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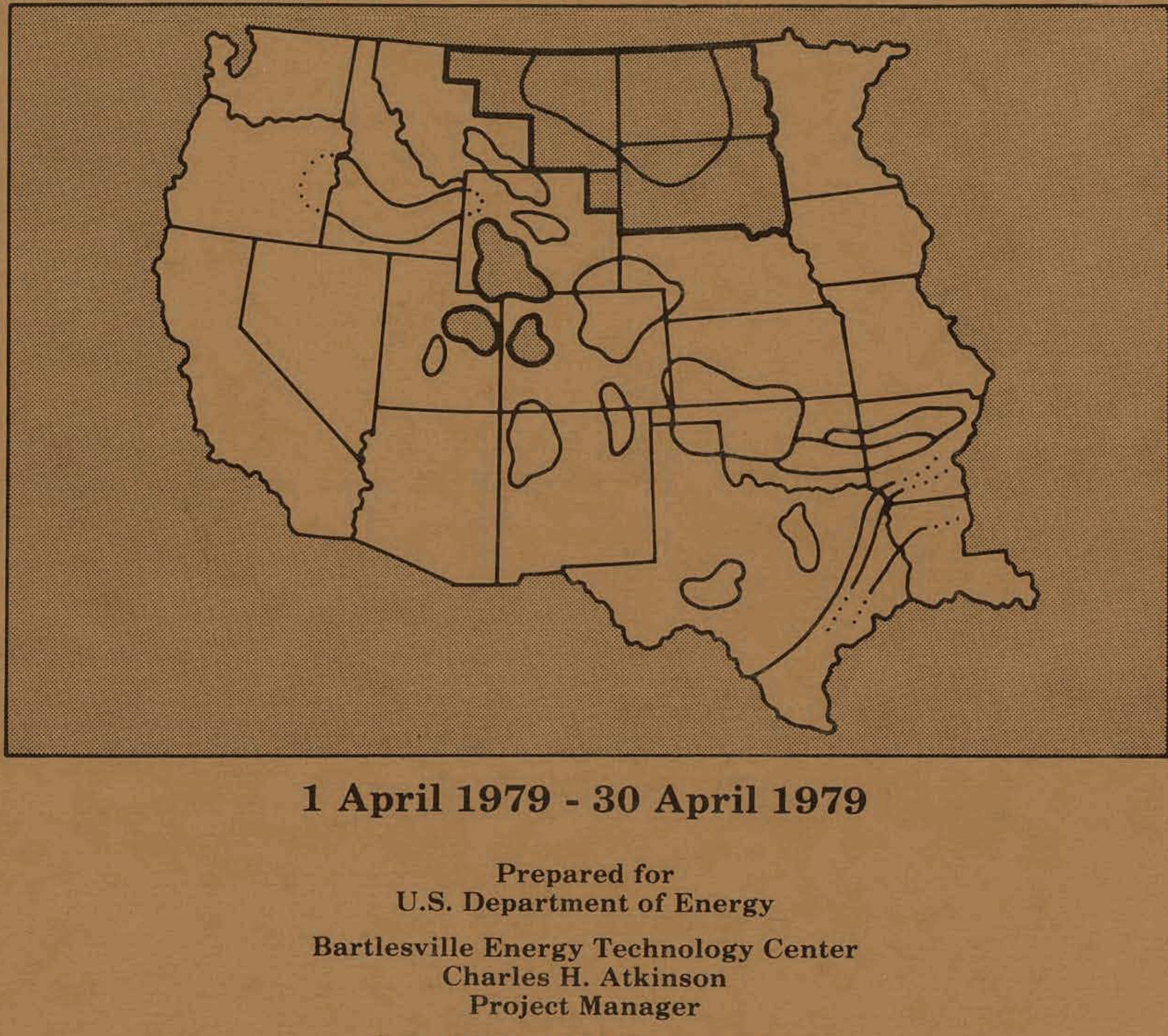
DOE/BG/01569-7

Western Gas Sands Project Status Report



1 April 1979 - 30 April 1979

Prepared for
U.S. Department of Energy

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Compiled by CER Corporation
Las Vegas, Nevada

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1. SUMMARY

This edition of the WGSP Status Report summarizes April, 1979 progress of government-sponsored projects directed toward increasing gas production from the low-permeability gas sands of the western United States. Background information is provided in the *September, 1977, Status Report, NVO/0655-100.*

Personnel from BETC, METC, CER Corporation, and DOE Headquarters met in Las Vegas on April 4 and 5 to discuss the Gas Resources RD&D Management Plan. Gas Research Institute personnel, the WGSP Project Manager, and CER Corporation personnel met in Las Vegas on April 27 to discuss reservoir fracturing and project plans.

Work by the USGS toward resource assessment in the four primary study areas continued.

During April, projects of the National Laboratories and Energy Technology Centers continued. Bartlesville Energy Technology Center continued work on fracture conductivity, rock-fluid interaction, and log evaluation and interpretation techniques. Experimental and theoretical work on hydraulic fracturing mechanics and analysis of well test data continued at Lawrence Livermore Laboratory.

The CER Corporation RB-MHF 3 final report has been distributed. Gathering of bottom-hole pressure data from the Miller No. 1 well and Sprague No. 1 well in the Wattenberg Field, Colorado continued. Fracturing fluid/ rock interaction tests have been completed by Terra Tek for Gas Producing Enterprises, Inc. on sandstone horizons in the lower Mesaverde. The Mitchell Energy Corporation Muse-Duke No. 1 was flowed 4,000 MCFGD in April. Fishing operations on the Mobil PCU F31-13G well were unsuccessful. Six zones of the first horizontal experimental hole in the Sandia Laboratories interface test series were mined back to examine the behavior of the hydraulic fracture at the interface.

Data collection by CER Corporation and TRW for GRI's Analysis of Tight Formations project continued.

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2. PROJECT MANAGEMENT

2.1 TECHNICAL MONITORING AND EVALUATION

Personnel from Bartlesville Energy Technology Center, Morgantown Energy Technology Center, CER Corporation, and DOE Headquarters met with the WGSP Project Manager in Las Vegas, Nevada, on April 4 and 5 to discuss the Gas Resources RD&D Management Plan, interrelationship of the various offices, and reporting requirements.

J. E. Evered, CER Corporation, attended a course concerning coring operations, equipment, procedures, and analysis techniques given by Core Laboratory in Casper, Wyoming.

R. L. Mann, CER Corporation, attended a National Petroleum Council meeting in Dallas, Texas on April 24.

The Project Manager and advisors of the Gas Research Institute, Unconventional Natural Gas Project met with the WGSP Project Manager and CER Corporation personnel in Las Vegas, Nevada on April 27, to review progress and proposed work for field evaluation of reservoir fracturing. The WGSP activities, budget, and the possibilities of interaction of the Gas Research Institute in areas of interest to the WGSP and DOE were also discussed.

2.2 TECHNOLOGY TRANSFER

2.2.1 Documentation and Reports

The Fourth Quarterly Basin Activities Report, January 31, 1979 and the WGSP Status Report, 1 January 1979 - 31 January 1979 were mailed out in April. The WGSP Status Report, 1 February 1979 - 28 February 1979 will be distributed by May 31. The final report on the CER-managed government/ industry RB-MHF 3 demonstration well was distributed April 30.

2.2.2 Project Data Bank

A map of a stratigraphic section of Cretaceous rocks of the Northern Denver Basin, northeastern Colorado and southeast Wyoming, and the proceedings of the Wyoming Oil and Gas Fields Symposium, "Greater Green River Basin" and 1979 SPE Symposium on Low-Permeability Gas Reservoirs were added to the WGSP data bank.

2.2.3 Articles and Publications

The following abstracts are from the proceedings of the 1979 SPE Symposium on Low-Permeability Gas Reservoirs.

Gas Recovery From Tight Formations: A Function of Technology and Economics
V. A. Kuuskraa, J. P. Brashear, Lewin and Associates, Inc.

Thirteen tight gas basins were analyzed in detail to assess their production potential under alternative levels of economic incentives and technology improvements. Additional analyses were conducted to assess the impact of selected development constraints (drilling, well stimulation, and pipelines) and to test the importance of individual technology improvements to overall performance.

The analysis yields estimates of ultimate recovery ranging from 70 to 108 TCF at prices ranging from $1.75 to $4.50 per MCF without accelerated R&D; and from 149 to 188 TCF with significant technology advances.

The technology improvements that appear to have the largest impact on ultimate recovery and net present value include (where applicable): improved ability to differentiate and characterize the gas reservoirs; capacity to stimulate multiple reservoirs from a common wellbore; improved predictability of fracture performance; increased effectively propped fracture length; ability for fractures to intersect lenses not directly in contact with the well; and optimizing field development (well spacing, siting, and frac size).

Influence of Diagenetic Reactions on Reservoir Properties of the Neslen, Farrer, and Tuscher Formations, Uinta Basin, Utah
C. W. Keighin, U.S. Geological Survey

Thirty-eight core samples of alluvial sandstones and siltstones from the Neslen, Farrer, and Tuscher Formations of the Upper Cretaceous Mesaverde Group from the Southman Canyon field, southeastern Uinta Basin, Utah, were studied in thin section and by scanning electron microscope (SEM). Extensive diagenetic modifications of the reservoir rocks have occurred, some of which significantly improved reservoir properties. Although early carbonate cement and authigenic clays are common, later dissolution and leaching at depth have created significant amounts of secondary porosity. Successful exploration programs are facilitated by recognition of diagenetic factors which influence the reservoir.

3. RESOURCE ASSESSMENT

Geological, geophysical and reservoir evaluation studies are necessary to define and characterize the resource base. The USGS is performing the majority of these studies with support provided by field test data and core acquisition and analysis.

3.1 U.S. GEOLOGICAL SURVEY ACTIVITIES

3.1.1 Greater Green River Basin

Work continued on the stratigraphic analysis of the Greater Green River Basin.

Work also continued on the petrographic examination of core chips from the Superior-Pacific Creek well in the Green River Basin and Tierney wells in the Washakie Basin.

The Washakie and Great Divide Basins lineament study continued and cross-sections through these basins are under preparation.

Cores from the Tierney No. 1-23 well, sec. 23, T. 19 N., R. 94 W., Washakie Basin were described and sampled. The USGS Open File Report 78-826 was completed by C. W. Spencer. The map is titled "Wildcat well penetration map showing wells drilled into and through potentially gas-bearing, low-permeability Upper Cretaceous and Tertiary reservoirs, Great Divide Basin, southwest Wyoming."

3.1.2 Northern Great Plains Province

Petrographic and clay mineralogy studies were conducted on Eagle core taken from the Joseph J. C. Paine well in north-central Montana.

A paper entitled "An evaluation of shallow, low-permeability, gas-bearing reservoirs in the western portion of the northern Great Plains" was prepared by D. D. Rice and G. W. Shurr for the AAPG Bulletin.

3.1.3 Piceance Basin—Uinta Basin

Examination began on thin sections of sandstone samples of Wasatch and Mesaverde reservoirs from the CIGE Natural Buttes 21 well in the Uinta Basin.

Preparation and final drafting continued on the open file report 79-365, "Preliminary chart showing distribution of rock types, lithologic groups, and interpreted depositional environments for some Lower Tertiary, Lower and Upper Cretaceous, and Upper Jurassic rocks in the subsurface between the Altamont oil field and San Arroyo gas field, north-central to southeastern Uinta Basin, Utah. This report will be released pending DOE release and final drafting.

3.1.4 Schedule Status

Figure 3-1 is a milestone chart depicting the status of all USGS projects within the WGSP.

3.2 C. K. GEOENERGY CORPORATION

3.2.1 Reservoir Characteristics of Uinta Basin Wells

During April, a meeting was arranged with Diamond Shamrock personnel in Vernal, Utah to discuss the logging and data acquisition program for their wells.

3.2.2 Optimizing Selection and Completion of Western Tight Gas Sands

During April, a meeting was held with the USGS and Sandia to select locations for the proposed core holes. It appears that a portion of the Tusher, Farrer and part of the Neslen can be cored at one location. Bryson Canyon gas field has an extensive road net and no problems are expected with tieing in Sandia's Seismic Study or the USGS studies with the two preliminary well locations.

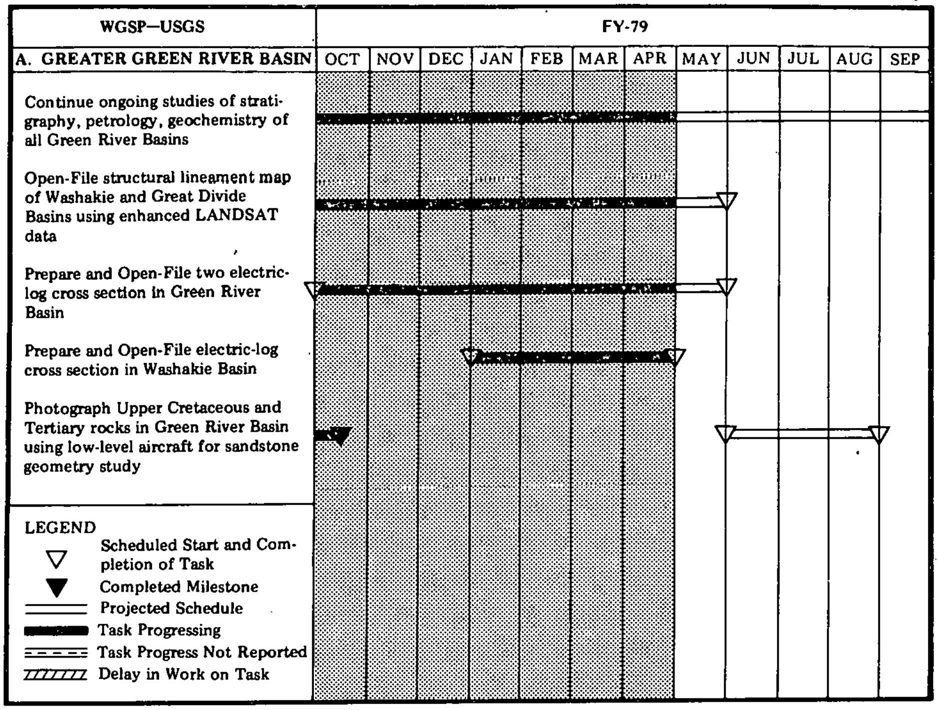
3.3 CORE PROGRAM

Members of CER's and Chandler and Associates' staff met in Denver on April 25 to discuss a coring project. A contract is now being finalized to obtain 360 ft of core (plus logs) from Chandler and Associates' Piceance Basin well located in Mesa County, Colorado. The well is scheduled to the Corcoran (5,100 ft) and core will be obtained between 2,500 and 3,500 ft. Spudding is scheduled for early June with coring activities to follow.

Mr. Carl Simpson of Christensen Diamond Products, Casper, Wyoming, visisted CER Corporation to discuss coring procedures and new equipment, which included new diamond drill bits, downhole motors, and plastic sleeve coring. This type of coring will be utilized in the Northern Great Plains Province with Kansas-Nebraska and probably Odessa Natural.

3.4 LOGGING PROGRAM

This paper was presented at the 1979 SPE Symposium on Low-Permeability Gas Reservoirs in Denver, Colorado, May 20-22 and directly relates to horizons of interest in the WGSP Logging Program.



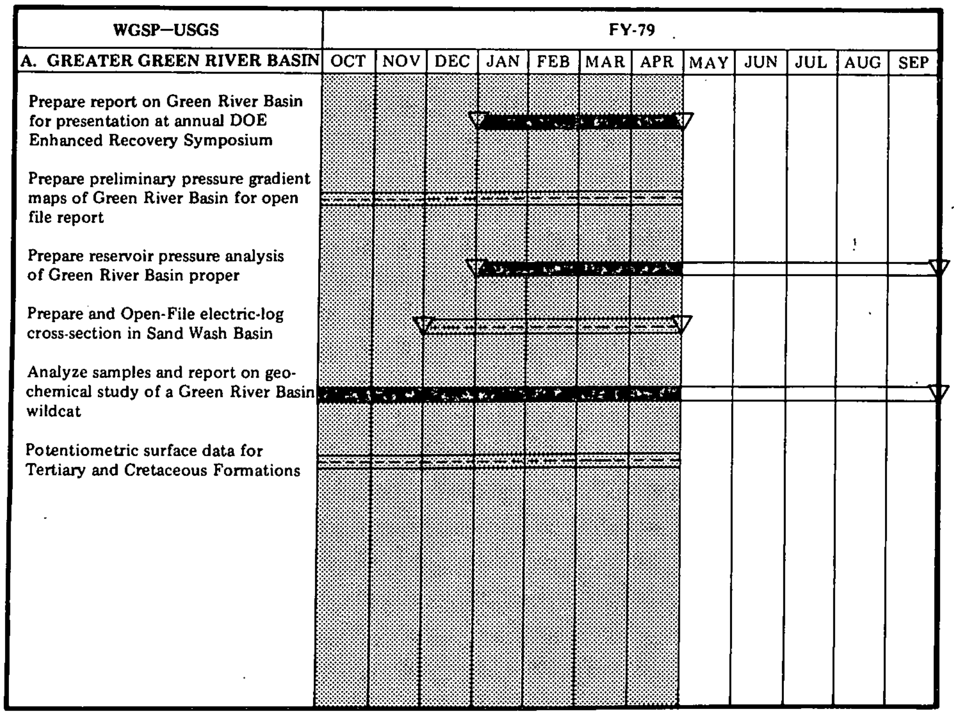
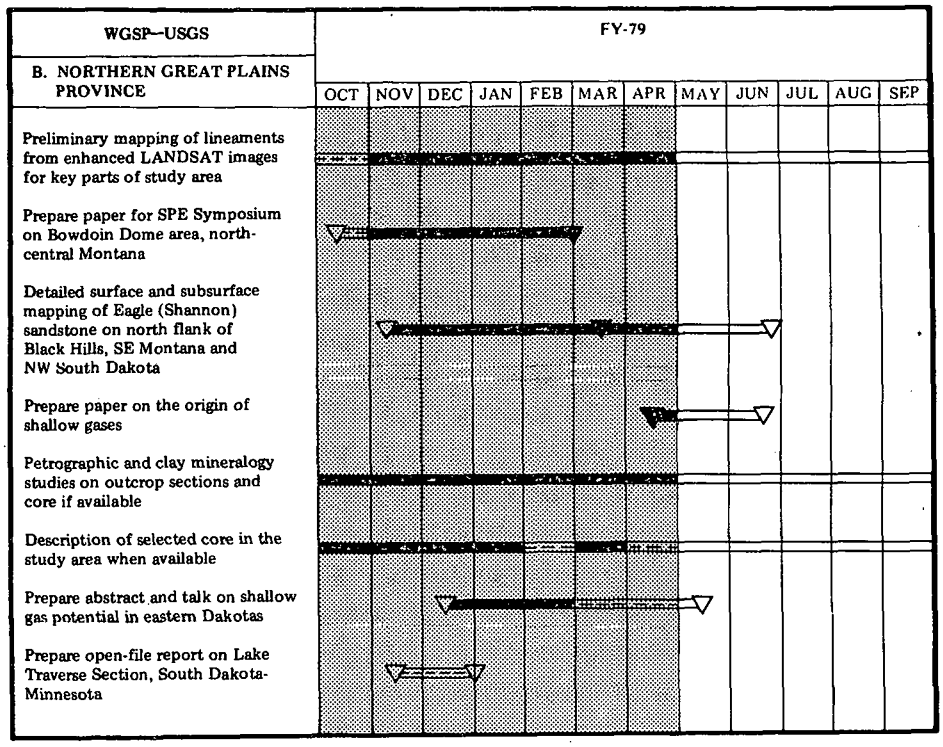


Figure 3-1 Milestone Chart—USGS



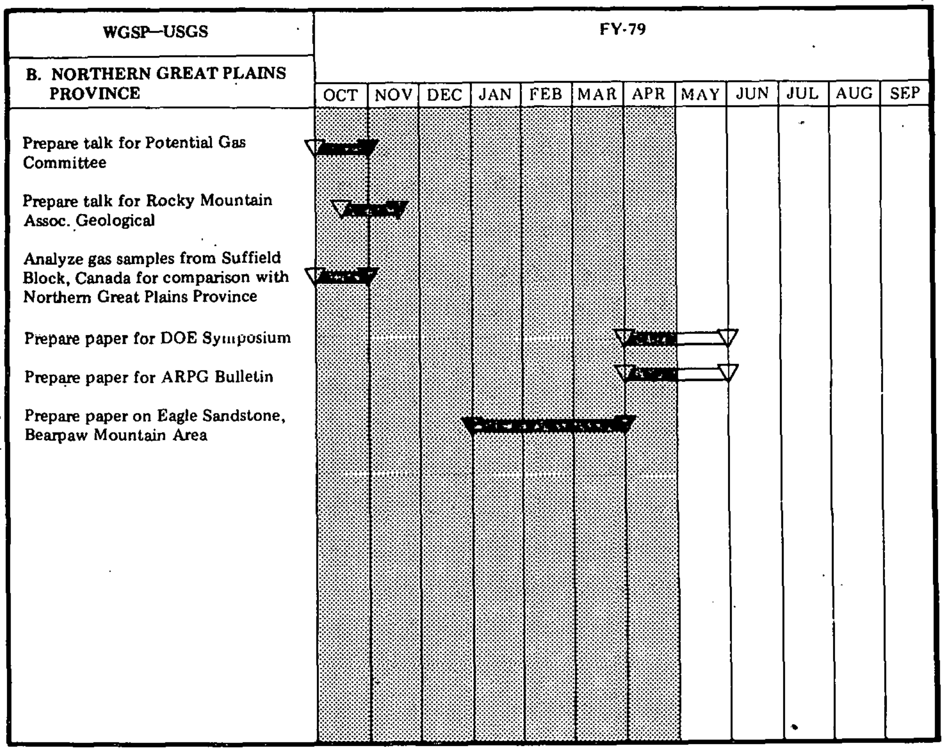
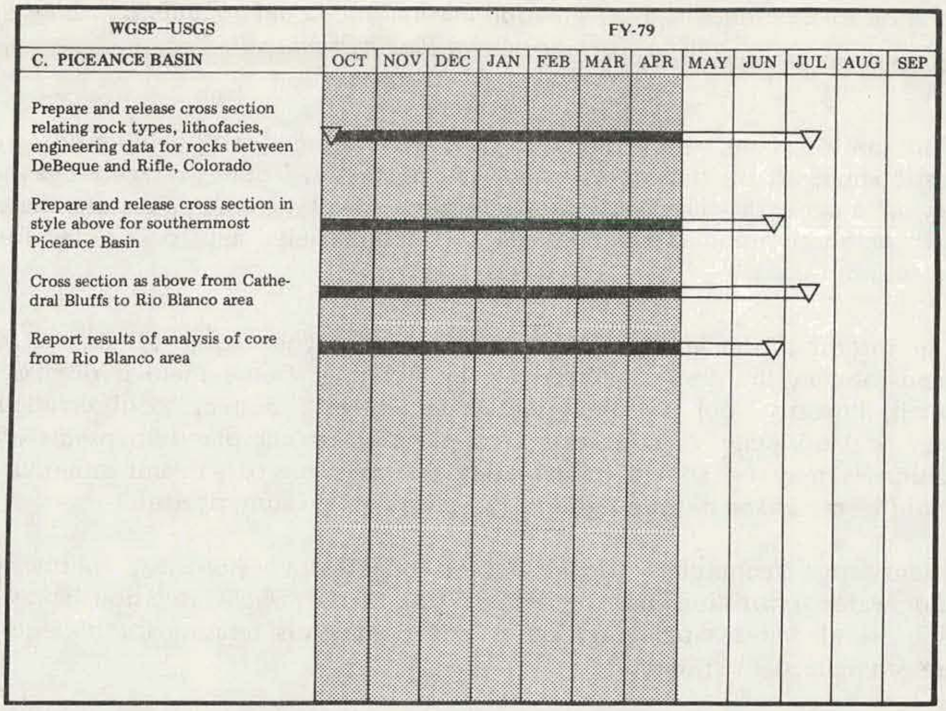


Figure 3-1 Continued



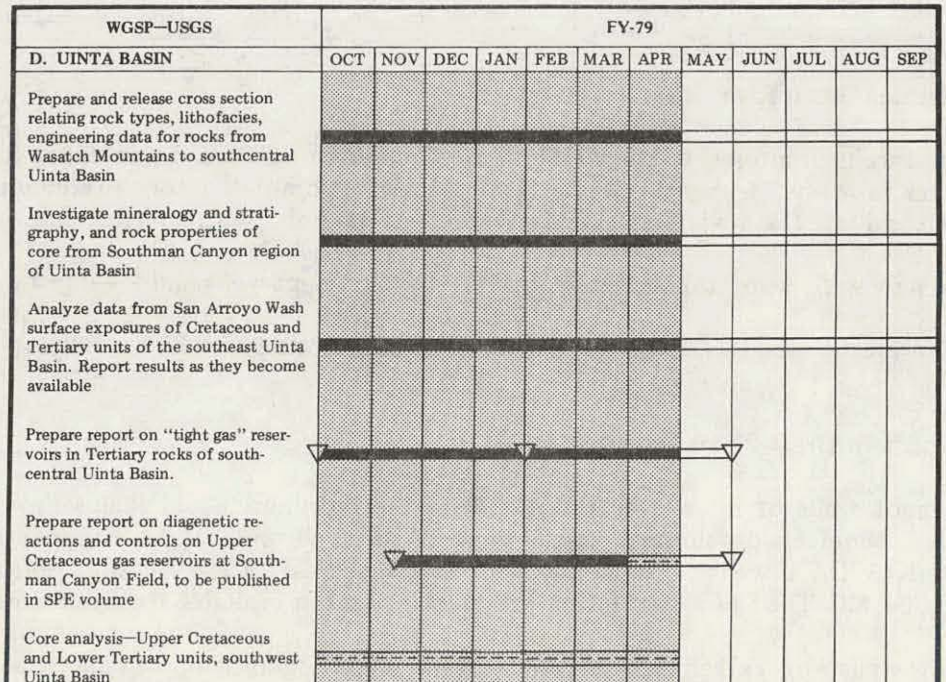


Figure 3-1 Continued

"Formation Evaluation and Gas Detection in Shallow, Low-Permeability Shaly Sands of The Northern Great Plains Province"
G. C. Kukal, CER Corporation

Montana log, core, and production data are combined with geology in a systematic approach for improved log analysis of shallow Upper Cretaceous gas sands having a high silt-clay content. Qualitative (overlay) techniques are reviewed with emphasis upon the normalized Δt - compensated neutron overlay for gas detection.

