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DEMONSTRATION PROJECT FOR METHANE RECOVERY FROM UNMINEABLE COALBEDS

Final Report

By
Larry D. Allred

August 1982

Work Performed Under Contract No. AC21-79MC10734

For
Morgantown Energy Technology Center
Morgantown, West Virginia

By
Mountain Fuel Supply Company
Salt Lake City, Utah

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DEMONSTRATION PROJECT FOR METHANE RECOVERY FROM UNMINEABLE COALBEDS

FINAL REPORT

Submitted to the United States Department of Energy

Contract No.
DE-AC21-79MC10734

PREPARED BY
LARRY D. ALLRED
MOUNTAIN FUEL SUPPLY COMPANY
SALT LAKE CITY, UTAH

AUGUST 1982

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1.0 INTRODUCTION AND SUMMARY

1.1 BACKGROUND

Mountain Fuel Supply Company is a publicly owned gas utility company with extensive natural gas production, pipeline, and distribution facilities in Utah and Wyoming. Through its subsidiary Mountain Fuel Resources, an active research program is being conducted under which various nonconventional sources of pipeline gas are being investigated. As part of this program, a jointly funded project was initiated in January 1979 with the U.S. Department of Energy to show the potential for commercial recovery of methane from deep, unmineable coalbeds.

The Book Cliffs coal field located in central Utah was selected as the site of the demonstration project. This coal field is known for its high methane emissions. Numerous projects have been initiated or conducted in this coal field over the past several years. These projects have drilled vertical wells as well as horizontal boreholes from within existing mines in the area.

A Bureau of Mines report (1)* noting the locations of high methane concentration coalbeds also mentions the Book Cliffs coal field. Figure 1, which was reproduced from this report, shows the counties in which coalbeds are located that emit in excess of 1 MMcfd of methane into mine ventilation systems. These counties are located in the states of Pennsylvania, West Virginia, Kentucky, Alabama, Illinois, and Ohio in the eastern part of the country, and in Utah and Colorado in the West.

The Utah Geological and Mineral Survey has also been conducting extensive studies relative to the methane production potential from Book Cliffs coals. Since 1975, they have been measuring the methane content of core samples. Data have been accumulated from over 200 core samples. Methane contents ranging up to 350 scf/ton have been reported.

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*Numbers in parentheses indicate references listed in Section 6.0

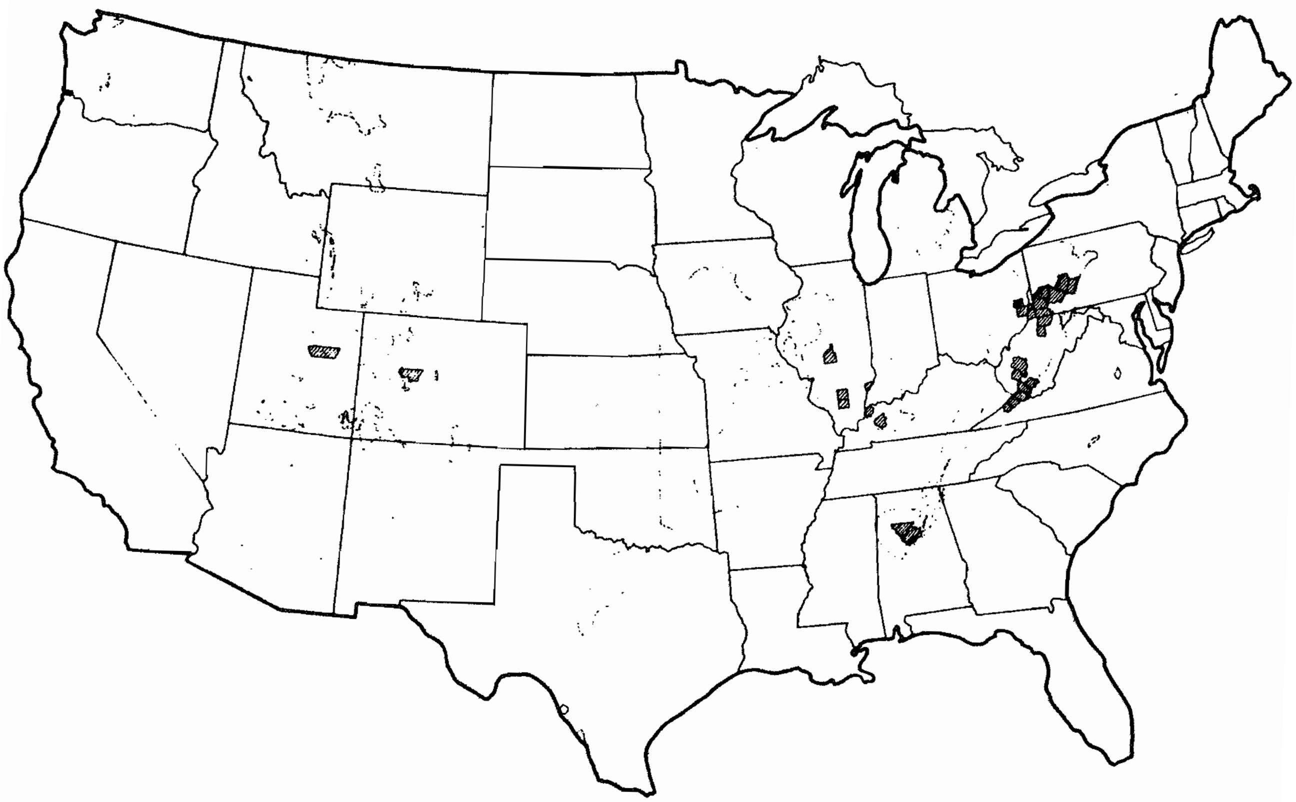


FIGURE 1 - Location Map of Counties with Total Methane Emissions in Excess of 1 MMcfd in 1975

1.2 OBJECTIVE AND SCOPE OF PROJECT

The objective of this project was to demonstrate drilling, fracturing, and completion techniques for recovery of methane from unmineable coalbeds. This work was intended to show the commercial potential for this type of methane recovery. Commercial interest was to be stimulated by making available reliable data, technologies, and economic analysis of methane recovery from coal.

The project was completed in three phases. Phase I covered site selection, system preliminary design, economic analysis, and selection of subcontractors. Phase II included the detailed design work, preparation of an environmental assessment, and detailed planning of the drilling, well completion, and testing operations. Phase III was the operational phase of the project, during which the designed operations were carried out. The entire project was completed over a 44-month period.

The scope of the project included drilling and testing three vertical boreholes into coalbeds that were considered unmineable because of depth and other factors. Each well was completed using hydraulic stimulation techniques similar to those successfully employed by the Bureau of Mines and conventional oil and gas production technologies. Based on drilling and coring information, the most promising coal seams were completed and tested prior to being stimulated. Each well was stimulated, dewatering equipment installed, and long-term production initiated. Long-term gas and water production was monitored over a 2-year period. However, operating problems severely hampered production during much of this period. Even though production data was more limited than planned, a major project accomplishment was the development of solutions to these operating problems.

2.0 WORK COMPLETED DURING PHASE I

The contract between Mountain Fuel Supply Company and the Department of Energy to perform this demonstration project was entered into on January 11, 1979. Prior to this date, preliminary work was done on several tasks which were completed during Phase I.

During Phase I of the project, the necessary analysis, design and development activities to develop a detailed demonstration plan were completed. This plan included the following:

1 - Site selection criteria and final site selection.

2 - Contractual and lease arrangements with site property and leaseowners.

3 - Preliminary overall system design and operation.

4 - Equipment performance specifications including performance verification, where applicable.

5 - Economic analysis of methane collection and end use system operation.

6 - Selection of subcontractors and other participants.

7 - Environmental assessment as applicable to the specific site, including safety considerations.

2.1 SITE SELECTION

Mountain Fuel Supply Company studied potential methane recovery sites near existing natural gas transmission lines. The Book Cliffs coal field in central Utah, see Figure 2, was selected as the site of this demonstration project. This coal field is known for its high methane emissions and Mountain Fuel Supply Company's transmission line No. 40 crosses the field (Figure 3). Kaiser Steel Company, with the support of the U.S. Bureau of Mines, has been conducting an exploratory program directed towards recovering methane from horizontal boreholes drilled from within mine workings located in the Book Cliffs coal field. Gas production per unit length of borehole has exceeded that from typical eastern drainage programs, and the methane has been produced for an extended period with negligible water production from the boreholes (2).

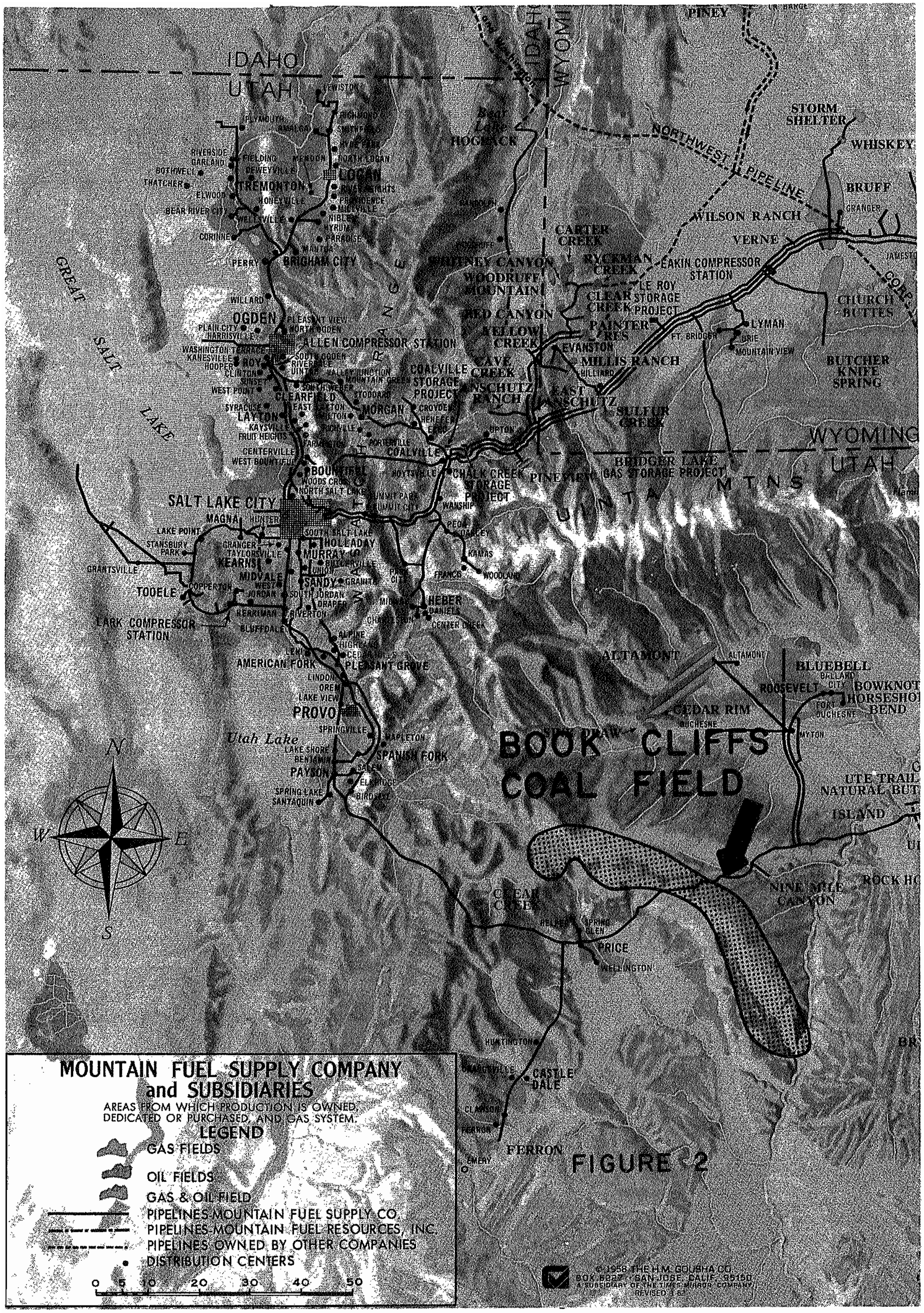
2.1.1 Location and General Description. The Book Cliffs coal field lies in the western 70 miles of an imposing physiographic feature known as the Book Cliffs which is 185 miles in length (see Figure 2). Coal seams are present along its entire length. The western end abuts against the Wasatch Plateau and is about 120 miles southeast of Salt Lake City. The western and northern parts are in Carbon County and the southern part is in Emery County. The north and east boundary, as indicated by H. H. Doelling (3), is placed a little beyond the 3000-foot coverline. However, coal exists beyond this boundary as evidenced by well logs from holes drilled for oil and gas to the north and east.

The principal coal-bearing strata in the Book Cliffs area is the Upper Cretaceous Blackhawk Formation. It is 1900 feet thick and consists of an alternating sequence of sandstone, sandy shale, carbonaceous shale and coal. Regionally, the Blackhawk coal sequence can be characterized as having thick, lenticular coal seams in the west, and grading eastward into thinner but more continuous coal seams. Subsurface data for coals at depths greater than 2000 feet are lacking throughout most of the Book Cliffs coal field. Mapping of the coal has been in an east-west direction and largely restricted to the prominent escarpments of the Book Cliffs.

A significant portion of the Book Cliffs coal field is below 2000 feet of overburden. Figure 3, which has been reproduced from Reference 3, indicates the extent of the deeper coal.

2.1.2 Utah Geological and Mineral Survey Data. The Utah Geological and Mineral Survey (UGMS) has conducted studies of the methane content of Utah coals since October 1975 under contracts with the Bureau of Mines and Department of Energy. Two reports on these studies have been prepared (4,5). Core data have been obtained which have delineated a "zone of gassy coals" in a northwest-southeast trend across the central and northern Book Cliffs coal field.

The first annual report from the UGMS study (4) presents annual data from 19 core samples from the Book Cliffs field. These data are reproduced in Table 1. All but six of these samples were obtained from vertical core holes drilled from the surface. Six samples were obtained from horizontal


IDAHO
UTAH
WYOMING
UTAH
NORTHWEST PIPELINE
STORM SHELTER
BRUFF
WILSON RANCH
VERNE
CARTER CREEK
RYCKMAN CREEK
EAKIN COMPRESSOR STATION
WHITNEY CANYON
WOODRUFF MOUNTAIN
CLEAR CREEK
LE ROY STORAGE PROJECT
RED CANYON
YELLOW CREEK
PAINTER RES
EVANSTON
MILLIS RANCH
CHURCH BUTTES
LYMAN
BUTCHER KNIFE SPRING
CAVE CREEK
ANSCHUTZ RANCH
EAST ANSCHUTZ
SULFUR CREEK
COALVILLE STORAGE PROJECT
BRIDGER LAKE GAS STORAGE PROJECT
CHALK CREEK STORAGE PROJECT
UINTA MTNS
GREAT SALT LAKE
LOGAN
TREMONTON
BRIGHAM CITY
OGDEN
ALLEN COMPRESSOR STATION
ROY
CLEARFIELD
LAYTON
MORGAN
COALVILLE
BOUNTIFUL
SALT LAKE CITY
MAGNA
KEARNS
MIDVALE
SANDY
MURRAY
HOLLADAY
TOOELE
LAKE COMPRESSOR STATION
HEBER
AMERICAN FORK
PLEASANT GROVE
PROVO
Utah Lake
SPANISH FORK
PAYSON
ALTAMONT
BLUEBELL
ROOSEVELT
BOWKNOT
HORSESHOE BEND
CEDAR RIM
BOOK CLIFFS COAL FIELD
NATURAL BUTTES
ISLAND
NINE MILE CANYON
ROCK HO
CLEAR CREEK
PRICE
WELLINGTON
CASTLE DALE
FERRON
N
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W
MOUNTAIN FUEL SUPPLY COMPANY and SUBSIDIARIES
AREAS FROM WHICH PRODUCTION IS OWNED, DEDICATED OR PURCHASED, AND GAS SYSTEM.
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GAS FIELDS
OIL FIELDS
GAS & OIL FIELD
PIPELINES-MOUNTAIN FUEL SUPPLY CO.
PIPELINES-MOUNTAIN FUEL RESOURCES, INC.
PIPELINES OWNED BY OTHER COMPANIES
DISTRIBUTION CENTERS
0 5 10 20 30 40 50
© 1958 THE H.M. GOUSHA CO.

FIGURE 2

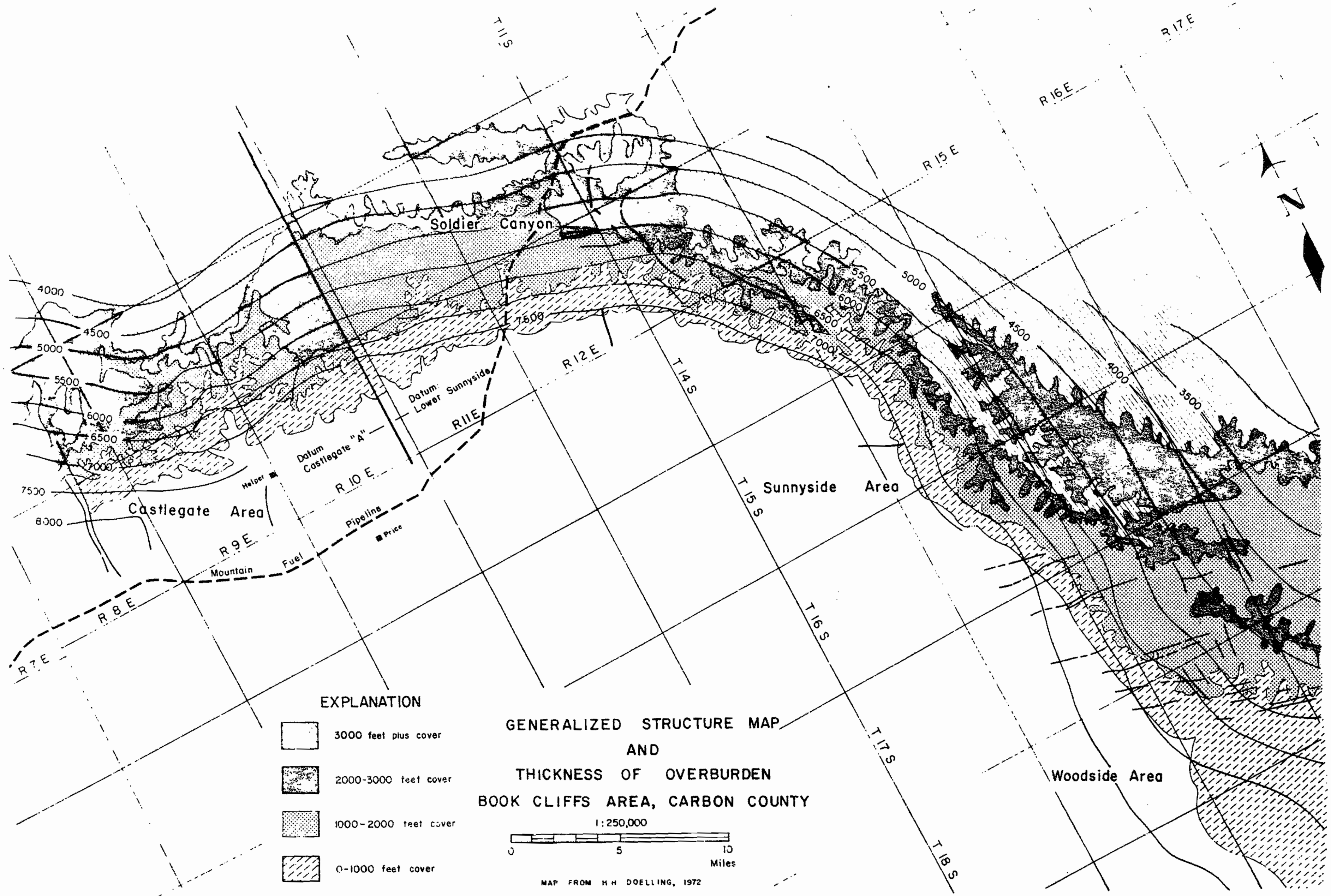
GENERALIZED STRUCTURE MAP
AND
THICKNESS OF OVERBURDEN
BOOK CLIFFS AREA, CARBON COUNTY
1:250,000
0 5 10
Miles
MAP FROM H H DOELLING, 1972
EXPLANATION
3000 feet plus cover
2000-3000 feet cover
1000-2000 feet cover
0-1000 feet cover
Soldier Canyon
Castlegate Area
Sunnyside Area
Woodside Area
Datum Castlegate "A"
Datum Lower Sunnyside
Helper
Price
Mountain Fuel Pipeline
T 11 S
T 14 S
T 15 S
T 16 S
T 17 S
T 18 S
R 7 E
R 8 E
R 9 E
R 10 E
R 11 E
R 12 E
R 15 E
R 16 E
R 17 E
N
4000
4500
5000
5500
6000
6500
7000
7500
8000
3500

Figure 3

core holes in the Kaiser No. 1 Mine. The total gas content of the samples and the gas content per ton of coal were calculated according to the concepts given in the U.S. Bureau of Mines Reports of Investigations 7767 and 8043. The residual gas content of each coal core was determined on the basis that it was a blocky coal rather than a friable coal.

The second annual report from the UGMS study (5) summarizes the results from 11 additional samples from the Book Cliffs coal field. These data are also included in Table 1.

2.1.3 Methane Content of Coalbeds. According to the Bureau of Mines (6), methane is always present in coal. It is formed as a normal part of the coalification process, and as a free gas it occupies the pores, fractures, or voids present in the coal. However, most of the methane present in coal is not in the form of a free gas but instead is adsorbed on the internal surfaces of micropores within the coal (7). The amount of gas that is adsorbed depends on the coal type and the pressure, temperature, and moisture level where the coal is located.

The Bureau of Mines has correlated methane content adsorbed on internal coal surfaces using an equation of the form

$$V = k\,P^{n} - bT \qquad (1)$$

where

V = volume of adsorbed gas, cc/gm MAF coal

P = pressure, atm

T = temperature, °C

and where k, n, and b are empirical constants.

By using parameters recommended by the Bureau of Mines for Book Cliffs Castlegate coal and the assumptions that the pressure is equal to the hydrostatic head, and that the temperature increases with increasing depth at approximately 0.18°C/meter, the recommended equation for Castlegate coal is

$$V = 0.80h^{0.37} - 0.00084h - 0.51 \qquad (2)$$

where depth h is measured in meters.

TABLE 1 - UTAH GEOLOGICAL AND MINERAL SURVEY DATA FROM CORE SAMPLES TAKEN FROM THE BOOK CLIFFS COAL FIELD (Cont'd.) Page 2

Sample	Company	Drill Hole Location	Name of Sample	Thickness of bed (ft.)	Description	Depth Interval (ft.)	Cu. Ft. of Gas Per Ton Coal
11	Braztah	NE Sec. 36, T12S, R9E	Castlegate "C" coal bed	13.0	Black, dirty, resinous	1247.7-1249.0	22.7
12	Braztah	SW Sec. 31, T12S, R10E	Unnamed coal bed 39.7' above "D" bed	3.2	Black, lustrous, resinous	128.6-129.6	37.4
13	Braztah	SW Sec. 31, T12S, R10E	Castlegate "D" coal bed	7.5	Black, lustrous, resinous	159.9 160.7	35.8
14	Braztah	SW Sec. 31, T12S, R10E	Castlegate "D" coal bed	7.5	Black, lustrous, resinous	169.3-170.1	40.3
15	Braztah	SW Sec. 31 T12S, R10E	Kenilworth coal bed	26.0	Black, lustrous, resinous	245.0-246.0	40.6
16	Braztah	SW Sec. 26, T12S, R10E	Kenilworth coal bed	7.4	Black, highly fractured	2448.3-2449.5	355.2
17	Braztah	SW Sec. 31, T12S, R10E	Castlegate "C" coal bed	11.5	Black, lustrous, resinous	299.5-300.5	67.2
18	Braztah	SE Sec. 31 T12S, R9E	Castlegate "A" coal seam	5.4	Black, attrital	2170.0-2172.9	249.0
19	Braztah	NE Sec. 4 T13S, R9E	Castlegate "D" coal seam	6.4	Black, attrital	1429.8-1431.4	52.5
20	Braztah	NE Sec. 4 T13S, R9E	Castlegate "A" coal bed	10.0	Slightly dirty, bony in places	16.44.6-1646.0	0.5
21	Braztah	SE Sec. 32 T12S, R9E	Castlegate "A" coal bed	10.0	Slightly dirty, resinous	1952.1-1953.0	16.0

2.6

TABLE 1

UTAH GEOLOGICAL AND MINERAL SURVEY DATA FROM CORE SAMPLES
TAKEN FROM THE BOOK CLIFFS COAL FIELD

Sample	Company	Drill Hole Location	Name of Sample	Thickness of bed (ft.)	Description	Depth Interval (ft.)	Cu. Ft. of Gas Per Ton Coal
1	PG&E	Sec. 4, T13S, R12E	Sunnyside coal bed	11.8	Black, blocky, lustrous	1797.8-1798.8	146.2
2	PG&E	Sec. 4, T13S, R12E	Rock Canyon coal bed (lower split)	4.55	Black, blocky, lustrous	2352.1-2353.1	173.4
3	PG&E	Sec. 4, T13S, R12E	Rock Canyon coal bed (upper split)	3.85	Black, lustrous, blocky	2339.15 2340.15	86.4
4	PG&E	Sec. 10, T13S, R12E	Gilson coal seam	3.0	Black, lustrous, blocky	2338.6-2339.6	40.0
5	Kaiser	SW Sec. 17, T14S, R14E	Lower Sunnyside Coal	7.0	Black, lustrous, blocky	19.0-21.0	59.2
6	Kaiser	SW Sec. 17, T14S, R14E	Lower Sunnyside Coal	7.0	Black, lustrous, blocky	41.5-43.0	53.4
7	Kaiser	SW Sec. 17, T14S, R14E	Lower Sunnyside Coal	7.0	Black, blocky, lustrous	61.5-64.0	119.6
8	Kaiser	SW Sec. 17, T14S, R14E	Lower Sunnyside Coal	7.0	Black, blocky, lustrous	68.0-70.2	130.9
9	Kaiser	SW Sec. 17, T14S, R14E	Lower Sunnyside Coal	7.0	Black, blocky, lustrous	41.5-44.5	105.0
10	Kaiser	SW Sec. 17, T14S, R14E	Lower Sunnyside Coal	7.0	Black, blocky, lustrous	44.5-47.0	30.7

2.7

TABLE 1 - UTAH GEOLOGICAL AND MINERAL SURVEY DATA FROM CORE SAMPLES TAKEN FROM THE BOOK CLIFFS COAL FIELD (Cont'd.) Page 3

Sample	Company	Drill Hole Location	Name of Sample	Thickness of bed (ft.)	Description	Depth Interval (ft.)	Cu. Ft. of Gas Per Ton Coal
22	Braztah	SE Sec. 32 T12S, R9E	Subseam 2 coal	10.0	Slightly dirty, resinous	2186.1-2187.1	80.0
23	Braztah	SE Sec. 32 T12S, R9E	Subseam 3 coal	2.5	Slightly dirty, resinous	2221.3-2222.3	12.8
24	PG&E	SW Sec. 15 T13S, R12E	Rock Canyon coal bed	7.9	Bright and dull bands	1705.4-1706.4	131.5
25	PG&E	SW Sec. 15 T13S, R12E	Fish Creek coal bed	4.8	Bright and dull bands	1726.7-1727.7	220.5
2.8 26	AEP	SE Sec. 34, T12S, R10E	Unnamed coal	3.9	Bright and dull bands	2079.7-2081.0	305.3
27	AEP	SW Sec. 35, T12S, R10E	Unnamed coal	7.2	Bright and dull bands	2056.0-2057.5	NA
28	AEP	SE Sec. 34, T12S, R10E	Castlegate "A" coal bed	16.9	Bright and dull bands	2558.0-2559.2	272.3

The curved line in Figure 4 indicating gas content in scf/ton versus depth in feet was constructed using this equation. This curve indicates methane concentrations in excess of 250 scf/ton of coal should be expected at depths greater than 2100 feet. It should be noted, however, that lower concentrations would occur if the methane formed during coalification was not confined by low permeability of the surrounding strata.

UGMS data were also plotted in Figure 4 to show their relationship with the Bureau of Mines adsorption curve for the Book Cliffs Castlegate coal. The core sample gas concentrations were plotted versus the depth at which the sample was taken. There are two noteworthy observations to be made from this comparison: (1) the data are qualitatively in agreement with the Bureau of Mines adsorption data; i.e., the gas content increases with increasing depth and reaches levels of 200-400 scf/ton; and (2) there are wide variations even from samples from the same seam.

2.1.4 Kaiser Drainage Program. Since 1977, the Bureau of Mines has been conducting studies in the Kaiser Steel Sunnyside mines which are located toward the southern end of the Book Cliffs coal field. Their conclusions are that methane recovery from the No. 3 mine was not feasible but that methane in the coal in the area of the No. 1 mine could be utilized as a potential source of pipeline gas (2).

Two shallow holes, drilled by the company to depths of 110 feet and 120 feet, had been flowing methane at a combined rate of 55 Mcfd for a year when a decision was made to drill two new holes to greater depths. These holes were drilled to 430 feet and 450 feet, at which point the gas escaping from the stuffing box that was used to form a seal around the drill stem reached dangerous levels and drilling had to be halted. In hole No. 1, very little gas was encountered in the first 150 feet and at this point was flowing 18 Mcfd. The next 30 feet of drilling produced a dramatic change in flow rate, increasing it from 18 Mcfd to 108 Mcfd. The low flow rate from the first 150 feet was probably due to degasification by the shallow holes drilled earlier by the company. The same sequence of events was experienced when the second hole was drilled. The methane flows

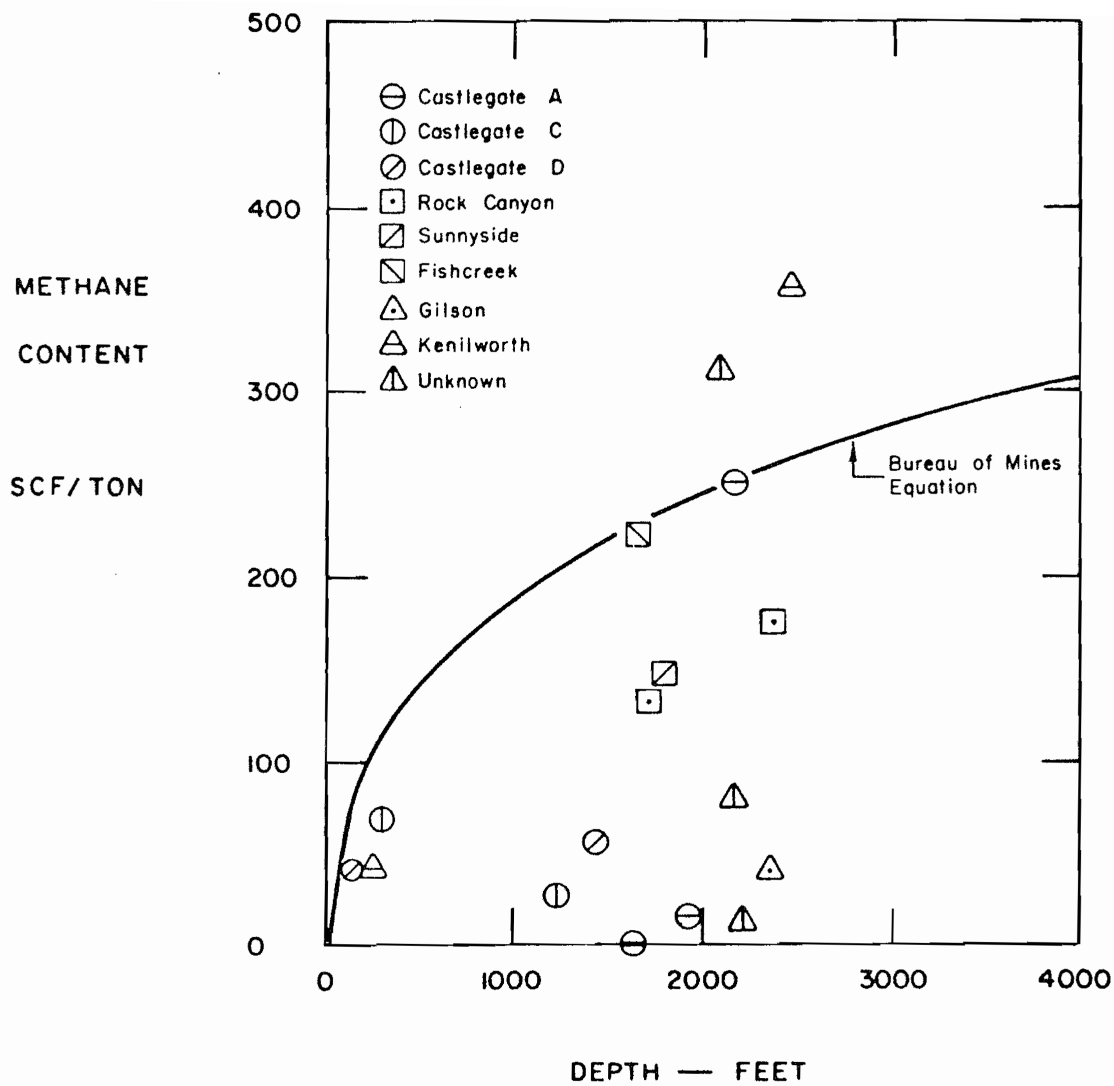

FIGURE 4. Comparison of UGMS data with the Bureau of Mines absorption equation for Castlegate coal.

T

CHEMIC

Company Mountain Fu
Well No.
Field
County
State
Line pressure psig; Sampl
Remarks

Date of Sam

Compone

Oxygen
Nitrogen
Carbon dioxide
Hydrogen sulfid
Methane
Ethane
Propane
Iso-butane
N-butane
Iso-pentane
N-pentane
Hexanes & high
TOTAL:

GPM of pentane

Gross btu/cu. ft
Specific gravity
Specific gravity

Remarks: *

were minimal until a depth of 190 feet was reached, afte
tion increased to 68 Mcfd. Upon reaching a depth of 450
increased to 177 Mcfd and drilling had to be halted becau
Production curves from these horizontal boreholes are pre
(8).

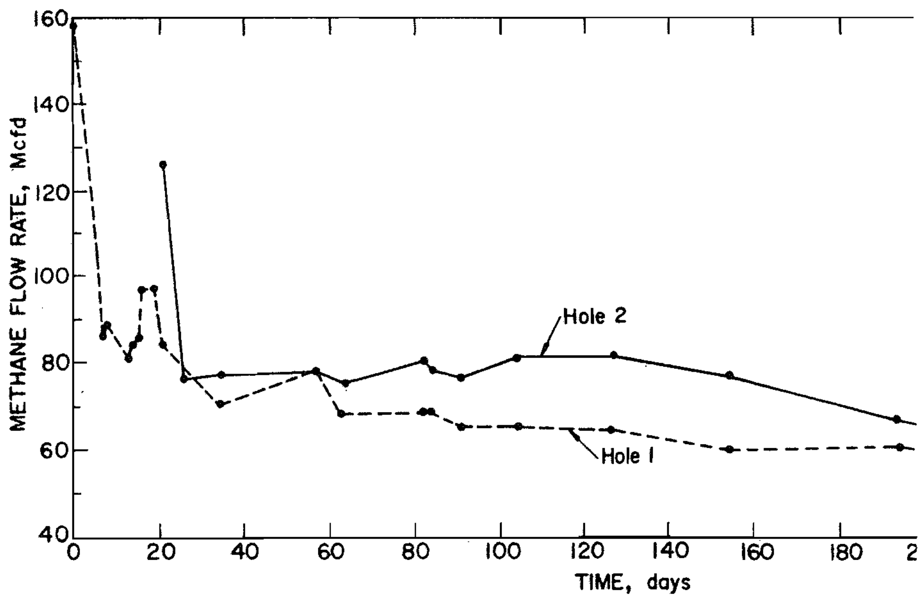

FIGURE 5 - Methane Decline Curves for Holes 1

The summary and conclusions drawn by the Bureau
34-day test period are as follows:

"Initial gas flows from Holes 1 and 2 were 222 a
respectively. The average gas flow from the two hol
the Upper Sunnyside coalbed is about 46 Mcfd/100 ft
hole. In comparison, flow averages 25 Mcfd/100
Pittsburgh, and 8 Mcfd/day/100 ft in the Pocahontas N
Therefore, the Upper Sunnyside coalbed at the No. 1 m
the potential for producing large volumes of methane
proposed boiler plant. Hole depths should be at leas

2.1.5 L

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Fuel Supply's n

Well No. 3

region (SE, Se

west of Wells No. 1 and No. 2. The highest gas content cc the UGMS studies were obtained in this area. Three samples of 275, 305, and 355 scf/ton of coal were taken less than east of the No. 3 well site from coal depths between 2100 to depth of coal from the No. 3 well was projected from 2240 to

The Castlegate well site was selected because of the h coal and because of an interest in obtaining production western portion of the Book Cliffs coal field.

2.2 SYSTEM DESIGN

2.2.1 Site Preparation

Description of Area. The Book Cliffs area surroundir project site is characterized by steep pinon and juniper cc deep eroded canyons. Rock ledges are exposed, forming cliff leading into most of the canyons. Because of the severe tc are few existing access roads in the area. The No. 1 and N chosen for the demonstration project are in the Whitm Whitmore Park is an open bench area with gentle slopes sepa Cliffs from the higher Roan Cliffs. Because of the break this area affords several alternatives to the proposed tent will provide for logical expansion of the project. Futu access roads and gathering lines could be constructed econom reduced environmental impact due to the topography that the a

Access to Sites. The demonstration facilities for No wells are on and adjacent to Mountain Fuel Supply's transmiss in the Whitmore Park area. The access to this location is f US-7, which is a graded dirt road close to the pipeline rig pipeline right of way is utilized for access from well site No. 2.

Access to the Castlegate well location is via Utah State an existing graded dirt road which passes close to the site the site would be the only necessary road construction.

Well Sites. A typical plan for a 0.50 acre drill site is shown in Figure 7. The natural contours at the locations of these sites would permit construction of these pads without excessive earthwork. Topsoil would be stockpiled for use in restoration of areas of non-use after drilling operations for rehabilitation of the site upon abandonment.

A reserve pit would be constructed to contain cuttings, drilling fluids, and produced liquids and prevent them from entering the natural drainage. The reserve pit was to be fenced to prevent entry of livestock or wildlife.

After drilling operations, production equipment, line heater, separator, pump, etc., would be installed on the site without any additional land use. The reserve pit would be emptied and backfilled. Areas of non-use would be restored and reseeded.

It was expected that produced water from the wells would be of such quality that it could be disposed of in an unlined pit or discharged into the drainage. Produced water from the nearby Kaiser Mine, which is thought to be of similar quality, is presently used to irrigate lawns, a golf course, and farmland crops downstream from the mine.

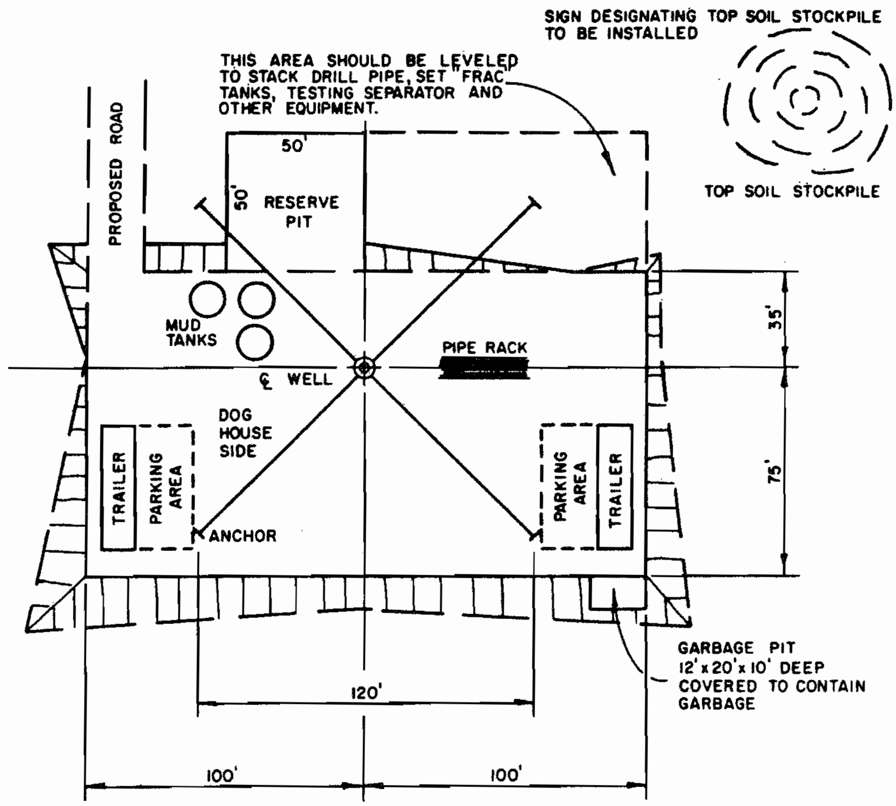
Restoration and Rehabilitation. One of the considerations used in selecting the sites for the demonstration project was that the facilities could be installed in close proximity to the existing pipeline and adjacent to existing access and man-made development. This would facilitate not only economical construction but would also allow easy restoration of the sites.

After drilling operations were complete, the drill sites would be cleared and cleaned and all sumps filled in. Areas of non-use would be restored and reseeded.

Upon abandonment of the facilities, the sites would be graded to blend with the adjacent contours and revegetated.

2.2.2 Well Drilling and Completion

Bureau of Mines Experience. In preparation for planning the well drilling and completion procedures, a review was made of the available data covering Bureau of Mines experiences in draining methane from coal. Since



GENERAL NOTES:

At sites where topsoil is present, same is to be removed and stored on the adjacent land for restoration of the site when required.

Reserve pit and garbage pit are to be fenced and unlined.

For well location profiles see drawing number M-_______.

Area for well location is 0.50 Acres.

Cuts are 1:1, Fills are 2:1

REVISIONS

NO.	DESCRIPTION	DATE	BY

MOUNTAIN FUEL
RESOURCES, INC.
SALT LAKE CITY, UTAH

TYPICAL WELL SITE PLAN
FOR
DEMONSTRATION PROJECT
METHANE RECOVERY
From UNMINABLE COALBEDS

DRAWN: 1-13-78 GeB	SCALE: 1" = 50'
CHECKED:	DRWG. NO. M-12838
APPROVED:	

Figure 7

1970, the Bureau of Mines has been involved in numerous methane drainage projects. Data from projects in which over 40 wells were drilled have been reviewed. Special attention was paid to the depth and interval of coal, the completion techniques, the stimulation methods and rates, and the gas production realized from these wells. Although much of the data reported is not complete, a good overview of the Bureau of Mines experience was obtained.

A summary of the Bureau of Mines data and its sources is presented in Table 4. From this data and communications with Bureau of Mines personnel, open hole or slotted perforations appeared to be preferred completion methods. These methods expose more coal surface to production and seem to decrease the risk of screenouts in the well. Nitrogen/foam stimulation techniques are preferred over water/gel methods. A comparison of stimulation techniques shows that nitrogen/foam has a high sand-carrying capacity and gives a better recovery of formation and stimulation fluids.

Tentative Drill Plan. A tentative drilling and completion plan was developed based on Bureau of Mines experiences, the drilling experience of Mountain Fuel Supply's petroleum engineers, and discussions from others with hydraulic stimulation experience. The tentative plan was expanded and finalized during Phase II of the project. A summary of the plan is outlined in Table 5. This table shows the location, depth, coal interval, completion method, and stimulation method expected to be used.

It was planned that samples of cores obtained from the coalbeds would be confined in airtight canisters as soon as possible after being removed from the core barrel. It was planned that the UGMS would test these samples for gas emissions using the same techniques developed in their work during the past two years.

The above testing was considered to be a minimal though adequate effort to support the demonstration project. To enhance the research aspects of the project, however, an extensive laboratory testing program coupled with computer-simulated production calculations would be completed. This effort was to be carried out by the Institute of Gas Technology.

Table 4

SUMMARY OF BUREAU OF MINES METHANE DRAINAGE EXPERIENCES

Well Location	Data Source	Date	No. of Wells	Well Depth (ft.)	Coalbed Thickness (ft.)	Completion Method	Stimulation Method	Stimulation Volume (gal.)	Stimulation Sand (lb.)	Injection Rate (Bbl/min)	Production Rate (mcfd)
Pocahontas No. 3 Buchanan Co., Va.	RI8047 (Ref. 8)	1970	1	1530	6	open hole	water/gel	14,800	4,000	10	12
Mary Lee Coal Warrior Field, Ala.	RI7968 (Ref. 9)	1973	5	1100	5	open hole	water/gel	10,000	6,000	10	70
Pittsburgh Coal Washington Co., Pa.	RI8047 (Ref. 8)	1974	1	450	7	open hole	water/gel	10,230	6,000	11.4	36
No. 6 Coal Jefferson Co., Ill.	RI8047 (Ref. 8)	1974	1	--	--	--	water/gel	12,000	6,400	--	4
Mary Lee Coal Oak Grove, Ala.	RI8295 (Ref. 10)	1976	1	1100	5	slotted perforations	water/gel	3,500	4,000	8	20
Pittsburgh Coal Greene Co., Pa.	RI8286 (Ref. 11)	1976	7	600-900	7	open hole	N_2/foam	32,800	11,100	12	65 (several 100+)
Pittsburgh Coal Waynesburg, Pa.	MERC/SP-78/1 (Ref. 12)	1976	1	1650	30	perforated	------Unsuccessful stimulation - well blocked------				85 Prestimulation
			3	825	8-25	open hole	N_2/foam	27,300	24,500	13	5
Mary Lee Coal Oak Grove, Ala.	Verbal Comm. S. W. Lambert (Ref. 13)	1976-77	19	1000	5	open hole and slotted perforations	N_2/foam	50,000	45,000	10	6-180 (several 100+)

Table 5

PROPOSED METHANE DRAINAGE DRILLING/COMPLETION PLAN

Procedure/Task Item	WELL #1	WELL #2	WELL #3
WELL LOCATION	Whitmore Park Carbon County, Utah T.12S., R.12E., Sec. 34	Whitmore Park Carbon County, Utah T.12S., R.12E., Sec. 34	Castlegate Carbon County, Utah T.12S., R.10E., Sec. 22
DRILLING (drill all wells at same time depending on contractor availability)	Drill to approximate top of upper coal seam with 7-7/8" hole (depth ~ 2500') using prescribed drilling procedures.	Same as #1. Depth to coal ~ 2325'.	Same as #1. Depth to coal ~ 2240'.
CORING (collect samples)	Core through all coal seams to a depth 100' below lowest coal seam (Gilson) with 7-7/8" diamond core bit. Total Depth: 2950'	Same as #1. Total Depth: 2775'	Same as #1. Total Depth: 2700'. Lowest coal seam known is the Kenilworth.
LOGGING	Run a full series of logs to determine characteristics of coal and surrounding formations above and below coal seams.	Same as #1.	Same as #1.
SET CASING	Set specified 4-1/2" casing to the top of the large Gilson coal seam (coal interval ~ 18-20'). Use a guide shoe with one-way portals on the bottom of the casing.	Set specified 4-1/2" casing to total depth below Gilson coal using guide shoe in bottom of casing.	Same as #1 setting casing to top of Kenilworth coal.
CEMENT CASING	Cement casing and well above Gilson coalbed with enough cement to fill 1000' above bottom of casing. Drill out guide shoe and cement in bottom of casing. (Casing and cementing procedures may vary depending on results of logging.	Cement bottom joint of casing and fill casing with a cement plug. Do not drill out plug.	Same as #1.
PERFORATIONS (variations may occur depending on coal thickness encountered)	No perforations required at this time. Later decision may be made to perforate upper seams.	Perforate three major coal seams (Sunnyside, Rock Canyon, Gilson) using jet-slotting technique. Slot one foot of casing per 3 feet of coal interval.	Perforate major coal seams based on core data with jet shots. Run 8 shots per foot into specified coal seams.
PRODUCTION TESTING	Use air from drilling rig to blow water out of well. Release rig and monitor production and pressure if gas flow results.	Same as #1 or run DST dependent on results of #1 experience.	Dependent on results of #1 and #2 wells.
WATER INJECTION TEST FOR PERMEABILITY	Set packer at bottom of tubing above open hole. Inject water down tubing into formation at constant rate. Monitor rate and pressure at surface. (May vary depending on production test results.)	Same as #1 with packer set above highest perforation.	Same as #2.
DEWATERING	Install oversized sucker rod pumps (~ 240 gph) and dewater well.	Install production tubing and sucker rod pump. Use air to remove water if dewatering is too slow.	Same as #2.
PRE-STIMULATION PRODUCTION TESTING	Install gas and water production monitoring equipment and record data over a 4-week period followed by a 2-week shut-in period.	Same as #1, extended over a 3-month period.	Same as #1, extended over a 4- to 5-month period.
STIMULATION (type and size stimulation pending further analysis)	Probable stimulation method: N_2/foam (based on logging and prior formation testing). Preliminary design based on eastern methane drainage experience. Western coal assumed to be similar.	Same as #1. Changes will be based on experience from #1 stimulation.	To be determined based on results of Wells #1 and #2.
CLEANUP	Use a sand pump bailer to clean out well if necessary. Install sucker rod pump.	Same as #1.	Same as #1.
POST-STIMULATION PRODUCTION TESTING	Monitor gas and water production and pressures.	Same as #1.	Same as #1.
INSTALL SURFACE PRODUCTION EQUIPMENT	Install if justified after production from Wells #1 and #2 is known.	Same as #1.	Produced gas will be vented.

Tentative Well Completion Plan. The tentative well completion plan, was developed by Mountain Fuel petroleum engineers, during Phase I, and further refined during Phase II. It is presented in the Phase II discussion.

Procedures for the second and third demonstration wells were expected to be changed to some extent based upon the experience gained from each previous well. However, several changes were planned to allow a comparison between different completion methods. The second well was to be cased to total depth and perforated with a jet slotting technique instead of being completed open hole. The third well would be completed open hole on the bottom seam with perforations made into appropriate upper coal seams with jet shots.

2.2.3 Well Testing and Production. Several tests were to be conducted at various stages of the project. These plans would be varied according to the results of prior testing and the experience gained from each demonstration well.

Many wells that have been drilled in this area of the Book Cliffs coal field have released gas as the drilling work was being done. The first well test was simply to remove all the water remaining in the well after drilling and casing the well. This was to be done by blowing the water out with air. If gas flow resulted, it would be monitored along with well pressures. If no production resulted, the well would be tested for permeability using a water injection test. This type of test has been used successfully during Bureau of Mines methane recovery projects. In this test, clean water is injected into the formation at a constant rate. The injection rate and surface pressure are recorded with time, and a log plot is made of the increase in pressure with time. Permeability is then calculated from the plot.

A prestimulation gas production test was also planned following the dewatering of the well. Dewatering and maintaining the holes free from water buildup has been most effectively accomplished by the Bureau of Mines using sucker rod pumps. Sucker rod pumps were planned for this demonstration project. Submersible pumps were also tried by the Bureau of Mines, but were not as effective due to sand fouling.

The time required for dewatering to the point where maximum gas flow occurred has varied considerably. For example, a stimulated well drilled into the Pittsburgh coalbed in Washington County, Pennsylvania, required approximately four months to reach a maximum gas production of 35 Mcfd (9), while one of the wells drilled into the Pittsburgh coalbed near Waynesburg, Pennsylvania, produced in excess of 100 Mcfd one day following the stimulation treatment, and continued production at more than 120 Mcfd for the next seven weeks until a problem developed with the pump (10).

It was anticipated that, in general, dewatering of the coal surrounding vertical boreholes into the Book Cliffs coalbed would require less time than is required for the Pittsburgh or Mary Lee coalbeds since this coalbed is in a region having a generally drier climate. The experience with horizontal boreholes at the nearby Kaiser mine supports this idea. Pumps with a substantially higher capacity than expected to be required were planned for installation. The water from the demonstration wells was to be sampled and then either collected in an unlined pit or discharged to the natural drainage. Water from the nearby Kaiser mine is of good enough quality to use for irrigation, as discussed earlier.

It has been recognized by Bureau of Mines personnel and verified by Intercomp production computer simulation that water production from a single isolated well will be greater than production from a well located near other wells.

A prestimulation gas production test of Well No. 1 was planned to cover a period of four weeks. The same test on Wells No. 2 and No. 3 was scheduled from three to five months. These extended tests were to be conducted while the stimulation and evaluation of the stimulation were in progress on Well No. 1.

A long-term production test was planned following the stimulation at each well. Both gas flow and water flow rates and pressures were to be metered and recorded. The gas was to be flared until stable production rates were established and the facilities for injection into the commercial natural gas line completed at Wells No. 1 and No. 2.

2.2.4 Equipment Performance Specifications. Equipment performance specifications were defined for the project equipment based on the design criteria known to date. Detailed design of most of the equipment installation was completed during Phase II of the project. The detailed facility requirements for compressing, dehydrating, and injecting gas into the commercial pipeline would be verified after stable production rates were determined. Table 6 summarizes the performance specifications for the project equipment. All equipment, wells, and piping would meet the requirements established by Mountain Fuel Supply in "Standard Practices of Mountain Fuel Supply Company." The manufacturers and contractors used by Mountain Fuel would be required to meet these standards in their contracts. Detailed specifications would be prepared for receiving bids on the compressor and dehydration units.

2.3 ECONOMIC ANALYSIS

2.3.1 Basis for Economic Analysis. An economic analysis was completed in March 1979 for an assumed commercial-scale methane recovery project. Commercial gas production costs for methane gas from the Whitmore Park area of the Book Cliffs coalbed were analyzed. A utility-financed cost of service analysis was used to obtain production costs. The analysis used current methods for calculating rate of return on invested capital, depreciation, taxes, working capital, and operating and maintenance expenses. The basis and assumptions used in this analysis are outlined in Table 7.

Capital cost estimates used in the economic analysis are based on a commercial-scale project in which 55 wells would be drilled. The cost estimates are based on recent gas well costs for wells drilled by Mountain Fuel Supply at similar depths, from suppliers' quotes, and from cost comparisons

TABLE 6

EQUIPMENT PERFORMANCE SPECIFICATIONS

EQUIPMENT ITEM	PERFORMANCE CRITERIA	SIZE/TYPE
Compressor	Approximately 300 Mcf/d gas, Compress from 20-660 psig.	Skid-mounted in metal building, 62 Hp, 2-stage, reciprocating with gas engine.
Dehydration Unit	Dewater from 43 to 4 lb/MMcf, Gas pressure - 660 psig.	300 Mcf/d, Glycol-water type.
Piping	Meets "Standard Practices of Mountain Fuel Supply Company" requirements. 2-3/8 inch individual well lines. 3-1/2 inch main line from compressor.	Low pressure - 20 psig before compressor. High pressure - 660 psig after compressor.
Valves	API Standards.	3000 psi rating on wellhead. 1000 psi rating on compressor suction and all lines after compressor. 50 psi rating between wellhead and compressor suction.
Meters	Water meter - 300 gph capacity. Gas meter - 300 Mcf/d capacity. Meters accurate to ± 2%.	Positive displacement type, Orifice or vortex meter.
Pump	Sucker rod type - Capacity: 240 gph Pump jack. Gas engine.	1-1/4 inch. 7-M-25-67-30 Churchill 7 Hp BKND Wisconsin
Wellhead	3000 psi	10- by 6-inch Type "B" tubing spool.
Casing	Surface casing Subsurface casing	8-5/8 inch, K-55, 32 lb., 8 round thread, ST&C; 4-1/2 inch, K-55, 11.6 lb., 8 round thread, ST&C.
Tubing	Subsurface	2-3/8 inch, V-55, 4.7 lb., 8 EUE, Butt weld.

TABLE 7

COST EVALUATION BASIS AND ASSUMPTIONS FOR BASE CASE ANALYSIS

Capital Investment Costs

Drainage wells - It is assumed that 55 methane drainage wells are drilled, completed, and placed on production.

Capital cost estimates are based on actual gas production well costs drilled by MFS at Lower Horse Draw (escalated for inflation), recent suppliers' estimates, and cost comparisons with similar methane drainage projects.

Production equipment is sized for 5.5 MMcfd flow with compression required from 20 psig to 660 psig.

Capital Expenses

Depreciation - Straight-line depreciation is taken on the plant investment. Well investment is depreciated with units of production.

Working capital - cash is 45 days of annual operating and maintenance expenses.

Working capital - materials and supplies is 2.7% of total capital investment.

Financing is assumed to be 50% debt, 50% equity.

Interest on debt is 10% of rate base debt.

Return on equity is 13.25% of rate base equity.

Tax rate for combined federal and state income taxes is assumed to be 47.67%.

Operating and Maintenance Expenses

Labor costs are based on the assumption of one operator per 18 wells and one mechanic per 55 wells. The present wage rate is $8.92/manhour for an operator and $10.45/manhour for a mechanic. Wages are assumed to escalate at 7% per year. Labor overhead is 89.78%.

Repair materials costs are 5% of capital equipment costs per year for compressors and dehydration units and 2% for production lines.

Fuel requirements were calculated to be 7.5% of gas produced.

Royalties are based on the escalating FERC regulated price of new gas. Federal royalties are 12.5% of the regulated value, and Utah state and county taxes are 8.5% of the regulated value.

Total Production Cost

Total gas production is assumed to decline 10% per year with a well life of five years.

made with similar Bureau of Mines methane drainage projects. The cost estimates are conservative since it was anticipated that some reductions in cost could be realized through the development of mass production techniques suitable for construction of a large number of wells in a short period of time. Table 8 gives the breakdown of capital costs for the assumed commercial project.

2.3.2 Gas Production Costs. The base case cost of service analysis assumed an initial production rate of 100 Mcfd per a coal interval available for production of (24 feet). Production rates were assumed to decline at 10 percent per year for 5 years. The short production life is thought to also be conservative. Results from the cost of service analysis are presented in Table 9. The cost of service analysis for the base case assumptions results in a gas production cost of \$3.31/Mcf. This compares with the calculated average FERC regulated price of gas over the same 5-year period of \$3.27/Mcf.

Table 9 also shows the effect of variations in well productivity, decline rate, well life, capital costs, escalation, cost of debt, and return on equity. These variations resulted in production costs ranging from \$2.50/Mcf to \$5.73/Mcf, with most costs being around \$3.45/Mcf. The gas production cost is most sensitive to variations in the assumed initial production rates. Variations in the decline rate and capital costs also affect the gas production cost, but not to as great a degree as the initial production rate. Variations in the actual decline rate or actual capital expenditures are not considered as likely to occur as a variation in the initial production rate.

Royalty payouts used in the cost of service analysis are based on the projected FERC price for new gas. Future prices were calculated based on the most recent Natural Gas Pricing Regulations (11). Future prices reflect cost increases due to inflation which has been projected by the Bank of America for a 10-year period. The resulting average FERC prices for new gas for a 5-year, 7-year, and 10-year period are \$3.27/Mcf, \$3.69/Mcf, and \$4.46/Mcf, respectively.

TABLE 8

ESTIMATED CAPITAL COSTS FOR COMMERCIAL METHANE RECOVERY

Production Capacity - 6MMcfd

Individual Well Costs

Materials:	Cost
Casing, 100 ft	$ 1,000
2900 ft	10,600
Tubing, 2900 ft	5,000
Pumping Unit	4,500
Wellhead	4,000
Pipeline to lateral	10,900
TOTAL MATERIALS	$ 36,000
Services:	
Site preparation	$ 4,000
Drilling, running casing	46,500
Logging	3,800
Cement, water, mud/air	10,200
Foam stimulation	52,000
Workover rig	7,200
Perforation	4,500
TOTAL SERVICES	$128,200
Engr./Supr. Labor & OH	$ 3,000
Contingency (10%)	16,400
TOTAL ESTIMATED COST PER WELL	$183,600
TOTAL ESTIMATED COST FOR 55 WELLS	$10,098,000

Production Equipment:	Cost	Salvage Value	Salvage Cost
Compressors	$755,000	$405,000	$ 5,000
Dehydration Units	62,000	38,000	2,000
Transmission Line	103,000	69,000	-0-
	$920,000	Net Salvage Value	$505,000

Table 9

ECONOMIC ANALYSIS RESULTS SUMMARY

Input Variables	Cost of Service Total	Total Unit Production Cost $/Mcf
Base case input (Table 7)	$25,826,690	$3.31
Variations:		
Well decline rate @ 5%	27,069,580	3.06
Well decline rate @ 20%	23,677,610	3.90
Cost of debt @ 12%	26,096,400	3.34
Return to equity @ 15%	26,277,670	3.36
Escalation @ 12%	25,979,270	3.33
Well production @ 50 mcf/day	22,386,610	5.73
Well production @ 150 mcf/day	29,263,360	2.50
Capital cost increased 20%	29,372,700	3.76
Capital cost reduced 20%	22,280,700	2.85
Ten-year well life	40,117,780	3.23
Seven-year well life	31,512,180	3.17

The cost of service for a 5-year well life project is only slightly higher than the FERC price ($3.31/Mcf vs. $3.27/Mcf). For projects with well life of 7 and 10 years, the cost of service ($3.17/Mcf and $3.23/Mcf) is substantially lower than FERC prices over the same period ($3.60/Mcf and $4.46/Mcf). This cost of service analysis shows that it continues to appear attractive to develop this energy source for use in the near future.

2.4 SUBCONTRACTORS

2.4.1 IGT Subcontract. A subcontract was negotiated with the Institute of Gas Technology (IGT) which included providing technical support for the design of the demonstration plan, analyzing data from previous relevant well tests, providing input for the hydraulic stimulation design, developing detailed procedures for data collection to meet computer simulation model requirements, analyzing core samples, and interpreting data using Intercomp computer simulation model. Summary reports of IGT's work are given in Section 5.0.

IGT work during Phase I of the project reached several conclusions and highlighted several areas requiring close attention in Phase II of the project. These conclusions were: current Mountain Fuel Supply assumptions for economic analysis may well be appropriate; proper core analysis and field testing is essential prior to hydraulic stimulation; additional computer simulation runs should be conducted to better understand key production variables; and extensive effort should be put into the design of each hydraulic fracture.

2.4.2 Other Subcontractors. In addition to the work contracted to IGT, Mountain Fuel made plans to hire subcontractors in four major areas: drilling, logging, workover rig operations, and hydraulic stimulations. Mountain Fuel routinely contracts these types of work in drilling and completing production wells. Table 10 lists typical subcontractors who have worked for Mountain Fuel in the western states. Specific contractors were to be chosen prior to drilling, based on availability and Mountain Fuel's most recent experience with contractors for a given job.

TABLE 10

METHANE DRAINAGE SUBCONTRACTORS

DRILLING

VECO 2457 Industrial Building Grand Junction, Colorado 81501	Burton/Hawks Drilling Box 359 Casper, Wyoming 82602

LOGGING

Dresser Atlas Box 790 Rock Springs, Wyoming 82901	Schlumberger Box 1335 Rock Springs, Wyoming 82901

WORKOVER RIGS

Aztec Well Service 107 West 32nd Farmington, New Mexico 87401	Colorado Well Service, Inc. Box 1006 Rangely, Colorado 81648

STIMULATION

Dowell Box 920 Vernal, Utah 84078	Halliburton Box 339 Vernal, Utah 84078

2.5 ENVIRONMENTAL ASSESSMENT

A preliminary environmental assessment was made for the three demonstration well locations. Final assessments and approvals were to be obtained during Phase II of the project.

The locations for Wells No. 1 and No. 2 in the Whitmore Park area are on land of private surface ownership. Surface use is provided for under the existing gas lease. Although no federal approval of the environmental plan was required, a detailed environmental assessment was made. This assessment is similar to that required for federal approval as described below.

The site and access road for Well No. 3 in the Castlegate area are on National Resource Lands under the jurisdiction of the Department of the Interior. Approval before entry and drilling must be obtained from the USGS. All plans must be in accordance with the National Environmental Policy Act of 1969 and are to be conducted according to the requirements of the USGS issue "Notice to Lessees (NTL) Number 6, Approval of Operations."

A series of procedures must be followed to obtain USGS approval for the drilling of each well. Although this approval procedure is very thorough and complete, it can be implemented efficiently. It is a procedure that Mountain Fuel Supply Company successfully completes at least 40 times per year. Due to this exposure, Mountain Fuel personnel are highly skilled at conducting operations that constitute the least amount of environmental impact possible.

It was necessary to obtain a Permit to Drill from the State of Utah Department of Natural Resources, Oil, Gas and Mining Division, for all three wells. The tentative drilling and completion plans were reviewed by that department during Phase I and were found to meet minimum State Planning requirements.

3.0 WORK COMPLETED DURING PHASE II

During Phase II of this project all analyses for the preparation of flow sheets, site layout plans, safety plans, and data collection and analysis plans were completed. The results of this effort include the following:

1. Final set of flow sheets for methane collection and end use system (including instrumentation to be utilized for monitoring system).
2. Plan views showing site and equipment installation (maps and aerial photographs of site prior to site preparation initiation).
3. Complete schedules for the performance of Phase III.
4. Detailed environmental plan including reclamation for any sites damaged during site preparation.
5. Detailed data acquisition and analysis procedures.
6. Detailed procedures and analysis of proposed operations to include plan for operations.
7. Detailed equipment delivery schedules.
8. Updated detailed cost of Phase III (equipment, site preparation, maintenance operation, and other applicable costs).

3.1 DEMONSTRATION WELL SITES

3.1.1 Final Site Selection. The general locations of the methane recovery wells were selected during Phase I of the project. The exact locations were surveyed and staked during Phase II of the project. The sites are as planned during Phase I with the exception of the No. 3 well location in Mathis Canyon. The site for this well was moved approximately 1800 feet further down Mathis Canyon than the location described previously. This change was made to minimize the amount of excavation required to prepare a drilling site in this narrow canyon. The locations for each of the three demonstration wells are listed in Table 11 below.

TABLE 11

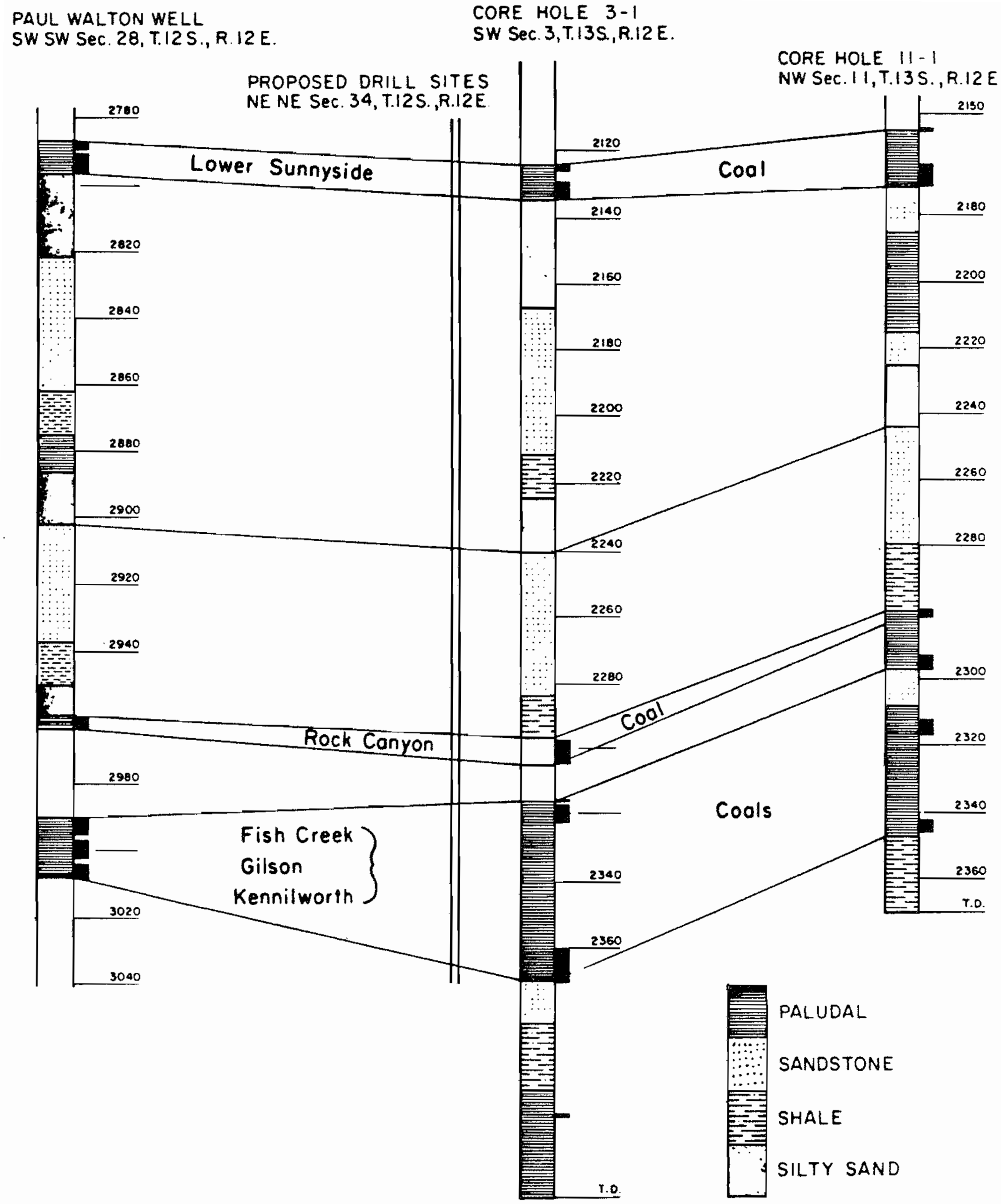
DEMONSTRATION WELL SITES - FINAL LOCATIONS

Well	Area	Township/Range	Section	Location
Well No. 1	Whitmore Park Carbon Co., Utah	T.12S/R.12E	34	532' FNL* 1701' FEL
Well No. 2	Whitmore Park Carbon Co., Utah	T.12S/R.12E	34	1756' FNL 2250' FWL
Well No. 3	Castlegate Carbon Co., Utah	T.12S/R.10E	21	246' FEL 1872' FSL

*FNL - From North Line

3.1.2 Stratigraphic Cross Sections. A detailed evaluation of the geologic and stratigraphic characteristics of each well location has been completed. The stratigraphic cross section derived from well data in the Whitmore Park area is shown in Figure 8. Data from the Paul Walton Well and Core Holes 3-1 and 11-1 were used to prepare the cross-sectional view of the Whitmore Park well sites shown in this figure. The core hole data were obtained from Pacific Gas and Electric Company.

The cross section is aligned in a northwest-southeast direction, as shown on the area map presented in Figure 9. This figure shows the relationship of the reference wells to the demonstration well sites. The actual locations for demonstration wells No. 1 and No. 2 are 5500 feet and 3000 feet, respectively, northeast of this cross-sectional plane. The coal is deeper north of the plane since the coal-bearing Blackhawk Formation dips in a northerly direction. This incline was accounted for in estimating the coal depth at these two locations. Three major coal seams were expected to be encountered in the Whitmore Park wells: the Lower Sunnyside; Rock Canyon; and Gilson coal seams. The top coalbed (Lower Sunnyside coal) was estimated to be at a depth of 2890 feet at well site No. 1, and 2660 feet at well site No. 2. The Sunnyside and Rock Canyon coals were expected to be from 4 to 6 feet thick at these locations. The Gilson coal was expected to



STRATIGRAPHIC CROSS-SECTION

COAL BEARING BLACKHAWK FORMATION

WHITMORE PARK AREA, CARBON COUNTY, UTAH

Figure 8

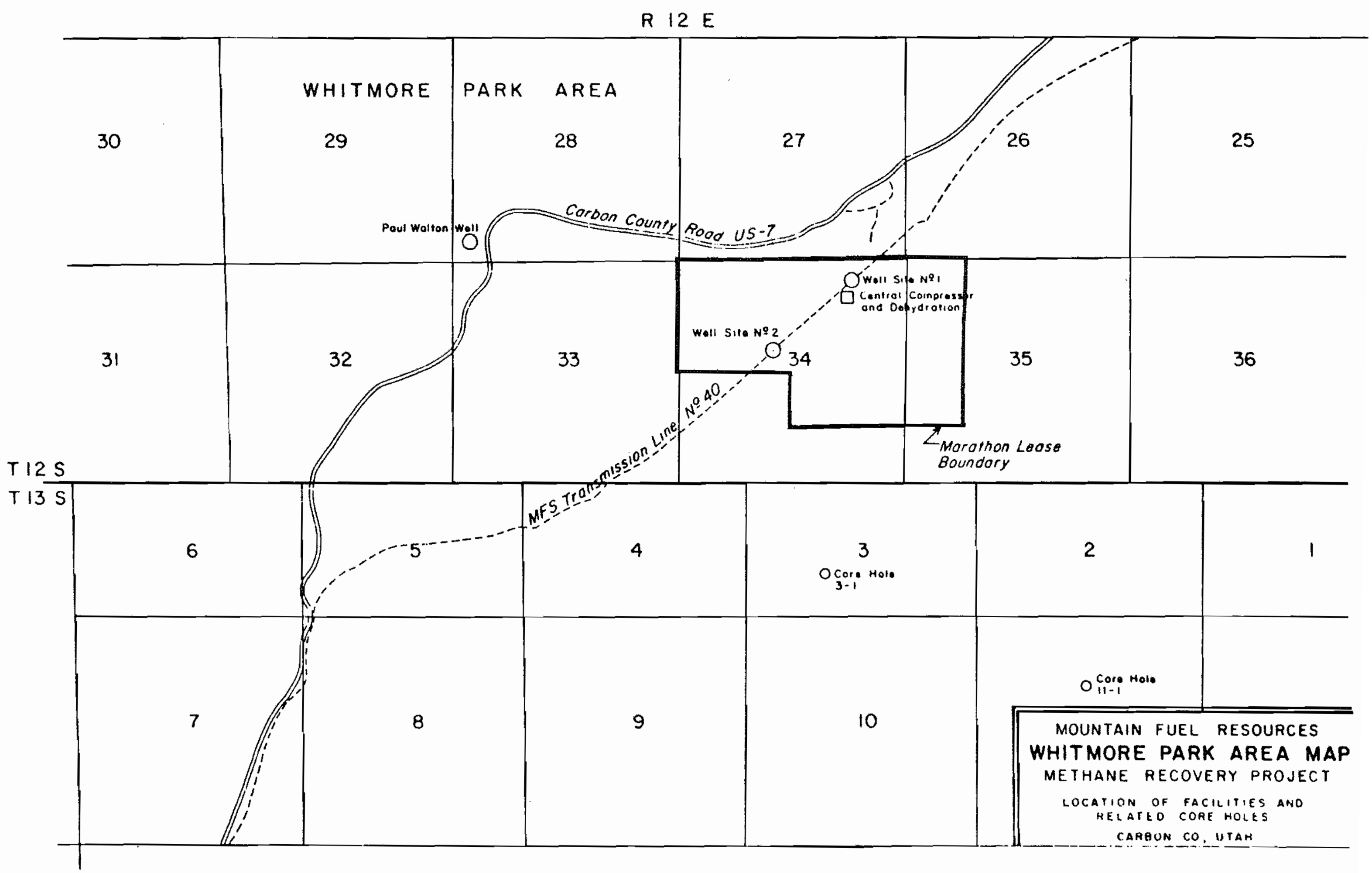

R 12 E
WHITMORE PARK AREA
30
29
28
27
26
25
Paul Walton Well
Carbon County Road US-7
Well Site Nº 1
Central Compressor and Dehydration
Well Site Nº 2
31
32
33
34
35
36
MFS Transmission Line Nº 40
Marathon Lease Boundary
T 12 S
T 13 S
6
5
4
3
2
1
Core Hole 3-1
Core Hole 11-1
7
8
9
10
MOUNTAIN FUEL RESOURCES
WHITMORE PARK AREA MAP
METHANE RECOVERY PROJECT
LOCATION OF FACILITIES AND RELATED CORE HOLES
CARBON CO, UTAH

Figure 9

to be 15 to 20 feet thick. The total depths of these two wells were projected to be 3200 and 2965 feet, respectively.

The location of Well No. 3 in Mathis Canyon of the Castlegate area was to be less than 4000 feet from an abandoned well drilled by Carter Oil Company. The location of the Carter well relative to demonstration well No. 3 is shown in Figure 10. The geologic structure of the No. 3 well will be very similar to the structure found at the Carter well, which is shown in Figure 11. Over 130 feet of coal was encountered in the Carter well. The coal is found in at least 9 seams spread over an 800-foot interval which includes Sunnyside, Kenilworth, Aberdeen, Spring Canyon, and Star Point Formations. Four large seams 19 to 26 feet exist. Other seams range from 5 to 13 feet. Production tests from several of these seams were planned. Core data obtained when this demonstration well was drilled would help determine which of these seams would be perforated and stimulated for these tests.

3.1.3 Site Preparation and Plans. After surveying each well, the preparation of the site plans for each location was completed. This included staking of a site boundary which was approximately 275 feet by 110 feet for the Whitmore Park Wells No. 1 and No. 2. The drilling location for the No. 3 Mathis Canyon well was slightly smaller due to restrictions in the narrow canyon. This drill site was approximately 200 by 105 feet, narrowing to 70 feet. Area location maps for the sites are shown in Figures 12 and 15. Plats of the well site plans for these three wells are shown in Figures 13, 14, and 16. Figure 17 shows the excavation work required to prepare the Mathis Canyon drill site.

Plans for both surface and subsurface protection were developed for each demonstration well site. The 10-Point Subsurface Protection Plan and the 13-Point Surface Use Protection Plan were filed with the USGS as part of the Application for Permit to Drill (APD) for the No. 3 well, which was to be located on federal land in Mathis Canyon of the Castlegate area. Similar plans were made for the No. 1 and No. 2 well sites which were located on fee land in the Whitmore Park area. Copies of the plans submitted to the USGS are included in the Appendix.

