a line separating commercial gas from water. This occurs since $\phi_{neutron}$ decreases with increasing low hydrogen density gas, while $\phi_{density}$ is slightly increased by low electron density gas. Clay affects neutron porosity due to its bound hydrogen and neutron absorbers. Clay fraction may be estimated by: (a) Total gammas; (b) ϕ_n-Th - ϕ_n-Epi; (c) K40 gammas or; (d) SP decrease from normal. Thermal capture cross section and aluminum activation should be investigated for clay fraction correlation.

4.8.3 Acoustic

4.8.3.1 Noise Log

The log of particular high frequency sound yields depths where gas enters the wellbore (either in open hole or through perforations). This occurs due to the whistling noise of expanding gas. The amplitude of the signal is proportional to velocity for simple perforations. Several frequency channels are available for sound detection.

4.8.3.2 Wave Train Log

A printout of transducer voltage amplitude versus time is available, so that the various acoustic signals may be viewed. The first arrival is the one used for acoustic logging. This dilatational wave is followed by several resonances and by later shear waves, Rayleigh waves, and mud waves. Shear waves do not propagate through fluid, and the one tabbed as shear wave may be shear-·induced dilatation wave. Fractures shift both waves in time and may eliminate shear waves.

4.8.3.3 Shear Wave Log

Schlumberger produces an independantly-calculated shear wave velocity (Δt_2) log with Δt_d printout, using four acoustic receivers and wave train printouts. Probably the first significantly different wave not matching the wave recurrence frequency of dilatational waves is used to determine Δt_s. The Δt_d and Δt_s logs are essentially parallel indicating that Δt_s is a lithology plus porosity log.

4.8.4 Practical Utility of Acoustic Devices in Tight Sandstones

Δt_d is sensitive to clay similarly to the ϕ_n log, but it does not respond to gas. An overlay of Δt with ϕ_d shows cleaner gas zones. Mechanical properties may be calculated from Δt_s and Δt_d, but Schlumberger suggests use of $\Delta t_s/\Delta t_d$ as a rigidity index (rather than a Poisson's ratio calculation).

5. FIELD RESEARCH AND DEVELOPMENT

5.1 BACKGROUND

The Uinta Basin in Utah and the Piceance Basin in Colorado have had seven massive hydraulic fracture (MllF) experiments in the Upper Cretaceous tight gas formations. These are:

Austral Oil Company	Federal 3-94
CER Corporation	MHF··3
Gas Producing Enterprises	Natural Buttes No. 14, 18, 19, 20
Mobil oil	F-31-13G
Pacific Transmission	Sand Ridge II Federal No. 23-25
Rio Blanco Natural Gas	498-4-1
Texas American oil and western Oil Shale	No. 1 Home Federal

In addition, Dallas Production has performed a MHF in No. l-A Ferguson, completed in the Bend Conglomerate of Pennsylvanian age in Wise County, Texas. Colorado Interstate Gas Company has recently been awarded a contract to determine if productivity in low permeability reservoirs can be improved by reducing the interstitial water saturation. They are using two wells, the Sprague No. 1 and Miller No.1, completed in the Dakota J formation in the Wattenberg Field in north central Colorado.

All of the n.ass i.ve hydraulic fracture wells, with the exception of the Pacific Transmission well, have been fractured in the scheduled target formations with the Mobil and GPE No. 14, 18 and 20 wells showing significant improvement as compared to the original flow rates. The Mobil well is being tested for additional MllF treatments. Table 5-1 is a tabular breakdown of each contractor, well and treatment performed. Colorado interstate gas company is not shown at this time.

The following sections summarize the location, technical progress and borehole schematic for the individual MHF experiments.

TABLE 5-1 MHF CONTRACTED LOCATIONS AND FRAC DATA

PROJECT	LOCATION	WELL	FRACTURED	FRAC TREATMENT	FLUID INJECTED
	T / R / Sec		Feet	Lbs of Sand	10^3 Gal
AUSTRAL **Piceance,** **Mesaverde**	7S,94W,S3 Garfield Co. **Colorado**	Federal 3-94	5,170-6,353	1,140,000	542 gel H_2O
CER **Piceance,** Mesaverde	3S,98W,S11 Rio Blanco Co. Colorado	RB-MHF-3	5,851-8,078 4 Fracs	400,000 880,000 815,000 448,000	117 Gel 285 Gel 400 Gel 241 Gel
COASTAL STATES uinta	10S,22E,S10 Uinta County Utah	Nat'l Buttes No. 18	6,490-8,952	1,480,000	745 Gel
	10S,21E,S21 Uintah county Utah	Nat'l Buttes No. 19	7,224-9,664	1,053,000	655 Gel
	9S,21E,S22 Uintah County Utah	Nat'l Buttes No. 14	6,646-8,004	1,093,000	544 Gel
	9S,21E,S28 uintah County Utah	Nat'l Buttes No. 20	8,498-9,476	826,000	322 Gel
	10S,22E,S21 uintah County Utah	CIGE No. 21			
DALLAS Wise County Bend Congl.	Ben D. Smith Survey A-779	Ferguson A-1	5,957-6,794	506,000	139 Foam 198 Ernul.
EL PASO NATL. GAS Northern Green **River**	30N,108W,S5 Sublette Co. Wyoming	Pinedale Unit No. 5	10,950-11,180 10,120-10,790	518,000 1,422,000	183 Ernul. i Gel 459 Gel

MHF CONTRACTED LOCAnONS AND FRAC DATA
(Continued)

PROJECT	LOCATION	WELL	FRACTURED	FRAC TREATMENT	FLUID INJECTED
	TI R I Sec		Feet	Lbs or sand	10^3 Gal
MOBIL **Piceance Creek** **Mesaverde**	2S,97W,S13 Rio Blanco Co. Colorado	F-31-13G	10,549-10,680 9,517- 9,538 9,392- 9,932	639,000 600,000	316 Gel 259 Gel
PACIFIC TRANSMISSION Sand Ridge **Mesaverde**	8S,23E,S25 uintah County Utah	Fed 23-25	NO F R A S	PER	FORME'
RIO BLANCO Piceance, **Mesaverde**	4S,98W,S4 Rio Blanco Co. Colorado	Fed 498- 4-1	6,150- 6,312	776,000	276 Gel
WESTCO Turtle Ck, Uintah, Mesaverde	10S,19E,S34 uintah Co. Utah	Home Fed. No. 1	7,826- 9,437 10,014-10,202	500,000 600,000	248 Gel 412 Gel

RULISON FIELD, COLORADO, MASSIVE HYDRAULIC FRACTURING DEMONSTRATION

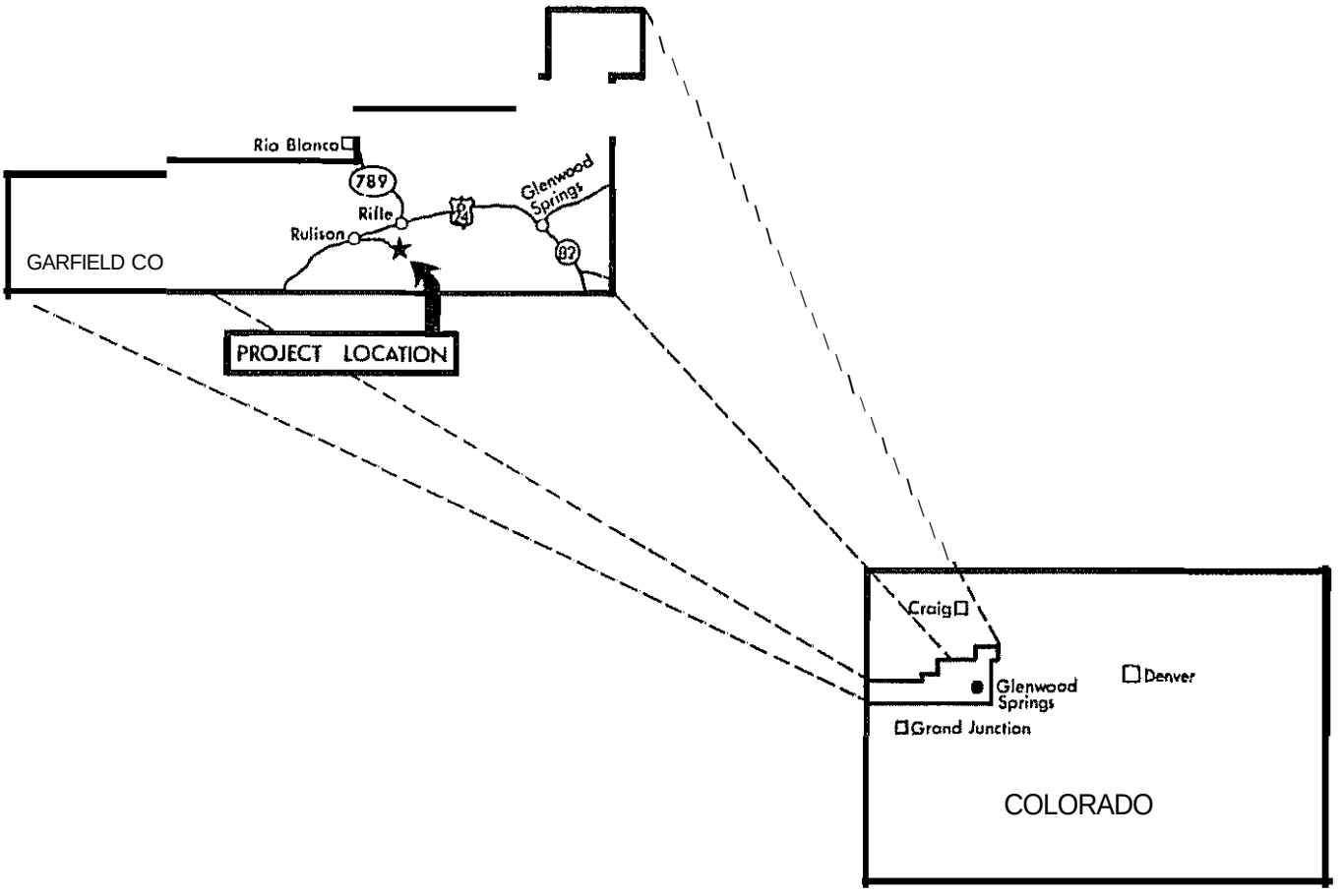
EY-76-C-08-0679

Austral Oil Company
Houston, Texas

Contrect Dete:	June 15, 1976
Anticipated Completion:	December 15, 1976 (Extended)
Total Project Cost:	ERDA, ... $334,000
	Contractor (value of test weill, ... 545,000
	Contractor ... 54,000
	Total, ... $933,000
Principal Investigator:	Miles Reynolds, Jr.
Technical Project Officer:	C. H. Atkin,on, Bartlesyille Energy Reseerch Center

Objective

To evaluate the effectiveness of massive hydraulic fracturing for stimulating natural gas production **from thick, deep sandstone reservoirs having extremely** low permeability.



5.2 AUSTRAL OIL COMPANY

5.2.1 Scope of Work

ERDA Contract EY-76-C-08-0679 was signed with Austral Oil Company in July 1976. The scope of work under the contract consisted of a two stage MHF treatment and evaluation of results in existing gas well (Federal #3-94) in the Rulison area, Garfield County, Colorado. The first stage MHF treatment design, approved by ERDA prior to fracturing operations, utilized approximately 226,000 gal of fracturing fluid and about 420,000 Ibs of sand. Upon completion of the first stage, the second stage treatment design was approved by ERDA. The second stage utilized approximately 316,000 gal of fracturing fluid and about 720,000 Ibs of sand. Upon completion of the treatments, the well was produced into a pipeline to determine stimulation results with one years production data to be provided to ERDA.

5.2.2 Description of Existing Well, Federal No. 3-94

This gas producing well is located 1,840 ft fr N/L and 1,520 ft fr W/L of Sec 3, T7S, R94W, Garfield County, Colorado. The total depth of this well is 6,515 ft with 9-5/8 in. casing set in 4,550 ft and a 7 in. liner casing set at 6,505 ft. The Mesaverde sand perforations at 6,333 - 6,353 ft; 6,198 - 6,205 ft; 5,484-1/2 - 5,630 ft; and 5,170 - 5,434 ft were fractured in stages with moderate-sized treatments in January, 1966 and the initial potential test indicated a producing rate of 595 thousand cubic ft per day (MCFD). The well was producing approximately 35 MCFD prior to the MHF work. Figure 5-2 shows the production history of Federal No. 3-94.

5.2.3 Summary of Work Completed

The lower perforations (6,198 to 6,353) were isolated by means of tubing (2-7/8 in. 00) and packer and were treated with approximately 226,000 gal of fluid containing 420,000 Ibs of sand (140,000 Ibs of 20/40 mesh, 210,000 Ibs 10/20 mesh and 70,000 Ibs 100 mesh) and 500 standard cubic ft per barrel of nitrogen. After a brief cleanup flow period, the lower perforations were isolated with a retrievable plug and the upper perforations (5,170 to 5,630) were treated with approximately 316,000 gal of the same fluid containing approximately 720,000 Ibs of sand (350,000 Ibs of 20/40 mesh, 300,000 Ibs 10/20 mesh and 70,000 Ibs of 100 mesh) and 500 standard cubic ft !bbl of nitrogen. The frac fluid used was Dowell's water base controlled gel (YF4G). Sand concentrations as high as 4 Ibs/barrel fluid were achieved.

A significant problem was discovered during the treatment of the lower perforations. When the 10/20 sand was being pumped the gelled water broke back to low viscosity during the treatment. It was discovered that the truck hauling the 10/20 sand had been used to haul potash. The truck had not been cleaned prior to hauling the sand. The potash changed the pH of the gel as soon as the 10/20 sand was added. The well started to sand out but the material was back flowed to clean out the sand and the job continued without the contaminated sand.

5.2.4 Post-Treatment Results

Following the execution of the fracturing treatments, the well was recompleted with a string of 2-3/8 in. 00 production tubing suspended without a packer to a

depth just above the perforations. The well was flowed to a pit for a period of several days prior to reconnection to the pipeline. A considerable amount of swabbing was required to remove large quantities of frac fluid and enable the well to flow. After recovery of approximately 50% - 60% of the frac fluid, the well was able to flow intermittently into the pipeline. Additional swabbing was required on occasion.

The well would flow at a rate of about 200 - 250 MCFD for 6 to 8 hours then load up and die. The average daily rate was about 50 - 60 MCFD; use of intermitters was tried but did not improve production significantly.

5.2.5 Conclusions and Recommendations

The reason for failure of the MHF treatment in the Rulison area is not known. Additional tests in this area need to be conducted. The fact that wells in this area have been producing gas (admittedly at low rates) for over 20 years, proves that the gas is present. What is needed is to develop the technology to stimulate these wells into commercial producers.

TABLE 5-2 TABULAR BREAKDOWN OF WORK PERFORMED ON FEDERAL 3-94

GROSS ZONE	PERFORATED ZONE	BHTP PSI	BHP* PSI	Ø %	k rod	GROSS	NET	NO. PERFS
Frac Interval 5,170 - 5,434								
5,156 - 5,185	5,170 - 5,186.5	3,937	1,500	12	_01*	29	21	5
5,284 - 5,327	5,304 - 5,330	3,937	1,500	8	.01*	43	19	8
							10	
5,337 - 5,368	5,359 - 5,368.5	3,937	1,500	5	.01*	31	5	2
							13	
5,404 - 5,534	5,416 - 5,434	3,937	1,500	11	.01*	30	30	6
Frac Interval 5,484 - 5,630								
5,455 - 5,517	5,484.5 - 5,586	4,077	1,500	13	.01*	62	13	2
	5,498 - 5,517			13.5	.01*		29	5
5,528 - 5,564	5,539 - 5,542	4,077	1,500	11	.01*	36	34	2
	5,554 - 5,564							3
5 580 - 5 586	5 588	4 077	1 500	9*	.01*	6	6	1
5,594 - 5,640	5,606 - 5,630	4,077	1,500	11	.01*	46	46	7
Frac Interval 6,198 - 6,205								
6,176 - 6,194	6,198 - 6,205	5,430	1,500	9*	.01*	18	14	14
6,212 - 6,222						10	10	
Frac Interval 6,333 - 6,353								
6,309 - 6,360	6,333 - 6,353	5,259	1,500	13.5	.01*	51	37	20

*Average Data As Submitted

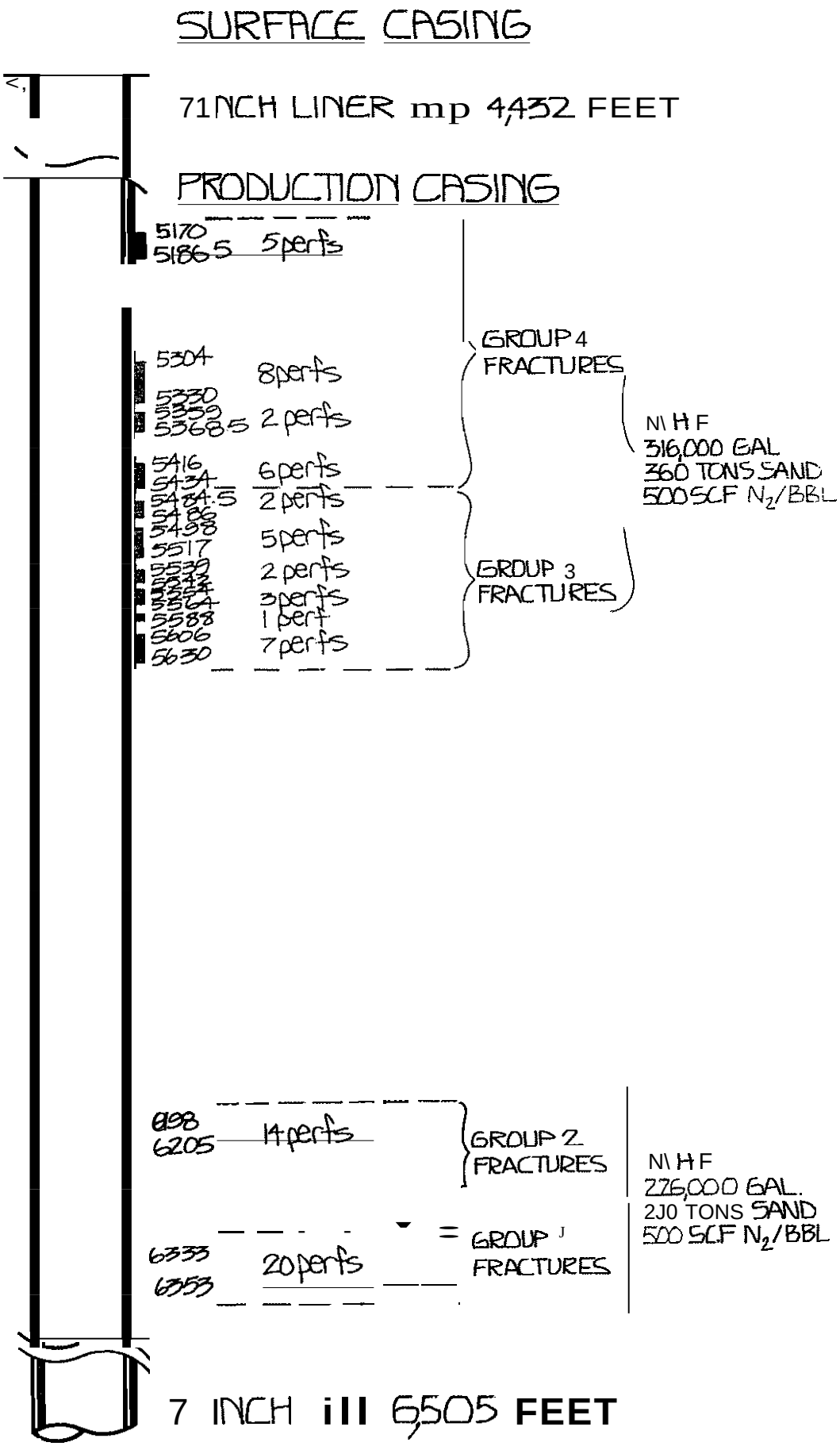


FIGURE 5- 1 SCHEMATIC OF FEDERAL 3-94 WELL

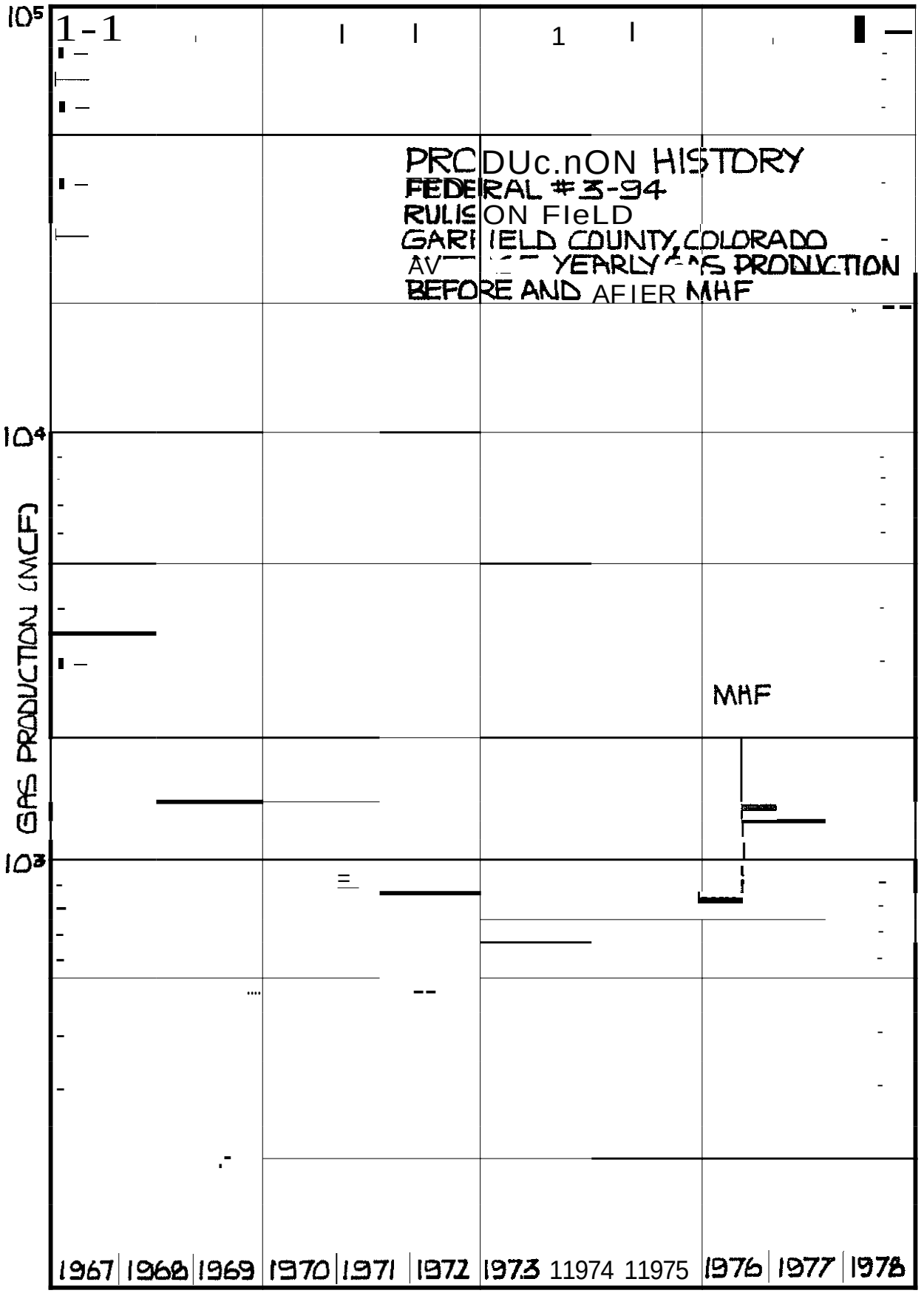


FIGURE 5- 2 PRODUCTION HISTORY OF FEDERAL 3-94 WEIL

RIO BLANCO MASSIVE HYDRAULIC FRACTURING EXPERIMENT

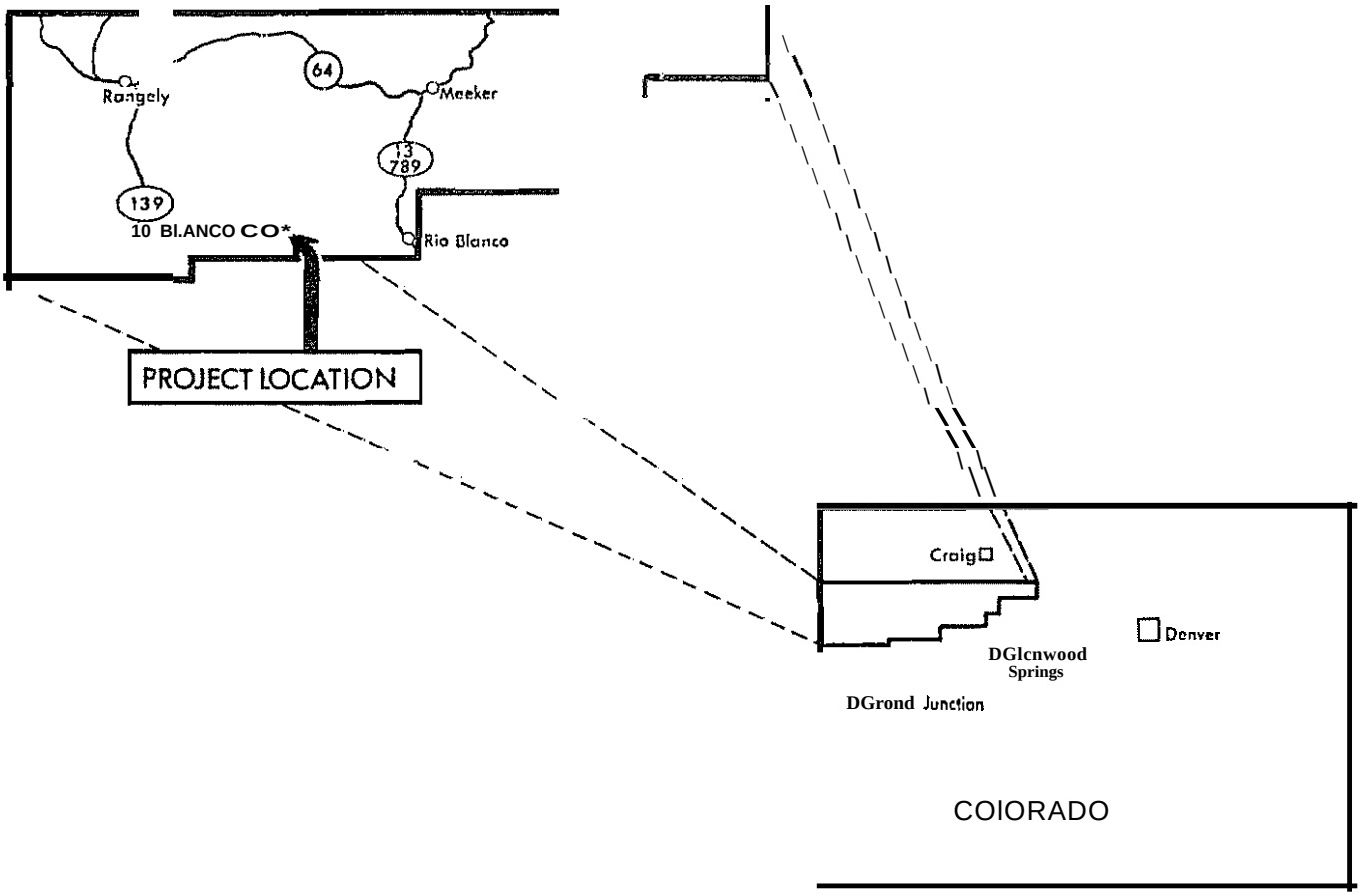
EY-76-C-08-0623

CER Geonuclear Corp.
Las Vegas, Nevada

Interagency Agreement Date:	June 19, 1974	
Project Cost {estimated}:	ERDA	$1,975,000
	Industry	1,500,000
	Total	$3,475,000
Principal Investigator:	G. R. Luetkehans	
Technical Advisor for ERDA:	**Charles H. Atkinson, Bartlesville Energy Research Center**	

Objective

This stimulation experiment is being conducted **in low-permeability, massive gas-bearing sandstone** reservoirs **in the Piceance Basin in western Colorado, to** test advanced hydraulic fracturing technology where it **has not been possible to obtain commercial production** rates. This test is located about 1 mile from the 1973 **Rio Blanco nuclear stimulation site to permit comparison** of nuclear and hydraulic fracturing techniques in **this area.**



5.3 CER CORPORATION

5.3.1 Scope of Work

ERDA Contract EY-76-C-08-0623 was signed with CER Corporation in March, 1974. The Rio Blanco Massive Hydraulic Fracturing Project was fielded in 1974 as a joint Industry/ERDA demonstration to test the relative formations that were stimulated by the Rio Blanco Nuclear fracturing experiment. The project is essentially a companion effort to and a continuation of the preceding nuclear stimulation project, which took place in May, 1973.

The Rio Blanco projects are located in the northern part of the Piceance Basin of northwestern Colorado, one of a number of basins in the Western United States that have substantial quantities of natural gas locked in tight sand-shale reservoirs.

In general, these tight gas formations comprise predominantly shales and siltstones with a few cleaner sandstones; the sandstones are frequently shaly and silty and contain water-sensitive clays.