Log interpretation of the Bowdoin Member of the Carlile Shale and Eagle Sandstone in the area peripheral to the Bowdoin Dome Field is discussed in detail. Porosity tool responses are examined with respect to observed lithology and mineralogy. Lithology cross-plots when compared to predicted log responses may be an aid in detecting the presence of gas and minerals that could be related to natural fracture systems (e.g., gypsum, pyrite).

Quantitative techniques for estimation of effective porosity, volume clay, and water saturation are presented. The Total Shale Relation appears to give useful water saturation values. Log parameters relating to this equation are generalized and refined.

3.5 SURVEY OF BASIN ACTIVITIES

3.5.1 Greater Green River Basin

Completed wells of interest to the WGSP in the Greater Green River Basin added 871 MCFD of new gas from the Mesaverde Group. Two wells were completed: one producing development well and one D&A wildcat. The Mesaverde was the only producing horizon.

Eighteen new wells were staked during April: 9 development wells and 9 wildcats.

Wells of interest to the WGSP are listed in Table 3-1 and located on Figure 3-2.

3.5.2 Northern Great Plains Province

Twenty-eight wells of interest to the WGSP in the Northern Great Plains Province were completed. Nineteen development wells were finalized (1 well D&A). Nine wildcats were completed (6 D&A wells). Producing horizons (Blackleaf, Eagle, Phillips and Shannon) added 8,094 MCFD of new gas. Initial production was not available for five Shannon wells.

Three new wells were staked during April with one spudding in by month end.

Wells of interest to the WGSP are listed in Table 3-2 and located on Figures 3-3 and 3-4.

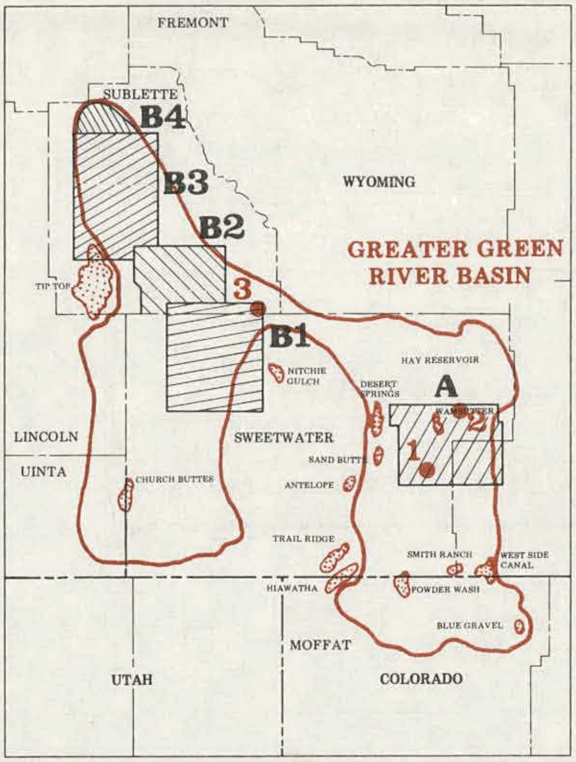


Figure 3-2

Greater Green River Basin Showing Wells of Interest and USGS Designated Core Areas (refer to Table 3-1)

Table 3-1 Summary of Wells - Greater Green River Basin

OPERATOR	WELL NAME	MAP INDEX NO.[1]	LOCATION Sec/T/R	HORIZON[2] ft	FINAL TD	FRACTURE TREATMENT	STATUS	IPF in MCFD
Amoco Production	1 Champlin 293 Amoco B	1	cnw 1-17N-95W Wildrose Field Sweetwater Cty, WY	Mesaverde (10,682-11,037) gross	11,235 PB: 11,090	40,000 gal acid 363,000 gal water 635,461 lb sand	DG completion, no cores located in core area A.	871
Amoco Production	9 Five Mile Gulch Unit	2	sesw 5-21N-93W Wildcat Field Sweetwater Cty, WY	Mesaverde (11,350)			WF located in core area A.	
Rainbow Resources	2-34 Pacific Creek Federal	3	nwse 34-27N-103W Wildcat Field Sublette Cty, WY	Frontier (21,000)			WF located in core area B.	

[1]Refer to Figure 3-2
[2]Horizon - projected depth or producing interval

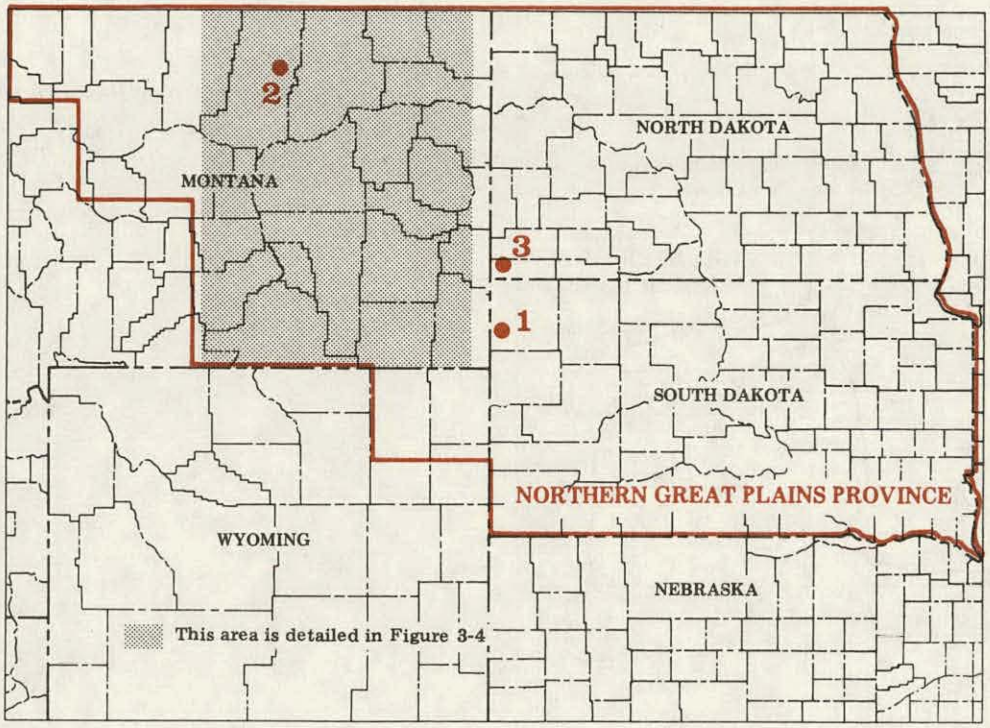


Figure 3-3
Northern Great Plains Province Showing Wells of Interest (refer to Table 3-2)

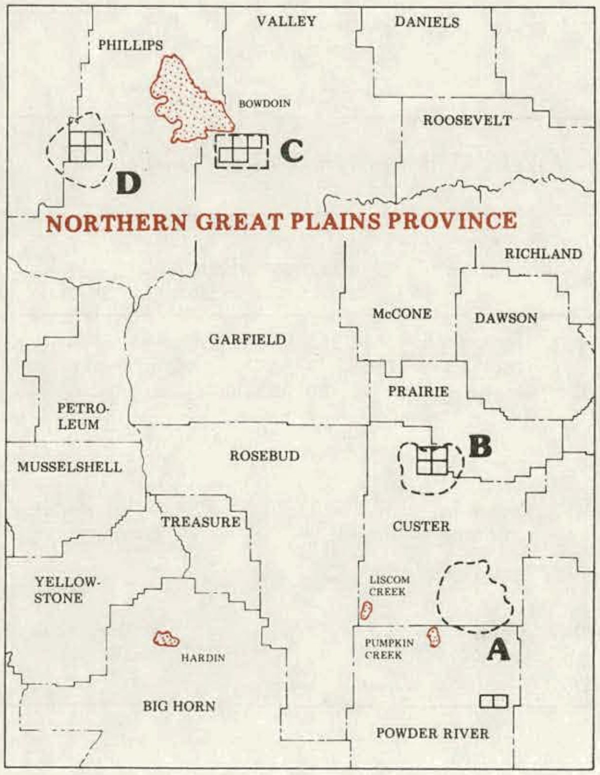


Figure 3-4
Detail of USGS Designated Core Areas (refer to Table 3-2)

Table 3-2 Summary of Wells - Northern Great Plains Province

OPERATOR	WELL NAME	MAP INDEX NO.[1]	LOCATION Sec/T/R	HORIZON[2] ft	FINAL TD	FRACTURE TREATMENT	STATUS	IPF in MCFD
J. McCutchin Jr.	1-18 Heikkila	1	w½se 18-16N-2E West Short Pine Hills Harding Cty, SD	Shannan (1,250-1,300)	1,480		DG, no cores or tests.	782 nat.
Southland Royalty	1-16-12 NE State	2	nwse 16-31N-32E Bowdoin Field Phillips Cty, MT	Phillips (1,040-1,102)	1,280	250 gal acid 23,878 gal water 60,000 lb sand	DG, no cores or tests.	1,002
Joseph J. C. Paine & Associates	1 Chapman	3	nwse 32-130N-106W Little Missouri Field Bowman Cty, ND	Eagle (1,164-1,235)	1,350 PB: 1,260		DG	30

[1] Refer to Figures 3-3 and 3-4
[2] Horizon - projected depth or producing interval

3.5.3 Piceance Basin

The Mancos zone in the Piceance Basin produced 1,595 MCFD of new gas in April. Five wells were completed: four producing development wells and 1 discovery wildcat.

One development well was staked this month.

Specific wells of interest are listed in Table 3-3 and located on Figure 3-5.

3.5.4 Uinta Basin

Eight development wells added 5,350 MCFD of new gas during April. Initial production for 2 of the 8 wells was not available.

Four new wells were staked: 3 development wells and 1 wildcat.

Wells of interest to the WGSP are listed in Table 3-4 and located on Figure 3-6.

Figure 3-5

Piceance Basin Showing Wells of Interest and USGS (Designated Core Areas (refer to Table 3-3)

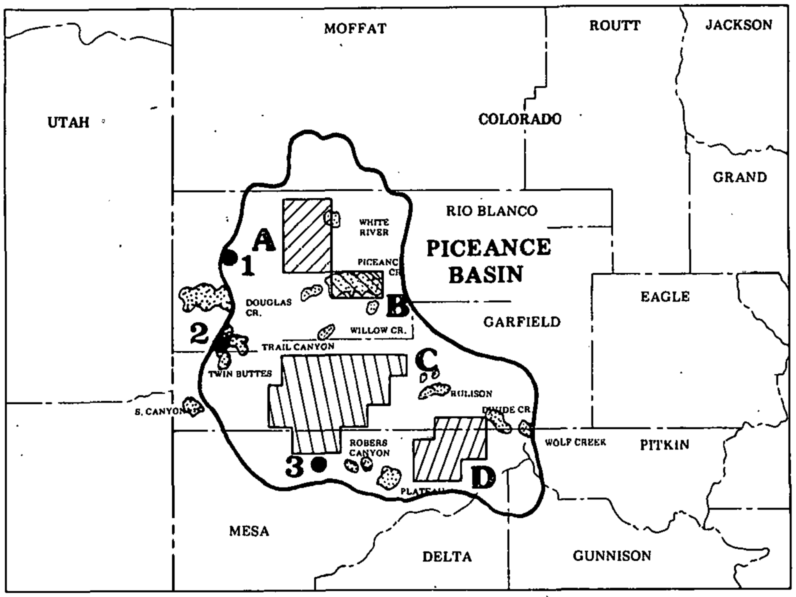


Table 3-3 Summary of Wells - Piceance Basin

OPERATOR	WELL NAME	MAP INDEX NO.[1]	LOCATION Sec/T/R	HORIZON[2] ft	FINAL TD	FRACTURE TREATMENT	STATUS	IPF in MCFD
Chandler & Associates	6-15-1-2 Fork Unit	1	senw 15-1S-102W Dragon Trail Field Rio Blanco Cty, CO	Emery (2,628-2,736)	2,907	250 gal acid 97,020 gal water 29,500 lb sand	DG completed, no cores or tests	810
Coseka Resources	5-H-9-4S-102W	2	sene 9-4S-102W South Douglas Creek Rio Blanco Cty, CO	Mancos B (2,851-3,150 gross)	4,465 PB: 3,417	41,500 gal water 117,000 lb sand	DG completed, no cores or tests.	577
Norris Oil	25-1 Federal	3	swsw 25-9S-97W Shire Gulch Mesa Cty, CO	Corcoran (3,300)			Development well near core area C.	

[1] Refer to Figure 3-5
[2] Horizon - projected depth or producing interval

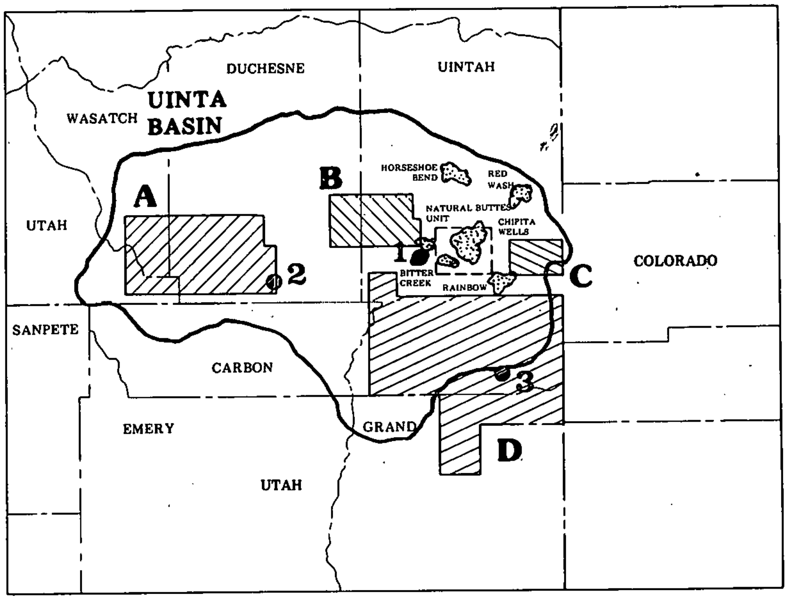


Figure 3-6

Uinta Basin Showing Wells of Interest and USGS Designated Core Areas (refer to Table 3-4)

Table 3-4 Summary of Wells - Uinta Basin

OPERATOR	WELL NAME	MAP INDEX NO.[1]	LOCATION Sec/T/R	HORIZON[2] ft	FINAL TD	FRACTURE TREATMENT	STATUS	IPF in MCFD
CIG Exploration	47-14-10-21 Natural Buttes Unit	1	nwse 14-10S-21E Natural Buttes Uintah Cty, UT	Wasatch (5,195-6,414) gross	6,550 PB: 6,519	1,500 gal acid 110,000 gal emulsion 255,000 lb sand	DG, completion, no cores or tests	2,100
Pacific Transmission Supply	33-6 State	2	nwse 36-11S-14E Wildcat Field Duchesne Cty, UT	Mesaverde (6,250)			Wildcat located in core area A.	
Coseka Resources	Main Canyon Unit 3-16-15S-23E	3	sesw 16-15S-23E (SLM) Main Canyon Uintah Cty, UT	Entrada (8,900)			D located in core area D.	

[1] Refer to Figure 3-6
[2] Horizon - projected depth or producing interval

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4. RESEARCH AND DEVELOPMENT BY ENERGY TECHNOLOGY CENTERS AND NATIONAL LABORATORIES

4.1 BARTLESVILLE ENERGY TECHNOLOGY CENTER

4.1.1 Improved Pressure Coring System

4.1.1.1 Core Retriever Design

An adapter sub has been designed for mating the 6-1/2 in. two piece Sandia core bit to the Diamond Oil Well Drilling Company (DOWDCO) pressure core barrel. These design modifications to the existing DOWDCO pressure core barrels are being made for field testing the low invasion coring fluid with the two piece Sandia bits.

4.1.1.2 Core Fluid Tests

Several room temperature static mud invasion tests were conducted in 1,550 md Brown sandstone. Three types of commercially available $CaCO_3$ bridging particles were tested in 2 lb/BBL HEC polymer mud with the following results. The loss from 5 min to 30 min is used as the stabilized fluid loss.

Material	"Wate"	"Safe-Seal"	"Safe-Seal X"
Size Range (microns)	10-59	0.5-200	53-1680
Mean Size (microns)	6	25	177
Concentration (16/661)	20	20	20
Differential pressure (psi)	100	100	100
Stabilized Fluid loss (cc)	25.5	1.4	4.1

Test results indicate that invasion by fluids from muds containing bridging particles is sensitive to pore size and particulate size. Particles will fail to bridge if too small and if too large, will coat the surface forming an ineffective surface filter cake which is often removed by bit action.

Use of the patented Brinadd magnesia additive appears to improve filtrate loss properties of HEC Polymer systems. It also reduces mixing time and stabilizes the polymer at temperatures above 275^{o}F. Since pilot bit temperatures may be high, this additive may be used in low invasion coring fluid field tests.

4.1.1.3 Bit Design and Fabrication

Design of a 2-1/2 in. pilot core bit body is complete and a fabrication contract requesting May delivery is being negotiated. Diamond compax cutters are on hand and diffusion bonding to the 2-1/2 in. pilot bit bodies is scheduled in June.

Layout of the 6-1/2 in. bit body is complete and computer studies for stud placements have started. Machining of 6-1/2 in. body blanks is scheduled during May with drilling of fluid passages and stud mounting holes dependent upon stud placement studies.

4.1.1.4 Request For Proposals

A letter of intent has been prepared regarding the contract with DOWDCO starting on May 1, 1979. This is a joint industry/DOE pressure core barrel development and test program. The contract is contingent on review by DOWDCO.

4.1.2 Interface Conductivity Effects on Electric Logging

Selected samples from the Natural Buttes No. 21 (CIGE No. 21) well were analyzed for minerals and clays by X-ray diffraction. The lack of montmorillonite and expandable illite confirms the relatively low CEC values reported last month. Table 4-1 summarizes the mineral content of the Natural Buttes No. 21 samples. Further X-ray diffraction analyses of wells from other basins are planned to determine mineral composition and the influence of clays on CEC measurements.

BETC received a Micromeritics Model 2205 surface area analyzer to study formation characteristics of cores. Test samples of the Mobil F31-13G and CIGE No. 21 cores were analyzed for surface areas. Initial results indicate that the measured areas are affected by sample outgassing temperatures. For samples outgassed the same length of time, higher outgassing temperatures produced higher surface areas as shown in Table 4-2. Tests are underway to establish optimum conditions.

Conductivity measurements for F31-13G and CIGE No. 21 cores are essentially complete. The conductivity apparatus is being redesigned for simultaneous measurement of 3 plugs. This apparatus will decrease the time required to measure cores for liquid permeability and conductivity effects.

4.1.3 Logging Techniques and Interpretations

Study of Sonic, Neutron and Density Logging of Low Permeability Gas Sands — Texas A & M.

Table 4-3 shows the petrographic samples. Log depths, porosity (determined from the helium porosimeter), and calculated matrix densities are also included in the table. It can be concluded that these sandstones are greywackes (sandstones with a high shale content). This type of sedimentary rock is relatively uncommon to the parameters of hydrocarbon reservoirs. In this case, it is possible that the source rock is included in the boundries of the hydrocarbon reservoir.

Table 4-1 X-Ray Diffraction Mineral Percentages for Natural Buttes No. 21 Well

Mineral	Depth (ft) 6475.0	6498.4	6499.4	6499.7
Quartz	67	67	68	63
Microline Feldspar	9	6	7	9
Calcite	3	—	1	3
Dolomite	2	7	5	7
Ankerite	2	2	4	4
Kaolinite	10	8	8	7
Chlorite	2	3	2	2
Illite *	5	7	5	5
Halite	Trace	Trace	Trace	Trace

* No expandable illite found.

Table 4-2 Surface Areas of PCU F31-13G and CIGE No. 21 Cores

Outgas temperature °C Well	Depth in ft	Measured surface areas m^2/g 150	300
F31-13G	8498.0	3.0	3.9
F31-13G	9946.0	3.3	—
F31-13G	9957.0	4.0	—
F31-13G	9958.0	4.3	5.6
CIGE No. 21	6475.0	2.1	2.2
CIGE No. 21	6499.0	2.0	—
CIGE No. 21	6499.5	1.6	2.2

Table 4-3 Natural Buttes No. 21 Plugs

Plug No.	Log Depth	Porosity percent porosimeter	Density (gx/cc)
5	4457 ft	2.82	2.680 - 2.685
7	4459 ft 1 in.	5.15	2.690 - 2.697
16	4465 ft 1 in.	4.17	2.700 - 2.703
12	6472 ft 1 in.	8.48	2.640 - 2.645
13	6472 ft 9 in.	5.52	2.670 - 2.674
30	7425 ft 6 in.	6.47	2.720 - 2.724
25	7476 ft 8 in.	2.47	2.750 - 2.751
32	7481 ft	5.61	2.699 - 2.700
38	8435 ft 4 in.	10.09	2.650 - 2.657
43	8483 ft	2.64	2.670 - 2.669

Table 4-4 shows the range of porosities determined from the helium porosimeter measurements reported in the January Status Report. Results of the highest and lowest values of the gamma ray, porosity from the density log (assuming sandstone), and porosity from the helium porosimeter from each zone are listed in the table.

Table 4-4 Porosity-Range from Core Measurements and Corresponding Range from Logs

			Range from logs				Range from porosimeter	
			Gamma ray API units		Density log porosity*		Helium porosity	
Zone	Core Interval		Lowest	Highest	Lowest	Highest	Lowest	Highest
A	4,441 ft 4½ in.	— 4,442 ft	70	80	2.6	2.7	2.6	2.7
B	4,457 ft	— 4,465 ft 10 in.	67	78	0.0	2.5	2.8	5.2
C	6,405 ft	— 6,406 ft	70	90	2.5	13.0	4.2	4.2
D	6,423 ft 8 in.		70	85	2.0	5.0	1.5	6.4
E	6,472 ft 1 in.	— 6,473 ft 10 in.	60	100	5.0	10.0	5.5	10.8
F	7,423 ft	— 7,430 ft	40	90	5.0	7.8	5.1	9.0
G	7,476 ft 8 in.	— 7,482 ft 1 in.	50	100	2.5	15.0	2.5	6.2
H	8,425 ft	— 8,425 ft 11 in.	30	35	5.0	10.0	3.8	4.1
I	8,434 ft 6 in.	— 8,439 ft	25	34	6.0	12.5	7.2	10.1
J	8,483 ft		25	30	9.0	15.0	2.6	2.6
K	8,510 ft	— 8,515 ft 3 in.	25	33	7.5	12.5	3.8	10.0

* From the Density Log (Assuming Sandstone)

The coding of points on Figure 4-1 shows the sample and the relative gamma ray level as a function of porosity from the helium porosimeter on the x-axis and porosity from the density log (assuming sandstone) on the y-axis. Points falling nearest the 45° line constructed on the graph would be considered good approximations of the log derived porosities with the laboratory results. Several of the points that vary from the line of unity would be due to the hole being washed out. These zones are high in shale and low in cementing material.

The cleanest sandstone is represented by zone K. The average porosity from all three logs agree relatively well with porosities determined from the helium porosimeter. Zones with greater amounts of shale do not seem to be represented correctly by the sonic and neutron log. These observations agree with the known properties of sonic and neutron logs in shaley formations.