Methane Recovery Project - Castlegate Area Map

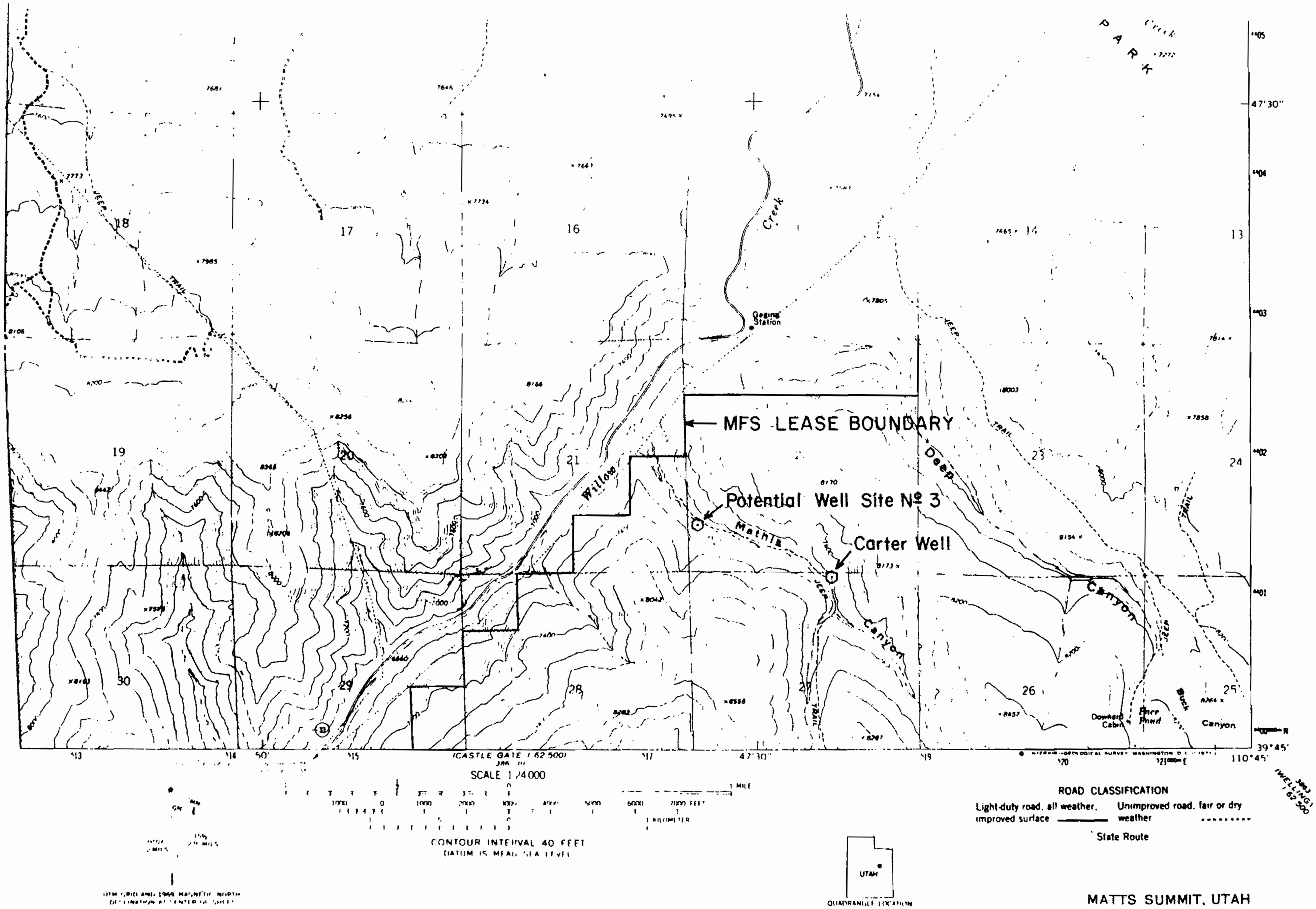
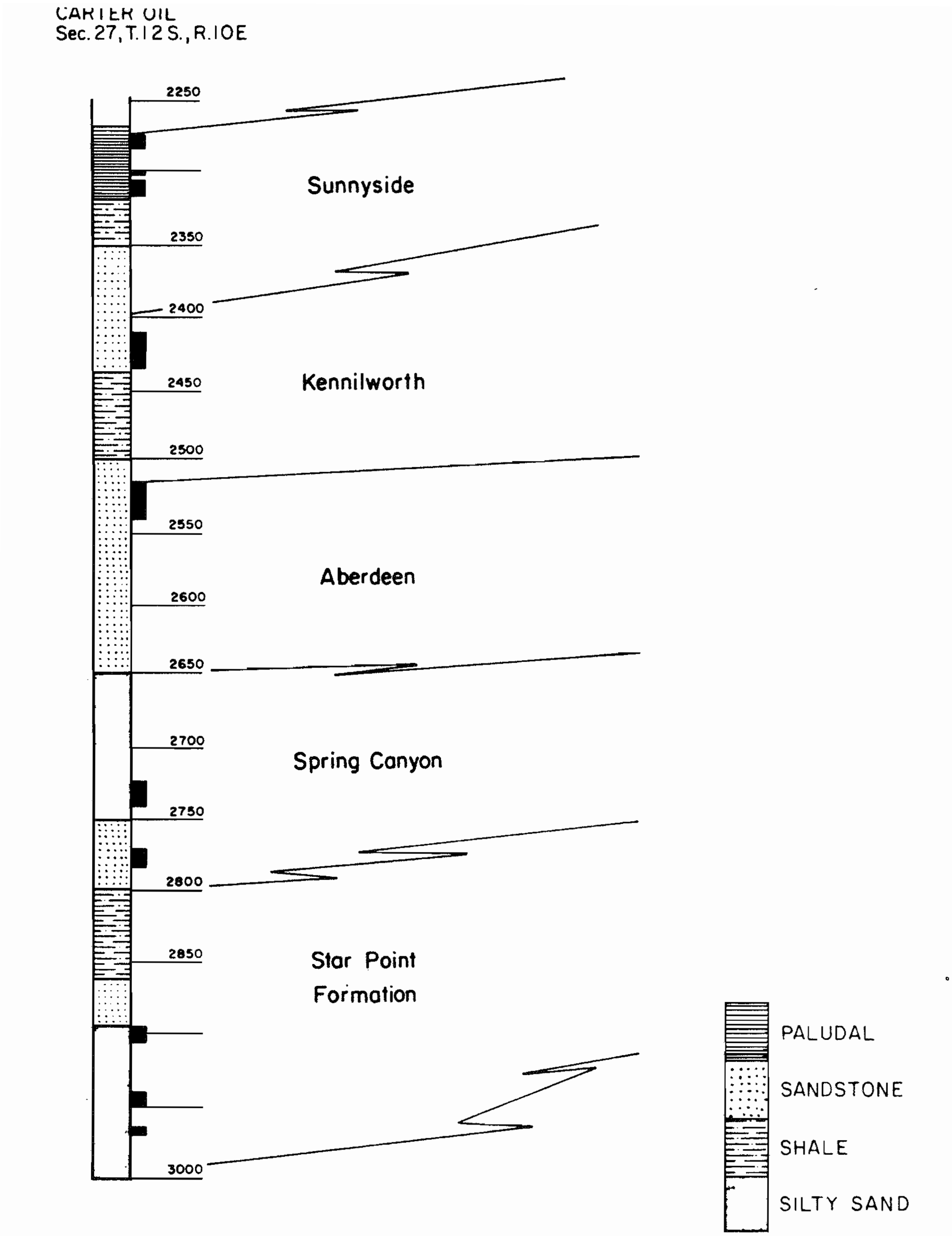


Figure 10



STRATIGRAPHY OF

COAL BEARING BLACKHAWK FORMATION

MATHIS CANYON AREA, CARBON COUNTY, UTAH

Figure 11

-3.7-

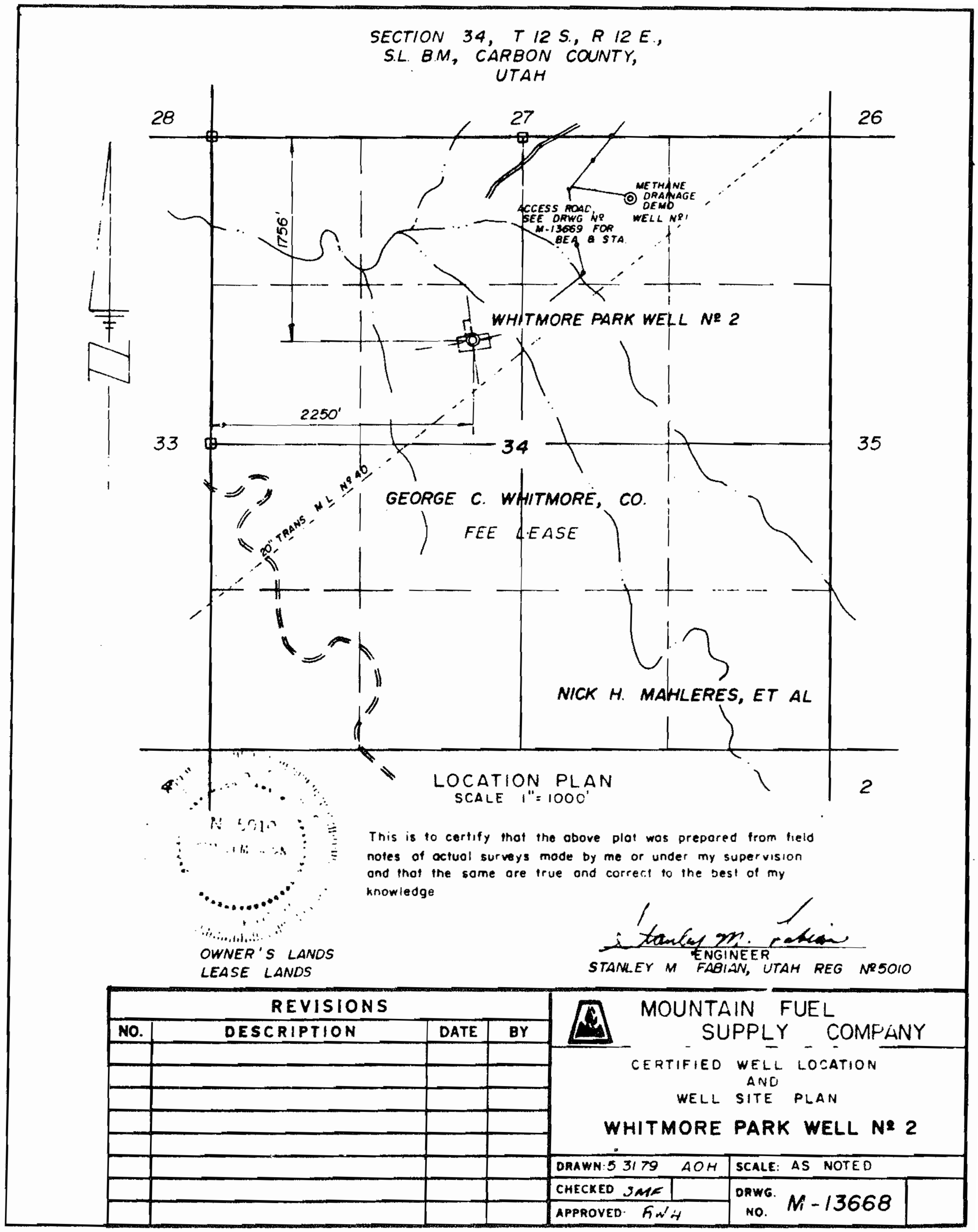
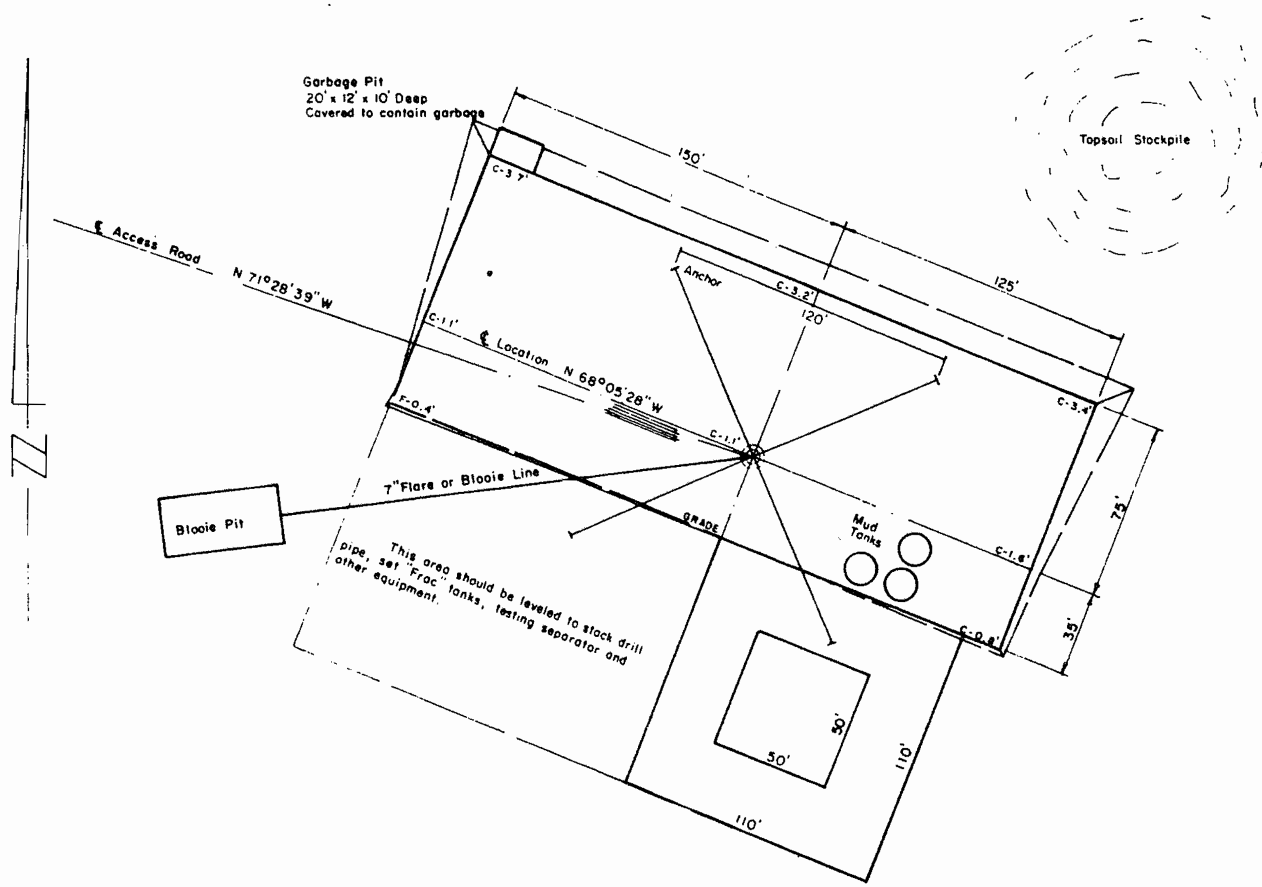


Figure 12

AREA LOCATION MAP



ENLARGED WELL SITE PLAN
SCALE 1" = 50'

GENERAL NOTES:

At sites where topsoil is present, same is to be removed and stored on the adjacent land for restoration at the site when required. 665 cubic yards or the top 6" of topsoil is to be stockpiled.

Mud pit and garbage pit are to be fenced and unlined.

[illegible]

Area for well location is 0.69 acres.

Cuts are at 3:1, Fills are at 3:1.

Sign designating topsoil stockpile to be installed.

REVISIONS			
NO.	DESCRIPTION	DATE	BY

Mountain Fuel Supply Company
Rock Springs, Wyoming

CERTIFIED WELL LOCATION
AND
WELL SITE PLAN

WHITMORE PARK WELL Nº 1

DRAWN 5/31/79 C.R.W.	SCALE 1" = 50'		
CHECKED SMF	DRWG NO	M-13671	2/4
APPROVED RWH			

Figure 13

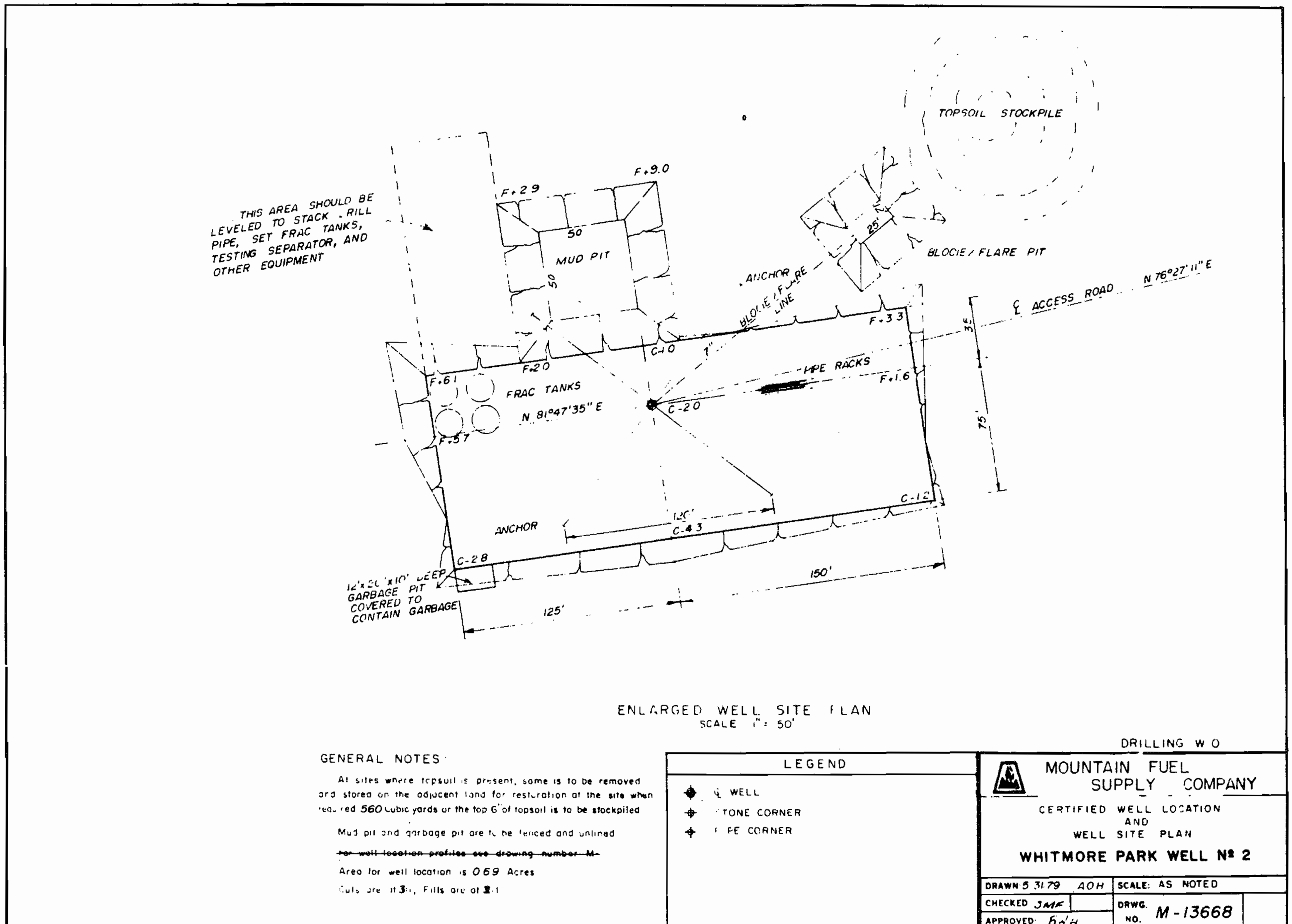

THIS AREA SHOULD BE LEVELED TO STACK DRILL PIPE, SET FRAC TANKS, TESTING SEPARATOR, AND OTHER EQUIPMENT
TOPSOIL STOCKPILE
BLOCIE / FLARE PIT
MUD PIT
FRAC TANKS
N 81°47'35" E
PIPE RACKS
ANCHOR
ACCESS ROAD
N 76°27'11" E
12'x20'x10' DEEP GARBAGE PIT COVERED TO CONTAIN GARBAGE
150'
125'
75'
ENLARGED WELL SITE PLAN
SCALE 1" = 50'
GENERAL NOTES
At sites where topsoil is present, some is to be removed and stored on the adjacent land for restoration of the site when required 560 cubic yards or the top 6" of topsoil is to be stockpiled
Mud pit and garbage pit are to be fenced and unlined
~~For well location profiles see drawing number M-~~
Area for well location is 0.69 Acres
Cuts are at 3:1, Fills are at 2:1
LEGEND
WELL
STONE CORNER
PIPE CORNER
DRILLING W O
MOUNTAIN FUEL SUPPLY COMPANY
CERTIFIED WELL LOCATION AND WELL SITE PLAN
WHITMORE PARK WELL Nº 2
DRAWN 5 31 79 AOH
CHECKED JMF
APPROVED
SCALE: AS NOTED
DRWG. NO. M-13668

Figure 14

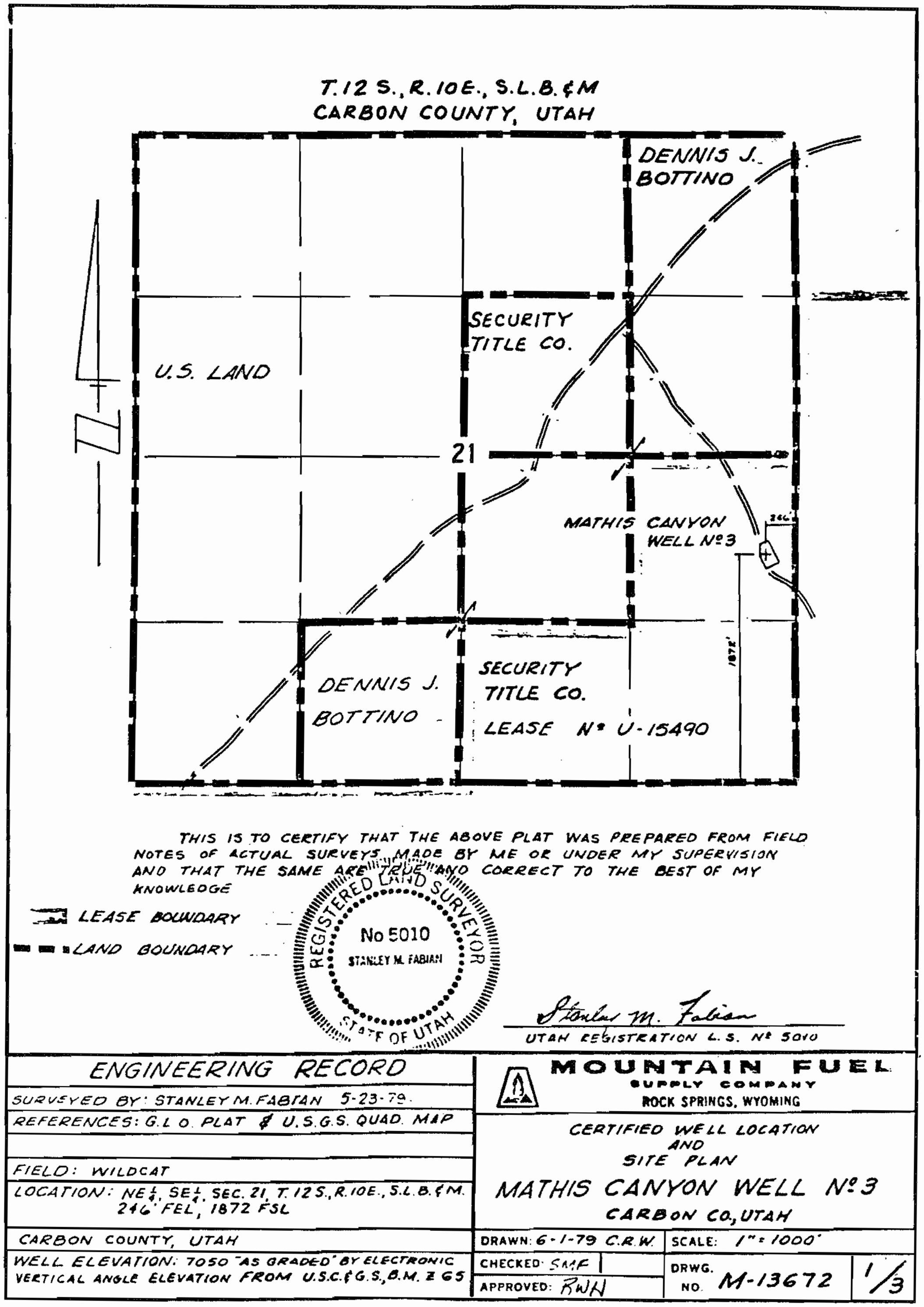


Figure 15
AREA LOCATION MAP

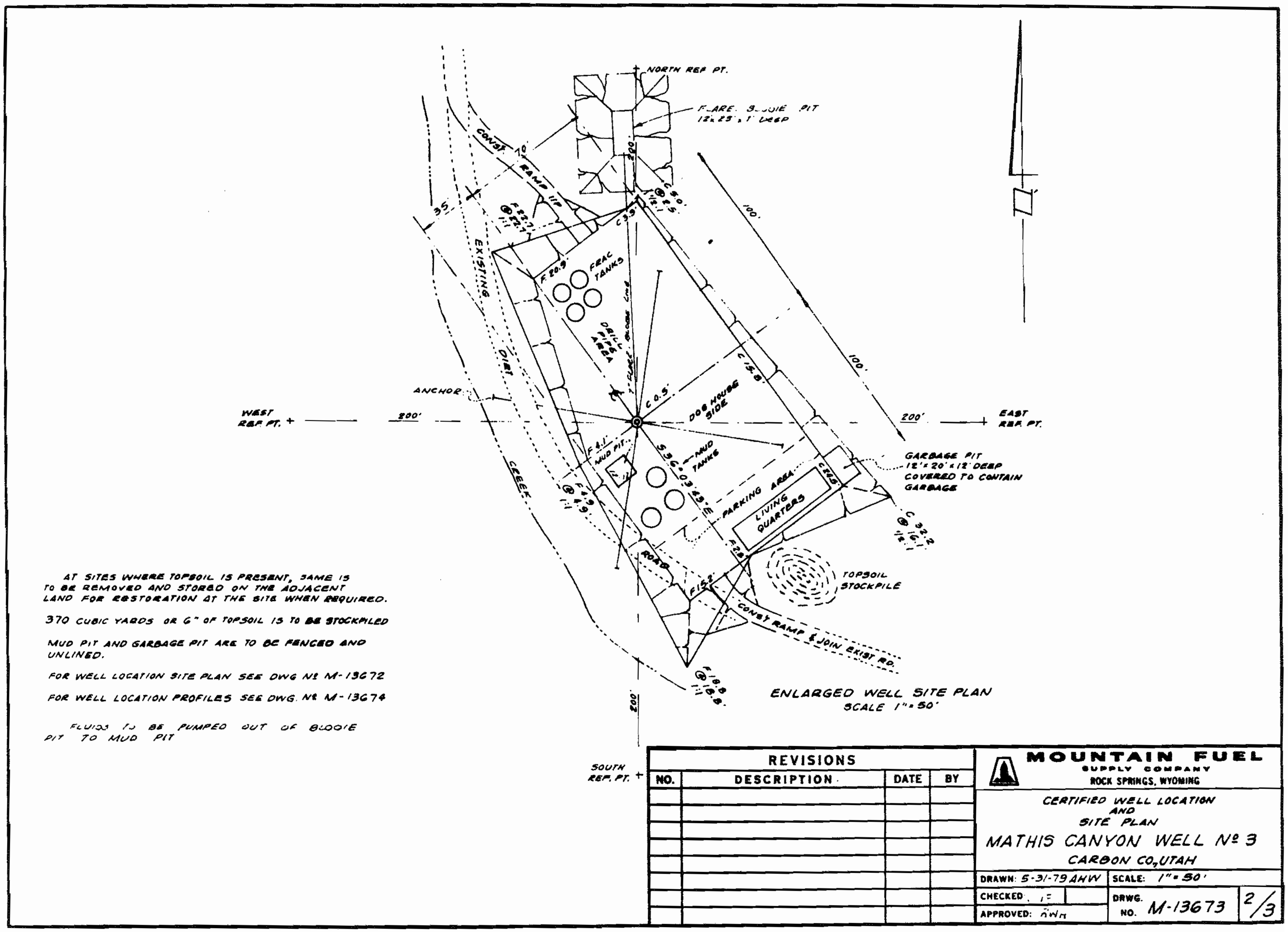

NORTH REF. PT.
FLARE. BLOOIE PIT 12x25' x 7' DEEP
CONST. RAMP 11%
EXISTING DIRT ROAD
CREEK
FRAC TANKS
DRILL PIPE AREA
ANCHOR
WEST REF. PT.
EAST REF. PT.
SOUTH REF. PT.
200'
100'
35'
DOG HOUSE SIDE
MUD PIT
MUD TANKS
S 56°03'43" E
PARKING AREA
LIVING QUARTERS
GARBAGE PIT 12'x20'x12' DEEP COVERED TO CONTAIN GARBAGE
TOPSOIL STOCKPILE
CONST. RAMP & JOIN EXIST. RD.
ENLARGED WELL SITE PLAN
SCALE 1" = 50'
AT SITES WHERE TOPSOIL IS PRESENT, SAME IS TO BE REMOVED AND STORED ON THE ADJACENT LAND FOR RESTORATION AT THE SITE WHEN REQUIRED.
370 CUBIC YARDS OR 6" OF TOPSOIL IS TO BE STOCKPILED
MUD PIT AND GARBAGE PIT ARE TO BE FENCED AND UNLINED.
FOR WELL LOCATION SITE PLAN SEE DWG Nº M-13672
FOR WELL LOCATION PROFILES SEE DWG. Nº M-13674
FLUIDS TO BE PUMPED OUT OF BLOOIE PIT TO MUD PIT
REVISIONS
NO.
DESCRIPTION
DATE
BY
MOUNTAIN FUEL
SUPPLY COMPANY
ROCK SPRINGS, WYOMING
CERTIFIED WELL LOCATION AND SITE PLAN
MATHIS CANYON WELL Nº 3
CARBON CO., UTAH
DRAWN: 5-31-79 AHW
SCALE: 1" = 50'
CHECKED
APPROVED:
DRWG. NO. M-13673
2/3

Figure 16

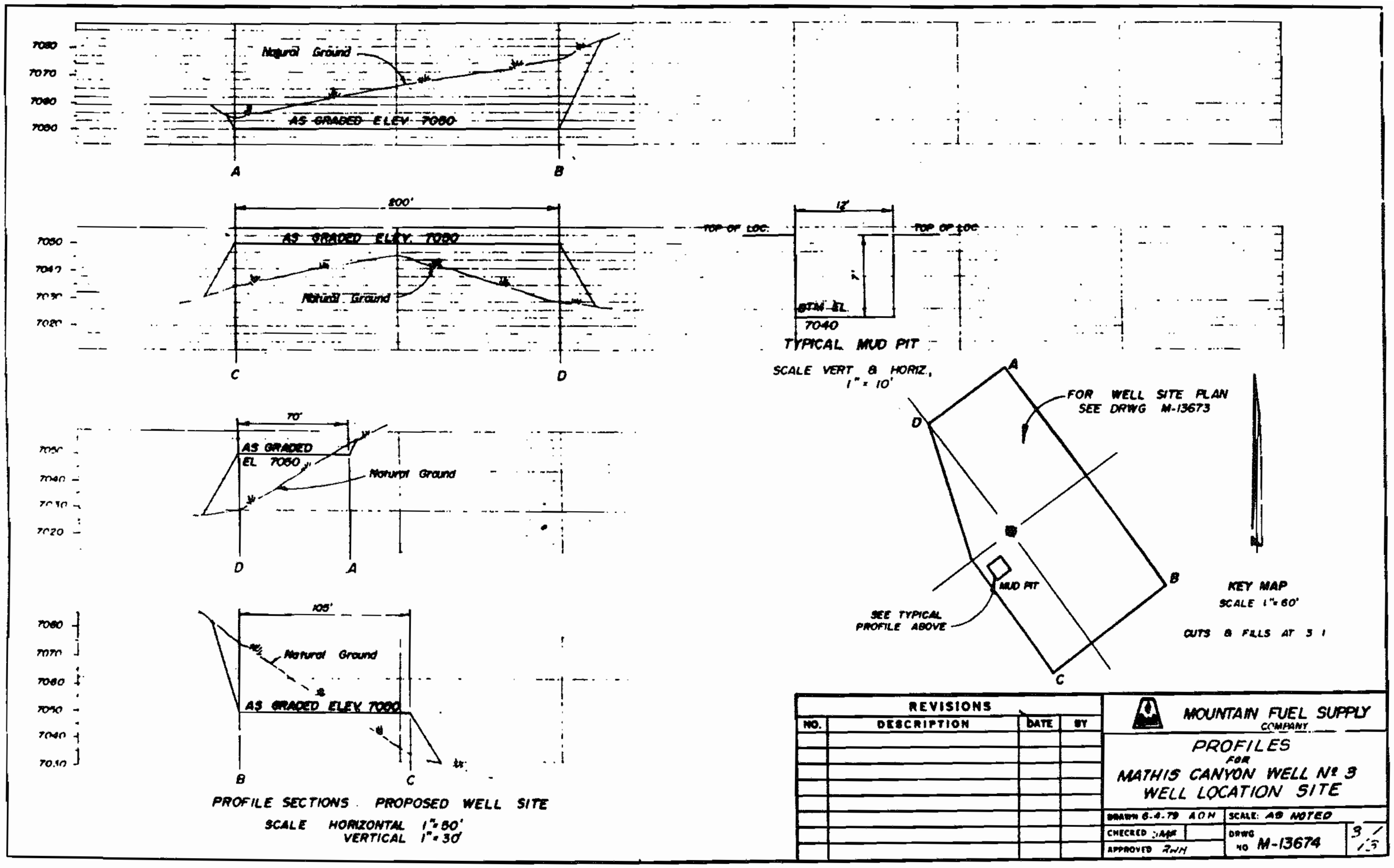


Figure 17

EXCAVATION PROFILES

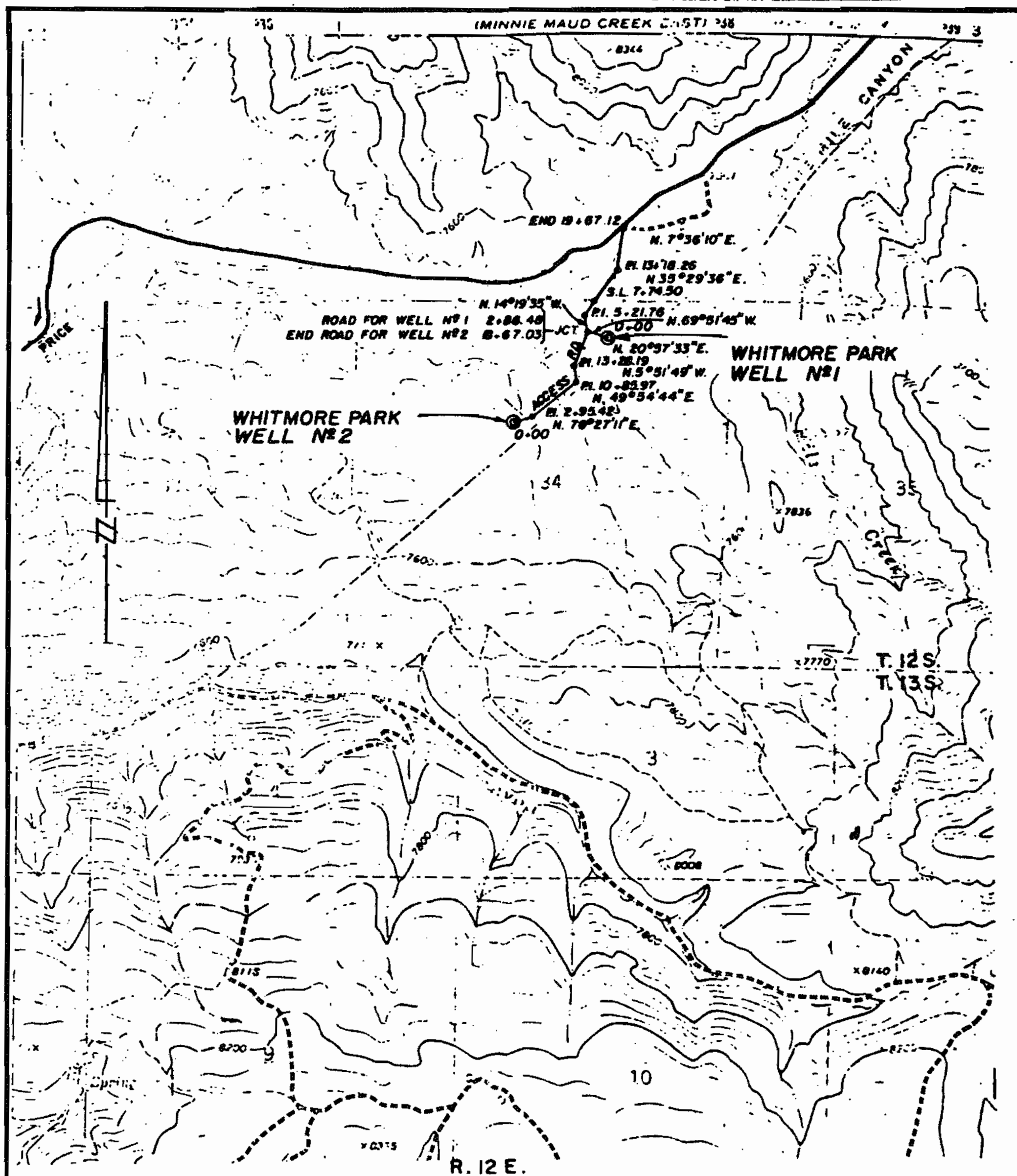
MATHIS CANYON WELL NO. 3

3.1.4 Access to Sites. The demonstration facilities for No. 1 and No. 2 wells are adjacent to Mountain Fuel Supply's transmission line No. 40 in the Whitmore Park area. Access to this location is from County Road US-7, which is a graded gravel road close to the pipeline right of way. From this county road, a small access road was constructed to give access to the two locations. Because of the gentle terrain, this access road was easily constructed. The construction of the road followed the plans outlined as part of the 13-Point Surface Use Protection Plan. The exact location of this access road is shown in Figure 18.

Access to the Mathis Canyon well location is via Utah State Highway 33 and an existing graded dirt road which passes next to the well site. A construction ramp from the existing dirt road to the drill site was the only necessary road construction.

3.1.5 Environmental Assessment. In addition to the environmental impact work normally done as part of the permitting process, a more detailed analysis of the environmental impacts of this project, as required by DOE, was completed. This environmental assessment was completed during June 1979 and transmitted to DOE for approval. The assessment included:

1. A general description of the project and its objectives;
2. A description of the physical, biotic, and human environments;
3. An assessment of the potential impacts on these environments;
4. A discussion of adverse environmental impacts;
5. A discussion of irreversible environmental impacts;
6. A discussion of interaction with other plans for the area and a list of permits required; and
7. A discussion of alternatives to the project.



REVISIONS			
NO.	DESCRIPTION	DATE	BY

MOUNTAIN FUEL
SUPPLY COMPANY
ROCK SPRINGS, WYOMING

AREA MAP
FOR

WHITMORE PARK WELL Nº 1 & 2

WHITMORE PARK AREA

DRAWN: 6-4-79 A.Q.H.	SCALE: 1" = 2000'
CHECKED:	DRWG. NO. M - 13669
APPROVED:	

Figure 18

WHITMORE PARK ACCESS

ROAD LOCATION MAP

3.2 PERMIT ARRANGEMENTS

3.2.1 Leases and Rights of Way. Mountain Fuel Supply holds oil and gas leases on much of northwestern section of the Book Cliffs coal field. Union Oil Company and Marathon Oil Company also hold gas and oil leases in this area. Demonstration wells No. 1 and No. 2 are located on fee land owned by the George C. Whitmore Company. The oil and gas lease on this property is currently held by Marathon Oil Company. Marathon and Mountain Fuel Supply have a farmout agreement covering drilling and methane production during this project under the Marathon lease. Coal rights for the Whitmore Park locations are held by the fee owner, and Mountain Fuel negotiated a formal agreement to disturb this coal and recover gas from the coal under the Marathon oil and gas lease.

The oil and gas lease for the location of the No. 3 well in Mathis Canyon is held by Mountain Fuel Supply Company. The coal at the No. 3 well location is unleased federal coal. A request was made to the Department of the Interior to approve disturbing this coal in order to recover the gas contained in it under the existing oil and gas lease.

Right of way agreements for the demonstration well sites and access roads for all three locations were negotiated in Phase II. The right of way agreement for the locations and access road to the Whitmore Park Wells No. 1 and No. 2 was negotiated with the George C. Whitmore Company. The right of way agreement to use the existing access road through Mathis Canyon, as well as for the No. 3 well site, was negotiated with Security Title Company which holds a lease on the surface land.

3.2.2 Drilling and Completion Permits. Permits to drill these demonstration wells fall into two categories. The State of Utah requires and issues permits for the drilling and completion of all wells within the state. In addition to the state requirements, a permit must be obtained from the USGS for wells drilled on federal land. Applications for Permits to Drill (APD's) were filed with the State of Utah for all three locations. The state issued drilling permits for each of these locations. In addition, because the No. 3 Mathis Canyon well is located on federal land, an APD was filed with the USGS. The drilling plan and location of this well were reviewed by the USGS. Final approval to hydraulically stimulate this well was denied in the early stages of the Phase III work. After a lengthy delay, the location of the third demonstration well had to be changed. Details are explained in the Phase III portion of this report.

3.3 WELL CONSTRUCTION PLANNING

3.3.1 Drilling Plan. Mountain Fuel's petroleum engineers finalized a drilling plan for the No. 1 well in Whitmore Park. This well is representative of the plans for all three wells. Minor deviations in the drilling of the second and third wells were anticipated as experience was gained through drilling of the first well. This drilling plan is outlined as follows:

1. Move in and rig up a contract rotary drilling rig which has the flexibility of quick-conversion air or mud drilling. Note: The rig must be capable of drilling a 7 7/8-inch hole to 3200 feet.

2. Using air, drill an 11-inch hole to a depth of 200 feet KBM. Note: For safety, all air and return lines must be adequately staked.

3. Run and cement approximately 200 feet of 8 5/8-inch O.D., 32-pound, K-55, 8 round thread, ST&C casing. The casing will be cemented with 100 sacks of regular cement, which represents theoretical requirements plus 100 percent excess for 8 5/8-inch O.D. casing in an 11-inch hole. The cement will be treated with 470 pounds of Dowell D-43A or 3 percent calcium chloride and 1/4 pound flocele per sack of cement. An 8 5/8-inch O.D. Baker guide shoe will be used on the bottom of the casing. The top and bottom of all casing collars will be spot-welded in the field and the guide shoe will be spot-welded to the shoe joint on the casing rack. The bottom of the casing should be landed in such a manner that the top of the 10-inch 3000 psi casing flange is approximately at ground level. A cellar 3 feet deep will be required. Pump 40 barrels of drilling mud prior to beginning cementing operations. Capacity of the 8 5/8-inch O.D., 32-pound casing and the 8 5/8-inch O.D. by 11-inch annulus is 22 barrels.

4. After a WOC time of 6 hours, wash off the collar at the bottom of the landing joint. Install a NSCo. Type B, 10-inch 3000 psi regular duty casing flange tapped for 8 5/8-inch O.D., 8 round thread casing. Install a 2-inch XH nipple 6 inches long and a WKM Figure B138 (2000 psi WOG, 4000 psi test) valve on one side outlet of the casing figure and a 2-inch XH bull plug in the other side.

Install a 10-inch 3000 psi double-gate blowout preventer with pipe rams in the bottom and blind rams in the top. Install a 10-inch 3000 psi rotating preventer and finish nippling up to drill out with air. After a WOC time of 12 hours, pressure-test surface casing and all preventers to 1000 psi for 15 minutes using rig pump and water. The internal pressure rating of new 8 5/8-inch O.D., 32-pound, K-55, 8 round thread, ST&C casing is 3930 psi.

5. Using air, blow water out of 8 5/8-inch O.D. casing. Drill a 7 7/8-inch hole with air to the top of the Lower Sunnyside coal seam or as indicated by the Geological Department. If air drilling is not feasible, a gel-water base mud system will be used. Samples will be caught at 30-foot intervals or at the discretion of the wellsite geologist.

Formation Tops:	Formation	Depth	Sea Level Datum
	Lower Sunnyside	2890	+ 4510
	Rock Canyon	3060	+ 4340
	Fish Creek	3080	+ 4320
	Gilson	3098	+ 4302
	Kenilworth	3143	+ 4257

6. Trip out of hole. Pick up a 7 7/8-inch diamond bit and a 5 3/4-inch core barrel and core approximately 160 feet of coal seams over the next 260 feet. Pull out of hole and lay down the core barrel and diamond bit.

7. Trip in hole and drill 7 7/8-inch hole to 50 feet below the bottom of the Gilson coal seam.

8. Rig up logging truck and run DIL, Sonic, Density, and Gamma Ray-Neutron logs to determine characteristics of coal and surrounding formations above and below coal seams as indicated by the Research Department.

9. Enter hole with 7 7/8-inch bit and drill pipe. Pull bit, laying down drill pipe and drill collars.

10. Conduct water injection tests and mini-fracture tests (see below).

11. Run 5 1/2-inch O.D., 15.5-pound, K-55, 8 round thread casing to 5 feet above the top of the Gilson coal seam. A Halliburton formation packer shoe will be run on bottom of casing as floating equipment. Weld top and bottom of first 4 joints of casing and guide shoe. Pump 100 barrels of mud prior to cementing. Cement casing and well to 500 feet above the top of the Gilson seam with regular cement treated with 2 percent by weight of calcium chloride. Actual cement volumes will be calculated from caliper

logs. Displace cement with water. Note: Cement should be as lightweight as possible.

12. Immediately after cementing operations are completed, land 5 1/2-inch O.D. casing with the full indicator weight on the slips in the 10-inch 3000 psi casing flange. Install a 10-inch 3000 psi by 6-inch 3000 psi Type B tubing spool. Pressure-test secondary seals and packing to 2000 psig for 5 minutes. Minimum collapse pressure for 5 1/2-inch O.D., 15.5-pound, K-55 casing is 4040 psi.

13. Install double-gate BOP with 2 7/8-inch pipe rams in top and blind rams in bottom and nipple up to drill out with air.

14. Rig up wireline unit and run cement bond log from PBD to top of cement.

15. After a WOC time of 20 hours, pressure-test casing and preventers to 2000 psi for 15 minutes using water and a pump truck. The minimum internal pressure rating for the 5 1/2-inch O.D., 15.5-pound, K-55 casing is 4810 psi and the wellhead is 3000 psi WOG and 6000 psi test.

16. Run in hole with 4 3/4-inch bit and 2 7/8-inch drill pipe. Use air from drilling rig to blow water out of wellbore. Using air, drill out guide shoe.

17. Flow well using rig air to clean out water. After water has been removed from wellbore, stop air injection. Monitor gas production by measuring flow through positive displacement gas meter with chart recorder. Use echometer to monitor water level and water influx into the wellbore. Repeat procedure by using rig air to clean out water again, stopping air injection, and monitoring production.

18. Kill well with water.

19. Pull bit, laying down drill pipe and drill collars. Release rig.

The samples of cores obtained from the coalbeds were confined in airtight canisters as soon as possible after being removed from the core barrel. These samples were tested by the Utah Geological and Mineral Survey (UGMS) for gas emissions using the standardized procedures developed by the U.S. Bureau of Mines. A duplicate analysis of these core samples for selected cores was completed by IGT. In addition, measurement of other critical coal properties was planned to be carried out by IGT.

3.3.2 <u>In-Situ Stress and Permeability Tests</u>. As mentioned in the drilling plan above, water injection and mini-fracturing tests were planned during the process of drilling. The results of this testing gave important insight into the characteristics of coal in this area.

Water injection tests were planned to determine in-situ permeabilities of the coal to water. This type of measurement has not been made for coals in this part of the country. It was planned that measurements of both relative permeability to gas and water and permeability to water would be measured in the laboratory. These laboratory measurements could then be compared with the field measurement of in-situ permeability to water. It was hoped that a correlation could be derived between the field measurements and the laboratory measurements. Such a correlation would prove to be valuable, since the field-measured permeabilities more accurately measure the effects of coal compressibility and natural fractures than the laboratory data.

The purpose of the mini-fracturing testing was to determine the relative in-situ stresses in the coal and surrounding strata. This would indicate whether a hydraulic stimulation was likely to propagate a fracture into the coalbed or whether propagation outside of the coalbed was likely to occur. Extensive experimentation by Sandia Laboratories indicates that a fracture will propagate in the direction of the least principal stress, and not necessarily in the rock or formation which has the least strength. The mini-fracture tests were scheduled prior to placing casing in the well. The tests consisted of isolating a narrow zone using retrievable packers and pumping water into this zone. Water injection was planned at a rate between 1 and 5 BPM. Injection pressures would be monitored and the pressure recorded corresponding to initial breakdown of the formation. This sequence of testing was to be carried out in the strata above and below the upper and lower coal seams, and in each coal seam itself. The initial breakdown pressure for the coal zone and the surrounding strata would then be compared to determine in which of these zones the hydraulic stimulation could be expected to propagate.

If air drilling was completed as planned, the water injection and mini-fracture testing would proceed as follows:

1. Run 2 3/8-inch tubing with Lynes packers spaced approximately 5 feet apart and with Amerada pressure recorder with 3000 psi range and 36-hour clock installed below bottom packer. Tubing is closed on bottom with perforations between packers.

2. Set top packer 20 feet below bottom of Gilson coal seam.

3. Rig up a Halliburton cement pumper, 2-inch turbine flow meter, and frac-van quality pressure recording equipment for both tubing and annulus. Install bypass line, with chemical injection pump in parallel with pumper truck.

4. Circulate water to displace all air and gas from tubing and annulus.

5. Stop water circulation, set upper packer, and monitor water level in tubing and annulus for 15 minutes with echometer.

6. Conduct mini-fracture on zone below Gilson coal with cement pumper, starting at 1 BPM and increasing pumping rate at 5-minute intervals until break in pressure curve is evident. Release pressure on tubing and move packers to center of Gilson coal seam.

7. Set bottom packer in Gilson coal seam.

8. Repeat step 5.

9. Pump water through tubing into the Gilson coalbed with chemical injection pump at constant rate of 1 BPD, recording injection pressure. Plot injection versus log time, continuing injection until pressure increase becomes linear or until pressure stabilizes.

10. Stop water injection and record pressure decline.

11. Repeat water injection procedure at rates of 2 BPD and 5 BPD.

12. Repeat step 6, then move packers to 10 feet above Gilson coal seam.

13. Set bottom packer.

14. Repeat steps 4 through 6.

15. Release pressure on tubing.

16. Pull tubing string and examine downhole pressure recorder to determine whether bottom packer seated sufficiently.

3.3.3 Prestimulation Completion Plan. An open hole completion was planned at the No. 1 well in Whitmore Park. Open hole completions have been demonstrated successfully at the U.S. Steel project in Alabama and the Emerald Mine project in Pennsylvania. This method of completion is preferred because higher gas production rates have resulted. Wells No. 2 and No. 3 were to be completed by casing the hole and perforating by cutting slots through the casing into the coal zones. A well completion plan for the Whitmore Park No. 1 well is given below. The completion plans for the second and third wells vary only slightly from the completion plan for the No. 1 well presented here. This plan is as follows:

1. Move in and rig up contract workover rig.
2. Install 2 3/8-inch pipe rams in top of double-gate BOP's.
3. Pick up Halliburton Hydrojet tool for 5 1/2-inch casing and run in hole on 2 3/8-inch O.D., 4.7-pound, J-55, 8 round thread, EUE tubing.
4. Rig up Halliburton pump truck and cut a 5-foot notch in the center of the Gilson coal seam. Depths are to be determined from open hole logs. Release pump truck.
5. Pull out of hole, standing tubing in derrick and laying down Halliburton Hydrojet tool.
6. Pick up 4 3/4-inch bit and run in hole on 2 3/8-inch O.D. tubing. Clean out to total depth of well.
7. Pull out of hole, standing tubing in derrick and laying down 4 3/4-inch bit.
8. Rig up gas line from main line tap. Use gas to blow water from well and then monitor gas and water production as in step 7 of drilling plan.
9. Pick up perforated joint of 2 3/8-inch seating nipple and Sperry-Sun downhole pressure chamber assembly and run in hole on 2 3/8-inch O.D., 4.7-pound, J-55, 8 round thread, EUE tubing. Land tubing 50 feet below bottom of Gilson coal seam on an H-1 tubing hanger. Note: It will be necessary to strap 3/32-inch tubing to the outside of 2 3/8-inch O.D. tubing. Hanger must be tapped to accept 3/32-inch tubing fitting on top and bottom.
10. Install 2-inch full opening valve in top of hanger and remove BOP's.

11. Pick up 1 1/2-inch pump and run in hole on 3/4-inch rods. Space out rods, install polish rod and install stuffing box.

12. Release workover rig.

13. Install pumping unit capable of pumping 200 BWPD from approximately 3100 feet.

14. Hook up test facilities and run production test.

15. Rig up contract workover rig.

16. Kill well, using water.

17. With well dead, remove upper wellhead, pull rod and pump, and install hydraulic double-gate BOP's with blind rams in bottom and 2 3/8-inch pipe rams in top.

18. Pull 2 3/8-inch tubing, standing same in derrick and laying down Sperry-Sun downhole pressure chamber assembly.

19. Run in hole open-ended with 2 3/8-inch tubing and land tubing just above Gilson coal seam.

3.3.4 Stimulation Plan. An extensive review was made by IGT and Mountain Fuel Supply personnel covering the key aspects of successful and unsuccessful methane recovery projects. Some computer modeling work was also done using the Intercomp production model, and some important observations were reached. It was concluded that the key to successful methane recovery is the hydraulic stimulation. A computer comparison of wells with short frac lengths versus longer frac lengths has shown that even over extended periods less methane will be recovered from a well with a short frac length than from one with a longer frac length. Because of the failure of most methane recovery projects to achieve frac lengths that equal the designed lengths, considerable emphasis was placed on obtaining improved laboratory and field data which would focus on improving the hydraulic stimulation design input.

IGT's review of experiences during prior methane recovery projects with emphasis on hydraulic fracturing of the coal seams supported the widespread feeling that foam fracturing generally results in greater gas production rates than other types of fracturing. The IGT review did not reveal a complete understanding of the reasons for this difference. Theoretically, foam fracturing has the advantages over other fluids of low fluid loss and being an ideal fluid for transport of proppant. However, it appears that foam fractures into coal have not been as effective as might be expected. Typically, excessively wide fractures have been observed near the wellbore in several instances where the wells have been mined out. IGT hypothesized that the wide fracture widths which have been observed can be the result only of very high fluid losses, the fluid loss resulting in a large quantity of proppant sand being deposited near the wellbore.

In several mineback situations the lack of proppant sand in the butt cleats intersecting the propped face cleat has been observed. It is therefore hypothesized that the apparent high fluid loss is due to a breakdown of the foam such that the gelled water and entrained sand remain in the fracture in the face cleat direction while the majority of the nitrogen leaks into the butt cleat system. A couple of observations which tend to support this hypothesis are as follows: Some observed foam fracs have been accompanied by an appearance of nitrogen at an observation well nearby during the stimulation operation. If large changes in the bottom hole treat pressure occur during a stimulation, breakdown of the foam will occur.

Because of the concerns and the observations mentioned above, special consideration was given to possible methods of preventing excessive fracture widths near the wellbore and the shortening of the fracture length. A need was seen to more accurately measure the bottom hole treating pressure during stimulation. It was planned that this would be accomplished by injecting a stream of nitrogen gas down the tubing while the remainder of the fracing fluid is being injected down the annulus in the wellbore. In addition, a gamma-ray device would monitor the densities of both the sand-laden liquid stream prior to adding the nitrogen and the foamed mixture following nitrogen addition. This permits more accurate control of the foam quality. In addition, extensive efforts were planned to collect both field and laboratory data which are pertinent to designing a hydraulic stimulation. Some of these critical data include permeability and porosity measurements, the elastic modulus, and fluid loss coefficients of the coal, as well as other parameters.

A moderate injection rate of approximately 20 BPM is planned for the Whitmore Park Well No. 1. IGT suggested that stimulation of the second or third wells should be at a higher pumping rate. Dowell personnel also suggested that higher pumping rates into coalbeds may give better results.

After a review of all of the previously discussed information, it was concluded that a nitrogen/foam stimulation equal to the largest previously used for coal seams should be attempted. A 50,000-gallon foam stimulation using 62,000 pounds of sand was selected for the first stimulation. Details of the stimulation design for Whitmore Park Well No. 1 are outlined in Table 12. Minor modifications were expected for the stimulations for Wells No. 2 and No. 3, based upon experience gained from the stimulation of Well No. 1.

3.4 GAS PRODUCTION PLAN

3.4.1 Production Modeling. In order to better understand some of the important properties in a methane recovery project, the computer production model developed by Intercomp Company was used to predict gas production. Different parameters were input into the computer model and a comparison was made between the input parameters. It was obvious from the early stages of this effort that a definite inadequacy of input data existed for coal characteristics for the coals in this part of the country. As mentioned previously, the testing and laboratory phases of this project were geared towards greatly improving the knowledge of coal characteristics for these specific locations. Because of the inadequacy of the input data into the computer model, accurate production predictions were not possible. However, the computer model does offer some valuable insight into the effects of different coal characteristics.

The modeling work did show the effect on predicted production rates of such parameters as water removal rates, fracture lengths, well spacing, and coal permeability and porosity.

TABLE 12 (Page 1 of 3)

Whitmore Park #1 Stimulation Design

FOAM DATA
****

DEPTH	3100.	FT
QUALITY AT BHTP & BHT	0.75	
BHTP	2400.	PSI
BHT	140.	DEG F
SURFACE TEMPERATURE	75.	DEG F
INJECTION RATE.	20.0	BPM
TUBING OD	2.375	IN.
CASING ID	4.778	IN.

BOTTOMHOLE CONDITIONS
****

TREATING PRESSURE (BOTTOM).	2400.	PSI
HYDROSTATIC PRESSURE (STATIC) . .	471.	PSI
HYDROSTATIC PRESSURE (DYNAMIC). .	782.	PSI
N2 VOLUME FACTOR	822.	SCF/BBL

SURFACE CONDITIONS - FOAM WITHOUTSAND
****

FRICTION PRESSURE LOSS.	508.	PSI
ACCELERATION PRESSURE LOSS.	-0.30	PSI
QUALITY AT SURFACE PRES & TEMP. .	0.77	
WATER RATE	5.0	BPM
N2 RATE	12853.	SCF/MIN
N2 GAS-LIQUID RATIO	2571.	SCF/BBL
FLUSH VOLUME (FOAM)	2173.	GALLONS
LIQUID VOLUME IN FOAM FLUSH . . .	524.0	GALLONS
FLUSH VOLUME (N2)	44.	MSCF
ISIP (FOAM)	1929.	PSI
ISIP (N2)	2160.	PSI
WELLHEAD TREATING PRESSURE. . . .	2126.	PSI

TREATMENT SCHEDULE VOLUMES
****

TREATING VOLUME	50000.	GALLONS
WATER VOLUME	12500.	GALLONS
N2 VOLUME	765.	MSCF
TREATING VOLUME	50000.	GALLONS
WATER VOLUME	12500.	GALLONS
N2 VOLUME	765.	MSCF

BED DEPOSITION FOR DESIGN NO. 1

PUMPING SCHEDULE
****

10000.0 GALLONS OF PAD VOLUME
4000.0 GALLONS WITH 0.50 LBS/GAL OF 20/40 MESH SAND
6000.0 GALLONS WITH 1.00 LBS/GAL OF 20/40 MESH SAND
12000.0 GALLONS WITH 1.50 LBS/GAL OF 20/40 MESH SAND
18000.0 GALLONS WITH 2.00 LBS/GAL OF 20/40 MESH SAND
620.0 SACKS TOTAL PROP

DEPOSITION PROFILES
****

AT THE END OF PUMPING :
CARRY DISTANCE . . . . 452.0 FT
MAX BED HEIGHT . . . . 0.0 FT
AVE BED HEIGHT . . . . 0.0 FT
% PROP DEPOSITED . . . . 0.0 %

DISTANCE FROM WELL	DEPOSITED PROP BED HEIGHT FT END OF PUMPING	FINAL	SUSPENDED PROP HEIGHT FT	CONC. #/GAL	#/SQ FT
4.0	0.0	5.3	40.0	2.0	2.66
40.0	0.0	5.3	40.0	2.0	2.66
68.0	0.0	5.3	40.0	2.0	2.63
104.0	0.0	5.3	40.0	2.0	2.63
132.0	0.0	5.4	40.0	2.0	2.58
168.0	0.0	5.5	40.0	2.0	2.58
196.0	0.0	4.4	40.0	1.5	1.87
232.0	0.0	4.0	40.0	1.5	1.87
264.0	0.0	4.1	40.0	1.5	1.77
300.0	0.0	4.2	40.0	1.5	1.77
332.0	0.0	3.2	40.0	1.0	1.09
368.0	0.0	2.9	40.0	1.0	1.09
404.0	0.0	1.8	40.0	0.5	0.50
440.0	0.0	1.5	40.0	0.5	0.50

EQUIVALENT BED
****

LENGTH = 452. FT
HEIGHT = 40.0 FT
BED CONCENTRATION = 1715. LB/1000 SQFT

TABLE 12

CONSTANT - WATER RATE,QUALITY,N2 RATE

QUALITY	0.75	
WATER RATE.	5.0	BPM
NITROGEN RATE	12859.	SCF/MIN
WELLHEAD PRESSURE . . .	2130.	PSI
FLUSH (FOAM).	2173.	GAL

STAGE #	TIME MIN	SLURRY RATE BPM	CUM WATER GAL	CUM N2 MSCF	CUM FOAM GAL	FOAM RATE BPM	SAND CONC LB/GAL WATER	FOAM	SAND SX
PAD	11.9		2500	153	10000	20.0			
1	16.7	5.5	3500	214	14000	20.5	2.00	0.50	20
2	23.8	5.9	5000	306	20000	20.9	4.00	1.00	80
3	38.1	6.4	8000	489	32000	21.4	6.00	1.50	260
4	59.5	6.8	12500	765	50000	21.8	8.00	2.00	620

Details of the modeling work accomplished by IGT are presented in the IGT Phase II Summary Report given in Section 5.0. Some of the major results obtained from this effort are outlined below:

1. Well spacing is an important parameter in the development of a methane drainage field. For example, three times more gas is produced from a well in an 80-acre spacing over a 20-year period as will be produced from a single well located in a very large reservoir. This is the result of removing sufficient water from the drainage area to decrease reservoir pressure, thereby permitting the desorption of a larger portion of the original adsorbed gas. However, it should be noted that for both spacing cases, the substantial difference in gas production was not observed until after two years.

2. It has been found that the shape of the relative permeability curve for two-phase flow through natural cleats and fractures in the coal seam is a very important factor on the gas production rate and on the ratio of produced gas to produced water. These factors may have an impact not only on the total gas being produced, but also upon the need for water pumping facilities in order to produce the gas. To illustrate this, the ratio of gas production to water production increases with time for a well in an 80-acre spacing plan. In contrast, if the well is an isolated well, the ratio is reduced with time. The result is that pumping may not always be necessary in an 80-acre field but it will always be necessary for an isolated well in a large reservoir.

3. The use of the computer model to predict long-range production will be valuable to make modifications to the operating and testing plan. Several computer runs were made in which peak gas production rates were not seen for a considerable period of time because of low water removal rates or because of low permeability of the coal. If a testing program were not sufficiently long, peak production rates may not be observed. This points out the

importance of appropriate input data for the computer model to predict peak production and make any necessary adjustments to the testing program.

3.4.2 Gathering System Design. Detailed design of the gas gathering system was completed during Phase II of the project. A schematic of this system is present in Figure 19. The system is very similar to other gas field recovery systems designed by Mountain Fuel Supply. It utilizes gas from the main transmission line as fuel for the pumps and compressor and to pressurize the control systems. Typical safety and shut-down systems are provided to protect the equipment. The compressor suction pressure is controlled by a recycle valve.

It should be noted that the production facilities for all three demonstration wells are the same. Figure 20 shows the field layout for these production facilities. This equipment consists of a sucker rod pump for water removal, separate lines for gas and water production, appropriate meters, an entrained water separator on the gas stream, a back-pressure control regulator, and a vent to the atmosphere equipped with a flame arrestor. These facilities were utilized from the beginning of the project. If sufficient quantities of gas are produced, the compression, filtration, and dehydration portions of the system will be added to the wells in the Whitmore Park area.

An important part of producing gas in this system is the need for water removal. Several methods were examined for water removal. The best service appeared to result through using sucker rod pumps. This type of pump was believed to be more reliable than downhole pumps, based on prior methane recovery projects. A sucker rod pump with the capacity to remove 200 BPD of water from a depth of 3100 feet was planned for the Whitmore Park No. 1 well. Similar pumps were planned for the second and third wells, but ordering of these pumps was scheduled after preliminary water production data had been obtained. The 200 BPD capacity was selected after conferring with several people who have had experience in methane production from western coal seams.

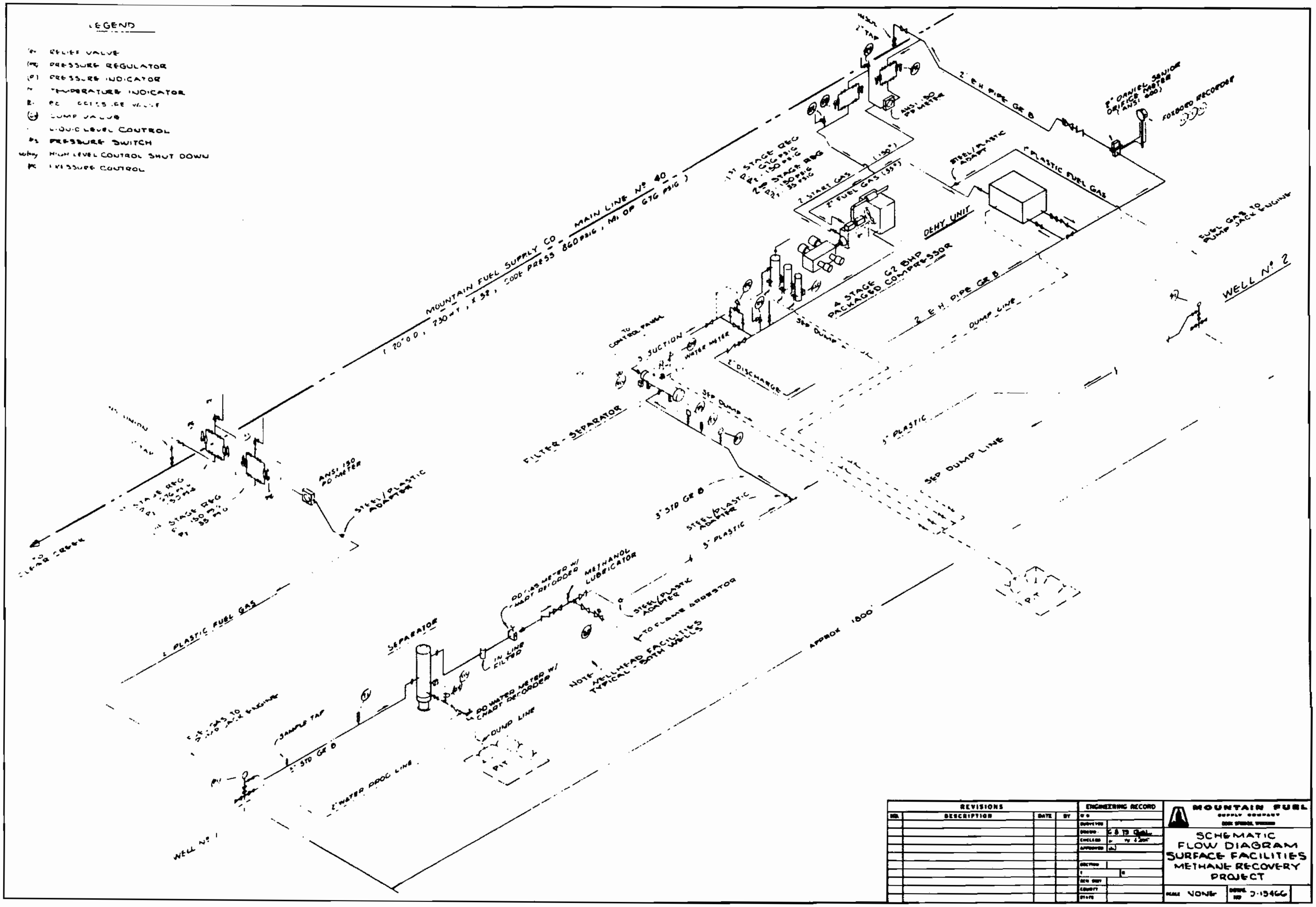


FIGURE 19

GAS GATHERING SYSTEM

3.4.3 Equipment Specifications. Detailed equipment specifications were developed in Phase II for the aboveground production and metering facilities. Specifications for the compressor and dehydration unit are presented in the Appendix. Each specification gives quality requirements for the controls and working systems. Bids for these major pieces of equipment as well as for the other aboveground equipment were received from manufacturers and suppliers, and selection of vendors for the wellsite equipment was completed. Selection of suppliers for the filter separators, compressor and dehydration unit was postponed until actual gas production rates were defined. A list of facility equipment requirements is given in the Appendix. This list shows the size, type, or quality of each piece of equipment that is required.

Concern was expressed by experienced personnel in Mountain Fuel's drilling department over the advisability of conducting tests and operating experimental facilities during the winter months. It is well known that drilling and operating costs can escalate very rapidly in the type of severe winter environment that exists in this area. Because of these concerns, it was planned that the prestimulation production tests on the Whitmore Park No. 1 well be extended only until severe weather hampered this operation. Stimulation of this well and the other wells would then be accomplished in the early spring during better weather conditions. However, production facilities were designed to allow future production to continue through the winter seasons.

Use of two idle Mountain Fuel sucker rod pumps was evaluated. However, it was found that these pumps would most likely not provide sufficient pumping capacity for this application. In addition, these pumps are quite old and would require extensive renovation. Therefore, a decision was made to purchase a new 200 BPD capacity pump which would give both the estimated capacity required as well as reliable service.

As can be seen from Figure 20, a water separator was designed for the gas production stream on each well. The purpose of this separator is to remove any entrained water found with the gas produced. This separator was sized to best handle this entrained water as well as being able to knock out some of the particulate matter which may be carried with the gas stream.

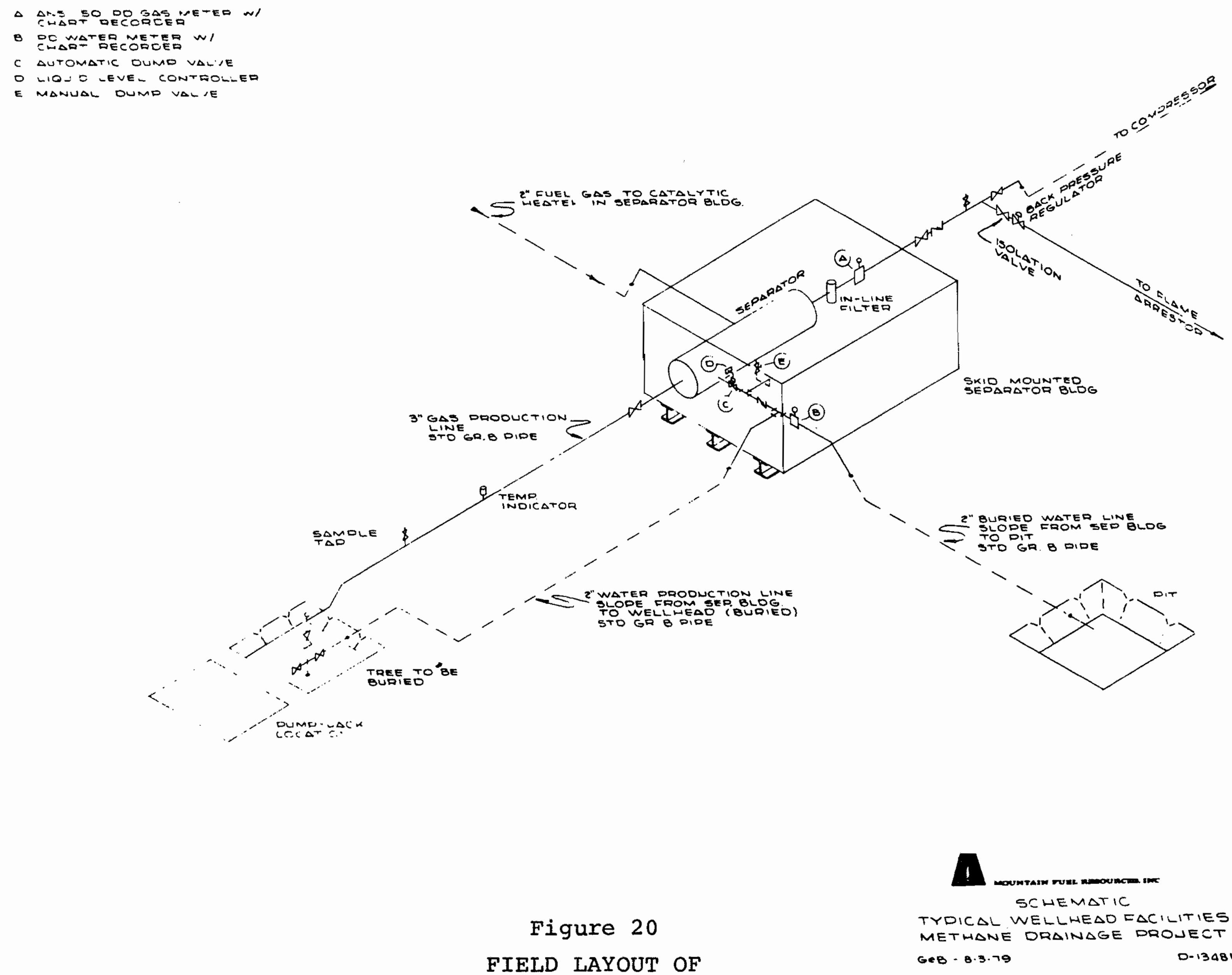


Figure 20

FIELD LAYOUT OF

PRODUCTION FACILITIES

The removal of particulate matter is important as additional protection against carrying this material into the compressor and eventually causing damage to the compressor.

3.5 TESTING OPERATIONS AND DATA COLLECTION

One of the most important aspects of the methane recovery from coalbeds project is the collection of data that will provide a better understanding of this technology and enhance gas production from this source. An effort was made to obtain and record all important data pertinent to various phases of the project. Major emphasis for data collection was directed towards understanding coal characteristics, designing the hydraulic stimulation, increasing gas production, and providing input for a long-range production model.

3.5.1 Testing. A comprehensive list of the tests planned during this project is given in Table 13. Field tests planned for the Whitmore Park Well No. 1 include: mini-fracturing, water injection for permeability, water and gas influx testing, initial static water level, prestimulation and poststimulation water and gas rates, and long-term water and gas production. After completion of the tests on the No. 1 well, the experience gained was used to determine which tests were appropriate for the subsequent wells. It was not deemed beneficial to conduct mini-fracturing and water injection testing on the second and third wells. The other tests for gas production were conducted for all three wells.

Measurements of the influx rates of both gas and water into the wellbore were scheduled immediately following the drilling of the first well. These measurements give an early indication of the capacity requirement for the water removal equipment and the gas handling equipment. Measurements of the water level in the wellbore were taken using an echometer after removing water in the wellbore using the drilling rig compressed air.

Both shorter-term prestimulation production tests and long-term production tests were planned for all three demonstration wells. Based on the recommendations of knowledgeable personnel, a decision was made to extend

TABLE 13

PRODUCTION AND OPERATION TESTING

	Testing	Test Method
A.	Preproduction Tests	
	1. In-situ permeability to water	Water injection testing
	2. In-situ stress in vicinity of coalbed	Mini-fracturing
	3. Prestimulation gas and water production	Continuous metering and recording
	4. Stimulation fluid flowback volumes	Meter at flowback tank
B.	Production Tests	
	1. Long-term gas production	Continuous metering and recording
	2. Long-term water production	Continuous metering and recording
	3. Different size hydraulic stimulation	Comparison of Well No. 1 vs. No. 2
	4. Individual coal zone production	Production logs: temperature, noise, radioactive gas
	5. Effect of variations in well bottom hole pressure	Vary compressor suction pressure

the initial prestimulation tests over a 3-month period. It was recommended that this prestimulation test be of sufficient duration to achieve stabilized gas production rates. The hydraulic stimulations were planned for the early spring of 1980. Following the stimulation, long-term gas and water production rates were monitored as previously planned.

It was planned that the size of the hydraulic stimulation treatments be varied between Wells No. 1 and No. 2. This would allow a comparison of the treatment size between these two wells to help understand what size of treatment is most economical compared to the amount of gas produced.

Tests to show the effect on gas production of variations in wellbore pressure were also planned. Gas production monitoring from individual zones, particularly for the Mathis Canyon No. 3 well, was scheduled.

3.5.2 Data Collection. A summary of the data planned to be collected during this methane recovery project is outlined in Table 14. This table lists data measured in the field as well as in the laboratory testing program conducted by IGT. The table also shows the methods for collecting these data. Most of the laboratory-measured data was derived by analyzing cores taken from each of the individual demonstration wells. These data were designed to provide valuable insight into the characteristics of coal in these specific areas, and also to provide part of the input data necessary to utilize the Intercomp computer model to predict long-range gas production.

The gas content of coals from each well was measured using the techniques developed over the past several years by the Bureau of Mines. Currently, the Utah Geological and Mineral Survey is under a contract with the Department of Energy to collect samples from coals in Utah and analyze them for gas content. The UGMS analyzed sample cores from all of the coal zones cored to determine the gas content for these individual zones. Duplicate analyses were made on selected zones using the same testing methods, but run in the IGT laboratory. These duplicate samples helped verify the validity and reproducibility of this test method.

3.5.3 Instrumentation. Instrumentation requirements for this project were developed by personnel in Mountain Fuel's engineering department. The instrumentation is consistent with typical field installations that Mountain Fuel has designed. Special precautions were taken to assure that this system was operable during severe winter weather. Complete metering was provided on each well on all incoming and outgoing streams. The meters used to measure gas and water production were positive displacement meters. This type of meter was chosen over other types of meters due to the unknown quantity of gas and water production expected from wells in this area. Each meter measuring gas production off the well was equipped with a spring-wound continuous recording chart. The field design for the gas metering system was designed so that an orifice meter run could be substituted for the positive displacement meter with very little effort. An orifice meter installed in this system would provide more accuracy in monitoring gas production once a range of production rates was defined.

TABLE 14

DATA COLLECTION

DATA	COLLECTION METHOD
A. Field Measured Data	
1. Wellhead pressure	Pressure recorder
2. Gas flow rate	Orifice meter
3. Gas temperature	Temperature recorder
4. Water flow rate	Orifice meter with recorder
5. Initial static water level	Echo meter and bottom hole pressure device
6. Initial reservoir pressure	Calculated from water level
7. Coal depth	Well logs
8. Coal thickness	Well logs
9. Initial gas desorption	Core testing
B. Laboratory Measured Data	
1. Coal porosity at in-situ conditions	Pressurized core analysis
2. Coal permeability at in-situ conditions	Pressurized core analysis
3. Coal methane content	Core analysis
4. Coal density	Core analysis
5. Coal mean effective particle diameter	Core analysis
6. Coal compressibility	Core analysis
7. Diffusivity in coal particle	Core analysis
8. Coal desorption isotherms	Core analysis
9. Coal water content	Core analysis
10. Gas composition	Gas bomb sample analysis
11. Gas gravity and viscosity	Laboratory analysis
12. Water quality	Laboratory analysis
13. Capillary pressure	Laboratory analysis

4.0 WORK COMPLETED DURING PHASE III

The plans made and approved during Phase II of this demonstration project were carried out during Phase III. This phase of the project was conducted over a 36-month period. The length of this phase was extended by mutual agreement with the Morgantown Energy Technology Center due to mechanical problems encountered and a delay in drilling the third demonstration well which resulted from a USGS drilling permit denial.

4.1 SITE LOCATIONS

Drilling sites for Whitmore Park Wells No. 1 and No. 2 were prepared for drilling the locations planned during Phase II of the project. The location of the third well was ultimately moved because of drilling permit delays discussed below.

4.1.1 USGS Drilling Permit Delay. Permits to drill all three demonstration wells were issued by the Utah State Division of Natural Resources. However, because the Mathis Canyon Well No. 3 was located on unleased federal coal, approval from the USGS was necessary. A project review meeting was held with key USGS personnel. At the meeting it was freely expressed by the Conservation Division District Engineer that he did not have the authority to grant a permit as this would set a national precedent. The USGS was concerned about the legal ownership of the gas, but even more concerned about possible damaging effects hydraulic fracturing might have on the coal. The permit was denied so that a formal appeal could be made that would automatically be addressed on the national USGS level. The permit denial stated that a permit could not be issued until the Solicitor's Office of the Department of the Interior decides whether the oil and gas lessee has the right under his lease to recover gas contained in coal.

On November 29, 1979, Mountain Fuel formally filed an appeal to the USGS denial of the Application for Permit to Drill this well under Federal Oil and Gas Lease No. U-15490. According to the decision statement, Mountain Fuel's request to drill was denied because the target coalbeds were "minable" because other mining was being conducted or requested at the same depths. Mountain Fuel based its appeal on three issues:

FIRST: That the coalbeds under the Mathis Canyon No. 3 well are in fact unminable, because the well is sited in a very narrow canyon, and the overburden under the sides of the canyon would exceed 3000 to 3200 feet. In addition, the high methane gas content of the coal (300+ scf/ton) would require excessive and costly air circulation equipment to meet mine safety gas concentration limits and thus render the coal economically unminable at today's prices.

SECOND: Even if the coal is minable, drilling and stimulation of the coalbed would not jeopardize later coal mining operations. It is Mountain Fuel's position that methane drainage will enhance future mining of coal. In support of this position we cited a letter from Kaiser Steel Corporation, Sunnyside, Utah. In effect, the letter says that methane drainage from coal would generally enhance safety of the miners by reducing methane concentrations and by decreasing the demand for ventilating air, which would mean less respirable rock dust would be present in the mine atmosphere. The letter also says that any degradation to the coal by a hydraulic stimulation would be negligible, and for the support of that position Mountain Fuel cited numerous authoritative articles.

THIRD: Mountain Fuel's final reason for appeal was a public policy argument that our national energy crisis demands that additional domestic energy resources such as methane recovery from coalbeds be developed.

After filing this appeal, Mountain Fuel attorneys made a continual effort to obtain a drilling permit. Eighteen months passed without any indication being given by the Solicitor's Office of the status of our appeal. This delay resulted in several problems: drilling and subsequent data collection from the third well could not be completed as scheduled; and the scheduled project completion date was drawing nearer.

Due to the approaching completion date of this project, the decision was made to select several alternate well sites for the third well. Each well site was selected and prioritized based on the following criteria:

1. Private coal ownership, thereby not requiring USGS approval;
2. Location within boundary of proposed unit (discussion follows);
3. Favorable gas lease ownership;
4. Total projected amount of coal;
5. Accessibility to site location; and
6. Projected coal depth.

The third project well was relocated to be in privately owned coal. The well was projected to be drilled to a 3500-foot depth and to encounter a total of at least 40 feet of coal.

Figure 21 shows the new location for the third project well in relation to the other project wells, and other available corehole data showing methane content of coals in the Book Cliffs coal field.

4.1.2 Unit Development. In order to retain most of the oil and gas lease acreage in this area, development was completed to unitize much of the lease acreage between Whitmore Park Well No. 1 and No. 2 and Mathis Canyon Well No. 3. The leases covering the Mathis Canyon Well No. 3 and other sites with very high methane recovery potential are contained within the unit boundaries. Coal contours, total coal thickness and an economic analysis were used to define the basis for the unit boundaries. It was planned that the third well would satisfy the first well requirement under the unit agreement. A complete copy of the unit proposal is appended.

Final approval of the Whitmore Unit was granted during August 1981. The unit encompasses 13,848 acres. Mountain Fuel holds some interest in about 72 percent of this acreage.

4.2 DRILLING PROGRAM

4.2.1 Whitmore Park Well No. 1. On October 5, 1979, drilling began on Whitmore Park Well No. 1, the first of three wells to be drilled during this project. A daily log of drilling activities for this well is presented in the Appendix. Surface casing was set to 200 feet and, using

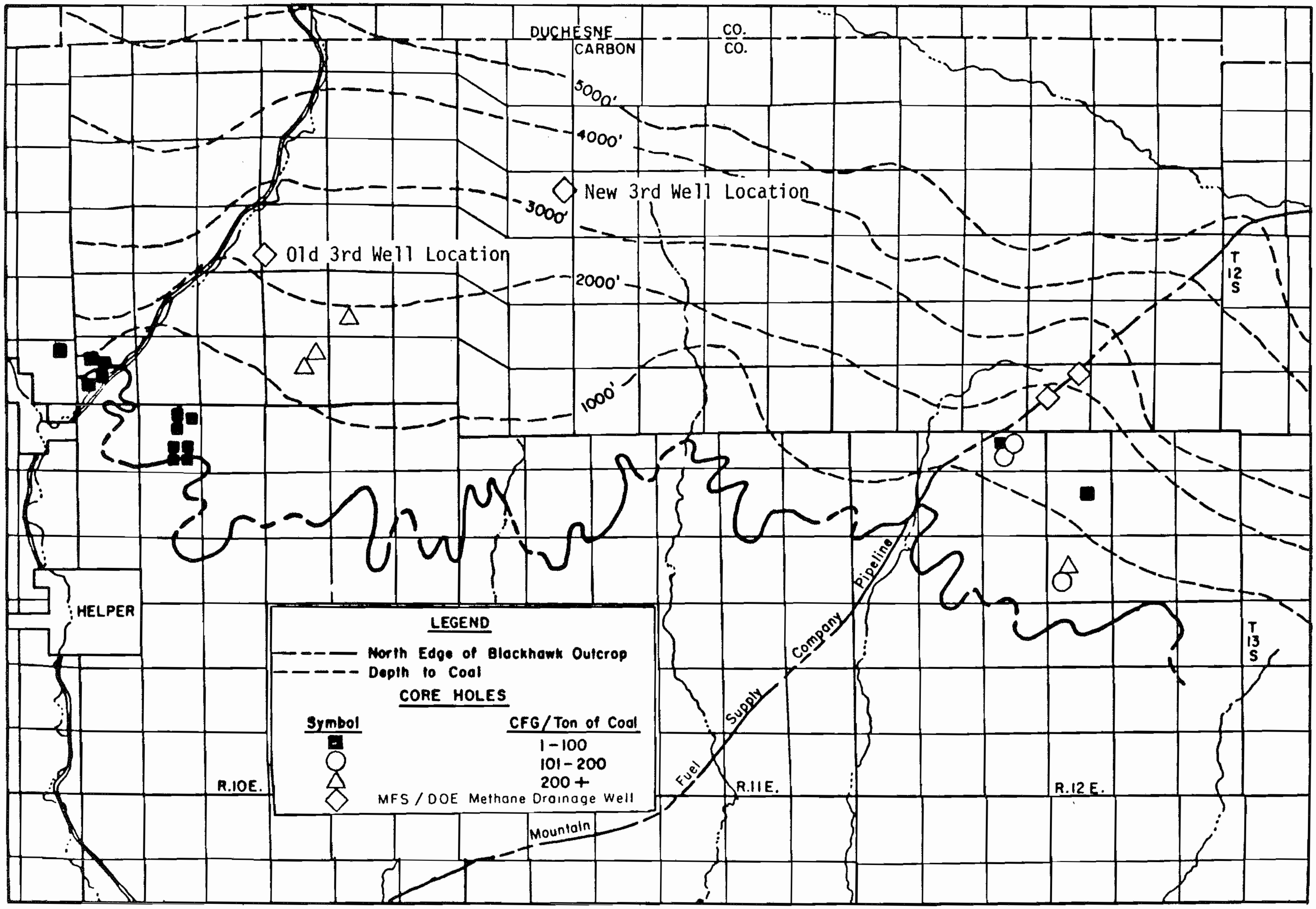


FIGURE 21
REVISED 3rd WELL LOCATION MAP

BOOK CLIFFS AREA
Carbon County, Utah

air circulation, drilling proceeded to a depth of 760 feet. At this depth an artesian aquifer was encountered which produced an estimated 10 BPM while drilling with air circulation. This aquifer was not known to exist in this area. Air circulation was stopped and conversion to mud circulation was made. After air circulation was halted, the aquifer produced an estimated 6 GPM of fresh water and, after shut-in for 12 hours, produced a surface pressure of 50 psig. The water flow was contained by drilling with 9.7 lb/gal mud.

Drilling with mud circulation proceeded to 2650 feet. Some difficulty was experienced in controlling the weight of the drilling mud. If the mud became too light, the aquifer zone would begin to produce water; while if the mud weight was too heavy, circulation losses occurred. The rate of drilling with mud was only about one-fourth as fast as with air.

Based on limited data from nearby core holes, this well was projected to encounter the Sunnyside coal seam at 2666 feet. This projection was based on formation inclines indicated by surface measurements to have an 8 degree northerly dip; however, it was later found that the actual dip was 12 degrees. Therefore, the coal seams were encountered at lower depths than projected. Table 15 below lists the projected coal seam depths versus actual depths. It also shows the thickness of the coal seams encountered.

