MERC/CR-77/4(Vol.1)
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Systems Studies of Energy Conservation
Methane Produced from Coalbeds

January 1977 • Volume I

prepared for
Morgantown Energy Research Center
under Contract E(46-1)-8042

by

TRW
ENERGY SYSTEMS GROUP
ENERGY SYSTEMS PLANNING DIVISION
McLEAN VIRGINIA 22101

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1.0 SUMMARY

1.1 GENERAL

Under Contract E(46-1)-8042 to the Morgantown Energy Research Center, TRW Energy Systems Planning Division performed a systems study directed at assessing potential for using methane produced from coalbeds. The systems study, first step in a major field demonstration program planned by the Energy Research and Development Administration (ERDA), concentrated on the definition of the coalbed methane resource in the Pittsburgh Seam, the determination of the technical and economical feasibility of production, collection, conversion, and/or utilization systems, and the synthesis of the basic elements of a field demonstration program plan.

1.2 THE COALBED METHANE RESOURCE

Methane, the major component of natural gas, is generated during the natural process of coal formation. Frequently, because of the low permeability of strata associated with coalbeds, it is trapped in the coal and associated strata which remain highly saturated with methane. Based on Bureau of Mines, ERDA, and other studies, ERDA has estimated that the recoverable quantity of methane from coalbeds is 250 trillion cubic feet, an amount equal to the known conventional natural gas reserves. Estimates of the volume of methane contained in the Pittsburgh Seam reserves range from 600 billion to 4 trillion cubic feet. Even the lowest estimates indicate that a significant amount exists in this single coalbed which should be utilized productively.

The extent of the coalbed methane resource available for utilization is a controlling factor in almost any practical application. Accordingly, in this study a comprehensive data base was developed on the quality and quantity of methane available for use. Although the scope was limited to acquiring this data base for the Pittsburgh Seam, other coalbeds were reviewed briefly to ascertain, in a general way, how they compared with the Pittsburgh Seam.

Currently, the most likely source for methane drainage for coalbeds is gas vented from coal mining operations. During coal mining operations, trapped methane is released, mixes with air, and may form an explosive or flammable mixture, an obvious safety hazard. In a working underground mine, ventilating air is introduced to sweep dilute methane from the mine into the atmosphere. Gas released in this manner is irretrievably wasted.

Safety considerations have led to development by the U. S. Bureau of Mines and many mining companies of techniques for draining methane from coalbeds before mining to prevent gas migration to working areas. These

methods, when draining virgin coal, produce methane comparable in quality to natural gas produced from gas reservoirs, as illustrated in Table 1-1.

TABLE 1-1. AVERAGE METHANE CONTENT IN THE COAL GAS OF APPALACHIAN COALBEDS

COALBED	METHANE %	AVERAGE DEPTH OF SAMPLES	NUMBER OF ANALYZED SAMPLES
Pittsburgh	90.75	516	4
Kittanning	97.32	753	2
Pocahontas No. 3	88.42	1,734	4
Mary Lee	96.05	1,070	1

Gas drained from gob areas may be somewhat diluted with air, with methane content varying from 25 to 90 percent.

Table 1-2 below shows the large quantities of daily methane gas emissions in Appalachian mine ventilation systems. Currently, no commercial use is made of this resource.

TABLE 1-2. METHANE EMISSION RATES IN APPALACHIA PER COUNTY

COUNTY	DAILY METHANE(1) EMISSION RATE (MMCFD)	
	1971	1973
1 MONONGALIA, W VA	39	40.7
2. MARION, W.VA.	30 4	23.1
3. BUCHANAN, VA.	21.6	22.1
4. WASHINGTON, PA.	11 9	12.4
5. GREENE, PA.	11 4	11.7
6. MCDOWELL, W.VA.	13.1	11.4
7. CAMBRIA, PA.	N.R.(2)	9 8
8. JEFFERSON, ALA.	10.3	9 5
9. WYOMING, W.VA.	N.R.	6.0
10. MARSHALL, W.VA.	N.R.	4.8
11 INDIANA, PA.	N.R.	4.8
TOTAL	137.7	156.3

(1): PURE METHANE (100%)
(2): N.R. NOT REPORTED

In the year 1976 alone, assuming a coal production of approximately 290 million tons by mines in the U. S. east of the Mississippi River, 7.2×10^{10} cubic feet of gas will have been wasted.

Increases projected for future coal production indicate that gas losses will increase to over 1/4 TCF annually by 1986. To stop this loss as soon as possible, early field demonstration projects to validate the feasibility

of using this gas productively are necessary. The demonstration program outlined in Section 5 could lead to commercial applications utilizing 2.1×10^{11} cubic feet of drained methane in the year 1986.

1.3 ALTERNATIVE PRODUCTION, COLLECTION, CONVERSION AND/OR UTILIZATION (PCCU) SYSTEMS

Several alternatives are feasible for the production, collection, conversion and/or utilization (PCCU) of methane drained from virgin coal in advance of mining, and from gob areas subsequent to mining. Only one basic subsystem, a pipeline, is suitable for collecting the gas in quantities adequate to economically justify the cost of a central facility for utilizing gas.

1.3.1 Production Subsystem Alternatives

The drainage of virgin coal before mining, often referred to as predrainage, may be accomplished by one system or a combination of three alternatives. This includes: 1) vertical wells in conjunction with stimulation for increasing gas flow; 2) horizontal boreholes drilled into the coal seam from the bottom of a shaft; and 3) horizontal boreholes drilled from the surface using directional (sometimes referred to as "slant") drilling techniques developed by the oil industry.

Methane diluted and discharged to the atmosphere via the mine ventilating system is not considered a viable source. No potentially economic utilization was identified as a result of this study effort.

1.3.2 Conversion/Utilization Subsystem Alternatives

Theoretically, any utilization appropriate for natural gas is applicable to coalbed methane gas. The cost to upgrade gob gas to methane quality and the large quantity (compared to that available at one location) required for some utilizations eliminated many applications immediately. Quantity limitations, as used here, refers to both the maximum practical flow rate and the time duration of flow.

Viable alternatives for predrained high quality gas include: 1) direct injection into a commercial natural gas pipeline; 2) electric power generation of gas turbine/generator units; 3) heating applications such as coal drying, building heating, water heating, etc.; 4) conversion to liquefied natural gas (LNG); and 5) conversion to ammonia.

Viable alternatives for gob gas include: 1) electric power generation by gas turbine/generator units; 2) heating applications such as coal drying, building heating, water heating, etc.; 3) upgrading and conversion to LNG; and 4) conversion to ammonia.

1.3.3 Economic Projections

Methane contained in most deep coalbeds in the Eastern United States may be recovered economically (20 percent ROI) at the currently regulated

price of $1.50/MCF by using the horizontal boreholes established by directional (slant) hole drilling technology. When using the stimulated vertical well technology, gas may be recovered economically from deeper, gasier coalbeds with the specific economics highly dependent upon cost of the wells. Recovering gas in the Pittsburgh bed, shallower parts of the Mary Lee bed, and in parts of the Beckley bed, will generally require that the degasification process also result in moderate coal mining cost savings. For the Pittsburgh bed, the required savings would be about $.50/ton for room-and-pillar mining methods and about $.30/ton for longwall methods.

The projected cost of establishing and operating the pipeline connecting the degasification boreholes to a commercial pipeline ranges from about 10 to 50 cents per MCF, depending upon distance to the pipeline and the necessity to remove the CO_2 from the gas before sale. When such pipelines are impractical, the gas may be converted economically to LNG or ammonia for the size of projected plants required, with the ammonia plant being applicable to the larger mines (2 MMCFD) or to combinations of adjacent smaller mines.

When considered as a separate system, gob gases may be collected for economical use in local heating and power generation applications, depending upon the specific siting factors. When considered as a part of a total system to recover gas in the virgin coal, wherein the well is used both for draining the coal seam and for removal of the gob gases, these gases may be converted economically to LNG.

The differences previously described require that a very careful selection of PCCU subsystems be made for each proposed site under consideration for methane drainage and utilization. It is believed that sufficient options are available so that a combination of PCCU subsystems offering favorable economics is possible for any mine in the country.

The system costs and operating lifetimes of the PCCU systems covered in this study are summarized in Table 1-3. The costs of the power plants are shown for a size which is compatible with a large mine (2 million tons per year) using room-and-pillar mining methods in the Pittsburgh Seam. The increments of the required selling prices associated with each PCCU subsystem element are based upon the projected well production rates for the Pittsburgh Seam for which the boreholes are spaced to result in recovering 80 percent of the gas contained in the area over a three-year time period, upon the lifetimes of the equipments that are listed in the table, and upon a minimum rate of return (before taxes) of 20 percent. The parameters used in making economic analyses and projections are summarized in Table 1-4.

The projected rates of return (before taxes) for typical large system configurations (using 2 MMCFD of gas from the virgin coal or 2 MMCFD of gob gas) located at mines in the Pittsburgh Seam are summarized in Table 1-5. In general, for the same product market values, the investment rates

TABLE 1-3. SUBSYSTEM COST SUMMARY - PITTSBURGH COAL SEAM CHARACTERISTICS

	UNIT CAPITAL COST $000	UNIT O&M COST $000/YR	LIFE EXPECT-ANCY YRS	CONTRIBUTION TO REQUIRED SELLING PRICE 20% ROI	NOTES
PRODUCTION SUBSYSTEMS					
STIMULATED VERTICAL BOREHOLES	24-38	.75	3	$1.18-1.75	BASED ON INITIAL FLOW OF 25 MCFD
HORIZONTAL BOREHOLES FROM DEVIATED BOREHOLES	74-141	2.5	3	$ .18-.32	BASED ON AVERAGE FLOW OF 500 MCFD DURING FIRST YEAR
HORIZONTAL BOREHOLES FROM VENT SHAFTS	194-263	5.8	3+	$ .23-.30	BASED ON AVERAGE FLOW OF 1000 MCFD DURING FIRST YEAR
VERTICAL BOREHOLES TO GOB AREA	19-28	.5	3	$ .28-.40	BASED ON AVERAGE FLOW OF 50 MCFD OF METHANE OVER THREE YEARS
COLLECTION SUBSYSTEMS					
STIMULATED VERTICAL BOREHOLES	4.6	.9	3	$ .51	COST BASED UPON FLOW RATES LISTED ABOVE
HORIZONTAL BOREHOLES FROM DEVIATED BOREHOLES	61	9.9	3	$ .32	DO
HORIZONTAL BOREHOLES FROM VENT SHAFTS	93	16.5	3+	$ .25	DO
VERTICAL BOREHOLES TO GOB AREA	11.8	1.4	3	$ .24	DO
PIPELINE TO CENTRAL POINT (5000 FEET) (1 MMCFD)	89	17	20	$ .11	ALSO REPRESENTATIVE FOR GOB GASES. TO OBTAIN COST IN $/MMBTU FOR GOB GASES MULTIPLY BY 2
(2 MMCFD)	144	26	20	$ .08	
UTILIZATION SUBSYSTEMS					
PIPELINE TO COMMERCIAL SALES POINT (2 MMCFD)					
10000 FEET	531	46	20	$ .25	ALSO REPRESENTATIVE FOR GOB GASES. TO OBTAIN COST IN $/MMBTU FOR GOB GASES MULTIPLY BY 2
20000 FEET	800	74	20	$ .38	
LNG PLANTS (2 MMCFD CAPACITY)					
95% METHANE (1.6 MMCFD)	1758	199	20	$1.00	
50% METHANE (.8 MMCFD)	1917	207	20	$2.14	
AMMONIA PLANTS (2 MMCFD CAPACITY					
95% METHANE (60 TPD)	5370	294	20	$66/TON	
50% METHANE (30 TPD)	6380	327	20	$163/TON	
GAS TURBINES (2 MMCFD CAPACITY)					
50% METHANE (1.6 MW)	560	31	5	16 MILLS/KWH	
LOCAL HEATING APPLICATIONS					
COAL DRYING (50% METHANE) (2 MMCFD)	36	–	20	$ .02	
SPACEHEAT (50% METHANE)	–	–	20		

TABLE 1-4. PARAMETERS USED FOR ECONOMIC PROJECTIONS

ECONOMIC PARAMETERS USED	
COAL MINING COST SAVINGS	$1.00/TON
95% METHANE MARKET VALUE	$1.50/MMBTU
LNG MARKET VALUE	$2.50/MMBTU
AMMONIA MARKET VALUE	$100/TON
ELECTRICAL POWER VALUE	20 MILLS/KWH
SPACE HEAT VALUE	$1.50/MMBTU
COAL DRYING VALUE	$ .40/MMBTU
ROOM & PILLAR MINING – 2 MILLION TONS/YEAR	
VIRGIN COAL AREA DRAINED/BOREHOLE-ACRES	
STIMULATED VERTICAL BOREHOLES –	8.3
HORIZONTAL BOREHOLES-DEVIATED –	115
HORIZONTAL BOREHOLES-VENT SHAFT –	230
COAL RECOVERED/BOREHOLE – 1000 TONS	
STIMULATED VERTICAL BOREHOLES	51
HORIZONTAL BOREHOLES-DEVIATED	706
HORIZONTAL BOREHOLES-VENT SHAFT	1432
GAS RECOVERY RATE	
VIRGIN COAL	2 MMCFD
GOB GAS	2 MMCFD

(1) SAVINGS FOR PREDRAINAGE; $.25/TON FOR GOB GAS REMOVAL.

TABLE 1-5. ECONOMIC PROJECTION SUMMARY - PITTSBURGH COAL SEAM CHARACTERISTICS BEFORE TAX RATES OF RETURN ON INVESTMENT - %

THIS TABLE SHOWS THAT A PROFITABLE OPTION IS POSSIBLE FOR ANY MINE IF PROPER ANALYSIS IS PERFORMED TO SELECT THE ALTERNATIVE BEST SUITED TO LOCAL CONDITIONS.

	STIMULATED VERTICAL BOREHOLES	HORIZONTAL BOREHOLES DEVIATED BOREHOLES	HORIZONTAL BOREHOLES VENT SHAFTS[1]	VERTICAL BOREHOLES TO GOB AREA	UNIFIED SYSTEM FOR GOB GAS COLLECTION
DIRECT SALE OF GAS	26	58	26	–	–
LNG	24	47	24	21	39
AMMONIA	20	33	20	10	17
POWER GENERATION	–	–	–	15	120
SPACE HEAT	26	58	26	222	530
COAL DRYING	–	–	–	74	273
GAS VENTED TO ATMOSPHERE	11	33	11	100	–

(1) USED IN CONJUNCTION WITH VERTICAL BOREHOLES.

of return will be somewhat less for smaller systems. The most sensitive of the configurations are those using the ammonia plants which are not considered practical for sizes less than 2 MMCFD gas capacity for the projected market price of $100/ton for ammonia. When used, the ammonia plant should be configured to use a combination of the gob gases and the gas drained from the virgin coal.

As the market value of the gas or products are considered volatile and highly area dependent, and since specific piping distances required will vary from mine to mine, the rates of return that are indicated are considered to represent nominal values but not necessarily typical for any specific mines.

1.3.4 System Synthesis

The subsystems identified above may be combined in several different ways to create viable system alternatives. Because of differences in type of mining in progress, site access, availability of commercial natural gas transmission pipelines, ownership of surface rights, ownership of gas rights, legal constraints, etc., a number of alternative systems must be demonstrated to assure that sufficient options are available. The systems selected for demonstration and ultimate commercialization must complement the mining operations and enhance mine safety.

Five alternative systems were identified to demonstrate the different production and conversion/utilization subsystems required owing to varying mine conditions. The economics of each selection were reviewed to assure they were the most favorable.

The five viable alternative systems are:

1. Draining methane from virgin coal in advance of mining operations. The production subsystem includes both vertical wells with stimulation and horizontal boreholes drilled from the bottom of a ventilation shaft sunk at least three years in advance of its being mined. The collection subsystem consists of a gathering pipeline to collect gas from the production wells and deliver it to the point of utilization. The utilization subsystem is direct injection into a commercial natural gas pipeline.

2. Draining methane from virgin coal in advance of mining operations. The production subsystem consists of horizontal boreholes drilled using directional (slant) drilling techniques. The collection subsystem is a gathering pipeline. The utilization subsystem is a plant for converting the methane to ammonia.

3. Draining the methane from gob areas subsequent to mining operations. The production subsystem consists of vertical wells. The collection subsystem is a gathering pipeline. The utilization subsystem consists of upgrading and conversion to LNG.

4. Draining the methane from gob areas subsequent to mining operations. The production subsystem consists of vertical wells. The collection subsystem is a gathering pipeline. The utilization subsystem consists of a gas turbine/generator unit for generating electric power.

5. Draining the methane from gob areas subsequent to mining operations. The production subsystem consists of vertical wells. The collection subsystem is a gathering pipeline. The production subsystem is a heating application, such as coal drying, building heating, water heating, etc.

1.4 FIELD DEMONSTRATION

Field demonstration projects are necessary to provide clear and credible evidence of technical and economic feasibility of the alternative utilization systems. Once this is established and made known to private interests, widespread commercial application is expected to follow.

Field demonstration of each system identified in Section 1.3.4 will provide the data required for analysis and evaluation necessary to validate technical and economic results. To assure acquisition of the necessary data, monitor wells and additional instrumentation unnecessary to a commercial venture are included in the demonstration projects. These will provide the engineering data necessary to ascertain initial methane concentrations, to monitor performance of the individual boreholes, and to monitor the drawdown of methane in the coalbed, so that theoretical projections may be empirically corrected and the theory projected to other mining areas. In addition, the five systems comprise all economically viable PCCU subsystems in various combinations, thereby providing an opportunity to verify the validity of the performance projected for each subsystem. The dissemination of data, results, and technical and economic information will provide the guidance needed by others to plan and implement commercial projects.

Project implementation includes many activities that must be coordinated and integrated to assure accomplishment within funding and on schedule.

There are many requirements for detailed planning and analysis in making final site/system selections. Alternatives will require a preliminary system design before technical and economical projections may be made with reasonable confidence. Detailed design for construction must then be accomplished for the specific site/system selected for demonstration. It then becomes necessary to acquire long-lead items, if applicable, to contract for the construction of facilities and installation of equipment. The final implementation activity involves operating the system and logging the necessary data to verify technical and economic results.

Program support must be provided to perform engineering evaluations, subcontract, review and approve designs, perform data analysis, etc.

The requirements for implementing a field demonstration project are shown in Figure 1-1. Details of the requirements are included in Section 5.0 of this report.

1.5 CONCLUSIONS

The conclusions listed below result from analyses and evaluations performed during the study effort.

- Utilization of coalbed methane gas is practicable and economically favorable.

- Drainage of methane in advance of mining, and from gob areas subsequent to mining, decreases the quantity of methane now being released into the mine environment. Such drainage reduces ventilation requirements and the hazards of removing methane by this technique. Therefore, a severe hazard is significantly reduced, greatly enhancing underground mine safety.

- Differences in type of mining in progress, site access, availability of commercial gas transmission pipelines, ownership of surface rights and gas rights, legal constraints, etc., require several different techniques for gas recovery and several variant uses for the recovered methane gas.

- Cost-sharing of demonstration projects between government and private interests is necessary to expedite early commercial applications and encourage conservation of this resource.

- Legal problems and possible litigation may result when coalbed methane gas is recovered and utilized in a profitable venture. Coal rights agreements vary in mining ventures, and when they do not specifically state or imply the right to recover gas released in conjunction with mining requirements, litigation to recover royalties is likely to result.

1.6 RECOMMENDATIONS

The recommendations listed below are considered necessary to implement a comprehensive coalbed methane gas conservation program. They are designed to encourage conservation of this precious resource at the earliest possible time. Their implementation also will improve mine safety to a significant degree by recovering large quantities of methane otherwise contributing to fire and explosion hazards if released during mining activity.

- Approve the detailed planning/analysis necessary for final site/system selection and expanding the preliminary program plan into a detailed program plan suitable for efficient project implementation.

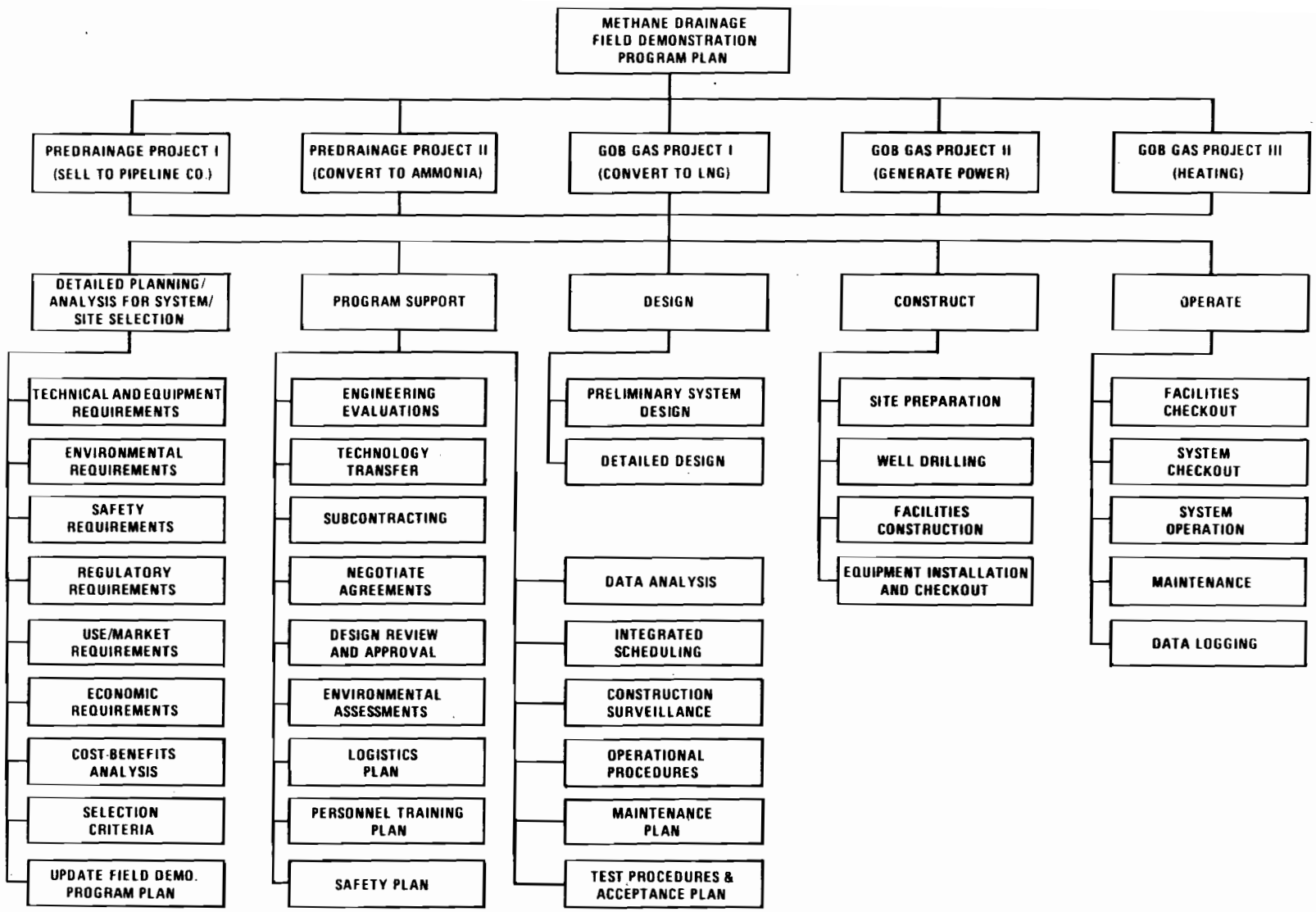


FIGURE 1-1. FIELD DEMONSTRATION PROGRAM STRUCTURE

- Approve implementation of the five field demonstration projects identified in the Methane Drainage Field Demonstration Program Plan contained in Section 5.0 of this report.

- Provide the necessary funding to accelerate implementation to what is attainable on a sound engineering basis. If additional FY 77 funding is made available, approximately six to eight months could be gained without sacrificing quality or altering total project costs.

- Seek industry cost-sharing of the projects, with flexibility to negotiate an equitable basis following detailed planning/analysis. when the projects are fully defined and cost-benefits determined for the specific system/site under consideration.

- If possible, select sites where the mine owner has the right to recover gas contained in the coalbed.

2.0 INTRODUCTION

Many of the anaerobic digestion and metamorphic processes associated with the transformation of vegetation to coal produce methane as a by-product. The methane produced by these processes often escapes through permeation and/or diffusion mechanisms operating over millions of years. Sometimes, however, the low permeability of strata associated with coalbeds limited escape of the gas, causing the coal and associated strata to remain highly saturated with methane. The removal of coal from these beds by underground mining techniques provides a free volume into which the methane can migrate and mix with air, forming a potentially explosive or flammable mixture and an obvious safety hazard.

In a working underground mine, ventilating air is introduced to sweep methane from the mine into the atmosphere. In this way, methane concentration is maintained at a level below the flammable limit, providing a safe working environment for miners. In particularly "gassy" mines, very large volumes of ventilating air must be used to maintain the methane concentration at a safe level, requiring extensive equipment installations and large energy usage. To increase safety margins and limit ventilation requirements, the U.S. Bureau of Mines and many mining companies have been investigating techniques for draining methane from coalbeds to prevent gas migration to working areas. These techniques include drilling vertical, slant wells, or horizontal holes from mine headings, etc., into virgin coalbeds in advance of the mine's working faces, and drilling horizontal holes into virgin coalbeds from a central shaft. These drainage methods produce natural gas comparable to that from other gas reservoirs. Drainage from gob areas is obtained through vertical wells that provide gas somewhat diluted with air, mixtures ranging from 25 to 90 percent methane.

It has been estimated that mines in the Pittsburgh Coalbed currently produce over 100 million cubic feet (100 billion Btu) per day of methane. The coal mining expansion expected over the next 10 years, together with extensive adoption of predraining and gob draining techniques, are likely to increase these amounts considerably. Currently, no commercial use is being made of this potential resource, and the gas is being vented to the atmosphere and wasted.

The Morgantown Energy Research Center initiated this system study to examine options for conservation of this resource. The specific objective has been to determine the systems most applicable to production (before, during, and after mining operations), collection, conversion and/or utilization of methane contained in coalbeds. It is anticipated that the results presented herein will be used to scope, plan, and initiate a field demonstration program for the recommended PCCU (Production, Collection, Conversion and/or Utilization) system(s).

Figure 2-1 shows the study general approach for obtaining the data base, identifying various technology options for the subsystems considered, and developing and analyzing the costs and benefits associated with the various systems, each of which consists of a gas production, collection, and conversion/utilization subsystem. The scope of this effort was limited specifically to the Pittsburgh coalbed. Other coalbeds may be similarly evaluated and choices made for field demonstrations that would maximize conservation throughout the entire United States rather than in a locale specific to one coalbed.

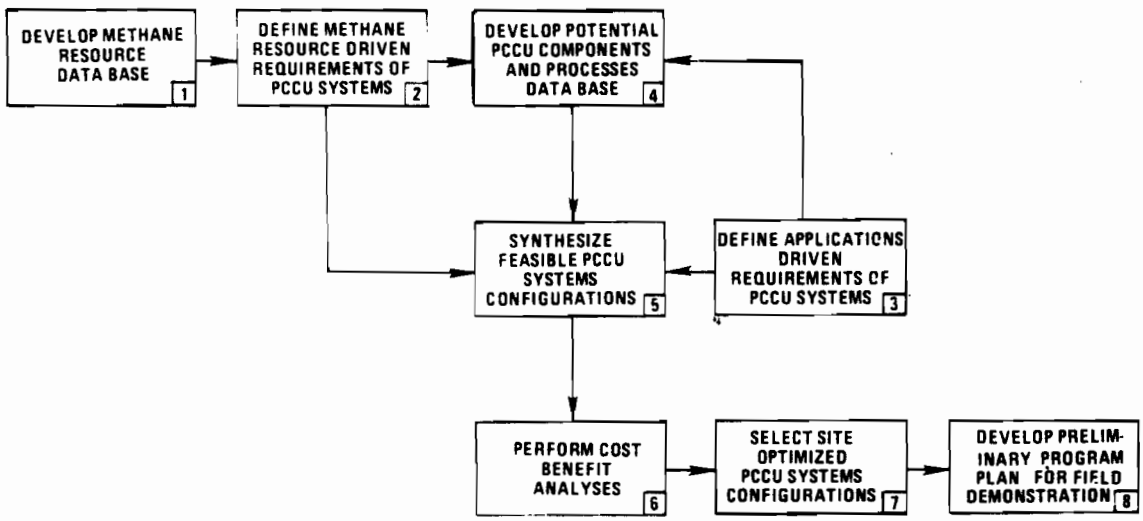


FIGURE 2-1. STUDY GENERAL APPROACH

This report is organized into two volumes, comprising seven sections and eleven appendices. Volume I contains Sections 1 through 7 and a list of references categorized to facilitate their use. Section 1 presents a concise summary of the results, conclusions and recommendations for executive review. Sections 2 through 7 present pertinent data on the Pittsburgh coalbed, potential uses of coalbed methane gas, candidate subsystems, feasible demonstration systems including a cost-benefit analysis, a preliminary field demonstration program plan, conclusions and recommendations. Volume II contains detailed support data which have been included as Appendices A through K.

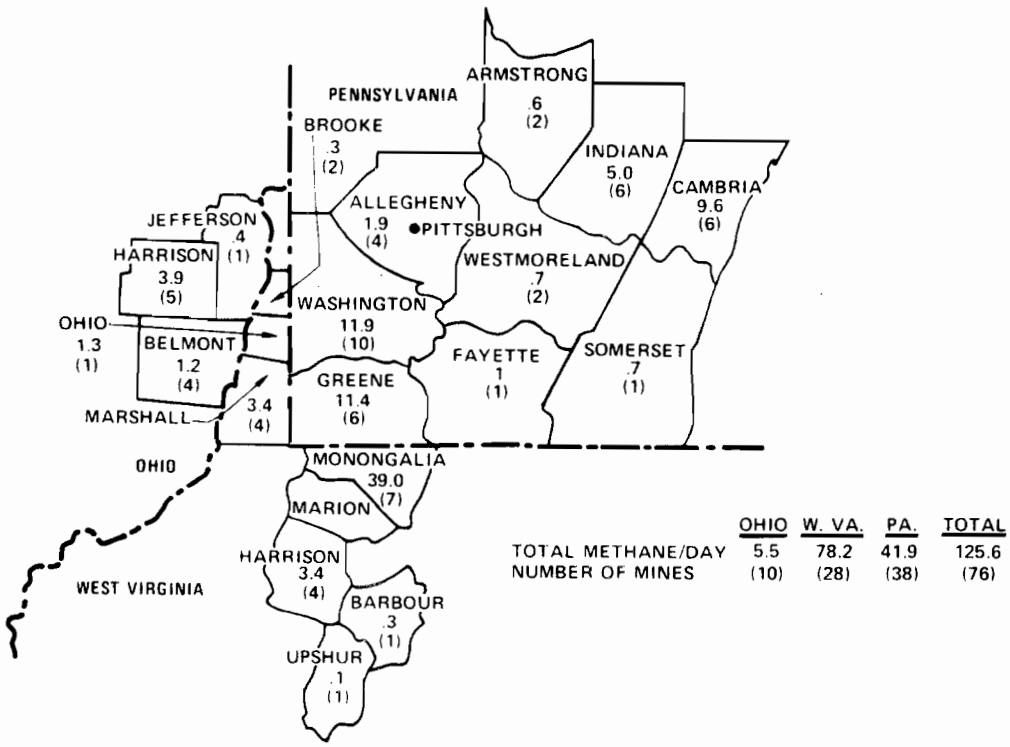
3.0 RESOURCE DATA BASE

In order to properly identify the methane resource data basis, it is necessary to first identify the source rock data base, i.e., the gaseous coalbeds. Thus, the present task is divided into three subsections:

- Appalachian Coalbed Reserves and Characteristics
- Pittsburgh Coalbed Mining Activities
- Gas Reserves and Characteristics of Appalachian Coalbeds

3.1 APPALACHIAN COALBED RESERVES AND CHARACTERISTICS

Several comprehensive data books are available on U.S. coalbed reserves and characteristics. The first category of references includes the most recent and well-publicized of such data sources. The A. D. Little study (Reference 1.9) specifies seven U.S. major areas underlain by coalbeds constituting extensive methane sources. The most important of these seven areas is that in northern Appalachia, i.e., southwestern Pennsylvania, northern West Virginia, and eastern Ohio (Figure 3-1, from Reference 1.9). The present study focuses on this area.



	OHIO	W. VA.	PA.	TOTAL
TOTAL METHANE/DAY	5.5	78.2	41.9	125.6
NUMBER OF MINES	(10)	(28)	(38)	(76)

FIGURE 3-1. NORTHERN APPALACHIAN COUNTIES UNDERLAIN BY THE PITTSBURGH COALBED

Several extensive coalbeds underlie the northern part of the Appalachian geosyncline. Their overall shape resembles an elliptical saucer with its long axis parallel to the geosyncline axis, i.e., N.E.-S.W. The deepest parts of these coalbeds are located close to the syncline center. They rise to shallower depths near the borders of the basin and outcrop towards the Blue Ridge and the Cincinnati Arch.

The four most important coalbeds in northern Appalachia are the Pittsburgh, Lower Kittanning, Upper Freeport and Campbell Creek coalbeds. This study focuses on the Pittsburgh bed. Three other beds are described briefly, and a quantitative data base is developed for the Pittsburgh bed.

3.1.1 Lower Kittaning Coalbed

The Lower Kittanning is also called the No. 5 Block. Thinner than the Pittsburgh bed, it underlies large parts of Pennsylvania, West Virginia, Maryland, and Ohio. The Princess, or No. 5 bed, in Kentucky has been correlated with the Lower Kittanning bed. The thickest part of the bed is in central West Virginia, thinning radially around this area. Thickness of the bed at several well-studied areas is as follows:

Area	Thickness, ft
Central West Virginia	12
Northern West Virginia	4
Western Pennsylvania	2.5-4
Ohio	2-4
Maryland	<3
Southern West Virginia	3-7

Most parts of the bed with thickness exceeding four feet have already been mined, and the bed currently sustains mining activities second only to the Pittsburgh bed.

3.1.2 Upper Freeport Coalbed

The Upper Freeport bed underlies the Pittsburgh bed and overlays the Lower Kittanning bed. A representative picture of the relative position of these three beds, as well as of all minable coalbeds in northern Appalachia, is given in Section 3.1.4.2, Stratigraphy. The Upper Freeport bed is less uniform in thickness than either one of the two previously mentioned coalbeds. According to Averitt (Reference 1.7) this is attributable to the bed's subjection to uplift, exposure, and erosion, before deposition of the overlying strata. Spreading over large parts of Pennsylvania, West Virginia and Ohio, it is the third most important bed in the northern Appalachian Basin, both in production and in reserves.

Mining activities in this bed are fewer than in the Lower Kittanning bed, although the latter is deeper, because the Lower Kittanning has a more uniform thickness and greater reserves.

The thickest part of the Upper Freeport bed lies in the eastern borders of the Appalachian Basin, in southwestern Pennsylvania and central West Virginia. The thickness of the bed in several well-studied areas is as follows:

Area	Thickness, ft Range	Thickness, ft Average
• Allegheny, Washington, Greene, Fayette, and Westmoreland Counties, Pennsylvania	2-10	5
• Monongalia, Preston, Marion, Taylor, Barbour, Upshur, Lewis, Braxton, Clay, and Webster Counties, West Virginia	3-12	5
• Clay and Braxton Counties		<2

The bed thins progressively from northern to southern West Virginia, covering a belt of 1,105 square miles centrally located in the state.

In Ohio, the Upper Freeport bed is very irregular in thickness. Its maximum thickness is 8 feet and its minimum 14 inches. The great lateral expansion, however, renders the bed fourth most important in the state in known resources.

3.1.3 Campbell Creek Coalbed

The Campbell Creek Coalbed is also known as No. 2 Gas bed. While exclusively located in West Virginia, it closely correlates with the Lower Elkhorn bed of easternmost Kentucky and the Imboden bed of southwestern Virginia. All three together cover an area of about 3,500 square miles in the three mentioned states. The bed thickness varies from 2 to 13 feet with an average thickness of 5 feet. The original resources were estimated at 9.5 billion tons.

3.1.4 Pittsburgh Coalbed

3.1.4.1 Geographic Location

The Pittsburgh bed is uniform in character over an area of about 6,000 square miles in West Virginia, Pennsylvania, Ohio and Maryland. It attains maximum thickness in western Maryland and northeastern West Virginia

and thins radially around this area. The thickness of the bed at several well-studied areas is as follows:

Area	Thickness, ft
Southwestern Pennsylvania and Northern West Virginia	8-14
Easternmost Ohio and Southern West Virginia	4-6
Northwestern Pennsylvania and Eastern Ohio	3

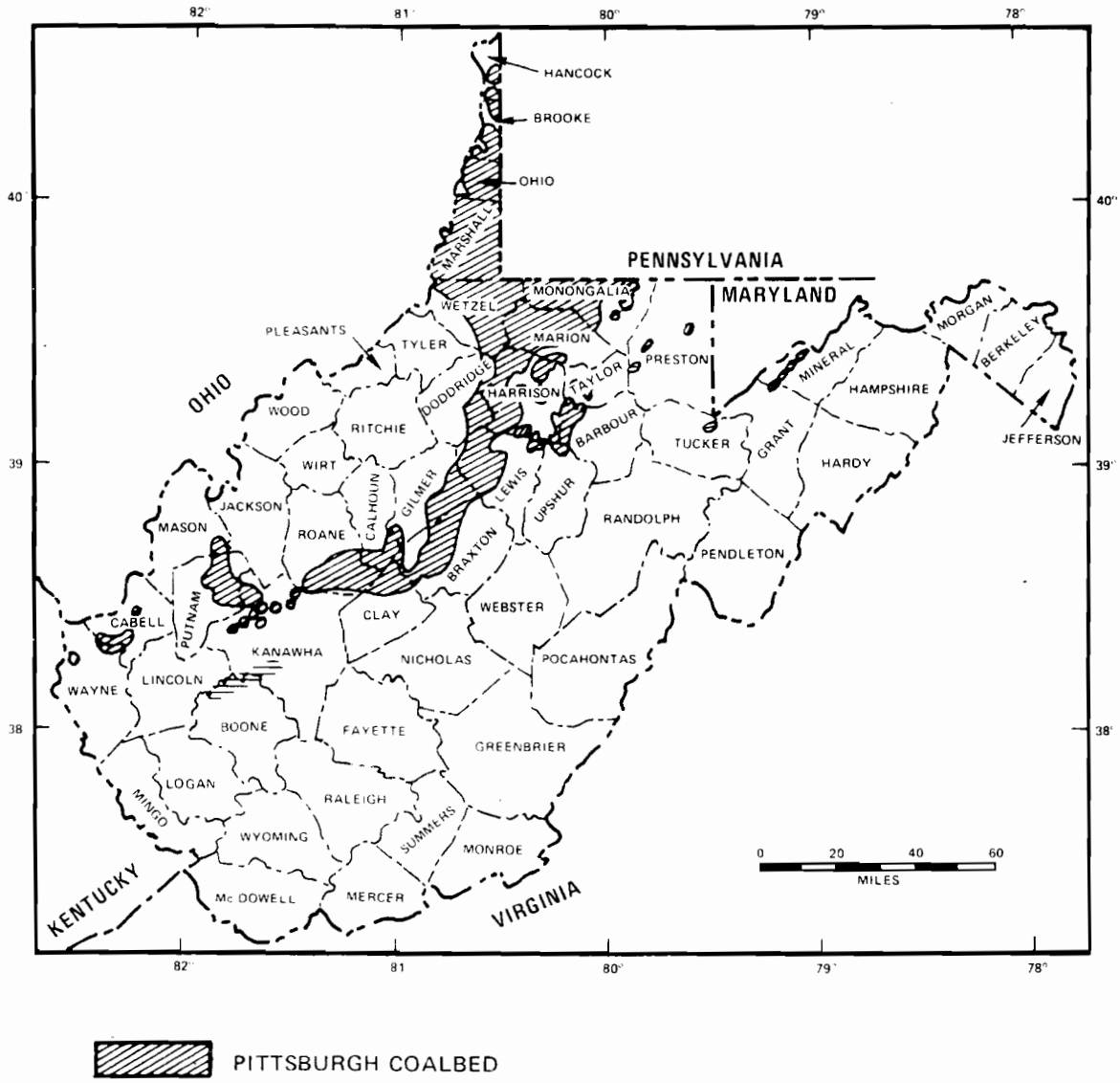
By January 1, 1974, the bed had yielded about nine billion tons of coal, about 35 percent of the total cumulative production of the Appalachian Basin and 21 percent of the total U.S. cumulative production to the same date (Reference 1.7).

