Western Gas Sands Project Status Report

1 December 1978 - 31 December 1978

Prepared for
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Bartlesville Energy Technology Center
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Las Vegas, Nevada

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MASTER

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1. SUMMARY

This edition of the WGSP Status Report summarizes December, 1978 progress of the 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*.

Work continued on the Technology Implementation Plan (TIP) during the month and C. H. Ware Jr., of Commercialization Insights, was called upon to contribute to and review the text.

CER Corporation personnel assisted in the coring and logging of two wells; a Twin Arrow well, C&K 4-14 on the Douglas Creek Arch, Colorado and a Pacific Transmission Supply Well, Federal No. 24-19 in Sublette County, Wyoming.

The USGS continued work toward resource assessment in the four primary study areas. As part of the work a brief report on the production of natural gas from the Upper Cretaceous Neslen, Farrer and Tuscher Formations of the Mesaverde Group in southeastern Unita Basin was completed.

National Laboratories and Energy Technology Centers continued work in research and development. The improved pressure coring system, being developed by Sandia and Maurer Engineering for BETC, is progressing on schedule. The mailing of the RFP for fabrication and field testing of the coring system is now scheduled for January 12, 1979. Lawrence Livermore Laboratory continued work on the analysis of a constant length quasi-static fracture when approaching and penetrating a well-bonded interface between two materials. Sandia Laboratories collected and analyzed electrical potential data during a MHF treatment on Amoco Oil Company's Gordon Turkey Farm Well D-1 and obtained no positive indication of a fracture. This work was part of Sandia's hydraulic fracture characterization program.

Field tests and demonstrations progressed as scheduled. The final report on CER's MHF-3 well is in the final stages of preparation and will be released for review in February, 1979. Colorado Interstate Gas Company has received a special compressor, along with dehydrators. Approximately one month will be needed to complete site preparation. The Mitchell Energy well, Muse-Duke No. 1, is flowing 6 MMCFD and a total of 10,568 barrels out of 21,223 barrels of frac fluid has been recovered to date. Work on the Sandia Mineback project involved continued evaluation of the Hole No. 6 Formation Interface Fracturing Experiment and analysis of the problem on containment of hydraulic fractures at geologic formation interfaces.

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2. PROJECT MANAGEMENT

2.1 TECHNICAL MONITORING AND EVALUATION

Work on the TIP during the month included text initiation, draft typing, graphics, administrative review and retyping. In addition, at the request of DOE-Headquarters, Charles H. Ware Jr., of Commercialization Insights, Poughkeepsie, New York was called upon to contribute to and review the text.

G. C. Kukal attended the Scientific Software Corporation Industry Course, "Use of Digitized Well Logs" in Denver, Colorado, November 27 to December 1, 1978. The course was designed toward the practical application and interpretation of computer-assisted well log analysis.

J. E. Evered, WGSP Core and Logging Program Manager, H. E. Newman and L. T. Hodges, CER Corporation, assisted in coring operations on the PTS well, Federal No. 24-19 in Sublette County, Wyoming. Details are presented in Sections 3.2 and 3.3 of this report.

D. C. Bleakly, L. T. Hodges and G. C. Kukal, were present for the coring of the Twin Arrow well, C&K 4-14 on the Douglas Creek Arch, Rio Blanco County, Colorado. Coring was done December 4 and 5. A report of this operation appears in Section 3.2.

Contract negotiations are proceeding between CER Corporation and the Gas Research Institute (GRI) for the purpose of implementing that portion of their research and development program directed at the western tight gas sands. CER is in a unique position to coordinate both the DOE and GRI programs.

2.2.1 Documentation and Reports

The fourth *Quarterly Basin Activities Report* is in final review and the *Status Report, October 31, 1978* has been completed and is awaiting DOE approval for printing. Work has begun on the *Status Report 1 January — 31 January, 1979*.

The DOE Test Facility Operations Manual is in review and will be taken to the field for use during operations.

The final report on CER-managed government/industry MHF-3 demonstration well is in the final stages of preparation and is expected to be released for review in February, 1979.

A Financial Supplement Report having limited distribution (20 copies) for the costs by the WGSP participants during December, 1978, will be released on January 15, 1979.

2.2.2 Articles and Publications

High Energy Gas Frac

N. R. Warpinski, R. A. Schmidt, H. C. Walling, P. W. Cooper, and S. J. Finley
SAND 78-2342

Abstract—A High Energy Gas Frac field test has been conducted at DOE's Nevada Test Site, Nevada. The Gas Frac utilizes a controlled propellant deflagration to initiate and extend multiple fractures in a borehole. Three different propellants were tested in a volcanic ash fall tuff medium and resulted in phenomenologically different behavior. Mineback of the experiments provided direct observational evidence to characterize the results. The slowest propellant (burn time = 0.9 sec) had a pressure loading rate (0.09 psi/ μ sec) and a peak pressure (6,250 psi) that were relatively low and resulted in a single fracture that was similar in appearance to a hydraulic fracture. The fast propellant (burn time approximately 1 msec) had a pressure load rate ($> 1,500$ psi/ μ sec) and a peak pressure ($> 20,000$ psi) that were so large that, although multiple fractures were initiated, considerable crushing near the wellbore was observed and only one fracture was extended more than 6 in. from the wellbore. The intermediate propellant (burn time = 9.4 msec) had a pressure loading rate (20 psi/ μ sec) and a peak pressure (13,800 psi) sufficient to initiate and extend 12 separate fractures in random radial directions. Lengths of these fractures varied from 6 in. to 8 ft for 20 lb of propellant in an 8 in. borehole. This technique provides a method to alleviate wellbore damage for other *in situ* technology applications.

Preliminary Report of Authigenic, Euhedral, Tourmaline Crystals in a Productive Gas Reservoir of the Tiger Ridge Field, North-Central Montana

D. L. Gautier for the Journal of Sedimentary Petrology

Bibliography of the Geology of the Green River Formation, Colorado, Utah, and Wyoming, to 1 March 1977

M. C. Mullens, U. S. Geological Survey, Circ.; No. 754, 1-52 (1977)

Abstract—This bibliography of 895 references was compiled to aid studies on the geology and resources of the Green River Formation. References included are mainly on the areal geology, stratigraphy, paleontology, geochemistry, and mineralogy of the Green River Formation, but some concern development of the oil-shale deposits. Recent studies also concern the effects that an oil-shale industry will have on the environment. The bibliography is arranged in three parts: U.S. Geological Survey reports on the Green River Formation; reports by U.S. Geological authors on geology of the Green River Formation in non-U.S. Geological Survey publications; and selected reports by non-U.S. Geological Survey authors on the geology of the Green River Formation.

2.2.3 Project Data Bank

Cross sections of the Washakie Basin were sent to DOE and CER by USGS and have been added to the project files. Work continued on the WGSP Bibliography.

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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 stratigraphic analysis of the Greater Green River Basin and on petrographic examination of core chips from Superior No. 1 Pac. Crk. well. Investigation of the relationships between temperature, pressure, and organic maturation is also progressing on this well.

A heavy-mineral investigation of samples collected during the 1978 field season in the northern Green River Basin (Hoback Basin) was initiated.

An east-west cross-section through the Green River Basin is being prepared for open-file. A cross-section A-A' (Open-File Report 79-357) through the Green River Basin has been completed.

Work continued on lineament study of the Washakie and Great Divide Basins.

3.1.2 Northern Great Plains Province

A report entitled *Preliminary Report of Authigenic, Euhedral Tourmaline Crystals in a Productive Gas Reservoir of the Tiger Ridge Field, North-Central Montana* by D. L. Gautier has been prepared for the Journal of Sedimentary Petrology.

SEM work was done on representative samples from Bowdoin Field for a SPE paper.

The USGS's input for a paper on the development of shallow gas reserves at Bowdoin Field has been written for the SPE Symposium on tight gas reservoirs.

Data on gas wells and gas shows from the Niobrara Formation in the eastern Dakotas has been collected.

Results of kerogen studies on core samples from the Bowdoin Dome, north-central Montana have been received.

Stratigraphic studies on the Niobrara Formation in the eastern Dakotas are being done.

Petrographic studies were continued on the Eagle Sandstone in the Bearpaw Mountains area.

3.1.3 Uinta - Piceance Basins

The preparation of a manuscript on Mesaverde Group reservoirs at Southman Canyon gas field continued and is to be published in the SPE volume.

The plotting of a rock inventory for Upper Cretaceous, Paleocene, and early Eocene rocks at Price River Canyon was initiated.

Arrangements were made with Shell Oil Company to examine core of Tertiary age reservoirs from the Natural Buttes area.

The running of porosity and permeability analyses on core samples of Tertiary and Cretaceous age sandstone beds from southeast Uinta Basin and from the Rio Blanco area of the Piceance Basin was started.

The analysis of palynomorphs and other microfossil groups from some of the potential reservoir units in the subsurface at Southman Canyon and from the outcrop at Westwater Canyon was completed.

A brief report by Bill Keighin and Tom Fouch (USGS) on the production of natural gas from sandstone in the Upper Cretaceous Neslen, Farrer, and Tuscher Formations of the Mesaverde Group in southeastern Uinta Basin follows:

Examination of the sandstone units of the Upper Cretaceous Neslen, Farrer, and Tuscher Formations of the Mesaverde Group along the eastern Book Cliffs indicates that most of the reservoir units are parts of alluvial channels. Sandstone beds in the Neslen represent relatively small and isolated meandering channels in swampy coastal plain settings. Sandstone beds in the Farrer were deposited by somewhat larger and more numerous meandering streams depositionally upslope from the Neslen setting. The Tuscher Formation represents the most landward facies and was deposited principally by meandering, laterally migrating, large streams with local braided courses.

Core samples of productive reservoir rocks from the Southman Canyon gas field (Natural Buttes Area) have been studied in thin section and with the scanning electron microscope (SEM). These studies indicate that extensive diagenetic modifications of the reservoir rocks have occurred and have strongly influenced reservoir characteristics.

Authigenic overgrowths on detrital quartz are common, but secondary silica is not a significant cementing agent. Feldspars are not abundant and are commonly altered to illitic clay. Carbonate minerals—dolomite, ankerite, calcite,

and minor siderite—account for up to 20 percent of the rock. They are generally interstitial and have replaced some detrital quartz and rock fragments. Chert and other rock fragments account for more than 20 percent of the volume of many sandstones. Some rock fragments are extensively altered by mechanical deformation, dissolution, and clay mineral formation. Dissolution and leaching, primarily of rock fragments, have improved the reservoir storage capacity of the sandstone units by producing a significant amount of inter- and intra-granular secondary porosity. The dissolution and leaching appear to have exerted a greater influence on reservoir characteristics than did mechanical deformation and growth of authigenic minerals. Most porosity in the units is of secondary origin.

3.1.4 Schedule Status

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

3.2 CORE PROGRAM

During December, CER Corporation personnel were active with coring operations in Sublette County, Wyoming (Federal No. 24-19) and in Rio Blanco County, Colorado on the Douglas Creek Arch (C&K 4-14).