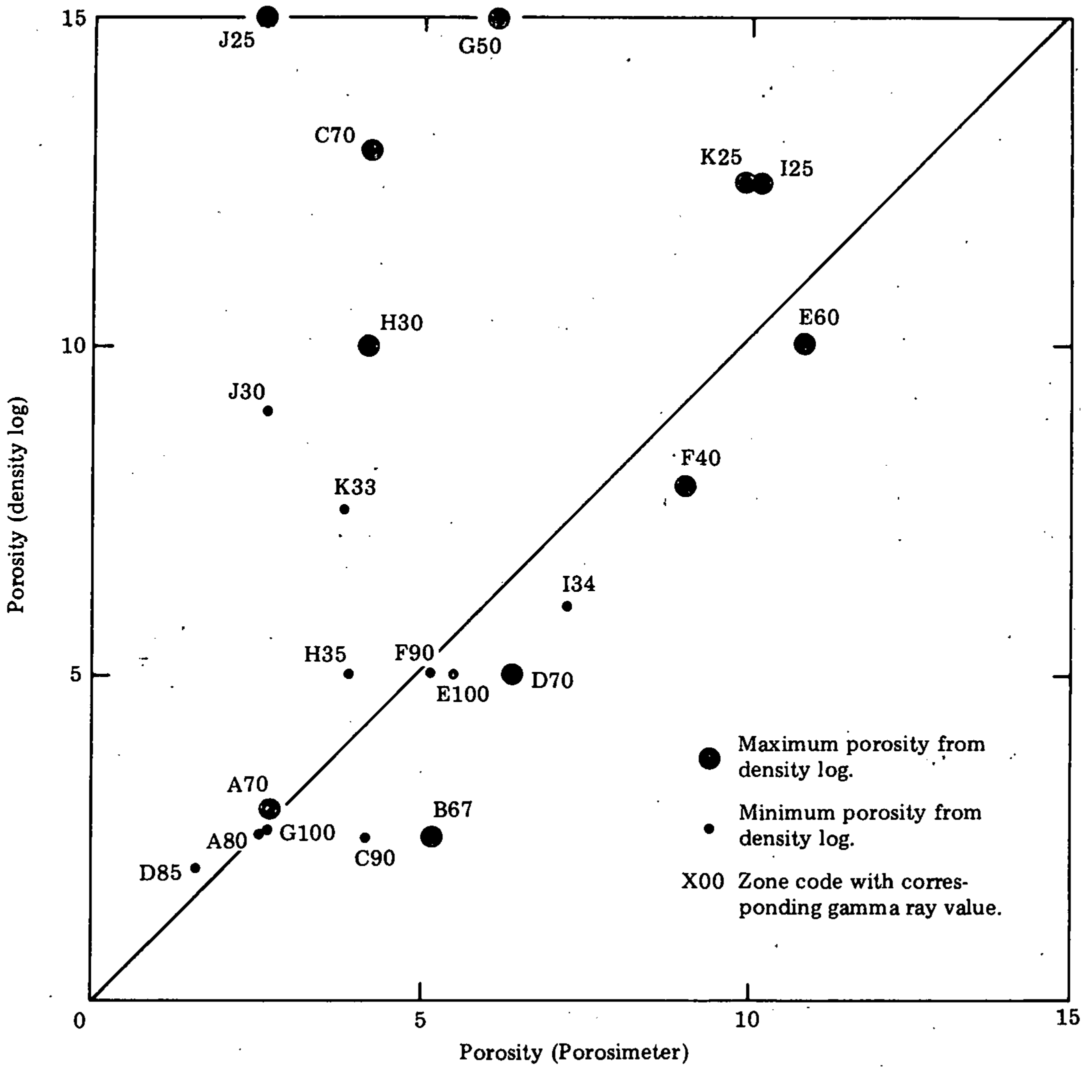


Figure 4-1 Plot of Porosity Determined from Cores Versus Porosity from Density Log

4.1.4 Reservoir Simulation Studies

Parametric Analysis of MHF Test Data—Intercomp Inc.

Pre-fracture pressure buildup data from zones 5 through 7 of Mobil Well F31-13G were analyzed using type curve analysis coupled with computer matching. The type curve analysis was done using the type curves reported in the March Status Report for the project. The results from the type curve analysis were used as input for a computer simulation of the buildup test. These results were used as a starting point for computer matching of the buildup data.

All three zones appear to be fractured. The fracture half length varies from 66 to 121 ft. The fracture permeability ranges from 500 md to 3,000 md. The matrix permeability is between 0.0034 md and 0.016 md.

The calculated reservoir pressures are from 500 to 800 psi below hydrostatic.

4.1.5 Rock Fluid Interaction

Three drilling muds were obtained for particle size distribution measurements of the drilling muds and to determine the potential of the mud to plug hydraulic fractures. A fresh-water mud had a range of 1.6 to 12 microns and a mean diameter of 3.5 microns. Two muds remain to be analyzed.

BETC received a new Model TA-11 Coulter Particle Size Analyzer for particle size studies.

4.1.6 Measurement of Formation Characteristics for Western Tight Sands—Institute of Gas Technology

4.1.6.1 In-Situ Permeability

Core has been obtained from the Canyon Largo No. 288 well and the Elmworth area. The Elmworth core is from within the Deep Basin near Grand Prairie, Alberta, Canada. The core is from a formation that has been logged, massive foam fractured, and tested. In addition, special core analysis has been performed on a number of cores.

4.1.6.2 Pressure Dependence of Single-Phase Permeability

A determination of permeability at high pore pressures is nearly complete on core F31-13G No. 8498A. This will test the precision of previously reported curves and obtain an accurate curve shape. Liquid permeability tests have been conducted to separate Klinkenberg effects from rock matrix effects. Results will be reported when the final gas permeabilities are completed.

Table 4-5 Elmworth Well No. 11-12-71-13W6

Reservoir pressure	220 psi
Reservoir temperature	171 ^{o}F
Gross thickness of Falher A and B sands	164 ft
Gas porosity	4.5 percent
Estimated net pay from pressure buildups	45 ft
Net feet with porosity > 7 percent	
a) from whole core analysis	45 ft
b) from plug analysis	66 ft
Average water saturation of net pay	40 percent
Gas permeability (in situ)	0.001 md
Fracture length	700 ft
Fracture conductivity	over 500 md-ft
Fracture gradient	0.87 psi/ft
Gas gravity (Air = 1.0)	0.68
Original gas formation volume factor	0.0068 RCF/SCF
Original gas viscosity	0.0169 CP
Original gas compressibility	0.000466 vol/vol/psi
Condensate ratio	2 BBL/MMCF

In situ gas permeabilities have been determined for the Canadian Hunter core from Well No. 11-12-71-13W6, in the Elmworth area, Alberta, Canada. Table 4-5 represents the well information. Table 4-6 shows gas permeability values under simulated reservoir conditions for core No. 14. Flow under these conditions does not require Klinkenberg correction because at these pore pressures any gas slippage effects would exist in the reservoir as they do in these tests. Average water saturation in the formation is 40 percent, and the gas permeabilities measured at high pore pressures are lower. The reservoir temperature of 171° F will probably have effects on the permeability. Immersion tests were conducted by Halliburton before fracturing. These tests (Table 4-7) indicate little fines displacement with 2 percent KCl solution. Despite this, gas permeabilities measured before and after water saturation showed a significant increase in permeability (Table 4-6). Whether this effect was experienced in the well initially is unknown. Initial low permeabilities may be due to the drying out of the core since the time of the coring. Low-pressure air permeability measurements agree well between Corelab, Halliburton, and IGT, although minor changes in confining pressure will have a strong effect on initial permeabilities. Klinkenberg extrapolations indicate a much lower absolute permeability than the air permeabilities would indicate. This is still under investigation.

Table 4-6 Permeability Measurements of Core No. 14, Elmworth Well

BEFORE SATURATION WITH 3 PERCENT KCl			
Confining Pressure:	164.73 psia		
P_m (psia)	29.100	40.376	41.700
ΔP (psi)	28.740	51.270	53.940
K (md)	0.188	0.168	0.164

AFTER SATURATION WITH 3 PERCENT KCl			
Confining Pressure:	164.73 psia		
P_m (psia)	23.18	28.97	46.10
ΔP (psi)	16.89	28.47	60.83
K (md)	0.30	0.25	0.21

SATURATION WITH 3 PERCENT KCl UNDER IN-SITU PRESSURES

Mean Confining Pressure = 6747 psia

Mean Pore Pressure = 2200 psia

Gas Permeability Under In-Situ Conditions = .0406 md

Table 4-7 Immersion Tests of Elmworth Well Core by Halliburton

Effects of immersion under vacuum at 160 °F (BHT) for one hour in the following:

Sample No.	Depth (ft)	Fresh Water	3 Percent KCl	2 Percent KCl	7½ Percent MCA	6 Percent HF	Kerosene	100 Percent Methanol
14	6,747	V-SAF	NFR	NFR	V-SAF	SAF	NFR	NRF

Sample No.	Depth (ft)	Water/Methanol mixture**	2 Percent HCl	60 Percent Acetic Acid
14	6,747	NFR	V-SAF	NFR

NFR = No fines released
V-SAF = Very small amount fines
SAF = Small amount fines

* One gal CLA-STA compound per 100 gal
** 70 percent water (2 percent KCl added)/30 percent Methanol

4.1.6.3 Effect of Core Saturation History on Relative Permeabilities to Gas and to Water

Tests for relative gas permeability have been performed on core No. 14. Water saturation achieved by evaporation at IGT gave a different gas relative permeability curve than wedge-type unsteady-state gas-water relative permeability tests conducted by Corelab.

4.1.6.4 Schedule Status

Figure 4-2 is a milestone chart of BETC WGSP activities.

4.2 LAWRENCE LIVERMORE LABORATORY

4.2.1 Theoretical Analysis

Recent analyses have been directed toward the study of crack propagation near interfaces. Many broken zones with the finite element model must be represented to obtain the necessary resolution for this type of problem. Oscillation in the displacements of points are far from the crack center and near the interface. Previously, this problem was solved by breaking a few zones where this oscillation was not present to a noticeable degree.

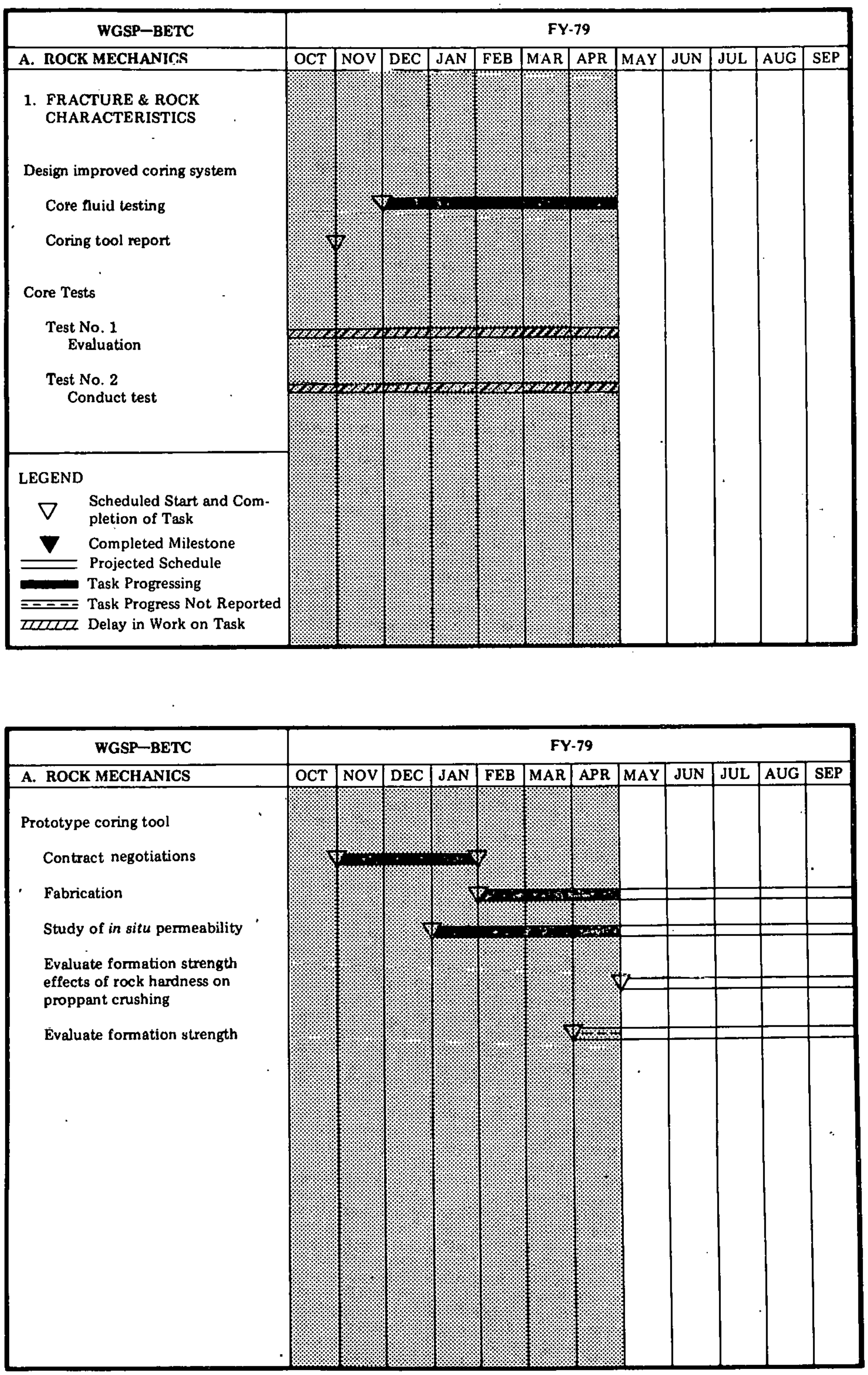
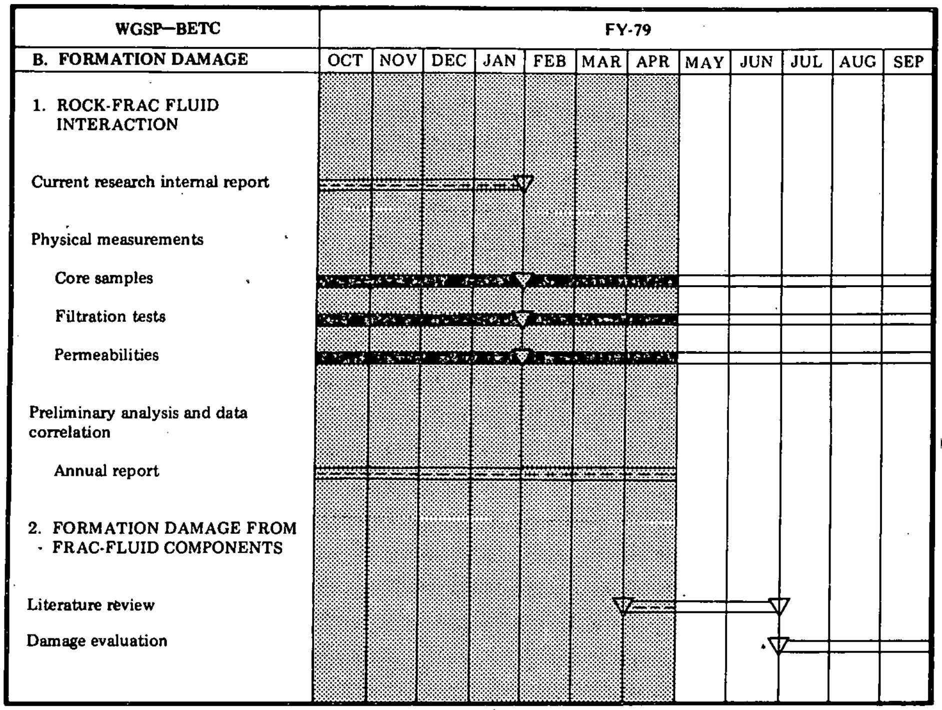


Figure 4-2 Milestone Chart — BETC



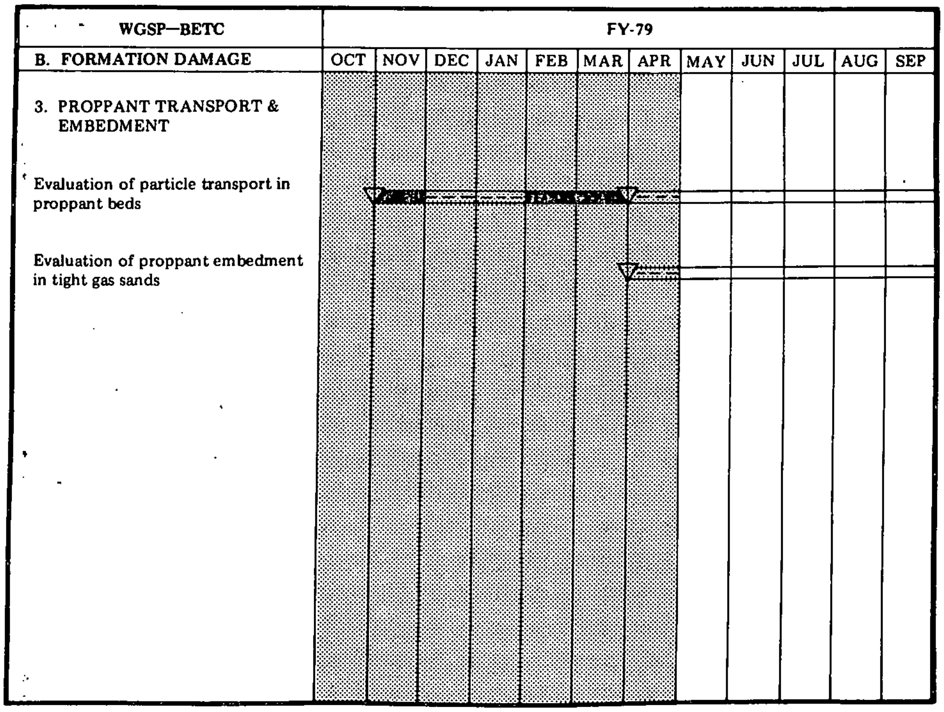
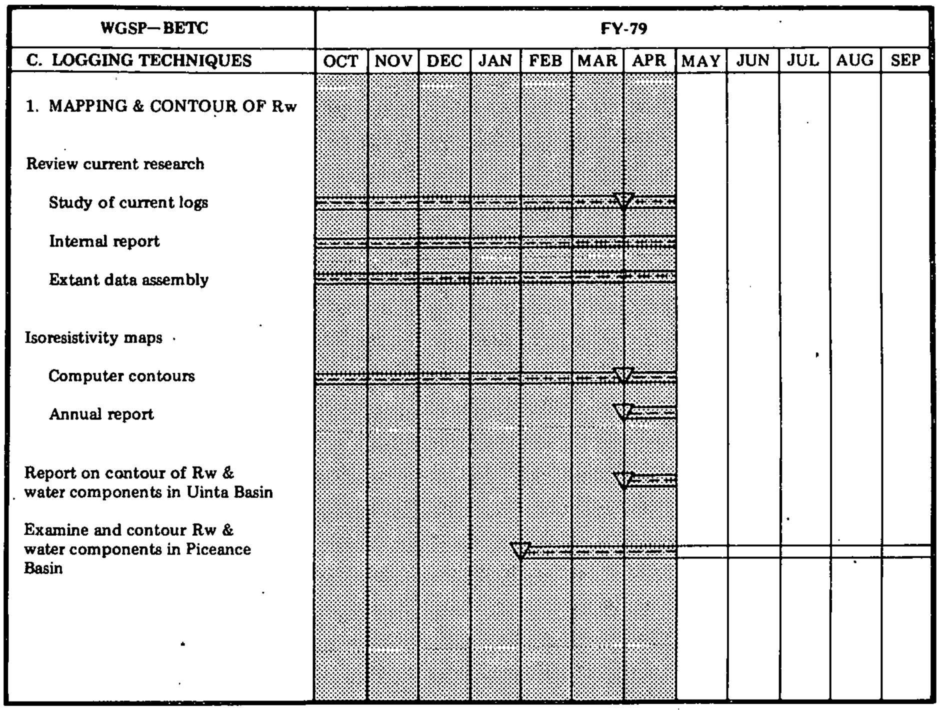


Figure 4-2 Continued



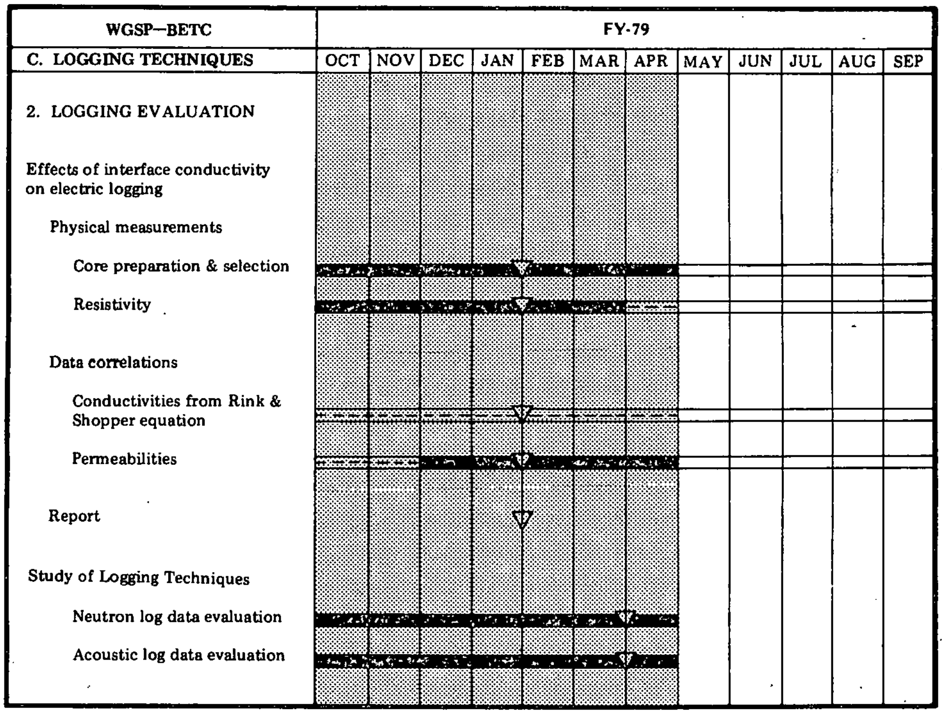
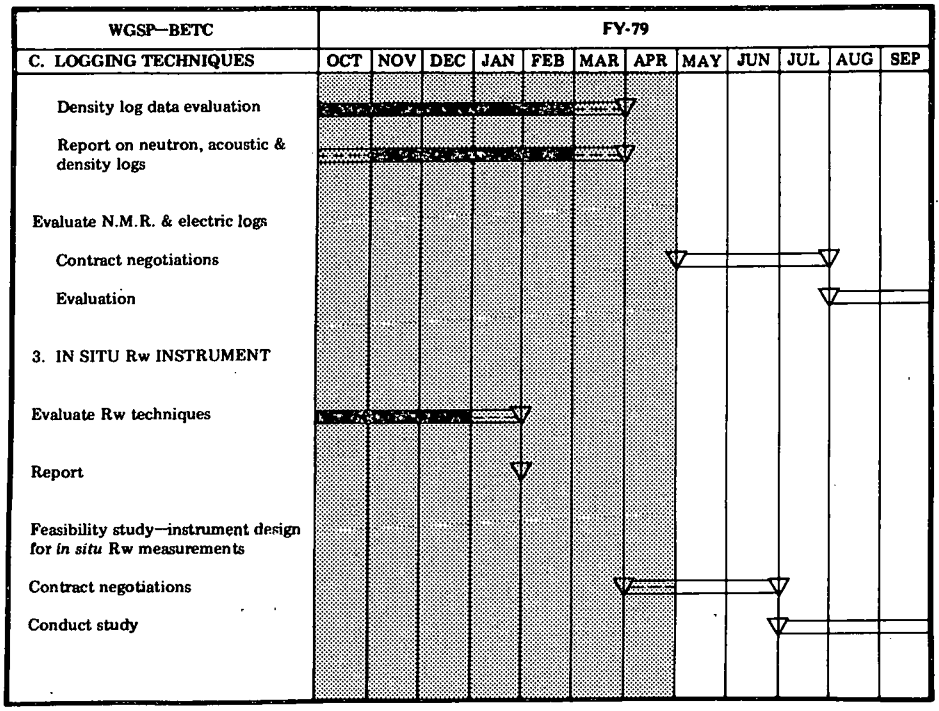


Figure 4-2 Continued



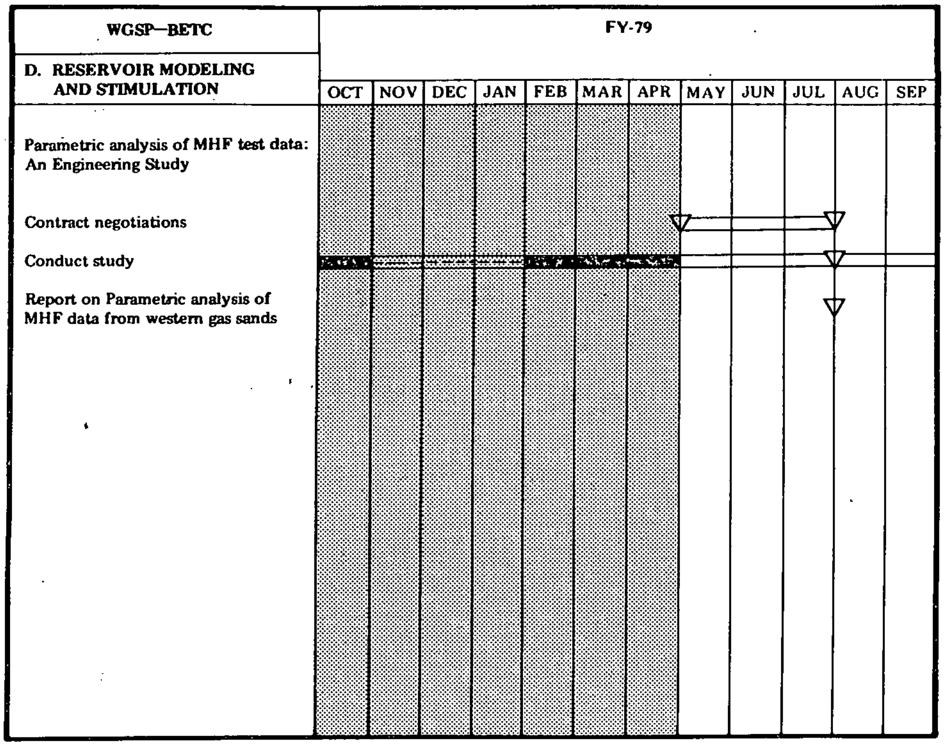


Figure 4-2 Continued

In April, the model was inspected in order to find the source of the oscillation and rectify it. The problem arises from the way the vertical shear was calculated in a zone. Due to restrictions in the displacement function of a finite element there is a certain amount of ambiguity in the way shear stresses are calculated in a fractured zone. When the zone fractures there are only two nodes in each side of the fractured zone. Displacements of the two nodes are not sufficient to precisely determine the shear strain or stress.