5.3.2 Description of Well, MHF No.3

The Rio Blanco unit MHF Well No.3 is located in Sec 11, T3S, R98W, in Rio Blanco County, Colorado, near the center of the Piceance Basin. It is on lands dedicated to the Rio Blanco Gas unit and is one mile northeast of the Rio Blanco Unit E-Ol, the nuclear emplacement well. The MHF 3 well was spudded on May 21, 1974 and completed on September 13, 1974. A total of four strings of casing were set. The 10-3/4 in. 00 intermediate casing was set at 5,603 ft in the top of the Fort Union Formation, casing off all the overlying Wasatch and Green River; 7 in. production casing was set at 8,162 ft in the lower Mesaverde.

A total of ten cores were cut between 5,925 - 7,085 ft. Five drill stem tests were attempted, but only one was considered successful; one test failed and on three tests packers leaked during shut in, a measure of the competency of the strata. Air and stable foam were used to drill the hole from 5,603 ft to 6,240 ft. Measurements of gas flow'from the open hole section through this interval aided in determining the reservoir quality of the sands; these rates ranged from 10 MCFD to a maximum of 89 MCFD. During the drilling of the well and after its completion, the hole was extensively logged.

5.3.3 Summary of Completed Work

The well has been fractured a total of four times (Figures 5-3, -4, -5, and -6): twice in the lower Mesaverde and twice in the Fort Union. A fifth zone in the Upper Mesaverde was extensively tested but abandoned as being of insufficient quality for fracturing. The self-imposed limits for fracturing required a minimum of 0.2 md-ft productive capacity or 5 microdarcies permeability in the zone.

Table 5-3 shows the characteristics and results of each of the fracturing treatments. Preparatory operations have been similar for each; the well is first

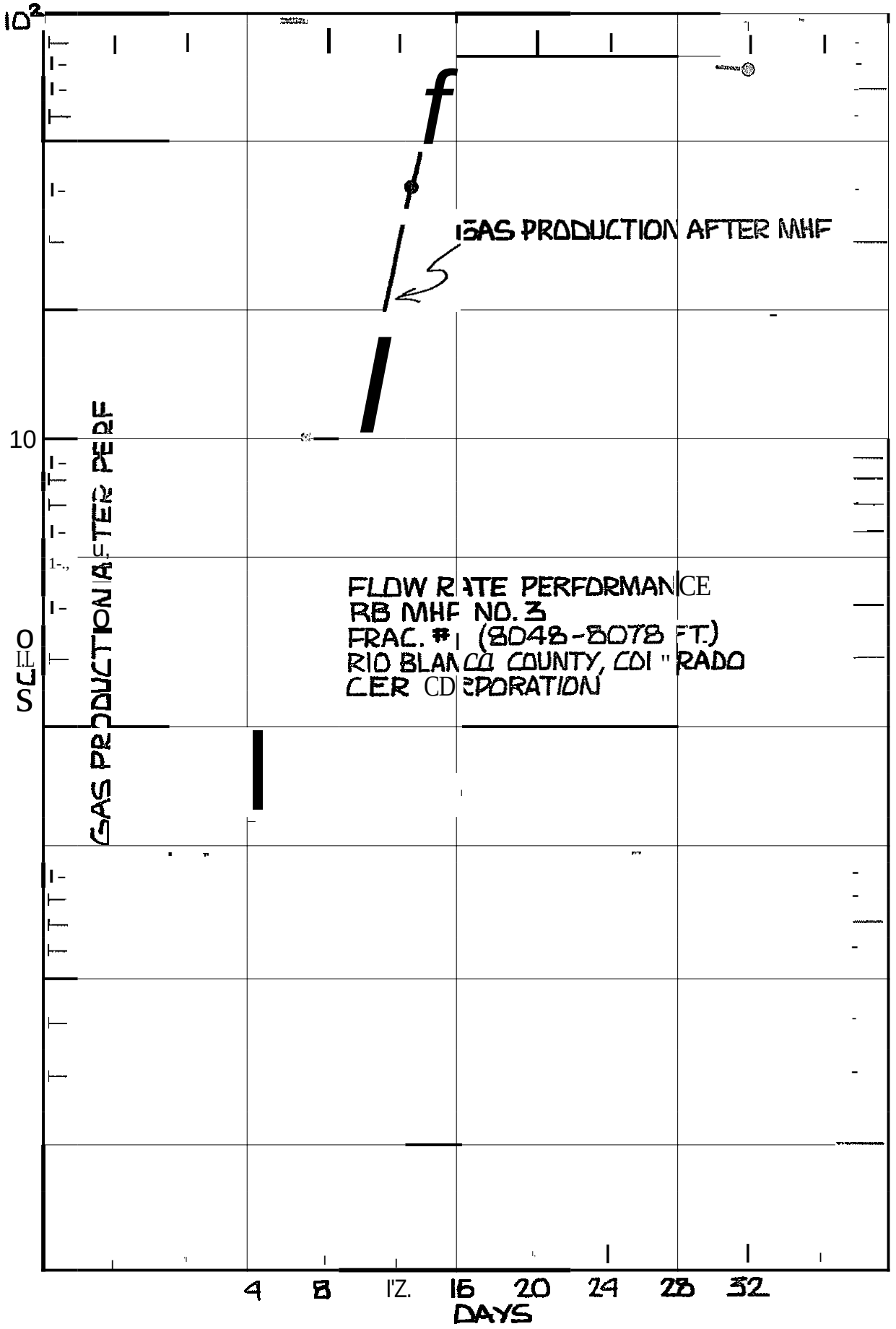


FIGURE 5- 3 PRODUCTION HISTORY OF RB MHF NO. 3 AFTER FRAC. 1

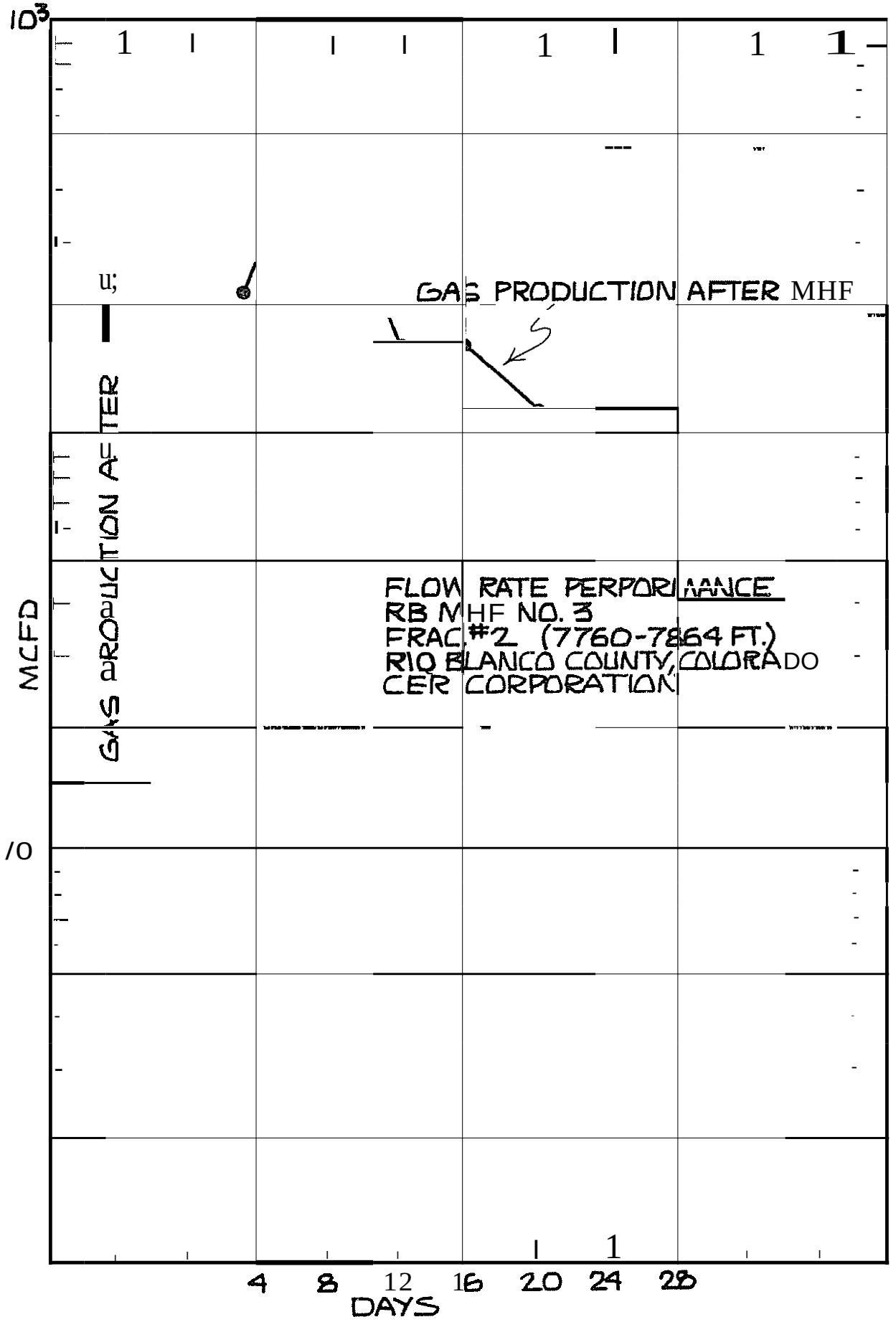


FIGURE 5- 4 PRODUCTION HISTORY OF RB MHF NO.3 AFTER FRAC. 2

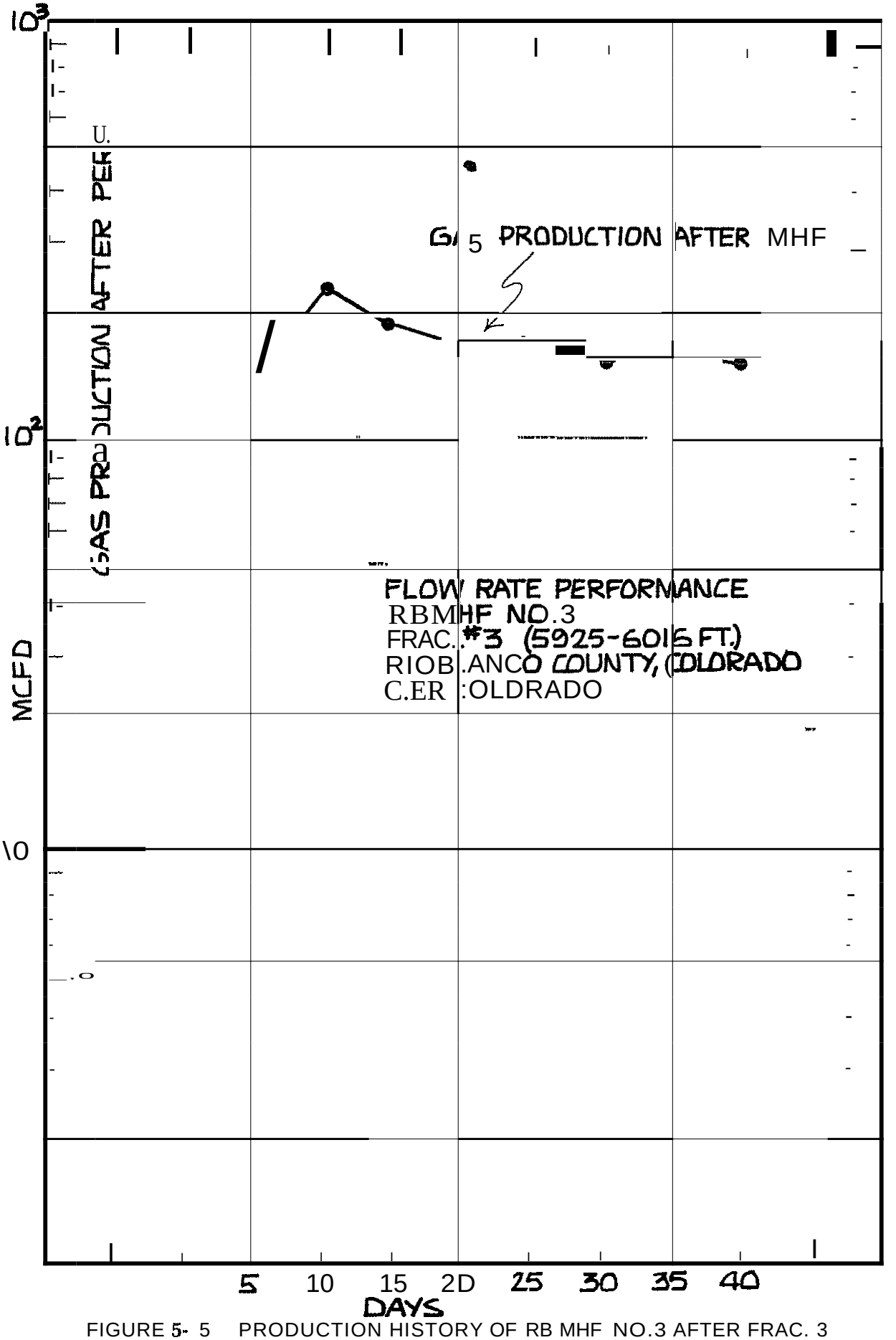


FIGURE 5- 5 PRODUCTION HISTORY OF RB MHF NO.3 AFTER FRAC. 3

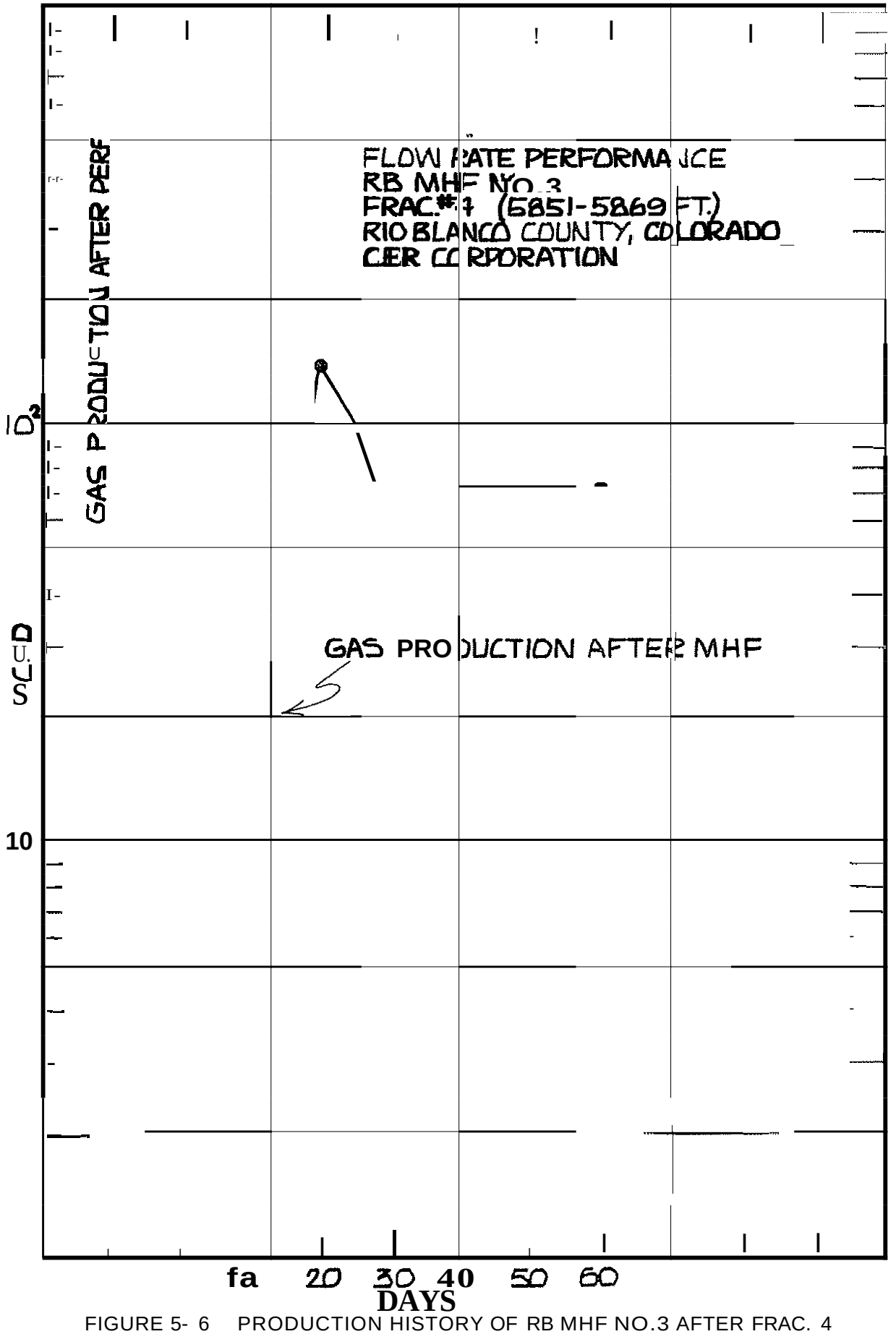


FIGURE 5- 6 PRODUCTION HISTORY OF RB MHF NO.3 AFTER FRAC. 4

perforated dry and the zone allowed to produce naturally for a short period. The perforated interval is then broken down with 5,000 to 10,000 gal of 2% KCL brine using ball sealers to assure breakdown of each perforation. This initial treatment is cleaned up and the zone flowed for 5 to 10 days, after which the well is shut in for two weeks to one month for pressure build up and analysis. This procedure permits the determination of the natural productive capacity, kh, upon which determinations of fracture capacity, and to some extent, geometry are based.

After completion of the pre-frac analyses, the zone is given a massive hydraulic fracturing treatment followed by a clean up and flow period of about two months. A packer is set on tubing above the zone during the initial clean up in order to reduce after flow volume. After gas flow has stabilized and about 55 to 60% of the frac load recovered, the well is again shut in for buildup, usually for two months.

The results of the fracturing treatments are presently being analyzed. The experiment has essentially been completed, lacking only a flow test of the combined zones and final analysis. A complete report will be published in the future.

5.3.4 Conclusions and Recommendations

In the four treatments, none appears to have fractured laterally as designed. In the Fort Union and Mesaverde each well must produce from numerous sand lenses, the lateral extent of which appears to be limited. This lenticularity substantially reduces the overall average permeability, formation productive thickness and effective drainage area available to the fracture. Calculated propped fracture lengths are quite short. In the analyses, CER has had to surmise very low fracture conductivities, 1/5 to 1/20 of design. Current analytical techniques assume infinite fracture conductivity. One MHF analytical effort has been able to obtain good performance matches in modelling continuous sands, but has had to reduce net sand quantity by 75% to match the production performance of lenticular sands such as those in the Mesaverde. There are several possibilities: (1) Fracturing out of zone with vertical propagation of the fractures instead of horizontal as designed; (2) Sand lenses have substantially smaller dimensions than design fracture lengths; and (3) Conventional logging and analytical techniques available to us are not sufficiently discriminatory in these environments to differentiate net pay from non-productive formation. It is probable that all of these possibilities are operative in the tight gas sands.

Techniques need to be developed that will define, if not control, the extent, shape, and orientation of fractures. This is primarily a function of mechanical rock properties and existing rock stresses; knowledge in these areas is deficient. Geologic analyses are required to define areas of maximum sand content, the probable extent and distribution of lenticular sands, and the stratigraphic and structural features that affect or control sand distribution and fracture orientation.

Fracturing fluid technology is advanced, but additional work is required to define viscosity changes with temperature, especially as it relates to fracture extension, closure, and proppant transport. In the first two of the treatments,

a polyemulsion suspending type fluid was used, and the last two, a single phase equilibrium bank fluid. Fluid returns after fracturing have been comparable for the two types of fluid, except for one abberration: In frac No.1 a preferential return of the lighter napthenic-oil over the heavier diesel oil from the frac oil mix occurred. Sand recovery after frac has been nominal, less than one percent of frac volume, except in the third frac which sanded out.

The reservoir rock properties of commercially productive reservoirs are substantially better than in these tight gas sands we are now evaluating. They are less affected by compaction and relatively slight changes in saturations.

The usual industry techniques for determining porosities, saturations, and permeabilities can be relied upon to produce acceptable if not precise answers in those formations. However, as the reservoir rock properties become poorer, the standard industry practices for determination of these variables becomes suspect. The need for new and better techniques for evaluation of the parameters is critical. Determinations of bottom hole temperatures, pressure and porosity appear to give reasonable results. However, accurately defining water, oil and gas saturations, permeability, and differentiating net pay, particularly under in situ conditions, are major areas where the present technology is lacking. Techniques must be refined to define these values in tight, shaly-silty sands, and their relation to productivity.

with the current state of technology, the best determinative technique is still long term testing. Accurate predictions of production depend upon reliable pressure testing, and in tight sands of the Western Rocky Mountains, this currently requires long term flow, followed by long term build up; each phase on the order of two to four months.

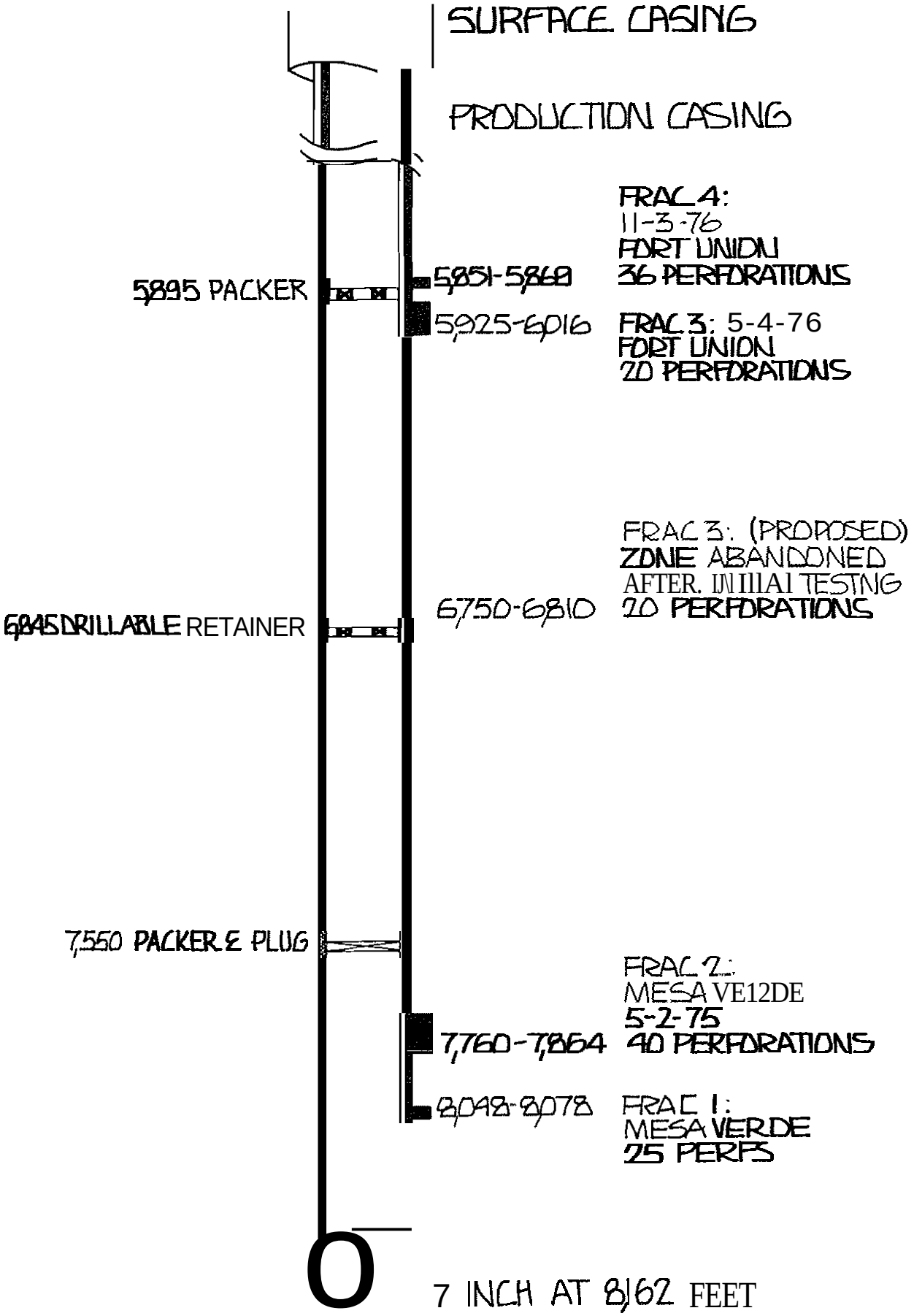


FIGURE 5- 7 SCHEMATIC OF MHF NO 3 WELL

TABLE 5-3 TABULAR BREAKDOWN OF WORK PERFORMED ON MHFNO.3WELL

FRAC NO.	1	2		3	4
ZONE	8048-8078 ft L. Mesaverde Single Sand	7760-7864 ft L. Mesaverde Multiple Sands	6736-6806 ft U. Mesaverde Multiple Sands	5925-6016 ft Fort Union Multiple Sands	5851-5869 ft. Fort Union Single Sands
PERFS	25	40	12	20	36
BHT	242°F	225°F	210°F	201°F	197°F
NATURAL FLOW	1 MCFD	5-10 MCFD	5-10 MCFD	42.5 MCFD	56 MCFD
AFTER B.D.	60 MCFD	57.3 MCFD	27.7 MCFD	42 MCFD	
BHP	3450 psi		2828 psi		2092 psi
MHF	Poly E, Suspended bed. 117,500 gal 400,000 Ibs Naptha-type Diesel mix refined oil. kcl brine	Poly E. Suspended bed. 285,000 gal 880,000 Ibs Naptha-type Refined oil, kcl brine	NO FRAC	Logel kcl brine. Equilibrium Bank 400,000 gal 815,000 Ibs	Logel kcl brine, Equilibrium Bank 241.000 448.000 Ibs
FRAC RATE	16-22 BPM	45 BPM		20-25 BPM	15-25 BPM
TREAT PRESS.	4880-5800 psi	3800-5300 psi		800-5500 psi	1200-5000 psi
ISIP	4500 psi	3170 psi		Sand Out	4450 psi
FLUID REC.	59%	59.5%		65.5%	56.4%
GAS RATE	60.7 MCFD	137 MCFD		160 MCFD	69 MCFD
PROD. CAP.	0.15 md-ft	.3 md-ft		.3-.5mdft	.3 md ft
CALCULATED FRAC LENGTH (Type Curve Match)	110' - 170'	150'		100'	20' - 30'
REMARKS	Sand Return Negligible	Plugged by fm. solids (Fe minerals.) Rec 7000 Ibs sand.	Zone Squeezed	Zone Squeezed Sanded out on frac - rec. 37000 Ibs sand	Rec 6200 Ibs sand

WATTENBERG FIELD EY-77-C-08-1514

Colorado Interstate Gas Company
Colorado Springs, Colorado

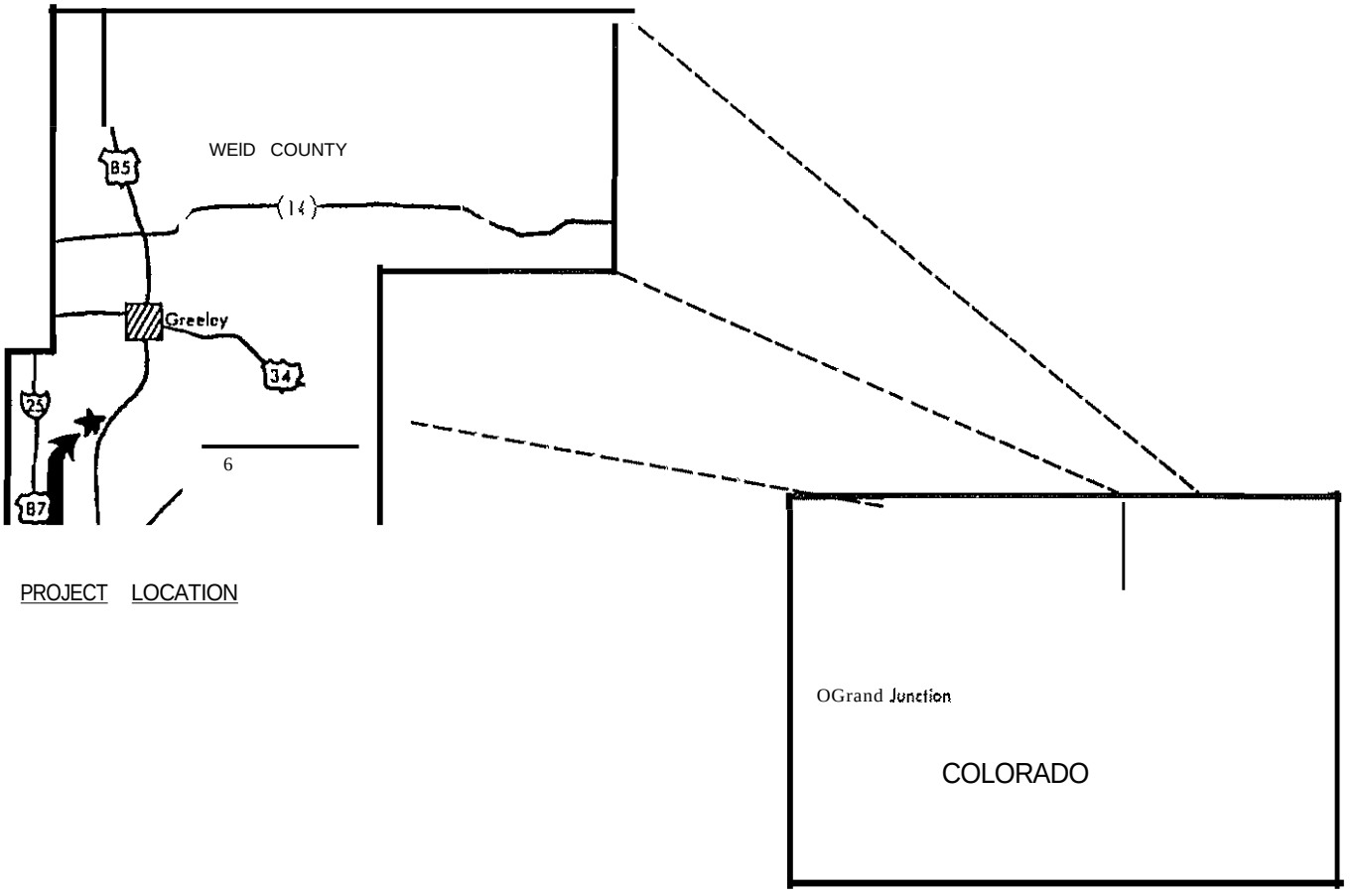
Total Project Cost: $169,000

Principal Investigator: Howard Fredrickson

Technical Project Olllcer for ERDA: C.H. Atkinson, Bartlesville Energy Research Center

Objective

Cyclic injection of dry natural gas is the method to be used to increase productivity of light gas sands



5.4 COLORADO INTERSTATE GAS COMPANY

5.4.1 Scope of Work

The Colorado Interstate Gas Company will attempt to determine if the productivity of wells completed in low permeability natural gas reservoirs can be improved by reducing the interstitial water saturation. The method used to accomplish this reduction of water saturation will be a cyclic injection of dry natural gas. In addition, cyclic injection of dry natural gas may improve the productivity through dehydration of matrix clays and the removal of formation damage adjacent to the surfaces of induced fractures.