Coring of the Twin Arrow well, C&K 4-14 was completed on December 5, December 9, and 10 were spent fishing and by December 13 the fish was cemented. Twin Arrow continued attempts to sidetrack the well until December 27, 1978. A decision was then made to abandon the hole and perhaps drill an extension in the spring. CER personnel then decided to cut back extensively the core lab analysis work, as there would be no logs available for comparison. Core Lab in Casper, Wyoming was subsequently notified to carry out the following work¹:

- Core gamma over the entire interval
- Whole core analysis using Boyle's Law-helium to determine porosity, horizontal permeability and grain density at listed depths in feet.

991 - 992	1,068 - 1,069	1,141 - 1,142
994 - 995	1,075 - 1,076	1,146 - 1,147
1,005 - 1,006	1,081 - 1,082	1,167 - 1,168
1,019 - 1,020	1,086 - 1,087	1,185 - 1,186
1,025 - 1,026	1,091 - 1,092	1,193 - 1,194
1,031 - 1,032	1,098 - 1,099	1,199 - 1,200
1,039 - 1,040	1,105 - 1,106	1,203 - 1,204
1,043 - 1,044	1,119 - 1,120	1,207 - 1,208
1,052 - 1,053	1,124 - 1,125	1,211 - 1,212
1,056 - 1,057	1,130 - 1,131	

¹Note: Due to a change in Twin Arrow plans, C&K 4-14X was spudded during the first week in January, 1979. A full suite of logs was obtained from the offset well on January 11, 12, and 13. A good correlation between the core and the logs was possible, therefore, at the end of January, additional Core Lab analysis was authorized.

Figure 3-1 Milestone Chart-USGS

WGSP-USGS	FY-79											
	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP
B. NORTHERN GREAT PLAINS PROVINCE												
Preliminary mapping of lineaments from enhanced LANDSAT images for key parts of study area												
Prepare paper for SPE Symposium on Bowdoin Dome area, north-central Montana												
Detailed surface and subsurface mapping of Eagle (Shannon) sandstone on north flank of Black Hills, SE Montana and NW South Dakota												
Prepare paper on the origin of shallow gases												
Petrographic and clay mineralogy studies on outcrop sections and core if available												
Description of selected core in the study area when available												
Prepare abstract and talk on shallow gas potential in eastern Dakotas												
Prepare open-file report on Lake Traverse Section, South Dakota-Minnesota												

WGSP-USGS	FY-79											
	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP
B. NORTHERN GREAT PLAINS PROVINCE												
Prepare talk for Potential Gas Committee												
Prepare talk for Rocky Mountain Assoc. Geological												
Analyze gas samples from Suffield Block, Canada for comparison with Northern Great Plains Province												

Figure 3-1 Continued

WGSP-USGS	FY-79											
	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP
C. PICEANCE BASIN												
Prepare and release cross section relating rock types, lithofacies, engineering data for rocks between DeBeque and Rifle, Colorado	▼								▼			
Prepare and release cross section in style above for southernmost Piceance Basin	▼								▼			
Cross section as above from Cathedral Bluffs to Rio Blanco area	▼								▼			
Report results of analysis of core from Rio Blanco area	▼								▼			

WGSP-USGS	FY-79											
	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP
D. UINTA BASIN												
Prepare and release cross section relating rock types, lithofacies, engineering data for rocks from Wasatch Mountains to southcentral Uinta Basin	▼											
Investigate mineralogy and stratigraphy, and rock properties of core from Southman Canyon region of Uinta Basin	▼											
Analyze data from San Arroyo Wash surface exposures of Cretaceous and Tertiary units of the southeast Uinta Basin. Report results as they become available	▼											
Prepare report on "tight gas" reservoirs in Tertiary rocks of southcentral Uinta Basin. To be published in SPE volume	▼								▼			
Prepare report on diagenetic reactions and controls on Upper Cretaceous gas reservoirs at Southman Canyon Field, to be published in SPE volume		▼							▼			
Core analysis—Upper Cretaceous and Lower Tertiary units, southwest Uinta Basin	▼											

Figure 3-1 Continued

Table 3-1 indicates the intervals cored, amount cut and amount recovered.

Table 3-1 Core Intervals—Twin Arrow Well, Rangely, Colorado

Run No.	Core Interval, ft	Amount Cut, ft	Recovered, ft
(Cores of Coal Sections for TRW Contract)			
1	636.0 - 691.8	55.8	20.0
2	691.8 - 748.3	56.5	55.7
3	748.3 - 773.8	25.5	25.5
4	773.8 - 827.7	53.9	48.8
(Sand Cores for WGSP)			
5	982.7 - 997.6	14.9	14.9
6	997.6 - 1,057.6	60.0	60.0
7	1,057.6 - 1,116.6	59.0	54.6
8	1,116.6 - 1,176.6	60.0	51.6
9*	1,182.6 - 1,210.7	28.1	28.1

*Run No. 9, 5 ft correction made in geolograph

J. E. Evered, CER Corporation, was present in Wyoming, December 1, 1978 to help carry out the coring operation on the PTS well, Federal No. 24-19. However, due to uncertain geology and weather, personnel, equipment and hole problems, actual coring did not commence until December 15. At this time about 200 ft of oriented 4 in. Upper Mesaverde core was taken from the well. The core was sent to Core Lab in Casper, Wyoming for analysis. Approximately 20 ft of the core was dipped in seal-peel for shipping to LLL, and BETC labs. Figure 3-2 is a photograph of the core site.

Operators contacted during the month about the possibility of participating in the WGSP core program included Davis Oil, Pacific Transmission Supply, Southland Royalty, and True Oil for sites in Wyoming and Midlands Gas Company and Odessa Natural Gas for sites in Montana. C. H. Atkinson and R. L. Mann met with True Oil personnel in Casper, Wyoming December 12 to explain the WGSP core program and to discuss True's possible participation. Although no agreements were reached with these operators, CER will continue to be aware of any new developments in areas of interest. Other operators that will be contacted for coring operations, include Universal Gas (Calgary) and Trio Petro (Denver) for Montana sites, and the South Dakota Geological Survey for South Dakota or Montana core.

Figure 3-2 PTS Well Site Location

Operators contacted in the Piceance and Uinta Basins include Teton Energy, Denver, with three locations in the central part of the Piceance Basin and Pacific Transmission Supply, Casper, with a location in the Uinta Basin.

3.3 LOGGING PROGRAM

Hours before the scheduled December 24 logging operations of the PTS well, Federal No. 24-19, PTS Management decided to drill stem test a zone that caused a gas kick. Unfortunately, hole problems ensued, circulation was lost, gas continued to cut the mud, and the driller was unable to get to bottom. After much delay, PTS elected to shut down operations and release the rig January 8, 1979. The hole will be logged when operations resume in the spring.

Refer to the Log Data Sheet for pertinent information relating to the logging of this well.

A logging program has been recommended by CER Corporation for a True Oil well, Smokey Bluewater Federal 3-18. This well is located in Sweetwater County, Wyoming, Section 18, T15N, R99W, and is a scheduled 10,350 ft Mesaverde test. The following suite of openhole logs were recommended:

Dual Induction Laterolog 8 with Gamma Ray/Spontaneous Potential

Borehole Compensated Sonic/Gamma Ray/Caliper/with Dual 5 in. F curve

Compensated Neutron/Density/Gamma Ray/Caliper

Proximity Microlog/Caliper

Spectral Gamma

Filed Taping, Library Tape, Saraband

3.4 SURVEY OF BASIN ACTIVITIES

Drilling and testing in the four primary study areas are monitored as part of assessing the resource and to identify possible core sites for the WGSP Core Program. Figures 3-3 to 3-7 show recent wells with significance to the WGSP and to the core program. Background information on the core areas is given in the WGSP *Quarterly Basin Activities Report April 1, 1978, NVO/0655-05*.

3.4.1 Greater Green River Basin

Thirteen wildcat locations and 11 development wells were completed in horizons and areas of interest to the WGSP. Both well types were 54 percent successful and added 18,173 MCFD of new gas. Producing horizons were the Almond (3,539 MCFD) and Ericson (1,199 MCFD) of the Mesaverde Group, the Ft. Union (8,297 MCFD), the Lewis (2,420 MCFD), commingled Lance/Lewis (789 MCFD), and the 2nd Frontier (1,929 MCFD).

There were 24 new locations staked during December (9 wildcats and 15 development wells), none of which were spudded by month end. The number of new locations staked decreased 238 percent from November activity (57 new locations). This large change in activity can be partially attributed to severe winter weather and the conclusion of the calendar year 1978.

Locations of interest to the WGSP Core Program include a Madison test by Amoco, staked south of area B1 (Figure 3-3) in Sweetwater County, a 12,000 ft Mesaverde test in Sublette County to be drilled by Davis Oil, also near the B1 core site, and another Davis location, south of core area A to test the Mesaverde at 14,500 ft. Both operators were contacted by CER Corporation personnel; however, no coring agreements were reached by month end.

Log Data Sheet

Elevations: KB _____ GL 8,156 ft

Driller's Borehole Record			Casing Record			
Size Bit	From	To	Size	Weight	From	To

Time Circulation Stopped _____

Log Data Sheet Continued

Pressure Control Equipment

Yes _____ No _____

Rig _____ Signal _____

Taping

Yes XX No _____

Computed Logs Saraband, Dipmeter, Directional Survey

Special Instructions Hold Saraband until further instructions. CER will request specific intervals for crossplotting and will supply input parameters for Saraband Library Tape — send to CER. Field engineer to follow WGSP Log Quality Control Checklist, watch logging speeds, record timing marks, alert to special calibrations. Record tension curves and down-hole temperature each log. Field Print 5 in. HDT.

Service	Log Interval	Repeat Interval	Scales, Logging Constants, etc.
DIL/SP/GR	TD to Surface Csg.	TD to Top Mesa-verde	Lin 0-100 Log 5 in. .2 - 2,000 10 MV 0-150 API (150-300 BU)
DIL/SP/ μ SFL	TD to Top Nugget 1	TD to Top Mesa-verde	Log 2 in. and 5 in. .2 - 2,000 10 MV 2 in. Mudlog from 100 ft above thrust to TD
BHC/GR/CAL	See Eldred Johnson	TD to Top Mesa-verde	Dual 5 in. - one with normal presentation, one with F-curve where $F = .8/\phi^2$ Δt 40 - 140 0-30 percent ϕ (15 CD) $V_{ma} = 19,000$ $V_{fl} = 5,300$
FDC/CNL/GR	See Eldred Johnson	TD to Top Mesa-verde	Dual 5 in. 2.0 - 3.0 1.0 - 2.0 BU 2.68 Pgr 1.00 Pfl 0-30 percent ϕ Sandstone Neutron ϕ 6 - 16 in. caliper 0-150 API
Dipmeter	See Eldred Johnson	TD to 200 ft min.	5 in. and computed logs

Figure 3-3 and Table 3-2 indicate recent wells of interest to the project during December.

Figure 3-3
Greater Green River Basin Showing
Wells of Interest and USGS Designated
Core Areas (refer to Table 3-2)

3.4.2 Northern Great Plains Province

Development wells completed during the month were 68 percent successful (15 producing wells and 7 completed dry and abandoned). There were no wildcat well discoveries and 9 wildcats were completed D&A. The development wells produced 6,281 MCFD of gas from the commingled Bowdoin/Phillips (1,417 MCFD), Phillips (2,959 MCFD), the 1st Frontier (670 MCFD), and the Bow Island (1,235 MCFD).