Previously, shear stress was matched to the shear on the crack face to achieve rotational balance about a node. This case is represented on the displacement plots as the dashed curve in Figures 4-3 and 4-4. In the plots, displacements perpendicular to the crack are plotted for two points: one near the crack center (Figure 4-3) and one near the interface (Figure 4-4). When the shear is calculated in this manner for a tensile crack, the shear strain is zero. For this case, the displacement of the point near the center of the crack is a fairly smooth function, as is desired, but the displacement of a point far from the center of the crack experiences oscillations after the crack tip passes. Displacement of the far point is needed and therefore a method was sought which would reduce the oscillations. To do this the vertical shear was changed in the cracked zones so that it depended on the relative displacements of the two nodes. This method has the implicit assumption that the vertical sides of the zone remain vertical with reference to a fixed grid. When this method was used the solid curves in Figures 4-3 and 4-4 were obtained. This case gives good results for the point far from the center (Figure 4-4). In addition, the non zero shear tends to slightly decrease the average magnitude of the displacements.

4.2.2 Experimental Program

Frictional experiments on dry Indiana limestone have yielded static coefficients of friction of μ = 0.61 and 0.51 for rough and smooth interfaces respectively. Similar experiments on dry Nugget sandstone have yielded static coefficients of friction of μ = 0.59 and 0.54 for rough and smooth interfaces respectively. These values are preliminary and subject to further analysis and interpretation. Hydraulic fracture experiments showed a different normal stress threshold for crack growth across rough and smooth interfaces in the sandstone while no difference in stress threshold was observed in experiments on limestone. Frictional characteristics of rough and smooth surfaces of Nugget sandstone at the present time appear more similar than those in the limestone. Uniaxial stress loading tests to measure the failure envelope of Mesaverde sandstone from Rio Blanco County, Colorado have been completed. Similar tests on Mesaverde shale from the same site have been started.

4.2.3 Schedule Status

Figure 4-5 is a milestone chart showing LLL progress in WGSP projects for FY 1979.

4.3 SANDIA LABORATORIES

4.3.1 EGR Instrumentation and Diagnostic Program

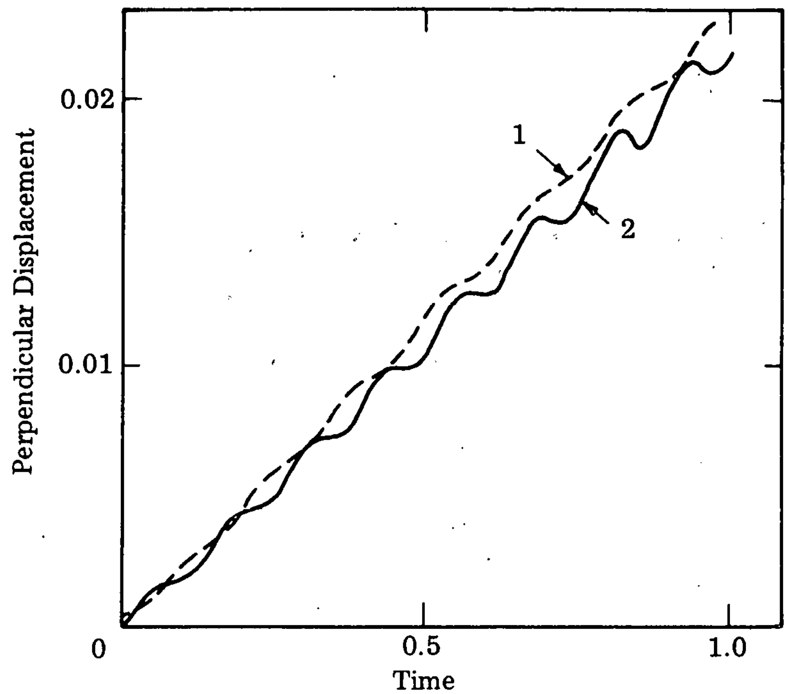


Figure 4-3 Displacements Perpendicular to the Crack near the Crack Center

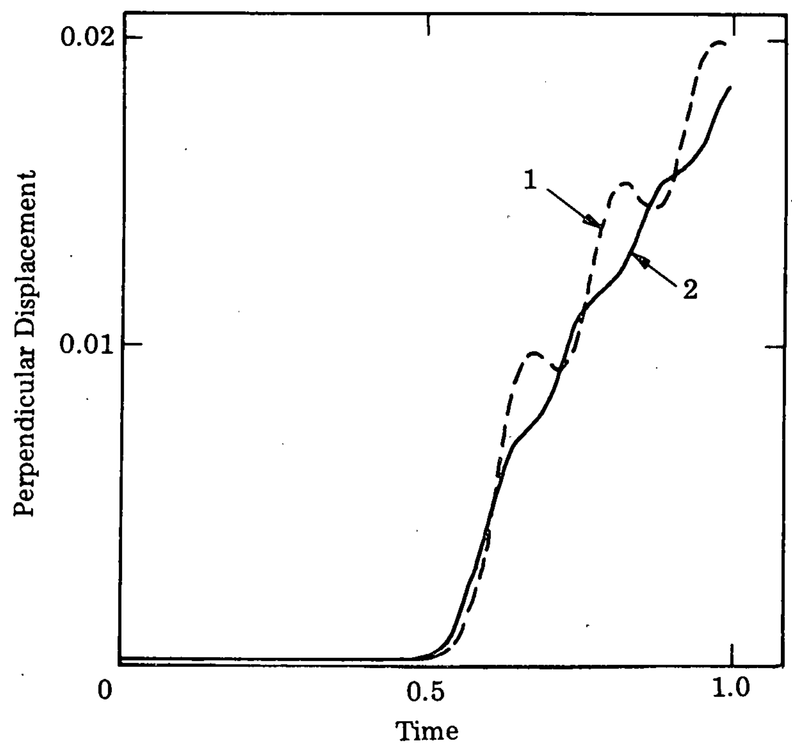
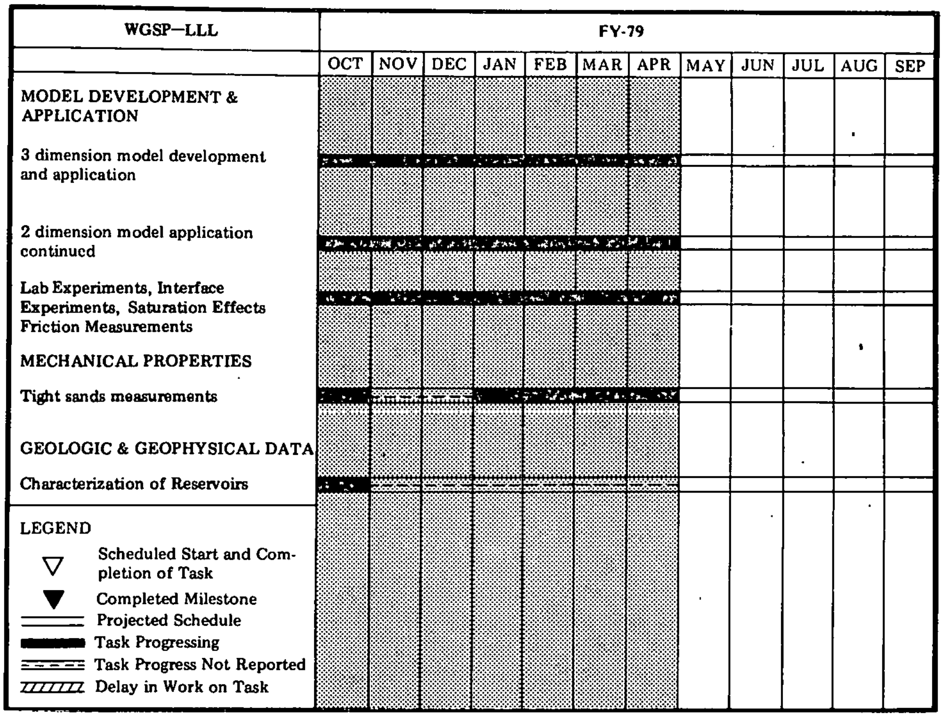


Figure 4-4 Displacements Perpendicular to the Crack near the Interface



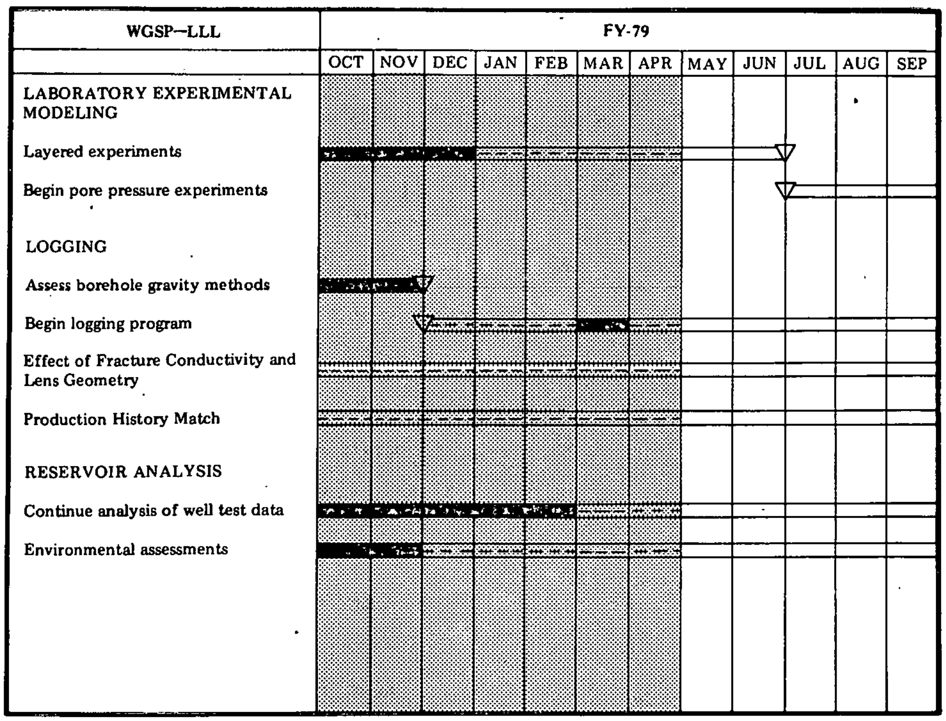


Figure 4-5 Milestone Chart — LLL

4.3.1.1 Hydraulic Fracture Characterization

Seismic evaluation tests of the borehole seismic unit at the Nevada Test Site have been completed. The borehole seismic unit was clamped in a 20 ft hole in the floor of the Madison drift in the G-Tunnel. A triaxial geophone unit (identical to the clamped unit) was grouted in a 20 ft hole 1.5 ft from the borehole seismic unit. Five other 20 ft holes were drilled to be used as locations for induced seismic activity from a spark plug, pellet gun and a solenoid. Various locations on the floor of the tunnel were used to induce signals from hammer blows. In addition to induced seismic signals, the borehole seismic unit was vibrated at numerous frequencies by use of the attached geophones in order to determine resonant frequencies.

Preliminary analysis of the data indicates resonances at several frequencies will prohibit extraction of information from the tail of the seismic signal. The seismic onset needs to be analyzed to determine if the unit is capable of showing the direction of the source accurately.

4.3.1.2 Advanced Borehole Logging

Eleven core samples from the CIGE No. 21 well, Natural Buttes Unit, Uinta Basin, Utah, were taken to the USGS Laboratories in Denver on April 3. At this time, an approximately 20 mm end section was slabbed from each core for analysis by the USGS. Analyses to be performed by the laboratory will include thin sectioning, scanning electron microscopy, x-ray diffraction, and electron microprobe analysis. Initial findings show that some samples have porosity which is as high as in conventional reservoirs. One sample shows an anhydrite-type cementation which has not been reported previously in such Cretaceous rock. Work is continuing and should be completed in May. The remaining lengths of core were re-sealed using plastic bags and tape and are awaiting transfer to Chevron Oil Field Research Laboratories for additional core and NMR analyses.

4.3.1.3 Formation Mapping

T. L. Dobecki, (Sandia), C. F. Knutson (C. K. GeoEnergy), and W. B. Cashion (USGS) visited the proposed area of the complementary seismic-borehole survey with the purpose of determining the best location within the area to accomplish survey objectives. The area is in east-central Utah near the Colorado border, on the southern edges of the Uinta Basin (Book Cliffs area, approximately N39°15', W109°15'). The prime criteria to be met by a satisfactory site were: relatively flat ground on top of a mesa or ridge, exposed Mesaverde Group rock in the cliff walls, and adequate existing well control for stratigraphic information and access for the proposed drilling operation. A site was found in the area of Sections 4, 5, 8, 9, 16, and 17, T17S, R24E. This area is on a ridge just west of East Canyon with approximately 1,000 ft of the Mesaverde Group exposed in the cliff faces.

An additional site was located a few miles to the northwest on top of the highest ridge in the area. At this location, the Mesaverde Group is approximately 1,200 ft sub-surface with outcropping Green River formation. This site has a large flat area and one gas well for subsurface control. It will be used in determining to ability to accurately map unknown structures at greater depths than at Site No. 1.

Future plans include coordination with CER Corporation for developing the seismic survey specifications for upcoming requests for proposals issued to seismic contractors. Further coordination will also be required with USGS and C. K. GeoEnergy in mapping existing channels as they outcrop on the cliff walls, and in obtaining necessary permits from the Bureau of Land Management and Utah State agencies.

In addition to the site visit, T. L. Dobecki met with Dr. A. Balch, head of the seismic stratigraphy section, USGS, Denver. Possible cooperation between Sandia and the USGS was discussed at this meeting. The USGS Phoenix (seismic) computer has a substantial seismic modeling capability which would be useful in modeling the synthetic seismic response of channel sands embedded in a sand-shale sequence. This is an important aspect in evaluating seismic techniques for mapping sand lenses. The computing facility has been made available to Sandia.

4.3.2 Schedule Status

Figure 4-6 is a milestone chart depicting Sandia's progress in WGSP activities.

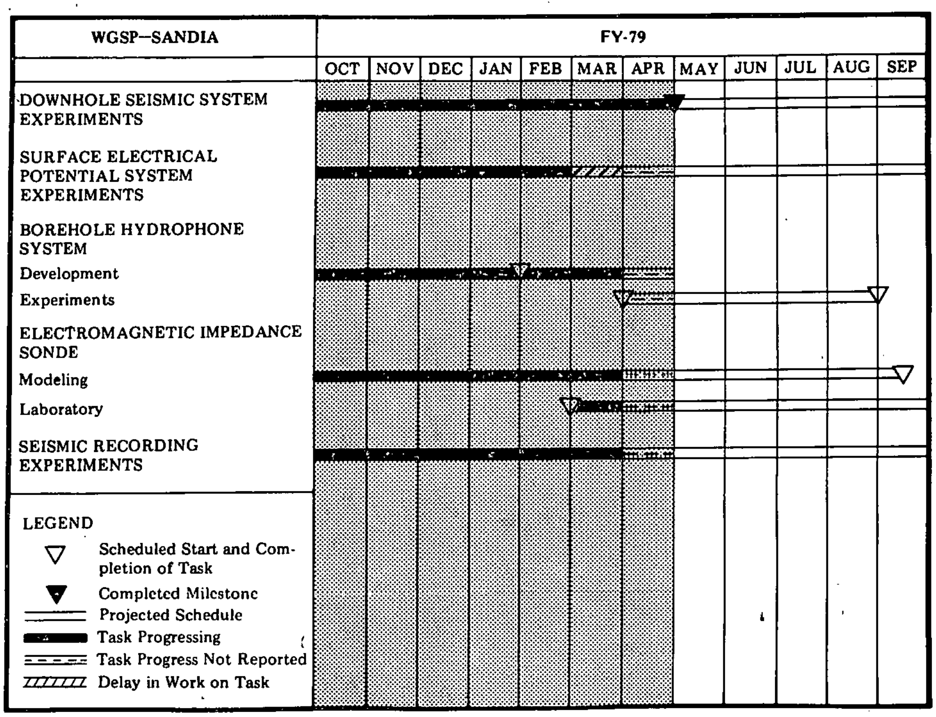


Figure 4-6 Milestone Chart — Sandia

4.4 GAS RESEARCH INSTITUTE

4.4.1 Analysis of Tight Formations — Data Collection

CER personnel collected data on 360 wells in the Piceance and Uinta Basins from the State Oil and Gas Commissions of Colorado and Utah.

Arrangements were made to obtain additional well data from the Wyoming Oil and Gas Commission.

4.4.2 Model Development

Available computer packages were evaluated, and the SPSS package was selected as the most suitable for this project. The GRI computer staff familiarized itself with this package.

The cost and regional production models which were developed jointly for this and another project have been verified based on data required by the other project.

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5. FIELD TESTS AND DEMONSTRATIONS

5.1 BACKGROUND

Field tests are essential to verify the findings of laboratory tests and modeling studies. The field test and demonstration program involves cooperation between industry and government and also interacts geologic studies with laboratory research and development. The following projects are in an active status in the WGSP:

- A dry gas injection experiment in the Wattenberg Field, Colorado, by Colorado Interstate Gas Company.
- MHF demonstrations by Gas Producing Enterprises in the Uinta Basin, Utah,
- MHF treatment of the Cotton Valley Limestone Formation in Limestone County, Texas, by Mitchell Energy Corporation,
- MHF demonstrations in the Piceance Basin, Colorado, by Mobil Research and Development Corporation and Rio Blanco Natural Gas Company, and
- A mineback testing program by Sandia Laboratories.

The CER Corporation RB-MHF 3 is on an inactive status pending satisfactory contractual arrangements to perform additional tests, and for final disposition of the well. The RB-MHF 3 Final Report has been issued in a three volume set. All participants have received a set. If desired, a set may be obtained by ordering from NTIS, U.S. Department of Commerce, Springfield, Virginia, 22161.

Table 5-1 summarizes completed and active WGSP MHF treatments. Progress of these projects is presented in the following sections.

Table 5-1 MHF Contract Locations and Frac Data

COMPANY, BASIN	LOCATION T/R/Sec	WELL	INTERVAL FRACTURED ft	FRAC DATE	FRAC TREATMENT Lb of Sand	INJECTED FLUID 10^3 Gal
AUSTRAL Piceance, Mesaverde	7S/94W, Sec 3 Garfield Cty Colorado	Federal 3-94	5,170- 6,333	8-25-76	1,140,000	542 Gel Gel H O
CONSORTIUM MANAGED BY CER CORPORATION Piceance, Mesaverde	3S/98W, Sec 11 Rio Blanco Cty Colorado	RB-MHF-3	8,048- 8,078 7,760- 7,864 5,925- 6,016 5,851- 5,869	10-23-74 5- 2-75 5- 4-76 11- 3-76	400,000 880,000 815,000 448,000	117 Gel 285 Gel 400 Gel 228 Gel
GAS PRODUCING ENTERPRISES, INC. Uinta, Wasatch and Mesaverde	10S/22E/Sec 10 Uintah Cty Utah	Natural Buttes No. 18	6,490- 8,952	9-22-76	1,480,000	745 Gel
	10S/21E/Sec 21 Uintah Cty Utah	Natural Buttes No. 19	8,909- 9,664 7,224- 8,676	9-21-76 9-28-76	424,000 784,000	280 Gel 364 Gel
	9S/21E/Sec 22 Uintah Cty Utah	Natural Buttes No. 14	6,646- 8,004	3-15-77	1,093,000	544 Gel
	9S/21E/Sec 28 Uintah Cty Utah	Natural Buttes No. 20	8,498- 9,476	6-22-77	826,000	322 Gel
	10S/22E/Sec 18 Uintah Cty Utah	Natural Buttes No. 22	6,858- 8,550	11-21-77	1,091,000	479 Gel
	9S/21E/Sec 19 Uintah Cty Utah	Natural Buttes No. 9	5,661- 8,934	3-27-78	554,000	349 Gel
	10S/21E/Sec 29 Uintah Cty Utah	Natural Buttes No. 2	7,251- 8,774	8- 8-78	1,965,000	722 Gel
	10S/22E/Sec 7 Uintah Cty Utah	Natural Buttes No. 23	5,080- 6,294	10- 4-78	440,000	240 Gel
DALLAS PRODUCTION Fort Worth, Bend Cong.	Ben D. Smith Survey A-779 Wise Cty Texas	Ferguson A-1	5,957- 6,794	9-10-76	506,000	139 Foam 198 Emul
EL PASO NATL. GAS Norther Green River, Fort Union	30N/108W/Sec 5 Sublette Cty Wyoming	Pinedale Unit No. 5	10,950-11,180 10,120-10,790	7- 2-75 10-20-75	518,000 1,422,000	183 Emul 8 Gel 459 Gel
MITCHELL ENERGY Cotton Valley, Limestone Trend	Limestone Cty Texas	Muse-Duke No. 1	11,220-11,430	11-15-78	2,800,000	891 Gel
MOBIL Piceance, Mesaverde	2S/97W/Sec 13 Rio Blanco Cty Colorado	F-31-13G	10,549-10,680 9,392- 9,538 8,765- 8,972 8,163- 8,650 7,704- 7,794 7,324- 7,476	6-22-77 8-24-77 5-10-78 7- 6-78 9- 7-78 11-15-78	580,000 600,000 388,000 660,000 218,000 700,000	316 Gel 260 Gel 150 Gel 288 Gel 120 Gel 365 Gel
PACIFIC TRANSMISSION Uinta, Mesaverde	8S/23E/Sec 25 Uintah Cty Utah	Federal 23-25	NO FRACS PERFORMED			
RIO BLANCO NATL. GAS Piceance, Mesaverde	4S/98W/Sec 4 Rio Blanco Cty Colorado	Federal 498-4-1	6,150- 6,312 5,376- 5,960	10-22-76 11-30-77	766,000 243,000+ 22,500 Beads	276 Gel 164 Gel
WESTCO Uinta, Mesaverde	10S/19E/Sec 34 Uintah Cty Utah	Home Fed No. 1	7,826- 9,437 10,014-10,202	12-21-76 10- 1-76	500,000 600,000	412 Gel 248 Gel

RIO BLANCO MASSIVE HYDRAULIC FRACTURING EXPERIMENT

EY-76-C-08-0623

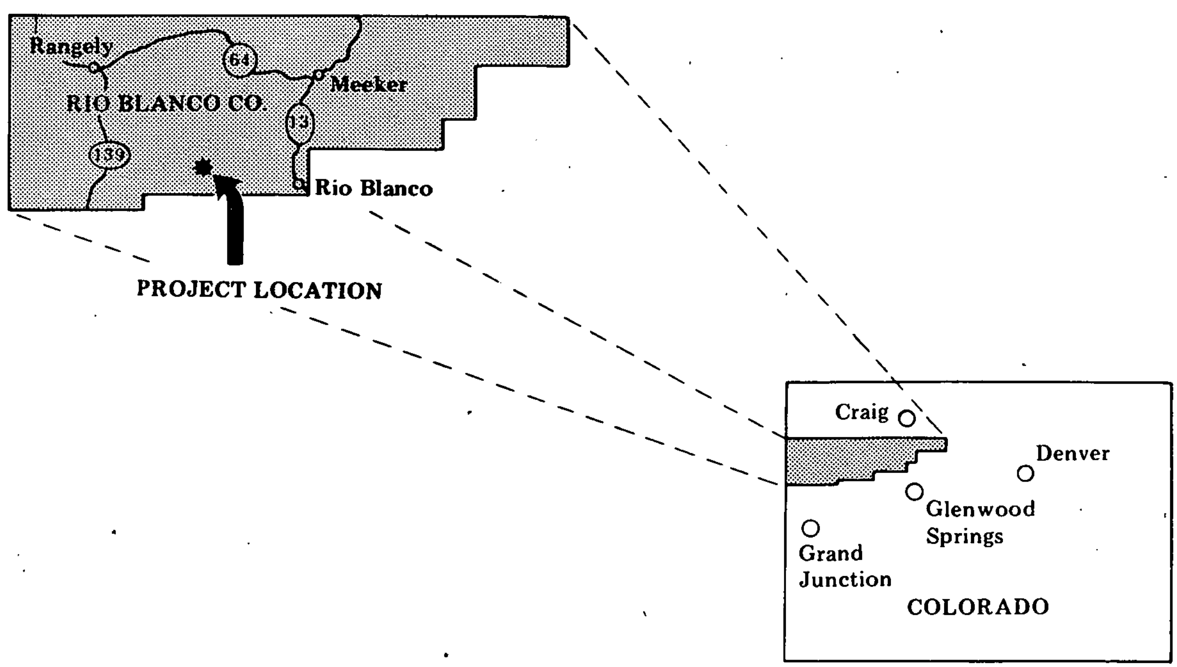
CER Corporation
Las Vegas, Nevada

Status: Awaiting Advisory Committee Decision

Interagency Agreement Date:	June 19, 1974	
Anticipated Completion Date:	July 1, 1979	
Project Cost (estimated):	DOE	$1,990,000
	Industry	1,630,000
	Total	$3,620,000
Principal Investigator:	G. R. Luetkehans	
Technical Advisor for DOE:	C. H. Atkinson	

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.