5.4.2 Description of Existing Wells, Sprague No. 1 & Miller No.1

The project location is in the Wattenberg Field of northeastern Colorado. The producing formation in this field is the Dakota J which has a potentially productive area of about 625 square miles.

CIG will utilize two wells which were contributed by the Machii-Ross Petroleum Company, both completed in the Dakota J sand for this project.

The location of the two wells are:

Sprague No. 1 (S-l)	Sec 9, T2N, R67W
Miller No. 1 (M-l)	Sec 17, T2N, R67W

5.4.3 Operational Plan

After the facilities are installed and serviceable, and the initial BHP buildup completed, the Miller No. 1 will be put on production and the Sprague No. 1 will be set up to receive the produced gas. The produced gas, water saturated at wellhead flowing temperature and pressure conditions, will be dehydrated by an Olman Heath Glycol Dehydrator to a water content of SIbs perMMCF before injection.

Two, 2 in. meter runs and orifice meters will be installed to simultaneously measure" produced volumes from the well on production and the vol,uue being injected into the other well. The difference will be accounted for as fuel gas for compression and dehydration. Dew points of the produced and injected gas will also be measured.

This operational mode will be continued for seven days, at which time it is estimated that the Sprague No. 1 wellhead injection pressure will be about 1,500 psi, and the Miller No. 1 wellhead flowing pressure, at 50 MCFD, will be about 300 psi.

The 75-horsepower compressor is designed to take 500 MCFD at a suction pressure of 200 psi and to compress it to 2,500 psi discharged pressure, a ten-fold increase in the productivity of the Miller No. 1 well without modification.

At seven days, or when the wellhead injection pressure on Sprague No. 1 reaches 2,500 psi, Mode 1 will be ended and the production and injection reversed for the Mode 2 operations. At the end of about six months, the wells will be shut in for a GO-day bottom hole pressure (BHP) buildup. Based on seven-day intervals of operation in each !lode, data will be available for 12 operating intervals in each Mode. Changes in the interval of operation in each Mode, however, may be required based on dew point and pressure data. The three-year term of the project will permit three subsequent six-month periods of cyclic injection, each followed by BHP buildup surveys.

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PINEDALE UNIT MASSIVE HYDRAULIC FRACTURING EXPERIMENT

E(34-1)-0033

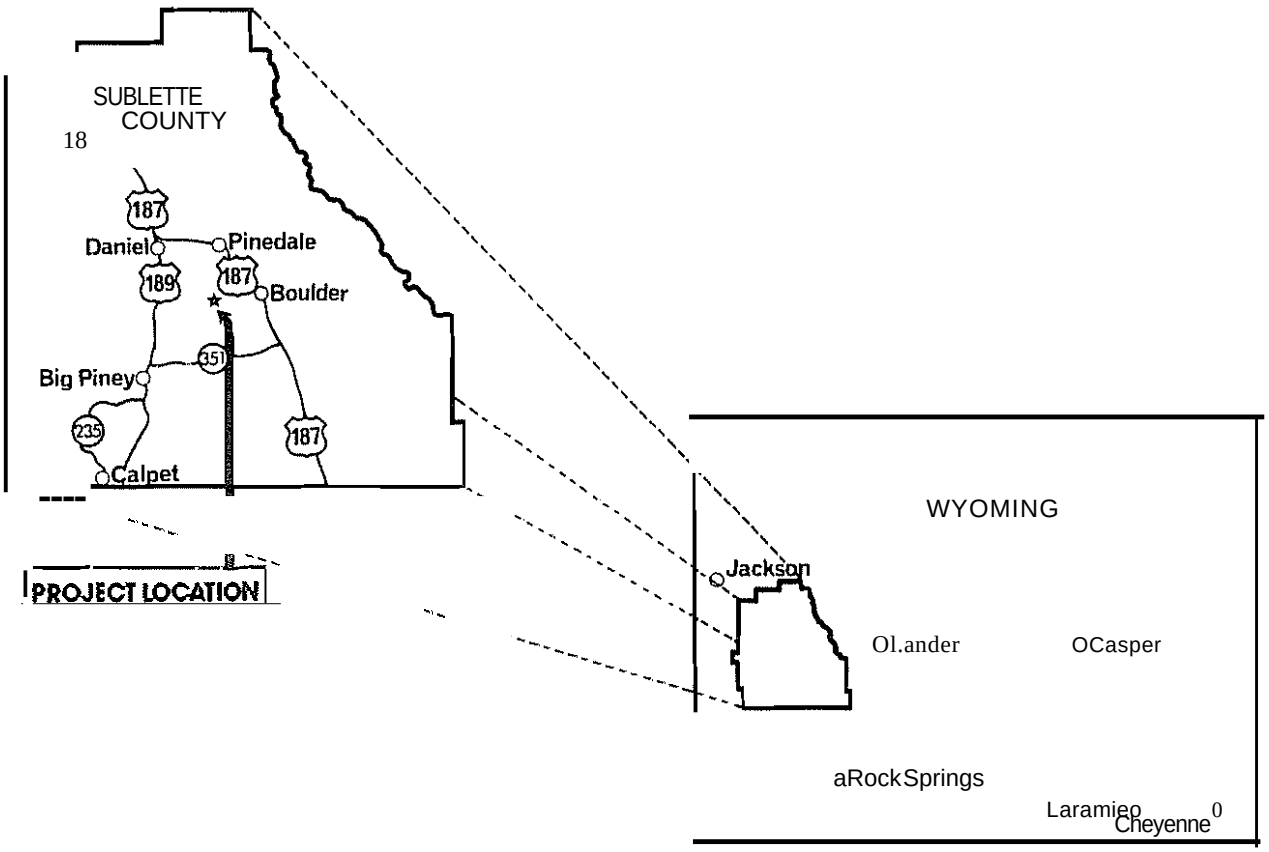
El Paso Natural Gas Company
El Paso, **Texas**

Contract Date: September, 1975
Completion: October, 1976
Project Cost: ERDA 583,263

Principal Investigator: Dr. Phillip L. Randolph
Technical Project Officer: Charles H. Atkinson

Objective

To evaluate the effectiveness of massive hydraulic fracturing for stimulating natural gas production from thick, deep sandstone reservoirs having low permeability



5.5 EL PASO NATURAL GAS

5.5.1 Scope of Work

On September 19, 1975 ERDA Contract No. E(34-1)-033 was signed with El Paso Natural Gas Company. The scope of work involved performing three MHF experiments in two wells completed in a low permeability reservoir in the Northern Green River Basin, at a depth interval between 8,000 ft and 12,000 ft. A total of 894,190 gal of fluid and 2,715,000 Ibs of sand were pumped in three stages in two wells with the limited entry technique. Fluid viscosities were designed to give propped lengths of 1,000 - 1,500 ft and proppant sand beds having heights greater than 50 percent of the thickness of each sandstone fractured.

The experiments included laboratory research to design limited entry with perforations through one and two strings of casing.

A high proppant concentration was used to assure that production would be limited to reservoir characteristics, rather than fracture conductivity. A comparison was made with results of prior hydraulic fractures propped with a partial monolayer.

5.5.2 Summary of Completed Work on Pinedale Unit No. 7 Well

In this experiment, performed by El Paso Natural Gas Company prior to the ERDA contract, a previous completion below 9,300 ft was isolated from the wellhead with a packer and cement. The casing was perforated with fourteen charges adjacent to sandstone strata believed to contain net pay.

On September 9, 1974, a total of 20,200 gal was pumped to initiate fractures behind the perforations. Balls, which would seat on open perforations were dropped while pumping KCl water.

On September 12, 1974, the well was fraced with polyemulsion fluid having a condensate/water ratio of 70/30. The water was gelled with 25 Ibs of cellulose gelling agent per 1,000 gal. In addition, the water contained KCl, the surfactant required to form an emulsion with condensate, a bacteriacide, a buffer to achieve desired pH, a de-foaming agent, and, near the end of the frac, "breakers" so that viscosity would be reduced in a few hours.

The pumping rate averaged 11.1 BPM with an average pumping pressure of 7,900 psi.

Production of frac fluid was begun the morning after fracturing and on the sixth day, a peak natural gas production rate of about 1,000 MCFD was experienced. By the eighteenth day, production rate had declined to 200 MCFD. With the exception of peaks after shut-in periods, production rate then declined monotonically to about 100 MCFD one year after fracturing. A total of 49.8 MMCF was produced.

At the end of the production test, water recovery was about twice the amount pumped and the water/gas ratio had stabilized at about 0.07 barrel of water per MCF of natural gas. Condensate recovered during the year of testing was only about 70 percent of the amount pumped.

5.5.3 Summary of Work Completed on Pinedale Unit No. 5 Well

For the first experiment with No. 5 well, the prior completion attempts at depths below 12,000 ft were isolated from the wellhead with a packer and cement plug. Since bond logs left doubt as to whether cement outside the old 7 in. O.D., casing was adequate to confine hydraulic fractures to desired depth intervals, that casing was perforated to test the cement. After performing 31 cement squeezes and milling through a problem area at a depth of about 9,300 ft, a centralized string of 5 in. O.D., casing was run, cemented and cleaned out to a depth of 11,277 ft.

The charge for perforating through the concentric strings of 5 in. and 7 in. casing was selected after laboratory tests involving full simulation of downhole pressures. This laboratory work revealed that a pumping rate in excess of 1.3 BPM per perforation was required to achieve the desired dynamic pressure drop in excess of 1,000 psi across perforations.

On June 16, 1975, the two strings of casing were perforated with eighteen holes adjacent to the two sandstone strata in the depth interval between 10,950 and 11,180 ft.

On June 16, 1975, fractures were initiated in the two sandstones by pumping about 46,000 gal of water containing KCl and a friction-reducing agent. The breakdown procedure was similar to that of the No.7 well.

During five days after breakdown, 926 barrels of water and 767 MCF of natural gas were produced. The gas production rate varied in the general range of 100 to 200 MCFD and was too low to lift enough liquid from the 4 in. I.D. casing to maintain bottomhole pressure below 2,500 psi or to obtain sufficient stability for accurate measurements.

Since this observed production was an order of magnitude less than anticipated, planned fracture fluid volume was reduced from 412,500 gal to 184,000 gal in order to minimize cost of evaluating production from the two sandstone strata. Calculated length of propped fractures for the reduced experiment size was 1,000 ft or the maximlnn considered by the Natural Gas Technology Task Force.

On July 2, 1975, the well was fraced with a polyemulsion fluid similar to that employed on the Pinedale unit No. 7 well experiment.

Pumping rate was varied between 20 and 29 BPM to improve lmderstanding of pipe friction for the polyemulsion fluid. The majority of fluid was pumped at about 25 BPM and a pressure of about 9,700 psi.

Production of frac fluid was begun on the morning after fracturing. Initial production was similar to that from the Pinedale Unit No. 7 well and the peak rate of about 1,000 MCFD was observed on the sixth day after fracturing. However, decline from this peak was less than for the previous experiment. Between the fifteenth and thirty-seventh day after fracturing, observed production rate declined from about 485 MCFD to about 340 MCFD and was about 1.5 times that observed at similar times for the Pinedale Unit No. 7 well experiment.

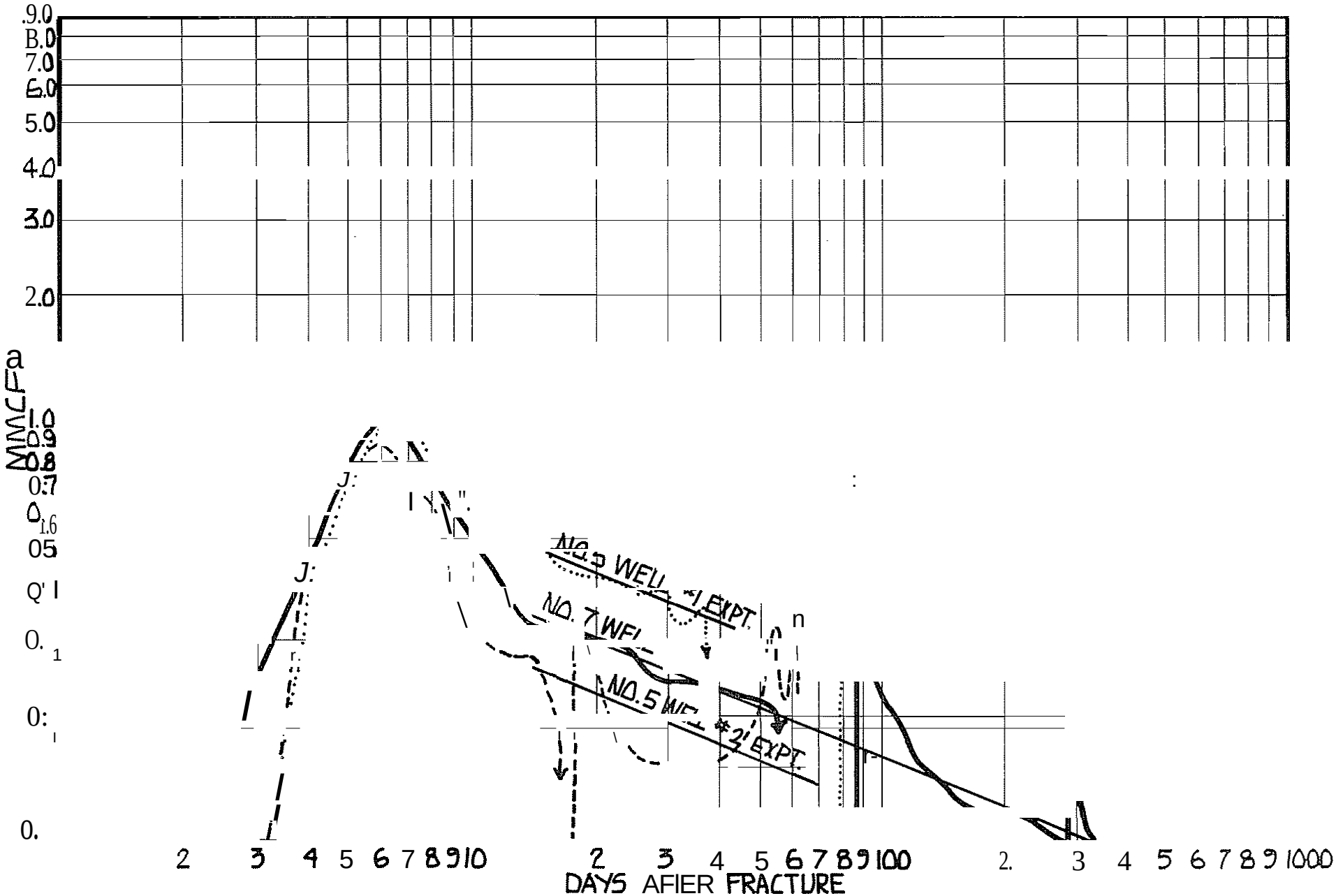


FIGURE 5- 8 OBSERVED PRODUCTION FROM THE 3 PINEDALE MHF EXPERIMENTS

Including forty-one days of shut in time, a cumulative production during eighty-eight days after fracturing was 23.4 MMCF.

At the end of the production test period, water recovery was 1.66 times the amount pumped but only 44 percent of the condensate phase of the frac fluid had been recovered. During the last ten days of production, the ratios of water and condensate production to natural gas production averaged 0.113 and 0.024 barrel per MCF, respectively.

For the second experiment the previous experiment was isolated from the wellhead by setting a bridge plug at a depth of 10,917 ft.

The same charges as for the previous experiment were used to make 26 perforations adjacent to six sandstone strata and on October 15, 1975, a breakdown procedure using about 66,000 gal of fluid was performed. The same fluids and a three-step procedure similar to the previous experiment were used.

Production was commenced the morning after breakdown. After three and one-half hours, natural gas production rate had increased to about 500 MCFD and the ratio of liquid to gas production was acceptable for separator operation. During the next twenty-one hours, 1,100 MCF of gas were produced as wellhead pressure decreased from about 2,200 psi to 500 psi. The ratio of water to natural gas production was about 0.58 barrel per MCF.

On October 20, 1975, the well was fraced with a gelled water fluid rather than the polyemulsion fluid perviously used.

Pumping rate averaged about 45 BPM. Pressure declined about 600 psi during the first 150,000 gal and then averaged about 6,000 psi while pumping sand with a concentration of four Ibs per gal.

The propped length of fractures is calculated to be approximately 1,000 ft for all six sandstone strata.

Production of frac fluid was begun the morning after fracturing. Natural gas production was again observed to peak on the sixth day after fracturing at 860 MCFD. By the fifteenth day after fracturing, production had declined to about 250 MCFD, or about one-half the average of the two previous experiments. with the exception of a peak after a one-day shut-in, production continued to decline to about 150 MCFD after 43 days.

Between forty-three and fifty-three days after fracturing, sand was cleaned from the wellbore by circulating water through 2-3/8 in. tubing. The tubing was then hung in the wellbore to a depth of 10,000 ft, or about 138 ft above the top perforation. During the next week, production rate averaged about 270 MCF, or 75 percent more than the week before cleanout. A total of 15.9 MMCF had been produced between perforation and sixty-two days after fracturing. Testing terminated after a bottomhole pressure bomb was lost in the well and sand bridging had plugged the production tubing. Water production was substantially greater in relation to natural gas production than for prior experiments.

5.5.4 Conclusions

These experiments have provided data on production from the Green River Basin. However, comparison with prior experiments reveals that major unresolved questions remain in relation to optimum hydraulic fracturing technology and the wellhead cost for commercial production.

One month production tests following fracturing of five independent sandstone reservoirs during the 1960s revealed cumulative natural gas production of 36.7 MMCF and production rates from the two wells totaled 835 MCFD at the end of the month. These quantities are within 10 percent of those observed at the end of the first month of testing during the three massive hydraulic fracturing experiments. The cost significance of this similarity in producing characteristics is apparent when one recognizes that the fracs in the 1960s involved 97,000 gal of gelled fluid and 55,000 Ibs of proppant whereas the recent experiments have involved pumping about 861,000 gal of gelled fluid and 2,715,000 Ibs of proppant into the formation.

Existing factual data is not adequate to resolve whether this comparison reveals the sandstones fraced in the 1960s and better reservoir characteristics or whether the partial monolayer propping actually resulted in high fracture conductivity to about the same distance as the recent packed bed fractures.

NATURAL BUTTES UNIT, UINTAH COUNTY, UTAH MASSIVE HYDRAULIC FRACTURING DEMONSTRATION

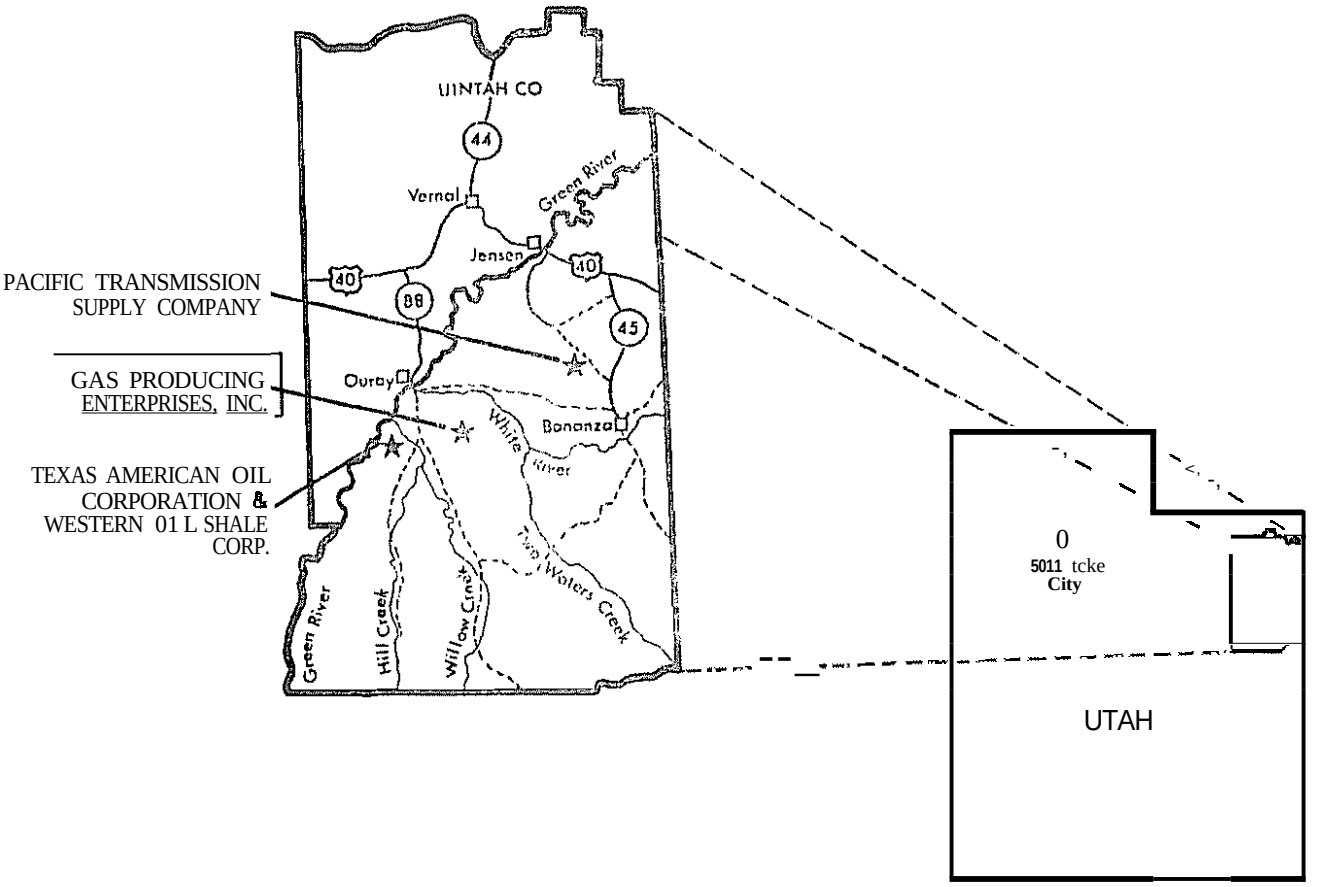
EY-76-C-08-0681

Gas Producing Enterprises, Inc
Subsidiary of Coastal States Gas Co.
Houston, Texas

Contract Date:	July 1,1976	
Anticipated **Completion:**	Sept. 30, 1978	
Total Project Cost:	ERDA	$2,155,000
	Industry (prior costs)	1,881,000
	Industry (new costs)	2,945,000
	Total	$6,981,000
Principal Investigator:	W. E. Spencer	
Technical Project Officer:	**C. H. Atkinson, Bartlesville Energy Research Center**	

Objective

To evaluate the effectiveness of massive hydraulic fracturing for stimulating natural gas production from thick, deep sandstone reservoirs having low permeability.



5.6 GAS PRODUCING ENTERPRISES INC.

5.6.1 Scope of Work

On July 1, 1976, a Contract, EY-76-C-08-0681, was entered into between ERDA and Gas Producing Enterprises Inc. concerning the conduct of a MHF experimental program. The GPE program was greater in scope compared to the other MHF contracting companies. Originally, two old wells, Natural Buttes 18 and 14, and four new wells, 19, 20, 21, and 22 were to be fractured using a new minimum viscosity cross-linked gel. Variations between wells were to consist of amounts of frac fluid, sand size, porosity of zone tested, and fluid design. A contract modification for Phase V of the MHF Demonstration Contract provides for an add-on to the CIGE #21 well (new well designation) to arrange for coring, running of extra logs, and to run production and buildup tests on individual sand members within two sections of the Mesaverde. The core data, including special interpretation, and production test data will be correlated. In addition, there will be an attempt to obtain post MHF performance of these individual sand members for better prediction of potential productivity of a sand member by electric log interpretation alone.

The contract modification provides for ERDA contribution of an extra $672,000 with GPE contributing roughly $100,000.

GPE will start drilling the #21 well approximately mid-September.

5.6.2 Summary of CornpletedWork

The following is a brief summary of completed work for each well.

Natural Buttes No. 18 Well

Production casing was set to 9,140 ft with 4-1/2 in. N-80; the interval from 6,490-8,952 ft was perforated in 18 four-ft zones with one shot per foot.