Activity in North and South Dakota is now monitored with new interest since the USGS expansion of the Northern Great Plains Province to include these two states. Shell Oil has set production casing in a 9,500 ft wildcat located in Renville County, North Dakota. The well is of interest to the WGSP because the operator has planned some tests of the shallow Cretaceous sands, which at present do not produce in this part of the Williston Basin (Table 3-3, Figures 3-4 and 3-5). Energetics Inc. plans to drill two wildcat Greenhorn tests. The first is 34 miles southeast of Pierre, Lyman County, South Dakota and is projected to 1,340 ft. The second Energetics wildcat is projected to 1,020 ft and is located on the Sioux Uplift, Tripp County, in south-central South Dakota.

Table 3-2 Summary of Wells—Greater Green River Basin

OPERATOR	WELL NAME	MAP INDEX NO. ¹	LOCATION Sec/T/R	HORIZON ²	FINAL TD	FRACTURE TREATMENT	STATUS	IPF in MCFD
Davis Oil	1 Triton Unit	1	NESW 33/14N/95W Wildcat Field Sweetwater Cty, WY	Mesaverde (14,500)			Located, of interest to the core program	
Amoco Production	1 Amoco-Texas Oil & Gas	2	SWNE 29/19N/105W Wildcat Field Sweetwater Cty, WY	Madison (18,550)			Drilling at 15,000 ft, of interest to core program	
Amoco Production	1 Buck Draw Unit	3	NESW 29/21N/91W Unnamed Field Sweetwater Cty, WY	Almond (11,815-11,828)	13,600 PB 12,130	Acidized 9,472 gal, 225,302 gal emul, 684,306 lb sand	Almond Discovery, New Field, cored 12,012-12,056	258
Davis Oil	2 Storm Shelter Unit	4	SENE Unnamed Field Sweetwater Cty, WY	2nd Frontier (10,533-10,589)	10,726 PB 10,651	315,500 gal emulsion, 636,000 lb sand	2nd Frontier Discovery, New Field	220
Davis Oil	1 Bright Trail Unit	5	SWNE 21/27N/108W Wildcat Field Sublette Cty, WY	Mesaverde (12,000)			Located, of interest to the core program	

¹ Refer to Figure 3-3

² Horizon - projected depth or producing interval

Montana had only one new location of interest to the WGSP. Universal Gas staked a location close to core area D, projected to 2,000 ft to test the Greenhorn.

The decrease in the Province scheduled drilling activity is normal for this time of year. According to the *Montana Oil and Gas Journal*, "drilling pace in Montana and the Dakotas customarily drops 30 percent below the established level during the preceding years fourth quarter."

Figure 3-4

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

Figure 3-5

*Detail of USGS Designated Core
Areas (refer to Table 3-3)*

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

OPERATOR	WELL NAME	MAP INDEX NO. ¹	LOCATION Sec/T/R	HORIZON ²	FINAL TD	FRACTURE TREATMENT	STATUS	IPF in MCFD
Trio Petro	1 Nylander	1	NWSE 1/31N/27E Wildcat Field Phillips Cty, MT	Phillips	2,197		Set pipe, located within core area D	
Trio Petro	1 Loomis	1	SWNE 23/32N/27E Wildcat Field Phillips Cty, MT	Muddy	2,949		Set pipe, located close to core area D	
Universal Gas	26-36-26 Bill Mayer	2	NWSE 26/36N/26E Wildcat Field Blaine Cty, MT	Greenhorn (2,600)			Drilling, located north of core area D	
Energetics Inc.	42-9 State	3	SENE 9/101N/75W Wildcat Field Tripp Cty, SD	Greenhorn (1,020)			Located	
Energetics Inc.	10-29 Williams	4	CNW 29/105N/75W Wildcat Field Lyman Cty, SD	Greenhorn (1,340)			Located	
Shell Oil	21-2 Osterberg	5	NENW 2/161N/85W Wildcat Field Renville Cty, ND	Madison (9,500)			Set production casing	

¹ Refer to Figure Figures 3-4 and 3-5

² Horizon - projected depth or producing interval

3.4.3 Piceance Basin

Development wells were 92 percent successful (12 producers of 13 completed) and one wildcat well was completed D&A. Producing horizons were the Wasatch (6,730 MCFD), commingled Rollins/Cozzette/Corcoran (1,454 MCFD), and the Mancos B (1,844 MCFD) for a total of 10,028 MCFD of gas.

Eight new development wells and four wildcats were staked. Development tests were located in the Foundation Creek Field in southwestern Rio Blanco County and in the White River Field, which is close to core area A (Figure 3-6 and Table 3-4). Wildcat locations were in the Twin Buttes Field, Garfield County, which is close to core area C and in the Banta Ridge area, Rio Blanco County, north of the Douglas Creek Arch.

Figure 3-6

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

3.4.4 Uinta Basin

Nine development and one wildcat well were completed during the month, but the initial production figures were not available. Two additional development wells were completed and produced 1,334 MCFD of gas from the Green River Formation. A wildcat well, completed by Pacific Transmission Supply produced from the Mesaverde and is a deeper pool discovery. The well, a north offset to an unnamed Carbon County, Wasatch (Tertiary) discovery, is of interest to the WGSP Core Program due to its closeness to core area A and D.

Eleven new locations were reported during December, four wildcats and seven development wells. W. A. Moncreif staked two Wasatch tests in Duchesne County in core area A. Belco Petroleum and CIG Exploration are active in the Natural Buttes Field, Uintah County.

Wells of interest to the project are listed in Table 3-5 and located on Figure 3-7.

Table 3-4 Summary of Wells—Piceance Basin

OPERATOR	WELL NAME	MAP INDEX NO. ¹	LOCATION Sec/T/R	HORIZON ²	FINAL TD	FRACTURE TREATMENT	STATUS	IPF in MCFD
American Resources Management	19-1-S Govt.	1	SESE 19/2N/97W White River Field Rio Blanco Cty, CO	Wasatch Test			Located, close to core area A	
Taiga Energy	8-23-1S- 103W	2	NESE 23/1S/103W Wildcat Field Rio Blanco Cty, CO	Mancos (3,300)			Located	
Provident Resources	10-25-4- 102 Govt.	3	SWNE 25/4S/107W Foundation Creek Rio Blanco Cty, CO	Mancos (3,475)			Located	
Cozeka Resources	11-8-5-101 Federal	4	SENE 8/5S/101W Twin Buttes Field Garfield Cty, CO	Mancos (5,950)			Located, close to core area C	
Flying Diamond Oil	30-3 Milholland	5	SENE 30/10S/95W Plateau Field Mesa Cty, CO	Rollins (3,959-4,027) Cozzette (4,314-4,322) Corcoran (4,416-4,484)	4,593 PB. 4,504	113,750 gal emulsion, 205,000 lb sand	Commingled production	562

¹ Refer to Figure Figure 3-6

² Horizon - projected depth or producing interval

Figure 3-7

**Uinta Basin Showing
Wells of Interest and
USGS Designated Core
Areas (refer to Table 3-5)**

Table 3-5 Summary of Wells—Uinta Basin

OPERATOR	WELL NAME	MAP INDEX NO. ¹	LOCATION Sec/T/R	HORIZON ²	FINAL TD	FRACTURE TREATMENT	STATUS	IPF in MCFD
W. A. Moncrief	11-1 Koch Tribal	1	NWSE 11/4S/6W (USM) Unnamed Field Duchesne Cty, WY	Wasatch (8,200)			Located, with- in core area A	
Phoenix Resources	22-1 Wolf Hollow	2	SWSW 22/6S/5W (USM) Unnamed Field Duchesne Cty, UT	Green River (3,959-3,966)	5,183	33,700 gal water, 99,000 lb sand, 29,621 gal foam, acid- ized - 1,000 gal	Completed, within core area A	not available
Belco Petroleum	2-15 G R Natural Duck	3	SWSW 15/9S/20E Natural Buttes Field Uintah Cty, UT	Wasatch (5,292)			Located	
Pacific Transmission Supply	21-22 Federal	4	NENW 22/12S/15E Unnamed Field Carbon Cty, UT	Mesaverde (6,818- 6,936)	7,000 PB 6,953	Acidized - 3,500 gal, 74,000 gal emulsion, 130,000 lb sand	Mesaverde deeper pool discovery	178

¹ Refer to Figure 3-7

² Horizon - projected depth or producing interval

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

Larry Russell and Associates, Inc., has been retained to review the Maurer drawings and to determine the state of readiness for fabrication. A report will be prepared to critique the following: a) design concepts, b) design execution, c) material considerations, d) overall state of design readiness for fabrication, and e) potential problems in fabrication, assembly, and certification. The firm also will participate in a design review with Sandia to discuss problem areas and make recommendations for solving these problems.

4.1.1.2 Core Fluid Tests

During the month of December, Brinadd "Sanheal" and IMCO "Polysafe", were subjected to a number of tests. These materials are both hydroxyethyl cellulose polymers (HEC); the Sanheal has lignosulfonate compounds and calcium carbonate bridging materials in addition to the HEC.

A core freezing experiment was performed using 100 lb/BBL of Sanheal in 30 percent CaCl_2 brine. The mud was placed inside a 3 in. inside diameter core barrel and a 2-3/4 in. pipe was inserted. This left a 1/8 in. mud filled annulus around the "core", which is the same clearance that the current pressure core barrel is designed to have. The core barrel was then frozen in dry ice (-190°F) overnight. An unsuccessful attempt was made to push the core out of the core barrel using a hydraulic piston. At this point, the outside of the core barrel was hosed down with water to melt the mud until the core could be removed by hand. The steel "core" was still at -43°F after removal, which indicated a low melting point for the very viscous mud. Further testing revealed that the Sanheal in 30 percent CaCl_2 brine froze at -55°F and was very soft and slick at -53°F. This shows that a core could easily be removed from a core barrel at -50°F or lower, depending upon how fast the outside film of mud could be melted.

This same mixture of Sanheal was tested in the High Pressure/High Temperature Filter Press to study the filtrate loss as a function of temperature. The results using 100 lb/BBL of Sanheal were as follows:

Test	Temperature, °F	Pressures, psig	Time, min	Filtrate Loss per 7.1 in. ² , c.c.
1	75	500/0	10	0.0
		1,000/0	50	2.0
2*	78	100/0	30	0.4
3	150	500/0	5	0.2
			30	2.2
4	250	600/0	5	0.6
			30	2.4
5*	300	600/100	5	2.2
			30	4.6

*Standard API filtrate tests

The Sanheal was quite viscous and a sample is currently being analyzed to obtain pseudo-plastic viscosity data from -50°F to 250°F. Although this fluid appears to meet the requirements of a low invasion coring fluid, further work is needed to optimize the amount of polymer and bridging material required to reduce the dynamic invasion to a minimum.