5.2 CER CORPORATION

DOE contract EY-76-C-08-0623 was awarded to CER Corporation in March, 1974. The original contract provided for the drilling of a new well and two MHF treatments. Contract modifications added two additional MHF treatments and extended the term of the contract to an undisclosed date.

Field activities on RB-MHF 3 well have been suspended. Negotiations have taken place with an outside party to complete the commingling of the fractured gas zones and to perform additional tests in return for the well and subsequent gas production. Legal documents have been distributed to the project participants for their concurrance.

A comprehensive 3 volume final report has been released.

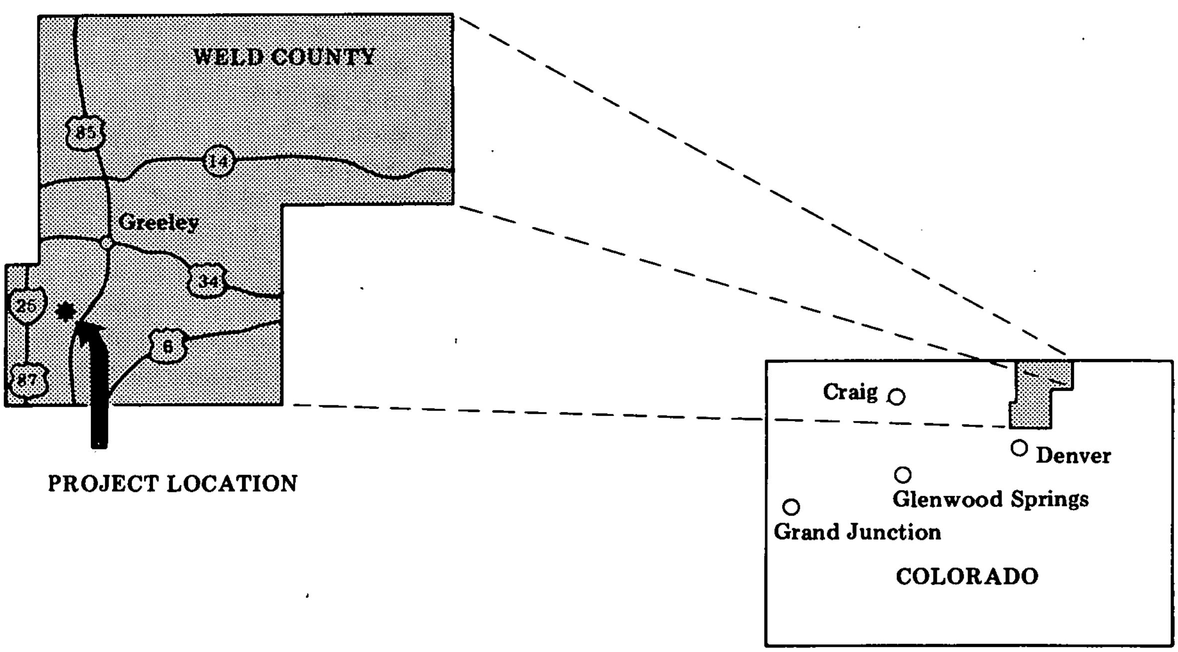
WATTENBERG FIELD — EY-77-C-08-1514

Colorado Interstate Gas Company Colorado Springs, Colorado	Status: Active

Contract Date:	September 1, 1977	
Anticipated Completion Date:	March 1, 1981	
Total Project Cost (estimated):	DOE	$ 75,000
	CIG	99,000
	Total	$174,000
Principal Investigator:	Howard Fredrickson	
Technical Project Officer for DOE:	C. H. Atkinson	

OBJECTIVE

Cyclic injection of dry natural gas is the method to be used to increase production of tight gas sands.



5.3 COLORADO INTERSTATE GAS COMPANY

DOE and Colorado Interstate Gas Company (CIG) entered into Contract No. EY-77-C-08-1514 on September 1, 1977. The experiment will determine if productivity of wells completed in low-permeability natural gas reservoirs can be improved by reducing the interstitial water saturation by cyclic injection of dry natural gas. In addition, cyclic injection of dry natural gas may improve productivity by dehydrating matrix clays and by removal of formation damage adjacent to the surfaces of induced fractures.

The special Ajax "DPC-160/H2" compressor has been ordered, installed, and made operational at the Sprague No. 1 well location along with the three Rolo dry bed dehydrators.

Measurement of bottom-hole pressure in both wells is continuing. As of April 19, 1979, BHP of the Miller No. 1 well was 1,033 lbs at 248°F. and, of the Sprague No. 1 well BHP was 941 lbs at 252°F. BHP is increasing slowly and inconsistently at 4 to 6 lbs per day at the Miller well and an average of 3 lbs per day at the Sprague well. At this rate of build-up, it appears there is little advantage to continue the BHP measurement. It is anticipated that the cycling process will commence when the compressor is installed and operating.

DOE WELL TEST FACILITY

EY-76-C-08-0623

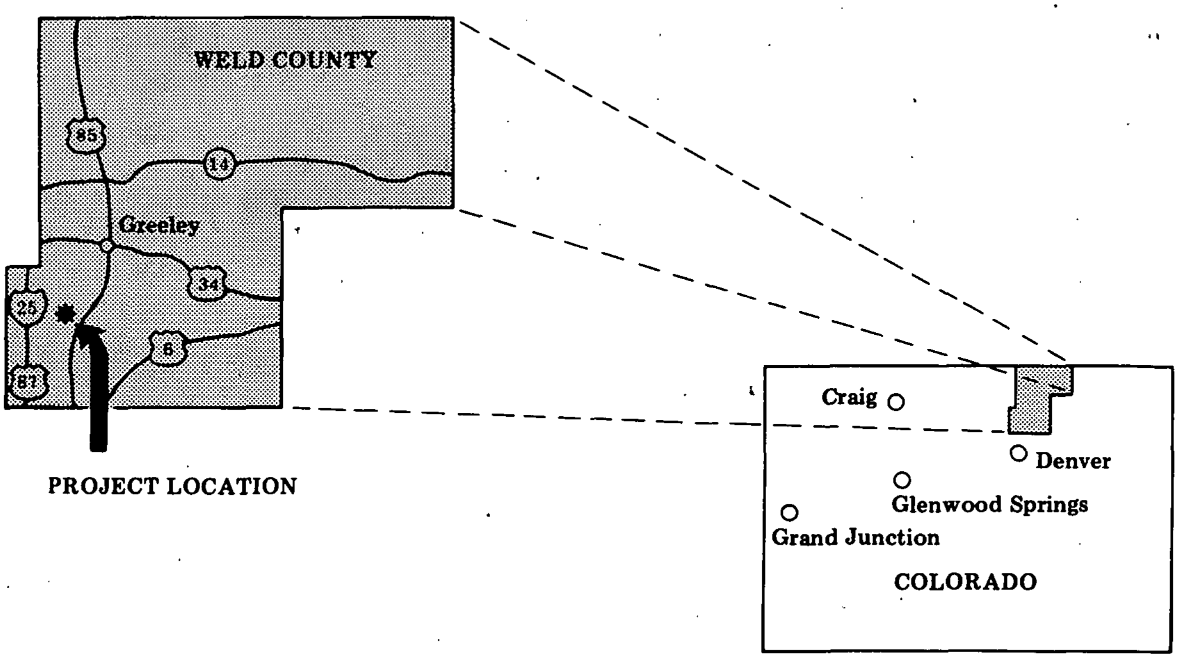
CER Corporation
Las Vegas, Nevada

Status: Equipment checkout and test proceeding

Principal Investigator: R. L. Mann
Technical Advisor for DOE: C. H. Atkinson

OBJECTIVE

The DOE Well Test Facility, consisting of two vehicles, will provide a deep well instrumentation and investigation system to monitor and evaluate the productive potential of all types of wells.



5.4 DOE Well Test Facility

Gathering of bottom-hole pressure buildup data is continuing from the Miller No. 1 well. Table 5-2 is an abridged list of bottom-hole buildup data acquired through April 30, 1979. Data have been recorded every ten minutes, therefore there are over 3,000 data points. A complete list of data will be available after the buildup test is completed.

The G.O. temperature tools periodically fail to operate, but the data available indicate the temperature has stabilized at 248°F. This value (248°F) has been used to correct the pressure value for temperature effects.

Surface tubing (P_{sst}) and surface casing (P_{ssc}) pressure measurements were taken at various time intervals because of the uncertain condition of the tubing and casing. Figure 5-1 is a plot of surface tubing and surface casing pressure measurements versus buildup time.

A log-log or type curve plot of the difference (ΔP^2) between the squared bottom-hole pressure (P^2_{ws}) and squared initial pressure (P^2_{wo}) versus buildup time (Δt) is shown in Figure 5-2. Several slopes are included as references, (1, 1/2 and 1/4). These slopes[1] are representative of wellbore storage, linear fracture flow, and bilinear flow, respectively. Radial flow would occur last and be defined by a set of points whose slope would be less than 1/4. The data are following along a slope which is greater than 1/4, and indicates some form of linear flow.

The compressibility (C_t) viscosity (μ), and gas factor (z) where taken from Grovier[2] for the Miller well conditions and were, 0.001176 psi^{-1}, 0.0135 cp, and 0.933 respectively. Porosity and fracture height taken from the logs were found to be 3.9 percent and 24 ft respectively. Standard pressure and temperature were taken as 14.7 psi and 520°F while the bottom-hole temperature (T) was measured and found to be 708°R. The flow rate was taken from the production data for the past year and amounted to 33 MCFD, while the formation permeability was assumed to be 0.010 md. A gas gravity measurement of 0.691 was derived using a gas chromatograph and a gas sample from the Miller No. 1 well.

A plot of bottom-hole buildup pressure squared (P^2_{ws}) versus the fourth root of the buildup time ($\sqrt[4]{\Delta t}$) is plotted in Figure 5-3. The slope (m_{bf}) for a bilinear flow period is found from Figure 5-3 to be $0.215 \times 10^6 psi^2/^4$ hr.

Calculated fracture parameters are:

Fracture conductivity = 9.68 md-ft
Fracture half length = 417 ft

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[1] Cinco-L. H., Samaniego - V. F., "Transient Pressure Analysis for Fractured Wells," SPE 7490, 1978 SPE Meeting, Houston, Texas

[2] Govier, G., "Theory and Practice of the Testing of Gas Wells," Energy Resources Conservation Board, Clagrry, Alberta, Canada, 1975, Third Edition.

Table 5-2 DOE/CIG Cyclic Dry Gas Project Bottom-Hole and Surface Build-up Data for the Miller No. 1 well.

Date	Time (hrs)	Δt (hrs)	P_{ws} (psig)	T_{ws} (F)	P_{sst} (psig)	P_{ssc} (psig)	Remarks
3/13	1005	0.000	506.59	292.3			
3/13	1015	0.167	506.57	292.3			
3/13	1025	0.333	517.59	292.3			
3/13	1035	0.500	528.76	292.3			
3/13	1045	0.667	535.06	292.3			
3/13	1120	1.250	539.89	292.3			
3/13	1200	1.917	547.11	292.3			
3/13	1255	2.833	556.46	292.3	437.0	460	
3/13	1516	5.183	586.46				
3/13	2000	9.917	621.01				
3/14	0010	14.083	640.90				
3/14	1005	24.000	675.45	291.6	504.0	540	
3/14	1630	30.417	691.67	289.8	550.0	560	
							Inoperable, temperature tool pulled at 2000 hrs and replaced
3/15	1510	53.083	728.50	248.3			
3/16	1035	75.500	755.52	247.7	600.0	620	
3/16	1435	79.500	760.34	247.6	612.5		
3/17	0830	94.420	779.56	246.5	612.5		
3/17	1700	102.920	787.62	247.4	625.0		
3/18	0830	118.420	800.92	247.4	625.0		
3/18	1700	126.920	807.50	247.4	630.0		
3/19	0800	141.920	817.90	247.2	655.0		
3/19	1600	149.920	823.80	247.0	637.5		
3/20	1000	167.920	835.11	246.8	650.0	675	
3/21	1000	191.920	848.85	246.8	662.5	700	
3/22	0800	215.920	860.05	247.1		700	
3/23	0800	239.920	871.41	248.2			
3/24							Inoperable, temperature tool pulled at 1400 hrs. Processor set at 248°F
3/24	1500	270.920	884.03	248*	700.0		
3/25	0800	287.920	890.93	248*	700.0	735	
3/26	1000	313.920	899.77	248*	712.0	735	
3/27	0800	335.920	908.46	248*	730.0	750	
3/28	0800	359.920	916.37	248*	745.0	755	
3/29	1300	389.920	926.35	248*	745.0	755	
3/30	0800	407.920	931.36	248*			
3/30	1700	416.920	933.99	248*	755.0	765	
3/31	0800	431.920	938.38	248*	755.0	765	

* Temperature set in G.O. Processor. No bottom-hole temperature available.

Table 5-2 continued

Date	Time (hrs)	Δt (hrs)	P_{ws} (psia)	T_{ws} (°F)	P_{sst} (psig)	P_{ssc} (psig)	Remarks
4/1	0800	455.92	944.96	248.0	760	765	
4/2	0800	479.92	951.16	248.0	765	775	
4/4	0800	527.92	963.07		775	785	
4/5	0800	551.92	968.79	248.0*	780	790	
4/6	0800	575.92	974.25	248.0*	785	798	
4/7							Pulled pressure gauge, temp tool returned to service
4/9	0800	647.92	991.47	267.1	805	810	
4/10	0800	671.92	996.42	266.7			
4/11							Pulled tools, repaired cable head. Returned to service
4/13	1630	754.42	1,014.70	286.4			
4/14							Temp. tool inoperable processor set at 248°F
4/16	0800	515.92	1,019.40	248.0*	725	735	
4/19	0800	887.92	1,032.30	248.0*	845	855	
4/21	0800	935.92	1,039.69	248.0*	840	850	
4/22	0800	959.92	1,043.44	248.0*	840	860	
4/24	0800	1,007.92	1,051.77	248.0*	840	860	
4/25	0800	1,031.92	1,054.31	248.0*	870	880	
4/26	0800	1,055.92	1,057.84	248.0*	870	880	
4/27	0800	1,079.92	1,061.35	248.0*	870	880	
4/30	0800	1,151.92	1,071.71	248.0*	860	870	

*Temperature set in G.O. Processor. No bottom-hole temperature available.

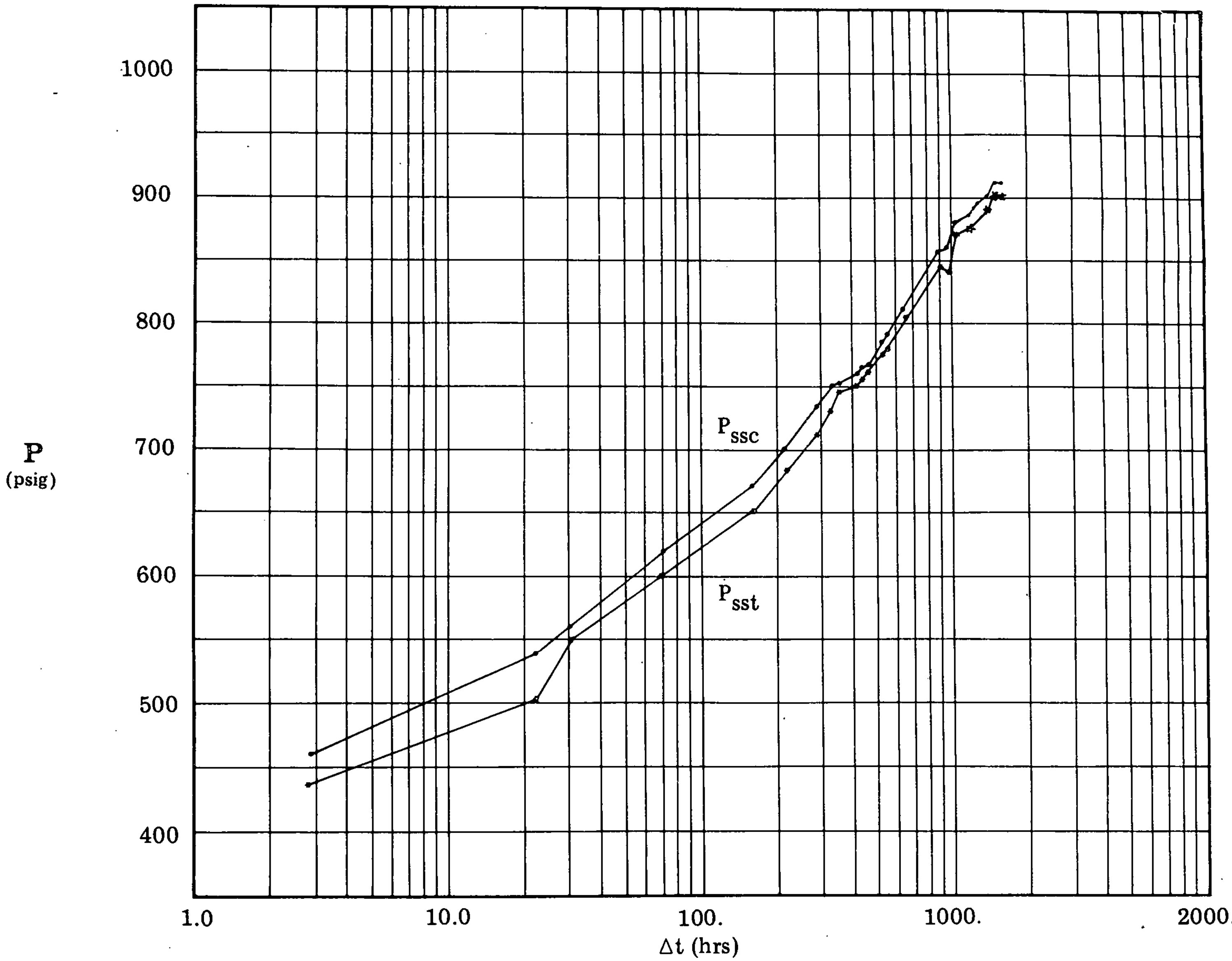

Figure 5-1 Surface Casing Pressure (P_{ssc}) and Surface Tubing Pressure (P_{sst}) versus Buildup Time Δt for the Miller No. 1 well

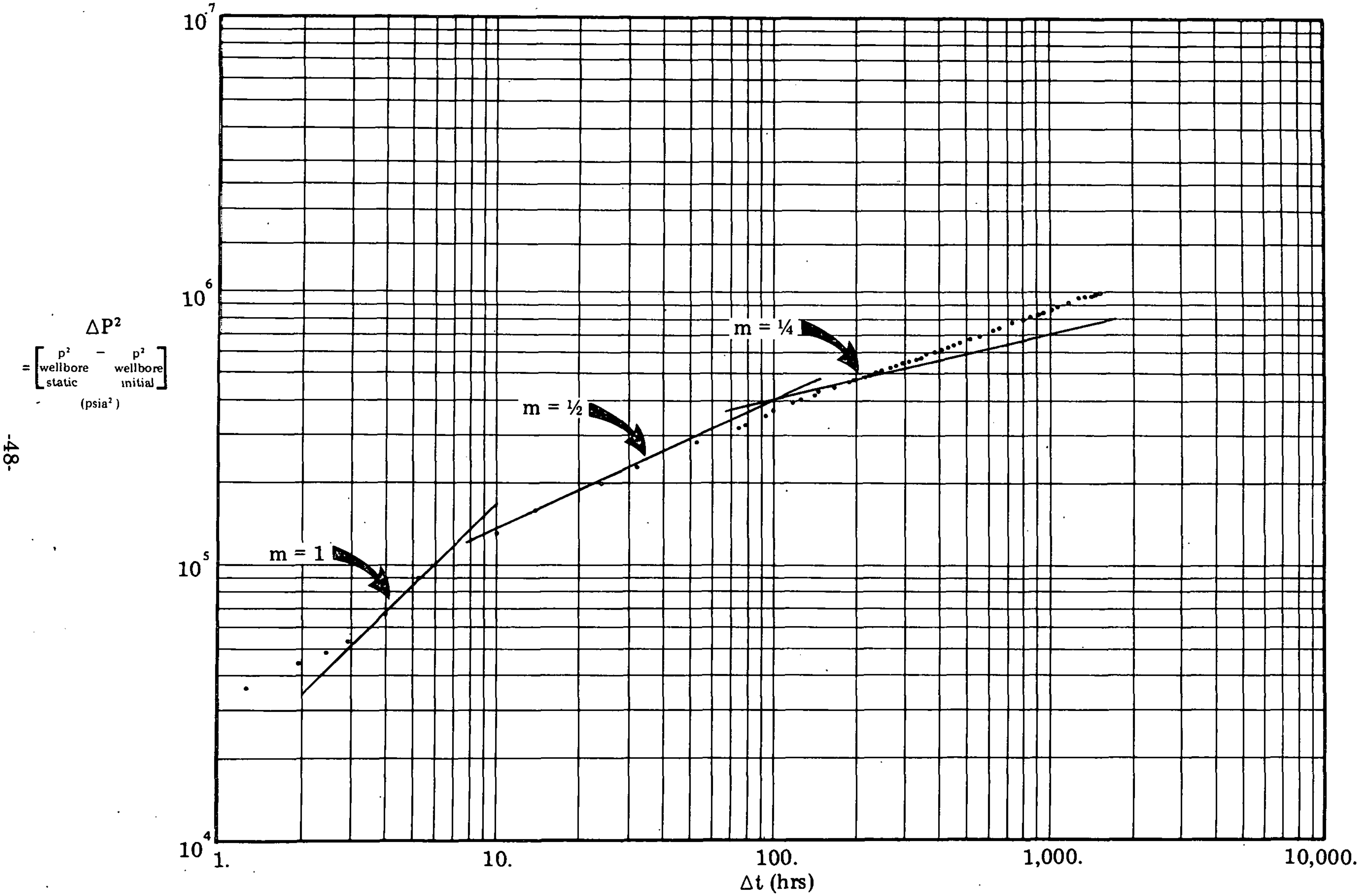

Figure 5-2 Type Curve Plot of Bottom-Hole Buildup Pressure Data for Miller No. 1

[redacted] [redacted] [redacted]

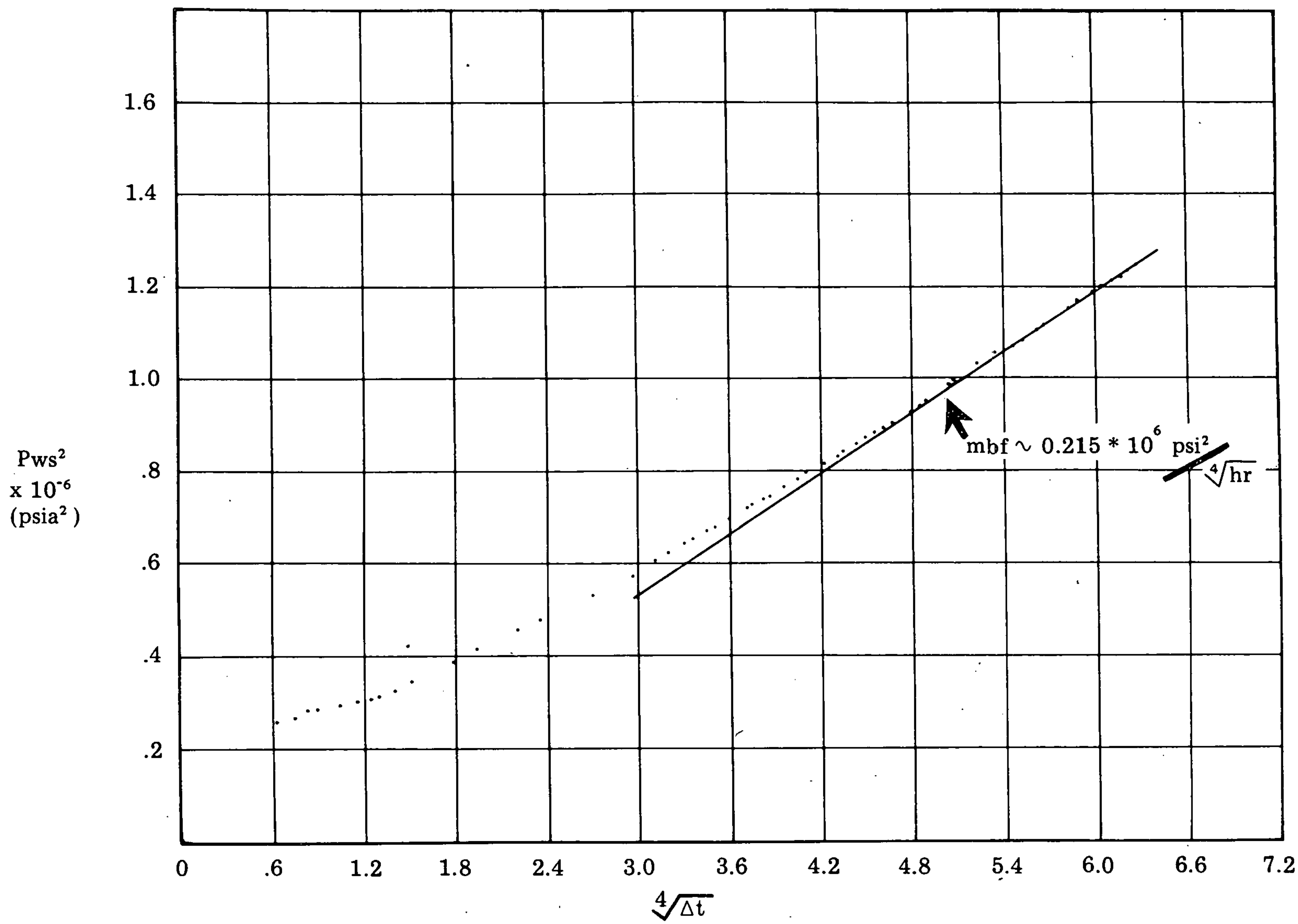

Figure 5-3 Miller No. 1 buildup pressure squared versus the fourth root of time

This fracture half length value compares favorably with the value of 360 ft derived using the square root method described by Argarwal[1] for linear flow systems. The slope from the square root plot has not yet flattened and tends to yield somewhat shorter values. Furthermore, it would not be unreasonable to expect a fracture of about 500 ft, based on fracture treatment records.