PERFORATION	FT. PAY	Ø	Sw	PERFORATION	FT. PAY	Ø	Sw
6,490 - 6,494	7	10%	50%	7,728 - 7.732	11	10%	50%
6,444 - 6,448	15	11%	50%	7,852 - 7,856	11	12%	40%
6,668 - 6,672	7	12%	57%	7,886 - 7,890	7	8%	50%
6,698 - 6,702	12	11%	50%	7,924 - 7,928	12	10%	50%
6,740 - 6,744	15	12%	39%	8,614 - 8,618	4	8%	35%
6,780 - 6,784	19	8%	50%	8,846 - 8,850	12	9%	38%
6,954 - 6,958	24	9%	60%	8,872 - 8,876	10	8%	45%
7,046 - 7,050	20	10%	56%	8,900 - 8,904	10	11%	39%
7,438 - 7,442	21	9%	54%	8,948 - 8,942	7	9%	48%
				TOTAL	224		
				AVERAGE		9.8%	47.8%

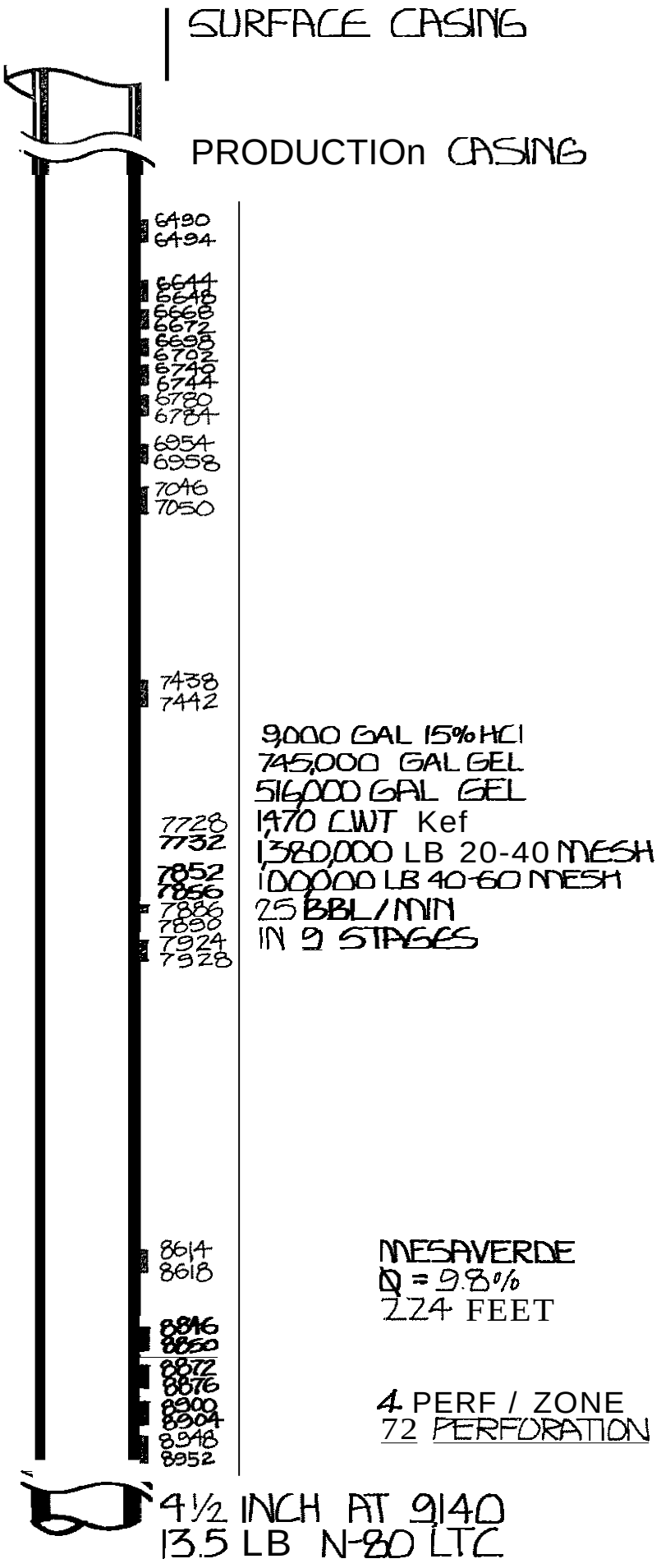


FIGURE 5- 9 SCHEMATIC OF NATURAL BUTTES NO. 18 WELL

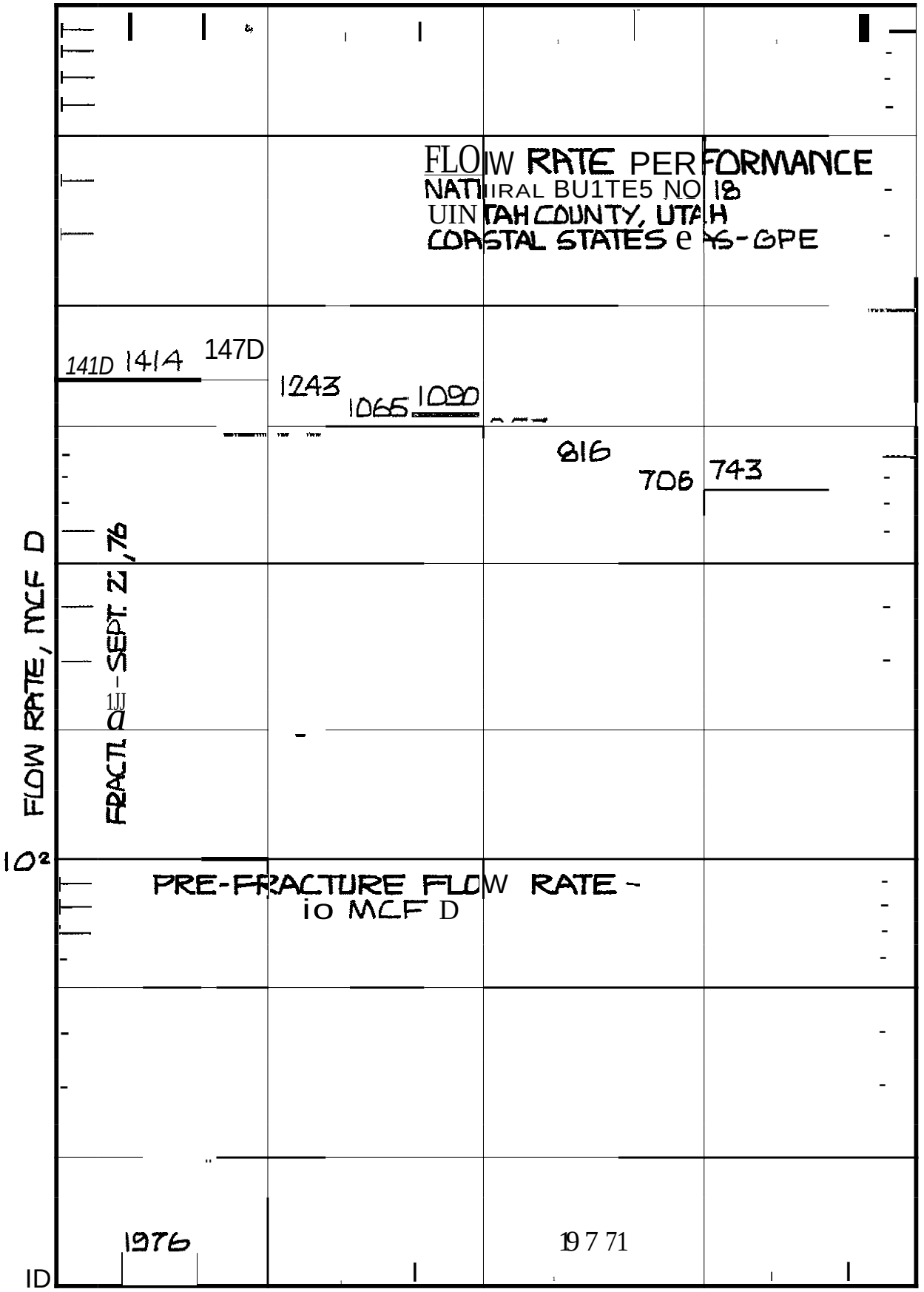


FIGURE 5-10 FLOW RATE PERFORMANCE OF NATURAL BUTTES NO. 18 WELL

The eighteen zones were fractured with 1.5 million lbs of sand, as shown in the accompanying well diagram, after BHP had built up to 3,970 psi (.44 psi/ft). Initial kh was estimated at .0189 md-ft. The frac job was done September 22, 1976, and after September 30, 1976, the well flowed at an average of 1,412 MCFD. Fracture length was calculated as 882 ft for the 20/40 mesh sand.

The well was cleaned of sand during December and has been flowing steadily since then, but production has declined steadily to somewhat less than 1 MMCFD (Figure 5-10) •

Natural Buttes No. 19 Well

Production casing was set at 9,697 ft with 4-1/2 in. N-80 pipe and perforated from 8,909-9,664 ft in 19 four-ft intervals with 1 shot per foot.

PERFORATION	FT. PAY	Ø	Sw	PERFORATION	FT. PAY	Ø	Sw
7,224 - 7,228	14	9%	55%	8,909 - 8,913	10	11%	35%
7,351 - 7,355	4	12%	45%	8,991 - 8,995	9	10%	40%
7,405 - 4,709	12	10%	52%	9,142 - 9,146	7	10%	65%
7,444 7,448	5	10%	55%	9,231 - 9,235	9	10%	55%
7,478 - 7,482	12	10%	50%	9,402 - 9,406	3	12%	55%
7,632 - 7,636	10	9%	50%	9,478 - 9,482	11	9%	45%
7,728 - 7,732	12	11%	40%	9,572 - 9,576	12	9%	35%
8,108 - 8,112	11	9%	45%	9,630 - 9,634	33	8%	45%
8,369 - 8,373	10	9%	53%	9,660 - 9,664	--	--	--
				TOTAL	194		
				AVERAGE		9.5%	47%

The well would not flow after perforation. The frac job on September 21, 1976 consisted of L05 million Ibs of sand with calculated fracture length of 950 ft, using a rate of 25 BPM. Temperature and radioactivity logs showed the top seven zones in the bottom stage and 10 sands in the upper stage had been treated. Analysis of the frac.job showed that a single sand size, 40/60 mesh, with an intermediate flowback, in a 3 ppg or more mixture yielded the optim,llU fracture time.

Noise and temperature logs indicated water flow from zones 6 and 7, and the water was sealed off with isolation packers. The 12 zones below produced 190 MCFD initially. Figure 5-12 shows the subsequent production decline.

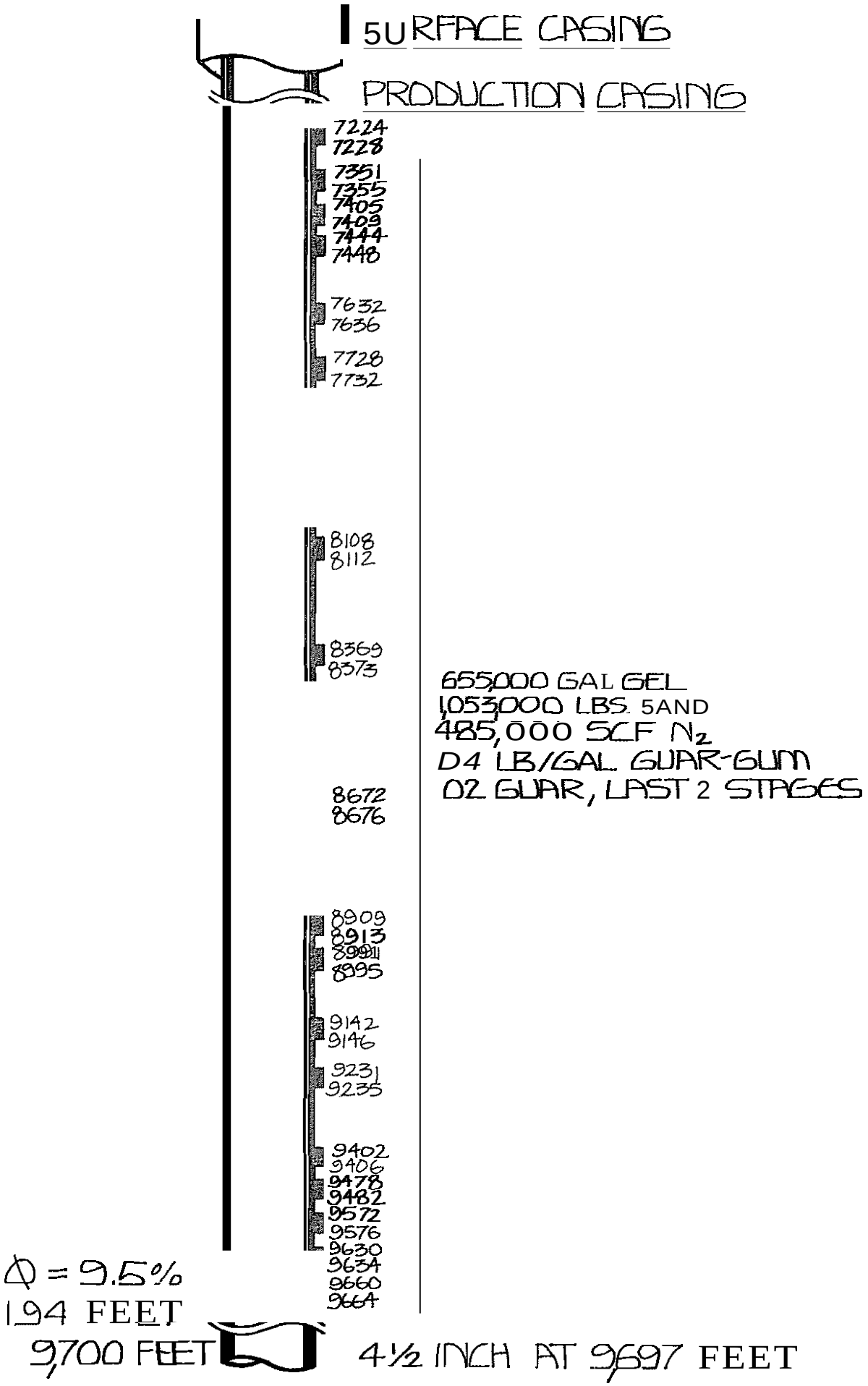


FIGURE 5-11 SCHEMATIC OF NATURAL BUTTES NO. 19 WELL

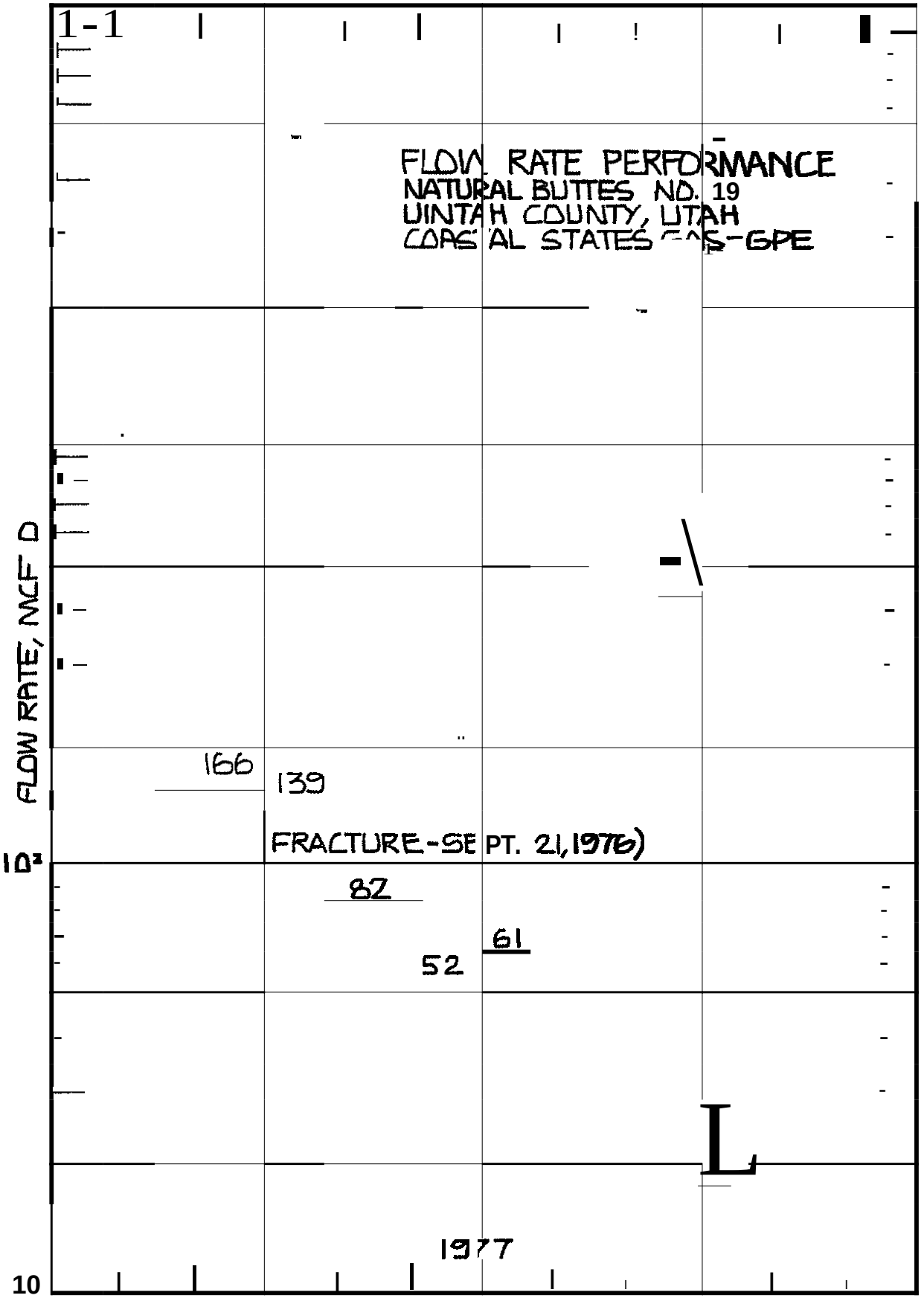


FIGURE 5-12 FLOW RATE PERFORMANCE OF NATURAL BUTTES NO. 19 WELL

Natural Buttes No. 14 Well

No 14 was an existing well, with a 4-1/2 in. casing set to 8,603 ft. The pipe has been inspected with electromagnetic caliper and casing inspection log and a TDT-K log. The top of the cement on the original job, completed on August 25, 1974, was at 6,250 ft (by CBL). On October 10, 1974 twelve sets of perforations were made at one perf per foot over four-ft intervals.

MARCH	6,297 - 6,301	7,261 - 7,265
1977	6,382 - 6,386	7,407 - 7,413
PERF.	6,642 - 6,646	7,572 - 7,576
	6,826 - 6,830	7,724 - 7,728
	6,874 - 6,878	7,790 - 7,794
	6,952 - 6,956	8,967 - 8,971
	6,970 - 6,974	8,000 - 8,004
	7,084 - 7,088	

The well was acidized with 500 gal of 15% Hcl at 10 BPM and 6,200 psi. MHF was made on March 15, 1977 with 1.1 million Lbs sand in 2 ppg mix with cross-linked gel, at 2,600 psi and 25 BPM. Initial production was 150 MCFD after MHF with 879 ft fracture. The well had produced 49.2 MMCF over 24 months from the original bottom 12 sets of perforations, an average of 69 MCFD and 38 MCFD last month.

Temperature and radioactive logs have been run on the fractured well, and production averaged 677 MCFD for the month of May 1977. The best month of production in the original unfractured well yielded only 170 MCFD. Improvement ratio of 17.8 is optimistic, since the final production includes flow from three new sets of perforations.

Natural Buttes No. 20 Well

After mechanical properties log was made from data collected by the open hole logs, perforations were picked over a total of eight zones. The number of perforations was limited to allow the frac job to be accomplished using the limited entry technique. The MHF was performed on June 22, 1977. The perforations were acidized and balled out with 3,000 gal of 15% acid and the well was allowed to clean up and flow test to the pit. The well would make approximately 75 MCFD and no water after the acid job.

The entire job was performed satisfactorily. After the well was treated, a wireline was run in the wellbore to 9,010 ft where it stopped on a small sand bridge which was removed by flowing the well back. The temperature log only covered one set of perforations before reaching the sand bridge and they showed a cooling effect indicating that the perforations took fluids d\uing the frac treatment.

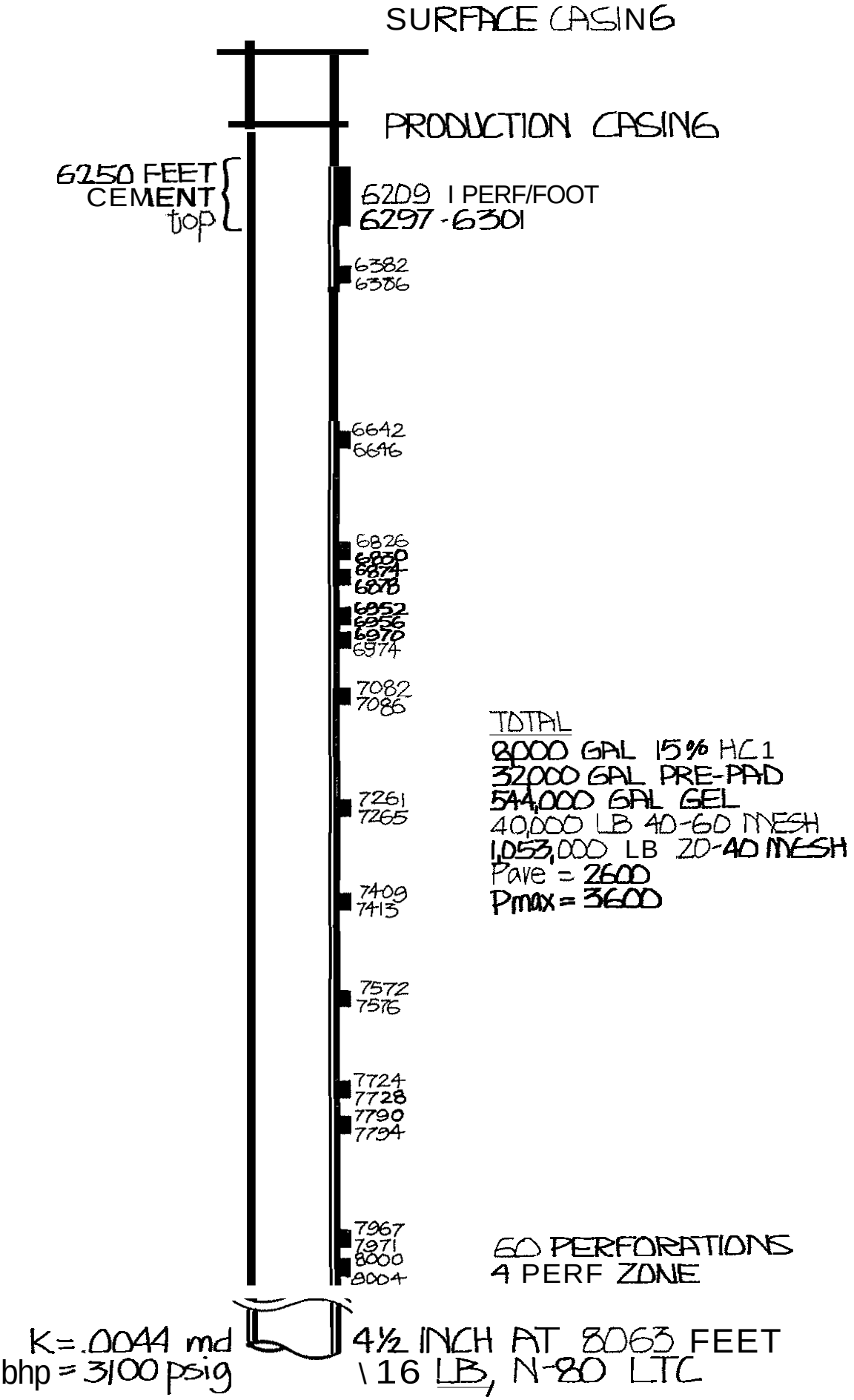


FIGURE 5·13 **SCHEMATIC OF NATURAL BUTTES** NO. **14 WELL**

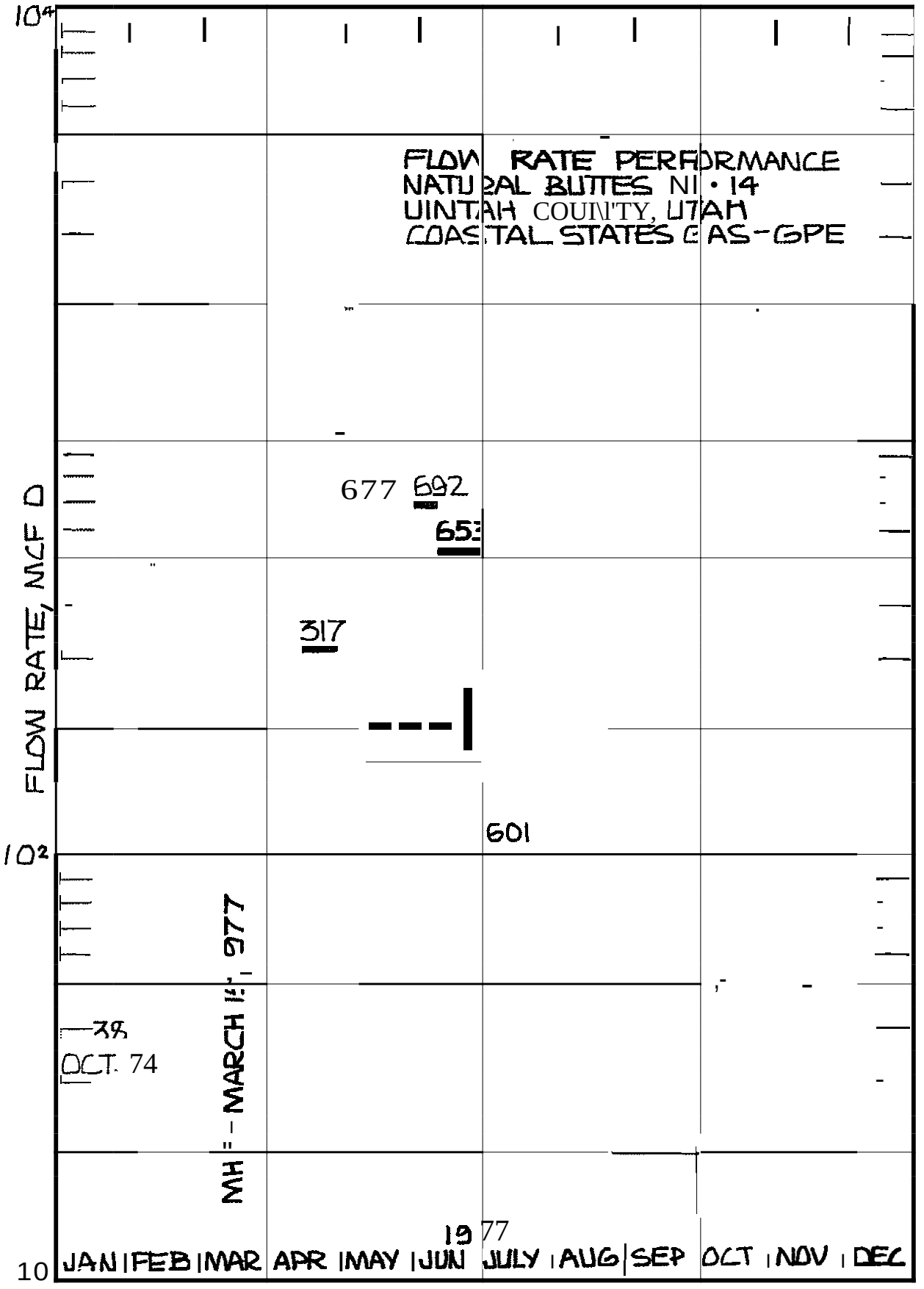


FIGURE 5-14 FLOW RATE PERFORMANCE OF NATURAL BUTTES NO, 14 WELL

Natural buttes No. 20 was turned to the pit twelve hours after fracturing to clean up for flow to sales. After clean up and before being shut in for removal of sand fill-up the well was producing 1.6 MMCFD. Over a 13 day period, the well had an average flow rate of 1,237 MCFD.

PERFORATION (Saraband Depths)	FT. PAY	Ø	Sw	PERFORATION (Saraband Denths\	FT. PAY	Ø	Sw
8 498 - 8 501	4	10%	50%	9.305 - 9 316	14	9%	44%
9,184 - 9,186	8	8%	55%	9,335 - 9,336	1	8%	50%
9,218 - 9,228	19	11%	40%	9,380 -	1	10%	40%
9,264 - 9,279	15	10%	45%	9,471 - 9 476	3	11%	28%
				TOTAL	65		
				AVERAGE		9.9%	44%

Natural Buttes No. 21 Well

Natural Buttes Well No. 21 is waiting on approval of the recommended research work.

Natural Buttes No. 22 Well

Drilling of this well was stopped at a total depth of 8,622 ft. The 8-5/8 in. surface casing parted at 1,050 ft and the subsequent fishing job resulted in the stopping of drilling activity. Production casing was rim and set at 8,622 ft. PBTD has been recorded at 8,515 ft. A program has been designed to clean out to 8,610 ft and run a TDT log on this well.

Natural Buttes No. 9 Well

MHF design work is in progress. A test of casing strength will be made prior to performing the MHF treatment.

TABLE 5-4 **SUMMARY OF MHF** WELLS

WELL	No. of Zones Perf.	Net Ft. of Pay	AVERAGE				Type of Fluid	Gals of Gel	Pounds of Sand	Frac Length Ft.
			Net Ft. Per Zone	Ø	Sw	% Sd				
NATURAL BUTTES NO. 18	28	335	12.5	10	48	88	VERSA FRAC	745,000	1,480,000	882
NATURAL BUTTES NO. 19	19	194	10.2	9.5	47	87	40# GUAR GUM	655,000	1,053,000	950
NATURAL BUTTES NO. 14	15	271	18.0	9.9	49	65	YF4-PSD	544,000	1,093,000	879
NATURAL BUTTES NO. 20	8	65	8.1	9.9	44	88.5	YF4-PSD	322,000	826,000	N/A *

PICEANCE CREEK FIELD, COLORADO, MASSIVE HYDRAULIC FRACTURING DEMONSTRATION

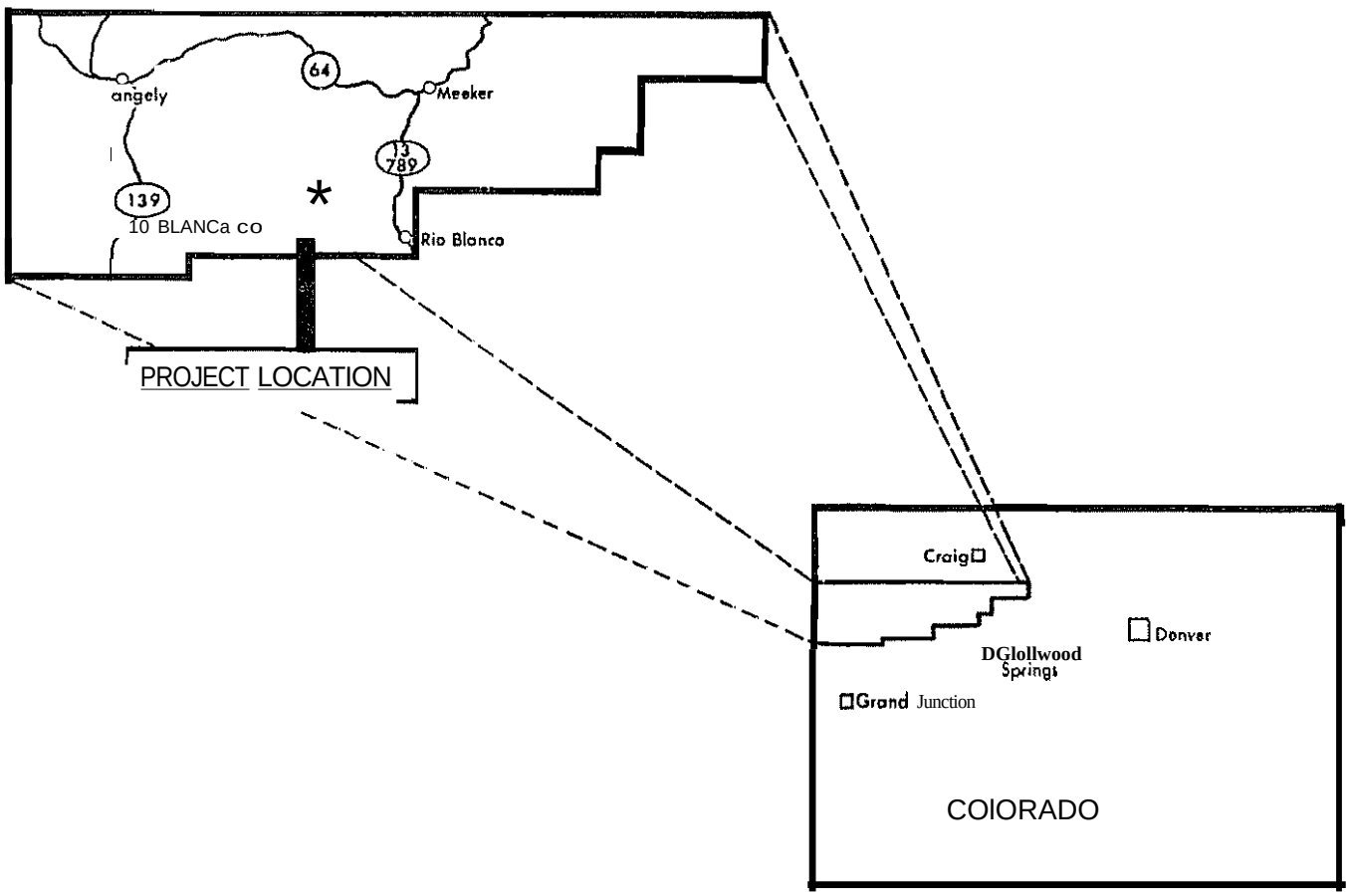
EY-76-6-08-0678

Mobil Research and Development Corporation
Dallas, Texas

Contract Date:	July 1, 1976
Anticipated Completion:	nee. 31, 1978
Total Project Cost:	ERDA..... $2,600,000
	Contractor (prior costs) ....., 2,376,485
	Contractor (new costs)..... 1.590,515
	Total $6.567,000
Principal Investigator:	John L Fitch
Technical Project Officer:	C. H. Atkinson, Bartlesville Energy Research Center

Objective

To evaluate the effectiveness of massivehydraulic fracturing for stimulating natural gas production from thick. deep saodstone reservoirs having extremely low permeability.