The expansion of the Pittsburgh bed in West Virginia, Pennsylvania and Ohio is illustrated in Figures 3-2, 3-3 and 3-4, based on References 1.15, 1.16, and 1.17, respectively. The counties underlain by the bed are:

West Virginia		Pennsylvania	Ohio
Barbour	Marshall	Allegheny	Athens
Braxton	Mason	Armstrong	Belmont
Brooke	Mineral	Bedford	Carroll
Clay	Monongalia	Fayette	Gallia
Doddridge	Ohio	Greene	Guernsey
Gilmer	Preston	Indiana	Harrison
Grant	Putnam	Somerset	Jefferson
Hancock	Roane	Washington	Meigs
Harrison	Taylor	Westmoreland	Monroe
Kanawha	Tucker		Morgan
Lewis	Upshur		Muskingum
Marion	Wetzel		Washington

3.1.4.2 Stratigraphy

The Pittsburgh bed in Pennsylvania and West Virginia constitutes the borderline between the Conemaugh and Monongahela groups, as is shown in Figures 3-5 and 3-6, taken from References 1.4 and 1.15, respectively. Similarly, the Upper Freeport bed constitutes the borderline between the Conemaugh and the Allegheny groups. The Upper Freeport bed lies approximately 600 feet below the Pittsburgh bed in West Virginia. The Lower Kittaning lies very close to the base of the Allegheny group. It lies approximately 275 feet below the Upper Freeport bed in West Virginia, and about 200 feet below it in Pennsylvania. The Campbell Creek coal occurs at various elevations and depths. This coal is strip-mined on ridge tops, drift-mined at its outcrop and occasionally shaft-mined throughout Kanawha, Boone, Mingo and Logan Counties in West Virginia. The 3,865 ft. depth cited



PITTSBURGH COALBED

FIGURE 3-2. AREA UNDERLAIN BY THE PITTSBURGH COALBED IN WEST VIRGINIA

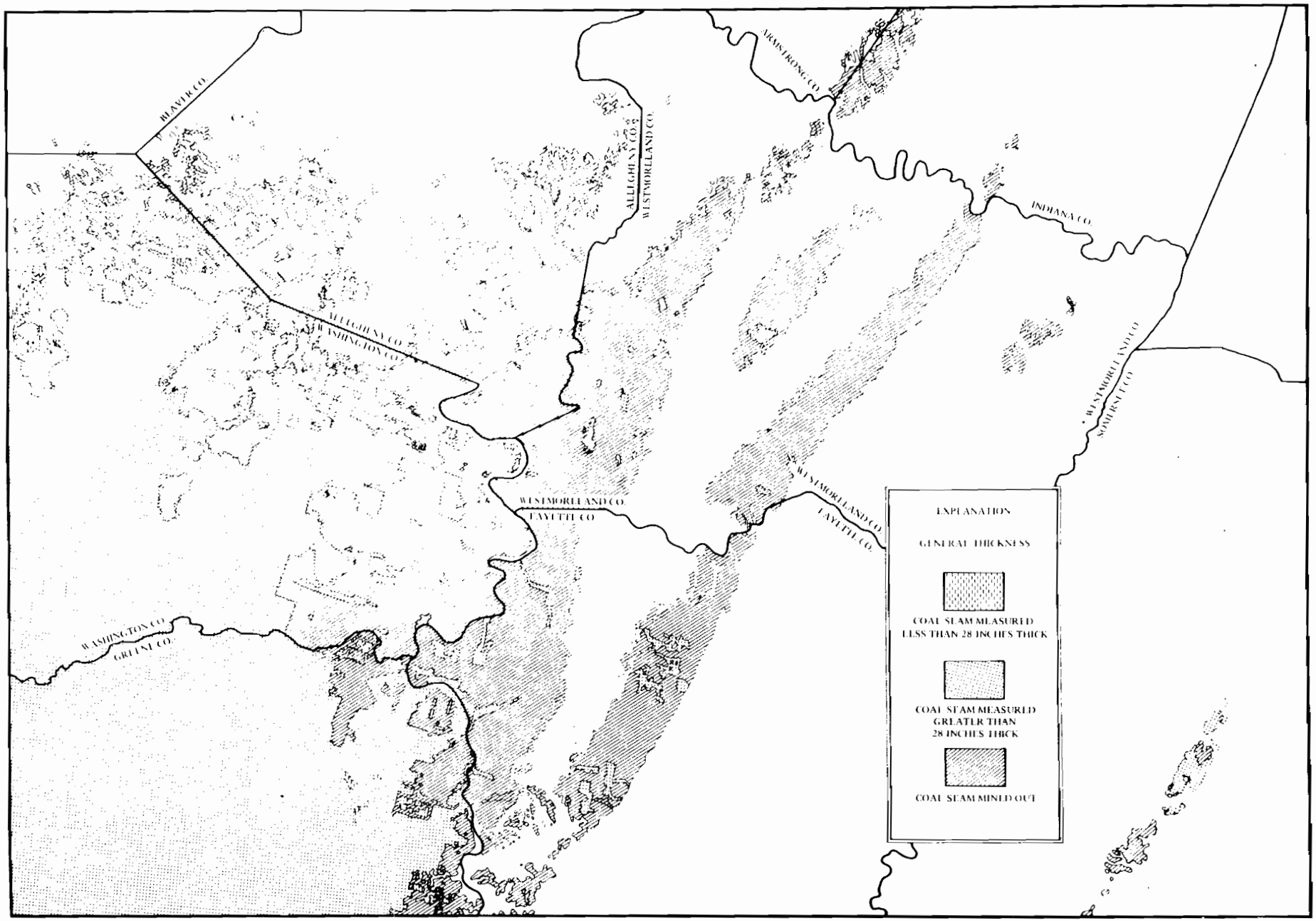


FIGURE 3-3. AREA UNDERLAIN BY THE PITTSBURGH COALBED IN PENNSYLVANIA

FIGURE 3-4. AREA UNDERLAIN BY THE PITTSBURGH COALBED IN OHIO

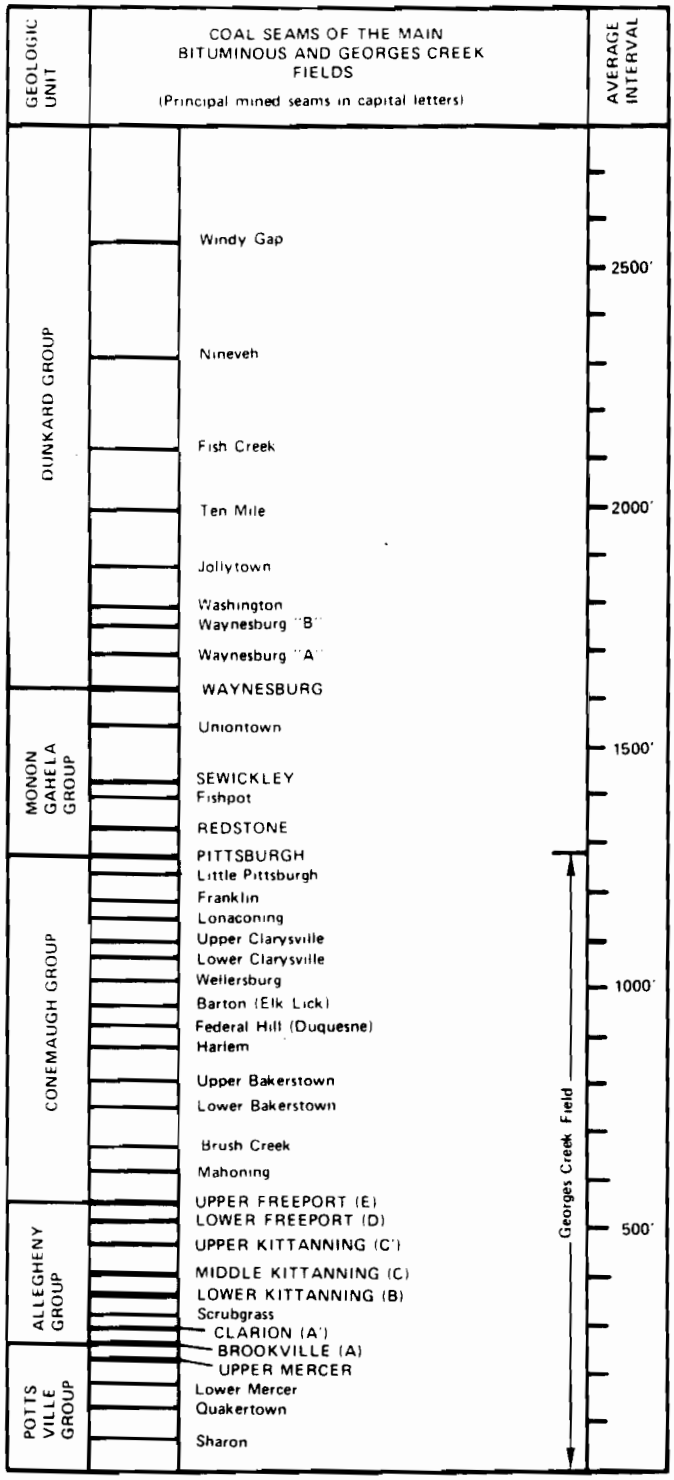


FIGURE 3-5. STRATIGRAPHIC SEQUENCE OF BITUMINOUS COALBEDS IN PENNSYLVANIA

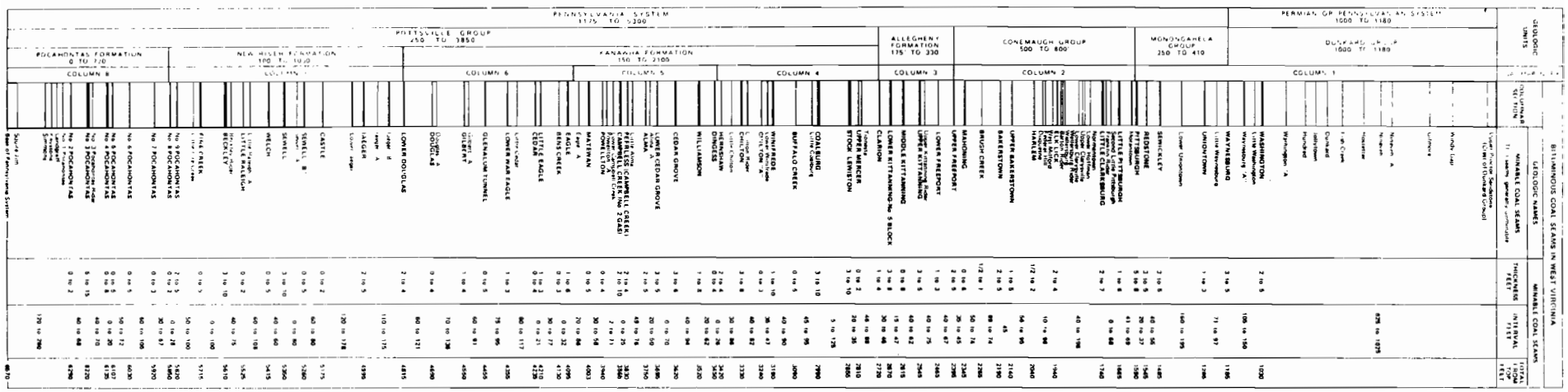


FIGURE 3-6. STRATIGRAPHIC SEQUENCE OF BITUMINOUS COALBEDS IN WEST VIRGINIA

in Figure 3-6 is based merely on a reconstructed stratigraphic column of the Pennsylvanian for the State of West Virginia and has no significant relationship as to depth of occurrence of the coalbeds. The interval of 2,275 ft. between the Pittsburgh and Campbell Creek is also misleading in that the Lower Pennsylvanian rocks of the Pocahontas, New River and Kanawha formations are generally absent in areas of occurrence of the Pittsburgh reserves.

The critical vertical sequence above the bed is normally less than 50 feet, for purposes of mine roof stability, gas drainage into the mines from the overburden, etc. However, for realistic estimates of drilling rates and projections of well development costs, all strata of the entire geologic column should be known. Berryhill and Swanson (Reference 1.18) divided the Monongahela group into two formations, the Pittsburgh and the Uniontown. The former is shown in Figure 3-7, taken from Reference 1.19. The Pittsburgh formation includes primarily calcareous rocks. This formation is further divided into five members: Lower member, Redstone, Fishpot, Sewickley, and Upper member. The Lower member consists of Pittsburgh bed at its base, and Pittsburgh bed riders, sandstone and sandy shale. The Redstone member comprises siltstone and mudstone overlain by limestone. The Fishpot member is composed of siltstone and mudstone. The Sewickley member has the Sewickley coalbed at its base, and a very thick limestone sequence above, progressively converting into limey shale and sandy shale towards the top of the member. The Upper member has four limestone units interbedding with sandy shale and limey shale. On top of the roof limestone of the member lies the Uniontown coalbed.

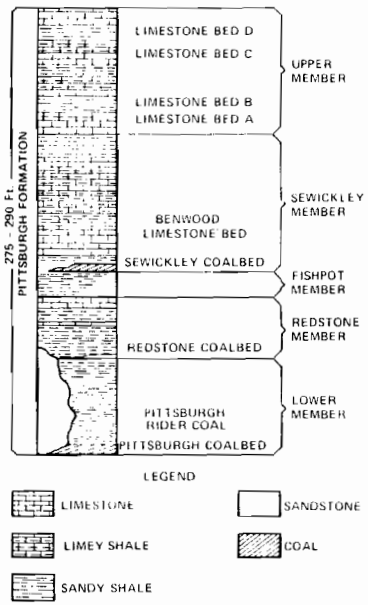


FIGURE 3-7. MEMBERS OF THE PITTSBURGH FORMATION (OF THE MONONGAHELA GROUP)

3.1.4.3 Geologic Age

The coalbeds of the northern Appalachian Basin are of the Carboniferous period of the Paleozoic era. The western coals belong to the most recent Cretaceous and Tertiary periods. The estimated duration of the Pennsylvanian part of the Carboniferous period is 30 million years, and its age to date is 280 million years, as shown in Figure 3-8.

ERA	PERIOD		EPOCH	ESTIMATED DURATION IN MILLIONS OF YEARS	ESTIMATED MILLIONS OF YEARS AGO
CENOZOIC	NEOCENE	QUATERNARY	(RECENT)		
			PLEISTOCENE		2.5
		TERTIARY	PLIOCENE	4.5	7
			MIOCENE	19	26
	PALEOCENE		OLIGOCENE	12	38
			EOCENE	16	54
			PALEOCENE	11	65
MESOZOIC	CRETACEOUS			71	136
	JURASSIC			54	190
	TRIASSIC			35	225
PALEOZOIC	PERMIAN			55	280
	CARBONIFEROUS	PENNSYLVANIAN		30	310
		MISSISSIPPIAN		35	345
	DEVONIAN			50	395
	SILURIAN			35	430
	ORDOVICIAN			70	500
	CAMBRIAN			70	570

FIGURE 3-8. GEOLOGIC TIME SCALE

The time required for formation of the Pittsburgh coalbed can be estimated from the theoretical rate of accumulation as proposed by Ashley (Reference 1.20). One foot of peat requires 10 years of plant matter accumulation. Compaction and dewatering reduce one foot of plant to 1-1/8 inches. Thus, approximately 100 years are required to produce one foot of compressed peat. Since three to three and a half feet of peat are ultimately converted into one foot of coal, it takes at least 300 years to produce one foot of coal. Thus, a six-foot thickness of Pittsburgh coal would require 1,800 years of accumulation. It is believed that the 16-foot thick coal was not formed throughout its entire thickness in place, but that the greater part was formed elsewhere and brought to basins by running waters where it settled above in-place formed coal.

The geologic age of the coal fields in West Virginia is given in Figure 3-9.

3.1.4.4 Coalbed Thickness

McCulloch, et. al., (Reference 1.19) have constructed Figure 3-10 on the basis of two data sources: drillers' logs of oil and gas wells, and core logs from coal companies. They compiled such data from more

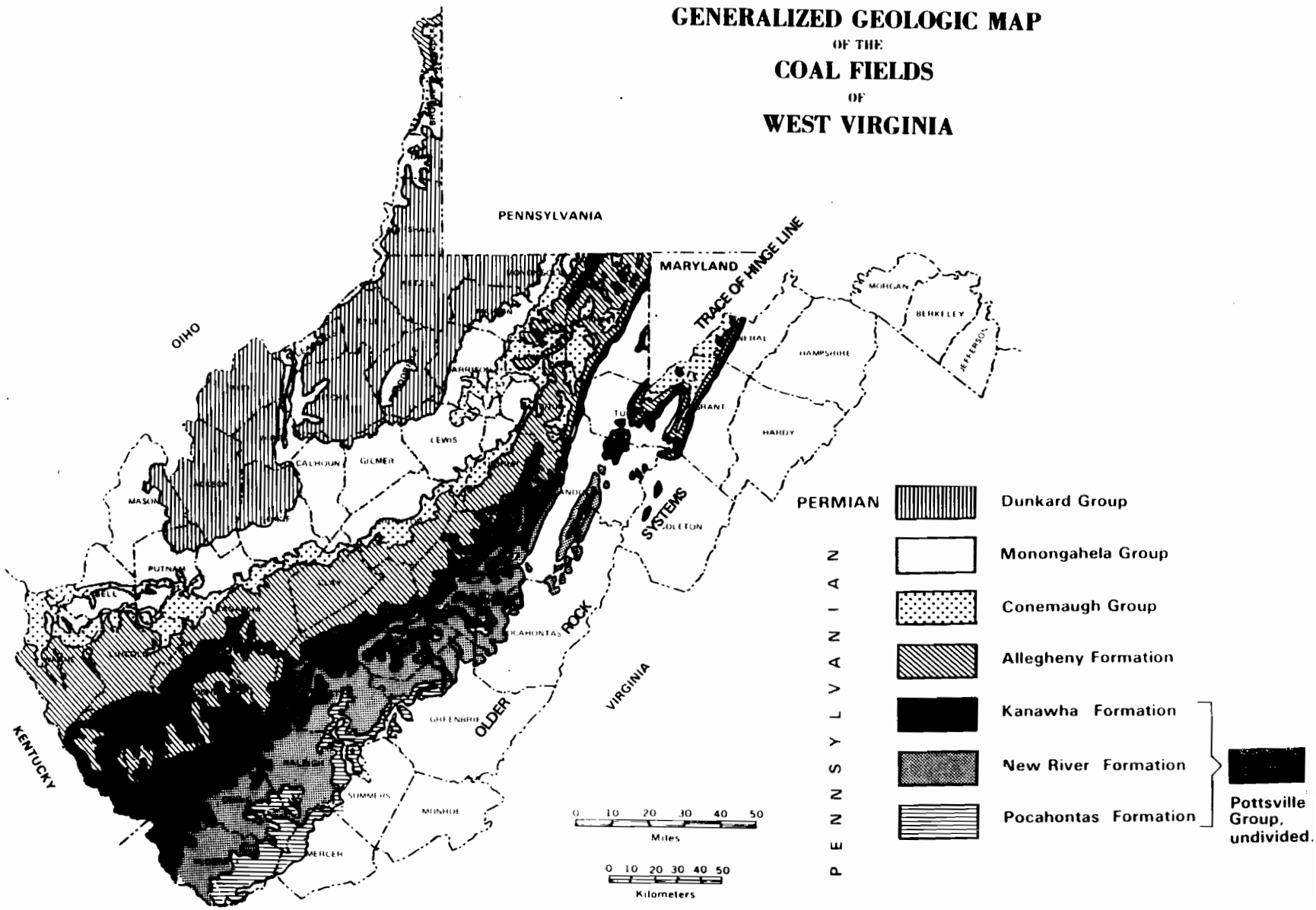


FIGURE 3-9. GENERALIZED GEOLOGIC MAP, WEST VIRGINIA COAL FIELDS

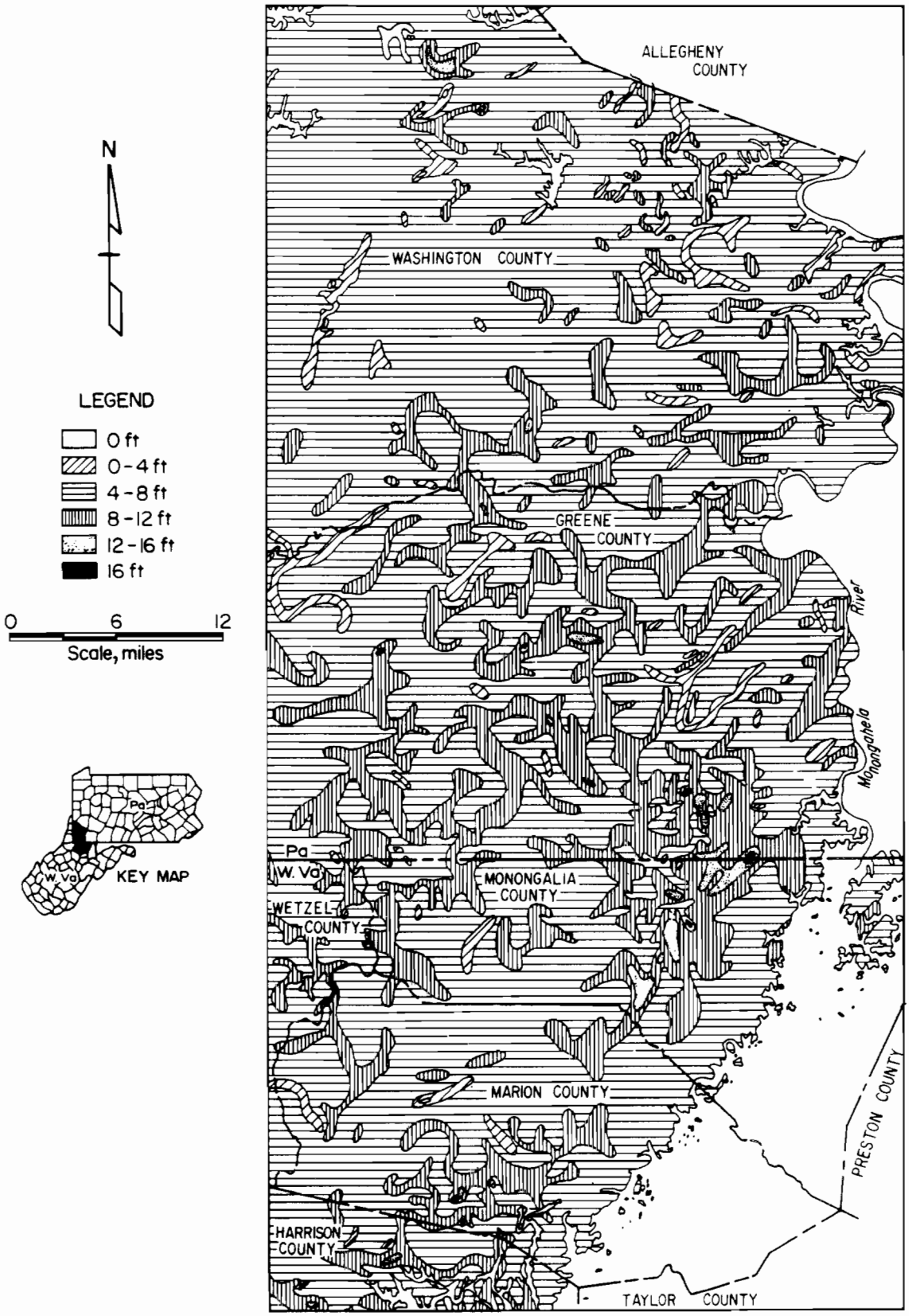


FIGURE 3-10. ISOPACH MAP OF THE PITTSBURGH COALBED

than 3,000 data points. Roof coal is included in the mapped total thickness when it is not separated by the main coalbed by more than six inches of shale or sandstone. This figure offers invaluable information for the selection of locations most suitable for demonstrations of deviated well drilling and methane drainage of the coalbed. For example, the eastern portion of the borderline between Monongalia and Greene Counties could have been ideal for such demonstrations, having an average thickness over 10 feet. Unfortunately, this area has already been mined out to a great extent, as will be shown in the section on "Pittsburgh Coalbed Mining Activities."

It has been established that the areas of thicker coal do not directly overlie the regional syncline troughs but are displaced on their flanks. The isopach of 8-12 foot thickness exhibits a well defined trend. It begins in northern Harrison County, West Virginia, runs through the central part of Marion and Monongalia Counties, and terminates inside eastern Greene County, Pennsylvania.

3.1.4.5 Overburden Thickness

McCulloch, et. al., (Reference 1.19) have constructed the isodepth map of Figure 3-11 by subtracting from the topographic elevation of a point the underground coalbed altitude under this point. The overburden thickness ranges from zero for outcropping beds in Washington County to more than 1,500 feet in southwestern Greene County and western Monongalia and Marion Counties.

The average overburden thickness in Washington County is 400 feet. Maximum thickness occurs at the southwestern part of the county and is slightly over 800 feet. In Greene County, the coalbed crops out and is strip-mined along the Monongahela River. The average thickness of cover throughout the county is 800 feet, and the maximum occurs in the southwestern segment of the county where it reaches 1,400 feet thickness. Obviously, the shallower overburden cover occurs on top of anticlines, and the thickest cover occurs along the axis of synclinal troughs.

In Monongalia County, the Pittsburgh bed outcrops along the eastern edge of the county. The cover thickness increases from east to west where it acquires a maximum thickness of 1,500 feet. In Marion County, the general trend is the same. The eastern parts of the bed are the shallowest, the central parts average 400-foot depth, and the western parts 1,000-foot depth.

The eastern parts of Wetzel County are the only ones of concern in this study, and will be outlined in the section on "Pittsburgh Coalbed Mining Activities." At this area, the coal cover ranges between 800 and 1,200 feet. In Harrison County the average cover thickness is 400 feet, with a maximum of 1,300 feet along the border between Harrison County and Marion and Wetzel Counties.

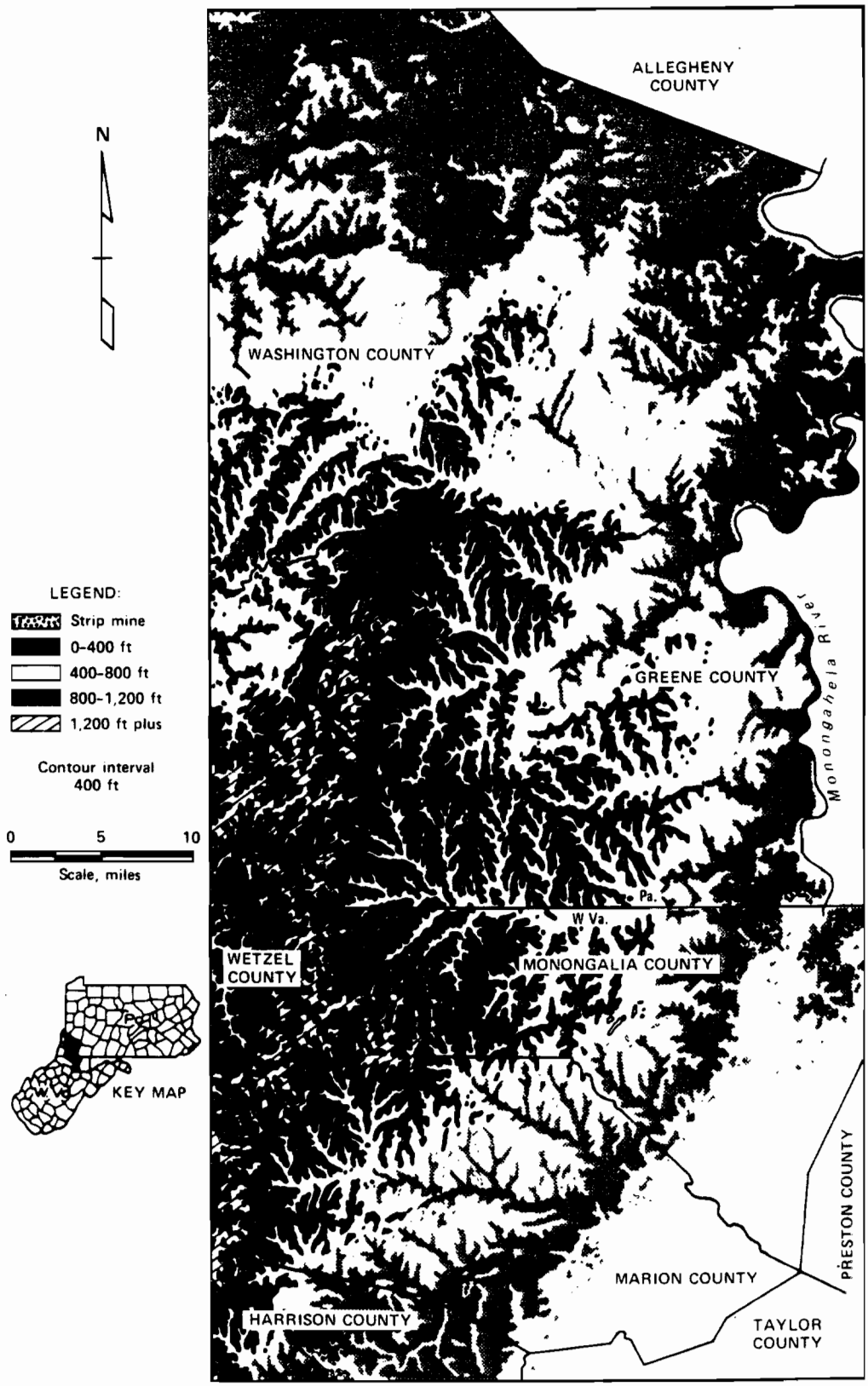


FIGURE 3-11. OVERBURDEN ISOPACH ABOVE THE PITTSBURGH COALBED

Exact knowledge of the overburden thickness is a fundamental input datum for the design of drilling demonstrations involving methane drainage through vertical wells.

3.1.4.6 Tectonism

The gently dipping basin underlain by the Pittsburgh coalbed is physiographically known as the Allegheny Plateau. This basin is folded by a great number of gentle synclines and anticlines. The intensity of these folds decreases westward. The fold axes are generally parallel to the axis of the basin, i.e., they are oriented N.E.-S.W. Roen and Farrel (Reference 1.22) have constructed a structural contour map of the general area of concern presented in Figure 3-12. This map is of great value for the design of drilling demonstrations aimed at methane drainage from the bed. Its value is twofold. First, it furnishes information on the overburden thickness above the bed. Indeed, it has already been stated that the cover is thinnest above anticlines and thickest over synclines. The cover thickness is a basic design criterion for vertical well demonstrations. Second, the map offers invaluable information for the design of horizontal boreholes, since it furnishes excellent information on cleat orientation.

Cleat is the natural vertical fracture system in bituminous coalbeds. There are two fundamental fracture directions at approximately 90° to each other, one parallel to the fold axes and one perpendicular to them. The fracture planes parallel to the fold axes constitute the butt cleat. These fractures are short, discontinuous, and usually terminate against the fracture planes perpendicular to the fold axes. The latter fractures define the face cleat. They are long, continuous, intersect coal bedding planes and determine the direction of maximum gas flow in the coalbed, i.e., they are responsible for the maximum directional permeability of the coalbed. A schematic diagram of cleat orientation is given in Figure 3-13.

McCulloch, et. al., (Reference 1.19) have found that the predominant cleat orientation in Washington, Pennsylvania is:

Butt cleat: N 28° E

Face cleat: N 67° W

They also found that the mean cleat orientation in southern Greene County, Pennsylvania, and Monongalia County, West Virginia is:

Butt cleat: N 17° E

Face cleat: N 76° W

Exact cleat orientation for each major mine in northern Appalachia will be given in the section on "Coal Properties and Characteristics."

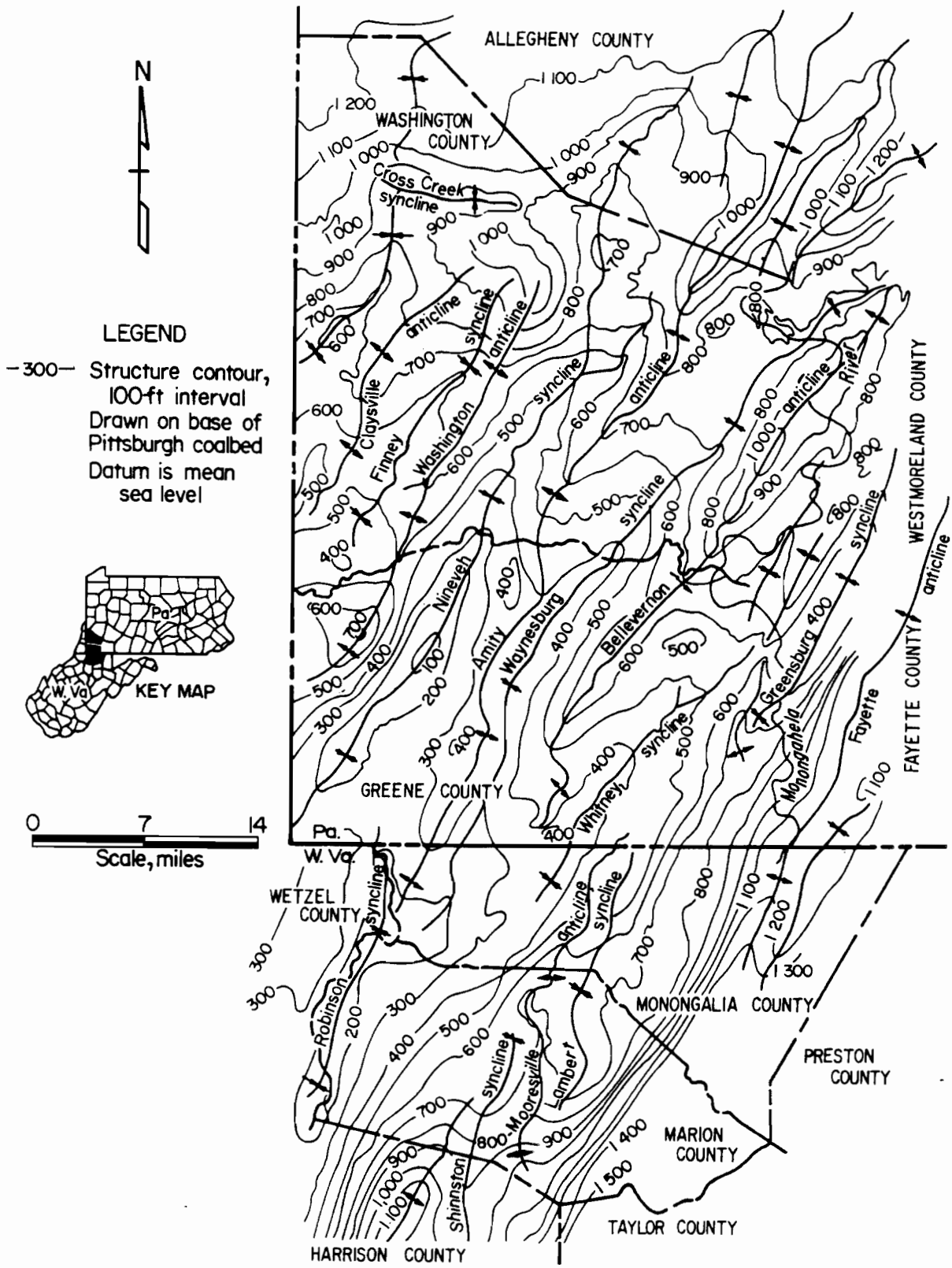


FIGURE 3-12. STRUCTURE MAP OF THE PITTSBURGH COALBED BASIN

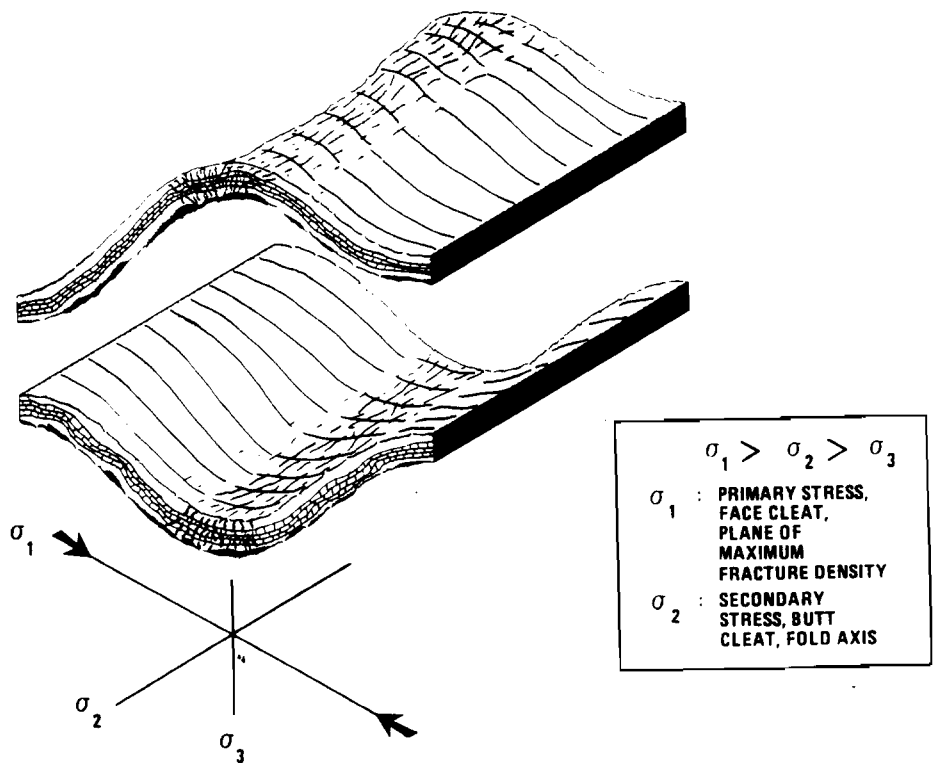


FIGURE 3-13. SCHEMATIC DIAGRAM OF FACE AND BUTT CLEAT ORIENTATION WITH REFERENCE TO THE FOLD AXIS

A most important fact in mine design and degasification borehole design is that drilling perpendicular to the face cleats releases much more gas and water into the drilled opening than drilling parallel to the face cleat. Thus, main headings in most northern Appalachian mines are oriented E-W, i.e., parallel to the face cleat, as may be seen in the maps of Appendix E. This orientation allows minimum gas entrance into the mine workings. On the other hand, horizontal degasification boreholes are drilled mostly N-S, i.e., perpendicular to the face cleat, allowing maximum gas flow rates into the gathering pipeline system. Testimony to this effect may be found in the production performance of previous demonstrations (References 1.19 and 6.3).