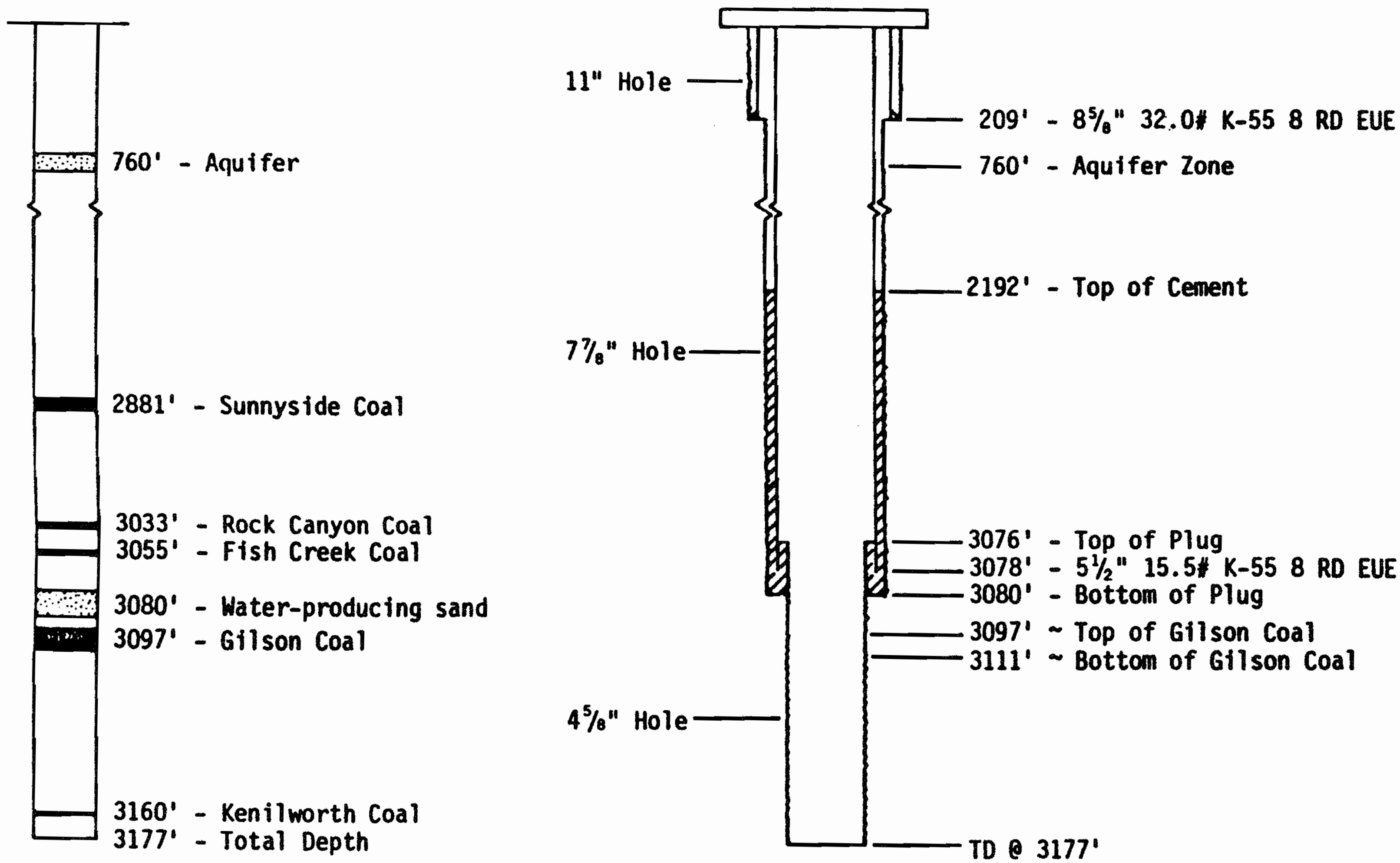
TABLE 15

Coal Seam	Projected Depth	Actual Depth	Actual Thickness
Sunnyside	2666	2881	17
Rock Canyon	2836	3033	5
Fish Creek	2856	3055	4
Gilson	2874	3097	15
Kenilworth	2937	3160	2

Coring was initiated at a depth of 2650 feet. Because excessive reaming was necessary to keep the core barrels from binding and because of restricted mud circulation due to pump problems, only 142 feet was cored over a period of 7 days. Because of the slow coring progress and since it was then apparent the projected depths were in error, a decision was made to drill through the upper coal seams. Penetration of the coal seams was clearly apparent from the increase in the drilling rate. Based on observations of the depths of the upper seams, the depth of the Gilson coal seam was projected to be near 3100 feet. Drilling proceeded to 3080 feet, and then 5 1/2-inch casing was cemented in place to a depth of 3078 feet. A 4 5/8-inch bit was used to drill through the cement plug at the bottom of the 5 1/2-inch casing. Water production was immediately encountered; however, the volume did not prevent coring and drilling with air circulation below this depth. The hole was cored below 3080 feet using a 4 5/8-inch diamond core head which produces a 1 1/2-inch diameter core. A total of 46 feet was cored and 39 feet of core were recovered, including 7 feet of coal core from the Gilson seam. Coring was completed to a depth of 3126 feet. Some gas production was apparent while coring through the coal. Although the coal core recovery was not complete and the coal was badly broken, 2 good samples were obtained for desorption analysis. Enough coal core was also obtained for the Institute of Gas Technology to test the coal for permeability, porosity, compressibility, and coal characterization analyses.

After coring of the Gilson coal seam, drilling was resumed to a total depth of 3177 feet. Drilling and formation depths for this well are shown in Figure 22. This figure also shows the initial completion status of the well.

A complete set of logs was run on the open hole well before casing was set at a depth of 3080 feet. A second set of logs, cement bond log and gamma-ray log, was run after drilling of the well was completed. Key portions of these logs are included in the Appendix. The logs showed a good cement bond from the bottom of the casing to several hundred feet above the Sunnyside coal seam. A permeable sand was observed from cores to extend from about 8 feet above the Gilson coal seam to the bottom of the casing. Eight feet of a very tight siltstone exists immediately above the Gilson and approximately 12 feet of black shale is immediately below the Gilson coal. A core sample of the siltstone was obtained by IGT for analysis. A verbal communication from IGT indicated a measurement of permeability of the siltstone to be approximately 0.05 millidarcies. It was concluded that the



WHITMORE PARK WELL NO. 1
INITIAL COMPLETION DATA
Figure 22

water production below the casing was coming from the sand zone just below the casing and not from the artesian aquifer found at 760 feet.

The drilling of this well emphasized some of the typical problems that can be encountered while drilling the first well in a virgin area. The unknown depth of the coalbeds, the water aquifer, and the other water producing zones that caused the wellbore to sluff, greatly extended the drilling time. This well was expected to be drilled in 10 days, but instead took 27 days to complete.

4.2.2 Whitmore Park Well No. 2. The second project well was spudded on November 1, 1979, and drilling commenced on November 2. A daily log of drilling activities for this well is presented in the Appendix. Several changes from the original drilling plan were made to eliminate the problems encountered in drilling the first well. It was planned that surface casing would be set deep enough to cover the artesian aquifer encountered on the first well. This aquifer was projected to be at a depth of 600 feet. However, it was not encountered even though the two wells are only 1807 feet apart. Surface casing was set to 784 feet with 9 5/8-inch OD, 36#, K-55 casing. Drilling went very slowly at the start because of extremely hard rock and the inability to put sufficient weight on the bit.

Coring was initiated at a depth of 2550 feet. Two days of coring were completed using air; however, the progress was very slow. The core barrel jammed several times, each resulting in recovery of only a partially full core barrel. Several trips into the well were made to clean out bridges at 1400 feet, 1800 feet, and 2000 feet. These same tight spots had to be drilled out three separate times. The formations at these depths were producing enough water to result in continual sluffing of the walls. A conversion to mud coring was made to reduce the sluffing problem. Although some improvement was seen, the well still had to be reamed several times.

Based on data from the first well, this well was projected to encounter the Sunnyside coal seam at 2568 feet. All the coal seams were encountered at depths approximately 150 feet deeper than projected. Table 16 below lists the projected coal seam depths versus actual depths. It also shows the thickness of the coal seams.

TABLE 16

Coal Seam	Projected Depth	Actual Depth	Actual Thickness
Sunnyside	2568	2681 (top parting)	12 (4 partings)
Rock Canyon	2720	2864	4
Fish Creek	2742	2876	2
Gilson	2783	2932	13
Kenilworth	2806	2985	2

The coring on this well produced 3 1/2-inch diameter cores. Core samples containing coal from all of the four upper seams were obtained. Samples for desorption were collected by IGT, Mountain Fuel Supply and the Utah Geological and Mineral Survey. Most of the coal cores were broken and consisted of small pieces. However, several large pieces of Gilson coal were recovered. These were to be used by IGT to cut sample plugs for permeability measurements. After the cores of Gilson coal were recovered, the well was drilled to a total depth of 3000 feet. The total depth was considered to be shallow enough to avoid encountering the Kenilworth sandstone known to exist below the Kenilworth coalbed, but deep enough to provide an adequate sump for the dewatering pump.

A complete set of logs was run on the open hole before casing was set. Portions of these logs are included in the Appendix. The drilling rig was released on November 22, after 21 days of drilling.

4.2.3 Whitmore Unit No. 1 Well. Spudding and drilling to set surface conductor pipe for the third project well began August 31, 1981. Drilling activity in this part of the country had been very heavy at that time and resulted in a shortage of available drilling rigs. After approval of the specific drilling site was granted, no rigs were available until mid-September. Even then, only a smaller and older-than-desirable rig was all that was available. Actual drilling began on September 22.

The plan for drilling this well was to drill to the coal depth as quickly as possible using air, pick the top of the uppermost coal from the drilling breaks, adjust the coring intervals from these data, and core a minimum amount to obtain coal samples for methane content analysis. The plan also called for drilling to a depth of 1000 feet before setting any surface casing. This would allow any shallow aquifers to be located behind casing so that the rest of the well could be completed by air drilling. These and other refinements based on the drilling experiences on the first two wells were included in the plan to minimize the risk of encountering problems in drilling which might result in project cost overruns.

The initial drilling to a depth of 1004 feet was completed with air drilling and without problems. No aquifers were found to this depth and the surface casing was set. After this time, numerous problems began. The rig and other equipment broke down several times, causing delays. At a depth of 1500 feet some water began to be produced. By the time a depth of 1756 feet was reached, 150 BPH of water was flowing into the well and drilling with air was terminated. The conversion to mud drilling was completed early in October. The drilling progressed much slower than anticipated because of numerous rig breakdowns and the time lost for repairs. Most of this lost time was not charged because the terms of the contract with the drilling rig only allow for a small amount of downtime to be charged. A detailed drilling report is included in the Appendix.

Drilling continued while watching for the anticipated drilling breaks and cutting samples showing coal to signal the first coalbed. The exact coring intervals would then be selected. This approach was designed to avoid cutting cores where no coals exist. Since the nearest well was over 4 miles away, the exact coal depths were unknown. The top coal was projected to be 2780 feet deep. However, the first drilling break was not encountered until 2951 feet, which was thought to be the beginning of the coalbeds. Three cores were recovered from 2962 feet to 3013 feet without any coalbeds being encountered. Based on cost considerations, it was decided to discontinue coring until a larger drilling break was encountered and cutting samples could verify that a coalbed had been found. Data from the nearest well indicated the existence of 2 or 3 coalbeds in excess of 20 feet thick. A drilling break greater than 8 feet would indicate that drilling had reached one of these large coalbeds.

Drilling continued without encountering any other coals until a depth of 3512 feet was reached. When a drilling break greater than 8 feet was encountered, drilling would be stopped and cores cut. However, no breaks larger than 6 feet were ever encountered and no cores were cut. Cutting samples were, however, obtained from 4 coalbeds and sealed in canisters for desorption analysis. These cutting samples were desorbed by Mountain Fuel Resources' personnel and corrections estimated for lost gas.

As the depth of 3715 feet was reached, the small drilling rig neared its capacity to lift the drill string from the well. Six small coalbeds had been reached to this depth. The depth and thickness of these beds supported the belief that more coalbeds, which were possibly thicker, lay at greater depths and that the lowest coal might be as deep as 4200 feet.

It was decided to put on a new drilling bit and remove 4 of the 12 drill collars to reduce the weight of the drill string. Drilling would continue until this bit was completely worn out. Drilling proceeded at a rate only slightly slower than with the weight of a full set of drill collars on the bit. Drilling stopped at a depth of 4062 feet after 8 more small coalbeds were drilled. A complete suite of logs was then run. The deepest coal was a 4-foot zone from 4015 to 4019 feet. When the well was cleaned following logging, 48 more feet were drilled to give more rathole below the lowest coal. Total depth of the well was 4110 feet.

A complete set of logs was run and portions of which are shown in the Appendix. They indicate a total of 42 feet of coal was encountered in this well.

4.3 PRESTIMULATION TESTING

4.3.1 Water Injection Tests. Testing of Whitmore Park Well No. 1 well was accomplished using Lynes packers. A combination of Lynes packer tools was run on 2 3/8-inch tubing and oriented to the Gilson coalbed. The system consisted of two Lynes retrievable packers spaced 12 feet apart to straddle the Gilson coalbed. Pressure recording bombs were located above and below the two packers with production ports located above, between, and below the packers. After the packers were inflated and set in position, each set of ports could be opened individually. This allowed the tubing to be opened to any of the 3 zones. Testing of each individual zone could then be accomplished without relocating the packers.

Each Lynes packer has a seating surface approximately 4 feet in length. When set in their final position, each packer covered the interface between the coal and the surrounding formation. Figure 23 shows the testing configuration with the Lynes packers. Proper packer seating was tested by pulling on the tubing string once the packers were inflated. Further verification was made by comparing the annulus and tubing water levels during testing as measured by an echometer and by comparing tubing and annulus pressure readings from the pressure recorder bombs. Satisfactory packer sealing was maintained throughout the injection and swabbing tests.

A series of water injection tests and swabbing tests was carried out on each zone. The first water injection tests were made into the Gilson coalbed at very low rates using a small, air-driven injection pump. This pump was to operate at a constant rate and the resulting pressure data was to be monitored and used to calculate permeability. However, a constant injection rate was very difficult to maintain. Fortunately, the coalbed showed high permeability to water, and after the initial tests with the small pump at about 1.3 GPM, tests were made at a 1.5 BPM rate using a Halliburton cement pumper truck. Pumping rates and pressures were also recorded on a Halliburton strip chart. A list of the injection test data for the Gilson coalbed is shown in Table 17. Pertinent portions of the strip chart recordings are shown in Figure 24 for injection testing into the Gilson coal.

Table 18 presents data from injection tests into the zone above the Gilson seam. This zone took water very readily at injection rates from 0.8 to 4.9 BPM and the surface pressure buildup occurred very rapidly. Even at the highest injection rate of 4.9 BPM, the surface pressure stabilized almost immediately at 1750 psig, as shown in the strip chart recordings given in Figure 25.

A series of multi-rate injection tests was also run on the upper formation. This consisted of changing the injection rate in steps and

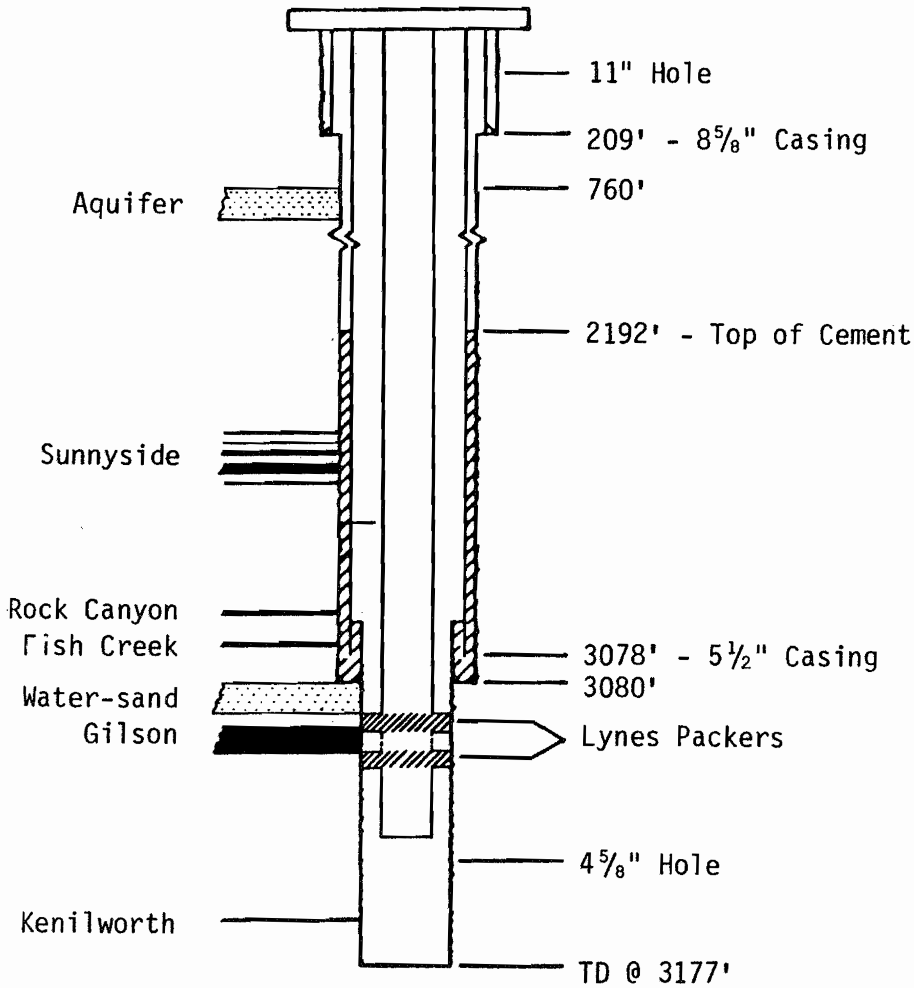


FIGURE 23

WHITMORE PARK WELL NO. 2

PRODUCTION TESTING CONTIGURATION

TABLE 17. WATER INJECTION TESTING DATA - GILSON COALBED

Date: November 3, 1979 Well: Whitmore Park No. 1 Zone: 3098-3314 ft.

Time	Lapsed Time, Sec	Injection Rate, gpm	Surface Pressure, psi
1:11 pm	0	1.4	48
1:25	880	1.3	60
1:28	1112	1.3	70
1:36	0	2.2	70
	67	1.8	80
	122	1.3	82
	235	1.5	87
	405	1.3	91
	540	1.3	95
	672	1.3	97
	965	1.3	99
1:55	0	1.2	97
	82	1.7	105
	140	1.4	110
	210	1.5	113
	275	1.5	113
	340	1.5	115
	405	1.4	118
	475	1.7	118
	535	1.5	118
	603	1.6	118
	667	1.6	120
	731	1.6	120
2:14	0	0.47	325
2:16	2	"	360
2:18	4	"	380
2:22	8	"	425
2:24	10	"	450
2:26	12	"	455
2:28	14	"	470
2:30	16	"	478
2:32	18	"	490
2:34	20	"	500
2:36	22	"	520
2:38	24	0.47	525
2:40	26	"	535
2:42	28	"	535
2:44	30	"	545
2:46	32	"	545
2:48	34	"	545
2:50	0	0.87	680
2:52	2	"	700
2:54	4	"	725
2:56	0	1.50	900
2:58	0	0.47	655
3:00	2	0.47	615

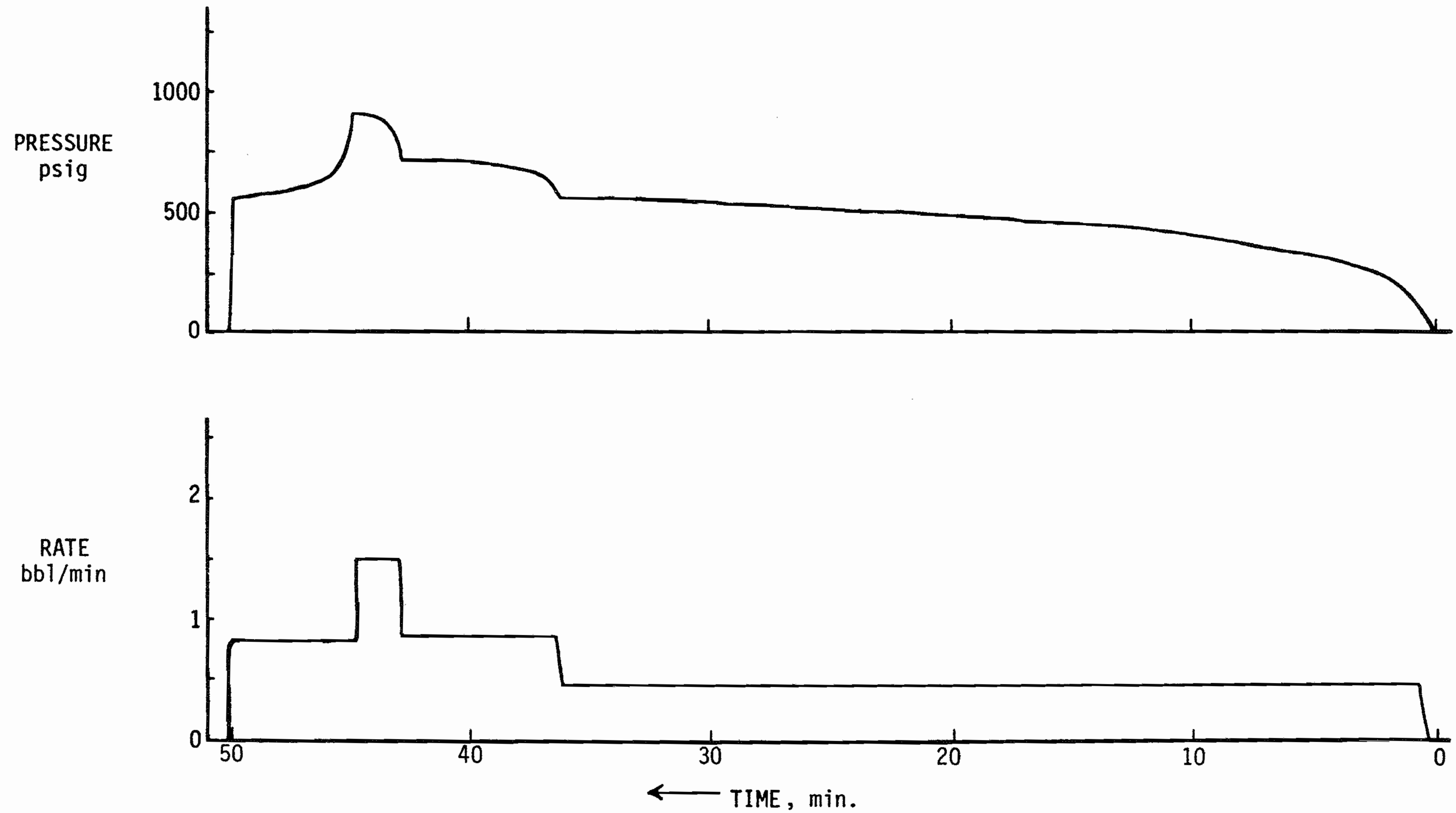


FIGURE 24

WHITMORE PARK WELL NO. 1

WATER INJECTION INTO GILSON COAL

TABLE 18. WATER INJECTION TESTING DATA
FORMATION ABOVE GILSON COALBED

Date: November 3, 1979
Well: Whitmore Park No. 1
Zone: 3080-3098 feet

Time	Lapsed Time, Min	Injection Rate, BPM	Surface Pressure, psi Gauge	Surface Pressure, psi Transducer
3:19 pm	0	variable	210	
3:20	0	.83	285	250
3:22	2	"	285	250
3:24	4	"	285	250
3:27	0	1.54	430	390
3:30	0	2.5	700	670
3:31	0	1.45	325	280
3:32	1	"	315	280
3:33	2	"	315	280
3:39	0	4.9	1750	1750

TABLE 19. MULTI-RATE INJECTION TESTING DATA*
FORMATION ABOVE GILSON COALBED

Date: November 3, 1979
Well: Whitmore Park No. 1
Zone: 3080-3098 feet

Time	Injection Rate, BPM	Stabilized Surface Pressure, psi Tubing	Stabilized Surface Pressure, psi Annulus
5:03 pm	3.5	980	280
5:04	3.08	810	250
5:05	2.55	600	180
5:07	2.1	410	130
5:10	1.4	220	80

*Pressure decline tests conducted. Water was injected to raise pressure, then pressure decline to be observed, but formation took water so rapidly that a constant injection rate and constant pressure were observed.

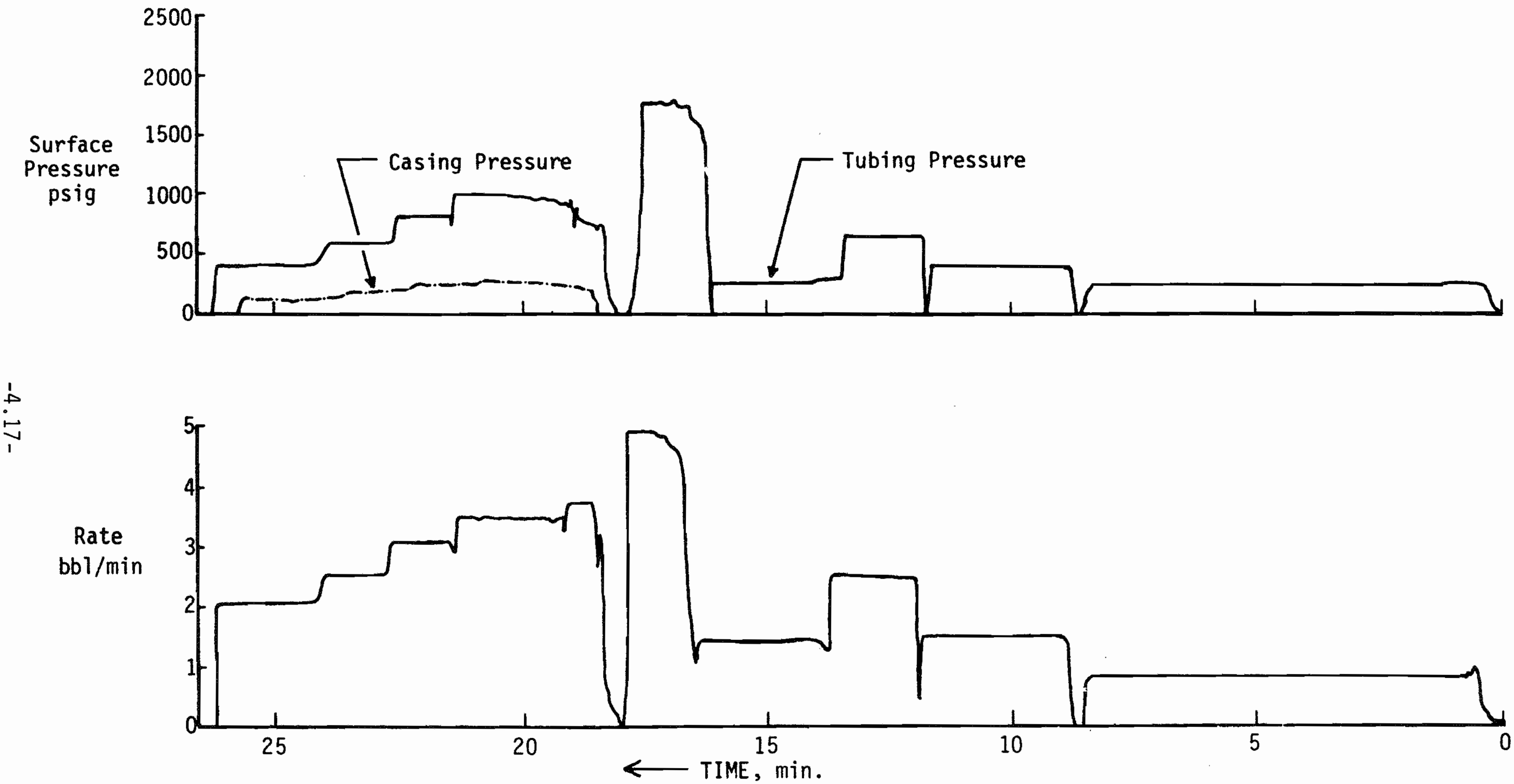


FIGURE 25

WHITMORE PARK WELL NO. 1

WATER INJECTION ABOVE GILSON COAL

monitoring the corresponding stabilized pressure. With each injection rate change, the pressure stabilized almost immediately. A listing of the injection rates and stabilized pressures is given in Table 19.

No attempt was made to conduct the mini-fracture that had previously been planned for the formation above the coal because extremely high rates would have been required, and any fracturing would have increased the water production from this formation.

Testing of the formation below the Gilson coalbed showed this formation to be almost impermeable. The formation would not accept sufficient water to conduct injection tests, so pressure decline tests were completed on this zone. These tests consisted of raising the pressure on the formation and monitoring the pressure decline during zero flow conditions. Pressure decline curves were developed from peak pressures ranging from 580 to 2700 psig. Pressure decline curves are shown in Figure 26. Higher pressure tests, including mini-fracture tests, were not attempted due to pressure limitations of the wellhead and injection piping. No evidence of a mini-fracture was observed for this formation even during the highest pressure test.

No water injection tests were conducted on either the second or third project wells.

4.3.2 Swab Tests and Influx Rates. A major part of the preliminary testing was conducting a series of swab tests which were completed on each of the three wells. The purposes of the swab tests were to remove water from the well and note any gas production, to measure the water influx from each formation, and to use the water influx data to calculate formation permeabilities. The water influx data were useful in properly sizing the water pumping equipment.

The swab testing on Whitmore Park Well No. 1 was completed on each of the three formations isolated by the Lynes packer system. The Gilson coal zone was swabbed first. After the water level was reduced from an initial depth of 540 feet to a depth of approximately 2000 feet, gas production was observed with each subsequent swab run. The gas appeared ahead of the

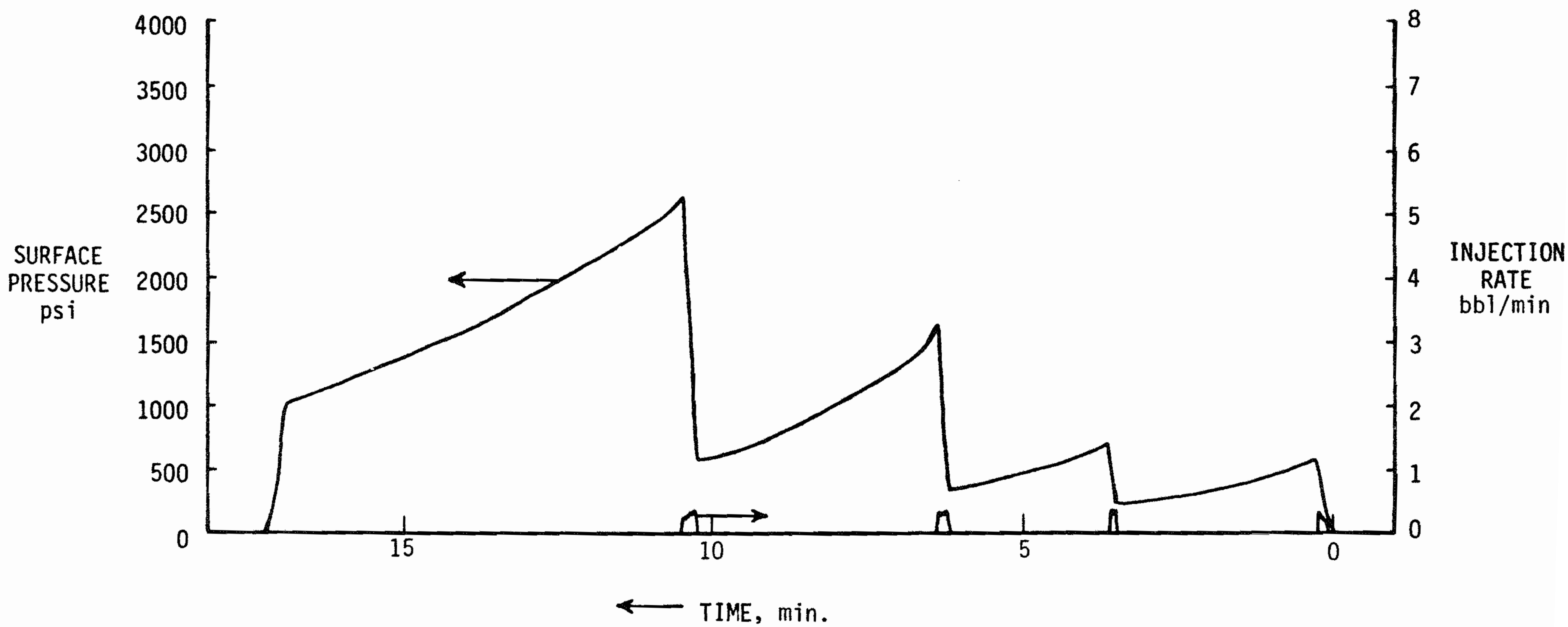


FIGURE 26

WHITMORE PARK WELL No. 1

PRESSURE DECLINE TESTS BELOW GILSON COAL column of water being swabbed and continued to appear in slugs with the water. The gas was ignited and flared during each of these swab runs. Gas was also detected during the swabbing of the formations below and above the Gilson coal zone.

Even though water injection into the formation below the Gilson coalbed was not possible, swab tests were successfully completed on this zone. This result was very surprising. Echometer data on water levels indicated that the formation was producing water during the swab runs. A field check of the pressure recording made by the pressure bomb located below the bottom Lynes packer indicated that this formation did see the high pressures applied at the surface.

The most significant conclusion derived from the swab data is that the formation above the Gilson coal produces water at rates in excess of the capacity of the pumping equipment that had been procured for this well. Cores and log data for this well showed that a permeable zone producing the high water influx rates is separated from the Gilson coal by a layer of relatively impermeable shale. This shale layer extends about 10 feet above the top of the Gilson seam.

In order to contain the water produced from this zone and the zone below the Gilson coalbed, a decision has been made to install a 3½-inch diameter liner over the open hole and to extend the casing to the total depth drilled. Perforations were then made to open the coal zone to production.

Two sequences of swab testing to measure influx rates were completed on Whitmore Park Well No. 2. The first was done on the zone isolated by the Pengo completion tool and the second on the entire open hole portion of the well.

After casing was set, tubing was run into the well to engage the mechanism used to open and close the ports between the Pengo packers. Swabbing equipment was then used to swab as much water from the well as possible before opening the Pengo tool to the Sunnyside coalbed located at a depth of 2700 feet. After swabbing the water level to 2200 feet, the Pengo ports were opened but no indication of either gas or water influx was detected. The tubing was connected to a positive displacement gas meter but no flow was measured. Several readings of the water level were made with an echometer but no change in water level was noted. The well was closed off at the surface and allowed to sit overnight with the Pengo ports open to the coal zone. Echometer readings of the water level the next day indicated that no water had come into the well during a 15-hour period. Two more swab runs were made with still no water or gas production. After the attempt to produce gas and water from the Sunnyside coal zone isolated by the Pengo system, the cement plug left in the bottom of the casing was drilled out. Swab tests were then run on this well similar to the Well No. 1 tests. These tests as shown in Table 20 indicated that the entire open hole formation produced from 71 to 162 BPD of water.

Completion of the open hole was made and swab tests were conducted through tubing set to a depth of 2970 feet. Gas production was observed after the water level was reduced from 400 feet to an approximate depth of 1800 feet. The gas appeared ahead of the column of water being swabbed and continued to appear in slugs with the water. Each subsequent swab run produced gas which was ignited and flared.

During the later swab runs, some uncertainty arose concerning the accuracy of tne water level measurements. The water level was detected by the rig operator when the swab cups were being lowered into the well. When the cups hit the water, the wireline goes slack. However, during most of the last swab runs, an indication of a water level was noted but was followed by a stronger water level indication at a lower depth. Echometer water level measurements taken during this same time period did not agree with the swab data. It is believed that the echometer data provide a more accurate measure of relative water level changes. Therefore, during the last five swab runs, an echometer shot was run just prior to pulling the swab from the bottom. A complete listing of all the echometer tests conducted on Well No. 2 is given in the Appendix.

Gas production from Well No. 2 was measured over a 20-minute period after the water level was reduced to 1800 feet below the surface. With the resulting hydrostatic pressure of 490 psi on the formation, a production rate of 189 cfd was measured.

TABLE 20
WHITMORE PARK

SUMMARY OF WATER INFLUX FROM SWAB TESTS

Production Zone	Depth ft.	Minimum Water Influx		Maximum Water Influx	
		Rate B/D	Formation Face Pres. psi	Rate B/D	Formation Face Pres. psi
WELL NO. 1					
Gilson Coal	3097-3111	51	430	78	380
Below Gilson Coal	3111-3177	130	340	220	340
Above Gilson Coal	3080-3097	610	1000	1040	960
WELL NO. 2					
Open Hole	2928-3000	71	580	162	620

Several encouraging signs were observed during the swabbing of Whitmore Unit No. 1 well. After drilling and completion, the well had to be killed by filling the wellbore with fresh water. When swabbing was initiated after being shut-in for a month, the initial water level was found at a depth of approximately 500 feet. No pressure was measured on either the tubing or the annulus. Swabbing began and a total of 2,300 gallons of fluid level was produced after several swab runs. The well was shut-in overnight.

Starting the second day of swabbing the well had built up 50 psig on the tubing and 300 psig on the annulus. Swabbing continued for 9 hours with approximately 7,600 gallons of water being recovered. During the day it was determined that the water level could not be reduced below a depth of about 1,600 feet. The rate of water influx into the well was equal to the rate water could be swabbed from the well. The average rate of water production during these operations was 530 BPD. It was anticipated that water production would exceed this rate as the pressure on the coal formations was reduced by further lowering the water level in the well.

Gas production was observed with the swab water after several runs were made. After two hours of swabbing, when the water level had been lowered to a 1,600 foot depth, large volumes of gas were returned with the swab water and the gas was ignited. Although no gas measurements were made, it was apparent from the size of the flare that the gas production continued to increase as the swabbing continued and the water level in the well was maintained at the 1,600 foot depth.

A third day of swabbing was conducted in order to obtain gas production measurements from the well. Overnight, the wellhead pressure had built to 210 psig on the tubing and 1,070 psig on the annulus. Some gas flowed from both the tubing and annulus prior to swabbing but for only a few minutes. The fluid level was measured to be 500 feet from the surface and swabbing through the tubing was started. After one hour of swabbing the water level was reduced to 1,600 feet and the annulus was opened to flow. Gas flow from the annulus was flowed through an orifice well tester initially with a 0.0625-inch orifice. The pressure drop across the orifice increased each time a swab run was completed until a maximum pressure drop of 100 psi was reached. When the orifice was changed it was found to be partially closed due to a buildup of ice. A 1.000-inch orifice was installed and it was observed shortly thereafter that a continuous flow of water was passing through the annulus. The water flow became more intermittent as the gas production again increased, as had been observed the day before.

Swabbing through the tubing was stopped and the annulus was shut in for 30 minutes to allow the water to settle. When the annulus was reopened, some water was still flowing with the gas. However, the water production gradually decreased until only occasional slugs of water were being returned. During this period the gas production was measured while no water was flowing. Two readings were obtained for each of two orifice sizes (1.000-inch and 0.3125-inch). From these readings peak gas flow rates up to 350 Mcfd were recorded. The average measured continuous flow was 120 Mcfd. Gas was also flowing through the tubing at this time; however, the flow rate was not measured. By the appearance of the flare, the rate of flow from the tubing was observed to be equal or greater than the measured rates through the annulus.

4.3.3 Coalbed Permeability. Sufficient data from swab tests conducted on Well No. 2 were obtained by IGT to calculate permeability. The Gilson coalbed formation permeability was determined to be about two millidarcies. This value is in the range of permeabilities measured using core samples obtained from the Kaiser mine. The swab data from Well No. 1, however, were too scattered to determine permeabilities accurately.

Water injection tests into the Gilson coal at Whitmore Park Well No. 1 were carried out at four rates, ranging from 0.47 BPM to 1.5 BPM. For each injection rate, a plot of surface pressure versus log of time was made and the slope of the pressure increase line was determined. Permeability was then calculated from Darcy's Law (Ref. Petroleum Production Handbook, pp. 32-34):

$$K = \frac{162.6\ q\,\mu\,B}{M\ h}$$

where

K = permeability (Millidarcies)

Q = rate (STB/D)

μ = viscosity of fluid (centipoise)

B = formation volume factor = 1

M = slope of pressure vs. log time (psi/cycle)

h = formation height (feet)

Permeabilities as calculated for the different injection rates varied with rate as seen in Table 21. The higher the injection rate and pressure the higher the calculated permeability. This result is not consistent with the permeability calculation made by IGT using swab data. The swab data calculation gave a permeability of approximately 2 millidarcies. One possible explanation for this change in permeability is that coal itself is quite impermeable but contains numerous natural fractures. Coal is also compressible and, when subjected to injection pressures, the natural fractures are opened. The higher injection pressures therefore result in higher calculated permeabilities. Water injection at very low rates may therefore yield more meaningful data for the permeability of the coal.

TABLE 21

PERMEABILITY FROM WATER INJECTION TESTS ON GILSON COAL

Test Series	Water Injection Rate, BPM	Calculated Permeability millidarcies
1	0.47	20
2	0.87	170
3	1.50	200
4	0.47	73

4.4 COAL CORE TESTING

4.4.1 Core Gas Content. Cores were obtained for gas content and other analyses from Wells No. 1 and No. 2. Due to the drilling problems and the difficulty in locating the coalbeds in the third well, no cores were obtained. As discussed previously, only 7 feet of coal core from the Gilson coalbed were recovered from Well No. 1. Samples for desorption were obtained by IGT and UGMS personnel. IGT personnel collected additional core samples of sandstone and shale formations surrounding the coalbeds. Some small quantities of methane were contained in these samples: details are reported in the IGT reports.

Coring at Well No. 2 was much more successful in recovering cores of the coal seams. Sufficient cores were obtained from all four of the major coalbeds so that multiple samples from each seam were obtained. Mountain Fuel Resources personnel obtained three duplicate samples from this well. All of the samples were desorbed using the standard procedure developed by the Bureau of Mines (12) in which core samples are sealed in containers and the desorbed gas is measured by displacement of water. This procedure involves making an extrapolated estimate of gas lost prior to being sealed in the desorption canister. A plot of total gas desorbed such as is shown in Figure 27 is used to make this estimate. A complete summary of desorption from all coal cores is given in Table 22.

The gas content of the cores greatly exceeded previously measured gas content of coals from this area of the Book Cliffs coal field. Some cores from each coalbed indicated very high gas content coal. At least one sample each of the Sunnyside, Rock Canyon, Fish Creek, and Gilson coals measured over 400 scf/ton of coal. Duplicate samples indicate a close relationship between the IGT samples and the Mountain Fuel Resources samples. However, samples taken by the UGMS were consistently lower. It was discovered that the containers used by the UGMS had been leaking, which would allow desorbed gas to be lost.

4.4.2 Drill Cuttings Gas Content. As discussed in the drilling section, no cores were obtained but drill cutting samples of four coalbeds were collected and analyzed. A "chip desorption technique" developed at the University of New Mexico (13) was used to correlate the total gas desorbed from the sample container to the total gas content including lost gas. Most of the core samples indicated high gas content while the drill cutting sample method indicated considerably lower gas content. The cutting sample data are believed to not truly represent the actual gas content of these

DESORPTION OF GILSON COAL
FROM WHITMORE PARK WELL NO. 1

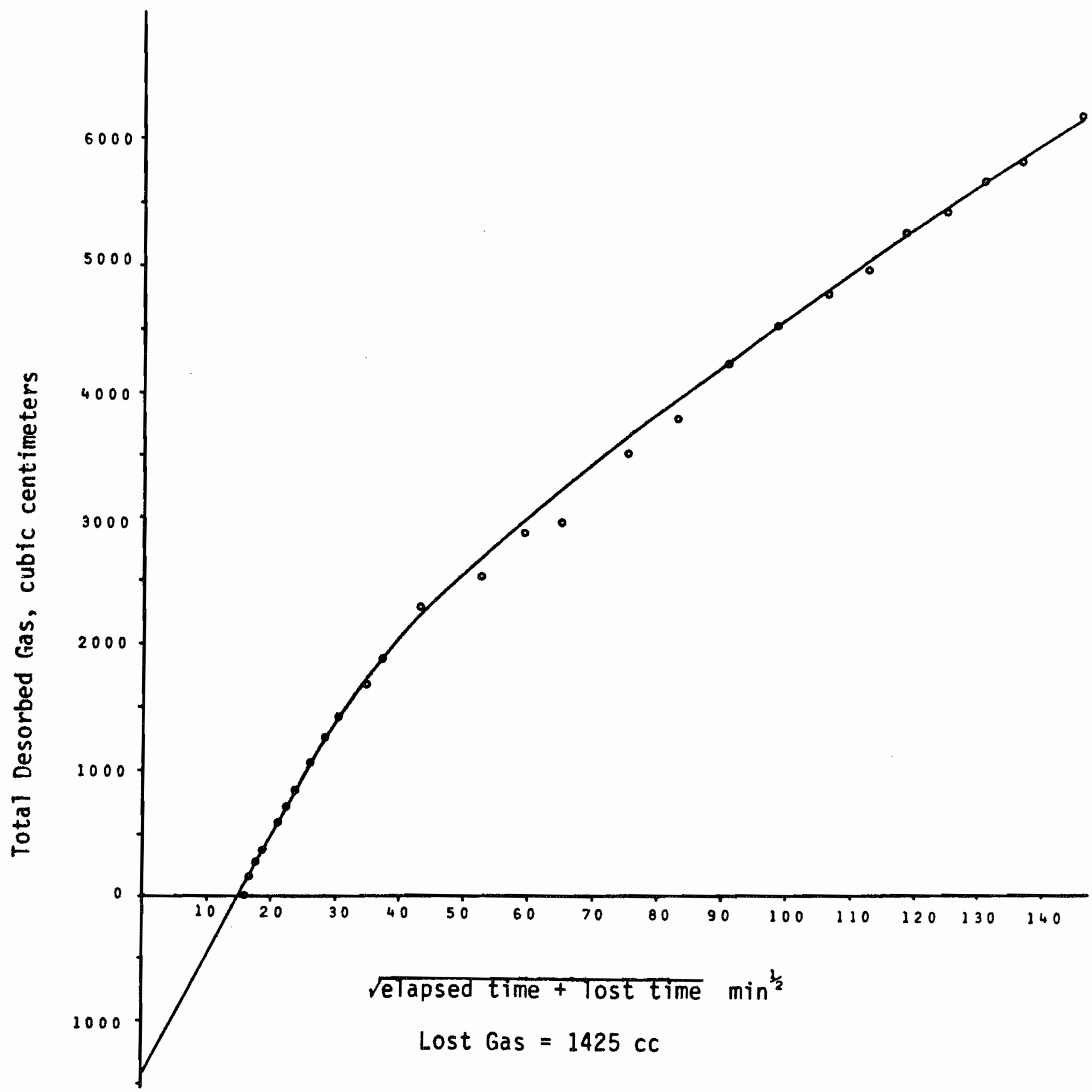


Figure 27

TABLE 22

SUMMARY OF CORE SAMPLE DESORPTION DATA

Well No.	Sample No.	Coal Seam	Depth feet	Laboratory	Total Gas Desorbed cc/gm	Total Gas Desorbed scf/ton
WP-1	2	Gilson	3099	IGT	13.9	443
WP-1	262	Gilson	3097	UGMS	6.6	212
WP-2	RC-1	Rock Canyon	2865	MFR	10.8	345
WP-2	RC-2	Rock Canyon	2867	MFR	12.6	403
WP-2	G-3	Gilson	2934	MFR	10.5	335
WP-2	261	Sunnyside	2720	UGMS	5.3	169
WP-2	260	Gilson	2935	UGMS	6.7	216
WP-2	8	Coal Stringer	2664	IGT	13.3	426
WP-2	10	Lower Sunnyside	2714-20	IGT	9.1	292
WP-2	11	Sunnyside	2703	IGT	12.7	406
WP-2	13	Fish Creek	2877	IGT	12.5	400
WP-2	14	Rock Canyon	2863	IGT	12.9	413
WP-2	16	Gilson	2934-7	IGT	12.1	387
WP-2	17	Gilson	2934-7	IGT	12.6	403
WU-1	1	Sunnyside	3651-6	MFR	5.1	165*
WU-1	2	Sunnyside Stringer	3685-7	MFR	3.7	118*
WU-1	3	Fish Creek	3762-5	MFR	5.6	180*
WU-1	4	Castlegate	3976-80	MFR	5.4	174*

* Estimated by "Chip Desorption Technique"

coal seams for two reasons. First, these coalbeds are the same seams encountered in the first two wells but at a greater depth. Second, previous core analysis of coals nearest the third well indicated this general area to be the most gassy part of the Book Cliffs. The exact reason for this inconsistency is unknown but may have resulted from either bad sample collection techniques or inaccuracy in the "chip desorption technique."

4.4.3 Desorbed Gas Composition. During the desorption process IGT collected samples of the gases evolved during different stages of desorption. Mass spectrometer analyses of the gases was then run to determine gas composition. A typical set of composition data for one core sample is shown in Table 23. The IGT work summary includes data from all the core samples. It was observed that the methane content ranges from 95 to 98 percent and that it increases during desorption while the percentage of carbon dioxide decreases. During the later stages of desorption, some heavier hydrocarbons (C_2, C_3, and C_4) started to appear in small concentrations.

4.4.4 Other Analyses. Numerous other types of testing were scheduled to be performed on the cores obtained from these wells. Plugs were to be cut so that permeability to gas and water, diffusion parameters, porosity and compressibility measurements could be conducted in the IGT laboratories. Unfortunately, IGT was not able to cut plugs out of the coal cores. Therefore, none of these tests could be conducted. Three other analyses were completed: coal analysis, water analysis, and adsorption isotherm measurements.

Each sample of coal from Wells No. 1 and No. 2 and a sample from both the Kaiser Sunnyside Mine (17 miles southeast) and the Soldier Creek Mine (4 miles southwest) were analyzed and ranked by the ASTM method. Table 24 shows a representative analysis of the Gilson coal compared to the Kaiser Sunnyside coal. The ASTM rank was made as high volatile A bituminous. These coals fit the criteria of less than 69 percent dry fixed carbon and volatile matter greater than 31 percent. However, this rank also requires a BTU content greater than 14,000 BTU/lb, which was met for only two samples

TABLE 23

DESORPTION GAS COMPOSITION (MOL %)

	Whitmore Park No. 1				
Sample No.*	2A	2C	2D	2E	2F
Volume Desorbed, cc	2,912	9,211	9,642	9,887	10,380
Components					
Carbon Dioxide	2.2	2.3	1.7	1.3	1.3
Hydrogen		0.2			
Methane	97.7	97.3	98.1	98.5	98.5
Ethane	0.1	0.1	0.1	0.1	0.1
Propane	Tr	0.1	0.1	0.1	0.1
n-Butane		Tr	Tr	Tr	Tr
i-Butane		Tr	Tr	Tr	Tr
TOTAL	100.0	100.0	100.0	100.0	100.0

* Numbers indicate core sample, letters indicate gas sample

TABLE 24

COAL ANALYSIS

Analysis	Whitmore Park #1 3101 ft. Gilson Coal Weight %		Kaiser Utah Sunnyside Mine Aug. Samples A-1, B-1, B-2, B-3 Weight %	
Proximate Analysis				
Moisture	1.8		2.8	
Volatile matter	39.3	40.0 (dry)	40.1	41.3 (dry)
Ash	3.1		2.6	
Fixed carbon	55.8		54.5	
Total	100.0		100.0	
Helium Density	1.34 gm/cc		1.29 gm/cc	
Ultimate Analysis				
Ash	3.2		2.6	
Carbon (total)	80.2		81.0	
Organic carbon		80.1		80.8
Mineral carbon		0.1		0.2
Hydrogen	5.5		5.7	
Sulfur	0.4		.5	
Nitrogen	1.6		1.9	
Carbon Dioxide		0.3		0.6
Oxygen (by difference)	9.1		8.3	
Total	100.0		100.0	
Gross Calorific Value	14,270 BTU/lb		14,441 BTU/lb	
ASTM Rank	High Volatile A Bituminous		High Volatile A Bituminous	
Estimated Gas Content at 2800'	450 cf/ton		450 cf/ton	

and was borderline for several other samples. The low BTU samples had higher mineral matter (ash), which could be the result of the coalbeds being in stringers and thin beds. Complete coal rank analyses are found in the IGT reports.

Three water samples were collected during the drilling of Well No. 1 and numerous samples were collected during the dewatering of all three wells. While air drilling, a water zone was encountered at a depth of about 760 feet. A sample of this water was obtained and analyzed for its major ions, pH, and solids. Also, two samples were taken after the Gilson coal seam had been cored in an effort to establish the zone of water entry into the well. One of these samples was water unloaded from the base of the Gilson coal. The other was taken from about 650 feet off bottom (2500 ft depth) after 16 feet of shale had been cored below the Gilson coal. These analyses are shown in Table 25. They show that some differences exist in the waters, but these differences are not very significant in verifying the origin of water by different chemistries. However, it does appear that the 760 feet aquifer showed a little less total ion concentration, as would be expected.

Water analyses from each of the three wells show the water to be good enough to be discharged into the existing runoff streams. No special treatment of the water was necessary.

A pulverized sample of Gilson coal was prepared for obtaining an equilibrium adsorption isotherm for methane adsorption. The preparation included a treatment for removing the last traces of gas and water vapor by treatment in a vacuum oven at 130°C for 24 hours. The sample was removed from the oven and placed into a vacuum-pressure system that was equipped with sensitive pressure transducers for pressure measurements. Pure gases from high-pressure cylinders were used in the determination. Helium was used to determine volumes in the system by expansion and calculation by Boyles Law. The ideal gas equation was used to determine the amount of methane adsorbed in the coal at various pressures. It was found that even a pulverized sample of the coal required some equilibration time after each

TABLE 25

WHITMORE PARK #1 - WATER SAMPLES

	pH	TDS	TSS	Na	K	Ca	Mg	Fe	$Co_3^=$	C^-
Whitmore Park Well No. 1										
(10-29-79)										
760' Aquifer	8.9	542	7	112	1.62	1.32	17.6	0.29	436	20
Unloading @ 2500'	8.0	521	33	72.5	13.4	73.6	44.7	10.7	629	30
Base of Gilson	7.5	531	90	74.6	14.5	75.6	45.4	6.2	657	30
Whitmore Park Well No. 2										
(9-15-80)										
Prestimulation production	7.7	230	83	350	20	200	150	11	673	26
Whitmore Unit No. 1 Well										
(8-12-82)										
Poststimulation production	7.9	3580								600

pressure was introduced. Six individual steps were used in which the pressure ranged from near zero to about 102 atmospheres, absolute (1500 psi). Figure 28, Curve 1, shows a plot of the isotherm.

These data indicate a characteristic equilibrium adsorption isotherm. The adsorption, which is rather steep at the lower pressures, begins to flatten out as the pressure increases. It is interesting to note that at the final experimental pressure point (about 102 atmospheres or 1500 psi), the methane content was about 14.8 cc/gm. The amount of methane desorbed from the Whitmore Park No. 1 Gilson coal seam was 13.9 cc/gm (443 scf/ton). The hydraulic head on that coal seam was observed to be about 500 feet subsurface using an echometer. Assuming fresh water in the coal, reservoir pressure at the depth of sampling (3100 feet) is estimated to be (3100 - 500) 0.434 = 1128 psig.

This adsorption isotherm shows very close agreement between the amount of methane actually desorbed from the sample and the value expected from the sample and the measured adsorption isotherm at a pressure of 1142 psia. This indicates that the Whitmore Park No. 1 Gilson seam contains the maximum possible amount of methane for its reservoir pressure.

Figure 28 also shows the isotherm assumed for prior computer simulation of Gilson coal seam production. This assumed isotherm was based upon prior USBM work as described in the Phase I work. Comparison of the assumed and measured values reveals that the coal contains 67 percent more methane than previously assumed. It also indicates the importance of reducing the pressure within the coal to its lowest possible point. Half of the methane present in the coal remains adsorbed at 100 psia.

4.5 WELL COMPLETION TECHNIQUES

4.5.1 Whitmore Park Well No. 1.

Originally this well was completed open hole across the 14-foot thick Gilson coalbed. Approximately 17 feet of open hole was exposed above the Gilson coal and 66 feet below as was shown previously in Figure 22. The injection tests completed on this well indicated a water influx rate from the zone above the coal that exceeded the available pumping capacity. The influx rate would be expected to increase after hydraulic stimulation of the well and as the bottom hole

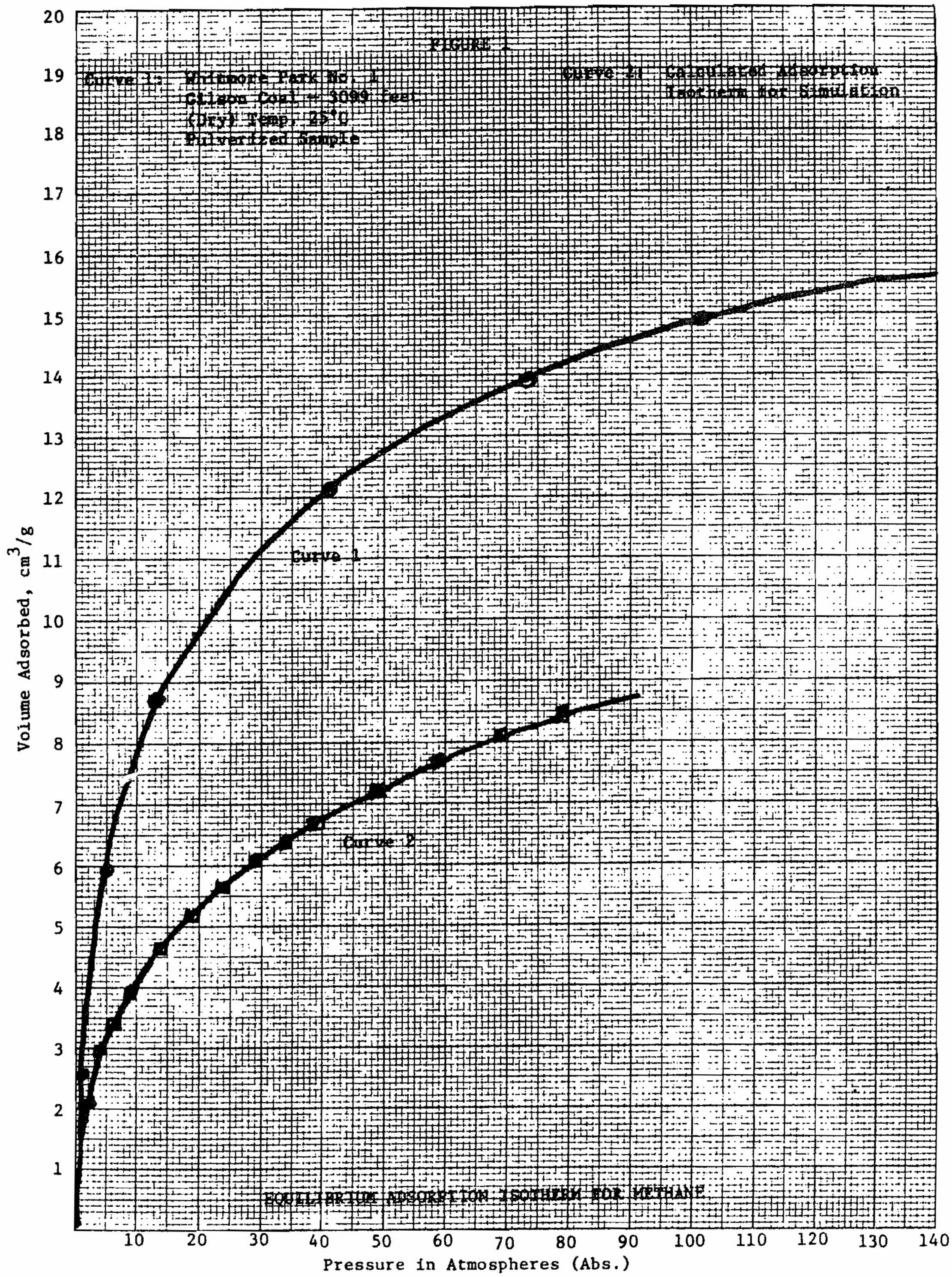


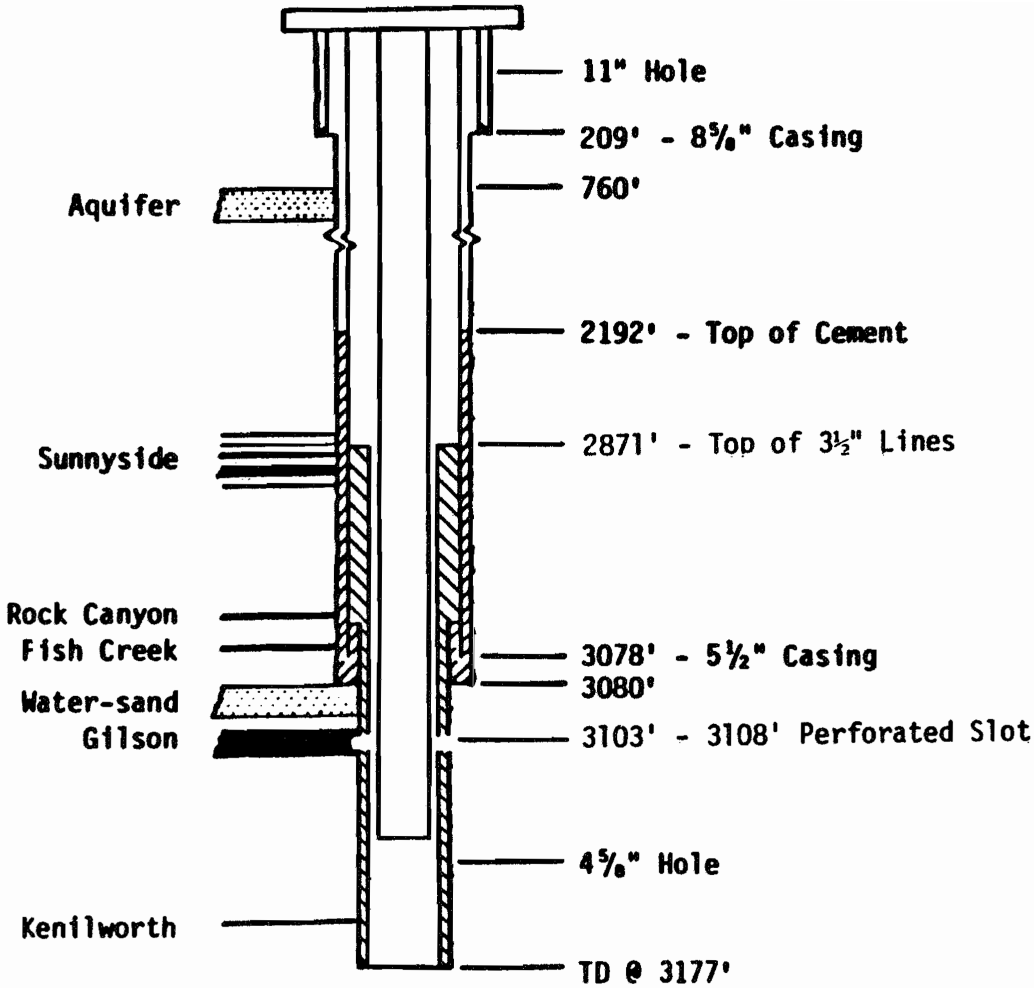
Figure 28
EQUILIBRIUM ADSORPTION ISOTHERM FOR GILSON COAL

pressure was further reduced. The zone above the coalbed produced 700 BPD of water with a bottom hole pressure of 990 psig. Because of the excessive water production, a decision was made to cement a 3½-inch casing liner from the bottom of the present casing to total depth and then perforate into the Gilson coalbed. The casing was anchored 208 feet up from the bottom of the 5½-inch casing as shown in Figure 29. Minimum-weight cement (14.28 lb/gal) was used to cement the casing to minimize the amount of cement pushed into the coal formation. The casing was slotted adjacent to the Gilson coalbed over a 5-foot interval from 3103 to 3108 feet using a Halliburton Hydra-Jet cutting tool. A substantial amount of coal and cement cuttings were returned to the surface to assure a complete perforation into the coalbed. This completion system was designed to seal off the water production zone above the Gilson zone, and to permit production only from the Gilson coalbed.

Production and metering facilities were installed following the installation and perforation of the casing liner, and dewatering of the well began. It quickly became apparent that the rate of water production coming into the wellbore continued to be much larger than was previously measured as coming from the Gilson coal alone. Efforts were made to increase the pumping rate but even at the maximum rate of 5 GPM the water level in the well was only reduced from a depth of 500 feet to 930 feet.

A careful examination of the cores obtained from this well has been made. It was determined that the sand above the coal zone did not contain sufficient permeability to allow the water production experienced on this well. However, a 5-foot to 8-foot section of sand appeared to be naturally fractured. The fractured zone does appear to be capable of transporting high water rates.

Several possibilities for the source of the water existed. One was that a poor cement job resulted in water entering the wellbore from the fractured sand zone, traveling down the wellbore, and then out through the perforations made into the Gilson coalbed. Cement bond logs, however, showed good bonding and made this possibility unlikely. A second possibility was that a path had been opened from the coal into the fractured



REVISED COMPLETION OF
WHITMORE PARK WELL No. 1

Figure 29

sand zone some distance from the wellbore. Previous swab test data indicated the source of the water production must be the zone above the Gilson coalbed. The exact path of the water flow into the wellbore could not be determined. It might have still been possible to squeeze cement into the formation and shut off the water production. However, successfully squeezing cement relies on the ability to squeeze enough cement under pressure and maintain that pressure long enough for the cement to set. The personnel experienced in squeeze jobs from both Halliburton and Mountain Fuel Supply concluded that there was too much permeability to have a good chance of successfully completing a squeeze job. The cement would probably leak off into the surrounding formation prior to setting up and sealing off the water production zone. The possibility of cementing over the existing perforations and completing new perforations directly into the fractured sand zone was discussed. Even though this approach offered the possibility of getting more cement into the actual water production zone, it would severely weaken the pipe in the well and still would encounter the problem of the cement leaking off into the surrounding formation faster than its ability to set up and seal off the zone. It was the general conclusion of MFS personnel that there was less than a 50 percent chance of successfully conducting a squeeze job that would completely isolate the current water production.

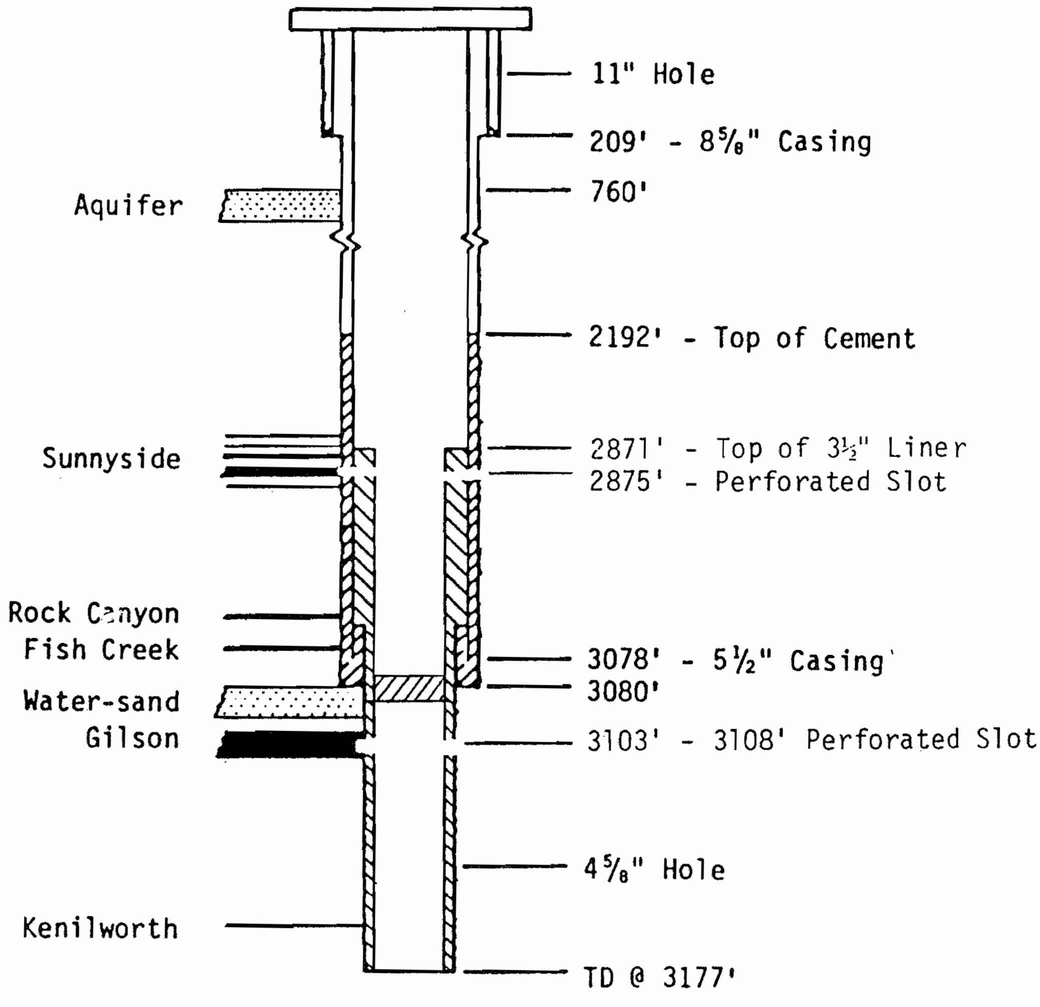
A second serious concern would exist even if a successful squeeze job were completed. After setting the cement, there would be an extremely high probability that any subsequent attempt to fracture the coal would reopen the water production zone. It was highly likely that a fracture would initiate and extend along the newly formed cement/formation boundary. If a hydraulic fracture were initiated in the coal zone, it would also be likely to extend out of the coal zone and up into the existing naturally fractured sand zone. The benefits of a successful squeeze job without a hydraulic stimulation were very small yet very costly. It was estimated that such an attempt would cost in the range of $75,000 to $100,000. In view of this high cost, it was not reasonable to attempt a squeeze job since the end results, even for a successful job, would be so minimal.

Whitmore Park Well No. 1 was used as a monitoring well during the stimulation of Well No. 2. The bottom portion of the well was then sealed and perforations completed into one of the upper Sunnyside coal seams. The seam is 6 feet thick, and is surrounded by apparently competent rock formations with low permeability. Conventional jet perforations were used to make 4 perforations per foot. The final completion configuration is shown in Figure 30.

4.5.2 Whitmore Park Well No. 2. Because of the change in the method for completing Well No. 1, a decision was made to provide for an open-hole completion in Well No. 2. This would permit comparison of production from the open hole in the No. 2 well with production from the same seam in Well No. 1 through perforations. However, because the Gilson seam in Well No. 1 was eventually sealed this comparison was not possible.

After completing drilling to a total well depth of 3000 feet, a 5½-inch casing was run in the well with a Halliburton packer on the bottom at a depth of 2929 feet (2 feet above the Gilson coalbed) to prevent any cement from entering the open hole below the packer. Within the casing string, a section of 5½-inch Pengo double-wall casing was run, this casing section being adjacent to the Sunnyside seam. The Pengo system has external packers that force cement to flow through the casing annulus and isolate the formation between the packers from the cement. It also has ports that can be opened and closed after cementing is completed. The Pengo packers and Halliburton packers were accurately spaced, based on log data, to permit landing the Halliburton packer immediately above the Gilson coalbed and positioning the Pengo packers straddling the main 7-foot parting of Sunnyside coal.

Once the properly spaced casing was run in the well, a gamma ray log was run to assure the desired positioning of the packers. The casing string was then cemented in place, leaving a cement plug in the bottom of the casing. The cement plug was drilled out to finish the completion and tubing and a sucker rod pump were installed to dewater the well. Figure 31 shows the completion of this well.



FINAL COMPLETION OF WHITMORE PARK WELL NO. 1

Figure 30

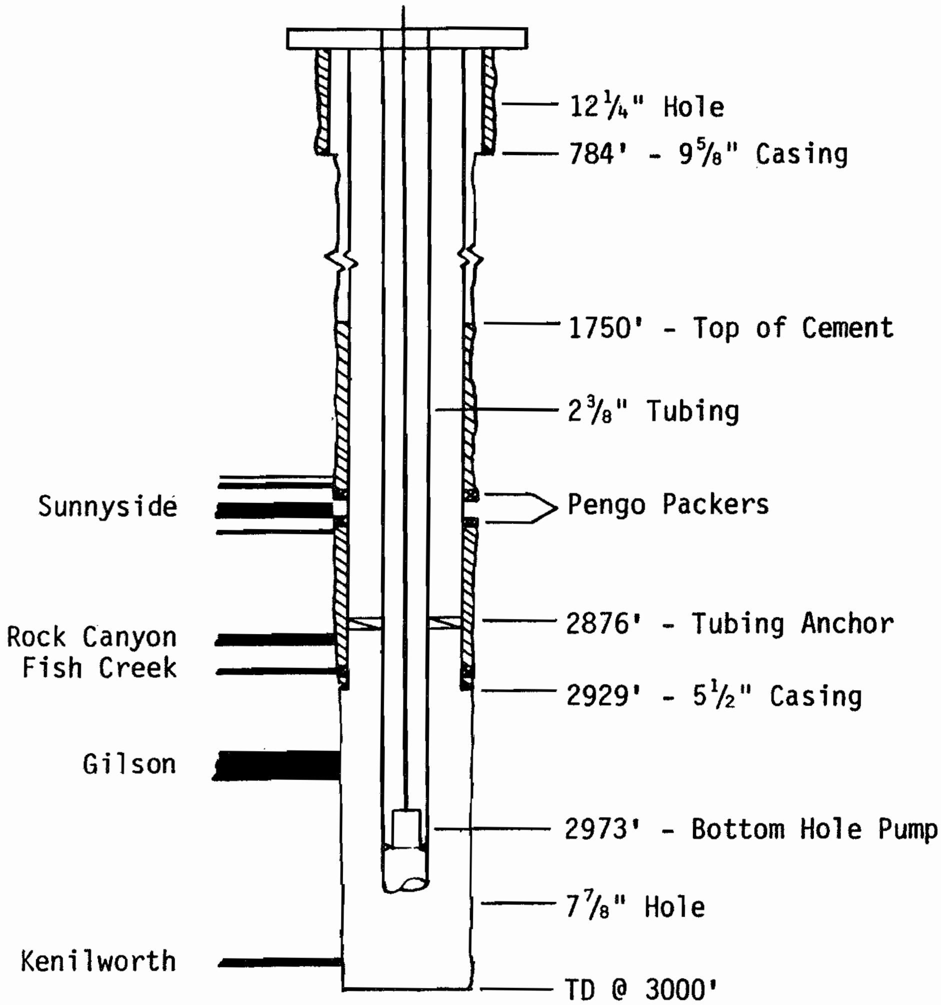


FIGURE 31

WHITMORE PARK WELL NO. 2

COMPLETION CONFIGURATION

4.5.3 Whitmore Unit No. 1 Well. A total of 42 feet of coal was encountered in this well. The coal was in 15 small beds ranging from 1 to 6 feet thick. The largest 6-foot coalbed was selected as being the most attractive over which to locate the Pengo selective completion tool, similar to that used at Whitmore Park Well No. 2. The well was cased to total depth with the Pengo tool located to straddle this coalbed. The system was installed with two sets of movable ports. One set was opened to flow during the hydraulic stimulation. The other set of ports was screened and used to limit the flowback of sand from the formation after the stimulation.

The data obtained from the well logs were analyzed to assess the quality of each coalbed and the specific characteristics of the formation surrounding each. To maximize the methane recovery from the third well, it was desirous to produce from as much coal as possible without running too high a risk of opening a coalbed that might also open an adjacent water aquifer. The quality of the coal in each seam was estimated from logs which were also used to identify the formations above and below each coalbed. Particular attention was paid to sandstones with high porosity which could produce substantial water flows thereby resulting in water containment problems similar to those encountered at the first two wells. Table 26 shows a summary of the coalbeds and surrounding formation analysis. Each of the ten seams selected for completion was perforated using a conventional perforating gun except for the large 6-foot coalbed which was completed using the Pengo completion tool.

4.5.4 Comparison of Completion Techniques. A direct comparison between an open hole completion versus a cased and perforated completion was planned for the Gilson coalbed at wells No. 1 and No. 2. Even though the Gilson coalbed at well No. 1 had to be plugged and abandoned some observations were made. A direct comparison was made between a Pengo completion system, which closely approximates an open hole completion, and a cased hole completion on the Sunnyside coalbed found in the first two wells.

TABLE 26

WELL NO. 3 FORMATIONS ANALYSIS

Coal Interval feet	Coal Thickness feet	Coal Density gm/cc	Formation Above	Formation Below	Complete	Comments
3494-3496	2	1.9	shale	sand	No	Shaly coal
3512-3514	2	1.4	tight shale	water sand	No	
3579-3580	1	1.6	shaly	shale	No	Low quality
3597-3599	2	1.6	water sand	shale	No	Low quality
3636-3636	1	1.7	shaly sand	sand	No	Low quality
3645-3651	6	1.3	shale	shale	Yes	Pengo tool
3658-3661	3	1.4	shaly	shaly	Yes	
3677-3679	2	1.9	shaly sand	shale	No	Low quality
3730-3732	2	1.4	tight sand	shale	Yes	
3755-3758	3	1.3	tight shale	tight sand	Yes	
3770-3773	3	1.4	shale	tight sand	Yes	
3798-3800) 3801-3804)	5	(1.6 (1.4	shaly	shale	Yes	
3944-3947	3	1.4	shale	shaly sand	Yes	
3968-3972	4	1.3	shale	shaly	Yes	
3975-3976	1	1.6	shaly	shaly	No	Too thin
3991-3994	3	1.3	shale	tight sand	Yes	
4015-4018	3	1.3	shaly	shaly	Yes	

It is generally considered within the industry that coal can be quite susceptible to drilling and cement damage. Open hole completions avoid possible cement damage but can result in other problems such as exposing an undesirable formation such as was experienced at well No. 1. In order to eliminate the risks of open hole completions the stratigraphy and exact location of the coal seams and water aquifers must be known. The experience with the Pengo completion system supports the belief that severe cement damage can occur in the coals in the Book Cliffs coal field.

As will be discussed later, a very unsuccessful attempt was made to stimulate the Sunnyside coalbed in well No. 1. An extremely high fracture gradient on the coal of over 1.8 psi/ft depth was measured after taking several actions to confirm that the perforations were open to the coal. By comparison a fracture gradient on the same Sunnyside coal seam in Well No. 2 located 1800 feet away was approximately 1.2 psi/ft depth. The major difference between the two wells is thought to be the completion technique. If is postulated that cement infiltration into the natural cleat systems may have resulted in the extremely high gradient at the first well that was not experienced at the second well.

A Pengo completion tool was also used across one of the coal seams at the third project well. Following the completion and stimulation of 10 coalbeds a gamma ray log was run to identify the presence of radioactive sand used in the treatment. It was found that 6 of the 10 coalbeds had accepted the treatment. The zone completed with the Pengo tool showed the most clear-cut indication of radioactive sand strictly across the coalbed of any of the zones treated. Although not conclusive evidence, this also tends to support the idea that the coals can be sensitive to damage. Also the fact that four zones in the middle of the interval wouldn't accept any treatment suggests possible damage from cementing the casing in place. It is concluded that the Pengo system offers a desirable completion approach particularly where open hole completion is not possible such as a multiple zone completion.

4.6 HYDRAULIC STIMULATION TECHNIQUES

A nitrogen foam treatment was conducted on each of the three wells. One coalbed was treated at Well No. 1, two seams were treated separately in Well No. 2, and multiple seams were treated in one stimulation of Well No. 3.

4.6.1 Hydraulic Stimulation of Well No. 2.

Well No. 2 was the first of the three wells to be hydraulically stimulated using a nitrogen foam treatment. The well had previously been completed open hole across the 13-foot thick Gilson coalbed. The stimulation was conducted in September 1980, following prestimulation testing of gas and water production over a 4-month period. Prior to the treatment the wellbore below the Gilson coal was filled with sand to within 10 feet of the bottom of the coalbed. About 2 feet of formation above the coalbed but below the casing was also exposed during the stimulation treatment.

Prior to the stimulation treatment it was decided not to exceed a bottom hole treatment pressure (BHTP) of 1 psi/ft depth. The Gilson coal is at an average depth of 2,939 feet which set the BHTP at 2,940 psi. The design was also set to keep the injection rate near 1 bbl/min/ft of coal thickness. Based on the 13-foot thick Gilson coalbed an injection rate of 15 BPM was set. These limits were established with the objective of containing the fracture within the coalbed. It was planned to terminate the job when the BHTP limit was reached or a sandoff occurred. Since it was anticipated that a limit might be reached early in the job, the plan was designed to reach higher concentrations of sand early in the treatment.

Following a 5,000 gallon foam pad, 5,000 gallons of foam containing 1 lb/gal of 10-20 mesh sand were injected. The concentration was then quickly raised to 1 lb/gal of 10-20 mesh sand and continued until 40,000 gallons of foam had been injected.

During the entire frac job a very gradual buildup in BHTP was experienced. The buildup was so gradual that the entire job was completed by the time the BHTP of 2,400 psi was reached. This allowed 85,000 lbs of sand to be injected into the Gilson coalbed. Nitrogen was used to displace the frac material from the annulus. Table 27 gives the details of the treatment of this well and compares it to the other 2 wells.

Particular attention was paid to two areas in designing the frac procedures: the accurate control of the foam quality and data collection to analyze the job after completion. The specific steps taken to accomplish these objectives are listed below:

(1) Inject a small amount of nitrogen down tubing and monitor tubing pressure to give a continuous direct reading of BHTP. Mix foam and sand at surface and inject down annulus.
(2) Hold the nitrogen rate constant and adjust the water rate to achieve the desired 75 percent foam quality.
(3) Add 2 percent KCl to frac water to distinguish the frac water from formation water during flowback.
(4) Use some radioactive sand throughout treatment to be able to identify fracture location in the open hole if needed.
(5) Utilize 2 radioactive densimeters on sand/water stream and on total fluid stream for control and analysis of stream qualities.
(6) Measure flowback after stimulation to determine when all frac fluids have been recovered.

Much of the success of the stimulation job and the lack of pressure buildup problems can be attributed to the excellent control of foam quality. Adjustments to maintain quality were easily made by controlling the water rate rather than the nitrogen rate. A set of curves was developed prior to the job to relate the water rate required to give 75 percent quality foam at the measured tubing pressure for a constant nitrogen rate. Water rate adjustments were made in seconds without burdensome calculations being necessary.

Flowback of the well was started as soon as the Halliburton pumping equipment was disassembled. It was planned to flow through a choke valve and then a field separator equipped with both gas and water meters. The gas flow would then pass through a blowdown line with a critical flow prover and discharge to a pit. The critical flow prover would give a second measurement of gas rates. The water stream off the separator would

TABLE 27

COMPARISON OF HYDRAULIC STIMULATION TREATMENTS

		Well No. 1	Well No. 2	Well No. 3
1.	Stimulation Parameters:			
	Type	Nitrogen Foam	Nitrogen Foam	Nitrogen Foam
	Hydraulic Pad Volume, gal water	10,000	5,000	8,720
	Total Volume, gal foam	16,000	50,000	42,250
	Foam Quality % N_2	75	75	80
	Sand, lb	6,000	85,000	66,900
	Pumping Rate, bbl/min	10	15	10/7
	Coalbed Thickness, ft	6	13	36
	Formation Pressure, psi	1,020	1,050	1,350
	Formation Temperature, °F	90	90	90
	Maximum BHTP, psi	5,300	2,400	3,030
	Casing, inches	5.5	5.5	5.5
	KCl Concentration, % in water	2	2	2
	Foaming Agent, gal/gal water	5/1,000	7/1,000	6/1,000
2.	Stimulation Results	Sanded off	Fracture out of coal zone	Final stage deleted

go back to the gauged frac fluid tank to measure total fluid recovery. A van-mounted gas chromatograph was brought to the location to continuously analyze the composition of the flowback gases.

After an initial flowback of a half hour, some proppant sand began to be lifted out of the well. Within a short period of time the sand cut out the choke valve and sand began to accumulate in the separator. For the remainder of the flowback the separator was bypassed, and the stream was diverted directly to the blowdown pit. A ¼-inch choke nipple was placed in the end of the blowdown line to limit the rate of flowback. Unfortunately only estimated flow rates could be made by using this system. During the initial flowback a considerable amount of foam was produced to the pit. The foam may have been reformed in the choke at the wellhead. However, since sand was produced with this foam it is possible that the foam did not completely break down. Less than the 7 gallons of foaming agent per 100 gallons of water that were used for this job was used on the subsequent treatments.