A similar series of static filtrate tests were run for the coring fluid recommended by IMCO, a 20 lb/BBL Polysafe (hydroxy ethyl cellulose) mixed with 20 lb/BBL Wate® (1 to 60 micron CaCO₃ bridging particles). The mud was again mixed using 30 percent CaCl₂ brine because of its low freezing point and its favorable clay stabilizing and filter loss properties. After Running filtrate tests using only 20 lb/BBL of bridging material, another Polysafe mix was tested. The only difference was the use of 50 lb/BBL Wate® and 50 lb/BBL Safe Seal (0.5 to 200 micron CaCO₃ bridging material) instead of just 20 lb/BBL Wate®. The results were as follows:

Test	Temperature, °F	Pressure, psig	Time, min.	Filtrate Loss per 7.1 in. ² , c.c.
1a	70	500/0	30	2.0
1b	250	600/100	30	faulty O-Ring
1c	250	600/100	5	1.0
			30	5.4
1d	250	600/100	5	faulty O-Ring
2a	65	500/0	30	0.8
2b	250	600/100	5	0.2
			30	1.6

In test 2B, which is representative of anticipated downhole conditions, there was an obvious improvement in filtrate loss control by using more bridging material. Although additional experimental work needs to be done, it appears that particle bridging is a more important mechanism in static filtration control than is high viscosity, since the Sanheal was much thicker than the last Polysafe mixture but had a higher fluid loss.

Current plans are to focus on polymer/bridging material systems which are compatible with the low freezing CaCl_2 brine and then select the best two or three candidates. When the Hassler cell and the core holder/filtration equipment are delivered, these fluids will be thoroughly tested in the three different rock types to optimize their static filtration and viscosity properties by varying the concentrations of polymer and different sized bridging materials.

4.1.1.3 Bit Design in Fabrication

The first bonding of the Stratapax cutters to the pilot bit bodies is scheduled for late January, 1979. Six pilot bodies have been fabricated, inspected, and are being cleaned prior to diffusion bonding of the Stratapax cutters. Laboratory drilling tests using the first two pilot bits are being planned.

Fabrication of the two main bit bodies is scheduled for the five axis milling machines starting on January 11.

4.1.1.4 Request for Proposal

Mailing of the RFP including a full set of drawings, parts list, and operating procedures for the "Improved Pressure Core Barrel" is scheduled for January 12, 1979. A two-week slippage was necessitated by the delay in funding transfer caused by the Christmas holidays.

The following have expressed a desire to examine the RFP:

DiKor
DOWDCO
Maurer Engineering
American Coldset
Rucker Hycalog
TRW-Energy Products Corp.
Longyear
Gulf Research and Development Co.

4.1.2 Interface Conductivity Effects on Electric Logging

During the month, work began on measuring surface area, permeability, porosity, and interface conductivity of GPE's Natural Buttes Unit Well No. 21 core. Uncertainties present in surface area generated during last month prompted a re-evaluation of the surface area equipment and techniques of measurements. Modifications of the interface conductivity apparatus are underway because of valve failure.

A technique using NH_4^+ (from NH_4Ac) exchange has been employed to measure the cation exchange capacity (CEC) of core samples. This procedure is essentially the same as that given by Davidson and Sheeler¹. CEC for the following samples in Table 4-1 have been determined at a pH of 7.0

Table 4-1 CEC Determinations of Mesaverde Formation Samples

Sample	Depth (ft)	CEC (meg/g)
Mobil (Core)	9,946	0.026
Austral-Hayward (Core)	7,530	0.014
Austral-Hayward (Core)	7,553	0.009
Bentonite (Fisher)	—	0.790

Although the CEC of Bentonite is probably somewhat high due to NH_4Ac retension through incomplete washing, it is comparable to that obtained by Worthington² at a pH of approximately 8 using a BaCl_2 technique. It is interesting to note that the CEC sand is 0.008 meg/g^2 , leading one to believe that there is little clay in the above core samples. Error in the above quantities may be as high as + or - .003 meg/g.

The automated CEC technique described in the two reports^{1,2} is waiting on parts for completion. This procedure will give the CEC at a pH of 8.3.

4.1.3 Logging Techniques and Interpretations

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

In December, forty-eight plugs were cut from the Natural Buttes No. 21 cores. The plugs are 1-1/2 in. in diameter and about 3 in. long.

Bulk volume of the cores will be determined by two methods: first, a caliper will be used to measure dimensions; second, a Modified Barnes Method will be used which requires saturation of the plugs with kerosene.

¹ D.T. Davidson and J.B. Sheeler, Symposium on Exchange Phenomena in Soils, ASTM Special Pub. No. 142, (1952) pp. 25-28.

² A.E. Worthington, Geophys. 28 (1973) 140.

Porosity will be calculated by two methods; the first method is an extension of the Modified Barnes Method and a helium porosimeter is used as the second method.

4.1.3.2 Instrumentation for Formation Evaluation and Advanced Logging Techniques—Sandia Laboratories

Electrical impedance logging is a two-pronged effort aimed at understanding the high frequency electrical behavior of low-permeability, clayey rock formations and the influence of borehole parameters (layering, invasion, etc.) on such measurements made in the borehole. Sandia has proposed to make variable frequency impedance measurements on typical low-permeability, clayey formations with the objective of establishing quantitative relationships among petrophysical parameters (e.g., S_w , R_w , ϕ) and the impedance versus frequency behavior of the samples. This effort is planned to start after January 1, 1979.

To model the response of an induction tool in a borehole with variable conditions of horizontal layering and depths of filtrate invasion, Sandia has been developing a finite difference computer code, INDINV, to solve the time-dependent Maxwell's equations. To date, the code has been hampered by proper treatment of boundary conditions at the edges of the model and at the edges of the source.

4.1.4 Reservoir Simulation Studies

4.1.4.1 Parametric Analysis of MHF Test Data; An Engineering Study of Western Gas Sands—Intercomp, Inc.

Heber Cinco-L. and Fernando Samaniego-V. presented a paper at the Fall SPE 1978 meeting (SPE 7490) entitled *Transient Pressure Analysis for Fractured Wells* in which they defined four flow periods during the transient test of a finite conductivity fracture. The first is a linear flow period where fracture alone is effecting the response of the well. During the first flow period the pressure response is a function of $\sqrt{\Delta t}$ (shutin or flow time).

The second flow period is defined as bi-linear flow where the reservoir as well as the fracture are both in linear flow. The pressure response is a function of $\sqrt[4]{\Delta t}$ during the bi-linear flow period. The third period is a linear flow period where the pressure response is due to linear flow from the reservoir matrix and the pressure response is again a function of $\sqrt{\Delta t}$. The fourth flow period is a radial flow period where the pressure response is for the reservoir matrix in radial flow. The pressure response during the radial flow period is a function of the log (Δt).

The slopes of the type curve plot, or log ($\Delta(p)$) versus log (Δt), should be 0.5, followed by 0.25, followed by 0.5, followed by a bend over the curve. In the equation below $m(p)$ is the real gas potential as used by Al-Hussainy, Ramey and Crawford.

$$m(p) = \int_{p_o}^p \frac{p}{\mu z} dp$$

where:

- p = pressure of the system, psi
 p_o = pressure base, psi
 μ = gas viscosity, cp
 z = gas deviation factor, fraction

This transformation is used to partially linearize the gas flow equation.

Depending on the system characteristics, any of the flow periods can be present or absent on any test. If the fracture is not long enough, the third flow period for the matrix in linear flow will not be present. The first linear flow period for the fracture alone may be masked by storage effects, etc. Type curve plots for well F31-13G demonstrate this behavior for the post breakdown pre-MHF cases for the zone 1 and zone 3 build-up data (See Figures 4-1 and 4-2).

The method of Cinco-L. and Samaniego-V. was used to analyze the zone 3 data. The type curve with a plot of the slopes delineated is given on Figure 4-3. The first slope (noted 1) is a 0.5 slope from first linear flow period. The second slope (noted 2) is the bi-linear flow period with a slope of 0.25. The Horner plot given in Figure 4-4 was analyzed using standard gas well techniques giving a kh value of 1.11 md ft or $k = 0.0182$ for a thickness (h) of 61 ft.

The analysis of the fracture parameters is calculated from an equation from Cinco, et al, modified to handle real gas potential. The equation is:

$$h_f \sqrt{k_f w} \sqrt{k} = - \frac{15709 q P_{sc} T}{T_{sc} (\phi \mu C_t)^{1/4} m_{bf}}$$

where:

- k_f = fracture permeability
 w = fracture width, ft
 k = matrix permeability, md
 h_f = fracture height, ft (61 ft)
 q = rate, MCFD (700 MCFD)
 P_{sc} = standard pressure, psia (14.65 psia)
 T = reservoir temperature, °R (675°R)
 T_{sc} = standard temperature, °R (520°R)
 ϕ = reservoir porosity (0.036)
 μ = initial viscosity, cp (0.242 cp)
 C_t = system compressibility, psi^{-1} ($1.74 \times 10^{-4} \text{psi}^{-1}$)
 m_{bf} = slope of bi-linear flow period on a $\sqrt[4]{\Delta t}$ versus $\Delta m(p)$ plot, $\frac{\text{psi}^2}{\text{cp} \sqrt[4]{\text{hr}}}$

Figure 4-1 Type Curve Plot, Mobil F31-13G, Zone 1, Pre-Frac, Post-Breakdown, Build-up

Figure 4-2 Type Curve Plot, Mobil F31-13G, Zone 3 Pre-Frac, Post-Breakdown, Build-up

Figure 4-3 Type Curve Plot, Mobil F31-13G, Zone 3, Pre-Frac, Post-Breakdown, Build-up, (Slope 1 = Linear Flow from Fracture, Slope 2 = Bi-linear Flow)

Figure 4-4 Horner Plot, Mobil F31-13G, Zone 3, Pre-Frac, Post-Breakdown, Build-up

plotting $m(p)$ versus $\sqrt[4]{\Delta t}$ as given on Figure 4-5 and applying the slope to the above equation:

$$k_f w = \frac{0.414}{\sqrt{k}}$$

The fracture half length was found from the dimensionless time to end of the straight line on the $\Delta m(p)$ versus $\sqrt[4]{\Delta t}$ plot given in Figure 4-5. The equation for dimensionless time is given as:

$$t_{Deb} \left[\frac{4.55}{\sqrt{k_{fd}w_{fd}}} - 2.5 \right]^{-4} \quad \text{for } k_{fd}w_{fd} < 1.6$$

$$\text{where } t_{Deb} = \frac{0.0002637 \ k \ t_{eb}}{\phi \ \mu \ c \ x_f^2}$$

$$\text{and } k_{fd}w_{fd} = \frac{k_f \ w}{k \ x_f}$$

t_{eb} = time, end of binary flow (hr)

x_f = fracture half length

The fracture half length was computed as 144 ft.

The data as calculated was input to the simulator and several runs attempted. It was found necessary to increase the matrix permeability as the afterflow is still effecting the solution and the permeability calculated from the Horner plot is lower than the actual matrix permeability. The simulation run which gave the best match was made using the following data. The matrix permeability was adjusted to 0.0215 md. The k_{fw} term was 2.15 md ft and the fracture half length was 150 ft.