3.1.4.7 Coal Reserves

Underground bituminous coal reserves for each of the above counties are given by bed thickness and sulfur range in Table 3-1 (Appendix A), based on Reference 1.1. Table 3-1 indicates that the counties with most prolific minable reserves (bed thickness exceeding 42 inches) are the following (reserves in million short tons):

West Virginia	Pennsylvania	Ohio
Marshall 1,924.67	Greene 3,537.94	Belmont 1,906.28
Monongalia 1,342.14	Washington 2,992.59	Monroe 344.23
Marion 1,020.80	Fayette 217.83	Jefferson 263.53
Wetzel 534.38	Westmoreland 95.13	Harrison 200.01

3.1.4.8 Coal Analysis

A comprehensive collection of average data on coal analyses by state and county is presented for the Pittsburgh bed in Table 3-2 (Appendix B), based on Reference 1.1. This table provides moisture, ash, sulfur, and Btu content for coal as received, (AR), dry coal, and moisture and ash free coal (M&AF). Table 3-3 provides complete proximate analyses taken from Reference 1.4. The above data indicate that the composition of the bed is of great uniformity throughout its entire body.

TABLE 3-3. TYPICAL COAL PROXIMATE ANALYSES IN NORTHERN APPALACHIA

	WEST VIRGINIA	PENNSYLVANIA		OHIO
		WASHINGTON COUNTY	GREENE COUNTY	
MOISTURE (%)	0.8	1.1-3.9	1.7-3.7	4.18
VOLATILE (%)	37	32.3-38.7	33.0-36.4	37.64
FIXED CARBON (%)	53	49.2-59.4	52.2-57.3	49.94
ASH (%)	7	4.8-9.6	4.2-10.8	8.24
SULFUR (%)	2.2	0.7-3.3	0.8-3.2	3.40
Btu	13,800	13,170-14,340	13,040-14,140	12,919

Figures 3-14, 3-15 and 3-16 illustrate the fixed carbon, ash, and sulfur content of West Virginia bituminous coal fields. These figures indicate that the Pittsburgh coalbed contains high volatile bituminous coal with under 69 percent fixed carbon. The ash content is between 6 and 12 percent for most parts of the bed, except for some areas in Wetzel, Monongalia, Doddridge and Harrison Counties, where the ash content exceeds 12 percent. Finally, the sulfur content for most parts is between 1.5 and 3 percent, except for some parts in Wetzel, Harrison and Doddridge Counties, where the sulfur content exceeds 3 percent.

3.2 PITTSBURGH COALBED MINING ACTIVITIES

Extensive mining activity is currently underway in the Pittsburgh coalbed. This section presents most of the companies possessing mining

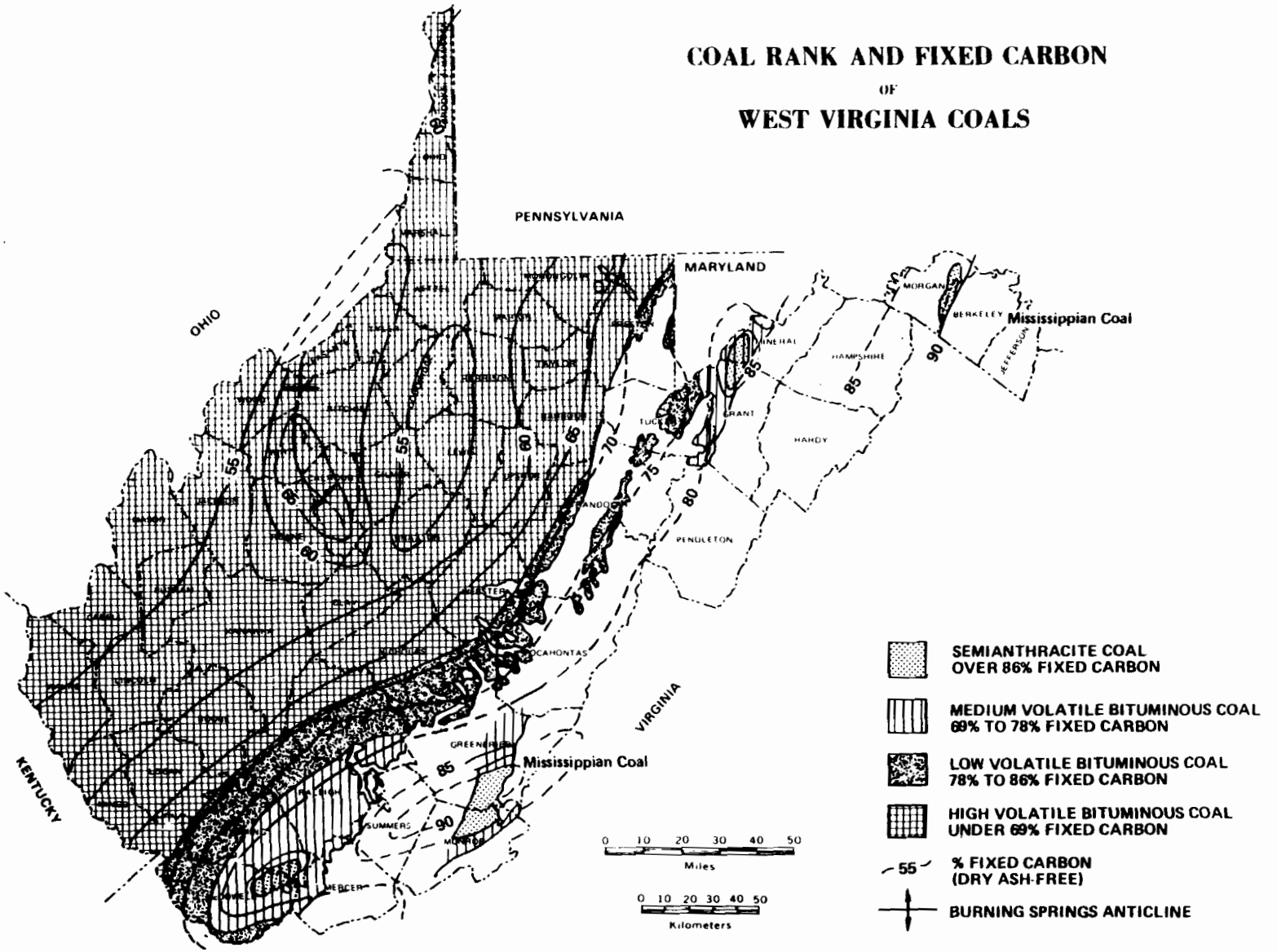


FIGURE 3-14. COAL RANK AND FIXED CARBON OF WEST VIRGINIA COALS

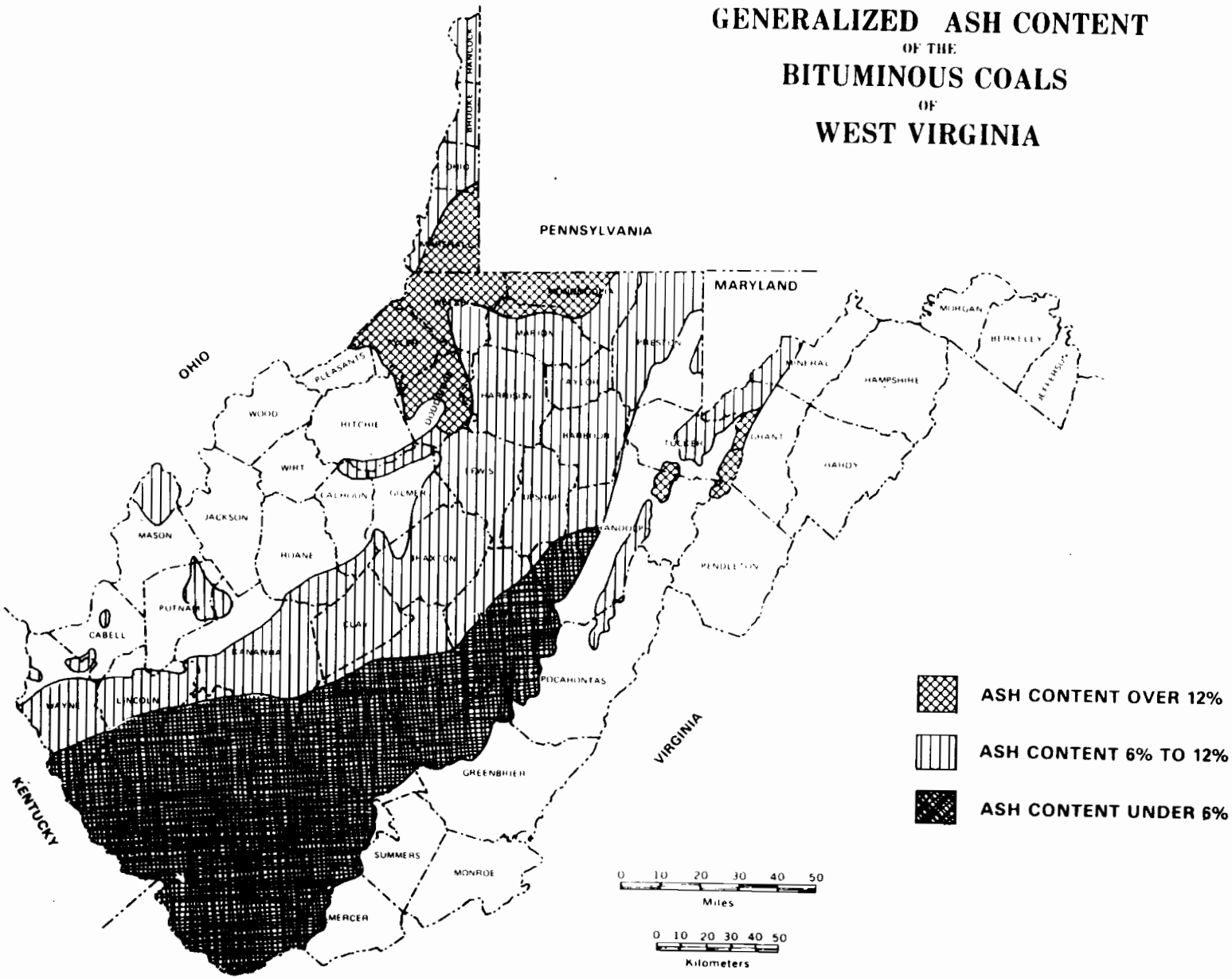


FIGURE 3-15. GENERALIZED ASH CONTENT OF THE BITUMINOUS COALS OF WEST VIRGINIA

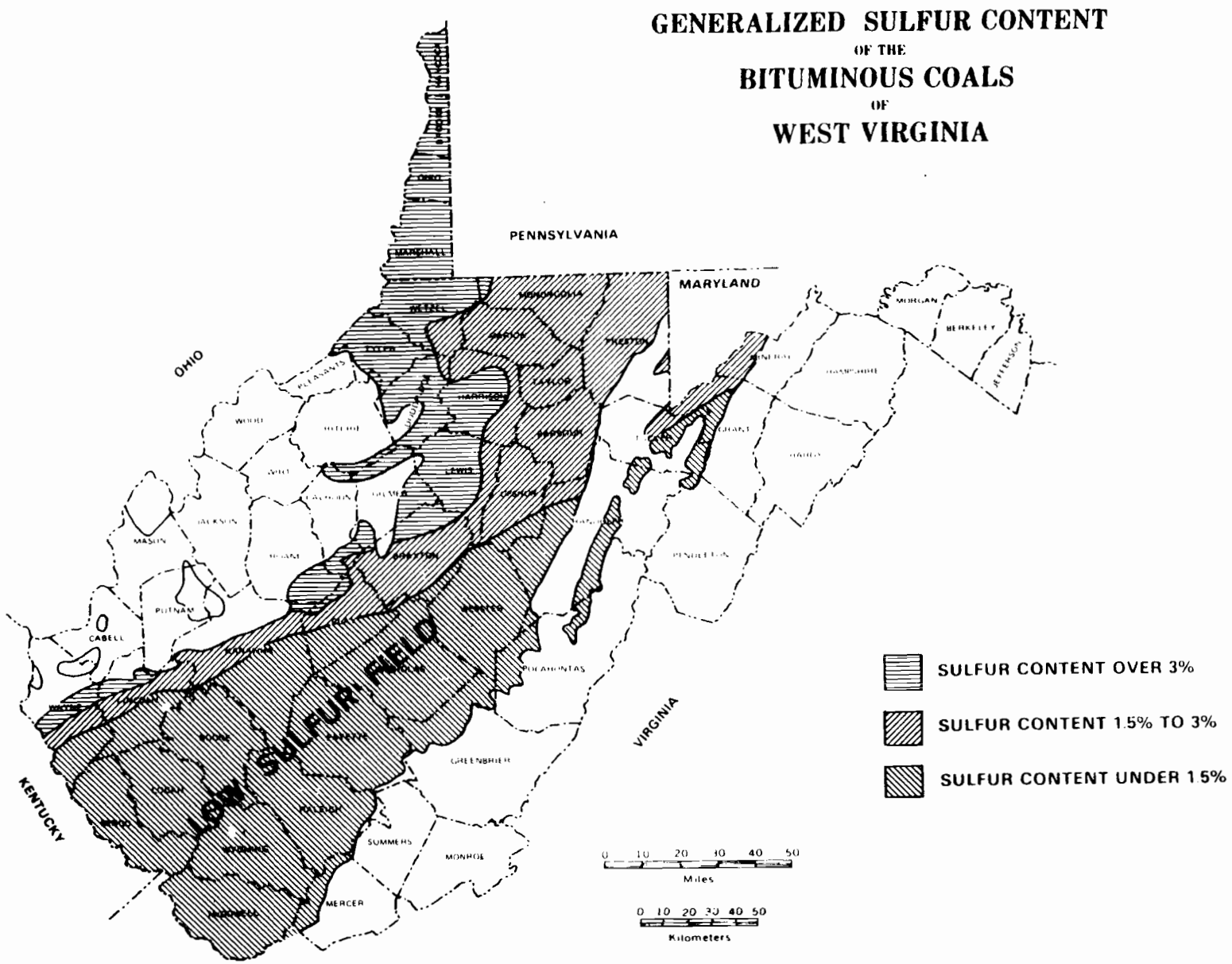


FIGURE 3-16. GENERALIZED SULFUR CONTENT OF THE BITUMINOUS COALS OF WEST VIRGINIA

rights in the Pittsburgh bed and furnishes design, equipment and production data for most underground mines. A general outline also is given of the mining industry upon which any degasification demonstration must draw. The second group of references provides the data basis for this section.

3.2.1 Companies Possessing Coal Mining Rights

Section 3.1.4.1 stated that the Pittsburgh bed underlies the states of West Virginia, Pennsylvania, Ohio and Maryland. Many companies possess coal mining rights and sustain mining activities (at different levels) in the Pittsburgh bed, in those four states. Table 3-4 (Appendix C) lists the most important of these companies, by state and county. It is obvious that the mining industry associated with the Pittsburgh bed in those four states is most prominent in West Virginia, followed by Pennsylvania, Ohio and Maryland, in that order.

Many companies named in Table 3-4 currently sustain only surface mining activities. However, several are planning to enter shortly into underground mining ventures. Thus, they represent potential future users of coal degasification technology. Table 3-4 is primarily based on Reference 1.4.

3.2.2 Design, Equipment and Production Data of Currently Active Underground Mines

The most important of currently active underground mines in the Pittsburgh coalbed are listed in Table 3-5 (Appendix D). This table is based on References 3.1 and 1.4 and is being constantly annotated with information through private communication with the mining industry of northern Appalachia.

The mines are listed in Table 3-5 in alphabetic order of the owner companies. Two basic groups of data are presented: design, equipment and production data of the underground mine, and of the preparation plant by the mines (whenever such a plant exists). These data offer very important information, not only for selection of demonstration sites for coal degasification but also for sites best suited for gas conversion and utilization demonstrations.

3.2.3 Location and Lease Boundaries of Major Underground Mines

The exact locations and lease boundaries of 30 major underground mines are shown in Figure 3-17, based on Reference 1.19. Mines with long production histories and greatly depleted coal resources are dotted and are marked in the legend as "mined-out area."

A more detailed presentation of the same information is also presented in Figures 3-18, 3-19, and 3-20 (Appendix E). These three maps also present the orientation of the main headings (and some sub-mains) of most mines, as well as major gas pipeline networks serving the area.

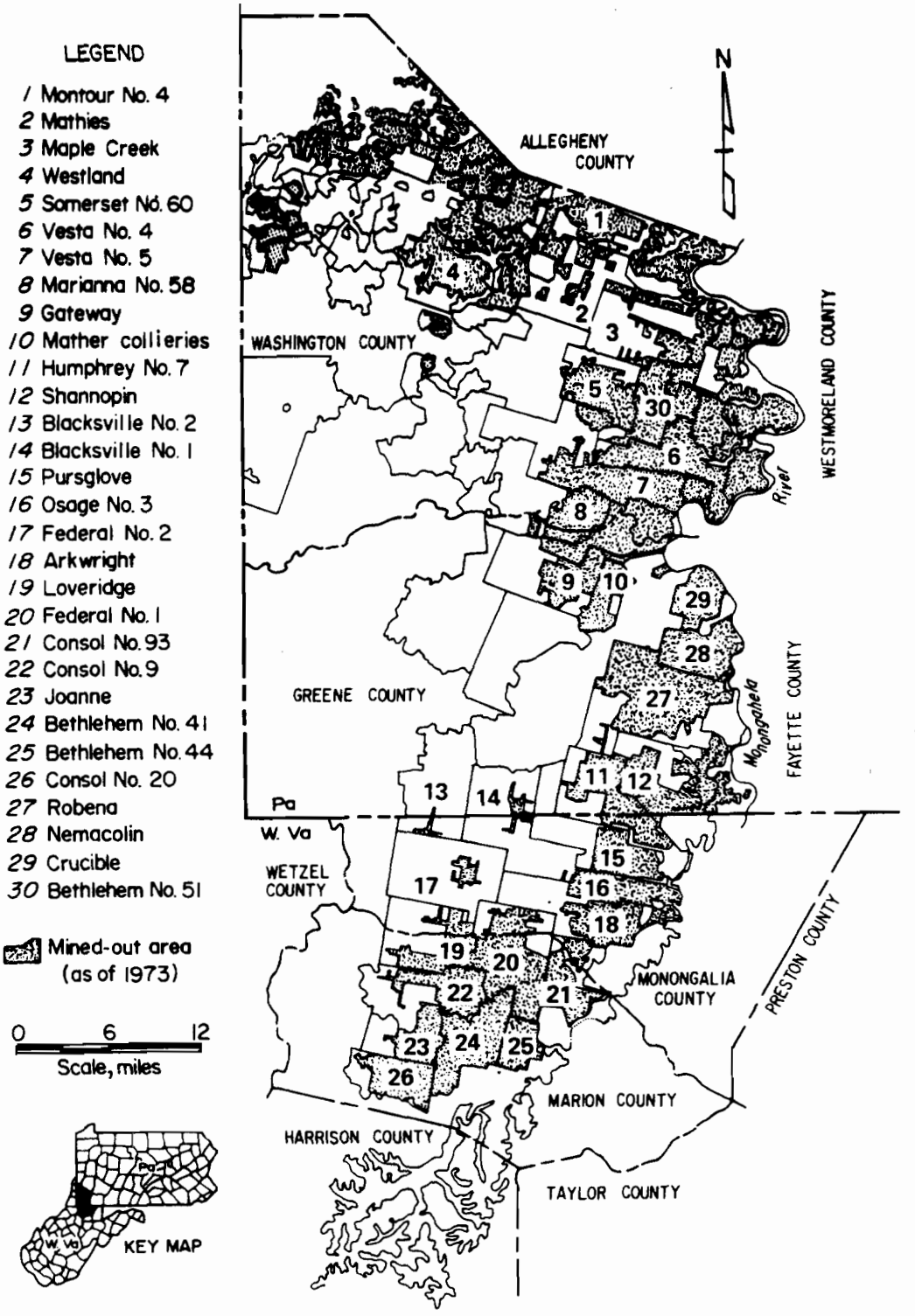


FIGURE 3-17. LOCATION AND LEASE BOUNDARIES OF MAJOR UNDERGROUND MINES IN THE PITTSBURGH COALBED

The above information is of great importance for system studies involving demonstrations of coal degasification and/or gas conversion and utilization from a group of mines.

The exact locations of mine portals for the Ohio mines are given in Figure 3-21.

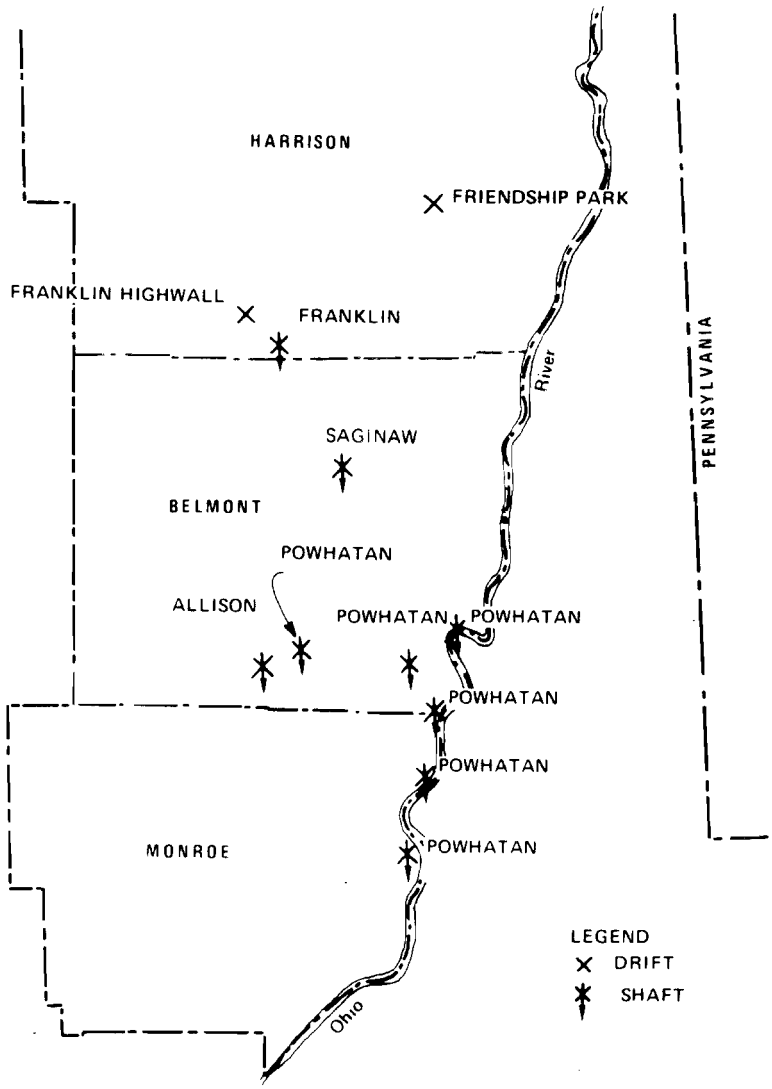


FIGURE 3-21. LOCATION OF PORTALS OF OHIO UNDERGROUND MINES IN THE PITTSBURGH COALBED

3.3 GAS RESERVES AND CHARACTERISTICS OF APPALACHIAN COALBEDS

The gas content of Appalachian coals per coalbed, geographic location, depth, rank of coal, etc., has been the subject of extensive investigations. Similarly, the gas compositions of coals of many origins, types, production histories, etc., have been subjected to extensive measurements. On the basis of the above data, elaborate calculations of

the gas reserves in Appalachia have been made. Reserves have been reported in volumetric as well as calorimetric units. Furthermore, the physicochemical modes of gas migration through coal, and liberation from coal, have been analyzed theoretically and measured experimentally. A brief summary of the ultimate findings, results, and conclusions of the above studies is presented in this section. The third section of references furnishes the most pertinent data sources for this section.

3.3.1 In-Place Gas Content of Appalachian Coalbeds

There are three basic methods for the calculation of a coalbed's coal gas content:

1. Direct method of measuring the total gas volume emitted from a core placed in an airtight vessel immediately upon recovery

2. Indirect method from equilibrium adsorption isotherms

3. Indirect method from methane emission rates during underground mining

The first method was developed in France by Bertard, et. al., (Reference 3.12) and extensively applied in eastern coalbeds, after modifications and improvements, by Kissell, et. al., (Reference 3.10). Three amounts of gas make up the total content: lost gas after drilling the core, but before placing it in the airtight vessel; gas emitted in the vessel from the core as a whole, over lengthy periods of time; and residual gas liberated after the core was crushed to grains of 200 mesh size order. The lost gas prior to casing represents about 25 percent of the total gas, and the most important improvement of the direct method by Kissell, et. al., lies in the method of calculating the lost gas. The results obtained by Kissell, et. al., are shown in Table 3-6.

TABLE 3-6. GAS CONTENT OF EASTERN COALBEDS BY THE DIRECT AND EQUILIBRIUM ADSORPTION ISOTHERM METHODS

MINE	COALBED	DIRECT METHOD		ADSORPTION ISOTHERM METHOD	
		cm^3 (STP)/g	cu. ft./ton	cm^3 (STP)/g	cu. ft./ton
VESTA NO. 5	PITTSBURGH	2.6	83*	3.4	109
LOVERIDGE	PITTSBURGH	5.8	186	5.2	166
HOWE	HARTSHORNE	11.1	355	10.5	336
BEATRICE	POCAHONTAS NO. 3	12.1	387	13.5	432
INLAND	ILLINOIS NO. 6	1.7	54	2.7	86
INLAND	ILLINOIS NO. 5	0.9	29	0.5	16
KEPLER	POCAHONTAS NO. 3	7.9	253	7.8	250
PRICE	CASTLEGATE	4.2	134	5.0, 6.2	160, 198

*1 cm^3/gr. is equivalent to 32 ft^3/ton

The second method allows calculation of the gas volume adsorbed per gram of coal, from knowledge of the in situ gas pressure of the coalbed, the moisture of the coalbed, and the laboratory-established equilibrium adsorption isotherm for the given moisture. The isotherms are hyperbolic

curves in the coordinate gas pressure-adsorbed volume. The in situ gas pressure is measured through routine drill stem tests in vertical or horizontal boreholes, after core removal. The moisture is measured on the recovered core. The equilibrium adsorption isotherm is experimentally established in the laboratory on powdered coal samples of known moisture.

A strong reservation is made on the accuracy of this indirect method. The in situ gas pressure is caused mostly by free gas compressed within the fracture porosity of the coal, and similarly with free gas compressed among sandstone grains. However, it is well known that most of the gas contained in the coal is not free, but adsorbed on the internal free surface of the coal. The folds of this surface are extremely close-packed, as little as five Angstroms apart. Characteristically, the internal free surface of the coal has a density of 100 M^2/gr. Thus, it is expected that the in situ gas pressure will not offer an accurate indicator of the amount of gas in the coal, even if the latter is crushed to 200 mesh grain size. Kissell, et. al., (Reference 3.10) have also calculated the gas content of the coalbeds they studied, through the adsorption isotherm method. The results obtained are shown in Table 3-6. It is apparent that the two methods exhibit remarkable agreement.

The third method of coal gas content calculation is based on two facts: first, it is known that gas emitted during mining is greater than the in-place gas content of the coalbed. Kim (Reference 3.5) postulates that only 20 to 30 percent of the emitted gas was contained in the mined coal. The remainder was released from the face, ribs, roof, floor and periphery of pillars. The second fact is that the amount of gas attributed to the mined coal represents only a fraction of the total gas contained in the coal. Kim postulates that 20 or 30 percent of the emitted gas amounts to 80 percent of the total gas in place. On the basis of these two assumptions and methane emission rates, Kim has calculated the in-place gas content of several Pittsburgh bed mines in Washington (Reference 3.5) and Greene (Reference 3.6) counties. Her results are shown in Figures 3-22 and 3-23. These two assumed figures are equivalent to postulating that the in-place gas content is 25 percent of the emitted gas. This figure is too high, according to a correlation between gas emitted and gas in-place established by Kissell, et. al., (Reference 3.10) for the mines of Table 3-6. This correlation shows that the gas emitted is 6 to 9 times the in-place gas measured by the direct method. Since Kim's assumptions have not been substantiated by any experimental evidence, for the purpose of this study the following ratio is accepted:

$$\frac{\text{mine gas emission}}{\text{gas in-place (direct method)}} = 6 \qquad \text{Equation 3.1}$$

On the basis of Equation 3.1 and gas emission data reported by Irani, et. al., (Reference 3.2) the in-place gas content of the coal reserves of 25 major Pittsburgh coalbed mines was calculated. The results are shown in Table 3-7.

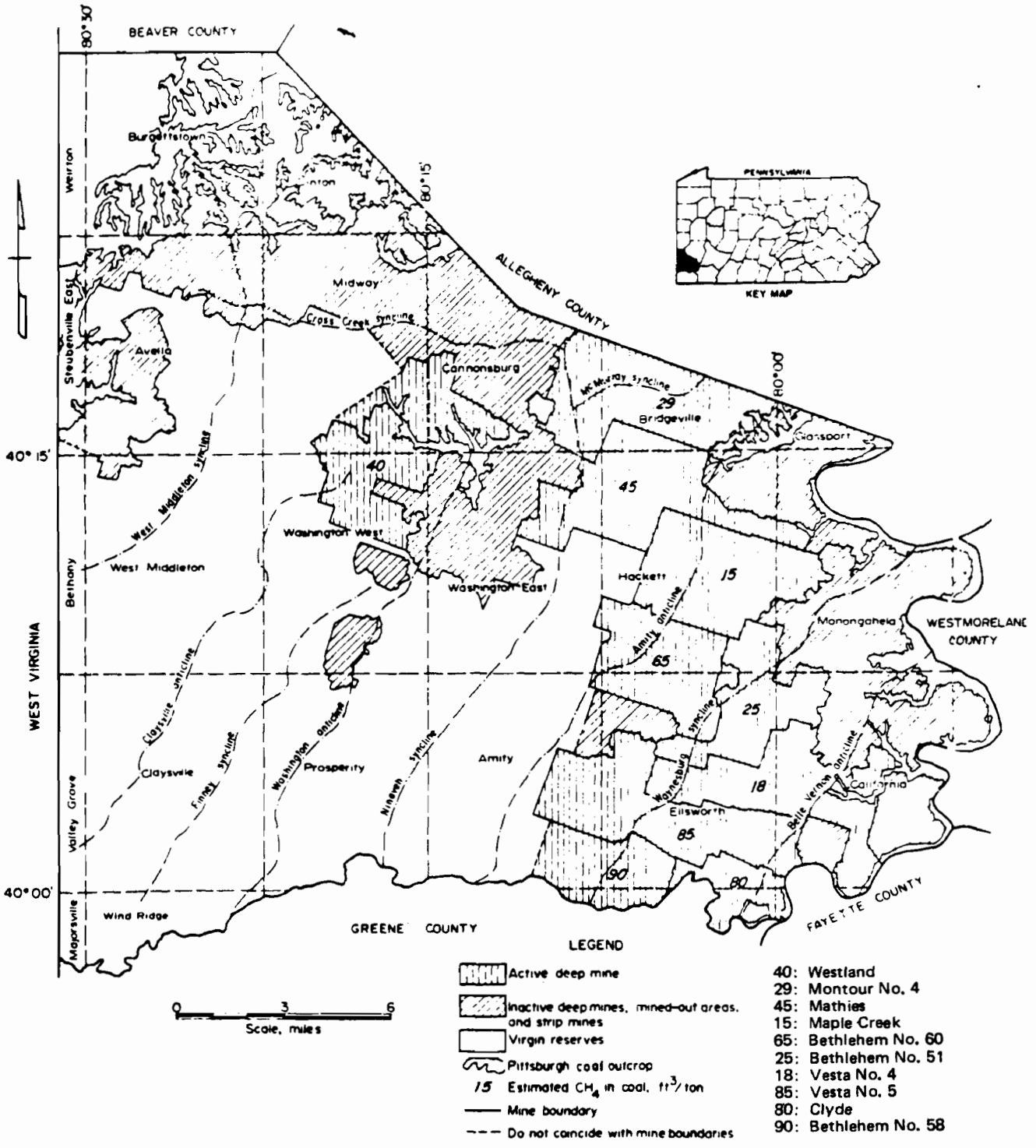


FIGURE 3-22. METHANE GAS CONTENT IN WASHINGTON COUNTY, PA., PITTSBURGH COALBED MINES

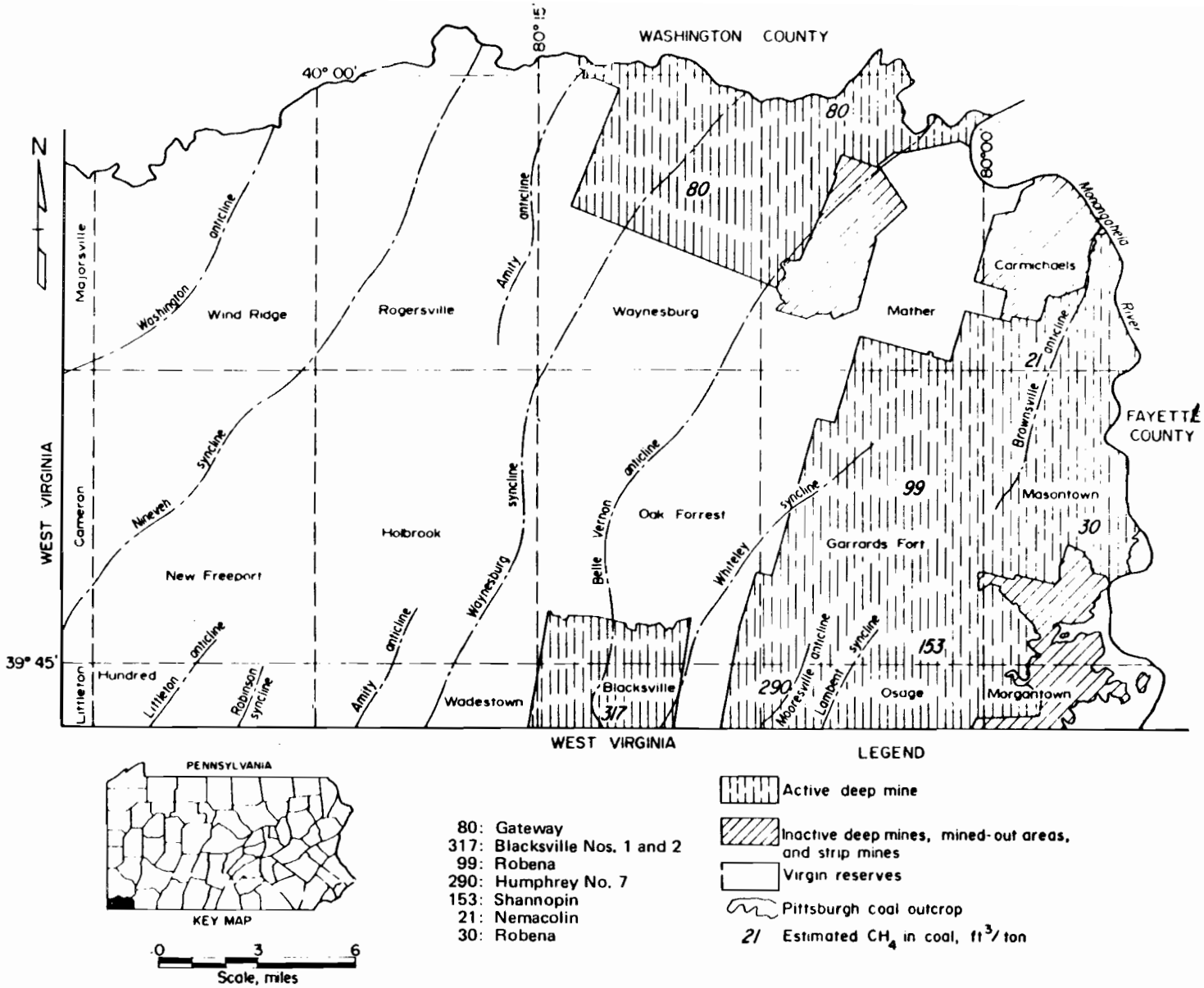


FIGURE 3-23. METHANE GAS CONTENT IN GREENE COUNTY, PA., PITTSBURGH COALBED MINES

TABLE 3-7. IN-PLACE GAS CONTENT OF PITTSBURGH COALBED MINES CALCULATED ON THE BASIS OF GAS EMISSION RATES AND ADSORPTION ISOTHERMS

MINE COUNTY, STATE	EMITTED GAS/ MINED COAL (1973) (cu. ft./ton)	IN-PLACE GAS CONTENT (Equ. 3.1) (cu. ft./ton)	MINE DEPTH (ft.)	ADSORBED GAS (Equ. 3.7) (cu. ft./ton)
LOVERIDGE MARION, W. VA.	1210	202*	721	216
HUMPHREY NO. 7 MONONGALIA, W. VA.	800	133	446	169
ARKRIGHT MONONGALIA, W. VA.	811	135	332	141
FEDERAL NO. 2 MONONGALIA, W. VA.	1426	238	788	224
FEDERAL NO. 1 MARION, W. VA.	814	136	488	178
BLACKSVILLE NO. 2 MONONGALIA, W. VA.	1080	180	713	215
BLACKSVILLE NO. 1 MONONGALIA, W. VA.	2000	333	725	216
OSAGE NO. 3 MONONGALIA, W. VA.	537	89	441	168
ROBENA GREENE, PA.	343	57	556	190
GATEWAY GREENE, PA.	420	70	375	152
SHANNOPIN GREENE, PA.	625	104	225	108
ROBINSON RUN NO. 95 HARRISON, W. VA.	200	33	300	132
MARIANA NO. 58 CAMBRIA, PA.	418	70	399	158
CONSOL NO. 28 MARION, W. VA.	467	78	398	158
IRELAND MARSHALL, W. VA.	210	35	370	151
MATHIES WASHINGTON, PA.	227	38	175	90
JOANNE MARION, W. VA.	505	84	404	159
CLYDE WASHINGTON, PA	598	100	487	177
SOMERSET NO. 60 WASHINGTON, PA.	327	54	605	198
VESTA NO. 5 WASHINGTON, PA.	667	111	250	116
PURSGLOVE MONONGALIA, W. VA.	292	49	394	157
VALLEY CAMP NO. 3 OHIO, W. VA.	309	51	471	174
McELROY MARSHALL, W. VA.	135	22		
MONTOUR NO. 4 WASHINGTON, PA.	119	20	145	77
SHOEMAKER MARSHALL, W. VA.	150	25	290	129

*Emitted Gas/In-Place Gas Content = 6

Tables 3-6 and 3-7 permit the following comparisons:

Mine	In-Place Gas Content (cu.ft./ton)		
	Direct Measurement	Calculated From Adsorption Isotherm	Calculated From Gas Emission Rate
Loveridge	186	166	202
Vesta No. 5	83	109	111

It is apparent that the three methods exhibit a reasonable agreement. Thus, in the absence of direct measurements or reservoir pressure data and adsorption isotherms, the gas emission rates can offer a reasonable ballpark figure.