Bottom-hole buildup pressure data for the Sprague No. 1 well is presented in Table 5-3. Figure 5-4 is a plot of ΔP^2 versus Δt, derived from the Table 5-3 data. A slope of 1/4 was added as reference to indicate bilinear flow. As was the case with the Miller No. 1 well, the condition of the tubing and casing was unknown. The apparent erratic behavior in the pressure is not understood and may be attributable to either or both sporadic or continuous leakage from the tubing to the casing, or the casing to the formation. Monitoring the surface casing pressure confirmed the fact that casing pressure tracked the tubing pressure and communication did exist between the tubing and casing.

Linear flow analysis using Cinco's method yeilds an exceptionally large fracture half length (> 1,100 ft) which, although is understandable from the erratic nature of the data, is significantly beyond expectation for the size of the fracture treatment.

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[1] Agarwal, R. G., et al., "Evaluation and Production of Performance of Low Permeability Gas Wells Stimulated by massive Hydraulic Fracturing," SPE 6838, 1977 SPE Conference, Denver, Colorado

Table 5-3 Bottom-Hole Buildup Pressure Data for the Sprague No. 1 well

Date	Δt (hrs)	P_{ws} (psia)	Date	Δt (hrs)	P_{ws} (psig)
3/07	0.0	544	3/23	380	854
3/07	0.5	637	3/24	400	857
3/07	1.0	661	3/25	420	860
3/07	2.0	665	3/26	440	864
3/07	3.0	695	3/27	460	867
3/08	4.0	703	3/27	480	872
3/08	5.0	707	3/28	500	874
3/08	6.0	710	3/29	520	876
3/08	7.0	715	3/30	540	879
3/08	8.0	720	3/31	560	881
3/08	9.0	725	4/01	580	887
3/08	10.0	730	4/01	600	891
3/08	12.0	735	4/02	620	894
3/08	15.0	744	4/03	640	896
3/08	20.0	759	4/04	660	898
3/08	25.0	749	4/05	680	899
3/09	30.0	747	4/06	700	903
3/09	40.0	749	4/06	720	901
3/10	50.0	754	4/07	740	908
3/10	60.0	759	4/08	760	914
3/10	70.0	761	4/09	780	925
3/11	80.0	759	4/10	800	925
3/11	90.0	774	4/11	820	930
3/12	100.0	781	4/11	840	938
3/12	110.0	784	4/12	860	941
3/12	120.0	789	4/13	880	943
3/13	130.0	793	4/14	900	947
3/13	140.0	810	4/15	920	941
3/14	150.0	803	4/16	940	947
3/14	160.0	801	4/16	960	950
3/14	170.0	801	4/17	980	955
3/15	180.0	803	4/18	1,000	960
3/15	190.0	806	4/19	1,020	965
3/16	200.0	808	4/20	1,040	972
3/16	210.0	811	4/21	1,060	972
3/17	220.0	813	4/21	1,080	985
3/17	230.0	815	4/22	1,100	989
3/17	240.0	816	4/23	1,120	990
3/18	250.0	818	4/24	1,140	992
3/18	260.0	820	4/25	1,160	989
3/19	280.0	821	4/26	1,180	189
3/20	300.0	837	4/26	1,200	990
3/21	320.0	840	4/27	1,220	994
3/22	340.0	845	4/28	1,240	996
3/22	360.0	850	4/29	1,260	997
			4/30	1,280	999

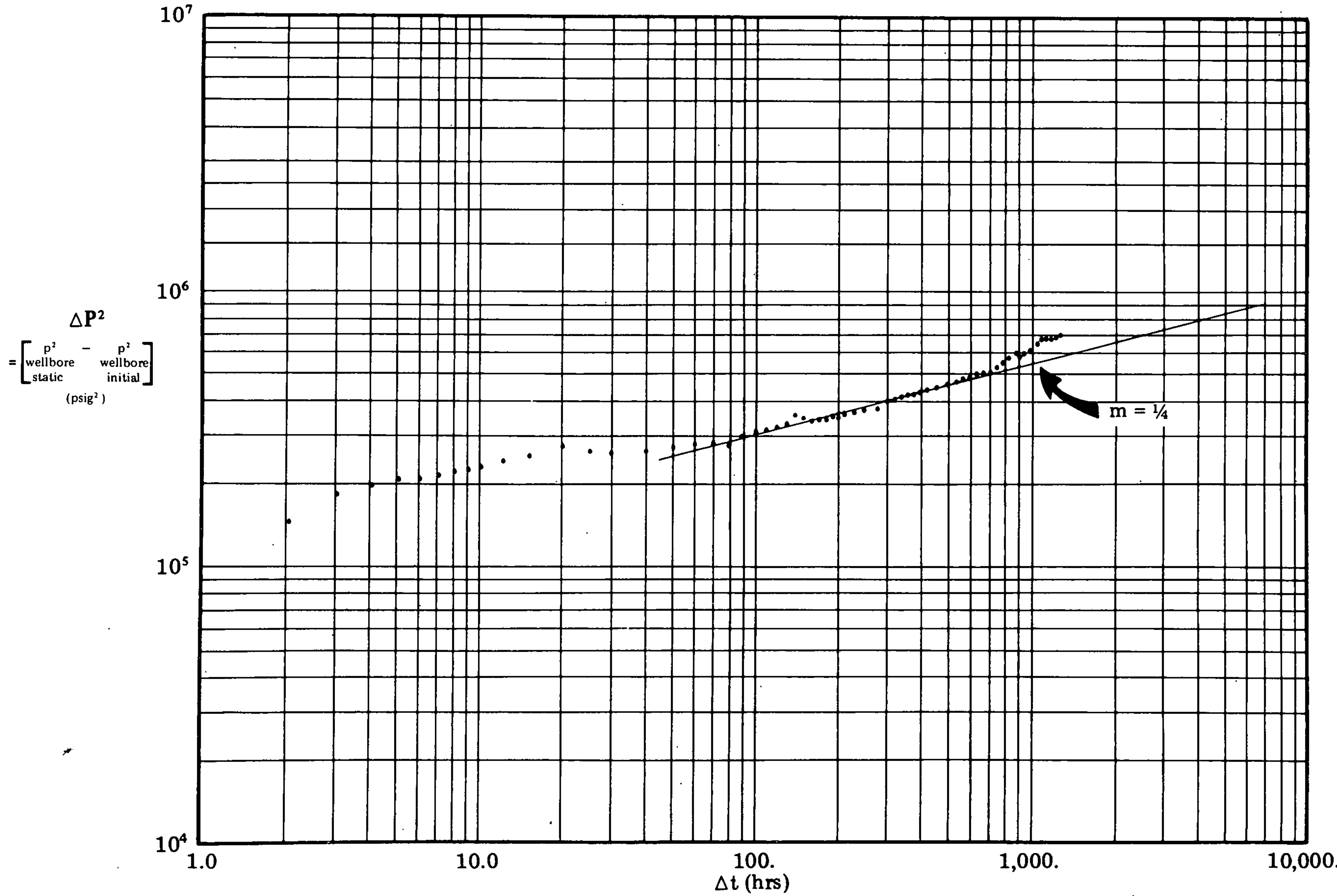


Figure 5-4 Type Curve Plot of Bottom-Hole Pressure for the Sprague No. 1 well

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

Status: Active

Contract Date: July 1, 1976
Anticipated Completion: September 30, 1979

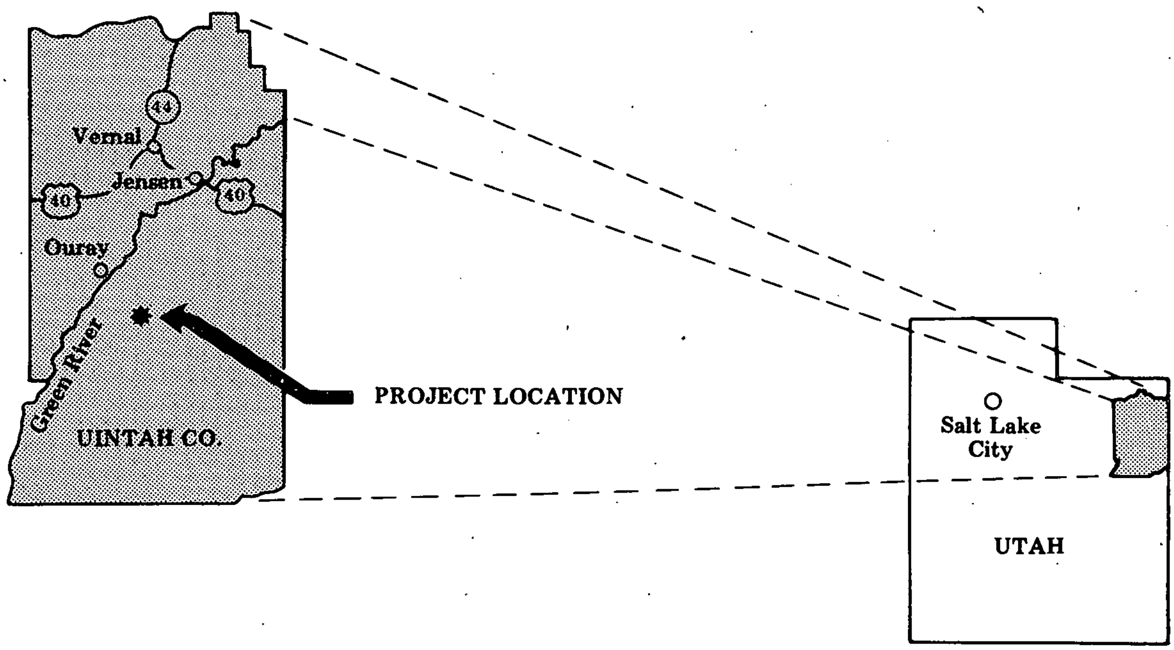
Total Project Cost (estimated):

DOE	$2,827,000
Industry (prior costs)	1,881,000
Industry (new costs)	3,051,000
Total	$7,759,000

Principal Investigator: W. E. Spencer
Technical Project Officer for DOE: C. 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 GAS PRODUCING ENTERPRISES, INC.

The GPE wells, Natural Buttes Units 9, 14, 18, 19, and 20 have been flowing to sales. Natural Buttes Unit 22 began flowing to sales on January 30. NBU 21 could not be completed in the gas-bearing formations to be tested under the contract because these formations were not gas productive. Figures 5-5 through 5-10 show production figures. Table 5-4 is a summary of MHF treatments performed on GPE wells.

Two fracturing fluid/rock interaction tests have been completed by Terra Tek on sandstones from the Lower Mesaverde Group. Here, only preliminary data is presented (Table 5-5). No discussion of results will be presented until all interaction tests are completed. Work is aimed at the assessment of damage to sample permeability caused by the interaction of fracturing fluids with the host rock. The tests also investigate the amount of permeability recovery after backflow.

All samples were one in. diameter by one in. long, with the sample axis parallel to the bedding plane. Permeability at atmospheric conditions for as-received cores was first determined. Pressure and temperature were gradually increased to in situ conditions to determine the effect of in situ stress and temperature on permeability. After the confining pressure, pore pressure and temperature reached in situ conditions, the fracturing fluid was flowed across one face of the sample for four hrs at an appropriate injection pressure (the particular time and injection pressure were used to simulate field fracture job conditions). Immediately after termination of fracturing fluid flow, permeability was measured to assess damage. Before allowing the fracturing fluid to break, nitrogen was backflowed for a short time (1-2 hrs) to assess any permeability recovery. Then a shut-in time of twelve hrs was allowed to assure the fracture fluid was completely broken up; nitrogen, at in situ pore pressure, was introduced at the sample back face to simulate clean up. Pressure at the fracture face was reduced according to the following schedule.

Pressure Reduction at Fracture Face (psi)	Remarks
500	Monitor permeability until 100 percent damage is recovered or move on to the next step if damage recovery stabilizes.
1,000	Same as above
2,000	Monitor permeability until 100 percent damage is recovered or stop test if damage recovery stabilizes.

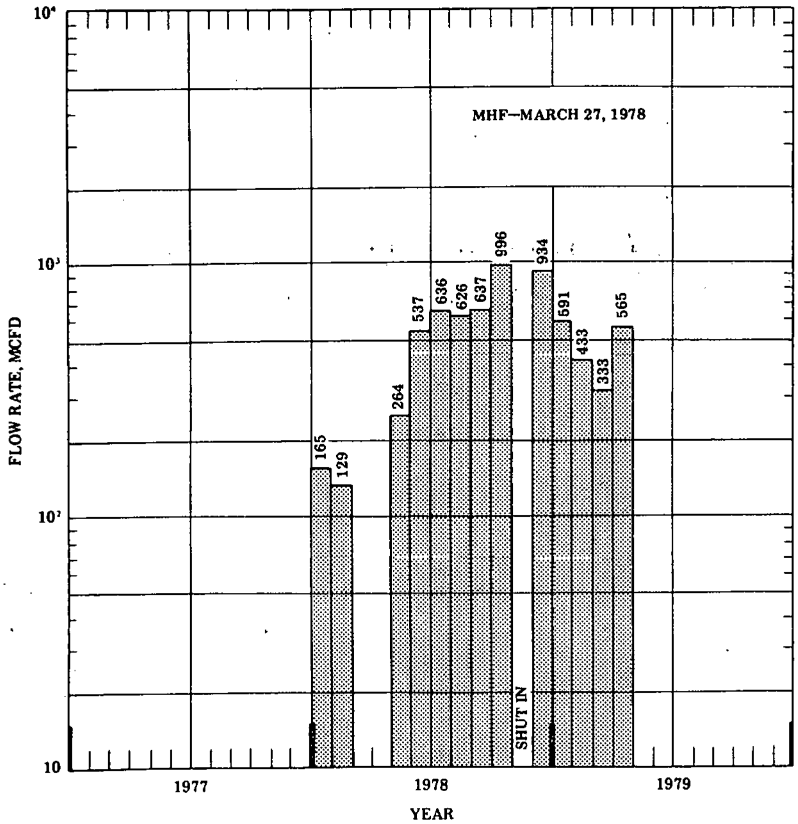


Figure 5-5
Flow Rate Performance of Natural Buttes No. 9 Well

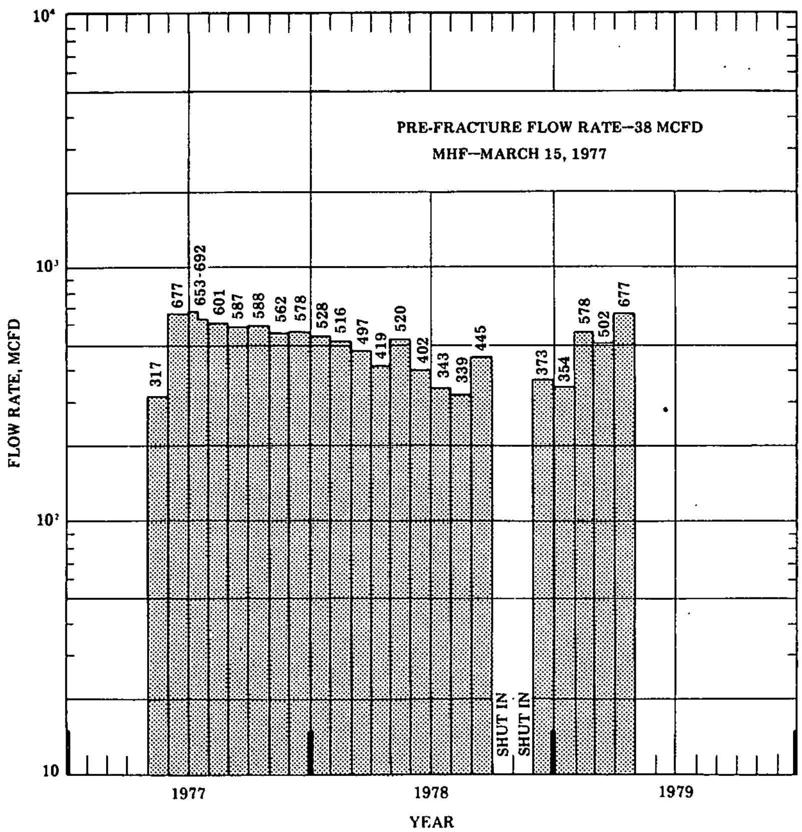
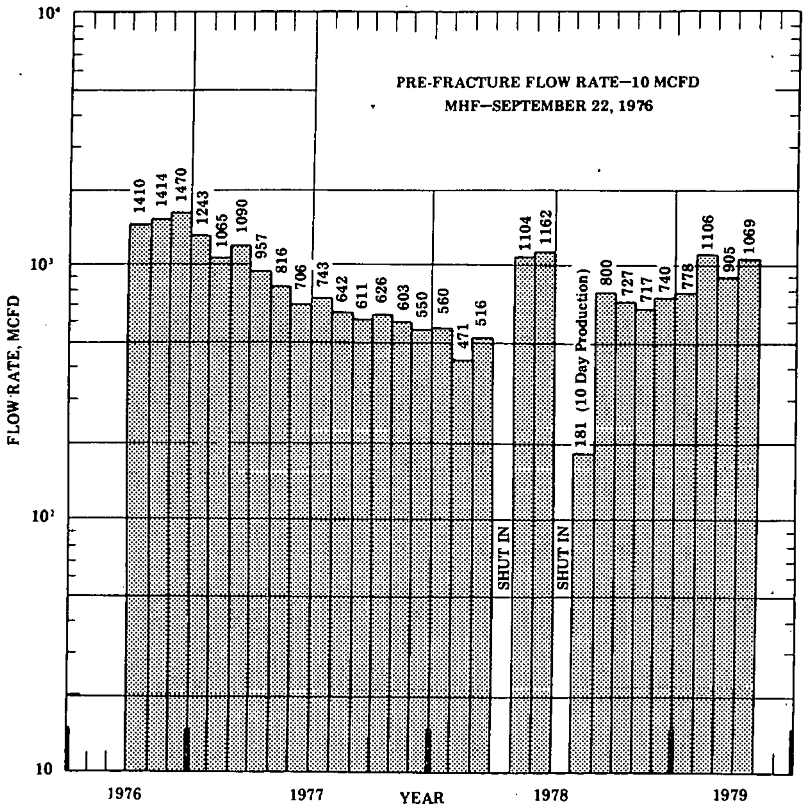