During the initial stages of flowback large chunks of coal (¼"x½"x¼") and a few pieces of rock were returned with the fluids. The size and number of coal chunks indicated that the fracture had entered the coalbed. These large particles caused the flowback line to become plugged frequently in the initial stages. Plug give became less frequent as the flowback continued. The total flowback lasted for approximately 18 hours until the formation water built up in the wellbore and killed the gas flow. Initially no methane was produced with the flowback but the methane content gradually increased to a maximum of 14 percent during the final hours. Average flowback rate was estimated at 3 - 400 Mcfd.

In June 1982, a second treatment on the Gilson coalbed was conducted. Because of a significant decline in the gas production rates from Well No. 2 while the water production was remaining constant, it was postulated that a wellbore restriction due to an accumulation of "fines" was not allowing the coal water saturation to be lowered. A short retreatment using gelled water was conducted. This treatment was designed to open the formation and give a dense sand concentration packed near the wellbore. The stimulation was completed as planned using 5700 gallons of fluid to carry 7800 lbs. of sand into the Gilson coal seam. No complications were experienced in completing the job, however, to date no significant improvement in production has occurred.

A hydraulic stimulation of the Sunnyside coal seam isolated by the Pengo system on Well No. 2 was also conducted in June 1982. This treatment was a duplicate of the nitrogen foam treatment on the same Sunnyside coal in Well No. 1 which was completed by perforating through casing, and cement. The direct comparison between the two wells allowed the different completion techniques used on each well to be compared.

4.6.2 Hydraulic Stimulation of Well No. 1 Because of the apparent success of the first hydraulic stimulation at Well No. 2, a similar treatment was planned for Well No. 1. The coalbed being treated in this well was a 6-foot thick Sunnyside coal at a depth of 2,882 feet in a cased hole which was initially perforated with conventional perforating guns. An injection test was conducted to determine whether the perforations were completely open. A pressure of 2,000 psig was measured while pumping water at a rate of 3.3 BPM. Although this was a higher pressure than was expected, it was concluded that sufficient perforations were open to proceed with the stimulation treatment.

The first attempt to stimulate the well was conducted by maintaining a column of nitrogen in the tubing and pumping the treatment fluid and sand down the annulus. The annulus pressure limitation was 3,500 psig. Prior to the actual treatment, another injection test was conducted. Water was again pumped down the annulus but at higher rates up to 8.8 BPM. The surface pressure was 2,550 psig.

The stimulation treatment was begun by pumping water at a rate of 2.5 BPM. Sufficient nitrogen was added to generate a 75 percent quality foam pumped at a rate of 10 BPM. During a 6-minute period after the foam was first generated, the annulus injection pressure increased to the limit of 3,500 psig. No break in the formation was observed. The nitrogen injection was stopped and the treatment restarted with water but at a reduced rate of

1.5 BPM. The pressure declined to 3,100 psig and then began to increase gradually during the 1.5 BPM injection rate. The casing pressure limitation was again reached after a 9-minute injection period and the pumping was discontinued. It was decided the casing and casing liner should be reperforated. A Halliburton Hydra-jet cutting tool was used to cut 4 vertical 5-foot high slots into the coalbed. This perforation method was selected because the cuttings are circulated to the surface and can be monitored to assure that both the casing and casing liner were perforated and that the slots were open to the coalbed.

The tubing string was measured three times to make sure of the correct positioning of the Hydra-jet tool adjacent to the Sunnyside coalbed. Cutting was started and held in the same location until coal cutting were returned to the surface. The tool was then lowered and raised repeatedly to slot the liner and casing. Many fragments of cement up to 1"x1"x½" and smaller pieces of coal were collected at the return flow line. Enough coal cuttings were collected to verify that a large surface area was open to the coalbed. The hole was circulated with 80 bbl of 2 percent KCl water to clean out the cutting sand and cutting fragments.

A series of injection tests was then performed by pumping 14 bbl of 2 percent KCl water at rates from 2 to 5 BPM at pressures from 3,200 to 3,500 psig. Initially the formation would only accept a 2.5 BPM pumping rate before the casing pressure limit of 3,500 psig was reached. However, the last injection test was at 5 BPM with the 3,500 psig limitation. Each time the rate was increased, the pressure increased only slightly. Several small pressure drops occurred as the injection rate was being held constant. This work indicated that the slots were open but that pressures greater than 3,500 psig would be required to successfully stimulate the formation.

It was decided that a nitrogen-foam stimulation down the tubing with a packer set just above the casing liner would allow pumping pressures high enough to successfully stimulate the coalbed. The pumping limit could be raised from the 3,500 psig casing limit to a tubing pressure limit of 7,500 psig. The treatment design was modified and rescheduled.

The entire treatment fluid was to be pumped down the tubing. A packer was placed to seal off the annular space above the casing liner. The job was initiated by pumping at a rate of 10 BPM of foam. The tubing pressure rose rapidly for the first 4 minutes of pumping and started to level off. When the tubing pressure at the surface reached 6500 psig the formation appeared to "break" and the pressure began to decline at about the same rate that it had risen. After 4 minutes the pressure leveled out between 4,200 and 4,400 psig with only minor fluctuations during the next 18 minute period that the formation was receiving no sand. A total foam pad of 10,000 gallons was used. The first stage consisted of adding 10/20 mesh sand to the foam at 1 lb/gal of foam. As soon as the sand reached the formation the tubing pressure began to increase. As the first stage was nearing completion, about 8 minutes after the sand reached the formation, the pressure had built to 6,400 psig. The sand concentration was maintained at 1 lb/gal of foam rather than increasing it as scheduled. Within 1 minute the pressure suddenly rose to the 7,500 psig limit and pumping was stopped. The sudden rise in pressure indicated a "sand off" had occurred. An attempt was made to restart the treatment but this was unsuccessful. A total of 6,000 lbs. of sand was pumped but only 3,300 to 3,500 lbs. entered the formation.

Flowback of the well was started after the Halliburton equipment was moved off the location. Very little flowback of gas or water was received and the well was dead within 5 hours. A Mountain Fuel Supply gas chromatograph was used on site to analyze the flowback gases. During this short flowback period, methane concentrations up to 5 percent were measured.

During the stimulation treatment a small amount of radioactive sand was used so the sand could be traced. The well was cleaned out and a hard plug of packed sand was removed from the well. After breaking the packed sand, the well began to flow small amounts of gas and water. A gamma ray log was run. This log clearly showed the radioactive sand to be located only in the center of the perforated Sunnyside coalbed.

The pressures required to "break" the formation represent an extremely high fracture gradient in excess of 1.8 psi/ft depth. The data indicate that the perforations were open to the coal and that the treatment went into the coalbed. However, it is believed that infiltration and damage to the coalbed, is the cause of this high gradient and not the result of the coal characteristics.

4.6.3 Hydraulic Stimulation of Well No. 3 The hydraulic stimulation selected for Well No. 3 was a nitrogen foam treatment similar to those for the first two wells. However, the specific design was modified because more total coal was treated in multiple, relatively thin seams located over a 370-foot interval. Some concern existed that the treatment fluids might not penetrate all the zones over this wide interval. This concern was based on the drastically different responses experienced with the first two wells.

Two main problems were considered in developing the plan to stimulate this well: (1) assuring that the treatment extended into all or most of these small coalbeds; and (2) keeping the frac fluids from propagating out of the coalbeds. It would be possible to assure that all the coal zones are treated either by perforating each individually or by using packers to isolate each zone for treatment. However, both of these approaches would be very costly, since each zone would have to be flowed back prior to moving the packers and treating another zone. It was determined that all zones would be treated simultaneously with a pretreatment breakdown using ball sealers. During the breakdown, ball sealers were dropped in an attempt to seal off the zones. Enough balls were dropped to seal all the perforations, plus 100 percent excess. Theoretically, if all the perforations could be sealed during the treatment, fluid would be diverted into each zone and a fracture or breakdown would be started into each coalbed. During this treatment stage it was evident from changes in treatment pressure that many perforations were being sealed. However, a complete "ball off" was not achieved before this stage was finished. Even though all the coalbeds were expected to break down at about the same pressure, the stimulation was completed in stages to divert the treatment into more zones. To minimize the chance of fracturing out of the coal zones, the pumping rate was kept as low as possible without running too high a risk of sanding off due to 10

BPM, but it was necessary to reduce the rate to 7 BPM in order to complete the treatment.

Some problems were experienced in controlling the foam quality. At one point the foam quality neared the unstable point of 85 percent quality foam. However, the sand carrying capability of the foam was maintained. A final stage was planned to inject fluid with sand concentration of 3 lb/gal of foam. This would more heavily load the fracture paths near the wellbore where a good sand pack is most important. However, when this stage was scheduled to begin, the surface treating pressure was within 500 psi of the tubing pressure limitation. To avoid running further risks of sanding off, the final stage was deleted and the treatment fluids were flushed to the perforations with nitrogen. The total treatment used about 45,000 gallons of nitrogen foam to pack 66,900 lbs of 20-40 mesh sand into the formation.

The instantaneous shutdown pressure following treatment was 2,200 psig. The pressure declined to 1,630 psig 3 hours later when the well was shut in for the night. The next morning the wellhead pressure had declined to 1,300 psig. A gamma ray log was run to identify the presence of radioactive sand in the coalbeds thereby indicating which coalbeds had received treatment fluids. A high level of radioactivity was detected in 6 of the 10 coalbeds opened to completion. The log very clearly showed that the 4 middle coalbeds at depths from 3,730 to 3,804 feet received no treatment fluids. The maximum treatment pressure on these 4 coalbeds represents a gradient of approximately 0.8 psi/ft depth. The log also showed that the clearest indication of radioactive sand (in the coalbed only and not extending into surrounding formations) was in the coalbed isolated by the Pengo completion tool.

4.7 PRODUCTION AND MONITORING PROBLEMS

Numerous problems were encountered during the course of this demonstration project and most were resolved. Many were the result of the severe weather conditions which prevail in the Book Cliffs area while others stemmed from the specific location and the previously unknown characteristics of these coalbeds.

4.7.1 Water Containment. The most dominant problem experienced at all three project wells was that of water containment. The specific problems have been discussed under the description of the drilling and completion progress. Delays and excessive costs can be the natural result of drilling into a virgin area. Once the stratigraphy of an area is well known the drilling and completion techniques can be revised to control or avoid such things as water aquifers, faulted areas, and water bearing formations.

The sizing of pumping equipment and monitoring facilities is dependant on water production rates. If these rates are unknown influx measurements or swab tests should be conducted before sizing the equipment. Production rates should also be expected to drastically increase following a successful hydraulic stimulation. The magnitude of the increase depends on the success of the treatment. It was also found in the case of the second well that water production can vary dramatically with a type of seasonal variation.

After the stimulation of Well No. 2 the pumping equipment demonstrated to have sufficient capacity to dewater this well. However, over a 1-month period during the winter of 1980-81 the water influx rate more than doubled going from 5 GPM to over 13 GPM. The water influx rate peaked at this point in time and gradually decreased over the next 6 months to approximately 7 GPM. Because of this unexpected fluctuation in water production, the pumping equipment had to be redesigned and a more expensive system installed with a very wide operating range. The required operating range was achieved by installing a submersible pump controlled by a variable speed drive. This controller is able to vary the pump rpm's by controlling the frequency of the electric current.

4.7.2 Pump Wear. During the early operation of the sucker rod pumps at both of the first two wells a severe wearing problem was discovered. A deviated hole ruined most of the rod string in Well No. 2 within the first month of operation. In this short time several couplings had been worn until the rods parted and had to be fished from the well. The start of similar wear at Well No. 1 was halted prior to the rods becoming damaged.

The problem was corrected by using teflon rod guides placed next to each collar to protect the collars from wear.

Solids in the pumping equipment also caused wear. Some coal particles, very little coal fines, and large amounts of frac sand were the source of wear. Both the sucker rod pumps and the submersible pumps used on the project were damaged due to sand getting into the pump. This was resolved at Well No. 2 by building a wire screen over the pump intake on the submersible pump. Mountain Fuel Supply personnel had to design this system since too tight of a clearance existed between the 4-inch pump and the 5½-inch casing to use a prefabricated screen section. To build the screen, eight 1/8-inch rods were spot welded to the outside of the pump casing as support for the screen. A 25-mesh stainless steel screen was then wrapped tightly over the support rods and secured with cable bands. The rods supported the screen away from the pump housing and increased the effective surface area through which water could flow into the intake. A 40-mesh screen was on the third well because smaller frac sand was used in the hydraulic stimulation. Several rub buttons were placed above and below the screen section and found to be very important in centralizing the pump in the well. Without the rub buttons it was difficult to lower the pump and screen to the bottom of the well without rubbing and damaging the screen.

The screen on Well No. 2 worked quite well in protecting the submersible pump on which it was used. As of this report, the screen used on a larger submersible pump at the third well was successful in blocking larger sand but substantial amounts of sand fines have filtered through the 20/40 mesh frac sand and the 40-mesh screen to reach the pump.

4.7.3 Metering Problems. Metering problems and inaccuracies have resulted from three sources: solids, water in the gas lines, and freezing. As mentioned above either coal or sand particles can reach the water pumping equipment. Small amounts of these particles were able to be carried to the surface. Positive displacement water meters and gas meters were used for the project which proved to be susceptible to clogging and malfunctions caused by these solids. Rotary gas and water meters are very susceptible because of the close tolerances within the rotating components.

These types of meters can be adequately protected with an inexpensive Y-strainer or filter. Strainers with a 40-mesh screen worked well to protect both gas and water meters.

Water in the gas lines was very troublesome for the bellows-type positive displacement gas meters. As the warm saturated gas is produced to the surface and cooled in winter, it's ability to carry moisture decreases and condensation occurs. Filters were not successful in correcting the problem of condensate collecting in the meter since some cooling and condensation is taking place inside the meter itself. Water accumulates within this type meter and causes inaccuracies and eventual meter failure. A positive displacement rotary gas meter proved to work well if protected by a filter. These meters were installed so that the production gas enters the top of the meter, passes vertically through the meter and exists the bottom. Through this arrangement any condensed water falls through the meter without accumulating.

Freezing of water in both the gas lines and water lines can be a problem if the production system isn't designed for freezing conditions. Figure 32 shows the production and monitoring system developed during the course of this project. Lines were run underground and sloped to drain after a shutdown. Above ground equipment and lines were located in a small metal building equipped with space heaters to prevent freezing. This system worked very well even during the most severe weather.

4.8 PRODUCTION RESULTS

Three drastically different results have been observed during the stimulation treatments and the subsequent production from the three methane recovery wells.

4.8.1 Whitmore Park Well No. 1 Production. The Gilson coalbed in this well was not hydraulically stimulated due to the water containment problems discussed. Only the 6-foot Sunnyside coal seam was stimulated. As discussed earlier, this coalbed was extremely tight and accepted only a small amount of stimulation fluids.

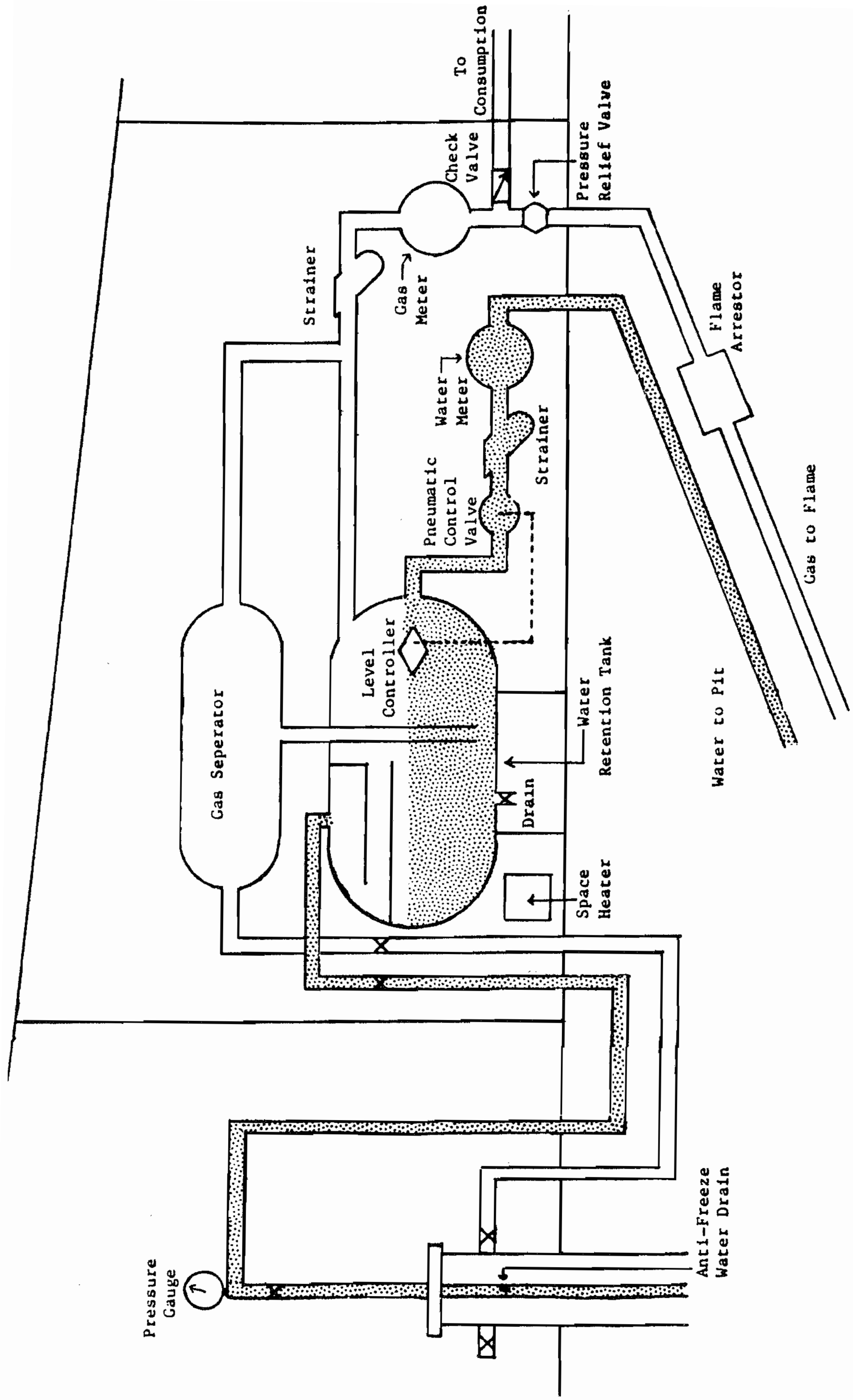


FIGURE 32
PRODUCTION SYSTEM

During the initial dewatering of this well with a sucker rod pumping system only intermittent operation was possible due to equipment problems. Even with this operation it was obvious that a very small amount of water, approximately 40 GPD, was being produced. With this small production, the water level was lowered to below the coalbed and some encouraging shows of gas were noted. While the well was shut-in each night, pressure buildups from 40 to 140 psig were measured over a 24-hour period. However, once continuous operation began only minimal amounts of water and gas were produced. With only 40 GPD of water being produced, less than one hour per day of pumping was sufficient to pump off all the water produced during a 24-hour period. The highest gas production measured was 12 Mscfd, but was not maintained after the first two days of metering this production. Gas production declined quickly to approximately 1 Mscfd after the first week and then even further to .1 - .2 Mscfd after the first month. The well was produced continuously for 65 days until severe winter weather began creating operational problems. Because of the disappointing production from Whitmore Park Well No. 1 no further testing was conducted.

4.8.2 Whitmore Park Well No. 2 Production. Dewatering of Whitmore Park Well No. 2 using a 5 GPM capacity sucker rod pump began in late March 1980. Several shutdowns occurred during the first 3 weeks of operation, such that the longest continuous dewatering lasted only 7 days. The water produced over this period averaged about 60 BPD. The gas produced was less than 500 scfd. A complete shutdown of the well occurred on April 15, when the sucker rods parted due to severe wear caused by a deviated wellbore. As soon as the well site became accessible after the spring run-off the rods were pulled and dewatering continued in June. Prestimulation testing continued for 3 months until the hydraulic stimulation was completed in September. During the prestimulation period water production declined except immediately after a shutdown period when the radius being drained tended to be recharged towards its initial state. Over this same period the gas production increased slightly from less than 0.5 Mscfd to near 1 Mscfd. Figure 33 shows the complete production history of this well.

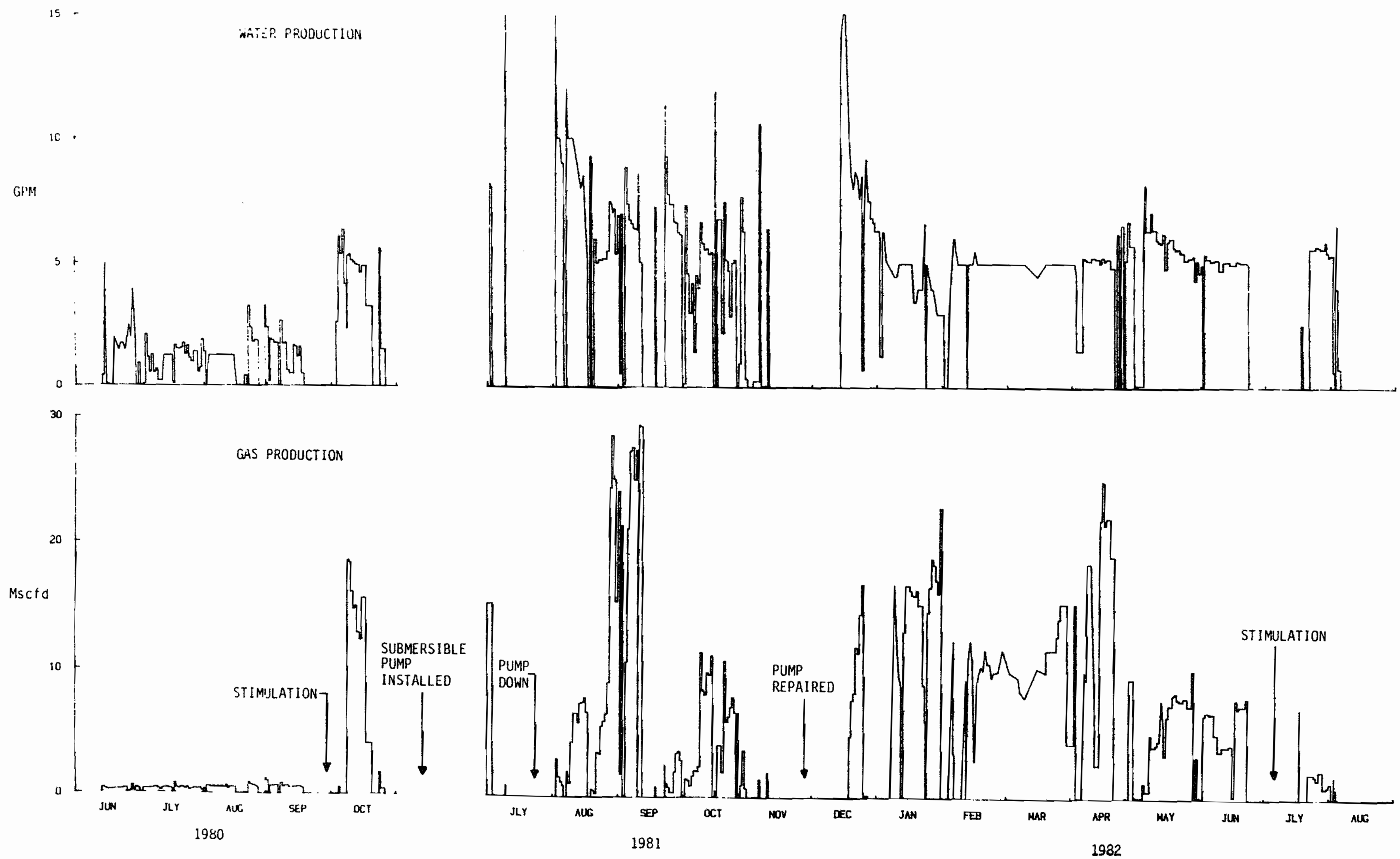


FIGURE 33

WHITMORE PARK WELL NO. 2 - PRODUCTION HISTORY

The hydraulic stimulation of Well No. 2 gave more encouraging results than those from Well No. 1. Flowback lasted for 20 hours and about one third of the treatment fluids were recovered. All of the treatment fluids were recovered within a week after dewatering of the well was initiated. A large increase in both water and gas production resulted following the stimulation treatment of this well. Figure 33 shows that water production rates tripled. It also shows that gas production increased over 20 times and that peak gas production rates from 20 to 30 Mscfd were measured after the bottom hole pressure (BHP) was reduced from 1,100 to 400 psig. It was expected that production rates 2 to 3 times higher might be achieved as the bottom hole pressure in the wellbore was reduced to near zero. However, because of mechanical pumping problems the reduction in BHP was achieved very slowly and the anticipated gas production increase did not occur.

Within approximately one month following the stimulation, recurring problems with the sucker rod pump began. The clutch on the pump motor had to be replaced three times, and was found to be the result of over working the pump jack, at too high of a stroke rate. It was later discovered that the pump efficiency had deteriorated. Excess loading of the pump was done in an attempt to handle the large volume of water being produced.

Four months after the stimulation, the worn sucker rod pump was pulled from Well No. 2 and replaced. At that time a TV camera was made available and was used to examine the condition of the open hole. It was observed that the Gilson coalbed had been fractured but that the fracture extended above the coalbed to at least the bottom of the casing 2 feet above the coal. Injection tests completed with the camera in the well also revealed that most of the fluids were flowing into the zone on top of the coal. It is possible that the large volume of water being produced into this well has flowed from the formation above the Gilson coalbed. This observation was very unexpected since no "break" had been observed during the stimulation treatment and the maximum gradient on the coalbed was less than 0.85 psi/ft depth. The pressure buildup during the entire treatment was very gradual and was thought to be contained within the coalbed.

In January 1981, when the worn sucker rod pump was replaced, a capacity of 6.6 GPM was projected to be needed to dewater the second well. The capacity of the replacement pump was marginal at 5 GPM. However, after the pump was replaced the rate of water influx into the well increased dramatically. Projections were made that a pumping rate near 13 GPM would now be needed to draw the water level down to the coal face. This increase was apparently due to a seasonal change affecting the ground water. The rate of water influx was monitored closely for the next 3 months. It was projected during this time that the water rate had peaked at 13 GPM as shown in Figure 34. The sucker rod system was no longer adequate to dewater this well.

In June 1981, a 15 GPM capacity submersible pump and variable speed drive (VSD) was installed in this well. The VSD was included with the system to extend the pump life and provide a wider operating range. The wide operating range was deemed necessary because the seasonal increases were expected to recur. A electric generator was also installed to provide power for the pump.

A normal "debugging" period was experienced on the new system while several operating problems were resolved. The first completely continuous operation was achieved in late August and early September. As the water level in the wellbore was drawn down to the coal face gas production rates from 20 to 30 Mscfd were again measured. A peak rate over 30 Mscfd was measured. During September through November the pump operation deteriorated until sufficient data were collected to determine that the pump was wearing due to coal and sand particles. This conclusion was drawn even though no particles were ever pumped to the surface.

The pump was pulled and repaired in December 1981. The pump was reinstalled with a specially built screen section over the pump intake as has been discussed. The screen on this pump worked very well in protecting the pump.

As can be seen from the well history in Figure 33, no production is shown during much of the December-March winter period, and only estimated water rates were available. Metering inaccuracies and failures resulting from the cold weather were a major problem during this period. These

Whitmore Park Well No. 2 Drawdown

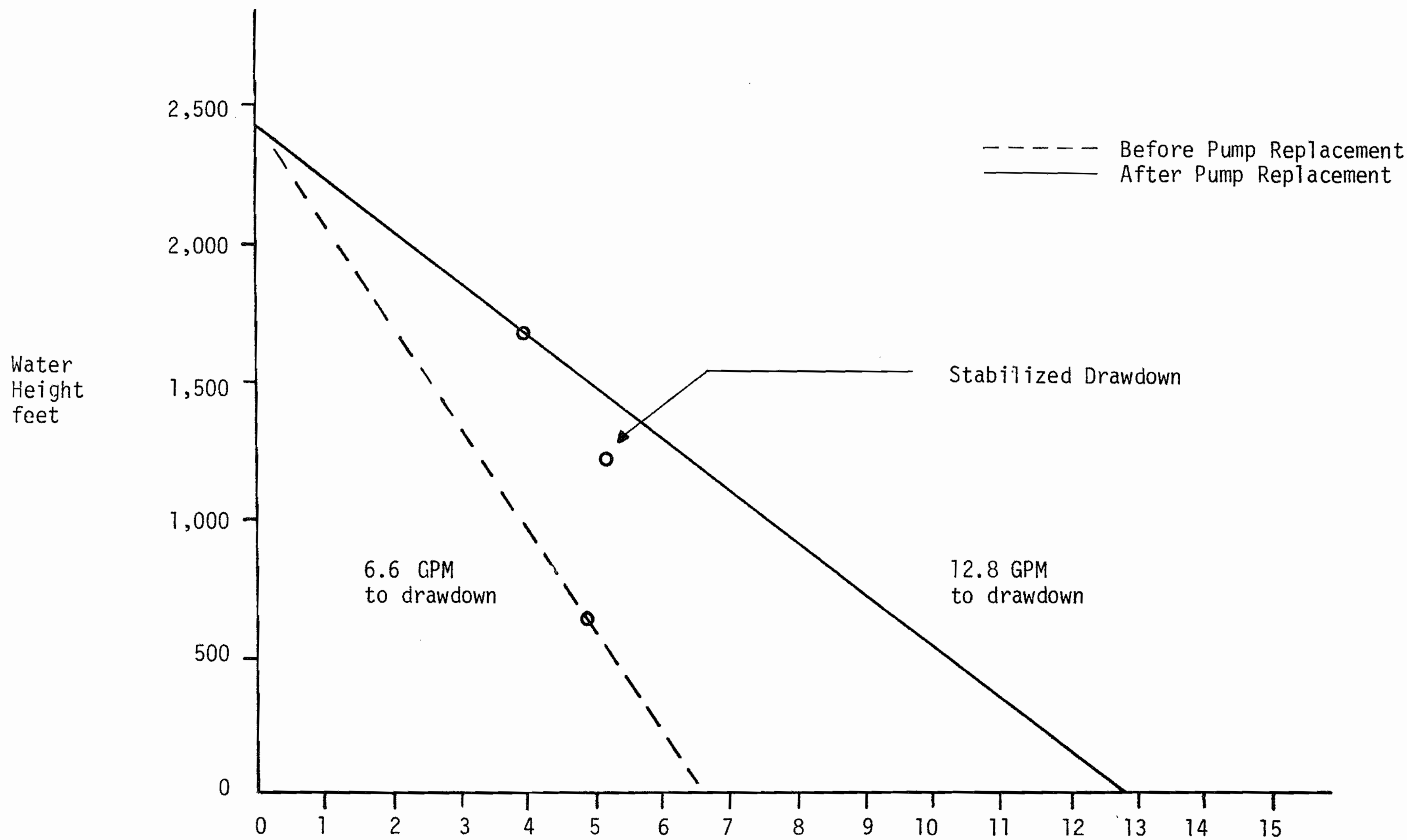


FIGURE 34

problems and solutions were discussed previously. The problem of water condensing from the gas and collecting in the gas meters was resolved by installing a Romet positive displacement rotary gas meter in late March 1982. Because the initial production measurements were noticeably higher then those recorded earlier in the winter, the earlier data is believed to be understated. The most accurate water and gas production data were gathered from March through the end of the project in August.

It was observed that the gas production rate declined steadily from April through June while the water production remained relatively constant. It was postulated that a blockage caused by the production of coal and sand "fines" may have reduced the effective permeability at the coal face. A retreatment of the Gilson coalbed was completed in late June in an attempt to open the formation and place a concentrated sand pack near the wellbore. Production from the Sunnyside coalbed was also opened and a treatment conducted on this coal seam. Despite having opened more total coal to production with these treatments, a decrease in gas production was measured during July until pumping was stopped on august 4, 1982 because of generator failure.

A significant and continuous decline in gas production was observed over the production life of Whitmore Park Well No. 2. This decline is similar to those reported for isolated wells in studies completed for the Department of Energy (14). Their studies verified the conclusions of the computer simulation work done under Phase I of this project, that single isolated wells are not able to reduce the coalbed pressure rapidly enough to yield high gas production rates. Over the intended period of testing Well No. 2 the water rate remained essentially constant except for the seasonal fluctuation already discussed.

4.8.3 <u>Whitmore Unit No. 1 Well Production</u>. A 1400 BPD capacity submersible pump was installed, and dewatering and production of the third demonstration well commenced in July 1982. A completely revised metering and production system was installed to accommodate the higher rates of production expected based on swab testing data.

Several unforeseen problems caused some inaccuracies in the data. The type of level control valve originally used on the water retention tank was unable to provide a tight shutoff so that when the water production ceased the pressure in the system reduced the water level such that gas was allowed to bleed through the water meter. This resulted in the water meter readings being overstated and the gas reading being understated. Some adjustments to the data have been made. Water production was typically 20 to 30 GPM, but rates as high as 40 GPM were experienced. Although operation during the the first ten days was quite intermittent, gas rates as high as 150 Mscfd were measured. Figure 35 shows these production rates. The submersible pump was shutdown on the 10th day of operation when coal particles and sand were found in the water meter filter. The size of these particles gave a clear indication that the screen built over the pump intake had been damaged while being installed.

The pump and screen were pulled in August and a new screen was installed over the pump intake ports. Rub buttons were added to protect the screen and extra care was taken to assure the screen could be installed without damage. A 40-mesh screen was wrapped very tightly over the pump intake and silver soldered at the seam to give an even tighter fitting screen than had been successfully used at the second well. This screen was small enough to retain the 20/40 mesh sand used in the stimulation treatment. The pump was reinstalled and operated through the rest of August.

Very little decline in gas production was measured during the August period even though the level of production was less than half that measured in July. During the last days of August the system was again shutdown when sand was recovered from the water retention tank. Unlike the sand recovered earlier, this sand was fine enough to pass through the 40-mesh screen. The sand appeared to be less than a 100-mesh size. Samples of the frac sand used on this well indicated 5-10 percent of the sand to be of similar "fines". Attempts to restart the submersible pump indicated it to be jammed, presumably with this fine sand.

Sand of this size poses some serious operating problems. It is believed that sand fines are washed from the formation with the high water

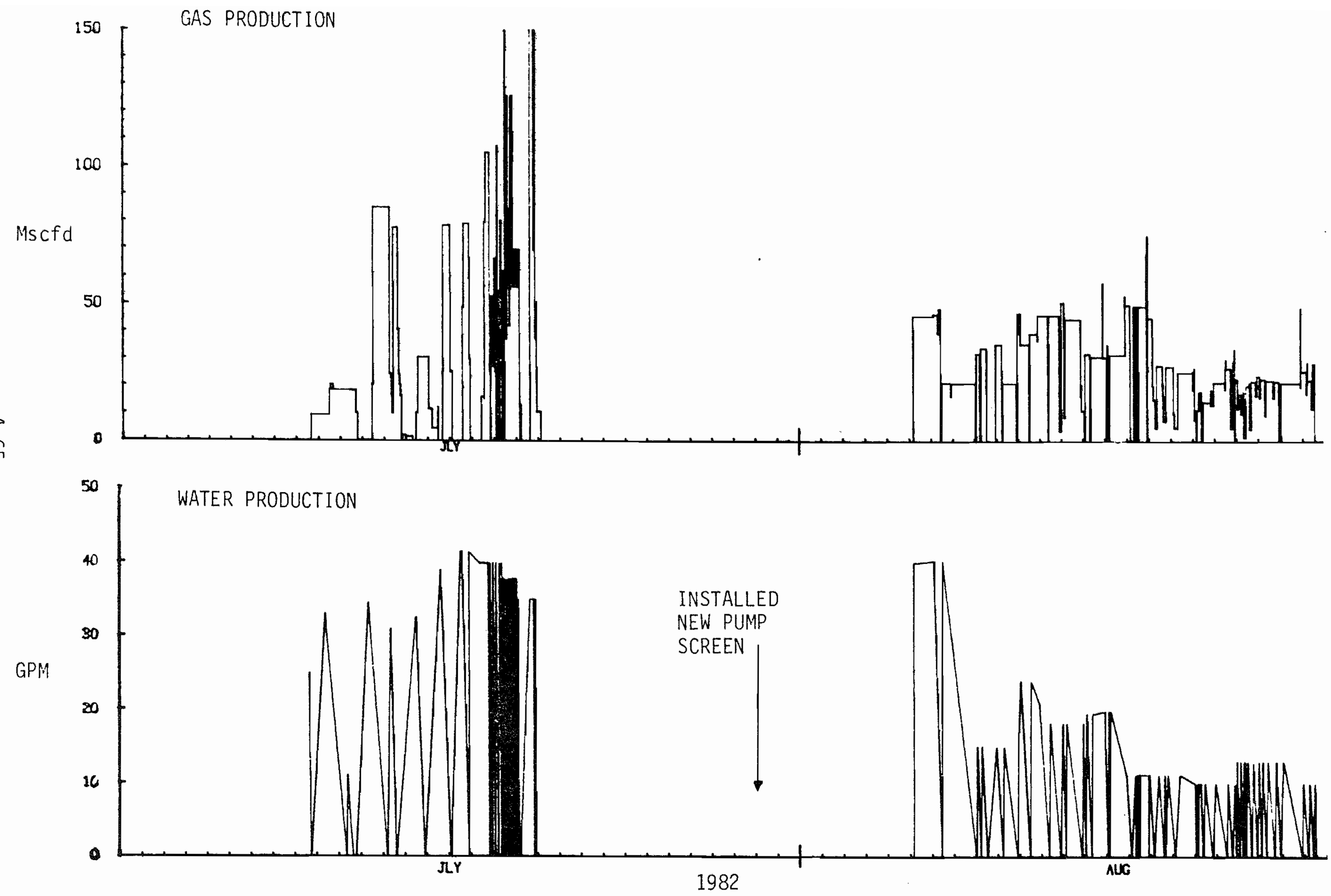


FIGURE 35 -WHITMORE UNIT WELL NO. 1 PRODUCTION HISTORY

production from this well. Due to the high water velocity they are carried into to the pump and to the surface.

Several types of alternate pumping systems were examined, none of which provide a suitable solution to this problem. Submersible and sucker rod pumps will wear in this sand environment. Manufacturers of Venturi-Jet pumps claim the sand would not erode their tungsten-carbide nozzle in the size needed for this application but the system would not be a practical way of pumping 20-30 GPM of water production. A gas lift system would appear to be a workable. However, no gas source is readily available for this remote location without incurring excessive costs for gas storage facilities.

4.8.4 Production Analysis. The level of water production from the second and third wells was substantially higher than expected. Water production from reported wells in Alabama (14) does not exceed 200 BPD while the production from the third project well averages 700 BPD with a peak production of 1400 BPD. Coalbeds in this area of the Book Cliffs were shown to contain relatively high concentrations of methane. Yet only a very small percentage of the methane in the vicinity of the well was able to be produced, indicating that significant pressure and water saturation reductions were not occurring. The high water rates tend to show that water is being supplied to the formation at approximately the same rate it is being removed. Therefore, the water saturation is not being reduced and only a very small area immediate to the wellbore is being drained. Effective drainage of methane from coalbeds can only be accomplished by reducing the water saturation of the coal. Reducing the saturation from 80 to 60 percent has been measured to have the effect of drastically increasing the relative permeability as shown in Figure 36 (15). To produce gas effectively the water saturation must be reduced. Data obtained from this project indicate that an isolated well may not be effective in reducing water saturation except under special circumstances where the water source to the coalbed is minimal or restricted.

GAS PERMEABILITY RELATIVE TO WATER SATURATION

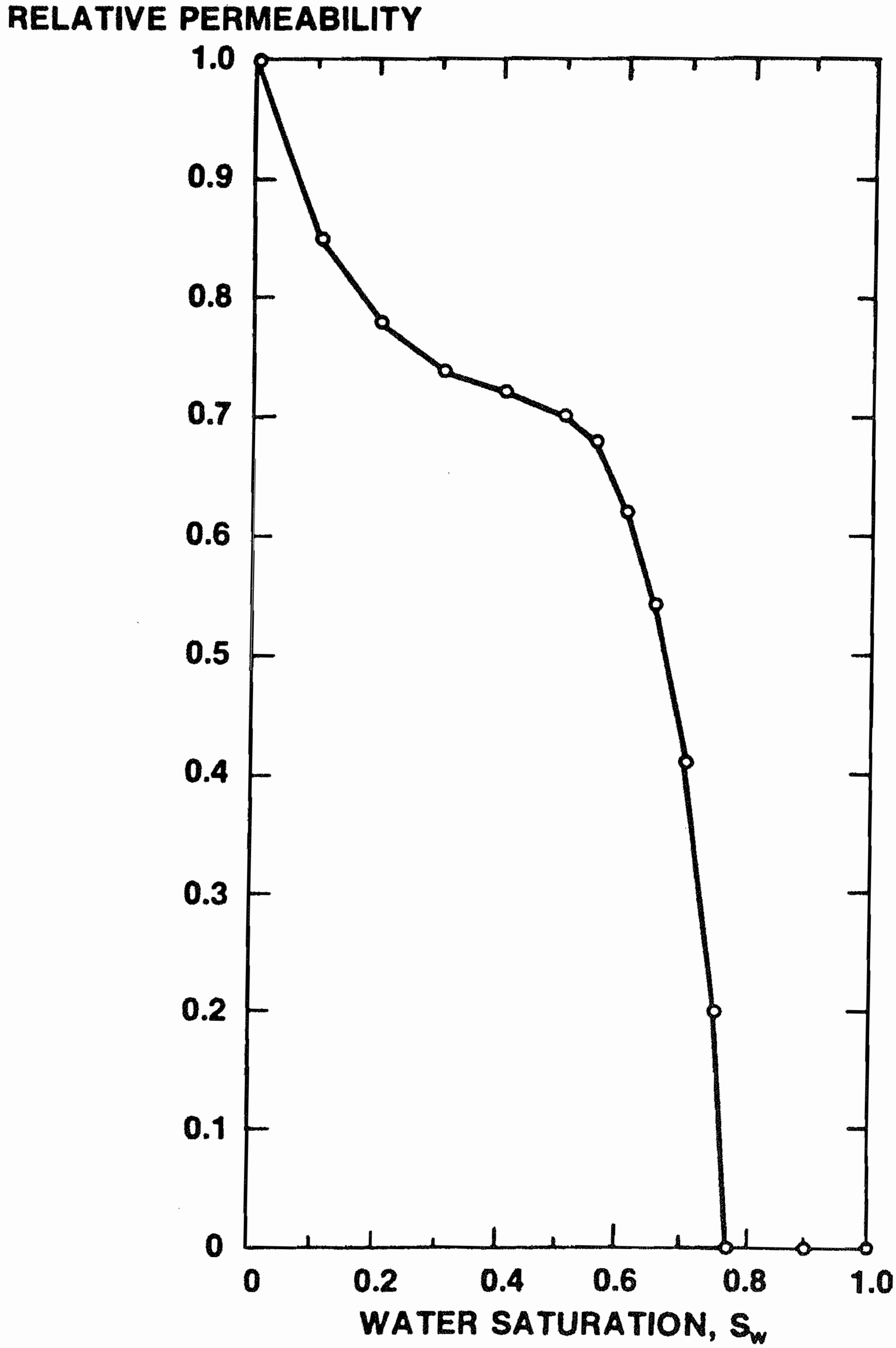


FIGURE 36

4.9 CONCLUSIONS AND RECOMMENDATIONS

During this demonstration project extended production data were obtained for the Gilson coalbed in the Book Cliffs coal field. Different completion techniques, pumping methods, and monitoring schemes were tested and compared. Conclusions were drawn based on the experience gained over the 3½-year life of this project. The following conclusions and recommendations derived are believed to apply very well to Book Cliffs coalbeds and may or may not be applicable to methane recovery from coals in other areas.

4.9.1 Conclusions.

(a) Large volumes of ground water exist in the Whitmore Park area of the Book Cliffs coal field which severely restrict and complicate the recovery of methane from these coalbeds.

(b) Fracture containment is necessary for deep coals in the Book Cliffs in order to minimize water production into the wellbore. Completion of a given coalbed should be based on an analysis of the surrounding formations which might produce excessive water.

(c) At least some of the coals in the areas tested are susceptible to damage caused by either drilling mud or cement infiltration. A direct comparison to show the effect of cement on coal was made for the Sunnyside coal between Wells No. 1 and No. 2. The cement infiltration into the coal was believed to be the cause of increasing the fracture gradient from 1.2 to over 1.8 psi/ft depth.

(d) Open hole completions or completions using a selective completion tool (i.e. Pengo system) offer the best chances of avoiding damage to the coal thereby resulting in a more productive well. The Pengo system is particularly applicable to multiple zone completions where an open hole is impractical.

(e) The completion method used is very important and may be the difference between a successful and an unsuccessful well. Certain methods may damage the coal and affect production. Other methods may result in excessive water production.

(f) Careful attention must be paid to control solids, freezing, and moisture in gas lines. In most cases filters ahead of meters and equipment and screens around pump intakes will control solids. Freezing can be prevented using space heaters, insulating lines, and providing drainage of lines. The metering problems caused by moisture condensing in gas lines can best be resolved by using a positive displacement rotary gas meter. It must be installed so that moisture will drain with the vertical flow through the meter.

(g) Gas production declined rapidly for the isolated wells in this demonstration project. This observation closely follows reports on most other isolated methane recovery wells. In areas with considerable ground water,it may only be possible to reduce formation pressure and water saturation in a pattern of wells or in wells located near a mine or other drainage point.

4.9.2 Recommendations. It is be recommended that further research be conducted in the following areas to most effectively improve the technology of methane recovery from coalbeds:

(a) Additional research is needed to determine if methane recovery can be enhanced by a pattern of wells.

(b) Methods of dewatering these wells should be improved. Alternative inexpensive methods are needed to handle very large volumes of water.

(c) Techniques to contain solids should be refined which either retain the sand and coal fines in the formation or allow them to be easily handled throughout the production and monitoring system.

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EVALUATION OF METHANE PRODUCTION FROM UNMINABLE COAL

Carbon County, Utah

Project 65019
Phase I Report

to

Mountain Fuel Supply Company

by

Philip L. Randolph
Institute of Gas Technology
3424 South State Street
Chicago, Illinois 60616

March 20, 1979

INTRODUCTION

The timing of contract and subcontract actions on Mountain Fuel's demonstration project for methane recovery from unminable coalbeds has been such that execution of IGT's subcontract has not yet occurred at the time of writing of this report. A necessary result is that work performed by IGT and reported herein is less than anticipated in the statement of work for Phase I of IGT's subcontract.

No problem is anticipated in completing the remaining Phase I activities, as well as IGT's Phase II tasks such that drilling can commence in the fall of 1979. The Phase I activities reported herein address two considerations judged to have high significance to identifying the major uncertainties and developing detailed project plans to effectively address those uncertainties during the field program. These two considerations are the ratio of gas to water production and hydrualic fracture design such that a single propped fracture, rather than proppant distribution into a multiplicity of cleats, can reasonably be expected. These considerations are addressed below.

RELATIONSHIP BETWEEN WATER PRODUCTION AND GAS PRODUCTION

This relationship was addressed by utilizing the Intercomp simulator with inputs that reflect current estimates regarding characteristics of the target coal seams. Results of four computer simulation runs are provided with this report. These runs examine the effect of only two parameter variations. Those variations are shape of the relative permeability curve and size of the producing reservoir. Details of those simulation runs and conclusions derived therefrom follow.

Assumed Characteristics

A full listing of input parameters used is provided in Table 1. Values for many of these parameters were derived from, or are consistent with, those set forth in Mountain Fuel's original proposal to the Department of Energy (DOE) and its Phase I report. Parameters in this category are —

- Methane content
- Adsorption isotherm
- Porosity
- Permeability
- Depth
- Water pumping rate.

Table 1. ASSUMPTIONS FOR SIMULATION

Geometry	
Seam Shape: Circular with the well in the center	
Radius for 80 acres	1,053 ft
for 11,816 acres	12,800 ft
Thickness	10 ft
Depth	2,600 ft
Coal Characteristics	
Density	1.4 g/cm^3
Adsorption Isotherm	See Figure 1
Original Adsorbed Gas in Place	8.3 std cm^3/g (265 SCF/ton)
Mean Particle Radius	1.0 cm
Diffusivity	1.0×10^{-8} cm^2/s
Reservoir Characteristics	
Initial Pressure	1130 psi
Coal Compressibility	1.0×10^{-5} psi^{-1}
Porosity	3%
Water Saturation (S_w)	1.0 (fraction)
Permeability	1.0 md
Relative Permeabilities	See Figure 2
Capillary Pressure	100 psi for $S_w < 0.4$ $<$ 2 psi for $S_w > 0.6$
Fluid Characteristics	
Gas Gravity Relative to Air	0.65
Gas Viscosity (pressure dependent)	0.0118-0.140 cp
Water Compressibility	3.0×10^{-6} psi^{-1}
Water Density	65.0 lb/ft^3
Water Viscosity	0.85 cp
Well Parameters	
Hydraulic Fracture Length (each wing)	500 ft
Fracture Conductivity	2085 md-ft
Water Pumping Rate	114 bbl/day (200 gph)
Minimum Bottom Hole Pressure	100 psi

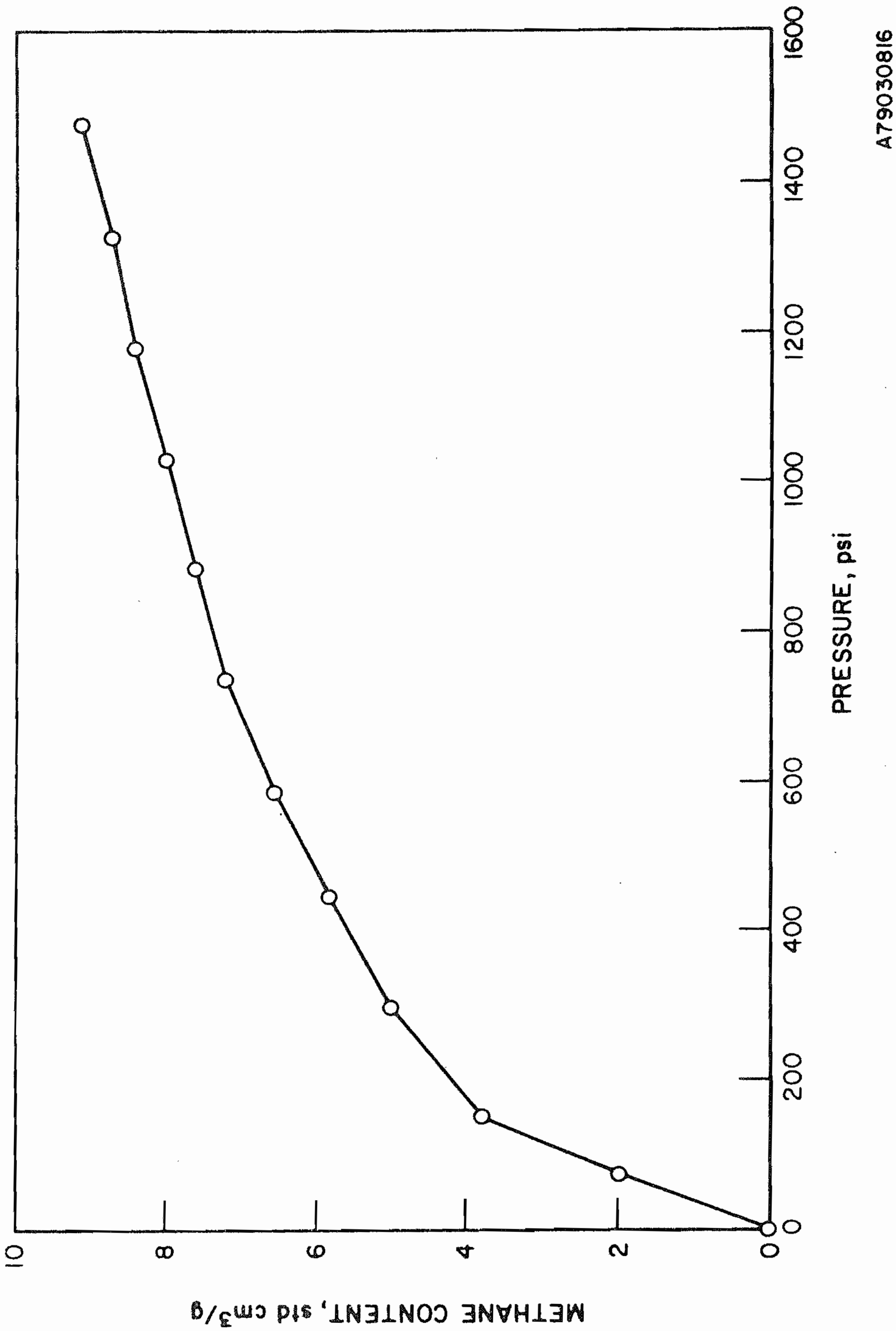

Figure 1. ADSORPTION ISOTHERM

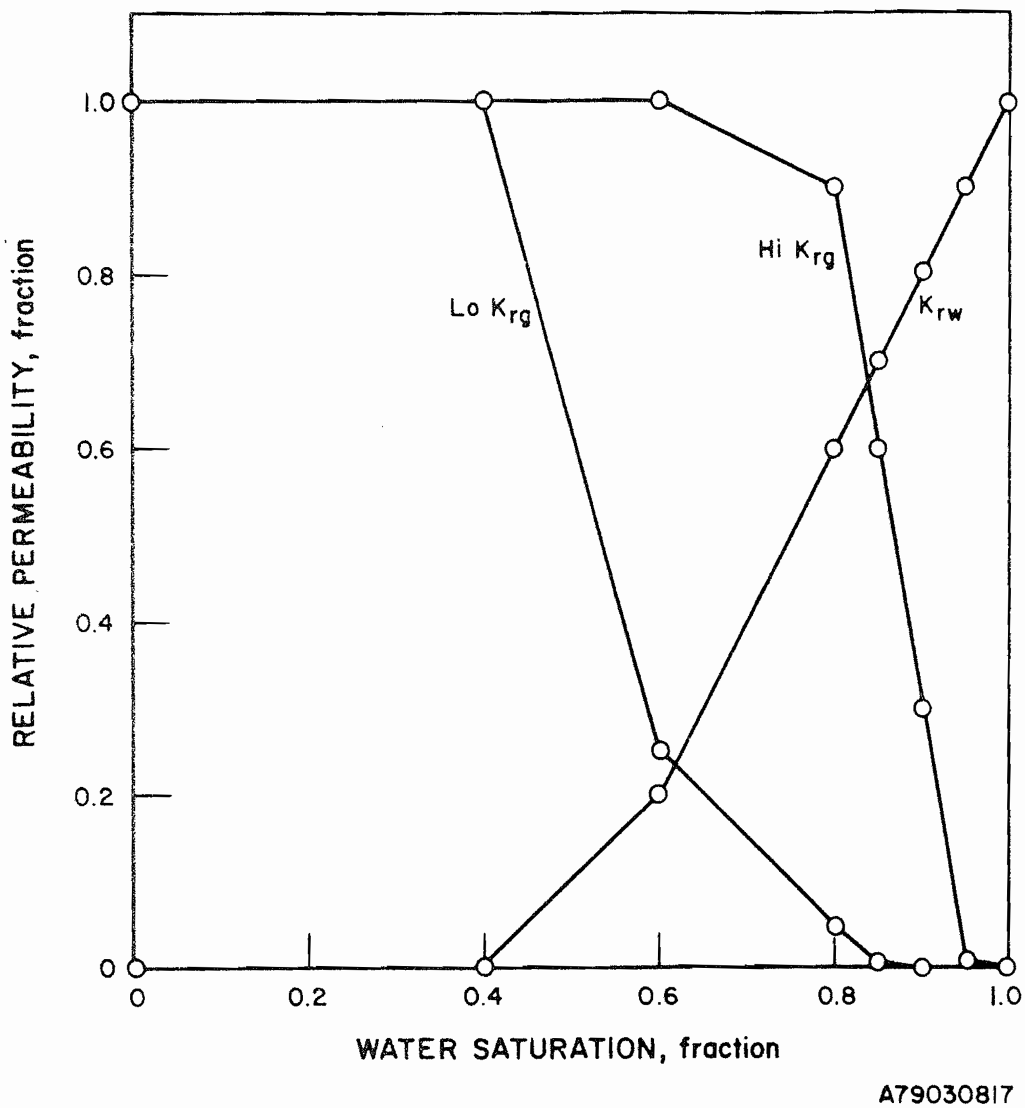

Figure 2. ASSUMED RELATIVE PERMEABILITIES

Assumed coal seam thickness was 10 feet. This is less than the total thickness of multiple seams to be completed and being considered for economic analysis by Mountain Fuel. Whether this assumed thickness is great enough to be representative of the anticipated first test of a single seam is open to question. However, the simulation results can be scaled to different coal seam thicknesses if the producing rates for both gas and water are scaled proportionally to coal seam thickness.

No information exists regarding values of several essential input parameters for the target coal seams. For simulation purposes, values deduced from prior studies of the Pocohantas and Pittsburgh seams were assumed. The most significant of such parameters are —

- Initial water saturation
- Relative permeabilities
- Capillary pressure
- Mean coal particle radius
- Diffusivity for methane in the coal particles.

Prior Intercomp experience in modeling production from coal seams had revealed that the fraction of water that must be produced before gas becomes mobile is probably the most sensitive of these assumed parameters. For this reason, simulation was performed utilizing approximations to the reported relative permeability curve for both the Pocohantas and the Pittsburgh coals. The approximations used are shown in Figure 2. These curves are labeled "Hi K_{rg}" and "Lo K_{rg}." Note that these curves have the major difference that permeability to gas reaches 50% of the single phase value after only 13% of the water is produced for the Hi K_{rg} curve, but that 47% of the water in place must be produced before 50% of the single phase permeability to gas is reached in the Lo K_{rg} case.

Although not explicitly tabulated in Mountain Fuel publications to date, the majority of remaining physical parameters for coal, water, and gas reflected in Table 1 are well-known and available from the literature.

The assumed well paramters are reasonably consistent with prior practice in hydraulic stimulation of production from coal seams and are reasonably consistent with Mountain Fuel's Phase I report. The assumed hydraulic fracture length of 500 feet for each wing and fracture conductivity of slightly above 2000 md-ft reflect propping to the distance of 500 feet with multiple layers of 24-40 sand. The water pumping rate of 200 gph is consistent with current Mountain Fuel planning, and the minimum bottom hole pressure of 100 psi reflects a judgment regarding likely pressure when the practical problems of balancing gas and water production from 2600 feet are taken into account.

Two different areas were assumed for coal seams containing a single well. The reservoir area of 11,816 acres was arbitrarily chosen to illustrate production that could reasonably be expected from a single test well in a large coal seam. The small reservoir assumption (80 acres) can be regarded as a potential mode of commercial development of the same large coal seam. Since no fluid flow is allowed across the boundaries of the assumed coal seam, the 80-acre area is equivalent to assuming that methane from the coal seam is produced using eight wells per square mile. This parameter variation was included to illustrate the critically important point that the time dependence of natural gas production, and therefore the economics of production, will be dependent upon well spacing and will differ from values observed in a long-term test of a single test well.

Description of Simulation Results

It is emphasized that the computer simulation results to be described do not constitute predictions for the upcoming field experiments. Rather, they only supply a "feel" for some of the key parameters whose values must be defined during conduct of the experiments. It is further emphasized that the results to be presented contain idiosyncracies that are not limitations of Intercomp's powerful computational tools. Rather, these idiosyncracies are limitations on quality of input dictated by IGT's decision regarding risk exposure in terms of work performed prior to contract execution.

Figure 3 is a plot of bottom hole pressure, water production, and gas production versus the logarithm of time for the input parameters set forth in Table 1, Figure 1, and Figure 2. This simulation assumes the most optimistic of the two relative permeability curves (Hi K_{rg}) and the large reservoir size appropriate to simulating results from long-term production of a single well. With the optimistic relative permeability curve characteristic of Pittsburgh coal, a modest amount of gas production has already started at the end of the first day of dewatering at a rate of 200 gph. In 16 days, dewatering at that rate reduces bottom hole pressure to the specified minimum of 100 psi, and a peak gas production rate of 250,000 CF/day is calculated. Calculated gas production then declines to about 100,000 CF/day at the end of 1 year and roughly 30,000 CF/day at the end of 10 years. The ratio of produced gas to produced water appears to be about 2500 CF/bbl of water. For this high ratio, it is probable that pumping would be required throughout the productive life of the well. It is very doubtful that gas flow velocity could become high enough to lift the associated water.

With the exception of the first peak, the oscillations in the gas and water production shown on Figures 3 through 6 are believed to be the result of sharp corners in the abbreviated tables used to describe the adsorption isotherm, relative permeabilities, and capillary pressure curves. More careful preparation of input tables using many more points to describe these curves is expected to result in future simulations providing a monotonic decline in production rates after the first peak.

Figure 4 differs from Figure 3 only because the more pessimistic relative permeability behavior reported for Pocohantas coal was used. Since more water must be produced before pressure reduction is sufficient for desorbed gas to become mobile, almost a week of pumping is required before any detectable gas production. Over 40 days of pumping are required to achieve the bottom hole pressure minimum of 100 psi and the associated first peak in gas production. Further, that peak is only about 100,000 CF/day, in contrast to 250,000 CF/day at 16 days for the Hi K_{rg} case. After the peak in gas production, the decline rate with time is similar to Figure 3; however, the produced gas to water ratio is about 1000 CF/bbl so that continued pumping would clearly be required for gas production.

Both Figures 3 and 4 suggest that, after 10 years of production, production rate will be only about 10% to 20% of the initial peak. However, at 10 years less than 0.4% of adsorbed gas in place has been produced from the large reservoir. The reason for the large decline in production after producing only a small fraction of adsorbed gas is that large volumes of water are being produced from remote portions of the reservoir, but providing minimal pressure drawdown for desorption of gas. In commercial development, a well spacing would be chosen such that pressure drawdown and gas desorption were more rapid.

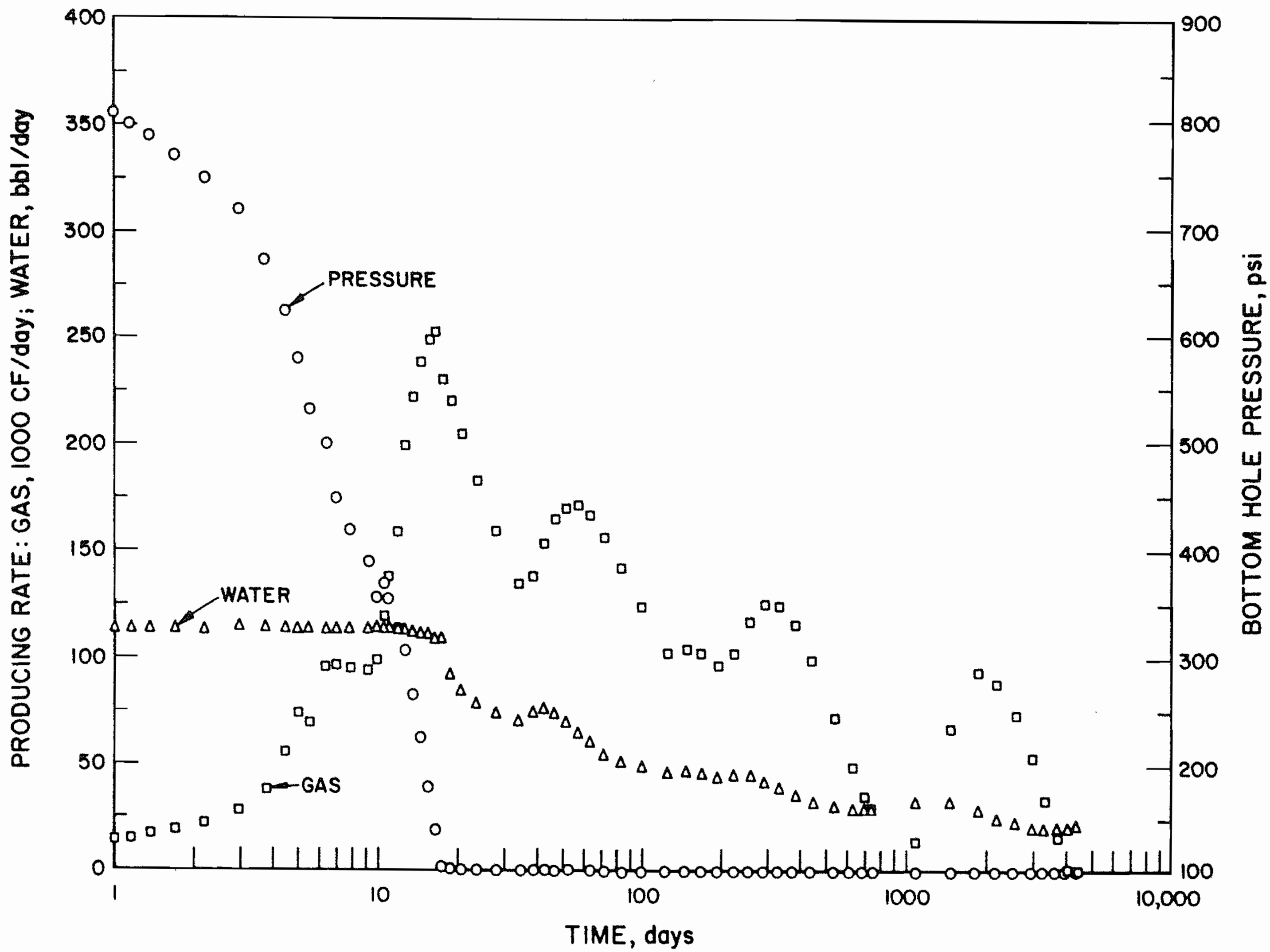

Figure 3. HI K_{rg} LARGE RESERVOIR (11,816 acres)

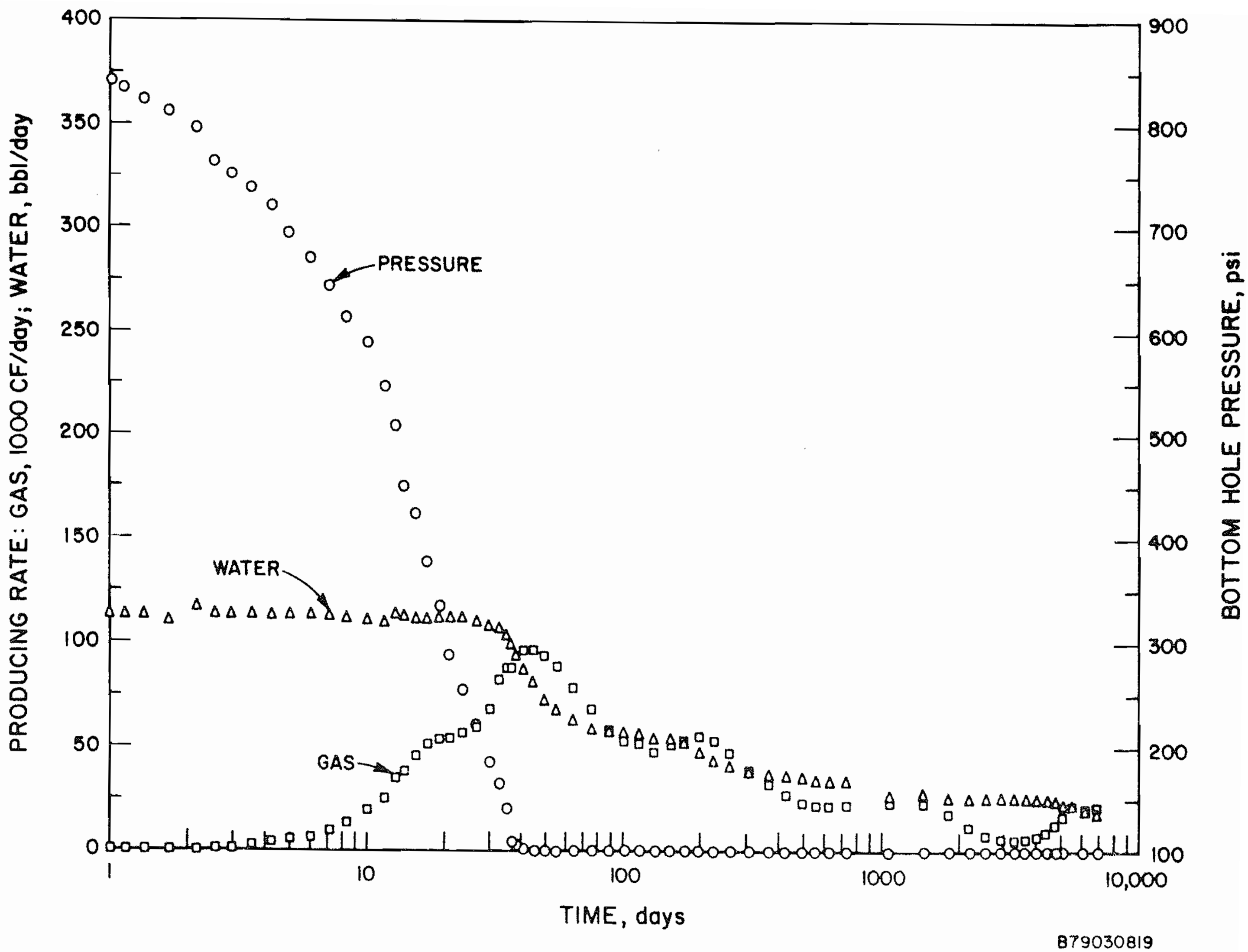

Figure 4. LO K_{rg} LARGE RESERVOIR (11,816 acres)

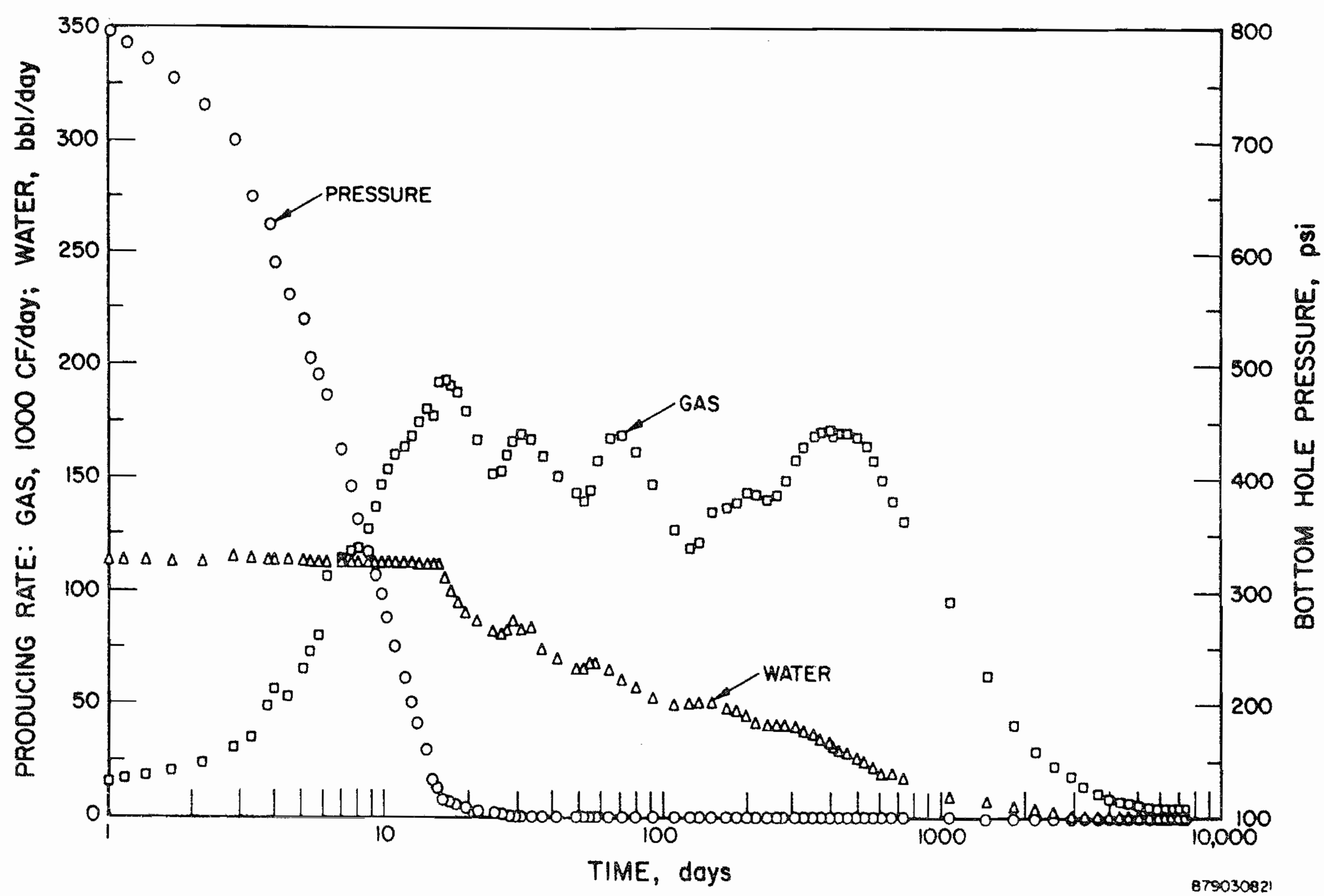

Figure 5. HI K_{rg} SMALL RESERVOIR (80 acres)

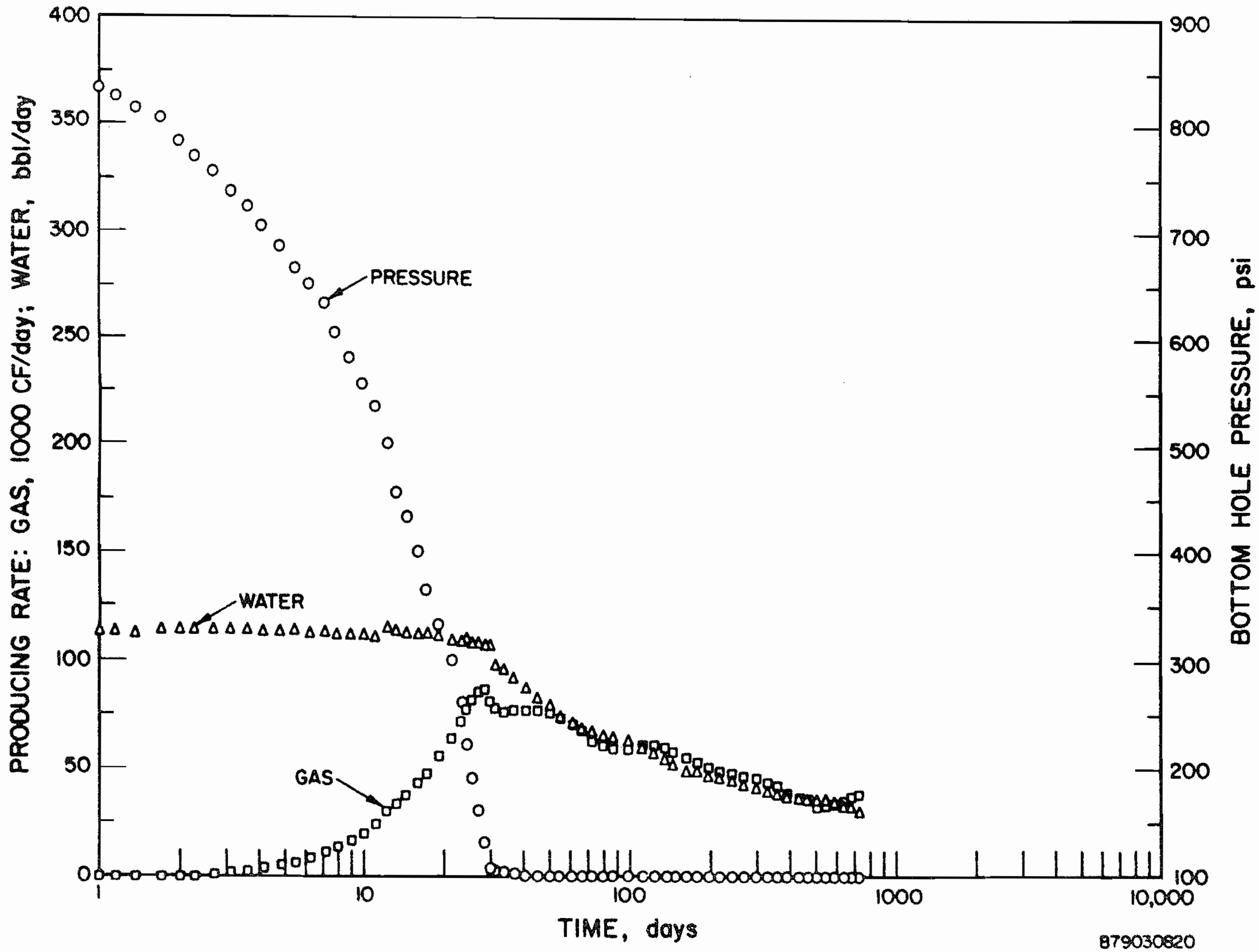

Figure 6. LO K_{rg} SMALL RESERVOIR (80 acres)

Figure 5 illustrates the dramatic improvement in production environemnt that could result from optimizing well spacing to provide drawdown and rapid desorption of gas. The only difference between Figure 3 and Figure 5 is drainage area for the well. However, 1 year after start of production, the gas flow rate from the small reservoir is nearly twice that from the large reservoir, whereas water production rates are essentially identical. After 1 year, pressure is being drawn down throughout the 80-acre reservoir so that the more favorable gas to water production ratio of about 5000 CF/bbl of water continues as the reservoir is depleted. In 10 years, over 50% of the original gas in place has been produced and the calculated gas to water ratio is 6400 CF/bbl.

Figure 6 shows the effect upon production from eight wells per square mile for the pessimistic relative permeability assumption. Comparison with Figure 4 reveals a less striking effect than the previous comparison of Figures 3 and 5. However, it is noteworthy that peak gas production occurs at about 30 days, rather than more than 40 days. Unfortunately, the simulation in Figure 6 terminates at 2 years, or 730 days. It is anticipated that continued production would reveal an improvement in gas to water ratio after 2 years.

Calculated cumulative gas production at various times for the four simulations is shown in Table 2.

Table 2. CUMULATIVE GAS PRODUCTION

	Year			
Large Reservoir	1	2	5	10
	10^6 CF			
Hi K_{rg}	44.6	67.7	132.0	230.5
Lo K_{rg}	18.5	27.2	51.6	66.0
Small Reservoir				
Hi K_{rg}	54.3	112.2	183.8	221.9
Lo K_{rg}	19.2	32.5	Not calculated	Not calculated

Conclusions Reached

Great caution must be exercised in drawing conclusions from this small number of very preliminary computer runs. However, the following conclusions are probably warranted.

- The current Mountain Fuel assumption for economic analyses may well be appropriate. That assumption is production at a rate of 100,000 CF/day for the first year followed by a decline of 10% per year for the next 5 years. A significant reservation is that such modest decline would probably result from less than eight wells per square mile and may be accompanied by a gas to water production ratio such that production can be continued for several more years before operating costs exceed revenue.

- The poor gas to water ratio revealed in the simulations presented may be worse than will actually occur. Reasons for this possibility are that the Kaiser mine in the sunnyside seam is much drier than would occur if gas to water production ratios were as simulated. Further, project personnel are aware that core holes drilled by others have unloaded and produced gas from seams believed similar to the targets for this project. This could not occur if the seams contained a 100% water-saturated porosity of 3%, with no free gas present, as assumed for the computer simulation. It is IGT's judgment that the reasons for this difference between simulation results and field observations are probably that <u>in situ</u> porosity is less than the 3% measured with conventional oil field core analysis procedures and that the fracture porosity, or adjacent porous strata, have a gas saturation in excess of the critical value for finite permeability to free gas.

- It is extremely important that the combination of core analysis and field testing prior to hydraulic fracturing provide improved understanding of the porosity, water saturation, and relative permeability curves for the target strata. Since data from mines and exploratory holes suggest that natural gas production may be possible without stimulation, definitive data from such production should be vigorously sought. Loading of fracture porosity adjacent to the wellbore with water by injection testing will undoubtedly be an appropriate step. However, if natural production is achieved, it may be appropriate to delay injection testing until definitive gas production data are obtained.

- A substantial number of computer simulations should be performed early in Phase II. Such simulation efforts should include seeking compatibility between assumed fractured porosity and fracture permeability in the context of understanding from 2 decades of fractured reservoir work on the Sprayberry formation and the current exchange between Dr. Lincoln Elkins and Dr. Todd Doscher regarding compatible fracture porosity and permeability assumptions for Devonian shale. In addition, the parametric studies should more accurately reflect the actual coal seam thicknesses anticipated and consider whether dewatering other than by use of a sucker rod system with a capacity of 200 gph is appropriate.

HYDRAULIC FRACTURE DESIGN

IGT personnel have a strong background in research on massive hydraulic fracturing of tight sandstone reservoirs to enhance gas recovery. Since some such sandstones are bounded by coal seams, that research has included consideration of details as to why a few feet of coal provide an effective barrier to vertical growth of large hydraulic fractures.

In applying that background to proprietary evaluation of hydraulic fracturing attempts in anthracite coal, IGT personnel were surprised to observe that the shut-in pressure at the end of hydraulic fracturing was roughly 1.3 times the pressure due to the weight of overburden. This very high pressure is surprising because there is a substantial background for the widely held view that hydraulic fractures are only vertical if the minimum principal stress that must be overcome for fracture propagation is less than vertical stress due to the weight of overlying rock.

Since the density of real earth materials is such that the vertical stress due to weight of overlying rock is very close to 1.0 psi/ft of depth, the anticipated shut-in pressure after creating a vertical hydraulic fracture is less than 1.0 psi/ft of depth. If the pressure is close to 1.0 psi/ft of depth, creation of a horizontal, rather than a vertical, fracture is considered probable.

Bureau of Mines Report of Investigations RI 8260, Effects of Hydraulic Stimulation on Coalbeds and Associated Strata, appears to offer some insight into why shut-in pressures are greater than 1.0 psi/ft of depth for operations in coal seams. That report provides details of hydraulic fracturing and subsequent mineback for one experiment in the Pittsburgh coalbed in Washington County, Pennsylvania, and a second experiment in the No. 6 coalbed in Jefferson County, Illinois. The report contains considerable detail on the hydraulic fracturing operations performed and on subsequent mineback to determine the size and shape of created fractures.

For the Pittsburgh coalbed, pressure and flow rate charts recorded during hydraulic stimulation reveal a surface shut-in pressure of approximately 600 psi for a hydraulic fracture at a depth of about 590 feet. Adding the additional pressure due to the column of water from 590 feet to the surface at shut-in reveals that at the coal horizon the instantaneous shut-in pressure was about 1.45 psi/ft of depth. Subsequent mineback revealed that proppant had been distributed into a single fracture in the face cleat direction plus multiple fractures in the butt cleat direction. This is in contrast to the anticipated single fracture extending a distance of roughly 300 feet in opposite directions from the wellbore. In addition to multiple proppant paths, propped widths were greater than anticipated, and the distance of proppant transport was generally less than 1/10 the value anticipated from design calculations generally believed valid for oil and gas production.

In contrast, the experiment in the Illinois No. 6 coalbed had a shut-in pressure of about 1.0 psi/ft at the coalbed depth of 733 feet. Subsequent mining revealed a single fracture whose direction did not parallel either the face cleat or the butt cleat direction. Further, fracture width and the distance of proppant transport were reasonably consistent with expectations from the design procedures normally used in oil and gas operations.

The data contained in RI 8260 reveal a high degree of similarity in all aspects of the two hydraulic fracturing operations, except the correlation of multiple proppant transport paths with a high shut-in pressure. However, the report does not contain the data on coalbed porosity, permeability, and mechanical characteristics that are essential to the detailed search for understanding of the major differences in the two experiments. Nevertheless, it is hypothesized that proppant transport along the existing cleat directions was due to permeability of the Pittsburgh seam being so high that hydraulic fracturing fluid leaked into the cleat structure in multiple directions before pressure was high enough to create new fractures in the coal structure. Such uniform fluid leak-off would then place the hydraulic confining pressure upon the coal blocks bounded by cleats adjacent to the wellbore. This pressure may have precluded initiation of fractures in a direction perpendicular to the minimum principal tectonic stress in the coalbed.