A specific application of the equilibrium absorption isotherm method to the calculation of the gas content of the Pittsburgh coalbed has been performed by Joubert, et. al., (Reference 3.14). The volume of gas adsorbed by the internal free surface of coal at a fixed temperature is given by the Langmuir adsorption isotherm:

$$V_{ad} = \frac{V_m bP}{1 - bP} \qquad \text{Equation 3.2}$$

Where

V_m = Saturation adsorbed volume (complete monolayer)

b = Constant

p = Equilibrium pressure (psia)

Joubert et. al., have determined for the Pittsburgh coalbed that:

$$V_m = 392.3 \text{ cu.ft.} \qquad \text{Equation 3.3}$$

and

$$b = 0.0039 \qquad \text{Equation 3.4}$$

Thus, Eq. 3.2 becomes:

$$V_{ad} = \frac{1.53\ P}{1 + 0.0039P} \text{ (cu.ft./ton)} \qquad \text{Equation 3.5}$$

In the above equation the equilibrium pressure, P, is taken to be equal with the hydrostatic pressure of the coalbed. Zabetakis, et. al., (Reference 3.13) have found that there is a linear relationship between the hydrostatic pressure and the depth of a coalbed. This relationship is:

$$P_{hyd.} = 0.435h \qquad \text{Equation 3.6}$$

Where

h = depth

Eqs. 3.5 and 3.6 indicate that:

$$V_{ad} = \frac{0.666h}{1 + 0.0017h} \qquad \text{Equation 3.7}$$

Equations 3.5 and 3.7 allow calculation of the amount of adsorbed gas on the internal free surface of the coal, from knowledge of the hydrostatic pressure and the depth, respectively. In order to compare the combined result of the Joubert et. al., and Zabetakis et. al., studies with the in-place gas content calculated on the basis of gas emission rates, we apply Eq. 3.7 to all mines of Table 3-7. The depths of these mines are taken from Reference 4.1. The results are shown in Table 3-7. Generally good agreement exists between the two methods of gas content calculation, although there are several great differences. Since the right-hand side of Eq. 3.1 was taken arbitrarily for all depths equal to 6, although it is established (Reference 3.13) that it increases with depth from 3.75 to 9, Eq. 3.7 should be preferred over Eq. 3.1.

3.3.2 Gas Composition of Appalachian Coalbeds

The composition of coalbed gas is not constant; it varies for different coalbeds and for different locations in a single coalbed. Methane is the major component, usually in excess of 80 percent. Ethane contributes up to two percent, and propane, butane and pentane constitute the balance of the hydrocarbons in the gas, with less than one percent each. Concentrations of CO_2 and N_2 vary from less than one to 15 percent; oxygen, hydrogen and helium may be present in trace quantities. Carbon monoxide and sulfur compounds are usually absent. The calorific value of the gas is a direct function of the total hydrocarbon content and makeup. Generally, the heat of combustion varies between 950 and 1,000 Btu/cu.ft., i.e., it is very compatible with the heat of combustion of natural gas.

Kim (Reference 4.9) has probably analyzed by far the most samples of Appalachian coal gases (by gas chromatography). The coalbeds sampled during her work are given in Table 3-8. The coal gas compositions determined from the coalbeds studied are given in Table 3-9 through 3-12. The CH_4 to CO_2 ratios in the analyzed coal gas sampled are given in Table 3-13. The heat of combustion of coalbed gas samples as received and CO_2 free are

TABLE 3-8. COALBEDS SAMPLED FOR GAS ANALYSIS

Site number	Coalbed	Location	Average depth[1] of overburden (feet)	Coal[1] thickness (inches)	Type of borehole	Number of samples
1	Pocahontas No. 3	Dismal Creek, Buchanan County, Va.	1,162	54	Horizontal	32
2	Pocahontas No. 3	Keen Mountain, Buchanan County, Va.	1,925	54	Horizontal	17
3	Pocahontas No. 3	Grundy, Buchanan County, Va.	1,925	54	Horizontal	2
4	Pocahontas No. 3	Van Sant, Buchanan County, Va.	1,925	54	Horizontal	9
5	Pittsburgh	Bobtown, Greene County, Pa.	225	56	Horizontal	4
6	Pittsburgh	Marianna, Washington County, Pa.	399	60	Horizontal	3
7	Pittsburgh	Fairview, Marion County, W. Va.	721	96	Horizontal	2
8	Pittsburgh	Fairview, Marion County, W. Va.	721	96	Vertical	2
9	Upper Kittanning	Ebensburg, Cambria County, Pa.	753	42	Horizontal	3
10	Upper Kittanning	Ebensburg, Cambria County, Pa.	753	42	Vertical	3
11	B Seam, Mesaverde Formation	Carbondale, Pitkin County, Colo.	(0-2, 500)	81	Horizontal	3
12	Lower Hartshorne	Heavener, LeFlore County, Okla.	350	39	Horizontal	2
13	Mary Lee	Oak Grove Area, Jefferson County, Ala.	1,070	63	Vertical	2

[1] Methane Emission From U.S. Coal Mines.[3.1]

TABLE 3-9. COMPOSITION OF GAS FROM PITTSBURGH COALBED

Site component	No. 5		No. 6		No. 7		No. 8	
	Percent	±	Percent	±	Percent	±	Percent	±
CH_4	88.91	0.99	95.86	1.02	93.85	0.35	84.4	0.85
C_2H_2	0.04	0.02	1.06	0.23	0.04	0.0	–	–
C_3H_8	–	–	–	–	–	–	–	–
C_4H_{10}	–	–	–	–	–	–	–	–
C_5H_{12}	–	–	–	–	–	–	–	–
CO_2	10.97	0.97	2.54	0.93	4.75	0.78	14.75	0.35
O_2	0.04	0.03	0.06	0.09	0.5	0.0	0.2	0.28
N_2	0.05	0.04	0.46	0.47	1.2	0.0	0.85	0.92
H_2	–	–	–	–	–	–	–	–
N_2	ND[1]	–	–	–	–	–	–	–

[1] ND: Not determined

TABLE 3-10. COMPOSITION OF GAS FROM KITTANNING

Site component	No. 9		No. 10	
	Percent	±	Percent	±
CH_4	95.47	0.95	99.17	0.47
C_2H_6	–	–	0.02	0.0
C_3H_8	–	–	–	–
C_4H_{10}	–	–	–	–
C_5H_{12}	–	–	–	–
CO_2	0.10	0.0	0.18	0.09
O_2	0.47	0.30	–	–
N_2	3.97	0.65	0.64	0.56
H_2	–	–	–	–
He	–	–	–	–

TABLE 3-11. COMPOSITION OF GAS FROM POCAHONTAS

Site component	No. 1[1]		No. 2		No. 3		No. 4	
	Percent	·	Percent	·	Percent	·	Percent	·
CH_4	97.07	1.75	95.93	1.70	63.1	2.4	97.61	0.24
C_2H_6	1.25	0.58	1.59	0.5	0.85	0.07	1.32	0.23
C_3H_8	0.0011	0.0021	0.0109	0.0337	–	–	0.0027	0.0012
C_4H_{10}[2]	0.0001	0.0003	0.0010	0.0013	–	–	0.0013	0.0005
C_5H_{12}[2]	–	–	Tr[3]	–	–	–	–	–
CO_2	0.20	0.31	0.57	0.21	0.06	0.01	0.30	0.14
O_2	0.16	0.24	0.31	0.40	–	–	0.04	0.05
N_2	2.79	1.74	1.61	1.52	35.96	2.48	0.70	0.12
H_2	0.02	0.02	ND[4]	–	0.006	0.0	–	–
He	0.05	0.02	ND[4]	–	0.03	0.0	0.02	0.02

[1] Numbers refer to table 8
[2] All isomers.
[3] Tr: Trace, less than 1 ppm.
[4] ND: Not determined

TABLE 3-12. COMPOSITION OF GAS FROM WESTERN AND SOUTHERN COALBEDS

Site component	No. 11		No. 12		No. 13	
	Percent	·	Percent	·	Percent	·
CH_4	87.84	3.64	99.22	0.0	96.05	0.21
C_2H_6	0.05	0.05	0.01	0.0	0.01	0.0
C_3H_8	0.0046	0.0092	–	–	–	–
C_4H_{10}	0.0011	0.0022	–	–	–	–
C_5H_{12}	–	–	–	–	–	–
CO_2	11.99	3.6	0.06	0.01	0.1	0.0
O_2	–	–	0.1	0.0	0.05	0.07
N_2	0.09	0.11	0.6	0.0	3.5	0.14
H_2	–	–	–	–	Trace	–
He	–	–	–	–	0.27	0.01

TABLE 3-13. RATIO OF CH_4 TO CO_2

Site No.	Coalbed	CH_4/CO_2
1	Pocahontas No. 3	495
2	Pocahontas No. 3	168
3	Pocahontas No. 3	1,051
4	Pocahontas No. 3	325
5	Pittsburgh	8
6	Pittsburgh	38
7	Pittsburgh	20
8	Pittsburgh	6
9	Upper Kittanning	955
10	Upper Kittanning	550
11	B Seam, Mesaverde Formation	7
12	Lower Hartshorne	1,654
13	Mary Lee	961

shown in Table 3-14. The average methane composition (over all analyzed samples) by coalbed is given in Table 3-15.

TABLE 3-14. HEAT OF COMBUSTION OF COALBED GAS AND NATURAL GAS

Gas	Heat of combustion, Btu/ft^3	Heat of combustion, CO_2 free, Btu/ft^3
Site No.:		
1	[1]1,058	1,061
2	1,053	1,031
3	689	689
4	1,066	1,069
5	949	1,043
6	1,043	1,046
7	1,001	1,011
8	900	1,015
9	1,019	1,019
10	1,059	1,060
11	938	1,066
12	1,058	1,059
13	1,024	1,026
Natural gas	[2]950	-
Natural gas	[3]1,035	-

[1] Calculated from Heat of Combustion for Organic Compounds, Handbook of Chemistry and Physics[4.11]

[2] Fuels and Combustion Handbook[4.12]

[3] Energy in the American Economy, 1850-1975[4.13]

TABLE 3-15. AVERAGE METHANE CONTENT IN THE COAL GAS OF APPALACHIAN COALBED

COALBED	METHANE %	AVERAGE DEPTH OF SAMPLES	NUMBER OF ANALYZED SAMPLES
Pittsburgh	90.75	516	4
Kittanning	97.32	753	2
Pocahontas No. 3	88.42	1,734	4
Mary Lee	96.05	1,070	1

Table 3-15 shows that the Pittsburgh coalbed has one of the lower methane concentrations in Appalachia. Kim did not attempt to make any correlations of the obtained results with parameters such as coalbed depth, age, rank, etc., due to the limited number of analyzed samples. However, the fact that deeper coalbeds are richer in both quantity and quality of gas has been well established. Table 3-15 would show such a trend if it were not for a very low methane content of one of the Pocahontas No. 3 samples (63.1 percent). This sample appears to have been taken from not exactly "virgin" coal but rather from coal near extensive gob areas.

Some very interesting gas composition data from gob areas of Pittsburgh bed mines have been reported by Evans and Thorne (Reference 4.14). These are presented in Table 3-16 (Appendix F). The average methane content of the gob gas in the studied mines is shown in Table 3-17. It is obvious that the methane content of gob gas varies within a

TABLE 3-17. AVERAGE METHANE CONTENT OF GOB COAL GAS IN PITTSBURGH COALBED MINES

MINE	AVERAGE METHANE %	NUMBER OF SAMPLES
HUMPHREY NO. 7	87.07	8
LOVERIDGE	95.57	2
BLACKSVILLE NO. 1	97.44	2
BLACKSVILLE NO. 2	77.52	8

great range. This is attributed to the many different types of gobs and gob conditions. Longwall gobs have much thicker caved roofs than room-and-pillar gobs. Thus, longwall gobs have the most and richest gas, due to liberation from highly disturbed overlying strata, many of which are also gas reservoirs. Among room-and-pillar gobs, the ones created during the phase of retreat (pillar extraction) have more and richer gas than gobs created during the phase of advancement (room opening), again because of more extensive disturbance of overlying strata. Furthermore, the same gob may exist under greatly varying conditions, depending upon the mining practice followed. It may be thoroughly ventilated, in which case its gas content is low and poor in methane. It may be isolated with curtains, permanent stoppings, line brattices, etc., in which cases its gas content is higher and richer in methane. Finally, the gob gas content and composition are obviously functions of the gas content and composition of the virgin coal reserves of the mine which, themselves, vary substantially, as has already been stated. The average methane content of the four mines studied is 84.4 percent, which is considerably higher than the 50 percent assumed in the A. D. Little study (Reference 1.9).

3.3.3 Gas Emission Rates from Appalachian Coalbeds and Pittsburgh Coalbed Mines

Probably the best study on gas emission rates from Appalachian coalbeds has been conducted by Irani et. al., (References 3.1, 3.2). These authors have found that the gas emission rate from a coalbed depends upon:

1. Nature of coalbed and surrounding strata

2. Coal mining rate

3. Mine depth

The Appalachian counties with maximum methane emission rates are given in Table 3-18.

TABLE 3-18. METHANE EMISSION RATES IN APPALACHIA PER COUNTY

COUNTY	DAILY METHANE[1] EMISSION RATE (MMCFD)	
	1971	1973
1. MONONGALIA, W.VA.	39	40.7
2. MARION, W.VA.	30.4	23.1
3. BUCHANAN, VA.	21.6	22.1
4. WASHINGTON, PA.	11.9	12.4
5. GREENE, PA.	11.4	11.7
6. McDOWELL, W. VA.	13.1	11.4
7. CAMBRIA, PA.	N.R.[2]	9.8
8. JEFFERSON, ALA.	10.3	9.5
9. WYOMING, W.VA.	N.R.	6.0
10. MARSHALL, W.VA.	N.R.	4.8
11. INDIANA, PA.	N.R.	4.8
TOTAL	137.7	156.3

(1): PURE METHANE (100%)
(2): N.R.: NOT REPORTED

Similarly, Reference 3.2 reports the maximum emission rates per state and coalbed. Tables 3-19 and 3-20 present these data. All reported figures in Tables 3-18, 3-19 and 3-20 represent volume of pure methane in the ventilating air of mine exhaust fans.

TABLE 3-19. METHANE EMISSION RATES PER STATE

STATE	DAILY METHANE EMISSION RATE IN 1973 (MMCF)
1. WEST VIRGINIA	100.7
2. PENNSYLVANIA	42.0
3. VIRGINIA	27.0
4. ILLINOIS	11.8
5. ALABAMA	11.1
6. OHIO	5.7
7 EAST TENNESSEE	2.6
8. EAST KENTUCKY	0.0
TOTAL	201.8

TABLE 3-20. METHANE EMISSION RATES PER COALBED

COALBED	DAILY METHANE EMISSION RATE IN 1973 (MMCF)
1. PITTSBURGH	99.9
2. POCAHONTAS NO. 3	34.9
3. ILLINOIS NO. 5 AND NO. 6	11.8
4. FREEPORT	10.9
5. KITTANNING	10.5
TOTAL	168

The daily gob gas emission rate from wells for the entire country has been estimated to be 15 MMCFD. A similar figure for gas from virgin coal drainage has not yet been calculated. However, it has been well established that more than 200 MMCFD of methane is lost in mine exhaust fans.

Tables 3-18, 3-19 and 3-20 demonstrate the dependence of gas emission rate upon geographic location and surrounding strata. Irani, et. al., (References 3.1, 3.2), determined the dependence of gas emission rate upon coal mining rate and mine depth by individual correlations for the Pittsburgh, Pocahontas Nos. 3 and 4 and Illinois Nos. 5 and 6 coalbeds. The correlation for the Pittsburgh coalbed is shown in Figure 3-24. The

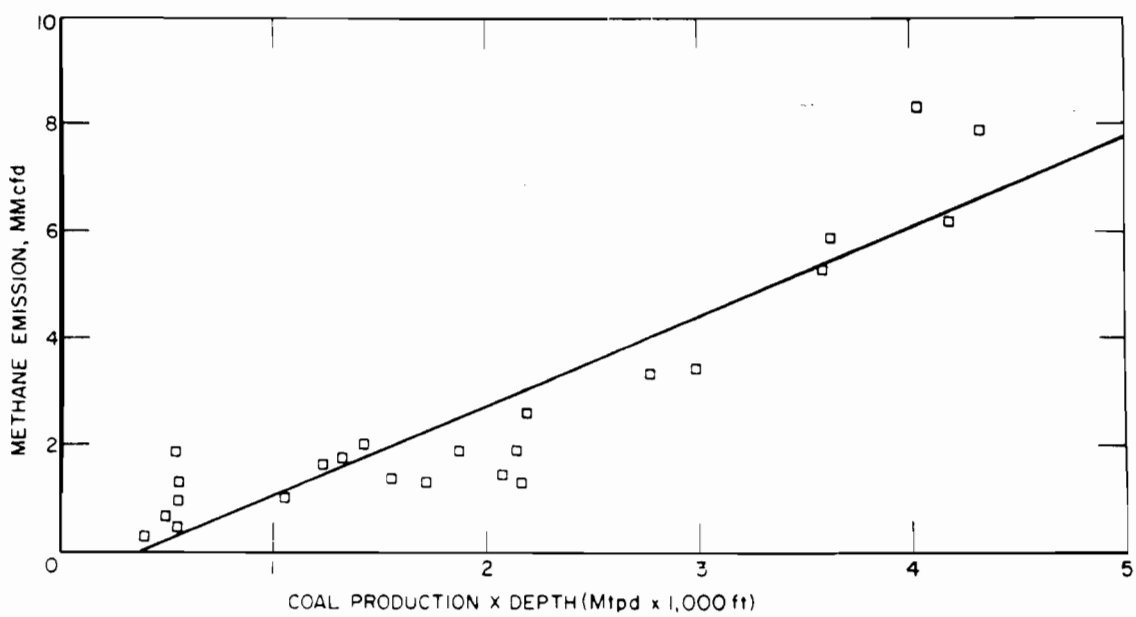


FIGURE 3-24. METHANE EMISSION RATE VERSUS COAL MINING RATE AND MINE DEPTH

mathematical expression of the data fitting curve is:

$$MER\ (Pgh) = -0.649 + 1.67 \cdot CPR \times D, \qquad \text{Equation 3.8}$$

when: $5 \geq CPR \times D \geq 0.388$

In the above equation the symbols stand for:

MER: Methane Emission Rate

CPR: Coal Production Rate

D: Mine Depth.

Emission rates for same depth and mining rate are, declining in bed order: Pittsburgh, Pocahontas, Illinois. Specifically, the above beds emit daily the following percentages of the national methane emission from bituminous coal mines:

Pittsburgh bed	44.5%
Pocahontas Nos. 3 and 4 beds	14.7%
Illinois Nos. 5 and 6 beds	6.6%

Arthur D. Little (Reference 1.9) has calculated 125.6 MMCFD emission rate out of 76 mines in 20 counties in southwestern Pennsylvania, northwestern West Virginia and eastern Ohio. The coal reserves of this area are 18 trillion tons.

In 1971, 28 mines in the Pittsburgh bed with methane emission rates over 1 MMCFD emitted 92.8 percent of all methane from this bed. Most of these mines also emitted over 1 MMCFD methane during 1973. The emission rates and operating characteristics of the Pittsburgh bed mines which scored emission rates over 1 MMCFD either in 1971 or in 1973 are presented in Table 3-21. This table is based on References 3.1 and 3.2. The data of this table are vital in calculating gas content, as shown in the previous section, and gas reserves, as will be shown in the next section.

The fifth section of references furnished a rather complete list of all studies published by the U.S. Bureau of Mines, not only on emission flow rate data but also instrumentation of measurements.

3.3.4 Gas Reserves of the Pittsburgh Coalbed

The exact reserves of any given region such as mine, county, state, etc., can be calculated from knowledge of:

- Gas content per ton in the region

TABL 3-21. METHANE EMISSION RATES AND OPERATING CHARACTERISTICS OF PITTSBURGH COALBED MINES WITH EMISSION RATES OVER 1 MMCFD

MINE RANK[1]	• NAME OF MINE • COUNTY, STATE	• OWNER • DIVISION	CH_4 EMISSION RATE (MMCFD)		AIR CIRCULATION RATE (MMCFD)		COAL PRODUCTION RATE (TONS/DAY)		GAS/TON OF MINED COAL (CF)		NUMBER OF DRIFTS, SHAFTS, SLOPES (1973)	• AVERAGE SHAFT DEPTH • SHAFT DEPTH RANGE (FT)	COALBED THICKNESS (INCHES)	MINE AGE (YEARS)	MINING METHOD (1975)	COAL PRINCIPAL APPLICATION(S)	COAL PROXIMATE ANALYSIS
			1971	1973	1971	1973	1971	1973	1971	1973							
1	OVERIDGE MARION, W VA	CONSOL MOUNTAINEER	12.2	12.1	2,527	2,890	7,062	10,000	1,724	1,210	5 SHAFTS 1 SLOPE	721	96, 84	27	R&P[3] 15 C. M.[4] R&P 5 CUT.[5]	STEAM	MOIST. 3.48%, VOL. MAT. 39.85%, FIX. C. : 50.04%, ASH : 6.83%, SULF. : 2.53%, BTU : 13,589, ASH SOFT. TEMP. : 2,140 °F
2	UMPHREY NO. 7 ONONGALIA, W VA GREENE, PA	CONSOL CHRISTOPHER	10.7	9.6	2,034	2,153	9,200	12,000	1,165	800	1 DRIFT 6 SHAFTS	446 (225-568)	90, 84	23	R&P 12 C. M. R&P CUT.		
3	RKRIGHT ONONGALIA, W VA	CONSOL CHRISTOPHER	3.4	7.3	1,011	1,695	9,166	9,000	373	811	1 DRIFT 5 SHAFTS	332	84, 90	56	R&P 8 C. M. R&P 6 DR.[6]		
4	EDERAL NO. 2 ONONGALIA, W. VA	EASTERN	8.1	6.7	1,331	1,380	4,700	4,700	1,722	1,426	3 SHAFTS	788 (734-842)	90, 78	11	LW[7] 1 S. M.[8] R&P 9 C. M.		
5	EDERAL NO. 1 MARION, W VA	EASTERN	5.1	5.7	1,696	1,926	7,666	7,000	665	814	8 SHAFTS	488 (260-637)	82	36	LW 1 S. M.[8] R&P 9 C. M., 8 DR SW 1		
6	LACKSVILLE NO. 2 ONONGALIA, W VA	CONSOL BLACKSVILLE	2.5	5.4	791	1,358	3,400	5,000	971	1,080	2 SHAFTS	713 (711-716)	78	9	LW 1 S. M. R&P 8 C. M.	STEAM	
7	LACKSVILLE NO. 1 ONONGALIA, W VA , GREENE, PA	CONSOL BLACKSVILLE	6.0	5.2	1,043	1,120	4,725	2,600	1,273	2,000	4 SHAFTS	725 (650-800)	78	11	R&P 8 C. M.	STEAM	
8	ISAGE NO. 3 ONONGALIA, W VA	CONSOL CHRISTOPHER	7.0	5.1	1,630	1,421	9,400	9,500	741	537	1 DRIFT 4 SHAFTS	441 (280-623)	96, 90	62	R&P 8 C. M. R&P 8 DR.		
9	OBENA GREENE, PA	U. S. STEEL	4.3	4.9	3,541	4,565	15,036	14,295	282	343	12 SHAFTS 1 SLOPE	556 (445-667)	84, 93	40	R&P 32 C. M.		
10	GATEWAY GREENE, PA	GATEWAY	2.6	2.9	1,265	1,925	7,410	6,910	347	420	2 SLOPES 6 SHAFTS	375 (50-700)	84, 78	60	LW 1 S. M. R&P 11 C. M. R&P DR		MOIST. 1.8%, VOL. MAT. : 35%, FIX. C. : 60%, ASH : 5%, SULF. 1.35%, BTU : 14,000
11	SHANNOPIN GREEN, PA	J&L STEEL VESTA SHANNOPIN	2.9	2.5	1,875	1,779	5,377	4,000	530	625	10 DRIFTS 5 SHAFTS	225 (0-450)	56, 78, 8	52	R&P 4 C. M. R&P 10 DR.		MOIST. 1.8%, VOL. MAT. : 37.0%, FIX. C. : 56.0%, ASH 7.0%, SULF. 1.70%, BTU : 13,750
12	ROBINSON RUN NO. 95 HARRISON, W VA	CONSOL MOUNTAINEER	1.1	2.4	694	1,239	9,000	12,000	127	200	10 DRIFTS 2 SHAFTS	300	72-92	12	LW 1 S. M. R&P 16 C. M.	STEAM	MOIST. 4.19%, VOL. MAT. : 40.72%, FIX. C. 48.11%, ASH 6.98%, SULF 2.89%, BTU : 13,413, ASH SOFT. TEMP 2,100 °F
13	MARIANA NO. 55 CAMBRIA, PA	BETHLEHEM	2.3	2.3	885	1,701	7,362	5,500	296	418	9 SHAFTS	399 (385-413)	60,65	57	R&P 9 CUT. R&P CON. M.[9]		
14	CONSOL NO. 20 MARION, W VA	CONSOL MOUNTAINEER	1.4	2.1	635	935	3,700	4,498	376	467	7 SHAFTS	398 (267-530)	84	68	LW 1 S. M. R&P 6 C. M.	STEAM	
15	IRELAND MARSHALL, W VA	CONSOL OHIO VALLEY	1.8	2.1	1,630	1,570	9,666	10,000	188	210	2 SLOPES 6 SHAFTS	370	62, 66	18	R&P 20 C. M.		
16	MATHIES WASHINGTON, PA	MATHIES	1.9	2.1	1,625	1,844	9,475	9,250	190	227	1 DRIFT 7 SHAFTS	175 (0-350)	42, 60	35	R&P 12 C. M. R&P 9 DR.		
17	JOANNE MARION, W VA	EASTERN	2.0	1.9	738	1,114	3,585	3,760	544	505	4 SHAFTS	484 (354-455)	84, 88	62	R&P 6 C. M.		
18	CLYDE WASHINGTON, PA	REPUBLIC STEEL	1.2	1.7	232	1,123	3,275	2,843	378	598	2 DRIFTS 5 SHAFTS	487 (450-525)	50, 72	40	R&P C. M. R&P DR.		
19	SOMERSET NO. 60 WASHINGTON, PA	BETHLEHEM	1.5	1.7	962	1,423	5,217	5,200	279	327	6 SHAFTS 1 SLOPE	605 (450-760)	48, 65	74	R&P CON. M.		
20	VESTA NO. 5 WASHINGTON, PA	J&L STEEL VESTA SHANNOPIN	1.9	1.6	1,229	1,575	2,925	2,400	658	667	7 DRIFTS 6 SHAFTS 1 SLOPE	250 (0-500)	84, 68	36	R&P 7 C. M. R&P 9DR		MOIST. : 1.8%, VOL. MAT. 35%, FIX. C. : 60%, ASH : 5.0%, SULF. : 1.35%, BTU : 14,000
21	PURSGLOVE MONONGALIA, W VA	CONSOL CHRISTOPHER	1.3	1.4	583	938	5,166	4,800	243	292	5 SHAFTS 2 SLOPES	394 (292-496)	96, 84	60	R&P 5 C. M. R&P 5 DR.		
22	VALLEY CAMP NO. 3 OHIO, W VA	VALLEY CAMP	1.3	1.4	728	643	4,533	4,533	282	309	4 SHAFTS 1 SLOPE	471 (350-600)	63, 58	61	R&P 5 C. M. R&P 1 CON. M		
23	MELROY MARSHALL, W VA	CONSOL OHIO VALLEY	0.8	1.0		592		7,400		135	1 SHAFT 7 SLOPES		62, 66	8	R&P 13 C. M		
24	MONTOUR NO. 1 WASHINGTON, PA	CONSOL PITTSBURGH	1.1	1.0	958	1,344	8,450	8,400	130	119	6 SHAFTS 2 SLOPES	145 (92-198)	52, 68	55	R&P 7 C. M R&P 2 DR		
25	SHOEMAKER MARSHALL, W VA	CONSOL OHIO VALLEY	0.3	1.0		1,252		6,660		150	1 DRIFT 2 SHAFTS 1 SLOPE	290	62, 66	12	R&P 11 C. M 9 CON. M		
26	MAPLE CREEK WASHINGTON, PA	U. S. STEEL	1.1	0.9	1,338		11,605	5,727[2]	95	–	3 DRIFTS 5 SHAFTS 1 SLOPE	230	96		R&P 17 C. M.	METALLURGY	
27	CONSOL NO. 93 MARION, W VA	CONSOL CHRISTOPHER	1.2	0.8	709	–	3,800	1,738[2]	312	–	2 DRIFTS 2 SHAFTS	226 (201-252)	78, 82		R&P 4 C. M. R&P 4 DR.		
28	NEMACOLIN GREENE, PA	BUCKEYE	1.0	0.5	1,344		5,946	3,052[2]	171		5 SHAFTS 1 SLOPE	466 (445-488)	80	58	R&P 7 C. M.	METALLURGY	MOIST. 5.8%, VOL. MAT. : 34.85%, ASH : 7.7%, SULF. 1.6%, BTU : 14,000
29	WILLIAMS MINE NO. 98 HARRISON, W VA	CONSOL MOUNTAINEER	1.0	0.2	918	–	5,000	2,030[2]	200	–	10 SHAFTS 1 SLOPE	111 (20-202)	96, 78		R&P 5 C. M R&P 5 CUT	STEAM	MOIST. 3.48%, VOL. MAT. : 39.69%, FIX. C. 49.89%, ASH 6.94%, SULF. 2.46%, BTU : 13,510 ASH SOFT. TEMP. 2,110 °F
30	CONSOL NO. 9 MARION, W VA	CONSOL MOUNTAINEER	8.0	–	–	–	9,500	268[2]	833	–	7 SHAFTS	456	80	55	R&P 1 C. M. R&P 3 DR.	STEAM	MOIST. 3.78%, VOL. MAT. : 39.06%, FIX. C. : 50.08%, ASH : 7.16%, SULF 2.70%, BTU : 13,521, ASH SOFT. TEMP 2,100 F

FOOTNOTES

(1) MINES RANKED ACCORDING TO CH_4 EMISSION RATE OF 1973
(2) BASED ON 365 WORKING DAYS PER YEAR
(3) R&P ROOM & PILLARS
(4) C. M. CONTINUOUS MINER
(5) CUT CUTTER
(6) DR. DRILL
(7) LW LONGWALL
(8) S. M. SHEAR MINER
(9) CON. M. CONVENTIONAL MINER

- Surface area of the region
- Bed thickness underlying the region

Gas content data were given in Section 3.3.1. Bed thickness data per geographic location were presented in Section 3.1.4.4. For simplification of gas reserves calculations, Table 3-22 is included, based on Reference 6.4. This table gives the gas volume contained in one square mile of a coalbed with thicknesses of 1, 3, 6, and 50 feet, when the gas content is 50, 75, 100, 300, 400, 500, 600 and 650 cu. ft./ton.

TABLE 3-22. COAL GAS RESERVES AS A FUNCTION OF COALBED THICKNESS AND GAS CONTENT

	VOLUME	ACRE-FOOT	1 FT/SQ MI	3 FT/SQ MI	6 FT/SQ MI	50 FT/SQ MI
	COAL, TONS	1.800	1.15×10^6	3.45×10^6	6.0×10^6	57.5×10^6
GAS CONTENT IN CUBIC FEET PER TON OF COAL	50	90×10^3	58×10^6	173×10^6	345×10^6	2.9×10^9
	75	135×10^3	87×10^6	255×10^6	515×10^6	4.3×10^9
	100	180×10^3	115×10^6	345×10^6	690×10^6	5.8×10^9
	200	360×10^3	230×10^6	690×10^6	1.4×10^9	11.6×10^9
	300	540×10^3	345×10^6	1×10^9	2×10^9	–
	400	720×10^3	460×10^6	1.4×10^9	2.7×10^9	–
	500	900×10^3	575×10^6	1.7×10^9	3.4×10^9	–
	600	1.1×10^6	690×10^6	2×10^9	4.1×10^9	–
	650	1.2×10^6	748×10^6	2.2×10^9	4.5×10^9	–

Coal gas reserves of the entire Pittsburgh bed have been estimated in several studies. Results differ greatly, indicating that different assumptions were made regarding local bed thickness and gas content. Deul, in one of his numerous review articles (Reference 6.1) estimates the reserves at 600 billion cu. ft. He states that these reserves are contained in an area of 575 sq. mi., with gas content varying from 50 to 200 cu. ft./ton. On the other hand, the A. D. Little study (Reference 1.9) estimates the Pittsburgh coalbed gas reserves at over 4 trillion cu. ft. ($4{,}050 \cdot 10^9$ cu. ft.), assuming an average gas content of 225 cu. ft./ton, contained in 18 trillion tons of coal.

Kim has calculated the total amount of gas contained in the virgin coal reserves of Pittsburgh coal in Washington (Reference 3.5) and Greene (Reference 3.6) counties. Her data base and results are shown in Table 3-23. The gas reserves of Pittsburgh coal under current mining in active mines or in panels of abandoned mines have not been included.

3.3.5 Gas Migration and Emission Mechanisms - Gas Production Decline Curves

Section 3.3.1 stated that any coalbed processes gas reservoir capacity is associated with sound matrix and fracture porosity. In the

TABLE 3-23. ESTIMATED METHANE CONTENT AND RESERVES IN VIRGIN PITTSBURGH COAL OF WASHINGTON AND GREENE COUNTIES, PA.

LOCATION	ESTIMATED AREA OF VIRGIN COAL RESERVES (ACRES)	AVERAGE THICKNESS (ft)	ESTIMATED TONNAGE (10^6 TONS)	ESTIMATED CH_4 CONTENT (ft^3/ton)	ESTIMATED CH_4 RESERVES (10^9 ft^3)
WASHINGTON					
WASHINGTON EAST	20,190	5.5	199.9	60	11.94
BETHANY	4,940	5.0	44.5	80	3.56
VALLEY GROVE	4,940	5.0	44.5	90	4.01
MAJORSVILLE	1,580	5.0	14.2	95	1.35
WIND RIDGE	7,410	5.0	66.7	95	6.34
W. MIDDLETOWN	35,821	5.0	322.4	80	25.79
CLAYSVILLE	36,333	6.0	392.4	95	37.29
WASHINGTON WEST	20,982	5.66	213.8	60	12.82
PROSPERITY	34,800	6.00	375.8	90	33.82
AMITY	8,648	5.5	85.6	85	7.28
SUB-TOTAL	175,644				144.2
GREENE					
MAJORSVILLE	3,430	5.5	34.0	130	4.4
CAMERON	5,145	6.0	55.6	150	8.3
LITTLETON	1,102	5.5	10.9	150	1.6
WIND RIDGE	27,685	6.0	299.0	140	41.9
NEW FREEPORT	38,750	8.0	529.2	175	92.6
HUNDRED	7,840	7.0	98.7	180	17.8
ROGERSVILLE	36,015	7.0	453.8	130	59.0
HOLBROOK	36,750	8.0	529.2	150	79.4
WADESTOWN	7,840	6.0	84.7	190	16.1
AMITY	2,205	5.5	21.8	90	2.0
OAK FOREST	22,050	8.0	317.5	125	39.7
WAYNESBURG	12,250	7.0	154.4	100	15.4
SUB-TOTAL	199,062				378.2
TOTAL	374,706				522.4

first case, gas is absorbed on the internal free surface of the sound matrix. Deul and Kissell (Reference 6.6) report internal free surface density equal to 100 m^2/gr. Marsh (Reference 7.13) elevates this density to 200 or 300 m^2/gr. (2,150 to 3,230 sq. ft./gr.). The internal free surface is a folded plane of matrix discontinuity. According to Anderson, et. al., (Reference 7.14), the gap of matrix continuity along the internal free surface is 5 Angstrom wide. Gas absorbed and stored on the internal free surface of coal migrates according to Fick's law of diffusion:

$$\frac{\partial q}{\partial t} = -DA \frac{\partial C}{\partial L} \qquad \text{Equation 3.9}$$

Where:

q = volume flow rate (cm^3/sec)

D = diffusion coefficient (cm^2/sec)

A = cross-sectional area (cm^2)

C = concentration of coal gas in solid coal (cm^3 of gas/cm^3 of coal)

t = time (sec)

L = migration distance (cm)

The driving force for migration by diffusion is the concentration gradient of the gas along the direction of migration. The diffusion coefficient is of the order of 10^{-13} cm^2/sec.

Whereas the migration of gas along the internal free surface obeys the diffusion law, the rate of desorption (or detachment) of the gas from any particular area segment of the free surface obeys the Langmuir (Reference 7.15) equilibrium absorption isotherm. In the original kinetic derivation the absorbed monolayer of gas on the solid free surface is regarded as being in dynamic equilibrium with the gas phase into the gap created by the free surface. The number of gas molecules, μ , striking the unit of coal surface per unit time, is found by kinetic theory to be:

$$\mu = \frac{P}{(2\Pi\ MKT)^{\frac{1}{2}}} \qquad \text{Equation 3.10}$$

Where:

P = equilibrium pressure ($gr./cm^2$)

M = gaseous mass (gr.)

K = Boltzman constant

T = absolute temperature

The molecules striking surface sites already occupied will immediately be reflected. A fraction, α , of the molecules striking empty surface sites will be held by surface forces for a finite time, considered as absorbed. The remainder will be reflected. If the fraction of sites already filled is θ , then the total empty sites offered for adhesion are $(1-\theta)$, the sites which will indeed sustain absorption are $x(1-\theta)$, and the rate at which molecules pass into the absorbed state is $\mu x(1-\theta)$. If the rate of desorption from a fully covered surface is ν , then the rate of desorption from the actual covered surface is $\nu\theta$. At equilibrium the number of molecules in the absorbed state at any instant is constant, therefore:

$$\mu\alpha(1-\theta) = \nu\theta \qquad \text{Equation 3.11}$$

Substituting μ from Equation 3.10 into Equation 3.11 gives

$$\frac{\alpha P}{\nu(2\Pi MKT)^{\frac{1}{2}}} = \frac{\theta}{(1-\theta)} \qquad \text{Equation 3.12}$$

This equation is known as the Langmuir absorption isotherm.

The gas reservoir capacity of coal associated with fracture porosity is similar to that of fractured shale gas reservoirs. Here the stored gas occupies natural macrofractures, usually in the form of vertical continuity failure planes parallel to the face cleat. Gas migration through macrofractures obeys Darcy's law:

$$q = \frac{KA}{\mu} \frac{\partial P}{\partial L} \qquad \text{Equation 3.13}$$

Where:

K = fracture permeability coefficient (Darcy)

μ = gas viscosity coefficient (centipoise)

P = gas pressure (atm)

and q, A and L as defined in Equation 3.9.

