U.S. DEPARTMENT OF ENERGY REGION IV UNCONVENTIONAL GAS PROGRAM: SUMMARY AND ANALYSIS

Prepared By

Whitney R. Telle, Staff Geologist

Dan A. Thompson, Technical Program Assistant

School of Mines and Energy Development
The University of Alabama
University, Alabama 35486

Under DOE Contract
#FG44-20-R410333
(Amendment #3)

December, 1984

EXECUTIVE SUMMARY

The DOE Region IV Unconventional Gas Program involved the evaluation of unconventional gas resources at ten sites in the coal fields of the Eastern United States. These projects dealt mainly with coalbed methane resources, although three of them also examined potential gas resources in Devonian black shales. The resource evaluations were accomplished primarily through recovery of core samples of potential gas-bearing strata and determination of specific gas content using the U.S. Bureau of Mines direct method. In some cases actual gas production from the test holes was evaluated.

Four of the projects were sited in the Warrior Basin, three in the Central Appalachian Basin, and one each in the Northern Appalachian Basin, the Deep River Basin of North Carolina, and the Valley Coal Fields of Virginia. Results from three of the projects, two in the Warrior Basin and one in the Northern Appalachian Basin, indicated the potential for economic recovery of coalbed methane.

The projects included in this program provided a large body of data which is valuable to subsequent unconventional gas research. The program also provides new direction for unconvential gas exploration. Adjustments to coalbed methane resource estimates for some Eastern coal basins may be indicated by the results obtained. An update on the legal status of coalbed methane ownership in states where projects were conducted is provided in Appendix I.

ACKNOWLEDGMENTS

Work on this project was conducted under the terms of an amendment to DOE grant # FG44-20-R41033. The project was conceived by Bill Rankin, former Program Manager for the Region IV Office of Resource Applications and work was begun under the direction of Dan A. Thompson, Technical Program Assistant, School of Mines and Energy Development (SOMED), University of Alabama. The report was prepared chiefly by Whitney Telle, SOMED Staff Geologist, with assistance from Dan A. Thompson and the SOMED support staff. The appended section on methane gas ownership was prepared by Sarah Katheryn Farnell, Office of Energy and Environmental Law, University of Alabama. The final report was reviewed and approved by J. Read Holland, Director, SOMED.

Appreciation is expressed to Bill Rankin and James Dickey both now of DOE Savannah River Operations Office for their support and cooperation. Special thanks are due the project directors and principal investigators who responded to questions and requests for information concerning their respective projects.

FOREWARD

The DOE Region IV Unconventional Gas Program was initiated on August 8, 1980 when the Region IV Office in Atlanta, Georgia began accepting proposals for development projects to be located primarily in the Southeast.

The ultimate goal of the program was to accelerate the availability of natural gas from coalbeds and Devonian shale in order to augment conventional supplies, especially during periods of deliverability short-fall.

As originally conceived, the program was to be characterized by three essential phases: (1) Exploratory Drilling, (2) Production Drilling and (3) Systems Development. Due to changing priorities within DOE, production drilling and systems development have received little support through the Region IV Program. Limited production drilling and systems development have been initiated at the University of Alabama through cost-sharing agreements with the American Public Gas Association (APGA) with APGA funds coming in part from the DOE Morgantown Energy Technology Center. Funds for Phase I (exploratory drilling) were made available to Region IV by the DOE Office of Oil and Natural Gas Resource Applications under the auspices of P.L. 95-238, Department of Energy Act of 1978.

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INTRODUCTION

Within the past five years unconventional natural gas has emerged as a viable and potentially profitable energy source. The Appalachian region has been a focus of the search for unconventional gas resources, particularly in the coal fields and in areas underlain by carbonaceous black shales. In order to encourage the development of unconventional natural gas the United States Department of Energy (DOE) funded a number of projects aimed at evaluating potential unconventional gas sources in the Appalachian region, which is included in the DOE Region IV (Fig. 1).

These projects were conducted by a number of educational and governmental agencies and by private consulting firms. Although there are many similarities in the manner in which these projects were conducted and in the way the resources were evaluated, many differences exist.

In order to make the data generated in the DOE Region IV Unconventional Gas Evaluation Program more accessible and usable, the Department of Energy awarded a contract to the School of Mines and Energy Development of The University of Alabama to prepare a standardized summary of the project reports. Each of the project reports was carefully reviewed and pertinent data was summarized according to a standard outline. This outline is presented below:

I. General Nature of Project

  A. Reason for Project

  B. Project Area

  C. Technical Aspects of Project

    1. Drilling Technique

2. Drilling Contractor
3. Preparer of Lithologic Logs
4. Types of Geophysical Data Generated
5. Type and Amount of Potentially Gas-bearing Strata Encountered

D. Testing Methods Employed
1. Coal Analysis
2. Gas Quantity Determination
3. Gas Quality Determination
4. Production Testing

II. Resource Characterization

A. Results of Testing
1. Coal Rank and Ash Content
2. Specific Gas Content of Coal
3. Gas Quality
4. Well Productivity

B. Coal Resource Base

C. Unconventional Gas Resource Base

D. Potential (or Actual) Gas Productivity
1. Recovery Method Proposed
2. Estimated Production Rate

III. Economics of Resource Development

A. Statement of Base Case

B. Sensitivity Analysis

C. Other Economic Factors Addressed

IV. Environmental Ramifications of Resource Development

V. Other Factors Addressed in Report

VI. Summarizer's Comments

Additionally, where applicable, the following maps, sections, and graphs were prepared:

1. Location maps of test well sites
2. Sections of potential gas producing strata encountered in drilling
3. Graphs showing intermediate coalbed methane content vs. depth.
4. Detailed sections of potential gas producing zones considered for development

The appendices contain tabulated data which includes general project information, results of desorption, gas quality, gas resource totals, production potentials, and projected economics of development. Additionally, methods used in determining coal gas content and in calculating coal and coalbed methane resources are outlined. A summary of current laws pertaining to the ownership of coalbed methane also appears in the appendices.

A summary of each project report follows, appearing in approximate chronological order of publication. No summary of the Richmond Basin Project, conducted by Merrill Natural Resources, Inc., is included since the project generated no useable information.

Conflicting or unclear information was found in some reports. Where possible, these problems were resolved and noted in this summary. For this reason, some data given in the summary may not agree exactly with that contained in the reports.

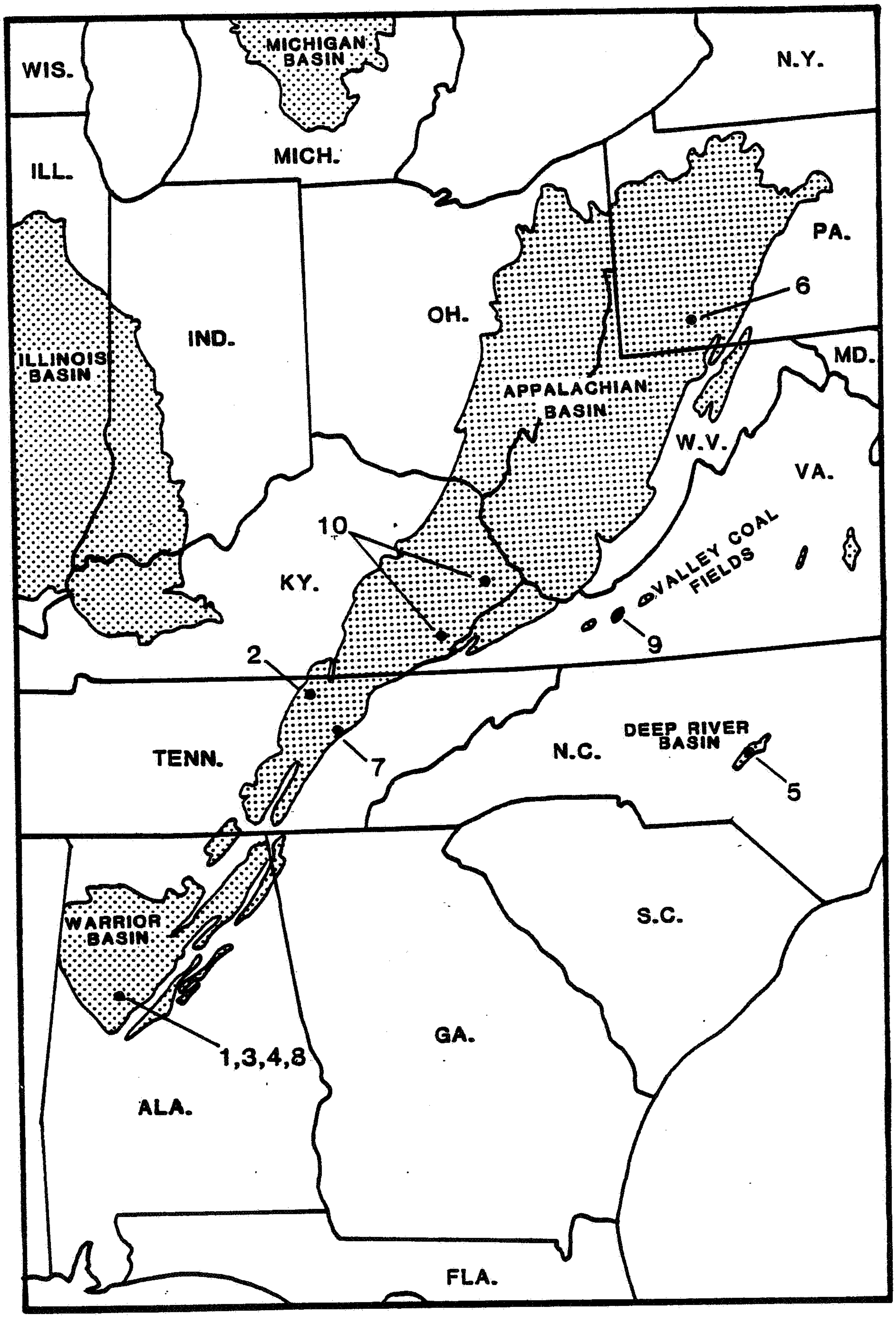


Figure 1 General location map of Eastern Coal Fields and D.O.E. Region IV Unconventional Gas Assessment Projects (See Appendix A for project reference numbers).

PROJECT REPORT SUMMARIES

1. UTILIZING THE UNCONVENTIONAL GAS RESOURCES OF THE POTTSVILLE FORMATION COALS IN TUSCALOOSA COUNTY, ALABAMA (UNIVERSITY OF ALABAMA PROJECT).

This report was prepared by the School of Mines and Energy Development of the University of Alabama for the U.S. Department of Energy under Contract Number DE-FG44-80R410333. The final report was submitted in September, 1981.

General Nature of Project

This project was conducted to assess the feasibility of providing coalbed methane for use by the physical plants of the University of Alabama and Bryce State Hospital. These institutions hold over 1000 acres in sections 13, 14, 23, and 24, Township 21 South, Range 10 West, Tuscaloosa County, Alabama.

In order to assess the unconventional gas resource of the area, 2965 feet of continuous NX core were recovered by Joy Manufacturing Company of LaPorte, Indiana using a wireline drilling rig. The core hole, located at latitude 33° 12' 44" north and logitude 87° 31' 48" west, Tuscaloosa County, Alabama, was sited at a surface elevation of 262 feet above mean sea level (Fig. 2). The recovered core was logged by personnel of the Geological Survey of Alabama. Upon completion of coring a suite of geophysical logs including natural gamma, long spacing density, caliper, bed resolution density, reversed expanded scale natural gamma, expanded scale long spacing density, single point resistivity, absolute temperature, and differential temperature was run by BPB, Incorporated.

The drilling targets were the coal seams of the Pottsville Formation in the Warrior Basin of Alabama. In all, 33 lineal feet of coal were recovered from the core hole, including coal seams of the Utley, Gwin, Cobb, Pratt, Mary Lee and Black Creek Coal Groups. Individual

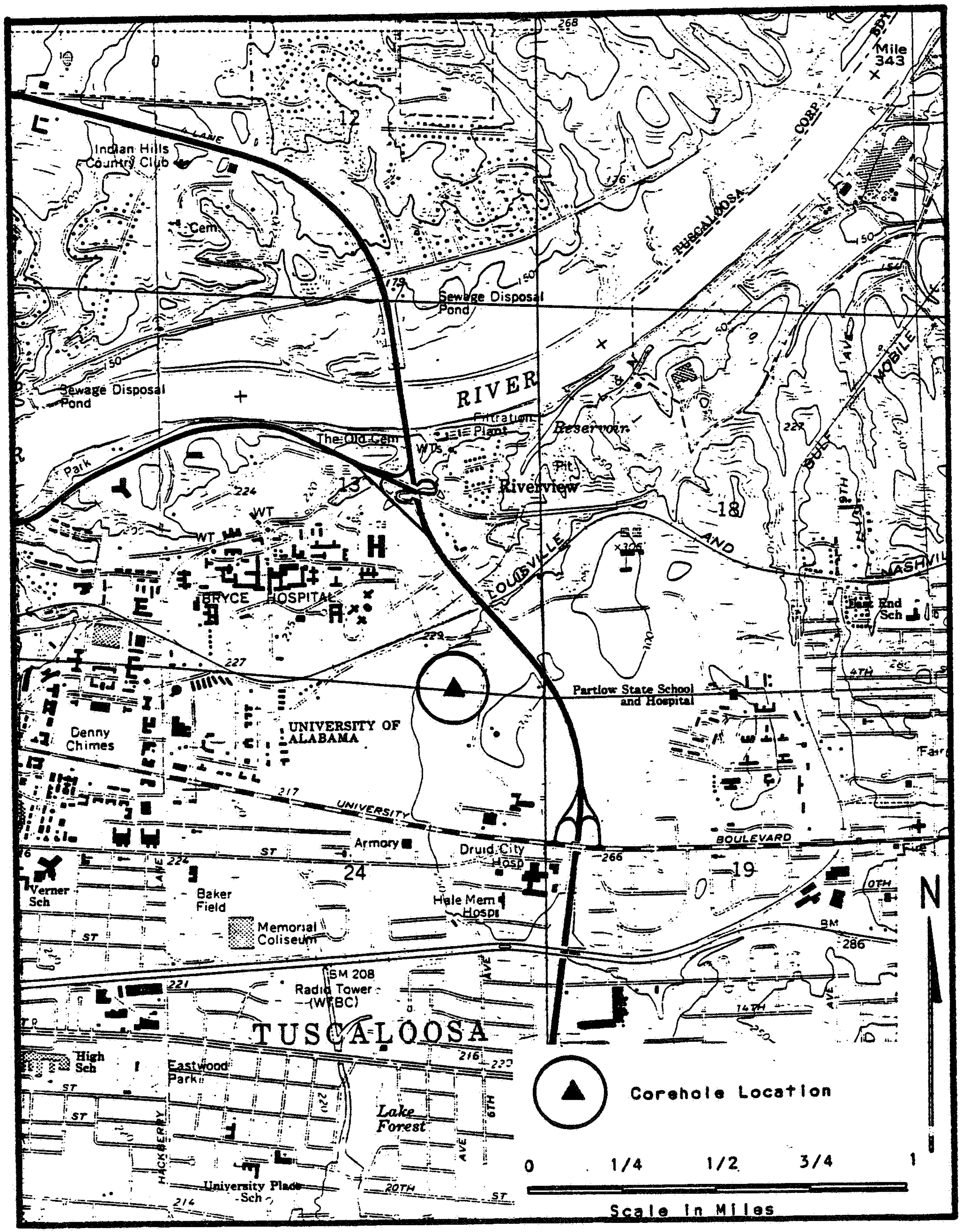


Figure 2. Location Map of the University of Alabama Corehole
(From Tuscaloosa, Alabama 7.5 minute topographic quadrangle)

coal seams recovered for testing ranged in thickness from 0.33 feet to 3.80 feet and ranged in depth from 227 feet to 2671 feet (Fig. 3).

Resource Characterization

Recovered coal cores were tested for gas content by the U.S. Bureau of Mines direct method (Appendix B). Selected coal samples were then subjected to short proximate analyses. No gas production testing was indicated in the report. Gas quality was determined by gas chromatography.

Analyzed coal samples all proved to be high volatile A bituminous in rank. As received, ash content ranged from 3.7% to 40.4% with a simple arithmetic average of 17.5% ash. Intermediate (lost plus desorbed) gas content of the coal seams sampled ranged from 4 cf/t to 452 cf/t with a weighted average intermediate gas content of 235 cf/t. Relative gas content of the coal samples appears to be a function of depth, with 168 cubic feet per ton of gas per 1000 feet of depth being the upper limit of intermediate gas content (Fig. 4). There is a considerable scatter of data points below this limit and below a depth of 300 feet, an approximate mean of the increase in gas content is 150 cubic feet per ton for every 1000 foot increase in depth.

Because of their total coal thicknesses and relatively high gas contents, the Mary Lee Group and Black Creek Group of coal seams are considered potential targets for coalbed methane gas development (Fig. 5). There is a total of 10.4 feet of producible coal within a 31.8 foot stratigraphic interval in the Mary Lee Group. This coal has a weighted average intermediate gas content of 328 cf/ton. The Black Creek seam contains 3.0 feet of producible coal with an intermediate gas content of 341 cf/ton.

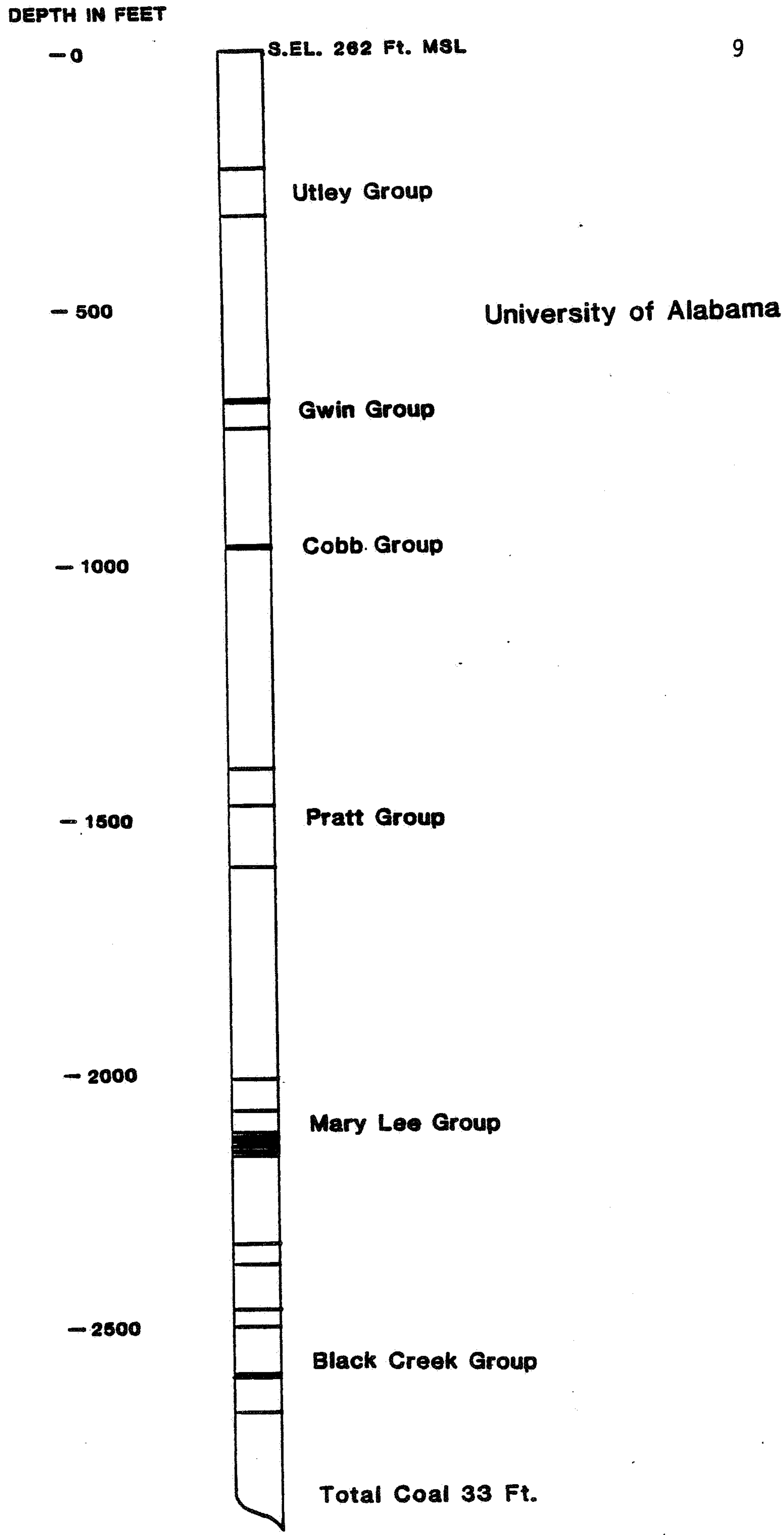


Figure 3. Stratigraphic Section Showing Potential Gas Producing Strata Encountered in the University of Alabama Corehole

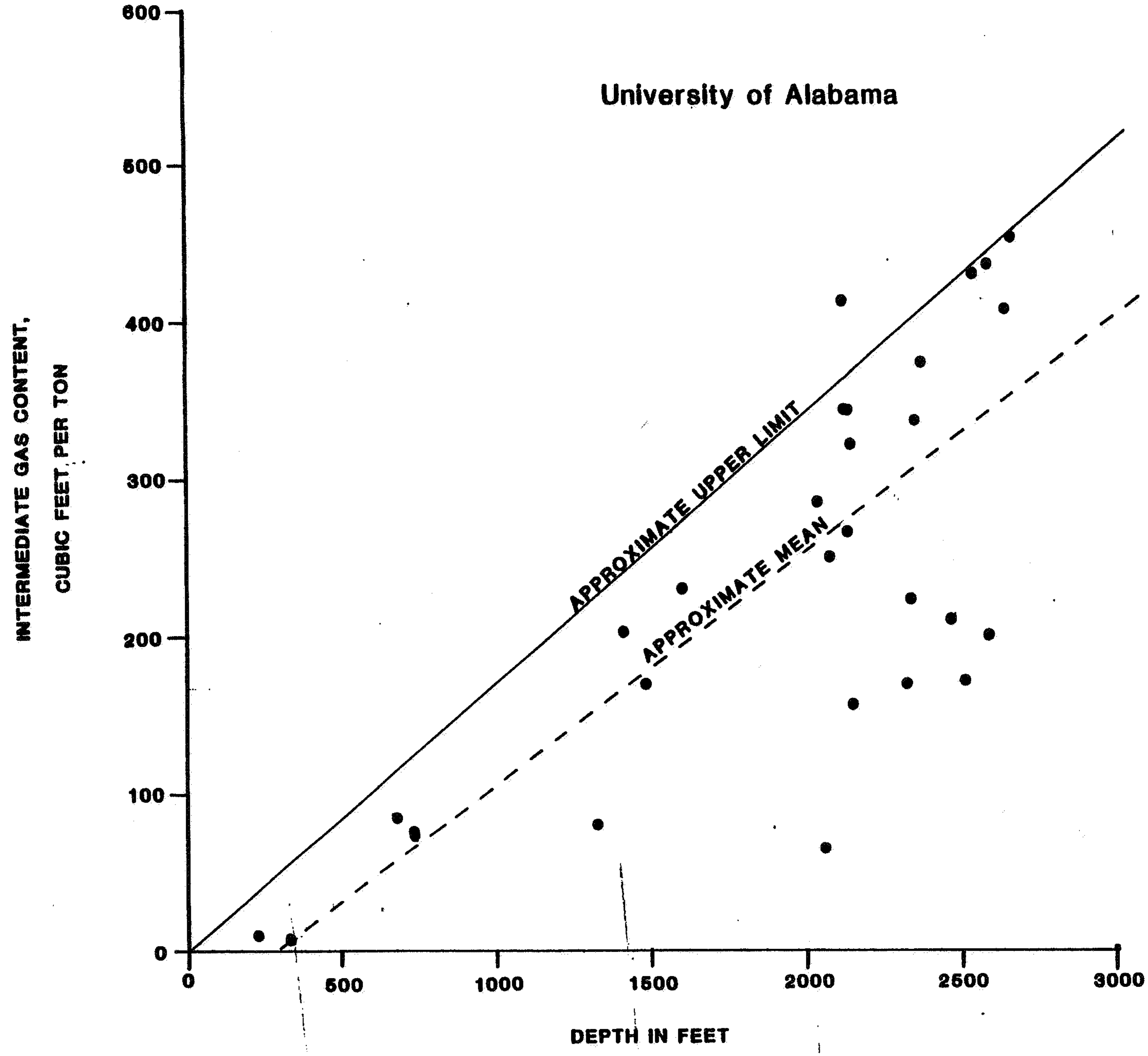


Figure 4. Graph Showing Intermediate Coalbed Methane Content vs. Depth in the University of Alabama Corehole

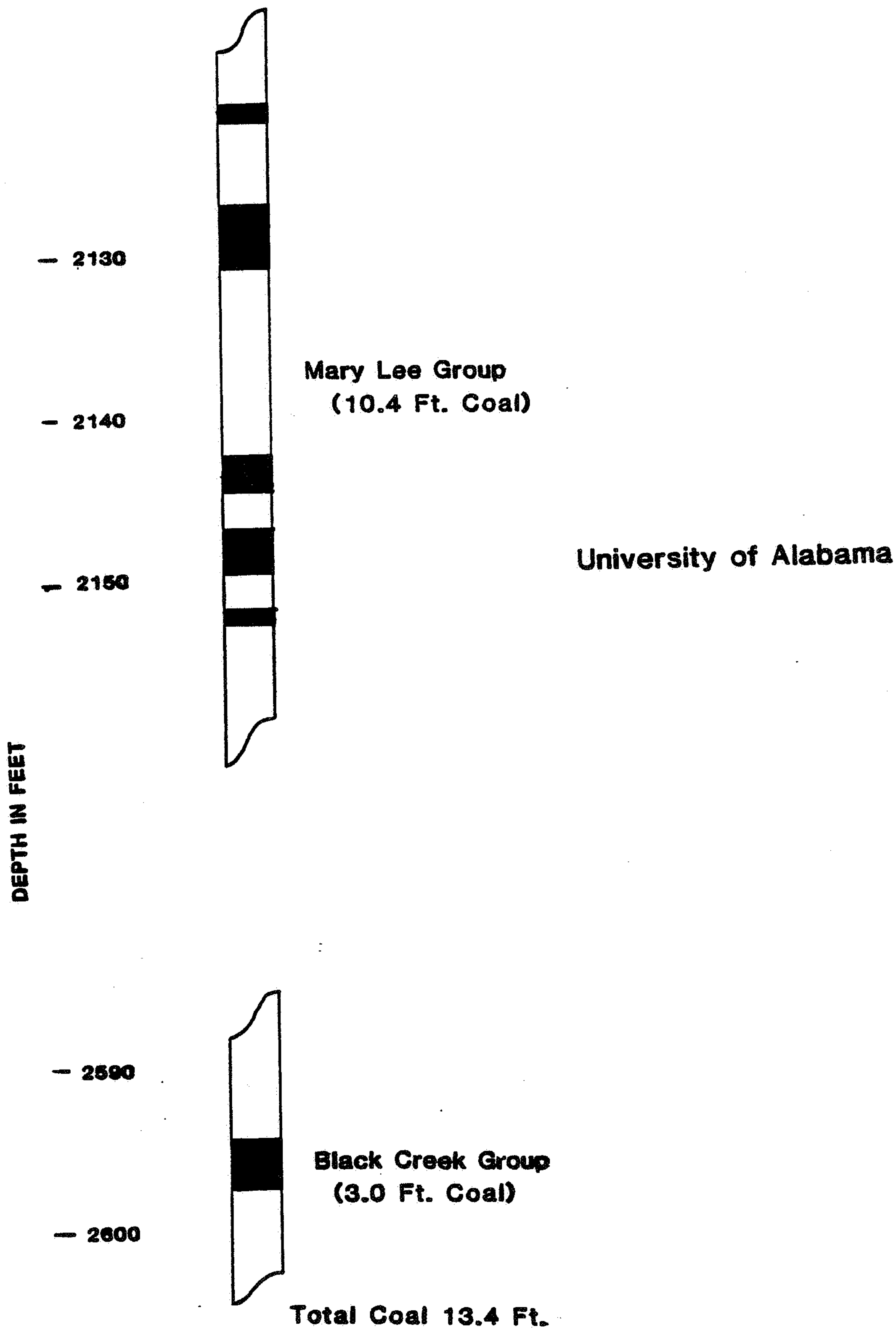


Figure 5. Detailed Sections of Potential Gas Producing Zones Considered for Development in the University of Alabama Report

Gas samples recovered from five coal cores of the Mary Lee Group yielded the following average composition:

	Component	Mol %
Methane	(CH_4)	90.2
Ethane	(C_2H_6)	0.078
Oxygen	(O_2)	1.50
Carbon Dioxide	(CO_2)	0.49
Nitrogen	(N_2)	7.70

Heating value of these samples averaged 915 Btu/cf. The report stated that two of the five gas samples possibly contained residual atmospheric gases due to collection of gas samples within a few days of sample collection. Average composition of the three remaining gas samples are as follows:

	Component	Mol %
Methane	(CH_4)	96.3
Ethane	(C_2H_6)	0.050
Oxygen	(O_2)	0.36
Carbon Dioxide	(CO_2)	0.45
Nitrogen	(N_2)	2.87

Heating value of these three samples averaged 975 Btu/cf.

The total coal resource for all seams encountered is approximately 55,000 tons per acre, or 55,000,000 tons over the 1000 acre project tract. Within the Mary Lee and Black Creek Group target zones, the in-place resource of coal is equal to 22,230 tons per acre, or approximately 22,230,000 tons on the entire project tract of approximately 1000 acres.

The methane resource contained in all coal seams encountered is approximately 13 MMcf/acre, or 13 Bcf over the 1000 acre project area. Within the production target zones the in-place producible coalbed methane resource is 5,972 Mcf/acre in the Mary Lee Group and 1,790 Mcf/acre in the Black Creek Group for a total of 7,762 Mcf/acre. This results in a total in-place producible gas resource of 7.8 Bcf over the approximately 1000 acre project area. Conventional vertical wells employing unspecified stimulation techniques are considered for coalbed methane gas recovery in the area. These wells will be situated on 40 acre spacings. The predicted gas production rate from the target zones is 22,876 Mcf/year for a period of ten years. This production rate constitutes approximately 75% total recovery of the in-place intermediate gas resource.

Economics of Resource Development

The base case model for the economic feasibility study stipulates a production well installation cost of $272,000 with $35,200 per year operating costs. With a production rate of 22,876 Mcf/year, payback is achieved in 5.8 years with an internal rate of return of 15.5%. Sensitivity studies were conducted using five factors listed below:

a. Natural gas price: Case 1 - low; Case 2 - expected; Case 3 - high

b. Well casing: Case 1 - open hole completion; Case 2 - continuous casing, slotted at production zones.

c. Stimulation: Case 1 - one zone; Case 2 - 2 zones.

d. Well life: Case 1 - 10 years; Case 2 - 15 years.

e. Total recovery of in-place resource: Case 1 - 75%, Case 2 - 65%; Case 3 - 50%.

Internal rates of return and payback periods for each case of each factor are presented below with the base case underlined. These cases were computed for a single well and for a three-well module in which some advantage is realized through economy of scale.

		1 Well		3 Wells	
Factor	Case	Payback Years	IRR%	Payback Years	IRR%
a	1	6.01	13.81	4.78	20.90
	2	5.79	15.49	4.59	22.46
	3	4.46	25.20	3.73	31.92
b	1	5.79	15.49	4.59	22.46
	2	6.13	13.84	4.88	20.55
c	1	8.22	5.89	6.08	15.49
	2	5.79	15.49	4.59	22.46
d	1	5.79	15.49	4.59	22.46
	2	13.65	2.09	9.06	9.74
e	1	5.79	15.49	4.59	22.46
	2	7.38	8.71	5.68	15.93
	3	>10	(7.78)	9.05	3.20

Additionally, 40 acre well spacings on 240 acres was compared to 80 acre spacings on the same area. In the case of 40 acre spacing, three wells are installed ~~in~~ year 1 with an additional three installed in year 11, making a total project life of 20 years. In the case of 80 acre spacing all three wells are installed in year 1.

	40 Ac. Spacing	80 Ac. Spacing
# Wells	6	3
Capital Investment	\$715,000 year 1; \$715,000 year 11	\$715,000 year 1
IRR%	23.68	25.35

This report states that a generally acceptable return on medium risk investments such as coalbed methane development is 20% or greater. If 75% recovery can be achieved over a 10 year well life, such a project appears justifiable at this time.

Environmental Ramifications of Resource Development

An environmental assessment presented in this report states that the coring project would cause slight negative effects through soil loss and loss of wildlife habitat, groundwater contamination, and noise. Installation of production wells could cause an additional negative impact through production of large quantities of water with a high chloride content. This effect can be mitigated, however, by releasing the water into the Tuscaloosa muncipal sewage system for treatment.

Other Factors Addressed in Report

Other factors addressed in this report include statements of human resoure management, financial management, and financing options. Well development will be accomplished by outside contractors under the supervision of the School of Mines and Energy Development. The University of Alabama will manage production and utiliation of gas through its existing facilities. Financing may be done by the University, or capital may be borrowed from local banks.

Summarizer's Comments

Subsequent to the completion of this project, the corehole was deepened to a total of 4,000 feet. The purpose of this extension was to test the deeper-lying seams of the "J" Coal Group. This coal group has seldom been explored in the deeper portions of the Warrior Basin, and geophysical logs derived from oil and gas exploration indicated the local presence of these deeper coals.

In this extension of the core hole, a total of 1.54 feet of coal lying in three benches at depth ranging from 3214 feet to 3738 feet were recovered. Specific intermediate gas content of the samples ranged from 300 cf/ton to 416 cf/ton with a weighted average value of 368 cf/ton.

Although the thickness of the coal encountered was insufficient to warrant development, this core hole extension provided the only published data on the gas potential of "J" Group seams. There are indications of thicker sections of "J" Group coals in other parts of the Warrior Basin, and the high specific gas content detected in this project extension will foster future exploration.

Because of the encouraging results of the University of Alabama project, the School of Mines and Energy Development installed two demonstration production wells on the University Campus. The first of these wells was completed in the Mary Lee and Blue Creek seams as a single zone completion. The second was completed in the Pratt, the Mary Lee and the Blue Creek seams as three separate zones. The Pratt completion was subsequently sealed off due to excessive water production.

Although initial gas production from these wells totaled as much as 45 Mcf/day, the wells have not at present been successfully dewatered. Eventualy gas production will be used to power an experimental fuel cell, to heat the University's physical plant and to provide compressed natural gas for the operation of University vehicles.

2. FENTRESS COUNTY UNCONVENTIONAL GAS WELL PROGRAM

This report was prepared by Hensley-Schmidt, Inc., of Chattanooga, Tennessee for the Tennessee Energy Authority and the Fentress County Chamber of Commerce under contract number DE-FG44-81R410426. The Final Report was submitted in May 1982.