IGT's proposed pursuit of detailed data on hydraulic fracture performance for these and other experiments has been minimal during Phase I because our subcontract has not yet been executed. However, it has involved considerable telephone contact with personnel in DOE, the U.S. Bureau of Mines, and oil field service companies. Those contacts suggest that analyses of hydraulic fracturing operations have not been performed by other parties. Further, they have revealed that Mr. Ray Wenzel of Halliburton's Pittsburgh Office specified details of field operations for many of the hydraulic fractures performed in coal seams, and that Mr. Wenzel would be pleased to make records from those hydraulic fractures available for analysis.

IGT expects to perform such analyses early in Phase II. It will include seeking additional data on coal seam properties and resultant gas production from other parties involved in key experiments so that "leak-off" during fracturing can be calculated. It is anticipated that this analysis will produce recommendations for pumping rates high enough to address fracturing in the injection testing to be performed before well stimulation.

EVALUATION OF METHANE PRODUCTION FROM UNMINABLE COAL

Carbon County, Utah

Project 65019
Phase II Report

to

Mountain Fuel Supply Company

by

Philip L. Randolph
Institute of Gas Technology
3424 South State Street
Chicago, Illinois 60616

August 20, 1979

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INTRODUCTION

The contract between Mountain Fuel Supply Company (MFS) and the Institute of Gas Technology (IGT) was executed on June 5, 1979, after approval of contract execution by the Department of Energy (DOE) in a letter dated May 29, 1979. The effective date of the contract is March 1, 1979, and the contract obligates $35,000 for work performed by IGT during Phases I and II, as defined in DOE Contract No. DE-AC21-78MC10734 between DOE and MFS. Obligation of additional funding is a prerequisite to initiation of the field work anticipated in Phase III of this program.

This report covers activity during Phase II through August 20, 1979. Work performed prior to March 20, 1979, was covered in IGT's previously submitted Phase I Report.

The work performed is broken into four categories: 1) computer simulation of production, 2) hydraulic fracture design, 3) preparation for laboratory analysis, and 4) drilling and testing recommendations. These are discussed under headings that follow. Planned future activities are discussed in the final section of this report.

COMPUTER SIMULATION OF PRODUCTION

IGT's Phase I Report contained results of preliminary computer simulation runs. The four results reported illustrate that —

- Field development with a well spacing of 80 acres or less will provide more rapid payout and the same 20-year or greater production per well as a single well in a very large reservoir. This is because a small drainage area per well is essential for sufficient water production to decrease reservoir pressure, and thereby permit desorption of a substantial portion of the natural gas.

- The natural gas production rate and the ratio of produced gas to produced water are strongly dependent upon the shape of the relative permeability curve for two-phase flow through the cleats and natural fractures in the coal seam. For a blocky coal, such as the Pittsburgh seam, other properties characteristic of the MFS prospect resulted in a peak gas production rate of less than 100,000 SCF/day and a long-term ratio of produced gas to produced water of less than 1,000 SCF/bbl. In contrast, for a relative permeability curve characteristic of the friable Pocahontas coal seam, calculated peak natural gas production rate was about 250,000 SCF/day, and the long-term ratio of produced gas to produced water was greater than 2,000 SCF/bbl.

- For both relative permeability curves, the long-term ratio of produced gas to produced water is higher for an 80-acre well spacing than for a single well in a very large reservoir.

The simulation results presented in the Phase I report contain oscillations in the time-dependence of production that are not representative of nature. These oscillations were computational artifacts due to the limited input tables and course zoning selected by IGT for preliminary calculations.

The computer simulation results presented in this report reflect a major improvement in the quality of the simulation. In contrast to the prior preliminary calculations to obtain a "feel" for potential production, the results presented herein are believed to bracket the range of possible production from Mountain Fuel's first experiment.

The selection of coal reservoir characteristics judged most likely to be representative of the first Mountain Fuel experiment is described below. Results are then presented for a more careful simulation of the effects of well spacing upon producing characteristics starting on page 8. These simulation runs are based upon a 10-foot thickness to facilitate comparison with the Phase I Report. Results of a base-case simulation for the first experiment start on page 13. Finally, the effect of possible ranges of experimental parameters is investigated.

Selection of Coal Properties

The logic used in selecting specific values for each of the coal reservoir characteristics required for computer simulation is described below.

Adsorption Isotherm

The adsorption isotherm used was based upon prior MFS considerations discussed on pages 2.5 and 2.6 of its technical proposal. Those prior considerations used the equation developed by the U.S. Bureau of Mines (USBM) with empirical constants in the equation based upon prior USBM studies of Castlegate coal from the Book Cliffs. After converting to the units required for Intercomp simulation, this equation becomes —

$$V = 1.90\ P^{0.37} - 0.00870\ P - 0.51 \qquad (1)$$

where —

P = pressure, atmospheres

V = gas content, standard cm^3/g.

A plot of this equation in relation to gas content measurements by the Utah Geological and Mineral Survey (UGMS) is shown in Figure 1. This figure is reproduced from the MFS proposal and MFS Phase I Report.

For computer simulation purposes, the hydrostatic head on the coal seam was assumed to be 2600 feet. The corresponding reservoir pressure is 1130 psi or 76.7 atmospheres, and the corresponding methane content is 8.29 cm^3/g or 265 SCF/ton.

A plot of the solution of the above equation reflecting the points and interpolations actually used in the computer simulation is shown in Figure 2.

The assumed reservoir pressure of 1130 psi may be an Achilles' heel for the projections to be presented. This pressure assumes hydrostatic equilibrium with a water table 2600 feet above the coal seam. However, coal seams in the Book Cliffs area do dip downward at a small angle from outcrops on the cliffs. Furthermore, face cleats in mines are observed to be perpendicular to the outcrop. Thus, the direction of highest permeability is toward the outcrop. If the coal seams dip 3^o, are continuous from the outcrop to a well 3.5 miles away, and have a hydrostatic head determined by elevation in relation to the outcrop, the hydrostatic head will be only about 1000 feet, and the reservoir pressure will be only about 435 psi or 29.5 atmospheres. The isotherm in Figure 2 reveals that the methane content would be about 5.88 cm^3/g, rather than the 8.3 cm^3/g for the assumed pressure of 1130 psi. If the reservoir pressure is only 435 psi, the methane producible with a minimum bottom-hole pressure of 100 psi will be cut in half. This is because the isotherm reveals that residual methane at 100 psi is 3.29 cm^3/g.

Alternatively, if the well can be successfully operated with a bottom-hole pressure of less than 100 psi, methane recovery may be substantially greater than estimated herein.

Relative Permeability Curves

The starting point in selecting relative permeability curves was the observation by Mr. Doug Reese, a geologist with Mountain Fuel, that coal mined from the Book Cliffs is reasonably similar to the blocky coal mined from the

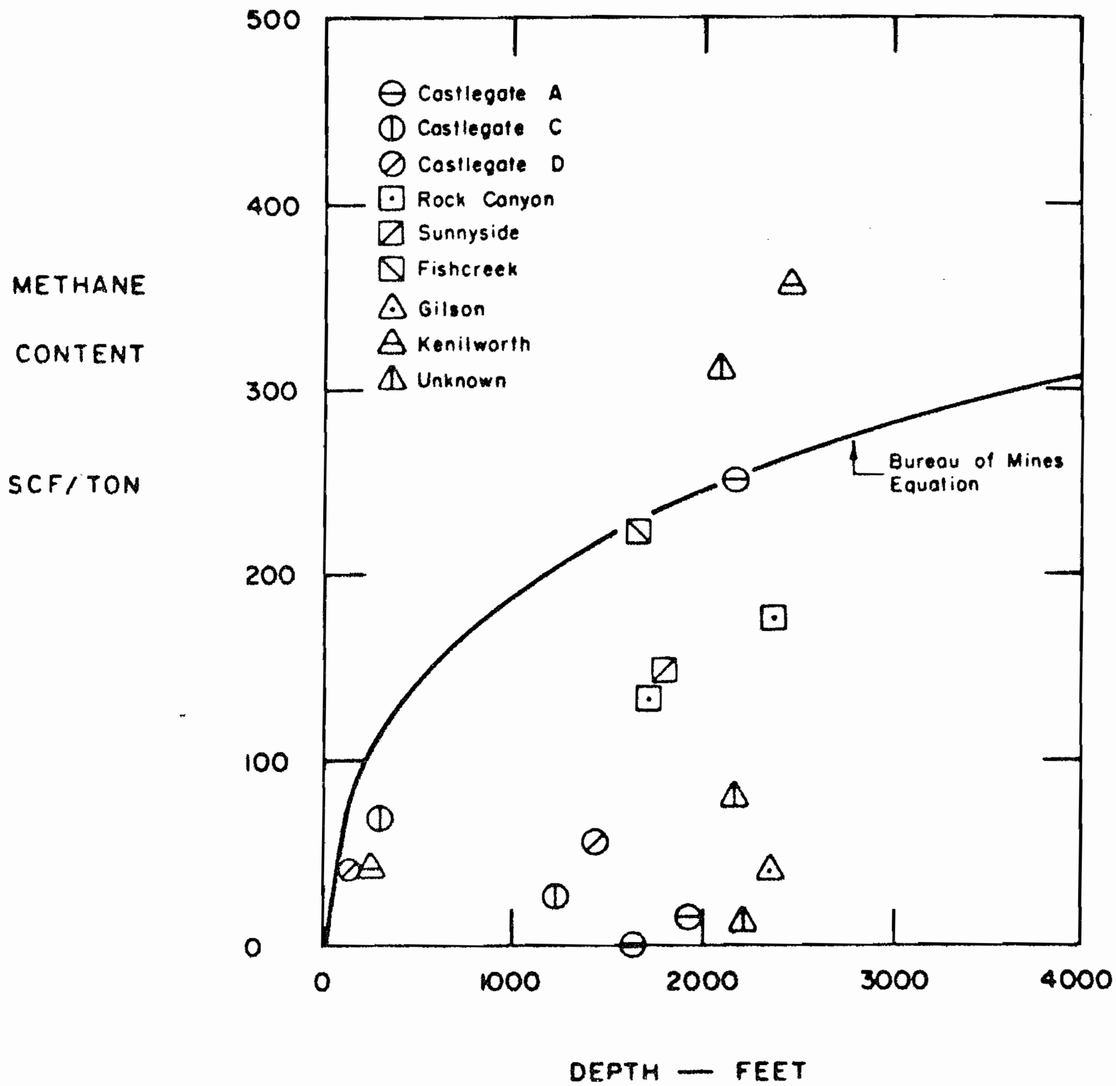

Figure 1. COMPARISON OF UGMS DATA WITH USBM ABSORPTION EQUATION FOR CASTLEGATE COAL

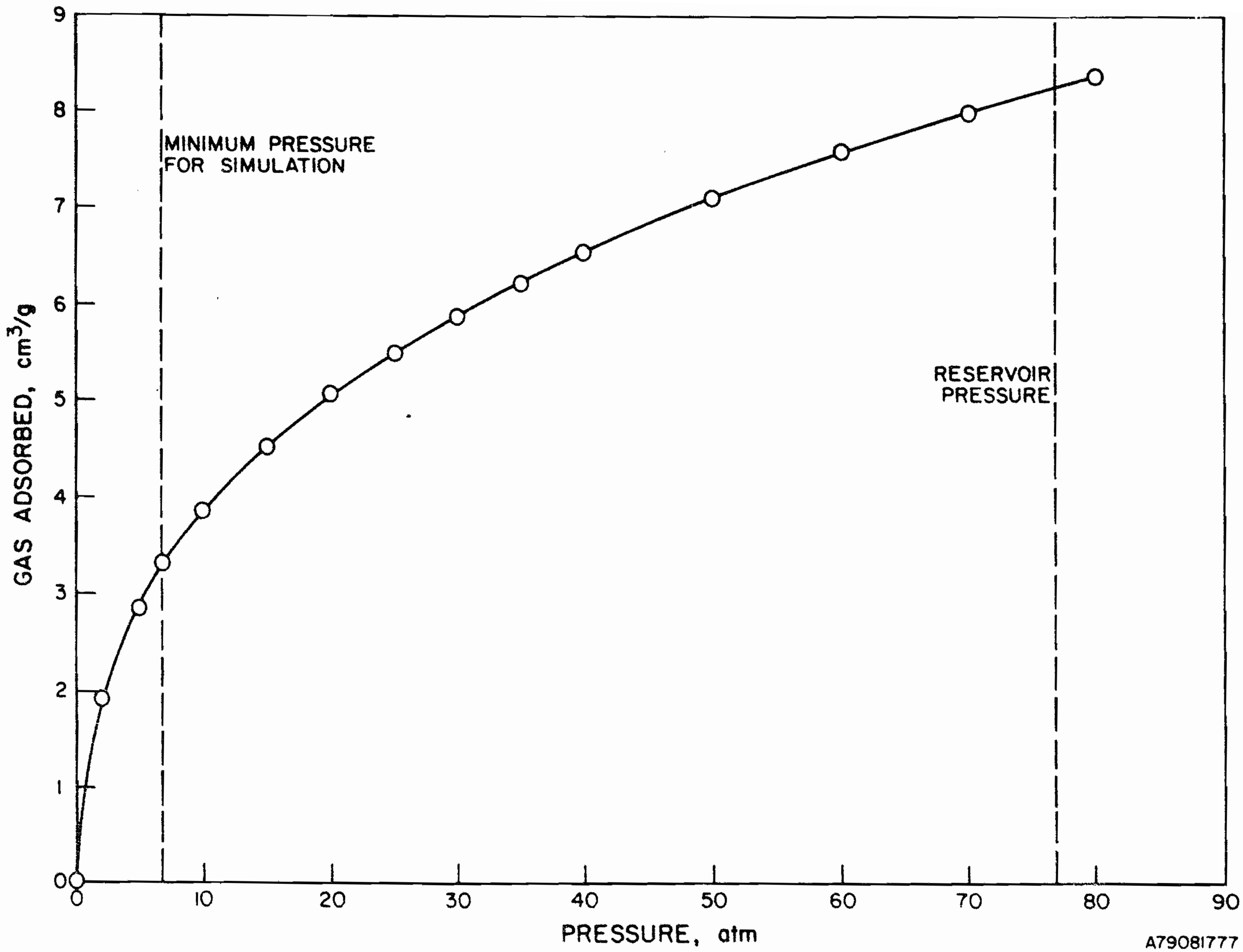

Figure 2. ADSORPTION ISOTHERM FOR SIMULATION

Pittsburgh seam. The coal is definitely not as friable as the Pocohantas seam. Permeabilities for six samples of Sunnyside seam coal have been measured in both the "as received" and dried conditions for Mountain Fuel by an oil field service company laboratory. In such laboratories, the confining pressure on the coal is normally about 120-140 psi. The measured porosity and permeability values span more than an order of magnitude, but average about 3.0% porosity and 1.0 md.

Relative permeability curves for computer simulation were estimated by using this information to determine relative permeability curves for a similar sample in the reports from the University of Pittsburgh. The curve selected for relative permeability to gas is reported for laboratory results for a Pittsburgh coal seam sample having a permeability of 0.43 md at a 200 psig confining pressure, and a porosity of 1.11% of bulk volume. This is the only sample having properties within the range observed for the Book Cliffs seams, for which relative permeability data have been reported. The curve actually used for relative permeability to gas is Figure 5 of a paper by Reznik, et al.* This figure has relative permeability curves for three values of confining pressure. The curve for the highest reported confining pressure, 1000 psig, was used.

The actual data points and interpolations used in computer simulation are shown in Figure 3. The paper by Reznik, et al. reported a value of zero for relative permeability to gas for fractional water saturations of about 0.76. The finite values used in computer simulation for higher fractional saturation are below resolution of the experiment, but were found necessary for computer simulation without excessive cost due to a very large number of time steps. The gas relative permeability values actually used for water saturations in the range of 0.8 to 0.9 are so small that they have no significant effect upon calculated natural gas production.

Unfortunately, curves showing the relative permeability to water are not reported by the Pittsburgh group using the same samples as the curves for relative permeability to gas. The water relative permeability curve actually

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*Reznik, A. A., Dabbous, N. K., Fulton, P. F. and Taber, J. J., "Air-Water Relative Permeability Studies of Pittsburgh and Pocahantas Coals," Soc. Petrol. Eng. J. (1974) December.

used is reported as a calculated-drainage relative permeability to water for a Pittsburgh coal sample with a gas permeability of 39.1 md at 200 psig and a water permeability of 110 md at 200 psig. The curve used is in Figure 9 of the above paper. This particular curve for relative permeability to water was selected only because the critical fractional water saturation of 0.45 is physically reasonable in relation to the shape of the previously selected curve for relative permeability to gas. Actual values and interpolations used in the computer simulation are shown in Figure 3.

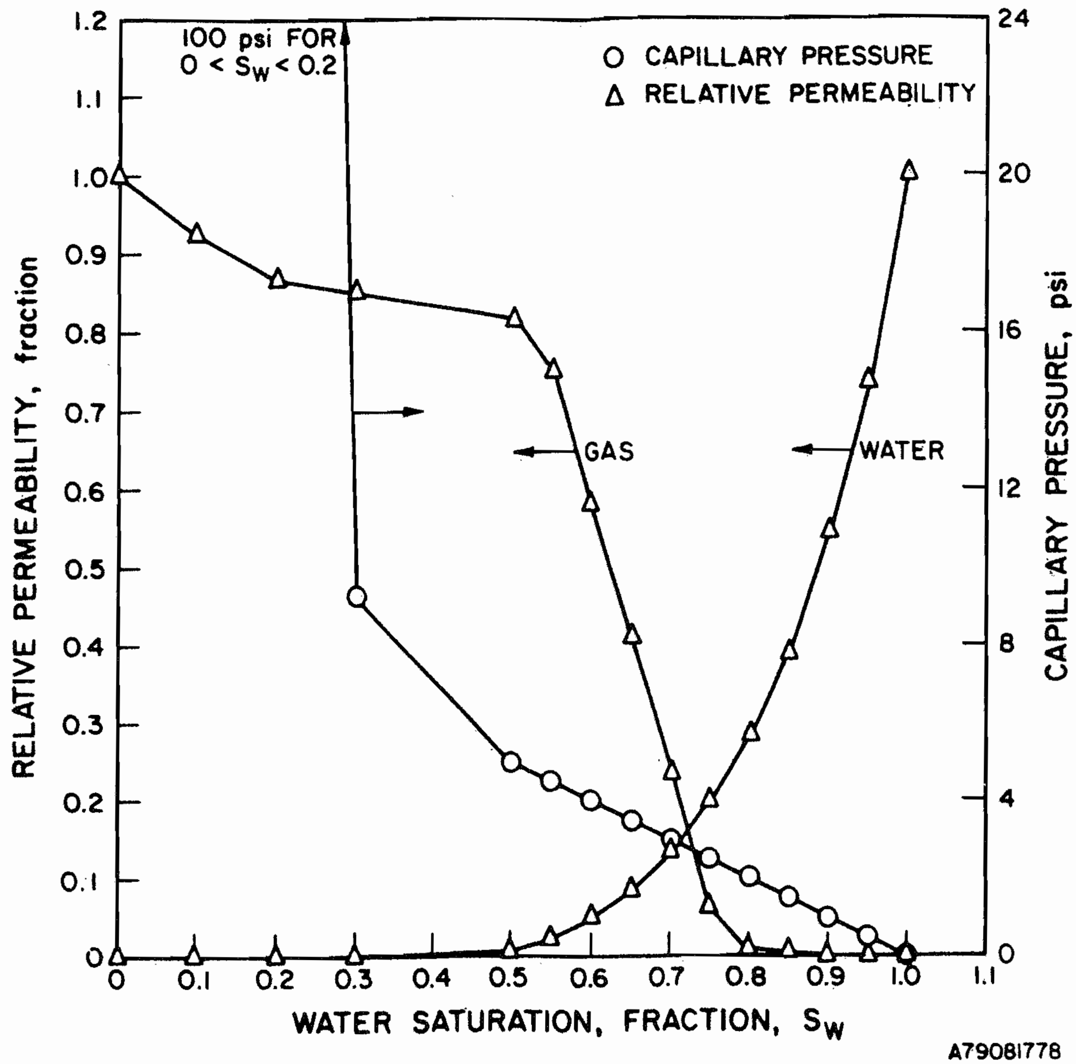

Figure 3. CAPILLARY PRESSURE AND RELATIVE PERMEABILITIES TO GAS AND TO WATER USED FOR SIMULATION

Capillary Pressure Curve

Capillary pressure studies on coal also were reported by the Pittsburgh group.* Unfortunately, it was not possible to correlate reported capillary pressure curves with the previously selected curve for relative permeability to gas. Because calculated production is virtually independent of capillary pressures if the capillary pressures are minimal for finite relative permeability to water, an artificial curve that meets this condition but corresponds to an unrealistically low critical water saturation, was arbitrarily chosen. The points and interpolations used in the computer simulation are shown in Figure 3.

Effect of Well Spacing Upon Production

These simulation runs differ from those presented in IGT's Phase I Report in that they —

- Use the coal reservoir parameters described above and illustrated in Figures 1 through 3.
- Use additional zoning and shorter time steps in the computer problems so that the spurious oscillations in the Phase I Report did not occur.

The remaining properties used for simulation are identical to those for the Phase I Report and are presented in Table 1. For those properties where Table 1 contains two entries, the first entry was used for these computer runs. Those entries are a coal thickness of 10 feet and a hydraulic fracture length (each wing) of 500 feet.

Results of simulation are shown in Figure 4 for a single well in an 11,816-acre reservoir, and in Figure 5 for field development with a well spacing of 80 acres.

Production histories for the two cases are virtually identical for the first 2 years. Pumping of water reduces reservoir pressure to the assumed minimum of 100 psi in 2 weeks. This coincides with start of a long peak in gas production that averages about 37,000 SCF/day for the next 3 months. Natural gas production then declines monotonically for both cases, reaching a value of about 16,000 SCF/day in 2 years.

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*"In Gas-Water Capillary Pressure in Coal at Various Overburden Pressures," Soc. Petrol. Eng. J. (1976) October.

Table 1. PROPERTIES USED FOR SIMULATION

Geometry	
Seam Shape: Circular with the well in the center	
Radius for 11,816 acres	12,800 ft
for 80 acres	1,053 ft
Thickness	10 ft;18 ft
Depth	3,100 ft
Coal Characteristics	
Density	1.4 g/cm^3
Adsorption Isotherm	See Figure 2
Original Adsorbed Gas in Place	8.3 std cm^3/g (265 SCF/ton)
Mean Particle Radius	1.0 cm
Diffusivity	1.0×10^{-8} cm^2/s
Reservoir Characteristics	
Initial Pressure	1130 psi
Coal Compressibility	3.0×10^{-5} psi^{-1}
Porosity	3%
Water Saturation (S_w)	1.0 (fraction)
Permeability	1.0 md
Relative Permeabilities	See Figure 3
Capillary Pressure	See Figure 3
Fluid Characteristics	
Gas Gravity Relative to Air	0.65
Gas Viscosity (pressure dependent)	0.0118-0.0140 cp
Water Compressibility	3.0×10^{-6} psi^{-1}
Water Density	65.0 lb/ft^3
Water Viscosity	0.85 cp
Well Parameters	
Hydraulic Fracture Length (each wing)	500 ft;200 ft
Fracture Conductivity	2085 md-ft
Water Pumping Rate	114 bbl/day (200 gal/hr)
Minimum Bottom Hole Pressure	100 psi

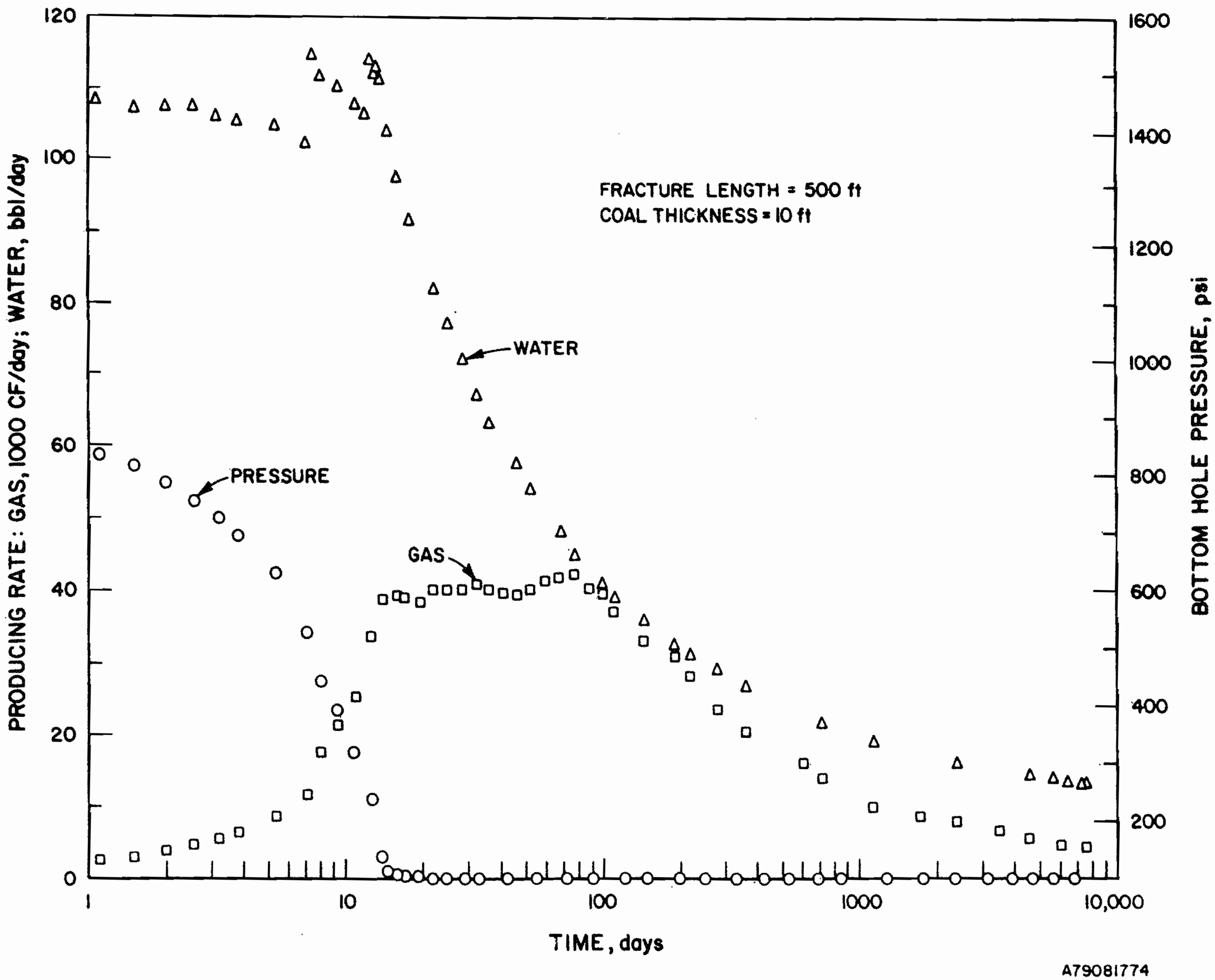

Figure 4. CALCULATED PRODUCTION FOR ONE WELL IN 11,816 ACRES

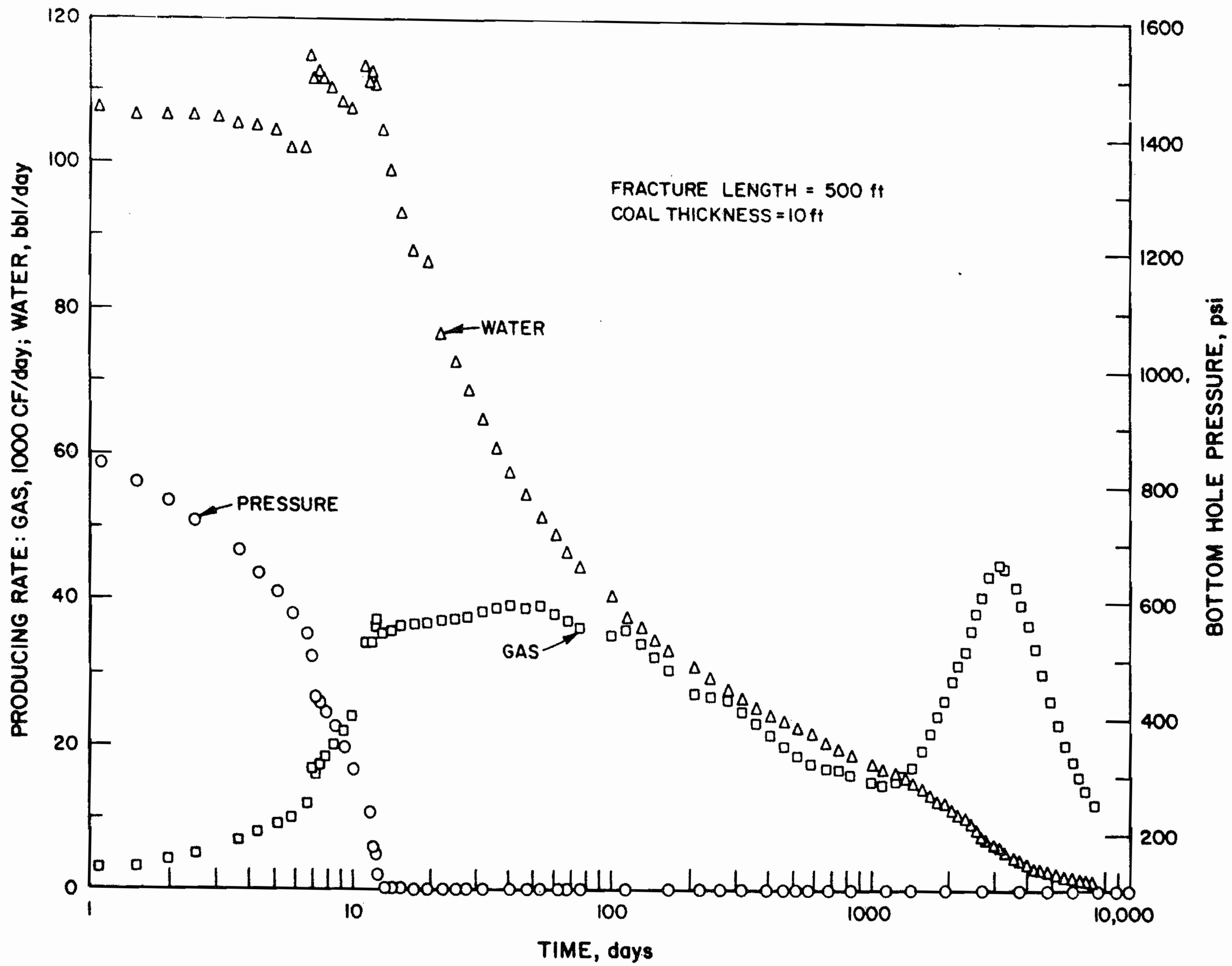

Figure 5. CALCULATED PRODUCTION FOR ONE WELL IN 80 ACRES

After 2 years, the effect of overall reservoir pressure reduction with the small well spacing becomes strikingly apparent. For the 80-acre well spacing, natural gas production rate again begins to increase and reaches a calculated peak of about 45,000 SCF/day, slightly less than 6 years after start of production. Flow rate then declines so that at the end of 20 years almost 190 million SCF of natural gas has been produced. This is 45% of original adsorbed gas in place.

In contrast, for the single well in a very large reservoir, natural gas production rate continues to decline after 2 years. Cumulative production in 20 years is only 59 million SCF of natural gas. This is less than 0.1% of original adsorbed gas in place and is only 31% as much gas as would be produced in the same time from each well if the reservoir were produced on an 80-acre spacing.

Still smaller well spacing would —

- Cause the peak due to overall reservoir production to start earlier in time so that the production rate between 1 and 4 years would be much higher;
- Provide more rapid reservoir depletion; and
- Increase percent of original gas in place recovered for a project life of 20 years.

Cumulative gas production at various times for these two cases are presented in Table 2. This table also summarizes the variation in produced ratio of gas to water for various time intervals. Note that the increase in gas production as reservoir pressure is reduced with an 80-acre spacing is accompanied by an increase in the ratio of produced gas to produced water that may be sufficient for well operation without pumping. In contrast, the ratio of produced gas to produced water deteriorates throughout the life of a single well in a large reservoir. Thus, pumping would probably be essential to maintain production at all times during the life of this single well.

Base Case for the First Experiment

Input parameters for the computer simulation to calculate the expected performance on the first test of a single coal seam are set forth in Table 1. For those parameters where two values are listed, the base case parameters are the second numbers. These are a coal seam thickness of 18 feet and an assumed propped length for the hydraulic fracture of 200 feet. This propped length is much shorter than service companies would calculate for a foam fracture treatment of 50,000 gallons. However, it is consistent with the propped length for the short, fat propped fractures actually revealed by minebacks after foam fracture treatments. It is also consistent with propped lengths from the United States Steel (USS) minebacks, which revealed widths reasonably consistent with expectations from service comapny design calculations. IGT's interpretation of the reports, however, is that the fractures diverted out of the coal seam in a distance of roughly 200 feet.

Table 2. CUMULATIVE PRODUCTION

	80 acres/well		11,816 acres/well	
Time	Gas, 10^6 SCF	Water, 1000 bbl	Gas, 10^6 SCF	Water, 1000 bbl
1 Month	0.84	2.72	0.86	2.81
3 Months	3.1	5.68	3.3	5.86
1 Year	10.7	13.97	10.8	14.50
2 Years	17.4	21.87	16.7	22.92
4 Years	29.0	34.17	24.1	36.80
6 Years	47.8	43.09	30.2	48.98
8 Years	76.3	49.10	35.7	60.14
10 Years	108.3	52.86	40.6	70.92
12 Years	134.2	55.24	45.0	81.41
14 Years	153.5	56.87	48.9	91.71
16 Years	168.5	58.01	52.5	101.80
18 Years	180.1	59.07	55.8	111.80
20 Years	189.5	59.85	59.1	121.60

Gas-to-Water Ratio:

	80 acres/well, 1000 SCF/bbl	11,816 acres/well, 1000 SCF/bbl
20 Years (avg)	3.03	0.486
First 2 Years (avg)	0.80	0.73
Remaining 18 Years (avg)	4.53	0.43
Last 10 Years (avg)	11.62	0.365

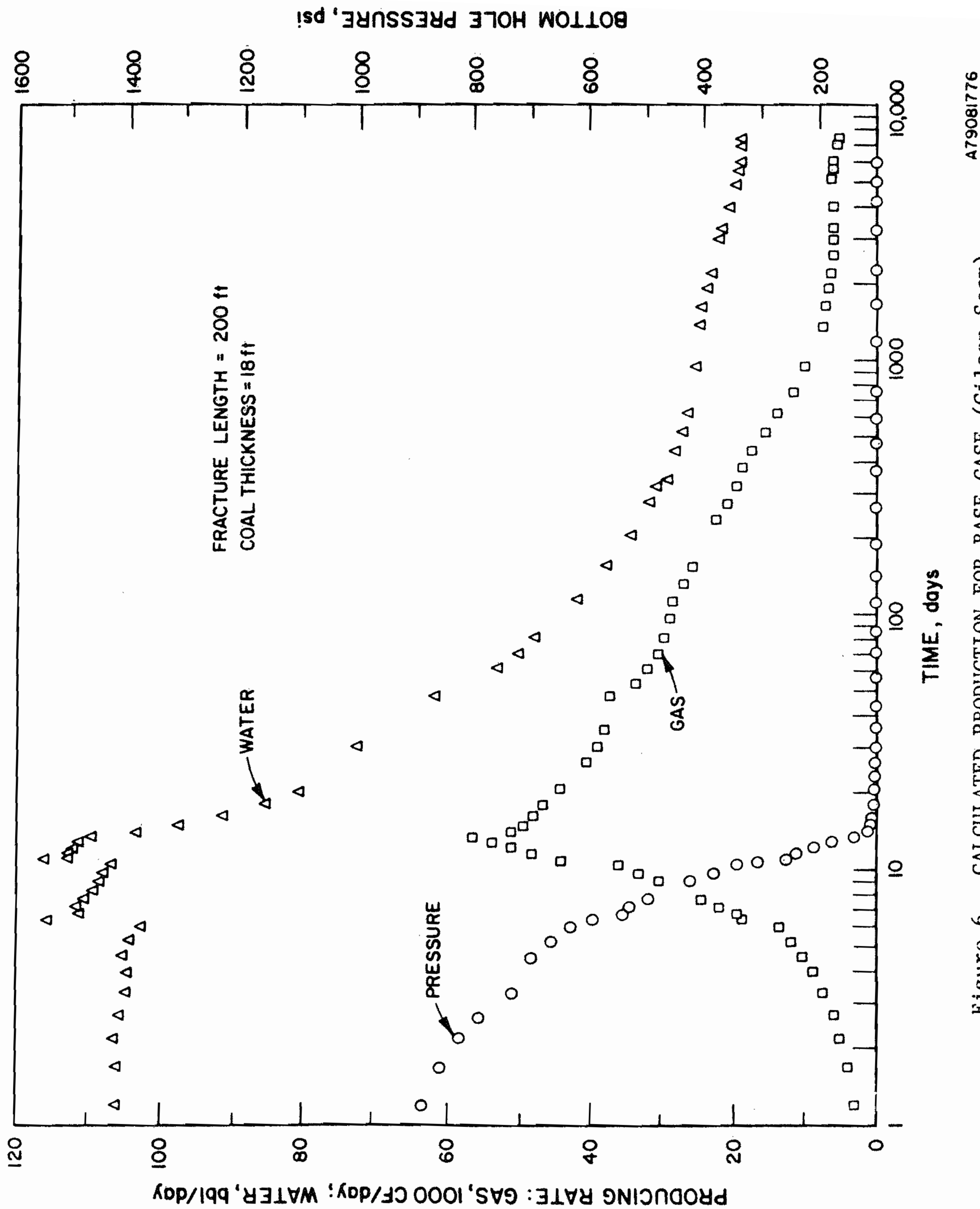

Figure 6. CALCULATED PRODUCTION FOR BASE CASE (Gilson Seam)

The time dependence of bottom hole pressure, water flow rate, and natural gas flow rates for the base case is shown in Figure 6.

For the first 13.5 days, water production rate will be the assumed 114 bbl/day capacity of the pumping system. At that time, pumping is calculated to have reduced reservoir pressure to the assumed minimum of 100 psi. Peak natural gas production occurs at this same time. After this peak, both water and natural gas production are projected to decline monotonically with time for the assumed single well in a very large reservoir. Since the ratio of gas production to water production never becomes as high as 1000 SCF/bbl, and the natural gas production rate is less than 50,000 SCF/day, it is doubtful whether the flowing gas stream would ever lift produced water from the well bore. Whenever water pumping is stopped, the well would probably load with water, so gas desorption and production would terminate due to bottom-hole pressure buildup.

Calculated production rates and cumulative production for both gas and water for various times during the well life are presented in Table 3.

Table 3. BASE CASE PRODUCTION

Peak Gas: 56,400 SCF/day at 13.5 days

	Gas Production		Water Production	
Time	Rate, 1000 SCF/day	Cumulative, 10^6 SCF	Rate, bbl/day	Cumulative, 1000 bbl
13.5 days	56.4	0.3	109.0	1.45
2 months	32.8	2.1	54.0	4.50
5 months	26.0	4.7	38.0	8.40
1 year	19.2	9.2	29.6	15.30
2 years	13.2	14.4	26.0	25.10
5 years	6.8	23.2	23.6	52.00
10 years	6.0	34.4	21.2	92.40
20 years	5.2	56.0	18.8	163.00

It should be emphasized that this base case calculation is not an appropriate basis for economic assessment of investment decisions. It is only useful in relation to field experiment design. In turn, results of such field experiments must be utilized to perform computer simulations of the effect of well spacing to provide a basis for economic analysis. Such computer studies would define the optimum well spacing to achieve the peak in gas production and dramatic improvement in ratio of produced gas to produced water previously illustrated by the comparison of Figures 4 and 5.

This base case projection has made maximum utilization of existing information to select the values of parameters listed in Table 1. However, it is emphasized that actual site-specific data are minimal. To investigate the credible range of departures from this calculation for the first experiment, a series of computer simulations were run. The variation of values for specific critical parameters and the resultant effect upon possible production are discussed below.

Reservoir Parameter Variations

Computer simulations reported in IGT's Phase I Report revealed that the difference in average shapes of relative permeability curves from the Pittsburgh and Pocohantas seams could cause variation by a factor of three in natural gas production and in the ratio of produced gas to produced water. As previously discussed, the relative permeability curves selected for this base case study are based upon laboratory studies of Pittsburgh coal and are therefore at the pessimistic end of the range presented in the previous report. Further variation of this parameter has not been undertaken due to the complete lack of information and the questionable validity of the laboratory studies that have been performed.

The validity of publicly reported relative permeability curves is questionable because the laboratory work has been done only on coal samples with sufficient integrity to survive the machining required for the laboratory measurements. IGT has found no data in which the larger cleats known to exist in nature have existed in samples actually studied in the laboratory. These cleats could substantially change the shapes of relative permeability curves.

The parametric variations that have been performed are discussed below. The variations are fracture length, porosity, permeability, and, for high permeabilities, water pumping rate.

Variation of Fracture Length

Fracture lengths of 100, 200, and 500 feet were used in computer simulation. The 200-foot length is the base case. Resultant calculated production of gas and water is summarized in Table 4. Graphs of production curves are not

Table 4. FRACTURE LENGTH VARIATION

	100-foot Fracture Peak Time 3.9 days		200-foot Fracture Peak Time 13.5 days		500-foot Fracture Peak Time 58.8 days	
	Gas Production					
Time	Rate, 1000 SCF/day	Cumulative, 10^6 SCF	Rate, 1000 SCF/day	Cumulative, 10^6 SCF	Rate, 1000 SCF/day	Cumulative, 10^6 SCF
Peak	37.2	0.1	56.4	0.3	82.0	2.1
2 months	19.6	1.1	32.8	2.1	80.4	2.2
5 months	14.4	2.4	26.0	4.7	60.4	8.2
1 year	10.0	4.9	19.2	9.2	39.2	18.2
2 years	8.4	8.1	13.2	14.4	22.8	28.1
5 years	5.2	14.4	6.8	23.2	15.4	46.3
10 years	4.0	22.0	6.0	34.4	12.4	71.1
20 years	3.6	35.9	5.2	56.0	NC*	NC
	Water Production					
Time	bbl/day	1000 bbl	bbl/day	1000 bbl	bbl/day	1000 bbl
Peak	111.2	0.4	109.0	1.45	106.0	6.4
2 months	36.8	3.1	54.0	4.5	105.0	6.5
5 months	29.2	5.9	38.0	18.4	64.0	13.3
1 year	23.6	11.4	29.6	19.3	48.4	24.8
2 years	20.8	19.2	26.0	25.1	40.4	40.4
5 years	19.6	40.8	23.6	52.0	32.1	78.5
10 years	18.0	74.6	21.2	92.0	27.6	131.5
20 years	16.0	135.6	18.8	163.0	NC	NC

*NC = Not calculated.

provided herewith because overall shape will be very similar to those shown in Figures 4 and 6. Times for the gas production peaks that correspond to reducing bottom-hole pressure to the assumed minimum of 100 psi and associated peak production are included in the table. Logarithmically spaced tabulated values of production rates for gas and water can be used to approximate such curves if the reader so desires.

With all other parameters equal to their base case values, the time to reduce bottom hole pressure to 100 psi and achieve peak gas production depends strongly upon fracture length. Calculated time varies from 3.9 days for a 100-foot fracture length (each wing) to about 59 days for a 500-foot fracture length. Peak natural gas production is less sensitive to fracture length. Calculated values range from 37,200 SCF/day for a 100-foot length to 82,000 SCF/day for a 500-foot fracture length.

Calculated production rates 1 year after fracturing provide a crude basis for considering the effect of fracture length upon production economics. Estimated cumulative production for the base case (200-foot fracture length) is 9.2 million SCF after 1 year. If the fracture length is only 100 feet, cumulative production is expected to be slightly more than half this value. A fracture length of 500 feet nearly doubles cumulative production at the end of the first year. Thus, it is very important that means be sought to achieve propped fracture lengths approaching those predicted with conventional oil and gas field fracture design procedures. Further economic benefit from a large fracture length is apparent when one recognizes that at the end of 1 year, the produced gas to water ratio would be about 425 SCF/bbl for a 100-foot fracture, but about 810 SCF/bbl for a 500-foot fracture. In both cases, continued pumping would be required to sustain gas production. However, the fraction of produced gas required for pump horsepower would be much less for a long, narrow fracture than for a short, fat fracture

Interestingly, although not particularly relevant to economics because a close well undoubtedly would be used for field development, the production advantage with a long fracture continues for the 10 years calculated. Both production rate and cumulative production at the end of 10 years would be more than twice as great as the base case (200-foot fracture) if the fracture of 500 feet is achieved. However, for all fracture lengths with a single well in a very large reservoir, the long-term ratio of produced gas to produced water deteriorates. In the tenth year for a 100-foot fracture, the calculated ratio is 220 SCF/bbl, and for a 500-foot fracture, the calculated ratio decreases to 450 SCF/bbl.

Variation of Porosity

Porosity values of 1%, 2%, 3%, and 5% were examined with computer simulation. The base case porosity is 3%. Resultant calculated production of gas and water is summarized in Table 5.

For the assumed pumping rate of 114 bbl/day, the time to reach minimum bottom hole pressure of 100 psi and achieve peak gas production is calculated to vary from 4.2 days for a porosity of 1% to 20.4 days for a porosity of 5%. These times are all within a reasonable range for a field experiment. Associated peak gas production is greatest for the smallest porosity (1%). Calculated peak production rate at 4.32 days is 99,000 SCF/day. In contrast, if porosity is as great as 5%, a peak production rate of about 37,000 SCF/day is expected 3 weeks after beginning continuous pumping.

Assuming cumulative production at 1 year has a rough correlation with economics for a close well spacing, the computer simulations reveal that a low porosity is most desirable. However, the sensitivity is not as great as sensitivity to fracture length. The range of variation is 15.4 million SCF at 1 year for a porosity of 1% to 7.1 million SCF for a porosity of 5%. Low porosity is accompanied by an advantage in the ratio of produced gas to produced water. For a porosity of 1%, the ratio of 1 year is calculated to be about 1230 SCF/bbl. In contrast, for the base case (3% porosity), the ratio at 1 year is only 650 SCF/bbl, and for a porosity of 5% the ratio is down to 400 SCF/bbl.

The effect of porosity upon long-term production from a single well in a large reservoir is speculative. This is because still finer zoning for the computation and greatly increased computation cost would be required to avoid computational artifacts in the form of oscillation production for the low porosity cases. The increase in gas production rate in Table 5 from 15,200 SCF/day at 2 years to 17,100 SCF/day at 5 years for a porosity of 1% is believed due to computational deficiencies. The same is true for the calculated increase between 5 years and 10 years for a porosity of 2%. Nevertheless, it is apparent that the long-term deterioration in the ratio of produced gas to

Table 5. POROSITY VARIATION

	1% Porosity Peak Time 4.2 days		2% Porosity Peak Time 8.6 days		3% Porosity Peak Time 13.5 days		5% Porosity Peak Time 20.4 days	
	Gas Production							
Time	Rate, 1000 SCF/day	Cumulative, 10^6 SCF	Rate, 1000 SCF/day	Cumulative, 10^6 SCF	Rate, 1000 SCF/day	Cumulative, 10^6 SCF	Rate, 1000 SCF/day	Cumulative, 10^6 SCF
Peak	98.8	0.2	69.6	0.3	56.4	0.3	36.8	0.3
2 months	51.6	3.5	38.8	2.5	32.8	2.1	27.6	1.6
5 months	46.4	7.9	31.6	5.6	26.0	4.7	20.4	3.6
1 year	27.1	15.4	22.5	11.3	19.2	9.2	14.0	7.1
2 years	15.2	21.9	13.5	17.1	13.2	14.4	10.0	11.2
5 years	17.1	41.0	8.4	27.4	6.8	23.2	5.6	18.8
10 years	NC*	NC	8.8	43.9	6.0	34.4	4.3	27.2
20 years	NC	NC	NC	NC	5.2	56.0	4.0	41.6
	Water Production							
Time	bbl/day	1000 bbl	bbl/day	1000 bbl	bbl/day	1000 bbl	bbl/day	1000 bbl
Peak	106.4	0.5	109.6	0.9	109.6	0.45	115.6	2.2
2 months	33.2	3.0	44.9	3.9	54.0	4.5	65.2	5.3
5 months	24.4	5.5	32.8	7.2	38.0	8.4	47.3	10.0
1 year	22.0	10.4	23.7	13.2	29.6	15.3	35.3	18.3
2 years	20.4	18.2	25.6	22.0	26.0	25.1	30.0	29.8
5 years	16.5	37.8	21.6	46.7	23.6	52.0	26.8	60.0
10 years	NC	NC	18.0	81.6	21.2	92.4	24.7	106.3
20 years	NC	NC	NC	NC	18.8	163.0	21.6	188.9

*NC = not calculated.

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produced water is less severe for lower porosities. For example, the calculated ratio of produced gas to produced water for the base case (3% porosity) is 280 SCF/bbl at 10 years. In contrast, for a porosity of 5%, the calculated value of that ratio has deteriorated to 170 SCF/bbl.

Variation of Permeability

Permeability values of 0.2, 1.0, and 5.0 md were used for computer simulation with 1.0 md as the base case. Resultant gas and water production is summarized in Table 6.

The time required for a pumping rate of 114 bbl/day to reduce bottom-hole pressure to 100 psi depends strongly on permeability. It varies from 2.64 days for a permeability of 0.2 md to 186 days, or 6 months, for a permeability of 5.0 md. It is apparent that if effective permeability, including the effect of cleats that have not been included in laboratory studies, is as great as 5.0 md, a higher pumping rate will be required for a field experiment to observe peak gas production in reasonable time. However, the anticipated peak natural gas production rate is almost independent of permeability. The calculated peak rate of 56,000 SCF/day at 2 weeks for the base case is greater than both the calculated peak rate of 36,000 SCF/day at 3 days for 0.2 md and the peak of 48,000 SCF/day at 186 days for 5.0 md.

Assuming a rough correlation with economics for field development with optimal and cumulative production for 1 year, high permeability is clearly desirable: For the base case permeability of 1.0 md, the 1-year cumulative production of 9.2 million SCF is more than twice the 4.5 million SCF calculated at that time for a permeability of 0.2 md. A permeability as high as 5.0 md has a less dramatic effect. Calculated 1-year production is 13.5 million SCF in contrast to 1-year production of 9.2 million SCF for the base case permeability of 1.0 md. The gas production advantage of high permeability is somewhat offset by the pore ratio of produced gas to produced water. In 1 year, the calculated ratio is 800 SCF/bbl for a permeability of 0.2 md, but only 400 SCF/bbl for a permeability of 5.0 md. Thus, the higher permeabilities would require a larger proportion of the produced gas energy for pumping water.

For a permeability of 0.2 md, production after 5 years was not calculated due to computational artifacts causing oscillations, as previously discussed for the variations involving low porosity. However, the 1.0 md and 5.0 md

Table 6. PERMEABILITY VARIATION

	0.2 md Permeability Peak Time 2.6 days		1.0 md Permeability Peak Time 13.5 days		5.0 md Permeability Peak Time 185.9 days	
	Gas Production					
Time	Rate, 1000 SCF/day	Cumulative, 10^6 SCF	Rate, 1000 SCF/day	Cumulative, 10^6 SCF	Rate, 1000 SCF/day	Cumulative, 10^6 SCF
Peak	35.6	0.04	56.4	0.3	48.4	5.1
2 months	16.8	1.2	32.8	2.1	BP[†]	BP
5 months	12.8	2.6	26.0	4.7	BP	BP
1 year	7.6	4.5	19.2	9.2	44.0	13.5
2 years	5.2	6.7	13.2	14.4	27.4	24.2
5 years	4.0	11.3	6.8	23.2	23.2	51.7
10 years	NC[*]	NC	6.0	34.4	17.2	86.8
20 years	NC	NC	5.2	56.0	12.8	140.5
	Water Production					
Time	bbl/day	1000 bbl	bbl/day	1000 bbl	bbl/day	1000 bbl
Peak	98.0	0.3	109.0	0.450	116.0	20.3
2 months	18.0	1.9	54.0	4.5	BP	BP
5 months	12.0	3.2	38.0	8.4	BP	BP
1 year	9.6	5.5	29.6	15.3	112.4	40.5
2 years	7.6	8.5	26.0	25.1	100.7	78.4
5 years	6.0	15.5	23.6	52.0	86.4	177.5
10 years	NC	NC	21.2	92.4	80.8	328.3
20 years	NC	NC	18.8	163.0	78.4	616.8

*NC = not calculated.
†BP = before peak gas production.

columns of Table 6 reveal that high permeability has a greater long-term advantage in gas production than was apparent at 1 year. In the 10-20 year period, cumulative production for 5.0 md is more than 2.5 times as great as for the base case of 1.0 md, in contrast to being only 50% greater at 1 year. This advantage has minimal cost in relation to fraction of produced energy required for water pumping. For the base case, the calculated produced ratio of gas to water at 10 years is 280 SCF/bbl and for a permeability of 5.0 md, the calculated ratio is 210 SCF/bbl at the same time.

Variations for Permeability to Gas Greater than to Water

All computer simulations previously covered in this report and IGT's Phase I Report have assumed that the single-phase permeability of coal to gas is identical to the single-phase permeability of coal to water. However, the laboratory research reported from the University of Pittsburgh reveals that, for high confining stress, observed permeability to water is less than observed permeability to gas for all coal samples studied. Because the maximum confining pressure reported was only 1600 psi whereas substantially higher pressures are expected at the 3000-foot depth of the MFS experiments, permeability to gas may well exceed permeability to water. This effect was examined in two computer simulation runs for which the permeability to gas was three times the permeability to water.

Table 7 presents results of the base case plus a simulation run using 3.0 md for gas permeability and 1.0 md for water permeability plus a computer simulation run using 15 md for gas permeability and 5.0 md for water permeability. Comparison of the base case with the variation in which gas permeability was increased to 3.0 md but water permeability remained at the base case value of 1.0 md reveals little change in the time or magnitude of peak gas production. However, when gas and water permeabilities are increased by a factor of 5.0 to 15 md for gas and 5.0 for water, the time of peak production is increased from 2 weeks to about 6 months. Thus, as with the previous permeability variation where both gas and water permeability were assumed to be 5.0 md, a pumping rate greater than 114 bbl/day is required to observe the peak gas production in a reasonable time.

Using 1-year cumulative production as a crude indication of relative economics revealed that if gas permeability is 3 times the base case value (or 3.0 md) but water permeability is unchanged (1.0 md), gas production is

Table 7. VARIATIONS FOR PERMEABILITY TO GAS GREATER THAN TO WATER

	$K_g = K_w = 1.0$ md, Peak Time 13.5 days		$K_g = 3$ md, $K_w = 1$ md, Peak Time 14.0 days		$K_g = 15$ md, $K_w = 5$ md, Peak Time 188.2 days	
	Gas Production					
Time	Rate, 1000 SCF/day	Cumulative, 10^6 SCF	Rate, 1000 SCF/day	Cumulative, 10^6 SCF	Rate, 1000 SCF/day	Cumulative, 10^6 SCF
Peak	56.4	0.3	60.8	0.5	48.8	6.9
2 months	32.8	2.1	42.0	2.6	BP*	BP
5 months	26.0	4.7	33.6	5.9	BP	BP
1 year	19.2	9.2	24.0	11.7	46.0	15.2
2 years	13.2	14.4	15.6	18.3	38.0	29.7
5 years	6.8	23.2	11.2	31.2	30.8	65.4
10 years	6.0	34.4	9.6	50.1	25.6	115.9
20 years	5.2	56.0	8.0	81.4	18.8	193.0
	Water Production					
Time	bbl/day	1000 bbl	bbl/day	1000 bbl	bbl/day	1000 bbl
Peak	109.0	0.450	105.2	1.5	111.2	20.6
2 months	54.0	4.5	55.2	4.6	BP	BP
5 months	38.0	6.4	40.8	8.6	BP	BP
1 year	29.6	11.3	32.0	16.0	109.2	40.1
2 years	26.0	25.1	29.1	26.8	99.6	77.2
5 years	23.6	52.1	26.0	56.3	87.6	176.3
10 years	21.2	92.4	22.4	99.3	82.0	327.8
20 years	18.8	163.0	20.8	177.6	85.6	634.3

*BP = before peak gas production.

increased by about 27%. The ratio of produced gas to water after the first year correspondingly improves from 650 SCF/bbl to 750 SCF/bbl for gas and water permeabilities of 15 md and 5.0 md, respectively, cumulative gas production during the first year is 15.2 million SCF or 65% greater than the base case where both permeabilities are 1 md. However, the ratio of produced gas to water is only 430 SCF/bbl at the end of the first year.

During the tenth year of production from a single well in a large reservoir, the advantage of permeability to gas three times the permeability to water is slightly greater than at 1 year. However, the variations in 10-year produced gas to water ratio are not of major significance. For the base case, that ratio is 280 SCF/bbl in the tenth year. With gas permeability increased to 3.0 md, the ratio improves to 430 SCF/bbl. However, for the higher permeabilities of 15 md to gas and 5.0 md to water, the tenth year produced ratio of gas to water is back down to 310 SCF/bbl.

Variation of Pumping Rate for High Permeability

The two previous parameter variations involving a permeability to water of 5.0 md both resulted in a time of roughly 6 months to draw well-bore pressure down to 100 psi and achieve maximum natural gas production when the pumping rate was 114 bbl/day. Because this is an unreasonably long time for a field experiment, the effect on these two cases of increasing pumping rate to 200 bbl/day (approximate maximum rate for sucker rods) was examined. Computer simulation results are set forth in Table 8 for the two cases of gas and water permeability both equal to 5.0 md and gas permeability equal to 15 md with water permeability held at 5.0 md.

For both cases, the time to observe peak gas production was reduced to a reasonable value for a field experiment. However, it is interesting to note that the time to peak gas production is only 15 days when gas permeability is three times the water permeability of 5.0 md, but is calculated to be greater than 36 days if the gas and water permeability are both equal to 5.0 md.

Table 8 reveals that variation in pumping rate has no significant effect upon production of gas or water after sufficient pumping to reduce reservoir pressure to the assumed 100 psi. The significance of high pumping is only in time required to achieve drawdown during a single well field experiment.

Table 8. PUMPING RATE VARIATION FOR HIGH PERMEABILITY

	$K_g = K_w = 5.0$ md				$K_g = 15.0$ md, $K_w = 5.0$ md			
	114 bpd, Peak Time 185.9 days		200 bpd, Peak Time 36.5 days		114 bpd, Peak Time 188.2 days		200 bpd, Peak Time 14.9 days	
	Gas Production							
Time	Rate, 1000 SCF/day	Cumulative, 10^6 SCF	Rate, 1000 SCF/day	Cumulative, 10^6 SCF	Rate, 1000 SCF/day	Cumulative, 10^6 SCF	Rate, 1000 SCF/day	Cumulative, 10^6 SCF
Peak	48.4	5.1	73.2	1.5	48.8	6.9	53.2	0.5
2 months	BP*	BP	62.0	3.0	BP	BP	61.6	3.3
5 months	BP	BP	52.0	8.0	BP	BP	52.8	8.4
1 year	44.0	13.5	33.8	16.5	46.0	15.2	42.0	18.1
2 years	27.4	24.2	26.4	26.8	38.0	29.7	36.8	31.8
5 years	23.2	51.7	22.8	53.2	30.8	65.4	30.8	67.0
10 years	17.2	86.8	17.2	87.9	25.6	115.9	25.2	117.1
20 years	12.8	140.5	12.8	141.3	18.8	193.0	18.8	194.0
	Water Production							
Time	bbl/day	1000 bbl	bbl/day	1000 bbl	bbl/day	1000 bbl	bbl/day	1000 bbl
Peak	116.0	20.3	194.4	6.9	111.2	20.6	200.4	2.8
2 months	BP	BP	156.6	10.9	BP	BP	143.5	10.2
5 months	BP	BP	122.4	22.8	BP	BP	121.6	21.5
1 year	112.4	40.5	110.4	47.4	109.2	40.0	108.8	45.6
2 years	100.7	78.4	100.0	84.9	99.6	77.2	98.4	82.2
5 years	86.4	177.5	86.0	183.5	87.6	176.3	88.0	180.9
10 years	80.8	328.3	80.8	333.9	82.0	327.8	82.0	332.3
20 years	78.4	616.8	78.4	622.2	85.6	634.3	85.6	638.8

*BP = before peak gas production.

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HYDRAULIC FRACTURE DESIGN

IGT's Phase I Report included a discussion of two hydraulic fracturing experiments reported in a USBM report.* We observed that the reported experiment in the Illinois No. 6 coal bed terminated with a shut-in pressure near lithostatic (1.0 psi/ft), and that the fracture width and distance of proppant transport were reasonably consistent with expectations from the hydraulic fracture design procedures normally used in oil and gas operations. In contrast, the reported experiment in the Pittsburgh coal seam experienced a shut-in pressure of about 1.4 psi/ft. Subsequent mineback revealed that the proppant was distributed in multiple fractures, that the propped width was much greater than anticipated, and that the distance of proppant transport was only about 10% of the value anticipated from design calculations generally believed valid for oil and gas production. The Phase I Report hypothesized that the high shut-in pressure in the Pittsburgh seam resulted from fracturing fluid liquid leakoff into the cleat structure in multiple directions before the pressure was high enough to initiate new fractures in the coal structure.

Since March 20, 1979, IGT's interactions with personnel from the USBM Research Center in Bruceton, Pa., have provided copies of service company pressure records for 10 additional hydraulic fracturing operations with water-based fluid. The portions of this information deemed most relevant to design of the MFS experiments are summarized in Table 9. Other interactions with USBM personnel, plus papers presented at DOE's Methane Recovery From Coalbeds Symposium in Pittsburgh on April 18-20, 1979, have provided additional fragmentary information on pressures experienced during numerous fracturing operations.

Review of Hydraulic Fracturing Experiments

Overall, hydraulic fracturing of coal seams appears substantially less effective than anticipated on the basis of current technologies for predicting fracture dimensions plus resultant production for oil and gas operations. Only 2 of the records obtained for hydraulic fracturing with a liquid carrier revealed shut-in pressures of about lithostatic (1.0 psi/ft) or less (Table 9).

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*Bureau of Mines, "Effects of Hydraulic Stimulation on Coalbeds and Associated Strata," Rep. Invest. No. RI 8260.

Table 9. SHUT-IN PRESSURES FROM WATER BASE FRACS

Coal Seam	Location	Thickness (ft)	Fluid Volume (gal)	Depth (ft)	Bottom-Hole Shut-In Pressure (psi)	Shut-In Gradient (psi/ft)
Kittauing	Bruceton, PA	4.5	30,000	830	1160	1.40
Mary Lee	Jefferson Co., AL	5	10,000	958	765+	0.80
Mary Lee	Jefferson Co., AL	5	3,500	1094	2200	2.01
Hartshorn	Oklahoma	4	12,000	553	840	1.52
Pocahontas No. 3	Wyo Co., WV	8	13,400	731	1320	1.81
Pittsburgh	Marion Co., WV	7	14,600	911	1400	1.54
Pittsburgh	Marion Co., WV	7	10,400	911	1500	1.65
Castlegate	Carbon Co., UT	6	10,400	1017	1740	1.71
Pittsburgh	Wash Co., PA	6	7,300	588	850	1.45
No. 6 Coalbed	Jefferson Co., IL	9	14,000	733	768	1.05
Pocahontas No. 3	Buchanon Co., VA	4.5	14,800	1525	3150	2.07

The remainder had shut-in pressures greater than 1.25 psi/ft, and for seven of these, shut-in pressure exceeded 1.50 psi/ft. One of the two records having shut-in pressures consistent with expectations was the Jefferson County, Ill., experiment in the No. 6 coal bed which was discussed in IGT's Phase I Report. The other fracture is described in Bureau of Mines Report of Investigations RI 7968, "Degasification of the Mary Lee Coalbed Near Oak Grove, Jefferson County, Alabama, by Vertical Borehole in Advance of Mining." In this experiment, 10,000 gallons of water gelled with 20 pounds of guar gum per 1,000 gallons of fluid emplaced 6,000 pounds of 10-20 mesh proppant with virtually constant rate and pressure. Instantaneous shut-in pressure at the coal seam depth of 958 feet was approximately 0.8 psi/ft. Propped fracture length, as calculated by conventional methods, was estimated to be 255 feet. Eleven days after fracturing, a maximum gas production rate of 90,000 SCF/day occurred. Production rate than declined rapidly to roughly 60,000 SCF/day and then remained constant at about 55,000 to 60,000 SCF/day for the 8 months covered in the report. This is one of the highest sustained production rates reported for any hydraulically fractured vertical bore hole.

Unfortunately, two USS stimulation attempts with gelled water were much less successful. These experiments were performed in the same county in Alabama, but at a location where the coal seam depth was about 150 feet greater than for the impressively successful stimulation discussed in the previous paragraph. The first USS experiment achieved gas production of less than 8500 SCF/day. Mineback revealed that the coal seam had been fractured by drilling mud and well cement prior to stimulation. The hydraulic fracture was in the rock below the coal seam. For the second USS experiment, care was taken to minimize hydrostatic pressure during cementing of the casing. Nevertheless, hydraulic fracturing pressure reached the preset limit of 2500 psi. Shut-in pressure was not reported. Gas production achieved a short-term peak of about 25,000 SCF/day when the well was dewatered. Average gas production during the 50 days of actual production during the 70-day period between fracturing and end of production associated with the approach of mining was less than half this peak value. Mineback revealed that the slots in the casing were located a foot below the interface of the coal and floor rock.

One of the USBM-funded hydraulic fracturing experiments that has not yet been publicly reported in detail is of particular concern in relation to the

Mountain Fuel Project. This fracture was performed in the Castlegate coal seam at a depth of 1017 feet and at a location only a few miles from the location proposed for Mountain Fuel's third well. During the first pumping attempt, surface pressure became excessive after only 14 minutes of pumping time. The well was allowed to flow for about 6.5 minutes to remove a suspected "sandout." Pumping was then resumed and pressures continued to build during the 22 minutes of the second pumping operation. Shut-in pressure was estimated to be 1.7 psi/ft at the depth of the coal seam. Natural gas production after fracturing peaked at only about 800 SCF/day and then rapidly declined.

Although it is generally agreed that hydraulic fracturing with foam produces higher natural gas production rates than fracturing with gelled water fluids, the fragmentary data available to IGT strongly suggest that the resultant propped fracture length is still much less than that calculated using design methods normal to oil and gas operations and that treating pressures are often very high. Summaries of foam fracture treatments and gas production for seven wells at the new Emerald Mine near Waynesburg, Pa.* Mr. Peter F. Steidl has provided supplementary data included in Tables 10 and 11. Additions to the published report include data for an eighth well (Well 11), the fracture lengths observed on mineback, and the shut-in pressures from the hydraulic fracturing operation.

In the new Emerald Mine wells, "screen-outs" were reported for four of the seven wells hydraulically fractured using foam. Following screen-outs on wells 1 and 3, the wells were allowed to flow back and flush out the sand blockage; then the treatments were completed. Treatments on wells 6 and 7 were terminated after screen-outs occurred because the treatments were almost complete.

Although neither coalbed thickness nor propped fracture length are reported for the Emerald Mine wells in RI 8286, comparison with propped lengths recently calculated for MFS by Halliburton and by Nowsco suggest that fracture lengths observed during mineback were much smaller than would be calculated for a fracture height of 20 feet. The calculations by Halliburton and Nowsco reveal propped lengths of about 650-700 feet for the foam volumes used in the

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*U.S. Bureau of Mines, "Foam Stimulation to Enhance Production from Degasification Wells in the Pittsburgh Coalbed," Rep. Invest. No. RI 8286.

Table 10. SUMMARIES OF FRACTURE TREATMENTS AT NEW EMERALD MINE

Well No.	Depth to Base of coal (ft)	Treatment Date	Treatment Pressure	Injection Rate (bpm)	Foam Volume (gal)	Sand Weight (lb)	Frac Length (ft)	Shut-In Pressure (psi)
1	641	6/10/76	1400	11.2	33,000	12,500	(1)	1000 (4)
3	908	8/18/76	1600	11.2	25,260	11,000	(1)	1200 (4)
4	849	8/25/76	1300	10.8	39,000	10,000	(1)	600
5	770	9/01/76	1375	11.6	31,500	10,000	270	800
6	588	4/15/77	1500	17.7	29,200	14,000	270-360	2200 (2)
7	734	9/08/77	1400	10.8	29,000	7,400	100+(5)	2400 (2)
8	652	9/15/77	1050	10.8	42,660	12,800	50-100	500
11	713	5/14/77	1100	19.0	54,600	22,000	120+(5)	(3)

(1) = Fracture not intercepted.

(2) = High pressure due to sandout.

(3) = Kill frac; data not available.

(4) = Sandout backflowed during frac.

(5) = Fracture extended into unmined section; propped length not determined.

Table 11. EMERALD MINE WELL DATA

Gas Production Data in Cubic Feet Per Day

Date Tested	Well No. 1	3	4	5	6	7	8	11
09-24-76	-	7,500	(1)	942	20,000-30,000	120,000	10,800	
10-01-76	14,000	-	(1)	-	2,000-8,000	122,000	10,800	
10-29-76	19,500	16,800	(1)	14,000	10,000	140,000	21,000	
11-10-76	25,200	16,700	(1)		100,000-34,000	(2)	-	
12-14-76	-	23,300	(1)	18,100	(2)	(2)	18,200	
01-08-77	-	24,500	(1)	100,000	(2)	105,000	8,100	
01-26-77	-	42,000	40,000	100,000	(2)	58,100	8,390	
02-08-77	10,400	-	-	-	-	(2)	-	
03-28-77	9,100	(2)	-	117,000	(2) 800	(2)	-	
03-29-77	-	(2)	16,000	-	(2)	(2)	19,000	
08-31-77	1,070	41,400	7,090	79,800	(2)	44,400	3,510	1,400
09-07-77	1,080	39,800	7,470	86,400	110,000	44,400	3,510	44,400
09-14-77	2,430	39,800	8,840	81,900	86,400	-	3,140	62,800
09-19-77	2,730	44,400	-	69,700	69,700	29,900	4,740	86,700
10-13-77	2,720	28,200	3,510	61,100	64,100	25,200	3,216	72,300
10-20-77	3,060	15,200	3,510	72,300	61,100	25,900	3,140	79,800
10-27-77	3,060	(2)	(2)	74,800	61,100	25,200	3,140	66,900
02- -78	1,800	(2)	(2)	(2)	59,000	13,000	2,700	57,000
06-02-78	-	30,000	-	(3)	82,000	28,000	2,000	30,400
07-20-78	(1)	17,500	(1)		(2)	14,400	(2)	16,500
09-11-78	625 (1)	1,000	(1)		24,400	5,800	(2)	16,000
10-26-78	(3)	800	(1)		(3)	(3)	(2)	8,000
01-19-79		-	(1)				(3)	3,000

(1) = No pump.

(2) = Pump down.

(3) = Plugged.

Emerald Mine experiments. Because the thickness of the Pittsburgh coalbed at the Emerald Mine is undoubtedly much less than the 18-foot thickness for the Mountain Fuel calculations, service company-calculated propped lengths for the Emerald Mine experiments would undoubtedly be much greater than 700 feet. Although mineback found the end of the fracture for only one of the Emerald Mine fractures, the short distances at which sand was detected in the other fractures, in addition to Mr. Steidl's verbal communication that the propped width observed on mineback was about 2 inches at the widest part close to the well with sand only in the bottom half of the fracture, strongly suggests that the propped length from foam fracturing was less than 50%, probably less than 33%, and possibly less than 10% of what would be expected from hydraulic fracture design calculations. In addition, only one open fracture extending into a nearby pillar was observed without sand.

During DOE's April 1979 Symposium in Pittsburgh, Mr. R. L. Mazza of Continental described a foam fracture treatment at the Loveridge Mine in Marion County, W. Va. In his words, visual inspection of this Pittsburgh coal seam fracture indicated that fracture length and width differed from predicted values by an order of magnitude. Shut-in pressure at the coal face was about 1.8 psi/ft (1525 psi at 840 feet). Perforations were in the center of the coal seam, the bottom of the fracture was about 1 foot above the bottom of the target coal, and the top of the fracture extended through 1 foot of shale and 1.5 feet of coal above the target seam. The observed propped fracture width was about 1 inch below the perforations and about 2.25 inches above the perforations. Using the observed fracture width and height, plus the known amount of sand, a propped length of 40 feet was calculated. This calculation is consistent with failure to observe proppant sand in a cross-cut 61 feet from the wellbore.

Available quantitative details regarding individual hydraulic fracturing operations performed by USS in Alabama are minimal. However, the following observations from DOE Report RI-PMTC-3 (79), "Methane Drainage Ahead of Mining Using Foam Stimulation, Mary Lee Coalbed, Alabama," appear particularly relevant to hydraulic fracture design for the Mountain Fuel experiments.

- Page 8: "Propagated fractures examined were vertical, typically began as a hairline crack about 3 feet above the base of the coal, and gradually widened to about 3/16 inch at the top of the coal. The fractures continued upward at the same thickness for an undetermined distance into the roof."

- Page 8: "Cement used to set casing was contained within the same vertical plane as the sand to lateral distances of up to 80 feet. Microscopic examination of samples of this cement showed that although the cement contains coal particles, no sand was observed."

- Page 13: "The fine-meshed sand used as a fluid-loss agent was the only sand found to be contained in the coal. This sand is thought to have caused the propagating fracture to clog or 'screen-out' in the coal early in the treatment. With continued pumping, it is possible that the fracturing fluids entered a pre-existing plane of weakness in the shale roof rock."

- Page 15: "Recent underground investigations indicate 'fractures', denoting rock breakage, do not normally occur as a result of stimulation. The physical evidence indicates that pre-existing fractures (rock joint, or coalbed cleats) or bedding planes are widened during stimulation."

During a side conversation with Mr. P. B. Stubbs of USS after his presentation at the April symposium, he indicated that "screen-out" or excessive pressure buildup has not been a problem in the Alabama treatments. He further stated that the fracture gradient at the coal seam depth of about 1100 feet was roughly 0.8 psi/ft.

It is hypothesized by IGT that the difference in observed propped widths and pressure behavior between the Appalachian wells and the USS Alabama wells is primarily due to differences in fracture characteristics of the rock overlying the target coal seams. In the Appalachian wells, high fluid loss into the coal results in screen-outs with very high treating pressures. In contrast, screen-out of the coal seams in the Alabama wells is accompanied by fracture diversion to the overlying rock and then fracture propagation in that rock with pressure and proppant transport characteristics similar to those normal in oil and gas reservoirs.

Considerations Relevant to Mountain Fuel Supply Stimulation Design

Only one of the hydraulic fractures that has been documented through mineback had dimensions characteristic of those predicted using design calculations normal to oil and gas hydraulic fracturing operations. That was the experiment in the Illinois No. 6 coalbed. Correlating unique features of that hydraulic fracturing operation are —

- Bottom-hole treating pressure throughout the fracture and the instantaneous shut-in pressure were about lithostatic for coal seam depth.

- Azimuthal orientation of the vertical did not coincide with either the face cleat or the butt cleat direction in the coal seam.

In contrast, the majority of other mineback operations have revealed extraordinarily wide fractures with the greatest length in the face cleat direction. In some cases, proppant also has been observed in multiple openings in the butt cleat direction as well.

Foam Stimulation

IGT's review of experience in hydraulic fracturing in coal seams supports the widespread belief that foam fracturing generally results in greater natural gas production rates than fracturing with a gelled water fluid. However, our review has not revealed understanding of the reasons for this difference.

When foam fracturing was developed, its primary advantages over other fluids were recognized to be —

- Very low effective fluid loss
- Ideal transport of proppant.

If these advantages were being realized in coal seams, the propped widths would be much less than observed and propped lengths would be much longer. Expected propped width can be estimated from proppant concentration and design calculation estimates of width during fracture propagation. For upper limits of 2.5 pounds of sand per gallon of foam and a width of 2 inches, the amount of sand per square foot of fracture area would be:

$$(2.5 \text{ lb/gal}) \frac{(2 \text{ in.})(144 \text{ in.}^2/\text{ft}^2)}{(231 \text{ in}^3/\text{gal})} = 3.12 \text{ lb/ft}^2$$

Figure 123 of the Halliburton Frac Book reveals that the resultant upper limit on expected width of the propped fracture is 0.375 inches or 3/8 inch. The propped width observed on mineback cannot be greater than this if the low fluid loss and ideal proppant transport of foam are actually being realized.

The enormous propped widths observed can be achieved only if very high rates of fluid loss result in deposition of large quantities of proppant very near the well bore. However, lack of proppant sand, including the 100-mesh sand used by USS, in butt cleats intersecting the propped face cleat makes this difficult to understand. The reason for using fine sand is that its entry into small branches from the main fracture is expected to inhibit fluid loss. Because this effect is not observed, IGT hypothesizes that the apparent high fluid loss is due to breakdown of the foam such that the gelled water and entrained sand remain in widened face cleats, while the nitrogen leaks into the butt cleat and runs ahead of the liquid in the face cleat direction.

Two additional observations support this hypothesis of very early foam breakdown during hydraulic fracturing. These are —

- Three of the foam fractures were accompanied by nitrogen arriving at a distant offset well during the hydraulic fracturing operation. These are one of the Emerald Mine fractures, the Leveradge Mine fracture by Continental, and one of the USS fractures in Alabama. The Continental experience is particularly relevant. Even though the mineback revealed that proppant had been transported in the face cleat direction, nitrogen production during the fracture was observed from a well about 500 feet away in the butt cleat direction.

- Foam breakdown is inevitable if large changes in bottom-hole treating pressure occur during a hydraulic fracturing operation. Foam is stable only in the quality range from about 65% to 85%. A design quality of 75% is normally chosen because it is the midpoint of this stable range. However, to a first approximation, if treating pressure doubles during a hydraulic fracturing operation in which the ratio of nitrogen pumped to water pumped remains constant. the nitrogen volume will be cut in half by the higher pressure. This will reduce foam quality to 60%, a value below the stable range. In contrast, if the ratio of nitrogen to water is increased as pressure increases so that the quality of 75% is maintained at the higher pressure, foam quality will exceed 85% and the foam will break down at any point where the traveling fluid encounters the pressure of lithostatic or below that is normal for hydraulic fracture propagation.

<u>Adequacy of Foam Fracture Control Information</u>

Early in the spring of 1978, IGT supervised a very large foam fracturing operation in a tight gas sand in Canada. This operation used 6 million SCF of nitrogen to emplace 250,000 pounds of proppant sand at a depth of about 6700 feet. Eight nitrogen pumpers were used to obtain the desired rate of 12 bbl/min. The large fracturing treatment was preceded by a mini-frac at the same rate to evaluate field equipment and procedures. Although improvements in standard procedures, such as including an orifice meter in the nitrogen line to monitor output of multiple pumpers, were implemented, it is doubtful whether the information available to the frac operator was adequate to stay within the quality range for stable foam throughout the job. One major problem was that the flowmeter on the blender was operating outside its range of linear response. Analysis after the fracture revealed that the blender operator had controlled sand input on the assumption that his flowmeter was correct. The result was a sand concentration in the blender of more than 12 lb/gal when the operator thought he was controlling at 8 lb/gal. Overall foam quality for the entire job averaged 82% versus a design quality of 75%. Furthermore, fluctuations in nitrogen and water rate during the job were large enough to go outside the quality region of 65%-85% for stable foam in both directions.

To date, IGT has not been successful in obtaining time-dependent pressure, water flow, and nitrogen flow data that can be interpreted to deduce variations in foam quality during any fracture operation in a coal seam. We suspect this is because real time recorded data do not exist for the nitrogen input. The operator of the nitrogen pumper is normally directed to hold a pumping rate that is displayed on a panel meter, but not recorded on a time-dependent basis. Furthermore, most recordings of water rate are on a scale of 50 bbl/min for full-scale deflection. The water rate of 2.5 bbl/min for most foam fractures in coal seams is such a small fraction of full scale that the recorded signal is only slightly larger than the noise level on the recording. Further, the size of the flowmeter used for water control is not normally recorded on customer tickets, thus it is impossible to determine whether the flowmeter was operating in its linear range.

As set forth in SPE 7935, "Analysis of an Elmworth Hydraulic Fracture — Alberta, Canada," IGT strongly recommends that all foam fracturing operators insist upon use of gamma ray-based monitoring of the densities of both the sand-laden liquid and the foam streams for control purposes during the hydraulic fracturing operation. Further, these densities, as well as pressures and flow rates, should be recorded so that subsequent detailed analysis of the hydraulic fracutring operation will be possible.

In summary, although higher gas production has been observed from coal seams following foam fracturing, it is doubtful whether this is due to the major advantages of foam over other fluids, namely, low fluid loss and ideal proppant transport. It appears that neither of these conditions are achieved in coal seams. Indeed, the greater gas production may only be due to large quantities of nitrogen displacing connate water by entering the cleat system in the coal and then providing a gas drive for well cleanup.

The Design of the First Mountain Fuel Supply Hydraulic Fracture

The discussions above have revealed that hydraulic fracturing of coal seams involves phenomena not properly taken into account by design procedures normally used to calculate propped length of hydraulic fractures in oil and gas operations. Whether this is due to deficiencies of the mathematical formulations or deficiencies in input parameters for the calculations is not clear. Discussions with Mr. Kurt Elder, who has had program responsibility for many USBM stimulations, revealed that few, if any, of the hydraulic fracture designs have been preceded by site-specific determination of critical input parameters into the calculations. Such parameters include —

- Elastic modulus of the coal bed — A value of 3.0×10^5 psi is used for the vast majority of design calculations. This is much lower than for reservoir rock, and we have been unable to find the original source of this number.

- Fluid loss coefficient — Reports available to IGT do not contain the value used for fluid loss coefficient in hydraulic fracture design calculations for experiments that have been performed. However, the Halliburton calculations performed for Mountain Fuel Supply in March 1979 use a value for the fluid loss coefficient (C_W) of 1.0×10^4 ft/sq rt (min). This value is consistent with that reported in SPE 5003, "Formation Fracturing With Foam," for sandstone with a permeability of 100 to 200 millidarcies (md) and a pressure difference between the fractures and pores of 900 psi. However, this value is less than 1/6 the value one would calculate from the porosity, permeability, and reservoir fluid characteristics used in the Halliburton design. A major question is whether fluid loss into the cleat system is such that a fluid loss coefficient several orders of magnitude greater would be an appropriate assumption.

If the short, fat fractures usually observed are the result of high fluid loss, the only obvious solutions are to pump much faster or to incorporate a fluid loss additive. Pumping rates for the best documented previous fractures have been in the range of 1-3 bbl/min per foot of fracture height. Within that range there is no apparent correlation between fracture shape and pumping rate. However, for the 18-foot thick coal seam anticipated by MFS, the upper limit of this range would require a rate of 54 bbl/min. Doubling this rate to about 100 bbl/min would be a minimal step to investigate hydraulic fracturing outside the range of prior experiments. Achieving such a rate with foam fracturing would involve a formidable and extremely expensive array of nitrogen pumpers. Also, control would be minimal for a modest volume. For example, 50,000 gallons would be pumped in only 12 minutes.

Future interaction with service companies is a prerequisite to meaningful IGT views regarding the feasibility of using fluid loss additives.

IGT is reluctant to consider volumes greater than about 50,000 gallons for the first MFS experiment. This is because the previous history of hydraulic fracturing of coal seams makes it appear unlikely that any larger volume will be successfully pumped into the coal seams due to screen-outs. The only reported success in consistently pumping volumes this large is that of USS in Alabama. However, in that case the evidence strongly suggests to IGT that the fractures divert out of the coal seam early in the fracturing operation, and that lack of sand-outs is due to fracture propagation in the low fluid loss strata above or below the target coal seam.