Figure 5-6
Flow Rate Performance of Natural Buttes No. 14 Well

Figure 5-7
Flow Rate Performance of Natural Buttes No. 18 Well



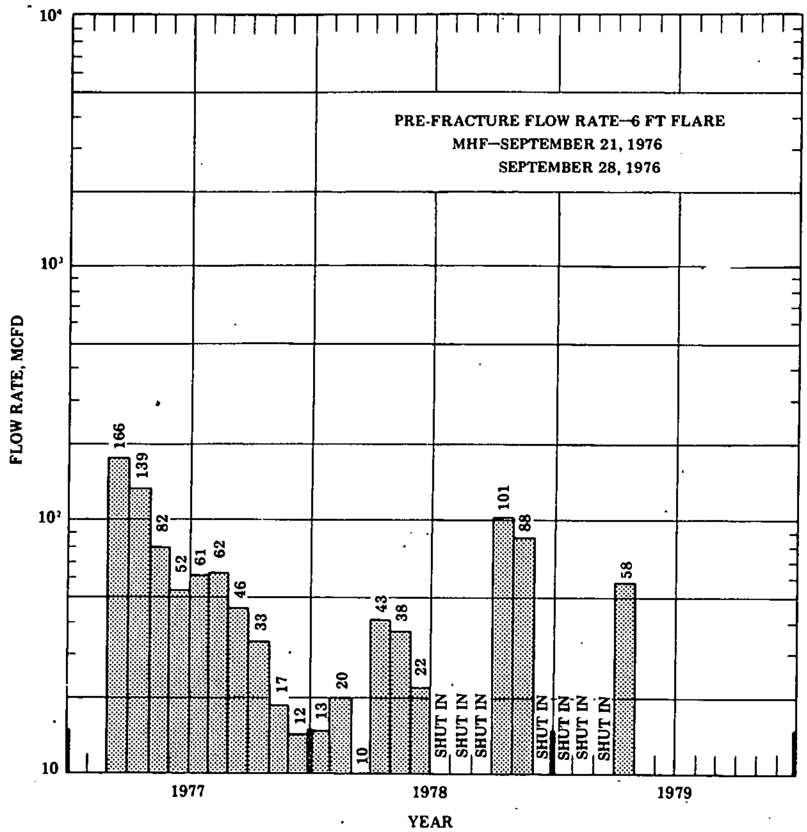


Figure 5-8
Flow Rate Performanee of Natural Buttes No. 19 Well

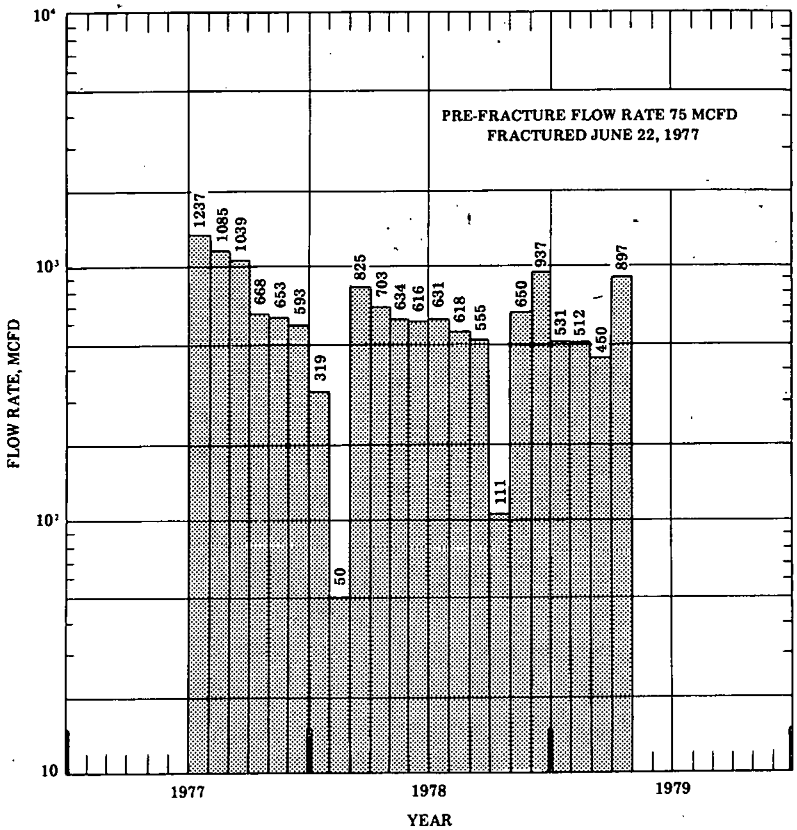


Figure 5-9
Flow Rate Performance of Natural Buttes No. 20 Well

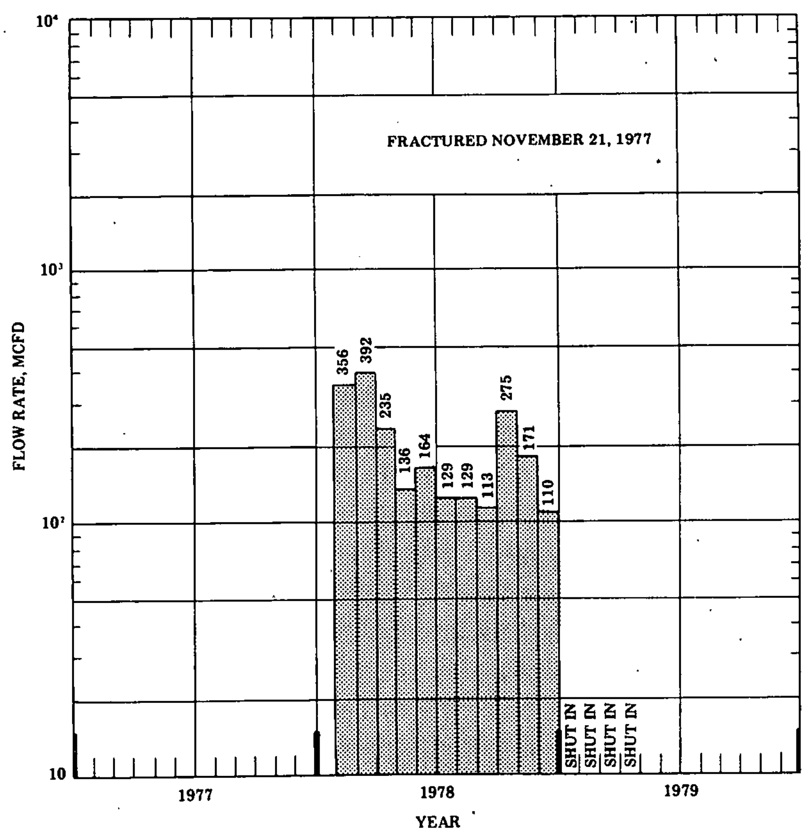


Figure 5-10
Flow Rate Performance of Natural Buttes No. 22 Well

Table 5-4 Summary of MHF Treatments

Well	No. of Zones Perf.	Net Ft. of Pay	Net Ft. Per Zone	Average ϕ	Average SW	% Sd	Type of Fluid	Frac Job Size Gal of Gel	Lb of Proppant	Calc. Frac Length ft	Est. 1st Year Avg. Prod. Rate MCFD
Natural Buttes No. 18 DOE	18	224	12.5	10.0	48	88.0	Versa Frac	695,000	1,480,000	882	1,200
Natural Buttes No. 19 DOE	19	194	10.2	9.5	47	87.0	40# Guar Gum	655,000	1,237,000	950	60
Natural Buttes No. 14 DOE	15	271	18.0	9.9	49	65.0	YF4-PSD	544,000	1,082,000	879	600
Natural Buttes No. 20 DOE	8	65	8.1	9.9	44	88.5	YF4-PSD	309,000	826,000	1,150	800
Natural Buttes No. 22 DOE	24	196	8.1	12.0	45	85.0	YF4-PSD	478,758	1,091,000		
Natural Buttes No. 9 DOE	(35)	779*	22.0*	Unkn	Unkn	Unkn	40# Guar Gum	314,000	553,000		
CIGE 2-29-10-21 DOE Stage 1	10	91	9.1	10.0	40	80.0	MY-T-GEL III	195,000	170,500		
CIGE 2-29-10-21 DOE Stage 2	12	181	15.1	11.3	42	85.0	MY-T-GEL III	805,230	1,956,000		
CIGE 23-7-10-22 DOE	10	156	15.6	9.0	60	78.0	YF4-PSD	240,000	470,000		

*Using GR as only indication of net sand which more closely equals gross sand.

Table 5-5 Fluid/Rock Interaction Tests on Sandstones from the Lower Mesaverde Group

Depth (ft)	Formation	Fracturing Fluid	Confining Pressure (psi)	Pore Pressure (psi)	Temperature (°F)	Permeability (μd)	Comments
8,493	Mesaverde Sandstone	Dowell YF4G-PSDW/ f-75A	200	0	75	81.0	Permeability at atmospheric conditions.
			4,000	500	173	16.0	At a higher stress level.
			8,490	4,400	173	12.8	At in situ stress and before fracturing fluid flow.
			8,490	4,400	173	0.1	After fracturing fluid flow.
			8,490	4,400	173	0.2	Backflow for 1 hr at 500 psi ΔP.
			8,490	4,400	173	0.2	After shut in for 12 hrs and backflow for 1 hr at 1,000 psi ΔP.
			8,490	4,400	173	5.2	Backflow for 1 hr at 1,000 psi ΔP.
			8,490	4,400	173	6.1	Backflow for 1 hr at 1,000 psi ΔP.
			8,490	4,400	173	6.1	Backflow for 2 hrs at 1,000 psi ΔP.
							Fracturing fluid bubbled out at the downstream face.
		— Fracturing Fluid Injection Pressure - 6,150 psi					
8493	Mesaverde Sandstone	Dowell YF4G-PSDW/ 0-75A	200	0	75	87.0	Permeability at atmospheric conditions.
			3,000	500	173	22.0	At a higher stress level.
			8,490	4,400	173	12.0	At in situ stress and before fracturing fluid flow.
			8,490	4,400	173	0.1	After fracturing fluid flow.
			8,490	4,400	173	0.1	Backflow for 1 hr at 500 psi ΔP.
			8,490	4,400	173	1.6	After shut in for 12 hrs and backflow for 4.5 hrs at 500 psi ΔP.
			8,490	4,400	173	4.5	Backflow for 1 hr at 500 psi ΔP.
			8,490	4,400	173	9.2	Backflow for 1 hr at 1,000 psi ΔP.
							Fracturing fluid bubbled out at the downstream face.
		— Fracturing Fluid Injection Pressure - 6,150 psi					

Core samples taken from GPE Natural Buttes Well No. 21 at depths of 4,406 ft, 6,492 ft and 8,492 ft were used to investigate fracture flow capacity. Sample 4,406 (ft) is from the Wasatch sandstone formation and the other two are from sandstone in the Mesaverde Group. Work was aimed at assessing flow capacity damage of the YF-PSD W/O-75A fracturing fluids to fractures propped with a packed layer of 20-40 mesh Ottawa sand. Here only preliminary data is presented. No discussion of results will be presented until all the fracture flow capacity tests are performed.

Core samples were saw cut and propped with a sand concentration of 0.58 lb/ft^2. Initially, the cores were subjected to a confining pressure of 100 psi for the proppants to settle in place. Flow capacity measurements were taken by flowing dry nitrogen gas through the propped channel. The change in flow capacity with effective pressure was determined by varying the confining pressure from 500 psi to the desired in situ confining pressure; in all cases, gas pressure within the fracture was maintained at in situ pore pressure. Fracturing fluid was subsequently flowed through the propped fracture for four hrs (to simulate field fracturing time). Nitrogen gas was then flowed at in situ stress conditions to simulate opening of the well and flow capacity measurements were taken until it stabilized. The change in flow capacity with decreasing effective pressure was then determined for the same confining pressure range. Results of the tests are presented in Tables 5-6, 5-7, and 5-8.

Table 5-6 Effect of Fracturing Fluid on the Fracture Capacity of Mesaverde Sandstone (4406) GPE Well No. 21

EFFECTIVE PRESSURE (psi)	FRACTURE FLOW CAPACITY md-ft	
	BEFORE FRACTURING FLUID FLOW	AFTER FRACTURING FLUID FLOW
100	273	107
500	259	101
1,000	243	96
1,500	230	91
2,000	216	86
2,360	207	84[2]
2,360	207	2[1]

[1] At maximum damage
[2] After clean up stabilized
Proppant distribution: 0.58 lb/ft^2 of 20-40 mesh Ottawa sand.
Test Temperature: 199^{o}F

Table 5-7 Effect of Fracturing Fluid on the Fracture Flow Capacity of Mesaverde Sandstone (6492 ft) GPE Well No. 21

EFFECTIVE PRESSURE (psi)	FRACTURE FLOW CAPACITY md-ft	
	BEFORE FRACTURING FLUID FLOW	AFTER FRACTURING FLUID FLOW
100	349	22.5
500	338	21.7
1,000	326	20.5
1,500	314	19.5
2,000	298	18.5
2,500	284	17.6
3,000	271	16.7
3,300	255	16.3[2]
3,300	255	10.0[1]

[1] At maximum damage
[2] After clean up stabilized
Proppant distribution: 0.58 lb/ft^2 of 20-40 mesh Ottawa sand.
Test Temperature: 147°F

Table 5-8 Effect of Fracturing Fluid on the Fracture Flow Capacity of the Mesaverde Sandstone GPE Well No. 21 (8492 ft)

EFFECTIVE PRESSURE (psi)	FRACTURE FLOW CAPACITY md-ft	
	BEFORE FRACTURING FLUID FLOW	AFTER FRACTURING FLUID FLOW
100	350	147.0
500	336	142.0
1,000	325	135.5
1,500	314	130.0
2,000	300	124.5
2,500	285	119.0
3,000	270	114.5
3,500	245	110.0
4,000	216	105.0
4,100	210	104.0
4,100	210	15.4

Proppant distribution: 0.58 lb/ft^2 of 20-40 mesh Ottawa sand.
Test Temperature: 173°F

FALLON-NORTH PERSONVILLE FIELD, TEXAS, MASSIVE HYDRAULIC FRACTURING DEMONSTRATION

EF-78-C-08-1547

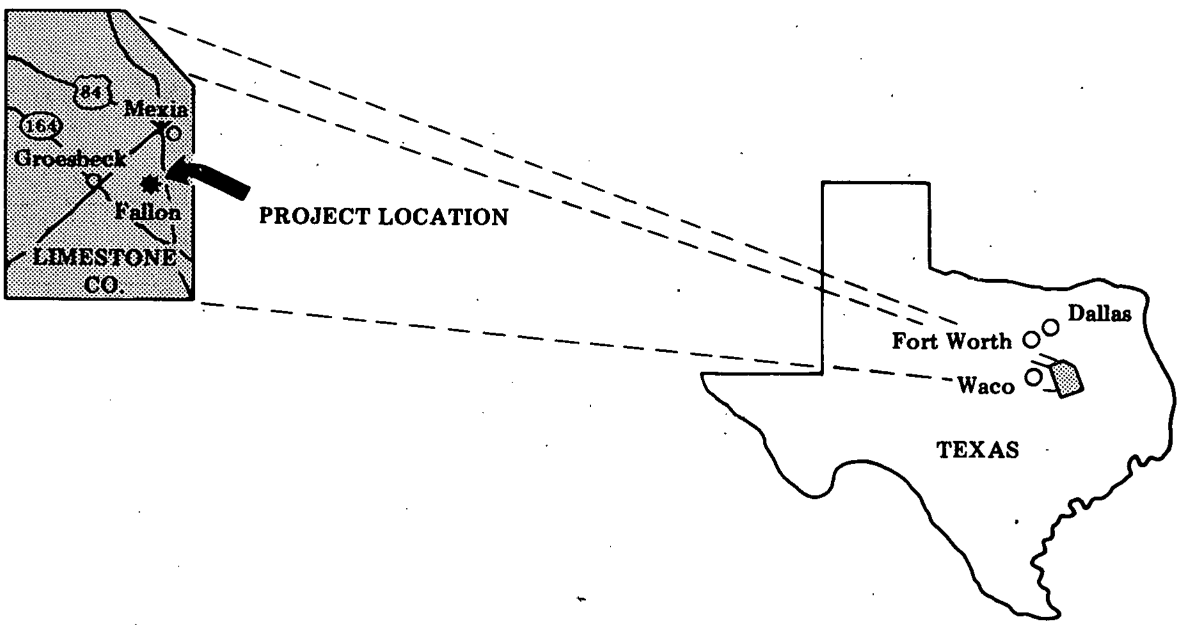
Mitchell Energy Corporation
Houston, Texas

Status: Active

Contract Date:	March 15, 1978	
Anticipated Completion:	April 30, 1979	
Total Project Cost (estimated):	DOE	$ 553,771
	Industry	1,074,550
	Total	$1,628,321
Principal Investigator:	F. D. Covey	
Technical Project Officer for DOE:	C. H. Atkinson	

OBJECTIVE

To test massive hydraulic fracturing in the Cotton Valley Limestone Formation.



5.6 MITCHELL ENERGY CORPORATION

On April 15, 1979, M.E.C. Muse-Duke No. 1 was flowing 4,000 MCFG and 25 barrels of frac water per day through a 24/64 inch choke with a flowing tubing pressure of 1,100 psi. Flow rates and pressures are continuing to drop slowly (see Figure 5-11).

Due to the heavy demand for natural gas, Mitchell Energy Corporation still has not been able to complete the scheduled post frac pressure transient tests and clean-out work as previously planned. It appears at this time that the gas demand will not slacken until June or July.

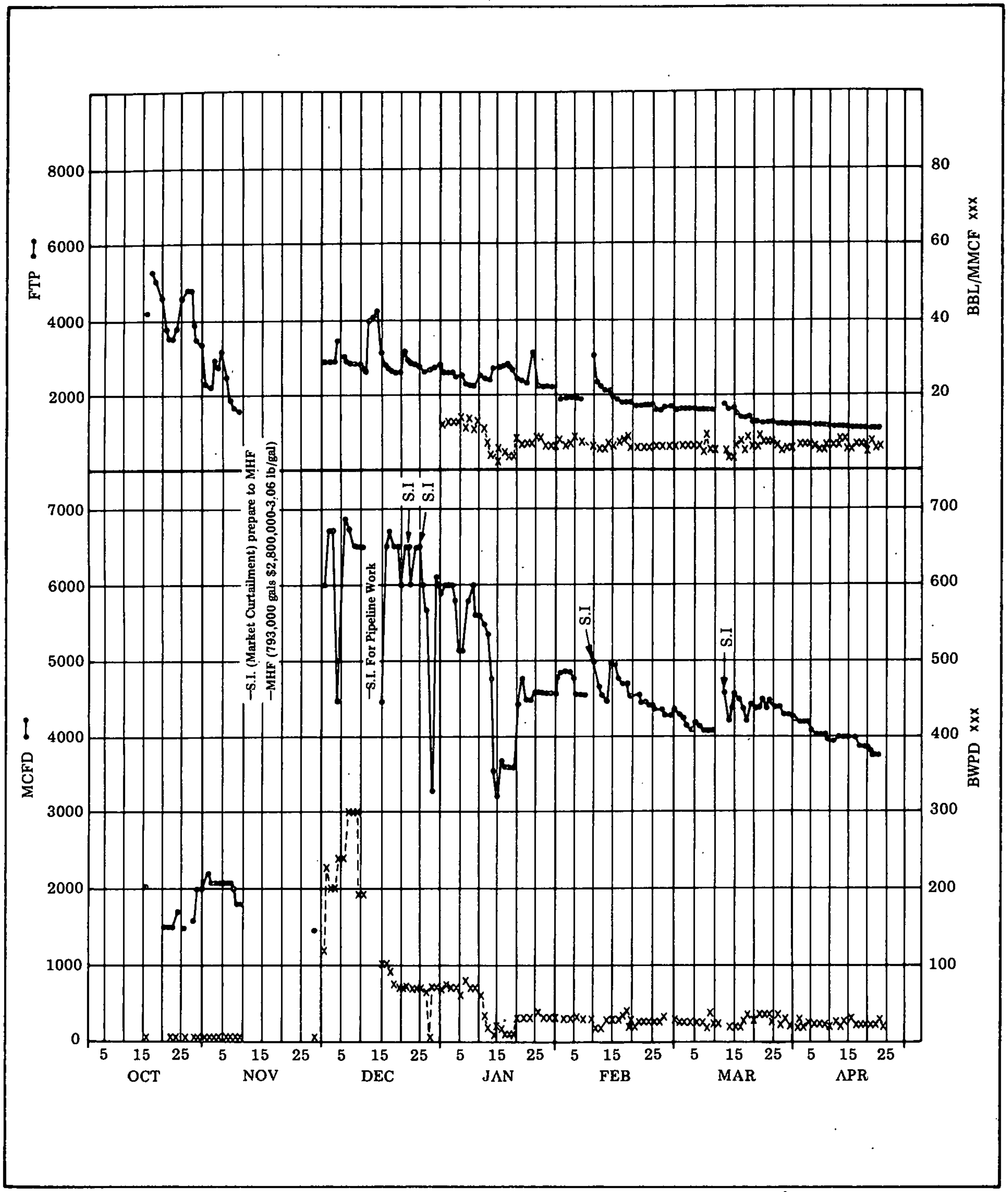


Figure 5-11 Muse-Duke No. 1 Well Test History

PICEANCE CREEK FIELD, COLORADO, MASSIVE HYDRAULIC FRACTURING DEMONSTRATION

EY-76-C-08-0678

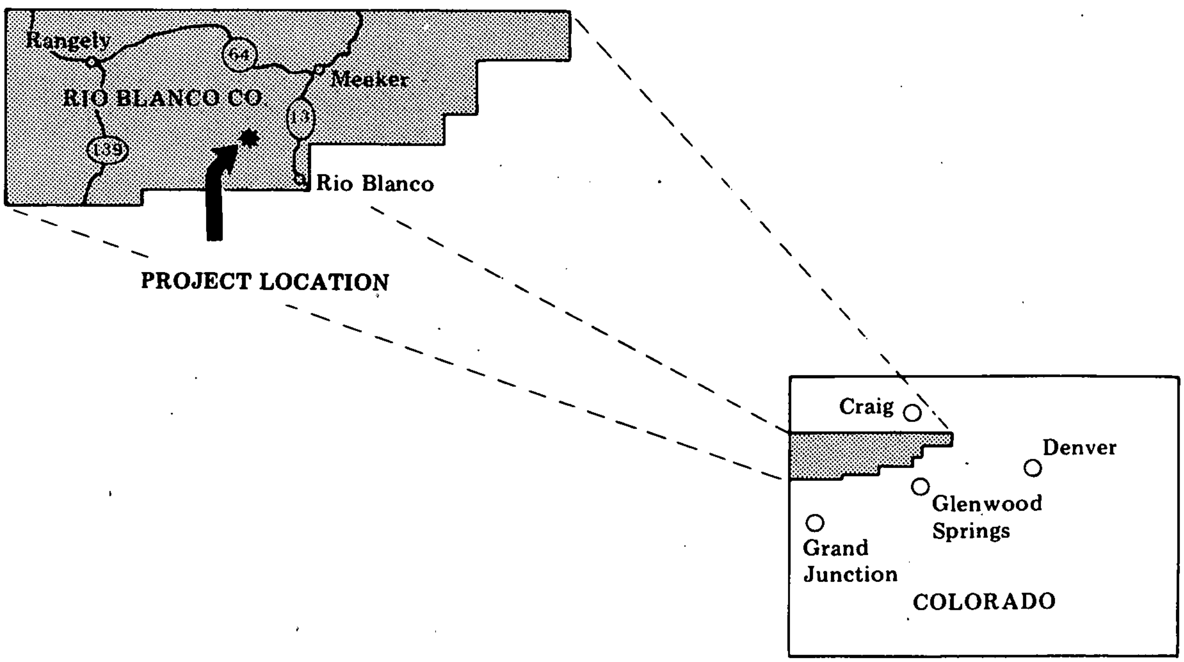
Mobil Research and Development Corporation
Dallas, Texas

Status: Active

Contract Date:	July 1, 1976	
Anticipated Completion:	June 1st 1979	
Total Project Cost (estimated):	DOE	$2,510,000
	Contractor (prior costs)	2,376,485
	Contractor (new costs)	1,590,515
	Total	$6,477,000
Principal Investigator:	John L. Fitch	
Technical Project Officer for DOE:	C. H. Atkinson	

OBJECTIVE

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



5.7 MOBIL RESEARCH AND DEVELOPMENT CORPORATION

Fishing operations on the PCU F31-13G well were suspended on April 5 and the rig was released to provide time for a thorough evaluation of the situation and additional planning.

Plans were formulated to resume fishing in early May. They include:

- Swage out a tight spot in the casing at 7,285 ft so that a 6 in. wash pipe will pass.
- Wash over the top of the fish to the overshot, screw into the fish and back off as far as possible. Clean out the sand from inside of fish if necessary.
- If all of the top fish is recovered, proceed. If not, mill over the overshot and retrieve top fish.
- Wash over the bottom fish and retrieve in normal manner.
- Run junk baskets and mills as required to remove junk from on top of the sand fill above the retrievable plug, being careful not to wash out all the sand fill until clear of junk.
- Wash to the plug and retrieve.
- Put well on production.

The clean-out work will proceed on a 24-hr basis to avoid frac sand influx during overnight shut-ins, which is thought to have contributed to the problem of tools sticking in the hole.

If clean-out operations are successful, production of all zones will proceed. If not, those zones not obstructed will be produced.

Tables 5-9, 5-10, 5-11 and 5-12 pertain to zone 9 of the Piceance Creek Well, F31-13G, Ohio Creek Formation. This was the final zone treated.

Table 5-9 PBU After Breakdown - Zone 9

Date (1978)	Time (hrs)	ΔT (hrs)	$T+\Delta T$	$\frac{T+\Delta T}{\Delta T}$	BHP, (psi)	$(P_w^2) \times 10^{-6}$ psi^2	Csg	Tbg
11/16	1400	0.0	80.0	—	1017	1.034	800	60
	1500	1.0	81.0	81.00	1261	1.590		
	1600	2.0	82.0	41.00	1415	2.002		
	1700	3.0	83.0	27.70	1539	2.369	1050	1050
	1800	4.0	84.0	21.00	1605	2.576		
	1900	5.0	85.0	17.00	1682	2.829		
	2000	6.0	86.0	14.30	1747	3.052		
	2200	8.0	88.0	11.00	1854	3.437		
	2400	10.0	90.0	9.00	1931	3.729		
11/07	0200	12.0	92.0	7.67	1979	3.916		
	0400	14.0	94.0	6.71	2021	4.084		
	0600	16.0	96.0	6.00	2055	4.223		
	0800	18.0	98.0	5.44	2089	4.364	1740	1740
	1000	20.0	100.0	5.00	2126	4.520		
	1200	22.0	102.0	4.64	2147	4.610		
	1400	24.0	104.0	4.33	2171	4.713		
	1800	28.0	108.0	3.86	2212	4.893		
	2200	32.0	112.0	3.50	2248	5.054		
11/08	0200	36.0	116.0	3.22	2280	5.198		
	0600	40.0	120.0	3.00	2308	5.327		
	0800	42.0	122.0	2.90	2321	5.387	1920	1920
	1800	52.0	132.0	2.54	2375	5.641		
	0800	66.0	146.0	2.21	2435	5.929	1980	2000
11/09	1800	76.0	156.0	2.05	2466	6.081	1910	2040
11/10	0800	90.0	170.0	1.89	2506	6.280	2030	2050
11/11	0930	115.5	195.5	1.69	2556	6.533	2100	N/A
11/12	0800	138.0	218.0	1.58	2588	6.698		

Table 5-10 Production from Zone 9 After Frac

Date (1978)	After Frac Daily Production, MCF	Remarks
11/27	1897	
11/28	1908	
11/29	1820	
11/30	1883	
12/01	1946	
12/02	1879	
12/03	1738	
12/04	1656	Off about 2 hrs
12/05	1935	
12/06	1153	Off almost 10 hrs
12/07	1335	Off about 8 hrs
12/08	1685	
12/09	592	Off 12 hrs-freezing up
12/10	1270	Off 8 hrs
12/11	1710	
12/12	1656	Off 2 hrs
12/13	1860	
12/14	1734	
12/15	1597	
12/16	1714	
12/17	1810	
12/18	1776	
12/19	1741	
12/20	1767	
12/21	1812	
12/22	1758	
12/23	1750	
12/24	1757	
12/25	1722	
12/26	1745	
12/27	1720	
12/28	1703	
12/29	1667	
12/30	1735	
12/31	716	

Table 5-11 Reported Water Production After Frac - Zone 9

Date (1978)	Water Produced, BBL
11/18	700
11/20	550
12/07	85
12/14	90
12/20	85
12/29	87

Table 5-12 Drawdown Test After Frac - Zone 9

Date (1978)	Time (hrs)	ΔT (hrs)	BHP, (psi)	$(BHP)^2 \times 10^{-6}$, psi^2	
11/16	1300	0.00	N/A	N/A	Opened well
11/18	1000	45.00	1,839	3.382	Flow Rate ~ 4.0 MMCFD
	1430	49.50	1,828	3.342	Water Rate
	1750	52.83	1,817	3.301	Declined
11/19	0100	60.00	1,788	3.197	From about
	0900	68.00	1,765	3.115	670 BBL/D
	1440	73.67	1,748	3.056	to 570 BBL/D
11/20	0600	89.00	1,725	2.976	During this Period

No rates are available from 11/21-11/27/78 due to logging efforts and flowing to the pit during well cleanup.