The run which gave the best result is compared to the actual data on Figure 4-6. It can be seen that the curves match well at long times but the initial data appears to be in error. If the wellbore storage was increased, the two curves should match, but there was no reason to assume the calculated storage was off that far. The important point is that the bi-linear flow period appears to match.

Figure 4-5 Real Gas Potential versus $\sqrt[4]{\Delta t}$, Mobil F31-13G, Zone 3, Pre-Frac, Post Breakdown, Build-up

Figure 4-6 Type Curve Plot, Mobil F31-13G, Zone 3, Pre-Frac, Post-Breakdown, Build-up, Comparison of Simulated Results and Actual Data

Zone 1 post-breakdown, pre-MHF build-up data is given on Figure 4-1. The well was analyzed using the Cinco method. Simulated results for zone 1 show that the well is more productive than actually observed. A number of trial runs were made but none were satisfactory. The initial storage period, on the observed data, shows a slope of about 1.5 on the type curve plot. All simulation runs had a slope of about 1 during the initial storage period. In an attempt to understand the phenomena, a table of afterflow was constructed from the observed data assuming a wellbore volume. The calculated rate required to obtain the observed pressure-time history in the wellbore is calculated by material balance. The wellbore volume of 234 cu ft was calculated for 2-3/8 in. tubing and 10,800 ft length.

The calculated afterflow rates are given in Table 4-2. The tubing volume gives a calculated afterflow rate between 0 and 0.25 hrs of 335 MCFD which is similar to the flow rate prior to shut-in of 300 MCFD. The assumed wellbore volume is probably too small. The tubing is not packed off according to Mobil and the assumed volume is significantly smaller than casing and tubing volumes. The post shut-in flow rate is close enough to the flow rate prior to shut-in, so it appears that the volume is about correct. The important point is that the rate after shut-in is fairly constant to about 1.5 hrs.

Normal afterflow behavior for a well is to start off at the pre shut-in rate and drop significantly as a function of time. Since the observed rate stays constant for a significant period of time following shut-in, it appears that some non-standard phenomena is effecting the buildup behavior.

Critical flow through the perforations would account for a constant flow rate until the wellbore pressure increased above the critical pressure level. Mobil noted that one or two perforations were contributing to flow prior to breakdown. The after-breakdown noise/temperature logs showed that most of the interval was contributing to flow but that ball-off was not achieved during the breakdown operations and it was reported that all of the interval may not have been open to flow. It may be that all the perforations were flowing but that one or two perforations were in critical flow in the most productive zone or zones.

If the well was in critical flow, the rate would stay constant until the wellbore pressure increased above the critical pressure in the perforations. The well has been analyzed as if the original flow rate was constant up to 1.5 hrs after shut-in and the reservoir flow would control the pressure behavior after that time. Simulation runs to date have not matched observed behavior. The assumption that reservoir flow would control the pressure response after the critical flow period is suspect. There is a pressure drop for normal orifice flow between the reservoir and the wellbore after the critical flow period is over.

4.1.4.2 Project Status

Zone 1 and 3 of the Mobil F31-13G well appear to have finite conductivity fractures prior to MHF treatments. The post treatment cases are being analyzed with this in mind.

It appears that the breakdown treatment for the wells prior to MHF will open fractures of significant transmissibility or there are nature fractures. The zone 1 test appears to have a down hole critical flow period associated with it. Zone 1 would produce at a much higher rate prior to MHF if it were not for the critical flow period.

**Table 4-2 Calculated Afterflow for Mobil Well F31-13G Buildup, Zone 1, Post Breakdown,
Pre MHF Assuming Wellbore Volume is 234 Cubic Feet**

Δt hr	p psia	z	V _{sc} SCF	q MCFD
0.00	180	0.989	2,489	
0.25	424	0.968	5,993	386.00
0.50	691	0.948	9,974	382.00
0.75	947	0.932	13,989	377.00
1.00	1,186	0.921	17,616	357.00
1.25	1,396	0.914	20,902	315.00
1.50	1,585	0.909	23,871	285.00
1.75	1,758	0.905	26,578	260.00
2.00	1,910	0.903	28,942	226.00
2.50	2,162	0.901	32,828	186.00
3.00	2,347	0.902	35,613	134.00
4.00	2,598	0.905	39,277	88.00
5.00	2,738	0.908	41,279	48.00
6.00	2,830	0.910	42,565	30.80
7.00	2,910	0.912	43,678	26.70
8.00	2,982	0.913	44,677	24.00
9.00	3,023	0.914	45,237	13.40
10.00	3,068	0.916	45,828	14.20
11.00	3,100	0.917	46,246	10.00
12.00	3,145	0.919	46,833	14.90
14.00	3,207	0.921	47,639	9.67
16.00	3,273	0.924	48,429	10.20
18.00	3,311	0.925	48,981	5.87
20.00	3,356	0.927	49,543	6.74
22.00	3,396	0.929	50,040	5.96
24.00	3,434	0.930	50,509	5.63
28.00	3,502	0.933	51,547	6.23
32.00	3,563	0.936	52,094	3.28
36.00	3,617	0.938	52,750	3.94
38.00	3,642	0.940	53,044	3.53
40.00	3,667	0.941	53,337	3.52
44.00	3,717	0.943	53,921	3.50
48.00	3,750	0.945	54,305	2.30
52.00	3,793	0.947	54,803	2.99
62.00	3,881	0.951	55,815	2.43
74.00	3,974	0.957	56,838	2.05
86.00	4,053	0.961	57,682	1.69
92.25	4,090	0.964	58,074	1.51
109.50	4,177	0.969	58,990	1.27
115.75	4,207	0.971	59,304	1.21
142.50	4,308	0.977	60,331	0.92
163.75	4,372	0.981	60,974	0.73
182.25	4,418	0.984	61,433	0.60

4.1.5 Petrophysics

Four logs selected for study in the Western Gas Sands Project were reviewed. To coordinate with the study being made in Denver, the Mobil well was chosen for study. A series of crossplots spanning an interval of approximately 1,000 ft each examined the relationship of Compensated Neutron Log (CNL) porosity versus formation density. In order to select a clay point to be used in computing porosity from these low-permeability sands using a shaly sand model, gamma ray and caliper values provided additional control to distinguish between actual clay points and points attributable to washed out conditions in the hole. Because the Mobil well did have a limited amount of core information available, a transform relating core porosity to Compensated Neutron Log-Formation Density Logging (CNL/FDC) porosity was generated. In reviewing the two computed porosities Intercomp Inc. decided that the lower values computed by the shaly sand model would be more consistent with the low porosities observed in the other wells in the area.

Water saturations using water resistivity recorded in the Mobil well were then calculated. A verbal report was made to Denver regarding the amount of possible net pay identified in their area of interest, the zones between 10,549 and 10,680 ft. In addition, a possible pay zone at approximately 10,100 ft was identified.

Similar crossplots of the other wells in the Rio Blanco unit of the Piceance Basin and Uinta Basin were generated, and the shaly sand model was used in computing porosity. Tabulation of the results is in the final stage.

4.1.6 Rock-Fluid Interaction

A 2 percent KCl solution in demineralized water was pumped through a 10 in. long, 1-1/2 in. diameter Bandera Core split in half length-wise and packed with 40-60 mesh sand to form a 3/64 in. fracture. The actual overburden pressures imposed on the core system were: 500, 1,000, 2,000, 3,000, 4,000, 5,000, 6,000, 7,000, and 8,000 psig. The initial liquid flowrate (injection rate) was approximately 2.86 ml/min. However, this decreased to 2.5 ml/min as the overburden pressure was increased.

100 ml samples of 2 percent KCl solution, containing fines were collected at the exit end of the mounted core for each of the overburden pressures. The first six samples were collected during the flushing operation on the mounted core in order to establish a constant background particle count for the saturation fluid.

The injection pressure at first was too low to be measured with the pressure gauges used. However, it did increase to about 3.0 psig at the end of the experiment. Thus, a gradual plugging off of the fracture was occurring as the overburden pressure increased, which is attributed to the proppant inbedding into the formation.

At the conclusion of the above injection experiment, two sand samples were scraped off of the faces of the core halves in the center of the fracture and at the exit end (including the sand adhering to the exit screen). Each of these sand samples was then placed in glass beakers and covered with 100 ml of 2 percent KCl solution. The mixtures were run through a 45 micron sieve to remove the un-fractured material preparatory to analyzing them with the particle counter.

The effluent samples of 2 percent KCl solution and sand fines from the above filtering operation and from the injection experiments were then analyzed with the particle counter. The particles were centered about a mode of ~1.77 microns and ranged from 1.65 microns to 5.0 microns for all samples. Only small deviations from the mode and range were noted.

4.1.6.1 Measurements of Formation Characteristics for Western Tight Sands—Institute of Gas Technology

Previously reported initial air permeability values for core from PCU 31-13G must be corrected. Because weights did not change significantly after vacuum heating, the low-permeability values could not be attributed to water in the core. On close investigation, it was found that due to a kink in the high pressure tubing, the end plug was set so that it did not touch the core and the rubber sleeve showed evidence of constriction at that point. It is likely that the sleeve, under pressure, closed off and controlled flow rates. After being in a vacuum oven (<0.1 psia, 90°C) for 10 days, air permeabilities were again tested at a confining pressure of 140 psig and differential pressure of 40 psig. New values are listed in Table 4-3 along with previous values for Canyon Largo No. 256 core. The curves shown in Figure 4-7 show values for permeability reduction with increasing overburden pressure intermediate between CL No. 256-7011 and CL No. 256-6949. A test on hysteresis, shown in Figure 4-8, on core No. 9957 also exhibited behavior similar to No. 7011.

Mercury capillary pressure tests were conducted to test for a correlation between pore size distribution and permeability reduction with increasing overburden pressure. There was a possibility that larger or smaller pores closed off first, leaving the other pores for gas flow. Capillary pressure curves are shown in Table 4-4 and Figures 4-9 and 4-10; a relationship between pore size distribution and permeability reduction as a function of overburden pressure is not apparent.

Sample size or handling can have an effect on the shapes of mercury injection curves. Samples that were crushed to -10+30 mesh exhibited linear plots of log pore entry diameter versus wetting phase saturation (Figure 4-11). However, the distribution displayed a significantly greater portion of large pores than uncrushed samples. The crushing appears to create fractures that seem to fracture the large number of pores of sizes between 1.5 and .27 microns. This could result from the nature of cementing since core No. 7011 had no fractures even after crushing as would also be indicated by Figure 4-11.

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

The relative permeability to gas for core No. 9957 was determined. Saturation was achieved by evaporation. This was performed on the core on which a hysteresis curve was also determined. Tests are now in progress to perform relative permeability to gas determination for an unstressed core to see if there are any differences (i.e., Have only certain pore sizes been primarily affected?). K_{rg} data for stressed No. 9957 is shown in Figure 4-12 and Table 4-5.