In addition to the possibility of fluid loss additives, further interactions with service companies should carefully consider whether foam provides any advantage other than a gas drive for cleanup. If this is the only advantage, the use of CO_2 or a nitrogen/gelled water ratio less than that required for foam, or a nitrogen pad, may be worth considering. This is particularly true if such an approach would make the use of a fluid loss additive with greater effectiveness than 100-mesh sand practical.

As this discussion of hydraulic fracturing has been gloomy enough to motivate thoughts regarding the possible alternative of drainhole drilling in coal, we will conclude it with an encouraging possibility. That possibility is based on the recognition that the MFS experimental well will be at a substantially greater depth than any of the well histories considered above. One possible effect of this greater depth is that <u>in situ</u> stresses will result in greatly reduced cleat permeability. Such greatly reduced permeabilities would reduce fluid leakoff and may result in fracturing without excessive pressure buildup and with a propped length much greater in relation to design calculations than in the prior experiences at shallower depths. This possibility should certainly be examined with a field experiment before considering the expensive alternative of drainhole drilling.

PREPARATION FOR LABORATORY ANALYSIS

Specific plans for the analyses to be performed have been finalized and the laboratory preparations for doing this work are underway. The analyses include the following:

- Direct determination of methane content of the coal and the emission rate. This also includes component analysis of the emitted gases.

- Routine coal characterization analyses to establish rank and characteristics of the coal. These include organic elemental analyses, percent moisture, percent ash, percent volatile matter, and density.

- Porosity, Darcy flow permeabilities, and compressibility.

- Adsorption and desorption isotherm determinations.

- Miscellaneous analyses.

Methane Content

One of the most important analyses made on coal for purposes of methane production is the direct determination of the methane content. This is performed using standard operating procedures on core samples taken during the drilling operations. Both methane content and the rate of gas emission are determined. Samples of the gas emitted are periodically obtained and analyzed by mass spectrometer or gas chromatography to monitor the composition of the emitted gases.

Coal Characterization

During the coring procedures, recovered samples are taken for the IGT analytical section to perform routine coal characterization analyses. These results determine the chemical constituents that establish the rank of the coal as well as its general character. The tests provide background data for each of the coal seams encountered. These analyses include organic elemental analyses for carbon, hydrogen, nitrogen, oxygen, and sulfur, including both fixed carbon and inorganic carbon determinations. The percent moisture, ash content, volatile matter, and density also are tested. In addition, other miscellaneous analyses may be necessary.

Porosity, Permeability, and Compressibility

Coal samples that are earmarked for core analysis are used for tests of porosity, Darcy permeabilities, and compressibilities. The tests require small plugs of the cores. The samples require special handling, particularly if the coals are friable. These tests are not routine for the IGT analytical section, so special equipment is being fabricated. These data are necessary for engineering and production analyses. They include the effect of water saturation on permeabilities as well as the effect of in-situ overburden pressures on the permeabilities. The resulting data provide input parameters for the computer simulation of the production of methane from coal.

Adsorption and Desorption Isotherms

Adsorption and desorption isotherm data for methane gas are developed. The adsorption data are used to calculate the capacity of the coal to hold methane gas. Results are compared to those obtained from the direct determination of methane by desorption measurements. Desorption data are required to establish the diffusion coefficients of the coals, and a determination is made of the particle size at which methane flow is diffusion limited. This work also requires special high pressure equipment, now on order.

Miscellaneous Analyses

During the course of the laboratory investigations, it is anticipated that miscellaneous analyses may be required. This work would be performed if the information obtained would be useful to the computer simulation or the field operations. It is expected that certain properties or constituents of the coal might affect production and a better understanding of them may be required. Tests could include formation water analyses, ash analysis for major elements, X-ray for elements and/or minerals, analysis of adjacent sandstone cores, and coal surface and pore size determination. In addition, tests determining flaws (Knudsen permeabilities) through discs of coal which have been selected to be mark-free by an optical or scanning electron microscope could be conducted. Such data would be useful in establishing diffusion constants for engineering and production analyses. This flow procedure can be performed with little additional equipment, however, it is somewhat time consuming.

DRILLING AND TESTING RECOMMENDATIONS

IGT's recommendations for those portions of the drilling and pre-fracture well testing program directly relevant to natural gas production from coal seams are provided in Appendix A. Details of drilling from the surface to slightly above the Sunnyside coal seam at a depth of 2800-2900 feet are being independently developed by MFS.

It is possible that program objectives could be accomplished at lower cost by modification of these recommended field procedures. Suggestions regarding possible changes to further reduce cost are solicited by IGT.

Compromises between cost and completeness of data are inevitable aspects of any drilling and testing program. The largest such compromise in Appendix A is drilling through all target coal seams before running and cementing casing. Cost is minimized thereby because —

- Only one, rather than two suites of wireline logs will be required
- Rigging for and performing injection tests with straddle packers will be required only once, rather than twice.

These cost savings involve the risk that all testing after cementing casing will provide erroneous and discouraging conclusions due to plugging of cleats with cement. If field data reveals loss of cement to the Gilson coal seam, it is recommended that the program for the second well include cementing the casing before drilling through that seam. A potentially attractive alternative is use of the PENGO™ Selective Completion Tool to prevent cement intrusion into coal seams. This tool is run as a part of the casing. Packers are set above and below the seam to be protected. Cement circulates into the annulus and through the lower packer into the concentric casing of the tool, flowing back into the annulus after reaching the upper packer. Ports through the cement in the concentric casing are opened with a wireline for completion in and production from the coal seam.

The recommended program places very heavy emphasis upon —

- Minimizing fines and cement injection into the coal seam and flushing by production from the seam to clean it after coring and after drilling out cement
- Maintaining an accurate inventory of fluid (gas and water) injection into and recovery from the coal seams
- Determining coal seam reservoir pressure and permeability.

Attachments A-1 and A-2 to Appendix A elaborate upon these points.

It is recommended that the tubing installation for pre-fracture testing be the same as for after hydrualic fracturing. Although a workover rig will be required for hydraulic fracturing, this installation will provide critically important data and may well provide a basis for system changes that will minimize the cost of the long-term production tests after fracturing.

The preliminary recommendations for hydraulic fracturing is to use foam as follows:

- Volume of 50,000 gallons
- Rate of 15 to 20 bbl/min
- Maximum surface pressure of 4500 psi
- Proppant size of 20/40 or larger; use only one size
- Cleanup by production to a tank as described in Attachment A-1 to Appendix A
- Insist upon a small turbine meter linear to as low as 1 bbl/min on the inlet to the blender, and upon gamma ray absorption instruments for on-line control of both the water/sand and foam streams on the surface.

Future interactions with service companies may lead to recommending a fluid loss additive or a gas/gelled water ratio lower than that required for foam.

APPENDIX A. Drilling and Preliminary Testing

APPENDIX A. Drilling and Preliminary Testing

The recommendations below cover drilling and preliminary testing in the vicinity of the coal seams. Many of these steps include details already agreed to in discussions between MFS and IGT personnel. However, some steps are new recommendations and some aspects are presented in more detail than previously discussed.

It is IGT's understanding that MFS intends to drill to 2800 feet with air unless mud is required by hole conditions. When the first target coal seam (Sunnyside) is reached, changing to natural mud is planned due to the greater probability of successful core recovery. The first step in procedures set forth below addresses details of depth selection for the start of coring and the change to natural mud.

1. Hopefully, air coring will be practical. If not, change from air to natural mud 50 feet above the Sunnyside coal seam and start coring at that point. Use the coring bit that will produce the largest practical size cuttings (clusterite or cones, not diamonds) to minimize coal seam plugging.

2. As coring proceeds toward the Sunnyside coal seam, carefully monitor returns for any indication of lost circulation to the coal seam. If the Sunnyside seam is a thief zone, determine the hydraulic head of the coal seam and then inject air or gas into the drilling mud so that the bottom-hole pressure balances the natural fluid pressure in the coal seam. (See Attachment A-1, Pressure Balance.)

3. Core to total depth, maintaining a record of water loss or gain as a function of depth. (See Attachment A-2, Fluid Volume Recording.) Personnel from both IGT and UGMS will select samples of core for desorption measurements as soon as core is removed from the barrel and described by the MFS geologist on location. (See Attachment A-3, Injection and Mini-Frac Testing.)

4. Swab or unload the well with air or gas until the lost mud volume is recovered and formation water is produced. This is to clean cuttings from the coal seams.

5. Run a full suite of logs from TD to 200 feet above the Sunnyside coal seam as directed by the MFS geologist in consultation with the IGT representative on location (minimum log suite will include caliper, gamma ray, density, and sonic data). Water level during logging is to balance reservoir pressure in the coal seams. DO NOT load the hole with mud to the surface unless required for safety due to observed natural gas production.

6. Utilize Lynes packers to perform open hole injection or mini fracture tests at six depth intervals. The intervals are to consist of the Sunnyside and Gilson coal seams plus 20± feet of the rock immediately above and

below each of the seams. Packer seats will be selected in the field after logging. The recommended test procedure is set forth in Attachment A-3, Injection and Mini Frac Testing.

7. If prior tests have revealed that the hydraulic head on the coal seam is more than 200 feet below ground level, set a drillable open hole packer above, but as close as practical to, the Gilson coal seam.

8. Run and cement a 5-1/2-inch casing, with a burst rating of at least 4500 psi, to as close to the top of the Gilson seam as practical. Use low density cement with a volume calculated to give a cement top 500 feet above the Sunnyside coal seam.

9. After the cement sets, use cement bond logging plus measurement of casing stretch or a free point locator to find the cement top and determine the maximum cement loss to the Gilson coal seam.

10. Drill out the cement shoe and clean hole to TD using air or natural gas (not mud). Record air (or gas) and water returns as described in Attachment A-2, Fluid Volume Recording.

11. Monitor fluid level rise in the well overninght using an echo meter. If gas production occurs, choke flow so that the well kills itself due to water influx. If gas production still exists the next morning, kill the well by pumping fresh water down the drill string to the bottom of the Gilson coal seam.

12. Rig up and pressure test wellhead to 4500 psi.

13. Run 2-3/8-inch tubing with a Sperry Sun bottom-hole pressure sensor. The tubing string should be equipped with either air lift valves or a sucker rod pump seat.

14. Remove fluid from the well bore by swabbing or gas lift. Continue until either gas or formation water is being produced. Maintain gas and water inventory.

15. When warranted by lack of problems due to solids production, install pumping hardware and release rig.

16. Determine reservoir pressure by measuring the static water head. If gas is being produced, choke flow and monitor fluid level to see if the well will kill itself. After monitoring fluid rise to a static level, pump a measured amount of water into the well, and then record the drop to the static level.

17. Perform injection tests to determine reservoir limits, kh (permeability times thickness), and minimum in situ stress. (See Attachment A-3, Injection and Mini Frac Tests.)

18. Pump well to determine whether gas production can be achieved prior to hydraulic fracturing.

ATTACHMENT A-1. PRESSURE BALANCE

Introduction

Production from coal seams occurs via the permeability of natural fractures (cleats) in the coal. Further, IGT's parametric computer simulation studies have revealed that knowledge of the porosity and permeability of the fracture (cleat) system, plus the fluid pressure therein, are critical to interpretating data from a test well to determine the well spacing appropriate to minimize the costs of gas production.

Laboratory determinations of porosity and permeability under simulated in situ conditions determine only lower limit values. This is because laboratory data has only been developed for coal samples strong enough for machining coal cylinders with dimensions of a few inches. Coal containing the larger cleats crumbles or breaks before the samples can be prepared for testing.

Reservoir fluid pressure must be determined in field tests. In addition, the most meaningful determinations of cleat porosity and permeability must come from injection and production tests on the well. However, such tests will not provide valid data if the cleats are loaded with mud, cuttings, or cement prior to the tests. IGT's recommended field procedures contain numerous details intended to ensure meaningful conclusions from the well tests. These are discussed below.

Drilling

Drilling coal seams for production differs from sandstones in two major ways.

- Fluid additives (such as KCl) to avoid formation damage are not required for coal and should only be used if needed to stabilize shale intervals drilled.

- If coal fines or solid components of the mud are forced into the cleats of the coal, the resultant "formation damage" will preclude obtaining critically needed cleat permeability data.

For these reasons, the recommended drilling program places strong emphasis upon avoiding overbalanced drilling and provides for production from the coal seam to flush the cleats as soon as possible after coring and after drilling out the cement shoe.

Cementing

If the coal seam reservoir pressure is not greater than hydrostatic, cement invasion of cleats is inevitable for the Sunnyside seam and may only be avoided for the Gilson seam if drillable packer is placed above the seam as recommended. For a minimal cement density of 12 lb/gal and an assumed reservoir pressure of hydrostatic, the previously agreed upon cement top of 500 feet above the Sunnyside seam gives a differential injection pressure of 95 psi into the Sunnyside seam and 137 psi into the Gilson seam. If the head of coal seam water is 200 feet below the surface, these pressures increase to 182 psi and 224 psi, respectively.

If cement loss into the Gilson seam occurs until the fluid head in the casing drops to a reservoir pressure, a water head 200 feet below surface, total cement loss will be over 350 feet of tubing/casing annulus volume or over 275 gallons (37 ft^3). This volume would fill 3% porosity to a radius of 4.7 feet from the well bore in an 18-foot coal seam. Such loss would drop the cement top to very near the Sunnyside seam and fill cleats to beyond the distance to which abrasive slotting has been shown effective.

ATTACHMENT A-2. FLUID VOLUME RECORDING

As previously emphasized, avoiding fines or cement injection into the coal seam is extremely important if data from the first experiment is to be analyzed. Achieving this requires an extraordinarily conscientious effort to maintain accurate records of liquid movement into or out of the coal seam.

Operational control to avoid fines injection into the coal makes careful monitoring of the fluid balance essential from the moment the bit encounters the Sunnyside coal seam and continuing throughout all well operations. During drilling, water balance can be adequately recorded by the use of still pits and careful monitoring of pit liquid level. However, it is doubtful whether this procedure will be adequate while using air for unloading the well bore or for well clean-out after cementing. At these times, excessive liquid loss due to droplet spray is a major concern.

We therefore recommend that all fluid returns from the well during air coring or after coring with mud be produced into the top of a vertical 400-barrel tank. Field experience, including that on the Pinedale No. 8 well in 1975, has revealed that this procedure is very effective for monitoring liquid production. It is further recommended that the tank hatch have a spring cover and be designed so that gas can leave the tank only through a single hole. Monitoring of air or gas production rates from about 20,000 to 100,000 SCF/day can be readily accomplished by using nipples to provide an appropriate size pipe for pitot tube measurement. A positive displacement meter for lower rates is very desirable.

A separate substantial advantage of using such a tank as a gas/water separator and fluid balance monitoring device is that all solids produced settle to the bottom of the tank so that total solids production over a period of days can be determined by removing the hatch at the bottom of the tank and manually removing accumulated solids.

In contrast, if a conventional separator is used, solids production provides an enormous headache in erosion of back-pressure control valves and plugging of the separator. In addition, during early production attempts an external gas supply will undoubtedly be required for successful operation of a conventional gas/water separator.

It is recommended that use of the vertical 400-barrel tank as a separator continue until no problems with production of solids have been observed after hydraulic fracturing. Such a demonstration can easily be accomplished by using a "T" at ground-level between the wellhead and riser to the top of the tank. A valve on the blind leg of the "T" will concentrate any solids in the flow stream and thereby permit sampling of solids by opening that valve to a bucket or pitcher.

As gas production begins, accuracy and convenience of gas rate measurement can be enhanced by installing a positive displacement meter on the gas outlet from the tank. However, such action must be accompanied by a choke between the wellhead and tank to dampen any large surges in gas production. This is not terribly critical because a spring-loaded hatch is capable of venting about 1 million SCF/day without creating excessive back pressure.

After pumping results in gas production from the annulus with water produced through tubing, no problem should be encountered in use of a choke and orifice meter for gas production metering. However, the tank should be retained on the liquid production from tubing to both facilitate liquid production measurement and to provide backup separation in case control from the Sperry Sun bottom-hole sensing system is not adequate to avoid gas surges through tubing, as reported by USS.

ATTACHMENT A-3. INJECTION AND MINI-FRAC TESTING

The objective of injection testing is to determine the product of permeability times thickness for the coal seams. Because the results of measurements made at the well bore will be applied to interpretation of production from great distances, it is extremely important that these tests be conducted in the manner so that any skin effect or formation damage at the well bore is minimal and measureable.

The objective of the mini-frac tests is to determine the initial shut-in pressure after hydraulic fracturing to develop quantitative data regarding fracture propagation in the coal seam versus fracture propagation in rock strata above and below the coal. Fractures actually created during such tests must be small enough to provide confidence that the test fractures have not extended into the adjacent strata. Therefore, data obtained will describe the near well-bore environment and will not be valid if the rock properties or stress conditions near the well bore are significantly altered by cement invasion.

The test procedures detailed below are tailored to minimize rig time, to provide insight into any alteration of strata by cement invasion, and to permit completion of injection tests before changing the bottom-hole geometry by conducting mini-frac tests in the coal seams.

IGT's recommended chronological sequence of tests is presented below.

Open-Hole Testing

Valid injection tests require that the strata to be tested uniformly at original reservoir pressure when the test commences. It is therefore recommended that the open-hole tests take place immediately after logging. Valid data will be obtained at this time _if_ the fluid level in the well balances reservoir pressure during logging as previously emphasized.

Down-Hole Hardware Configuration

Recommended down-hole hardware consists of tubing with Lynes packers spaced at ±20 feet. Ideally, three sets of dual Armarada pressure recorders with 3000 psi full scale and 36-hour clocks will be run with the packers. Sets of dual recorders would be installed below the bottom packer, between the two packers, and above the top packer. If sufficient recorders are not available, frequent echo-meter readings can be used for the annulus and tubing fluid levels. Actual packer spacing will be determined by field examination of wireline logs. No valve is required in the down-hole assembly. The tubing is to be opened only to the space between the packers.

Injection Test Procedures

1. Seat the packers straddling the Gilson coal seam.

2. Connect the top of the tubing to a gravity drain from a 55-gallon drum of fresh water on the rig floor.

3. Flow about 15 gallons (accurately measured) from the drum into the tubing while observing annulus fluid level with an echo meter to verify sealing of the upper packer.

4. Fill the remainder of the tubing with water from the 55-gallon drum, with provision for air escape, and then measure the decrease in the 55-gallon drum fluid level for 30 minutes. Continue echo meter monitoring of the annulus fluid level to establish test validity.

5. Disconnect the top of tubing from the 55-gallon drum and monitor fluid level decline in the tubing with an echo meter for 2 hours.

6. Unseat the packer, move to straddle the Sunnyside coal seam, and then repeat the above steps for the Sunnyside seam.

7. Pull the tubing string, examine the pressure recorders from below the bottom bomb to determine whether the lower packer was adequated seated, redress the packers as appropriate, adjust packer spacing if required by seats for mini-fracture testing, and rerun the bottom-hole assembly.

8. If needed because of inadequate data, repeat the injection test while rigging for the mini-frac test.

Mini-Frac Tests

9. Rig for the mini-frac testing using a cement truck, Halliburton 2-inch turbine flow meter, and frac-van-quality pressure recording equipment for both the tubing and annulus. This fast time-response, high chart-speed equipment is essential for reasonably accurate picks of ISIP.

10. Seat the bottom packer at the selected point above the Sunnyside coal seam.

11. Circulate the water to load the tubing and annulus.

12. Seat the upper packer and shut in the annulus.

13. Pump about 1 barrel of fluid into the tubing at the lowest possible rate, shut in the tubing, and observe the tubing and annulus pressure gauges to verify adequate packer seats.

14. After adequate packer seats are verified, resume pumping into the tubing at the minimum possible rate until a total of 5 barrels have been pumped.

15. Stop pumping and record ISIP.

16. Resume pumping at approximately twice the previous rate, continue until an additional 3 to 5 barrels have been pumped, and then record ISIP.

17. Allow the well to flow back through tubing.

18. Move the packers to the strata underlying the Sunnyside seam and repeat steps 10 through 17.

19. Move the packers to the rock strata overlying the Gilson seam and repeat steps 10 through 17.

20. Move the packers to the rock strata underlying the Gilson seam and repeat steps 10 through 17.

21. Pull the tubing assembly and examine the recorders from beneath the bottom packer to determine whether any tests must be repeated due to bottom-hole pressure buildup.

Starting with the shallowest mini-frac tests and then performing the tests in order of increasing depth minimizes rig time by permitting bleed-off of fluid from previous mini-fracs from above the top packer while test preparations are being made. Field experiments have revealed that in testing the deepest interval first, bleed-off may cause pressure buildup below the bottom packer that interferes with its seating. Also, the slow bleed-off after flow-back may force fines into the Gilson seam if deep mini-frac tests are conducted first.

Injection Tests After Running Casing and Releasing Rig

The previously discussed open-hole injection tests of the Gilson seam emphasized minimum cost to obtain a preliminary indication of permeability times thickness (kh) for that coal seam. Additional and more elaborate testing after cementing the casing is important to determine the extent to which cement invasion or other formation damage has occurred, to provide average kh data at greater distances from the well bore, and to determine whether the coal seam has reservoir limits within an area that would complicate interpretation of production test data.

A reservoir limit test to determine whether substantial changes in permeability exist near the well bore is recommended to minimize uncertainty in ultimate interpretaion. One such test is a long-term injection test in which reservoir boundaries or substantial changes in reservoir properties are detected by reflected pressure pulses during injection and during pressure decline after injection.

A reservoir limit injection test of 1 week is recommended. This duration will reveal any boundaries within a 6.5-acre area around the well bore and may test as much as 50 acres, depending upon the value of the effective compressibility and other reservoir parameters.

This injection test should be performed at constant rate and at a positive wellhead pressure of a few hundred psi. The required injection rate is expected to be about 0.2-2.0 gal/min. This value can be defined with greater accuracy after the short-term open-hole injection test is performed. In addition to careful monitoring of the constant injection rate, it is very desirable that the bottom-hole pressure be recorded with the greatest practical resolution. Ideally, a Hewlett-Packard bottom-hole instrument with a resolution of a few hundredths of a psi would be used. If this is not judged practical, IGT can supply transducers and recorders with a resolution of about 1.0 psi for use with the Sperry-Sun system.

After 1 week of injection and 1-2 weeks of monitoring pressure decline, the mini-frac of the Gilson seam should be performed. Procedures would be the same as for the open-hole mini-frac test with the exceptions that packers would not be required, and bottom-hole pressure monitoring would be via the Sperry-Sun system.

BB/CL

EVALUATION OF METHANE PRODUCTION FROM UNMINABLE COAL

Carbon County, Utah

Project 65019

Phase III Monthly Reports

to

Mountain Fuel Supply Company

by

Institute of Gas Technology
3424 South State Street
Chicago, Illinois 60616

CHARACTERIZATION ANALYSES OF KAISER'S SUNNYSIDE UTAH COAL

Two pieces of coal from Kaiser Steel's Sunnyside mine in Utah were sent to us by Mountain Fuel Supply, Salt Lake City, Utah. These samples were taken from the mine at an unknown depth. One sample was taken right out of the mine where mining was occuring. The other was from a previously mined shaft and had apparently been exposed for a considerable period of time. These pieces were labeled Coal Sample A (current fresh mining) and Coal Sample B (previously mined-weathered). These samples were sent at our request for the purpose of gaining experience in handling coal and for developing techniques for running future analyses and tests on coal which will be sampled while drilling seams for methane production.

The samples were submitted first to the analytical section for routine analyses. These results are used to establish the rank. The analyses include both a proximate and an ultimate analyses, and the results are included in this report. Tests such as permeabilities, porosities, compressibility, and adsorption-desorption isotherms will eventually be determined when equipment is ready for such tests. These data can be used as background information later when the Sunnyside coal seam is actually drilled by Mountain Fuel Supply at a deeper depth for methane production.

Samples taken from the two coal pieces (A & B) were labeled as follows: two samples, A-1 and A-2, were taken from the A piece and 3 samples, B-1, B-2, and B-3, were taken from the B piece. These spots were samples from areas in the coal piece which appeared to be different from each other.

The five samples were analyzed, and after results were obtained it was found that four of them were very close in composition. Sample A-2 was different, primarily in the amount of ash after combustion. Since this sample was a nearby area to the other A sample, it points out the known existence of nonhomogeneities within coal beds. Table I shows the analyses of the average of the four samples (A-1, B-1, B-2, B-3), while Table II gives the results of the sample (A-2) that was different for comparison. This sample is not considered to be typical of the coal seams. Table III gives all the data that were obtained on the elemental constituents in the ash, as determined by atomic absorption spectroscopy. It appears that silicon (Si), iron (Fe), and aluminum (Al) make up the bulk of the elements in the ash, although there is a small quantity of other elements present. Other data such as surface area and mercury porosimeter data were obtained, but these are not shown as they were only obtained for possible future references.

Also not shown, but worthy of mention, are the qualitative results from an x-ray fluorescence scan of material coated on the face cleats of this sample. This material was a white powder coating. The x-ray scan of the surface was able to pick up elements that were in higher concentration than in the coal by itself. They were found to be mostly calcium (Ca), aluminum (Al), and silicon (Si). These elements suggest the material to be a clay residue or a salt residue or both. It was apparently not a coal oxidation product as the cleats inside the coal piece contained this white coating also. It is significant, however, that the white residue was most likely left by flowing water in the cleat system.

It can be seen from the results of the promimate analyses in Table I that the coal had a fairly low as received moisture content (2.8%) as well as a low ash content (2.6%), a fairly high volatile matter content (42.4%) and a fixed carbon content of 54.5%. With this as a guide, the ASTM chart for ranking coal was consulted and a preliminary rank of high volatile A bituminous was assigned. This was further substantiated by a gross calorific value of 14,441 Btu/lb. In addition, these analytical data were used by IGT's D. M. Mason to calculate the rank and he also calculated it as a high volatile A bituminous. The USGS lists the Sunnyside coal seam in Utah as this rank.

It is also evident from the results of the ultimate analysis in Table I that the total carbon was about 81% and that both sulfur and nitrogen are low. The oxygen content (7.9%) may not be representative of what this coal is _in situ_, since this is a mine sample which has been exposed to air and some coal oxidation may have occurred. The mineral carbon content is low and substantiates the low ash content. The gross calorific value of 14,441 Btu/lb fits well with the other analysis for a rank of high volatile A bituminous.

It is known that the methane content of a coal is dependent on its rank and its depth. The higher the rank and deeper the depth, the higher the methane content. Using published data on these values and by extrapolation, it was estimated that a high volatile A bituminous coal such as this would contain 450 cu ft of methane/ton of coal at a depth of 2800 feet. This is the depth of the Gilson coal seam that is to be the first drilling by Mountain Fuel Supply in their methane from coal project. If the assumption is made that the Gilson coal is similar in rank to the Sunnyside, which is very likely, then the amount of methane contained in the Gilson can be approximated. This was done using a thickness of 18 ft for the Gilson bed and was calculated to be 9.2 billion cu ft/sq mile. If the initial in place methane is higher or the seam is thicker, then the methane content would be greater. However, if these values are lower, then the methane content would be lower. At any rate, these figures can offer some speculation as to the amount of methane contained in these coal seams before they are actually drilled and stimulated for methane production.

Table I. KAISER'S UTAH SUNNYSIDE MINE COAL SAMPLES
Avg. of Samples (A-1;B-1;B-2;B-3)

Proximate Analysis (He density = 1.29 gm/cc)

Proximate Analysis	Wt %	(as Received)	
Moisture	2.8		
Volatile Matter	40.1	41.3 (dry)	42.4 (DAF)
Ash	2.6		
Fixed Carbon	54.5		
Total	100.0		

Ultimate Analysis	Wt %		(Dry Basis)
Ash	2.6		2.6
Carbon (Total)	81.0		
a) Organic		80.8	80.8
b) Mineral		0.2	
Hydrogen	5.7		5.7
Sulfur	.5		.5
Nitrogen	1.9		1.9
Carbon Dioxide		0.6	0.6
Oxygen (by Difference)	8.3		7.9
Total	100.0		100.0

Gross calorific value: 14,441 Btu/lb.

Table II. KAISER'S UTAH SUNNYSIDE MINE COAL SAMPLE (A-2)

Proximate Analysis (He density = 1.43 gm/cc)

Proximate Analysis	Wt % (as received)		
Moisture	2.8		
Volatile Matter	32.1	33.0 (dry)	41.4 (DAF)
Ash	19.1		
Fixed Carbon	46.0		
Total	100.0		

Ultimate Analysis	Wt % (Dry Basis)		
Ash	19.6		19.6
Carbon (total)	65.8		
a) Organic		65.7	65.7
b) Mineral		0.1	
Hydrogen	4.8		4.8
Sulfur	0.4		0.4
Nitrogen	1.4		1.4
Carbon Dioxide		0.2	0.2
Oxygen (by difference)	8.0		7.9
Total	100.0		100.0

Gross calorific value: 11,569 Btu/lb.

Table III. KAISER'S UTAH SUNNYSIDE MINE COAL SAMPLES — ASH ANALYSIS FOR MAJOR ELEMENTS

Sample	SiO_2	Al_2O_3	Fe_2O_3	TiO_2	P_2O_5	CaO	MgO	Na_2O	K_2O	SO_3	Total	% Ash*
A-1	57.9	26.4	3.52	1.6	N.D.†	2.74	0.40	3.90	0.43	1.8	98.69	1.85
A-2	48.9	37.0	0.46	1.7	N.D.	6.48	0.11	0.36	<0.1	0.3	95.31	19.6
B-1	30.6	18.0	34.1	0.8	N.D.	4.47	1.86	1.52	<0.1	6.6	97.95	2.55
B-2	32.8	10.1	38.1	0.8	N.D.	4.74	1.99	2.12	<0.1	6.2	96.85	3.34
B-3	28.9	9.37	40.3	0.8	N.D.	5.03	2.18	1.95	<0.1	7.0	95.53	3.73

* Sample dried at 110°C for 1 hour, then ashed at 760°C.

† Not detected.

Monthly Report for October 1979

METHANE FROM COAL SAMPLES

Project 65019

This report includes data thus far obtained on all samples taken during the drilling and coring by Mountain Fuel Resources of the Whitmore Park No. 1 and Whitmore Park No. 2 wells in Utah for methane production from coal. A general status report is included for all the tests to be done on these samples.

Whitmore Park No. 1

Water Sample Analysis

Three water samples were taken during the drilling of the Whitmore Park No. 1 well. While air drilling, a water zone was encountered at a depth of about 760 feet. A sample of this water was obtained and analyzed for its major ions, pH, and solids. Also two samples were taken after the Gilson coal seam had been cored in an effort to establish the zone of water entry into the well. One of these samples was taken at 2100 hours on October 29, 1979 and was water unloaded from base of Gilson coal in which it required greater than 1000 psi to break the water over. The other was taken at 1940 hours from about 650 feet off bottom (2500 ft depth) after 16 feet of shale had been cored below the Gilson coal. These analyses are shown in Table 1. These analyses show that some differences exist in the waters, but these differences are not very significant in verifying the origin of water of different chemistries. However, it does appear that the 760 feet aquifer showed a little less total ion concentration, as would be expected.

Coal Sample Analyses

The upper coal seams in this well were not sampled because they were drilled instead of cored. The Gilson seam was, however, cored, and a few pieces of solid core plus some broken pieces were retrieved. This sample has been analyzed for rank classification and is still in the process of desorbing its methane for the methane content. Table 2 shows the results of the rank analyses and helium density. The results for the major ions in the oxidized ash are included in Table 3. In Table 2, a proximate and ultimate analysis both are included. From the proximate analysis, a low as-received water content of 1.8% was obtained. A dry, ash-free volatile matter of 41.3% was obtained along with a fixed carbon of 55.8%. A gross calorific value of 14,270 Btu/lb and a helium density of 1.34 g/cc were obtained. With these values, the ASTM rank was established as high volatile bituminous A coal. This is the same rank as was previously established for the Kaiser Sunnyside sample sent to us previously. The ultimate analysis is included for background information. As noted from this analysis, a fairly low ash content (3.19%) was obtained, indicating the coal to be free of most mineral matter. This is further substantiated by the low mineral carbon content (.09%). The other analyses show low sulfur and carbon dioxide values and average hydrogen, nitrogen, and oxygen values for this rank of coal. A breakdown of the major ions in the oxidized ash (Table 3) are indicated to be largely silicon, aluminum, iron, and calcium, although small quantities of others are present.

Desorption Samples for Methane Content

During the coring of Whitmore Park No. 1, several samples of core other than coal were sealed into containers to see if any gas was released. This was only intended for qualitative purposes, and no attempt has been made to quantify any of these results. One good coal sample from the Gilson seam was sealed for desorption and as of this data, the desorption is still not complete. The other samples were sandstone, shale, and shale with coal partings. All of these data are shown in Table 4. It can be seen from this table that the Gilson coal has desorbed a total of 9427 cc, including a graphically determined "lost gas" content as well as a correction for altitude change from the site in Utah to Chicago, Ill., during its desorption period. A weight of 849.6 g for this sample has desorbed the 9427 cc of methane. This calculates as 11.10 cc/g or 355 cu ft/ton of coal. More desorbed gas is anticipated, however, the rate is dropping fast.

Gas samples from these coal samples were taken in the field during desorption for component analysis. However, the portable electrical vacuum pump which was to be used in obtaining relatively air-free gas samples for analysis would not operate on rig power, so samples were taken with an inadequate, small hand vacuum pump. This, coupled with the large void volume of the sample containers resulted in these samples having too much air for a reliable mass spectrometer analysis. One good gas sample, which was relatively air-free, has been obtained on the coal gas desorbed from the Gilson coal since returning the samples to Chicago, but results have not yet been received. Others are possible from this sample if desorption continues.

Permeability measurement on the Whitmore Park No. 1 Gilson coal will not be possible due to inadequate sample sizes; however, they can be made on the same coal seams from the Whitmore Park No. 2 coal. After the Whitmore Park No. 1 sample has desorbed, it will be possible to obtain equilibrium sorption isotherms on powdered samples.

Whitmore Park No. 2

A total of 12 samples were taken for desorption analysis during the drilling of this well. These samples represent generally the main seams (Sunnyside, Rock Canyon, Fish Creek, and Gilson); however, stringer samples were also taken for desorption. The data thus far obtained on these desorption samples are presented in Table 5.

Currently, the graphs are being drawn for "lost gas" determinations for these samples. Also, samples are being prepared for submission for rank analysis. (Several of the samples have to wait until desorption is complete before the rank or other analysis can be done.) Gas samples have been taken in the lab from the desorbed gases. These are awaiting analysis for components by mass spectrometer.

Sample No. 10 (Sunnyside) has desorbed 150 cu ft/ton; sample No. 11 (Sunnyside stringer) has desorbed 232 cu ft/ ton; samples No. 16 and No. 17 (Gilson) have each desorbed 170 cu ft/ton. Weights on the other coal samples have not been taken. None of these samples have been corrected for "lost gas" or for altitude change from moving from Utah location to Chicago. This latter calculation cannot be made until densities are obtained on each sample so that void volume of the containers can be calculated.

Samples are being prepared for equilibrium sorption isotherm determination as well as for permeabilities, wherever the sample size permits. Some of these tests cannot be run until the samples have been completely desorbed.

Table 1. WHITMORE PARK #1 — WATER SAMPLES

Sample	pH	TDS	TSS	Na	K	Ca	Mg	Fe	$Co_3^=$	Cl^-
760' Aquifer	8.9	542	7	112	1.62	1.32	17.6	0.29	436	20
Unloading @ 2500' — 10/25/79, 1940 Hrs.	8.0	521	33	72.5	13.4	73.6	44.7	10.7	629	30
Base of Gilson — 10/25/79, 9:05 p.m.	7.5	531	90	74.6	14.5	75.6	45.4	6.2	657	30

TDS = Total Dissolved Solids

TSS = Total Suspended Solids

Table 2. WHITMORE PARK #1 – 3101 ft GILSON COAL

Proximate Analysis	(He Density = 1.34 g/cc)		
	Wt %	(As Received)	
Moisture	1.8		
Volatile Matter	39.3	40.0 (dry)	41.3 DAF
Ash	3.1		
Fixed Carbon	55.8		
Total	100.0		

Ultimate Analysis	Wt %	(Dry Basis)	
Ash	3.19		3.19
Carbon (total)	80.25		
Organic Carbon		80.16	80.16
Mineral Carbon		0.09	
Hydrogen	5.50		5.50
Sulfur	0.39		0.39
Nitrogen	1.59		1.59
Carbon Dioxide		0.32	0.32
Oxygen (By Diff)	9.08		8.85
Total	100.00		100.00

Gross Calorific Value = 14,270 BTU/lb.

Table 3. WHITMORE PARK #1 — 3101 ft GILSON COAL

Major Ions in Oxidized Ash

Element Oxide (% Ash = 3.59)	Wt %
SiO_2	42.0
Al_2O_3	21.0
Fe_2O_3	5.70
TiO_2	0.7
P_2O_5	N/D
CaO	10.3
MgO	2.32
Na_2O	2.09
K_2O	1.37
SO_3	8.9
Total:	94.38

Table 4. WHITMORE PARK #1 — DESORPTION SAMPLES

Sample No.	Description	Depth ft	cc's Desorbed	Complete
1	Sandstone	2736	799	Yes
2	Gilson Coal	3099	9427*	No
3	Sandstone	3092	129	Yes
4	Shale w/Coal	3109	126	Yes
5	Shale	2718	723	Yes

* This number includes a lost gas value of 1500 cc's determined by graphical means and a correction of 601 cc's for altitude change in elevation from Whitmore Park #1 location in Utah to Chicago, Illinois.

Table 5. WHITMORE PARK #2 — DESORPTION SAMPLES

Sample No.	Description	Depth ft	cc's Desorbed	Complete
6	Sandstone	2560	475	Yes
7	Shale w/Coal Stringers	2628	588	No
8	Coal Stringer	2664	3266	No
9	Coal Stringer	2688	6566	No
10	L. Sunnyside	2714-20	3981	No
11	Sunnyside Stringer	2703	6742	No
12	Rock Canyon Main Seam	2864-67.5	3435	No
13	Stringer between R.C. & F.C.	2876-77.5	3443	No
14	R.C. Upper Stringer	2862.5-63	3154	No
15	Fish Creek (Carbonaceous Spl.)	2883	1837	No
16	Gilson (Upper)	2934-37	3813	No
17	Gilson (Lower)	2934-37	2815	No

IGT

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GENERAL PHONE 312 ...
TELEX 25-6189
DIRECT DIAL 312 567

December 11, 1979

Mr. Larry Allred
Mountain Fuel Supply Co.
P. O. Box 11368
180 East First South
Salt Lake City, Utah 84111

Dear Larry:

Enclosed find our report on Mr. O. P. Funderburk's data and my calculations of the coal permeability.

To summarize, I get the following values for Gilson coal permeability, based on a formation thickness of 18 ft:

Injection:	K = 21 md
Swabbing:	K = 1.3 md

The swabbing data is handled assuming a constant pressure draw down. After staring at the data, I came to the conclusion that it does not warrent more sophisticated treatment.

Also enclosed is a graph of permeability as a function of "start injection" time, based on the injection data, which shows how the "computed value" of permeability varies with "start time." These values are based on a formation thickness of 14 ft.

Yours sincerely,

SKelkar

Sherad Kelkar

SK:jml
Encl.

WHITMORE PARK #1, GILSON COAL SEAM

Permeability from Pressure Buildup Analysis

For an infinite-acting reservoir with constant flow rate, pressure at the well bore is given as a function of time by the following equation:

$$P = P_r + \frac{1}{2} \cdot \frac{.141\ q\mu}{Kh} \left(\ell n\ t + \ell n \left(\frac{6.33\ K}{q\mu c r_w{}^2}\right) + 0.800\right) \qquad \text{Ref. 1}$$

where

P = pressure at time t (psi)

P_r = reservoir pressure = 1106 psi

q = flow rate (bpd) = 576 bpd

μ = water viscosity (cp) = 0.85 cp

K = permeability (darcies)

h = formation thickness (ft) = 18 ft

t = time (hrs)

ϕ = porosity (fraction)

c = water compressibility (1/psi)

r_w = well bore radius (in)

A plot of ℓn t vs. P will give a straight lime with slope = $\frac{.141 q\mu}{Kh}$

Note:

1. The units of time don't affect the permeability.

2. If all values of the pressure are changed by a constant, the permeability is unchanged. It was found that the pressure reading from the upper and the lower gauge differed by a constant. The readings from the Halliburton recorder were found to agree with the surface guages.

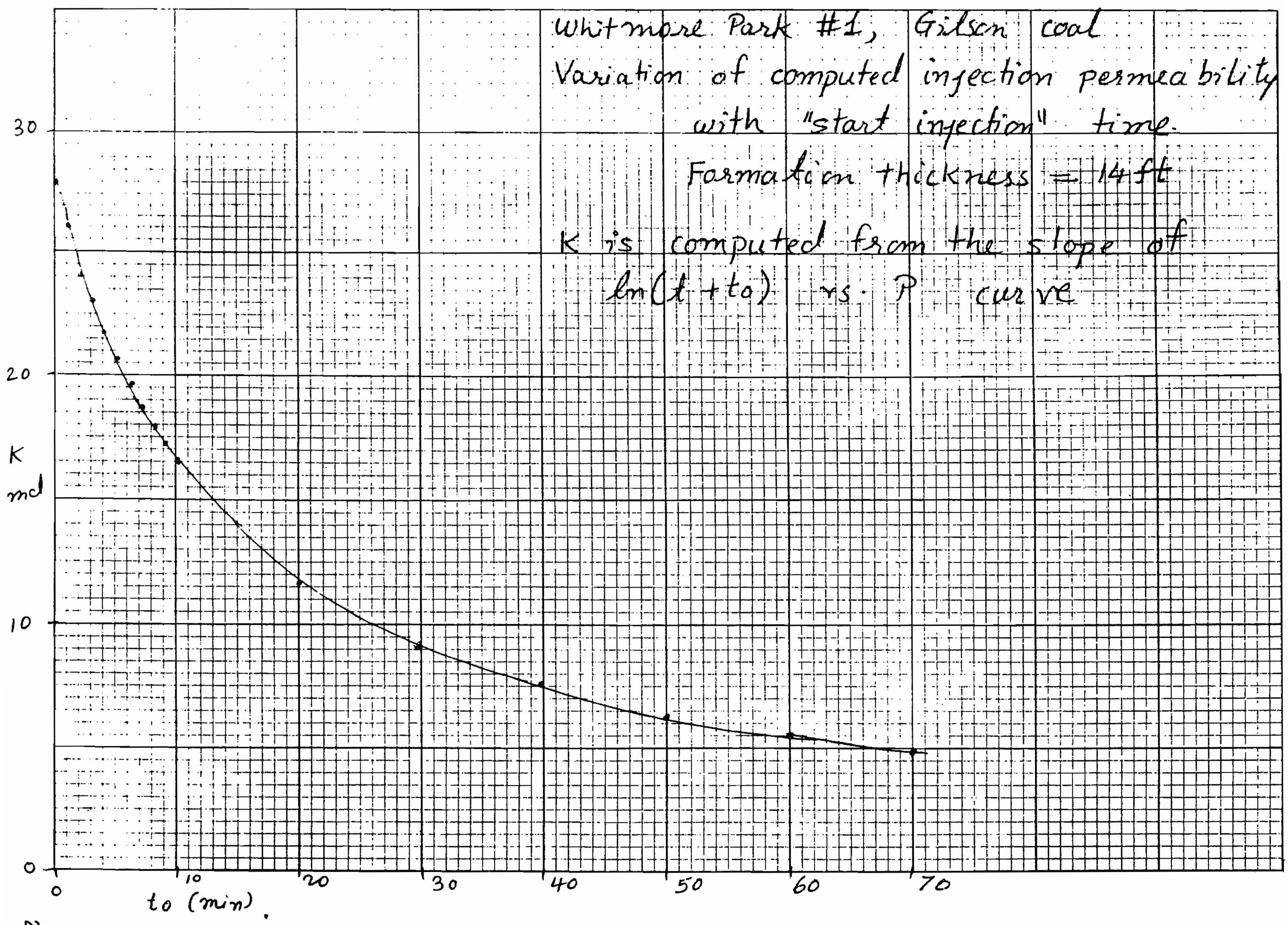
PRESSURE BUILDUP DATA

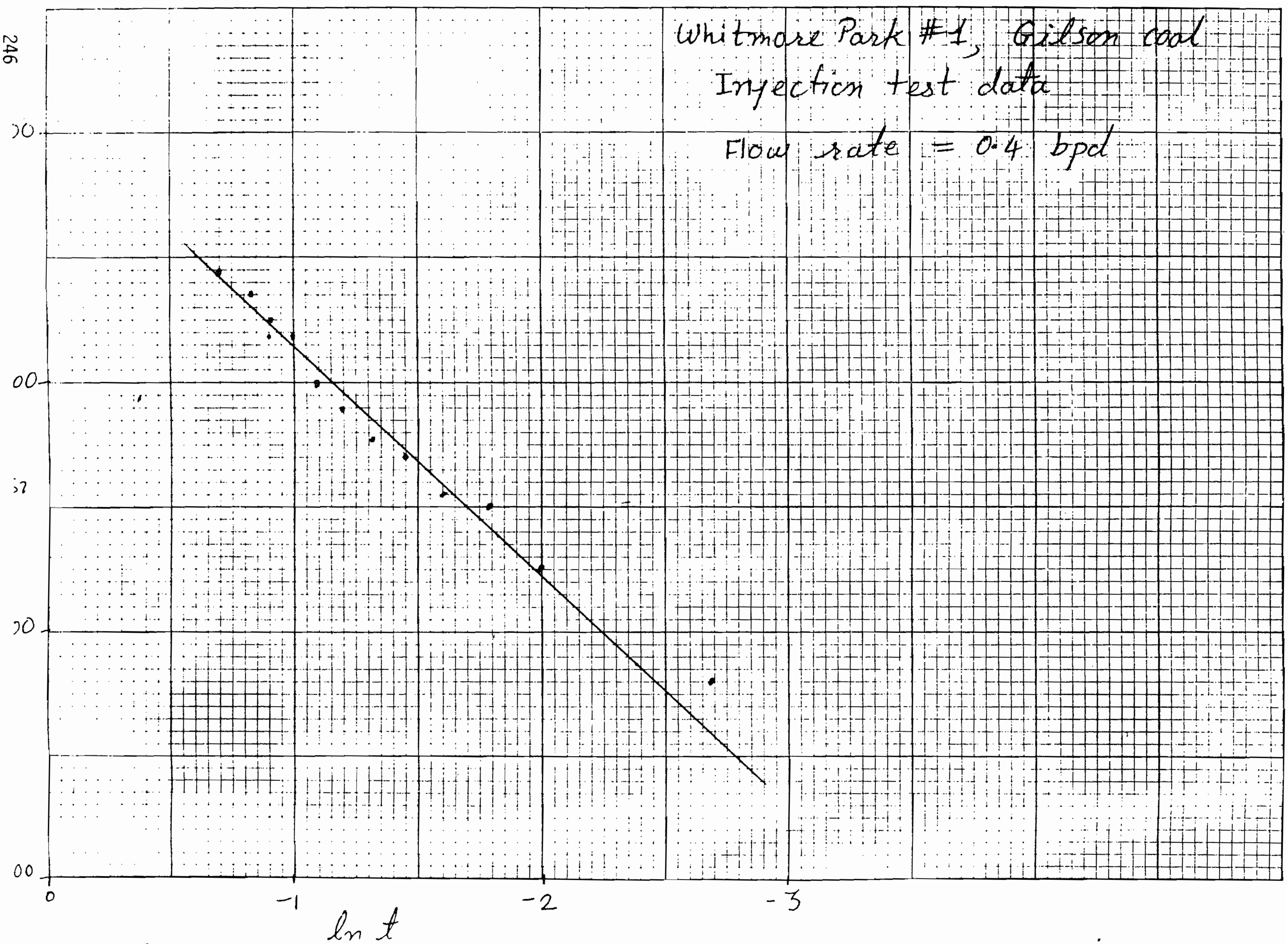
No.	Time, t, hrs	ℓnt	P (Upper guage) psi
1	0.00		325
2	0.033	−3.411	360
3	0.067	−2.703	380
4	0.133	−2.017	425
5	0.167	−1.790	450
6	0.200	−1.609	455
7	0.233	−1.457	470
8	0.267	−1.321	478
9	0.3	−1.204	490
10	0.333	−1.100	500
11	0.367	−1.002	520
12	0.4	−0.916	525
13	0.433	−0.837	535
14	0.5	−0.693	545

Slope of the line = 92.9 psi

$$\therefore = 92.9 = \frac{1}{2}\,\frac{.141 \times 576 \times .85}{K \times 18}$$

$\therefore$ K = 21 md


Whitmore Park #1, Gilson coal
Variation of computed injection permeability with "start injection" time.
Formation thickness = 14 ft
K is computed from the slope of ln(t + to) vs. P curve
K md
30
20
10
0
0
10
20
30
40
50
60
70
to (min)



Whitmore Park #1, Gilson coal
Injection test data
Flow rate = 0.4 bpd
0
-1
-2
-3
ln t

WHITMORE PARK #1, GILSON COAL SEAM

Permeability from Swab Test

It is assumed that a constant pressure analysis adequately represents the swab test. Due to the nature of the test, more sophisticated treatments are nor warrented.

Flow rate at the well bore for a constant pressure draw down is given as a function of time by:

$$\frac{1}{q} = m \frac{\ell n\ t}{2.3026} + C \qquad \text{Ref. 2}$$

where

$$m = \frac{162.6\ B\mu}{Kh\ (P_i - P_w)}$$

q = flow rate (bpd)

t = time

B = formation volume factor = 1

μ = viscosity (CP)

K = permeability (md)

h = formation thickness (ft) = 18 ft

P_i = reservoir pressure = 1103 psi

P_w = flowing well bore pressure (psi)

C = a constant.

A plot of $\ell n\ t$ vs. 1/2 will give a straight line with:

$$\text{slope} = \frac{m}{2.3026}$$

Swab #	Time, t hr	Flow Rate bpd	ℓnt	1/2
1 - 2	0.1	464	−2.3	2.2×10^{-3}
2 - 3	0.38	204	−0.97	4.9×10^{-3}
3 - 5	0.77	125	−0.26	8×10^{-3}
5 - 7	1.43	99	−0.36	10.1×10^{-3}
8 - 9	2.30	86	−0.832	11.6×10^{-3}

From the swab data, average well bore pressure is:

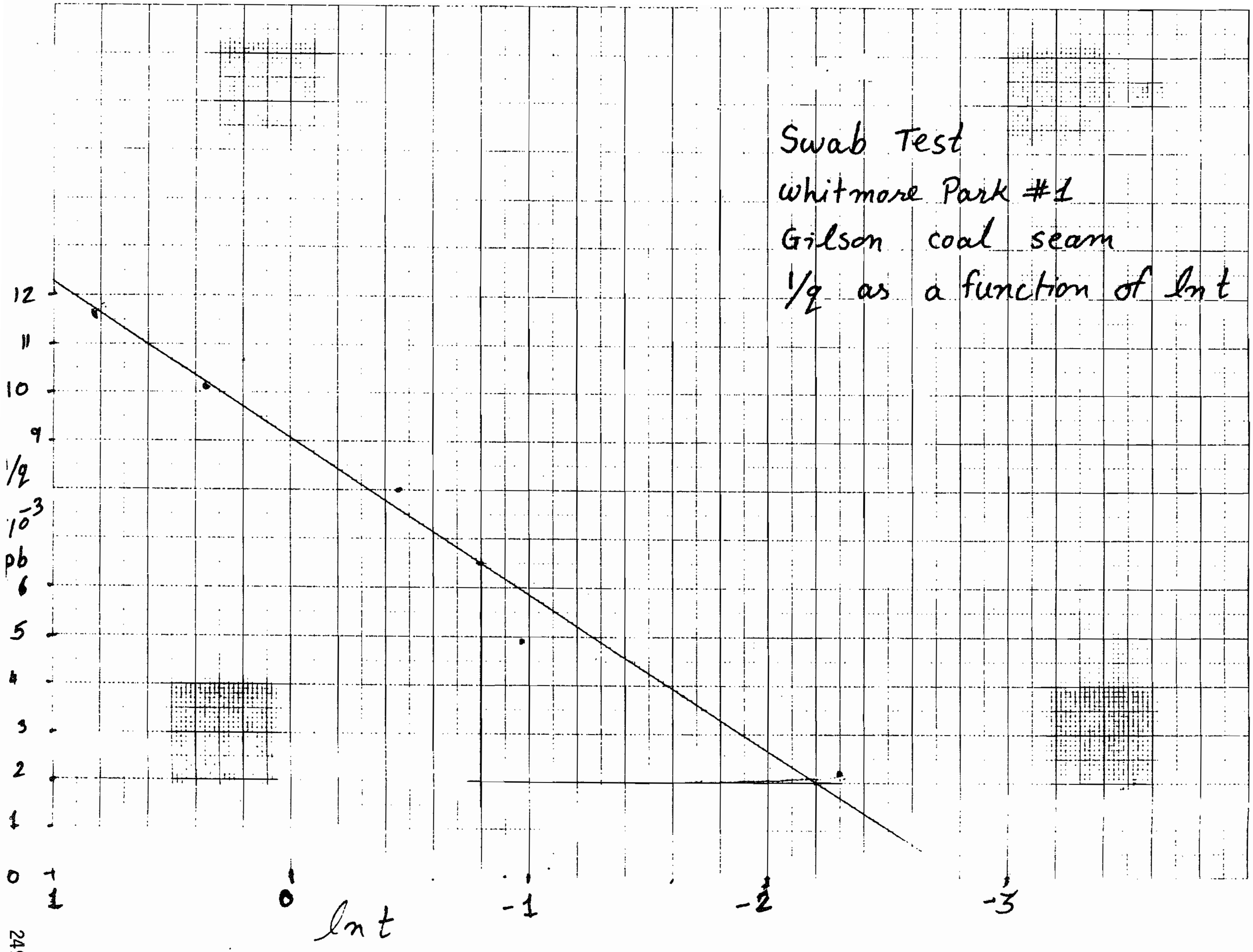
$$P_w = 340 \text{ psi}$$

For the graph,

$$\text{slope} = 3.2 \times 10^{-3} \text{ dpb}$$

$$\therefore K = \frac{162.6 \times .85}{18 \times (1103 - 340) \times 3.2 \times 10^{-3}} \times \frac{1}{2.3026}$$

$$\therefore K = 1.4 \text{ md}$$



Swab Test
whitmore Park #1
Gilson coal seam
1/q as a function of ln t
12
11
10
9
1/q
10^-3
pb
6
5
4
3
2
1
0
1
0
-1
-2
-3
ln t

References

1. Practical Petroleum Reservoir Engineering Methods, H. C. Slider, Petroleum Publishing Company.

2. Advances in Well Test Analysis, R. C. Earlogher, Jr., Monograph Volume 5, SPE.

ANALYSIS OF SWAB TEST DATA FROM WHITMORE PARK NO. 2 WELL, GILSON COAL SEAM

During the swab test, the following quantities were recorded as a function of time:

1. Depth at which the driller hit the water level with the swabbing tool
2. Depth from which the swab was pulled
3. Length of cable in the hole when water appeared at the ground level
4. Amount of water flown out into measuring drums
5. Echometer recordings to get independent measurements of the water level in the hole.

While the test was in progress, it was noted that there was a large amount of uncertainty as to when the swabbing tool hit the water level. As a result of this, the water level data from this measurement shows a lot of scatter and cannot be used in pressure drawdown analysis. Hence, the available echometer recordings are used as the most reliable water level indicators (Figure 1). The uncertainties in the data do not permit an analysis based on the assumption of constant pressure. Hence, the formation permeability is computated assuming a constant flow rate drawdown where the flow rate is estimated from the gross water produced during the test. The amount of water measured in the drums is used as the best estimate of the water produced. Figure 2 shows gross water production as a function of time.

Unfortunately, pressure build-up data using echometer was not obtained at the end of the swab down. This data would have permitted a much more reliable estimate of the formation permeability.

Data and Calculations

Formation depth (from logs) = 2940 ft

Formation thickness (from logs) = 14 ft

Flow Rate Calculations

Total water pulled out = 45.2 bbl

Decrease in the water level in the hole = 1660 − 285 = 1375 ft

Hole capacity (tubing and annulus) = 0.0224 bbl/ft

therefore, water pulled out of the hole = 30.8 bbl

therefore, water produced from the formation = 45.2 - 30.8 = 14.4 bbl

Total time for swabbing = 5.66 hours

therefore, flow rate = 60.9 bbl/day.

<u>Echometer Data</u>

Formation depth (from logs) = 2940 ft

Echometer calibration: 160 ft depth = 1 inch of strip chart record

T = time at which the ecometer was shot

ΔT = time lapsed since the first swab

D = depth recorded on the echometer

P = bottom-hole hydrostatic head = 0.433 X (2940 ft - D)

The bottom-hole pressure is plotted as a function of ΔT on a semilog paper (Figure 3), and the slope of the best straight line is determined from the graph.

Slope = 322 psi/cycle

From "Advances in Well Test Analysis," SPE Monograph, V5

$$\text{Slope} = \frac{162.6\ \beta \mu q}{kh}$$

where

β = formation volume factor = 1

μ = water viscosity = 0.85 cp

q = flow rate = 60.9 bpd

h = formation thickness = 14 ft

$$\text{therefore, } k = \frac{162.6 \times 0.85 \times 60.9}{322 \times 14} = 1.9 \text{ md.}$$

ECHOMETER DATA

T	ΔT, hr	D, ft	P, psi
11:00 am	0.00	285	1150
11:19	.32	730	957
12:34 pm	1.57	1195	756
1:20	2.33	1430	654
1:31	2.52	1395	669
1:50	2.83	1360	684
3:21	4.35	1630	567
3:49	4.82	1520	615
4:00	5.00	1600	580
4:11	5.18	1630	567
4:27	5.45	1645	561
4:39	5.65	1660	554

Fig 1

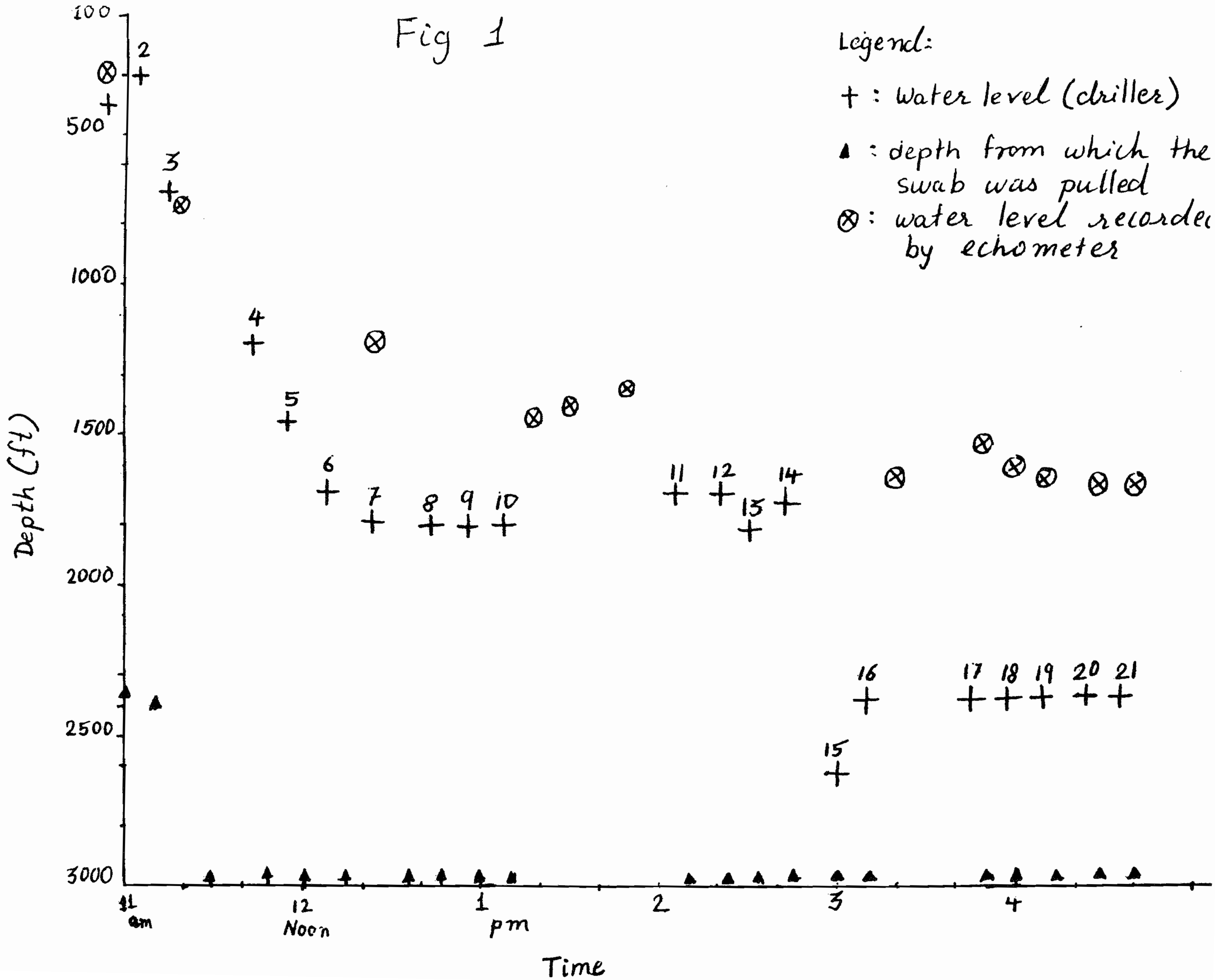

Legend:
+ : water level (driller)
▲ : depth from which the swab was pulled
⊗ : water level recorded by echometer
Depth (ft)
100
500
1000
1500
2000
2500
3000
11 am
12 Noon
1
pm
2
3
4
Time
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21

FIG. 3

Pressure drawdown as a function of time

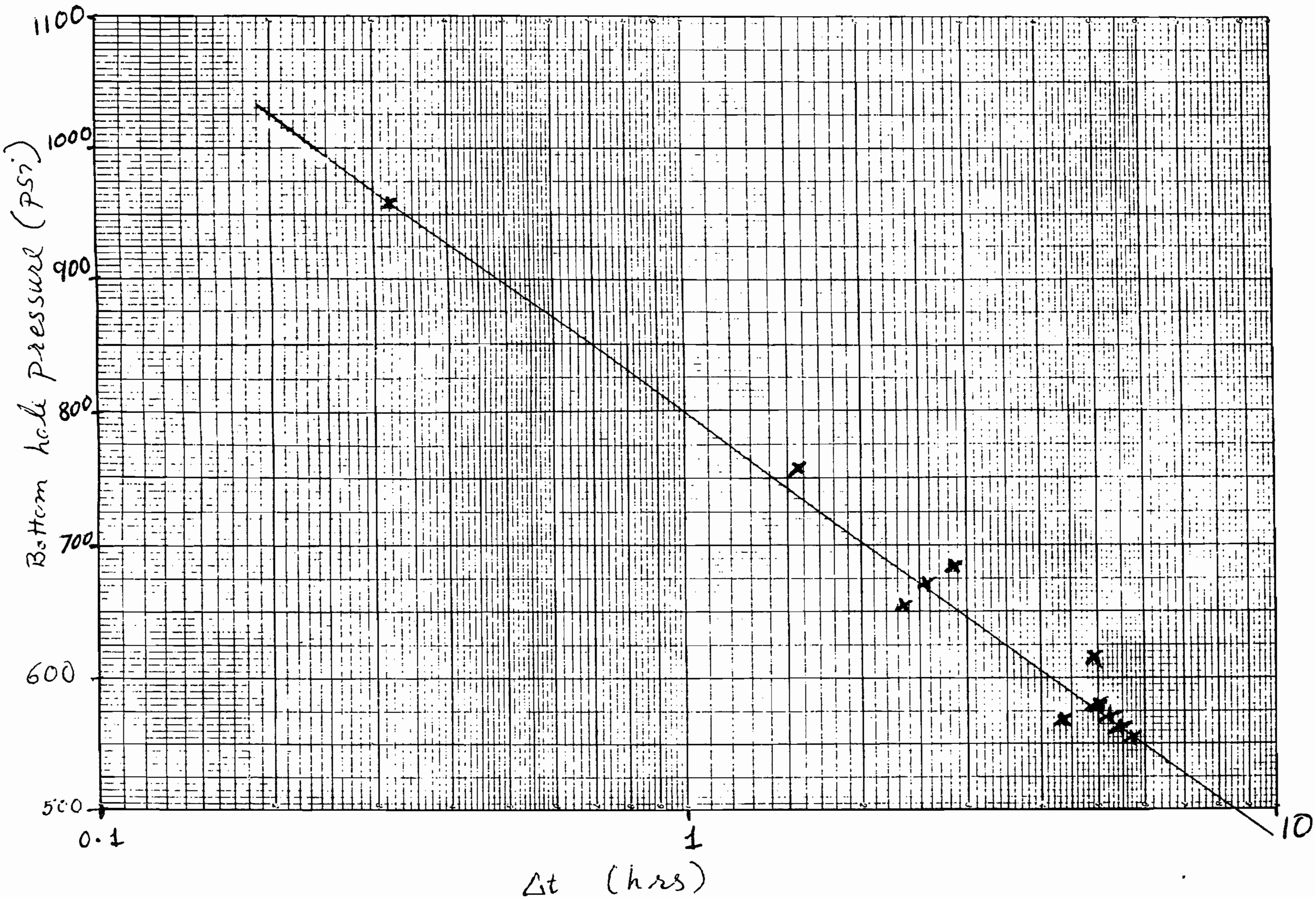
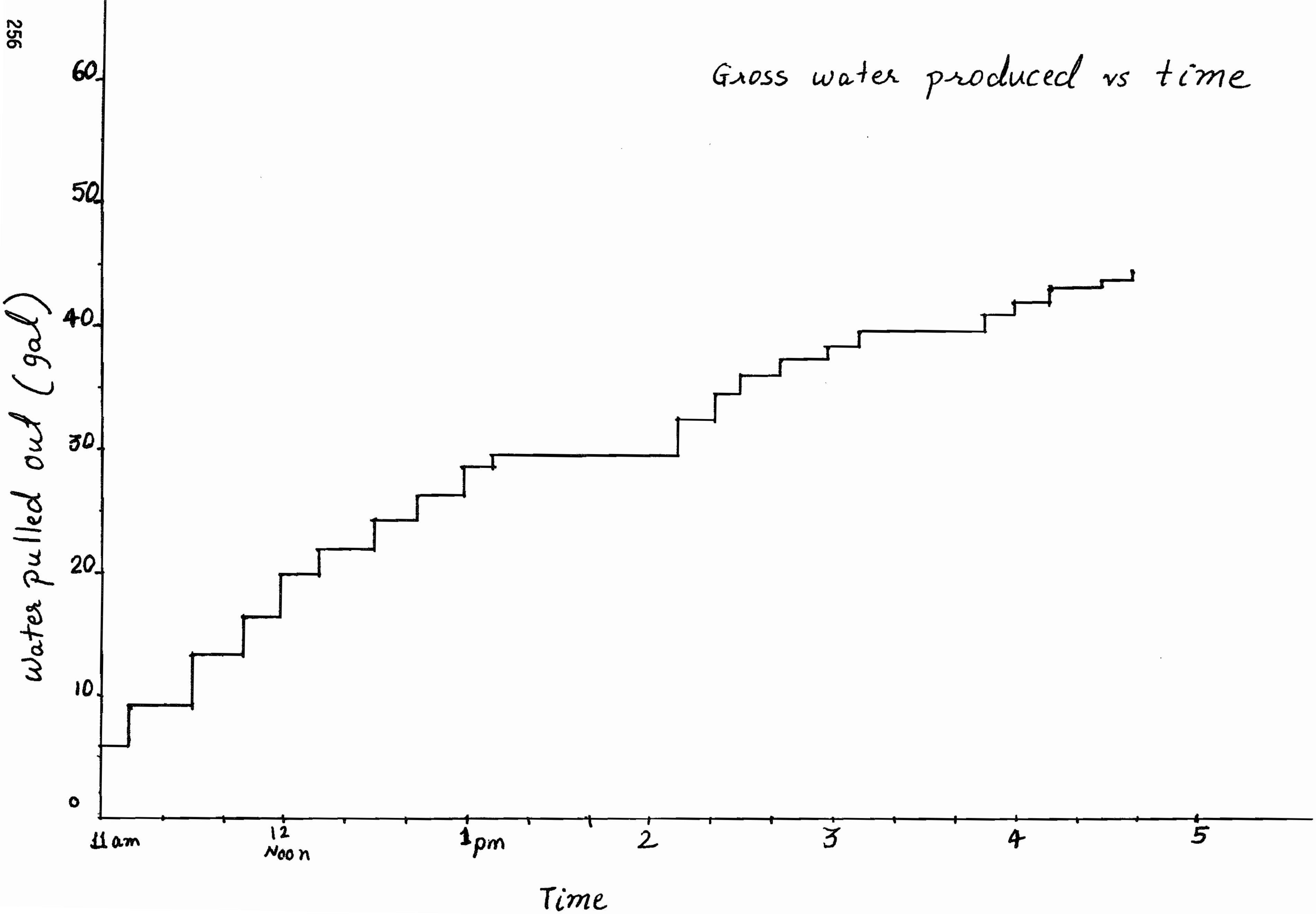


FIG. 2



Gross water produced vs time
Water pulled out (gal)
60
50
40
30
20
10
0
11 am
12 Noon
1 pm
2
3
4
5
Time

METHANE FROM UNMINEABLE COAL SEAMS
IGT Project 65019

This month's work has included a continuation of the desorption measurements on all samples taken during the Whitmore Park No. 1 and No. 2 drillings. It has also included data obtained on gas analyses from samples taken at various stages of the coal desorption measurements. These measurements are continuing. Partial rank analysis on some of the samples taken adjacent to the samples sealed into containers for desorption from Whitmore Park No. 2 have been obtained. Actual rank analyses on samples sealed into containers will be obtained later if necessary. Lost gas curves have been plotted and determinations made for each of the sealed samples. The construction of equipment for measuring both residual gas and adsorption-desorption isotherms on the sealed samples is nearing completion.

The updated data, together with new data obtained in January 1980, are given below.

WHITMORE PARK NO. 1

The Gilson coal seam (No. 2) taken from this well is still desorbing after more than 3 months in the container. It has now desorbed a total of 10, 442 cc of gas. For a weight of 849.6 grams, this calculates as 393 cu ft/ton of coal. The total volume includes 1500 cc of lost gas plus 601 cc of additional volume due to altitude change.

Mass spectrometer analyses of two gases from the Gilson coal in addition to those reported last month have been received. They are shown in Table 1 with the desorbed values corrected for lost gas and altitude change. Very little change in gas composition is noted in these last samples. It is noted from the earlier samples that carbon dioxide apparently decreases while methane increases as the desorption proceeds. Also, it is evident that the heavier hydrocarbons (C_2, C_3, and C_4) are starting to appear in only small to trace amounts. It does not seem likely that heavy hydrocarbons will appear to any significant extent this late in the desorption process. It is planned to take a sample of residual gas for analysis to see if any of these heavier components are liberated on pulverization of the coal.

Table 1. WHITMORE PARK NO. 1 — GAS SAMPLES FROM GILSON COAL

Components		Sample No. 2A	2C	2D	2E	2F
	Volume Desorbed, cc*	2912	9211	9642	9887	10,380
Carbon Dioxide		2.2	2.3	1.7	1.3	1.3
Hydrogen			0.2			
Methane		97.7	97.4	98.1	98.5	98.5
Ethane		0.1	0.1	0.1	0.1	0.1
Propane		Tr	0.1	0.1	0.1	0.1
n-butane			Tr	Tr	Tr	Tr
i-butane			Tr	Tr	Tr	Tr
	Total	100.0	100.0	100.0	100.0	100.0

*Corrected for lost gas and altitude change.

Tr = Trace.

WHITMORE PARK NO. 2

Table 2 presents the updated desorption data obtained on Whitmore Park No. 2 coal samples. The samples with presently known weights show present values of methane content in cu ft/ton, which includes lost gas values, but not altitude change or residual gas values. The lost gas values as determined graphically are also included in Table 2. The helium densities, available from the rank analyses which are now only partially complete, will be used to calculate a value for the amount of gas to be added due to altitude change from the well site in Utah to Chicago, Illinois. Complete rank analyses on samples taken adjacent to samples sealed into containers are nearing completion and will be reported when available.

All of the samples have desorbed enough gas to allow at least two samples to be taken for component analysis. These data are shown in Tables 3, 4, and 5. Nearly all of these samples show greater than 95 mol % methane content. Each sample contains some carbon dioxide, which apparently gets less as the desorption continues. The diminishing carbon dioxide content reflects an increase in the methane content with time. There seems to be little indication at this point in the desorption process, that heavy hydrocarbons are beginning to show in the desorbed gases. Samples will continue to be taken whenever possible to monitor these gases.

O. P. Funderburk

Table 2. WHITMORE PARK NO. 2 — DESORPTION SAMPLES

Sample No.	Description	Depth, ft	Amount Desorbed,* cc	cu ft/ton	Lost Gas, cc	Complete
6	Sandstone	2560	475	--	--	Yes
7	Shale with Coal Stringer	2628	588	--	--	Yes
8	Coal Stringer	2664	5,116	--	1390	No
9	Coal Stringer	2688	9,643	--	1080	No
10	Lower Sunnyside	2714-2720	5,901	222	990	No
11†	Sunnyside Stringer	2703	11,537	397	3540	No
12	Rock Canyon	2864-2867.5	4,255	--	740	No
13	Stringer between Rock Canyon and Fish Creek	2876-2877.5	6,078	--	1340	No
14	Upper Rock Canyon Stringer	2862.5-2863	4,489	--	1175	No
15	Fish Creek (Carb)	2883	2,904	--	795	No
16	Gilson (Upper Zone)	2934-2937	6,236	279	800	No
17	Gilson (Lower Zone)	2434-2437	4,680	283	740	No

*Includes lost gas, but not altitude change.

†This sample was small and had been crushed in core barrel. It was not sampled until it had remained in the core tray for about 1 day in sub-freezing temperature. It is suspected that drilling mud froze on the outside, thus trapping gases from desorbing. The lost gas value in this instance may not be valid.

Table 3. WHITMORE PARK NO. 2 — GAS SAMPLES (Mol %)

Components		Sample No. 8A	8B	9A	9B	10B	10C
	Volume Desorbed, cc	4361	5116	6503	7758	2579	4452
Carbon Dioxide		3.3	1.4	4.8	3.9	4.3	4.1
Hydrogen		0.2		0.1			
Methane		96.0	98.2	94.6	95.5	95.2	95.5
Ethane		0.2	0.2	0.3	0.3	0.4	0.3
Propane		0.3	0.2	0.1	0.3	0.1	0.1
n-butane		Tr	Tr	0.1	Tr	Tr	Tr
i-butane			Tr		Tr	Tr	Tr
	Total	100.0	100.0	100.0	100.0	100.0	100.0

Tr = Trace.

Table 4. WHITMORE PARK NO. 2 — GAS SAMPLES (Mol %)

Components		Sample No. 11B	11C	12B	12C	13B	13C	14B	14C
	Volume Desorbed, cc	5710	10,362	3804	4275	3989	4838	4148	4489
Carbon Dioxide		4.8	3.3	2.4	2.6	2.2	2.7	1.9	1.6
Hydrogen		0.1				0.2		0.5	
Methane		94.9	96.3	97.0	97.1	96.7	96.7	96.7	97.2
Ethane		0.2	0.3	0.3	0.2	0.5	0.4	0.6	0.7
Propane		Tr	0.1	0.2	0.1	0.3	0.2	0.3	0.4
n-butane		Tr	Tr	0.1	Tr	0.1	Tr	0.1	0.1
i-butane					Tr	Tr	Tr	Tr	Tr
	Total	100.0	100.0	100.0	100.0				

Tr = Trace.

Table 5. WHITMORE PARK NO. 2 — GAS SAMPLES (Mol %)

	Sample No.					
	15A	15B	16A	16B	17A	17B
Volume Desorbed, cc	2399	2644	3535	4613	2725	3445
Components						
Carbon Dioxide	2.6	2.6	2.2	1.9	2.4	2.2
Hydrogen	0.6		0.2			
Methane	95.6	96.7	96.5	97.3	96.8	97.0
Ethane	0.6	0.4	0.5	0.4	0.4	0.4
Propane	0.3	0.3	0.4	0.4	0.3	0.3
n-btuane	0.1	Tr	0.1	Tr	Tr	0.1
i-butane	Tr	Tr	Tr	Tr	Tr	Tr
Total	100.0	100.0	100.0	100.0	100.0	100.0

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March 7, 1980

Mr. Larry Allred
Mountain Fuel Resources
36 South State Street
Suite 1540
Salt Lake City, Utah 84111

Re: Monthly Letter Report for February,
"Methane from Unmineable Coal Seams,"
IGT Project No. 65019

Dear Mr. Allred:

Desorption studies on all coal samples collected for this project have continued. These data show some of the samples to be completely desorbed, and thus ready for residual gas analyses. Table 1 contains all the data obtained to date on all samples collected. It will be noted that Whitmore Park No. 1 (W.P.#1) Sample 2 Gilson coal still is not completely desorbed and has desorbed a total gas content of 414 ft^3/ton. Also, the sandstone and shale samples taken from this well (Samples 1, 3, 4, and 5) have desorbed completely and the total amount desorbed is very small. Nothing more is planned for these shale and sandstone samples.

Samples taken from Whitmore Park No. 2 (W.P.#2) are shown as Samples 6 - 17. Samples 6 and 7 are sandstone, and shale with coal partings, respectively, and are similar to those from W.P.#1. Nothing more is planned. Samples 8 - 17 are the coal samples taken from W.P.#2 and these data are presented in Table 1. The weights have now been obtained on all samples. Table 1 lists these weights, which enabled the calculation of total gas desorbed in cu ft/ton which is also shown for each sample. Lost gas values were reported last month and are included here also. The corrections for the altitude change (Utah to Chicago) have been calculated for W.P.#2 samples and are also included in Table 1. The helium density values were obtained in the rank analyses which are now complete for all these samples. The rank analyses were done on samples taken adjacent to those sealed into containers.

The samples in Table 1 which appear to be completely desorbed are among those with the smallest amount of coal and with apparent high ash contents. It would be expected that these would be the first to completely desorb. For example, the lowest value, 185 ft^3/ton (Sample 15), was labeled as carbonaceous when sealed into the can. Also, the rank analysis of an adjacent sample shows a helium density of 1.53 and an ash content of more than 29%. The highest value shown is 429 ft^3/ton (Sample 11), however, this sample was not sealed into a container until after a day at subfreezing temperatures at wellsite in a core tray. The lost gas calculation which is extremely high in this case is considered to be in error. It is possible that frozen drilling mud in the outside pores during this long lost gas period prevented methane desorption.

The rank analyses for all W.P.#2 samples are presented in Table 2. In each case, except for Sample 8, these samples were taken adjacent to the one sealed in a container for desorption. A 2675' stringer sample was used for Sample 8. If necessary, those sealed in the cans could be submitted for rank analysis after the desorption is completed. Sample 18 is a sample taken from freshly mined coal obtained from the Soldier Creek Mine which is close to the Whitmore Park location. This represents an outcrop sample of the Rock Canyon seam and is only included for comparison.

The ASMT method of establishing rank was used for these samples. The rank of high volatile A bituminous was made since the criterion of $<$69% dry fixed carbon and a $>$31% volatile matter was met. However, the Btu qualification for this rank of $>$14,000 Btu/lb is only satisfied in two (Samples 14 and 16) of the samples with four others being borderline (Samples 9, 12, 13, and 17). This is apparently due to the high ash contents of the low Btu samples. The mineral matter (ash) in effect acts as a diluent in the Btu determination. These high ash contents are explained from the fact that coals are known to be nonhomogeneous and stringers and thin beds such as these are even more susceptible than others.

These samples contain very little mineral carbon such as carbonates as indicated by the analyses. Also, the hydrogen, nitrogen, oxygen, and sulfur contents seem to be normal, although two samples (14 and 15) have higher sulfur contents than the others.

In conjunction with the rank analyses, the oxidized ash content from each of these coals were analyzed by atomic absorption spectrophotometry for their major elements. These results are shown in Table 3. It can be seen that the ash contents ranged from a low of about 3% to a high of about 45%. Recoveries of from about 87% to 100% were indicated. The analyses show that the oxide of silicon, aluminum, and iron make up the bulk, however, in a few instances (low ash contents) there is also high calcium and sulfur oxides. The predominantly high silicon and aluminum contents would suggest the ash to be primarily shaly sand material. Small amounts of other elements are present in less quantities as indicated.

Future work will concentrate on finishing the desorption measurements with subsequent residual gas determinations. A vessel for the residual gas determination has been constructed and pressure tested. The sample, or portion thereof, of the sealed coal samples will be used for the residual gas determinations. If rank analyses are required, this too can be done on a portion of this sealed sample as well as adsorption-desorption isotherm determinations. Also, if plugs suitable for core analysis can be obtained on the one coal seam sample (W.P.#2 Gilson) available with large enough dimensions (3-1/2" dia.), then permeability tests will be conducted on those core plugs.

Very truly yours,

O.P. Funderburk

O. P. Funderburk
Senior Advisor
Reservoir Sample Analysis

OPF:jml

Table 1. WHITMORE PARK (W.P.) NO. 1 AND NO. 2 — DESORPTION STUDIES

Sample	Description	Depth, ft	Weight, g	Volume Desorbed, cc	Lost Gas, cc	Altitude Correction, cc	He Density, g/cc	CH_4 Content, ft^3/ton	Complete
1(W.P.#1)	Sandstone	2736	--	799	--	--	--	--	Yes
2(W.P.#1)	Gilson Coal	3099	849.6	10,997	1500	601	1.34	414	No
3(W.P.#1)	Sandstone	3092	--	129	--	--	--	--	Yes
4(W.P.#1)	Shale with Coal	3109	--	126	--	--	--	--	Yes
5(W.P.#1)	Shale	2718	--	723	--	--	--	--	Yes
6(W.P.#2)	Sandstone	2560	--	475	--	--	--	--	Yes
7(W.P.#2)	Shale with Coal	2628	--	588	--	--	--	--	Yes
8(W.P.#2)	Coal Stringer	2664	495.7	5,961	1590	770	1.44	385	†
9(W.P.#2)	Coal Stringer	2688	1408.0	10,678	1080	605	1.30	243	No
10(W.P.#2)	Lower Sunnyside	2714-20	848.8	6,807	990	726	1.56	257	No
11(W.P.#2)	Sunnyside Stringer	2703	930.6	12,464	3540	722	1.65	429	No
12(W.P.#2)	Rock Canyon	2864-67.5	600.4	5,002	740	747	1.33	267	†
13(W.P.#2)	Stringer	2876-77.5	657.1	7,141	1340	743	1.40	348	No
14(W.P.#2)	Upper Rock Canyon Stringer	2862.5-63	432.0	5,292	1175	773	1.30	392	†
15(W.P.#2)	Fish Creek (Carb.)	2883	641.3	3,698	795	754	1.53	185	†
16(W.P.#2)	Upper Gilson	2934-37	716.5	7,426	800	725	1.31	332	No
17(W.P.#2)	Lower Gilson	2934-37	528.0	5,774	740	764	1.41	350	No
18(W.P.#2)	Soldier Creek Mine	Rock Canyon Outcrop	--	--	--	--	--	--	--

† Desorption apparently complete.