General Nature of Project

This project was conducted to assess the feasibility of establishing an unconventional gas supply at the Fentress County Industrial Park site, a 32.5 acre tract adjoining the northwest corporate limits of the city of Jamestown, Tennessee.

In order to assess the unconventional gas resource of the area, Smith Brothers Drilling Company was contracted to drill a test well to a total depth of 1405 feet. Continuous core was recovered at two intervals, from 80 feet to 90 feet and from 1320 feet to 1370 feet. This drilling site, located at latitude 36° 25' 42" north and longitude 84° 55' 57" west, Fentress County, Tennessee lay at a surface elevation of 1758 feet (Fig. 6). Recovered core was logged by Dixie Brackett of Hensley-Schmidt, Inc. Upon completion of drilling, Well Services, Inc. ran a suite of geophysical logs consisting of gamma ray/neutron resistivity, bulk density, porosity, and differential temperature. The drilling targets were the Nemo coal seam and the Chattanooga Shale. In all, 19 inches of coal were encountered at a depth of 84.5 feet and 46 feet of black shale were encountered at a depth of 1320 feet (Fig. 7).

Upon retrieval the coal core was measured, described, and divided into three separate samples for gas testing. Gas testing was conducted in accordance with the U.S. Bureau of Mines direct method (Appendix B).

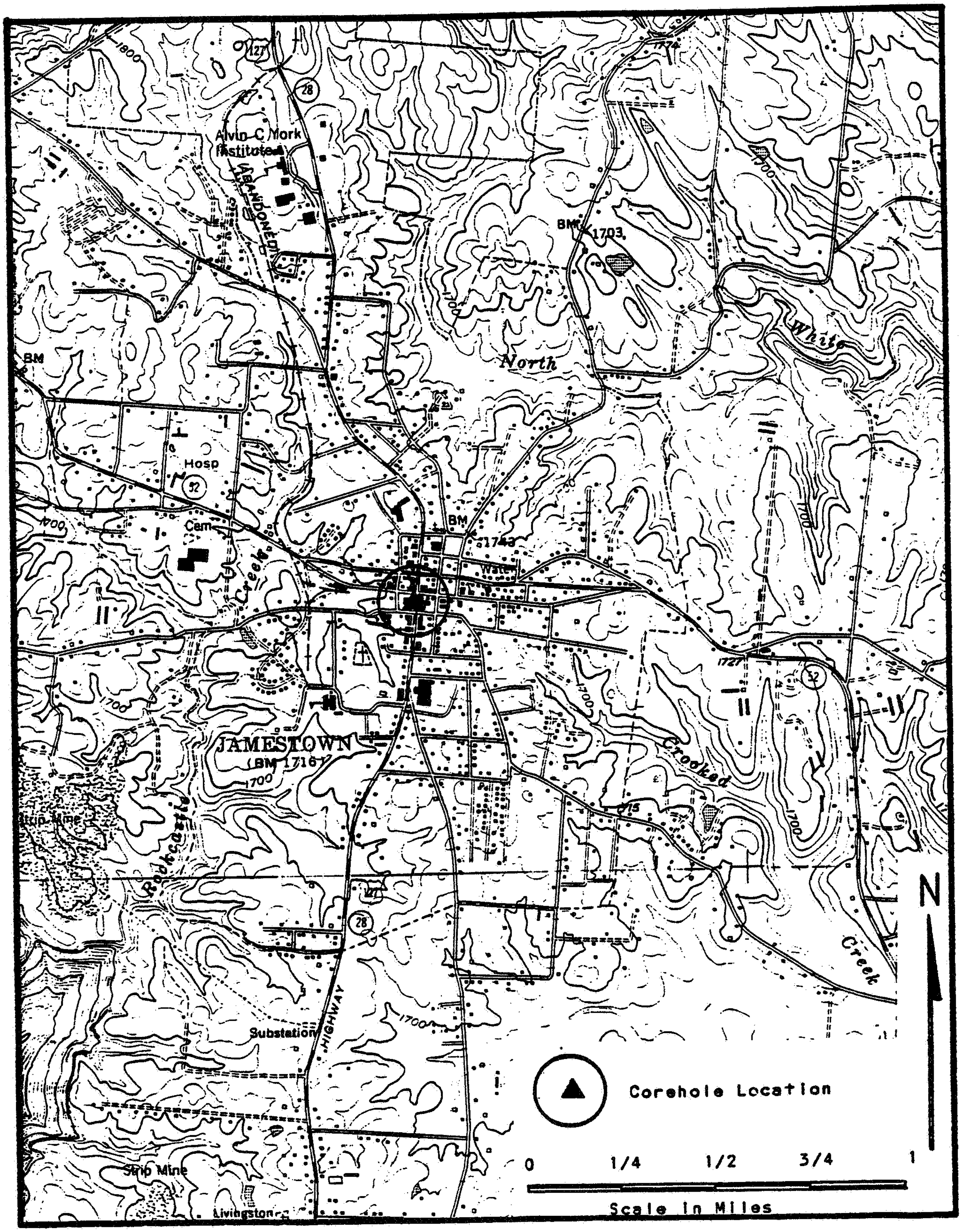


Figure 6. Location Map of The Fentress County, Tennessee Corehole (From Jamestown, Tennessee 7.5 minute topographic quadrangle)

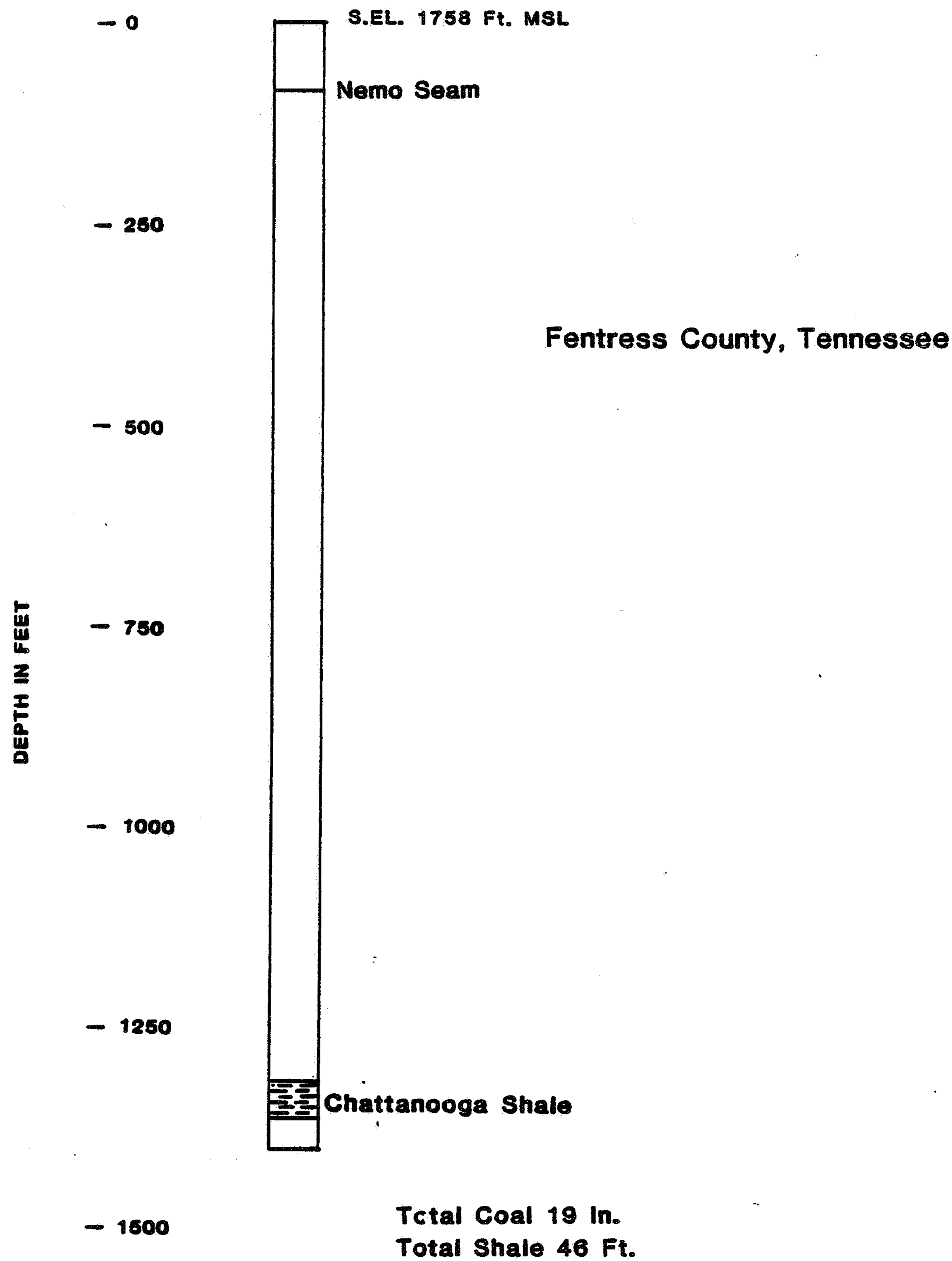


Figure 7. Stratigraphic Section Showing Potential Gas Producing Strata Encountered in the Fentress County, Tennessee Corehole

Coal samples were then subjected to short proximate analyses. Six feet of the recovered Devonian shale taken from two intervals were also placed in two canisters for desorption by the direct method.

No analyses of gas quality were reported. A gas deliverability test was performed on the hole prior to sealing.

Resource Characterization

Rank of the Nemo coal seam ranged from high volatile C bituminous in the upper and lower portions of the seam to low volatile bituminous in the middle seam sample. As-received ash content of the samples was not reported. Total gas content of the coal samples ranged from 0 to 8 cf/t with a weighted average total gas content of 4.7 cf/t. No gas was detected through direct method determination of the black shale samples. During the gas deliverability test, no measureable accumulation of gas was observed in the well. The report suggested, however, that the well may have contained fluid which should be bailed out for retesting of the well.

No calculation of the coal resource base was presented in the report, but the 19 inch Nemo seam would comprise an in-place coal resource of 2850 tons per acre or 92,625 tons on the 32.5 acre industrial park site. The in-place methane resource (on the 32.5 acre site) was reported as 408 cubic feet of gas but this should read 408 Mcf.

Economics of Resource Development

Because of the extremely small amount of gas resource indicated at the site, no production method was proposed nor was any production rate predicted. At the reported Federally regulated gas price of $2.59 per thousand cubic feet, the value of the coalbed methane lying under the 32.5 acre site was calculated at $1,056.72. With such a low resource value, there is little prospect of development.

Environmental Ramifications of Resource Development

No assessment of the environmental impact of coalbed methane development in the area was presented.

Other Factor Addressed in Report

A paper entitled "Survey of Gaseous Components of the Chattanooga Shale in the Northern Highland Rim Area" was appended to the report. This paper was prepared by H. Wayne Leimer of the Department of Earth Sciences, Tennessee Technological University. The paper presents an analysis of gaseous and hydrocarbon values of Chattanooga Shale samples in the Fentress County area, and states that the Chattanooga Shale section encountered in the Fentress County well was anomalously thick.

Summarizer's Comments

Kim (1977) stated that the methane content of shallow, high-volatile bituminous coals may be estimated using the formula $V = 0.-25h - 0.5$ where V is the gas volume in cc/g and h is the seam depth in meters. Applying this formula to the Fentress County Well, a methane content of 5 cf/ton is estimated, which agrees well with the actual data.

3. UTILIZING THE UNCONVENTIONAL GAS RESOURCES OF THE POTTSVILLE FORMATION COALS IN TUSCALOOSA COUNTY, ALABAMA (CITY OF TUSCALOOSA PROJECT)

This report was prepared by the School of Mines and Energy Development of The University of Alabama and by the City of Tuscaloosa for the U.S. Department of Energy under contract number DE-FG44-80R410337. The final report was submitted in June, 1982.

General Nature of Project

This project was conducted to assess the potential for coalbed methane development in the Kauloosa Industrial Park, an area in the southwestern section of the City of Tuscaloosa comprised of several moderate-sized industrial facilities. Estimated natural gas consumption of these industries on average exceeds 20 million cubic feet per month. In addition to potentially providing a gas supply to these industries, the gas in liquefied form could serve as fuel for municipal vehicles.

To evaluate the unconventional gas resource of the area, 2882 feet of continuous core were recovered by Joy Manufacturing Company of LaPorte, Indiana. The site chosen for drilling was situated at latitude 33° 10' 41" north and longitude 87° 33' 58" west, Tuscaloosa County, Alabama, and lay at a surface elevation of 156 feet above mean sea level (Fig. 8). Recovered core was logged by personnel of the United States Geological Survey and the Geological Survey of Alabama. Upon completion of drilling, a suite of geophysical logs comprised of natural gamma, long spacing electron density, caliper, expanded scale reversed electron density, high resolution electron density, absolute temperature, and differential temperature was run by BPB, Inc.

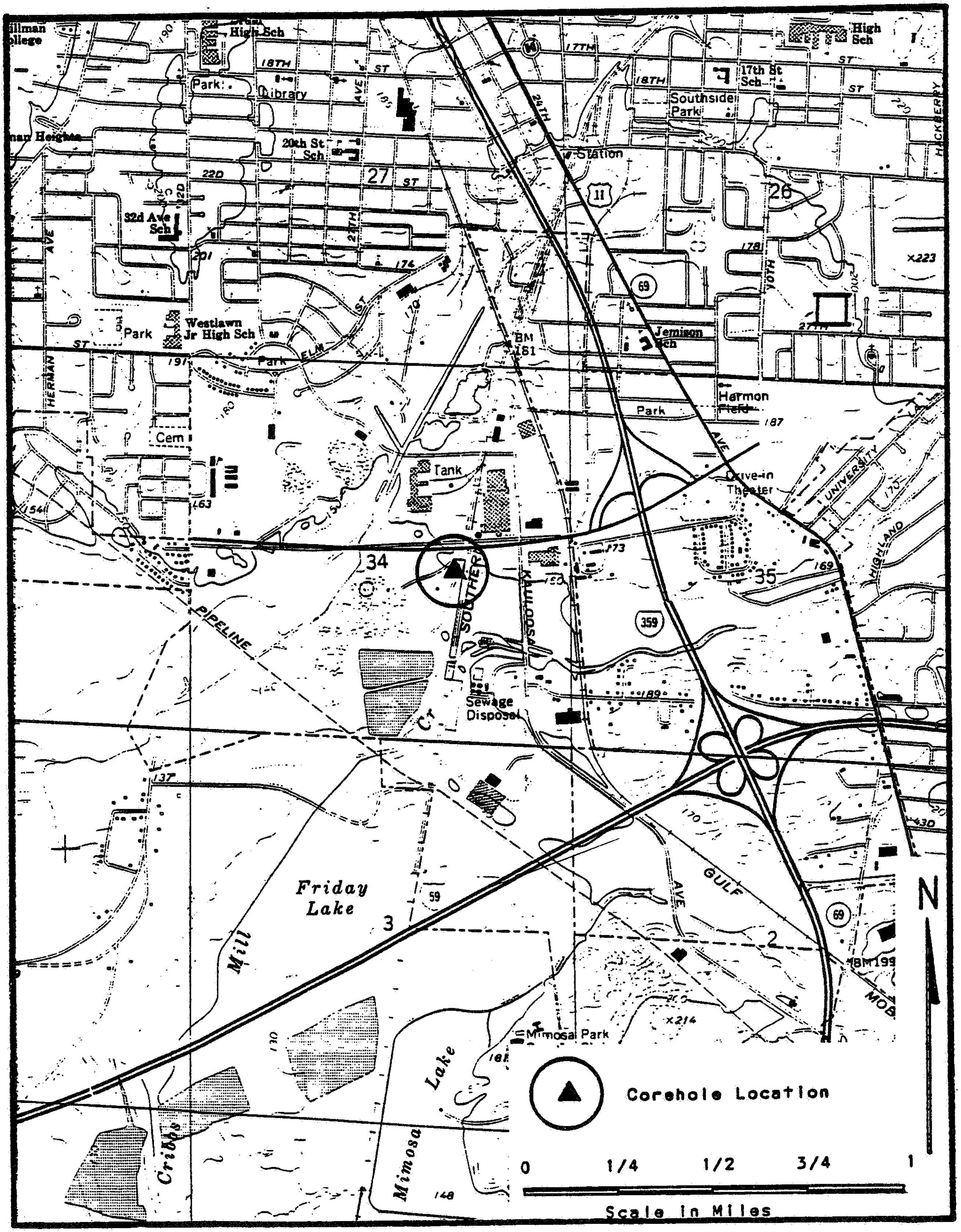


Figure 8. Location Map of the City of Tuscaloosa, Alabama Corehole (From Tuscaloosa, Alabama 7.5 minute topographic quadrangle)

The coal seams of the Pottsville Formation of the Warrior Basin of Alabama were the drilling targets. In all, approximately 33 lineal feet of coal were encountered in six groups ranging from the Utley Group down to the Black Creek group (Fig. 9). The individual coal seams ranged from 0.1 feet to 3.58 feet in thickness and from 388 feet to 2857 feet in depth.

The coalbed methane content of the coal seams was determined by the U.S. Bureau of Mines direct method determination (Appendix B). Subsequent to gas content determination, short proximate analyses and other tests were run on selected coal samples. Composition of selected samples of the desorbed gas was determined by gas chormatography. No production testing of the drill hole was attempted.

Resource Characterization

Results of coal sample analyses indicate that the analyzed coal sample are high volatile A bituminous in rank. Intermediate gas content of the coal samples range from 29 cf/ton to 455 cf/ton. A correlation exists between coal depth and gas content, with 158 cf/ton of gas per 1000 feet of depth serving as an upper limit to gas content. There is a considerable amount of scattering of the data points below this limit (Fig 10). An approximate mean of the increase in gas content with depth is approximately 100 cubic feet per ton per 1000 feet. As-received ash content of the coal samples analyzed range from 4.5% to 50.0% with a simple arithmetic average ash content of 22.1%.

Seams in three of the coal groups cored are considered targets for potential coalbed methane recovery due to the high specific methane content of the coal and the relative thickness of the seams. The development strategy assumes that all coal within a fifty foot stratigraphic interval

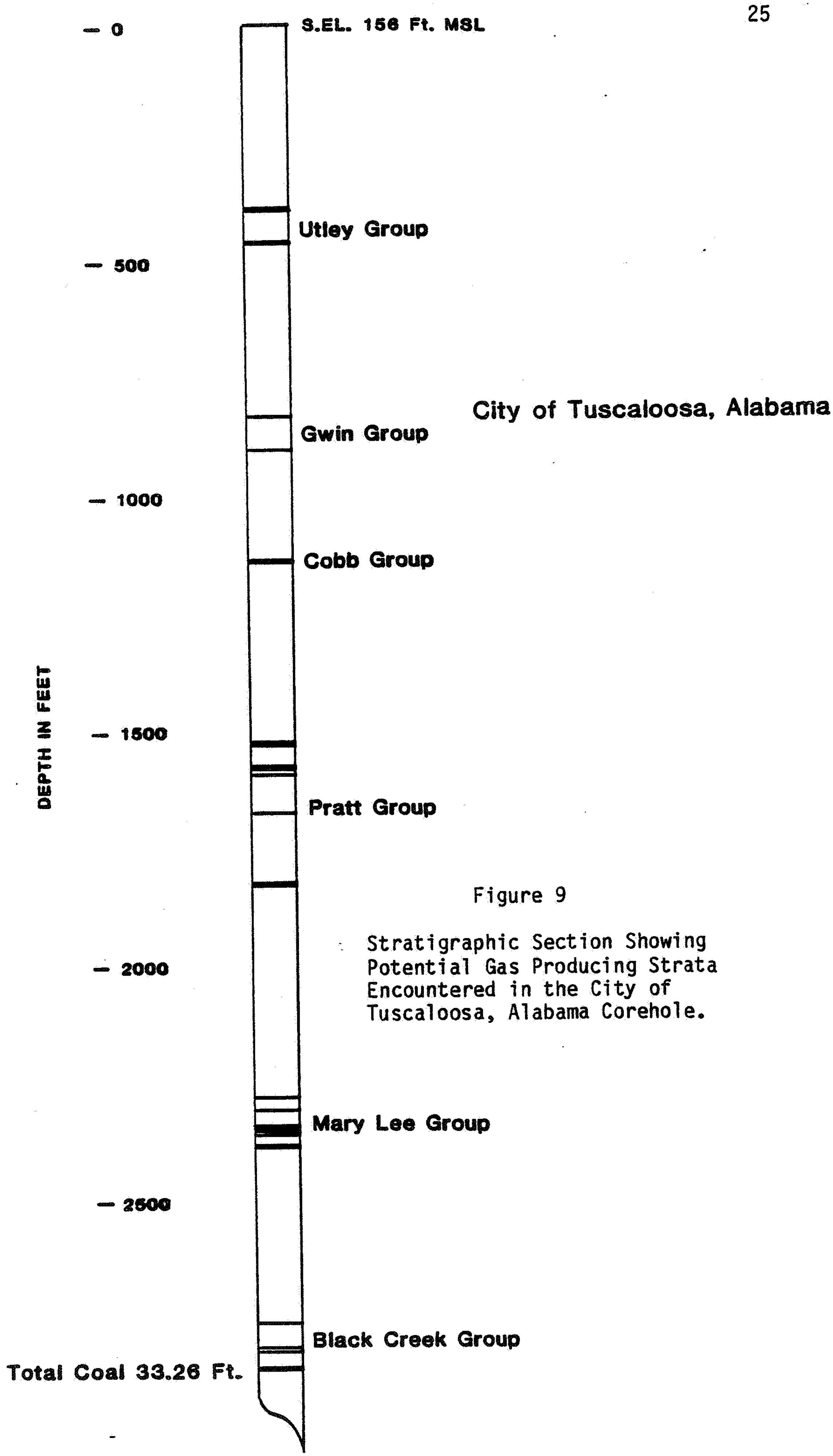


Figure 9

Stratigraphic Section Showing Potential Gas Producing Strata Encountered in the City of Tuscaloosa, Alabama Corehole.

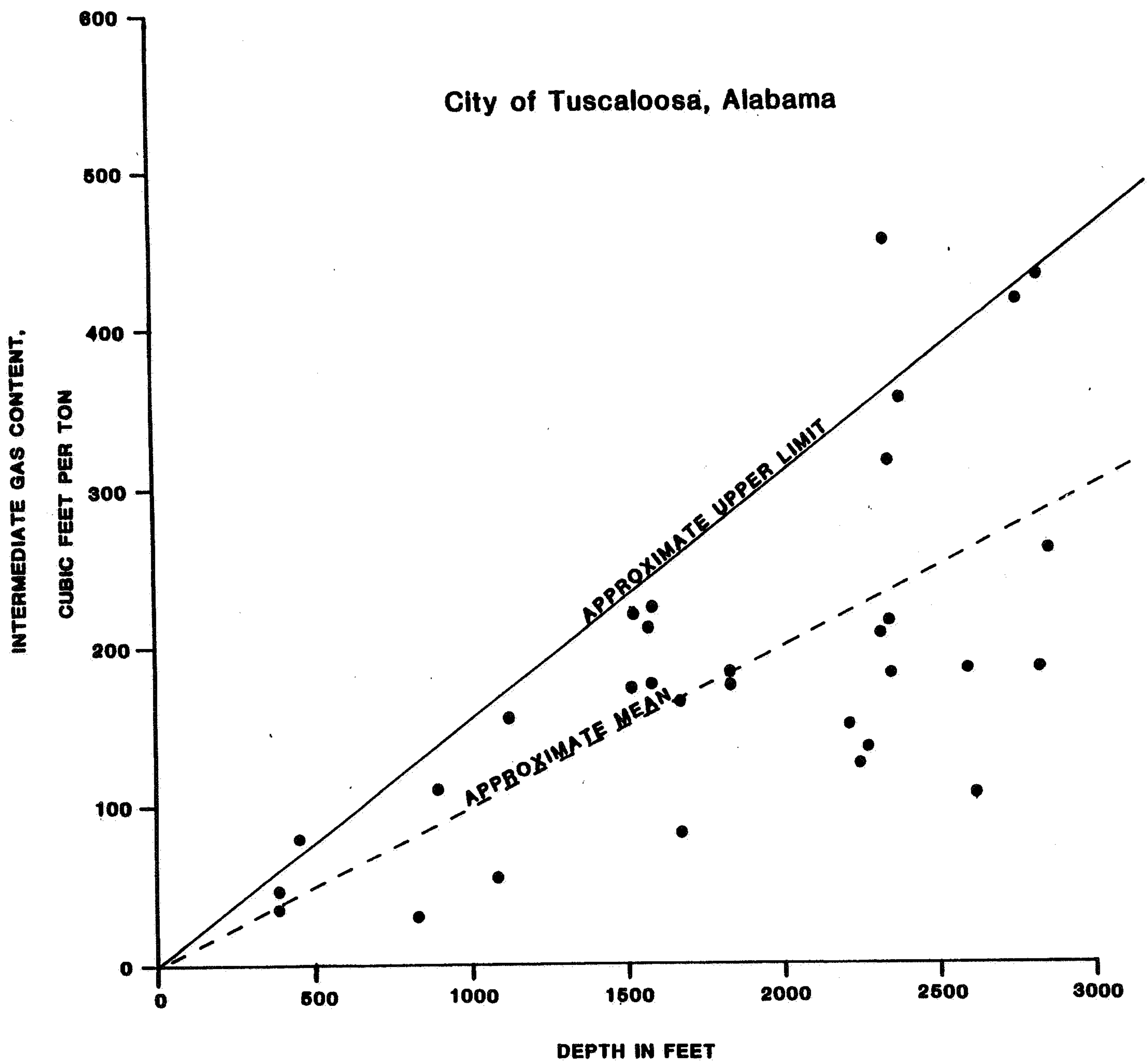


Figure 10. Graph Showing Intermediate Coalbed Methane Content vs. Depth in the City of Tuscaloosa, Alabama Corehole

can be stimulated together, but this should be re-evaluated in consultation with a well service company if development proceeds. Potential target zones include seams in the Pratt, Mary Lee, and Black Creek Coal Groups (Fig. 11). The Pratt Group contains 4.73 feet of coal within a stratigraphic interval of 61.6 feet. This coal has a weighted average producible methane content of 214 cf/ton. The Mary Lee Group contains 8.09 feet of coal within a 46.8 foot stratigraphic interval. Weighted average producible methane content of this portion of the Mary Lee Group is 328 cf/ton. The Black Creek seam is 3.58 feet thick with a weighted average producible methane content of 259 cf/ton.

Gas quality analyses were performed on gas samples from five seams, four from the Mary Lee Group and one from the Black Creek seam. An average of these analyses is given below.

Component	Mol %
Nitrogen (N_2)	4.34
Carbon Dioxide (CO_2)	0.80
Oxygen (O_2)	0.78
Methane (CH_4)	93.30
Ethane (C_2H_6)	0.62
Propane (C_3H_8)	0.12

Average heating value of these samples is 947.3 Btu/cf.

The size of the coal reserve underlying the study area was not presented in the report. Based on the total coal thickness of 33.26 feet encountered in the core hole, a coal resource of 58,200 tons per acre or 2.3 million tons per 40 acres lies under the project area. In the target ~~zones, the~~ Pratt Group contains 6,160 tons per acre, the Mary Lee Group

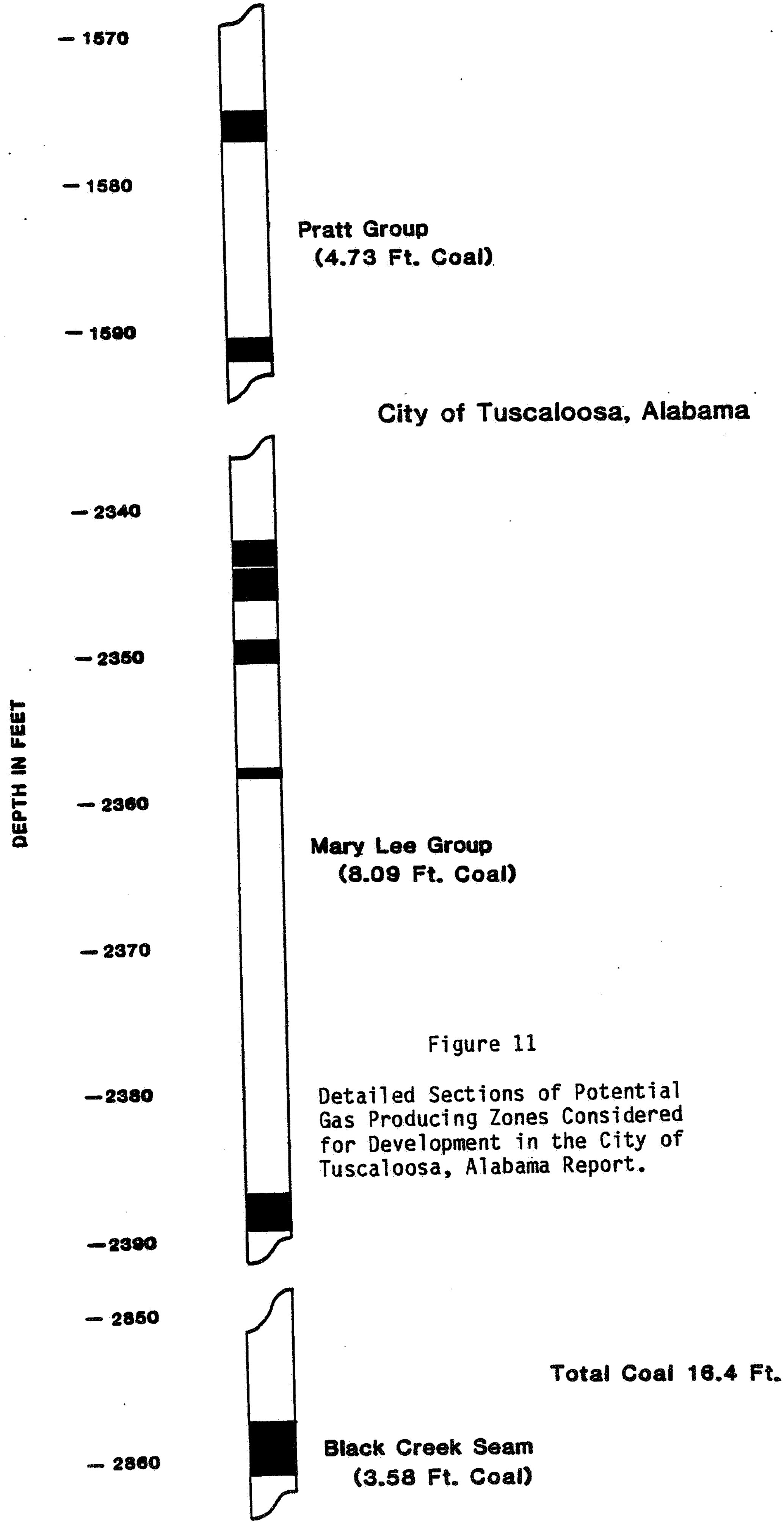


Figure 11

Detailed Sections of Potential Gas Producing Zones Considered for Development in the City of Tuscaloosa, Alabama Report.

contains 14,157 tons per acre, and the Black Creek Group contains 8,715 tons per acre. The total tonnage contained in target zone seams is 29,032 tons per acre, or 1,161,300 tons per 40 acres.

Based on coal resource tonnage calculations of and a weighted average intermediate methane content of 215 cf/ton for all seams encountered, a total of 12,525 Mcf/acre or 501 million cubic feet per 40 acres exists in the study area. The target zone seams contain 8,265 Mcf per acre or 330 million cubic feet per 40 acres.

Conventional rotary-drilled vertical wells are considered for coalbed methane recovery. Stimulation of three target zones is recommended in this area. Based on a levelized production from the target zones over a period of ten years with 75% total recovery of the in-place intermediate gas resource, a production rate of 23,862 Mcf per year for a single 40 acre well is predicted.

Economics of Resource Development

A total of eight developmental options are presented in the report. These options are summarized below.

	Developer	No. of Wells	Gas Use	Comments	IRR	Payback Period
1.	City of Tuscaloosa	1	City vehicle fuel	Acceptable	26.69%	4.8 yrs
2.	City of Tuscaloosa	12	Market to local industries	Unacceptable: regulatory restrictions	-	-
3.	City of Tuscaloosa	12	Market to transmission company	Unacceptable: outside city's role	-	-
4.	Private Company	1	Use gas internally	Acceptable	13.6%	6.02 yrs

	Developer	No. of Wells	Gas Use	Comments	IRR	Payback Period
5.	Private Company	12	Use gas internally; market surplus gas to other industries	Unacceptable: regulatory restrictions	-	-
6.	Private Company	12	Use gas internally; market surplus gas to transmission company	Acceptable	27.9%	3.85 yrs
7.	Industry Co-op	12	Gas used by co-op members	Unacceptable: regulatory restrictions	-	-
8.	Outside Developer	12	Market to transmission company	Acceptable	27.9%	3.85 yrs

Options 1 and 4 are based on an installation cost of $255,400 and a yearly operating cost of $30,000 for a single well. Option 1 assumes that capital for the project is borrowed at an 11% interest rate. Option 4 assumes that capital is borrowed at a 14% interest rate and that a 6% severance tax is paid to the state and a one-sixteenth royalty is paid to the City of Tuscaloosa.

Options 6 and 8 are based on an installation cost of $2,635,800 and a yearly operating cost of $274,000 for a 12 well module. These options assume that capital is borrowed at 14% interest, that a 6% severance tax is paid to the State of Alabama, and that a one-sixth royalty is paid to the City of Tuscaloosa. Under these conditions the internal rate of return is 27.9% and the payback period is 3.85 years.

All financial analyses discussed above assume a gas replacement price of $5.50/Mcf in year 1 of the 10 year project. Gas prices are projected to increase by an average of 2% per year to a price of $6.57/Mcf by year 10 of the project.

Sensitivity of the internal rate of return and payback period to variations in replacement fuel cost and well production were examined. A 20% increase in replacement fuel cost would, of course, significantly enhance the profitability of all options. With a 5% decrease in replacement fuel cost, options 1 and 8 remain viable.

With a reduction of well productivity to 60% of in-place intermediate gas resources, the internal rates of return of all options fall below 20%, and the payback periods exceed 5 years.

Environmental Ramifications of Resource Development

An environmental impact analysis for the test-well site was completed and submitted to the U.S. Department of Energy in July 1981. The only negative impact anticipated in implementing any of the development options is the prodiction of 10 to 200 barrels of water per well per day. This water may contain deleterious quantities of chloride.

Summarizer's Comments

Additional research conducted following preparation of this report suggest that water production from coalbed methane wells in the Warrior Basin may exceed 1000 barrels per day locally. Such conditions, if encountered, may lead to complications in water disposal methods.

4. UTILIZING THE UNCONVENTIONAL GAS RESOURCES OF THE POTTSVILLE FORMATION IN TUSCALOOSA COUNTY, ALABAMA (B.F. GOODRICH INDUSTRIAL SITE PROJECT)

This report was prepared by the B. F. Goodrich Company of Akron, Ohio, and the School of Mines and Energy Development of The University of Alabama for the U.S. Department of Energy under contract No. DE-FG44-81R410428. The final report was submitted in September 1982.