Table 4-3 Effect of Overburden Pressure on Initial Gas Permeability

Canyon Largo No. 256 Core No.	Mercury Porosity (%)	K* (md)	Percent Initial Permeability At Overburden Pressures						
			500	1,000	2,000	3,000	4,000	5,000	6,000
6949	7.3	.042	49.4	31.9	18.3	11.2	6.9	4.6	3.6
7001	11.0	.067	38.8	29.9	22.4	17.9	13.3	7.7	3.6
7011H		.035	25.0	19.4	14.1	11.2	7.4	6.9	3.6
7103	6.9	.047	---	26.2	12.7	7.1	6.0	2.6	---
PCU 31-13G									
8498	6.4	.027	43.8	34.4	23.0	13.3	8.9	5.5	
9957	9.5	.110	53.9	47.7	28.7	18.4	12.7	9.7	
9957H		.055	34.1	24.7	16.0	12.2	10.3	9.7	
9998	7.3	.029	48.7	41.0	27.0	17.8	14.2	10.2	

H — Hysteresis test data. Percentages listed are of initial unstressed permeabilities.

*Permeability at 40 psi inlet pressure and 140 psi confining pressure.

Figure 4-7 Effect of Overburden Pressure on Gas Permeability

Figure 4-8 Effect of Hysteresis at Decreasing Overburden Pressure

Table 4-4 Mercury Injection Capillary Pressure Test Data for Uncrushed Samples

Pressure (psig)	Wetting Phase Saturation (%)					
	6949	7011	7103	8498	9957	9998
0	0.0	0.0	0.0	0.0	0.0	0.0
10	0.0	0.6	3.1	0.0	1.5	0.9
20	1.0	1.1	4.8	0.0	2.9	1.8
35	1.4	1.7	5.7	0.5	4.0	2.2
50	3.2	1.9	7.0	1.0	5.1	2.6
75	3.6	3.1	4.9	1.9	5.9	2.6
100	4.5	3.6	9.6	2.4	8.1	3.1
200	6.8	7.2	11.8	4.8	24.9	4.8
400	10.0	22.2	31.0	23.8	47.6	14.0
600	14.0	43.1	41.9	33.3	53.1	28.4
800	19.0	53.6	47.6	44.8	56.4	39.7
1,000	24.4	60.3	51.1	51.4	59.3	45.0
2,000	36.2	73.6	61.1	64.8	68.5	59.0
4,000	57.5	84.4	76.9	77.6	79.1	76.4
6,000	72.9	90.3	84.3	86.2	86.1	85.6
8,000	83.7	94.2	91.3	91.0	91.2	90.4
10,000	90.5	96.7	95.2	93.8	93.8	94.8
15,000	100.0	100.0	100.0	100.0	100.0	100.0

Figure 4-9 Mercury Injection Capillary Pressure Tests

Figure 4-11 Mercury Injection Capillary Pressure Test for Crushed Samples

Figure 4-12 and Table 4-5
Effect of Water Saturation on Gas Permeability for PCU 31-13G, Core No. 9957

S_w	Air K (md)	% $K_{S_w} = 0$
62.6	1.3×10^{-3}	1.2
55.1	8.2×10^{-3}	7.5
43.4	2.8×10^{-2}	25.5
35.4	4.5×10^{-2}	40.9
24.2	5.7×10^{-2}	51.8
0.0	1.1×10^{-1}	100.0

Cores were saturated by being evacuated for one hr and then letting 10 g/lit NaCl solution into the vacuum. They were then left in solution for 24 hrs. Results for porosity determined by water and by mercury are shown in Table 4-6. Either incomplete saturation is taking place or mercury porosities are too high. The mercury porosity values were determined on .5 gm samples from the plug end pieces. This size sample may not be completely representative or may have been slightly fractured in the sizing operation. Intercomp Inc. will test porosity changes with sample size.

Table 4-6 Mercury and Water Porosity Determinations

Core No.	Water Porosity (%)	Mercury Porosity (%)	Water Porosity Mercury Porosity (%)
6949	6.8	7.3	93.2
7011	9.9	11.0	90.0
7103	6.8	6.9	98.6
8498	5.6	6.4	87.5
9957	8.1	9.5	85.3
9998	6.1	7.3	83.6

Initial permeability changes were discovered in core plugs that were subjected to saturation with 15 g/lit NaCl solution. Only one core showed a decrease; however, cores No. 6949, and No. 7103 showed a marked increase in permeability. This change may result from stabilization of clays by the salt solution. It is, however, not known to what degree Thomas' (BETC) previous measurements reflect such changes due to effects of solution chemistry on clays. This makes comparison of K_{rg} curves difficult for these cores. Intercomp Inc. will contact R. Thomas and resolve what his solution was, although it is felt that thorough study of this would give information pertinent primarily to only Canyon Largo No. 256 clays. Intercomp Inc. will concentrate on K_{rg} , K_{rw} data for the PCU 31-13G core next month and on differences between stressed and unstressed core if this would be more appropriate.

Gas relative permeabilities, calculated by the Corey approximation, required values of $S_{wc} = 0.0$, $S_{gc} = 0.35$, $M = \sim 1.1 \rightarrow 2.0$ for a close fit when the Corey approximation takes the form

$$K_{rg} = \left[1 - \frac{S_w - S_{wc}}{1 - S_{gc} - S_{wc}} \right]^m \quad 1 - \left[\frac{S_w - S_{wc}}{1 - S_{wc}} \right]^2$$

where:

- K_{rg} = relative permeability to gas (fraction)
- S_w = fractional water saturation of pores
- S_{wc} = critical, or irreducible water saturation (fraction)
- S_{gc} = critical, or irreducible gas saturation (fraction)
- m = empirical constant

4.1.7 Schedule Status

Figure 4-13 is a milestone chart and depicts the progress during the reporting period of BETC projects.

4.2 LAWRENCE LIVERMORE LABORATORY

4.2.1 Theoretical Modeling and Analysis

The characteristics of a constant length quasi-static fracture approaching and penetrating a well-bonded interface between two materials have been analyzed. The materials are simulated by a difference in the Young's modulus across the interface. These results, presented previously^{1,2}, indicate that the stress intensity factor at each crack tip is affected considerably by the influence of the material on the other side of the interface. It was also noted that when the fracture is wholly in the smaller modulus material and quasi-statically approaching the higher modulus material, the stress intensity factor is seen to decrease significantly as the tip approaches the interface. However, as the leading crack tip penetrates the interface and enters the higher modulus material its stress intensity factor increases to a value larger than that for a homogeneous material with this higher modulus. It is also predicted by these calculations that the stress intensity factor at the following crack tip in the lower modulus material decreases. The stress intensity factor is a measure of the stress level in the tip region of the crack and is normally used to predict the onset of fracture propagation.

A series of calculations to assess the effects of existing fractures in the higher modulus material on the stress intensity factor as the pressurized fracture approaches the interface have begun. The objective is to simulate pressurized fractures in the material with a smaller Young's modulus. Poisson's ratio for both materials was taken to be the same and the larger modulus was taken as twice that of the smaller, $E_2 = 2E_1$. Calculations for the case when the pressurized crack penetrates the interface have not been performed, hence, only the effects of existing cracks in the higher modulus material on the stress intensity factor of the fracture that is approaching the interface are being assessed. The results of two sets of calculations are presented and compared with the results of previous calculations where there were no pre-existing cracks in the medium, designated herein as Case 1. The geometry of the problems with existing cracks is shown on Figure 4-14. Figure 4-14a shows the geometry of the problem (Case II) with one existing crack in the higher modulus material with length a . This pre-existing fracture did not intersect the interface. The length of the pressurized crack is $2a$. Figure 4-14b shows the geometry with pre-existing cracks in the higher modulus material (Case III). Here the pre-existing cracks are symmetrically located on either side of an extended fracture axis with an equal length of a and are spaced $2a$ apart. The length of the pressurized fracture is $2a$.

¹ M. Hanson, et al., LLL Gas Stimulation Program Quarterly Progress Report, April through June 1978, Lawrence Livermore Laboratory, Report UCRL-50036-78-2, (July 1978).

² M. Hanson, et al., LLL Gas Stimulation Program Quarterly Progress Report, July through September, 1978, Lawrence Livermore Laboratory, Report UCRL 50036-78-3 (October 1978).

Figure 4-13 Milestone Chart-BETC

WGSP-BETC		FY-79											
B. FORMATION DAMAGE		OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP
1. ROCK-FRAC FLUID INTERACTION													
Current research internal report													
Physical measurements													
Core samples													
Filtration tests													
Permeabilities													
Preliminary analysis and data correlation													
Annual report													
2. FORMATION DAMAGE FROM FRAC-FLUID COMPONENTS													
Literature review													
Damage evaluation													

WGSP-BETC		FY-79											
B. FORMATION DAMAGE		OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP
3. PROPPANT TRANSPORT & EMBEDMENT													
Evaluation of particle transport in proppant beds													
Evaluation of proppant embedment in tight gas sands													

Figure 4-13 Continued

Figure 4-13 Continued

Figure 4-13 Continued

Figure 4-14 Geometries of the Problems for a Pressurized Fracture near an Interface with a) One Fracture Across the Interface in the higher modulus material—Case II, and b) Two Fractures Across the Interface in the Higher Modulus Material—Case III.

Figure 4-15 Normalized Mode I Stress Intensity Factors as a Function of Scaled Distance from the Interface for no Pre-existing Fractures near the Interface, Case I and with Pre-existing Fractures—Cases II and III

Figure 4-15 shows the stress intensity factor as a function of normalized distance of the fracture from the interface. This plot compares the stress intensity factor for the two cases with pre-existing cracks to Case I (no pre-existing fractures in the medium). The pre-existing fractures were assumed to be perfectly slipping (no frictional stress).

It can be seen from these preliminary calculations that pre-existing fractures can reduce the effects of a materials properties change across an interface on the stress intensity factor. For the preliminary geometries studied, Case III (two pre-existing fractures in the higher modulus material) showed the largest change from the base case, Case I. This brings up an important point in that when the mechanical properties are measured an intact sample of the material is normally chosen. However, in many cases the bulk material has a significant amount of fractures greater than some given size. The results presented above show that the effective bulk elastic moduli are important parameters. This can present a dilemma in that measurement of the effective bulk moduli may be extremely difficult.

4.2.2 Experimental Program

During the past month the construction of the apparatus for friction measurements was completed. The apparatus is shown schematically in Figure 4-16. A two-inch cube of the rock to be studied is held between two 2 in. x 4 in. x 4 in. prismatic blocks of the same material. A normal load in the horizontal direction is applied across the two interfaces by a hydraulically driven ram. The load is determined by measurement of the hydraulic fluid pressure with a pressure transducer. A vertical driving force is applied to the center cube by a vertical hydraulic ram. The force is measured by a load cell. The static coefficient of friction can then be determined from a measurement of driving force necessary to initiate slippage as a function of applied normal load. Both the driving force and the normal load are monitored as a function of time and recorded on chart recorders.

4.2.3 Reservoir Analysis

A second analysis of the data from the Mobil Research and Development Corporation's Piceance Creek Unit Well F31-13G has been completed. The previous analysis¹ used "scum", a fracture-formation resistance factor similar to skin damage, but on the fracture faces, to fit the data. This second model did not use "scum" but rather used a finite conductivity in the fracture. Figure 4-17 shows the good fit achieved by the two models to the data. Where there is a difference in the models the finite conductivity fracture model shows a slightly higher pressure.