Table 2. WHITMORE PARK NO. 2 —
SAMPLE NO. 8 — 2675 FT STRINGER

Proximate Analysis (He Density = 1.44 g/cc)

	Wt% (As Received)		
Moisture	1.6		
Volatile Matter	36.2	36.7 (Dry)	44.9 DAF
Ash	17.9		
Fixed Carbon	44.3		
Total	100.0		

Ultimate Analysis

	Wt% (Dry Basis)		
Ash	18.14		18.14
Carbon (Total)	64.70		
Organic Carbon		64.70	64.70
Mineral Carbon		0.00	
Hydrogen	4.73		4.73
Sulfur	0.70		0.70
Nitrogen	1.31		1.31
Carbon Dioxide		0.01	0.01
Oxygen (by Diff.)	10.42		10.41
Total	100.00		100.00

Gross calorific value = 11,538 Btu/lb

SAMPLE NO. 9 — 2688 FT STRINGER

Proximate Analysis (He Density = 1.30 g/cc)

	Wt% (As Received)		
Moisture	2.0		
Volatile Matter	42.2	43.1 (Dry)	45.9 DAF
Ash	6.0		
Fixed Carbon	49.8		
Total	100.0		

Ultimate Analysis

	Wt% (Dry Basis)		
Ash	6.08		6.08
Carbon (Total)	77.56		
Organic Carbon		77.43	77.43
Mineral Carbon		0.13	
Hydrogen	5.65		5.65
Sulfur	0.67		0.67
Nitrogen	1.59		1.59
Carbon Dioxide		0.49	0.49
Oxygen (by Diff.)	8.45		8.09
Total	100.00		100.00

Gross calorific value = 13,928 Btu/lb

Table 2, Cont. WHITMORE PARK NO. 2 —
SAMPLE NO. 10 — 2714-20 FT

(He Density = 1.56 g/cc)

Proximate Analysis	Wt% (As Received)		
Moisture	1.3		
Volatile Matter	28.8	29.2 (Dry)	46.6 DAF
Ash	36.8		
Fixed Carbon	33.1		
Total	100.0		

Ultimate Analysis	Wt% (Dry Basis)		
Ash	37.33		37.33
Carbon (Total)	50.33		
Organic Carbon		50.24	50.24
Mineral Carbon		0.09	
Hydrogen	3.83		3.83
Sulfur	0.38		0.38
Nitrogen	1.10		1.10
Carbon Dioxide		0.32	0.32
Oxygen (by Diff.)	7.03		6.80
Total	100.00		100.00

Gross calorific value = 8,888 Btu/lb

SAMPLE NO. 11 — 2703 FT

(He Density = 1.65 g/cc)

Proximate Analysis	Wt% (As Received)		
Moisture	1.1		
Volatile Matter	25.4	25.7 (Dry)	42.1 DAF
Ash	38.5		
Fixed Carbon	35.0		
Total	100.0		

Ultimate Analysis	Wt% (Dry Basis)		
Ash	38.94		38.94
Carbon (Total)	43.63		
Organic Carbon		43.58	43.58
Mineral Carbon		0.06	
Hydrogen	3.35		3.35
Sulfur	0.43		0.43
Nitrogen	0.98		0.98
Carbon Dioxide		0.21	0.21
Oxygen (by Diff.)	12.67		12.51
Total	100.00		100.00

Gross calorific value = 7793 Btu/lb

Table 2, Cont. WHITMORE PARK NO. 2 —
SAMPLE NO. 12 — 2864-67.5 FT

(He Density = 1.33 g/cc)

Proximate Analysis	Wt% (As Received)		
Moisture	1.6		
Volatile Matter	37.5	38.2 (Dry)	40.4 DAF
Ash	5.4		
Fixed Carbon	55.5		
Total	100.0		

Ultimate Analysis	Wt% (Dry Basis)		
Ash	5.52		5.52
Carbon (Total)	79.28		
Organic Carbon		79.11	79.11
Mineral Carbon		0.17	
Hydrogen	5.29		5.29
Sulfur	0.59		0.59
Nitrogen	1.59		1.59
Carbon Dioxide		0.63	0.63
Oxygen (by Diff.)	7.73		7.27
Total	100.00		100.00

Gross calorific value = 13,975 Btu/lb

SAMPLE NO. 13 — 2876-77.5 FT

(He Density = 1.40 g/cc)

Proximate Analysis	Wt% (As Received)		
Moisture	1.3		
Volatile Matter	37.8	38.3 (Dry)	45.5 DAF
Ash	15.6		
Fixed Carbon	45.3		
Total	100.0		

Ultimate Analysis	Wt% (Dry Basis)		
Ash	15.78		15.78
Carbon (Total)	68.74		
Organic Carbon		68.70	68.70
Mineral Carbon		0.40	
Hydrogen	5.04		5.04
Sulfur	0.79		0.79
Nitrogen	1.53		1.53
Carbon Dioxide		0.16	0.16
Oxygen (by Diff.)	8.12		8.00
Total	100.00		100.00

Gross calorific value = 12,323 Btu/lb

Table 2, Cont. WHITMORE PARK NO. 2 —
SAMPLE NO. 14 — 2862.5-63 FT

(He Density = 1.30 g/cc)

Proximate Analysis	Wt% (As Received)		
Moisture	1.2		
Volatile Matter	46.2	46.8 (Dry)	48.6 DAF
Ash	3.7		
Fixed Carbon	48.9		
Total	100.0		

Ultimate Analysis	Wt% (Dry Basis)		
Ash	3.74		3.74
Carbon (Total)	78.65		
Organic Carbon		78.55	78.55
Mineral Carbon		0.10	
Hydrogen	5.80		5.80
Sulfur	1.98		1.98
Nitrogen	1.61		1.61
Carbon Dioxide		0.36	0.36
Oxygen (by Diff.)	8.22		7.96
Total	100.00		100.00

Gross calorific value = 14,239 Btu/lb

SAMPLE NO. 15 — 2883 FT

(He Density = 1.53 g/cc)

Proximate Analysis	Wt% (As Received)		
Moisture	1.1		
Volatile Matter	31.7	32.0 (Dry)	45.5 DAF
Ash	29.3		
Fixed Carbon	37.9		
Total	100.0		

Ultimate Analysis	Wt% (Dry Basis)		
Ash	29.65		29.65
Carbon (Total)	55.83		
Organic Carbon		55.80	55.80
Mineral Carbon		0.03	
Hydrogen	4.05		4.05
Sulfur	3.68		3.68
Nitrogen	1.20		1.20
Carbon Dioxide		0.10	0.10
Oxygen (by Diff.)	5.59		5.52
Total	100.00		100.00

Gross calorific value = 10,193 Btu/lb

Table 2, Cont. WHITMORE PARK NO. 2 —
SAMPLE NO. 16 — 2934-37 FT

(He Density = 1.31 g/cc)

Proximate Analysis	Wt% (As Received)		
Moisture	1.7		
Volatile Matter	40.1	40.7 (Dry)	41.8 DAF
Ash	2.5		
Fixed Carbon	55.7		
Total	100.0		

Ultimate Analysis	Wt% (Dry Basis)		
Ash	2.49		2.49
Carbon (Total	80.76		
Organic Carbon		80.48	80.48
Mineral Carbon		0.28	
Hydrogen	5.49		5.49
Sulfur	0.58		0.58
Nitrogen	1.69		1.69
Carbon Dioxide		1.04	1.04
Oxygen (by Diff.)	8.99		8.23
Total	100.00		100.00

Gross calorific value = 14,311 Btu/lb

SAMPLE NO. 17 — 2934-37 FT

(He Density = 1.41 g/cc)

Proximate Analysis	Wt% (As Received)		
Moisture	1.3		
Volatile Matter	37.0	37.5 (Dry)	42.4 DAF
Ash	11.6		
Fixed Carbon	50.1		
Total	100.0		

Ultimate Analysis	Wt% (Dry Basis)		
Ash	11.71		11.71
Carbon (Total)	71.45		
Organic Carbon		70.77	70.77
Mineral Carbon		0.68	
Hydrogen	4.84		4.84
Sulfur	0.45		0.45
Nitrogen	1.46		1.46
Carbon Dioxide		2.47	2.47
Oxygen (by Diff.)	10.09		8.30
Total	100.00		100.00

Gross calorific value = 12,529 Btu/lb

Table 2, Cont. SOLDIER CREEK MINE —
OUTCROP ROCK CANYON COAL

(He Density = 1.28 g/cc)

Proximate Analysis	Wt% (As Received)		
Moisture	3.0		
Volatile Matter	40.6	41.8 (Dry)	43.9 DAF
Ash	4.6		
Fixed Carbon	51.8		
Total	100.0		

Ultimate Analysis	Wt% (Dry Basis)		
Ash	4.75		4.75
Carbon (Total)	77.45		
Organic Carbon		77.36	77.36
Mineral Carbon		0.09	
Hydrogen	5.38		5.38
Sulfur	0.44		0.44
Nitrogen	1.53		1.53
Carbon Dioxide		0.32	0.32
Oxygen (by Diff.)	10.45		10.22
Total	100.00		100.00

Gross calorific value = 13,702 Btu/lb

Table 3. WHITMORE PARK NO. 2
ASH ANALYSIS FOR MAJOR ELEMENTS

Sample No.	Depth, ft	SiO_2	Al_2O_3	Fe_2O_3	TiO_2	P_2O_5	CaO	MgO	Na_2O	K_2O	SO_3	Total	% Ash
8	2675	63.9	17.1	1.69	.9	N.D.	.63	.60	.21	1.7	.54	87.3	20.2
9	2688	51.0	18.2	4.37	1.0	N.D.	7.36	1.64	1.31	1.1	9.7	95.7	6.27
10	2714-20	70.3	17.5	1.18	1.0	N.D.	.85	2.34	.33	1.8	.95	96.2	37.6
11	2703	75.3	14.4	1.26	.7	N.D.	.40	.73	.23	2.2	.63	95.8	45.3
12	2864-67.5	56.4	10.1	3.23	.9	N.D.	9.80	1.93	1.48	.28	13.0	97.1	5.75
13	2876-77.5	66.1	22.6	.91	.7	N.D.	.87	.25	.33	.92	1.2	93.3	15.6
14	2862.5-63	27.9	14.1	34.6	.4	N.D.	6.72	1.02	1.50	.46	8.0	93.7	4.03
15	2883	73.7	8.28	10.7	.4	N.D.	.24	.23	.14	.14	.42	95.5	29.9
16	2934-37	14.7	11.7	8.29	.4	N.D.	26.0	5.11	1.59	.47	32.1	100.4	3.80
17	2934-37	25.1	16.4	5.49	.9	N.D.	18.0	3.87	.47	.27	18.6	89.1	14.5
Soldier Creek Mine	--	66.7	14.7	2.12	1.0	N.D.	4.16	1.17	1.08	.16	4.0	95.1	5.08

N.D. = Not Determined

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GENERAL PHONE 312/567-3650
TELEX 25-6189
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April 11, 1980

Mr. Larry Allred
Mountain Fuel Resources
36 South State Street
Suite 1540
Salt Lake City, Utah 84111

Re: Monthly Report for March 1980, "Methane From Unmineable Coal Seams," IGT Project No. 65019

Dear Mr. Allred:

Residual gas analysis procedures have been started for all desorption samples under test. Table 1 is a continuation of these desorption data from previous reports and includes the residual gas analyses for two samples (samples No. 8 and No. 10) that have completely desorbed. Three more samples have also completely desorbed, and these residual gas analyses are in progress. The desorption values in Table 1 show all the additions since last month's report.

Included in last month's report were all the rank analyses values for Whitmore Park No. 2 samples. Whitmore Park No. 1 Gilson coal had been presented in a previous report. Table 2 is included in this report to show and discuss the effects of some of the variables in rank analysis values on the methane content of coal. Because most of the gas is adsorbed on the internal surface of the micropores, the total methane content would be expected to become altered if this porosity was disturbed in any way. Apparently, this is exactly what happens when a sample of coal is diluted with other sedimentary matter or water. Because rank analyses are used to classify the coal, it is desirable to obtain at least a proximate analysis which gives such values as percent moisture, percent ash, percent volatile matter, and percent fixed carbon. The percent moisture and percent ash are the most critical factors with respect to diluting the methane content. Also, ultimate analyses are important when considering the organic makeup of the coal, such as carbon, hydrogen, sulfur, and oxygen contents.

In Table 2, only two of the samples are total methane contents (samples No. 8 and No. 10). The other samples are included in the "corrected" column at their present stage of desorption. It can be noted from the "measured" column that when the combined moisture plus ash content of the coals is high; it generally reflects a low total methane content. Accompanied with this is usually a higher helium density value, reflecting the presence of inorganic sedimentary matter. Sample No. 10 is a good example of this because the total ash plus moisture is 38.1% from the rank analysis. Helium density is 1.56 g/cc, and total measured methane content is 292 ft^3/ton. If this value is corrected to 5% total ash plus moisture (normal), the value is 378 ft^3/ton, which is more in line with other low ash samples. All the values in the "corrected" column assume ash plus moisture content of 5%. Samples No. 11 and No. 15 also should fit this category, but as explained in an earlier report, the Sample No. 11 values are probably high due to a large "lost gas" value which had to be assumed for this sample. Other samples (Samples No. 8, No. 13, and No. 17) apparently follow this same pattern although they were in the intermediate ash plus moisture contents. Again, the "corrected" values for these samples are more in line with actual values from low ash plus moisture samples. Samples No. 9 and No. 12 are two exceptions to the above category. The methane contents are too low for the low ash plus moisture contents. These can only be explained by nonhomogeneities in the samples taken for the two analyses. This nonhomogenous characteristic is an ever present problem when sampling coals and should always be given consideration.

The final column in Table 2 ("Estimated" methane content) is included for 4 samples only for comparison to the actual measured values. These values were calculated using rank analysis plus known depth of the samples using the following U.S. Bureau of Mines (U.S.B.M) adsorption equation:[1]

$$V = \left(\frac{100 - \%\ \text{Ash} - \%\ \text{Moisture}}{100}\right) \left(\frac{Vw}{Vd}\right) \left[k_o\ (.096h)^{n_o} - b\ \left(\frac{1.8h}{100} + 11\right)\right]$$

[1] Kim, Ann G. "Estimating the Methane Content of Bituminous Coal Beds From Adsorption Data," U.S. Bureau of Mines RI 8245, Pittsburgh, Pa., 1977.

This equation considers the effect of pressure, temperature, percent moisture, and percent ash from the rank analysis. The U.S.B.M. value of .75 was used for the ratio of volume of wet coal to volume when dry ($\frac{Vw}{Vd}$). The constants k_o and n_o were obtained from the rank data according to the U.S.B.M. procedure. These were determined for each sample and found to be only slightly different. The value of .14 was used as the temperature constant as determined by the U.S.B.M., and h was the depth of each sample in meters.

Only four samples were calculated by this procedure, two of which are completely desorbed (samples No. 8 and No. 10). These should give some indication as to the accuracy of the estimation calculation. Sample No. 8 showed 462 ft^3/ton measured versus 398 ft^3/ton estimated. Sample No. 10 showed 292 ft^3/ton measured versus 277 ft^3/ton estimated. These results are in fairly good agreement. Because total methane contents for the other samples were not available, they were not included. However, Sample No. 2, the deepest sample of the coals, and Sample No. 18, the shallowest of the samples, were included to show the effect of depth and temperature on the calculation. Sample No. 2 has measured to date 418 ft^3/ton, while the calculated value of 484 ft^3/ton was obtained. When this sample has completely desorbed and a residual gas value has been determined, it is expected to be in very good agreement with the calculated value.

From these results, it appears that by use of this adsorption equation, together with values from rank analyses of the coal and with depth or known pressure and temperature data, it is possible to make an estimation of in-place methane content of coal seams. The examples given show fair agreement between actual measured values and calculated values.

Sincerely

O. P. Funderburk

O. P. Funderburk
Senior Advisor
Reservoir Sample Analysis

OPF/cel

Attachments

Table 1. WHITMORE PARK (W.P.) NO. 1 and NO. 2 — DESORPTION STUDIES

Sample	Description	Depth, ft	Weight, g	Volume Desorbed, cc	Lost Gas, cc	Altitude Correction, cc	Residual Gas, cc	He Density, g/cc	CH_4 Content, ft^3/ton	Complete
1 (W.P. No. 1)	Sandstone	2736	--	799	--	--	--	--	--	Yes
2 (W.P. No. 1)	Gilson Coal	3099	849.6	11,092	1500	601	--	1.34	418	No
3 (W.P. No. 1)	Sandstone	3092	--	129	--	--	--	--	--	Yes
4 (W.P. No. 1)	Shale with Coal	3109	--	126	--	--	--	--	--	Yes
5 (W.P. No. 1)	Shale	2718	--	723	--	--	--	--	--	Yes
6 (W.P. No. 2)	Sandstone	2560	--	475	--	--	--	--	--	Yes
7 (W.P. No. 2)	Shale with Coal	2628	--	588	--	--	--	--	--	Yes
8 (W.P. No. 2)	Coal Stringer	2664	495.7	5,961	1590	770	586	1.44	426	Yes
9 (W.P. No. 2)	Coal Stringer	2688	1408.0	11,108	1080	605	--	1.30	253	No
10 (W.P. No. 2)	Lower Sunnyside	2714-20	848.8	6,962	990	726	770	1.56	292	Yes
11 (W.P. No. 2)	Sunnyside Stringer	2703	930.6	12,658	3540	722	--	1.65	435	No
12 (W.P. No. 2)	Rock Canyon	2864-67.5	600.4	5,002	740	747	--	1.33	267	†
13 (W.P. No. 2)	Stringer	2876-77.5	657.1	7,416	1340	743	--	1.40	362	No
14 (W.P. No. 2)	Upper Rock Canyon Stringer	2862.5-63	432.0	5,292	1175	773	--	1.30	392	†
15 (W.P. No. 2)	Fish Creek (Carb.)	2883	641.3	3,753	795	754	--	1.53	187	†
16 (W.P. No. 2)	Upper Gilson	2934-37	716.5	7,696	800	725	--	1.31	344	No
17 (W.P. No. 2)	Lower Gilson	2934-37	528.0	5,942	740	764	--	1.41	360	No
18 (W.P. No. 2)	Soldier Creek Mine	Rock Canyon Outcrop	--	--	--	--	--	--	--	--

†Desorption apparently complete.

TABLE 2

Sample	Desorption	Depth, ft	He Density, g/cc	% Moisture	% Ash	Total Methane Content, ft^3/ton		
						Measured	Corrected (2)	Estimated (4)
W.P. No. 1 SPL 2	Gilson Coal	3099	1.34	1.8	3.1	418	418	484
W.P. No. 2 SPL 8	Coal Stringer	2664	1.44	1.6	17.9	426 (1)	498	398
W.P. No. 2 SPL 9	Coal Stringer	2688	1.30	2.0	6.0	253	261 (3)	--
W.P. No. 2 SPL 10	Lower Sunnyside	2714-20	1.56	1.3	36.8	292 (1)	378	277
W.P. No. 2 SPL 11	Sunnyside Stringer	2703	1.65	1.1	38.5	435	665	
W.P. No. 2 SPL 12	Rock Canyon Coal	2864-67.5	1.33	1.6	5.4	267	272 (3)	--
W.P. No. 2 SPL 13	Stringer	2876-77.5	1.40	1.3	15.6	362	410	--
W.P. No. 2 SPL 14	Upper Rock Canyon Stringer	2862.5-63	1.30	1.2	3.7	392	396	--
W.P. No. 2 SPL 15	Fish Creek (Carb.)	2883	1.53	1.1	29.3	187	250	--
W.P. No. 2 SPL 16	Upper Gilson Zone	2934-37	1.31	1.7	2.5	344	344	--
W.P. No. 2 SPL 17	Lower Gilson Zone	2934-37	1.41	1.3	11.6	360	391	--
Soldier Creek Mine SPL 18	Rock Canyon Outcrop	--	1.28	3.0	4.5	--	--	175

(1) Total methane contents (includes residual gas).

(2) Corrected to 5.0% total moisture and ash content.

(3) Although low ash and moisture contents indicated, actual sample desorbing probably nonhomogenous.

(4) Calculated using U.S. Bureau of Mines adsorption formula for in-place estimation.

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GENERAL PHONE 312/567-3650
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May 8, 1980

Mr. Larry Allred
Mountain Fuel Resources
36 South State Street
Suite 1540
Salt Lake City, Utah 84111

Re: Monthly Report for April 1980, "Methane From Unmineable Coal Seams," IGT Project No. 65019

Dear Mr. Allred:

The desorption phase for all field samples taken during the drilling of Whitmore Park No. 1 and Whitmore Park No. 2 wells in Carbon County, Utah, has now been completed. These samples have been desorbing in sealed containers after being taken at the well site during October and November of 1979. Gas emissions from these samples were essentially complete although a few were still desorbing a small quantity of gas occassionally. The equipment used to desorb these samples was inexpensive and found to be adequate and reliable.

The values that are reported are total methane contents of the coal in place, which includes lost gas, desorbed gas, and residual gas. The residual gas was determined as a final stage of the desorption procedure. It was done by crushing the actual coal sample desorbed in the sealed container and measuring the amount of gas liberated after pulverizing. A special container, with steel balls inside with the coal, was used in conjunction with a paint can shaker to determine the residual gas. For samples that were still desorbing gas slowly, this gas was included in their residual gas values.

The complete desorption data are shown in Table 1. This same table was presented incomplete in last month's report. In that report, a column was included for a correction for altitude change, but in this table, the altitude

Table 1. WHITMORE PARK (W.P.) NO. 1 AND NO. 2 — DESORPTION STUDIES

Sample	Description	Depth, ft	Weight, g	Volume Desorbed,* cc	Lost Gas, cc	Residual Gas, cc	Total Gas, cc	CH_4 Content, cc/g	CH_4 Content, ft^3/ton
1 (W.P. No. 1)	Sandstone	2736	--	799	--	--	799	--	--
2 (W.P. No. 1)	Gilson Coal	3099	849.6	9,593	1500	678	11,771	13.9	443
3 (W.P. No. 1)	Sandstone	3092	--	129	--	--	129	--	--
4 (W.P. No. 1)	Shale with Coal	3109	--	126	--	--	126	--	--
5 (W.P. No. 1)	Shale	2718	--	723	--	--	723	--	--
6 (W.P. No. 2)	Sandstone	2560	--	475	--	--	475	--	--
7 (W.P. No. 2)	Shale with Coal	2628	--	588	--	--	588	--	--
8 (W.P. No. 2)	Coal Stringer	2664	495.7	4,621	1390	586	6,597	13.3	426
9 (W.P. No. 2)	Coal Stringer	2688	1408.0	10,168	1080	2737	13,985	9.9	318
10 (W.P. No. 2)	Lower Sunnyside	2714-20	848.8	5,972	990	770	7,732	9.1	292
11 (W.P. No. 2)	Sunnyside Stringer	2703	930.6	9,174	3540	1182	13,896	14.9	478
12 (W.P. No. 2)	Rock Canyon	2864-67.5	600.4	4,262	740	318	5,320	8.9	284
13 (W.P. No. 2)	Stringer	2876-77.5	657.1	6,141	1340	754	8,235	12.5	401
14 (W.P. No. 2)	Upper Rock Canyon Stringer	2862.5-63	432.0	4,117	1175	281	5,573	12.9	413
15 (W.P. No. 2)	Fish Creek (Carb.)	2883	641.3	2,958	795	0	3,753	5.9	187
16 (W.P. No. 2)	Upper Gilson	2934-37	716.5	6,986	800	889	8,675	12.1	387
17 (W.P. No. 2)	Lower Gilson	2934-37	528.0	5,272	740	657	6,669	12.6	404
18 (W.P. No. 2)	Soldier Creek Mine	Rock Canyon Outcrop	--	--	--	--	--	--	--

* Includes altitude correction.

correction is included in the "Desorbed Gas" column. This table shows that the residual gas quantities are different for each sample, which no doubt is due to the impurities in the samples as well as the stage of desorption when the residual gas values were obtained. A total methane content of greater than 400 ft^3/ton of coal is indicated in many of the samples. Again, the impurities, as shown previously in rank analyses, are having their effect on the gas content. The deepest and shallowest coal seams in the Whitmore Park No. 2 well were compared in their total gas contents, however, no correlation with depth was apparent. There was only about a 300-foot difference in these depths, so that difference is probably not detectable from the desorption data.

The Table 2 in last month's report showing some of the rank analysis values with methane contents obtained by measurement, after correction for high ash plus moisture contents and estimated by U.S. Bureau of Mines (U.S.B.M.) adsorption equation, has been included in this report also. The measured values are now the final ones, and the corrected values are now calculated from the final measured amounts. The estimated calculations by the U.S.B.M. equation have also now been completed for all the samples. The corrected values reflect considerable increases in the total amounts in the high ash plus moisture contents, but fail to bring all of them up to the 400 ft^3/ton level. A general observation from using the U.S.B.M. equation to calculate gas contents using rank analysis data is that the results are, in most cases, higher than the actual measured values.

Gas samples taken during the last stages of desorption on some of the samples have been collected and analyzed by mass spectrometer. There is little change in the gas composition from earlier samples. Residual gas samples were not taken due to the introduction of large quantities of air into the residual gas container, making an analysis unreliable.

Sincerely,

O. P. Funderburk

O. P. Funderburk
Senior Advisor
Reservoir Sample Analysis

OPF/cel

TABLE 2

Sample	Desorption	Depth, ft	He Density, g/cc	% Moisture	% Ash	Total Methane Content, ft^3/ton		
						Measured(1)	Corrected(2)	Estimated(4)
.P. No. 1 SPL 2	Gilson Coal	3099	1.34	1.8	3.1	443	443	484
.P. No. 2 SPL 8	Coal Stringer	2664	1.44	1.6	17.9	426	498	398
.P. No. 2 SPL 9	Coal Stringer	2688	1.30	2.0	6.0	318	328(3)	472
.P. No. 2 SPL 10	Lower Sunnyside	2714-20	1.56	1.3	36.8	292	436	277
.P. No. 2 SPL 11	Sunnyside Stringer	2703	1.65	1.1	38.5	478	730	321
.P. No. 2 SPL 12	Rock Canyon Coal	2864-67.5	1.33	1.6	5.4	284	290(3)	501
.P. No. 2 SPL 13	Stringer	2876-77.5	1.40	1.3	15.6	401	455	415
.P. No. 2 SPL 14	Upper Rock Canyon Stringer	2862.5-63	1.30	1.2	3.7	413	413	475
.P. No. 2 SPL 15	Fish Creek (Carb.)	2883	1.53	1.1	29.3	187	250	367
.P. No. 2 SPL 16	Upper Gilson Zone	2934-37	1.31	1.7	2.5	387	387	525
.P. No. 2 SPL 17	Lower Gilson Zone	2934-37	1.41	1.3	11.6	404	439	486
›ldier Creek Mine SPL 18	Rock Canyon Outcrop	--	1.28	3.0	4.5	--	--	175

l) Total methane contents (includes residual gas).

?) Corrected to 5.0% total moisture and ash content.

3) Although low ash and moisture contents indicated, actual sample desorbing probably nonhomogenous.

›) Calculated using U.S. Bureau of Mines adsorption formula for in-place estimation.

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GENERAL PHONE 312/567-3650
TELEX 25-6189
DIRECT DIAL 312/567- 5818

June 11, 1980

Mr. Larry Allred
Mountain Fuel Resources
36 South State Street
Suite 1540
Salt Lake City, Utah 84111

Re: Monthly Letter Report (May 1980)
"Methane From Unmineable Coal
Seams," IGT Project No. 65019

Dear Mr. Allred:

Last month's report included all the completed data on methane content by direct desorption of the coal samples under test. Previous reports also included the analyses of desorbed gases at different stages of their desorption and the routine coal rank and characterization analyses. A portion of these samples are being retained for any future characterization analyses that may be needed.

The work for this month has concentrated on testing the coal samples for other properties, particularly those that are needed for use in the computer simulation program for methane production. It should be noted at this point that most of the data remaining to be obtained require measurements made on specially prepared plugs taken from the coal samples. The only samples that are available which are sufficiently large enough for plugging is from limited pieces of 3-1/2 inch core from the Whitmore Park No. 2 Gilson seam. Adsorption-desorption isotherm data do not require plugs. However, if different size particles are tested for methane diffusion rates, a considerable amount of coal may be required to obtain a large enough quantity of each size for testing. Since the rank analyses, methane contents, and general characterization of all the different seams that were sampled have been found to be very similar, our efforts will be concentrated on the Gilson coal seam by necessity due to lack of sufficient samples of the others. Also, this Gilson seam is the thickest of those encountered and is scheduled to be the first seam to be individually tested for methane production.

A pulverized sample of Gilson coal was prepared for obtaining an equilibrium adsorption isotherm for methane adsorption. The preparation included a treatment for removing the last traces of gas and water vapor. This was accomplished by treatment in a vacuum oven at 130°C for 24 hours. The sample was removed from the oven and placed into a vacuum-pressure system that was equipped with sensitive pressure transducers for pressure measurements. Pure gases from high-pressure cylinders were used in the determination. Helium was used to determine volumes in the system by expansion and calculation by Boyles Law. The ideal gas equation was used to determine the amount of methane adsorbed in the coal at various pressures. It was found that even a pulverized sample of the coal required some equilibration time after each pressure was introduced. Six individual steps were used in which the pressure ranged from near zero to about 102 atmospheres, absolute (1500 psi). The ranges used and corresponding quantity of methane adsorbed are shown in Table 1. Figure 1, Curve 1, shows a plot of the isotherm.

These data indicate a characteristic equilibrium adsorption isotherm. The adsorption, which is rather steep at the lower pressures, begins to flatten out as the pressure increases. This is explained by the fact that as the pore system begins to fill with methane, the pressure must become greater and greater in order to adsorb less and less methane. It is interesting to note that at the final experimental pressure point (about 102 atmospheres or 1500 psi), the methane content was about 14.8 cm^3/g.

The amount of methane desorbed from the Whitmore Park No. 1 Gilson coal seam was 13.9 cm^3/g (443 SCF/ton). The hydraulic head on that coal seam was observed to be about 500 feet subsurface using an echometer. Assuming fresh water in the coal, reservoir pressure at the depth of sampling (3100 feet) is estimated to be —

$$(3100 - 500)\ 0.434 = 1128 \text{ psig.}$$

Figure 1 reveals very close agreement between the amount of methane actually desorbed from the sample and the value expected from the sample and the measured adsorption isotherm at a pressure of 1142 psia. It, therefore,

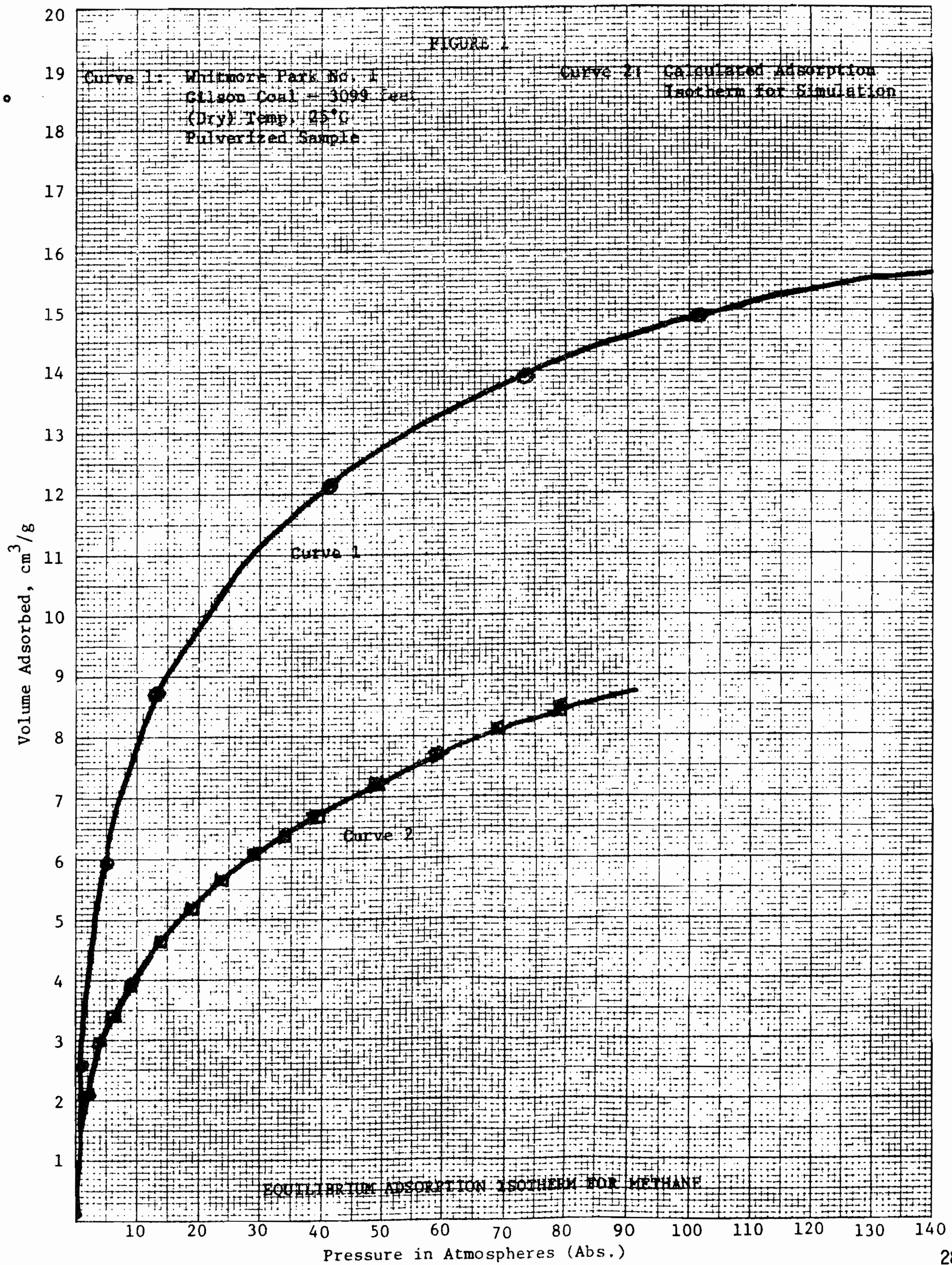
FIGURE 1
Curve 1: Whitmore Park No. 1
Gilson Coal - 3099 feet
(Dry) Temp. 25°C
Pulverized Sample
Curve 2: Calculated Adsorption
Isotherm for Simulation
Curve 1
Curve 2
EQUILIBRIUM ADSORPTION ISOTHERM FOR METHANE
Volume Adsorbed, cm3/g
Pressure in Atmospheres (Abs.)
20
19
18
17
16
15
14
13
12
11
10
9
8
7
6
5
4
3
2
1
10
20
30
40
50
60
70
80
90
100
110
120
130
140

appears that the Whitmore Park No. 1 Gilson seam contains the maximum possible amount of methane for its reservoir pressure.

Figure 1 also shows the isotherm assumed for prior computer simulation of Gilson coal seam production. This assumed isotherm was based upon prior USBM work as described in the Mountain Fuel Supply Phase I report. Comparison of the assumed and measured values reveals that the coal contains 67% more methane than previously assumed.

If the minimum bottom-hole pressure during production is 100 psia, as previously assumed for computer simulation, the maximum amount of producible methane will be 7.0 cm^3/g (224 SCF/ton) rather than the 5.0 cm^3/g (160 SCF/ton) deduced from the assumed isotherm. If a lower mean pressure in the coal seam can be achieved in practice, methane production will increase substantially. This is because half of the methane remains adsorbed on the coal at 100 psia.

Presently we are in the process of determining a desorption isotherm on the same pulverized sample as the adsorption work discussed above. This is not complete. It has been found that considerable time for desorption equilibrium is being required for each desorption step even using a pulverized sample. Also, some very minor modifications of the equipment to eliminate a small pressure restriction may be done before the desorption run is completed.

Sincerely,

O. P. Funderburk

O. P. Funderburk
Senior Advisor
Reservoir Sample Analysis

OPF/cel
Attachments

Table 1. WHITMORE PARK NO. 1 COAL (3100 Feet) ADSORPTION ISOTHERM — 25°C, PULVERIZED SAMPLE

Step No.	Pressure Range (Absolute)				Methane Content, cm^3/g
	Initial		Final		
	atm	psi	atm	psi	
1	0	0	2.3347	34.3	2.42
2	2.3347	34.3	6.3522	93.4	5.84
3	6.3522	93.4	13.8982	204.3	8.61
4	13.8982	204.3	41.6945	612.9	12.06
5	41.6945	612.9	74.7030	1098.1	13.81
6	74.7030	1098.1	102.3424	1504.4	14.81

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APPENDIX A

MOUNTAIN FUEL SUPPLY COMPANY
WHITMORE PARK WELL NO. 1
LEASE: FEE
SECTION 34, T.12S., R.12E., SLB & M, CARBON COUNTY, UTAH
10-POINT PLAN

1. The surface formation is Colton Formation.

2. The estimated tops of important geological markers:

Lower Sunnyside	2,890'	Gilson	3,098'
Rock Canyon	3,060'	Kenilworth	3,143'
Fish Creek	3,080'	Total Depth:	3,200'

(All above zones are coal seams which are the Black Hawk member of the Mesa Verde Formation)

3. Estimated depths of anticipated water, oil, gas or other mineral bearing formations that are expected to be encountered:

No water flows expected. No oil expected. Gas expected in above described coal beds.

The coal seams to be tested are defined as unminable coal.

4. The proposed casing program, including the size, grade and weight per foot of each casing string and whether new or used is:

Surface: 0-200'; 200'; 8-5/8"; 32#; K-55; 8rd THD; ST&C; NEW
Production: 0-3,200'; 3,200'; 4-1/2"; 116#; K-55; 8rd THD; ST&C; NEW

5. Operators minimum specifications for pressure control equipment requires a 10-inch, 3000 psi double gate blowout preventer with 4-1/2" pipe rams in the bottom and blind rams in the top, and a 10-inch 3000 psi rotating preventer from 200' to total depth. See attached diagram. Blowout preventers will be tested by rig equipment after each string of casing is run.

6. Air will be used to drill the well from 0' to total depth. If air drilling is not feasible, a water gel base mud system will be used.

7. Auxiliary equipment will consist of: (1) A manually operated kelly cock; (2) A Baker float at bit; (3) No monitoring equipment for mud system (air drill); (4) Full opening Shafer floor valve manually operated.

8. No drill stem tests. Coring from 2,890' to 3,150'.
Logging: DIL Sonic Density Gamma Ray Neutron from bottom of surface casing to total depth.

The well stimulation will consist of a foam frac with approximately 30,000 gallons liquid and approximately 70,000 pounds of sand, 20-40 mesh.

9. No abnormal pressures expected. No abnormal temperatures expected. No H_2S expected.

10. Anticipated spud date is approximately September 10, 1979. Duration of drilling operations are expected to be approximately five days. Stimulation and completion to last approximately 30 days.

DEVELOPMENT PLAN FOR U.S.G.S. APPROVAL OF SURFACE USE
MOUNTAIN FUEL SUPPLY COMPANY DRILLING WELLS

Well Name - Mathis Canyon Well No. 3

Field or Area - Carbon County, Utah

1. Existing Roads -
   A) Proposed well site as staked - Refer to well location plat no. M-13672, well pad layout map no. M-13673 and area map no. M-13677 for location of well, access road, cuts and fills, directional reference stakes, etc.
   B) Route and distance from nearest town or locatable reference point to where well access route leaves main road - Refer to area map no. M-13677 From the well to Price, Utah is 14 miles.

   C) Access road to location - Refer to well location plat no. M-13672 and area map no. M-13677 for access road. (Color coded red for existing road and blue for road to be constructed.)

   D) If exploratory well, all existing roads within a 3-mile radius of well site - Refer to area map no. M-13677. This well is an experimental well. The coal seams will be stimulated for the purpose of withdrawing methane.

   E) If development well, all existing roads within a 1-mile radius - Not a development well.

   F) Plans for improvement and/or maintenance of existing roads - An existing road as shown on area map No. M-13677 will be used for the wells access.

2. Planned Access Road - An existing road to be used for access.
   A) Width - 16' wide from shoulder to shoulder.

   B) Maximum grade - The maximum grade on the road is 12 percent.

   C) Turnouts - No turnouts will be constructed.

   D) Drainage design - A drainage ditch on the uphill side of the road will be constructed. It will be a minimum of one foot below the surface of the road. No water diversion ditches are anticipated.

   E) Location and size of culverts and description of major cuts and fills -
   1) No culverts required. A Kansas crossing will be used on Willow Creek. The existing road was constructed to allow water drainage.
   2) No new roads or existing roads to be constructed. The existing road has several side hill cuts.

   F) Surfacing material - None anticipated.

   G) Necessary gates, cattle guards or fence cuts - None required.

H) New or reconstructed roads - No new roads required.

3. Location of Existing Wells - Refer to area map no. M-13677

A) Water wells - None within the area.

B) Abandoned wells - An abandoned well is located on the north line of Section 27, as shown on the area map.

C) Temporarily abandoned wells - None within the area.

D) Disposal wells - None within the area.

E) Drilling wells - None within the area.

F) Producing wells - None within the area.

G) Shut-in wells - None within the area.

H) Injection wells - None within the area.

I) Monitoring or observation wells for other resources - Several coal core holes are located within the area.

4. Location of Existing And/Or Proposed Facilities - Refer to area map no. M-13677

A) 1) Tank batteries - None within the area.

2) Production facilities - None within the area.

3) Oil gathering lines - None within the area.

4) Gas gathering lines - None within the area.

5) Injection lines - None within the area.

6) Disposal lines - None within the area.

B) 1) Proposed location and attendent lines by flagging if off the well pad - None to be installed. The gas will be flared during testing operations. If the project does prove to produce enough gas to justify a pipeline, then a pipeline will be dealt with under formal right-of-way.

2) Dimensions of facilities - Refer to drawing No. M-13680 for proposed testing facilities.

3) Construction methods and materials - All on-location line will be surface. The separator will be a prefabricated unit. The flare stake will be anchored. The sump pit will be installed as described in Part 4.

4) Protective measures and devices to protect livestock and wildlife

All sump pits will be fenced. The fence shall be woven wire at least 48-inches high and within 4-inches of the ground. If oil is in the sump pit, the pit will be overhead flagged to keep birds out.

C) Plans for rehabilitation of disturbed area no longer needed for operations after construction is completed - Areas of none use will be restored and reseeded as recommended by the B.L.M.

5. Location and Type of Water Supply -

A) Location of water - Willow Creek - Point of diversion will be the SW 1/4 NE 1/4 Section 21, T.12S., R.10E.

B) Method of transporting water - To be hauled by tank truck.

C) Water well to be drilled on lease - None

6. Source of Construction Material - None anticipated.

A) Information -

B) Identify if from Federal or Indian land -

C) Where materials are to be obtained and used -

D) Access roads crossing Federal or Indian lands -

7. Method for Handling Waste Disposal -

A-D) Cuttings and drilling fluids will be placed in the mud pit. Any produced liquids will be placed in test tanks and hauled out by tank trucks. A chemical toilet will be installed on the well pad. The mud pit shall be constructed with at least 1/2 of its holding capacity below ground level. It shall be fenced as described in Section 10-A.

E) Garbage and other waste material will be placed in the burn pit and covered over with wire mesh to contain the garbage.

F) After drilling operations have been completed, the location will be cleared of litter, and the trash will be burned in the burn pit. The burn pit will be covered over. The mud pit liquids will be allowed to evaporate. Any fill material on the mud pit will be compacted with heavy equipment.

8. Ancillary Facilities - No camps or airstrips exist now, and Mountain Fuel Supply Company has no plans to build them.

9. Well Site Layout - Refer to drawing no. M-13673

1) Refer to drawing no. M-13674 for cross section of drill pad and mud pit with cuts and fills.

2, 3) Refer to the location plat for location of mud tanks, reserve pit, burn pit, pipe racks, living facilities, soil material stockpile, rig orientation, parking areas and access roads.

4) The mud pit is to be unlined. The drilling fluids in the reserve pit will be hauled off and disposed of at an acceptable site.

10. Plans for Restoration of Surface -

A) After drilling operations, the well site will be cleared and cleaned and the burn pit filled in. Should the well be a dry hole, the surface will be restored to the extent that it will blend in with the landscape. Prior to the onset of drilling, the mud pit shall be fenced on three sides. Immediately upon completion of drilling, the fourth side of the pit will be fenced. The fence will be maintained until restoration.

B) Revegetation and rehabilitation of the location and access road will be done to comply with Bureau of Land Management recommendations.

C) Prior to rig release, pits will be fenced and so maintained until clean up. The trash pit will be dug so when filled, the depth will be at least three-feet below the finished contour of the location.

D) If oil is in the mud pit, overhead flagging will be installed to keep birds out.

E) Clean up will begin within two months after drilling operations have been completed and the land will be restored at this time.

11. Other Information -

A) The location lies adjacent to an existing road near the bottom of Mathis Canyon. The soil is clay and sandstone. The vegetation is grass and Juniper trees.

B) The surface is U. S. Government. A portion of the existing access road crosses Fee lands belonging to Pete Bottino.

C) Water can be located in Willow Creek approximately 0.4 miles west of the well site. No archaeological, cultural or historical sites exist within the area to my knowledge. No occupied dwellings are within the area.

12. Lessee's or Operator's Representative -

A. J. Maser, Drilling Superintendent, P.O. Box 1129, Rock Springs, Wyoming 82901, Telephone No. 307-362-5611.

13. Certification -

I hereby certify that I, or persons under my direct supervision, have inspected the proposed drill site and access route; that I am familiar with the conditions which presently exist; that the statements made in this plan are, to the best of my knowledge, true and correct; and, that the work associated with the operations proposed herein will be performed by Mountain Fuel Supply Company and its contractors and sub-contractors in conformity with this plan and the terms and conditions under which it is approved.

Date 6/7/79

Name A. J. Maser

Title Drilling Superintendent

APPENDIX B

The Proposed Whitmore Unit

The proposed Whitmore Unit is located in the western end of an imposing physiographic feature known as the Book Cliffs which is 185 miles in length. The southern unit boundary is approximately 10 miles north of Price, Utah in Carbon County (T12S; R9-11E). The proposed unit is based on methane contained in known coal formations within the Book Cliffs Coal Field. Recovery of methane gas from two wells is presently underway to the southeast of the proposed unit area. The unit outline is based on projected depth to coal contours between 2,000 feet and 3,500 feet. Projections are made from seismic and topographic map data, coal data from nearby mines, and well data. Topographically, the area is characterized by precipitous cliffs with elevations ranging from 7,200 feet to 8,750 feet within the proposed unit. The major drilling objectives of the Whitmore Unit are the coal-bearing strata mainly in the Upper Cretaceous Blackhawk Formation.

Structure

Regionally, the Whitmore area is located on the southwestern flank of the Uinta Basin Syncline. Major structural elements are located to the south and southeast of the area and consist of the San Rafael and Uncompahgre Uplifts. Seismic data, well control and surface mapping reveal that only regional north dip is present throughout most of the proposed Whitmore Unit. These data indicate a dip of approximately 5½ degrees or 500 feet per mile. In some areas to the east of the proposed unit, a dip of up to 8 degrees has been measured on the surface. A few faults are known to exist, but generally have displacements of less than 25 feet and should be of little consequence in the development of the Whitmore Unit.

Stratigraphy

The proposed unit well is designed to test the methane potential of the coals in the Cretaceous Blackhawk Formation of the Mesaverde Group. The well will spud in the Tertiary North Horn Formation, and will penetrate (in descending order) the following formations in the Mesaverde Group: (1) Price River Formation (sands and shales with minor coal); (2) Castlegate Sandstone (sandstone with minor shale); and (3) Blackhawk Formation (littoral and lagoonal deposits of sand stones, shales and major coal seams).

The Blackhawk Formation was deposited in a progradational sequence in a deltaic environment of deposition in Upper Cretaceous time. Regionally, the Blackhawk Formation can be grossly characterized as being predominantly non-marine fluvial in the Wasatch Plateau area and marine in the eastern part of the Book Cliffs.

Across the Whitmore Unit area the Blackhawk Formation should consist of an upper delta plain sequence in the west and a lower delta plain sequence in the east. Coals in the upper delta plain tend to parallel depositional dip, are laterally discontinuous, and occur as pod-shaped bodies. The coals deposited in the upper delta plain accumulated on the flood plains adjacent to coexisting meandering channels. Coals formed in this environmental setting display abrupt variations in thickness over short lateral distances, and have numerous splits that occur near channel levees.

Coals deposited in the lower delta plain are also elongate parallel with depositional dip. This trend exists because the only sites where peat swamps can develop are on the narrow, poorly developed. levees along the distributary channels. The river-dominated lower delta-plain channels generally are straight and prograde seawead in the direction of depositional dip. For this reason, the coals that develop in this environment are continuous laterally in the depositional dip direction, but discontinuous parallel with depositional strike. Seams within the lower delta plain commonly are relatively thin and contain numerous splits. The splits are caused by bay-fill deposits (crevasse splays) that breached the poorly developed levees along the distributary channels.

In summary, the coals that are present within the proposed Whitmore Unit are generally thicker, but more laterally discontinuous in the western part of the proposed unit than in the eastern part. Additionally, the coal seams should also display a vertical change. The coal in the upper part of the Blackhawk Formation should be more characteristic of the upper delta-plain environment. The lower delta-plain coals should generally occur stratigraphically lower in the Blackhawk Formation.

Unit Basis

The basis for the proposed Whitmore Unit was established for coals between the depths of 2,000 and 3,500 feet within the Blackhawk Formation. Coals between these depths afford the best prospect for recovering economic quantities of methane gas from coalbeds in this area. Methane is contained in these coals and is adsorbed on the micropore surface of the coal. The degree of adsorption is dependent upon the rank of the coal and the depth of the coal. Samples of the Gilson Coalbed from Mountain Fuel Supply Company's Whitmore Park No. 2 well were examined to determine the degree of adsorption vs. pressure or coal depth (Appendix 1). According to these tests, the minimum target coal depth should be approximately 2,000 feet (Appendix 2). The amount of methane adsorbed into the Gilson coal increased for depths below 2,000 feet but at a decreasing rate. That is, each successive increase in coal depth results in a proportionately smaller increase in adsorbed methane. Therefore, recovery of methane from coals at deeper depths becomes progressively less attractive as increased drilling costs are not justified by increased production. The 3,500 foot coal depth is believed to be the lower depth limit for economic recovery of methane from coals within the Whitmore Unit (Appendices 3-5). The 3,500 foot depth limit is based upon the coal rank and adsorption characteristics of the Blackhawk Formation Coals.

Contours of depth to the uppermost coalbed were developed. The boundaries for the proposed unit were then set on the south by the 2,000 foot contour and on the north by the 3,500 foot depth contour. Several coalbeds exist throughout this unit and are spread over a 700 foot thick interval on the western end of the unit and over a 400 foot thick interval on the east.

Besides the methane content of coals, the total coal thickness is a factor in establishing a large enough gas reserve to recover gas economically. Data indicates a minimum total thickness of 40 feet of coal is required within the Blackhawk Formation to make the recovery of methane economically feasible. The minimum thickness is based upon approximately 359 cf/ton gas content as measured by Mountain Fuel Supply Company on Blackhawk Coalbeds near the proposed unit. Verification of the minimum coal thickness and adsorbed methane content has been established at the Whitmore Park No. 2 well. The 13 foot thick Gilson coal seam produced approximately 20 mcfd during an initial flow test.

Extensive data have been published by H. H. Doelling[1] which show coalbed thicknesses in mining areas near the coal outcrop, from one to three miles south of the proposed unit. These data were used to project a minimum coal thickness of 40 feet along the western unit boundary.

Summary

Two east-to-west trending depth to coal contours define the north and south boundaries of the proposed Whitmore Unit. The unit outline includes all full and half sections intersected by these contours. The southern unit boundary is based upon the 2,000 foot depth to coal contour. The northern boundary limit is the 3,500 foot contour. The western boundry is limited to a minimum projected coal thickness of 40 feet and severe topographic changes that would interfere with the access to economically drillable locations. Several major canyons immediately to the west of the proposed unit would be environmentally and logistically difficult to develop if included within the unit.

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[1] H. H. Doelling, Central Utah Coal Fields: Sevier-Sanpete, Wasatch Plateau, Book Cliffs and Emery (Utah Geological and Mineralogical Survey, Monograph Series No. 3, 1972), page 571.

The eastern boundary of the proposed unit is set on the basis of the minimum amount of coal thickness that can be projected from well data and measured sections.

To evaluate the proposed Whitmore Unit, a well will be drilled to test the Blackhawk Formation coalbeds in the SE¼ NE¼ of Sec. 17-T12S-R11E. The total depth of the proposed unit well will be 3,500 feet. Future drilling within the proposed unit will be contingent upon the results of the initial well.

Respectfully submitted this _____ day of June, 1981.

By ________________________________
G. G. Francis
Western Division
Exploration Manager
Mountain Fuel Supply Company

APPENDIX 1

SUMMARY OF CORE SAMPLE DESORPTION DATA

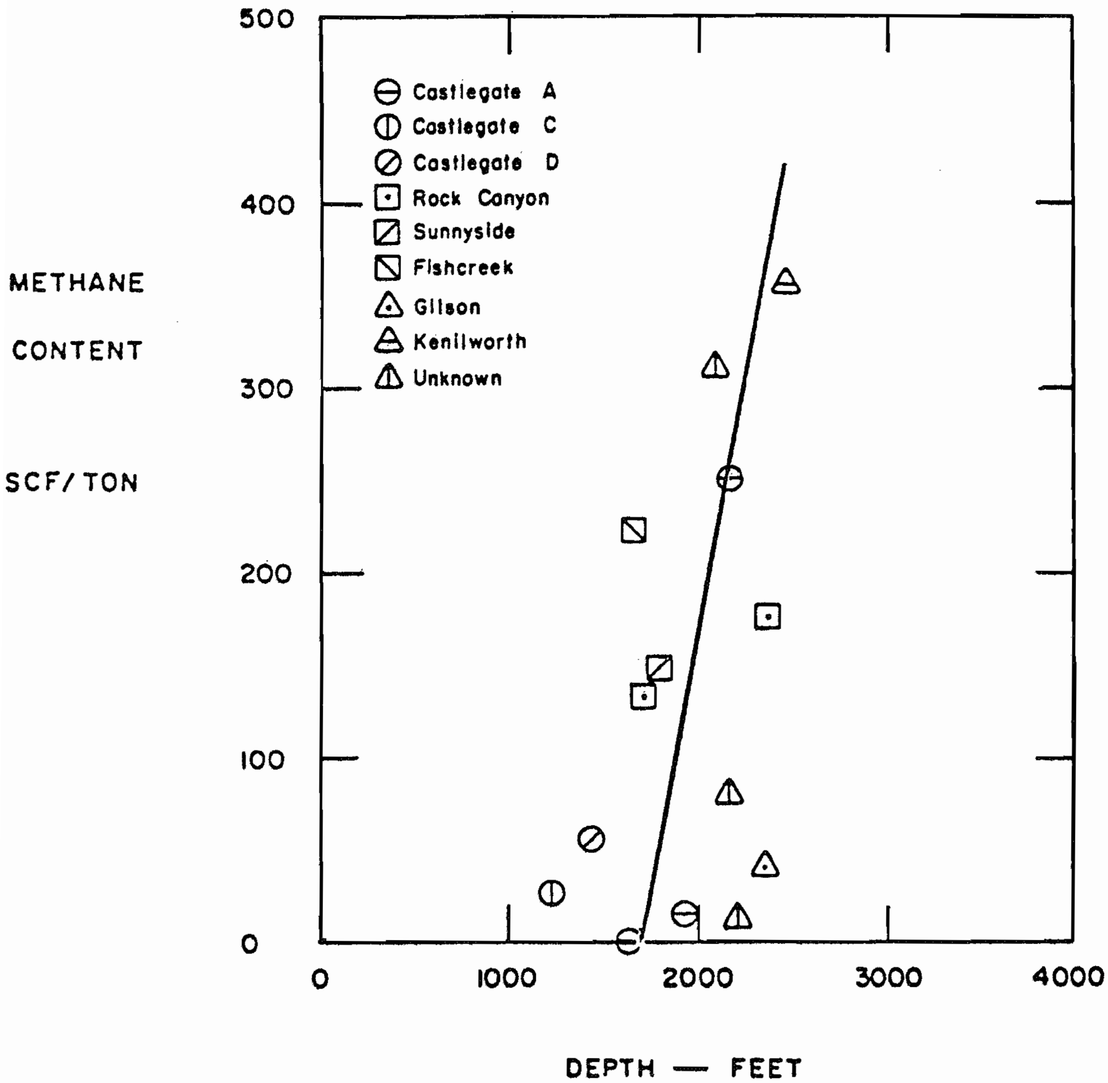
Coal Seam	Location	Depth Feet	Laboratory	Total Gas Desorbed cc/Gm	Total Gas Desorbed cu.ft./ton
Subseam 1	12S,9E,Sect.29	2,083	UGMS	9.9	317
Subseam 2	12S,9E,Sect.28	1,435	UGMS	8.4	269
Castlegate A	12S,9E,Sect.28	2,641	UGMS	8.9	285
Castlegate A	12S,9E,Sect.28	2,655	UGMS	9.4	301
Kenilworth	12S,9E,Sect.33	785	UGMS	6.6	211*
Unnamed	12S,10E,Sect.34	2,080	UGMS	6.1	195*
Castlegate A	12S,10E,Sect.34	2,558	UGMS	5.9	189*
Castlegate C	12S,10E,Sect.27	3,176	UGMS	11.0	353
Kenilworth	12S,10E,Sect.27	3,291	UGMS	10.6	340
Kenilworth	12S,10E,Sect.26	2,449	UGMS	10.9	350
Sunnyside	13S,12E,Sect.4	1,798	UGMS	4.8	152*
Rock Canyon(u)	13S,12E,Sect.4	2,339	UGMS	2.8	89*
Rock Canyon(L)	13S,12E,Sect.4	2,352	UGMS	5.4	172*
Coal Stringer	12S,12E,Sect.34	2,664	IGT	13.3	426
Sunnyside	12S,12E,Sect.34	2,703	IGT	12.7	406
Lower Sunnyside	12S,12E,Sect.34	2,714-20	IGT	9.1	292
Sunnyside	12S,12E,Sect.34	2,720	UGMS	5.3	169*
Rock Canyon	12S,12E,Sect.34	2,863	IGT	12.9	413
Rock Canyon	12S,12E,Sect.34	2,865	MFR	10.8	345
Rock Canyon	12S,12E,Sect.34	2,867	MFR	12.6	403
Fish Creek	12S,12E,Sect.34	2,877	IGT	12.5	400
Gilson	12S,12E,Sect.34	2,934	MFR	10.5	335
Gilson	12S,12E,Sect.34	2,935	UGMS	6.7	216*
Gilson	12S,12E,Sect.34	2,934-7	IGT	12.1	387
Gilson	12S,12E,Sect.34	2,934-7	IGT	12.6	403
Gilson	12S,12E,Sect.34	3,097	UGMS	6.6	212*
Gilson	12S,12E,Sect.34	3,099	IGT	13.9	443

Avergae Gas Content Without Questionable Data = 359

*Questionable Data Due to Leaking Containers

APPENDIX 2

Correlation of UGMS Gas Content Data for Blackhawk Coals



APPENDIX 3

Volumetric Calculation of Gas in Place in the Blackhawk Formation Coal Seam, Proposed Whitmore Unit, Carbon County, Utah.

Given

Average Coal Seam Depth	3,000 feet
Net Pay Thickness	40 feet
Productive Area	80 acres
Weight of Coal	82.5 lb./cf
Gas Content	359 scf/ton
Water Saturation	100%
Gas Gravity	.60
Reservoir Temperature	75° F
Percent Gas Recoverable	15%

Solve for Gas in Place

G_v = 43,560 x 80 acres x 40 ft. x 82.5 lbs./cf x ton/2,000 lbs. x 359 scf/ton

G_v = 2,064,221 MCF

Solve for Recoverable Gas

G_r = (2,064,221) (.15)

G_r = 309,633 MCF

APPENDIX 4

ECONOMIC ANALYSIS FOR 2,500 FOOT WELL
(Most Likely Case)

Given

Number of Years of Analysis	15 years
First Year of Evaluation and Production	1981
Total Gas Reserves	2,064 MMCF[1]
Recoverable Reserves	310 MMCF[2]
1981 Primary Gas Price	$6.50/MCF
Total Tangible Investments	$103,200
Total Intangible Investments	$239,800
Salvage Value	$5,400[3]
General and Administrative Expenses	$1,000 per year
Operating Cost	18% of revenues
Advalorem Tax Rate	1.5%
Severance Tax Rate on Gas	4.0%
Federal Income Tax Rate	47.67%
Depreciable Life on Equipment	10 years
Investment Tax Credit	10%
Discount Rate	16%
Escalation on Prices and Costs	10% per year

Results

Net Present Value of Pre Tax Cash Flow	$168,279
Present Worth After Tax Cash Flow	$70,935
Before Tax Discounted Cash Flow Rate of Return	24.89%
After Tax Discounted Cash Flow Rate of Return	22.09%[4]
Discounted Profit/Investment	0.19
After Tax Discounted Profit/Investment	1.67
After Tax Return on Investment	2.67
Maximum Negative Cash Flow	-$165,112
Payout	5.70 years
Gross Gas Produced	140.087 MMCF
Net Interest Gas	122.576 MMCF
Net Revenue Gas	$1,578,943
Operating Cost	$49,971
General and Administrative Costs	$31,772
Local Taxes	$86,842
Depreciation	$97,800
Total Deductions	$506,184
Capital Investment	$337,600
Pre Tax Cash Flow	$1,072,752
Federal Income Tax	$501,063
After Tax Cash Flow	$571,694

---

1 See Appendix 3

2 See Appendix 3

3 40% of compressor and dehydrator capital costs prorated for one of 55 total wells.

4 Mountain Fuel Supply Company required rate of return is 16%.

APPENDIX 5

ECONOMIC ANALYSIS FOR 3,500 FOOT WELL
(Economic Limit Case)

Given

Number of Years of Analysis	15 years
First Year of Evaluation and Production	1981
Total Gas Reserves	2,064 MMCF[1]
Recoverable Reserves	310 MMCF[2]
1981 Primary Gas Price	$6.50/MCF
Total Tangible Investments	$126,434
Total Intangible Investments	$346,566
Salvage Value	$5,400[3]
General and Administrative Expenses	$1,000 per year
Operating Cost	18% of revenues
Advalorem Tax Rate	1.5%
Severance Tax Rate on Gas	4.0%
Federal Income Tax Rate	47.67%
Depreciable Life on Equipment	10 years
Investment Tax Credit	10%
Discount Rate	16%
Escalation on Prices and Costs	10% per year

Results

Net Present Value of Pre Tax Cash Flow	$65,822
Present Worth After Tax Cash Flow	$13,474
Before Tax Discounted Cash Flow Rate of Return	18.56%
After Tax Discounted Cash Flow Rate of Return	16.87%[4]
Discounted Profit/Investment	0.03
After Tax Discounted Profit/Investment	1.18
After Tax Return on Investment	2.18
Maximum Negative Cash Flow	-$237.127
Payout	6.83 years
Gross Gas Produced	140.087 MMCF
Net Interest Gas	122.576 MMCF
Net Revenue Gas	$1,578,943
Operating Cost	$49,971
General and Administrative Costs	$31,772
Local Taxes	$92,886
Depreciation	$121,034
Total Deductions	$645,705
Capital Investment	$467,600
Pre Tax Cash Flow	$1,043,127
Federal Income Tax	$484,615
After Tax Cash Flow	$588,512

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1 See Appendix 3

2 See Appendix 3

3 40% of compressor and dehydrator capital costs prorated for one of 55 total wells.

4 Mountain Fuel Supply Company required rate of return is 16%.

APPENDIX C

API #: 43-007-30045

Projected depth:
3200' Kenilworth (WC)

Whitmore Park Well No. 1
Wexpro Company, Operator
Lease No.: Fee
532' FNL, 1701' FEL
NW NE 34-12S-12E
Carbon County, Utah
Ground elevation 7398'

Permit No.: 43-007-30045
June 18, 1979

Drilling contractor: Veco Drilling Company - Rig No. 1

SPUDDED OCTOBER 5, 1979 at 8:00 p.m.

October 6, 1979:
Depth 200', 200', day 1, pump 175, table 65, wt on bit 5 tons, water, bit #1, 12¼" dgh cut 200' from 0' to 200' in 9-3/4 hours, survey 133' 0°, lost time 14¼ hours--¼ rig service and survey; 14 drill rat hole, rig up water pump and prepare to spud. Drilling.

October 7, 1979:
Depth 215', 15', days 2, pump 200, table 60, wt on bit 5 tons, mud wt 8.9, vis 36, bit #1 12¼" dgh cut 15' from 200' to 215' in 1½ hours, survey 215' ¼°, lost time 22½ hours--½ survey; 1 trip out; 1 rig up and run 5 jts 8-5/8", 32#, K-55, ST&C casing, landed at 210.21'; 1 circulate and cement casing with 150 sacks of regular G cement treated with 5% D-43A, cement in place at 10:45 a.m. on October 6, 1979; 6 WOC; 11 nipple and drill with air; 1 test BOP to 1000#, held OK. Drilling cement.

October 8, 1979:
Depth 677', 462', days 3, air 210, table 65, wt on bit 10 tons, bit #2, 7-7/8" f3 cut 462' from 215' to 677' in 15 hours, lost time 9 hours—4½ wait on welder, repair goose neck on swivel; 3½ repair air booster; 1 drill cement. Drilling.

October 9, 1979:
Depth 818', 141', days 4, pump 600, table 65, wt on bit 10 tons, mud wt 9.5, vis 70, sand ¼%, wl 4, fc 1/32, ph 12, solids 12.5, bit #2, 7-7/8" f3 cut 141' from 677' to 818' in 7½ hours, survey 750' ¼°, lost time 16½ hours--13-3/4 water flow at 770', 45# psi surface pressure, tripped out, changed jets in bit, rigged up flow line, mix mud and mud up to 10 ppg; 1 trip in; 1 work on pumps; ½ kill water flow, lost 70 barrels of 10 ppg mud, flow starts at 9.5 ppg. Drilling.

October 10, 1979:
Depth 1090', 272', days 5, pump 700, table 65, wt on bit 10 tons, mud wt 9.6, vis 47, sand ¼%, wl 10, fc 2/32, ph 9, solids 8.5, LCM 15%, bit #2, 7-7/8" f3 cut 272' from 818' to 1090' in 22 hours, lost time 2 hours--2 mix mud, LCM and kill water flow. Drilling.

CASING REPORT

Landed 8-5/8" OD, 32#, K-55, ST&C casing at 210.61' KBM, set with 150 sacks regular G treated with 5% D-43A, returned 5 barrels cement to surface, cement in place at 10:45 a.m. on October 6, 1979.

October 11, 1979:
Depth 1351', 261', days 6, pump 350, table 65, wt on bit 20 tons, mud wt 9.6, vis 40 sand 1%, wl 8.8, fc 2/32, ph 9, solids 9, LCM 12%, bit #2, 7-7/8" f3 cut 261' from 1090' to 1351' in 19½ hours, lost time 4½ hours--4½ trip out and pick up 10 drill collars, lost 150 barrels mud from 1150' to 1300'. Drilling.

Whitmore Park Well No. 1

October 12, 1979:
Depth 1681', 330', days 7, pump 800, table 60, wt on bit 20 tons, mud wt 9.6, vis 53, sand 1%, wl 4.8, fc 2/32, ph 10.5, solids 12, LCM 10%, bit #2, 7-7/8" f3 cut 330' from 1351' to 1681' in 24 hours, no mud loss. Drilling.

October 13, 1979:
Depth 1942', 261', days 8, pump 800, table 65, wt on bit 20 tons, mud wt 9.7, vis 53, sand 1%, wl 5.6, fc 2/32, ph 10, solids 11, 8% LCM, bit #2, 7-7/8" f3 cut 125' from 1681' to 1806' in 10 hours, bit #3, 7-7/8" f2 cut 136' 1806' to 1942' in 10 hours, drilling time 20 hours, lost time 4 hours—3½ trip; ½ rig service. Drilling.

October 14, 1979:
Depth 2285', 343' days 9, pump 800, table 60, wt on bit 20 tons, mud wt 9.8, vis 45, sand 3/4%, wl 6.8, fc 2/32, ph 10, solids 11, bit #3, 7-7/8" f2 cut 343' from 1942' to 2285' in 24 hours, Drilling.

October 15, 1979:
Depth 2493', 208', days 10, pump 800, table 60, wt on bit 20 tons, mud wt 9.7, vis 50, sand ¼%, wl 8, fc 2/32, ph 10, solids 11, LCM 8%, bit #3, 7-7/8" f2 cut 208' from 2285' to 2493' in 22½ hours, lost time 1½ hours--½ survey; 1 trip out. Trip.

October 16, 1979:
Depth 2493', 0', days 11, pump 800, table 90, wt on bit 4 tons, mud wt 9.8, vis 53, sand ¼%, wl 8.8, fc 2/32, ph 10, solids 11%, LCM 8%, bit #4, 7-7/8" dtg ream, bit #5, 7-7/8" h7sg ream, lost time 24 hours--5 trip out; 1½ trip in to 2283'; 4½ wash from 2283' to 2410', bit #3 was 1-3/4" out of gauge, reamed from 2410' to 2480'; 4 trip out with bit #4, 1¼" out of gauge; 5 break drill collars and wait on 6-point knobby reamer; 1½ pick up bit and trip in to 600'; 2½ ream from 600' to 690'. Reaming at 690'.

October 17, 1979:
Depth 2568', 75', days 12, pump 80, table 50, wt on bit 20 tons, mud wt 9.7, vis 42, sand 3/4%, wl 5.6, fc 2/32, ph 10, solids 11, LCM 8%, bit #5, 7-7/8" h7sg cut 32' from 2493' to 2525' in 3 hours, bit #6, 7-7/8" h7sg cut 43' from 2525' to 2568' in 4½ hours, drilling time 7½ hours, lost time 16½ hours--2 ream 700' with 6-point reamer; 3½ trip out and lay down 6-point reamer; 4½ ream with bit #5 from 2410' to 2493'; 5 trip for bit #6, recovered part of junk and a tong die, bit #5 full gauge; 1½ wash and ream to bottom with bit #6. Drilling.

October 18, 1979:
Depth 2650', 82', days 13, pump 800, table 50, wt on bit 20 tons, mud wt 9.8, vis 44, sand 3/4%, wl 5.6, fc 2/32, ph 10, solids 11, 8% LCM, bit #6, 7-7/8" h7sg cut 82' from 2568' to 2650' in 11 hours, survey 2650' 5¼°, lost time 13 hours--1 circulate; 8 trip; 2 wait on Christensen; 2 pick up and make core barrel. Trip for core barrel.

October 19, 1979:
Depth 2650', 0', days 14, pump 800, table 50, wt on bit 2 tons, mud wt 9.8, vis 43, sand 1½%, wl 8, fc 2/32, ph 10, solids 11, bit #7, 7-7/8" h7sj cut 1800' from 850' to 2650' in 10 hours, lost time 24 hours--2 trip in with core barrel, hit bridge at 850'; 3 trip out, stand back core barrel, pick up bit and 3-point reamer, trip in to 840'; 10 ream tight hole 850-2650'; 3 trip out with bit and reamer; 3 trip for core barrel to 840'; 3 ream in with core barrel. Ream in with core barrel.

Whitmore Park Well No. 1

October 20, 1979:
Depth 2650', 0', days 15, pump 800, table 50, wt on bit 2 tons, mud wt 9.7, vis 43, sand 1-1/2%, wl 8, fc 2/32, ph 10, solids 11, bit #7, 7-7/8" h7sj reamed from 550' to 1625' in 12 hrs, lost time 24 hrs--2 ream with core barrel to 900'; 2 trip out; 2 stand back core barrel & pick up 6 pt. reamer & bit; 1 trip in to 550'; 12 ream from 550' to 1625'; 2 trip out, lay down 6 pt. reamer; 2 change core barrels; 1 trip in with core barrel. Trip with core barrel.

October 21, 1979:
Depth 2681', 31', days 16, pump 800, table 55, wt on bit 10 tons, mud wt 9.8, vis 45, sand 1-1/2%, wl 8, fc 2/32, ph 10, solids 14, 5% LCM, bit C.H. #1, core #1, 6-3/4" chris mc231 cut 31' from 2650' to 2681' in 6-1/2 hrs, drilling time 6-1/2 hrs, lost time 17-1/2 hrs--8 trip with 7-7/8" core head, clean out tight spots, could not get below 2370'; 6 trip out, lay down 7-7/8" core barrel and core head, pick up 5-3/4" core barrel & 6-3/4" core head; 3-1/2 trip in hole, wash in core #1. Cut core #1.

October 22, 1979:
Depth 2726', 45', days 17, pump 800, table 55, wt on bit 10 tons, mud wt 9.8, vis 45, sand 1-1/2%, wl 8, fc 2/32, ph 10, solids 14, 5% LCM, bit C.H. #1, core #1, 6-3/4" mc231 cut 29' from 2681' to 2710' in 7 hrs, bit C.H. #1, core #2, 6-3/4" mc231 cut 16' from 2710' to 2726' in 4-1/2 hrs, drilling time 11-1/2 hrs, lost time 12-1/2 hrs--4 trip out with core #1, lay down core & service barrel, cut 60', recovered 60'; 2 pump repairs; 3-1/2 trip in for core #2; 3 trip out with core #2, barrel jammed. Trip out with core #2.

October 23, 1979:
Depth 2750', 24', days 18, pump 800, table 55, wt on bit 10 tons, mud wt 9.8, vis 50, sand 1%, wl 8, fc 2/32, ph 11, solids 11, 2% LCM, bit C.H. #1, core #3, 6-3/4" chris mc231 cut 24' from 2726' to 2750' in 7 hrs, bit #7, 7-7/8" h7sj reamed, drilling time 7 hrs, lost time 17 hrs—1 trip out with core #2, handle core & core barrel; 4 trip for core #3, handle core and core barrel, had full recovery on both cores; 2 clean mud pits; 10 trip in with bit and 3 pt. reamer and ream core hole. Ream core hole.

October 24, 1979:
Depth 2789', 39', days 19, pump 800, table 55, wt on bit 12 tons, mud wt 9.8, vis 43, sand 1-1/2%, wl 10.5, fc 2/32, ph 10.5, solids 13, bit #7, 7-7/8" h7sj reamed 39', bit C.H. #1, core #4, 6-3/4" chris mc231 cut 39' from 2750' to 2789' in 11 hrs, lost time 13 hrs--5 ream core hole to 2750'; 3 trip & pick up core barrel; 2 cut drilling line; 3 trip in with core barrel for core #4. Cut core #4.

October 25, 1979:
Depth 2950', 161', days 20, pump 800, table 55, wt on bit 10-15 tons, mud wt 9.8, vis 44, sand 1-1/2%, wl 10, fc 2/32, ph 11, solids 12, bit C.H. #1, core #4, 6-3/4" chris mc231 cut 2' from 2789' to 2791' in 1 hr, bit #8, 7-7/8" f3 cut 159' from 2791'-to 2950' in 13 hrs, drilling time 14 hrs, lost time 10 hrs--6 trip out with core #4, handle core & lay down core barrel; 3 trip in with bit; 1 ream 41' of core hole, core #4, 2750'-2791', recovered 41', no coal. Drilling.

October 26, 1979:
Depth 3080', 130', days 21, pump 800, table 55, wt on bit 15 tons, mud wt 9.8, vis 43, sand 1%, wl 9.6, fc 2/32, ph 12, solids 12, 8% LCM, bit #8, 7-7/8" f3 cut 130' from 2950' to 3080' in 9-1/2 hrs, survey 6-1/4° @ 3080', drilling time 9-1/2 hrs, lost time 14-1/2 hrs--1-1/2 pump repair; 2 circulate to log; 3 trip out, SLM, no correction; 8 rig up and run logs, drillers TD 3080.86', log TD 3081'. Logging.

Whitmore Park Well No. 1

October 27, 1979:
Depth 3080', 0', days 22, pump 600, mud wt 9.8, vis 43, sand 1%, wl 9.6, fc 2/32, ph 12, LCM 8%, solids 12, lost time 24 hours--2 run logs; 2 trip in; 3½ circulate to run casing; 3½ lay down drill pipe and collars; 3½ rig up and run 5½" casing. Ran 95 jts 5½", 15.5#, K-55, 8rd, LT&C casing, landed at 3079.09' KBM; 1½ rig up and circulate with rig pumps; 1 cement casing with 140 sacks regular G with 2% calcium chloride, full returns throughout, bumped plug with 1500#, floats held good, cement in place at 11:00 p.m. on October 26, 1979; 7 land casing, nipple up. Nipple up BOP's.

October 28, 1979:
Depth 3080', 0', days 23, air 400, bit #9, 4-5/8" y22r drill cement and plugs, lost time 25 hours--7 nipple up and rig up to drill with air, pressure tested BOP's to 1000#, held OK; 15 pick up 2-7/8" drill pipe, 4-1/8" drill collars; 2 drilling cement and plugs to 3080'; 1 attempt to dry hole at 3080'. Drilling cement and plugs.

October 29, 1979:
Depth 3109', 29', days 24, air 400#, table 55, wt on bit 4 tons, bit # CH#3, core #5, 4-5/8" by 1-3/4" mc231 cut 8' from 3080' to 3088' in 1 hour, bit # CH#3, core #6, 4-5/8" x 1-3/4" mc231 cut 21' from 3088' to 3109' in 2 hours, drilling time 3 hours, lost time 21 hours--2 blow hole, attempt dry same, make water; 3 trip out; 2 pick up 3-1/8" core barrel; 2 trip in hole; 1 unload hole; 5 trip and lay down core #5, cut 8', recovered 3'; 1 unload hole for core #6; 5 trip, lay down core #6, cut 21', recovered 15', unload hole at 2000'. Trip for core No. 7.

October 30, 1979:
Depth 3177', 68', days 25, air, table 55, wt on bit 4 tons, corehead #3, 4-5/8" x 1-3/4" Chris. cut 17' from 3109' to 3126' in 4-3/4 hours, bit #10, 4-5/8" y22r cut 51' from 3126' to 3177' in 7 hours, drilling and coring time 11-3/4 hours, lost time 12¼ hours--3 trip in and unload hole with air; 7-3/4 trip out, lay down core #7, core #7 cut and recovered 17', lay down core barrel, trip in hole with bit #10; ½ unload hole at 3177'; 1 lay down 2-7/8" drill pipe. Lay down 2-7/8" drill pipe.

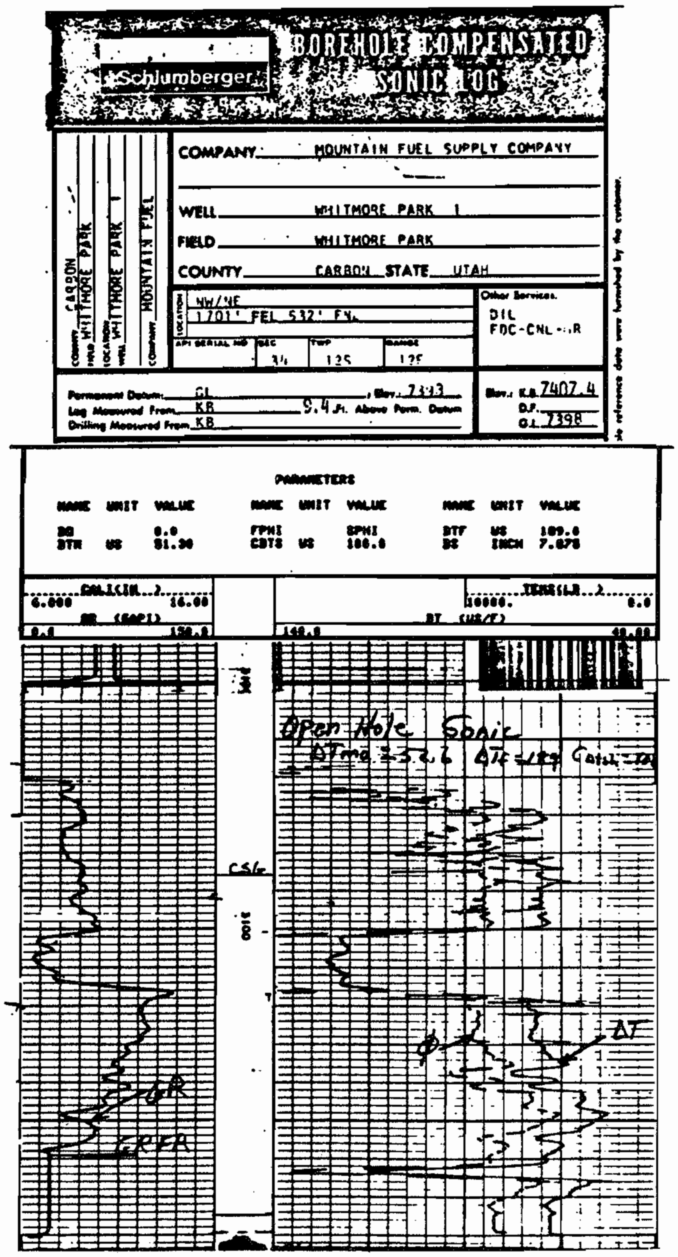
October 31, 1979:
Depth 3177', 0', days 26, lost time 6 hours--3 lay down drill pipe and drill collars; 3 break out blooie line and BOP.

RIG RELEASED OCTOBER 30, 1979 at 12:00 a.m.

<u>CASING REPORT</u> KB 7407.40'

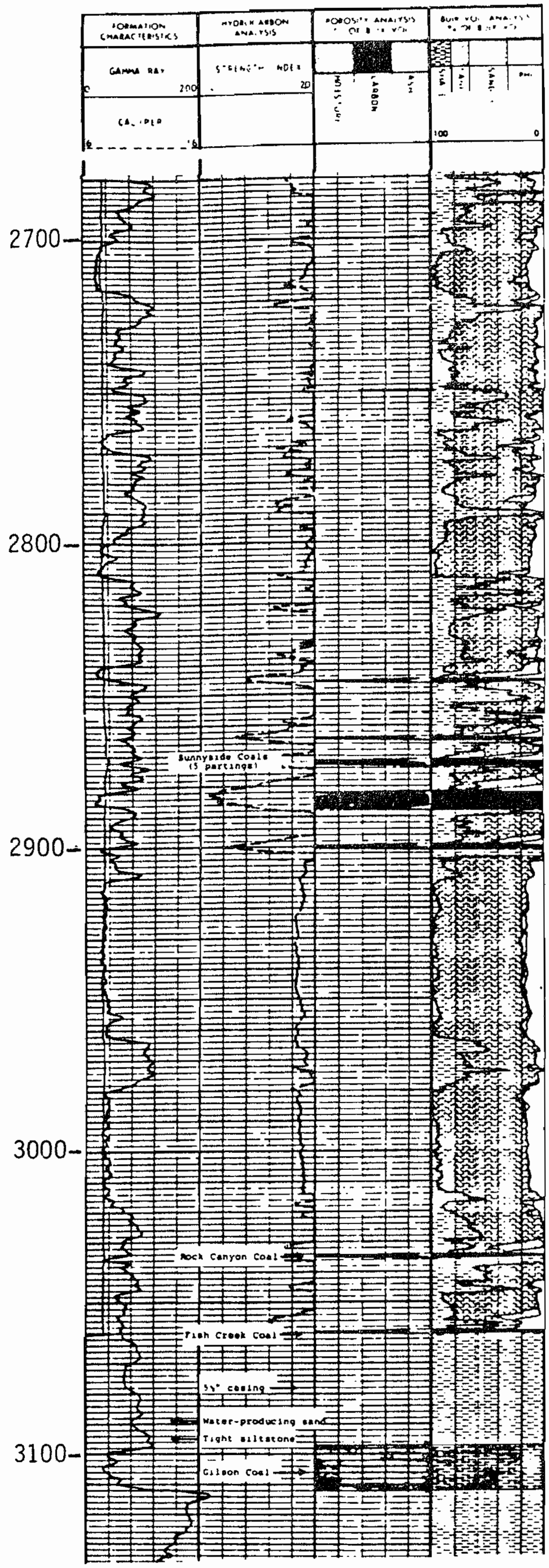
Landed 5½" OD, 15.5#, K-55, 8rd thd, LT&C casing at 3079.09' KBM, set with 140 sacks of regular class G cement treated with 2% calcium chloride, full returns while circulating, mixing and displacing, floating equipment held OK, cement in place at 11 pm on 10-27-79.