The driving force for transport according to Darcy's law is the pressure gradient of the gas along the direction of migration. The equilibrated concentration of gas in solid coal, C_o , and the equilibrium gas pressure, P , are related (over a limited range of pressures) by the empirical equation

$$C_o = bP^n \qquad \text{Equation 3.14}$$

Where:

C_o = equilibrium gas concentration (cm^3 of gas/cm^3 of coal)

b = empirical constant

n = empirical constant

Equation 3.14 indicates that there is a balance between gas pressure in the macrofractures and gas concentration in the coal matrix. When gas evacuates the macrofractures migrating outside the coalbed, the pressure is reduced and the balance is upset. Gas then starts bleeding from the matrix into the macrofractures, until the reduced concentration and the reincreased pressure reach a new balance.

Most coalbeds have a rather constant gas reservoir pressure throughout their body. The Pittsburgh coalbed has gas pressure of the order of 260 psig, whereas the Pocahontas No. 3 bed has a gas pressure greater than 550 psig.

Several important data for transport considerations are given below:

- The saturation volume of methane absorbed (experimentally) on the internal surface area of coal, for gas pressures between 1500 and 7500 psig, is 21.34 $cm^3/gr.$ (684 cu. ft./ton). This is approximately 28 times the volume absorbed at standard conditions. Thus, an acre-foot of coal, at gas pressures greater than 1500 psig, contains approximately 1.2 million standard cu. ft. of methane.

- The fracture spacing of the Pittsburgh coalbed is of the order of 6 inches.

- At atmospheric pressure fine coal (275-324 mesh) absorbs all its gas in about one hour. One-quarter-inch coal requires 30 days. One-half-inch coal requires six months to one year.

- One ton of coal occupies 25 cu. ft.

- The permeability coefficient of deep coalbeds is only a few tenths of a millidarcy. Kissell (Reference 7.7) has calculated at Federal Mine No. 2 (800 ft. overburden) permeability equal to 0.7, 7.7, 33, 82.5, and 181 md, depending upon direction.

- Cervik (Reference 7.11) has reported the gas production decline curve of Figure 3-25, based on the performance of a group of 20 wells drilled into the Pittsburgh coalbed. These wells are spaced at 1500-foot centers. This curve is a typical constant percentage decline curve. Initial production rates were of the order of 15 to 20 MMCFD, and the economic life is of the order of 35 to 40 years.

The seventh section of references gives a rather complete list of U. S. Bureau of Mines publications on transport considerations.

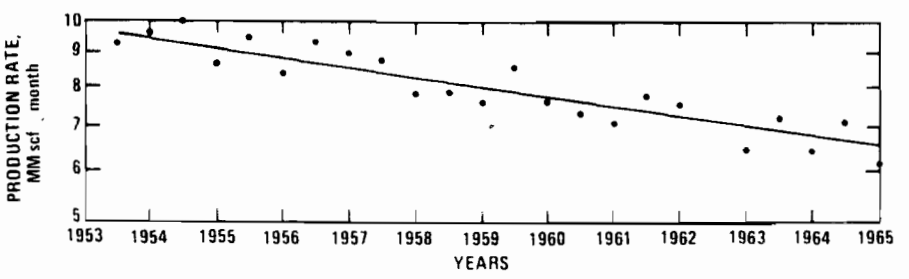


FIGURE 3-25. PRODUCTION DECLINE CURVE FOR COAL GAS WELLS IN THE PITTSBURGH COALBED

3.4 SELECTION OF A GROUP OF MINES FOR THE SYSTEM ANALYSIS OF THE PRESENT STUDY

This section describes the selection and acquisition of site-specific data packages. Information presented in the previous sections will be cited in the selection process, and the criteria to be utilized are:

- Mine location
- Mine classification as a major or minor producer, with respect to both coal gas and coal
- Particular type of mining method employed
- Particular type of drainage technique used in the mine
- Accessibility to the mine for coal gas drainage studies, determined by willingness of the owner company to cooperate in this program

Possible choices available for the decision are:

1. Develop data packages for all major mines
2. Develop data packages for a representative sample of major mines
3. Develop data packages for a representative sample of major and minor mines

The major area selected for this study has already been shown in Figure 3-1. Thus, mines to be selected must be located within this major area. Mines with the most immediate interest obviously are major coal gas producers. Irani, et. al., (References 3.1, 3.2), have reported all underground mines in the nation with methane emission rate over 0.1 MMCFD. There are 48 such mines in the Pittsburgh coalbed underlying the Pennsylvania and West Virginia counties shown in Figure 3-1, and six more such mines are within the Ohio counties shown in Figure 3-1. It was decided not to include all these mines in the present study phase, since many of these mines are minor coal producers and minimal data have been published about them or are even available to their owners. Thus, it was decided to consider only mines with methane emissions rates exceeding 1 MMCFD. Irani, et. al., have reported emission data for 1971 and 1973. Several mines had emissions over 1 MMCFD only in one of the above years. In the present report all mines examined had emissions over 1 MMCFD either in 1971 or in 1973. There are 30 such mines in Pennsylvania and West Virginia and none in Ohio.

Mining methods employed in these 30 mines are room-and-pillar, advancing longwall, retreating longwall, and shortwall. One of these methods is excluded in the present study. On the contrary, it was deemed highly desirable to develop as many comparative data as possible.

The particular types of drainage techniques employed in some of these 30 mines are:

- Controlled air flow through curtains, brattices, permanent stoppings, etc.
- Panel isolation and gas removal either periodically from the surrounding headings or continuously from vertical or horizontal boreholes within the isolated panel
- Vertical boreholes from the surface to virgin coal reserves or gobs
- Horizontal boreholes from production faces to the coal reserves under immediate mining
- Horizontal boreholes from ribs of headings to virgin coal reserves
- Deviated wells (or slant holes) from the surface to the coalbed virgin reserves
- Horizontal boreholes from headings and water infusion

Only the first and last of the above techniques is excluded from the present study. These two methods aim at removal of coal gas from the mine workings, but render impossible the collection and utilization of coal gas.

Finally, with respect to the criterion of mine accessibility due to owner's policy, the above 30 mines are treated on two different levels of vigor and detail. First, all data published on all 30 mines are collected and presented as background information for the system analysis. Second, only very few mines owned by companies which cooperated in preparation of this report are treated in great detail, as potential sites for coal gas drainage field demonstrations. The 30 candidate mines are listed in Table 3-21.

3.5 DATA PACKAGES FOR THE SELECTED MINES

This section presents data packages for the 30 mines discussed in the previous section. The purpose of these packages is to provide an adequate data base to quantify methane production associated with mining and to allow selection of sites for demonstration of Production, Collection, Conversion and/or Utilization (PCCU) systems.

Each data package includes four types of input: (1) data pertaining to the location and locale of the mine; (2) data pertaining to the mining and drainage technique; (3) data pertaining to the coal, and (4) data pertaining to the gas.

3.5.1 Terrain Data

Table 3-24 provides a summary of the data and additional information where related information may be found in the report.

TABLE 3-24. REFERRAL TABLE TO TEXT CITATIONS OF LOCATION AND LOCALE DATA FOR SELECTED MINES

TYPE OF DATA	TEXT CITED
1. Lease Boundary	Figs. 3-17, 3-18, 3-19, 3-20, 3-21, 3-22, 3-23, 3-27
2. Depth of Mine	Table 3-21
3. Underground Mine Plan	*
4. County of Location	Tables 3-5, 3-21
5. Latitude and Longitude of Main Portals	Table 3-25
6. Transportation Systems To and From the Mine	Table 3-5, Figs. 3-18, 3-19, 3-20
7. Water Availability and Quantity	Figs. 3-30, 3-31
8. Terrain	Figure 3-12
9. Vegetation	Figure 3-28
10. Abandoned Mines	Appendix H
11. Environmental Regulations	Table 3-27
12. Ownership of Gas Rights	Table 3-5
13. Expected Lifetime of Mining Operations	*
14. Planned Extension or New Mines on the Leasehold	
15. Underground Proximity of Other Mines With Common Drainage Paths or Methane Sources	Figs. 3-17, 3-18, 3-19, 3-20, 3-22, 3-23
16. Lithological and Structural Description of Overburden	Secs. 3.1.4.2, 3.1.4.6, Figs. 3.5, 3.6, 3.7
17. Depth to the Top of Coalbed	Sec. 3.1.4.5, Figs. 3-11, 3-28, 3-29, Table 3-21

*Data has been requested but not received, will be included when available

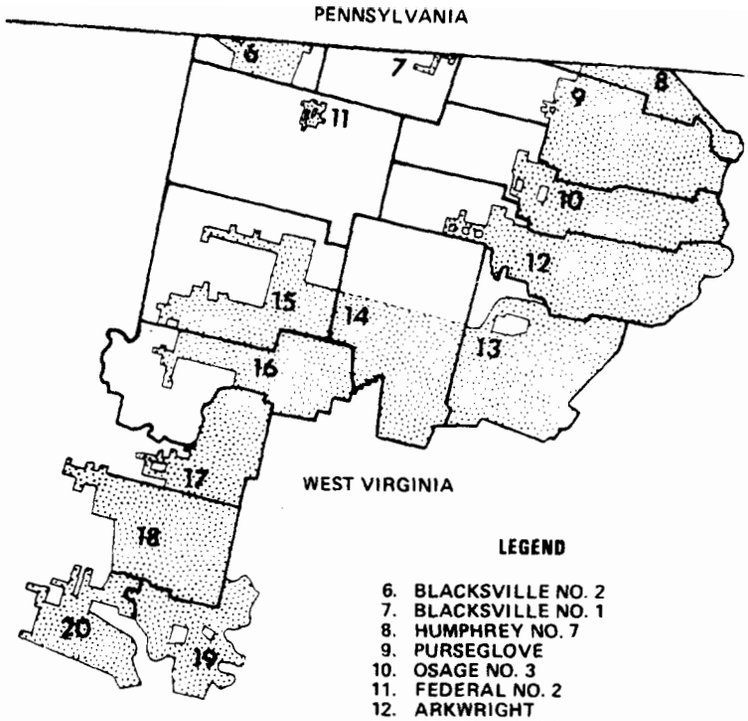
3.5.1.1 Location and Locale

The location of major West Virginia mine main portals is provided in Table 3-25. Figures 3-26 and 3-27 show lease boundaries.

TABLE 3-25. COORDINATES OF WEST VIRGINIA ACTIVE MINE PORTALS IN LATITUDE AND LONGITUDE DEGREES

MINE	TYPE OF PORTAL	LATITUDE			LONGITUDE			QUAD-RANGLE
		DEGREES (°)	MINUTES (′)	SECONDS (″)	DEGREES (°)	MINUTES (′)	SECONDS (″)	
LOVERIDGE	SHAFT	39	36	20	80	16	20	MANNINGTON
HUMPHREY NO. 7	DRIFT	39	44	15	80	3	36	OSAGE
ARKRIGHT	DRIFT	39	37	52	80	8	3	BLACKSVILLE
FEDERAL NO. 2	SHAFT	39	40	30	80	19	0	WADESTOWN
FEDERAL NO. 1	SHAFT	39	36	33	80	11	52	GRANT TOWN
BLACKSVILLE NO. 2	SHAFT	39	42	35	80	17	35	WADESTOWN
BLACKSVILLE NO. 1	SHAFT	39	42	58	80	11	24	BLACKSVILLE
OSAGE NO. 3	DRIFT	39	41	0	80	8	49	BLACKSVILLE
ROBINSON RUN NO. 95	DRIFT	39	24	9	80	21	47	SHINNSTON
MOUNTAINEER NO. 20	SHAFT	39	29	52	80	22	43	WALLACE
IRELAND	SHAFT	39	53	4	80	43	23	MOUNDSVILLE
JOANE	SHAFT	39	31	12	80	18	1	MANNINGTON
PURSGLOVE	SLOPE	39	39	58	80	0	57	OSAGE
VALLEY CAMP NO. 3	SHAFT	40	1	13	80	30	21	VALLEY GROVE
McELROY		39	49	15	80	47	43	POWHATAN POINT
SHOEMAKER		40	0	13	80	42	40	WHEELING
CHRISTOPHER NO. 93	DRIFT	39	33	05	80	05	10	RIVERSVILLE
WILLIAMS-MINE NO. 98	SLOPE	39	25	21	80	17	46	SHINNSTON
MOUNTAINEER NO. 9	SHAFT	39	33	43	80	16	9	MANNINGTON

*FROM REF. 2.12



LEGEND

6. BLACKSVILLE NO. 2
7. BLACKSVILLE NO. 1
8. HUMPHREY NO. 7
9. PURSEGLOVE
10. OSAGE NO. 3
11. FEDERAL NO. 2
12. ARKWRIGHT
13. CONSOL NO. 93
14. FEDERAL NO. 1 (INCOMPLETE)
15. LOVERIDGE
16. CONSOL NO. 9
17. JOANNE
18. CONSOL NO. 20
19. WILLIAMS
20. ROBINSON RUN

FIGURE 3-26. LOCATION AND LEASE BOUNDARIES OF MAJOR UNDERGROUND PITTSBURGH COALBED MINES IN NORTHERN WEST VIRGINIA, BY PENNSYLVANIA BORDER

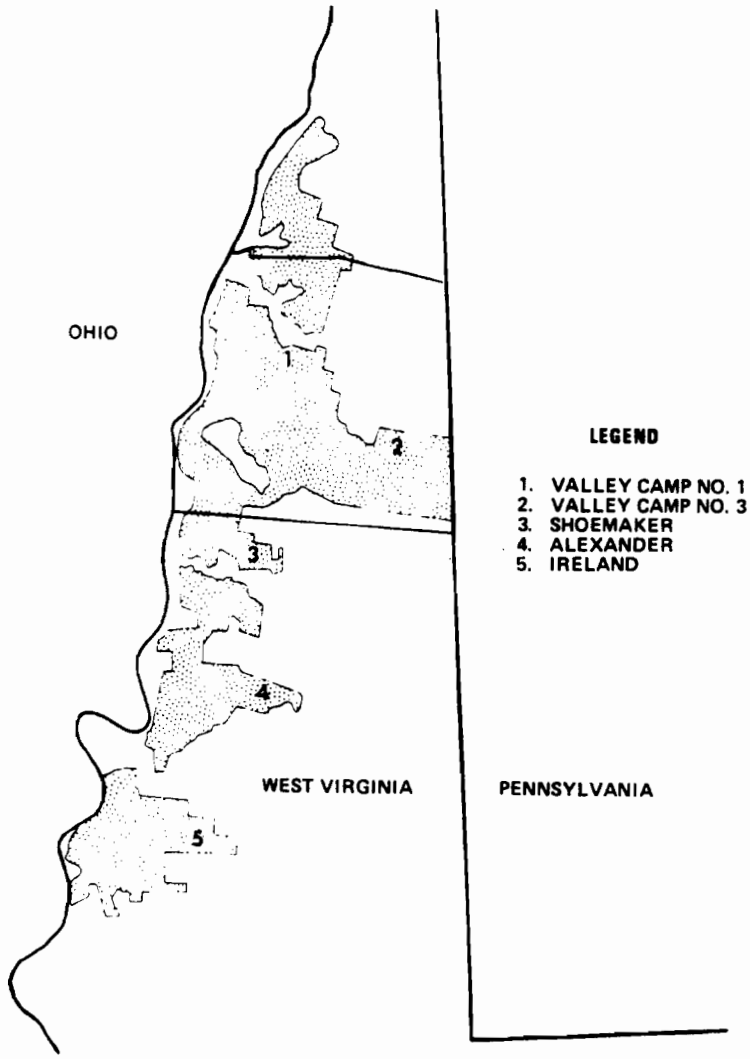


FIGURE 3-27. LOCATION AND LEASE BOUNDARIES OF MAJOR UNDERGROUND PITTSBURGH COALBED MINES IN NORTHERN WEST VIRGINIA, BY OHIO BORDER

3.5.1.2 Major Abandoned Mines

Major abandoned mines are identified in Table 3-26.

TABLE 3-26. MAJOR ABANDONED MINES IN THE PITTSBURGH COALBED OF WEST VIRGINIA

MINE	COUNTY	QUADRANGLE
BEECH BOTTOM	BROOKE	TILTONSVILLE
CONSOL NOS. 21, 25, 27, 29, 31, 33, 48, 50, 51, 52, 55, 58, 62, 69, 70, 77, 78, 91, 94	HARRISON	CLARKSBURG
CONSOL NOS. 23, 40, 42, 54, 76, 88, 89, 90, 98	HARRISON	SHINNSTON
CONSOL NOS. 35, 50, 62, 94	HARRISON	WOLF SUMMIT
CONSOL NOS. 39, 44, 46, 60, 64	HARRISON	MOUNT CLARE
CONSOL NOS. 32, 61, 65	HARRISON	FAIRMONT WEST
DAWSON COAL CO MINES	HARRISON	CLARKSBURG
ERIE	HARRISON	CLARKSBURG
KATHERINE	HARRISON	CLARKSBURG
MCCANDLISH	HARRISON	CLARKSBURG
CONSOL NOS. 38, 96	MARION	GRANT TOWN
CONSOL NOS. 22, 34, 36, 47, 53, 56, 59, 68, 74, 75	MARION	FAIRMONT WEST
CONSOL NOS. 28, 43, 63, 67, 84, 86, 92	MARION	SHINNSTON
CONSOL NOS. 24, 73, 97	MARION	RIVESVILLE
DAKOTA	MARION	GRANT TOWN
MONUNGAH NOS. 6, 8	MARION	FAIRMONT WEST
MORGAN	MARION	RIVESVILLE
MONTANA	MARION	RIVESVILLE
HITCHMAN	MARSHALL	MOUNDSVILLE
PANAMA (OR BEN FRANKLIN)	MARSHALL	MOUNDSVILLE
WHEELING STEEL AND IRON MINE	MARSHALL	WHEELING
RICHLAND	OHIO	WHEELING
BOOTH NO. 1	MONONGALIA	RIVESVILLE
EMILY	MONONGALIA	MORGANTOWN NORTH
KELLEYS CREEK COLLIERY	MONONGALIA	MORGANTOWN NORTH
NATIONAL FUEL NO. 1	MONONGALIA	RIVESVILLE
ROSEDALE	MONONGALIA	MORGANTOWN NORTH

3.5.1.3 Pipeline and Natural Gas Data

Table 3-27 provides information on the location of natural gas pipelines with respect to major mines and, as furnished by Mr. James Tilton of Equitable Gas and cited in the Pennsylvania mine and gas pipeline map of Appendix E, the owners of natural gas rights of the properties listed.

3.5.1.4 Coalbed Thickness and Overburden

Figures 3-28 and 3-29 identify coalbed thickness and overburden at selective locations in Washington and Greene Counties, Pennsylvania.

3.5.1.5 Surface Drainage

Figures 3-30 and 3-31 show surface running waters in Washington and Greene counties, Pennsylvania.

3.5.1.6 Vegetation

Figures 3-32, 3-33 and 3-34, contained in Appendix G, show the vegetation existing in the area overlying the Pittsburgh coalbed.

3.5.1.7 Coal Cleat Systems

Figure 3-35 illustrates the coal cleat system in mines operating in the Pittsburgh coalbed.

3.5.2 Mining and Drainage Practices

Table 3-28 presents the type and data gathered for mining and drainage practices of the selected mines and refers to tables, figures and text sections which present these data. Most data gathered and compiled on mining and drainage practices have never been published before. They were obtained through numerous visits to mining companies, telephone conversations with mine superintendents and headquarters engineers, and by circulation of an extensive questionnaire among the above mining circles. This questionnaire is included as Appendix I. Data of this nature are currently being compiled, and will be added at a later date when complete.

3.5.3 Coal Properties and Characteristics

Table 3-29 shows the type of data gathered for coal properties, with characteristics of the selected mines, and refers to tables, figures and text sections presenting these data. Thereafter, the data which were not introduced in previous sections are reported in Table 3-29.

3.5.4 Gas Properties and Characteristics

Table 3-30 presents the type of data gathered for gas characteristics of the selected mines, and refers to tables, figures, and text sections which present data.

TABLE 3-27. MAJOR OWNERS OF NATURAL GAS RIGHTS IN NORTHERN APPALACHIAN MINES

MINE COUNTY, STATE	OWNER COAL CO. DIVISION	MAJOR OWNERS OF NATURAL GAS RIGHTS ON THE ACREAGE OF THE MINE	UTILITY COMPANIES HAVING GAS PIPELINES LAID ON THE ACREAGE OF THE MINE
LOVERIDGE MARION, W. VA.	CONSOL MOUNTAINEER	EQUITABLE, HOPE, CARNEGIE, MOUNTAINEER, INDEPENDENT	HOPE (6"),* EQUITABLE (12"), CARNEGIE (12")
HUMPHREY NO. 7 MONONGALIA, W. VA. & GREENE, PA.	CONSOL CHRISTOPHER	CARNEGIE, PEOPLES, EQUITABLE, HOPE, CHRISTOPHER, INDEPENDENT	PEOPLES (8"), CARNEGIE (6", 10")
ARKRIGHT MONONGALIA, W. VA.	CONSOL CHRISTOPHER	EQUITABLE, OWENS-ILLINOIS, CHRISTOPHER, INDEPENDENT	EQUITABLE (16"), HOPE (6", 8", 12"), CARNEGIE (10")
FEDERAL NO. 2 MONONGALIA, W.VA.	EASTERN	EQUITABLE, CARNEGIE, HOPE, EASTERN, INDEPENDENT	HOPE (6", 10"), CARNEGIE (12"), EQUITABLE (12", 16")
FEDERAL NO. 1 MARION, W. VA.	EASTERN	EQUITABLE, COLUMBIA, PENNZOIL, HOPE, EASTERN, INDEPENDENT	HOPE (3", 4", 6", 8", 10", 12")
BLACKSVILLE NO. 2 MONONGALIA, W.VA.	CONSOL BLACKSVILLE	EQUITABLE, PEOPLES, HOPE, BLACKSVILLE, INDEPENDENT	HOPE (6", 10"), CARNEGIE (10"), EQUITABLE (6", 8", 10", 16"), COLUMBIA TRANSMISSION (8", 10", 20"), PEOPLES (8", 12", 24")
BLACKSVILLE NO. 1 MONONGALIA, W.VA. & GREENE, PA.	CONSOL BLACKSVILLE	HOPE, CARNEGIE, EQUITABLE, BLACKSVILLE, INDEPENDENT	HOPE (6", 8"), CARNEGIE (6", 12", 16"), EQUITABLE (10", 12", 16"), PEOPLES (12", 24")
OSAGE NO. 3 MONONGALIA, W. VA.	CONSOL CHRISTOPHER	HOPE, EQUITABLE, CHRISTOPHER, INDEPENDENT	EQUITABLE (10"), HOPE (6", 8", 12")
ROBENA GREENE, PA.	U.S. STEEL	EQUITABLE, CARNEGIE, PEOPLES, U.S. STEEL, INDEPENDENT	CARNEGIE (6", 8"), COLUMBIA OF PENNA (10"), COLUMBIA TRANSMISSION (12", 20")
GATEWAY GREENE, PA.	J & L STEEL CO.	EQUITABLE, COLUMBIA TRANSMISSION, PEOPLES, J & L STEEL, INDEPENDENT	EQUITABLE (16"), COLUMBIA TRANSMISSION (10", 12", 20"), CARNEGIE (12"), PEOPLES (12", 24"), TEXAS EASTERN TRANSMISSION (20", 24", 30", 36")
SHANNOPIN GREENE, PA.	J & L STEEL CO. VESTA-SHANNOPIN	EQUITABLE, CARNEGIE, PEOPLES, VESTA-SHANNOPIN, INDEPENDENT	CARNEGIE (6", 10"), PEOPLES (6")
ROBINSON RUN NO. 95 HARRISON, W. VA.	CONSOL MOUNTAINEER	EQUITABLE, CARNEGIE, HOPE, MOUNTAINEER, INDEPENDENT	CARNEGIE (12"), EQUITABLE (10"), HOPE 10", 16")
MARIANA NO. 58 CAMBRIA, PA.	BETHLEHEM	EQUITABLE, BETHLEHEM, INDEPENDENT	
CONSOL NO. 20 MARION, W. VA.	CONSOL MOUNTAINEER	EQUITABLE, HOPE, CARNEGIE, MOUNTAINEER, INDEPENDENT	HOPE (10", 16"), EQUITABLE (16"), CARNEGIE (12")
IRELAND MARSHALL, W. VA.	CONSOL OHIO VALLEY	HOPE, MANUFACTURERS, OHIO VALLEY, INDEPENDENT	HOPE (6", 12", 18"), MANUFACTURERS LIGHT & HEAT (8", 10") TEXAS EASTERN TRANSMISSION COR. (20", 24", 30")
MATHIES WASHINGTON, PA.	MATHIES	CARNEGIE, COLUMBIA TRANSMISSION, COLUMBIA OF PENNA, MATHIES, INDEPENDENT	CARNEGIE (6", 8", 16", 20", 24"), COLUMBIA TRANSMISSION (6", 10"), COLUMBIA OF PENNA (10"), PEOPLES (20")
JOANNE MARION, W. VA.	EASTERN	HOPE, CARNEGIE, EASTERN, INDEPENDENT	HOPE (8"; 10", 12"), CARNEGIE (12")
CLYDE WASHINGTON, PA.	REPUBLIC STEEL	EQUITABLE, COLUMBIA TRANSMISSION, PEOPLES, REPUBLIC STEEL, INDEPENDENT	EQUITABLE (12", 20"), COLUMBIA TRANSMISSION (12"), PEOPLES (12", 24")
SOMERSET NO. 60 WASHINGTON, PA.	BETHLEHEM	COLUMBIA TRANSMISSION, CARNEGIE, BETHLEHEM, INDEPENDENT	EQUITABLE (16", 20", 24"), COLUMBIA TRANSMISSION (6" 10"), CARNEGIE (6", 16", 20", 24")
VESTA NO. 5 WASHINGTON, PA.	J & L STEEL CO. VESTA-SHANNOPIN	CARNEGIE, COLUMBIA, VESTA-SHANNOPIN, INDEPENDENT	CARNEGIE (6", 16", 20", 24"), EQUITABLE (12", 16", 20"), COLUMBIA TRANSMISSION (10", 12"), PEOPLES (12", 24")
PURSEGLOVE MONONGALIA, W. VA.	CONSOL CHRISTOPHER	HOPE, CARNEGIE, CHRISTOPHER, INDEPENDENT	HOPE (6", 8", 10", 12"), CARNEGIE (10")
VALLEY CAMP NO. 3 OHIO, W. VA.	VALLEY CAMP	MANUFACTURERS LIGHT & HEAT, VALLEY CAMP, INDEPENDENT	MANUFACTURERS LIGHT & HEAT (10", 16")
McELROY MARSHALL, W. VA.	CONSOL OHIO VALLEY	COLUMBIA TRANSMISSION, OHIO VALLEY, INDEPENDENT	
MONTOUR NO. 4 WASHINGTON, PA	CONSOL PITTSBURGH	COLUMBIA OF PENNA, COLUMBIA TRANSMISSION, PEOPLES, PITTSBURGH, INDEPENDENT	EQUITABLE (16"), COLUMBIA TRANSMISSION (10", 24"), COLUMBIA OF PENNA (8", 10", 12"), PEOPLES (8", 20")
SHOEMAKER MARSHALL, W. VA.	CONSOL OHIO VALLEY	MANUFACTURERS LIGHT & HEAT, OHIO VALLEY, INDEPENDENT	MANUFACTURERS LIGHT & HEAT (8", 10")
MAPLE CREEK WASHINGTON, PA.	U.S. STEEL	EQUITABLE, CARNEGIE, COLUMBIA TRANSMISSION, REVIAR, RIVERVIEW-FINLEYVILLE, BEEDLE, U.S. STEEL, INDEPENDENT	CARNEGIE (6", 8", 16", 20", 24"), EQUITABLE (16", 20", 24"), COLUMBIA TRANSMISSION (6"), PEOPLES (20")
CONSOL NO. 93 MARION, W. VA.	CONSOL CHRISTOPHER	HOPE, CARNEGIE, CHRISTOPHER, INDEPENDENT	HOPE (2", 3", 4", 6"), CARNEGIE (10")
NEMACOLIN GREENE, PA.	BUCKEYE	EQUITABLE, COLUMBIA OF PENNA, CARNEGIE, BUCKEYE, INDEPENDENT	COLUMBIA OF PENNA (4", 10"), TEXAS EASTERN TRANSMISSION (20", 24", 30", 36"), CARNEGIE (6", 8")
WILLIAMS-MINE NO. 98 HARRISON, W. VA.	CONSOL MOUNTAINEER	EQUITABLE, CARNEGIE, HOPE, MOUNTAINEER, INDEPENDENT	EQUITABLE (6", 10", 16"), CARNEGIE (12"), HOPE (10", 16")
CONSOL NO. 9 MARION, W. VA.	CONSOL MOUNTAINEER	HOPE, MOUNTAINEER, INDEPENDENT	HOPE (6", 8", 10", 12", 16"), EQUITABLE (12"), CARNEGIE (12")

*INCHES OF PIPELINE'S INTERNAL DIAMETER

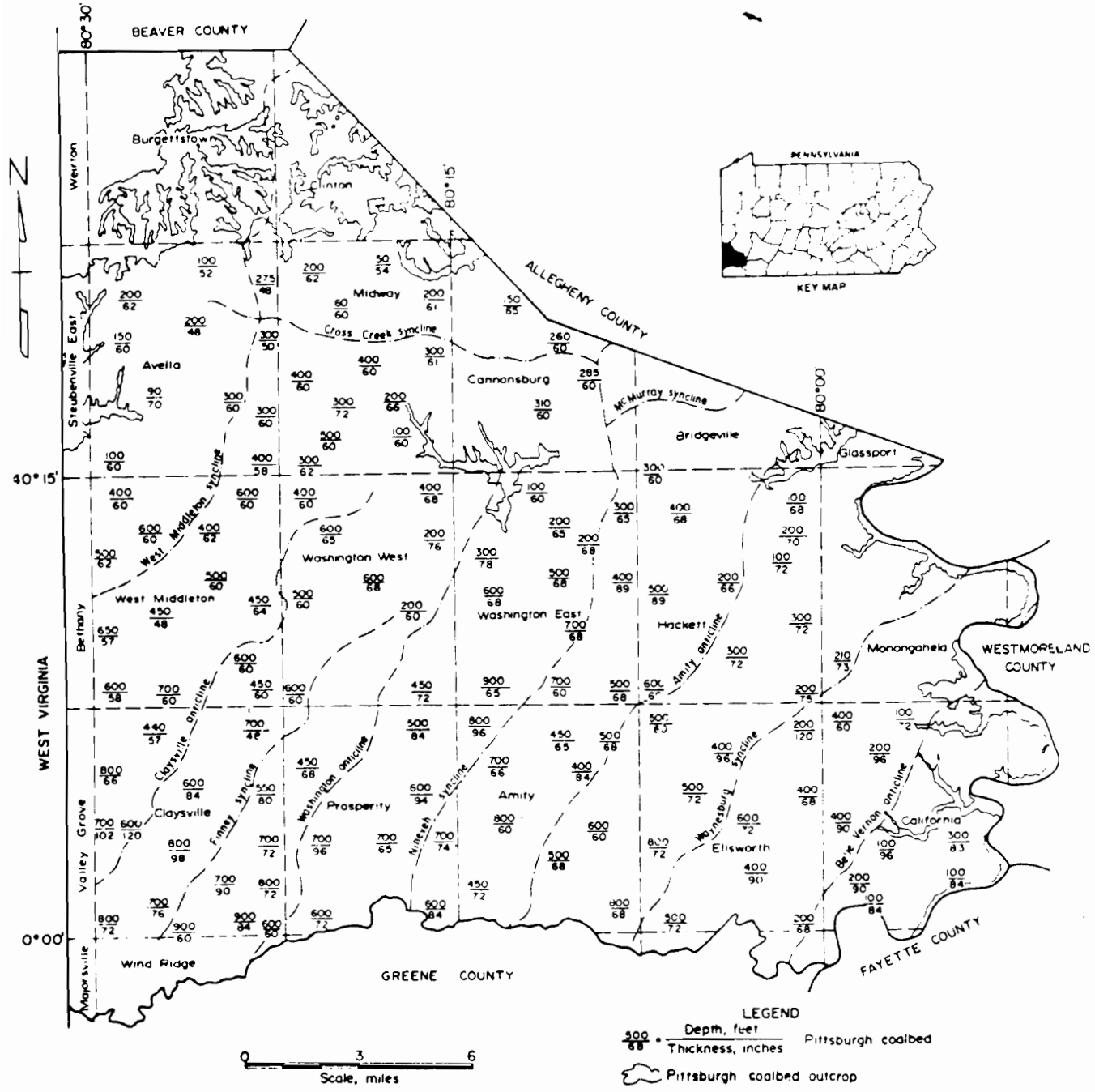


FIGURE 3-28. PITTSBURGH COALBED THICKNESS AND OVERBURDEN THICKNESS AT SELECTIVE LOCATIONS OF WASHINGTON COUNTY, PA.

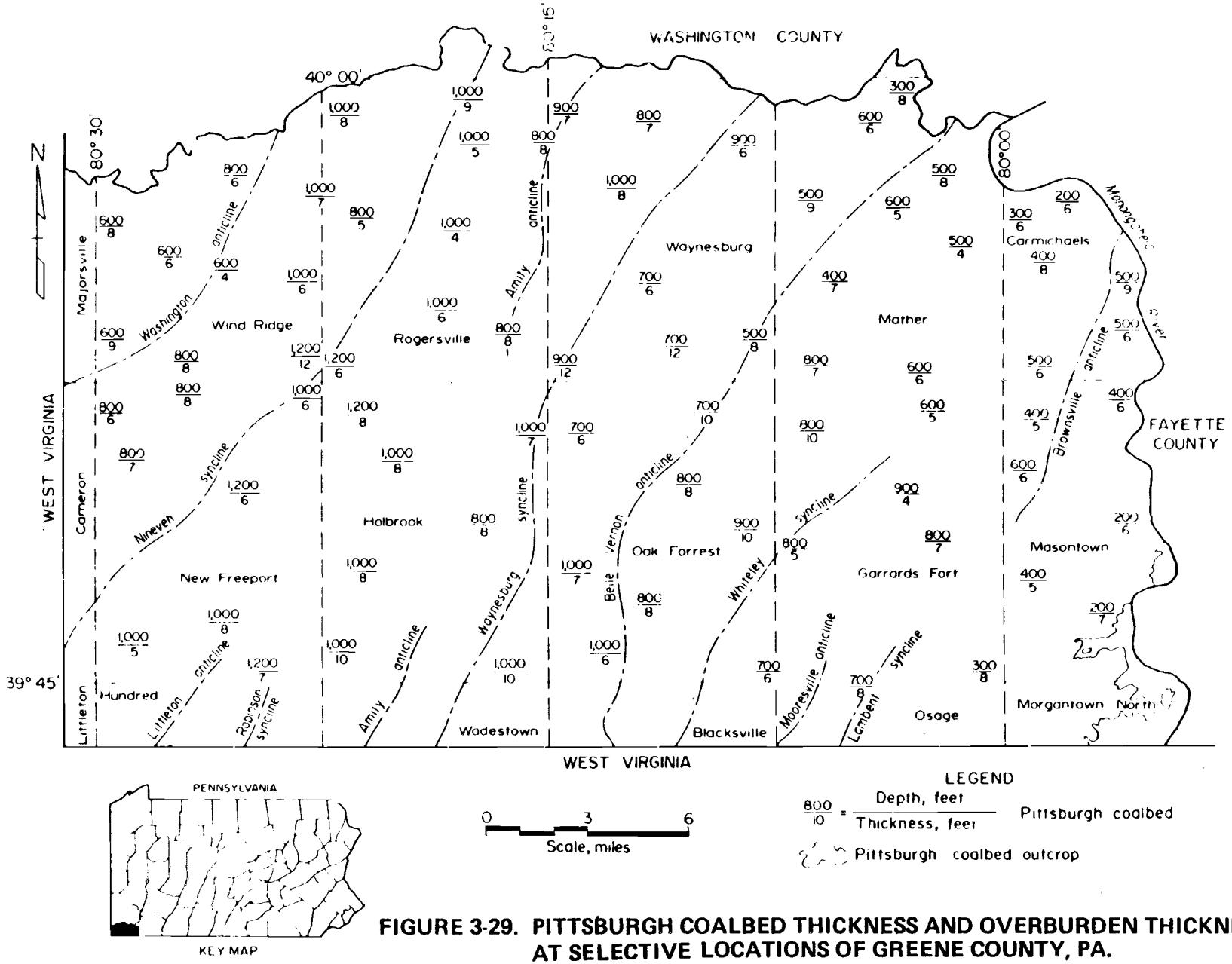


FIGURE 3-29. PITTSBURGH COALBED THICKNESS AND OVERBURDEN THICKNESS AT SELECTIVE LOCATIONS OF GREENE COUNTY, PA.

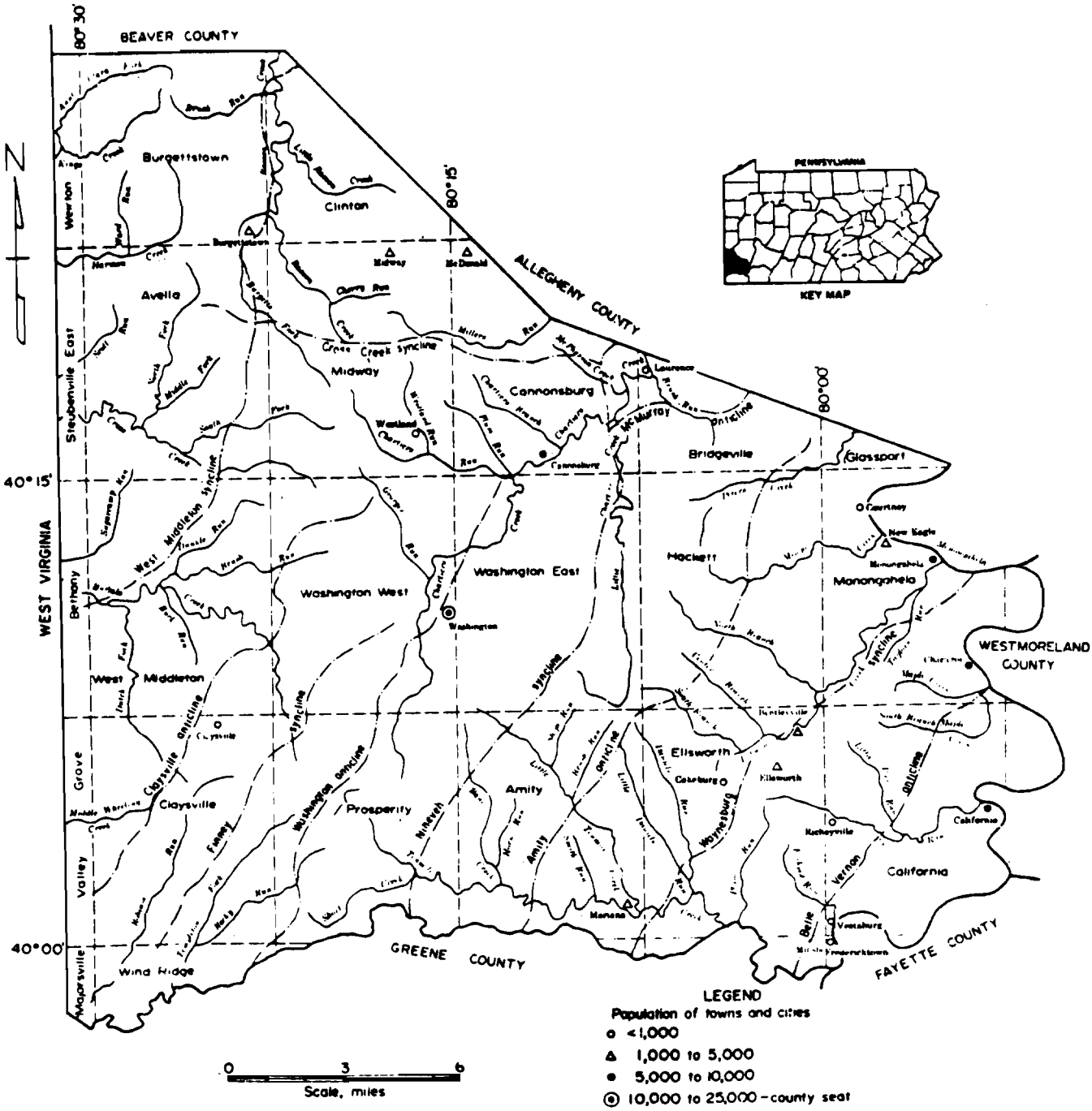


FIGURE 3-30. SURFACE RUNNING WATERS IN WASHINGTON COUNTY, PA.