General Nature of Project

This project was conducted to assess the feasibility of supplying unconventional gas at the rate of approximately 3 million cubic feet per day to the B. F. Goodrich Tire Plant in Tuscaloosa, Alabama. Coalbed methane production is proposed to displace conventional natural gas which is currently purchased on an interruptible basis. The B. F. Goodrich Company controls approximately 220 acres in the southwestern portion of the City of Tuscaloosa.

To effect this study, 3429 feet of continuous NX core was retrieved using a wireline drilling rig by Joy Manufacturing Company of LaPorte, Indiana. The corehole was located at latitude 33° 11' 26" north and logitude 87° 36' 35" west, Tuscaloosa County, Alabama, and at a surface elevation of 154 feet above mean sea level (Fig. 12). The core was logged by personnel of the Geological Survey of Alabama. Geophysical logs, including natural gamma, long spacing electron density, caliper, expanded scale reversed gamma, expanded scale long spacing electron density, high resolution electron density, absolute temperature, and differential temperature were run by BPB, Inc.

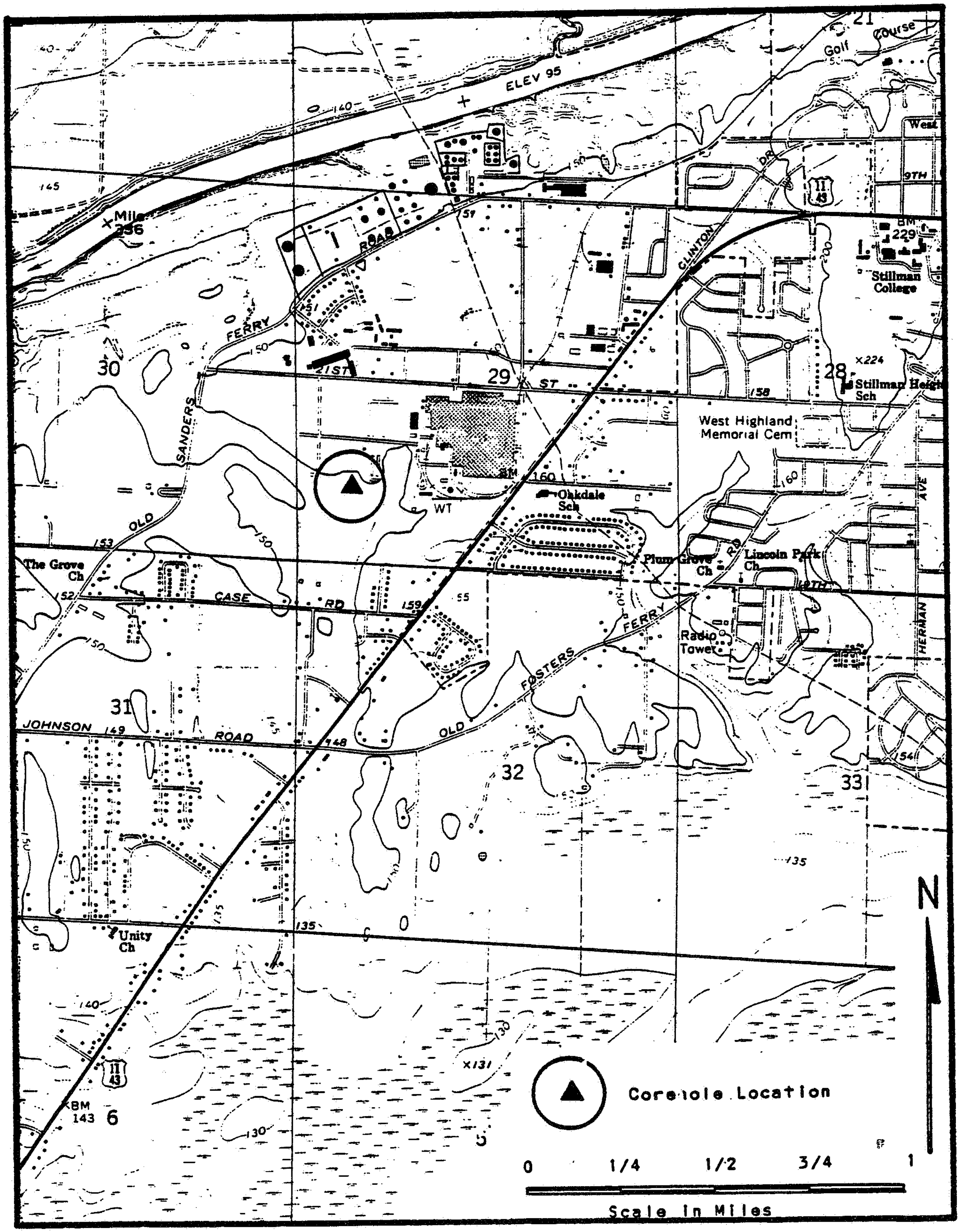


Figure 12. Location Map of the B.F. Goodrich, Alabama Corehole (From Tuscaloosa, Alabama 7.5 minute topographic quadrangle)

The drilling targets were the coal seams of the Pottsville Formation in the Warrior Coal Basin of Alabama. In all, 33.9 lineal feet of coal comprising eight coal groups were encountered in drilling. These coal groups ranged from an unnamed coal group lying above the Brookwood Group downward through the Black Creek Group (Fig. 13). Individual coal seams ranged in thickness from 0.25 feet to 2.55 feet and ranged in depth from 169 feet to 3339 feet.

Upon retrieval of the coal cores, gas contents were determined by the U.S. Bureau of Mines direct method (Appendix B). Short proximate analyses were subsequently performed on selected coal samples, and gas chromatography was used to determine the quality of selected samples of the desorbed gas. No well production testing was attempted in this study.

Resource Characterization

All seams analyzed are high-volatile A bituminous in rank. Intermediate gas content of the samples range from 4 cf per ton to 462 cf per ton with a weighted average for all seams sampled of 168 cf per ton. Gas content of the coal shows a general increase with depth, although the increase is not consistent in all samples. The upper limit of intermediate gas content appears to be approximately 170 cf/ton per 1000 feet of depth, and there is a considerable amount of scatter in gas content vs. depth below this limit (Fig. 14). An approximate mean of increase in gas content with depth is 75 cubic feet per ton per 1000 feet of depth. As received ash content of the coal samples analyzed ranged from 4.5% to 70.4% with a simple arithmetic average ash content of 20.6%.

Three coal groups contain four potential target zones for development, assuming that all seams lying in a 50-foot stratigraphic interval may be

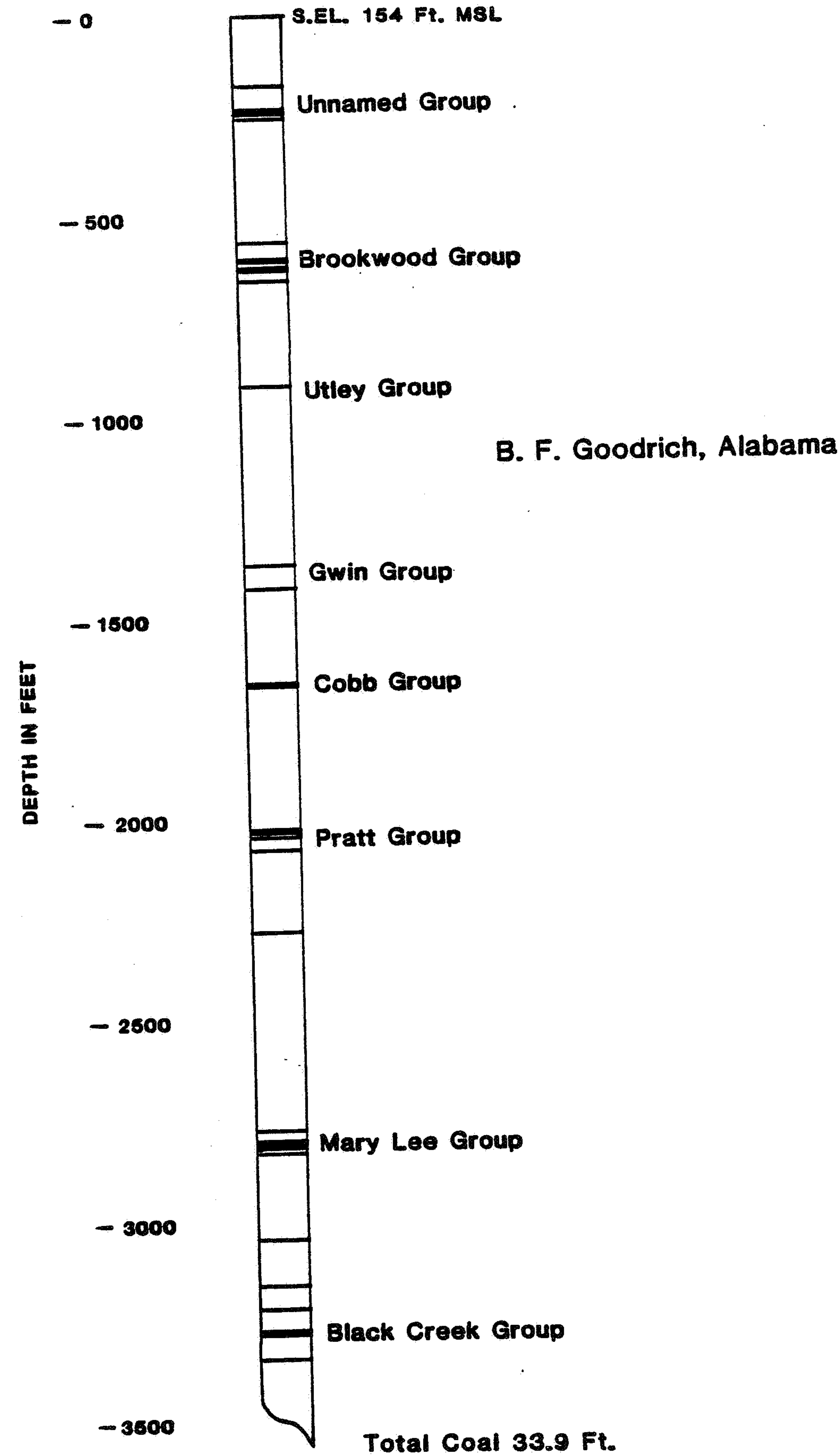


Figure 13. Stratigraphic Section Showing Potential Gas Producing Strata Encountered in the B.F. Goodrich, Alabama Corehole

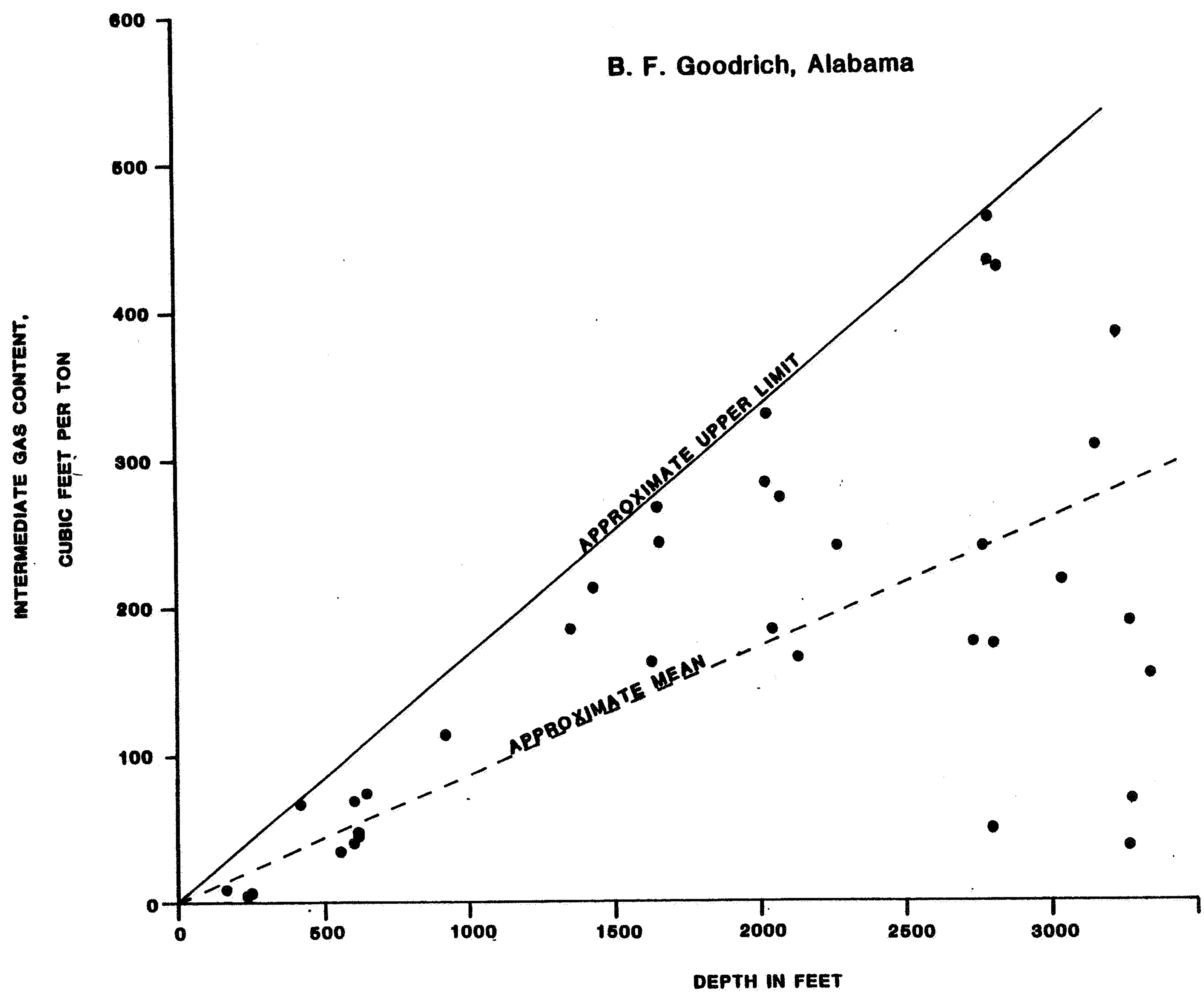


Figure 14. Graph Showing Intermediate Coalbed Methane Gas Content vs. Depth in the B.F. Goodrich, Alabama Corehole

sucessfully stimulated simultaneously (Fig. 15). The Cobb Group, containing 2.42 feet of coal within a 2.47 foot stratigraphic interval, has a weighted average intermediate gas content of 257 cf/ton. The Pratt Group, containing 1.37 feet of coal in a 9.87 foot stratigraphic interval, has a weighted average intermediate gas content of 314 cf/ton. The Mary Lee seam of the Mary Lee Group, containing 4.93 feet of coal in a 9.6 foot stratigraphic interval, has a weighted average intermediate gas content of 278 cf/ton. The Blue Creek seam of the Mary Lee Group, containing 1.5 feet of coal in a 1.5 foot stratigraphic interval, has an intermediate methane content of 430 cf/ton. All four target zones contain a total of 10.22 feet of coal with a weighted average intermediate gas content of 300 cf/ton.

Gas quality analyses were performed on seven samples of desorbed gas, six of which came from coal seams in the target zones. Average composition of the seven samples is given below in mole percent.

Component	Mol %
Methane (CH_4)	93.16
Ethane (C_2H_6)	1.13
Nitrogen (N_2)	4.74
Carbon Dioxide (CO_2)	0.39
Oxygen (O_2)	0.47

Average heating value of the seven samples is 965 Btu/cf.

Coal resources in the area, calculated at 1750 tons per acre-foot, are 59,360 tons per acre for all coal encountered in the core hole. Using this figure, there is a total of 13.06 million tons of coal on B. F. Goodrich's 220 acre tract. In the target zones, containing 10.22 linear feet of coal,

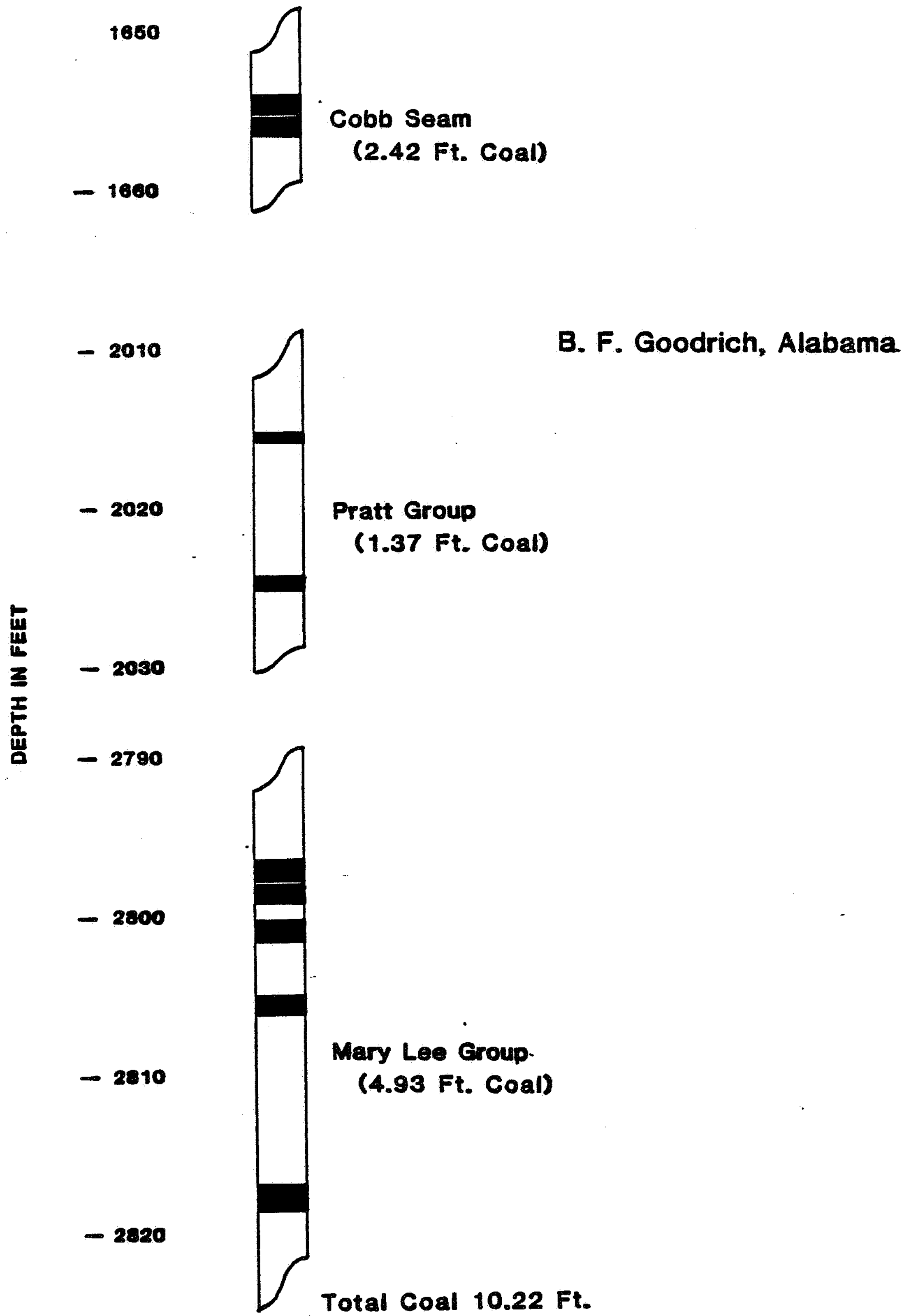


Figure 15. Detailed Sections of Potential Gas Producing Zones Considered for Development in the B.F. Goodrich, Alabama Report

there are 17,885 tons per acre, or 3.9 million tons on B. F. Goodrich's tract.

The total methane resources for all coal seams encountered in the core hole are 10.0 million cubic feet per acre, or 2,189 million cubic feet throughout B. F. Goodrich's 220 acre tract. Coal seams in the target zones contain 5.4 million cubic feet per acre, or 1,180 million cubic feet throughout the B. F. Goodrich tract.

Conventional rotary-drilled vertical wells on 40 acre spacings are considered as a means of recovery of coalbed methane resources in the area. Up to four coal-bearing target zones are to be stimulated, probably with a nitrogen foam or "slick" water carrier and 20x40 mesh sand proppant.

Economics of Resource Development

Production under this development scenario is projected at 50% to 75% of the total in-place gas resource over a 10 year period. At 75% recovery, an average of 16.1 million cubic feet per year should be produced. At 50% recovery, an average annual production of 10.7 million cubic feet is projected.

The economic analysis base case makes the following assumptions:

- o All capital and cost estimates are in constant 1982 dollars.
- o Project life is 10 years.
- o Gas production is constant over project life.
- o Severance tax is deducted at the rate of 6% of net gas value.
- o Purchased gas will cost B. F. Goodrich $4.72/Mcf in 1983, increasing approximately 5% per year to $7.62/Mcf in 1992.
- o Capital cost is $255,400 for a single well.
- o Operating cost is $30,000 per year for a single well.

- o Interest charges are not included in the calculations.
- o The economics of one well are also applicable to three wells.
- o Depreciation follows current IRS rules.
- o Depletion is 15% of the net gas value, observing a 50% taxable income limitation.
- o A marginal corporate tax rate of 46% is used where applicable.
- o Salvage value is 10% of tangible cost after 10 years.

Under these assumptions the internal rate of return is 17.90% and the payback period is 5.1 years. These results are currently considered marginal by corporate standards for medium risk investment returns

Sensitivity to natural gas price, well production rate, and intangible drilling costs were examined. The results are tabulated below.

	Payback (yrs)	IRR (%)	Avg. Cost/ Mcf ($)
Base Case	5.10	17.90	4.24
+20% Gas Price	4.04	25.45	4.40
-5% Gas Price	5.45	16.01	4.20
Life of Well Production 50% of In-place Resource	8.70	4.31	3.85
Reduce Drilling Cost to $120,000	4.26	23.43	3.93

By either increasing gas prices 20% or reducing drilling cost to $120,000 per well, development of coalbed methane may become financially feasible. All other variations have a negative effect on economic feasibility.

Environmental Ramifications of Resource Development

An environmental impact analysis was conducted for the test well and submitted to the U.S. Department of Energy. Production development is expected to produce only one potential negative impact. Coalbed methane wells in the Warrior Basin produce from 10 to 1000 barrels of water per day and this water may contain deleterious quantities of dissolved chloride.

Summarizer's Comments

Under Alabama Law, disposal of produced water would require a disposal permit from the Alabama Department of Environmental Management. At present the most cost-effective means of disposal appears to be direct discharge into the Black Warrior River, which lies approximately one mile from the project site. If the quality of water produced is better than 500 mg/l T.D.S., other disposal methods may be allowed.

5. DEEP RIVER DEVELOPMENT PROJECT FROM UNCONVENTIONAL GAS-EXPLORATORY DRILLING AND COMPLETION

This report was prepared by Richard A. Beutel and Associates of Chapel Hill, N.C. and the North Carolina Energy Institute, North Carolina Department of Commerce, for the U.S. Department of Energy under contract no. DE-FG44-81R410400. The final report was submitted in September 1982.

General Nature of Project

This project was conducted to evaluate the coal seams of the Cummnock or Deep River Coal Field as a source of unconventional natural gas. The evaluation involved drilling a combination rotary-core hole to a total depth of 953 feet by Patterson Exploration Services and a foam fracture of the lower portion of the hole (below 604 feet) by the Dowell Division of the Dow Chemical Co. The drill hole was situated near the line between Lee and Chatham Counties, North Carolina at 35° 32'45" north latitude an 79° 17'45" west longitude, lying at a surface elevation of 234 feet above mean sea level (Fig. 16). The rotary drill cuttings and the core were logged by James E. Jones III and O.F. Patterson III of Patterson Exploration Services. Upon completion of drilling a suite of geophysical logs consisting of natural gamma, long-spacing density, caliper, spontaneous potential, resistivity, sonic, neutron, micro resistivity, detailed sonic, and bed resolution logs was run by BPB, Inc.

Coal seams of the Triassic Cummnock Formation were the drilling targets. Before successful completion in the Cummnock Formation, two other holes were drilled to a total depth of 400 feet and abandoned because thick diabase intrusives were encountered in the sediments. Excessive water production from these holes hampered drilling and also contributed to their abandonment. In the third hole, positioned down-dip of the first

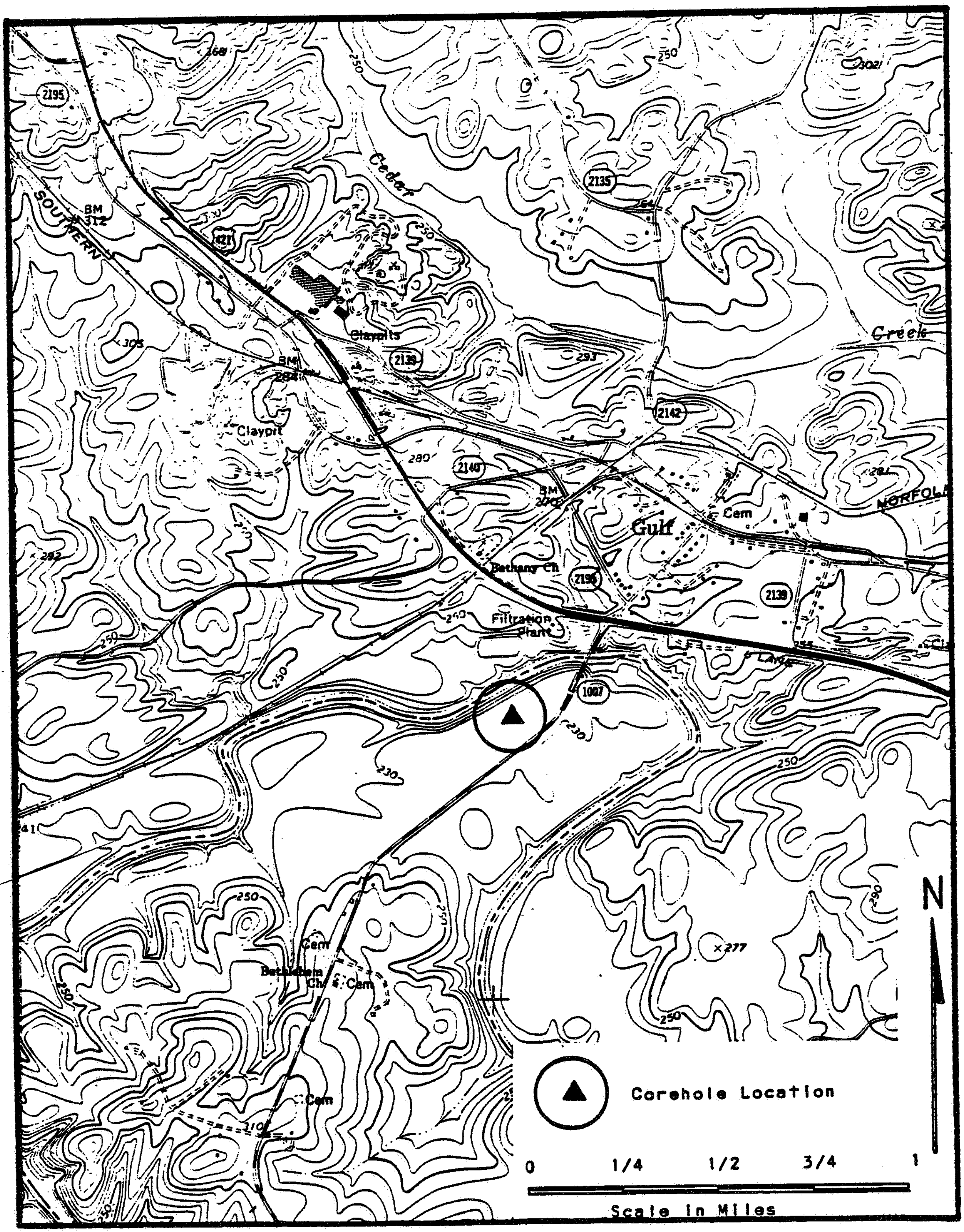


Figure 16. Location Map of the Deep River, North Carolina Corehole (From Goldston, North Carolina 7.5 minute topographic quadrangle)

two, the diabase section had apparently thinned and water production was reduced sufficiently to allow completion in the Cummnock Formation. A total of 7.2 lineal feet of coal was encountered in the Cummnock seam between the depths of 900 feet and 909.5 feet (Fig. 17). Eight and one-half inches of coal were encountered in the Gulf coal seam at a depth of 951.5 feet. Sixteen inches of carbonaceous black shale were also recovered from the vicinity of the Gulf seam.

Gas content of the coal and black shale samples was established by U.S. Bureau of Mines direct method determination (Appendix B). The report does not indicate that any coal quality analyses were conducted on the samples. Gas quality was determined by the U.S. Bureau of Mines Analytical Research Group using gas chromatography. A nitrogen foam fracture was applied to the lower, uncased portion of the drill hole to test potential production.

Resource Characterization

No coal quality data was reported in the study, so the rank of the coal seams cannot be reported. Intermediate (lost plus desorbed) gas content was 298 cf/t for the Cummnock seam, 365 cf/t for the Gulf seam, and 70 cf/t for the black shale intervals tested. Gas from the coal seams averages 96.68% methane and has an average heating value of 980 BTU/cf. The major non-hydrocarbon component of the gas is nitrogen, which accounts for an average of 2.73%. Gas desorbed from the black shale samples is lower in quality than that from the coal samples, averaging only 88.4% methane and a proportionately larger 10.9% nitrogen. Heating value of the black shale-derived gas is 900 Btu/cf.

After the lower strata of the well was fractured with nitrogen foam, overnight pressure buildup of 100 PSI was noted. This indicates a bottom

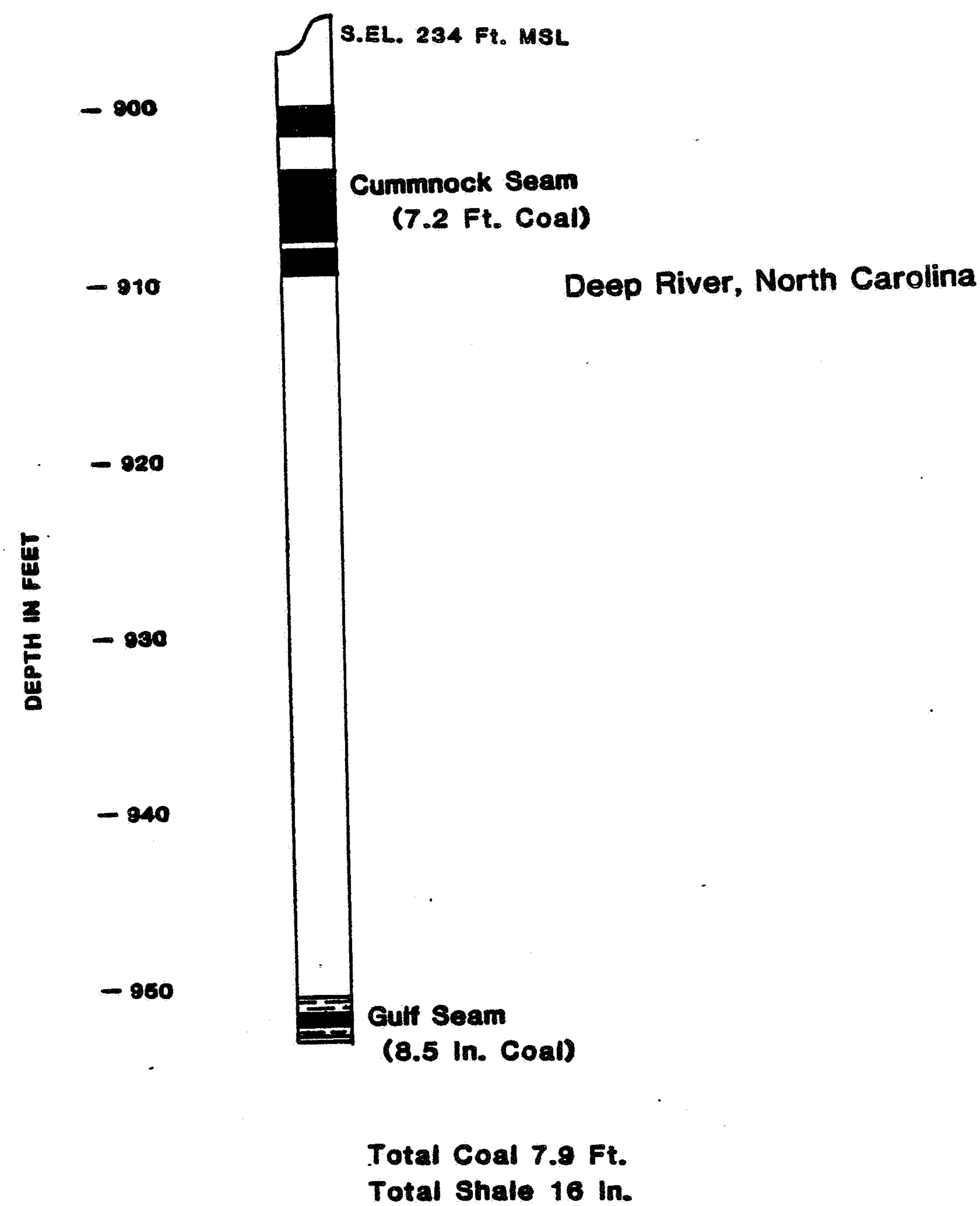


Figure 17. Detailed Section Showing Potential Gas Producing Strata Encountered in the Deep River, North Carolina Corehole

hole pressure of approximately 200 PSI. At the time of preparation of the report, the well contained a substantial amount of fluid. Further plans included cleaning out the well and re-testing it for gas deliverability.

No estimate of the coal resource base was presented in the report, but for the 7.9 feet of coal encountered, the in-place coal resource at 1800 tons per acre-foot amounts to 14,235 tons per acre or 569,400 tons per 40 acres. Based on the in-place coal resource base and a specific intermediate gas content of 304 cf/t, an in-place producible methane resource of 4.3 million cubic feet per acre or 173 million cubic feet per 40 acres is indicated.

No production method proposals, production rate estimates, economic feasibility analyses, or environmental statements were included in the report.

6. FEASIBILITY STUDY OF COALBED METHANE DEVELOPMENT AT WESTMORELAND MANOR, WESTMORELAND COUNTY, PENNSYLVANIA

This project was prepared by Pacifica Services, Incorporated of Los Angeles, California for the U.S. Department of Energy and the Westmoreland County Department of Planning and Development under contract no. DE-FG44-81R410566. The final report was submitted in September, 1982.

General Nature of Project

The Westmoreland Manor project was conducted to assess the feasibility of providing unconventional gas to offset part of the energy demands of two county-owned facilities, a high-rise apartment and a hospital for the elderly, jointly known as Westmoreland Manor. This complex occupies a 220 acre tract on the outskirts of Greensburg, PA.