5.7 MOBIL RESEARCH AND DEVELOPMENT CORPORATION

5.7.1 Scope of Work

Mobil was awarded ERDA Contract EY-76-C-08-0678, along with Signal Drilling in the amount of $2.6 million for a MHF experiment in Rio Blanco County, Colorado. The scope of work under the contract is to be performed in three phases involving a well to be drilled in the Piceance Creek gas field, Rio Blanco County, Colorado.

5.7.2 Description of Well, F-31-13G

The well was drilled at a location 1,126 ft fr N/L and 1,683 ft fr E/L, Section 13, T2S, R97W, Rio Blanco County, Colorado. The well was to be drilled to a depth of 10,600 ft, but mud gas at that depth resulted in a revised TD of 10,798 ft. 10-3/4 in. casing was set at 1,540 ft; and 7 in. casing was set to 10,798 ft. Cores were recovered at 8,440 - 8,500 ft and 9,940 - 10,000 ft sand porosities averaged 6.6% with water saturations of 57%. No cores were taken for the interval 10,549 - 10,680 ft which was the zone selected for testing.

5.7.3 Summary of Completed Work

Dual induction, sonic, caliper, long-spaced sonic, temperature log in casing, borehole televiewer, and noise logs were run. The perforated interval was 10,549-10,680 ft with 35 holes substantiated by BHTV. Production rate was 300 MCFD from 10,550-60, 10579-83; 10,613; 10,617··28; 10,655-66 ft as noted by gas cooling and noise log.

The perforations, 10,549-10,680 ft,were broken down by pumping 5,000 gal. of 2% KCl water at 10 bbls per min. Ball sealers in excess of the number of perfs were dropped but ball-off was not achieved. The well was flowed back immediately with gas to the surface in 2 hrs. Measured gas flow averaged 325 MCFD over 3 days. Noise/temperature logs indicated that most of the interval was contributing to the flow.

After 6 days of shut-in sufficient build-up data was obtained to calculate kh. The value obtained was 0.3 md-ft. Although a kh of 0.5 or greater is desirable for application of MHF, a decision to fracture this lower-most interval was made.

The treatment consisted of 639,000 lbs of 20/40 mesh sand carried by a 40 lb/ 316,000 gal cellulose gel pumped at 60 BPM.

In addition, a pre-frac pump-in test was performed to investigate the "fracturability" of the zone. The test consisted of pumping 20,000 gal. of 2% KCl water at 8 BPM and, on the basis of these data, no fracturing problems were anticipated.

The treatment was performed as planned, except that a "screen-out" occurred late in the treatment that insured that the fracture was completely propped near the well.

During the treatment, a large treating pressure increase occurred which began as soon as fracturing pressure was reached and was quite large before any sand entered the perforations. This treating pressure increase was completely unexpected in view of the pre-frac pumping data. The treating pressure increase certainly created a wider, shorter fracture than planned, and the larger than planned fracture width undoubtedly resulted in, Or at least contributed to, the "screen-out" near the end of the treatment. Of potentially greater significance, such a treating pressure increase strongly suggests that the fracture propagated into mechanically different rock, such as shale.

About 15 minutes after fracturing, the well was gradually opened to flow. The flow rate was increased to about 4 BPM within the first hour. Some sand was produced during the early flow period--estimated at equal to, or less than, the amount of sand left in the pipe when the pumps were shut down due to "screen-out". Gas-to-surface was observed within 4 hrs. The amount of sand in the flow stream rapidly decreased and no sand was detected after 12 hrs. of flow.

Observed gas flow rates in MCFD are as follows:

June 23	500	(estimated)
June 24	750	
June 25	1000	
June 26	900	
June 27	800	
June 28	780	
June 29	800	

The well was shut-in for buildup on June 29 and as of that date, water production rate was 40 BPD with estimated total frac fluid recovery of about 25%.

During the period from July 1 through July 17, flow and pressure buildup tests were conducted after fracturing. From July 18 to July 31, the fractured zone was plugged off and four new sands were perforated, broken down and "fracturability" tests performed. Preliminary indications are that the four perforated sands, as a group, do not meet requirements for MHF. Consideration is being given to either perforating sands in addition to the first group of four, or moving up the hole and testing additional intervals.

After-frac pressure buildup data were co.ilected during the period June 29 to July 11.

A short flow test was performed after the buildup and it appeared that the well performed somewhat better after the buildup than before.

During the period July 18 to July 31, preparations were made for a second MHF test. Four sands were perforated at 10,472-76 ft (Sand A), 10,415-29 ft (Sand B), 10,255-61 ft (Sand C), and 10,186-10,204 ft (Sand D. Early flow tests following breakdown of the A and B sands indicate that this zone would be suitable for a massive frac test. A massive frac was designed and is now planned for August 24.

The 3A sand, 9,517-34 and the 3B sand, 9,392-9,432 were broken down simultaneously on August 8 with 12,000 gal of 2% KCl water and 84 ball sealers pumped at 12-14 BPM.

After the breakdown and injectivity tests, the well was flowed to the pit starting at 6 p.m. on August 8. On August 9 the gas rate was measured at 930 MCFD declining to 799 MCFD by August 11. Flowing noise and temperature log measurements were made on August 10 and showed that both the 3A and 3B sands were producing gas.

The well will be shut in for pressure buildup measurements.

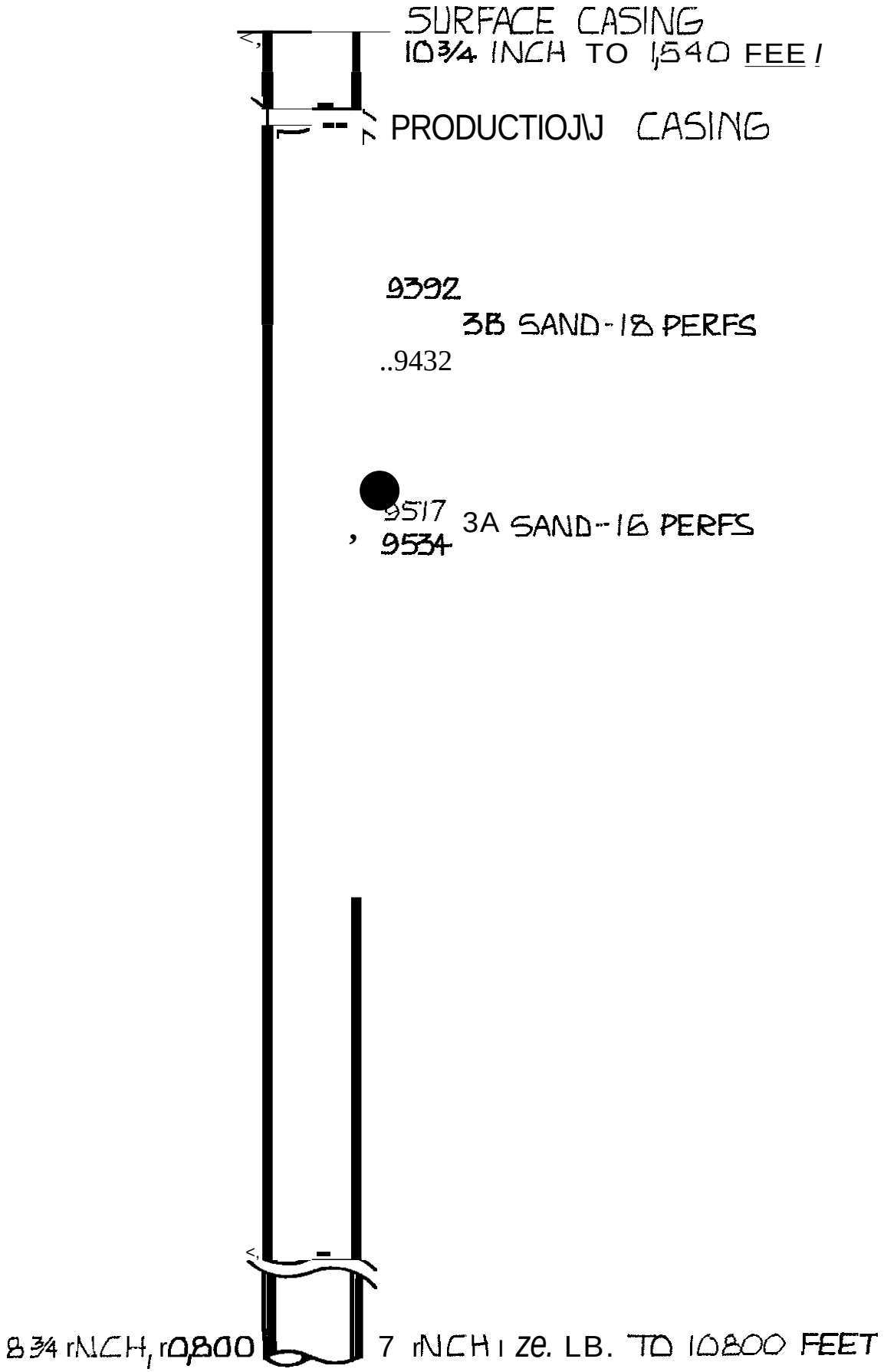


FIGURE 5-15 SCHEMATIC OF MOBIL F-31-13G WELL SHOWING 3A AND 3B ZONES

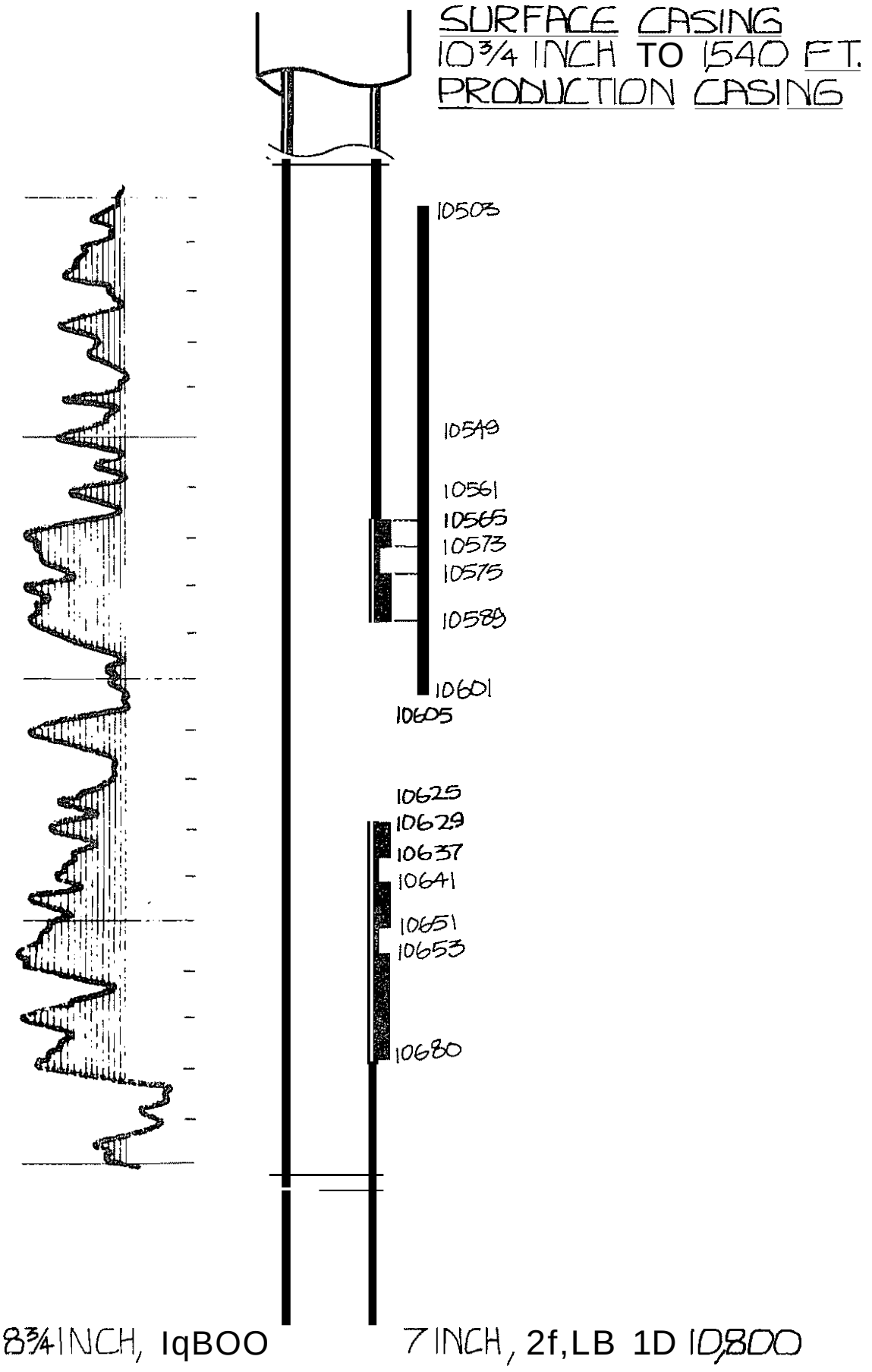


FIGURE 5-16 SCHEMATIC OF **MOBIL** F-31-13G **WELL**

SAND RIDGE AREA, UINTAH COUNTY, UTAH, MASSIVE HYDRAULIC FRACTURING DEMONSTRATION

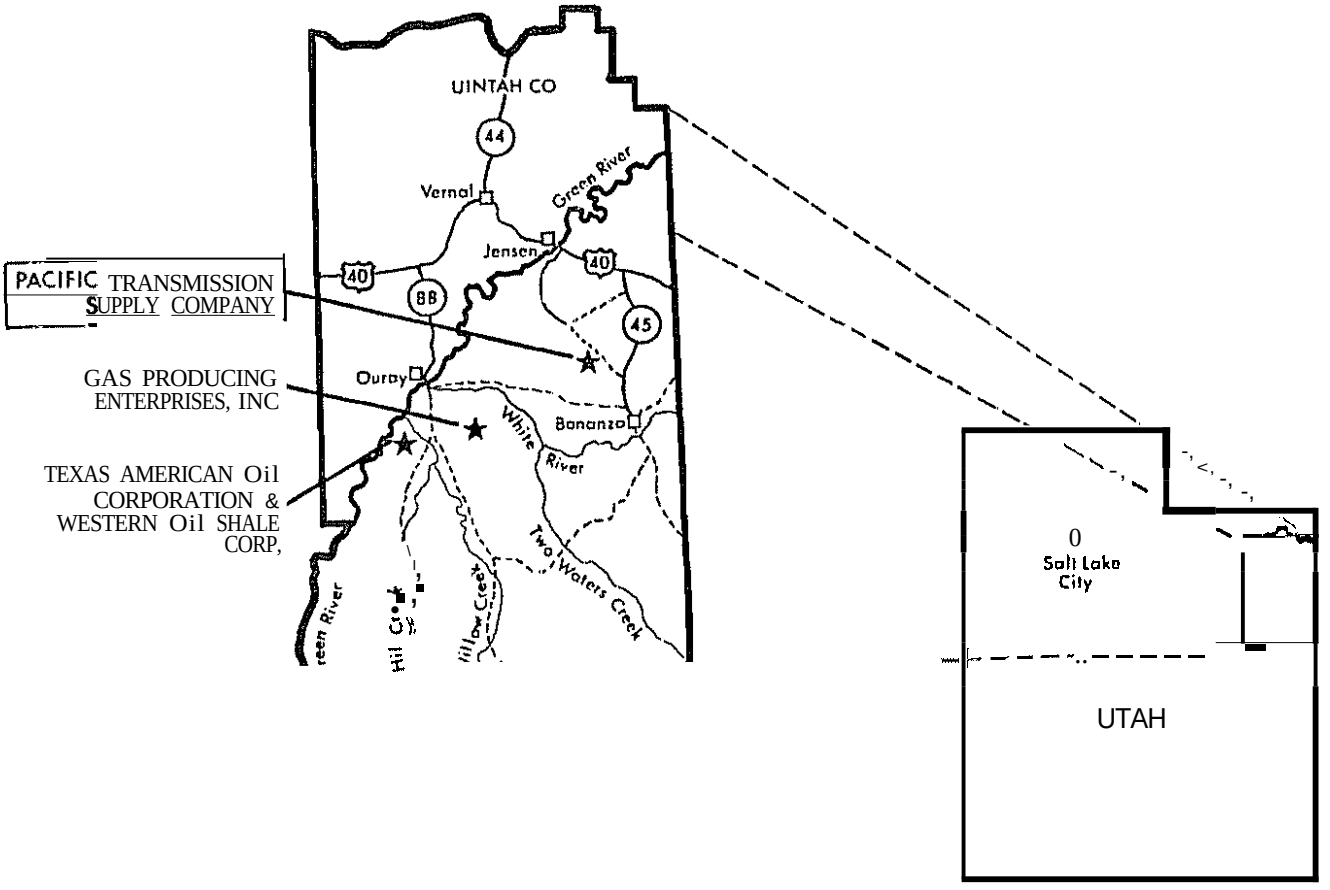
EV-76-C-OS-06S0

Pacific Transmission Supply Company
San Francisco, California

Contract Date:	Sept. 1, 1976
Anticipated Completion:	Jan. 31,1979
Total Project Cost:	ERDA. $1,098,775
	Contractor 1,296,737
	Total $2,395,512
Principal Investigator:	Jack L. Wroble
Technical Project Officer:	C. H. Atkinson, Bartlesville Energy Research Center

Objective

To evaluate the effectiveness of massive hydraulic fracturing for stimulating natural gas production from thick, deep, low permeability sandstone formations.



5.8 PACIFIC TRANSMISSION SUPPLY COMPANY

5.8.1 Scope of Work

On September 1, 1976, Pacific Transmission Supply Company was awarded ERDA Contract EY-76-'C-08-0680 to evaluate the effectiveness of massive hydraulic fracturing for stimulating natural gas production from thick, deep, low permeability sandstone formations in the Uinta Basin, Utah.

5.8.2 Description of Well, No. 23-25 Federal

The Pacific Transmission Supply Well No. 23-25 Federal is located in Sec 25, T8S, R23E, Uintah County, Utah and is completed to a total depth of 9,282 ft with 5-1/2 in. casing.

5.8.3 Summary of Completed Work

During the drilling of the well, the Mesaverde was drillstem tested almost continuously with 18 tests being run or attempted in the Mesaverde beginning at 6,560 ft. Only five misruns, resulting from packer seat failures, occurred for a 72 percent success factor.

Twelve cores were cut, totaling 469 ft, with a recovery of 427 ft (91 percent). Four cores were oriented for stress relaxation testing by TerraTek.

Open hole mini-frac experiments were attempted for the intervals 9,017 ft to 9,032 ft and 8,822 ft - 8,830 ft with only the 9,017 ft - 9,032 ft interval being successful. An attempt to examine the resulting fracture by the use of impression packers was unsuccessful.

The following open-hole logs were run by Schlurnberger:

Dual Induction Laterolog
Dual Laterolog
Gamma Ray-Sonic (BHC) with Caliper
Compensated Neutron
Compensated Density (with Caliper and Gamma Ray
Experimental Long-Spaced Sonic Logs
Differential Temperature Logs

Pacific Transmission Supply Company, after perforating, acidizing and flow testing each sand of the Mesaverde group (Castlegate, Nelson and Farrer Facies), which has indicated gas potential while drilling, or upon drillstem testing, or by analysis of all available log data, was unable to find a zone of sufficient kh as set forth as a parameter in the program to qualify for a massive hydraulic fracture treatment. This kh was to be .5 millidarcy-feet in the Castlegate facies and 1.0 millidarcy-feet in the Nelson and Farrer facies. Since the criteria for a massive hydraulic fracture treatment could not be met, and with the verbal approval of ERDA, it was concluded that the wellsite phases of the contract were met.