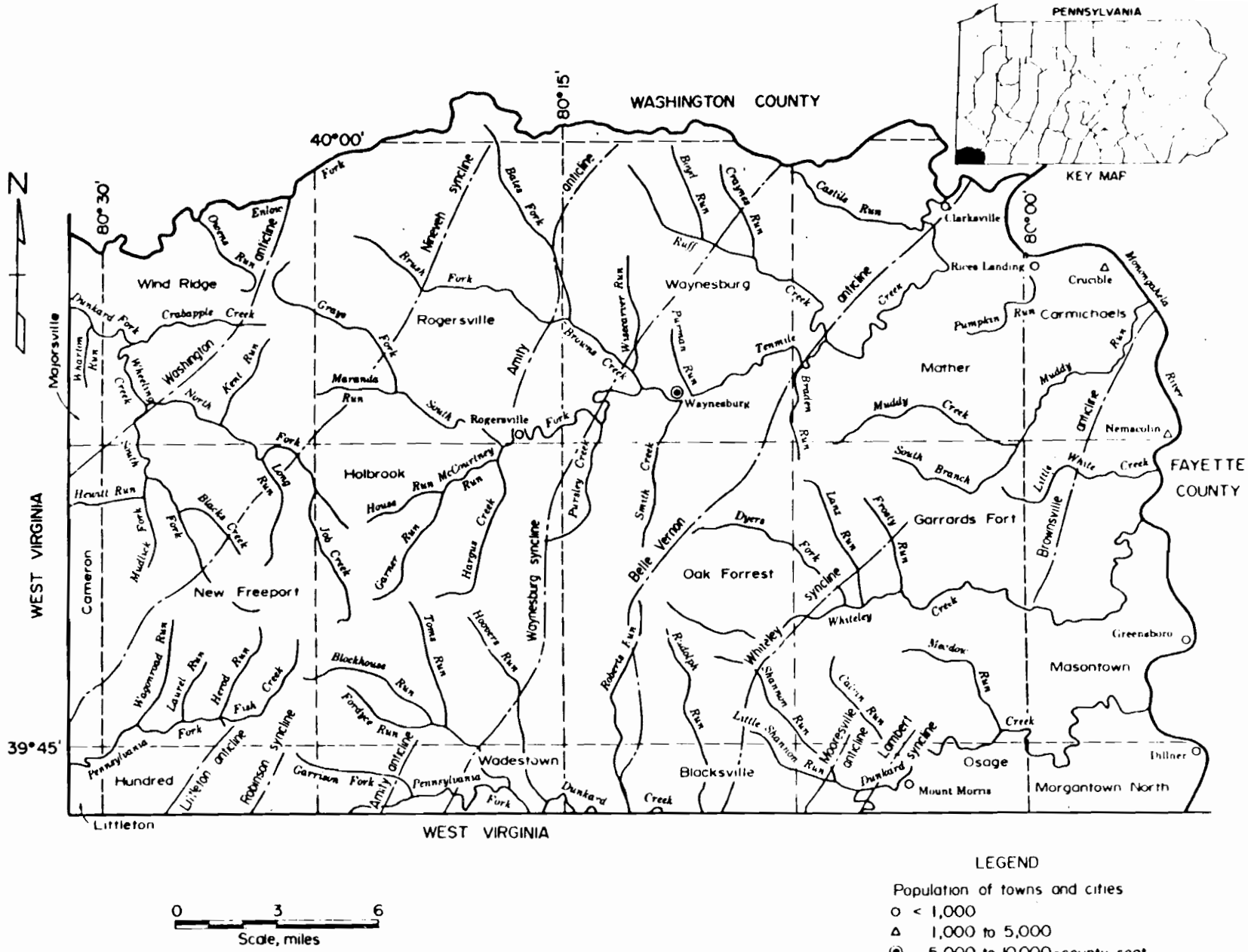


FIGURE 3-31. SURFACE RUNNING WATERS IN GREENE COUNTY, PA.

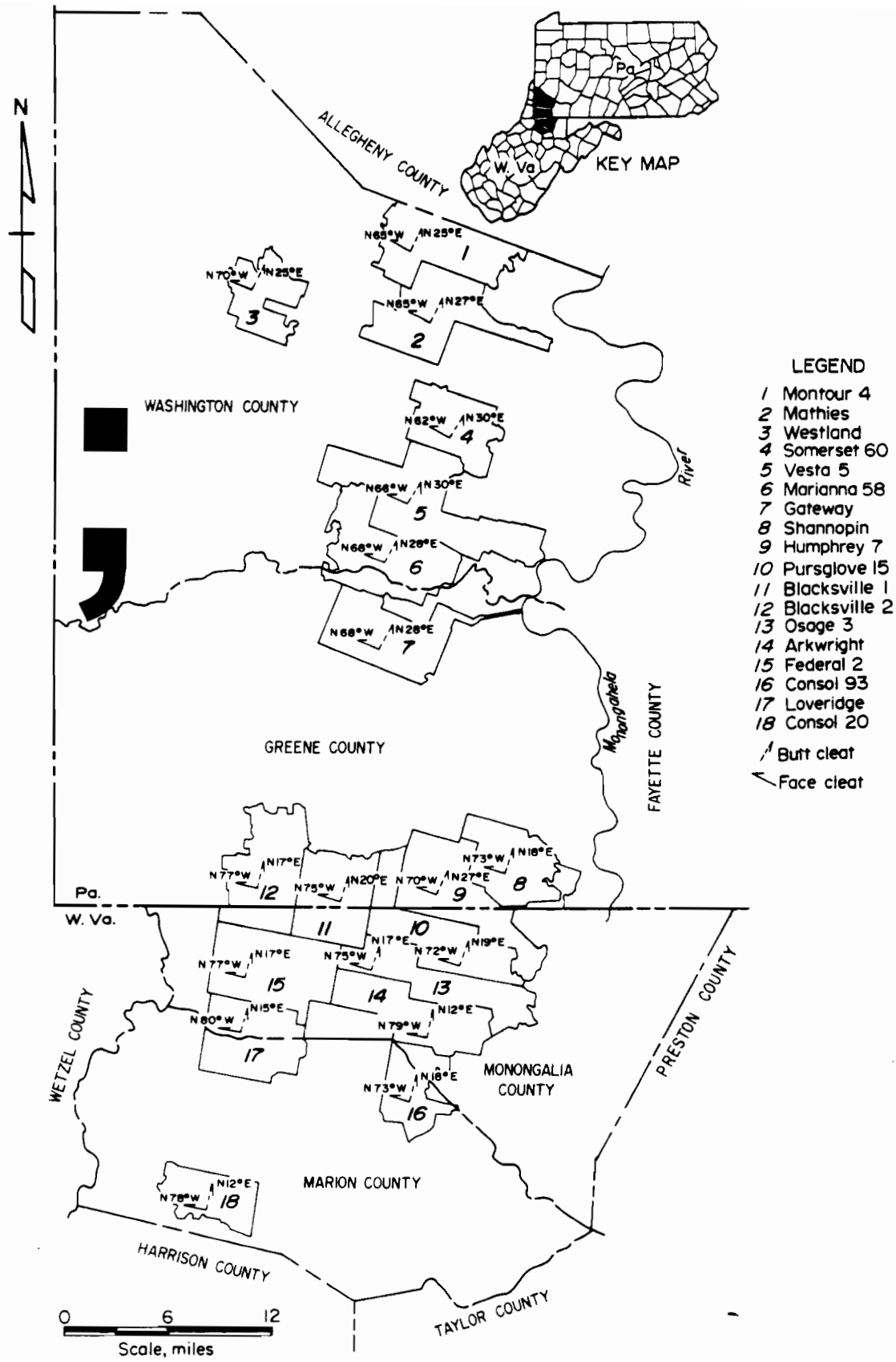


FIGURE 3-35. CLEAT SYSTEMS IN MINES OPERATING IN THE PITTSBURGH COALBED

TABLE 3-28. REFERRAL TABLE TO TEXT CITING MINING AND DRAINAGE TECHNIQUE DATA FOR THE SELECTED MINES

TYPE OF DATA	TEXT CITED
I. MINING TECHNIQUE	
A. MINE DESIGN	
1. Number of Main Sets of Headings	Appendix I
2. Number of Headings per Main Set	Appendix I
3. Dimensions of Headings	Appendix I
4. Operational Function of Headings	Appendix I
5. Number of Sub-Main Sets of Headings	Appendix I
6. Number of Headings per Sub-Main Set	Appendix I
7. Number of Shafts and Slopes	Table 3-21
8. Dimensions and Operational Function of Shafts and Slopes	Appendix I
9. Dimensions and Number of Headings per Set of Buff-Headings	Appendix I
10. Pillar Pattern and Dimensions	Appendix I
11. Barrier Pillar Dimensions	Appendix I
12. Single or Multiple Level Mining	Appendix I
13. Single or Bench Level Mining	Appendix I
14. Method of Pillaring Retreat	Appendix I
15. Dimensions of Room Panels	Appendix I
16. Dimensions of Longwall Panels	Appendix I
17. Angle of Intersection of Main Headings and Cross-Cuts	Appendix I
18. Number and Dimensions of Developed But Not Yet Mined Panels	Appendix I
19. Location and Spacing of Air Return Shaft With Respect to Main Headings	Appendix I
20. Total Length of Headings in Main, Sub-Main and Buff Sets	Appendix I
B. MODE OF OPERATIONS	
1. Conventional, Continuous, Longwall, Shortwall Mining Method	Table 3-5
2. Methods of Stabilizing Mined-Out Stopes	Table 3-5
3. Methods of Roof Support in Roadways and Return Airways	Appendix I
4. Ventilation Method, Structures, and Equipment	Table 3-5
5. Advancing or Retreating Longwalls	Appendix I
6. Number and Type of Conventional Miners	Table 3-5
7. Number and Type of Continuous Miners	Table 3-5
8. Number and Type of Longwall Shear Units	Table 3-5
9. Heading Rate of Advancement (ft/hr)	Appendix I
10. Room Rate of Advancement (ft/hr)	Appendix I
11. Longwall Rate of Advancement (ft/hr)	Appendix I
12. Room Mining Rate (tons/hr)	Appendix I
13. Longwall Mining Rate (tons/hr)	Appendix I
14. Type and Equipment of Haulage System	Table 3-5
15. Coal Shipment Media	Table 3-5
16. 1974 Tonnage Mined	Table 3-5
17. Mine Tonnage Class	Table 3-5
18. Mine Equipment Other Than Production and Haulage	Table 3-5
19. Coal Preparation Plant Daily Capacity	Table 3-5
20. Underground Mine and Coal Preparation Plant Electrical Data	Table 3-5
21. Range of Coal Particles Washed, Dried and Shipped in the Preparation Plant	Table 3-5
22. Origin of Feedstock Coal to the Preparation Plant	Table 3-5
23. Daily Coal Production Rate	Table 3-21
24. Mine Age	Table 3-21
25. Total Surface of Mine Lease	Appendix I
26. Room to Pillar Surface Ratio in Advancement	Appendix I
27. Percent of Pillar Recovery During Retreat	Appendix I
II. DRAINAGE TECHNIQUE	
1. Number and Type of Coal Gas Drainage Boreholes Drilled in the Mine	Appendix I
2. Location, Dimensions, Equipment, Features of Drilled Coal Gas Drainage Boreholes	Appendix I
3. Number of Stopes (Headings, Rooms, Gobs) Sealed and Tapped For Coal Gas Drainage	Appendix I
4. Number of Stopes Sealed But Not Tapped For Coal Gas Drainage	Appendix I
5. Number of Open Gobs Drained Through the Conventional Ventilation System of the Mine	Appendix I
6. History of Accidents Caused by Coal Gas Explosions	Appendix I

TABLE 3-29. REFERRAL TABLE TO TEXT CITING COAL PROPERTIES AND CHARACTERISTICS DATA FOR THE SELECTED MINES

TYPE OF DATA	TEXT CITED
1. Gas Content	Tables 3-6, 3-7, Figs. 3-22, 3-23
2. Coalbed Thickness	Tables 3-5, 3-21, Figs. 3-10, 3-28, 3-29
3. Coalbed Dip	*
4. Coalbed Aerial Extent	Appendix I
5. Cleat Orientation	Figure 3-35
6. Fracture Porosity and Permeability of Coalbed, Roof Rock and Basement Rock	Section 3.3.1
7. [redacted]ctural and Tectonic Features Associated With the Bed Which May Constitute [redacted] Reservoirs	Section 3.1.4.6
8. [redacted] Production Rate	Tables 3-5, 3-21
9. [redacted] Production History (Mine Age)	Table 3-21
10. [redacted] Reserves	Table 3-1
11. [redacted] Lithological Properties	*
12. [redacted] Mechanical Properties	*
13. [redacted] Chemical Properties	*
14. [redacted] Physical Properties	*
15. [redacted] Electrical Properties	*
16. [redacted]	*
17. [redacted]	Tables 3-2, 3-5, 3-21

*Data has been requested but not received; will be included when available

TABLE 3-30. REFERRAL TABLE TO TEXT CITING GAS PROPERTIES AND CHARACTERISTICS DATA FOR THE SELECTED MINES

TYPE OF DATA	TEXT SITES
1. Methane Production Rate	Tables 3-18, 3-19, 3-20, 3-21, Fig. 3-24, Equ. 3-8
2. Methane Production History	Table 3-21, Figure 3-25
3. Types of Coal Gas Mixtures Produced	Tables 3-9, 3-10, 3-11, 3-12, 3-15, 3-16, 3-17
4. Saturation Concentration of Gas in Coal	Table 3-23, Section 3.3.5
5. BTU Content	Table 3-14
6. Reservoir Gas Pressure	Section 3.3.5
7. Diffusion Rate	Equation 3.9
8. Permeation Rate	Equation 3.13
9. Desorption Rate	Equation 3.12
10. Production Decline Curves	Figure 3-25
11. Gas Content of Eastern Coalbeds	Table 3-6
12. Gas Content of Pittsburgh Coalbed Mines	Figs. 3-22, 3-23, Table 3-7, Equations3.5, 3.7
13. Gas Reserves as a Function of Coalbed Thickness and Gas Content	Table 3-22
14. Methane Content and Reserves of Virgin Pittsburgh Coal in Pennsylvania Districts	Table 3-23

4.0 METHANE UTILIZATION

There are many potential uses for coalbed methane gas, and if maximum practical utilization of this resource is to be realized, several alternatives will require development and implementation. The variables associated with quantity/quality; economic, legal and regulatory constraints; mining activity; lease agreements; etc., will influence the use most advantageous to any specific mine or group of mines. This study addresses the Pittsburgh coalbed specifically. Other coalbeds are reviewed in less detail for comparison purposes.

Gas drained from virgin coal prior to mining and gas drained from gob areas have potential practical applications. Gas removed by the mine ventilation system is so diluted (less than one percent methane) that no practical application has been identified during this study. Gas removed by the ventilation system will always constitute a significant amount, and the search for practical applications should continue in future efforts. All systems selected for demonstration and ultimate commercialization complement mining operations and enhance safety.

After the potential uses of coalbed methane were determined, applications were identified that are within the quality and quantity capabilities of the source. Subsystems for production, collection, conversion and/or utilization (PCCU) were then defined and combined into cost effective systems capable of operating within the source constraints. Finally, a cost-benefits analysis was performed to determine the relative merit of proposed applications.

Potential uses of coalbed methane are discussed in Section 4.1. The capability of mines to supply this resource, in terms of quality, flow rate, and total quantity are discussed in Section 4.2. Section 4.3 defines suitable PCCU subsystems for applications within the constraints of the methane supply and synthesizes feasible PCCU systems configurations. Section 4.4 contains cost-benefit analyses of alternative subsystems and systems, and the selection of systems recommended for field demonstration.

4.1 VIABLE POTENTIAL USES

4.1.1 Electric Power Generation

Predrainage and gob gas are both suitable for this use. Mining operations require very large quantities of electric power, and the more probable use of power generated in this application would be to operate such mine equipment as pumps, fans, lighting, etc., or connect into mine power grid for general use.

4.1.2 Fuel for Mine Heating Applications

Several applications are possible using gas as a fuel for heat. They include coal drying, coal thawing railroad cars, building heating,

ventilation air heating, etc. All mines do not use all of these applications; however, all have at least one requirement for heat. Predrainage and gob gas are both suitable for this use.

4.1.3 Liquefied Natural Gas (LNG) Conversion

Both gob and predrainage gas can be converted to LNG and transported by tank trucks to purchasers/consumers. Local gas utilities would be good customers for this product as would individual rural and industrial consumers not serviced by a utility.

4.1.4 Sale to Commercial Pipeline Company

Most predrained gas from virgin coal is of suitable quality for direct injection into a commercial natural gas pipeline. Virtually all mines in the Pittsburgh coalbed are close to a commercial pipeline, and sale of the gas to pipeline companies is a desirable option. If used for this market, gob gas would require processing to upgrade it to commercial quality. This requires expenditures for capital equipment, operating and maintenance expenses, and is not as economically favorable as predrained gas.

4.1.5 Chemical Feedstock

Methane gas from coalbeds, either predrained from virgin coal or drained from gobs, can be upgraded and used as a chemical feedstock for any application using natural gas. The relatively small quantity of gas available, short duration of production at most locations, and cost of upgrading limits serious consideration to only a few uses. Uses investigated during this study include plants for the production of ammonia, methanol, hydrates, and chloromethanes.

4.2 METHANE DRIVEN RESOURCE REQUIREMENTS OF PCCU SYSTEMS

Practical application of methane uses discussed in Section 4.1 requires selection on the basis of methane quality, production rate, and total quantity capability of the supply source. The source is either an individual mine with a relatively limited capability or a group of mines with an interconnecting pipeline that will deliver methane from each connected mine to a central location for further processing. The much larger supply capability from a group of mines is highly desirable for many applications; however, the obstacles to such a venture prohibit considering it for any near-term field demonstrations. Those obstacles include acquisition of pipeline right-of-way (ROW), negotiation of financial agreements, determination of environmental impacts and preparation of environmental assessment reports, acquisition of necessary gas rights, etc. For purposes of this study, methane supply is based on individual mine capabilities.

Section 3.0 identifies and discusses methane emission rates from significant mines in the Pittsburgh coalbed. Table 3-21 provides detailed data on an individual mine basis. It is pointed out that emission rates

in this table represent only methane removed by the mine ventilation system and thereby wasted. It is a larger quantity than would be possible to drain from virgin coal or gob areas.

4.2.1 Predrainage of Methane from Virgin Coal

Methane quality, production rate, and total quantity available for the utilization under consideration represent resource driven requirements that must be satisfied when selecting PCCU components. Based on what is realistic for a number of mines in the Pittsburgh coalbed, the following is established for this study:

- Coalbed gas quality - 95 percent methane
- Production rate - one to two million cubic feet per day (CFD)
- Total quantity available - three-year supply based on recovering 80 percent of the methane contained in the coalbed/borehole.

The following sections of this report include, when appropriate, the coal tonnage, drainage area, etc. required to obtain the production rate and total methane quantity required for particular applications.

4.2.2 Gob Gas Recovery

As with predrainage, the quality, production rate, and total quantity of gob gas available for the utilization under consideration represent the resource driven requirements that must be satisfied when selecting PCCU components.

It is very difficult to predict these for gob gas. The gas quality depends largely on how much ventilating air has become mixed with the gas before it is drained from the mine. The rate at which methane will drain into the gob areas depends on specific location conditions, with very little data available from which to project actual emission rates. The same performance is assumed for both longwall and room-and-pillar gobs. Longwall gobs will probably yield larger quantities per acre, but typical room-and-pillar mines will probably produce longer from larger areas.

Based on the limited data available, the following is established for this study:

- Gob gas quality - 50% methane average
- Production rate - one to two million CFD
- Total quantity available - three-year supply/borehole.

The following sections report, when appropriate, how the production rate and total methane quantity required for a particular application are to be achieved.

4.3 SYNTHESIS OF FEASIBLE PCCU SYSTEMS CONFIGURATIONS

Uses of coalbed methane are identified in Section 4.1, and the resource capability available for specific applications identified in Section 4.2. The resource capability establishes the PCCU requirements. Applications for utilizing the gas have no limiting requirements on the PCCU selections.

4.3.1 Coalbed Methane Subsystem Requirements

This section identifies and defines requirements for production, collection, and conversion/utilization (PCCU) subsystems that, when combined into operating systems, will effectively use coalbed methane gas.

4.3.1.1 Production Subsystems

Production subsystems must produce methane of sufficient quality and quantity to satisfy conversion/utilization requirements in a cost-effective manner. The Bureau of Mines has developed and demonstrated three effective methods for draining gas from coalbeds. The Bureau's objective in draining methane was primarily to promote mine safety. The techniques it developed are applicable to conservation requirements; however, combinations of its methods and more wells producing at one time are required for some utilization subsystems. Production subsystem requirements are described in the following paragraphs.

4.3.1.1.1 Predrainage

Coalbed methane drained in advance of mining operations is of the highest quality, frequently equal to that of natural gas. Some uses require this quality, and the economics of all applications are better with higher quality methane.

Gas may be drained from the coalbed by means of:

1. Vertical boreholes drilled from the surface into the coal seam, in which gas flow is stimulated by fracturing the coal and by removing water as it collects at the well bottom. Figure 4-1 shows a schematic of a predrainage vertical well.

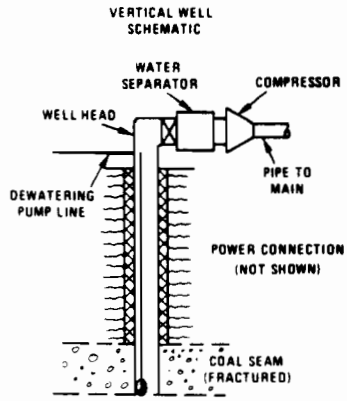


FIGURE 4-1. VERTICAL WELL SCHEMATIC

2. Horizontal boreholes drilled into the coal seam from the bottom of general purpose or ventilation shafts, in which gas flows are maintained by periodic cleaning of the holes and by removing water as it collects. Figure 4-2 shows a schematic of this arrangement.

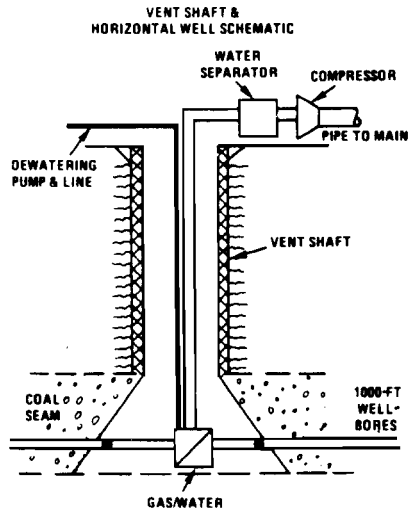


FIGURE 4-2. HORIZONTAL BOREHOLE FROM A VENT SHAFT

3. Horizontal boreholes drilled into the coal seam from the surface using slant hole drilling techniques, in which gas flows are maintained by periodic cleaning and removal of water as it collects in the wellbore. Figure 4-3 shows a schematic of this arrangement.

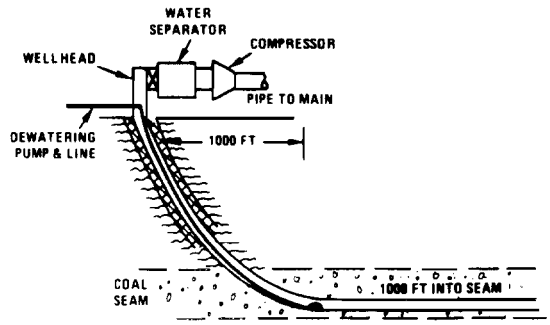


FIGURE 4-3. HORIZONTAL BOREHOLE DRILLED USING SLANT DRILLING TECHNIQUE

Predrainage subsystem requirements include completed well(s) and/or boreholes, water removal from the well, and water removal from the gas stream.

4.3.1.1.2 Gob Drainage

Gob areas are created as mining progresses and subsidence occurs. The gob gas quality (usually 40% to 90% methane) is not comparable to that obtained from predrainage but is available in quantities that make its cost-effective utilization important to the conservation program.

Gob gas subsystem requirements are the same as those identified for predrainage, except for drilling of horizontal boreholes which is not applicable to gob areas.

4.3.1.1.3 Ventilation Systems

Most coalbed methane gas is released in conjunction with active mining operations. This gas then must be removed from the mine's working area by means of the mine ventilation system. For safety, and also to satisfy legal constraints, the methane concentration must be kept below one percent, requiring very large quantities of ventilating air for dilution. No economic utilization has been found for this source of methane.

Predrainage of virgin coal and recovery of gob gases must be encouraged so that methane is recovered at maximum quality for utilization. The methane quantity that must be removed by the ventilation system and wasted is therefore reduced to a minimum.

4.3.2 Collection Subsystem Requirements

The collection subsystem is essentially the same regardless of the production subsystem. Gas must be collected from the boreholes and delivered to the conversion/utilization subsystem. Requirements for this subsystem include the interconnecting piping, compressors and necessary right-of-way (ROW) for installation.

4.3.3 Conversion/Utilization Subsystem Requirements and Feasible System Synthesis

The conversion/utilization of methane gas obtained from either gob areas or predrainage of virgin coalbeds is strongly dependent on the available quality and quantity of these gases. Furthermore, steady production of the gas over a period of time, and its ability to maintain a constant methane level for that period, are important considerations in choosing an appropriate application for the methane gas. For example, the work conducted by the Bureau of Mines at the Federal No. 2 mine (References 11.3, 11.2) owned by Eastern Associated Coal Company showed steady production of 90 percent methane gas for a period of about two years. This gas production rate, obtained by predrainage ahead of the mining face, is expected to continue for the next three years. On the other hand, gob gas compositions vary from 40 to 90 percent methane, and

have been known to decline steadily over a one-year period from about 90 to 40 percent methane. Along with methane concentration, the gob gas production rate also declines with time during production.

Various conversion/utilization systems for methane gas from gob areas and predrainage are discussed below.

4.3.3.1 Direct Injection Into a Pipeline

In order to inject methane gas directly into commercial pieplines, the gas must meet certain specifications established by the pipeline gas companies. Specifications on quality of purchased gas set by the Equitable Gas Company are listed below (Reference 17.1). The barometric pressure for pressure calculations is 14.73 psia.

The gas quality shall:

a. Be in its natural state as produced

b. Be commercially free from dusts, gums, gum-forming constituents, or other liquid or solid matter which might become separated from the gas in the course of transportation through pipelines

c. Not contain more than three-tenths (0.3) of a grain of hydrogen sulfide (H_2S) per one hundred (100) cubic feet

d. Not contain more than thirty (30) grains of total sulfur per one hundred (100 cubic feet

e. Not contain more than four percent (4%) by volume of a combined total of inerts such as carbon dioxide, nitrogen, argon and helium; provided, however, that the total carbon dioxide content shall not exceed three percent (3%) by volume

f. Not contain more than one percent (1%) of oxygen by volume

g. Have at least nine hundred and fifty (950) British Thermal Units per cubic foot calculated as the gross saturated value at 14.73 psia and 60°F

h. Be dehydrated by seller, if necessary, and shall in no event have a water content in excess of seven (7) pounds of water per million cubic feet of gas measured at the purchase base of 14.73 psia and 60°F

i. Be in conformance with any existing regulatory standards.

It is evident from the above specifications that gob gases, which typically run 50% methane by volume with large percentages of other constituents like carbon dioxide, nitrogen, oxygen, etc., are unsuitable for direct pipeline injection without substantial upgrading.

Methane gas obtained by predrainage of coalbeds can be, and currently is, sold as pipeline quality gas. Approximately 113 MMSCF of 89% methane gas produced from five horizontal holes, drilled from the bottom of vertical shafts at the Federal No. 2 mine, has been purchased by Consolidated Natural Gas Supply Corporation. This gas is being supplied to the local community of Wadestown, West Virginia. Although the CO_2 content of these gases runs about 10% by volume, the small quantities purchased and subsequent mixing with Consolidated's normal supply, probably results in sufficient dilution of the carbon dioxide so as not to cause any problems. Emerald Mines Corporation, on the other hand, has signed a Structured Sales Agreement with Equitable Gas to sell 50% of the gas produced from vertical holes drilled ahead of its mining plan in Greene County, Pennsylvania. The gas production rate at this mine is 40,000-50,000 SCFD per hole, with a methane content similar to that measured at the Federal No. 2 mine by the Bureau of Mines, but with lower carbon dioxide levels of about 3 percent.

The process layout for direct injection of predrained methane gas, either from horizontal holes or vertical holes is, therefore, as follows.

Because gas from the wells is saturated with moisture, water separators are provided at each wellhead to remove water contained in the gas streams. The steady-state gas pressure, as measured at the wellhead, varies from coalbed to coalbed; therefore, small compressors are provided to raise the gas pressure to approximately 100 psi before the gases are injected into a gathering pipeline system which accumulates gases from the producing wells and feeds them into the utility pipeline system. Should high carbon dioxide levels in the gas pose a problem, CO_2 scrubbing systems must be provided for in the general process layout.

4.3.3.2 Gas Turbines/Generators

Both gob gases and predrained gases may be used for power generation. However, the use of gob gases for power generation is particularly attractive, and is being seriously considered by Bethlehem Steel's Cambria Mines Division. The combustor section of the turbine/generator unit can readily burn 50% methane gas, and can handle reasonable fluctuations in methane concentration; the units are available for small output capacities, can be skid-mounted for ease of transportation, and require low maintenance. Furthermore, if the power generated is to be used underground to drive machinery (as in the case of Bethlehem Mines), transmission lines can be run through the mines via boreholes already in existence, and thereby obviate many problems connected with obtaining surface rights-of-way for methane pipelines.

Turbine/generator units rated at 800 KW are available off-the-shelf with delivery times of 6-7 months. At this rated output, approximately 1 MMSCFD of 50%CH_4-50% air mixtures are required after proper optimization of the combustion equipment. One MMSCFD of gas is a reasonable flow rate to expect for process demonstration purposes.

The process flow for power generation using turbine/generators is as follows: Gob gases are collected from vertical or horizontal holes to yield approximately 1 MMSCFD, are dewatered, and then fed into a gathering pipeline system. These gases are compressed to 150 psig before being fed into the combustor section of the turbine. The generated power goes into an electrical distribution system which consists of transformers, power transmission lines, breakers, switchgears, etc.

4.3.3.3 Fuel Cells

An alternate means of power generation is the use of fuel cells. The Power Systems Division of United Technologies Corporation is actively developing fuel cells for power generation. It currently has a 40 KW package in operation of the South Windsor, Connecticut, power plant where it has been in operation for a cumulative 8,000 hours. Although reliability and onstream availability data for this unit is not available, the stated goal is to operate the fuel cell stacks for a period of five years before overhauling, 10 years between overhauls for the reformer, and 20 years for the inverter.

Gob gases from coal mine drainage can probably be used in the fuel cells, although oxygen in the gases will have to be removed ahead of the reformer. Oxygen is detrimental to the reformer catalyst. The carbon dioxide content of the gob gases would not pose a problem because phosphoric acid fuel cells will be used.

Because of the unavailability of any fuel cells, their long leadtime for manufacture (two to three years), and the high costs associated with fabrication of a few units, fuel cells will probably be unavailable for any immediate field demonstration purposes. However, because of the enormous potential of fuel cells for power generation, gob gases should be used for initial laboratory experimentation and subsequent fuel cell modifications before any field demonstrations are contemplated.

4.3.3.4 Heating Applications

4.3.3.4.1 Coal Drying

During coal mining operations, rock and clay material tend to get mined out along with the coal. To maintain a high heating value of this coal, the rock and clay material are removed in coal cleaning plants. The coal from these cleaning plants contains approximately 13% moisture and must be dried before it can be marketed. The coal may be dried by different means, the most common, however, being fluidized bed dryers. For Eastern Coals, these dryers are typically designed to handle about 250 tons per hour (TPH) of dry, clean coal, and the moisture content decreased from 13 to 4 percent. Better than 90% of these dryers are stoker fired. A potential application for methane gas obtained either by predrainage or as gob gases is to fire these dryers. Modifications of existing stoker fired boilers is relatively easy and would not require high capital expenditures.

The amount of gas required to dry 256 TPH of dry, clean coal by reducing its moisture content from 13 to 4 percent is given in Table 4-1 as a function of the gas quality.

TABLE 4-1. COAL DRYING REQUIREMENTS

GAS COMPOSITION, PERCENT	CFD OF GAS REQUIRED
50 CH_4/50 AIR	4.9×10^6
60 CH_4/40 AIR	4.1×10^6
70 CH_4/30 AIR	3.5×10^6
80 CH_4/20 AIR	3.1×10^6
90 CH_4/10 AIR	2.7×10^6
95 CH_4/ 5 AIR	2.7×10^6

Table 4-1 shows that 4.9×10^6 CFD of a 50 percent CH_4-50 percent air mixture is required to dry coal from a typical coal cleaning plant. Because such large quantities of gas are not being considered for initial field demonstration purposes, it would be more practical to modify existing dryers to handle about 1 MMCFD of this mixture and burn this gas in conjunction with the middling coals currently being used exclusively.

4.3.3.4.2 Other Heating Applications

Use of the gas for heating buildings, water, railroad cars, ventilating air, etc., presents excellent utilization alternatives with the same subsystem requirements as for coal drying.

4.3.3.5 LNG

Both gob and predrainage gases are well suited for the manufacture of LNG. Whereas with predrainage gas existing LNG technology can be used, gob gases require some modification of the air separation technology for LNG manufacture.

The basic scheme for manufacture of LNG from gob gases would be as follows. Gas is first collected from the wellheads, dewatered, and fed into a gathering pipeline system. It is then compressed to 300-400 psig and passed through molecular sieves to remove the CO_2. Gases stripped of the CO_2 are then fed through a series of heat exchangers where they are further cooled before being rectified. Most of the air is stripped in the rectification column and pure LNG is produced from the bottom of the column. Part of the cross heat exchange for the warm feedgas is provided by cold air leaving the top of the rectifier. Additional cooling is provided by an external closed-loop refrigeration cycle which uses pure methane as feed. Delivery times for this size plant run about 12 months.

To manufacture 0.5 MMCFD of LNG approximately 1.5 MMCFD of 50 percent CH_4-50 percent air mixture must be fed to the LNG plant. This value includes parasitic fuel requirements. Correspondingly, if the gob gas has a methane concentration of 90 percent, then approximately 1 MMSCFD of this gas must be supplied to manufacture 0.5 MMSCFD of LNG. The manufactured LNG is stored in 90,000-gallon storage tanks. The LNG may be shipped to distribution points in tank cars.

Although the LNG plant is small and can be skid-mounted, certain site selection criteria must be satisfied. Right-of-way must be obtained (if necessary) for building a road to the well site, and for gathering lines supplying the feed gas. Furthermore, the plant site must be near a major highway to permit tank trucks easy access to the plant.

Finally, a market for disposal of the LNG must be established by negotiations with nearby gas suppliers.

4.3.3.6 Chloromethanes

The manufacture of chloromethanes (methyl chloride, methylene chloride, chloroform, and carbon tetrachloride) requires pure methane as a feedstock. Consequently, gob gases (50 percent CH_4-50 percent air mixtures) will have to be upgraded before they can be used for chloromethane manufacture. An encouraging factor, on the other hand, is that plants producing chloromethanes are relatively small and do not require extremely large quantities of methane.

A recent survey shows that typical chloromethane plants run in the order of 200 TPD with methylene chloride (CH_2Cl_2) constituting 60 percent of the production, chloroform ($CHCl_3$) 30 percent, and carbon tetrachloride (CCl_4) 10 percent. Delivery times for these plants are approximately two years.

The market for chloromethanes is not strong and the EPA's recent ban on fluorocarbon aerosols is expected to further weaken demand. No further consideration is given chloromethanes in this study.

4.3.3.7 Hydrates

The chemical combination of hydrocarbons and water under pressure results in the formation of hydrates. Investigators have found that between six to seven moles of water combine with methane to form a hydrate. In other words, seven to eight times as much of a mixture will have to be transported. The air in gob gases must be separated from the methane prior to or during the hydration process as it does not form hydrates. It has been found that low temperatures and high pressures favor the formation of hydrates. For example, methane gas will have to be cooled to 32°F and then pressurized to about 375 psia to form a hydrate. At room temperatures, the gas must be compressed to about 2000 psia before hydrates can be formed. The high pressures or low temperatures must be maintained during manufacture, storage, transportation, receiving, etc.

This utilization is not considered attractive compared to other alternatives and is not considered further in this study.

4.3.3.8 Ammonia

Predrainage and gob gas are both suitable for conversion to ammonia. Some upgrading of most gob gas is required. The lowest methane concentration for which an ammonia plant has been designed is about 80 percent. Lower concentrations of methane (and therefore higher concentrations of N_2) can be handled; however, the heat load on the reformer increases as does the cost of the plant. For this reason upgrading, if needed, of gob gases to a minimum of 80 percent methane is required.

Approximately 1.3 to 1.5 MMCFD of 80 percent methane gas is required to operate a 30 ton-per-day ammonia plant. The delivery time for a plant of this size is about 27 months. A 60 ton-per-day plant can be purchased for slightly more than the 30-ton size. If a site can be found with adequate methane production, the 60-ton plant would provide much better economics.

Requirements for right-of-way, road access, etc. are the same as those described for LNG.

4.4 COST-BENEFITS ANALYSES AND DEMONSTRATION SYSTEM SELECTION

In general, the currently high selling price of natural gas together with improved mining productivities and reduced mine operating costs that will likely accrue by draining methane from the coal seam and surrounding areas will make recovery and use of the gas a profitable venture. This section describes the relative economics of recovering and using gas that may be drained from virgin coal seams and gob areas. The relative economics depend upon the initial and operating cost of the boreholes, related equipment and right-of-way; the quantity of gas contained in the coalbed; the sales value of the gas or product that is made; the mining cost reductions that may be realized; and any royalties that may have to be paid to sell or use the methane. Individual parameters will likely vary considerably from mine to mine, and the sales value of the methane or products that could be made - such as LNG and ammonia - are quite volatile and could change over time.