To determine the unconventional gas resource, 1089 feet of continuous NX core were recovered by the Pennsylvania Drilling Company using a wireline rig. This corehole, situated at 40° 16'23" north latitude and 79° 33'43" west longitude, lay at a surface elevation of 1080 feet (Fig. 18). Recovered core was logged by personnel of the Pennsylvania Geological Survey. Upon completion of drilling, geophysical logging of the hole, including caliper, natural gamma, high-resolution density, gamma-gamma density, and resistivity was conducted by Appalachian Coal Surveys.

The drilling target was coal seams lying in the Monongahela, Conemaugh, Allegheny, and Pottsville Groups of the Main Bituminous Field of Pennsylvania. In all, 19.9 lineal feet of coal were recovered from the core hole. This coal was distributed in 12 coal beds ranging in thickness from 0.5 foot to 3.3 feet and ranging in depth from 371 feet to 1041 feet. These seams included the Pittsburgh seam downward to the Mercer seam (Fig. 19).

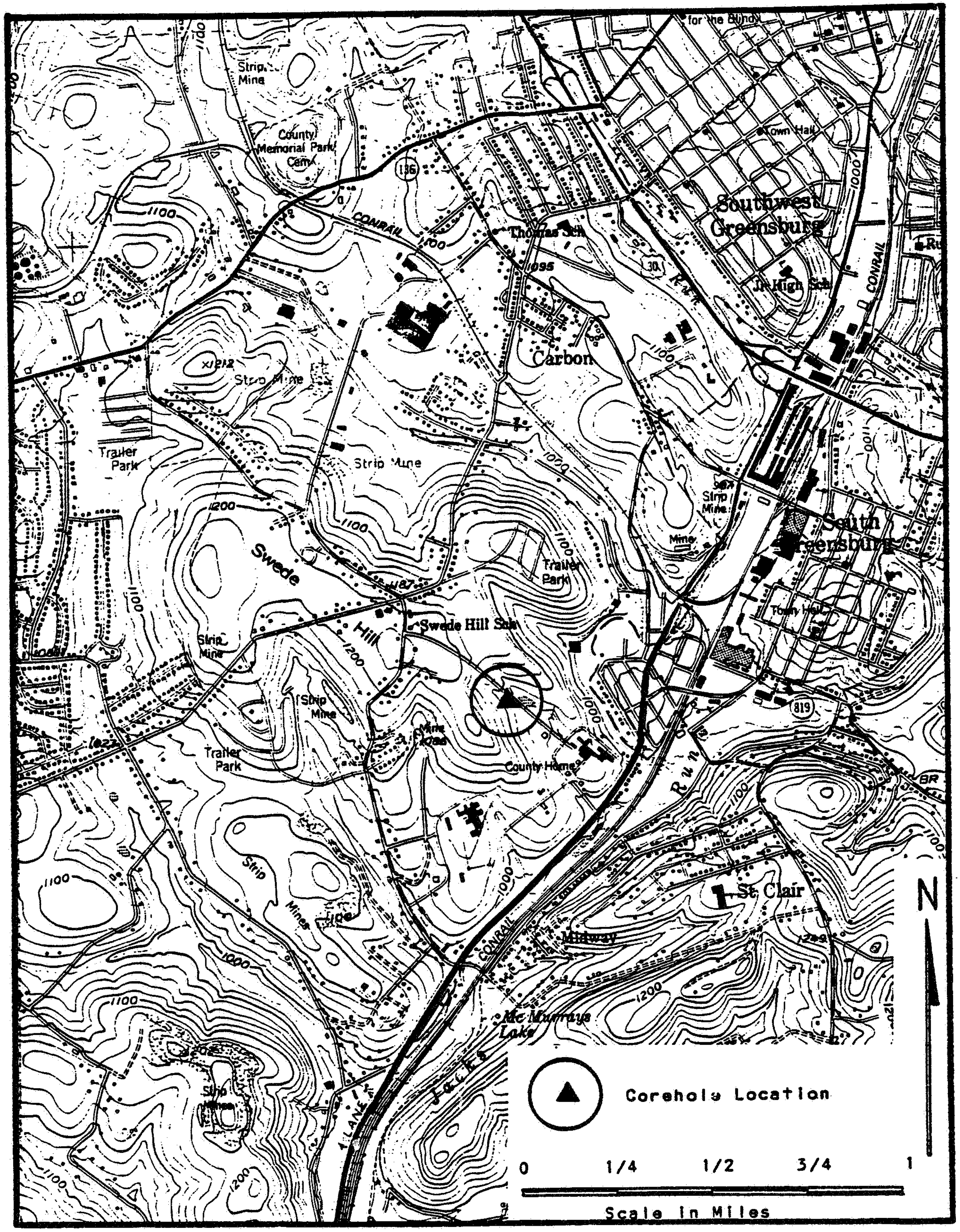


Figure 18. Location Map of the Westmoreland Manor, Pennsylvania Corehole (From Greensburg, Pennsylvania 7.5 minute topographic quadrangle)

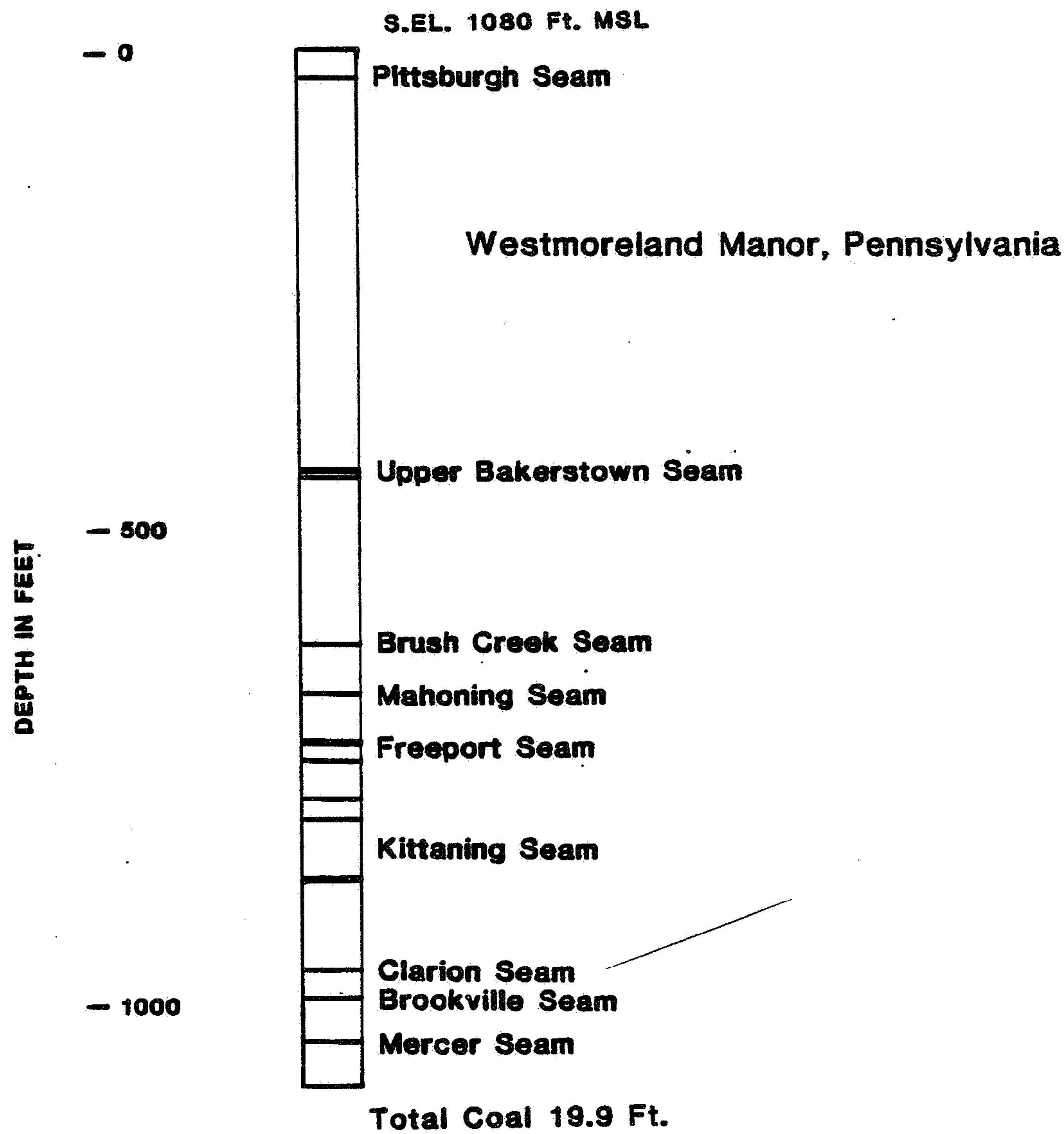


Figure 19. Stratigraphic Section Showing Potential Gas Producing Strata Encountered in the Westmoreland Manor, Pennsylvania Corehole

Gas Contents of the coal samples were established using U.S. Bureau of Mines direct method determination (Appendix B). The samples subsequently were analyzed to determine the ash content, heating value, and rank of the coal. No determination of gas quality was conducted, nor was any production testing attempted.

Resource Characterization

All coal seams analyzed were either-medium volatile bituminous or high-volatile A bituminous in rank. As-received ash content of the coal samples ranged from 12.3% to 37.6% with a simple arithmetic average of 21.5% ash. Total gas content of the coal ranged from 125 cf/t to 294 cf/t, with a weighted average content of 214 cf/t. Intermediate (lost plus desorbed) gas content ranged from 64 cf/t to 256 cf/t with a weighted average of 176 cf/t (Fig. 20). No gas quality or well productivity data were presented in the report.

No figures presented in the report specifically address the size of the coal resource base under the 220-acre Westmoreland Manor tract. Three production scenarios are outlined, however, which involve production from 19.4 feet of coal (best case), 9.5 feet of coal (worst case), or 15 feet of coal (likely case). Figure 21 illustrates all coal seams present in the target zones which corresponds to the best-case development scenario. The worst case scenario assumes that the stimulation will concentrate in the thinnest seam in each zone, while the likely case scenario lies between the best and worst cases. Under these scenarios, the coal resource base for the Westmoreland Manor properties would be 7.7 million tons (best case), 3.8 million tons (worst case), or 5.9 million tons (likely case). These figures assume a coal density of 1800 tons per acre-foot.

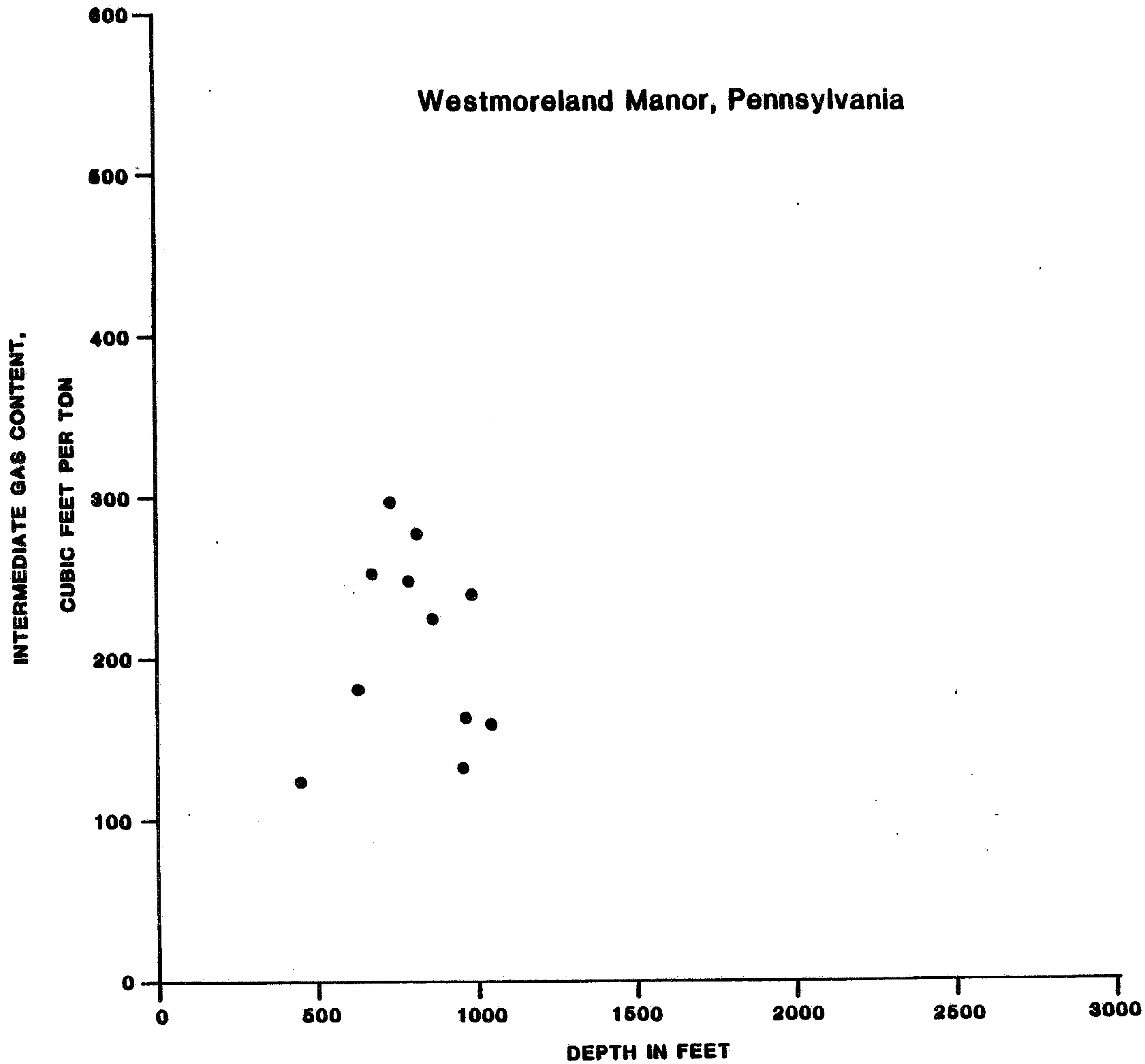


Figure 20. Graph Showing Intermediate Coalbed Methane Gas Content vs. Depth in the Westmoreland Manor, Pennsylvania Corehole

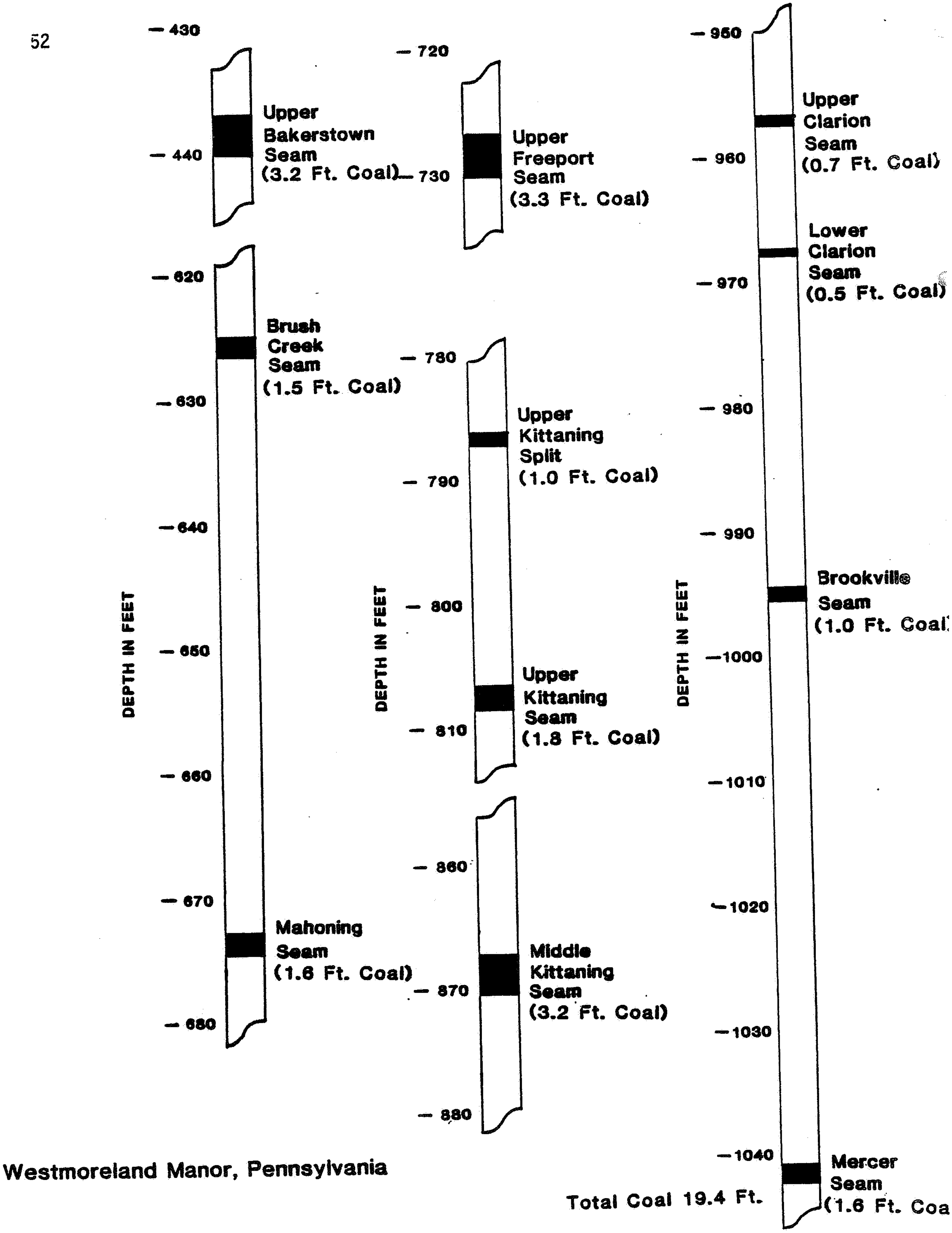


Figure 21. Detailed Sections of Potential Gas Producing Zones Considered for Development in the Westmoreland Manor, Pennsylvania Report

Based on the coal resource base and the specific total gas content of the seams considered for development, the coalbed methane resource base is 1.6 Bcf (best case), 0.91 Bcf (worst case), or 1.4 Bcf (likely case)on the 220 acre tract. The coal resource base and coalbed methane resource base are summarized below:

	Developed Coal Thickness	Acres	Coal Resource (Million Tons)	Total Specific Methane Content (cf/t)	Coalbed Methane Resource (Bcf)
Best Case	19.4	220	7.7	213	1.6
Worst Case	9.5	220	3.8	242	0.91
Likely Case	15	220	5.9	217	1.3

Proposed gas production at the Westmoreland Manor site involves installation of six 7-inch diameter conventional rotary-drilled wells on approximately 40 acre spacings. These wells are to be cased to the top of the coal measures, and five potential production zones in the coal measures are to be stimulated individually for an essentially open-hole production.

Production rate estimates are based on comparision of the specific gas content and thickness of the tested coal samples with drill stem test data obtained from a four well methane development project located at Waltz Mill, 11 miles south-southeast of the Westmoreland Manor site. From these comparisons a "best case" scenario predicts a 78 Mcf/day production per well and a "worst case" scenario of 12 Mcf/day per well. The "expected case" is 20-27 Mcf/day per well. These figures represent average daily production over a ten-year period.

Economics of Resource Development

An economic feasibility analysis based on a six well production module is presented in the report. Each well is projected to cost approximately $150,000 for a total capital expenditure of $900,000. Operation and maintenance cost is projected at $40,000 in 1984 (proposed project inception) and is escalated 10% annually. Projected 1984 wellhead gas price is $4.11/Mcf which is escalated an average of 12.25% per year. Average field production is projected at 50 milion cubic feet per year. Under these conditions, the investment payback period is less than four years and the internal rate of return is 29%. No sensitivity analyses were reported except to state that even if the production rate varies somewhat or the capital and operating costs vary by 10%, the project still appears feasible.

Environmental Ramifications of Resource Development

An environmental impact statement encompassing three developmental scenarios was prepared for the Westmoreland Manor project. The first scenario involves drilling of the exploratory core hole only. The second scenario involves development of a six-well field on the manor property, and the third is the same as the second with the addition of a cogeneration facility. The first scenario is anticipated to have no significant environmental impact, either positive or negative. The second scenario is anticipated to cause slight negative impact to water quality, soils, terrestrial ecology, land use, scenic values and recreation, and noise. A slight positive impact on socio-economic factors is anticipated in the second scenario. Impacts from the third scenario are the same as for the second except that terrestrial ecology and ambient noise levels may be moderately to strongly impacted.

Summarizer's Comments

The statement on pages 13 and 14 of the report that gas production from a six-well field would save the county over $260,000 a year in gas purchases appears to be in error. In 1981 the county and nearby state facilities jointly purchased 123 MMcf of gas for $432,621. This breaks down to $3.52/Mcf. Annual production from the six well module is projected at 49,932 Mcf/yr, amounting to gas purchase savings of $176,000 a year, as opposed to the reported $260,000 annual savings. This error in computing total savings is offset, however, by using the projected 1984 wellhead gas price of $4.11/Mcf, which brings total savings to $205,220 annually.

There also appear to be some discrepencies between the lost gas figures reported in Table 1 and the lost gas determination graphs included in Appendix C of the report. Sample weight data is not consistently reported, and so these discrepencies can neither be positively confirmed nor can they be corrected in this summary.

7. FEASIBILITY STUDY ON THE ROCKWOOD UNCONVENTIONAL GAS PROJECT, ROCKWOOD, TENNESSEE

This report was prepared by Wayne L. Smith and Associates of Knoxville, Tennessee for the Tennessee Energy Authority and the city of Rockwood under contract number DE-FG44-80R410336. The final report was submitted in October of 1982.

General Nature of Project

The Rockwood, Tennessee project was initiated to determine the feasibility of producing unconventional gas from the known coal reserves in the Rockwood area. Any production realized would be supplied to the City of Rockwood's municipal gas distribution system and to the several large industrial gas users in the area that are currently operating on an interruptible gas supply contract.

To assess the potential coalbed methane resource, Joy Manufacturing Co. of La Porte, Indiana recovered 1011 feet of continuous core using a wireline drilling rig. The corehole, located approximately 2 miles north of the Rockwood Municipal Airport in Morgan County, Tennessee, was commenced at a surface elevation of approximately 1600 feet above mean sea level. No descriptive log of recovered core was included in the report. Subsequent to drilling a suite of geophysical logs including a coal lithology log, coal quality log, seam thickness log, spontaneous potential log, and single point-resistivity log was prepared by BPB, Inc. The drilling targets were coal seams contained in the Gyzard Group and the Crab Orchard Mountains Group of Pennsylvanian age. In all, 3.6 lineal feet of coal included in the Sewanee seam were encountered at a depth of 819.9 feet (Fig. 22).

Gas contents of the coal samples were measured using U.S. Bureau of Mines direct method determination (Appendix B). Coal samples were

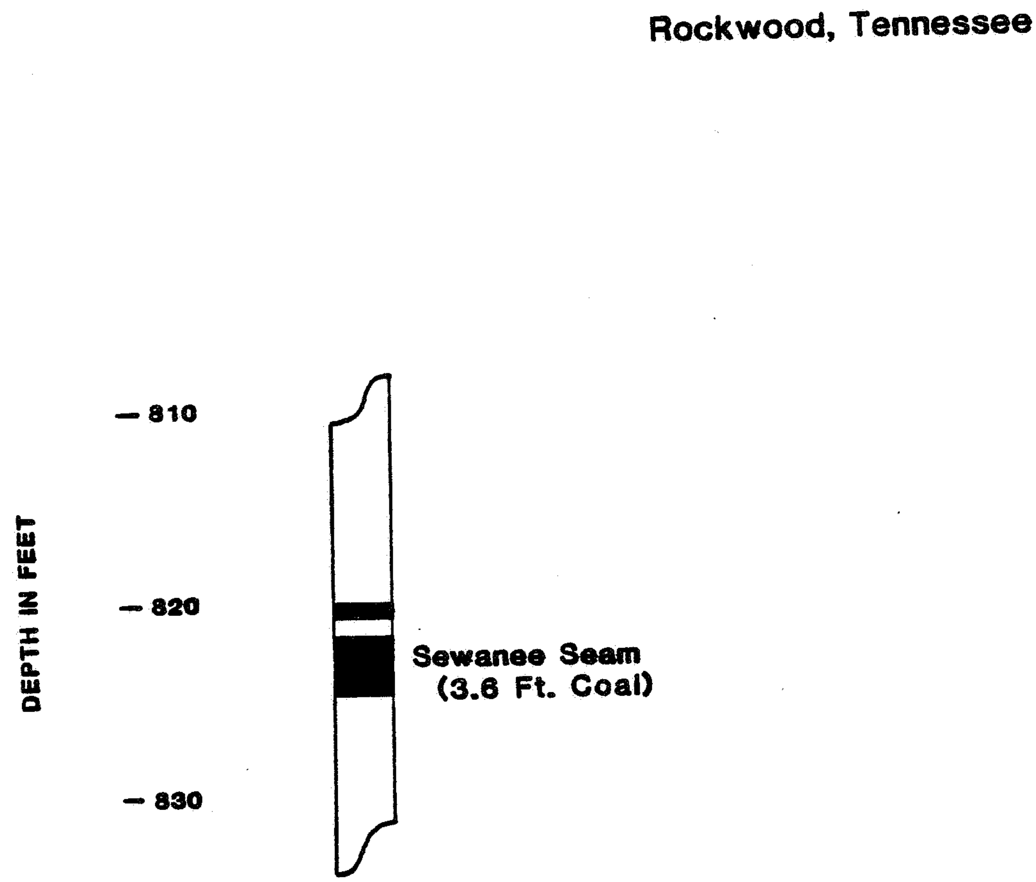


Figure 22. Detailed Section Showing Potential Gas Producing Strata Encountered in the Rockwood, Tennessee Corehole

subsequently subjected to proximate and ultimate analyses, maceral analysis, reflectance analysis, and porosity analysis by Wyoming Analytical Laboratories, Inc. No gas quality data were generated, nor was any production testing attempted.

Resource Characterization

All coal samples analyzed were determined to be medium volatile bituminous both by chemical analysis and by vitrinite reflectance. The as-received ash content of the coal samples ranged from 7.07% to 21.8% with a simple arithmetic average of 12.0% ash. Total gas content ranged from 32 cf/t to 80 cf/t with a weighted average gas content of 72 cf/t. Intermediate (lost plus desorbed) gas content ranged from 26 cf/t to 58 cf/t with a weighted average of 49 cf/t. No gas quality data or well productivity data were presented in the report.

No assessment of in-place coal resource estimate was presented in the report, but an average seam thickness of 3.6 feet indicates a resource of 6,480 tons per acre or 259,200 tons per 40 acres. Similarly, no in-place coalbed methane gas resource estimate was presented in the report, but assuming an average total specific gas content of 72 cf/t, this figure is estimated at 467 Mcf/acre, or 18.7 million cubic feet per 40 acres.

Because of the very low specific gas content of the coal and the thinness of the seam, no production is proposed and no production rate estimates are given. The recovery of coalbed methane is deemed unfeasible in the area. The report states that less than one-forth the quantity of gas usually considered necessary for development was indicated by the study.

An assessment of environmental impact of development was not prepared since no development appears likely. An environmental report on the assessment project was presented to the Tennessee Energy Authority prior to drilling.

Summarizer's Comments

Results of this study indicate a weighted average total specific methane content of 72 cf/t or 2.25 cc/g. Using the depth that the coal was encountered and quality of the coal samples, a gas content of 352 cf/t or 11 cc/g is predicted using Kim's (1977) method. Among other factors, inadvertently siting the well near an abandoned underground mine may account for this discrepency. Even at this higher specific gas content, development is unlikely to be feasible due to the small amount of coal encountered.

8. UTILIZING THE UNCONVENTIONAL GAS RESOURCES OF THE POTTSVILLE FORMATION COALS IN TUSCALOOSA COUNTY, ALABAMA

(TUSCALOOSA COUNTY INDUSTRIAL DEVELOPMENT AUTHORITY PROJECT)

This report was prepared by the the School of Mines and Energy Development of The University of Alabama for the Tuscaloosa County Industrial Development Authority and the U.S. Department of Energy under contract No. DE-FG44-80R410427. The final report was submitted in January 1983.

General Nature of Project

This project was conducted to assess the feasibility of producing unconventional gas from a 1037 acre industrial park located northwest of the City of Tuscaloosa. Gas produced from this tract could be utilized by the industries located in the industrial park.

To assess the potential production, 2901 feet of continuous NX core were recovered by Joy Manufacturing Company of LaPorte, Indiana using a wireline core drilling rig. The drilling site was located at latitude 33° 12' 59" north and longitude 87° 37' 09" west, Tuscaloosa County, Alabama, and lay at a surface elevation of 163 feet above mean sea level (Fig. 23). The recovered core was logged by staff of the Geological Survey of Alabama. After drilling was completed, a suite of geophysical logs, including expanded scale reversed gamma, expanded scale long spacing electron density, high resolution electron density, caliper, absolute temperature, and differential temperature was run by BPB, Inc.

The targets of the core drilling were coal seams of the Pottsville Formation of the Warrior Basin of Alabama. In all, 32.45 lineal feet of coal lying in seven coal groups ranging from an unnamed coal group above

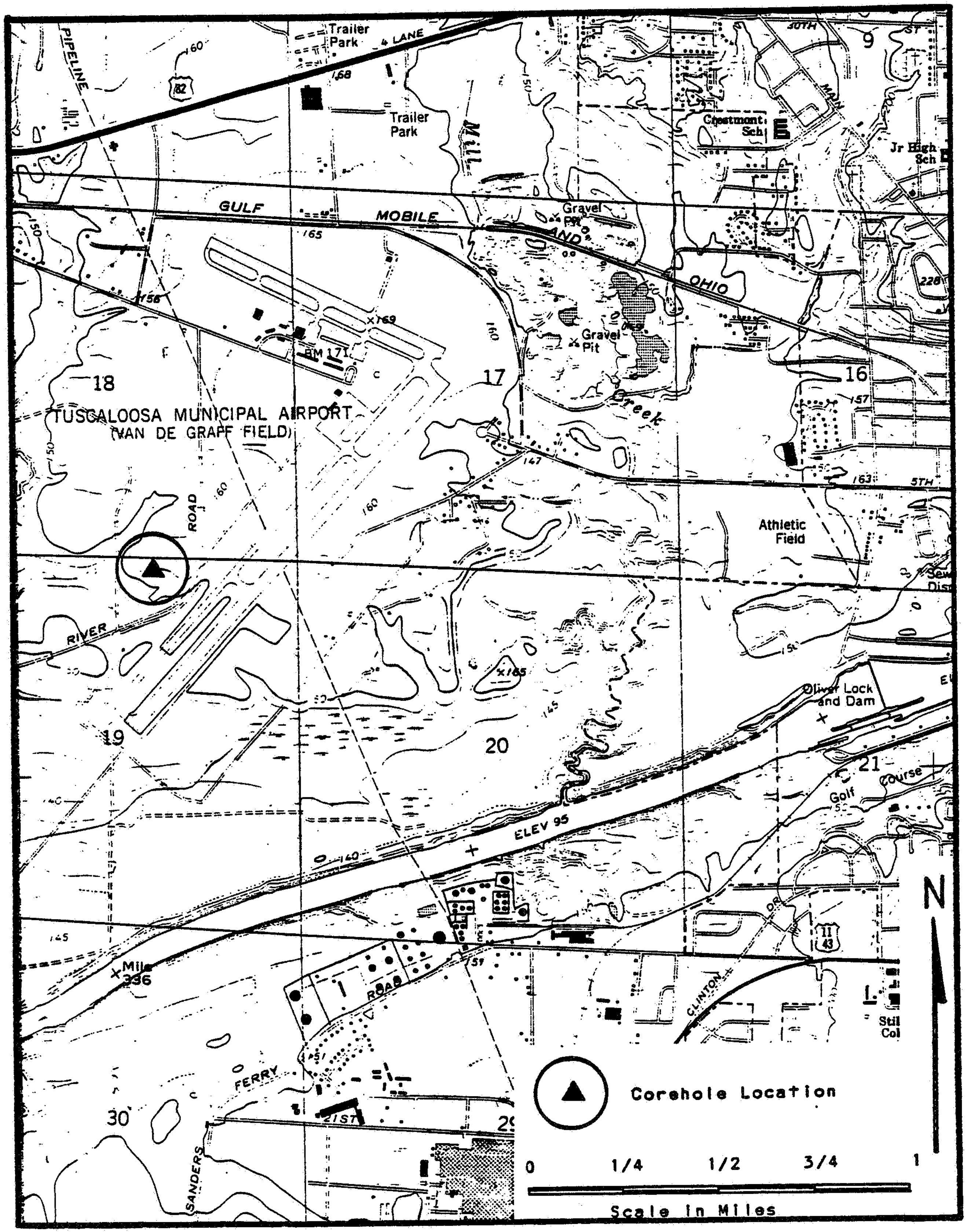


Figure 23. Location Map of the Tuscaloosa County Industrial Development Authority, Alabama Corehole (From Tuscaloosa, Alabama 7.5 minute topographic quadrangle)

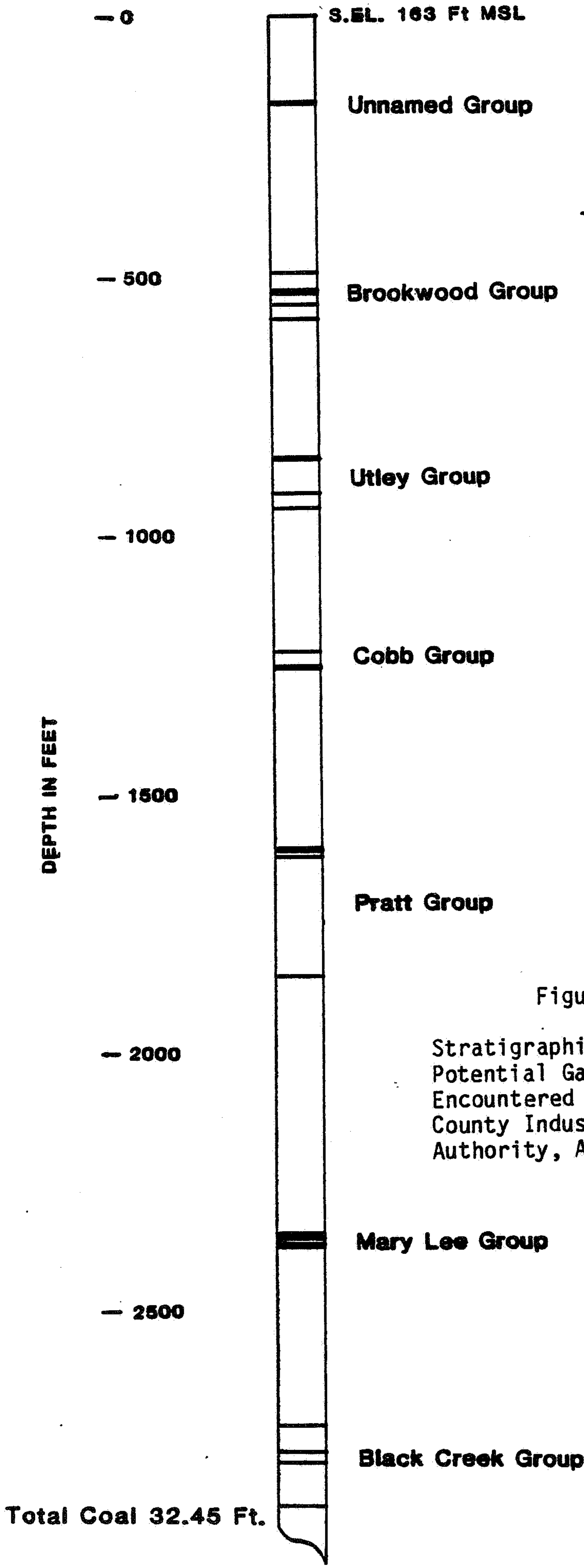
the Brookwood Group downward to the Black Creek Group were recovered in the coring (Fig. 24). The individual coal seams ranged in thickness from 0.2 feet to 2.75 feet and ranged in depth from 169 feet to 2878 feet.