¹ Hanson, et al., LLL Gas Stimulation Program Quarterly Progress Report, January through March 1978, Lawrence Livermore Laboratory Report UCRL 50036-78-1 (1978).

Figure 4-17 Fracture Conductivity Calculation Comparisons

The model parameters that were used for the final fit are:

formation pressure	4,675 psi
kh	1.12 md-ft
$\phi L^2 h$	9,200 ft ³
well and fracture storage	3,350 ft ³
C _D	1.34
C _f	1.5 md-ft ²

The fracture conductivity is determined from C_D, the dimensionless fracture conductivity:

$$C_D = \frac{k_f w_f h_f}{k L_f h} = \frac{C_f}{C_{rf}}$$

Here, quantities with an f subscript refer to the fracture. The other quantities are for the formation. For a specific value of C_f a fracture conductivity can be calculated. If it is assumed that:

L =	100 ft
h _f =	100 ft
w _f =	0.05 ft (fracture half width)

then

$$k_f = 30 \text{ md.}$$

Also calculated, were the flow rate, Figure 4-18, and cumulative production, Figure 4-19, for 20 years. This is shown along with the results for a fracture with and without "scum".

A clear fracture, "scum" = 0, shows the highest flow rates and production. This is followed by the "scum" model. The effects of finite conductivity in the fracture are to lower the curves some more. This shows that while both models fit the data the effects on long term production are different.

4.2.4 Rock Mechanics Measurements

During the month of December, 1978, work for the Gas Stimulation Program included the following:

Figure 4-18 Flow Rate for Twenty Years

Figure 4-19 Twenty Year Cumulative Production

- Model study of the hot-gas permeability measurement. The purpose of this study is to determine the suitable sizes of reservoirs for the hot-gas permeability apparatus and the time characteristics that may be dealt with in the measurement.
- A 15-ft core sample was obtained (2 in. diameter) from the Mesaverde Group (Western Tight Gas Sands), Rio Blanco County, Colorado. The specimen preparation for the equation-of-state studies has been started.

4.2.5 Related Activities

LLL personnel attended a Denver, Colorado meeting concerning hydraulic fracturing and explosive stimulation problems in the Devonian shales. LLL was also informed that a paper submitted for inclusion in a spring SPE meeting on the problems associated with tight gas reservoirs has been accepted.

4.2.5 Schedule Status

Figure 4-20 is a milestone chart of LLL activities through December, 1978.

4.3 SANDIA LABORATORIES

4.3.1 EGR Instrumentation and Diagnostic Program

4.3.1.1 Hydraulic Fracture Characterization

The electrical potential data collected during the MHF experiment on the Amoco Oil Company's Gordon Turkey Farm D-1 well have been analyzed. No positive indication of a fracture was obtained.

Two factors prevented this information from being obtained, assuming it was available.

- Transient voltage spikes in excess of 1 volt were present on the leading and trailing edges of the millivolt level data potentials. These transients saturated the instrumentation amplifiers and prevented an accurate measurement of the desired signals. Since these transients were coincident with the leading and trailing edges of the induced current, transient suppression is being incorporated into the current generator.
- The induced current level increased abruptly from 4 amps to 12 amps approximately half-way through the experiment with no increase in applied voltage. The current probe was located in tubing at a depth of 8,000 ft. The change in current required a change in contact resistance between the probe and the surrounding tubing and frac fluid. Turbulence or fluid flow in the tubing could have

Figure 4-20 Milestone Chart—LLL

caused a change in the character of the fluid surrounding the current probe, but this is mere speculation. Changes in excitation signals of this magnitude hinder the comparison of potential signals occurring before and immediately after commencing pumping, with the potentials occurring during the latter stages of the experiment.

The seismic signals received from the breakdown experiments on Gordon Turkey Farms D-1 and UPRR Pan Am 50E1 in the Wattenberg field have been examined. The analog playbacks do not reveal sufficient information to determine fracture direction. These signals will be digitized in an effort to determine fracture orientation.

The layout for the printed circuit boards was completed and the first boards delivered for circuit assembly and checkout. These consist of the high-gain amplifier, the amplifier line driver and mixer, and the power supply circuits. Three of the six hydrophones ordered from Edo Western have been received along with the hardware designs initiated for making a high pressure (10,000 psi) test on the hydrophone units. The EMR subcarrier discriminators for the system have also been received.

Two separate approaches for determining the location of an acoustic source in a formation were worked out and coded for use in the desk-top programmable calculator. One requires that the acoustic velocity in the formation be known and the other does not require any prior knowledge of the velocity.

4.3.1.2 Advanced Borehole Logging Program

December activities concentrated on continued debugging of the computer code INDINV. This program mathematically models the earth's time-dependent response to a borehole induction logging tool in a horizontally and radially (invaded zone) layered earth. At the outer boundaries of the modeled finite difference mesh, the electromagnetic fields are now assumed to obey either outgoing spherical wave or local outgoing plane wave boundary conditions. Such boundary conditions have proven satisfactory to date, indicating the artificial layering approach, described in the *Status Report 1 November 1978—30 November 1978*, is not necessary. In the finite difference formulation used in INDINV, the boundary conditions at the source edges are the basic drivers for the electromagnetic field in the space surrounding the source. The present source is taken as a constant frequency magnetic dipole embedded in the source material. Current and future activity involves formulation of the proper boundary conditions at the edges of such a source.

4.3.2 Schedule Status

Figure 4-21 is a milestone chart showing the status of Sandia's WGSP activities.

Figure 4-21 Milestone Chart—Sandia

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5. FIELD TESTS AND DEMONSTRATIONS

5.1 BACKGROUND

Specific 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 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. A draft copy of the RB-MHF 3 final report is being prepared.

Table 5-1 summarizes both completed and active WGSP MHF treatments. Progress of these ongoing 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	400,000 880,080 815,000 448,000	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	10,548-10,680 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	\$1,975,000
	Industry	1,630,000
	Total	\$3,605,000

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

5.2.1 Summary of Past Activities

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.

5.2.2 Current Status

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 are being prepared for distribution to the project participants for their concurrence.

A draft of a comprehensive final report is being prepared and is expected to be released for review in February, 1979.

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

5.3.1 Scope of Work

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.

5.3.2 Current Status

The special compressor arrived during December and is in storage, along with the dehydrators. Most of the concrete work and pipeline laying has been completed but inclement weather has postponed completion. About one month will be needed to complete the site preparation and BHP buildup. Sixty days will be needed to monitor the BHP after which the first cyclic injection-withdrawal is expected to begin.

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.

5.4 GAS PRODUCING ENTERPRISES, INC.

5.4.1 Summary of Past Activities

The GPE wells, Natural Buttes Units 18, 19, 20, and 22 flowed to sales during November. Natural Buttes Unit 14 and 9 were shut in, Unit 2 was waiting on a pipeline connection and Unit 23 was shut in waiting on pipeline capacity. Natural Buttes No. 21 flowed to the pit after the interval 6,486 - 6,490 ft was perforated.

5.4.2 Current Status

The GPE wells, Natural Buttes Units 14, 18, 20, and 22 flowed to sales during December. Figures 5-1 through 5-6 show production figures for the month. Natural Buttes No. 19 and 21 were shut in and NBU 2 and 23 were also shut in waiting on a pipeline connection. Table 5-2 is a summary of MHF treatments performed to date.

Future plans are to flow Units 18, 19, 14, 20, 22, 2, 9 and 23 to sales and to temporarily abandon Unit No. 21.

Figure 5-1
Flow Rate Performance
of Natural Buttes No. 9
Well

Figure 5-2
Flow Rate Performance
of Natural Buttes No. 14
Well

Figure 5-3
Flow Rate Performance
of Natural Buttes No. 18
Well

Figure 5-4
Flow Rate Performance
of Natural Buttes No. 19
Well

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

Figure 5-6
*Flow Rate Performance
of Natural Buttes No. 22
Well*

Table 5-2 Summary of MHF Treatments

Well	No. of Zones Perf.	Net Ft. of Pay	Net Ft. Per Zone	Average		% Sd	Type of Fluid	Frac Job Size Gal of Gel	Lb of Proppant	Calc. Frac Length ft	Est. 1st Year Avg. Prod. Rate MCFD
				ϕ	SW						
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		
Stage 1 CIGE 2-29-10-21 DOE	10	91	9.1	10.0	40	80.0	MY-T-GEL III	195,000	170,500		
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.

**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	<u>1,074,550</u>
	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.

5.5 MITCHELL ENERGY CORPORATION

5.5.1 Summary of Past Activities

The Muse Duke No. 1 well was fractured on November 15, 1978 with a record treatment—891,000 gal of fluid and 2.8 million lb of sand. Early producing rates indicated that the treatment was successful.

5.5.2 Current Status

The M.E.C.-Muse Duke No. 1 is flowing 6 MMCFD and 80 BBL of frac water per day through a 22/64 in. choke with a flowing tubing pressure of 2,275 psi. A total of 10,568 BBL out of 21,223 BBL of frac fluid has been recovered to date.

A second attempt was made to determine the orientation of the fracture with the Radial Differential Temperature (RDT) tools. Unfortunately, the tool shorted out again because of "O" ring failures. Also, radioactivity in the well bore from the radioactive sand placed in the proppant could not be located. However, during the logging run, a sand bridge was located at 11,331 ft covering the bottom seven perforations and possibly isolating about 18 net ft out of a total of 36 net ft of pay zone.

Plans are to clean out the sand bridge and relog. It is possible, by cleaning out the sand, that production could be increased. The post frac pressure transient tests will also be conducted after cleaning out the sand.

Flow capacity (kh) for the Mitchell Energy Corporation Muse-Duke No. 1 was evaluated by CER personnel from well test data supplied by MEC. Using a multirate buildup, kh was found to be 8.8 md-ft, which is in good agreement with the value of 9.4 md-ft derived by MEC from the buildup and 8.7 md-ft from the two rate test analysis.

Figure 5-7 is a time history of the flow data for Muse-Duke No. 1 from September 29, 1978 through October 10, 1978. It can be seen that the flow rate was substantial and varied considerably during the first couple of days of production. In fact, gas produced during this period accounted for over 70 percent of the total production prior to buildup.

Odeh¹ suggests that buildup data beyond a time corresponding to the last stabilized period divided by four may yield erroneous data. In this case that time would be $\Delta t = 98/4 = 24.5$ hrs. Since significant data in the buildup beyond that time is available, the time correction method may lead to questionable results. Further, well pressure at the end of the shut-in on October 5 had not returned to the initial value recorded on September 29. Consequently, it was considered appropriate to perform a multiple rate buildup rather than utilizing the typical horner plot with a corrected flow time, t_c .

¹ Odeh, A. S. *Flow Test Analysis*, lecture notes for SPE Short Course, Houston, Texas, 1978.

The production history was somewhat arbitrarily divided into seven different flow rates, which were taken as averages over the appropriate time interval. The time intervals and flow rates are tabulated in Table 5-3, diagrammatically displayed in Figure 5-8 and indicated with arrows in Figure 5-7.