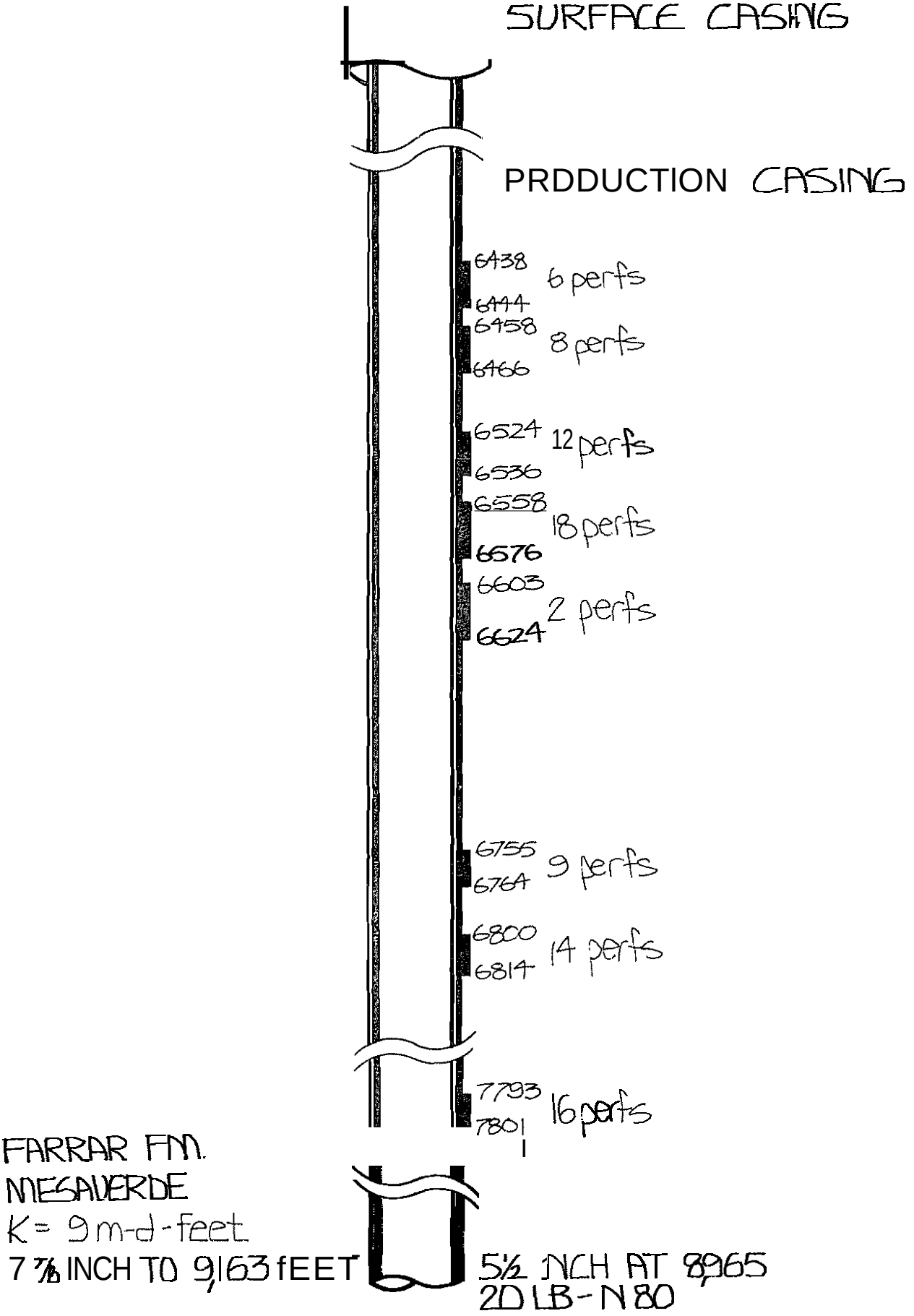


FIGURE 5-17 **SCHEMATIC OF FEDERAL** 23-25 **WEII**

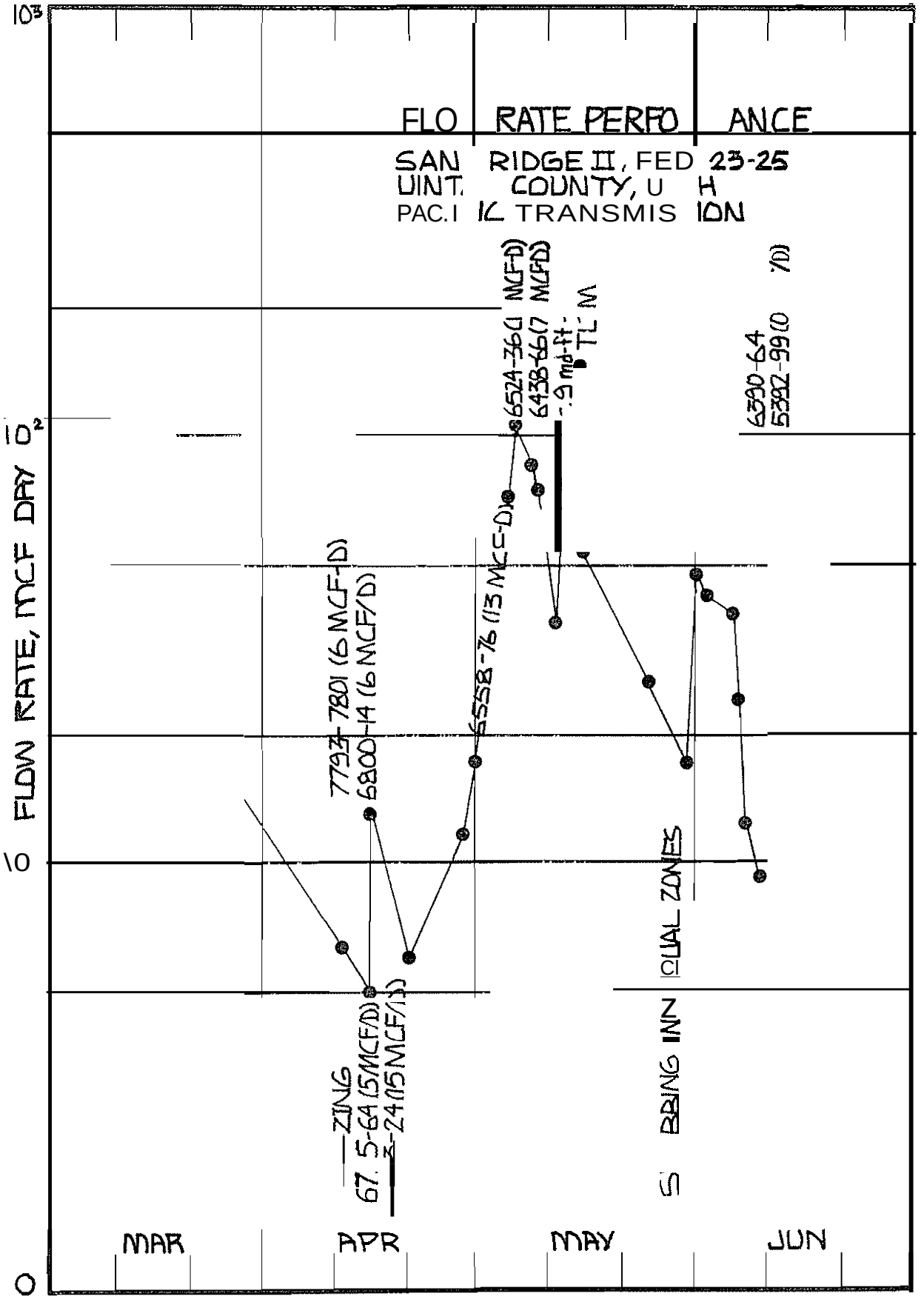


FIGURE 5-18 n.ow RATE PERFORMANCE OF FEDERAL 23-25 WELL

RIO BI.ANCO COUNTY, COI.ORADO
MASSIVE HYDRAULIC FRACTURING
DEMONSTRATION

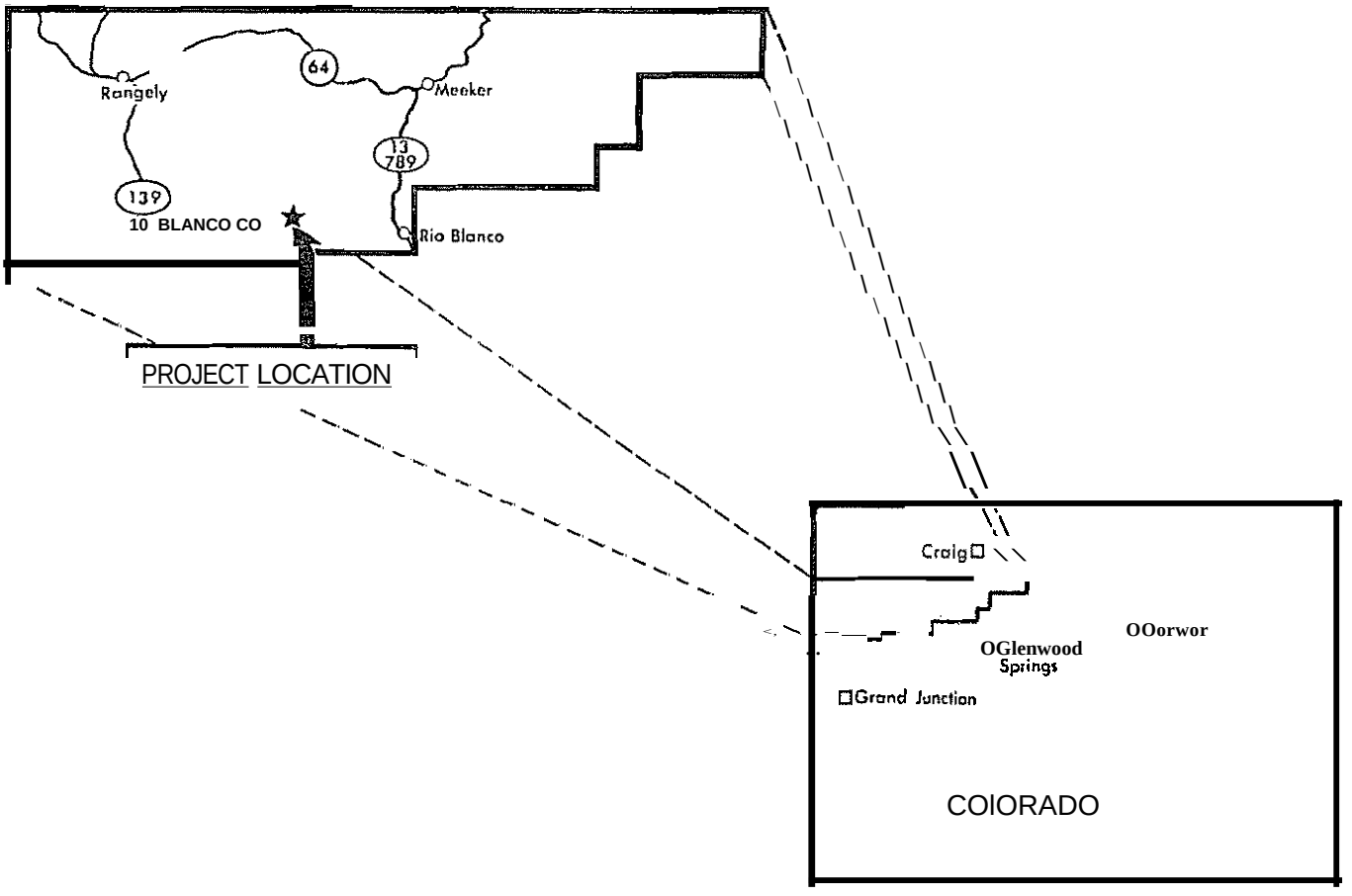
EY-76-C-08-0677

Rio Blanco Natural Gas Company
Denver, Colorado

Contract Date:	Aug. 1, 1976
Anticipated Completion:	March 31, 1977
Total Project Cost:	ERDA. . . . . , ... ' . . . ,,$260,000
	Contractor , . " , , , . ' . . . . . " 528,736
	Total . , , , . , " ' , , , , , . , ,,$788,736
Principal Investigator:	Robert E. Chancellor
Technical Project Officer:	**C. H. Atkinson, Bartlesville Energy Research Center**

Objective

To evaluate the effectiveness of massive hydraulie fracturing for stimulating natural gas production **from thick,** deep **sandstone reservoirs having extremely low permeability.**



5.9 RIO BLANCO NATURAL GAS COMPANY

5.9.1 Scope of Work

In June, 1976, ERDA Contract EY-76-C-08-0677 was signed with Rio Blanco Natural Gas Company. The scope of work consisted of preparing an existing well (Federal 498-4-1) for the MHF treatment. First, the interval from 6,150 ft to 6,312 ft was perforated and the well production tested. Then a breakdown in the perforated interval was conducted, a second production test, and then the well was shut in for pressure buildup measurements. The MHF design was planned to utilize approximately 280,000 gal of gelled water and approximately 770,000 Ibs of sand. Production testing and logging was to be used to determine the results of the MHF treatment.

There were two decision points under this Contract. The first required that the ERDA Technical Project Officer determine the acceptability of the Federal 498-4-1 Well for MHF treatment, based on analysis of the production and pressure buildup testing in the interval 6,150 ft to 6,312 ft. In particular, the permeability-thickness product (kh) calculated from test data was to be no lower than 0.5 md-ft. If the interval was judged not suitable for MHF, the Contractor could repeat perforating and testing operations until a suitable interval was established. The second decision point occurred when a suitable interval had been established and required that the final design be approved by ERDA and the Contractor's Operations Manager, based on the results of the well tests.

5.9.2 Description of the Existing Well, Federal 498-4-1

This well, located 3,490 ft fr *NIL* and 2,710 ft fr E!L, Sec 4, T4S, R98W, Rio Blanco County, Colorado, was drilled and cased to a total depth of 6,963 ft in March 1975. The Mesaverde formation was stimulated in two separate treatments: The first was in the interval 6,850 - 6,928 ft which was treated with 50,000 gal of gelled KCl water and 133,000 Ibs of sand. This first zone produced at a rate of approximately 225 thousand cubic ft per day (MCFD). The second zone, 6,590 - 6,750 ft was treated with 67,000 gal polyemulsion fluid and 154,000 lbs of sand but the production rate was not appreciably improved. With both zones open to production, the well produces approximately 280 MCFD.

5.9.3 Summary of Completed Work

A bridge plug was set at 6,525 ft to isolate the lower zones from the zones of interest. The casing was squeeze cemented above and below to isolate the zone to be treated. The zone was perforated with 17 holes from 6,150 ft to 6,312 ft.

A Drill Stem Test (DST) was run but the test failed when the packer leaked. A second DST attempt was made but also failed. The perforations were then broken down with 111 BBL of 3% KCl water and ball sealers, and the well then flow tested at 58 MCFD. A pressure build up test was run and the build up data indicated a kh of 1.0 md-ft so the MHF treatment was acceptable in the present perforated intervaL

The actual pumping for the Massive Fracturing started at 1000 hours on October 22, 1976 with a total of 276,000barrels pumped, including sand volume and flush.

Injection rate was 37 BPM at 1,200 to 1,800 psig, with the rate being reduced at the end of the treatment. The job was performed as scheduled.

The 775,000 lbs of sand pumped during the treatment was composed of 225,000 lbs of 100 mesh sand; 434,000 lbs of 20/40 mesh sand; and 116,000 lbs of 10/20 mesh sand. The frac fluid used was YF 4 PSD.

A short shut-in time was desired so flowback could be started as soon as possible to reduce fluid imbibition by the formation so only one temperature run was made. The temperature survey showed fairly uniform coverage of the entire section from 6,126 ft to 6,308 ft. Some fluid cooling was detected starting at 6,104 ft at the top end and normal gradient is reached at approximately 6,318 ft for a total of 214 ft. It is not possible to interpret this survey quantitatively, since only one run was made.

5.9.4 Post-Fracture Performance

The post-frac cleanup proceeded quite satisfactorily. In brief, 30% of the fluid flowed back in the first 36 hours. Following eight days of swabbing and a total fluid recovery of 46%, the zone began continuous flow, which with an additional three days, brought total fluid recovery to 70%. Gas flow increased from gas-cut water to 800 MCFD. Within 22 days the gas flow declined to the 200 MCFD range, with average fluid production being 3.5 BBL of water and 3.5 BEL of oil per day.

This production rate appeared to reach a stable rate of 130 MCFD after three months of production.

5.9.5 Conclusions and Recommendations

The rapid decline in flow rate may be indicative of fracture healing due to sand grain crushing or imbedment. It is recommended that additional work be performed to determine if fracture healing is a problem in this area of the Mesaverde.

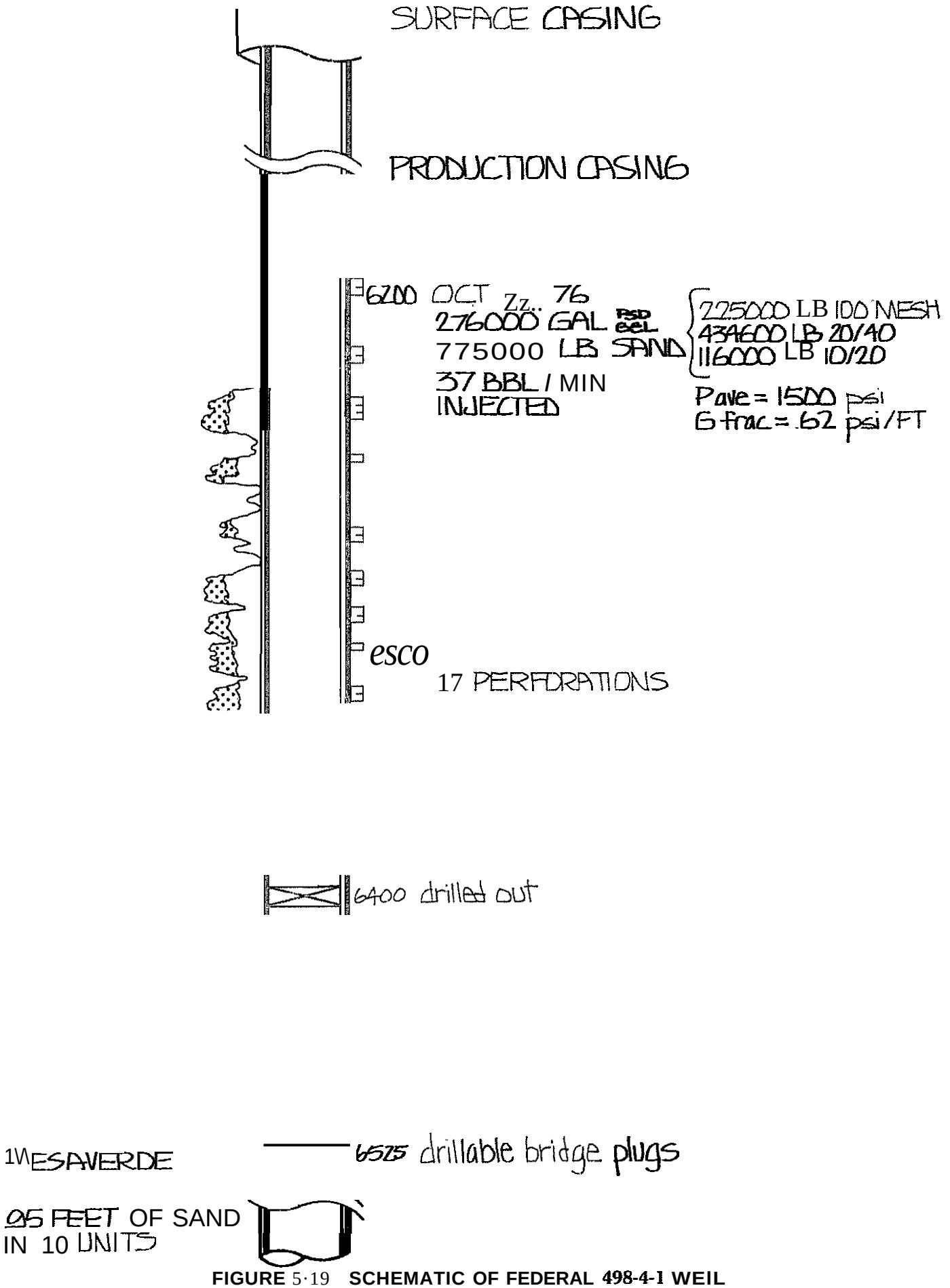
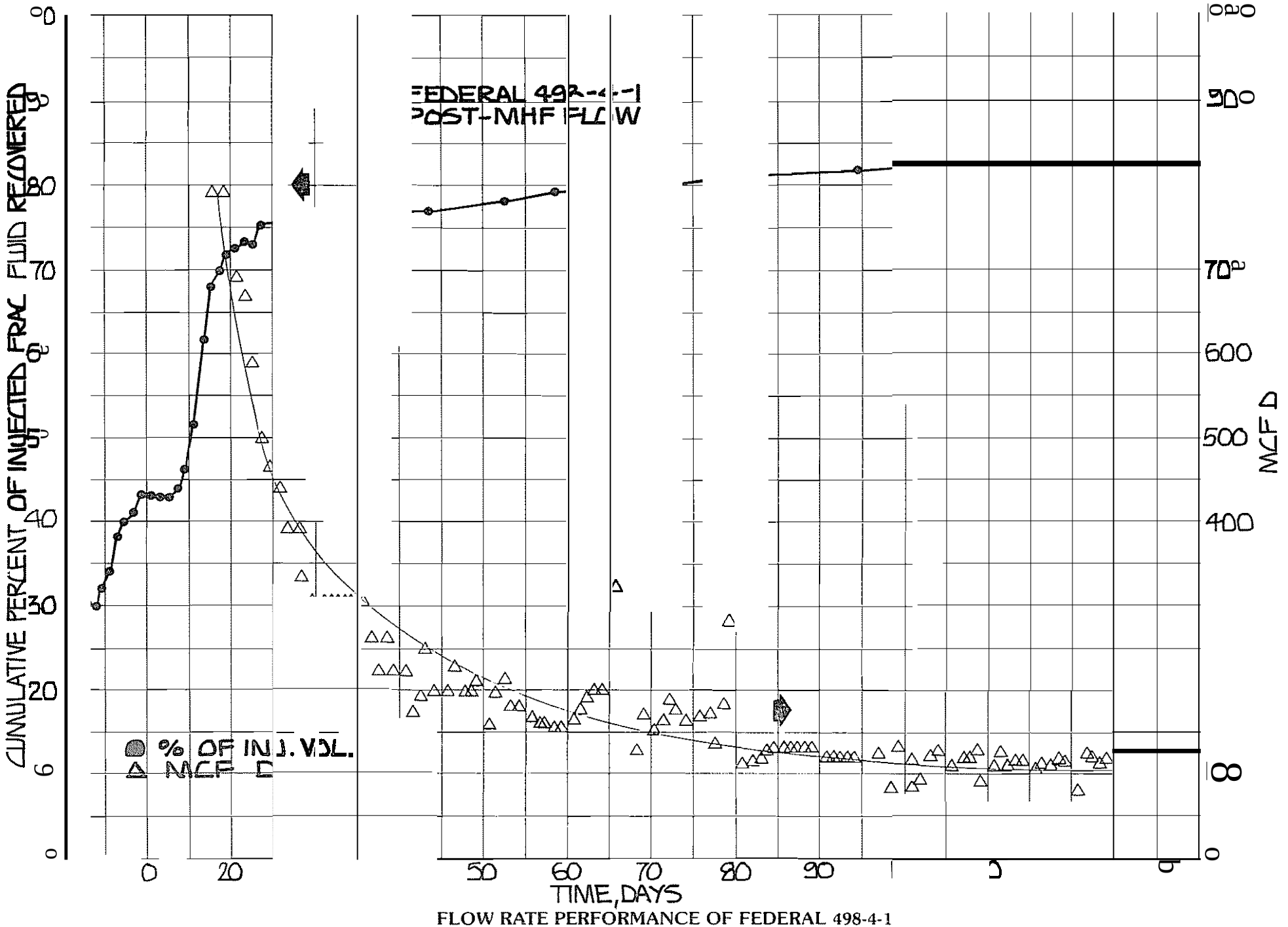


FIGURE 5·19 SCHEMATIC OF FEDERAL 498-4-1 WEIL



FLOW RATE PERFORMANCE OF FEDERAL 498-4-1

TURTLE SHELL UNIT,
UINTAH COUNTY, UTAH
MASSIVE HYDRAULIC FRACTURING
DEMONSTRATION

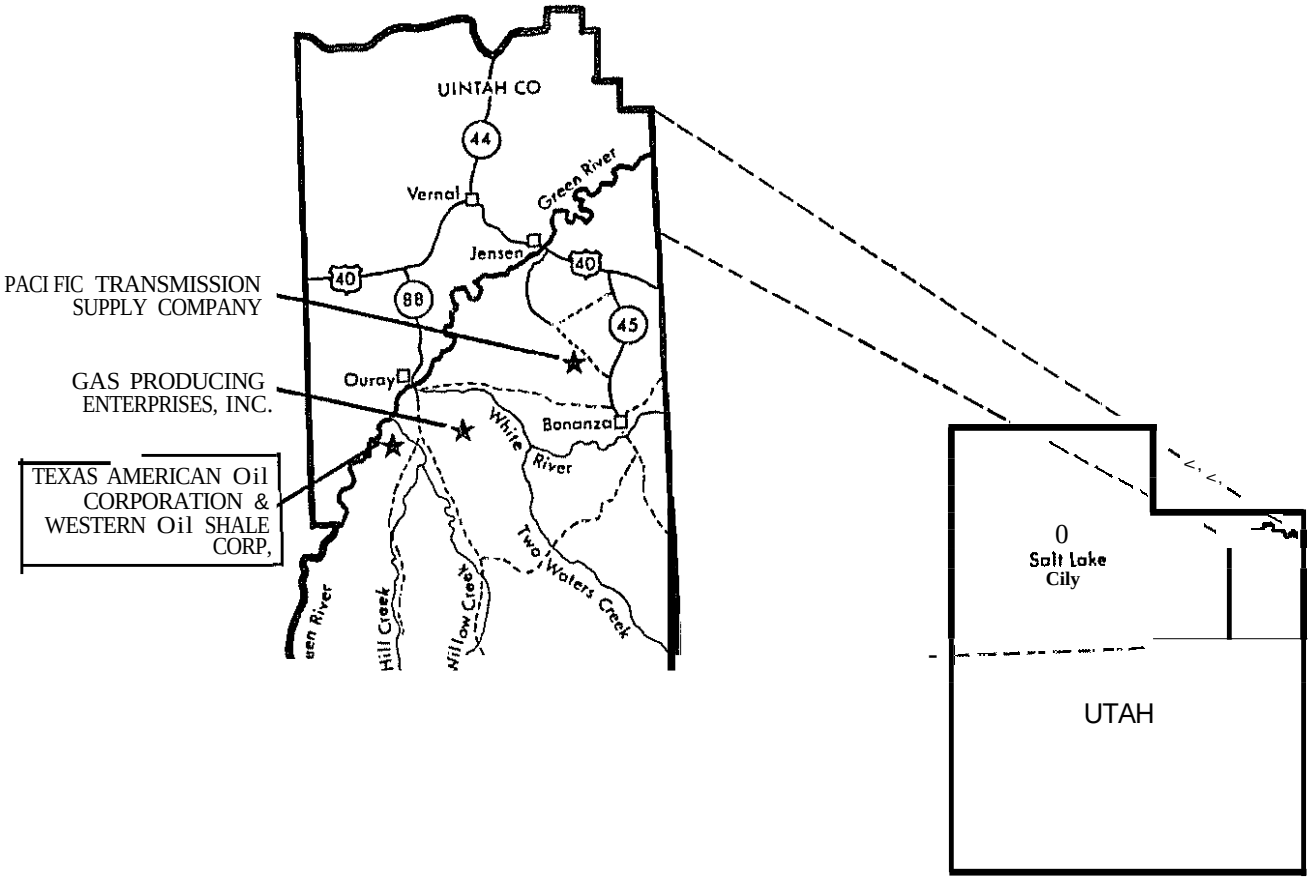
EY-76··C-08-0683

Texas American Oil Corporation and
Western Oil Shale Corporation
Midland, Texas

Contract Date:	Julv 1,1976
Anticipated Completion:	Sept. 30, 1977
Total Project Cost:	ERDA $150,000
	Contractor (prior costs) . . . . . ". 565,791
	C.ontractor (new costs)" . " 193,031
	Total $913,822
Principal Investigator:	Charles R. Boardman
Technical Project Officer:	**C. H. Atkinson, Bartlesville Energy Research Center**

Objective

To evaluate the effectiveness of massive hydraulic fracturing for stimulating natural gas production from thick, deep, low-penneability sandstone reservoirs.



5.10 TEXAS AMERICAN OIL CORPORATION AND WESTERN OIL SHALE CORPORATION

5.10.1 Scope of Work

ERDA Contract EY-76-C-08-0683 was signed with Texas American Oil Corporation and Western oil Shale Corporation in July 1976. The scope of work consisted of performing an MHF treatment of an interval from 10,014 ft to 10,202 ft and continuously producing the well into a pipeline for at least one month. The MHF treatment was to consist of 300,000 gal of gelled KCl water and 570,000 Ibs of sand. If the proved capable of producing into the pipeline at the sustained rate of 1 million cubic ft per day (MMCFD) 6 months after the frac was completed, it was to be judged a commercial success and the fracturing phase of the project would be complete. If, however, the production rate at the end of one month was below 500,000 cubic ft per day the interval was to be isolated and a shallower interval perforated and tested as in the previous manner. Acceptability of this second interval for MHF was to be determined by the Contractor and ERDA, based on analysis of the well tests. In particular, the kh calculated from test data was to be at least 0.4 md-ft. The MHF treatment design was finalized by ERDA and the Contractor after well test results were evaluated.

The scope of work also included the research proposal "Study of Possible Relationships Between Linear Features on Ground Surface and Potential Gas Production - Uinta Basin, Utah," submitted by the Contractor to ERDA on April 28, 1976.

The stUdy included three tasks. Task I included updating WESTCO's extensive Uinta Basin well data to include latest available drill stem tests, flow rates, pipeline production volumes, data analysis, criteria selection for data plotting on base maps of suitable scale. Task II consisted of replotting data on suitable lineament maps in numerical form, if necessary, and overlying Task I maps for analysis of correlation possibilities. Task III consisted of the study of the correlated data, preparation of data plots and writing of the final report.

5.10.2 Description of Existing Well, Home Federal No.1

The recently completed gas well, Horne Federal No.1, located 837 ft fr N/L and 726 ft fr E/L, Sec 34, TIOS, R19E, SLM, uintah County, utah was bottomed at 10,780 in January 1976. After running Guard Electrical, Forxo, Density, Sidewall Neutron, BHC-Velocity, Caliper and Mud log, 5-1/2 in. 00 casing was run to total depth and selectively perforated in the Mesaverde sand within the interval 10,014 to 10,202 ft. An acid breakdown treatment was performed using 1,250 gal of 15% HCl and 420 gal of 3% KCl water containing a nonemulsifying agent with ball sealers. Flow testing was conducted and the well shut in and the pressure allowed to build up for 10 days.

5.10.3 Summary of Completed Work

MHF No. 1 Experiment consisted of 411,640 gal of frac fluid and 600,000 Ibs of sand. Injection rate varied between 19 and 46 BPM. Wellhead injection pressure varied between 6,400 and 7,000 psi.

5.10.4 Pre-Frac Treatment

On March 31, 1976, Welex perfora-ted the target interval with twenty-three 1/4 in. diameter holes with Sidewinder jet charges between the depths of 10,014 ft and 10,202 ft. No gas showed at the surface after the perforating job was completed.

On April 4, 1976, the perforations were broken down using acid, KCl water and ball sealers. Total breakdown fluid used was 380 barrels, most of which were recovered by April 13.

Pre-frac flow rate testing indicated a rate of approximately 40 MCFD from the perforated section.

Halliburton started the massiv2 frac with a KCL water prepad stage on September 29 at 0100 hours. Maximum injection rate achieved was 12 BPM at 7,000 psig wellhead pressure (target rate was 42 BPM). The frac was stopped and 50 ball sealers were dropped, along with 3,000 gal of acid in an attempt to increase the injection rate. The prepad stage of 43,400 barrels was completed at approximately this injection rate.

On September 29, 1976, another temperature survey was run to determine appropriate locations for additional perfora-tions,

Based upon the analysis of this temperature log and Halliburton calculations, on September 30, thirty-two new 1/4 in. perforations were added to the target interval between 10,014 ft to 10,202 ft. The Fracture was initiated with a 90,000 pad followed with a 6 stage frac treatment consisting of 218,000 gal of gelled water with 200,000 lbs of 40/60 sand and 400,000 lbs of 20/40 sand. The average injection rate was 29 BPM at 6,850 psi.

The well was flowed back to clean up. Initial gas flow rate was 59 MCFD. Several attempts were made to unload the well during the next several months and the well would flow for a few days and then die.

The flow rate required to sauisEy the contract was never attained, so the Contractors elected to cover the lower zo1e with sand and to perforate and test the upper zone.

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

The tubing was pulled to allow the remainder of the Mesaverde pay zones to be perforated with a Welex 3-1/8 in. casing gun. On December 2 the wel I casing was perforated with nineteen .34 in. perforations from 7,826 ft to 9,437 ft.

Flow tests with bottom hole pressure build up were run between December 14 and December 20, but the t.est; results were too poor for qualitative interpre'lation. The required kh of .4 md-ft could not be determined from the test data.

Texas American Oil made the decision to proceed with the second frac job even if the contract requirements had not been met.

5.10.5 MHF No. 2 Description

Halliburton conducted the MHF of the well on December 21. The job was begun at 1015 hours and was completed at 1342 hours. The average injection pressure was 6,500 psi with an average injection rate of 35 BPM. The average hydraulic horse power used was 5,576. The total fluid volume used was 247,500 gal which included a pad of 40,000 gal, a treatment of 200,000 gal and displacement of 7,500 gal. The frac fluid was Halliburton's "Versagel." 50,000 Ibs of 40/60 sand and 450,000 Ibs of 20/40 sand were used to prop the fracture.

5.10.6 Post Frac Production and Testing

The load water was flowed back beginning at 1915 hours on December 21. Sand which flowed back in sufficient quantities to erode holes in the flow line stopped flowing back at 0500 hours on December 22.

On December 27 the well was hooked up to the treating unit and gas sales were commenced at a rate of 477 MCFD. The production rates as a function of time from December 27, 1976 through June 30, 1977 are depicted in Figure 5-17. As indicated in this figure, the rate had essentially stabilized at about 155 MCFD in April and remained at this average level throughout May and June.

Cumulative water production from the start of flowback throughout June, 1977 was about 7,500 gal, with the water production rate stabilizing in March at about 20 BPD.

5.10.7 Conclusions and Recommendations

The second frac interval responded better than the initial zone. However, the flow rates are still considered non-commercial.

It appears that the zone is producing formation water because the cumulative water production is about 1500 bbls more than had been injected.

It is recommended that better bottom hole pressure and flow data be collected in order to make meaningful calculations on the reservoir properties.