U.S. Bureau of Mines direct method determination was used to measure gas content of 30.5 feet of the recovered coal core (Appendix B). After gas testing, proximate and ultimate analyses were run on selected coal samples. Selected samples of desorbed gas were tested by gas chromatography to determine gas quality. No gas production testing was conducted on the core hole.

Resource Characterization

All coal samples analyzed are high-volatile A bituminous in rank. As received ash content ranged from 6.6% to 39.1% with a simple arithmetic average of 18.2% ash. Intermediate gas content of the coals ranged from 0 to 351 cf/ton, with a weighted average intermediate gas content for all samples tested of 130 cf/ton. Intermediate gas content shows a direct correlation with coal seam depth and approaches an upper limit of 174 cubic feet of gas per ton of coal for each 1000 feet of depth (Fig. 25). There is a substantial amount of scatter among data points below this limit. An approximate mean of all coal seams encountered indicates an increase in intermediate gas content of less than 100 cubic feet per ton for every 1000 foot increase in depth.

Two groups of coal seams are considered potential targets for coalbed methane development. These groups were selected under the assumption that all coal seams lying within a 20-30 foot stratigraphic interval may be stimulated simultaneously. The Pratt Group contains 4.35 feet of coal lying in a 25 foot stratigraphic interval and having a weighted average intermediate methane content of 217 cf/ton. The Mary Lee Group contains



T. C. I. D. A., Alabama

Figure 24

Stratigraphic Section Showing Potential Gas Producing Strata Encountered in the Tuscaloosa County Industrial Development Authority, Alabama Corehole.

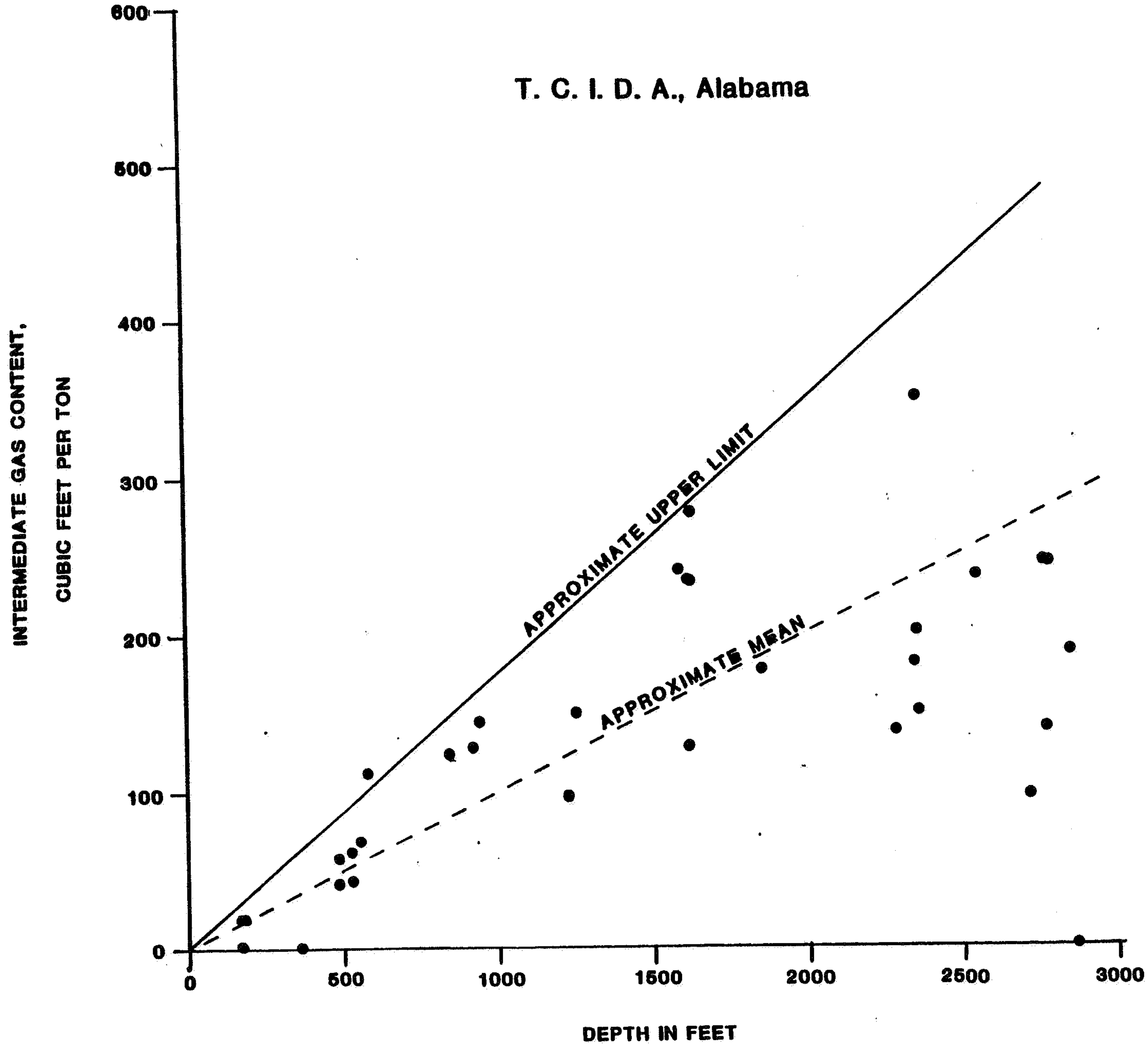


Figure 25. Graph Showing Intermediate Coalbed Methane Content vs. Depth in the Tuscaloosa County Industrial Development Authority Alabama Corehole

6.30 feet of coal lying in a 13 foot stratigraphic interval and having a weighted average intermediate methane content of 204 cf/ton (Fig. 26).

Gas quality analyses were performed on seven samples, one each from the Cobb, Pratt, and Black Creek Groups, and four of which were desorbed from cores from the Mary Lee Group. The average composition of these samples is given below.

Component	Mol %
Nitrogen (N_2)	5.25
Carbon Dioxide (CO_2)	0.43
Oxygen (O_2)	0.20
Methane (CH_4)	92.65
Ethane (C_2H_6)	1.10
Propane (C_3H_8)	0.19
Isobutane (C_4H_{10})	0.04
n-Butane (C_4H_{10})	0.03

Average heating value of the these gas samples is 965 Btu/cf.

The size of the coal reserve underlying the TCIDA Industrial Park was not presented in the report, but the 32.45 lineal feet of coal encountered in the corehole would comprise a coal resource of 56,788 tons per acre, or 59 million tons over the 1037 acre Industrial Park. The Pratt target zone contains 7,612 tons per acre, or 7.9 million tons in the Industrial Park, and the Mary Lee target zone contains 11,025 tons per acre, or 11.4 million tons in the Industrial Park. Both target groups contain 18,637 tons of coal per acre, or 19.3 million tons throughout the Industrial Park.

Total resources of intermediate coalbed methane gas for all coal seams encountered is 7,410 Mcf/acre, or 7.7 Bcf over the entire Industrial Park. The target zones contain 3,900 Mcf/acre, or 4.0 Bcf throughout the Industrial Park.

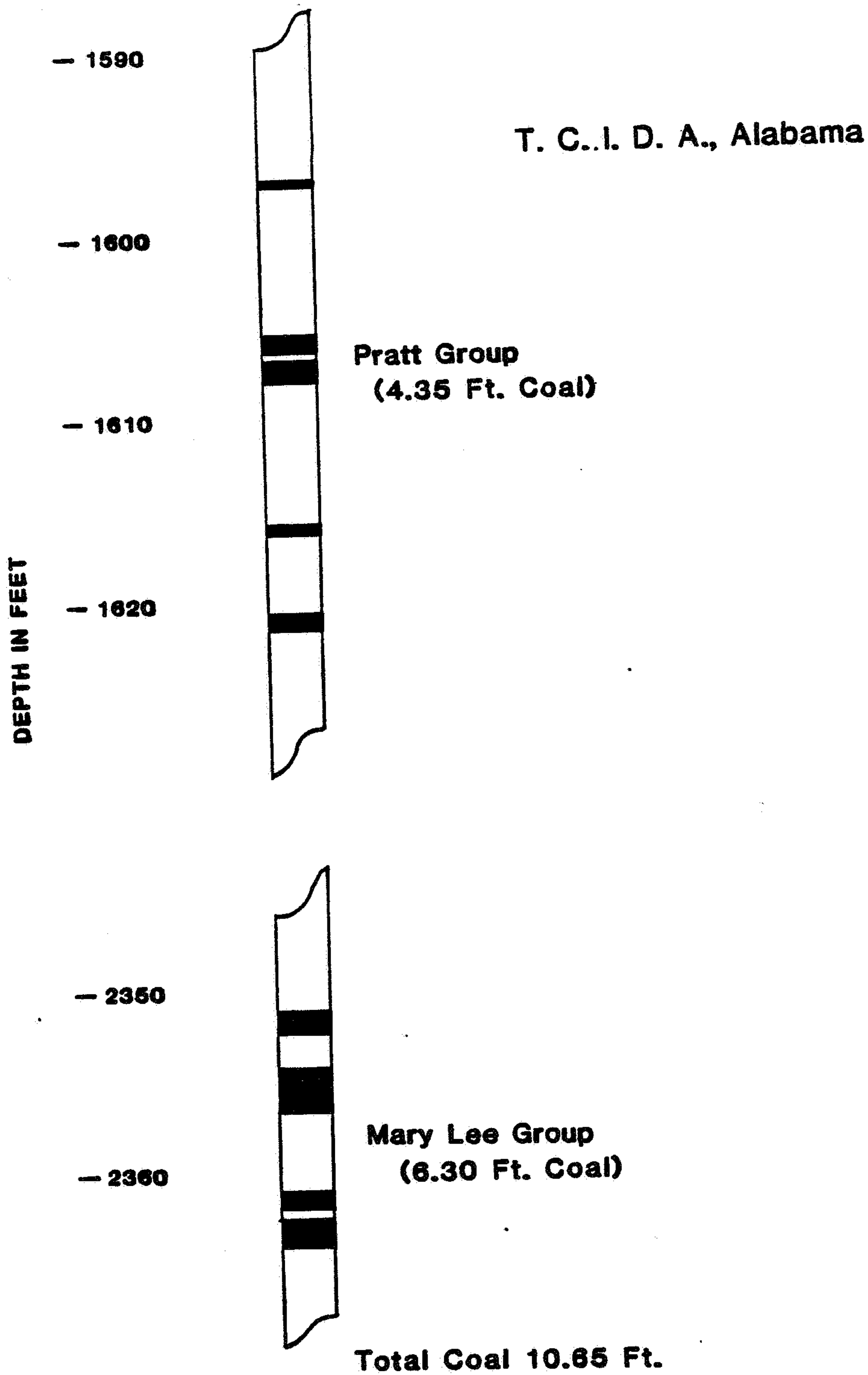


Figure 26. Detailed Sections of Potential Gas Producing Zones Considered for Development in the Tuscaloosa County Industrial Development Authority, Alabama Report

Conventional rotary-drilled vertical wells on 40 acre spacings are considered for coalbed methane recovery in the area. Stimulation of the two target zones either with nitrogen foam or slick water fracturing is recommended. Based on a level production scenario with 75% total recovery of producible methane from the target zones over a 10 year well life, production of 11,700 Mcf/year is predicted for a single well.

Economics of Resource Development

Proforma cash flows were developed to assess economic feasibility of development of producing gas wells in the area. The cash flows are based on the following parameters:

- o All capital and costs are stated in constant 1982 dollars.
- o 75% recovery of producible gas from the target zones over a 10 year project life is assumed. Production is level over project life.
- o Replacement natural gas cost for industrial users is predicted to be $4.72/Mcf in 1983, increasing approximately 5.5% a year to $7.62/Mcf in 1992.
- o A severance tax of 6% is deducted from the net value of the gas.
- o A 1/6 royalty is paid to the owner of the coalbed methane rights.
- o Development cost of a single well is $205,400 with an annual operating cost of $30,000.
- o Interest charges are not included in the calculations.
- o Depreciation conforms to current IRS laws.
- o Depletion is calculated at 15% of the net gas value, observing a 50% taxable income limitation.
- o A marginal corporate tax rate of 46% was used where applicable.
- o Salvage value is 10% of tangible costs at end of project.

Using these parameters, the internal rate of return is calculated at 4.74% and the payback period is 8.59 years. These are substantially below current standards for investment returns.

Economic sensitivity to variations in three factors, including gas replacement cost, well productivity, and drilling costs were examined. The results of these senstivity analyses are summarized below.

	Payback (yrs)	IRR (%)	Avg. Cost/ Mcf ($)
Base Case	8.29	6.58	5.40
+20% Gas Price	6.39	14.81	5.34
-5% Gas Price	9.09	3.93	5.49
Reduce gas recovery to 50% Base Case	> 10	Negative	9.10
Decrease Drilling Costs by $50,000 per well	7.55	9.36	5.09

Even with such positive variations as an increase in gas price or a decrease in drilling costs, returns on the project still fall below current standards for the degree of risk involved.

Environmental Ramifications of Resource Development

An environmental impact analysis of installation of the core hole was presented to the U.S. Department of Energy in January 1982. In this analysis the impact of the installation of production wells was also addressed. The only negative impact potentially arising from such a project is the production of significant amounts of water (up to 1000 barrels per day) which may contain deleterious quantities of dissolved chloride. Depending upon the quantities of water produced, chloride concentrations of the water, and applicable regulations, treatement of this discharge may be required.

Summarizer's Comments

Gas samples from this core hole contained relatively larger concentrations of more complex hydrocarbon gases than found in samples from other core holes and gas wells in the area. The specific gas content of the coal seams was also significantly less than typical values for the area (refer to Figure 33). Approximately 350 feet of stratigraphic section, including the Gwin Coal Group, were missing from the core and extensive fracturing was noted in the core. These factors indicate that the core hole intersected a fault zone which impacted the coalbed methane resource. Apparently the lighter hydrocarbon gas (methane) was more readily lost, resulting in a concentration of the more complex hydrocarbon gases. These observations may be important in future coalbed methane exploration and resource evaluation, as structural features may have a significant local impact on the accumulation of coalbed methane.

9. COALBED METHANE RESOURCE EVALUATION MONTGOMERY COUNTY, VIRGINIA

C.B. Stanley and A.P. Schultz of the Division of Mineral Resources, Department of Conservation and Economic Development of the Commonwealth of Virginia prepared this report for the U.S. Department of Energy under contract number DE-FG44-81R410431. The final report was submitted in 1983.

General Nature of Project

This project was conducted to determine the feasibility of coalbed methane recovery from the coal measures of the Valley Coal Fields Basin of western Virginia. In order to evaluate this resource, three core holes were initiated near Blacksburg, Virginia. Two of these were successfully completed in the coal measures. The third hole was abandoned before reaching the coal measures due to insurmountable problems in drilling. The successfully completed holes, designated the Sunnyside and Merrimac Wells, were cored using a NX wireline rig to total depths of 1672 feet and 1674 feet respectively. This coring was conducted by Joy Manufacturing Company of La Porte, Indiana. The Sunnyside Well, located at 37° 13' 48" north latitude and 80° 32' 30" west longitude was commenced at a surface elevation of 2015 feet (Fig. 27). The Merrimac Well, located at 37° 12' 08" north latitude and 80° 25' 47" west longitude lay at a surface elevation of 2090 feet (Fig. 28). Recovered core was logged by C.B. Stanley and A.P. Schultz. Upon completion of drilling, a suite of geophysical logs consisting of natural gamma, spontaneous potential, resistivity, expanded natural gamma, gamma-gamma density, expanded gamma-gama density, neutron density, caliper, and temperature was run by the Department of Geological Sciences of Virginia Polytechnic Institute and

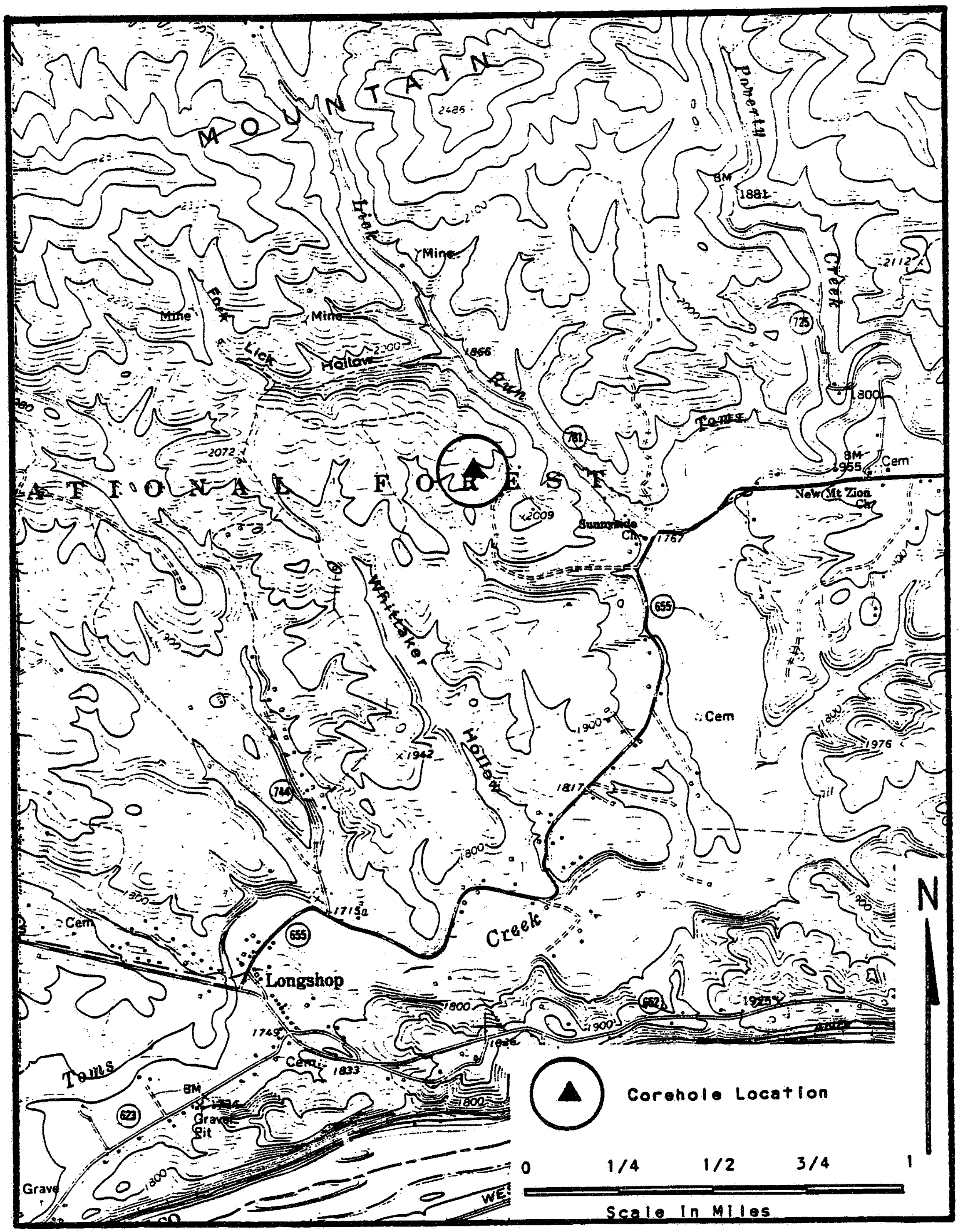


Figure 27. Location Map of the Sunnyside Well, Montgomery County, Virginia
(From Radford North, Virginia 7.5 minute topographic quadrangle)

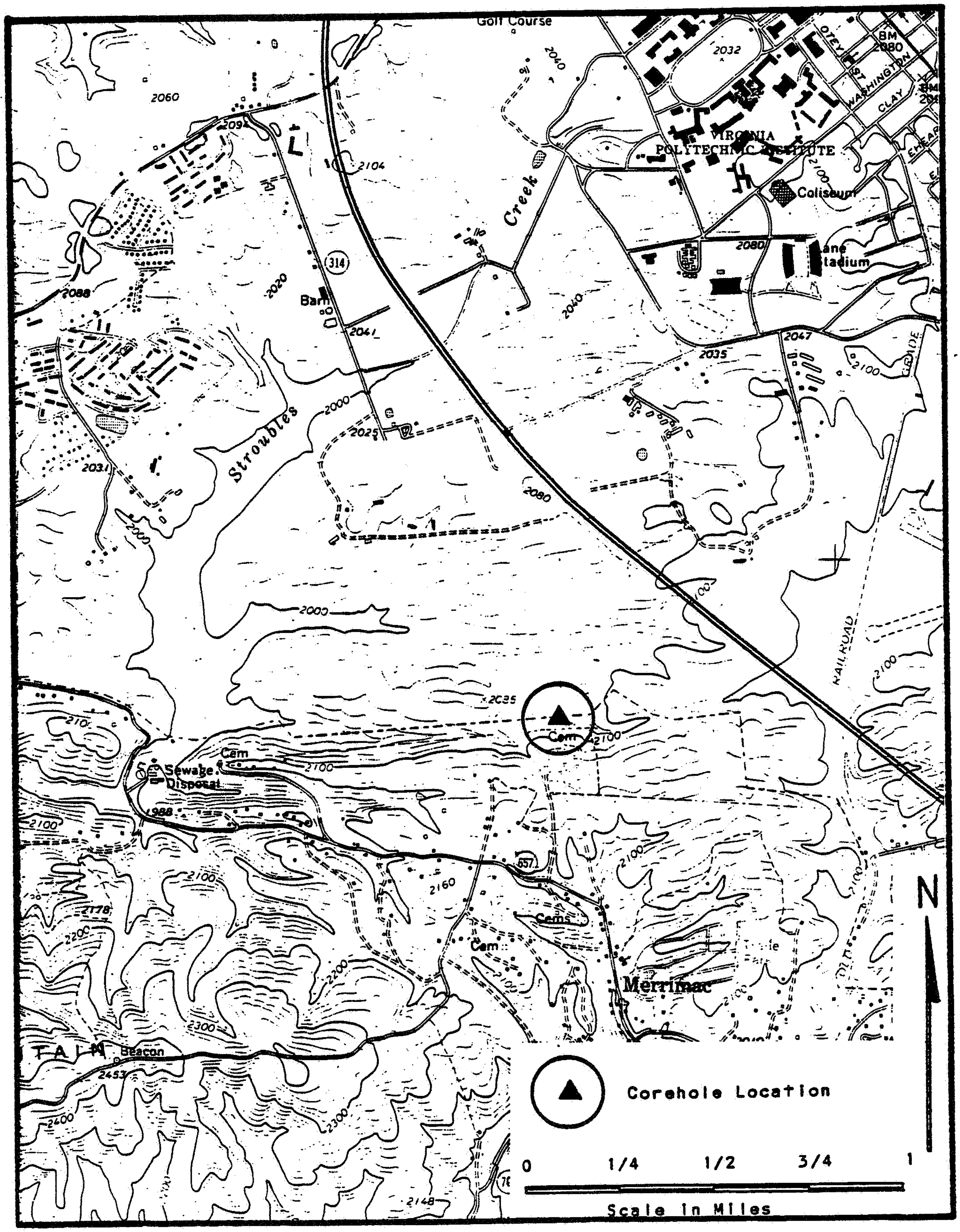


Figure 28. Location Map of the Merrimac Well, Montgomery County, Virginia (From Blacksburg, Virginia 7.5 minute topographic quadrangle)

State University (VPI). Two seismic sections of the study area also were generated by the Department of Geological Sciences using a Vibroseis System.

The drilling targets were coal measures of the Mississippian Price Formation, which include the Merrimac and Langhorne Seams. These coal measures lie in the Saltville Thrust Sheet which is in turn overlain by the Pulaski Thrust Sheet. In all, 10.45 lineal feet of coal lying between 1110 feet and 1199 feet in depth were recovered in the Sunnyside Well and 7.85 lineal feet of coal lying between 1404 feet and 1481 feet in depth were encountered in the Merrimac Well (Fig. 29).

Gas content of recovered coal cores was measured according to the U.S. Bureau of Mines direct method determination (Appendix B). The coal samples were subsequently analyzed by Geochemical Testing of Somerset, PA. No gas analyses were submitted, nor was any well production testing conducted.

Resource Characterization

All coal samples recovered are semi-anthracite except one, which is apparently low-volatile bituminous in rank. As received ash content of the coal samples range from 9.5% to 40.7% with a simple arithmetic average of 21.7% ash. Total gas contents of the coals range from 80 cf/t to 394 cf/t with a weighted average content of 214 cf/t. Intermediate (lost plus desorbed) gas contents range from 38 cf/t to 314 cf/t with a weighted average content of 179 cf/t (Fig. 30). No gas quality or well productivitiy data were presented in the report.

In the report, the coal resource base of the Valley Coal Fields Basin was divided into identified and hypothetical resources in accordance with the U.S. Geological Survey Coal Resource Classification System. A total

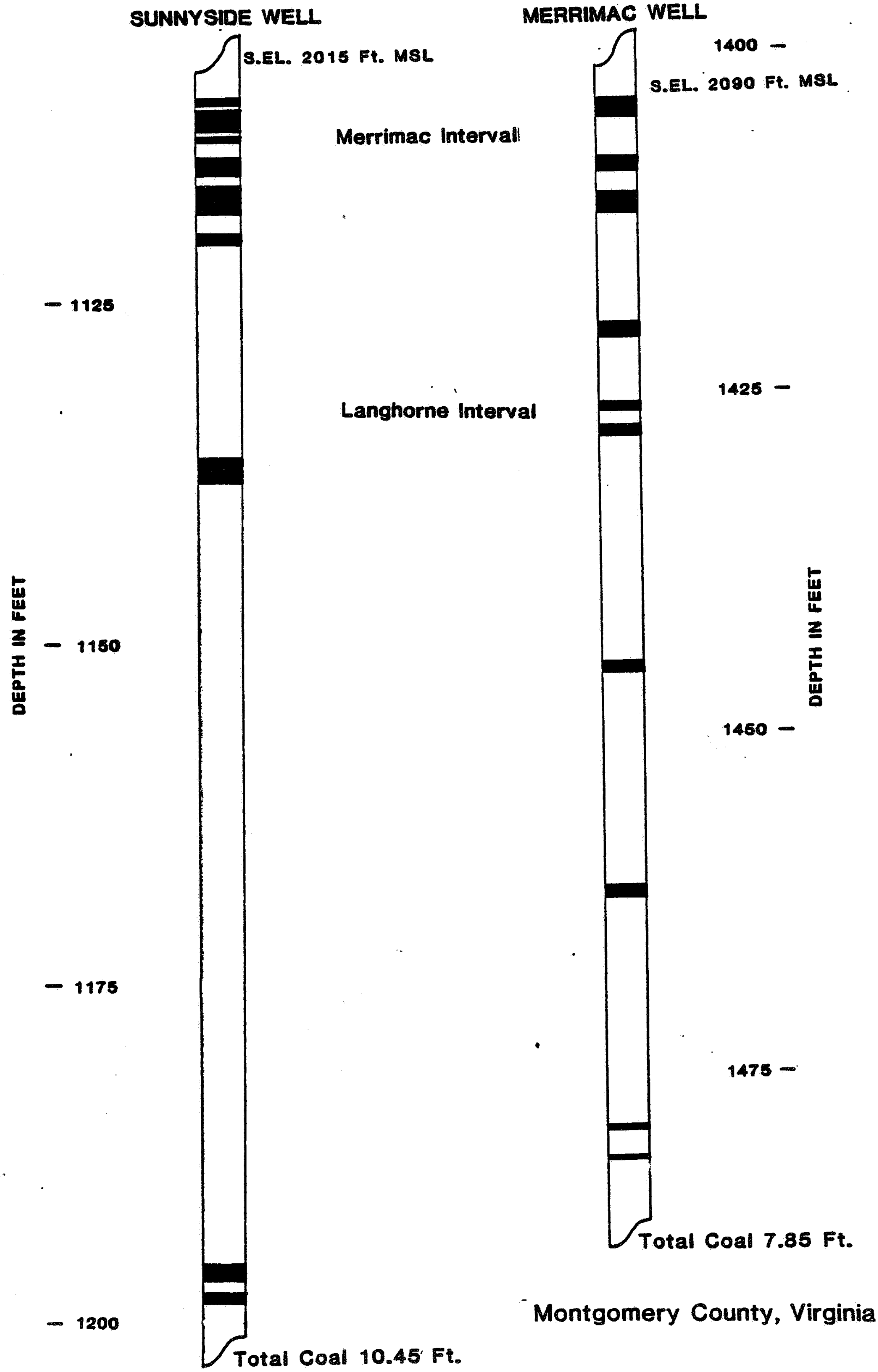


Figure 29. Detailed Section Showing Potential Gas Producing Strata Encountered in the Montgomery County, Virginia Coreholes

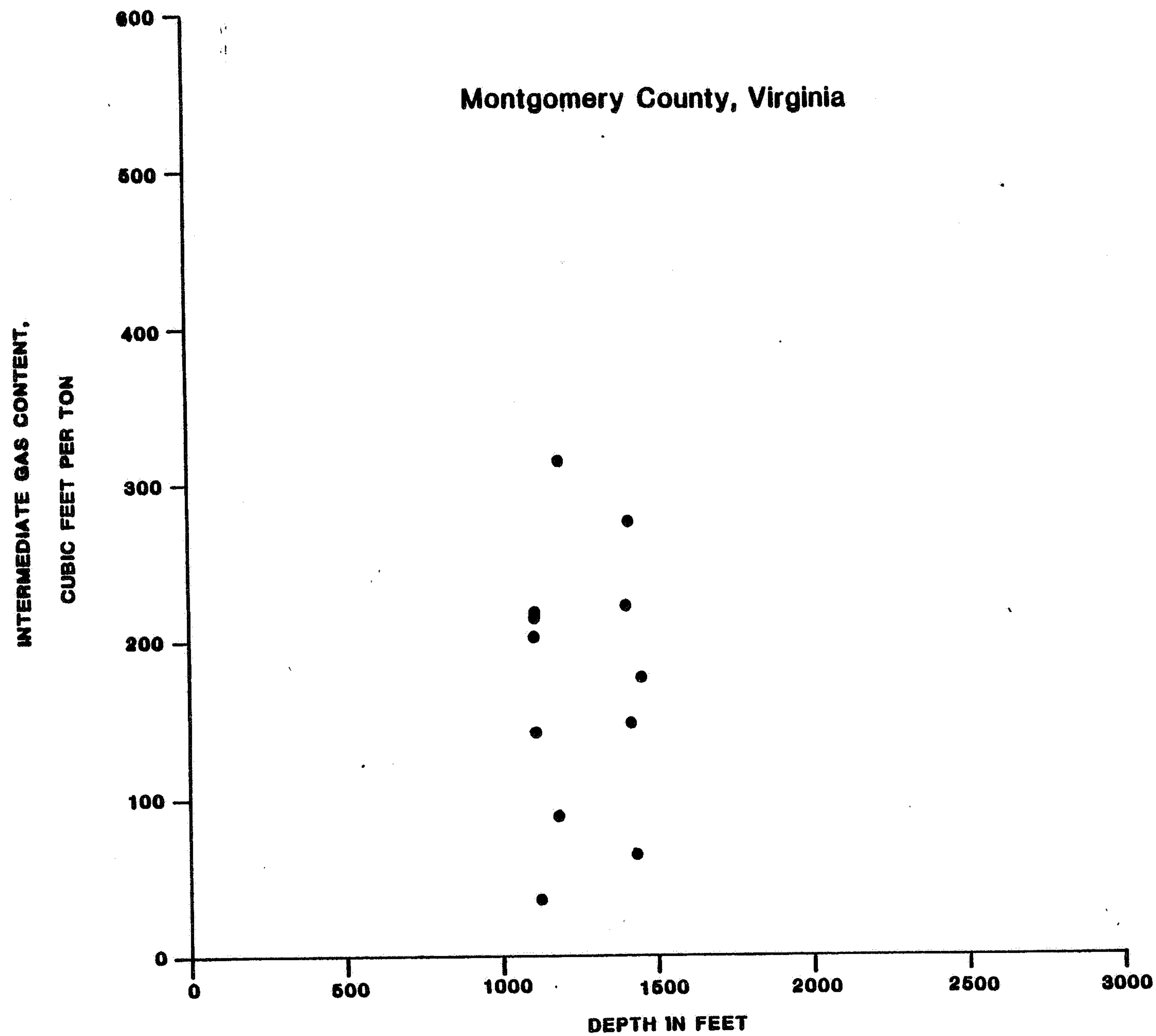


Figure 30. Graph Showing Intermediate Gas Content vs. Depth in the Montgomery County, Virginia Coreholes

coal thickness of five feet was assumed for identified resources and a thickness of 1.2 feet was assumed for hypothetical resources. The identified coal resource base is 10,000 tons/acre, and the hypothetical coal resource base is 2,400 tons/acre.

The coalbed methane resource base is reported at 3.2 million cubic feet per acre or 128.9 million cubic feet per 40 acres. It is assumed that these figures apply to the areas underlain by identified resource, although the methane resource estimate appears to have been generated independently of the coal resource estimate. To arrive at the coalbed methane resource, a seven foot coal thickness, equal to 560,000 tons of coal per 40 acres, with a specific total methane content of 230 cubic feet per ton was apparently assumed.

The production methods considered were not addressed in the report, but discussions of the economic feasibility of development indicate that conventional vertical wells are proposed. Production rate estimates are based on an initial production of 3 MCF/day per lineal foot of coal developed, or 20 MCF/day in this case. Production is expected to decline hyperbolically, as is typical in fractured reservoirs.

Economics of Resource Development

The economic feasibility study presented in the report is based on 40-acre wells spacing, a 1275 foot well depth, a well cost of $156,000, an annual operating cost of $4800, a gas sales price of $5.00/Mcf, 15% depletion, no severance tax, a well life of 15 years, and 10% of gas production to be used in compression. In this base case, development is not considered economically feasible either as a private or a government-sponsored enterprise.