Accordingly, the relative cost benefits are shown over the range of values that may reasonably be expected for each parameter using mine operation planning factors considered typical for mines located in the Eastern United States.

The following subsections develop subsystems costs, determine systems cost-benefits, and identify systems configurations recommended for field demonstration.

4.4.1 Subsystem Costs

This subsection presents costs of the subsystem elements for recovering and using gas contained in the coal seams and surrounding areas. The projected costs are based upon quotations furnished by potential suppliers of the equipment and/or services, or from mine operators, and are representative of costs in mid-1976.

4.4.1.1 Production Subsystem Costs

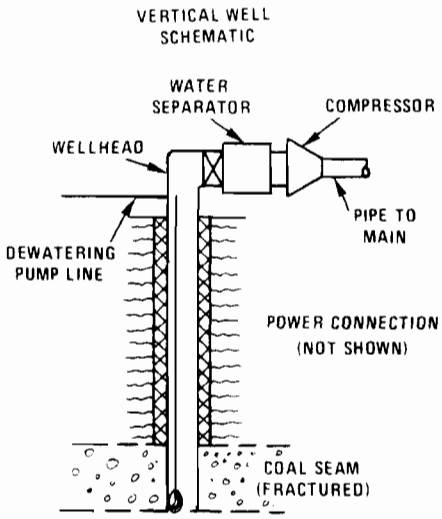
The cost of the production subsystem is dependent upon the types of wells that are used. The projected gas production rates and well spacing requirements used herein are described in Appendix J.

4.4.1.1.1 Stimulated Vertical Wells

The costs for establishing and operating a stimulated vertical well to degasify a coal seam are provided in Figures 4-4 and 4-5. The range of costs reflect the probable ranges of drilling environment, size of well bore required, and number of wells to be drilled over the area of primary interest. In some cases, the costs may be reduced to values lower than that shown by reducing the casing and grouting lengths. As indicated, the costs of the completed wells are dominated by the well costs. The costs of vertical wells that would be established to recover gob gases are substantially the same as those for degasifying a coal seam with the primary exception that stimulation and dewatering equipment costs would not be incurred.

4.4.1.1.2 Horizontal Boreholes from the Bottom of Vent Shafts Sunk in Advance of Mining

The basic cost of establishing a horizontal wellbore into a coal seam is estimated to be about $6/foot for borehole depth of the order of 1000 feet. The actual costs for establishing such boreholes must account for the costs of establishing the vent shaft ahead of the time that it would normally be established to support mining operations and the cost of the equipment required to remove the water, to duct the gases to the surface, and the cost of the equipment required to process the gas before injecting it into the collection system. Based upon a 15 percent discount rate and neglecting inflation and depreciation effects, the cost of establishing the vent shaft three years ahead of schedule would be approximately 34 percent of the original costs. For establishing the vent shaft two years ahead of schedule, the cost is approximately 24 percent of the original cost. Including the effects of inflation at five percent/year results in costs of about 24 percent of the original costs for establishing the shaft three years in advance and 17 percent for two years in advance. If the shafts are depreciated and assuming a 50 percent income tax rate, the costs for establishing the shaft (assuming five percent inflation) would be about nine percent of the cost for two years in advance and 13 percent for three years in advance. The basic cost of a typical finished vent shaft is estimated to be about $2,000 per foot of depth. For this



COST COMPONENT	RATE	COST (800 FOOT SEAM DEPTH) $000 1976 LOW	HIGH
WELLBORE			
DRILLING	$10-20/FT	8.0	16.0
PIPE	$4-5/FT	3.2	4.0
GROUTING	$5/FT	4.0	4.0
STIMULATION	$5000-10,000	5.0	10.0
DEWATERING PUMP	$150-250/HP	.3	.5
LAND	$5000/ACRE	3.2	3.7
		23.7	38.2
OPERATION & MAINTENANCE			
1 MAN/40 WELLS	$500/YEAR		
POWER	$250		
TOTAL	$750/YEAR		

FIGURE 4-4. STIMULATED VERTICAL WELL COST PROJECTIONS COMPLETED WELL, GAS INJECTED INTO COMMERCIAL PIPELINE

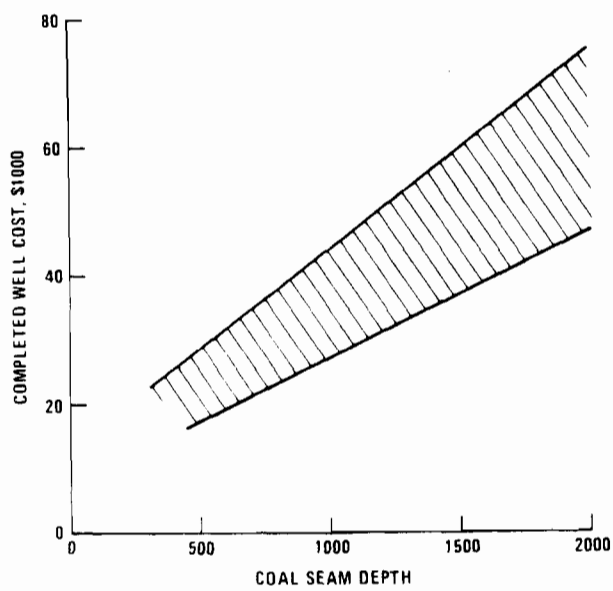


FIGURE 4-5. STIMULATED VERTICAL WELLBORE COST

analysis, the depreciation effects were included and the cost of vent shaft for establishing the horizontal wells was taken to be between $180 and $260/foot of depth. The costs of the remaining elements (based upon using six horizontal boreholes at the bottom of the shaft) are provided in Figures 4-6 and 4-7.

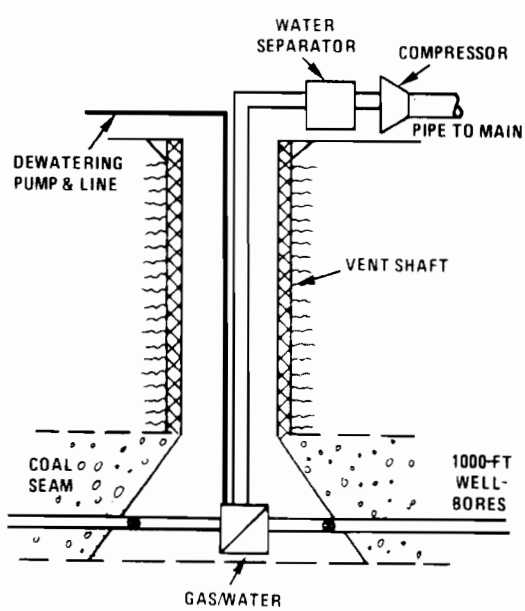
4.4.1.1.3 Horizontal Borehole Drilled Using Slant Drilling Technique

The costs for establishing and operating a horizontal well drilled using available slant hole drilling concepts to degasify a coal seam are provided in Figures 4-8 and 4-9. These costs represent the probable ranges of drilling environments, size of wellbore required, and number of wells to be drilled over the area of primary interest; however, this technology remains to be fully developed, and it remains to be proved that these costs may be realized (on the average and accounting for failures).

4.4.1.2 Collection Subsystem Costs

Collection systems are considered to consist of two separate components - the primary system for manifolding the outputs of the individual wells, and the main pipeline for moving the gas to the point where it will be used.

Based upon the projected gas production rates and well spacing requirements described in Appendix J, typical well patterns would be: vertical wells spaced about 1200 feet along the cleat, and 400 feet normal to the cleat, and slant holes spaced 4000 feet along the cleat (as constrained by drawdown times). Typical installations using such patterns are illustrated in Figures 4-10 and 4-11. As indicated for vertical holes, each well would require approximately 500 feet of piping. Slant holes would require approximately 5000 feet of piping. The costs of the collection subsystems are provided in Tables 4-2 and 4-3.



VENT SHAFT & HORIZONTAL WELL SCHEMATIC

COST COMPONENT	RATE	COST (800-FOOT SEAM DEPTH) $000 1976 LOW	HIGH
VENT SHAFT	$180-260/FOOT	184	208
BORE HOLES			
DRILLING & CASE	$6/FOOT	36	36
COLLECTION	$2000	2	2
DEWATERING PUMP	$150-250/HP	1.5	1.5
LAND	$5000/ACRE	10	15
TOTAL		193.5	262.5

NOTE: COST BASED UPON CONSTRUCTING VENT SHAFT 2-3 YEARS AHEAD OF SCHEDULE, 5% INFLATION, 50% TAX RATE, 10-YEAR LIFE FOR VENT SHAFT, AND 15% ROI

FIGURE 4-6. VENT SHAFT WITH HORIZONTAL WELLBORES, COMPLETED SYSTEM COST

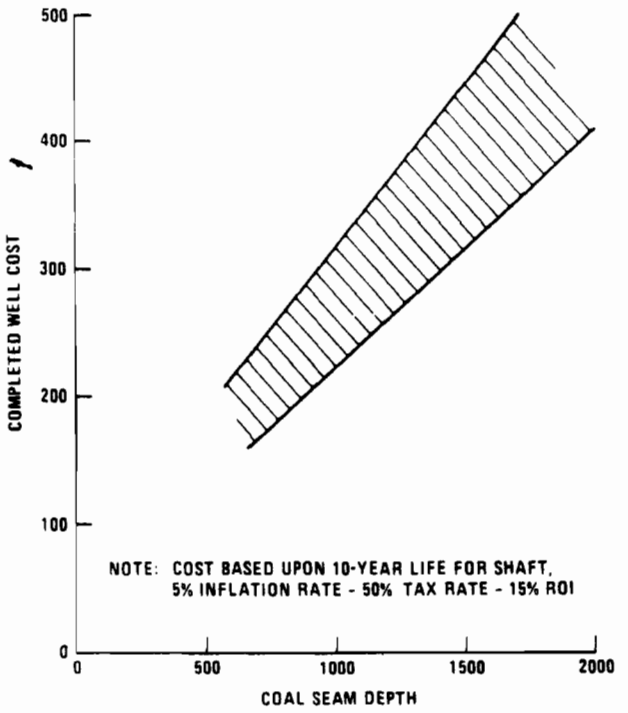
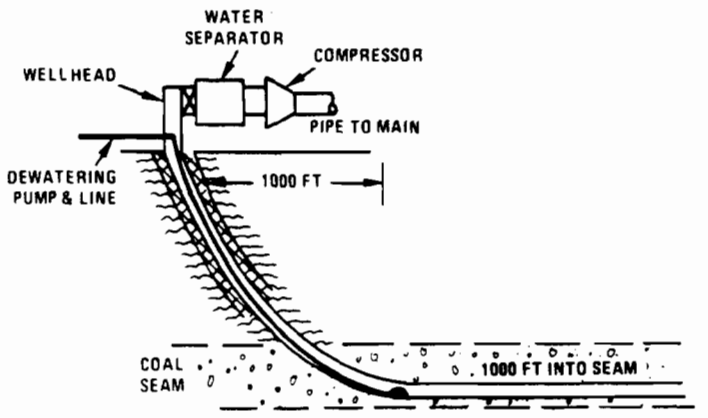


FIGURE 4-7. HORIZONTAL BOREHOLE SYSTEM COST FROM BOTTOM OF VENT SHAFT; SHAFT EMPLACED 2-3 YEARS AHEAD OF SCHEDULE; 6 BOREHOLES EMPLACED AT BOTTOM



COST COMPONENT	RATE	COST (800-FOOT SEAM DEPTH) $000 - 1976 DOLLARS LOW	HIGH
WELLBORE	$50-100/FOOT(1)	65	130
PIPE	$4-5/FOOT	2	2.5
GROUTING	$5/FOOT	2.5	2.5
DEWATERING PUMP	$150-250/HP	.8	1.2
LAND(2)	$5000/ACRE	3.5	5.0
		73.8	141.2

1. PROJECTED COST FOR EARLY WELLS. COST MAY BE REDUCED BY A FACTOR OF 2 OR MORE AS THE TECHNOLOGY IS DEVELOPED. LONGER INSEAM LENGTHS MAY ALSO BE ACHIEVED AS THE TECHNOLOGY MATURES.
2. LAND COST INCLUDES ROW TO WELL SITE AND WELL SITE AREA.
3. MAINTENANCE COST ABOUT $400/YEAR. WELL CLEANING COST ESTIMATED AT $5000 AFTER 1 YEAR OPERATION.

FIGURE 4-8. HORIZONTAL WELLBORE-SLANT HOLE WELL, COMPLETED WELL COST; GAS INJECTED IN COMMERCIAL PIPELINE

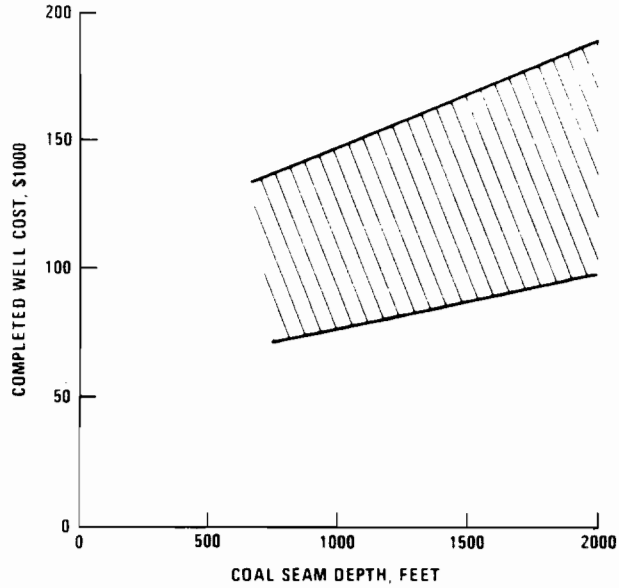
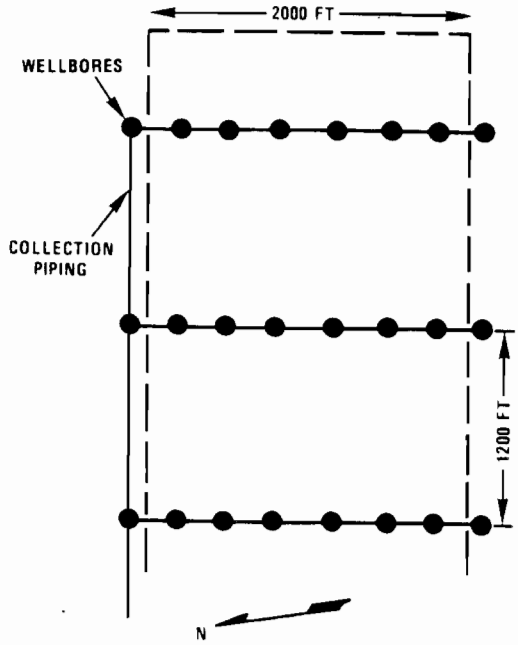


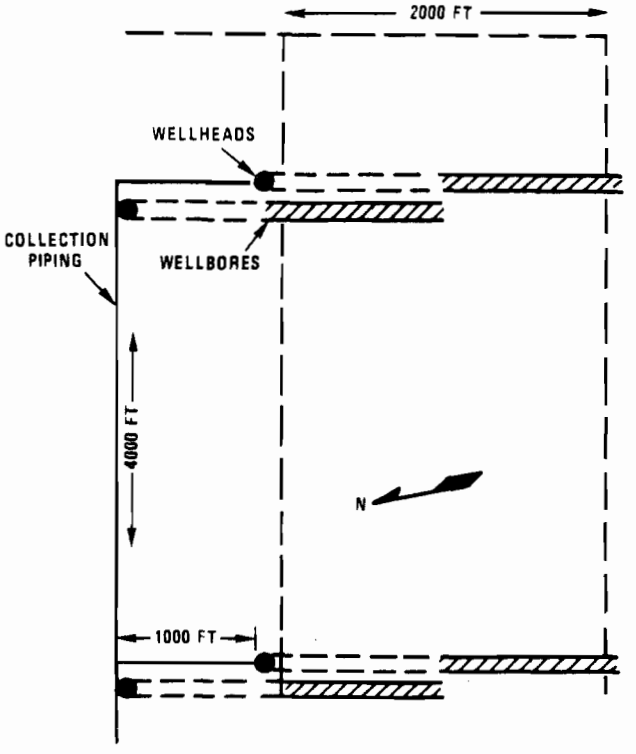
FIGURE 4-9. SLANT HOLE WELLBORE COSTS; 1000-FOOT BORE IN COAL SEAM



WELL SPACING 1200 FT PARALLEL TO CLEAT
300 FT NORMAL TO CLEAT

NOTE: WELLBORES LOCATED OUTSIDE OF AREA TO DRAIN SURROUNDING RIBS. WELL EMPLACEMENT SCHEDULE DEPENDENT UPON MINING RATE. SPACING NORMAL TO CLEAT DEPENDENT UPON FRACTURE PATTERN OBTAINED. ACTUAL LOCATIONS TO BE BASED UPON SPECIFIC MINE PLAN TO FACILITATE REMOVAL OF GOB GASES.

FIGURE 4-10. TYPICAL VERTICAL WELLBORE ARRAY, PITTSBURGH SEAM, 3-YEAR DRAWDOWN



WELL SPACING 4000 FT PARALLEL TO CLEAT AND 1000 FT FROM POINT OF SEAM ENTRY

NOTE: WELLBORES EXTEND PAST MINING AREA TO DRAIN RIBS. WELL EMPLACEMENT SCHEDULE DEPENDENT UPON MINING RATE. ACTUAL LOCATIONS TO BE BASED UPON SPECIFIC MINE PLAN TO FACILITATE REMOVAL OF GOB GASES.

FIGURE 4-11. TYPICAL SLANT HOLE ARRAY, PITTSBURGH SEAM, 3-YEAR DRAWDOWN

TABLE 4-2. PRIMARY COLLECTION SYSTEM COST, VERTICAL WELLBORES

COMPONENT	SYSTEM COST $000 - 1976 WELL PRODUCTION RATE (INITIAL) MCFD				
	25	50	100	200	400
PIPING[1] (500 FT/WELL)	3.0(2)	4.0(3)	5.5(4)	7.5(5)	10.0(6)
COMPRESSOR[2]	1.0(2)	1.5(3)	2.5(5)	6.0(12)	13.0(33)
WATER SEPARATOR $4/MCFD	.1	.2	.4	.8	1.6
POWER LINE (500 FEET/WELL)	.5	.5	.5	.5	.5
TOTAL	4.6	6.2	8.9	14.8	25.1
OPERATION & MAINTENANCE					
GENERAL – 1 MAN/40 WELLS	.5	.5	.5	.5	.5
MAINTENANCE @ 3%	.1	.2	.3	.4	.7
ELECTRICAL POWER @ 20 WELLS/KWH	.3	.4	.6	1.5	4.2
TOTAL	.9	1.1	1.4	2.4	5.4
COST LMCF 3-YEAR OPERATION[2] 20% DCF $/MCF	.51	.33	.23	.19	.18

1. NUMBERS IN PARENTHESES INDICATE PIPE DIAMETER-INCHES OR POWER RATING HP.
2. BASED ON 3-YEAR DRAWDOWN TIME, DCF BEFORE TAXES, NO SALVAGE, NO INFLATION, NO CARRYING COST DURING CONSTRUCTION.

TABLE 4-3. PRIMARY COLLECTION SYSTEM COST, SLANT HOLE WELLBORES

COMPONENT	SYSTEM COST $000 - 1976 AVERAGE WELL PRODUCTION RATE - MCFD 500	1000	2000	4000
PIPING[1] (5000 FT/WELL)	40(3)	55(4)	100(5)	185(8)
COMPRESSOR[2]	14(47)	29(93)	39(120)	99(240)
WATER SEPARATOR $4/MCF	2	4	8	16
POWER LINE (5000 FT/WELL)	5	5	5	5
TOTAL	61	93	152	285
OPERATION & MAINTENANCE				
GENERAL 1 MAN/10 WELLS	2.0	2.0	2.0	2.0
MAINTENANCE @ 3%	1.8	2.8	4.6	8.6
ELECTRICAL POWER @ 20 WELLS/KWH	6.1	11.7	15.1	30.2
TOTAL	9.9	16.5	21.7	40.8
COST/MCF (3-YEAR OPERATION)[2] 20% DCF, $/MCF	.32	.25	.19	.18

1. NUMBERS IN PARENTHESES INDICATE PIPE DIAMETER-INCHES OR POWER RATING-HP.
2. BASED ON THREE-YEAR DRAWDOWN, DCF BEFORE TAXES, NO SALVAGE, NO INFLATION, NO CARRYING COST DURING CONSTRUCTION.

The cost of the pipeline to move gases from the area to be drained to the point where they will be used depends upon the amount of gas to be moved and the distance. Estimated costs are provided in Table 4-4. As indicated, costs of the compressor and CO_2 scrubber (if the scrubber is required) represent a substantial fraction of the system costs.

TABLE 4-4. MAIN PIPELINE COST

COST COMPONENT	GAS PRODUCTION RATE MMCFD 1			2			4		
	DISTANCE (1000 FT) (4" PIPE)			DISTANCE (1000 FT) (6" PIPE)			DISTANCE (1000 FT) (8" PIPE)		
	5	10	20	5	10	20	5	10	20
PIPING[1]	55	110	220	100	280	400	165	330	660
LAND	5	10	20	5	10	20	5	10	20
COMPRESSOR[2]	29(94)	55(139)	111(196)	39(123)	71(193)	130(286)	99(237)	172(374)	304(557)
CO_2 SEPARATOR	200	200	200	250	250	250	300	300	300
TOTAL	289	375	531	394	531	800	569	812	1284
OPERATION & MAINTENANCE									
GENERAL 1/2 MCN @ 18000	9	9	9	9	9	9	9	9	9
MAINTENANCE	9	11	15	12	16	24	17	24	39
ELECTRICAL POWER[2]	5	9	17	11	21	41	16	44	61
$M/YR TOTAL (WITH SCRUBBER)	23	29	41	32	46	74	42	77	109
COST $/MCF[3] WITH CO_2 SCRUBBER	26	.34	.48	.18	.25	.38	.13	.19	.30
WITHOUT CO_2 SCRUBBER	.11	.19	.33	.08	.15	.28	.07	.14	.24

[1] PIPE COST – 4"-$11/FOOT 6"-$20/FOOT 8"-$33/FOOT – INCLUDES INSTALLATION (TOTAL COSTS IN $M).
[2] NUMBERS IN PARENTHESES INDICATE POWER RATING - HP.
[3] BASED ON DCF = 20% BEFORE TAXES, 10-YEAR OPERATING LIFE, NO SALVAGE VALUE, NO CAPITAL CARRYING COST DURING CONSTRUCTION, NO INFLATION.

4.4.1.3 Conversion/Utilization Subsystem Costs

4.4.1.3.1 Injection into Commercial Pipeline

The only costs incurred for injecting methane into a commercial natural gas pipeline involve a compressor if needed to boost pressure and a CO_2 scrubber if necessary to remove CO_2. These costs, when applicable, are shown with the collection subsystem and may be found in Table 4-4.

4.4.1.3.2 LNG Subsystems

The costs of the LNG plants are based upon estimates provided by Kennedy Engineering and Cleanair Combustion Systems Ltd. The costs of the plants vary according to the quality of the input gas and upon the plant capacity. The costs of the plants (1 and 2 MMCFD capacity) based upon a 95 percent methane feed and CO_2 levels of about four percent are provided in Table 4-5. Such plants would be applicable for using the high quality gas that may be obtained by predraining the coal seam. The costs of the LNG plants (1 and 2 MMCFD capacity) for processing 50 percent methane 50 percent air mixtures are also provided in Table 4-5. Such plants would be applicable for processing gob gases.

TABLE 4-5. LNG PLANT COSTS—1976 DOLLARS

COST COMPONENT	COST $000 95% METHANE GAS PLANT CAPACITY-MMCFD		COST $000 50% METHANE GAS PLANT CAPACITY-MMCFD	
	1	2	1	2
LNG PLANT	800	1150	900	1300
COMPRESSOR	80	220	93	229
CO_2 SCRUBBER	200	250	200	250
SUPPORT FACILITIES	40	40	40	40
CONSTRUCTION	45	90	45	90
LAND	5	8	5	8
TOTAL	1170	1758	1273	1917
OPERATION & MAINTENANCE				
LABOR	45	90	45	90
ELECTRICAL POWER	30	60	32	64
MAINTENANCE	32	49	35	53
TOTAL	107	199	112	207
LNG PRODUCTION - MMCFD	.80	1.6	.40	.80

4.4.1.3.3 Ammonia Subsystems

The costs of the ammonia plants are based upon estimates provided by Kennedy Engineering and C&I Girdler. The cost of the plants are somewhat dependent upon the input gas quality, and the economies of scale at the sizes considered appropriate for single mine operations are substantial. The costs of the plants for 1 and 2 MMCFD capacity are provided in Table 4-6. As for LNG plants, the lower costs are applicable for using

TABLE 4-6. AMMONIA PLANT COSTS

COST COMPONENT	COST $000 95% METHANE GAS PLANT CAPACITY-MMCFD		COST $000 50% METHANE GAS PLANT CAPACITY-MMCFD	
	1	2	1	2
AMMONIA PLANT	5000	5000	5500	6000
COMPRESSOR	75	150	80	160
SUPPORT FACILITIES	40	50	40	50
CONSTRUCTION	75	150	75	150
LAND	10	20	10	20
$M TOTAL	5200	5370	5705	6380
OPERATION & MAINTENANCE				
LABOR	65	110	65	110
ELECTRICAL POWER	15	30	16	32
MAINTENANCE	152	154	167	185
$M/YR TOTAL	232	294	248	327
AMMONIA PRODUCTION TONS/DAY	30	60	15	30

predrainage gas qualities and the higher costs for processing gob gas. As indicated, the small ammonia plants are more expensive than LNG plants and due to the economies of scale will likely be economical only for capacities greater than 2 MMCFD.

4.4.1.3.4 Gas Turbine Power Plant Subsystems

The costs of the gas turbine power plants are based upon estimates provided by Solar Division of International Harvester. The costs of the plants are dependent upon the input gas quality and the performance is dependent upon optimizing the plant operation in the field. The cost of the plants in the size range projected for single mine operations to use the 50 percent methane gas is provided in Table 4-7. The cost of the plant is dependent upon the level of automatic operation afforded the plant and upon the facilities provided to house the equipment. The cost and performance of such plants will be improved if the higher quality methane is used.

4.4.1.3.5 Coal Drying Units and Other Heating Application Subsystems

The cost for retrofitting an existing coal drying unit to burn 50 percent methane 50 percent air gas mixture was obtained from Heyl and Patterson. A typical unit currently burns 256 tons of coal per hour and would require 5 MMCFD of gob gas. The estimated cost is $90,000-$115,000 which includes removal of the fluidized bed equipment, reconfiguring the furnace to burn gas, and installation of the gas burner equipment.

In those cases where a complete retrofit is not desired and gob gas is to be used, when available, to substitute for coal, the cost of retrofitting the furnace is estimated to be approximately $18,000/MMCFD of gob

TABLE 4-7. GAS TURBINE POWER PLANT COSTS—1976 DOLLARS: 50% METHANE GOB GAS CONFIGURATION

COST COMPONENT	COST $000 GOB GAS INPUT – MMCFD	
	1	2
GAS TURBINE & GENERATOR	185	370
GOB GAS COMPRESSOR	75	150
ELECTRICAL CONNECTION & CONTROL	15	15
FACILITIES & INSTALLATION	40	50
LAND	5	5
TOTAL	320	590
OPERATION & MAINTENANCE		
MAINTENANCE	8	16
LABOR	7	7
TOTAL	15	23
POWER PRODUCTION – KW NET AFTER COMPRESSION OF GOB GAS	800	1600

gas capacity. This cost represents adding the required gas burner equipment and baffles and is based upon receiving the gas at a pressure about 40 psig. The gob gases may also be used to substitute for natural gas or oil heating applications. The basic costs are those associated with changing the burner units to account for the lower quality gas and providing larger piping to the burner units. These costs are generally small if the distances from the gob gas availability point to the burner connection are reasonably short.

4.4.2 Cost-Benefits Projections

The basic technique towards defining the profitabilities of the different possible ventures is based upon the conventional 'constant dollar' (no inflation effect) discounted cash flow approach. For those investments representing low risks, the minimum acceptable rate of return (before taxes) is set at 15 percent. For those investments associated directly with recovering and using the methane, the minimum acceptable rate of return is set at 20 percent (before taxes) to account for the higher investment risk. In those cases where the after tax rate of return is provided, the equipments were depreciated using the straight line method and the tax rate was set at 50 percent. The salvage value of the equipments at the end of the period and the cost to restore the areas were not specifically included in the cash flow analysis. In certain cases, the value of the gas or product is not sufficient to meet the minimum acceptable rates of return that are required. For these cases, the after tax rates of return are provided as a function of the coal mining cost savings that would accrue due to degasifying the coal seam. The coal mining cost savings that would accrue due to degasifying the coal seam are presumed to occur directly after the coal seam was drained - generally three to four years. The actual savings are based upon the

coal mined in the area and depends upon the mining technique, i.e., room-and-pillar or longwall methods.

Specific details of the investment analyses are provided in Appendix K. The costs of the system elements and the gas production rates are described in Sections 4.4.1 and Appendix J. In all cases, the rates of return indicated are the appropriate future cash flow discount factors (DCF) or the effective investment index (i) conventionally used to calculate the present worth of the yearly revenues, and/or expenditures.

4.4.2.1 General Economic Factors

Cost of the individual system elements to recover and use the methane, gas production rates of the wells, value of the methane or product that is formed, the specific plan for installing degasification boreholes, and the value of removing the gas from virgin coal in advance of mining or from gob areas, represent the primary variables used in the venture analysis.

The profitability of recovering methane contained in the coal seam and surrounding areas - based on value of the gas alone - depends upon the cost of required equipments, the rate and quality of gas recovered, and the gas value. In those cases where it is practical to establish a pipeline from the area being drained to a commercial pipeline, selling the gas directly represents the simplest approach to effective use of the gas. Where such lines are impractical - because of distance or other obstacles - converting the gas to LNG or ammonia represent practical options. The gob gases may also be converted to LNG or ammonia or be used to generate electrical power or for local heating applications.

Markets for the high quality gas, LNG, and ammonia are considered volatile and area dependent. For these economic projections, the value of the high quality gas is taken to be about $1.50/MCF. The value of the LNG is taken to be about $2.00-$2.50/MMBtu and the value of ammonia is projected to be $75-$100/ton. When the gob gases are used for local heating applications to substitute for natural gas or oil, the value of the gas is taken to be about $1.50/MMBtu. When used to substitute for coal, the value of the gob gases are taken to be about $.40/MMBtu - i.e., $10/ton coal. When the gob gases are used to produce electrical power, the value of the power is taken to be 20 mills/kwh.

At the present time, there is insufficient data to accurately project the quantity of gas that may be recovered from the virgin coal and surrounding areas or from the gobs. Additionally, there is insufficient data to accurately project coal mining savings that would accrue by predraining the virgin coal seams or by removing the gas in gob areas. Conceptually, the mining cost savings would include reduced ventilation air requirements, reduced cost for establishing the headings, reduced lost time due to methane buildups, and improved productivity of mining equipment. For the economic projections provided in the remainder of this section, the coal mining cost savings are treated as a variable. Values are expressed in terms of savings per ton of coal mined in the area that has been drained - ranging up to $3.00/ton - and as such, the savings should be

associated with the total cost of mining a ton of coal that is associated with methane concentrations in the coal seam and surrounding area.

Since the savings will depend directly upon methane concentrations in the coal seam at the time of mining, the economic projections are based upon draining approximately 80% of the methane contained in the virgin coal and upon removing the gob gases until the methane concentration falls to about 30 percent. The most economic plan for reducing the cost by removing the gases remains to be established.

As described in Section 3, the methane production rates that might be realized from individual wellbores drilled into virgin coal are highly dependent upon the specific coal seam characteristics, maintenance and operation of the wellbores, and in the case of the vertical wells, the degree of fracturing that is obtained. The rates at which gob gases may be recovered also depend upon the specific coal bed characteristics and upon the mining method (room-and-pillar or longwall) and the rate at which the gob areas are generated. If drainage of the virgin coal is coupled directly to coal production rates, drainage will precede mining activity by a time which provides the most economic investment opportunity, and the sale or use of the methane would be based upon the projected production rates.

The projected methane recovery rates and the number of vertical or horizontal wellbores that would be required for the different coal seams are provided in Table 4-8. These data are based upon recovering 80% of the methane contained in the coal seam over a four-year drawdown time. using well production rates that have been projected for the areas and that account neither for gas contained in the area surrounding the coal seam nor for the effects of previous mining or drilling activities.

As indicated, for the same mine production rates, it is necessary to drain larger areas using more wells if room-and-pillar mining methods are used as compared to using longwalls. The methane drainage rates will vary from about 350 MCFD for small mines (500,000 tons/year) producing coal from the Pittsburgh seam to about 10 MMCFD for large mines (2,000,000 tons/year) producing coal from the Freeport seam.

Specific potential uses of the methane that would represent practical investment opportunities for an individual mine operator, and described in Section 4.4.1, are:

1. Selling the methane to a commercial distributor or public utility. This would require - generally - upgrading the gas to pipeline standards and piping the gas to a point where it may be injected into an existing pipeline.

2. Converting the methane to LNG.

3. Converting the methane to ammonia.

4. Using the gas to produce electrical power with a gas turbine, and using the power locally.

TABLE 4-8. VIRGIN COAL SEAM DRAINAGE REQUIREMENTS AND DEGASIFICATION BOREHOLE PERFORMANCE PROJECTIONS

COAL SEAM	DEPTH FEET	GAS CONTENT SCF/TON	INITIAL GAS PRODUCTION RATE MCFD/WELL		AREA DRAINED* ACRES/WELL		REQ. GAS PRODUCTION RATE** MMCFD/10' TONS COAL/YEAR		REQ. NUMBER OF VERTICAL WELLS/10' TONS COAL/YEAR		REQ. NUMBER OF HORIZONTAL WELLS/10' TONS COAL/YEAR	
			VERTICAL	HORIZONTAL	VERTICAL	HORIZONAL	ROOM & PILLAR	LONGWALL	ROOM & PILLAR	LONGWALL	ROOM & PILLAR	LONGWALL
PITTSBURGH	800	180-300	18-30	360-660	9	140	.7-1.25	.8- .9	17	11	1.1	.7
BECKLEY	800	400-520	40-52	800-1040	9	140	1.7-2.2	1.1-1.5	17	11	1.1	.7
FREEPORT	1200	1200	180	3120	13	165	5	3.4	12	8	.9	.6
POCOHONTAS	1500 2000	340-560 340-560	65-110 85-140	1020-1680 1190-1960	18 22	190 215	1.4-2.3 1.4-2.3	1.0-1.6 1.0-1.6	8 7	6 5	.8 .7	.5 .5
MARY LEE	1500 2000	240-400 420-600	46-76 100-150	770-1200 1470-2100	18 22	190 215	1-1.7 1.7-2.5	.7-1.1 1.1-1.7	8 7	6 5	.8 .7	.5 .5

*BASED UPON RECOVERING 80 PERCENT OF THE GAS OVER 4-YEAR DRAWDOWN TIME. COAL SEAM DIRECTIONAL PERMEABILITY FACTOR 4:1 PARELLEL: NORMAL TO CLEAT.
**BASED UPON COAL RECOVERY FACTORS OF 55% FOR ROOM-AND-PILLAR AND 80% FOR LONGWALL.

5. Using the gas to satisfy local heating requirements. When used for space and water heating applications, the methane would substitute for natural gas or oil. When used for coal drying applications, the methane would substitute for coal.

As indicated in Section 4.4.1, the required systems are generally available in the capacity ranges compatible with the methane production rates projected for the different areas. However, the costs of the ammonia plants at the capacities indicated are strongly influenced by the economies of scale and are appropriate options for gas supply rates above 2 MMCFD. Upgrading the low quality gob gas to pipeline standards is not considered an economical option. In a practical application, a combination of system technologies may be warranted as the virgin coal seam is drained and the gob gases recovered. Specific costs and benefits are described for these systems in the following sections.

4.4.2.2 Virgin Coal Seam Predrainage Economic Projections

Recovering gas in virgin coal may be accomplished well in advance of mining operations. For this case, when economically practical, large areas could be drained and large volumes of gas produced.

Pipeline costs, costs of the primary collection system, costs of the degasification boreholes, and projected gas production rates are provided in Appendix J and Section 4.4.1. For this analysis, it is assumed that a large area will be drained, resulting in producing at least 4 MMCFD of high quality gas for a 10-year period and requiring piping the gas four miles to the connection point. The cost of the pipeline (with the CO_2 scrubber) is estimated to be approximately $1.284 million with annual operating costs of $109 thousand. Based upon the 20% discount rate, and a 10-year life, these translate into a cost of $.30/MCF of gas.

The cost of the primary collection system depends upon the gas production rate for each wellbore and upon the well spacings involved. Based upon the spacings described in Appendix J and assuming individual wells are located so as to drain the individual areas in six years, the vertical wells will be spaced from 1400 to 2200 feet apart in a direction parallel to the face cleat, depending upon the coalbed depths. Spacing parallel to the butt cleat would be from 350 to 550 feet. For the same conditions, horizontal boreholes established using the slant hole technology would be spaced from 8000 to 14000 feet apart in a direction parallel to the face cleat.

Based upon projected costs and production rates, the required gas selling price to realize a 20% before tax return on investment will vary depending upon the specific coal seam characteristics. The required selling prices of gas recovered from the different coal seams - based upon the value of the gas alone - are provided in Figures 4-12 and 4-13. These prices were established by associating the high capital costs and low gas production projections to project the high prices, and the low capital costs and high gas production projections to project the low prices.