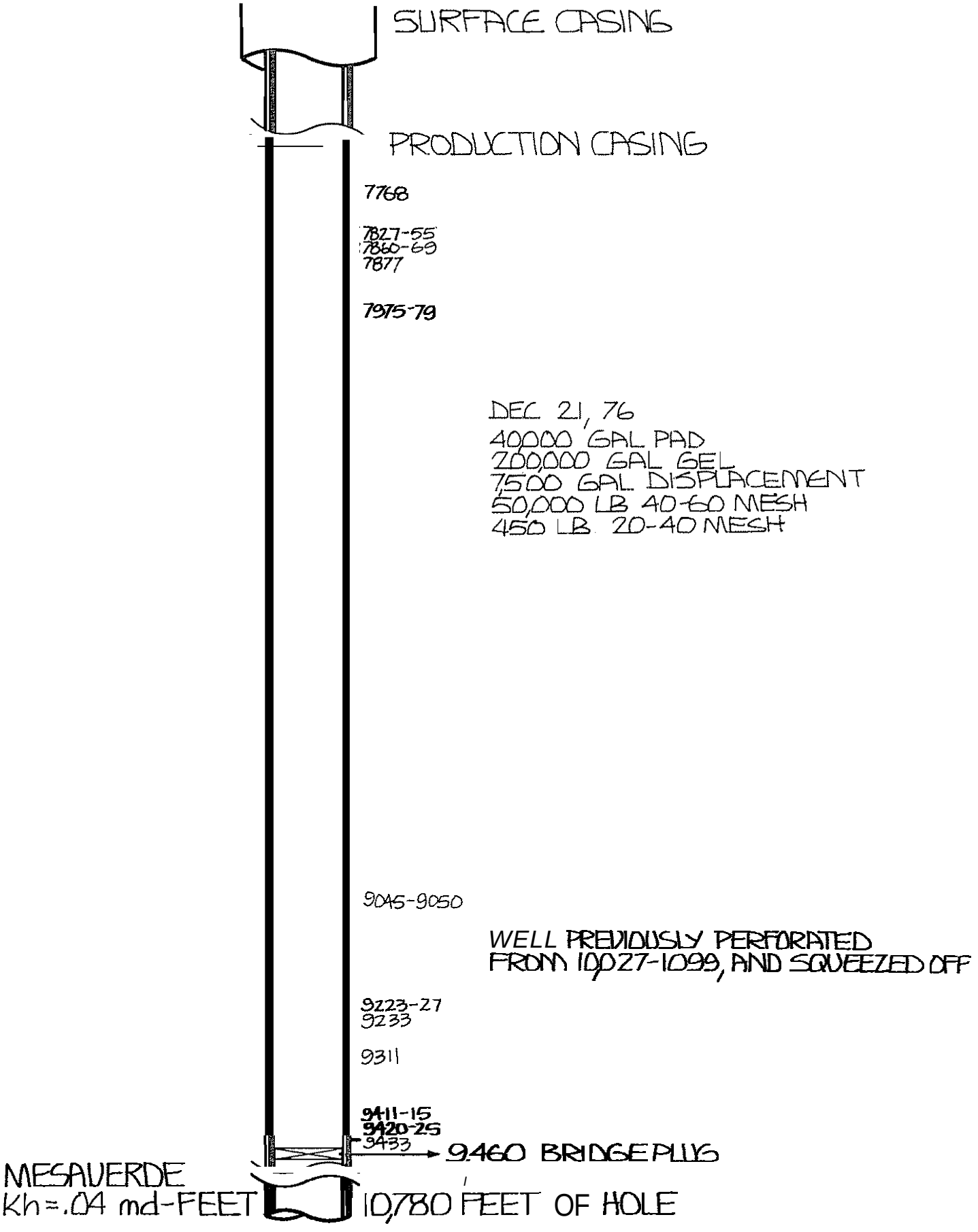


FIGURE 5-21 SCHEMATIC OF HOME FEDERAL NO.1 WELL

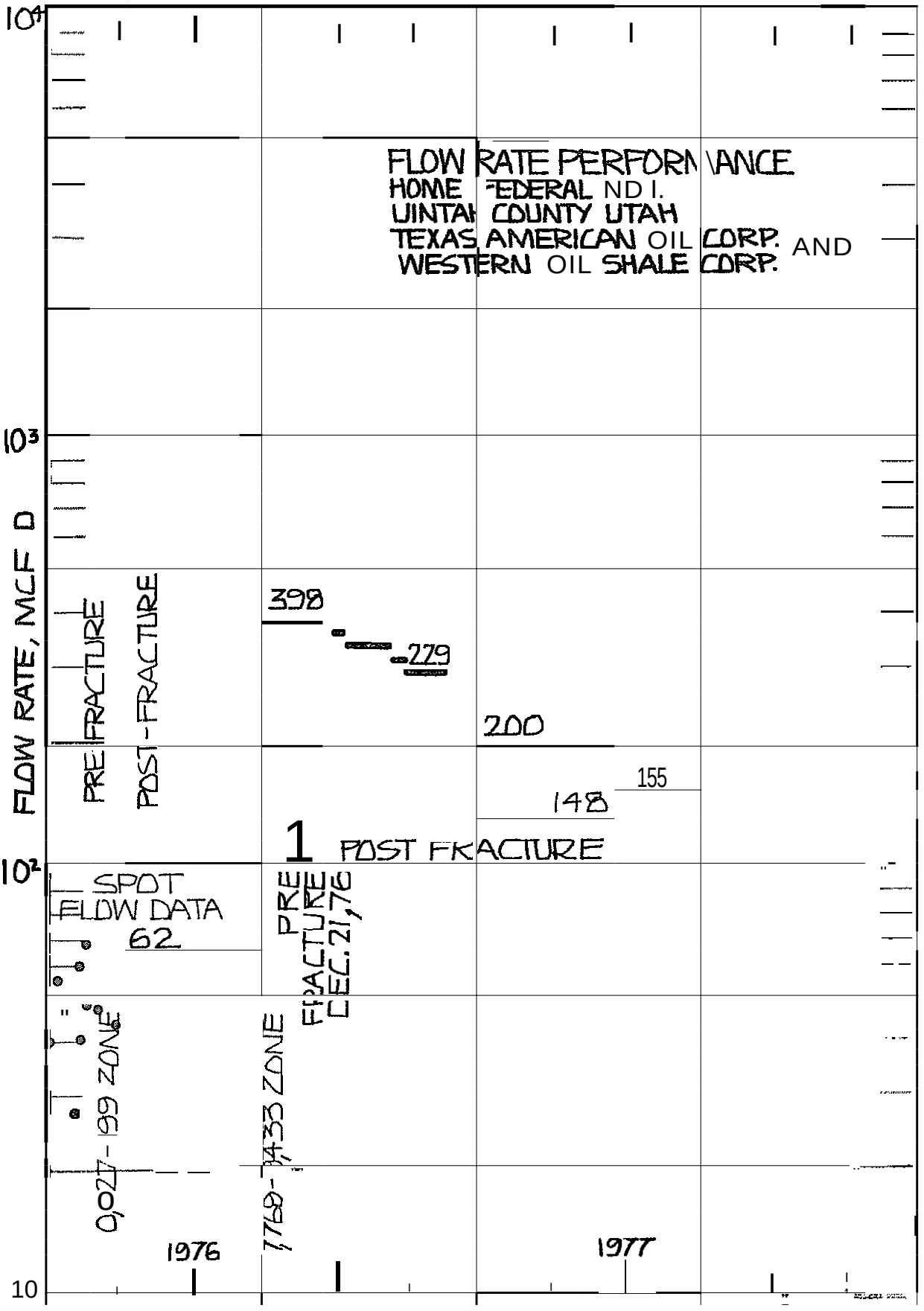


FIGURE 5-22 FLOW RATE PERFORMANCE OF HOME FEDERAL NO. I WELL

WISE COUNTY, TEXAS, MASSIVE HYDRAULIC FRACTURING DEMONSTRATION

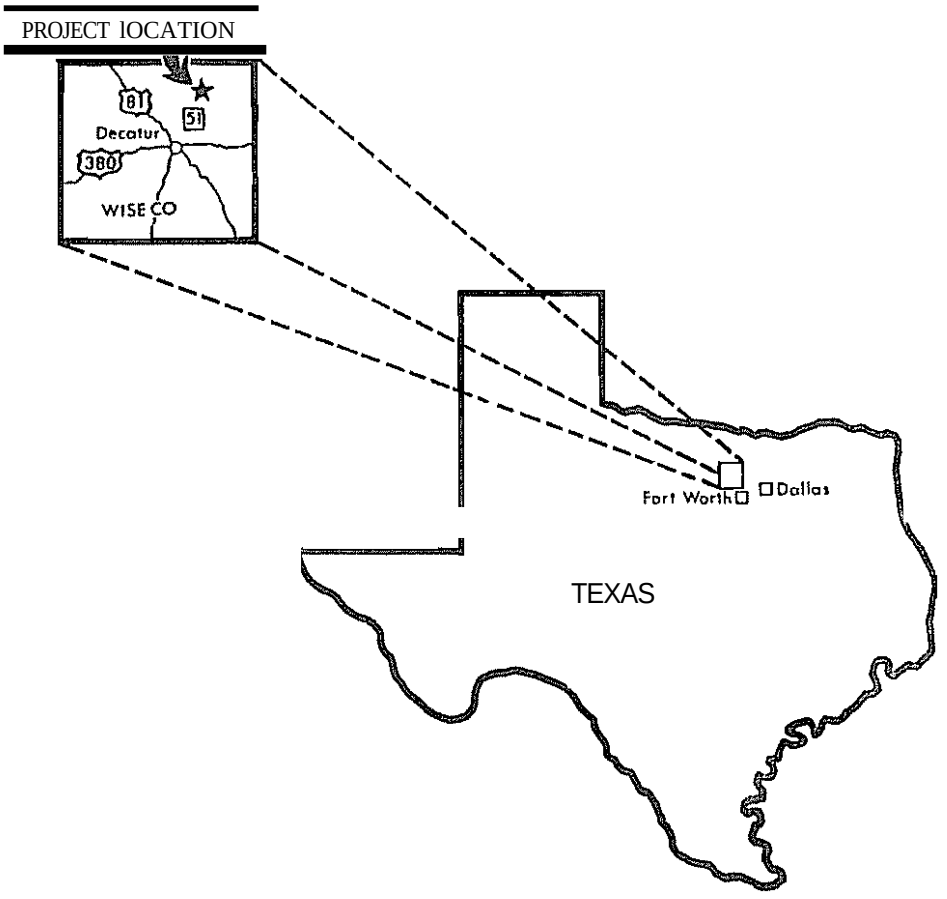
EV-76-C-08-0684

Dallas Production, Inc.
Dallas, Texas

Contract Date:	Aug. 1,1976	
Anticipated Completion:	Dec, 31, 1976	
Total Project Cost:	ERDA,	$150,000
	Contractor.	178,073
	Total	$328,073
Principal Investigator:	**Archie Crawford**	
Technical Project Officer:	**C. H. Atkinson, Bartlesville Energy Research Center**	

Objective

To evaluate the effectiveness of massive hydraulic fracturing for stimulating natural gas production from marginal, low-permeability reservoirs at moderate depths and having large areal extent.



5.11 DALLAS PRODUCTION, INC.

5.11.1 Scope of Work

ERDA Contract EY-76-C-08-0684 was signed with Dallas Production, Inc. on July 30, 1976. The Scope of work consisted of preparing an existing well (Ferguson No.1-A) for the MHF treatment by first running flowing production (spinner) and temperature surveys, shutting in the well for a 96-hour pressure buildup test, then resuming production for a second flowing production (spinner) and temperature survey. The well was then to be shut in for 48 hours prior to the MHF treatment. The MHF design was tentatively to be a five-stage treatment using ball sealers between stages, utilizing approximately 138,500 gal of foam pad with 100,000 lbs of 100 mesh sand, and 198,000 gal of polyemulsion fluid with 667,000 lbs of *10/20* mesh sand. After sufficient cleanup, production tests were again to be run by the Contractor to determine results of the stimulation treatment.

5.11.2 Description of Existing Well, Ferguson No. I-A Well

This currently producing gas well, located 1,320 ft fr *NIL* and 1,320 ft fr *ElL*, Ben D. Smith Survey A-779, Wise County, Texas, was bottomed at 7,090 ft in December 1972. The *4-1/2* in. production casing was perforated in intervals from 5,957 to 6,794 ft and fractured in five stages, each consisting of 20,000 lbs of *20/40* mesh sand in gelled calcium chloride water at the rate of 2 lbs of sand per gal. Production rate prior to the MHF work was 43 MCFD.

5.11.3 Summary of Work Completed

The temperature and spinner surveys were run on September 3, 1976 and a resurvey rtm on September 7. The spinner survey indicated flow from 4 of the 5 zones. The frac was initiated on September 14 and after pumping about one-third of the designed amount of *10/20* sand, the *4-1/2* in. casing burst and the frac job was aborted. The sand was cleaned out and *2-7/8* in. tubing with a packer was run to isolate the ruptured casing and the frac was then completed on September 16, 1976.

A total of 506,000 lbs of sand in 138,800 gal of foam and 198,000 gal of emulsion were pumped into the well in the two treatments.

5.11.4 Post-Fracturing Performance

Load recovery commenced at 2:00 a.m. on September 17, flowing at approximately 10 BBL load per hour. By September 22, the flow had decreased to less than 100 *BID* and continued to decrease until September 30, at which time total recovery amounted to 1,136 BBL. At this point a decision was made to clean the sand fill-up from the hole to uncover the bottom perforations. This operation was completed on October 1, and the tubing and packer were run on October 2. Swabbing operations commenced on October 4, with 240 BBL load being swabbed on this date. Swabbing was discontinued on October 6, and the well flowed 60 BBL of load.

Flow had declined by October 25 to less than 10 BBL per day and November 1, a decision was made to set a pumping unit and pump the load back. On November 11 the pump and rods were run and pumping preparations were made. Bad weather delayed operations until November 18 when the pump was started but failed to operate properly.

A decision was made to squeeze the hole in the casing in order to allow the load to be pumped via the tubing while allowing the gas to flow via the annulus. It was felt that this would allow faster recovery of the load while some stabilized gas flow could be measured.

These operations were commenced on December 2, 1976, and the hole was located at 4,813 ft. A squeeze operation was conducted on December 4 using 100 sacks of cement to a squeeze pressure of 2,000 psi. The squeeze packer was pulled and cement was drilled out to the bridge plug by December 8. The bridge plug became stuck at 5,440 ft while pulling. Fishing operations were commenced but were unsuccessful, so on December 19 it was decided that the plug would have to be milled over. Subsequent milling and fishing operations continued until January 15, 1977. Tubing and rods were run and pumping started on January 19.

Initial load production was 40 *BID* with a gas flow rate of 135 MCFD. Since that time through March 25, 1977, recovery has declined to 4 *BID* with a gas flow of 15 MCFD.

Prior to pumping, the well had flowed an estimated 2,158 BBL and has since pumped 1,268 BBL out of a total load of 7,144 BBL. This indicates that approximately 48% of the load has been recovered if fluid lost during the milling and fishing operations is ignored.

A final report was submitted and accepted in June 1977, and the contract has been terminated.

5.11.5 Conclusions and Recommendations

In the final report the Industrial participant has drawn the following conclusion:

> "It would appear that this type reservoir is a poor candidate for further utilization of MHF technology. The reasons for this probably involve the geology of the region and reservoir limits rather than the mechanical problems that plagued this operation."

It *is* possible that this conclusion is premature and not warranted on the meager data available. The mechanical problems in the well did not allow early clean-up of the frac fluids which could account for some of the low productivity.

While this particular fracturing system did not work, the entire area, and the MHF should not be abandoned based on this one unsuccessful test.

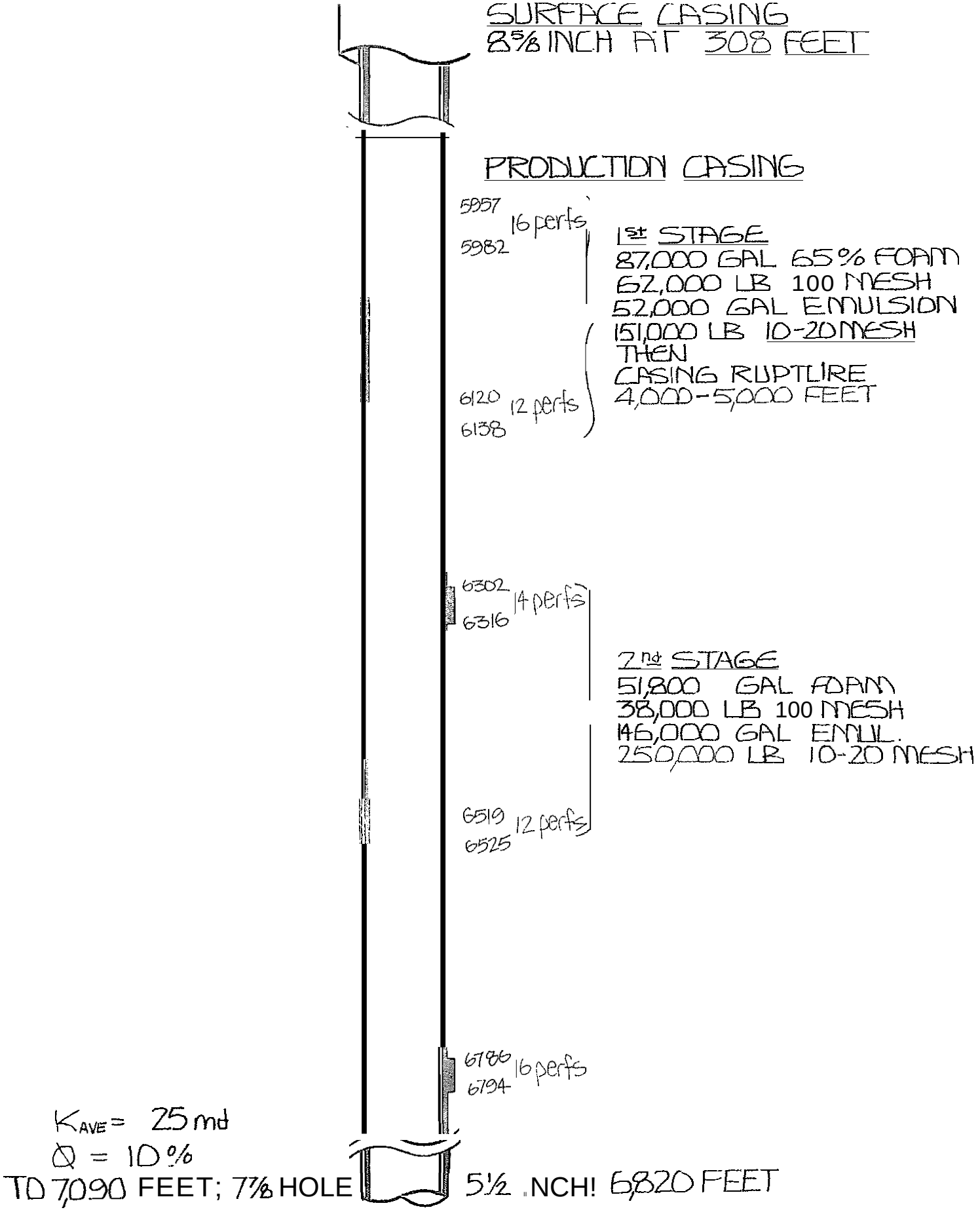


FIGURE 5-23 SCHEMATIC OF FERGUSON NO. A-I WELL

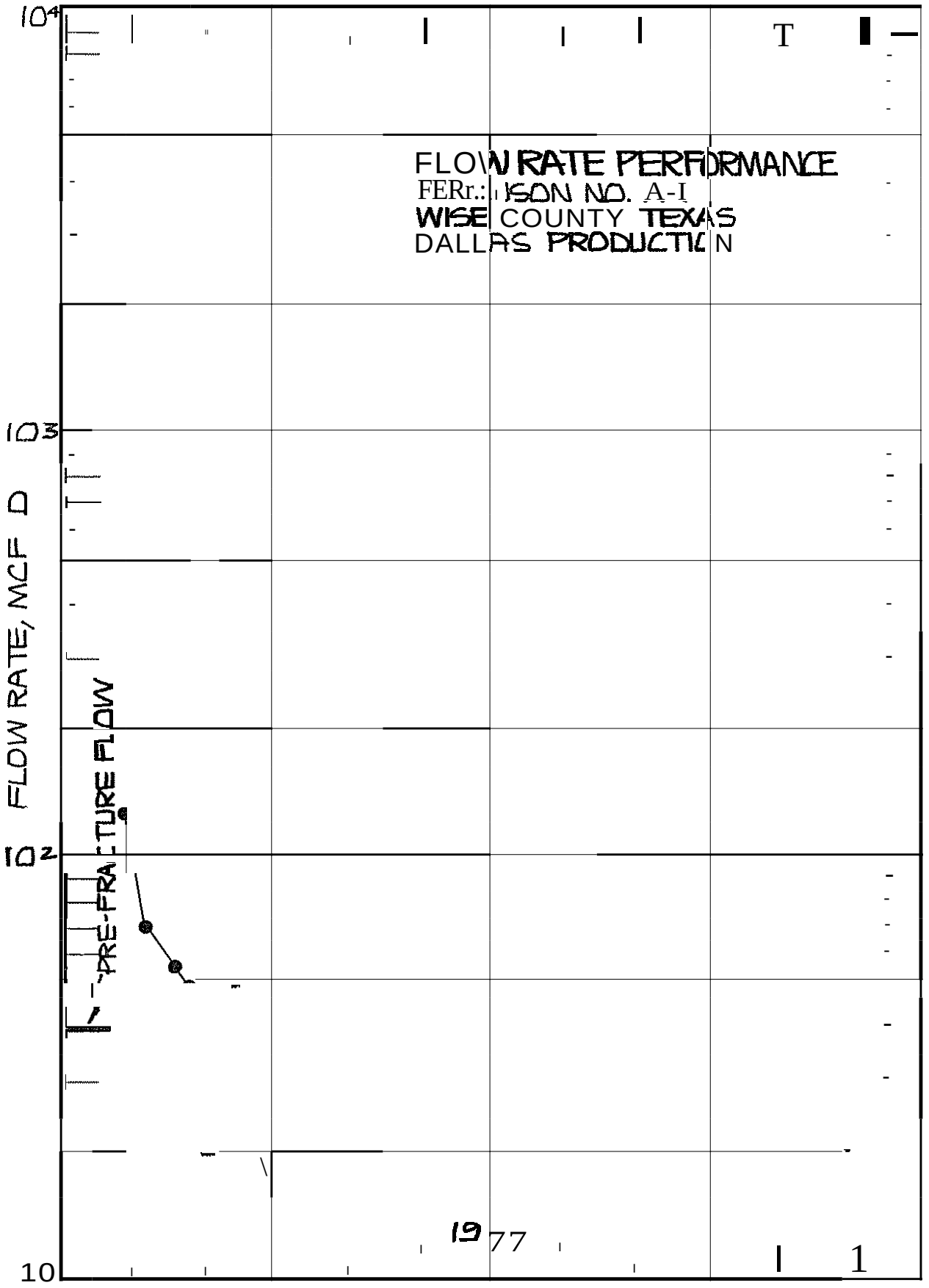


FIGURE 5-24 FLOW RATE PERFORMANCE OF FERGUSON A-I WEIL

6. NATIONAL LABORATORIES AND ENERGY RESEARCH RESEARCH CENTERS

6.1 LAWRENCE LIVERMORE LABORATORY

6.1.1 Model Development Mechanical Measurements

A two-dimensional hydraulic fracturing model has been developed and is being applied to analyze the effects of pore pressure on the elastic stress field around a fracture which is opened by the hydraulic pressure. The calculations indicate significant changes in the local stresses as the fluid migrates from the fracture into the reservoir rock. The model in its present state uses a point iteration scheme for solution of the elastic parts of the problem. For large grids this solution technique uses substantial amounts of computer time. Several other solution techniques are being tested to speed the computational aspects of the problem. These include: 1) the Cholesky incomplete matrix iteration scheme; 2) the multigrid relaxation scheme was advertised to be faster than the Cholesky method and required considerably less storage. For our test problem, this method was considerably faster than the point scheme. However, the speed of the method depends strongly on the type of problem being solved. In addition, it is difficult to use on the more complicated problems and, in fact, cannot be used for some problems; 3) a block-line iteration scheme is currently being analyzed to determine its applicability to the solution of the elastic parts of the problem. This technique is also very appealing because of the low computer storage requirements, but its computational speed has not been adequately established. The solutions obtained with the scheme are correct.

6.1.2 Laboratory Experiments

Experiments have continued with layered laboratory models under no confining stresses. A tool was developed to create stress risers in the borehole which allows the control of the initial orientation of the fracture. Results from some of the unconfined experiments indicate that the physical characteristics of the layer boundary and the mechanical properties of the material on both sides of the boundary have a significant effect on the propagation of a pressure driven fracture in the boundary region.

6.2 SANDIA LABORATORIES

6.2.1 Fracture Orientation

Sandia, by participating in MHF experiments with private industry, has developed the surface electrical potential system for fracture orientation determinations (see Table 4-1). Development of this system has been incremental and it has successfully demonstrated that not only can fracture orientation be determined but also the asymmetry of the two fracture wings can be shown. Other geophysical techniques for fracture characterization have been investigated and in the case of micro-seismic recording has caused redirection of the activity. Surface monitoring appears to be of limited value as a result of low seismic signal amplitudes; however, a down-hole seismic sensor may offer a better oppDrtunity to measure the fracture height and orientation in the near field of the wellbore.

Development of the seismic diagnostic technique will shift emphasis from the surface detection of fracture related signals to a down-hole system to detect close in fracture profiles. This will require an increased emphasis on wave transmission properties, formation properties and source signals. An improved understanding of these principles will also be beneficial for improved exploration seismology and logging.

The surface electrical potential method is associated with the science (or art) of electrical prospecting used in the investigation of geological structures. The casing of the well to be fractured is used as the probe for inducing current into the earth. A remote well casing serves as the return current probe. Before fracture, the potential distribution is measured at the surface and on a circumference around the well. Theoretically, the equal potential lines form concentric circles with the well as their center. After fracture, the fracture fluid being conductive causes elliptically-shaped, equal potential lines to form at the surface. The surface electrical potential measured after the fracture is the resultant of the field from the vertical casing and the horizontal fluid. This causes a predictable distortion of the concentric circles formed by the vertical well casing. Because of the variation in the earth's electrical constants in the vicinity of the well, a reference measurement is made before the fracture. If the potential measurements before and after the fracture are normalized and compared, diagnostic information about the fracture is obtained. A layout of the surface potential instrumentation is shown in Figure 6-1.

To aid in the interpretation of the surface electrical potential data, a mathematical modeling effort was undertaken. This modeling method utilizes the Green's function integral equation approach where the so-called half-space Green's function is used. The potential difference that exists at the surface between pairs of potential probes placed circumferentially around the well as a function of fracturing conditions are calculated. This calculated potential difference made before the fracture is compared with the calculated potential difference after fracturing and the change in potential gradient for various angles around the well are determined.

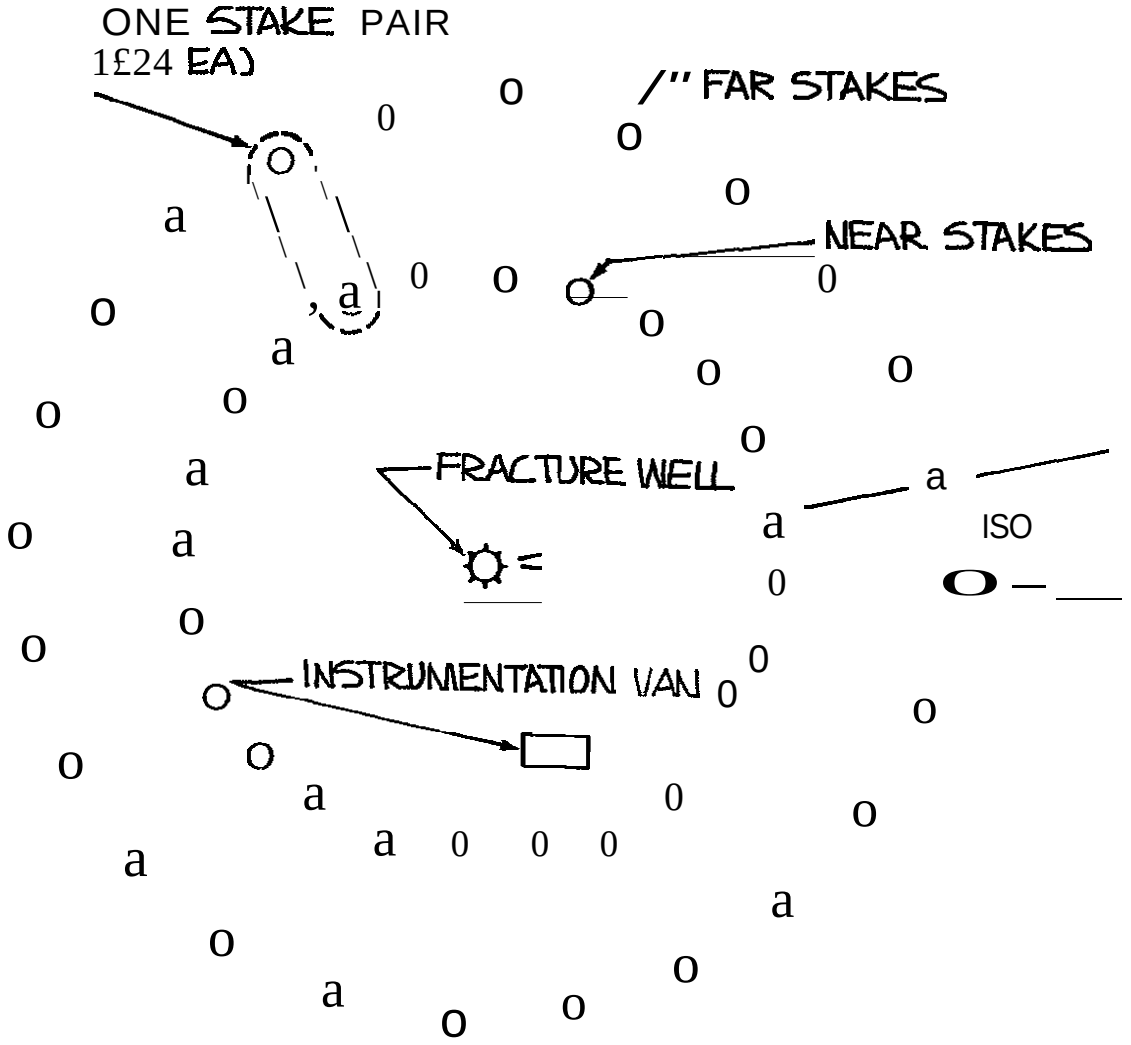


FIGURE 6- 1 LAYOUT OF THE SURFACE POTENTIAL INSTRUMENTATION

Although the mathematical model calculations are for a homogeneous and isotropic earth, the results are believed to describe the azimuthal directions, any asymmetry of the fracture, and the direction of the major portion of the fracture.