Variations in the economic base case examined include increasing gas sales price to $10.00/Mcf, decreasing it to $3.00/Mcf, 10 and 20 acre well spacing, doubling the coal thickness, and adding a 12 1/2% override. By doubling coal thickness or increasing gas sales price to $10.00/Mcf, a 20% return on investment may be realized. These advantages would be offset, however, if a 12.5% override were levied on production.

Environmental Ramifications of Resource Development

No assessment of environmental impact of coalbed methane development in the area is presented in the report.

Summarizer's Comments

Desorption data generated in this study show a weighted average intermediate (lost plus desorbed) methane content of 179 cf/ton. The economic feasibility analysis assumed an in-place methane resource of 230 cf/ton. Calculations based on coal analysis data and depth using Kim's (1977) methods indicate that an in-place gas resource of approximately 420 cf/ton should exist in semi-anthracite coal at the depths at which it was encountered in the test wells. Several conditions, including the positioning of the test wells near old mine workings, may account for these discrepancies. If the lower than predicted gas contents are a localized phenomenon and predicted gas contents are realized elsewhere in the basin, development could become economically feasible.

At the time of this writing a private company is proceeding with exploration and development of coalbed methane in the Valley Coal Fields Basin of Virginia. No new data has yet emerged to further assess the viability of such a venture, but the enterprise may eventually provide a more representative picture of the gas resources in the area.

10. FEASIBILITY ASSESSMENT OF UNCONVENTIONAL GAS IN KENTUCKY

This report was prepared by the Kentucky Center for Energy Research for the U.S. Department of Energy under contract number DE-FG-44-80R410334. The final report was submitted on June 29, 1984.

General Nature of Project

This project was conducted to determine the feasibility of producing unconventional gas from coal seams and from Devonian black shale to supply the municipal gas distribution systems of the cities of Prestonburg and Somerset, Kentucky.

Three holes were drilled to assess this potential resource. Two of these holes, one near Prestonburg Kentucky and one near Somerset, Kentucky were rotary drilled through the Devonian section, while the third, located near Prestonburg, was core drilled through the coal measures using a wireline rig. The Prestonburg shale test well, located in Section 19 of Carter Coordinates O-18, Floyd County, Kentucky, was commenced at a surface elevation of 659.2 feet and drilled to a total depth of 2231 feet. The Somerset shale test well, located in section 4 of Carter Coordinates H-74, Leslie County, Kentucky, lay at a surface elevation of 1317 feet and was drilled to a total depth of 3151 feet (Fig. 31). The Prestonburg coal test well, located approximately 200 feet south of the Prestonburg shale test well, was sited at a surface elevation of 645 feet and drilled to a total depth of 604 feet. Shale test holes were drilled by J.W. Kinzer of Allen, Kentucky, and the coal test hole was drilled by Evans and Dixon. Core and cuttings descriptions of all holes were provided by the Kentucky Geological Survey. Geophysical Tests, consisting of specific conductance, resistivity, caliper, natural gamma, density, and expanded density logs were conducted on the coal test hole by the Kentucky Geological Survey.

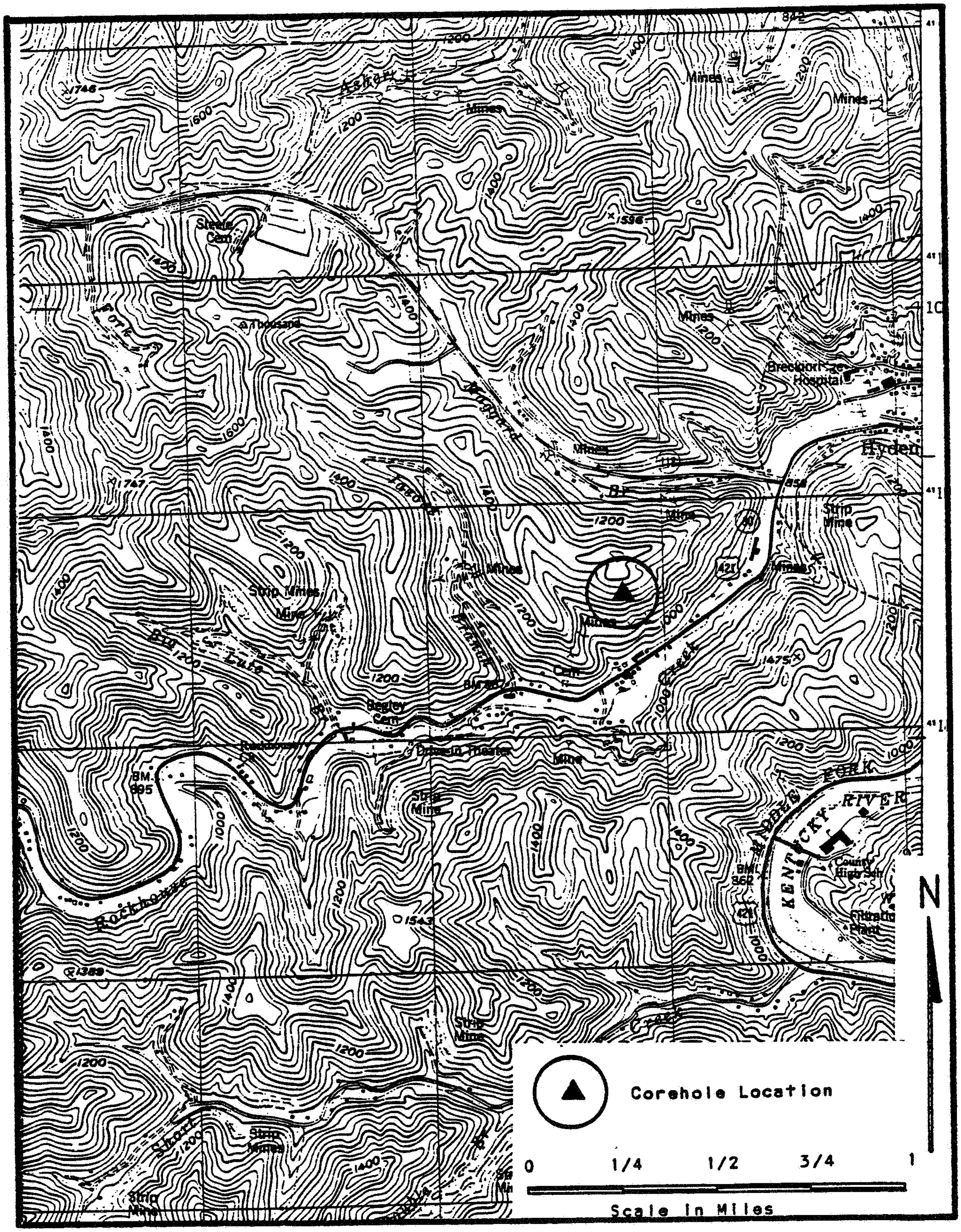


Figure 31. Location Map of the Somerset Well, Kentucky Project
(From Hyden West, Kentucky 7.5 minute topographic quadrangle)

Schlumberger Well Services, Inc. ran caliper, temperature, audio, induction, gamma, sidewall neutron porosity, compensated formation density, and coriband logs on the Prestonburg shale test well. Caliper, compensated density, temperature, sibilation, gamma ray, neutron, and induction logs were generated for the Somerset shale test well by the Birdwell Division of the Seismograph Service Corporation.

The drilling targets in this study were several Pottsville Group coal seams which have been mined in the Prestonburg area and lower Mississipian to upper Devonian carbonaceous shales. In the Prestonburg coal test well, a total of less than 4.5 feet of coal in seven seams was encountered at depths from 127 feet to 278 feet (Fig. 32). None of these seams was greater than one foot in thickness. In the Prestonburg shale test well a total of 692 feet of Devonian shale was encountered at depths from 1504 to 2196 feet. Potential production zones are the Cleveland member of the Ohio Shale from 1503 feet to 1600 feet and the lower Huron member of the Ohio Shale between 1,865 feet and 2,006 feet (Fig. 32). A total of 256 feet of Devonian shale lying between 2731 feet and 2987 feet were encountered in the Somerset shale test well. Potential production zones lie in the upper and middle Huron members of the Ohio Shale between 2780 feet and 2831 feet and in the lower Huron member of the Ohio Shale between 2910 feet and 2914 feet.

Gas contents of coal core samples from the Prestonburg coal test well were measured in accordance with U.S. Bureau of Mines direct method determination (Appendix B). Coal quality and coalbed methane gas quality apparently were not determined in the study.

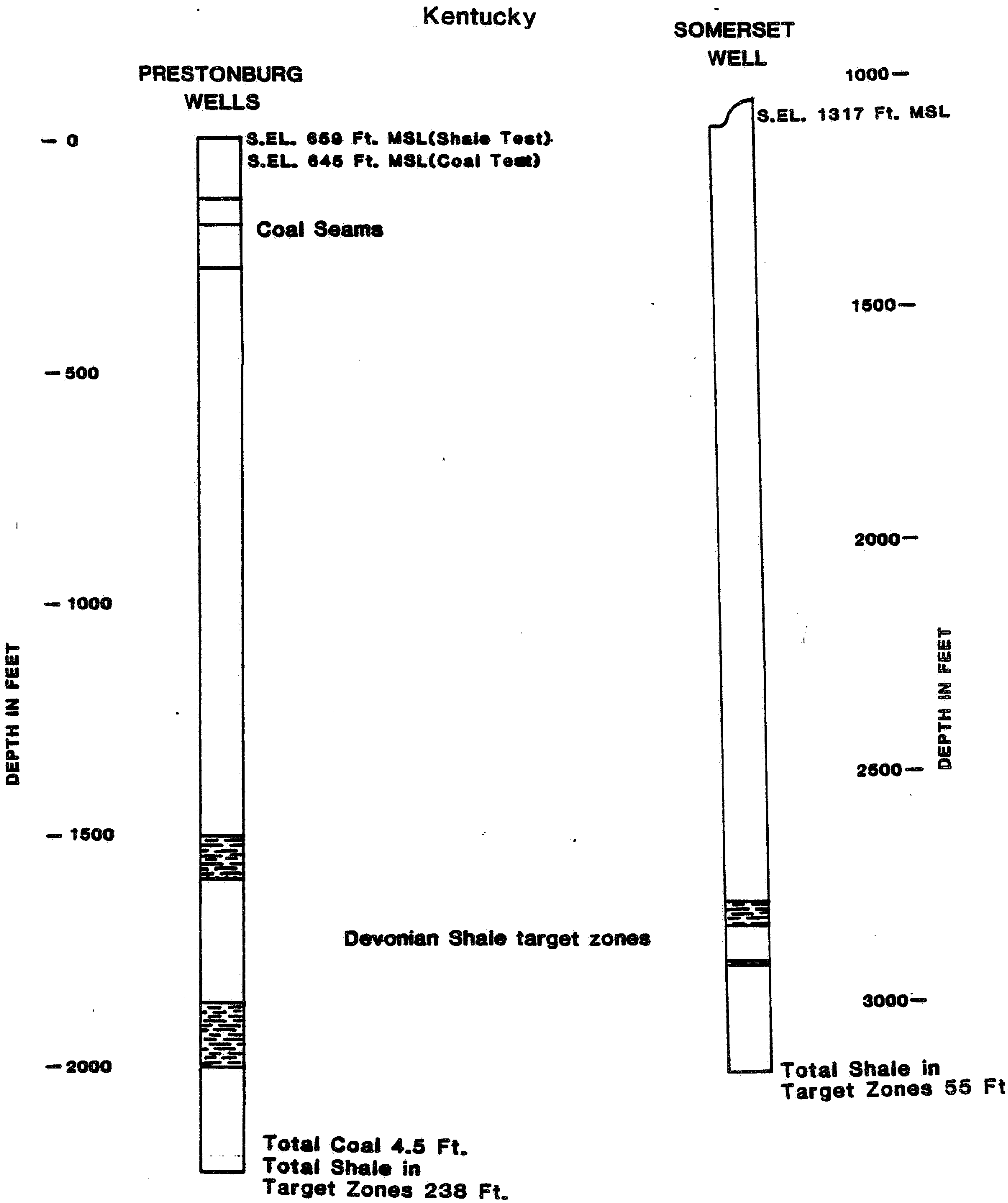


Figure 32. Stratigraphic Sections Showing Potential Gas Producing Strata Encountered in the Kentucky Project

Open hole gas flow was determined for both shale test wells to estimate potential long-term production rates. Following the open hole testing, the Somerset shale test well was stimulated with 4,400 pounds of solidified gelatin placed in the 2,711-3,151 foot interval. A gas quality analysis for production from the Somerset shale test well was submitted by the Somerset Gas Service.

Resource Characterization

The lack of coal quality data precluded determination of the rank of coal seams recovered from the Prestonburg coal test well. Total gas content of the three coal samples desorbed are 32 cf/t, 64 cf/t, 96 cf/t, with a weighted average total gas content of 54 cf/t. No gas quality or productivity data were presented in the report.

Open hole flow tests on the unstimulated Prestonburg shale test well yielded a total flow of 103 Mcf/day. Of this, only 15 Mcf was estimated to derive from the Devonian black shale target zones with the remainder being produced from the overlying Newman Limestone. Open hole flow from the Somerset shale test well was 10 Mcf/day prior to stimulation and 35 Mcf/day afterward. Analysis of gas from the Somerset shale test well indicates that it is composed of 98.3% hydrocarbon gases, 1.7% non-hydrocarbon gases, and has a dry heating value of 1251 Btu/cf.

No estimate of the in-place coal resource was presented in the report, but assuming a total coal thickness of 4.5 feet, an in-place coal resource of 8,100 tons per acre or 324,000 tons per 40 acres exists beneath the Prestonburg site. With a weighted average gas content of 54 cf/t of coal, the in-place coalbed methane gas resource totals 44/Mcf per acre or 18 MMcf/40 acres at the Prestonburg site.

Recovery of coalbed methane gas at the Prestonburg site is deemed unfeasible due to the low specific methane content and thinness of the coal, and thus no method for production of coalbed methane was considered. Production of unconventional gas from shale at both sites through conventional vertical rotary drill holes was considered. Stimulation of the Prestonburg shale test well was not recommended, while the Somerset site is to be further stimulated in an unspecified manner.

Production estimates are 5 Mcf per day for both the Prestonburg and Somerset test holes. This production rate is anticipated for 300 days per year over a ten-year well life. Total life of well production is estimated at 15,000 Mcf for each site.

Economics of Resource Development

Recovery of unconventional gas from Devonian black shale does not appear to be economically feasible in the area since the local wellhead gas price is much less than would be required to make such a venture profitable. Economic sensitivity analyses were generated for changes in debt ratio, interest rates, income tax rates, well life, total investment cost, and annual production. The results of these sensitivity analyses are presented graphically in the report and discussed in detail.

Environmental Ramifications of Resource Development

No assessment of enviromental impact of unconventional gas development is presented as development is not deemed economically feasible.

SUMMARY AND CONCLUSIONS: A PROGRAM OVERVIEW

Of the ten individual unconventional gas development projects reviewed for this summary (Appendix A), three found gas in sufficient quantities to be deemed economically recoverable under conditions prevalant at the times the reports were prepared. These were the University of Alabama Project, the City of Tuscaloosa, Alabama Project, and the Westmoreland Manor, Pennsylvania Project. In each of these projects an adequate amount of coal containing a quantity of producible methane sufficient to sustain economically viable production wells was encountered. In the remaining seven projects the coal thickness encountered combined with the specific producible methane content of that coal would not yield sufficient quantities of methane to be judged economically recoverable by the researchers.

To establish a rough quantitative comparison of these projects, Table 1 lists the factors critical to the in-place gas resource (coal thickness and specific producible gas content of the coal) and the estimated producible gas resource per 40 acre block. The three projects delineating economically recoverable reserves show the largest gas resources by virtue of adequate coal thickness and specific producible methane content. The remaining projects show a deficiency in one or both of these factors.

It is difficult to ascertain whether the thickness of coal encountered in each project is typical for each region. By comparing the four Alabama projects, all of which were conducted within 3 miles of each other, it is apparent that significant variations in coal thickness can occur locally.

TABLE 1

COMPARISION OF IN-PLACE METHANE RESOURCES
ENCOUNTERED IN DOE REGION IV PROJECTS

(Reported For Development Target Zones Where Designated)

	Project	Producible Coal Thickness, Ft.	Weighted Average Intermediate Gas Content, cf/t	Producible Gas Resource MMcf/40 Acre
1.	University of Alabama	13.4	331	319
2.	Fentress Co., TN	1.6	4.7	0.53
3.	City of Tuscaloosa, AL	16.6	277	331
4.	B.F. Goodrich, AL	10.2	301	221
5.	Deep River, N.C.	7.9	304	173
6.	Westmoreland Manor, PA	19.4	176*	245*
7.	Rockwood, TN	3.6	49	12.6
8.	T.C.I.D.A., AL	10.7	209	161
9.	Montgomery Co., VA	7.0	179*	100*
10.	Kentucky	4.5	13	4.33

* Based on intermediate (lost plus desorbed) gas content; figures in original reports calculated on other bases.

Target zone coal thickness ranged from 10.2 feet to 16.6 feet in the Alabama projects with a range in producible gas resource from 161 million cubic feet per 40 acres to 331 million cubic feet per 40 acres. This example illustrates the impact of local coal thicknesses on the gas resources, and suggests that anomalously thin coal sections may be responsible for the low resource values encountered in some of the projects. Certainly the coal sections encountered in the Fentress County, Tennessee, the Rockwood, Tennessee, and the Kentucky projects could not contain economically recoverable gas resources even with optimum specific gas contents. Whether or not these sections represent typical coal sections for those areas has not been determined, but this possibility should be considered.

Determining whether specific gas contents of the coals encountered in the projects are typical is simpler than determining thickness of coal sections. By plotting the weighted average intermediate gas content vs. the weighted average depth of coal in the production target zones of each project on a diagram showing expected gas content for coal of given rank and depth (Fig 33), this factor may be evaluated. In this comparison it is readily apparent that the coal encountered in the University of Alabama Project (1) has a higher than expected specific gas content, while the Westmoreland Manor, Pennsylvania (16), the Rockwood, Tennessee Project (7), and the Montgomery County (9), Virginia Project showed substantially lower than expected values. Based on this diagram, Table 2 compares actural gas resources encountered with those expected for coal of the rank and depth reported.

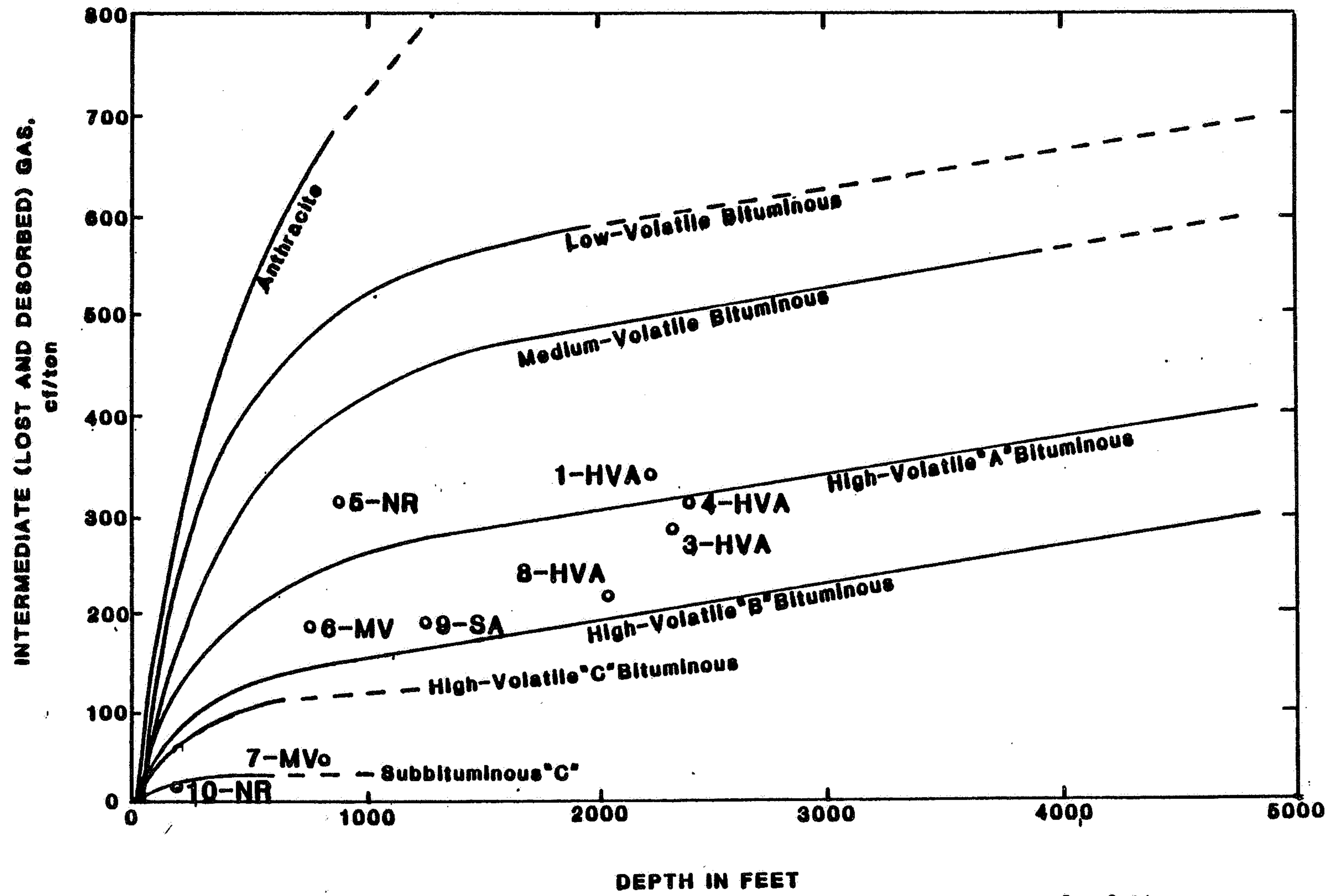


Figure 33. Graph Showing Actual vs. Expected Gas Content for Coal of the Ranks and Depths Encountered in DOE Region IV Unconventional Gas Projects (SA - Semi-Anthracite; MV - Medium Violative Bituminous; HVA - High Volatile A Bituminous; NR - Not Reported. See Appendix A for Project Reference Numbers. Modified From Eddy et al., 1982)

Table 2

ACTUAL VS. EXPECTED SPECIFIC GAS CONTENT OF COALS AND GAS RESOURCE ENCOUNTERED IN PROJECT AREAS

	Project	Measured Weighted Average Intermediate Gas Content, cf/t	Expected Weighted Average Intermediate Gas Content, cf/t	Measured Producible Gas Resource MMcf/40 Acre	Expected Producible[a] Gas Resource MMcf/40 Acre	Percent Difference
1.	University of Alabama	331	255	319	246	+30%
2.	Fentress Co., TN	4.7	N.D.	0.53	N.D.	-
3.	City of Tuscaloosa, AL	277	265	331	317	+ 4%
4.	B.F. Goodrich, AL	301	265	221	195	+13%
5.	Deep River, N.C.	304	N.A.	173	N.A.	-
6.	Westmoreland Manor, PA	176[b]	310	245[b]	431	-43%
7.	Rockwood, TN	49	320	12.6	81	-84%
8.	T.C.I.D.A., AL	209	250	161	193	-17%
9.	Montgomery Co., VA	179[b]	575	100[b]	321	-69%
10.	Kentucky	13	N.A.	4.33	N.A.	-

N.D. - Not Determined.
N.A. - Not Available, No coal rank given.
a - This estimation based only on coal rank and depth; does not compensate for other factors affecting specific gas content such as ash and moisture content, and should only be regarded as a rough approximation.
b - Based on intermediate (lost plus desorbed) gas content; figures in original reports calculated on other bases.

Mroz et al. (1983) summarized the potential for recovery of coalbed methane in four of the coal-bearing areas examined in the Region IV Projects. These are the Northern and Central Appalachian Basins, the Warrior Basin, and the Deep River Basin. Data derived from the Region IV Projects may indicate the need for adjustments to some of these evaluations as outlined below.

Two previous projects conducted in the Northern Appalachian Basin resulted in coal desorption data for some of the same seams examined in the Westmoreland Manor, Pennsylvania Project. In the Waynesburg College Multiple Coal Seam Project seams ranging stratigraphically downward from the Bakerstown Seam to the Mercer Seam had a weighted average intermediate gas content of 88 cf/t. Seams ranging stratigraphically downward from the Upper Freeport seam to the Lower Mercer seam yielded a weighted average intermediate gas content of 30 cf/t in the Westinghous Electric Company Well (Waltz Mill Site). Both projects indicate significantly lower gas contents than the weighted average intermediate gas content of 176 cf/t reported in the Westmoreland Manor Study. The coal seams encountered in the Westinghouse Electric Company Well lay at a greater depth than those at Westmoreland Manor, while those at Waynesburg College lay at a lesser depth. Depending upon the actual methods employed in estimating the coalbed methane resource of the Northern Appalachian Region as reported by Mroz, data generated in the Westmoreland Manor Project may warrant an upward adjustment to the estimate.

The opposite situation exists in the coalbed methane resource estimate reported by Mroz for the Middle Appalachian Basin. Estimates of coalbed methane content in coals of this area range from a low estimate of 125 cf/ton to a high estimate of 400 cf/ton. The Fentress County, Tennessee, the Rockwood, Tennessee, and the Kentucky studies all indicate specific gas content values significantly less than Mroz's low estimate. The only data which may have a true bearing on Mroz's estimates, however, is that generated in the Rockwood, Tennessee Project, since coal was encountered at depths insufficient to promote significant gas adsorption in the other two projects. Based on the Rockwood Report a downward revision of coalbed methane resource estimates may be indicated in the Central Appalachian Region.

The four projects conducted in the Warrior Basin indicate an average intermediate gas content of 284 cf/ton for production target seams in the Mary Lee Group. All coal samples were recovered from depths greater than 2000 feet. Mroz reported that a realistic maximum of 20 billion tons of coal containing 10 trillion cubic feet of gas lie in the deeper portions of the Warrior Basin. This estimate apparently is based on an average specific coalbed methane content of 500 cf/ton, which is significantly higher than indicated in the Region IV projects. This higher value was probably derived from earlier research which concentrated on the southeastern edge of the Warrior Basin where coals are typically low to medium volatile bituminous in rank.

A large proportion of the coal in the basin however, like that tested in the Region IV projects, is high volatile A bituminous. Caution should therefore be applied in formulating resource estimates in the Warrior Basin, with specific gas content adjusted to reflect local coal rank.

The discussion of the Deep River Basin of North Carolina presented in the Mroz report was based on results of the Region IV Drilling Project. No coalbed methane resource estimate was included by Mroz. Since the Region IV Drilling Program indicated a potential for economic recovery, however, a resource estimate for the Deep River Basin may be in order.

No discussion of potential coalbed methane resources in the Valley Coal Fields of Virginia, in which the Montgomery County, Virginia Project was conducted, was included in the Mroz report.

REFERENCES

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Eddy, G.E., Rightmire, C.T., and Byrer, C.W., 1982, Relationship of methane content to coal rank and depth: Theoretical vs. observed: SPE/DOE 10800, p. 117-122.

Kim, A.G., 1977, Estimating methane content of bituminous coalbeds from adsorption data: U.S. Bureau of Mines R. I. 8245, 22 p.

Mroz, T.H., Ryan, J.G., and Byrer, C.W., (Eds.) 1983, Methane recovery from coalbeds: a potential energy source: DOE/METC/83-76, 458 p.

School of Mines and Energy Development of the University of Alabama, 1984, The development of potential of coalbed methane in the vicinity of the Radford Army Ammunition Plant, Radford, Virginia: (Unpublished Report), 83 p.

APPENDICES

APPENDIX A

GENERAL INFORMATION ON DOE REGION IV
UNCONVENTIONAL GAS STUDIES

	1. Univ. of Alabama	2. Fentress Co., TN	3. City of Tusc. AL	4. B.F.G. AL	5. Deep River NC	6. Westmoreland Manor, PA	7. Rockwood TN	8. TCIDA AL	9. Mtgy. Co. VA[a]	10. Kentucky[b]
Contract #	DE-FG44-80R 410333	DE-FG44-81R 410426	DE-FG44-80R 410337	DE-FG44-81R 410428	DE-FG44-81R 410400	DE-FG44-81R 410566	DE-FG4480R 410336	DE-FG44-80R410427	DE-FG44-81R 410431	DE-FG44-80R 410334
Report Preparer	SOMED	Hensley - Schmidt, Inc. TN. Energy Authority	University SOMED - City of Tuscaloosa	SOMED - B.F. Goodrich, Inc.	Richard A. Beutel & Assoc N.C. Energy Inst.; N.C. Dept. of Comm.	Pacifica Services	Wayne L. Smith and Assoc.	University SOMED	VA. Div. of Min. Resources	Ky. Center For Energy Research
Report Date	Sept. 1981	May 1982	June 1982	Sept. 1982	Sept. 1982	Sept. 1982	Oct. 1982	Jan. 1983	1983	June 1984
Drill Hole Location:										
Lat.	33°12'44" N	36°25'42" N	33°10'41" N	33°11'26" N	35°32'45" N	40°16'23" N	N.S.	33°12'59" N	37°13'48"N; 37°12'08"N	N.S.;37°09'15" N
Long.	87°31'48" W	84°55'57" W	87°33'58" W	87°36'35" W	79°17'45" W	79°33'43" W	N.S.	87°37'09" W	80°32'30"W; 80°25'47"W	N.S.;88°23'21" W
Drill Hole Location: County, State	Tusc., AL	Fentress, TN	Tusc., AL	Tusc., AL	Lee, N.C.	Westmoreland PA	Morgan TN	Tusc., AL	Mtgy., AL	Floyd, Leslie, KY
Coal Field	Warrior	Wilder-Fentress District	Warrior	Warrior	Deep River	Main Bituminous of PA	Rockwood District	Warrior	Valley	Big Sandy; Hazard
Surf. El. (MSL)	262	1758	156	154	234	1080	1600	163	2015; 2090	659; 1317
Total Depth of Drill Hole (Feet)	2965	1405	2882	3429	953	1089	1011	2901	1672; 1674	2331; 3151
Total Resource Encountered (Feet)										
Coal	33	6.6	33.26	33.92	7.9	19.9	3.6	32.45	10.45; 7.85	4.5; 0
Shale	0	46	0	0	1.3	0	0	0	0; 0	692; 256

N.S. = Not Specified

[a] First Set of Figures Refers To Sunnyside Test Well, Second Set to Merrimac Test Well

[b] First Set of Figures Refers To Prestonburg Coal and Shale Test Wells, Second Set To Somerset Shale Test Well

APPENDIX B

DESCRIPTION OF THE U.S. BUREAU OF MINES DIRECT METHOD DETERMINATION OF THE GAS CONTENT OF COAL

The U.S. Bureau of Mines Direct Method Determination of Gas Content as described by Diamond and Levine (1981) was used in all studies included in this summary which report the gas content of coal samples. This method assumes that the total gas content of a coal sample is the sum of three components - the desorbed gas, the lost gas, and the residual gas.

The desorbed gas component is released over a period of time after the coal sample is retrieved. It is retained and measured by sealing the sample in an air-tight container. Lost gas is that fraction of the desorbed gas that is lost to the atmosphere between the time the coal is penetrated by the drill bit and the time the coal sample is sealed in the air-tight container. Residual gas is that component which remains adsorbed in the coal sample after significant desorption ceases.

To determine gas content according to this method, a coal sample is retrieved, described, and measured as rapidly as possible after being cut by the drill bit. The recovered sample is then placed in a sealed canister fitted with a release valve. Periodically the gas is released into an inverted graduated cylinder filled with water, and the gas volume is determined by the amount of water displaced (Fig. B-1).

Determination of lost gas is dependent on initial measured desorption rates and the amount of time which elapses between sample cutting, sample retrieval, and sealing the sample in the canister. Determinatior of lost

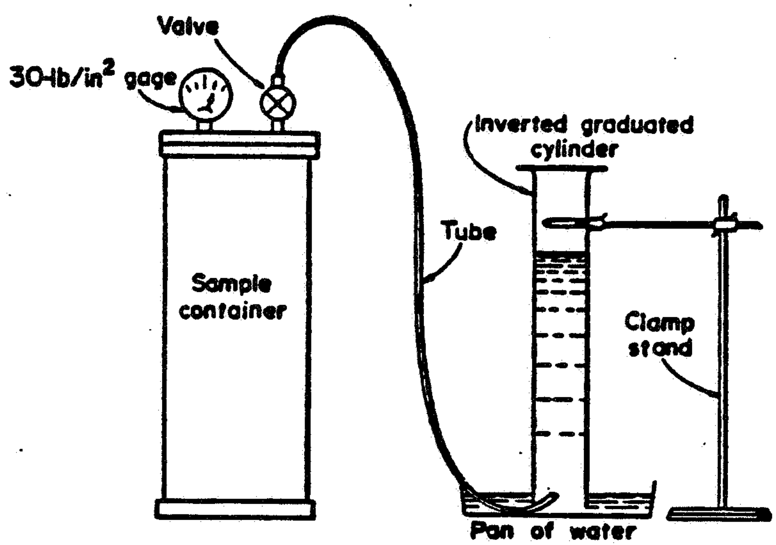

Figure B-1. Schematic Representation of U.S.B.M. Direct Method Desorption Apparatus.

gas assumes that gas desorption commences when the external pressure acting on the coal sample falls below a certain level. This condition is assumed to be met when the sample is halfway between its in-situ depth and the surface during core retrieval. At that point the pressure imparted by drilling fluids is assumed to be sufficiently reduced to initiate desorption. For this reason, the time at which core retrieval begins and the time at which the core reaches the surface are recorded so that the time desorption is assumed to commence can be established.

Initial desorption rates are then used to extrapolate the amount of lost gas. This method assumes that the cumulative volume of gas desorbed is proportional to the square root of the desorption time. By plotting cumulative desorbed gas vs. the square root of the time since canister desorption commenced, the resulting curve can be extended to the time of initial desorption to estimate lost gas (Fig. B-2).

After measured desorption from the coal sample sealed in the desorption canister becomes insignificant, the sample is removed from the canister and placed in a specially designed sealed ball mill. The sample is crushed and gas released during this process is measured in the same manner as desorbed gas. The gas so evolved is recorded as residual gas.

Diamond and Levine (1981) state that residual gas may not be producible from a normally stimulated coalbed methane well. For this reason some workers calculate gas resources and production rate estimates using only the "intermediate", or "producible" specific gas content of the coal sample, which is the sum of lost and desorbed gas. Other workers base their calculations on the "total" specific gas content of the sample, which also includes residual gas.