APPENDIX D



Schlumberger
BOREHOLE COMPENSATED SONIC LOG
COMPANY MOUNTAIN FUEL SUPPLY COMPANY
WELL WHITMORE PARK 1
FIELD WHITMORE PARK
COUNTY CARBON STATE UTAH
LOCATION NW/NE 1701' FEL 532' FNL
Other Services: DIL FDC-CNL-GR
SEC 34 TWP 12S RANGE 12E
Permanent Datum: GL, Elev.: 7393
Log Measured From: KB 9.4 Ft. Above Perm. Datum
Drilling Measured From: KB
Elev.: K.B. 7407.4 D.F. G.L. 7398
PARAMETERS
NAME UNIT VALUE
DD 0.0
DTM US 51.30
FPHI SPHI
CBTS US 100.0
DTF US 189.0
BS INCH 7.875
CALI (IN) 6.000 16.00
GR (GAPI) 0.0 150.0
TENS (LB) 10000. 0.0
DT (US/F) 140.0 40.00
CSG
3100
Open Hole Sonic
ΔTma = 52.6 ΔTf = 189
GR
GRFA
ΔT
φ

COAL LOG FOR
WHITMORE PARK WELL NO. 1



Schlumberger — **CEMENT BOND LOG**

COMPANY: Mountain Fuel Supply Company

WELL: Whitmore Park #1

FIELD: Whitmore Park

COUNTY: Carbon STATE: Utah

COUNTY / Field or LOCATION / WELL / COMPANY

LOCATION API Serial No.

Sec. 34 Twp. 12S Rge. 12E

Other Services: NONE

Permanent Datum: GL, Elev. 7398

Log Measured From: KB, 9 Ft. Above Perm. Datum

Drilling Measured From: KB

Elev.: K.B. 7402.4, D.F. , G.L. 7398

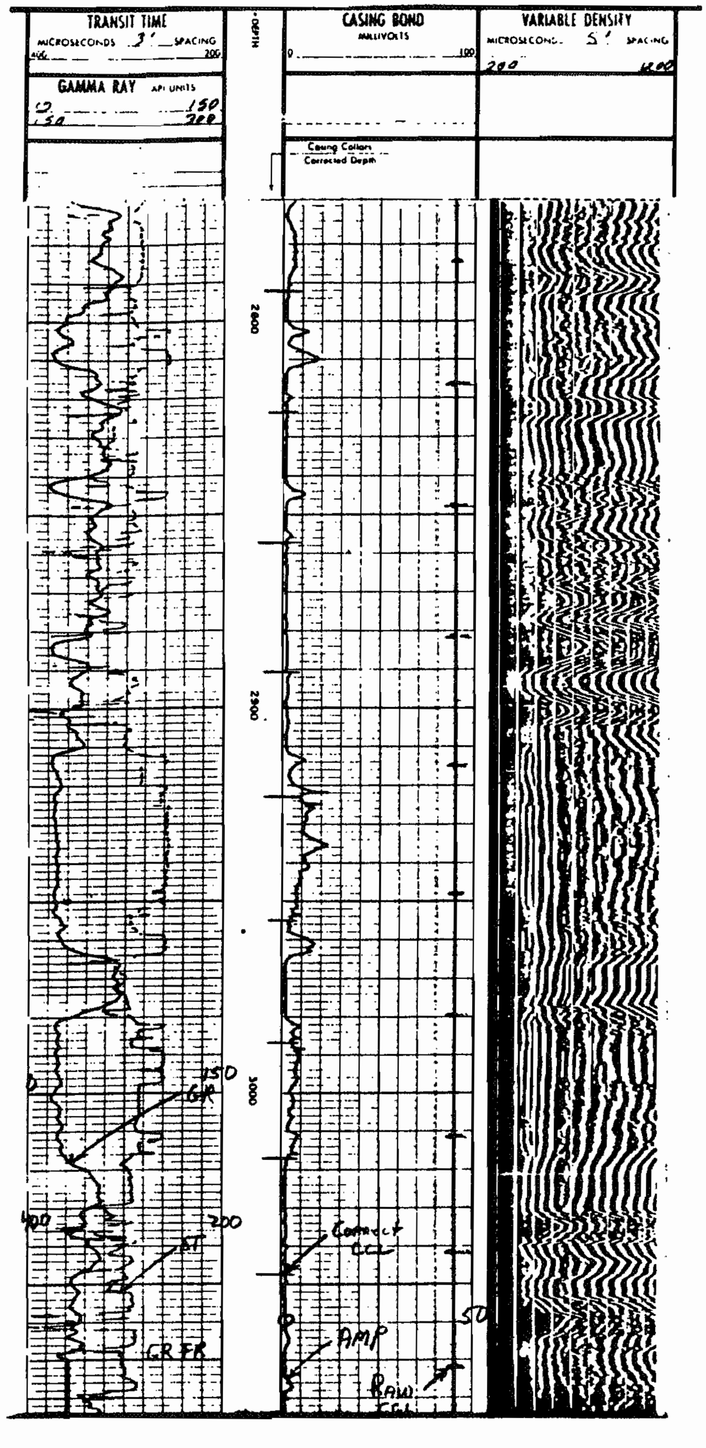
Date	Nov 1 79	Casing Fluid	Formation H2O
Run No.	one	Fluid Level	570
Depth — Driller	~~3233~~ 3199	Max. Rec. Temp.	— °F —
Depth — Logger	3159	Est. Cement Top	2174
Btm. Log Interval	3126	Unit / District	5749 / Vernal
Top Log Interval	1978	Recorded By	Salzman
Open Hole Size	7 7/8	Witnessed By	Mr. Bridges

CASING REC.	Size	Wt/Ft	Grade	Type Joint	Top	Bottom
Surface String	8 5/8				Surf	1200
Prot. String	5 1/2	15 1/2			Surf	3051
Prod. String						
Liner						

PRIMARY CEMENTING DATA

STRING	Surface	Protection	Production	Liner
Vol. of cement				
Type of cement				
Additive				
Retarder				
Wt. of slurry				
Water loss				
Type fluid in csg.				
Fluid wt.				

The well name, location and borehole reference data were furnished by the customer.



Schlumberger

DUAL INDUCTION-SFL WITH LINEAR CORRELATION LOG

COUNTY CARBON
FIELD WHITMORE PARK 1
LOCATION
WELL WHITMORE PARK 1
COMPANY MOUNTAIN FUEL

COMPANY MOUNTAIN FUEL SUPPLY COMPANY

WELL WHITMORE PARK 1

FIELD WHITMORE PARK

COUNTY CARBON STATE UTAH

LOCATION NW NE

API SERIAL NO	SEC	TWP	RANGE
	34	12S	12E

Other Services:
BHC-GR
FDC-CNL-GR

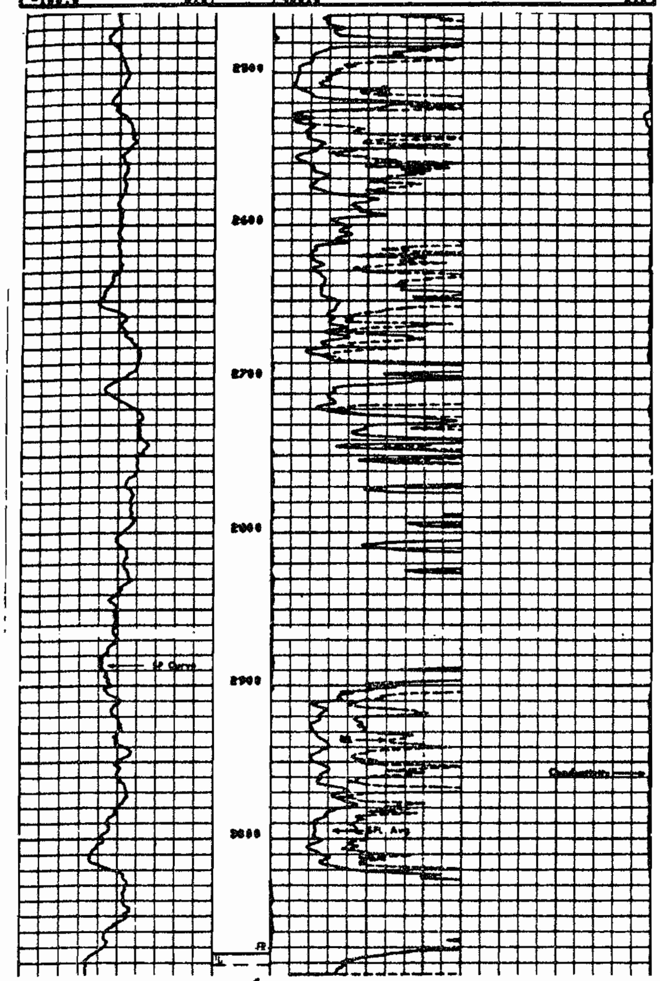
Permanent Datum: GL, Elev. 7398
Log Measured From KB 9.4 Ft. Above Perm. Datum
Drilling Measured From KB

Elev.: K.B. 7407.4
D.F.
G.L. 7399

Date	10/23/79			
Run No	ONE			
Depth—Driller	3080			
Depth—Logger	3081			
Btm. Log Interval	3075			
Top Log Interval	209			
Casing—Driller	8 5/8 @ 209	@	@	@
Casing—Logger	209			
Bit Size	7 7/8			
Type Fluid in Hole	FGM			
Dens. / Visc.	10.0 / 43			
pH / Fluid Loss	12.0 / 9.5 ml	ml	ml	ml
Source of Sample	PIT			
Rm @ Meas. Temp	1.59 @ 58 °F	@ °F	@ °F	@ °F
Rmf @ Meas. Temp	1.21 @ 58 °F	@ °F	@ °F	@ °F
Rmc @ Meas. Temp	2.39 @ 58 °F	@ °F	@ °F	@ °F
Source: Rmf / Rmc	M / C			
Rm @ BHT	1.11 @ 83 °F	@ °F	@ °F	@ °F
Time: Circulation Stopped	1900			
Time: Logger on Bottom	2230			
Max. Rec. Temp.	83 °F	°F	°F	°F
Equip. / Location	7674 / VERNAL			
Recorded By	SMITH			
Witnessed By	REESE			

PARAMETERS

NAME	UNIT	VALUE	NAME	UNIT	VALUE	NAME	UNIT	VALUE
BO		0.0	FPHI		PHIX	RSEC	MM/M	6.200
SDR	OHMM	1.000	BSEC	MM/M	4.200	BS	INCH	7.875



Schlumberger

BOREHOLE COMPENSATED SONIC LOG

COUNTY	CARBON
FIELD	WHITMORE PARK
LOCATION	
WELL	WHITMORE PARK 1
COMPANY	MOUNTAIN FUEL

COMPANY MOUNTAIN FUEL SUPPLY COMPANY

WELL WHITMORE PARK 1

FIELD WHITMORE PARK

COUNTY CARBON STATE UTAH

LOCATION NW/NE 1701' FEL 532' FNL

API SERIAL NO	SEC	TWP	RANGE
	34	12S	12E

Other Services: DIL FDC-CNL-GR

Permanent Datum: GL, Elev.: 7393

Log Measured From KB 9.4 Ft. Above Perm. Datum

Drilling Measured From KB

Elev.: K.B. 7407.4 D.F. G.L. 7398

Date	10/26/79			
Run No.	ONE			
Depth—Driller	3080			
Depth—Logger (Schl.)	3081			
Btm. Log Interval	3069			
Top Log Interval	209			
Casing—Driller	8 5/8 @ 209	@	@	@
Casing—Logger	209			
Bit Size	7 7/8			
Type Fluid in Hole	F.M			
Dens. | Visc.	10.0 | 43			
pH | Fluid Loss	12.0 | 9.6 ml	ml	ml	ml
Source of Sample	PIT			
Rm @ Meas. Temp.	1.59 @ 58 °F	@ °F	@ °F	@ °F
Rmf @ Meas. Temp.	1.21 @ 58 °F	@ °F	@ °F	@ °F
Rmc @ Meas. Temp.	2.39 @ 58 °F	@ °F	@ °F	@ °F
Source: Rmf | Rmc	M | C			
Rm @ BHT	1.10 @ 84 °F	@ °F	@ °F	@ °F
TIME Circulation Stopped	1900			
TIME Logger on Bottom	2430			
Max. Rec. Temp.	84 °F	°F	°F	°F
Equip. | Location	7574 | VERNAL			
Recorded By	SMITH			
Witnessed By Mr.	REESE			

The well name, location and borehole reference data were furnished by the customer.

FOLD HERE

PARAMETERS

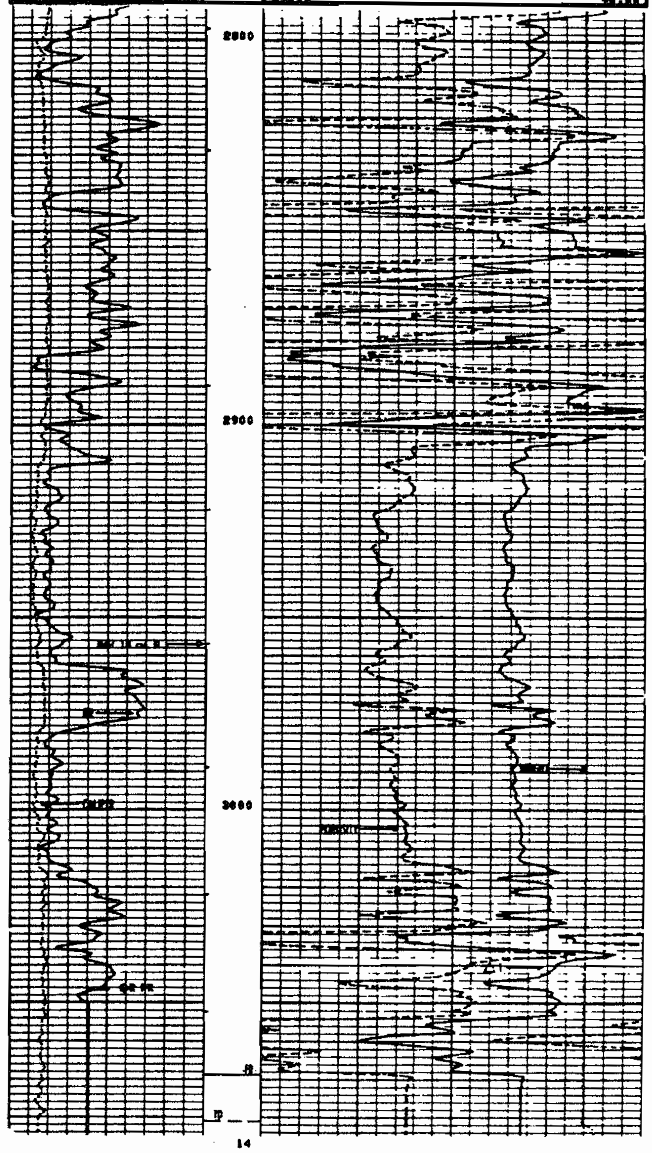
NAME	UNIT	VALUE	NAME	UNIT	VALUE	NAME	UNIT	VALUE
DO		0.0	FPHI		SPHI	DTF	US	189.0
DTM	US	51.30	CDTS	US	100.0	BS	INCH	7.875

CALI(IN) 6.000 16.00

GR (GAPI) 0.0 150.0

TENS(LB) 10000. 0.0

DT (US/F) 140.0 40.00



Schlumberger

SIMULTANEOUS
COMPENSATED NEUTRON FORMATION DENSITY

COMPANY MOUNTAIN FUEL SUPPLY COMPANY

WELL WHITMORE PARK 1

FIELD WHITMORE PARK

COUNTY CARBON STATE UTAH

COUNTY CARBON
FIELD WHITMORE PARK
LOCATION
WELL WHITMORE PARK 1
COMPANY MOUNTAIN FUEL

LOCATION NW/NE
1701' FEL 532' FNL

API SERIAL NO	SEC	TWP	RANGE
	34	12S	12E

Other Services: DIL BHC-GR

Permanent Datum: GL ; Elev.: 7398
Log Measured From KB 9.4 Ft. Above Perm. Datum
Drilling Measured From KB

Elev.: K.B. 7407.4
D.F.
G.L. 7398

Date	10/26/79			
Run No	ONE			
Depth Driller	3080			
Depth Logger	3081			
Btm Log Interval	3080			
Top Log Interval	200			
Casing Driller	8 5/8 @ 209	@	@	@
Casing Logger	209			
Bit Size	7 7/8			
Type Fluid in Hole	F.M			
Dens. | Visc	10.0 | 43	|	|	|
pH | Fluid Loss	12.0 | 9.6 ml	| ml	| ml	| ml
Source of Sample	PIT			
Rm @ Meas Temp	1.10 @ 58 °F	@ °F	@ °F	@ °F
Rmf @ Meas Temp	1.22 @ 58 °F	@ °F	@ °F	@ °F
Rmc @ Meas. Temp	2.39 @ 59 °F	@ °F	@ °F	@ °F
Source Rmf | Rmc	M | C	|	|	|
Rm @ BHT	1.11 @ 83 °F	@ °F	@ °F	@ °F
TIME Circulation Stopped	2100			
TIME Logger on Bottom	0300			
Max Rec Temp	83 °F	°F	°F	°F
Equip | Location	7674 | VERNAL	|	|	|
Recorded By	SMITH			
Witnessed By Mr	REESE			

The well name, location and borehole reference data were furnished by the customer

FOLD HERE

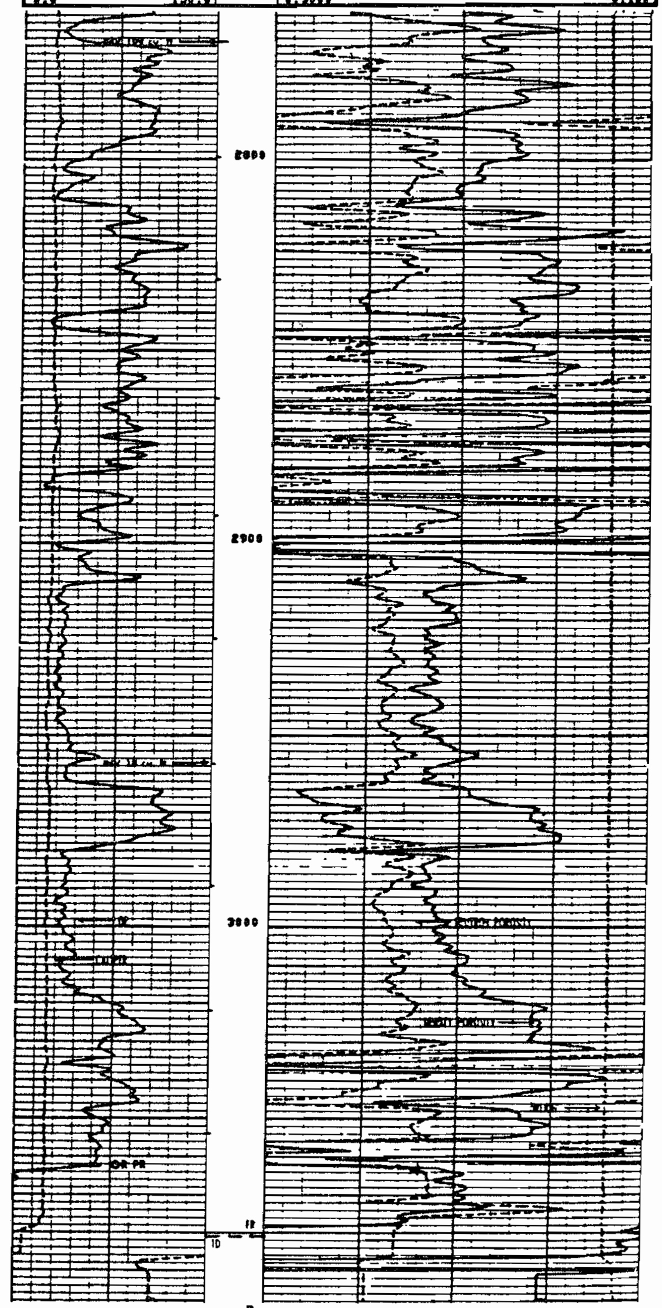
PARAMETERS

NAME	UNIT	VALUE	NAME	UNIT	VALUE	NAME	UNIT	VALUE
BD		0.0	FPHI		PHIX			

TENS(LB) 10000. 0.0

GR (GAPI) 150.0 300.0
CALI(IN) 6.000 16.00
GR (GAPI) 0.0 150.0

NPHI( ) 0.7000 0.3000
NPHI( ) 0.3000 -0.100
DPHI( ) 0.3000 -0.100



APPENDIX E

API #: 43-007-30046

Projected depth:
2965' Kenilworth (WC)

Whitmore Park Well No. 2
Wexpro Company, Operator
Lease No.: Fee
1756' FNL, 2250' FWL
SE NW 34-12S-12E., SLB&M
Carbon County, Utah
Ground elevation 7408'

Permit No.: 43-007-30046
June 18, 1979

DRILLING CONTRACTOR: Veco Drilling Company - Rig No. 1

SPUDDED at 8:00 a.m. on November 1, 1979.

November 2, 1979:
Depth 25', 25', day 1, 250 psi air, table 50, wt on bit 2 tons, bit #1 RR, 17½" OSC cut 25' from 0' to 25' in 6 hours, lost time 18 hours--18 repair rig. Rig repairs.

November 3, 1979:
Depth 37', 12', days 2, air, table 55, wt on bit 2 tons, bit #1, 17½" osc cut 12' from 25' to 37' in 1½ hours, lost time 22½ hours--2½ repair rotary drive; 3 ran 1 jt. 13-3/8" OD, conductor pipe, cemented through 1" pipe with Dowell with 40 sacks of regular G cement treated with 3% calcium chloride, cement in place at 11:00 a.m. on November 2, 1979; 17 rig up and drill rat hole and mouse hole. Drill mouse hole.

November 4, 1979:
Depth 44', 7', days 3, air, table 45, wt on bit 2 tons, bit #2, 12¼" s3rt cut 7' from 37' to 44' in 18 hours, lost time 6 hours--3 drill mouse hole; 3 nipple up on 13-3/8" conductor pipe with rotating head and blooie lines. Drilling 12¼" hole.

November 5, 1979:
Depth 109', 65', days 4, air, table 45, wt on bit 2 tons, bit #3, 12¼" s3j cut 35' from 44' to 79' in 5½ hours, bit #3 RR, 12¼" v2h cut 30' from 79' to 109' in 4 hours, drilling time 9½ hours, lost time 14½ hours--14½ drill mouse hole. Repair rotary drive.

November 6, 1979:
Depth 450', 341', days 5, air 250, table 60, wt on bit 5 tons, bit #3, 12¼" v2h cut 79' from 109' to 188' in 3-3/4 hours, bit #4, 12¼" f4 cut 262' from 188' to 450' in 12½ hours, drilling time 16¼ hours, lost time 7-3/4 hours--5¼ rig repairs to rotary drive, repack swivel and repair air lines; 2½ trip for bit, picked up air hammer. Drilling with air.

November 7, 1979:
Depth 830', 380', days 6, air 250, table 60, wt on bit 5 tons, bit #4, 12¼" f4 cut 380' from 450' to 830' in 15½ hours, lost time 8½ hours--1½ rig repairs; 1 circulate with air; 2 trip out; 1 rig to run casing; 3 run 9-5/8" casing. Running 9-5/8" casing.

November 8, 1979:
Depth 1188', 358', days 7, 250, 2000 CFR, table 50, bit #5, 7-7/8" f45 cut 358' from 830' to 1188' in 8 hours, lost time 16 hours--3/4 cement and displace; 5¼ wait on cement; 2 back off conductor; 6 nipple up, test BOP's to 1000#, held OK; 1-3/4 trip in the hole; ¼ drill cement, picked up small amount of moisture at 938', began mist drilling, ran 20 jts. 9-5/8", 36#, K-55, 8rd thd, ST&C casing, landed at 783.65', cemented with 450 sacks H with 3% calcium chloride and ¼# flocele per sack, returned 30 barrels cement to surface, cement in place at 6:45 a.m. on November 7, 1979. Drilling.

November 9, 1979:
Depth 1985', 797', days 8, air 325, 2000, table 50, wt on bit 14 tons, bit #5, 7-7/8" f45 cut 797' from 1188' to 1985' in 23½ hours, survey 1382' 1°, lost time ½ hour--½ survey. Drilling.

Whitmore Park Well No. 2

November 10, 1979:
Depth 2310', 325', days 9, air 350, 2000, table 50, wt on bit 12 tons, bit #5, 7-7/8" f45 cut 310' from 1985' to 2295' in 13½ hours, bit #6, 7-7/8" f45 cut 15' from 2295' to 2310' in ½ hour, survey 2000' 1-3/4°, drilling time 14 hours, lost time 10 hours--½ survey; 6 trip; 1 blow hole at 1000'; 2½ blow hole at 2245', reamed 2245-2295'. Drilling.

November 11, 1979:
Depth 2550', 240', days 10, air 350, 2000, table 50, wt on bit 12 tons, bit #6, 7-7/8" f45 cut 240' from 2310' to 2550' in 11 hours, CH #1, 7-7/8" mc23, lost time 13 hours--2-3/4 change pumps; 1-3/4 repair rotating head; ½ blow hole at 2550'; 3 trip out; 4 pick up core barrel; 1 trip in with core barrel. Trip in.

November 12, 1979:
Depth 2568', 18', days 11, air 400, table 50, wt on bit 12 tons, bit #1, 7-7/8" mc20 cut 13' from 2550' to 2563' in 2 hours, bit #6 RR, 7-7/8" f45 cut 5' from 2563' to 2568' in 1 hour, drilling time 3 hours, lost time 21 hours--4 trip, pick up core barrel, blow hole at 1800', clean 60' to bottom; ½ blow well to trip out; 4½ trip out; 2 handle core and lay down core barrel; 5 trip in with bit and junk sub, clean out bridges and clean bottom for slip die; ½ blow well; 3 trip out; ½ pick up new core barrel. Pick up core barrel.

November 13, 1979:
Depth 2602', 34', days 12, air 400, 2000 cfm, table 50, wt on bit 12 tons, bit #1 core #2, 7-7/8" mc20 cut 34' from 2568' to 2602' in 6 hours, lost time 18 hours--1 pick up and servic core barrel; 8 trip in, clean out bridges at 1400', 1800', 2000'; 5½ trip in and work throu tight hole 1400', 1800', 2000'; 1½ lay down core; 2 mix mud. Core #2 cut 34', recovered 33'. Mixing mud.

November 14, 1979:
Depth 2602', 0', days 13, mud wt 9.0, vis 45, sand trace, wl 26, fc 2/32, ph 9.5, solids 3, lost time 24 hours--3 mix mud; 5 trip in and clean out; 3 circulate at 2602', condition hole and mud; 3 trip out for core barrel; 3 clean out and wash bridges; 1½ wash bridge at 1800'; 2½ trip out and pick up bit and reamer. Pick up bit and reamer.

November 15, 1979:
Depth 2628', 26', days 14, pump 800, table 50, wt on bit 6 tons, mud wt 8.5, vis 40, sand ¼%, wl 14, fc 2/32, ph 9.5, solids 1½, CH #1, core #3, 7-7/8" mc20 cut 26' from 2602' to 2628' in 5½ hours, lost time 18½ hours--2 trip for bit and reamer; 4½ trip in, clean out bridges; 2½ trip out, trip in, no fill up; 3½ trip out; 4½ pick up core barrel, trip in, circulate and start core #3; 1½ trip out, core jammed. Trip for core #3.

November 16, 1979:
Depth 2688', 60', days 15, pump 700, table 50, wt on bit 6 tons, mud wt 8.7, vis 59, sand ¼%, wl 6.4, fc 2/32, ph 8.5, solids 5, ch#1, core #4, 7-7/8" mc20 cut 60' from 2628' to 2688' in 13½ hours, lost time 10½ hours--3 trip out, handle core, service barrel; 3½ trip in, clean out to bottom, cut core #4; 2½ trip out for core #4; 1½ handle core and service barrel. Full recovery on core, no coal. Service core barrel.

November 17, 1979:
Depth 2743', 55', days 16, pump 700, table 50, wt on bit 6 tons, mud wt 8.8, vis 48, sand ¼%, wl 16.4, fc 2/32, ph 8.5, solids 4, bit #1, core #5, 7-7/8" mc20 cut 35' from 2688' to 2723' in 8 hours, bit #9, 7-7/8" f3 cut 20' from 2723' to 2743' in 2½ hours, drilling time 10½ hours, lost time 13½ hours--4 trip, circulate, drop ball; 5 trip, handle core, stand core barrel in derrick; 4½ trip in with bit and 6-point reamer. Drilling.

Whitmore Park Well No. 2

November 18, 1979:
Depth 2862', 119', days 17, pump 700, table 50, wt on bit 6 tons, mud wt 8.9, vis 48, sand ½%, wl 6.4, fc 2/32, ph 8.5, solids 4, bit #9, 7-7/8" f3 cut 117' from 2743' to 2860' in 11¼ hours, CH bit #1, core #6, 7-7/8" mc20 cut 2' from 2860' to 2862' in 1 hours, drilling time 12¼ hours, lost time 11-3/4 hours--1 circulate to cut core; 7¼ trip out with bit, SLM, no correction, picked up core barrel, trip in and start core #6; 3 trip out, service barrel, cut 2', recovered 2', inner barrel swivel locked up. Trip in to cut core #7.

November 19, 1979:
Depth 2920', 58', days 18, pump 700, table 50, wt on bit 6 tons, mud wt 8.6, vis 48, sand ½%, wl 6.4, fc 2/32, ph 8.5, solids 4, bit #1, core #7, 7-7/8" mc20 cut 16' from 2862' to 2878' in 4½ hours, bit #1, core #8, 7-7/8" mc 20 cut 42' from 2878' to 2920' in 12 hours, drilling time 16½ hours, lost time 7½ hours--2 trip in hole, drop ball for core #7; 5½ trip out, handle core and trip in. Full recovery on core. Core #8.

November 20, 1979:
Depth 2965', 45', days 19, pump 750, table 65, wt on bit 14 tons, mud wt 8.8, vis 45, sand ½%, wl 8.2, fc 2/32, ph 8.5, solids 7, ch bit #1, core #8, 7-7/8" mc20 cut 4' from 2920' to 2924' in ½ hour, ch #1, core #9, 7-7/8" mc20 cut 18' from 2924' to 2942' in 5 hours, bit #9, 7-7/8" f3 cut 23' from 2942' to 2965' in 2½ hours, drilling time 8 hours, lost time 16 hours--16 trips, lay down core barrel and cores, core #9 cut 18', recovered 14'. Drilling

November 21, 1979:
Depth 3000', 35', days 20, pump 750, table 65, wt on bit 14 tons, mud wt 8.8, vis 45, sand ½%, wl 7.2, fc 2/32, ph 8.5, solids 5, bit #7 RR, 7-7/8" f3 cut 35' from 2965' to 3000' in 3 hours, lost time 21 hours--1½ circulate to log; 3 trip out; 16½ logging. Logging.

CASING REPORT KB 7417.00'

Landed 9-5/8" OD, 36#, K-55, 8rd thd, ST&C casing at 783.65' KBM, cemented with 450 sacks southwest H cement with 3% calcium chloride and 1/4-pound flocele per sack of cement, returned 30 barrels slurry to surface, cement in place at 6:45 a.m. on November 7, 1979.

November 22, 1979:
Depth 3000', 0', days 21, lost time 24 hours--4 log with Schlumberger; 3 trip in hole, clean out to bottom; 2 circulate and condition hole; 4½ lay down drill pipe and drill collars; 6¼ rig up and run 5½" casing, ran 73 jts 5½", 15.5#, K-55, 8rd thd, ST&C, landed at 2929.40' KBM; 4¼ rig up Schlumberger, run log to set Peugo packers, shear pins on Peugo packer, Peugo top packer at 2702', bottom Peugo at 2716', bottom Halliburton packer at 2928', cement 5½" casing with 225 sacks class A treated with 2% calcium chloride and 0.6% CFR-2, full returns, cement in place at 7:00 a.m. on November 22, 1979. Cement 5½" casing.

November 23, 1979:
Depth 3000', 0', days 22, lost time 10 hours--1 finish cementing; 9 remove BOP's, land casing with 35,000# on slips, clean mud tanks and remove MFSCO equipment.

RIG RELEASED NOVEMBER 22, 1979 at 4:00 p.m.

CASING REPORT

Landed 5½" OD, 15.5#, K-55, 8rd thd, ST&C casing at 2929.40' KBM, set with 225 sacks class H cement treated with 2% calcium chloride and 0.6% CFR-2, full returns throughout, cement in place at 7:00 a.m. on November 22, 1979.

Whitmore Park Well No. 2

11-26-79: Rig up contract work over rig, shut down for night.

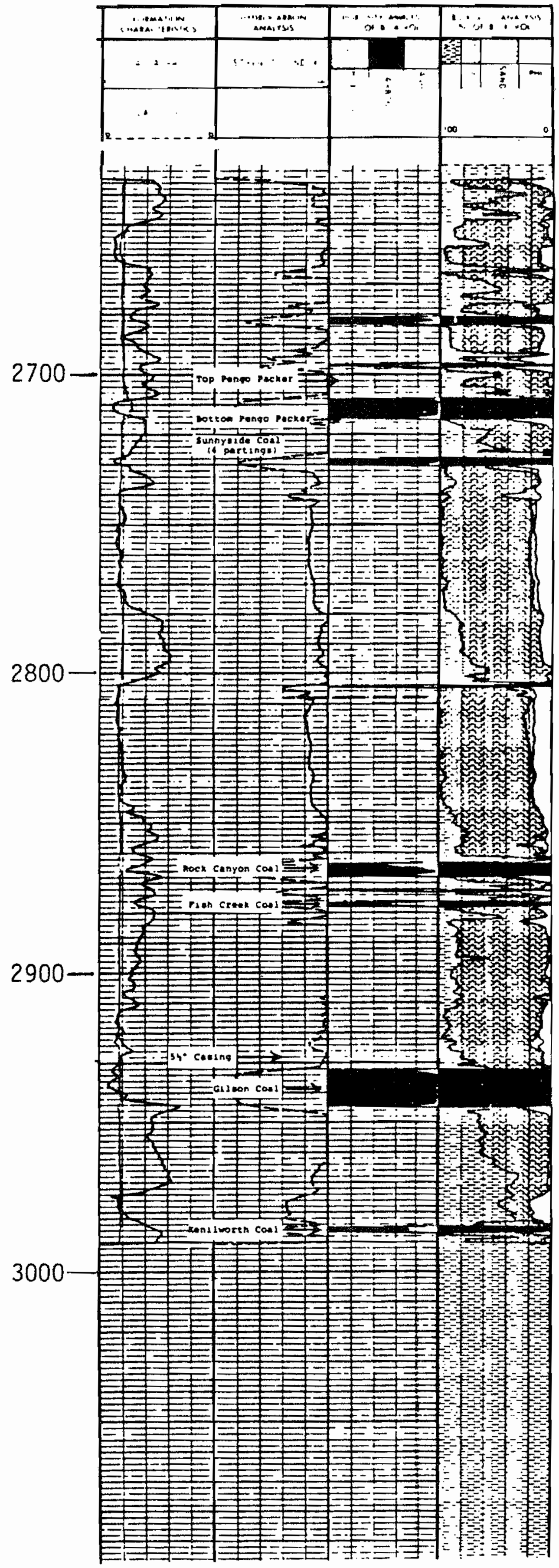
11-27-79: Installed 10" 3000 psi by 6" 3000 psi tubing spool, pressure tested primary and secondary seals, held OK, installed 6" 3000 psi double gate BOP with 2-3/8" pipe rams in top and blind rams in bottom; rigged up OWP wire line and ran cement bond log from PBD 1764' KBM, good bond indicated behind Pengo completion system, picked up and ran 70 joints of 2-3/8", 4.6#, J-55, seal lock tubing, shut down for night.

11-28-79: Picked up 2-3/8" tubing and stood in derrick, picked up Pengo shifting tool and ran in hole to 2675' KBM with 1 joint of tubing below shifting tool, swabbed well down to 2200' KBM, opened both Pengo sleeves, no indication of gas or water influx, made 2 swab runs and recovered 1½ barrels completion water, no gas, Echometer did not indicate any water influx, shut down for night.

11-29-79: Checked fluid level with swab and echometer, no fluid entered wellbore overnight, made 2 swab runs, recovered 2 barrels water, no gas, closed Pengo sleeves, pulled tubing, picked up 4-3/4" bit and ran to 2905', rigged up power swivel, swivel would not work, shut down for repairs.

APPENDIX F

COAL LOG FOR
WHITMORE PARK WELL NO. 2



Schlumberger

BOREHOLE COMPENSATED SONIC LOG

COUNTY: CARBON
FIELD: WHITMORE PARK
LOCATION:
WELL: WHITMORE PARK 2
COMPANY: MOUNTAIN FUEL SUPPLY

COMPANY: MOUNTAIN FUEL SUPPLY COMPANY

WELL: WHITMORE PARK 2

FIELD: WHITMORE PARK

COUNTY: CARBON STATE: UTAH

LOCATION: 2250' FNL 1750' FWL

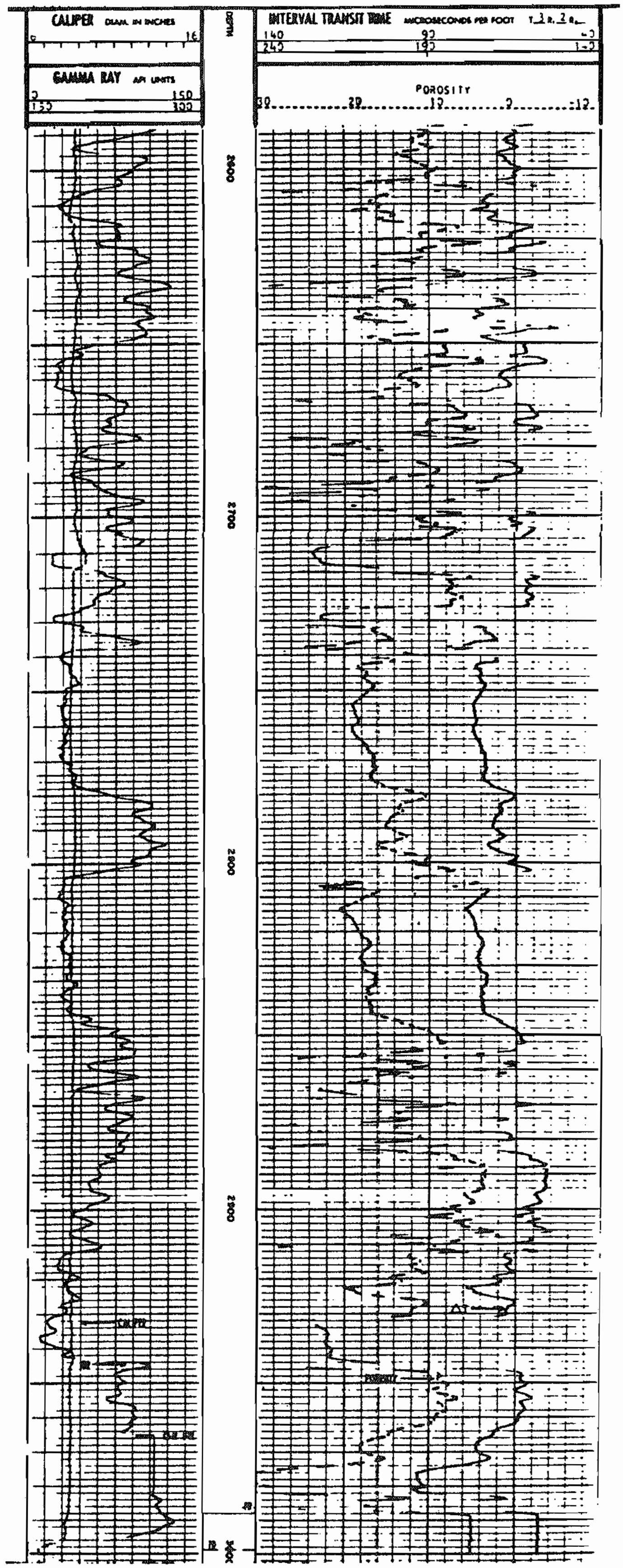
Other Services: DIL, FDC-CNL-GR

API SERIAL NO	SEC	TWP	RANGE
	34	12S	12E

Permanent Datum: GL, Elev. 7408
Log Measured From: KB 9.6 Ft. Above Perm. Datum
Drilling Measured From: KB

Elev.: K.B. 7417.6, D.F. , G.L. 7408

Date	11/20/79			
Run No.	ONE			
Depth—Driller	3000			
Depth—Logger (Schl.)	2999			
Btm. Log Interval	2988			
Top Log Interval	786			
Casing—Driller	8 5/8 @ 793	@	@	@
Casing—Logger	786			
Bit Size	7 7/8			
Type Fluid in Hole	FGM			
Dens. / Visc.	9.0 / 45			
pH / Fluid Loss	8.5 / 7.2 ml	ml	ml	ml
Source of Sample	FLOWLINE			
Rm @ Meas. Temp.	3.32 @ 57 °F	@ °F	@ °F	@ °F
Rmf @ Meas. Temp.	.93 @ 57 °F	@ °F	@ °F	@ °F
Rmc @ Meas. Temp.	4.9 @ 57 °F	@ °F	@ °F	@ °F
Source: Rmf / Rmc	M / LC			
Rm @ BHT	2.4 @ 76 °F	@ °F	@ °F	@ °F
Circulation Stopped	1030			
Logger on Bottom	1630			
Max. Rec. Temp.	77 °F	°F	°F	°F
Equip. / Location	7074 / VERNAL			
Recorded By	VALLNII			
Witnessed By	WIESE			



Schlumberger

SIMULTANEOUS
COMPENSATED NEUTRON-FORMATION DENSITY

COMPANY MOUNTAIN FUEL SUPPLY COMPANY

WELL WHITMORE PARK 2

FIELD WHITMORE PARK

COUNTY CARBON STATE UTAH

LOCATION 2250' FWL 1750' FNL

Other Services: DIL, BHC-GR

API SERIAL NO. | SEC. 34 | TWP. 12S | RANGE 12E

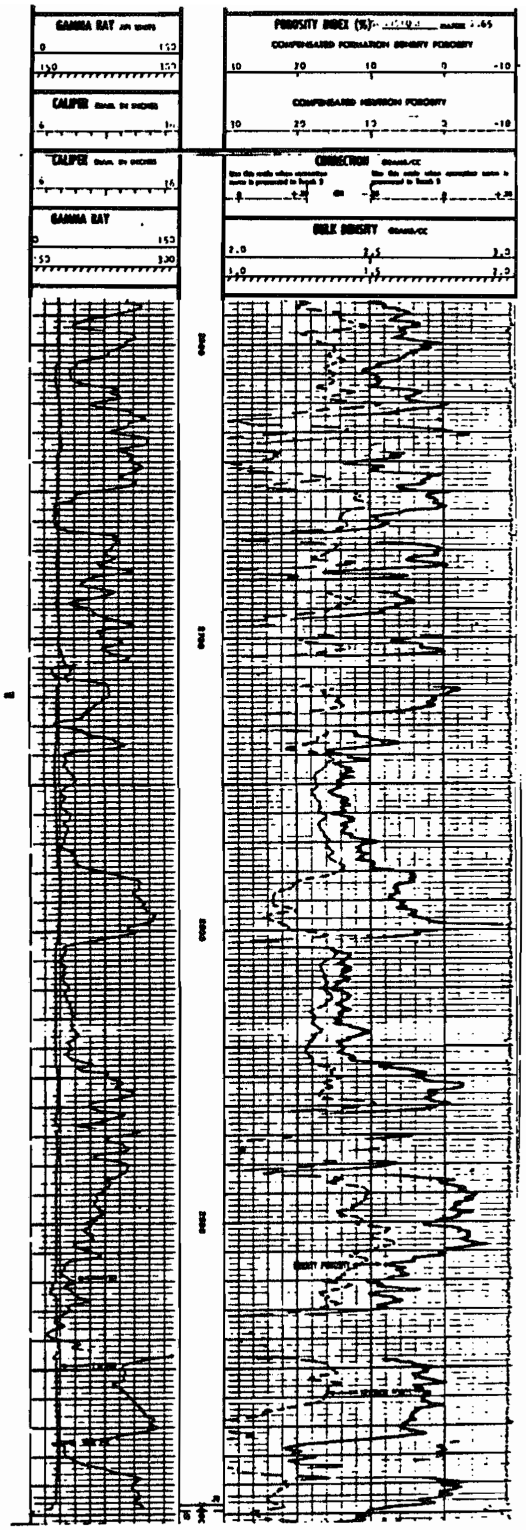
Permanent Datum: GL, Elev 7400

Log Measured from KB 9 Ft. Above Perm. Datum

Drilling Measured From KB

Elev.: K.B. 7412; D.F.; G.L. 7403

Date	11/20/79			
Run No.	ONE			
Depth—Driller	3308			
Depth—Logger	2399			
Btm. Log Interval	2997			
Top Log Interval	786			
Casing—Driller	9 5/8 @ 793	@	@	@
Casing—Logger	786			
Bit Size	7 7/8			
Type Fluid in Hole	GEL			
Dens. / Visc.	9.2 / 45			
pH / Fluid Loss	8.5 / 7.2 ml	ml	ml	ml
Source of Sample	FLOWLINE			
Rm @ Meas. Temp.	1.30 @ 57 °F	@ °F	@ °F	@ °F
Rmf @ Meas. Temp.	[illegible] @ 57 °F	@ °F	@ °F	@ °F
Rmc @ Meas. Temp.	[illegible] @ 57 °F	@ °F	@ °F	@ °F
Source: Rmf / Rmc	[illegible]			
Rm @ BHT	[illegible] @ [illegible] °F	@ °F	@ °F	@ °F
Time Circulation Stopped	[illegible]			
Time Logger on Bottom	0600			
Max. Rec. Temp.	77 °F	°F	°F	°F
Equip. / Location	7674 / VERNAL			
Recorded By	VALENTI			
Witnessed By Mr.	[illegible]			



Schlumberger

DUAL INDUCTION-SFL WITH LINEAR CORRELATION LOG

COMPANY: MOUNTAIN FUEL SUPPLY COMPANY

WELL: WHITMORE PARK #2

FIELD: WHITMORE PARK

COUNTY: CARBON STATE: UTAH

LOCATION: 2250' FNL & 1725' FWL SE/4NW

Other Services: BHC-GR, FDC-CNL-GR

SEC: 34

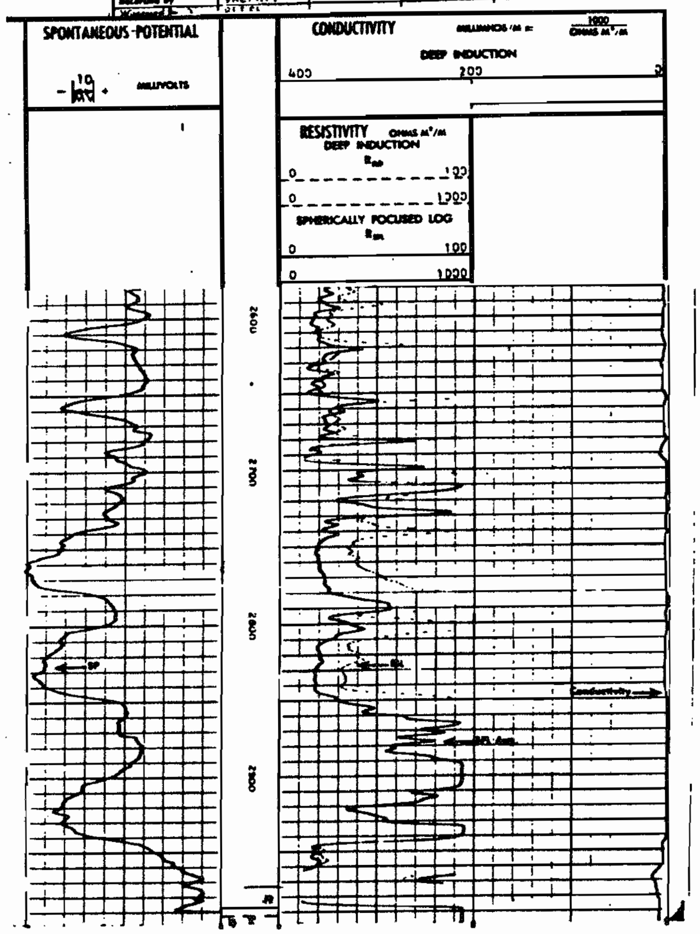
Permanent Datum: GL, Elev. 7405

Log Measured From: KB, 9.5 Ft. Above Perm. Datum

Drilling Measured From: KB

Elev.: K.B. 7418, D.F., G.L. 7405

Date	11/20/79
Run No.	ONE
Depth—Driller	3008
Depth—Logger	2993
Btm. Log Interval	2937
Top Log Interval	786
Casing—Driller	8 5/8 @ 793
Casing—Logger	786
Bit Size	7 7/8
Type Fluid in Hole	FGM
Dens. / Visc.	9.0 / 45
pH / Fluid Loss	9.5 / 7.2 ml
Source of Sample	FLOWLINE
R_m @ Meas. Temp.	3.30 @ 57 °F
R_{mf} @ Meas. Temp.	.33 @ 57 °F
R_{mc} @ Meas. Temp.	4.9 @ 57 °F
Source: R_{mf} / R_{mc}	M / C
R_m @ BHT	2.4 @ 76 °F
Circulation Stopped	1330
Logger on Bottom	1430
Max. Rec. Temp.	76 °F
Equip. / Location	7674 / VERNAL
Recorded By	VALENTI
Witnessed By	[illegible]



oil well perforators inc.

O.W.P.

ACOUSTIC CEMENT BOND–GAMMA RAY LOG

COMPANY: MOUNTAIN FUEL SUPPLY COMPANY

WELL: NUTTMORE PARK #2

FIELD: NUTTMORE PARK

COUNTY: CARBON STATE: UTAH

Location: 2250 FNL/1756 FNL SE/NW

Sec 34 Twp 12S Rge 12E

Other Logs

Elevation: KB 7417.6 DF GL 7408

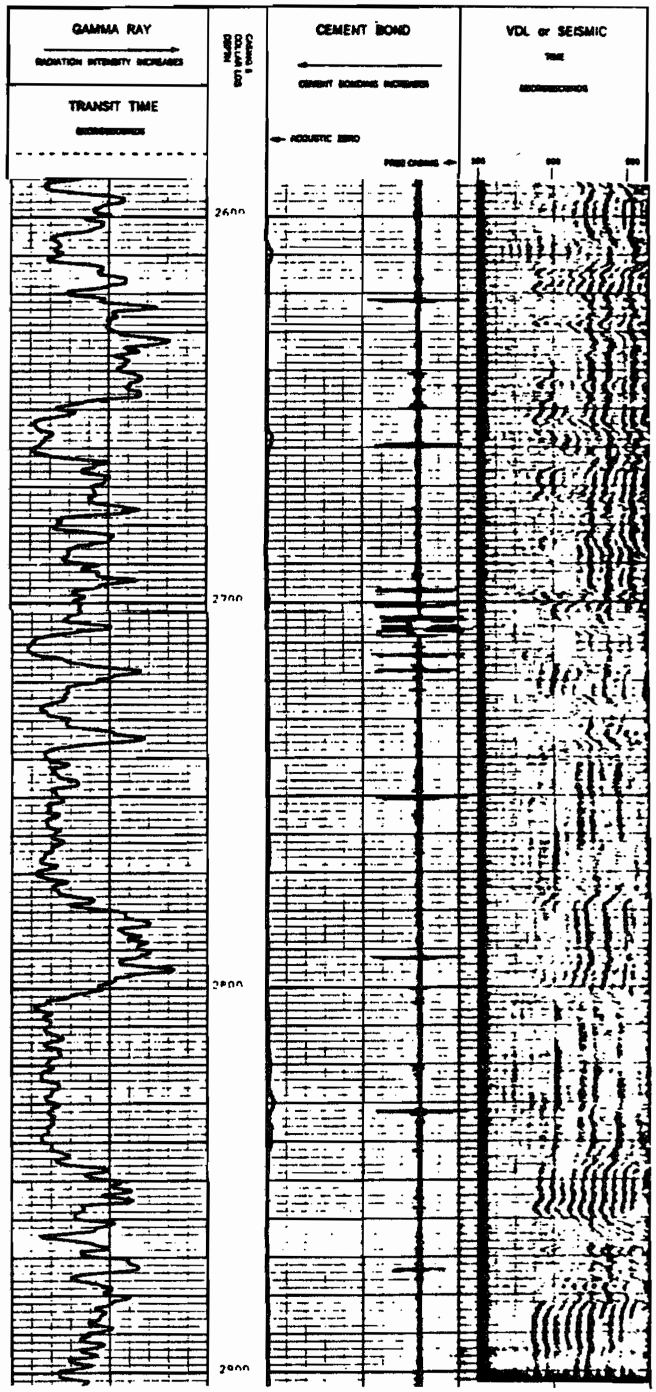
Permanent Datum: GROUND LEVEL Elev. 7408

Log Measured From: 9.6' ABOVE GROUND LEVEL

Drilling Measured From: K.B. 9.6' ABOVE GROUND LEVEL

Type Log	VDL	GAMMA RAY		
Run No.	ONE	TWO		
Date	11-27-79	11-27-79		
Total Depth Driller	3005			
Present Depth Driller				
Total Depth O.W.P.	2905			
Survey Begins	1500	2905		
Survey Ends	2905	1500		
Truck No	529			
Location	VERNAL			
Type Fluid in Hole	WATER			
Salinity PPM Cl				
Weight lb./gal.				
Fluid Level	100'			
Max Hole Temp.				
Recorded By	COUGHLIN			
Witnessed By	MR. BULFER			

BORE HOLE RECORD				CASING RECORD			
Run	Bit	From	To	Size	Wgt	From	To
				5½"	15.5#	SURFACE	2926'



APPENDIX G

API #: 43-007-30067

Projected depth:
3500' Mancos (WC)

Whitmore Unit Well No. 1
Wexpro Company, Operator
Lease No.: Fee
2065' FNL, 601' FEL
SE NE 17-12S-11E., SLBM
Carbon County, Utah
Ground elevation 7561'

Drilling contractor: Arapahoe Drilling

SPUDDED AUGUST 31, 1981 at 7:30 p.m.

September 1, 1981:
Depth 120', 120', day 1, air, bit #1, 12¼" cut 120' from 0' to 120' in 10½ hours, lost time 0 hours. Drilling.

September 2, 1981:
Depth 130' 12¼" hole, 116' 17" hole, 10', days 2, air, bit #1 retip cut 10' from 120' to 130' in 1 hour, bit #2, 17" reamed 116' from 0' to 116' in 8 hours, ran 3 joints 13-3/8", 54.8#, K-55, 8rd thd, LT&C casing, landed at 115' GL, cemented with 135 sacks class H cement treated with 3% calcium chloride, full returns while cementing, cement in place at 11:00 p.m. 9-1-81. WOC Pat Leech

September 22, 1981:
Depth 270', 155', days 3, air 250 psi, 1800 cfm, table 60, wt on bit 10 tons, bit #1, 12-1/4" j22, EB-281 cut 155' from 115' to 270' in 9 hours, lost time 15 hours--6 nipple up to drill with air; 3 pick up 8" drill collars, install rotating head; 6 drill cement and shoe from 70' to 115'. Drilling with air. LEM

September 23, 1981:
Depth 680', 410', days 4, air 210 psi, 1800 cfm, table 65, wt on bit 10 tons, air, bit #1, 12¼" j22 EB-228 cut 410' from 270' to 680' in 23½ hours, survey 310' 3/4°, lost time 1/2 hour--½ survey. Drilling with air. LEM

September 24, 1981:
Depth 1004', 324', days 5, air 210, table 65, wt on bit 10 tons, air, bit #1, 12¼" j22 EB-228 cut 324' from 680' to 1004' in 15½ hours, survey 727' ¼°, lost time 8½ hours--1 survey; 1½ repair air leak; 1 rig service; 2 circulate; 2 trip out; 1 lay down 8" drill collars. Waiting on casing crew. RPM

September 25, 1981:
Depth 1004', 0', days 6, lost time 24 hours--1 lay down 8" drill collars; 3 wait on casing crews; 4½ ran 23 jts 9-5/8", 36#, K-55, ST&C casing, landed at 964' KBM; 1½ circulate with rig pump; ½ cement with 600 sacks class H with 3% calcium chloride and ¼# per sack flocele; 6 WOC; 7½ nipple up, returned 17 barrels slurry to surface. Nipple up. RPM

September 26, 1981:
Depth 973', 31', days 7, air 210, table 65, wt on bit 5 tons, air, bit #2, 8-3/4" f3 BG6211 cut 31' from 942' to 973' in 3½ hours, lost time 20½ hours--15½ nipple up, pressure test blind rams to 1000#, held OK; 3½ pick up 8-3/4" bit and 6" drill collars, trip in with 1 stand drill pipe, pressure test pipe rams and casing to 1000 psi, held OK; 1½ trip in hole and tagged cement at 942'. Drilling cement. RPM

September 27, 1981:
Depth 1163', 190', days 8, air 300 psi, table 60, wt on bit 8½ tons, bit #2, 8-3/4" f3 BT-6211 cut 190' from 973' to 1163' in 10½ hours, lost time 13½ hours--3 dry up hole; ½ rig service and check BOP's; 10 trip for

Whitmore Unit Well No. 1

September 28, 1981:
Depth 1529', 367', days 9, air 300, table 60, wt on bit 8 tons, air, bit #2, 8-3/4" f3 BT-6211 cut 367' from 1162' to 1529' in 22 hours, survey 1600' 3/4°, lost time 2 hours--1 survey; 1 repack swivel. Drilling with air. RPM

September 29, 1981:
Depth 1756', 227', days 10, pump 300, table 60, wt on bit 8 tons, bit #2, 8-3/4" f3 cut 227' from 1529' to 1756' in 17-3/4 hours, lost time 6¼ hours--1 change flow line from #1 reserve pit to #2 pit; 1¼ trip out with 13 stands; 4 rig repairs, began making water at 1500', steady increase to 150 barrels per hour at 1756', will mud hole up. Rig shut down for repairs, rotary drive out. RPM

September 30, 1981:
Depth 1576', 0', days 11, pump 600, table 65, wt on bit 15 tons, mud wt 8.9, vis 45, bit #3 8-3/4" f3 CA-6175, lost time 24 hours--3½ repairs to rotary drive; 4½ trip out; 7½ mix mud; 5 trip in hole; 1½ displace water out with mud and wash 120' to bottom. Wash and ream to bottom. RPM

October 1, 1981:
Depth 1756', 0', days 12, pump 600, table 65, wt on bit 5 tons, mud wt 8.6, vis 45, sand trace, wl 13.6, fc 2/32, ph 11.5, solids 3, bit #3, 8-3/4" f3 CA-6175, lost time 24 hours--16½ wash and clean fill up from 1576' to 1756'; 7½ repair swivel. Repair swivel. BPM

October 2, 1981:
Depth 1826', 70', days 13, pump 900, table 60, wt on bit 10 tons, mud wt 8.6, vis 35, sand trace, wl 11.2, fc 2/32, ph 10, solids 3, bit #3, 8-3/4" f3 CA-7165 cut 70' from 1756' to 1826' in 7 hours, lost time 17 hours--14 repair swivel; 2 trip in hole; 1 wash and ream 240' to bottom. Drilling. RPM

October 3, 1981:
Depth 1928', 172', days 14, pump 550, table 70, wt on bit 10 tons, mud wt 8.7, vis 37, sand 3/4%, wl 10.8, fc 2/32, ph 10.5, solids 4, bit #3, 8-3/4" f3 DA-6175 cut 172' from 1756' to 1928' in 17 hours, lost time 7 hours--1 mud pump broke down, trip out into casing; 6 rig new mud pump and unload drill collars. Rig new mud pump. JRG

October 4, 1981:
Depth 1928', 0', days 15, bit #3, 8-3/4" f3 CA-6175, lost time 24 hours--24 rig up pumps and rig repairs, change pump liners. JRG

October 5, 1981:
Depth 2064', 136', days 16, pump 700, table 60, wt on bit 15 tons, mud wt 8.7, vis 38, sand ½%, wl 10, fc 2/32, ph 10, solids 4, bit #3, 8-3/4" f3 BA-6175 cut 136' from 1928' to 2064' in 8-3/4 hours, lost time 15¼ hours--3½ pump repairs; 10½ trip pick 6¼" drill collars, lay down 4½" drill collars, trip in hole; 1¼ trip into casing to change swivels. Change out swivel. JRG.

October 6, 1981:
Depth 2215', 151', days 17, pump 650, table 60, wt on bit 15•tons, mud wt 9.0, vis 41, sand 3/4%, wl 9, fc 2/32, ph 10.5, solids 5, bit #3, 8-3/4" f3 CA-6175 cut 151' from 2064' to 2215' in 9 hours, lost time 15 hours--14 repairs, wait on swivel; 1 trip in. Drilling. JRG

Whitmore Unit Well No. 1

October 7, 1981:
Depth 2381', 166', days 18, pump 650, table 70, wt on bit 15 tons, mud wt 8.9, vis 64, sand 3/4%, wl 9, fc 2/32, ph 10.5, solids 4, bit #3, 8-3/4" f3 CA-6175 cut 166' from 2215' to 2381' in 22½ hours, lost time 1½ hours--1 clean mud pit; ½ rig service. Drilling. JRG

October 8, 1981:
Depth 2633', 252', days 19, pump 650, table 60, wt on bit 6 tons, mud wt 8.9, vis 64, sand 1½%, wl 9, fc 2/32, ph 10.5, solids 4, bit #3, 8-3/4" f3 CA-6175 cut 252' from 2381' to 2633' in 21 hours, lost time 3 hours--½ repair mud line; 2½ change out swivel. Repairing swivel. RPM

CASING REPORT KB 7568.00'

Landed 9-5/8" OD, 36#, K-55, 8rd thd, ST&C casing at 964.68' KBM, set with 600 sacks of regular H cement with 3% calcium chloride and ¼# flocele per sack, good returns throughout, returned 17 barrels good cement to surface, cement in place September 24, 1981 at 3:15 p.m.

October 9, 1981:
Depth 2717', 84', days 20, pump 650, table 65, wt on bit 16 tons, mud wt 8.8, vis 37, sand ½%, wl 6.6, fc 2/32, ph 11, solids 3, bit #3, 8-3/4" f3 CA-6175 cut 84' from 2633' to 2717' in 11 hours, lost time 13 hours--13 repairs to swivel and rotary drive bushings. Trip for bit. RPM

October 10, 1981:
Depth 2871', 154', days 21, pump 750, table 60, wt on bit 16 tons, mud wt 8.8, vis 36, sand trace, wl 6.6, fc 2/32, ph 11.5, solids 3, bit #4, 8-1/2" f2, BT-6848 cut 154' from 2717' to 2871' in 10-1/2 hours, drilling time 10-1/2 hours, lost time 13-1/2 hours--13-1/2 trip for bit. Drilling. RPM

October 11, 1981:
Depth 2958', 87', days 22, pump 750, table 60, wt on bit 16 tons, mud wt 8.9, vis 37, sand trace, wl 7.4, fc 2/32, ph 10.5, solids 4, bit #4, 8-1/2" f2, BT-8648 cut 87' from 2871' to 2958' in 10-3/4 hours, core head #1, 7-7/8" mc23, 9w2558 cut 0', drilling time 10-3/4 hours, lost time 13-1/4 hours--2 circulate, 2 repair rig motor, 9-1/4 trip. Trip in with core barrel. RPM

October 12, 1981:
Depth 2980', 18', days 23, pump 800, table 60, wt on bit 10 tons, mud wt 9.0, vis 35, sand 1/4%, wl 6, fc 2/32, ph 9.5, solids 5, core head #1, 7-7/8" mc23, 9w2558 cut 18' from 2962' to 2980' in 3 hours, survey 2-1/4° @ 2962', drilling time 3 hours, lost time 21 hours--10-1/2 trip core #1; 5-1/2 trip out with core #1, jammed; 1 lay down core #1, 18 foot recovery no coal; 4 trip in for core #2. Trip in core #2. RPM

October 13, 1981:
Depth 2997', 17', days 24, pump 750, table 60, wt on bit 9 tons, mud wt 8.9, vis 38, sand 1/4%, wl 8.8, fc 2/32, ph 9.5, solids 4, core head #1, core #2, 7-7/8" mc23, 9w2558 cut 7' from 2980' to 2987' in 1-1/2 hours, core head #1, core #3, 7-7/8" mc23, 9w2558 cut 10' from 2987' to 2997' in 4-1/2 hours, drilling time 6 hours, lost time 18 hours--2-1/2 trip in core #2; 3/4 wash and ream 40'; 1-1/4 circulate; 5-1/2 trip out, core jammed, cut 2980' to 2987', recovered 6-1/2'; 2 service core barrel; 3-1/2 repair rig engine; 1-3/4 trip in; 3/4 circulate and start core #3. Cut core #3. RPM

October 14, 1981:
Depth 3134', 137', days 25, pump 700, table 60, wt on bit 15 tons, mud wt 9.1, vis 39, sand 1/4%, wl 8.8, fc 2/32, ph 9.5, solids 4, core head #1, core #3, 7-7/8" mc23, 9w2558 cut 16' from 2997' to 3013' in 3-1/4 hours, bit #5, 7-7/8" f3, CA-7462 cut 121' from 3013' to 3134' in 6-3/4 hours, drilling time 10 hours, lost time 14 hours--3-1/4 trip out with core #3, cut 26', recovered 26'; 2 dump core and service barrel; 1-1/2 wait on orders from Salt Lake; 6-1/2 pick up bit, shock sub, and trip in hole; 1/2 wash and ream to bottom; 1/4 rig service. Trip. JRG

October 15, 1981:
Depth 3296', 162', days 26, pump 750, table 60, wt on bit 15 tons, mud wt 8.9, vis 37, sand 1/4%, wl 8, fc 2/32, ph 10.5, solids 4, bit #5, 7-7/8" f3, CA-7462 cut 162' from 3134' to 3296' in 14-1/2 hours, bit #6, 7-7/8" f3, CA-4136 cut 0', drilling time 14-1/2 hours, lost time 9-1/2 hours--1/2 circulate sample, 1/2 rig service, 7 tripped for bit, 1-1/2 rig repair. Trip. JRG

October 16, 1981:
Depth 3459', 163', days 27, pump 850, table 55, wt on bit 15 tons, mud wt 8.9, vis 38, sand 1/4%, wl 7.2, fc 2/32, ph 10.5, solids 4, bit #6, 7-7/8" f3, CA-4136 cut 163' from 3296' to 3459' in 16-1/2 hours, drilling time 16-1/2 hours, lost time 7-1/2 hours--4-3/4 trip in, 2-1/2 ream 78' to bottom, 1/4 rig service. Drilling. JRG

October 17, 1981:
Depth 3715', 256', days 28, pump 800, table 55, wt on bit 15 tons, mud wt 8.9, vis 38, sand 1/4%, wl 7.6, fc 2/32, ph 10, solids 4, bit #6, 7-7/8" f3, CA-4136 cut 256' from 3459' to 3715' in 23 hours, drilling time 23 hours, lost time 1 hour--3/4 circulate; 1/4 rig service. Circulate to log. JRG

October 18, 1981:
Depth 3771', 56', days 29, pump 750, table 55, wt on bit 12-1/2 tons, mud wt 9.0, vis 40, sand 1/4%, wl 5.8, fc 2/32, ph 11.5, solids 5, bit #6, 7-7/8" f3 circulating, bit #7, 7-7/8" f3, CA-9759 cut 56' from 3715' to 3771' in 6-1/4 hours, drilling time 6-1/4 hours, lost time 17-3/4 hours--3 wait on orders; 2 trip out; 3-3/4 lay down four 6-1/2" drill colla and core barrel; 4 pick up shock tool and trip in; 2 ream 90'; 3 repair hook lock. Drilling JRG

October 19, 1981:
Depth 3949', 178', days 30, pump 750, table 75, wt on bit 12-1/2 tons, mud wt 9.1, vis 40, sand 1/4%, wl 5, fc 2/32, ph 10.5, solids 4, bit #7, 7-7/8" f3, CA-9759 cut 178' from 3771' to 3949' in 23-1/2 hours, drilling time 23-1/2 hours, lost time 1/2 hour--1/2 rig service and check BOPs. Drilling. MRS

October 20, 1981:
Depth 4062', 113', days 31, pump 750, table 55, wt on bit 15 tons, mud wt 9.0, vis 40, sand trace, wl 6.6, fc 2/32, ph 10, solids 4, bit #7, 7-7/8" f3, CA-9759 cut 113' from 3949' to 4062' in 12 hours, drilling time 12 hours, lost time 12 hours--1/2 rig service, check BOPs; 1 clean mud tanks; 2 circulate and condition hole; 8-1/2 trip out, SLM. Rigging up to log. MRS

Whitmore Unit Well No. 1

October 21, 1981:
Depth 4062', 0', days 32, mud wt 8.7, vis 38, sand trace, wl 7, fc 2/32, ph 10, solids 4, bit #7 rerun, 7-7/8" f3, CA-9759 cut 0', lost time 24 hours--14 log; 10 trip, SLM, repair air lines. Repair air lines to drum clutch. MRS

October 22, 1981:
Depth 4062', 0', days 33, lost time 24 hours--24 rig repairs to drum clutch. MRS

October 23, 1981:
Depth 4062', 0', days 34, lost time 24 hours--24 repair rig. MRS

October 24, 1981:
Depth 4076', 14', days 35, pump 750, table 60, wt on bit 12½ tons, mud wt 8.6, vis 38, sand trace, wl 7, fc 2/32, ph 10, solids 2, bit #7, 7-7/8" f3 cut 14' from 4062' to 4076' in 4 hours, lost time 20 hours--10 rig repair; 6-3/4 work stuck pipe 3440', spotted 80 barrels diesel, pipe came free; 3/4 finish trip in; 2½ wash from 3985-4062'. Drilling. MRS

October 25, 1981:
Depth 4110', 34', days 36, pump 700, table 60, wt on bit 15 tons, mud wt 8.5, vis 52, sand trace, wl 4, fc 2/32, ph 11, solids 2, bit #7, 7-7/8" f3 cut 34' from 4076' to 4110' in 9½ hours, lost time 25 hours--2 circulate; 12 lay down drill pipe; 1½ rig to run casing. Rig to run casing. MRS

October 26, 1981:
Depth 4110', 0', days 37, lost time 24 hours--7½ ran 102 jts 5½", 17#, K-55, 8rd thd, ST&C casing, landed at 4081' KB, Pengo packers 3641-3655'; 1½ circulate; 3 rig GO International, ran correlation log; 2 circulate casing and set packers; 1 cement with 115 sacks Halco Lite with 3% calcium chloride, good returns, bumped plug with 2100 psi, floats held, cement in place at 9:00 p.m. 10-25-81; 9 set slips, clean pits, nipple down BOP's. MRS

RIG RELEASED OCTOBER 26, 1981 at 6:00 a.m.

CASING REPORT

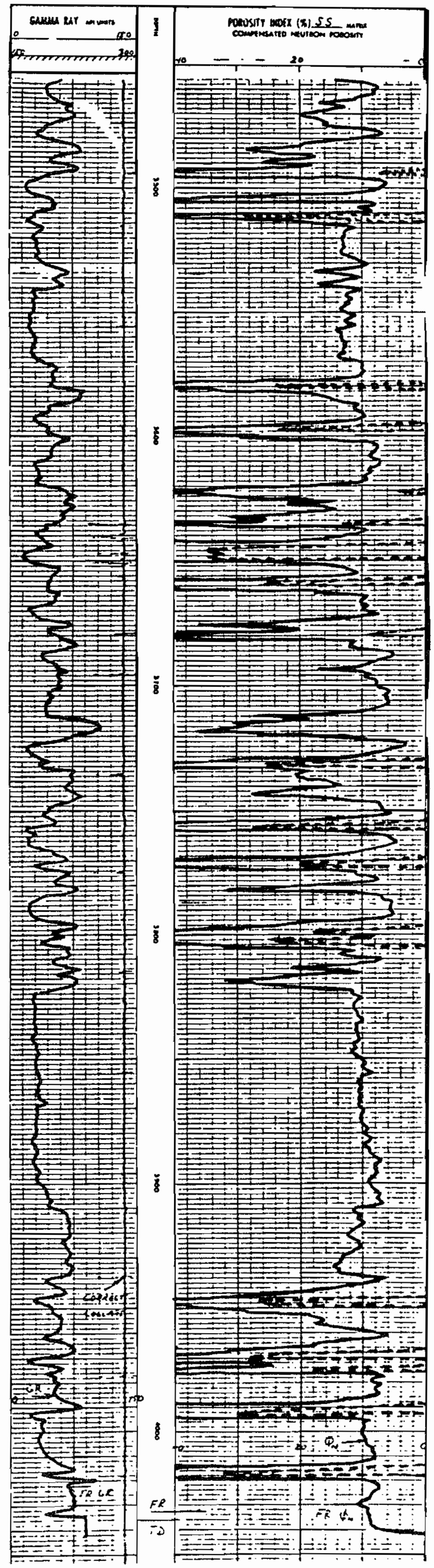
Landed 5½", 17#, K-55, 8rd thd, LT&C casing at 4109.15' KBM, Pengo tool at 3637.5' KBM, set with 115 sacks Halco lite with 2% calcium chloride, good returns throughout, floating equipment held OK, cement in place October 25, 1981 at 9:00 a.m.

APPENDIX H

Compensated Neutron

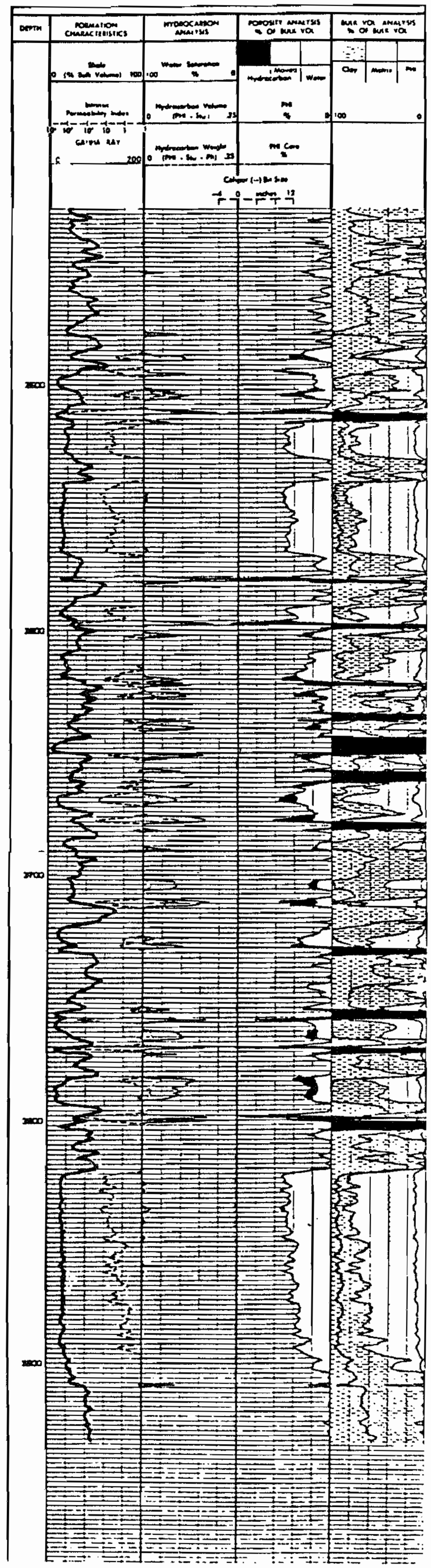
Log in Cased Hole

Whitmore Unit No. 1



Saraband Log

Whitmore Unit No. 1



APPENDIX I

TABLE 6. Sequence Log for Swabbing Tests on Whitmore Park Well No. 2, November 28-29, 1979.

Time	Action
11/28/79	
11:00 am	Ran $2^3/_8$-inch tubing with Pengo shifting tool into hole. Pengo casing previously spaced over Sunnyside coalbed and casing cemented in place. Cement plug at bottom of casing still in place.
12:00 pm	Pengo ports closed. Swabbing water from closed well.
3:50	Shot echometer test on tubing prior to opening Pengo ports to Sunnyside formation, water depth 1460 feet.
3:55	Opened ports to Sunnyside coalbed.
4:01	Echometer water depth 1450 feet.
4:03	" " 1440 feet.
4:30	" " 1440 feet.
4:31	" " 1430 feet.
4:40	" " 1460 feet.
4:40	Ran swab #1 in tubing. Water depth measured at 2060 feet.
4:44	Swabbed from 2640 feet, water observed at surface at 420 feet, collected 37 gallons of water.
4:59	Swab #2 measured water depth at 1950 feet, swabbed from bottom (2970 feet), collected 38 gallons of water; no more swabbing.
5:05	Echometer water depth measured at 1590 feet.
5:15	Echometer water depth measured at 1540 feet; closed in wellhead.
11-29-79	
7:35 am	Wellhead opened after being closed overnight; slight vacuum noted, indicating no formation production.
7:37	Echometer water depth measured at 1550 feet.
7:40	Echometer water depth measured at 1550 feet.
8:00	Started swabbing, hit water at approximately 2200 feet.
8:12	Swabbed from bottom, collected 23 gallons of water.
8:30	Closed Pengo ports, coming out of well.

TABLE 7. Sequence Log for Swabbing Tests on Whitmore Park Well No. 2, December 5-6, 1979.

Time	Action
12/5/79	
7:50 am	Open hole formation drilled out and left open since 3:30 pm on 11/4/79, with water at surface.
7:51	Shot echometer prior to running tubing in well, measured water depth 407 feet.
7:52	Echometer repeat, measured water depth 417 feet.
8:02	Echometer repeat, measured water depth 412 feet.
8:10	Running tubing in well.
9:23	Tubing in well; annulus echometer shot, measured water depth 266 feet.
10:05	No swabbing; annulus echometer shot, measured water depth 286 feet.
10:23	No swabbing; annulus echometer shot, measured water depth 295 feet.
10:53	No swabbing; annulus echometer shot, measured water depth 281 feet.
10:54	Started first swab, hit water at 400 feet.
11:00	Bottom of swab at 2400 feet (upstroke begins); collected 275 gallons.
11:05	Started second swab, hit water at 300 feet.
11:10	Pulled swab from 2400 feet, collected 155 gallons.
11:16	Started third swab, hit water at 690 feet.
11:19	Annulus echometer shot, measured water depth 678 feet.
11:28	Pulled swab from 2970 feet, collected 150 gallons.
11:43	Started fourth swab, hit water at 1180 feet.
11:47	Pulled swab from 2970 feet, collected 155 gallons.
11:55	Started fifth swab, hit water at 1450 feet.

TABLE 7. (Continued)

Time	Action
12/5/79	
12:00 pm	Pulled swab from 2970 feet, collected 140 gallons.
12:08	Started sixth swab, hit water at 1690 feet.
12:13	Pulled swab from 2970 feet, collected 100 gallons.
12:23	Annulus echometer shot, measured water depth 1170 feet. Started seventh swab, hit water at 1800 feet.
12:34	Pulled swab from 2970 feet, collected 85 gallons.
12:43	Started eighth swab, hit water at 1800 feet.
12:45	Pulled swab from 2970 feet, collected 90 gallons.
12:56	Started ninth swab, hit water at 1800 feet.
12:58	Pulled swab from 2970 feet, collected 63 gallons; first gas appears ahead of water; gas flared.
1:08	Started tenth swab, hit water at 1800 feet.
1:11	Pulled swab from 2970 feet, collected 59 gallons; gas flared.
1:20	Annulus echometer shot, measured water depth 1400 feet.
1:31	" " 1370 feet.
1:50	" " 1330 feet.
2:00	Installed new swabbing cups.
2:06	Started eleventh swab, hit water at 1700 feet.
2:10	Pulled swab from 2970 feet, collected 132 gallons; gas flared.
2:20	Started twelfth swab, hit water at 1700 feet.
2:23	Pulled swab from 2970 feet, collected 100 gallons; gas flared.
2:31	Started thirteenth swab, hit water at 1820 feet.
2:33	Pulled swab from 2970 feet, collected 60 gallons; gas flared.
2:43	Started fourteenth swab, hit water at 1800 feet.
2:45	Pulled swab from 2970 feet, collected 40 gallons; gas flared.

TABLE 7. (Continued)

Time	Action
12/5/79	
2:59 pm	Started fifteenth swab, hit water at 1800 feet; operater noted water level not solid (gassy); felt solid at 2640 feet.
3:00	Pulled swab from 2970 feet, collected 37 gallons; gas flared.
3:10	Started sixteenth swab, hit water at 1800 feet; solid water noted at 2400 feet.
3:12	Pulled swab from 2970 feet, collected 47 gallons; gas flared.
3:20	Opened line to gas meter.
3:21	Annulus echometer shot, measured water depth 1590 feet.
3:41	Line to gas meter closed, measured 2.75 cubic feet of gas.
3:46	Started seventeenth swab, hit water at 1950 feet; solid water at 2400 feet.
3:49	Annulus echometer shot; remaining echometer shots taken just prior to beginning to pull swab, measured water depth 1480 feet.
3:50	Pulled swab from 2970 feet, collected 65 gallons; gas flared.
3:57	Started eighteenth swab, hit water at 1950 feet; solid water at 2400 feet.
4:00	Annulus echometer shot, measured water depth 1560 feet; pulled swab from 2970 feet, collected 55 gallons; gas flared.
4:08	Started nineteenth swab, hit water at 1950 feet; solid water at 2400 feet.
4:11	Annulus echometer shot, measured water depth 1590 feet.
4:12	Repeat annulus echometer shot, measured water depth 1580 feet.
4:13	Pulled swab from 2970 feet, collected 47 gallons; gas flared.
4:23	Started twentieth swab, hit water at 1950 feet; solid water at 2400 feet.
4:27	Annulus echometer shot, measured water depth 1600 feet.
4:28	Pulled swab from 2970 feet, collected 28 gallons; gas flared.

TABLE 7. (Continued

Time	Action
12/5/79	
4:36 pm	Started twenty-first swab, hit water at 1950 feet; solid water at 2400 feet.
4:39	Annulus echometer shot, measured water depth 1620 feet.
4:40	Pulled swab from 2970 feet, collected 42 gallons; gas flared.
4:49	Annulus echometer shot, measured water depth 1650 feet.
12/6/79	
8:10 am	Annulus echometer shot, measured water depth 756 feet.

Note: Total water swabbed from well was 45.8 barrels. Formation took 40 barrels while circulating after drilling out cement, plus some water left in well above static water level.

TABLE 8. WHITMORE PARK WELL NO. 2 ECHOMETER DATA*

Date	Echo #	Time	1st Reflection Length, in.	Est Water Depth, ft.	Comments
11/28/79	B 1	3:50p	9 7/16	1460	Sunnyside zone closed.
	B 2	4:01	9 3/8	1450	Sunnyside zone open.
	B 3	4:03	9 5/16	1440	(use 155 ft./inch chart)
	B 4	4:30	9 5/16	1440	
	B 5	4:31	9 7/32	1430	
	B 6	-	-	-	
	B 7	4:40	9 13/32	1460	No water production.
	B 8	5:05	10 1/4	1590	Ran additional swabs.
	B 9	5:15	9 29/32	1540	No water production.
11/29/79	B 10	7:37a	10	1550)	Sunnyside zone open overnight;
	B 11	7:40	9 31/32	1550)	no water production.
12/5/79	B 12	7:51a	2 5/8	407)	
	B 13	7:52	2 11/16	417)	No tubing; open hole since 3:30 pm
	B 14	8:02	2 21/32	412)	on 12/4/79.
	B 15	9:23	1 23/32	266	Level raised by running tubing.
	B 16	10:05	1 27/32	286	Level declining; no swabbing.
	B 17	10:23	1 29/32	295	" "
	B 18	10:53	1 13/16	281	" "
	B 19	11:19	4 3/8	678	Second swab completed.
	B 20	12:23p	7 9/16	1170	Begin 7th swab.
	B 21	1:20	9 1/32	1400	Changing swab cups after 10th swab.
	B 22	1:31	8 27/32	1370	No swabbing; level increasing.
	B 23	1:50	8 19/32	1330	" "
	B 24	3:21	10 1/4	1590	Completed 16th swab, metering gas.
	B 25	3:49	9 17/32	1480	Prior to pulling 17th swab.
	B 26	4:00	10 1/16	1560	" 18th "
	B 27	4:11	10 9/32	1590	" 19th "
	B 28	4:12	10 7/32	1580	" 19th "
	B 29	4:27	10 11/32	1600	" 20th "
	B 30	4:39	10 7/16	1620	" 21st "
	B 31	4:49	10 5/8	1650	Swabbing completed.
12/6/79	B 32	8:10a	4 7/8	756	Level increased overnight.

*Echometer shots run on annulus unless stated otherwise.

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