RIO BLANCO COUNTY, COLORADO MASSIVE HYDRAULIC FRACTURING DEMONSTRATION

EY-76-C-08-0677

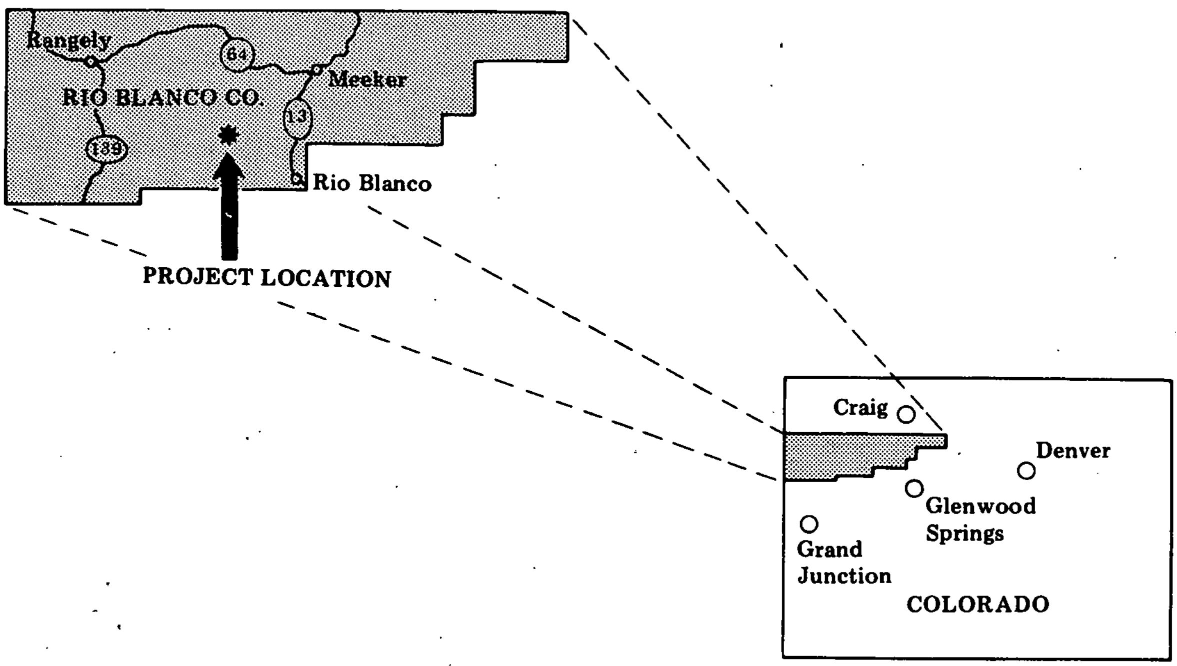
Rio Blanco Natural Gas Company
Denver, Colorado

Status: Active

Contract Date:	August 1, 1976	
Anticipated Completion:	December 15, 1978	
Total Project Cost (estimated):	DOE	$ 410,000
	Contractor	593,000
	Total	$1,003,000
Principal Investigator:	Robert E. Chancellor	
Technical Project Officer for DOE:	C. H. Atkinson	

OBJECTIVE

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



5.8 RIO BLANCO NATURAL GAS COMPANY

DOE Contract EY-76-C-08-0677 was signed with Rio Blanco Natural Gas Company in June, 1976. The first MHF treatment was performed on October 22, 1976. A supplemental agreement, effective October 1, 1977, provided for a second MHF treatment which was performed on November 30, 1977.

Gas flow continued to be restricted due to persistant water production. The present production rate is 200 MCFD plus water, with clean up continuing.

NEVADA TEST SITE
NYE COUNTY, NEVADA
MINEBACK TESTING

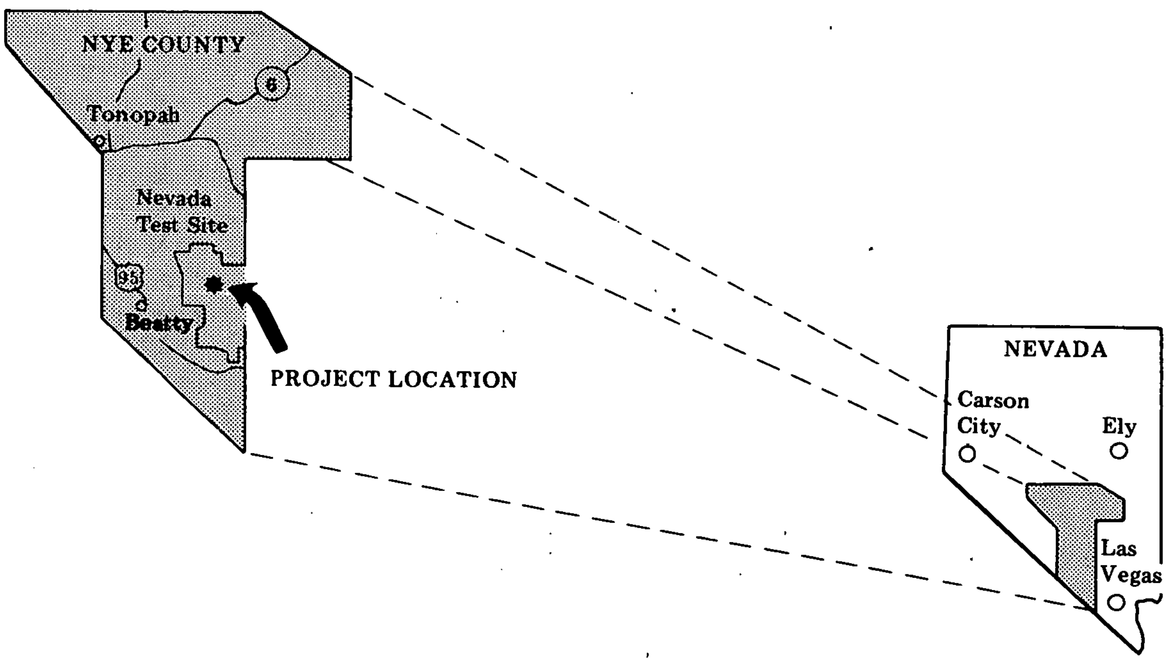
Sandia Laboratories
Albuquerque, New Mexico

Status: Active

Principal Investigator: D. A. Northrop

OBJECTIVE

To develop an understanding of the fracturing process for stimulation and thereby improve the production of natural gas from low-permeability reservoirs. This will be accomplished by conducting controlled fracture experiments which are accessible by mineback for direct observation and evaluation.



5.9 SANDIA LABORATORIES - MINEBACK

5.9.1 Summary of Past Activities

There was no work on the Hole No. 6 experiment during March. One preliminary hydraulic fracture test (CFE NO. 1) was conducted in the Interface Test Series to determine if the proposed pumping rate was sufficient to propagate fractures across an interface, verify the Hole No. 6 results, and determine the in situ stresses in the region. Tiltmeters were fielded to monitor the CFE No. 1 hydraulic fracture. Material property measurements were taken on tuff cores near the Hole No. 6 experiment.

5.9.2 Current Status

Exploratory coring of the Hole No. 6 experiment was restarted in April. The purpose of the coring program is to delineate the general shape of the fractures in order to determine the the effect of the material property interface on fracture growth. In the EV6-22, which was cored in April, a 5-6 mm, gray grout fracture was located about 95 ft below the invert of the mineback drift as shown in Figure 5-12. The coring program will continue until the general shape and width contours can be drawn.

The Interface Test Series is a set of small hydraulic fracture experiments designed to test the effect of pump rate on the containment of hydraulic fractures at material property interfaces, reconfirm the results of the Hole No. 6 test, and provide in situ stress data in the region near the interface. Six zones of the first, horizontal, experiment hole (CFE-1) were fractured in March with 150 gal of dyed water at 8 gpm. All six zones were mined back in April to examine the behavior of the fractures at the interface. Figure 5-13 shows the interface region and Young's modulus of each zone. Initially, it was thought that the vitric, densely-welded tuff would provide the greatest material property contrast, however, recent tests have shown that the geologic contact between the ashfall and ash-flow tuffs is the most significant material property interface. All of the interfaces are well bonded, and with the exception of vitric/basal, ash-flow interface, all are discrete.

Results of the mineback showed that all six fractures broke through the interfaces without any obvious change in orientation or behavior. Although 150 gal of fluid were pumped into each zone, none of the fractures propagated lower than about 3 ft below the hole. This may be attributed to the stress distribution in this area (lower stress in the ash-flow tuff). In the vitric, densely-welded tuff, fractures propagated along and through many of the abundant natural fractures that were present in this zone.

Mineback results are positive (the fracture propagated across the interface), therefore two more holes will be drilled and four zones in each hole will be fraced at different, lower flow rates in order to test the effect of flow rate on containment. These results, validate the results of the Hole No. 6 formation interface fracture and show that material property differences between the reservoir rock and the bounding layer may not be a significant factor in favor of hydraulic fracture containment.

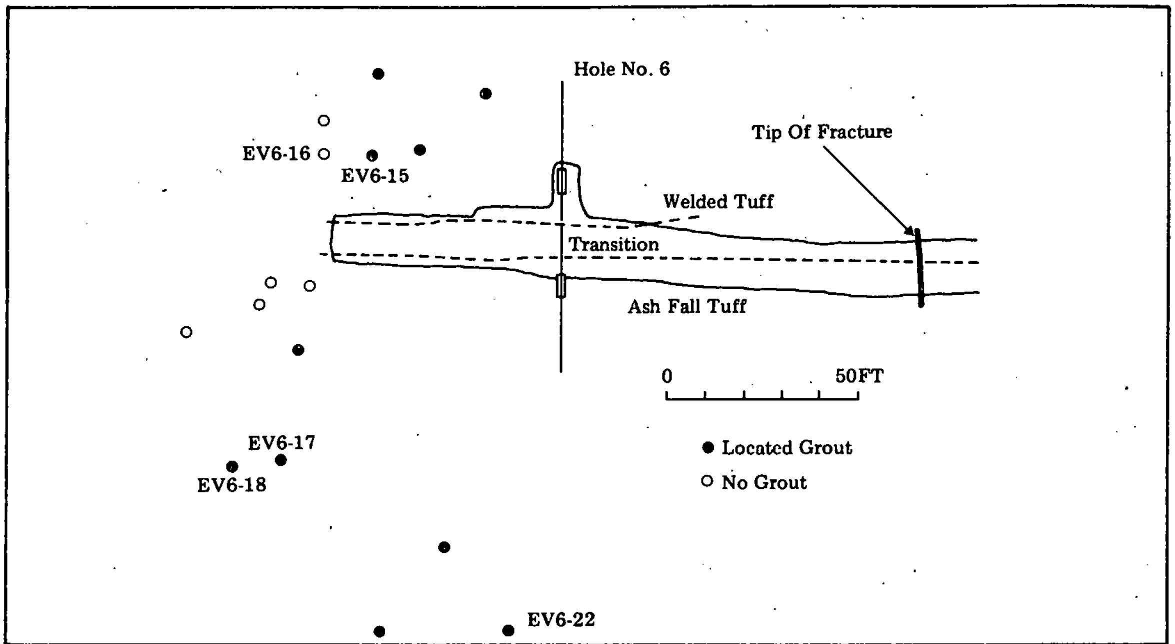


Figure 5-12 Results of Exploratory Coring for the Hole No. 6 Formation Interface Experiment

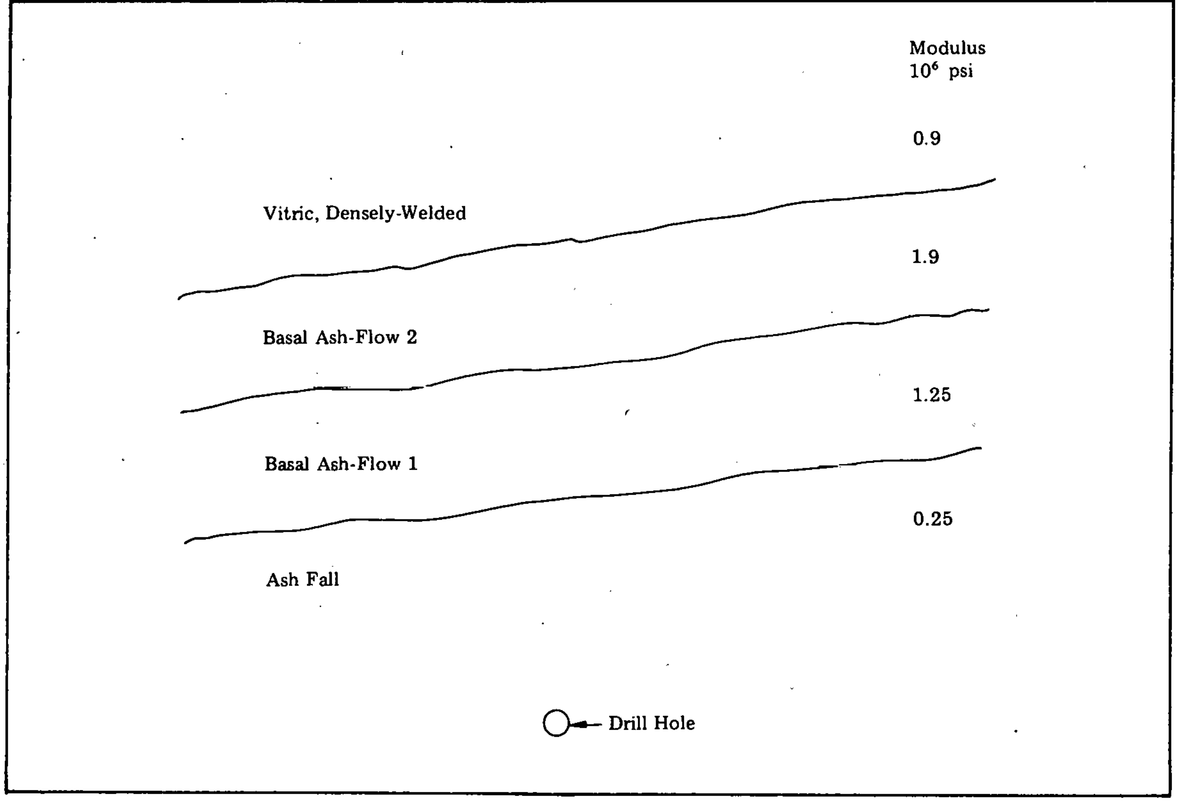


Figure 5-13 Schematic of the Strata and Modulus in the Vicinity of CFE-1 of the Interface Test Series

Preliminary work was done to measure the velocity of an air-driven fracture in the tunnel bed tuff. This work addresses the compressible flow part of the stream hydrofrac problem. The air frac showed breakdown and driving pressures reasonably close to pressures obtained from a nearby hydrofrac experiment. Air pressure and displacement gages detected the arrival of the fracture in a hole spaced a known distance from the source hole.

A presentation of the proposed microcrack model was given in Cincinnati at an ASTM committee meeting which is concerned with fracture testing of brittle nonmetallic materials. Cooperative work was later discussed with Dr. Bill Fourney and his colleagues at the University of Maryland which would involve fracture testing at Sandia with direct microscopic observations of microcracking at the Univeristy of Maryland. A proposed outline of work has been received.

Results from tension and fracture toughness tests (Hole No. 6 experiment) indicates that a change in Young's modulus occurs lower in the transition layer than previously thought. Data scatter from this limited test series indicates that a more thorough test series is needed and plans have been made for these tests.

Work on the fluid mechanics of the fracturing model is progressing slowly due to nonconvergence problems with the system of equations for width, continuity, and momentum. Some preliminary results are presented to show the effect of the transient terms and the resultant calculated pressure distribution. Figure 5-14 shows the calculated pressure distribution for two cases using the same design parameters. The steady state curve is the pressure distribution obtained by solution of the system of equations without the transient terms in the continuity and momentum equations.

This is the type of pressure distribution would be found at large times (long fractures) when there is very little change in width or length with incremental volume pumped. The transient curve shows the pressure distribution for a fracture at very small times (short fractures). For short times the width and length are increasing markedly with incremental volume pumped and transient terms are important. It is expected that this distribution should approach the steady state case as time increases but this has not been verified yet due to the difficulty of coring the system of equations to converge to a solution on a regular basis in a reasonable number of iterations.

5.9.3 Schedule Status

Figure 5-15 is a milestone chart showing progress of Sandia's mineback program.

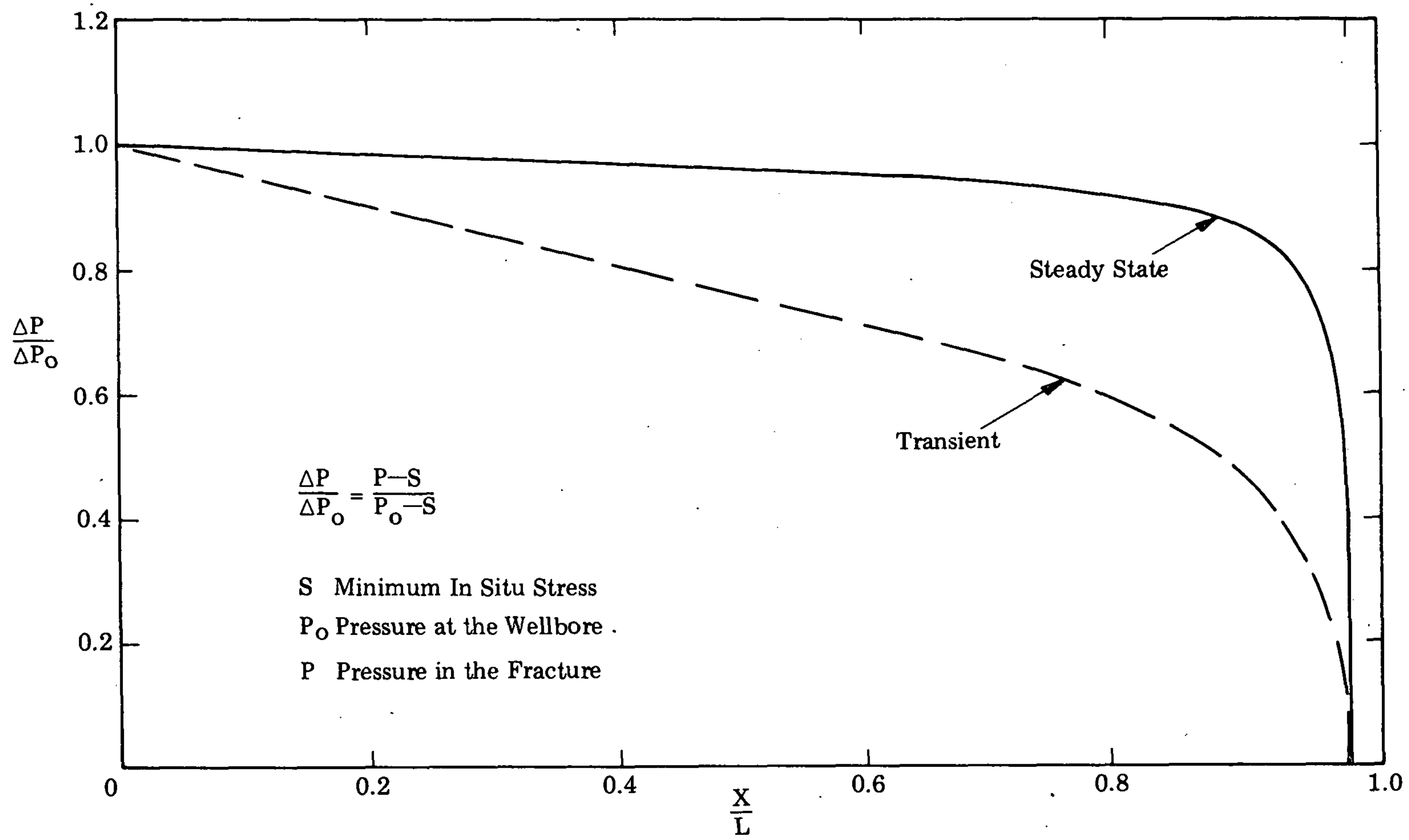
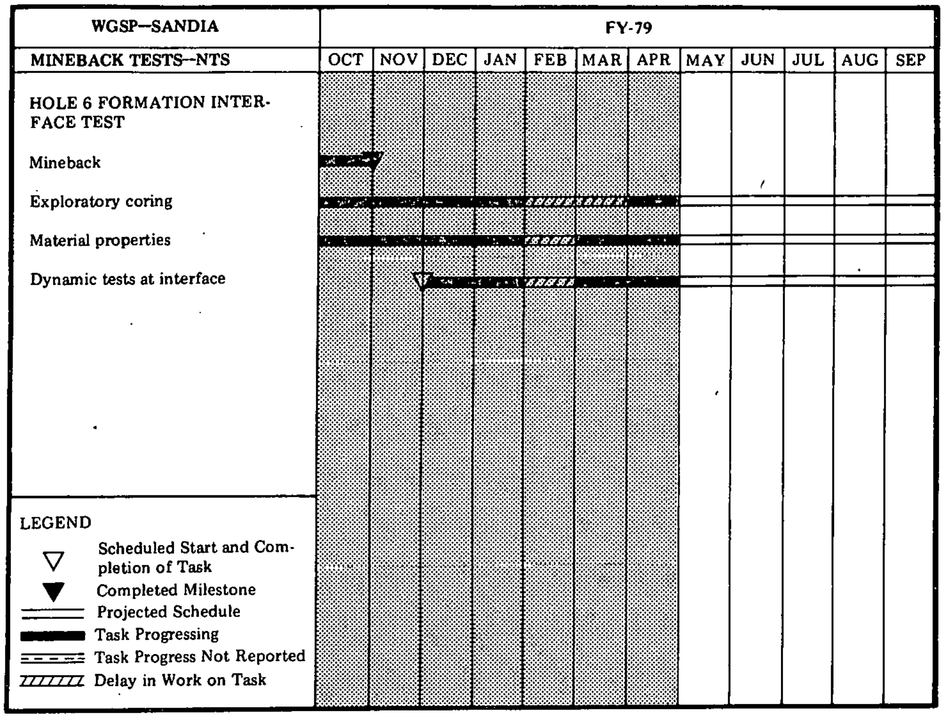


Figure 5-14 Preliminary Results of the Calculated Pressure Distribution with (Dashed line) and Without (Solid line) Inclusion of Transient Terms



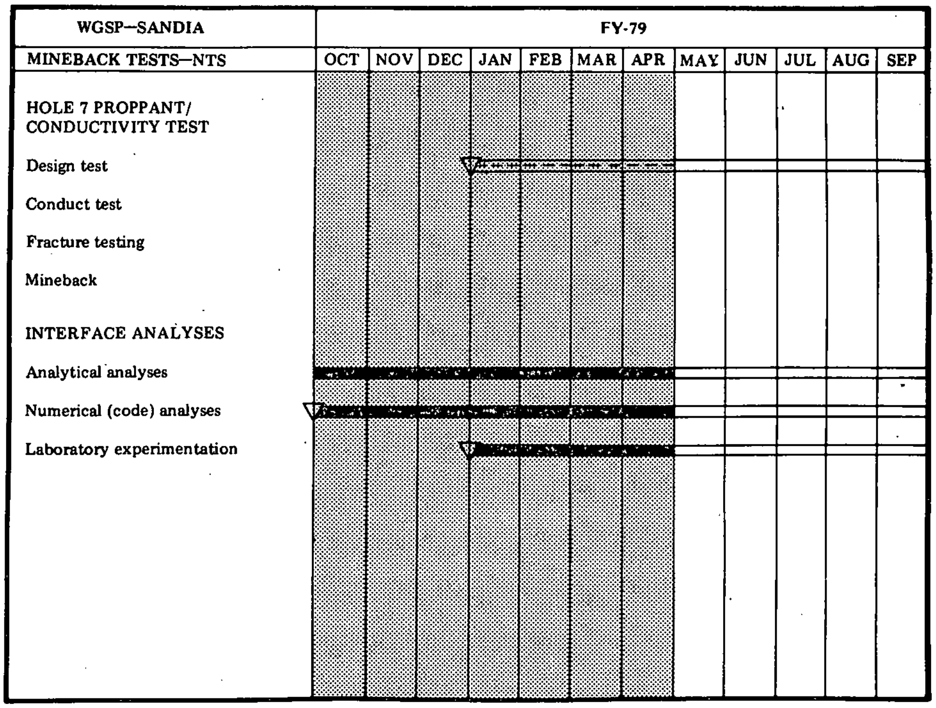


Figure 5-15 Milestone Chart — Sandia Mineback