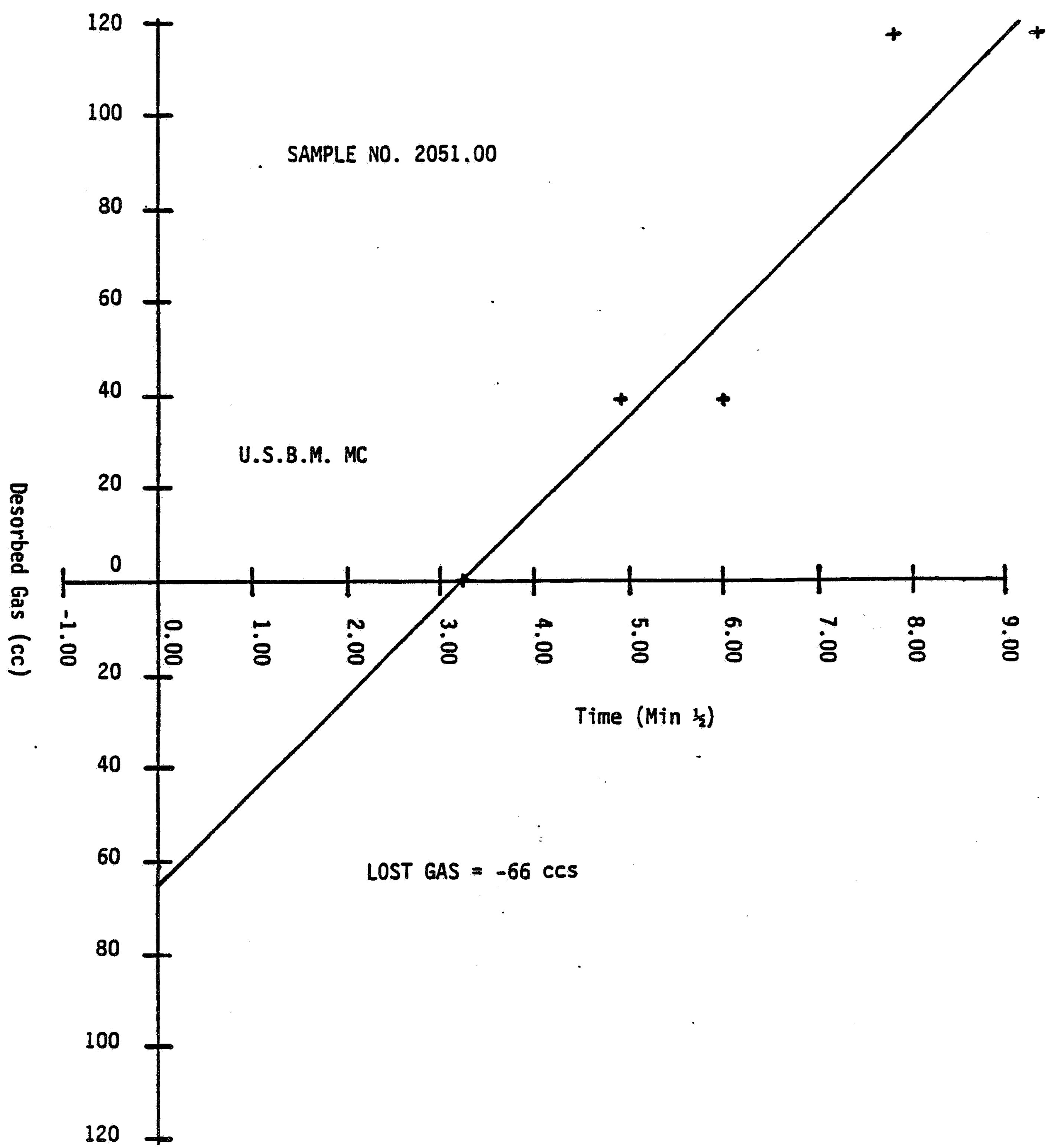

Figure B-2. Example of Lost Gas Extrapolation Curve Used in the U.S. Bureau of Mines Direct Method Determination of Desorbed Gas.

APPENDIX C

METHODS USED TO CALCULATE IN-PLACE COAL AND COALBED METHANE RESOURCES

The coalbed methane resource of an area is the product of the specific methane content of the coal as determined through sample desorption and the tonnage of coal present in the area. The latter factor is the product of the volume of coal present as determined through exploratory drilling and the density of the coal. Coal tonnages are usually calculated using a density factor which releates linear coal thickness to coal tonnage. This factor is usually stated as 1800 tons per acre/foot for bituminous coal and 2000 tons per acre/foot for anthracite and semi-anthracite coal. Some studies used a more conservative factor of 1750 tons per acre/foot for bituminous coal. The density factor is multiplied by the linear coal thickness to estimate the in-place coal resource tonnage per acre. The resulting number is then simply multiplied by the specific gas content of the coal (either intermediate or total) in cubic feet per ton to give the in-place coalbed methane resource per acre. If specific gas content is stated as cubic centimeters per gram, this number is multiplied by a factor of 32 to yield cubic feet per ton. The result is often multiplied by 40 acres to yield the gas resource thought to be available for recovery through a conventional vertical well.

An example of this type of calculation is given below:

Given: Bituminous coal (1800 tons per acre/foot density factor), 6 foot coal thickness, with a specific intermediate gas content of 300 cf/ton.

Calculations: 1800 tons per acre/foot x 6 feet = 10,800 tons per acre in-place coal resource.

10,800 tons per acre x 300 cf gas/ton = 3,240 Mcf gas/acre

3,240 Mcf gas/acre x 40 acres = 129,600 Mcf gas/40 acres

APPENDIX D

GAS CONTENT DATA

Coalbed	State	County	Sample Depth, Feet	Lost Gas, cc	Desorbed Gas, cc	Intermediate Gas Content, cc/g	Residual Gas, cc/g	Total Gas Content, cc/g	Apparent Coal Rank	Percent Ash as Received	Study Sample Number	U.S.B.M. Code #	Study
Utley Group	Alabama	Tuscaloosa	226.9	2	139	0.2	0.4	0.6	HV-A	21.7	AU-1-14A	1474	1, Univ. of Al.
			318.4	ND	180	0.1	0.4	0.5	HV-A	22.6	AU-1-11A	1475	1, Univ. of Al.
Gwin Group	Alabama	Tuscaloosa	689.5	88	4,069	2.6	1.8	4.4	HV-A[1]	NR	AU-1-6A	1476	1, Univ. of Al.
			737.0	79	1,662	2.3	1.5	3.8	HV-A	14.3	AU-1-3A	1477	1, Univ. of Al.
Cobb Group	Alabama	Tuscaloosa	968.1	103	1,453	2.3	3.6	5.9	HV-A	3.7	AU-1-4A	1478	1, Univ. of Al.
			969.0	67	1,433	2.1	2.8	4.9	HV-A	5.6	AU-1-24A	1479	1, Univ. of Al.
Pratt Group	Alabama	Tuscaloosa	1315.3	26	805	2.5	1.3	3.8	HV-A	40.4	AU-1-20A	1480	1, Univ. of Al.
			1405.1	74	7,321	6.3	2.3	8.6	HV-A[1]	NR	AU-1-1A	1481	1, Univ. of Al.
			1479.5	175	2,130	5.2	2.1	7.3	HV-A[1]	NR	AU-1-5A	1482	1, Univ. of Al.
			1596.7	36	3,909	7.2	2.8	10.0	HV-A[1]	NR	AU-1-21A	1483	1, Univ. of Al.
Mary Lee Group	Alabama	Tuscaloosa	2015.1	ND	4,048	9.1	1.0	8.4	HV-A[1]	NR	AU-1-13A	1484	1, Univ. of Al.
			2058.0	81	760	2.0	2.0	4.0	HV-A	17.7	AU-1-18A	1485	1, Univ. of Al.
			2077.5	137	3,575	7.7	0.8	8.5	HV-A[1]	NR	AU-1-12A	1486	1, Univ. of Al.
			2120.7	148	6,940	8.3	0.7	9.0	HV-A[1]	NR	AU-1-22A	1487	1, Univ. of Al.
			2126.9	299	20,443	10.8	1.0	11.8	HV-A[1]	NR	AU-18-3	1488	1, Univ. of Al.
			2129.1	253	13,872	12.9	1.4	14.3	HV-A[1]	NR	AU-18-5	1489	1, Univ. of Al.
			2142.3	484	20,035	10.7	0.7	11.4	HV-A[1]	NR	AU-18-1	1490	1, Univ. of Al.
			2146.7	582	22,633	10.0	0.8	10.8	HV-A[1]	NR	AU-18-4	1491	1, Univ. of Al.
			2151.8	116	3,465	4.9	0.7	5.6	HV-A[1]	NR	AU-1-2	1492	1, Univ. of Al.
			2321.6	71	1,550	5.3	1.2	6.5	HV-A[1]	NR	AU-1-7A	1496	1, Univ. of Al.
			2340.5	278	6,420	7.0	0.4	7.4	HV-A[1]	NR	AU-1-16A	1493	1, Univ. of Al.
			2356.7	95	3,770	10.5	0.9	11.4	HV-A	24.3	AU-1-25A	1494	1, Univ. of Al.
			2378.1	104	5,040	11.7	1.3	13.0	HV-A[1]	NR	AU-1-17A	1495	1, Univ. of Al.

Coalbed	State	County	Sample Depth, Feet	Lost Gas, cc	Desorbed Gas, cc	Intermediate Gas Content, cc/g	Residual Gas, cc/g	Total Gas Content, cc/g	Apparent Coal Rank	Percent Ash as Received	Study Sample Number	U.S.B.M. Code #	Study
Black Creek Group	Alabama	Tuscaloosa	2469.7	131	3,110	6.6	0.9	7.5	HV-A[1]	NR	AU-1-8A	1497	1, Univ. of Al.
			2502.5	407	5,410	5.2	0.4	5.6	HV-A[1]	NR	AU-1-23A	1498	1, Univ. of Al.
			2542.4	64	2,020	13.4	2.1	15.5	HV-A	11.4	AU-1-19A	1499	1, Univ. of Al.
			2594.4	431	6,295	6.3	1.0	7.3	HV-A[1]	NR	AU-1-9A	1500	1, Univ. of Al.
			2595.6	855	17,730	13.6	0.7	14.3	HV-A[1]	NR	AU-18-6A	1501	1, Univ. of Al.
			2648.2	95	2,215	12.7	0.7	13.4	HV-A	13.2	AU-1-15A	1502	1, Univ. of Al.
			2670.9	531	9,645	14.1	0.9	15.0	HV-A[1]	NR	AU-1-10A	1503	1, Univ. of Al.
Nemo	Tenn.	Fentress	84.6	23	15.5	0.2	ND	0.2	HV-C	NR	H-5-T	-	2, Fentress Co
			85.0	0.2	0.5	<0.01	ND	<0.01	LV	NR	H-5-M	-	2, Fentress Co
			85.6	34	24	0.3	0.02	0.3	HV-C	NR	H-5-B	-	2, Fentress Co
Utley Group	Alabama	Tuscaloosa	387.7	31	1,615	1.4	1.1	2.5	SA	22.9	2	-	3, City, Tusc.
			388.8	4	605	1.1	1.0	2.1	HV-A	41.7	19-A	1781	3, City, Tusc.
			460.1	97	4,335	2.5	0.6	3.1	HV-A[1]	NR	3	-	3, City, Tusc.
Gwin	Alabama	Tuscaloosa	831.4	86	1,030	0.9	2.4	3.3	HV-A	19.1	20	1782	3, City, Tusc.
Thompson Mill	Alabama	Tuscaloosa	901.5	109	2,940	3.4	1.7	5.1	HV-A[1]	NR	21	-	3, City, Tusc.
Upper Cobb	Alabama	Tuscaloosa	1096.5	27	660	1.7	1.4	3.1	HV-A	37.4	24	1783	3, City, Tusc.
Lower Cobb	Alabama	Tuscaloosa	1134.3	347	11,380	4.8	1.4	6.2	HV-A	25.1	31	-	3, City, Tusc.
Pratt	Alabama	Tuscaloosa	1523.0	68	3,200	5.4	1.2	6.6	HV-A[1]	NR	18	-	3, City, Tusc.

Coalbed	State	County	Sample Depth, Feet	Lost Gas, cc	Desorbed Gas, cc	Intermediate Gas Content, cc/g	Residual Gas, cc/g	Total Gas Content, cc/g	Apparent Coal Rank	Percent Ash as Received	Study Sample Number	U.S.B.M. Code #	Study
Nickel Plate	Alabama	Tuscaloosa	1530.5	271	8,815	6.9	NR	6.9	HV-A	19.1	22	-	3, City, Tusc.
American	Alabama	Tuscaloosa	1575.2	166	7,995	6.6	0.7	7.3	MV	15.6	14	-	3, City, Tusc.
			1576.5	76	3,070	5.5	NR	5.5	HV-A[1]	NR	6	-	3, City, Tusc.
			1590.7	134	7,530	7.1	1.1	8.2	HV-A	9.9	16	-	3, City, Tusc.
Curry	Alabama	Tuscaloosa	1674.5	36	540	2.6	0.4	3.0	MV	50.0	4	1784	3, City, Tusc.
			1674.7	55	2,140	5.2	1.5	6.7	HV-A	27.6	5	1785	3, City, Tusc.
Gillespie	Alabama	Tuscaloosa	1824.0	66	4,365	5.7	1.4	7.1	HV-A[1]	NR	23	-	3, City, Tusc.
			1825.0	15	2,030	5.5	2.5	8.0	HV-A	24.3	7	1786	3, City, Tusc.
Marker	Alabama	Tuscaloosa	2213.5	52	2,255	4.6	1.5	6.1	HV-A[1]	NR	25	-	3, City, Tusc.
Unnamed	Alabama	Tuscaloosa	2256.5	27	590	3.9	2.5	5.4	HV-A	22.3	9	1787	3, City, Tusc.
Newcastle	Alabama	Tuscaloosa	2283.0	61	2,045	4.3	0.6	4.9	HV-A	24.2	10	1788	3, City, Tusc.
Unnamed	Alabama	Tuscaloosa	2307.5	81	2,340	6.5	1.1	7.6	LV	23.8	12	1789	3, City, Tusc.
Mary Lee	Alabama	Tuscaloosa	2342.2	470	15,740	14.2	0.8	15.0	MV	4.6	8	-	3, City, Tusc.
			2243.9	522	17,110	9.9	1.0	10.9	LV	9.6	28	-	3, City, Tusc.
			2349.0	239	7,865	6.7	1.0	7.7	LV	18.7	29	-	3, City, Tusc.
			2357.8	61	2,605	5.7	1.0	6.7	HV-A[1]	NR	15	-	3, City, Tusc.
Blue Creek	Alabama	Tuscaloosa	2386.8	338	18,850	11.1	1.0	12.1	HV-A	4.5	27	-	3, City, Tusc.
Ream	Alabama	Tuscaloosa	2600.5	56	1,275	5.7	0.9	6.6	HV-A	30.4	11	1790	3, City, Tusc.
			2618.0	29	470	3.3	2.0	5.3	LV	11.3	13	1791	3, City, Tusc.
Lick Creek	Alabama	Tuscaloosa	2764.8	189	8,130	13.0	0.3	13.3	HV-A[1]	NR	17	-	3, City, Tusc.
Jefferson	Alabama	Tuscaloosa	2814.8	218	7,600	13.5	0.2	13.7	HV-A[1]	NR	19 B	-	3, City, Tusc.

Coalbed	State	County	Sample Depth, Feet	Lost Gas, cc	Desorbed Gas, cc	Intermediate Gas Content, cc/g	Residual Gas, cc/g	Total Gas Content, cc/g	Apparent Coal Rank	Percent Ash as Received	Study Sample Number	U.S.B.M. Code #	Study
Jefferson	Alabama	Tuscaloosa	2825.5	76	2,980	5.8	0.5	6.3	HV-A[1]	NR	1	-	3, City, Tusc.
Blackcreek	Alabama	Tuscaloosa	2857.3	786	22,600	8.1	0.5	8.6	HV-A[1]	NR	26	-	3, City, Tusc.
Unnamed Group	Alabama	Tuscaloosa	169.0	ND	170	0.3	0.4	0.7	HV-A	10.4	601	1775	4, BF Goodrich
			227.7	54	150	0.2	0.1	0.3	HV-A	15.2	600	1776	4, BF Goodrich
			229.5	ND	130	0.1	0.3	0.4	HV-A	9.9	602	1777	4, BF Goodrich
			752.0	32	160	0.2	0.4	0.6	HV-A	22.9	603	1778	4, BF Goodrich
			425.0	ND	340	2.1	2.7	4.8	HV-A	12.3	4 B	1779	4, BF Goodrich
Guide	Alabama	Tuscaloosa	559.4	17	1,060	1.1	1.5	2.6	HV-A	19.0	24 B	1991	4, BF Goodrich
Brookwood	Alabama	Tuscaloosa	601.2	ND	465	2.1	0.9	3.0	HV-A	38.1	20 B	1780	4, BF Goodrich
			601.5	61	2,885	1.3	0.8	2.1	HV-A	25.5	30 B	1992	4, BF Goodrich
Mildale	Alabama	Tuscaloosa	619.3	54	810	1.4	1.8	3.2	HV-A	16.3	57	1993	4, BF Goodrich
Carter	Alabama	Tuscaloosa	620.1	55	1,200	1.5	1.1	2.6	HV-A	20.9	56	1994	4, BF Goodrich
Johnson	Alabama	Tuscaloosa	651.2	39	2,560	2.4	0.7	3.1	HV-A	7.6	55	1995	4, BF Goodrich
Utley	Alabama	Tuscaloosa	915.8	47	3,550	3.6	2.0	5.6	HV-A	16.3	605	1996	4, BF Goodrich
Gwin	Alabama	Tuscaloosa	1361.8	81	4,935	5.6	0.7	6.3	HV-A	15.1	9 B	1997	4, BF Goodrich
Thompson Mill	Alabama	Tuscaloosa	1418.2	751	3,880	6.7	2.4	9.1	HV-A	18.5	13 B	1998	4, BF Goodrich
Upper Cobb	Alabama	Tuscaloosa	1629.3	46	1,390	5.1	2.1	7.2	HV-A	27.2	11 B	1999	4, BF Goodrich
Lower Cobb	Alabama	Tuscaloosa	1653.9	144	7,505	8.4	1.9	10.3	HV-A	4.5	608	2000	4, BF Goodrich
			1655.2	33	5,520	7.7	3.3	11.0	HV-A	6.6	606	2001	4, BF Goodrich

Coalbed	State	County	Sample Depth, Feet	Lost Gas, cc	Desorbed Gas, cc	Intermediate Gas Content, cc/g	Residual Gas, cc/g	Total Gas Content, cc/g	Apparent Coal Rank	Percent Ash as Received	Study Sample Number	U.S.B.M. Code #	Study
Pratt	Alabama	Tuscaloosa	2015.1	60	2,680	8.9	1.5	10.4	HV-A	16.3	602 B	2002	4, BF Goodrich
			2024.1	110	7,670	10.4	1.2	11.6	HV-A	17.2	604	2003	4, BF Goodrich
Nickel Plate	Alabama	Tuscaloosa	2037.2	49	3,090	5.8	2.4	8.2	HV-A	18.9	20 C	2004	4, BF Goodrich
American	Alabama	Tuscaloosa	2070.2	147	7,030	8.6	1.5	10.1	HV-A	20.3	601 B	2005	4, BF Goodrich
Curry	Alabama	Tuscaloosa	2129.3	145	1,975	5.2	1.2	6.4	HV-A	30.2	4 C	2007	4, BF Goodrich
Gillespie	Alabama	Tuscaloosa	2274.0	68	2,690	7.5	2.4	9.9	HV-A	15.1	2 B	2008	4, BF Goodrich
Unnamed	Alabama	Tuscaloosa	2728.5	14	2,060	5.5	0.2	5.7	HV-A	25.4	5 B	2006	4, BF Goodrich
Newcastle	Alabama	Tuscaloosa	2770.6	59	5,925	7.5	1.2	8.7	HV-A	20.6	7 B	2009	4, BF Goodrich
Mary Lee	Alabama	Tuscaloosa	2796.5	339	12,690	13.6	1.1	14.7	HV-A	11.4	10 B	2010	4, BF Goodrich
			2797.8	355	13,160	14.4	1.2	15.6	HV-A	8.1	12 B	2011	4, BF Goodrich
			2800.2	344	1,280	1.5	0.2	1.7	HV-A	17.9	607	2012	4, BF Goodrich
			2805.0	92	5,160	5.4	0.6	6.0	HV-A	48.5	58	2013	4, BF Goodrich
Blue Creek	Alabama	Tuscaloosa	2817.0	151	16,670	13.4	0.6	14.0	HV-A	8.6	600 B	2014	4, BF Goodrich
Ream	Alabama	Tuscaloosa	3043.0	28	1,915	6.8	0.3	7.1	HV-A	18.4	603 B	2015	4, BF Goodrich
Lick Creek	Alabama	Tuscaloosa	3154.7	212	2,845	9.6	1.0	10.6	HV-A	15.1	18 B	2016	4, BF Goodrich
Unnamed	Alabama	Tuscaloosa	3213.6	118	6,870	12.0	ND	12.0	HV-A	10.2	1 B	2017	4, BF Goodrich
Jefferson	Alabama	Tuscaloosa	3270.1	82	1,400	1.2	0.5	1.7	HV-A	70.4	56 B	2018 A	4, BF Goodrich
			3270.7	18	1,040	2.1	0.7	2.8	HV-A	38.5	57 B	2018 B	4, BF Goodrich
			3271.4	112	1,900	5.9	2.2	8.1	HV-A	27.7	25 B	2019	4, BF Goodrich

Coalbed	State	County	Sample Depth, Feet	Lost Gas, cc	Desorbed Gas, cc	Intermediate Gas Content, cc/g	Residual Gas, cc/g	Total Gas Content, cc/g	Apparent Coal Rank	Percent Ash as Received	Study Sample Number	U.S.B.M. Code #	Study
Black Creek	Alabama	Tuscaloosa	3338.6	150	2,210	4.4	NR	-	HV-A	35.3	21 B	2020	4, BF Goodrich
Cumnock	N.C.	Lee	900.0	294	9,185	9.3	0.3	9.6	NR	NR	1745	1745	5, Deep River
Gulf	N.C.	Lee	952.2	199	7,587	11.4	0.7	12.1	NR	NR	1746	1746	5, Deep River
Gulf (Shale)	N.C.	Lee	952.9	185	3,050	2.2	0.2	2.4	NR	NR	1747	1747	5, Deep River
Ames	PA	Westmoreland	371.3	NR	NR	3.6	1.0	4.6	HV-A	12.3	1730	1730	6, Westmoreland
Upper Bakerstown	PA	Westmoreland	437.1	197	6,535	2.9	1.0	3.9	HV-A	24.4	1715	1715	6, Westmoreland
Brush Creek	PA	Westmoreland	624.9	109	6,195	5.1	0.6	5.7	HV-A	37.6	1731	1731	6, Westmoreland
Mahoning	PA	Westmoreland	672.8	116	7,045	6.5	1.4	7.9	MV	15.2	1732	1732	6, Westmoreland
Upper Freeport	PA	Westmoreland	726.9	561	16,631	8.0	1.2	9.2	NR	NR	1741	1741	6, Westmoreland
Upper Kittaning	PA	Westmoreland	786.1	260	7,453	6.9	0.8	7.7	MV	27.4	1742	1742	6, Westmoreland
			806.5	107	6,672	6.8	1.9	8.7	MV	19.7	1743	1743	6, Westmoreland
Middle Kittaning	PA	Westmoreland	867.1	94	6,125	5.8	1.2	7.0	MV	14.4	1744	1744	6, Westmoreland

Coalbed	State	County	Sample Depth, Feet	Lost Gas, cc	Desorbed Gas, cc	Intermediate Gas Content, cc/g	Residual Gas, cc/g	Total Gas Content, cc/g	Apparent Coal Rank	Percent Ash as Received	Study Sample Number	U.S.B.M. Code #	Study
Upper Clarion	PA	Westmoreland	956.9	N.D.	1,137	2.0	2.2	4.2	MV	26.9	1764	1764	6, Westmoreland
Lower Clarion	PA	Westmoreland	967.5	N.D.	1,397	3.3	1.8	5.1	HV-A	18.7	1766	1766	6, Westmoreland
Brookville	PA	Westmoreland	994.5	54	3,475	5.7	1.8	7.5	MV	16.5	1767	1767	6, Westmoreland
Mercer	PA	Westmoreland	1041.0	126	5,077	4.3	1.3	5.6	MV	24.2	1768	1768	6, Westmoreland
Sewanee	TN	Morgan	819.9	130	1,151	0.8	0.2	1.0	MV	21.8	1931	1931	7, Rockwood, TN
			821.5	101	2,150	1.8	0.7	2.5	MV	7.3	1929	1929	7, Rockwood, TN
			823.5	206	947	1.4	1.1	2.5	MV	7.0	1930	1930	7, Rockwood, TN
Unnamed Group	AL	Tuscaloosa	168.9	16	80	<0.1	<0.1	0.1	HV-A	9.8	35	2021	8, T.C.I.D.A AL
			172.8	19	130	0.7	<0.1	0.8	HV-A	25.8	66	2022	8, T.C.I.D.A AL
			200.0	6	120	0.7	0.5	1.3	HV-A	31.9	337	2023	8, T.C.I.D.A AL
			359.0	N.D.	N.D.	-	0.7	0.7	HV-A	39.1	620	2024	8, T.C.I.D.A AL
Guide	AL	Tuscaloosa	493.0	23	210	1.3	1.6	2.9	HV-A	26.7	222	2025	8, T.C.I.D.A AL
			493.2	15	430	1.5	2.2	3.6	HV-A	9.8	610	2026	8, T.C.I.D.A AL
Brookwood	AL	Tuscaloosa	524.4	0	1,045	1.6	<0.1	1.7	HV-A	9.2	322	2027	8, T.C.I.D.A AL
			525.3	48	2,460	1.9	0.5	2.4	HV-A	21.6	317	2028	8, T.C.I.D.A AL
Milldale	AL	Tuscaloosa	553.7	12	1,245	2.2	1.3	3.5	-	-	425	2029	8, T.C.I.D.A AL
Carter	AL	Tuscaloosa	582.5	28	3,620	3.5	1.0	4.5	HV-A	7.4	34	2030	8, T.C.I.D.A AL
Utley	AL	Tuscaloosa	850.6	86	7,000	3.9	1.4	5.3	HV-A	15.9	26 B	2031	8, T.C.I.D.A AL
Unnamed	AL	Tuscaloosa	918.2	45	2,920	4.0	N.D.	4.0	HV-A	25.0	3 B	2032	8, T.C.I.D.A AL
			945.8	68	2,520	4.5	0.8	5.3	HV-A	23.0	24 C	2033	8, T.C.I.D.A AL

Coalbed	State	County	Sample Depth, Feet	Lost Gas, cc	Desorbed Gas, cc	Intermediate Gas Content, cc/g	Residual Gas, cc/g	Total Gas Content, cc/g	Apparent Coal Rank	Percent Ash as Received	Study Sample Number	U.S.B.M. Code #	Study
Upper Cobb	AL	Tuscaloosa	1223.7	53	795	3.0	1.9	4.9	HV-A	26.4	22 B	2034	8, T.C.I.D.A AL
Lower Cobb	AL	Tuscaloosa	1253.8	184	7,595	4.7	1.7	6.3	HV-A	6.6	31 B	2035	8, T.C.I.D.A AL
Pratt	AL	Tuscaloosa	1596.7	36	2,000	7.5	1.9	9.4	HV-A	18.4	23 B	2036	8, T.C.I.D.A AL
Nickel Plate	AL	Tuscaloosa	1605.4	103	5,160	7.4	1.4	8.7	HV-A	24.3	55 B	2037	8, T.C.I.D.A AL
			1606.7	250	7,715	7.3	1.2	8.5	HV-A	29.1	620 B	2038	8, T.C.I.D.A AL
American	AL	Tuscaloosa	1615.9	41	1,730	3.9	2.3	6.2	HV-A	18.3	8 B	2039	8, T.C.I.D.A AL
			1620.7	157	5,800	8.7	0.2	8.9	HV-A	6.8	14 B	2040	8, T.C.I.D.A AL
Gillespie	AL	Tuscaloosa	1851.7	57	2,390	5.5	1.6	7.1	HV-A	16.8	16 B	2041	8, T.C.I.D.A AL
Newcastle	AL	Tuscaloosa	2296.5	31	1,290	4.3	0.9	5.2	HV-A	23.7	11 C	2042	8, T.C.I.D.A AL
Mary Lee	AL	Tuscaloosa	2351.0	94	5,945	6.3	0.8	7.0	HV-A	16.6	4 D	2043	8, T.C.I.D.A AL
			2354.1	602	12,140	5.6	0.4	6.1	HV-A	8.7	27 B	2044	8, T.C.I.D.A AL
Blue Creek	AL	Tuscaloosa	2361.0	374	9,860	11.0	1.0	11.9	HV-A	10.4	13 C	2045	8, T.C.I.D.A AL
			2362.6	401	5,960	4.7	0.8	5.5	HV-A	28.1	32 B	2046	8, T.C.I.D.A AL
Ream	AL	Tuscaloosa	2551.0	66	1,260	7.4	0.6	8.0	HV-A	11.4	33 B	2047	8, T.C.I.D.A AL
Lick Creek	AL	Tuscaloosa	2722.3	144	4,970	3.0	0.2	3.2	HV-A	9.4	2 C	-	8, T.C.I.D.A AL
Jefferson	AL	Tuscaloosa	2771.8	66	4,150	7.6	0.6	8.2	HV-A	10.3	30 C	2051	8, T.C.I.D.A AL
			2774.7	259	550	4.3	N.D.	4.3	HV-A	32.2	25 B	2052	8, T.C.I.D.A AL
			2792.7	183	8,140	7.6	0.4	8.1	HV-A	8.2	29 C	2053	8, T.C.I.D.A AL

Coalbed	State	County	Sample Depth, Feet	Lost Gas, cc	Desorbed Gas, cc	Intermediate Gas Content, cc/g	Residual Gas, cc/g	Total Gas Content, cc/g	Apparent Coal Rank	Percent Ash as Received	Study Sample Number	U.S.B.M. Code #	Study
Black Creek	AL	Tuscaloosa	2857.0	16	1,890	5.8	0.8	6.6	HV-A	16.6	337 B	2054	8, T.C.I.D.A AL
			2878.0	ND	ND	-	0.6	0.6	HV-A	14.6	35 B	2055	8, T.C.I.D.A AL
Merrimac	VA	Montgomery	1110.1	262	9,094	4.4	1.3	5.7	SA	40.7	1933	1933	9, Mtgy. Co. VA
			1112.9	242	14,005	6.7	0.4	7.1	LV	28.2	1934	1934	9, Mtgy. Co. VA
			1116.5	269	8,663	6.8	0.8	7.6	SA	20.6	1935	1935	9, Mtgy. Co. VA
			1120.0	54	2,962	6.3	2.6	8.9	SA	9.5	1936	1936	9, Mtgy. Co. VA
Langhorne	VA	Montgomery	1136.4	26	1,453	1.2	1.3	2.5	SA	15.9	1937	1937	9, Mtgy. Co. VA
			1195.7	20	2,695	2.8	1.8	4.6	SA	11.8	1938	1938	9, Mtgy. Co. VA
			1197.8	48	4,876	9.8	2.5	12.3	SA	12.1	1939	1939	9, Mtgy. Co. VA
Merrimac	VA	Montgomery	1403.5	372	7,541	7.0	0.4	7.4	SA	19.1	1986	1986	9, Mtgy. Co. VA
			1407.7	1621	9,431	8.7	0.4	9.1	SA	19.0	1987	1987	9, Mtgy. Co. VA
Langhorne	VA	Montgomery	1420.0	219	5,073	4.7	0.8	5.5	SA	22.5	1988	1988	9, Mtgy. Co. VA
			1445.0	25	606	2.0	2.9	4.9	SA	33.2	1989	1989	9, Mtgy. Co. VA
			1461.3	104	1,297	5.6	1.9	7.5	SA	27.7	1990	1990	9, Mtgy. Co. VA
N.R.	KY	Floyd	127.0	25	237	0.2	0.8	1.0	N.R.	N.R.	1654	1654	10, Kentucky
N.R.	KY	Floyd	185.9	10	335	0.6	1.4	2.0	N.R.	N.R.	1655	1655	10, Kentucky
N.R.	KY	Floyd	277.2	11	332	0.7	2.3	3.0	N.R.	N.R.	1656	1656	10, Kentucky

Abbreviations Used in this Appendix:
N.R. - Not Reported
N.D. - Not Determined
SA - Semi-Anthracite
LV - Low Volatile Bituminous
MV - Medium Volatile Bituminous
HV-A - High Volatile A Bituminous
HV-B - High Volatile B Bituminous
HV-C - High Volatile C Bituminous

APPENDIX E

AVERAGE QUALITY OF DESORBED GAS IN THE DOE REGION IV STUDY

Component	1. Univ. of AL[a]	3. City of Tuscaloosa, AL	4. B.F.G., AL	5. Deep River, N.C. (Coal)	5. Deep River N.C. (Shale)	8. TCIDA, AL	10. Kentucky[b] (Somerset)
Number of Samples	5	6	7	2	1	7	1
Methane (CH_4) Mol %	90.20	93.30	93.16	96.68	88.40	92.65	76.17
Ethane (C_2H_6) Mol %	0.08	0.62	1.13	0.15	0.30	1.10	14.07
Propane (C_3H_8) Mol %	N.R.	0.12	0.05	<0.01	<0.01	0.19	5.92
Isobutane (C_4H_{10}) Mol %	N.R.	<0.01	<0.01	<0.01	<0.01	0.04	0.32
n-Butane (C_4H_{10}) Mol %	N.R.	0.01	<0.01	<0.01	<0.01	0.03	1.30
Hexane Plus (C_{6+}) Mol %	N.R.	<0.01	<0.01	<0.01	<0.01	0.01	0.17
Nitrogen (N_2) Mol %	7.70	4.34	4.74	2.73	10.85	5.25	1.64
Oxygen (O_2) Mol %	1.50	0.78	0.47	0.12	0.28	0.20	N.R.
Carbon Dioxide (CO_2) Mol %	0.49	0.80	0.39	0.20	0.17	0.43	0.05
Heating Value Btu/cf	915	947	965	980	900	965	1251

[a] Two of five samples possibly contaminated with atmospheric gases

[b] Contains 0.36 mole % of pentane isomers.