It can be shown that the static well pressure p_{ws} for a multiple rate buildup can be written as:

$$P_{ws} = P_i - m \sum_{j=1}^n q_j \log \left(\frac{t_n + \Delta t - t_{j-1}}{t_n + \Delta t - t_j} \right)$$

and thus the slope (m) of a linear plot of P_{ws} VS $\sum_{j=1}^n q_j \log \left(\frac{t_n + \Delta t - t_{j-1}}{t_n + \Delta t - t_j} \right)$ will yield flow capacity (kh).

Table 5-4 lists the buildup time (Δt), the summation term and the pressure (p_{ws}) for gauge No. 15000. Figure 5-9 is a plot of

$$P_{ws} \text{ VS } \sum_{j=1}^n q_j \log \left(\frac{t_n + \Delta t - t_{j-1}}{t_n + \Delta t - t_j} \right)$$

with the slope (m) determined to be -0.30. The resulting flow capacity is then given by,

$$kh = 8.8 \text{ md-ft}$$

This value agrees well with the value that MEC derived, and was reported verbally to the WGSP Project Manager, C. H. Atkinson during the first week in December.

Table 5-3 Buildup Time and Pressure for Gauge No. 1500

j	q_j (MCFD)	t_j (hr)	$\frac{t_n + \Delta t - t_{j-1}}{t_n + \Delta t - t_j}$
1	3,737	10.0	$\frac{266.5 + \Delta t}{255.5 + \Delta t}$
2	3,400	20.0	$\frac{255.5 + \Delta t}{245.5 + \Delta t}$
3	1,926	32.0	$\frac{245.5 + \Delta t}{234.5 + \Delta t}$
4	2,022	55.0	$\frac{234.5 + \Delta t}{211.5 + \Delta t}$
5	0	142.0	$\frac{211.5 + \Delta t}{124.5 + \Delta t}$
6	815	168.0	$\frac{124.5 + \Delta t}{98.5 + \Delta t}$
7	374	266.5	$\frac{98.5 + \Delta t}{\Delta t}$

Figure 5-8 Flow Rate Averages for Muse-Duke No. 1

Table 5-4 Time Intervals and Flow Rates for Muse-Duke No. 1

Δt (hr)	$\sum_{j=1}^n q_j \log \left(\frac{t_n + \Delta t - t_{j-1}}{t_n + \Delta t - t_j} \right)$	P_{ws} (psia)
0.03		—
0.10	1,459	6,208
0.20	1,346	6,216
0.42	1,226	6,224
0.83	1,115	6,232
2.00	972	6,248
3.00		—
4.00	859	6,271
6.00	793	6,279
8.00	746	6,287
10.00	709	6,295
12.00	680	6,311
20.00	596	6,326
32.00	519	6,342
56.00	428	6,574
76.00		—
84.00	363	6,389
92.00	349	6,397
100.00		—
104.00	330	6,405

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.

5.6 MOBIL RESEARCH AND DEVELOPMENT

5.6.1 Summary of Past Activities

Zone 9 was completed during November and a long-term flow test of the zone started. The fracture treatment was executed as planned on November 15, and consisted of 700,000 lb of 20-40 mesh sand carried by 365,000 gal of gel. Temperature and gamma ray logs were obtained on November 16 which indicated that the fracture did not extend much above the perforations at the wellbore and that all of the perforated intervals took fluid.

5.6.2 Current Status

The well flowed to the sales line during December. Zone 9 only was open to flow. Production data are given in the following table:

Date	Gas, MMCFD	Water, BWPD
12/ 7	2.0	85
12/14	2.0	90
12/20	1.8	85
12/31	2.2	87 + 13 BBL Condensate

A plot of both of the 1978 long-term production tests is shown in Figure 5-10. The data are manually smoothed in this plot.

The well was shut-in on December 31 due to expiration of the temporary sales permit. Granting of a new sales permit is expected early in 1979.

5.6.3 Future Plans

Work to remove the two existing casing plugs is scheduled to begin in late-January. This work may be delayed if the severe weather experienced during late-December to early-January continues. Following removal of the plugs the well will be circulated to PBTD and 2-3/8 in. tubing landed at approximately 10,600 ft. All zones will then be put on production. It is assumed that the necessary sales permits will be granted by the time the well clean-out work is completed.

Figure 5-10 1978 Long Term Production Tests

**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.

5.7 RIO BLANCO NATURAL GAS COMPANY

5.7.1 Summary of Past Activities

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.

5.7.2 Current Status

Gas flow continued to be restricted due to persistent cyclical water production. The present production rate is 200 MCFD plus water with the well being flowed for further clean up.

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 mine-back for direct observation and evaluation.

5.8 SANDIA LABORATORIES—MINEBACK

5.8.1 Summary of Past Activities

Efforts last month centered around the investigation of the containment of hydraulic fractures, and in particular the evaluation of the Hole No. 6 Formation Interface test.

5.8.2 Current Status

Evaluation of the Hole No. 6 Formation Interface Fracturing Experiment and analysis of the problem on containment of hydraulic fractures at geologic formation interfaces continued in December. The Hole No. 6 Interface Experiment was a large scale field test and mineback of grout-filled fractures which were initiated above and below a welded tuff/ashfall tuff interface to determine if the order of magnitude difference in the elastic moduli across the interface was sufficient to contain the fractures. During mineback, it was found that the fracture, which had been initiated in the ashfall tuff, broke into the higher modulus welded tuff. The fracture which had been initiated in the welded tuff is more complicated since in many locations it is found alongside the lower fracture and it appears to have filled many natural fractures.

A coring program is underway to determine the extent of the fractures as well as provide information on their behavior. One fracture wing has been explored and it appears that the fractures are approximately penny-shaped and have not been influenced by the presence of the interface. In the hard welded tuff, grout-filled fractures appear to have been considerably affected by the abundant natural fractures found in this zone. Most of the exploratory coreholes intercepted 3 to 5 separate grout-filled strands separated by as much as 12 ft.

A series of interface fracturing experiments will be conducted early in 1979 to examine the effect of the fluid pumping rate on the containment of hydraulic fractures. The experiments will be small scale tests conducted in the G-tunnel adjacent to the Hole No. 6 Interface test, and will utilize the contact between the ashfall tuff and a hard, vitric layer in the ash flow tuff (the lowest transition layer) as the interface. The tests will be conducted by:

- Drilling nearly horizontal holes that parallel the interface about 4 to 8 ft below the contact.
- Fracturing in a number of zones in each hole with 150 gal of dyed water (simple calculations show that a fracture of 20-30 ft radius should be created) with various flow rates.
- Evaluating the results by mineback.

Since the borehole, in which the fractures will have been initiated will be horizontal and entirely within the ashfall tuff, there will be no question as to whether the fractures might have penetrated the interface along the borehole. These tests will also provide considerable information on the *in situ* stresses in this region.

Since the flow rate of the in-tunnel pumping system is rate limited (approximately 10 gal/min. maximum), a series of preliminary tests will be conducted to assure that the maximum flow rate is sufficient to propagate the fracture through the interface. These preliminary tests will also investigate whether the distance of the borehole (in which the fractures are initiated) from the interface has an effect on the direction of fracture propagation and subsequent containment.

Material properties such as Young's modulus, tensile strength, and fracture toughness are needed for the various rock layers near the Hole No. 6 formation interface experiment. Coring operations were completed this month and all the necessary cores were obtained and shipped to Albuquerque where they will be machined, instrumented, and tested. A Rock Properties Lab in Building 855 has been established and the cores will be prepared for testing in this facility. Also, a number of other tuff samples, containing the grouted fracture, and at various distances from it, have been sent to Michael Feves at Dowell for microscopic examination.

Two contracts were written this month to Dr. A. R. Ingraffea and Cornell University, and are awaiting necessary signatures. These contracts are for an experimental investigation of fracture propagation in layered rock-like materials. The fracture specimens will be fabricated using layers of high-strength concrete with varying properties to simulate the situation of a fracture near a formation interface. Results of these tests will be used in conjunction with analytical and numerical calculations and with results of the Hole No. 6 experiment and material property measurements to formulate and test a criterion for containment of hydraulic fractures.

5.8.3 Related Activities

Sandia has released a draft proposal for a "Fracture Conductivity-Proppant Distribution Experiment". The Objectives of the experiment are:

- To measure the conductivity of a sand-propped hydraulic fracture,
- To determine the proppant distribution in a fracture and compare with design,
- To determine the pressure and width at various locations in the fracture during the treatment in order to understand fracture geometry and growth characteristics, and
- To observe proppant embedment.

Experiment Plan

The fracture conductivity test would consist of (1) a small, dyed water, pilot fracture which could be located and instrumented followed by (2) a full scale hydraulic fracture in which various flow tests would be performed. Afterwards, much of the fracture would be mined back to determine the proppant distribution.

There are several areas in the G-tunnel where *in situ* stresses are well documented so that the fracture azimuth is predetermined. A well can be drilled from the top of Rainier Mesa to a depth of 1,400 ft in a location where the *in situ* stresses dictate that a vertical hydraulic fracture would nearly parallel a nearby existing tunnel. A zone in ashfall tuff would be fractured with a sufficient fluid volume to create an initial fracture of approximately 100 ft (design) length. The fluid would be dyed water or water with some other tracer. From the nearby tunnel complex, a series of exploratory holes would be cored to locate and intersect the fracture. (If dyed water is the frac fluid, air coring would be necessary; otherwise some logging technique would be needed to find the fracture.) An instrumentation package containing a pressure transducer and a linear variable differential transformer, LVDT, to measure the width of the fracture would be grouted into each corehole at the location of the fracture and hard-wired back into the tunnel. The direction of the fracture would be determined and several other instrumentation packages would be installed at locations ahead of the initial fracture tip where the subsequent fracture would intersect them.

After these preliminaries have been completed, the main treatment would be conducted. This hydraulic fracture would be designed for approximately 300 ft length with several stages of colored sand. The major limitation of this design is that there is no reservoir pressure so that none of the frac fluid would be recovered. Therefore, the frac fluid must be water or some other fluid that will not leave a residue since this would affect subsequent fracture conductivity measurements. A fluid which could be drained by subsequent coreholes could also be considered. The type of treatment must be designed accordingly.

While the main treatment is being conducted, flow rate, well head pressure and bottom hole pressure would be measured and the data from the instrumentation packages to measure width and pressure emplaced in the various coreholes would be recorded. At shut in, the fracture closure would be monitored and the final propped fracture width obtained.

After the treatment, additional coreholes would be drilled from the tunnel to intersect the fracture. The fracture conductivity can be determined by pressurizing individual coreholes and monitoring the pressure transducers in the instrumentation packages (assuming a radial flow geometry) or by pressurizing the wellbore (assuming a linear flow geometry). Since the conductive length of the fracture is important, it must be insured that a few transducers are near the tip of the fracture. Both water and gas could be used for pressure and flow testing.

Upon completion of the flow testing, the fracture would be mined back to reveal the proppant distribution in the fracture. This would include location of the various colored sands and a close look at proppant embedment.

5.8.4 Schedule Status

Figure 5-11 is a milestone chart of Sandia Mineback progress.

Figure 5-11 Milestone Chart—Sandia (Mineback)