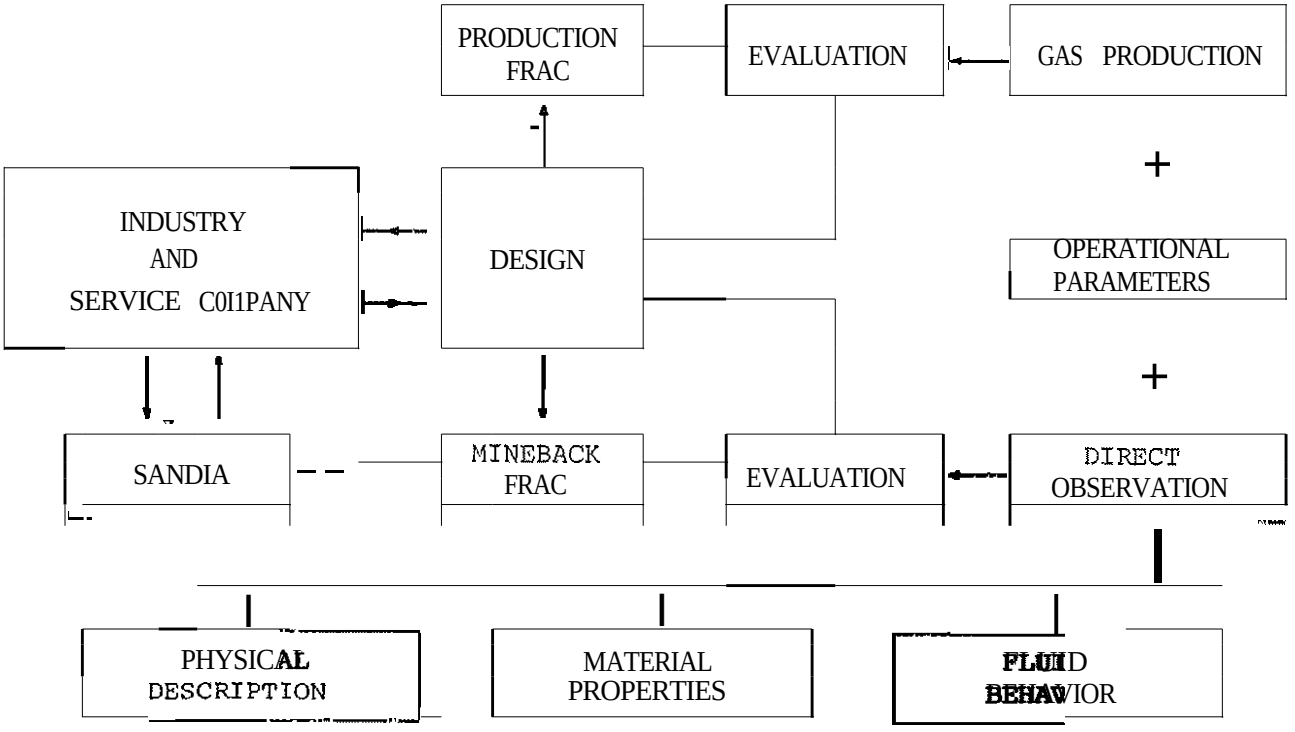
The surface electric potential system has shown promise, not only in fracture orientation determination, but possibly as a diagnostic tool in understanding some features of fracture dynamics. Data collected on recent events indicates some heretofore unnoticed phenomena occurring at very early times in the fracture treatments. One possible interpretation is that the total fracture length occurred within the first few minutes and subsequent injection of material just served to increase the fracture width. This early action would not be seen on a tiltmeter.

A MHF experiment in cooperation with Shell Oil on their RACHAL #2 well near Laredo, Texas is being planned for August 1977. The well location has been visited and is the responsibility of Sandia and Shell for the experiment have essentially been agreed upon. Shell has initiated and signed-off on a letter to ERDA requesting both Sandia and the USGS support for their fracturing experiments.

The USGS will field their tiltmeter array and Sandia has agreed to record their data via Sandia's minicomputer system.

6.2.2 In Situ Mineback Experiments

Since 1974 Sandia Laboratories has had an active research program in hydraulic fracturing. The objective of the fracturing program is to study the behavior of hydraulically formed cracks in an in situ environment. The role of mineback testing is shown schematically as:



Physical Description	Material Properties	Fluid Behavior
Length	In Situ Stress	**Pressure**
Height	Strength	Flow
Width	Modulus	Rheology
Orientation	Fracture Toughness	Proppant Distribution
Variation	Saturation	Fracture Conductivity
	Permeability	Leak-Off
	Geologic Variation	

Mineback evaluation is based upon direct observation and comparison with measured material properties, fluid behavior, and the operational parameters. Industry and service company participation in the mineback program has been encouraged and industry interest has been high. This program provides a unique opportunity to quantify fracture behavior. ERDA's Nevada Test Site provides this opportunity at a reasonable cost through the use of an existing tunnel complex and the vast support facilities of the site. Sandia has performed several hydraulic fracturing experiments and the feasibility of mineback and coring to delineate the fractures has been demonstrated. In situ stress distributions, fracture orientations, the independence of closely-spaced fractures, and the effect of tunnels have been determined.

This work was done in the G Tunnel Complex of Rainer Mesa at ERDA's Nevada Test Site. All the experiments were conducted adjacent to the tunnel so that the fracture data could be collected during a mining operation.

Three hydraulic fracture experiments are described below. All of the experiments were conducted in 4 in. diameter uncased holes at a nominal depth of 1,400 ft. Two experiments were conducted in Hole U12g10.3 using colored grouts as a fracture fluid. The third experiment was done in Hole U12g10.5 using a water based gel as a fracture fluid.

Hole U12g10.3. Two hydraulic fracture experiments were conducted in this hole at different depths. The bottom fracture used a red grout fracture fluid at a bottom hole depth of 1,395 ft. After the first experiment was accomplished, a grout plug was poured and the second experiment was done with a yellow grout at a depth of 1,365 ft. The fracture interval in the hole for both experiments was 20 ft with a bridge plug set at the top of the interval. Formation breakdown was done by initially injecting 200 gals. of water. This was followed by 272 gal. of grout with water to flush the system. The total volume injected was 700 gal. The average treatment rate was 3.2 BPM. Flow rate and surface injection pressure were only measured.

The formation rock for these experiments was a uniform ash-fall tuff. The mineback investigation showed that both fractures were almost vertical with a dip that varied between 83^0 and 87^0 NW. The fractures were also planar in that the bearing for the yellow fracture was N 53^0 for 20 ft of recovery and the red fracture bearing varied from N 47^0 E to N 53^0 E over a distance of 50 ft. No lateral and vertical extents of the fractures have been defined as yet, but a coring program is underway to complete the fracture geometry definition. The dip and bearing directions of the two fractures correspond to the minimum horizontal principal stress direction. The calculated downhole shut-in pressures compared well with those measured by small hydraulic fracture in situ stress tests done in the tunnel complex. (1) The tunnel tests gave 894 psi for the minimum principal stress with a value of 1,065 psi for the Hole l2gl0.3 fractures. The dip and bearings found for the small test agreed well with the two grouted fractures.

Hole U12gl0. 5. A single fracture experiment was done in this hole. The purpose of this experiment was to try to gain some information on the fracture fluid motion during the fracture creation and to get some data on fracture width. The experiment was done in the ash-fall tuff rock. The fracture design called for a water-based gel (PWG/FR2GL) with colored 20-40 sand of different concentrations to be phased into the fracture schedule at an injection rate of 4 BPM. The design schedule is given in Table II. Flow rate and surface pressures were measured. An annulus pressure was measured to help determine the downhole values.

The mineback evaluation of the experiment has not been completed, but some very interesting results have been obtained. The hole drilled for this experiment penetrated a region of the formation between two faults which strongly influenced the fracture growth and orientation. The faults had small displacements of the order of an inch and contained a rubble zone

which was about an inch wide. The formation also had a number of thin bedding planes in the experimental area. The effect of these features on fracture geometry are presented below.

The plan view shown in Figure 6-2 shows the outline of the tunnel excavated for fracture examination. The enclosed area shown at the bottom of the figure is an excavated bench. The experiment hole is shown at the 55 ft station. The first view of the fracture system is a profile along the line A-A. The A-A view, Figure 6-3 shows the entire mined fracture system projected on the A-A line. Two fractures were formed. The primary fracture was nearly vertical with a dip varying between 85^0 NE to 85^0 NW and essentially lies in the A-A plane except for the tail from CS20 to CS40 which curved out of the plane. The faults and bedding planes are as observed in the A-A plane. The secondary fracture system shown was projected on the A-A plane from the tunnel bench noted in Figure 6-2. The experiment hole is shown as VDH #5 with the fracture initiation interval being the thin line below the wide line. Two important results about the primary fracture can be seen in this profile. First, the fault to the left of the hole blocked the lateral growth to the north; and, secondly, a bedding plane a few feet above the initiation level served as a barrier to vertical growth. The effect of the fault to the right of the hole is shown in later views. Basically, the path of least resistance was downward.

A vertical cross section, plane D-D, is shown in Figure 6-4 . The primary fracture system is shown passing through the hole and stopping just below the upper bedding plane. The secondary fracture is shown to the left. This fracture has a dip which varies from 10^0 NE to 80^0 NE. The marked changes in fracture dip are due to very thin bedding planes. The dashed line at the intersection of the two fractures denotes the absence of sand. Referring to Figure 6-3, the next view of the fracture system is a plan view of plane E-E. The E-E plane is shown in Figure 6-5 . The fault to the left has retarded the lateral growth, as mentioned earlier, to the north and a new weak fault is evident between the other two faults. The fracture is not connected across the fault to the right in this plane. On the right side of this fault, the fracture begins to change bearing by approximately 40^0 to the east. Another observation is that the secondary fracture system does not extend to this depth.

From the observations of the placement of the sand and the shape of the fracture system, it appears that the fracture initiated and grew in the downward direction because of barriers due to the fault to the north and the parting plane above. The fault to the south did not stop growth but there is evidence that a marked change of in situ stress exists across the fault because of the direction change of the fracture. Continued exploration of this fracture is planned which includes in situ stress determinations across the faults and bedding planes in addition to further fracture examination.

The above results from the mineback investigation of the hydraulic fracture experiments have demonstrated how different geological features affect fracture growth. In a uniform media, the fractures are vertical with a consistent dip and bearing. When faults or bedding planes are present,

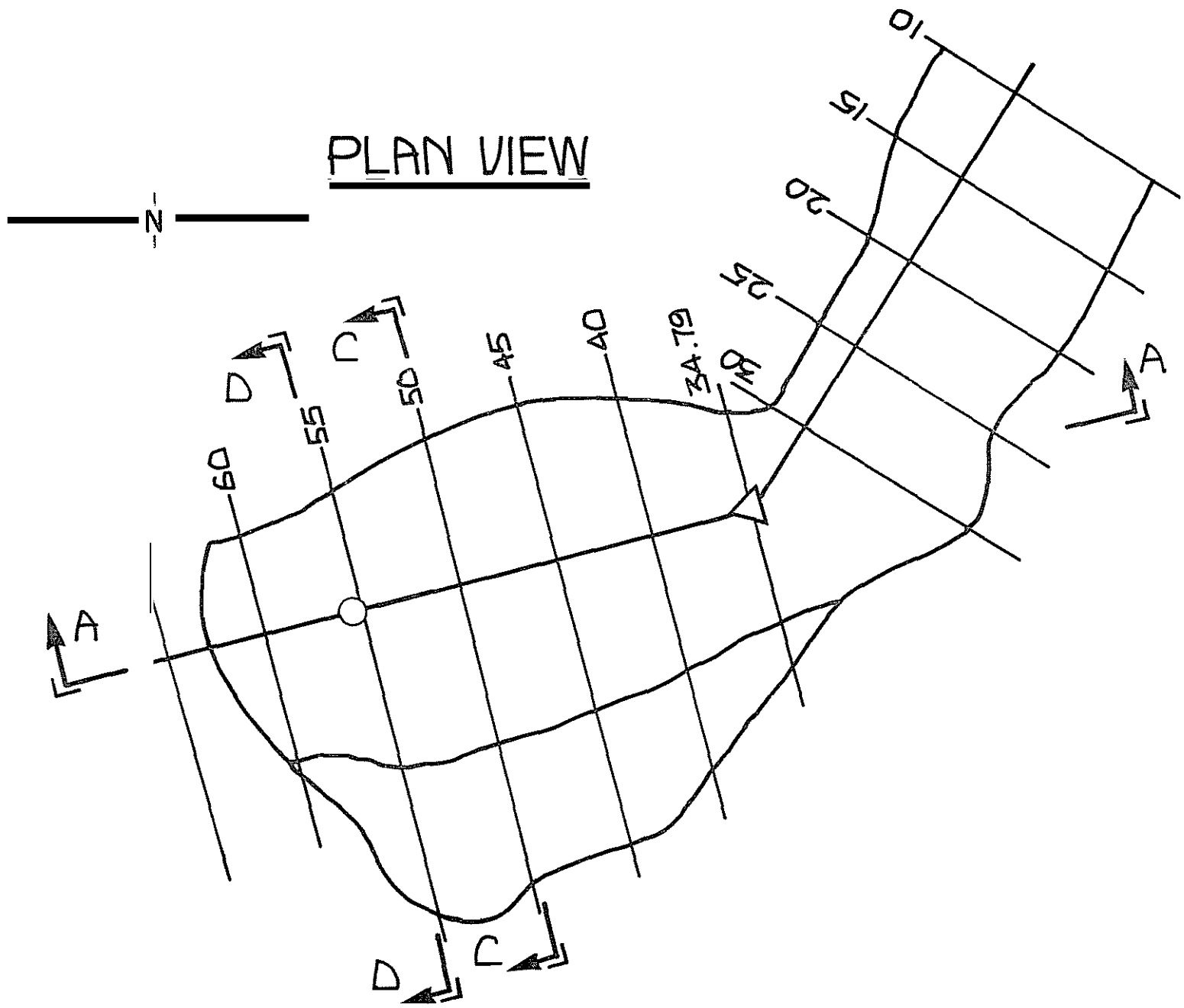


FIGURE 6- 2 PLAN VIEW

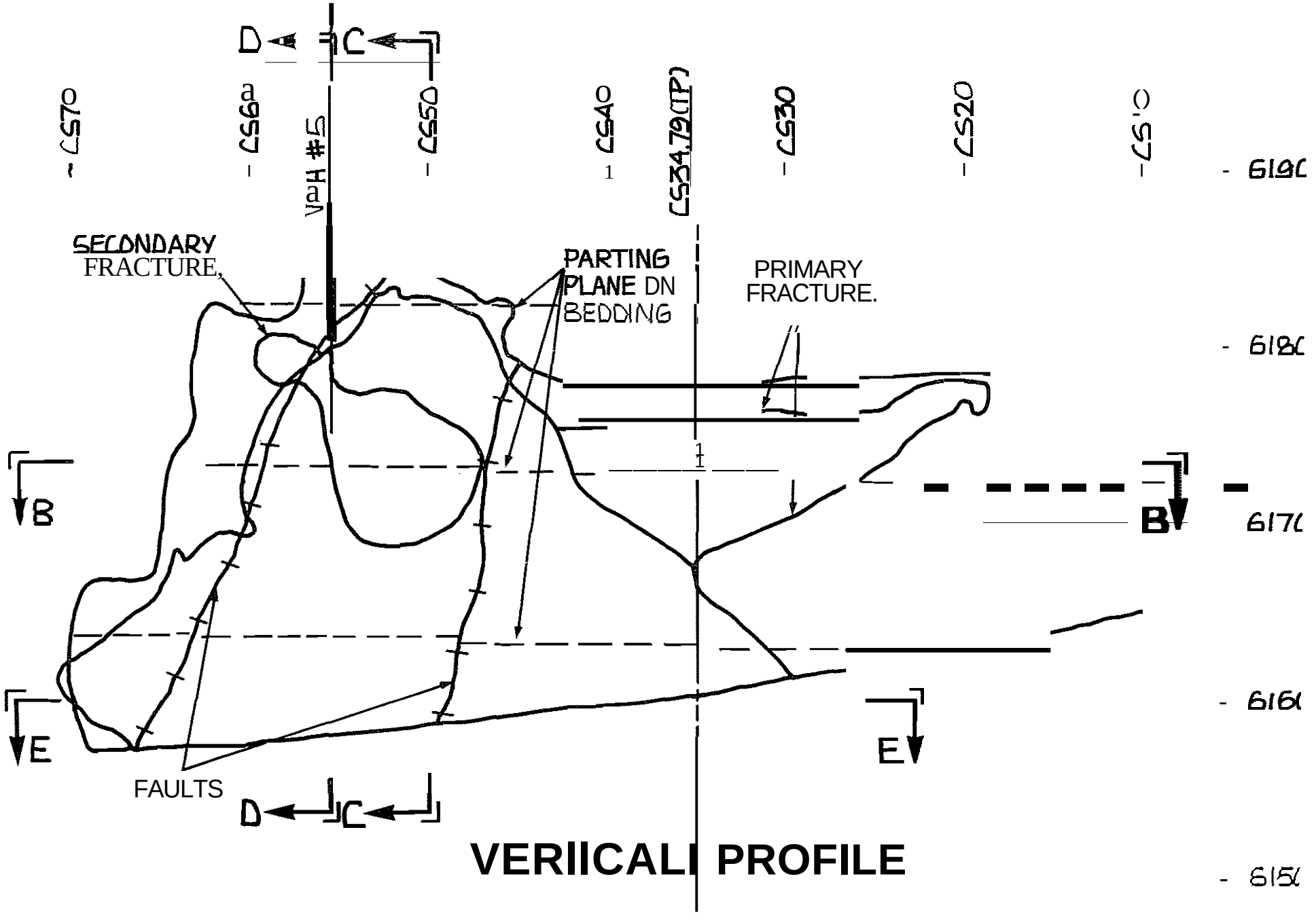


FIGURE 6- 3 VERTICAL PROFILE, PLANE *A-A*

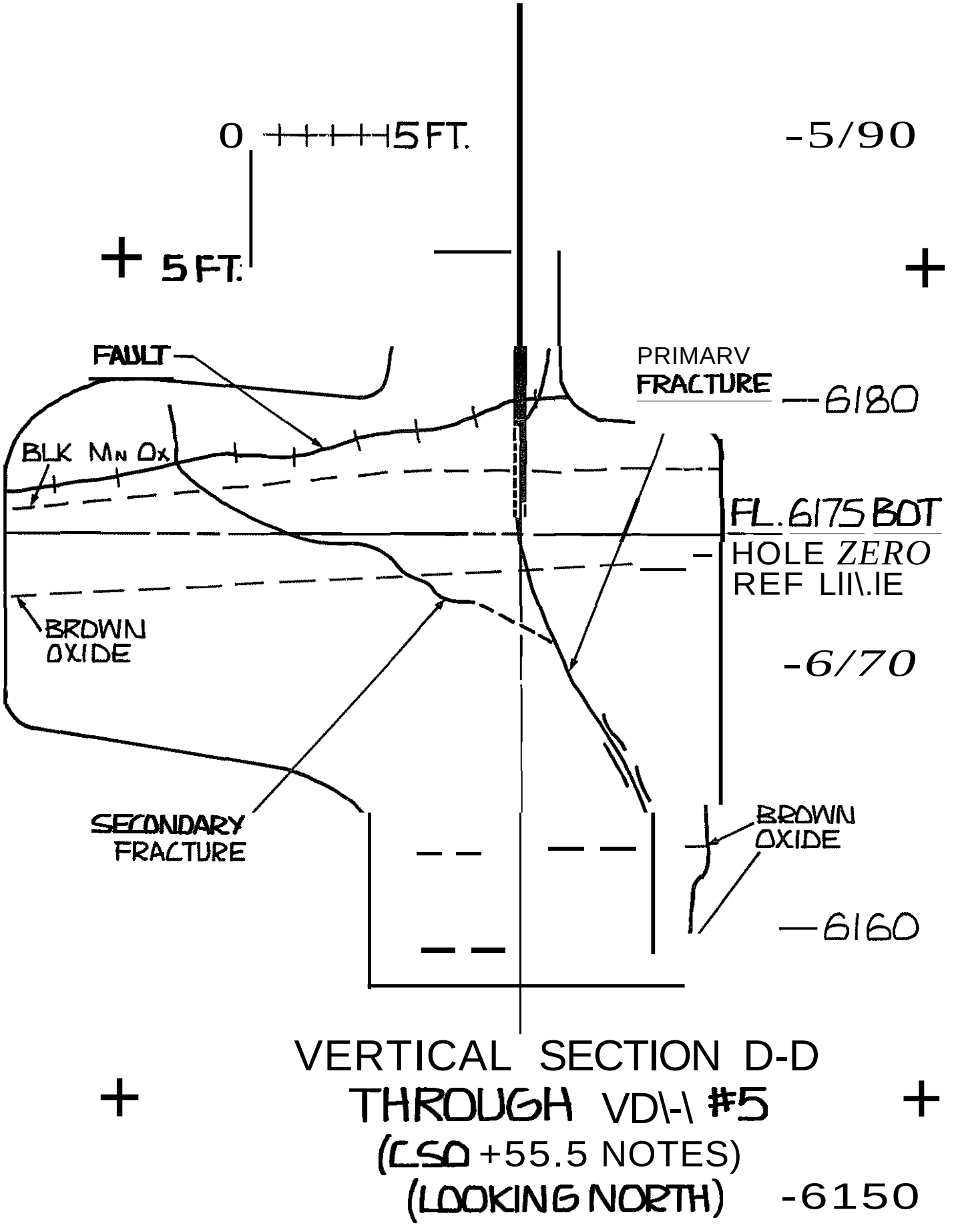
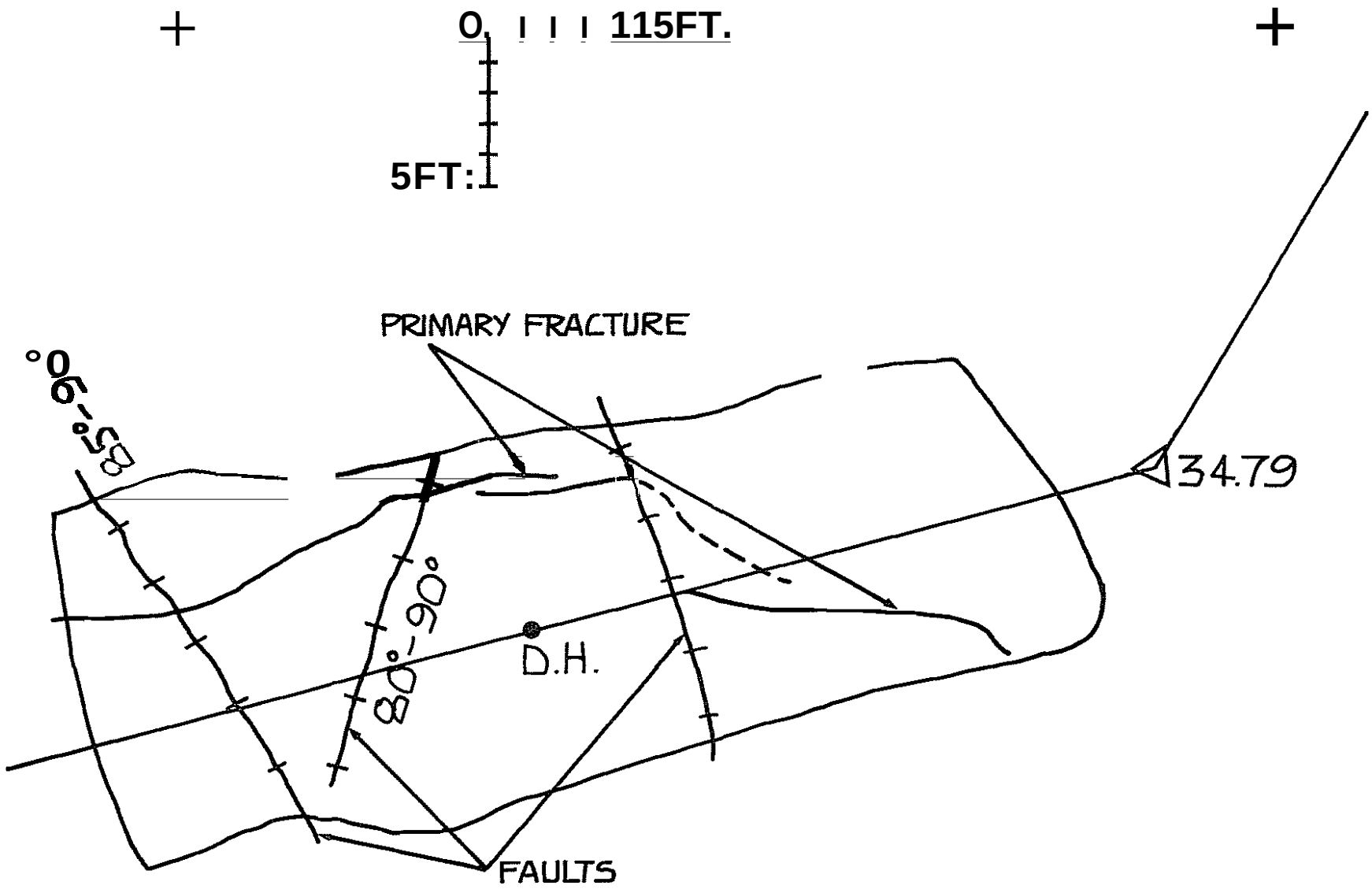


FIGURE 6- 4 VERTICAL SECTION *D-D* THROUGH VDH #5



PLAN E-E (6160 ELEV)
-ISI

FIGURE 6- 5 PLANE E-E

the fracture growth may be retarded or reoriented. Additional in situ stress measurements and material property data are being obtained to further quantify the observed fracture behavior in these experiments.

An experiment is planned in Hole U12gl0.6 which will investigate the effects of fracture treatments at the interface of a zone of welded tuff and ash-fall tuff at a depth of 1,455 ft. Their formation properties differ significantly; for instance, Young's modulus between these zones differs by an order of magnitude.

The plans have been finalized, and the interface experiment is scheduled for August 22-25, 1977.

The zone of interest, from 1,318 to 1,346 ft, is a 28 ft thick zone that the welded tuff was intercepted. Ash fall tuff lies above and below. The plan is to initiate two hydraulic fractures, one immediately below the welded tuff followed by another in the middle of the most dense section of the welded tuff.

The ash fall tuff will be isolated to a 12 ft zone and then the formation broken down with water. The fracture plan calls for 4,000 gal of green colored grout immediately followed by another 4,000 gal of black colored'grout. Downhole pressures will be monitored by an Amerada type pressure bomb suspended by wire line and stationed in the open hole section. A back-up system consists of a pressure transducer placed above the packer that will be hard-wired to the surface.

The second fracture will be much like the first. A notch will have been previously cut at 1,328.5 ft in the eight-ft zone. The purpose of the notch is to reduce break-down pressure in the welded tuff and to insure fracture initiation in the mid point of the dense portion of that section. Again, two pressure sensing systems will be used. The hydraulic fracture treatment will consist of 5,000 gal of blue colored grout.

The difference in the volumes of the two treatments (8,000 gal in the ash fall versus 5,000 in the welded) is due to the difference in elastic and fluid loss properties between the two formations. If the estimates of these properties are correct, each fracture will have 300 ft fracture wings.

Four hydrophones urrit.s will be placed in drilled holes to monitor acoustic signals generated by the fracture process.

6.2.3 Puff-n-Tuff Experiment, "G" Tunnel, NTS

The initial experiment was designed to study certain aspects of containment of spherical explosive charges in volcanic tuff; the principal objectives of the test related to containment phenomenology. A separate drift was driven for the Puff-n-Tuff experiment, and the distance was such that the older test would not influence the newer one. A 256 lb spherical charge of high explosive was sealed into the end of the drift with grout that closely matched the physical properties of tuff. A previously drilled hole estended from the charge out into virgin tuff for 28 ft. The hole was 6 in. diameter into which an open 4 in. transite pipe was placed. An identical transite pipe was sealed into the

grout filled drift. The latter was instrumented with time-of-arrival gauges, but was otherwise open. The plexiglass lItransition" cones were placed between the charge and the two pipes. The purpose of these cones was to prevent the open pipes from prematurally closing by the hydrodynamic forces generated at the detonation. The aim of the experiment was to hold the pipes open during the period of cavity growth immediately following detonation for sufficient time to allow the gases formed by the explosion to escape down the open conduits.

The experiment went almost as had been predicted. The detonation formed a small expansion cavity, but a compressive hoop stress was formed once the cavity rebounded back inward after the passage of the shock wave. Explosive gases were then allowed to escape down the two open pipes.

On mining back towards the point of detonation it was found that the 4 in. transite pipe placed in the grout was filled with debris. Apparently the effect of the plexiglass transition cone was not sufficient to prevent closure in the grout. However, once the cavity was reached it was f'ound that the pipe extending out into virgin tuff was still open. The transition cone on that side apparently accomplished its task. Mining continued down the axis of this pipe, and at a distance of six ft beyond the cavity the first evidence of a nearly vertical explosive gas induced fracture was observed. The fracture continued along the pipe to its end. The fracture induced by the explosive gases is remarkably similar to what was observed nearby at Hole #3, even though the mechanism for creating them was markedly different. The fact that fracture initiation did not commence lmtil six ft out from the cavity verified that compressive hoop stress was induced around the cavity. This stress was superimposed on the initial in situ stress field. It follows that the gas fracture would commence outside of that field.