APPENDIX F

COAL AND COALBED METHANE GAS RESOURCES PRESENT IN STUDY AREAS (CALCULATED ON A 40 ACRE BASIS)

	Total Coal Resource All Seams (Thousand Tons)	Coalbed Methane Resource All Seams (MMcf)	Number of and Linear Feet of Coal In Target Zones	Coal Resource In Target Zones (Thousand Tons)
1. University Of Alabama	2,200[a]	520[d]	2 - 13.4	889[a]
2. Fentress County, TN	114[b]	0.56[e]	No Target Zones Designated	No Target Zones Designated
3. City of Tusc., AL	2,330[a]	501[d]	3 - 16.6	1,161[a]
4. B.F.G., AL	2,370[a]	399[d]	4 - 10.2	715[a]
5. Deep River N.C.	569[b]	173[d]	No Target Zones Designated	No Target Zones Designated
6. Westmoreland Manor, PA	1,433[b]	308[e]	5 - 19.4	1,396[b]
7. Rockwood, TN	259[b]	18.7[e]	No Target Zones Designated	No Target Zones Designated
8. T.C.I.D.A., AL	2,271[a]	296[d]	2 - 10.6	745[a]
9. Montgomery County, VA	560[c]	129[f]	2 - 7.0	560[c]
10. Kentucky	324[b]	18[e]	No Target Zones Designated	No Target Zones Designated

[a] Calculated On A Basis Of 1750 Tons Per Acre-Foot.
[b] Calculated On A Basis Of 1800 Tons Per Acre-Foot.
[c] Calculated On A Basis Of 2000 Tons Per Acre-Foot.
[d] Based On Intermediate Gas Content (Excluding Residual Gas).
[e] Based On Total Gas Content (Including Residual Gas).
[f] Gas Content Basis Not Specified In Report.

APPENDIX G

BASE-CASE UNCONVENTIONAL GAS PRODUCTION POTENTIALS IN THE DEPARTMENT OF ENERGY REGION IV STUDY AREA

	1. Univ. of AL	3. City of Tusc. Alabama	4. B.F.G. AL	6. Westmoreland Manor, PA	8. TCIDA, AL	9. Montgomery Co., VA	10. Kentucky
Proposed Well Spacing (Acres)	40	40	40	40	40	40	Not reported
Estimated Gas Available Per Well (MMcf)*	305	362	215	234	156	129	Not reported
Estimated Well Life (Yr)	10	10	10	10	10	15	10
Total Lifetime Production Per Well (MMcf)	229	271	161	88	117	53	15
Total Recovery Of In-Place Resource (%)	75	75	75	38	75	41	Not Reported

* Producible Gas Resource in Production Target Zones Over Well Spacing Area

APPENDIX H

ESTIMATED BASE-CASE ECONOMICS OF UNCONVENTIONAL GAS RECOVERY, SINGLE WELL BASIS

	1. Univ. of Alabama	3. City of Tusc. AL[a]	4. B.F.G. AL	6. Westmoreland Manor, PA	8. TCIDA AL	9. Mtgy. Co. VA	10. Kentucky[b] (Preston-burg Site)	10. Kentucky (Leslie Co. Site)
Proposed Well Spacing (Acres)	40	40	40	40	40	40	N.S.	N.S.
Project Life (Years)	10	10	10	10	10	15	10	10
Production Well Installa-tion Cost	$272,000	$255,400	$255,400	$150,000	$205,400	$156,000	$103,478	$155,831
Annual Operating Expense	$35,200	$30,000	$30,000	$6,700 + 10%/year	$30,000	$4,800	$2,000	$2,000
Baseline Mcf Gas Price and Base Year	$3.45-1981	N.S.	$4.72-1983	$4.56-1984	$4.72-1983	$5.00	$3.52-1984	$3.52-1984
Projected Annual Gas Price Increase Over Well Life (Levelized)	5.5%	N.S.	5.5%	12.3%	5.5%	0	N.S.	N.S
Average Yearly Production (Mcf)	22,876	23,862	16,119	8,322	11,700	3,520	1,500	1,500

APPENDIX H
(Cont.)

	1. Univ. of Alabama	3. City of Tusc. AL[a]	4. B.F.G. AL	6. Westmoreland Manor, PA	8. TCIDA AL	9. Mtgy. Co. VA	10. Kentucky[b] (Prestonburg Site)	10. Kentucky (Leslie Co. Site)
I.R.R.	15.49%	26.69%	17.90%	29%	6.58%	N.S.	N.S.	N.S.
Payback Period (Years)	5.79	4.8	5.10	4	8.29	N.S	N.S	N.S
Production Cost Per Mcf	N.S.	N.S.	$4.24	N.S.	$5.40	N.S.	$14.77[c]	$21.46[c]

N.S. = Not Specified

[a] Based On Option 1 Of Three Possible Acceptable Development Options.

[b] Based On Case A, Development By A Municipality.

[c] Gas Price Required To Produce A 20% Return On Investment.

APPENDIX I

METHANE GAS OWNERSHIP UPDATE
WITH SPECIAL EMPHASIS ON
DOE REGION IV PROJECT AREAS

BY

Sarah Kathryn Farnell, JD

INTRODUCTION

Coalbed methane gas has significant potential as an alternate energy source. The commercial development of coalbed methane actually began in the early 1930's. However, recently the increased commercial potential for coalbed gas exploitation has resulted in legal questions over ownership. Legal issues could be the biggest stumbling block to the development of coalbed gas.

After the main body of this appendix was prepared the Pennsylvania Supreme Court handed down the latest decision in the landmark methane ownership case, Hoge v. U.S. Steel Corp., 468 A2d 1380 (Pa 1983). This latest decision overturns a 1982 Pennsylvania Superior Court ruling which granted methane gas reights to a natural gas lessee under a conveyance which used the general term "gas". Reversing the lower court, the Pennsylvania Supreme Court held that the owner of coal rights also owns the methane gas found with the coal, while the surface owner continues to hold title to coalbed methane which has migrated out of the coal into the surrounding property area. The latest Hoge decision, because of the importance of the issues involved and the narrowness of the decision is expected eventually to be appealed to the U.S. Supreme Court. [NOTE: References to the earlier Hoge case, U.S. Steel v. Hoge, 450 A2d 162 (Pa Superior 1982), were left intact in this text.]

Conventional oil and gas and hard mineral leases should be modified to be used for methane conveyances. Any conveyance must take into account the existence of any coalbed methane production regulations, such as those approved by the Alabama State Oil and Gas Board in 1984, as well as other statutory and administrative control. Such controls may be authorized under oil and gas conservation statutes or mining regulations. Several states have addressed the issues of ownership or use of conflict through statutory provisions.

Federal pollution laws covering discharges into federal or state waters may be applied to methane development operations. Therefore, the most important policy consideration for coalbed methane development should be the timely and efficient development of energy resources with a minimum of environmental degradation. One approach to this problem would be a statute enabling a commission or board to handle conflicts between various natural resource developers to avoid litigation and attain overall perspective on resource development.

This report reviews and updates legal issues affecting methane gas ownership. Special emphasis is given to developments in Alabama, Kentucky, North Carolina, New York, Pennsylvania, Tennessee, and Virginia. The report is divided into three sections: state and federal regulations affecting methane ownership; state and federal case law affecting ownership; and an update on literature relating to methane ownership and related issues.

State and Federal Regulations

State laws affecting methane gas ownership fall into two categories. The first includes oil, gas, and coal production regulations. The second is safety laws regulating methane ventilation from coal mines. With a few exceptions, none of the laws take into account the possibility of commercial exploitation of coalbed methane. A few states in the group studied, however, have passed laws relating to drilling of oil or gas wells through workable coal seams. These laws are relevant to methane production. Other laws may affect methane ownership depending upon the language employed in that state to define "oil," "gas" and "coal." Regulations prohibiting waste may also be applicable to release of methane, although such release is presently required by mining safety laws.

The states of Alabama, Kentucky, New York, North Carolina, Pennsylvania, Tennessee and Virginia all have oil and gas and mining laws and regulations which could be interpreted to apply to methane gas production. Of special significance is the language employed by each statute to define "gas."

In Alabama, Code of Alabama 9-17-1 defines "oil" as "crude petroleum oil and other hydrocarbons, regardless of gravity, which are produced at the well in liquid form by ordinary production methods and which are not the result of condensation of gas after it leaves the pool." "Gas" is defined as "all natural gas, including casinghead gas, and all other hydrocarbons not defined as oil." The definition of "waste" includes "inefficient, excessive or improper use or dissipation of reservoir energy and underground wastes however caused and whether or not defined." The definition of "waste" includes permitting of gas produced from a gas well to escape into the air. This is undoubtedly a reference to the practice of flaring but the language does not rule out the venting of methane gas. Venting methane in order to begin coal mining might not come under this regulation since the methane would not technically be coming from a "gas well."

Code of Alabama §25-9-80 to -91 deals with mining safety regulations. These sections require that methane gas be ventilated before coal mining begins.

Kentucky law includes a number of regulations pertaining to oil and gas wells in coal-bearing strata. Section 353.060 provides that if the drilling of a well on any tract underlain with coal-bearing strata will endanger the present or future use or operation of a workable coalbed, the coal owner has five days in which to file an objection and request a hearing. Section 353.080 provides that a well penetrating a workable coalbed shall be drilled in such manner as will, if practicable, exclude all oil, gas or gas pressure from the coalbed, except that which is found in the coal itself.

Section 353.050 requires a plat to be filed if a well is to extend through coal-bearing strata. A copy of the map of the mine must be sent to the well operator and the Department of Mines and Minerals, which has jurisdiction over oil and gas operations, when mining extends to within 500' of a well under the provisions of Section 352.510.

Section 353.510 defines "oil" as "petroleum" and "gas" as "natural gas." Anti-waste provisions found at 353.160 state that "natural gas shall not be permitted to waste or escape from any well or pipeline when it is reasonably possible to prevent such waste."

Provisions requiring ventilation of coal mines are found at 352.020. 352.040 provides that working places are not to be driven in advance of ventilation.

The laws of New York define gas, in Section 22-0101 as "all natural, manufactured, mixed and byproduct gas, and all hydrocarbons not defined as oil in this section." Oil is defined as "crude petroleum oil and all other hydrocarbons, regardless of gravity, that are produced at the wellhead in liquid form by ordinary production methods and that are not the result of condensation of gas." Section 590 defines "oil and gas rights" as "any right to explore for, extract, produce or sell oil or gas located on or below real property." This section relates to taxation. "Waste" is defined in Section 23-0101 as "physical waste as that term is generally understood in the oil and gas industry...including the inefficient, excessive or improper use of or the unnecessary dissipation of reservoir energy." Section 23-1501 provides that it is unlawful to waste oil or gas.

North Carolina law at Section 113-389 defines gas as "all natural gas, including casinghead gas, and all other hydrocarbons not defined as oil." Oil is defined as "crude petroleum oil and other hydrocarbons, regardless of gravity, which are produced at the well in liquid form by ordinary production methods, and which are not the result of condensation of gas after it leaves the reservoir." The definition of waste includes "inefficient, excessive or improper use or dissipation of reservoir energy;... abuse of correlative rights and opportunities of each owner of oil and gas in a ....reservoir due to nonuniform, disproportionate, and unratable withdrawals causing undue drainage between tracts of land;...underground waste, however caused and whether or not defined;...permitting gas from a gas well to escape into the air." Section 113-391 provides that the Department of Natural Resources is given jurisdiction over laws relating to oil and gas.

Pennsylvania law contains several provisions relating to wells drilled in coal bearing strata. Title 52 § 2201 provides that before drilling through workable coal seams, the oil and gas operator must file a plot and forward it to the Oil and Gas Division of the Department of Mines. The coal operator has the right to file an objection.

Section 2203 provides that a coal operator who mines within 500' of a well or approved well location must file a copy of a map of the mine with the well operator and the Oil and Gas Division. An objection may be filed by the well operator. Gas is defined in §2101 as "any natural, manufactured or byproduct gas or any mixture thereof." Oil is defined as "petroleum."

Tennessee law defines gas in Section 60-1-101 as "all natural gas and all other fluid hydrocarbons not defined as oil, including condensate because it originally was in a gaseous phase in the reservoir." Oil is defined as "crude petroleum that was originally in an oil phase in the reservoir." Waste is defined as including underground waste and inefficient, excessive or improper use or dissipation of reservoir energy. Waste is prohibited by Section 60-1-102. Section 60-1-202 sets forth the powers of the Oil and Gas Board, which include the power to regulate drilling, casing and plugging of wells in such manner as to protect "potentially minable" coal.

Virginia law defines gas at Section 45.1-286 as "natural gas, whether bydrocarbon or non-hydrocarbon or any combination or mixture thereof, including hydrocarbons, hydrogen sulfide, helium, carbon dioxide, nitrogen, hydrogen, casinghead gas, and all other fluids not defined as oil in this section." Oil is defined as "natural crude oil or petroleum and other hydrocarbons regardless of gravity, produced at a well in liquefied form by ordinary production methods and which are not the result of condensation."

Coal seam, workable coal bed and workable coal seam are defined jointly as "any seam 20" or more in thickness, unless a lesser thickness is being worked."

The definition of waste includes "underground or above ground waste in production or storage of oil or gas however caused."

Section 45.1-318 provides for objections by a coal owner to a proposed well to be drilled through a seam. The state inspector is authorized to consider only whether work can be done safely with respect to persons engaged in coal mining at or near the well site, and whether the well work is an unreasonable or arbitrary exercise of the well operator's right to explore for, market and produce oil and gas.

The inspector is also directed to consider the extent to which the proposed drilling location will unreasonably interfere with present or future coal operations, and whether the inspector's decision will substantially affect the right of the gas operator to explore for and produce gas.

Section 45.1-321, relating to the establishment of gas drilling units, provides that the gas operator must show that the drilling location has been agreed to by coal operators or the owner of record of all coal seams.

Section 45.1-340 requires a map to be filed by the coal operator when mining within 500' of a well.

Section 45.1-63 provides that in a mine classified as "gassy" - that is, one in which 1/4 of 1% methane has been detected 12" from the roof or face - work must be stopped when gas is detected. Section 45.1-65 provides that an examination must be made for gas before workers can enter a mine.

Section 55.154.1 provides that all migratory gases are conclusively presumed to be the property of the surface owner. The language employed specifically mentions methane: "all migratory gases, including but not limited to propane and methane, shall be conclusively presumed to be the property of the owner of the surface real property beneath which such gases are or may be located." The act provides that litigation concerning the legal construction of base agreements entered into prior to January 1, 1978, the effective date of the Act, is governed by "the applicable law in effect at the time the agreement or agreements were entered into."

This Act is the most explicit state legislation affecting methane ownership. However, it leaves unresolved the question of whether leases written when coalbed methane was not known to possess any value should be interpreted to include methane.

Federal mining safety regulations include provisions governing methane gas. See for example 30USC §§801-960 (1976). Other federal regulations applicable to methane include provisions governing oil and gas leases.

The Multiple Mineral Development Act, 30USC §§521-531 (1976) provides that various minerals on federal lands should be managed "in a manner compatible with...multiple use." A lease to develop one mineral granted under this Act does not preclude the development of other minerals on the same land. Mining operations must be conducted, however, to avoid damage to any other known deposit of minerals under §526(b). In the case of coalbed methane, a coal owner could not mine the coal in a way that would prevent extraction of the methane, and a methane owner could not damage the coal seam while extracting the gas. State regulations governing oil or gas drilling through coal seams, and mining within 500 feet of an oil or gas well attempt this same kind of protection of multiple uses.

Two acts regulating federal lands may affect methane production. The Mineral Leasing Act of 1920, 30USC §181-263 (1976) provides for lease permits for oil and gas exploration. The terms "oil" and "gas" are not defined. The Federal Coal Leasing Amendments Act of 1975, 90 Stat 1087 (1976) requires the Secretary of the Interior to prepare a land use plan before any land is leased for coal mining and authorizes a comprehensive exploratory program to evaluate potential coal resources.

Federal oil and gas lease provisions apply to methane. See Solicitor's Opinion, Ownership of and Right to Extract Coalbed Gas in Federal Coal Deposits, U.S. Department of Interior, M-36935 (May 12, 1981). In this opinion, the Solicitor contended that methane gas under certain federal lands was not included in a reservation of coal in nominal patents issued by the United States in connection with certain Homestead Acts of 1909 and 1910, but that methane was included in a subsequent Congressional reservation of oil and gas. The Solicitor's opinion relied on the wording of the Mineral Lands Leasing Act to support the contention that coalbed methane is covered by a lease of oil and gas, arguing that the absence of a specific definition of the term "gas" in the Act implies that Congress intended the terms "gas" and "natural gas" to be broadly construed.

State and Federal Case Law

The leading case interpreting coalbed methane ownership remains U.S. Steel v. Hoge, a Pennsylvania case decided in 1980. The trial court resolved an ownership conflict based on ambiguities in lease language in favor of the natural gas lessee and surface owner, concluding that, legally, coalbed methane is a separate substance from coal. The court held that methane is not a byproduct of coal, that it is chemically almost identical to other natural gases, and that like other gases, methane is fugitive by nature. The trial court recognized the coal owner's obligation to ventilate the coal seam before mining, but denied that this obligation gives the coal owner the right to all methane gas in the seam. The court did hold that the coal owner had the right to capture and sell the methane vented. Because the deeds conveying the coal rights were drawn in 1920 before methane was generally thought to have commercial value, the trial court inferred that the landowner did not intend to include methane in the sale of the coal rights.

An appeal was filed in the Hoge case by U.S. Steel. In U.S. Steel v. Hoge, 450A2d162 (Pa, 1982), the Superior Court of Pennsylvania upheld the lower court's ruling. U.S. Steel had argued an appeal that under the language of the severance deeds, title to the coal should have passed to it, not to Hoge and the other gas owners. U.S. Steel advanced four arguments based on these deeds, each of which was addressed in the decision of the Superior Court.

U.S. Steel's first argument was that it owned not only the coal but everything in the geological stratum comprising the coal vein. U.S. Steel cited several old cases in support of this proposition: Lillibridge v.

Lackawanna Coal Co., 143 Pa 293, 22 A 1035; Chartiers Block Coal Co. v. Millan, 152 Pa 295, 25 A 598; and Webber v. Vogel, 189 Pa 156, 42 A 4 (1899). All these cases were cited by U.S. Steel for the proposition that land may be divided for purposes of ownership, into horizontal strata, and there may be as many owners as there are strata. U.S. Steel relied on these old cases in support of its argument that it owned the geological stratum occupied by the coal; the Superior Court disagreed, holding that none of these old cases stood for the proposition that title to coal in place is also title to the space made vacant by coal removal. The court referred to Craig and Myers, Ownership of Methane Gas in Coal Beds, 24 Rocky Mtn. Min. Inst. 767 (1978) for their analysis of coal ownership; despite repeated references to coal as land, it is not land but a mineral deposited within the land. Furthermore, said the court, the concept of a horizontal division of land ownership is more a metaphor than a legal definition of the relative rights of surface and mineral owners; a particular mineral substance such as coal or gas, not any given stratum, is the true subject of the conveyance.

The second argument advanced by U.S. Steel is that geologically and physically, coal and methane are so intimately bound up as to be essentially inseparable; and that at the time of the severance deeds, coal and methane gas were generally considered to be two different aspects of one substance. At the trial the lower court found that at the time the deeds were executed, although it was well known that methane occurred in coal seams, there was no general acceptance of the idea advanced by U.S. Steel that methane and coal were "essentially inseparable" or part of one substance.

The third argument advanced by U.S. Steel was that the right to drill through the coal seam in order to recover gas reserved by the grantors in the severance deeds does not include the reservation of the right to recover the coalbed gas contained in the coal seam. In rejecting this argument, the court noted that it "ignores both the historical fact of gas exploitation in the region and the law of gas ownership in Pennsylvania." The lower court found that at the time of execution of the deeds, the practice in the gas industry was to take gas from any stratum or geological formation which produced it. The lower court cited several instances in which gas was produced solely from coal seams. Addressing this argument, the Superior Court stated that the argument "assumes that the surface owners intended to part with the rights to the coalbed gas when they granted the rights to the coal." Even reading the reservations strictly against the owners, the court continued, "the most that can be said...is that the surface owners were aware...that there might be gas on the premises, and that they might be held liable for damages to the coal if they were obliged to drill through it to extract the gas, and to avoid this liability they reserved the right to drill through the coal without any imputation of liability to the severed estate."

U.S. Steel's fourth argument rests on the right granted by the severance deeds to ventilate the methane for safety reasons. U.S. Steel argued that the right to ventilate the methane carried with it the right of absolute ownership in the vented gas. In rejecting this contention, the Superior Court followed the holding of the lower court that the right to ventilate the mine carried no right of ownership, except that the coal owner could capture the methane vented and sell or use it. The Superior Court noted that Hoge and the other appellees had not filed an appeal and thus did not challenge the lower court's conclusion that the coal owner could sell the vented methane. The Superior Court went on to state that as there had been no appeal made as to this portion of the lower court's decision, the Superior Court was constrained to affirm.

In addition to these four arguments based on the deeds, U.S. Steel advanced an argument based on public policy, joined by the Keystone Bituminous Coal Association which filed a brief as amicus curiae. The court stated that aside from the holding that the coal owner may sell vented methane, cases point to a victory for the landowner and natural gas lessee. The court said that "based on the legal setting and factual background adhering at the time of the deeds' execution, we cannot say that the parties intended title to coalbed gas to pass to the coal owners under the deeds...if any intent can be reasonably inferred, it was that the landowner intended to sell the coal to one purchaser and the (coalbed) gas...to another."

The court added that "...the issue before us is the interpretation of instruments of transfer - coal severance deeds - and not the lack of wisdom or prescience with which those deeds were drawn, or the impracticability of the transferred natural resources' exploitation in accordance with the terms of those instruments. ...Based on the evidence adduced at trial, the chancellor found that little if any distinction was made in the gas industry at the time of the coal deeds' execution between the gas found in coalbeds (coalbed gas) and the gas found in oil-and-gas-bearing sands (natural gas)... As for U.S. Steel's invocation of the geological and generational link between coal and coalbed gas, we note that a similar nexus exists between petroleum and 'natural gas'. Yet, these latter resources are systematically viewed as distinct and are routinely so dealt with."

In affirming the decision of the lower court, the Superior Court stated "We feel obliged to make the following caveat. That is, from the date of this decision it will be necessary for landowners and potential purchasers of their oil, gas and coal rights to proceed with caution in the drafting of the applicable transfer instruments. The parties and their scriveners must be careful to include coalbed gas in their negotiations and agreements lest the failure to do so result in unnecessary and potentially costly litigation."

In Henry et al v. Federal Power Commission et al, 513 F2d 395 (DC, 1974), the U.S. Court of Appeals considered the question of whether the jurisdiction of the Federal Power Commission under the Natural Gas Act, 15USC §717 et seq, extends to the production, transportation and sale of unmixed synthetic gas produced from coal. The Court of Appeals affirmed a lower court decision that jurisdiction did not extend to such synthetic gas, holding that such gas was "artificial" under the terms of 15USC §717(a)(5). The Environmental Defense Fund had joined other plaintiffs in the case to argue that the unmixed gas was under the jurisdiction of the FPC, and that the Commission was required by law to consider related environmental regards from the proposed coal gasification projects that formed the basis for this litigation.

The court first noted that 15USC, §717(B) defines natural gas as "either natural gas unmixed, or any mixture of natural or artificial gas." The court stated that the language of the act which distinguishes between natural and artificial gas requires the court to look into the origin of the gas rather than its physical characteristics such as heat value or methane content.

The court next considered the petitioners claim that, in enacting the National Gas Act, Congress was concerned with the interstate character of the market rather than with the origin of the regulated product. Petitioners contended that the court should take an expansive view of the commission's jurisdiction, despite the implicit exclusion of artificial gas, because Congress could not have foreseen at the time of passage of the legislation, the production of synthetic gas which could easily be transported out of state. The court found, however, that the legislative history of the Act indicated that Congress was aware that the expansion of the synthetic gas industry into interstate commerce was a potential development. The court noted that in debates on the proposed act, the limited reach of the Act was directly linked to the "insubstantiality" of interstate transportation of artificial gas. The court found that Congress intended to defer regulation of unmixed artificial gas. The court went on to note that the possibility that gas produced from coal and never mingled with natural gas for transport or sale would completely escape commission regulation was "unlikely given the great cost of constructing separate and parallel pipeline systems... However, if substantial interstate commerce in pure coal gas does come to exist, Congress will have to decide whether, to what extent, and by which agency, if any, it should be regulated."

Literature Update

Several relatively recent articles appearing in law-related journals deal with subjects relevant to methane ownership. The author of this report has written "Methane Gas Ownership: A Proposed Solution for Alabama" which is found at 33 Alabama Law Review 521 (Spring 1982). This article includes an analysis of the trial court's decision in Hoge, a study of legislative attempts to settle methane ownership questions, and presents a model methane ownership statute designed for the state of Alabama. The author notes that any such statute must consider two constitutional provisions -- the prohibition against taking property without due process and the prohibition against impairment of contracts. The proposed ownership statute reads as follows: "All coalbed methane gas in this state is hereby conclusively presumed to be the property of the owner of the surface real property under which such methane gas is or may be located in its natural state. This Act shall not apply to situations in which a valid conveyance has been made that specifically includes methane gas. This Act shall apply to conveyances which use only the terms "mineral rights," "oil and gas rights," and/or "coal rights," without a specific mention of methane gas." The author believes that such a statute would withstand a constitutional challenge. The author concludes that because of the present uncertainty surrounding the legal aspects of coalbed methane ownership, state legislatures should begin to formulate policy concerning coalbed methane development. On the national level, mining safety laws which require venting of methane gas should be rewritten, as capture of such gas becomes feasible, to allow and encourage such capture whenever possible.

A discussion of the legal issues in determining the meaning of the phrase "oil, gas and other minerals" is found in "Developing Lands Characterized by Separate Ownership of Oil and Gas and Surface Minable Coal and Uranium - The Other Side of Acker v. Guinn and Its Progeny," by Phillip E. Norvell, 33 Southwestern Legal Foundation Institute on Oil and Gas Law and Taxation 193 (1982). The author notes that controversy surrounding the legal meaning of the term "minerals" remains at the forefront of issues affecting hard mineral development. He cites Acker v. Guinn, 4645W2d 348 (Tex 1971) for the proposition followed by Texas courts that in ascertaining the meaning of the term "minerals" the "general intent" of the parties as calculated by the "manner of enjoyment" of the several and retained interests is determinative. By the Acker standard, the term "minerals" without other qualifying language, encompasses all substances capable of beneficial enjoyment by commercial exploitation. The two cases of Reed v. Wylie I and Reed v. Wylie II, discussed elsewhere in this report, modified the Acker rule to provide that, if the mineral deposit is near the surface and any reasonable method of removal will destroy the surface, the substance will not be included within a grant or reservation of minerals absent explicit language to the contrary. The author notes that none of these decisions held whether surface mining would be considered a "reasonable method of removal." The Acker and Reed cases have also been criticized by Texas legal scholars for "making the ownership of coal and uranium a function of the physical location of the deposit in relation to the earth's surface", thus requiring a factual inquiry independent of the legal one.

The author notes that the uncertainty of ownership of surface minable coal or uranium deposits has resulted in the mine operator's having to secure leases from both the several "mineral" owner and the surface owner. He criticizes the Acker decision for creating potential for new legal conflicts between surface mining and oil and gas owners. To avoid interference with oil and gas operations, the coal or uranium surface review will be precluded from mining the surface area utilized by the oil and gas lessee as well as the adjacent area, which acts as a protective barrier against blast damage. Conversely, surface mining of a tract can deprive the oil and gas lessee of the immediate right of access; and blasting may result in damage to the well. The author contends that an implied easement of "reasonably necessary surface usage" exists in favor of the dominant mineral estate and should be applied by the courts to encourage timely development of natural resources and protect existing investment. The author notes two legislative attempts at resolving the conflict. North Dakota Cent. Code §38-15 et seq (1971) vests the State Industrial Commission with the jurisdiction to resolve "conflicting interests" which cannot be "voluntarily" concluded by the affected parties. West Virginia Code §22-46 et seq requires the lessee of a shallow gas well to give notice of the proposed well location to the owner or operator of any commercial seam of coal underlying the tract. The owner has the right to file an objection. The State Shallow Gas Well Board has authority to decide whether a permit will issue. The author concludes that the need to encourage maximum development of all natural resources indicates that "mutual accomodation" will prevail among conflicting owners.

A brief discussion of the trial judge's ruling in the U.S. Steel v. Hoge case is found in "Ownership of Coalbed Gas: United States Steel Corp. v. Hoge," by Richard H. Lorenson, 82 W. Va. L. Rev. 1451 (1980). Lorenson notes the limitations of the decision in Hoge, first considering the question of whether the coal operator could be required to pay royalties to the gas lessor if the coal operator captures and makes a separate sale of the methane. He notes that it is also unclear which method the coal operator can use to remove the coalbed gas and how far in advance of the actual removal of coal the gas can be vented for the ventilation to be considered within the "course of the mining operation."

Lorenson notes that Hoge did not attempt to address opposing interests which may develop between gas grantors or lessors and gas grantees or lessees. Other issues left unsettled include when the coal operator can degasify the mine; whether the gas can be sold; whether the gas owner or surface owner must be compensated; at what point will hydrofracturing be considered a viable technique for extracting coalbed gas; can hydrofracturing be used to extract coalbed gas from extremely deep seams currently considered unmineable; what is the measure of damage if a coal seam is harmed by conventional gas extraction techniques; to what extent does the coal operator have the duty to capture the gas; and what would be the legal implications if a coal operator without filing a specific mining plan, announces plans to use the "long wall" method of mining at some future date?

The question concerning use of hydrofracturing to extract methane from deep and presently unmineable seams takes on added significance in light of the language used in present state laws requiring notice to be given to coal operators if an oil or gas drilling operation will pass through a seam. These statutory requirements generally specify "mineable" coalbeds. It is possible that a drilling operation designed to use hydrofracturing on extremely deep beds could bypass the notice requirements of these statutes.

Unfortunately, Lorenson does not attempt to answer any of his own questions, merely concluding that the Hoge case has raised as many issues as it settled.

Conflicts between an oil or gas lessee and an iron ore, coal or lignite lessee involving use of surface mining are considered in "Multiple Use and Conflicting Rights," by Guy L. Nevill, 13 St. Mary's Law Journal 783 (1981). In disputes between lessees each of whom hold leases on a dominant mineral estate, Nevill argues that priority of time should determine superiority of right.

Nevill's discussion centers on Texas law and discussions which are not binding authority on Alabama courts. He cites Getty Oil Co. v. Jones, 470SW2d 618 (Tex 1971) for the holding that a reasonable use of the surface by a mineral owner may require the owner to employ alternate means of production when the proposed means of production will impair or preclude a prior existing use of the surface by the surface owner. In the case of a severance of a named mineral substance, the question arises as to the right of a surface mineral lessee to use destructive mining methods unless the method is expressly set forth in the lease. In Acker v. Guinn, 464SW2d 348 (Tex 1971) the Texas Supreme Court had held that it is not ordinarily contemplated that the utility of the surface be destroyed or substantially impaired.

Regarding decisions in other state courts, the author recognizes a split, but says that the majority rule holds that the right to use so much of the surface as necessary cannot be interpreted as the right to destroy the value of the surface of land, citing Newell v. Randall, 373So2d 1068 (Ala 1979). The Newell case held that a reservation of minerals did not include sand, gravel, clay or other substances that have no special value, in the absence of language to the contrary in the reservation.

The question of whether subsurface minerals can be gain through adverse possession was considered in "Adverse Possession of Subserface Minerals," by Paul N. Bowles, 71 Kentucky Law Journal 83 (1982-83). Bowles' discussion centers on adverse possession of solid subsurface minerals. He states, however, that actual adverse possession of coal accompanied by color of title to the coal, oil and gas should not adversely affect the true owner's title to any other minerals. He goes on to state that arguably, one who has no true title to oil and gas but attempts to possess them by drilling commits trespass against the owner of the surface and any subsurface strata penetrated in the course of the drilling. If such trespass continues for the required statutory period, the owner of the surface and subsurface strata may be alleged to have allowed the adverse claimant to establish surface and subsurface easements by prescription, even though the adverse possessor will not have acquired a fee title.

In "Breaking the Trust: Adverse Possession of Subsurface Minerals Under Kentucky Law," 71 Kentucky Law Journal 237 (1982-83), M. Gabrielle Hils states that the general rule of adverse possession may not be appropriate as applied to fugacious minerals such as oil and gas. The author notes that adverse possession of solid minerals theoretically can be limited to the area of actual mining; with oil and gas, the adverse possession has the potential to take over minerals underlying all of the surface, not just those in the vicinity of the drilling activity. The author cites Sanford v. Alabama Power Company, 54 So 2d 562 (Ala. 1941).

Coal gasification is the subject of "Implied Covenants and the Duty to Develop in Underground Coal Gasification" by Charles E. Trost, Jr., 59 Texas Law Review 1303 (1981). This article discusses the legal implications of underground coal gasification technology, said to be the most promising means of developing coal and lignite resources without hazardous deep-shaft mining. The author notes that an operator attempting to exploit those large deposits must lease the mineral rights from the owner of each individual tract, while the technology requires that the mineral seam be treated as a unit.

Courts in most jurisdictions will imply covenants in minerals leases, one of the most important being the covenant to develop, which imposes a duty on the operator to produce the mineral diligently. Most jurisdictions apply the "reasonably prudent operator" standard to determine whether the producer is adequately developing the lease. Under this standard the operator must develop the lease in a manner calculated to benefit both himself and the landowner. The author contends that the reasonably prudent operator standard should be modified before courts can apply it to underground coal gasification technology. Unlike oil and gas operations, in which the reasonably prudent operator is required to drill a new well every sixty to ninety days until the lease is developed, which normally will take no more than one year, the coal gasification operator must drill new wells every few weeks for the life of the lease. The author cites judicial failure to differentiate between oil and gas technology and strip mining technology as a possible threat to coal gasification projects. He cites Dallas Power And Light Co. v. Clighorn, 623 SW 2d 310 (Tex 1981), which involved lignite deposits. The Texas Supreme Court held that an express provision in the lignite leases permitting indefinite payment of delay rentals precluded any implied covenant to develop. The author criticizes the court's application of the oil and gas lease implied covenant to develop to hard minerals. He notes that one justice in a concerning opinion, argued that the covenant to develop was inapplicable because of the different recovery technology involved.

Ambiguity in minerals leases is the subject of "The Need for Certainty in Ownership of Minerals: Coal, Lignite 'and Other Minerals,'" by Charles L. Lacallade, 22 S Texas Law Review 287 (1981). The author notes that in Texas the ordinary meaning is given to the term "mineral" when used in a conveyance and that this ordinary meaning is not limited to the scientific definition. Texas has adopted a "surface destruction rule", set out in the decision of Acker v. Guinn, and Reed v. Wylie discussed earlier. The court stated that unless a contrary intention is expressed, a grant or reservation of mineral rights should not be construed to include a substance that must be removed by methods that will, in effect, consume or deplete the surface estate. The court relied on the general intent of the parties, noting that the surface owner would not reasonably convey a mineral, the mining of which would destroy his surface estate, without expressing that intention. Noting the uncertainty that can arise when the mineral estate has been severed, the author recommends an alternative approach to construing "oil, gas and other minerals' which would include only oil-and-gas-related minerals in a grant of "oil, gas and other minerals." This construction would exclude coal and lignite but include casinghead gas, helium, carbon dioxide and "other associated gases or liquids." The author argues that this approach is consistent with the general intent of the typical lessor (in Texas, a farmer, rancher or forester) who would not intend that the surface of the land be destroyed.