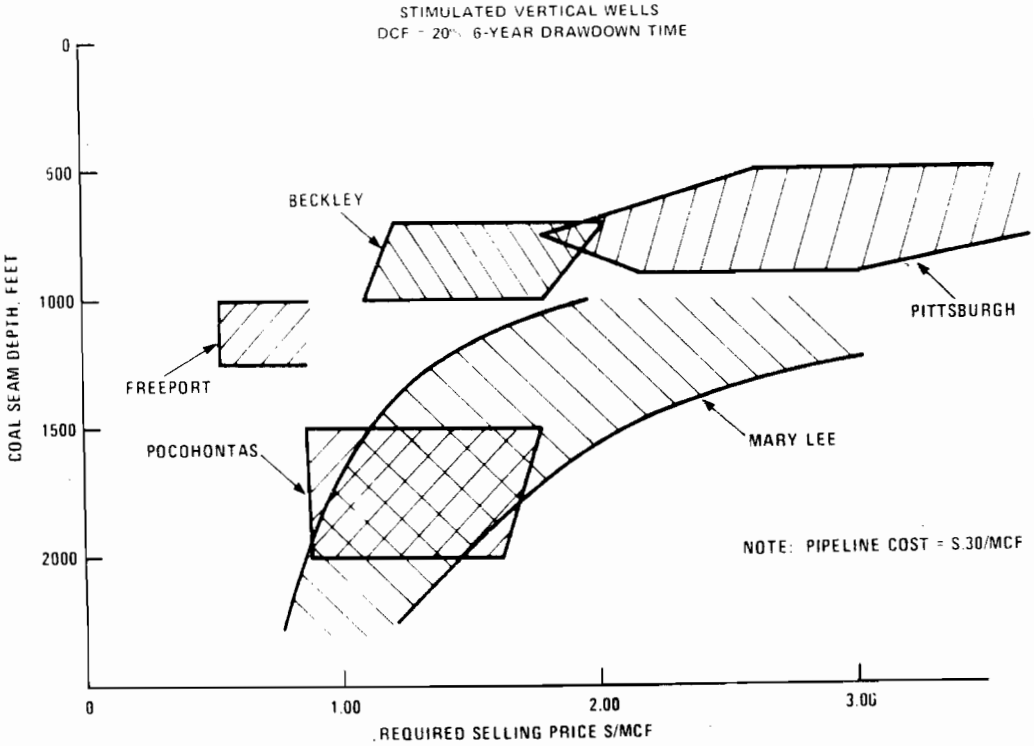


FIGURE 4-12. REQUIRED GAS SELLING PRICE, STIMULATED VERTICAL WELLS

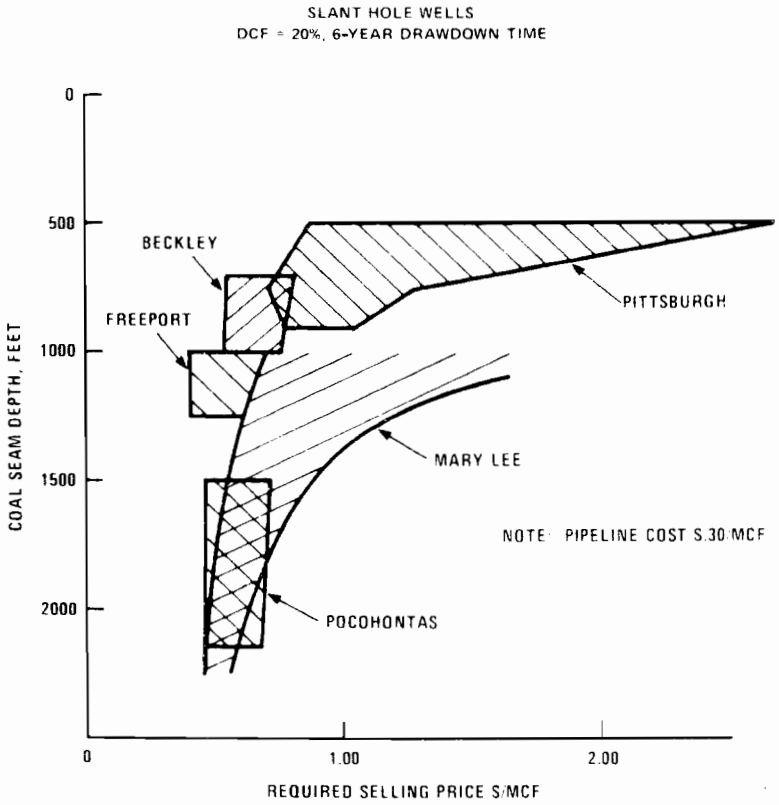


FIGURE 4-13. REQUIRED GAS SELLING PRICE, SLANT HOLE WELLS

As indicated in Figure 4-12, when using stimulated vertical degasification boreholes, the required selling price is higher than the projected value of $1.50/MCF for the shallower, less gassy coalbeds. As such, recovering the gas in this manner will, generally, not be economically attractive.

As indicated in Figure 4-13, when using horizontal wells established with slant hole drilling techniques, the required price is generally less than $1.50/MCF and the venture would generally be economically attractive.

In cases where it is impractical to establish a pipeline connecting the degasification boreholes to a commercial pipeline, the gas may be used to produce LNG or ammonia. When coal seams are drained well in advance of mining, which could be the case if the slant hole technologies are developed, then large quantities of methane are produced and large commercial size plants could be used to produce LNG or ammonia. In this case, the economic practicality of converting the gas to LNG or ammonia is dependent upon the price of the methane as compared to prices that must be paid by other competing plants. When using slant hole wellbores, the required selling price of the methane is generally less than $1.50/MCF, the projected price that would be paid by a competing plant. Based upon this comparison, converting the gas to LNG or ammonia could be economically practical depending upon the market for the product. When using vertical wells, the required selling prices are higher and the practicality of the investment is highly dependent upon market forces in the specific area.

Under conditions where the areas to be drained are small, the gas production rates will be low, and smaller, more expensive conversion plants will be required. Consequently, the product's required selling price - if methane prices are the same - will be higher when using smaller plants. Required selling prices of LNG and ammonia when using small plants are provided in Figure 4-14. These prices are based upon the plant costs described in Section 4.4.1 and are shown as a function of the gas cost. As indicated, LNG could be produced at competitive market prices if the gas cost does not exceed $1.00/MCF. Ammonia could also be produced at competitive prices when using the larger plant (2 MMCFD) if the gas price does not exceed $1.00/MCF. The smaller ammonia (1 MMCFD) would be uneconomical unless prevailing prices for ammonia are greater than $150/ton.

As such, the case of the economic practicality of converting the gas to LNG or ammonia is considered as an option to establishing a connecting pipeline from the degasification boreholes to a commercial pipeline only under specific circumstances. The most appropriate option would depend upon specific market conditions in the general area affecting selling price of the products.

In general, the LNG plant would represent the most practical option, but since the market for LNG is highly localized, the ammonia plants could be required for many specific locations, i.e., no LNG market. The specific choice would depend upon actual market conditions. The most appropriate

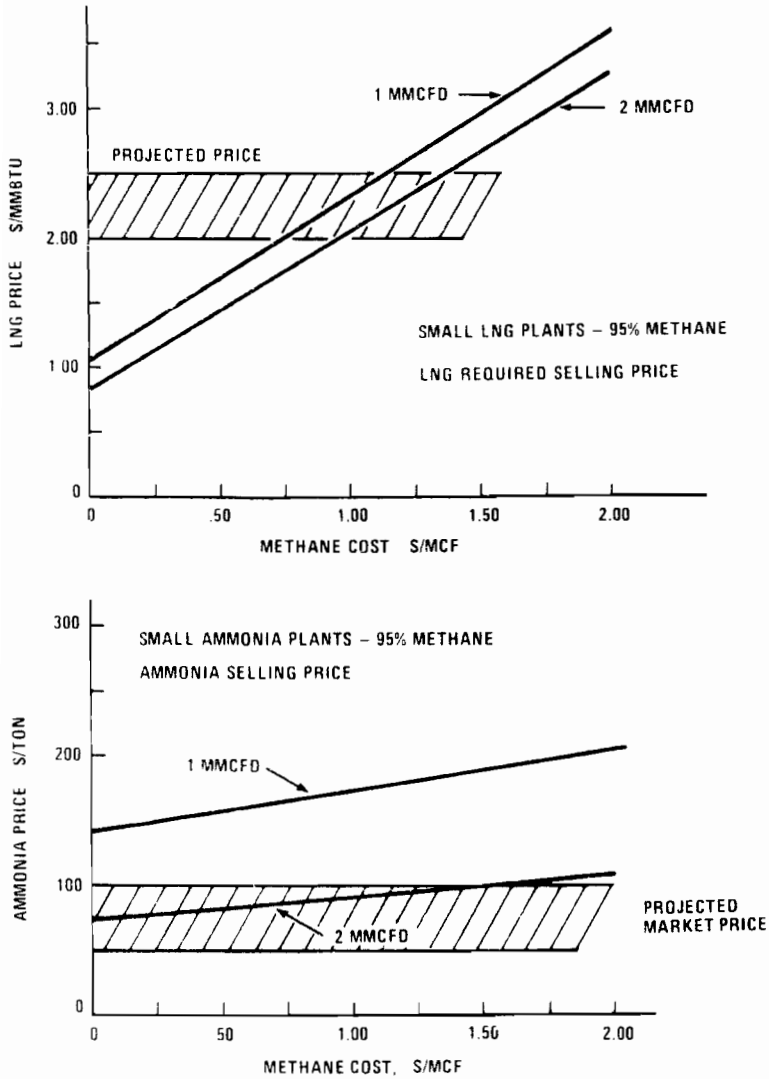


FIGURE 4-14. REQUIRED SELLING PRICE FOR AMMONIA AND LNG

choice is indicated in Figure 4-14. These data are based upon equating the required selling prices of LNG or ammonia shown in Figure 4-15 for equal gas costs. If higher LNG or ammonia prices are realized, then the rates of return will be higher than 20 percent.

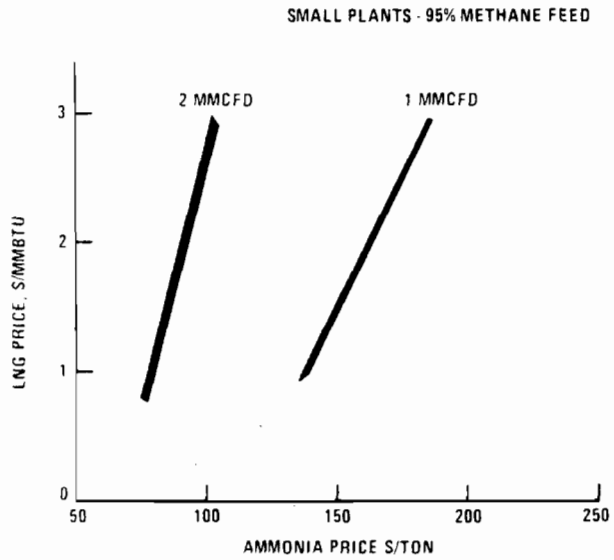


FIGURE 4-15. EQUIVALENT SELLING PRICES, LNG AND AMMONIA

4.4.2.3 Gob Gas Recovery Economic Projections

Recovering the gas in gob areas may be accomplished using the degasification boreholes and collection systems installed to drain the virgin coal, or separate boreholes may be drilled into the gob areas and appropriate collection systems established. In either case, the gas that may be recovered from gob areas varies in quality depending upon how well the areas are sealed to the ventilation air in the mine workings. For this analysis, the quality of gob gases is taken to be about a 50% methane-50% air mixture. Upgrading these gases to pipeline quality and selling them at pipeline prices is impractical. As such, the basic options for using the gas is either to convert the gas to LNG or ammonia, to produce electrical power, or to use the gas for local heating purposes as a substitute for natural gas or coal.

Techniques for recovering gob gases include establishing vertical wells from the surface and removing the gas directly or establishing ducts within the mine workings and bringing the gas to the surface through a ventilation shaft. The costs of establishing the required ducts for collecting gob gases within the mine are difficult to establish due to the mining safety regulations and, as such, an economic analysis for such systems is not included in this report.

The relative economics of converting the gob gas to LNG or ammonia, to produce electrical power, or for local heating purposes are described in this section. The relative economics are based using the plant costs provided in Section 4.4.1, upon the costs of the gas being from 0 to $.50/MMBtu, and upon recovering 1 to 2 MMCFD of gob gas averaging 50% methane. The operational life of the LNG and ammonia plant - before major overhaul - is assumed to be 20 years. The operational life of the gas turbines is assumed to be 40,000 hours (five years) before major overhaul. When used for local heating applications, the operational lifetimes are assumed to be 10 years, although much longer lifetimes may be realized.

The cost of producing and collecting the gob gases depends upon whether the boreholes and collection system to be used are those that were established to drain the virgin coal or if new systems are required. The cost, if a new system is required, is provided in Table 4-9. The resulting cost of the gas, assuming that the wells produce for three years, is provided in Figure 4-16. These data were developed as a function of the coal mining cost savings based upon a mine production rate of one million tons/year that would be realized as the gas is recovered.

TABLE 4-9. GOB GAS PRODUCTION AND COLLECTION SYSTEM COSTS, 50% METHANE–50% AIR MIXTURE

	SYSTEM COSTS $000 TOTAL GAS PRODUCTION RATE MMCFD			
	1 WELL PRODUCTION RATE MCFD		2 WELL PRODUCTION RATE MCFD	
	100	200	100	200
BOREHOLES	240 - 300	100 - 150	400 - 600	200 - 300
PRIMARY COLLECTION SYSTEM	118	95	236	190
PIPELINE (5000 FEET)	89	89	144	144
TOTAL	407 - 507	284 - 334	780 - 980	534 - 634
OPERATION & MAINTENANCE				
PRIMARY	14	12	28	24
PIPELINE	17	17	24	24
$M/YR TOTAL	31	29	52	48

As indicated, small savings will result in recovering the cost of the systems. Based upon the costs provided in Table 4-9, the cost of gas collection varies from $.30 to $.40/MMBtu with an additional cost of about $.20/MMBtu if the gas must be piped 5000 feet to a central location for conversion. Thus, the minumum value of the methane if collected and used will range from $.30 to $.60/MMBtu if new collection systems are required. If the collection system established to drain the virgin coal is also to be used to collect the gob gases, then in some cases the size of the predrainage system must necessarily be increased to handle the gob gas flows. These cost increases would represent the cost of collecting the gob gases.

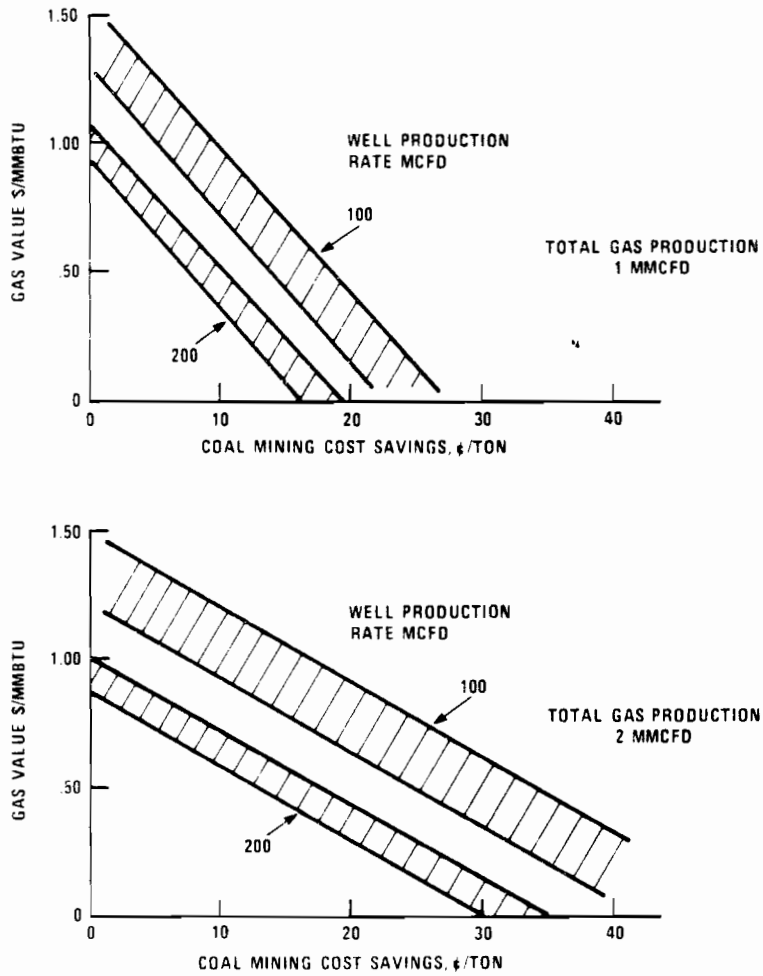


FIGURE 4-16. GOB GAS VALUE

4.4.2.3.1 LNG and Ammonia Plant Economies for Gob Gas Utilization

The costs of the plants to convert gob gases to LNG or ammonia are provided in Section 4.4.1. Based upon these costs, the required selling prices of LNG and ammonia are provided in Figure 4-17. As indicated, LNG could be sold at competitive prices if the cost of gas collection is less than $.25/MMBtu and if larger plants are used. However, the required selling price of ammonia is higher than the projected market price, and these plants are unlikely to be economically practical. The required value of the gas - less the $.25/MMBtu - also indicates that these options are likely to be practical only if the collection system used is that which would also be used to drain the virgin coal.

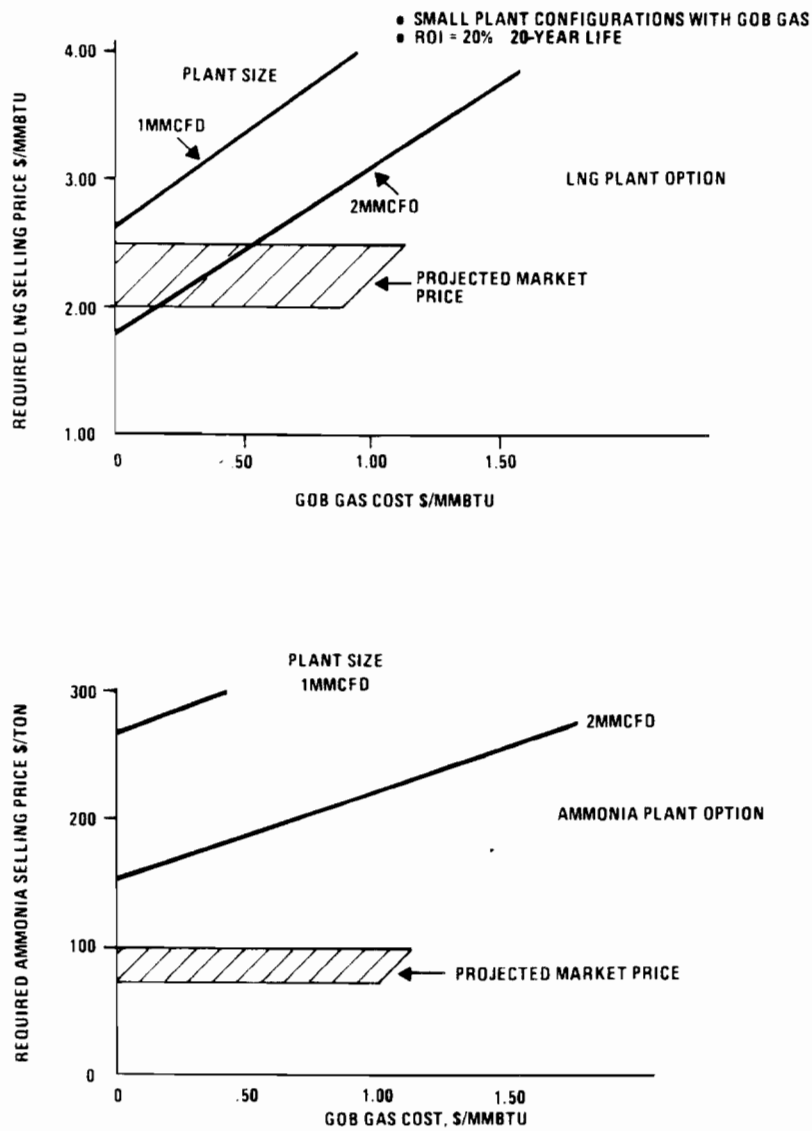


FIGURE 4-17. REQUIRED SELLING PRICE FOR LNG AND AMMONIA

4.4.2.3.2 Power Production Plant Economic Projections

Costs of the small power plant configurations suitable to use gob gases are provided in Section 4.4.1. These costs are based upon consuming the power locally and using short transmission distances. The value of the power, indicated in Figure 4-18, is based upon the projected costs and realizing a 20 percent rate of return for five years' operation. As indicated, the option would be economically practical if the gob gas costs are less than $.25/MMBtu.

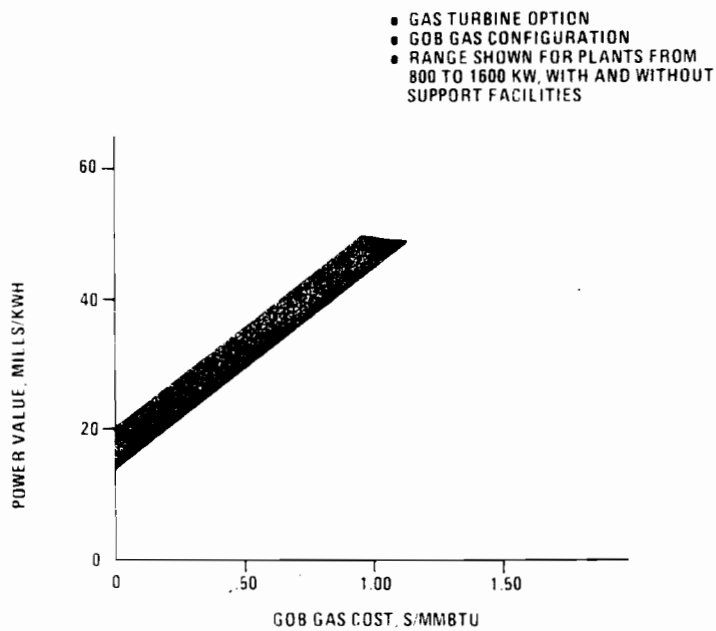


FIGURE 4-18. REQUIRED POWER VALUE

4.4.2.3.3 Local Heating Options

The value of using gob gas for local heating applications depends upon cost of the alternative fuel. If used for spacing heating applications, the fuel displaced would usually be natural gas or oil. Substituting gob gases for such fuels will reduce the heating cost by a factor of about 3, and large savings could result if substantial quantities of fuel are required. If the gas is used for coal drying applications then the fuel displaced will usually be boiler quality coal with a nominal selling price of about $.40/MMBtu. This price represents the approximate cost of establishing the collection system and pipeline. As such, this investment would represent a practical investment option depending upon the specific cost involved in establishing a pipeline to the coal drying facility.

4.4.2.4 Applications to the Pittsburgh Seam

As indicated in the previous sections, predraining the Pittsburgh seam would not be economically attractive - based on methane sales alone -

when using vertical degasification boreholes - but would be economically practical in some areas when using the slant hole technology. To be economically attractive, degasifying the Pittsburgh seam in advance of mining must also result in improved mining productivity and reduced mining costs. When degasifying the coal seam in advance of mining to reduce mining costs, it would be drained at a rate compatible with the planned mine production rate, and the degasification boreholes would be spaced so as to obtain the highest practical investment return rate. Under such conditions, the proper spacing depends upon relative value of the gas, value of the mining cost savings that would be realized, costs of establishing and operating the wells, and the cost of piping the gas to a commercial pipeline or using point.

As indicated in Appendix K, proper spacings for the Pittsburgh seam result in relatively short drawdown times - three to four years. For these conditions, the required vertical well spacings are about 1200 feet and the spacing for slant hole wells are about 5000 feet. Under some conditions, longer drawdown times and larger spacings would improve the attractiveness of the investment. However, these projections are based upon sustained gas production rates which remain to be proven for the Pittsburgh seam. Accordingly, the economic projections are based upon the short drawdown times and appropriate wellbore spacings. The cost of the systems used are provided in Section 4.4.1.

4.4.2.4.1 Predrainage in Advance of Mining - Direct Methane Sale

The after tax rates of return for draining the virgin coal in the Pittsburgh seam when using the vertical boreholes with room-and-pillar mining methods are illustrated in Figure 4-19. These data are based upon

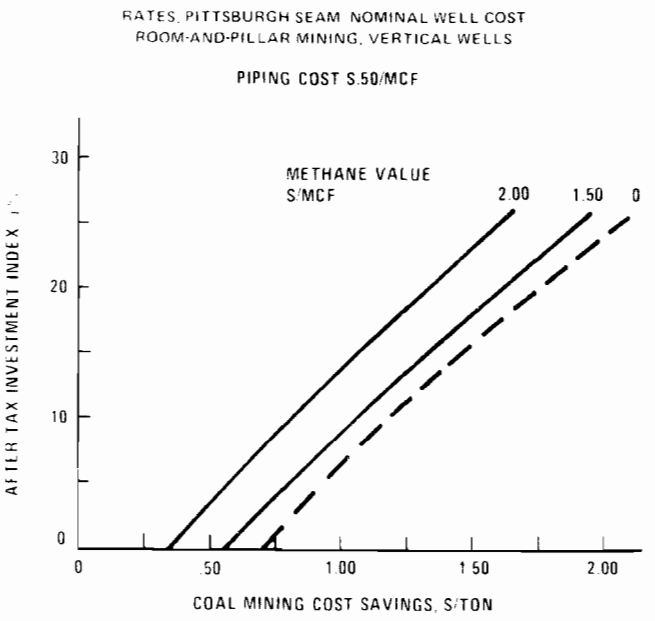


FIGURE 4-19. PREDRAINAGE INVESTMENT RETURNS

using a three-year drawdown time with coal mined in the third year, and are shown as a function of the mining cost savings that would be realized. For the case shown in which no methane value is taken, the gas was vented to the atmosphere. These data indicate that to be economically practical, coal mining cost savings of about $1/ton would be required and that the sale of the methane improves the profitability. Since longwall mining methods result in removing about 60% more coal from the area drained, the required savings to break even are about 60% of the savings required for room-and-pillar methods or about $.60/ton.

Similarly, the after tax rates of return for the case in which slant hole wellbores are used are provided in Figure 4-20. For this case, since

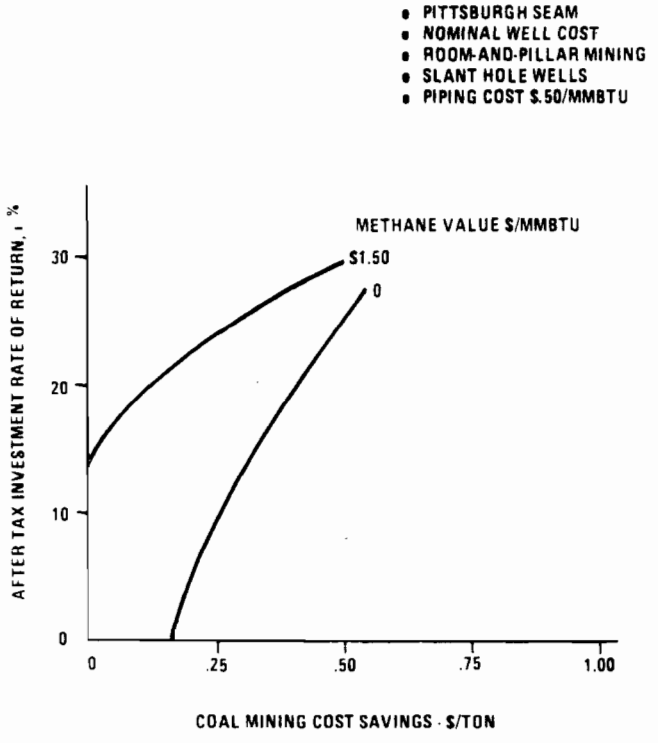


FIGURE 4-20. PREDRAINAGE INVESTMENT RETURN RATE

the area drained is large, it was assumed that the coal was mined in the fourth year. As indicated, the projected rates of return are large for small mining cost savings. As indicated, the projected rates of return are large for small mining cost savings. As indicated in Section 4.4.2.3, predraining the coal seam would be economically attractive in some areas, based upon the sale of methane alone, when using the slant hole technology.

The projected cost of using the horizontal wells from the bottom of a vent shaft established three years ahead of schedule is given in Section 4.4.1 as $262,000. The cost of the collection system is given as about $93,000 (1 MMCFD production rate). The total operation and maintenance cost is estimated to be about $20,000/year. These costs are approximately twice that estimated for the nominal slant hole well, approximately twice as much methane would be drained, and approximately twice as much coal

could be recovered from the drained area. Consequently, the effective investment returns indicated for using slant hole wells would also be realized when using the vertical vent shafts.

4.4.2.4.2 LNG and Ammonia Production Options

As indicated in Section 4.4.2.2, the practicality of converting the high quality gas to LNG or ammonia is dependent upon cost of the gas. As indicated in Section 4.4.1, the gas cost based upon cost of the collection system is about $.50/MCF when using vertical wellbores and about $.32/MCF when using the slant hole technology. Based upon a design that would locate the plants about 5000 feet from the degasification boreholes (average distance for 20 years of coal mining operations), an additional cost of $.18-$.26/MCF to cover the piping cost must be added to cost of the gas. The total cost of collecting and piping the gas to a central location would then be from $.50 to $.76 depending upon the type wellbores used and gas production rates. For these conditions, producing LNG or ammonia (with the larger plants) would be economically attractive at the projected market prices.

As in the case for selling the methane directly, when using the stimulated vertical wells, it will be necessary to realize a coal mining cost savings sufficient to offset the cost of establishing the wellbores. As indicated earlier, the required savings are about $1/ton for room-and-pillar mining and about $.60/ton for longwall mining methods.

4.4.2.4.3 Gob Gas Recovery and Utilization

As indicated in Section 4.4.2.4.2, the relative economics favor draining the coal seams in advance of mining, and the gas may either be sold to a commercial supplier or used to produce LNG or ammonia if coal mining cost savings of about $1/ton may be realized. As indicated in Section 4.4.2.3.1, providing systems to recover and use gob gases are marginally economic and require that the gas costs be less than $.25/MMBtu if the products are to be within the competitive range. Such gas costs are approximately equal to the projected collection system costs. As such, it will generally be necessary to base the utilization of gob gases upon using the collection system established for predraining the virgin coal and upon locating the plants near the degasification boreholes.

A typical system that could be established in the Pittsburgh seam would locate the LNG or ammonia plant in the general vicinity of the degasification boreholes so as to minimize the overall system cost. The initial primary collection piping system would be sized to handle the maximum expected gob gas flow rates, and the system would be established so as to facilitate either piping the predrainage gas to the commercial pipeline or to the ammonia or LNG plant. With such a concept, the plant would be built three to four years after degasification was started, the appropriate vacuum type compressors added to the boreholes as mining progresses through the area, and production of the LNG or ammonia would commence. As mining progresses, the degasification boreholes are systematically disconnected from the pipeline, the proper compressors are

added, and gob gases are piped to the plant using an established collection system, i.e., reversed flow. The individual wells draining gob gases would remain connected to the system as long as the gas flows (primarily gas quality) are adequate for economic system operation. In those circumstances in which gas flows from the virgin coal are higher than expected, gas from the predrainage system would be diverted into the LNG or ammonia plant, and, if necessary, the least economic gob gas well is disconnected.

In those cases in which LNG or ammonia would be produced from gas drained from the virgin coal, the appropriate concept would be to install plants with sufficient capacity - initially - to process both predrainage and gob gases. In either case, if coal mining cost savings of $1/ton are realized so as to offset costs of the wellbores, the revenues will be sufficient to realize the minimum acceptable rate of return (20%) at projected market prices for the products.

The economic practicality of using gob gases for local heating purposes in the Pittsburgh seam is described in Section 4.4.2.3.3. As indicated, the practicality depends greatly upon the value of the fuel to be displaced, and the distance to the point where it is to be used. For power generation applications, the practicality also depends upon the value of the power. As indicated in Section 4.4.2.3.3, minimum acceptable rates of return can be realized for some applications.

4.4.3 Recommended Systems for Field Demonstrations

Projections have indicated that predraining coalbeds using stimulated vertical boreholes in advance of mining will be economically attractive for some coal seams but generally will require that the potential coal mining cost savings result in offsetting the cost of degasification boreholes. When using slant hole technologies, economic projections indicate that mining the coal seams may be degasified well in advance of mining and the gas may be utilized with very favorable investment return rates. Converting high quality gas drained from virgin coal to LNG or ammonia has also been shown to be economically practical depending upon the quantity of gas available. Converting low quality gob gases to LNG, ammonia, or electrical power has been shown to be economically practical for some mine locations. Investment opportunities for converting gob gases are improved when the systems originally established to drain methane from virgin coal are also used to recover gob gases. Using gob gases for local heating applications also represents a practical option, depending upon piping costs and upon value of the fuel displaced.

Based upon economic projections, the following five subsystems for production and conversion are recommended for demonstration to verify the practicality of recovering and using the methane:

1. Utilization of stimulated vertical boreholes to drain virgin coal.

2. Utilization of slant hole technologies to drain virgin coal.

3. Utilization of horizontal holes drilled from the bottom of vent shafts, headings, or ribs to drain virgin coal.

4. Conversion of high quality gas drained from virgin coal to LNG and ammonia.

5. Recovery of gob gases using vertical boreholes and conversion of low quality gas to LNG, ammonia, electrical power, and local heating applications.

Not all system configurations need to be demonstrated but the demonstrations should be sufficiently complete so that any mine owner may use the demonstration results to plan and implement a profitable commercial application within the particular site's peculiar constraints.

Considering the technical and economic requirements, the following five specific demonstration projects are recommended:

1. Draining methane from virgin coal in advance of mining operations using a combination of vertical wells and horizontal boreholes drilled from the bottom of a ventilation shaft sunk at least three years in advance of its need for mining. The vertical wells will be stimulated to increase gas flows. The gas will be collected by a gathering pipeline system and transported to a central location where the total gas produced will be sold to a commercial natural gas distributor.

   The technology to implement this project is generally available. The results in terms of improved mining productivity and safety, gas quantities recovered, overall profitability, etc., would be proved by the demonstration and the resulting information base made available to the private sector so it will be able to implement similar commercial methane conservation projects.

2. Draining methane from virgin coal in advance of mining operations using directional drilling of horizontal boreholes from the surface. This technique requires drilling vertically (or at a small angle) to a predetermined position above the coal seam, drilling a curved path that will enter the coal seam approximately horizontally, and drilling one to two thousand feet horizontally into the coal seam.

   The drilling technology is not fully established for this application and must be further developed and demonstrated. Directional drilling in the oil industry has been successfully performed for many years; however, the applications are not as technically difficult as drilling one to two thousand feet horizontally into the coal seam. This drainage technique appears to offer significant economic advantages and requires rights to a much smaller surface area than project I and should be demonstrated at the earliest possible opportunity.

As in project I, the gas is collected in a pipeline and transported to a central location for processing. The utilization subsystem proposed for this project provides for converting methane to ammonia. The ammonia is to be sold as a chemical to producers of fertilizers. The technology for converting methane to ammonia is well established; however, current commercial plants are built to a scale larger than that proposed for this project. Equipment for a plant of this size is available but the economics of competing with much larger units is uncertain.

Implementation of this project is necessary to demonstrate and develop the ability to drill directional boreholes successfully and to establish the economics of small scale ammonia production in this application.

3. Recovering methane from gob areas, collecting by means of a gathering pipeline, upgrading and converting to liquefied natural gas (LNG). Methane recovery is accomplished with vertical wells. Conversion to LNG is proposed for this project as it provides for direct consumer utilization of gas, and its economics appear favorable for plant capacities of one to two million cubic feet per day and a selling price of about $2.50 per million Btu. (LNG is currently selling for $3.00.)

   The technology for converting methane to LNG is well established; however, current commercial plants are much larger than is proposed for this project (on the order of 100 times). An additional operation must be performed to upgrade gob gas to a sufficiently pure methane for conversion. This additional processing and the economics of operating a relatively small scale conversion plant require demonstration to establish feasibility.

4. Recovering methane from gob areas and utilizing it to produce electric power by means of a gas turbine. The power would be used locally for mine operations.

   This utilization alternative offers an opportunity for conservation when local conditions are prohibitive to an extensive pipeline collection subsystem. A skid-mounted gas turbine can be installed in the proximity of the wells and the generated power distributed via the mine's internal electrical distribution system.

   The equipment required for this project is available and of conventional design. The economics appear to be favorable, but as with other projects must be demonstrated to prove feasibility.

5. Recovering methane from gob areas and utilizing it for a direct heat application such as coal drying, building heating, water heating, etc. This project appears to be very attractive economically and probably will be favored for those mines with a physical layout permitting the necessary pipeline network for gathering gas and piping it to the point(s) of use.

Under this project the gas will be burned and used in an existing heating application where the only utilization cost incurred will be a relatively inexpensive burner conversion to accommodate the methane content of the gob gas. The technology for this application is well established and a demonstration project is required only to confirm that the projected gas quantities are realistic and that the costs are credible. Once this is demonstrated, it is expected that this option will be implemented by private interests wherever the mine layout is suitable.

The recommended demonstration implementation system is described in Section 5.0.

5.0 FIELD DEMONSTRATION

Early field demonstration of selected systems is essential for the conservation of methane now being wasted. A preliminary field demonstration program plan is included in this section and presents the background, objectives, scope, assumptions/constraints, strategy/approach, program structure, and identifies the detailed requirements for final system/site selection and project implementation. This preliminary program plan identifies the elements necessary for project implementation.

5.1 PRELIMINARY PROGRAM PLAN

5.1.1 Background

The Division of Conservation Research and Technology of the Energy Research and Development Administration (ERDA) has overall management responsibility for a methane-from-coalbed conservation program. Methane is generated during the natural process of coal formation and frequently, because of the low permeability of strata associated with coalbeds, is trapped in the coal and associated strata which remain highly saturated with methane. During mining operations, this methane is released, mixes with air, and may form a potentially explosive or flammable mixture, an obvious safety hazard.

In a working underground mine, ventilating air is introduced and used to sweep methane from the mine into the atmosphere. In this way, the methane concentration is maintained at a level below the flammable limit, providing a safe working environment for the miners. In particularly "gassy" mines, very large volumes of ventilating air must be used to maintain the methane concentration at a safe level, requiring extensive equipment installations and large energy usage. To increase the margin of safety and limit ventilation requirements, the U.S. Bureau of Mines and many mining companies have investigated and are investigating techniques for draining methane from coalbeds to prevent gas migration to the working area. These techniques include drilling of vertical or deviated wells into virgin coalbeds in advance of the mine working faces and drilling of horizontal holes into virgin coalbeds from a central shaft. These drainage methods produce natural gas comparable to that from other gas reservoirs. Drainage from gob areas is obtained through vertical wells which provide gas diluted somewhat with air (mixtures range from 25 to 90 percent methane). ERDA estimates that recovery of 250 trillion cubic feet of this resource appears readily feasible. This quantity is approximately equal to the total known U.S. natural gas reserves. At present, no commercial use is being made of this potential resource; the gas is wasted.

The methane-from-coalbed conservation program is established to develop ways to utilize this resource, with implementation responsibility assigned to the Morgantown Energy Research Center (MERC). This document describes the plan for implementing field demonstration projects. It identifies

activities and actions necessary for the detailed analysis/planning for final system/site selections, design, construction, operation, evaluation, and technology transfer of project results enabling others to implement similar projects.

5.1.2 Objectives and Scope

The near-term objective of demonstration projects is to provide clear and credible evidence of the technical and economic feasibility of a variety of utilization systems that will provide at least one option for methane conservation at each mine in the United States. Early implementation is necessary to halt irretrievable waste of this energy source. The long-term objective is to implement projects to demonstrate more advanced systems currently in the research and development phase. The advanced systems are expected to have increased energy efficiencies and attractive economics.

Systems to be demonstrated in the near-term, as currently envisioned, include the following:

Predrainage Project I - This project provides for draining the methane from virgin coal in advance of mining operations. Methane is recovered using a combination of vertical wells and horizontal boreholes drilled from the bottom of a ventilation shaft that is sunk at least three years in advance of its need for mining (Figure 5-1). The vertical wells will be stimulated to increase gas flows. The gas will be collected by a gathering pipeline system and transported to a central location where the total gas produced will be available for processing.

The utilization subsystem to be demonstrated by this project consists of upgrading the methane as necessary for sale and injection into a commercial natural gas pipeline.

Predrainage Project II - This project also provides for draining methane from virgin coal in advance of mining operations. The difference lies in the technique used for recovering the methane which in this project is accomplished by directional drilling of horizontal boreholes from the surface. This technique requires drilling vertically (or at a small angle) to a predetermined position above the coal seam, drilling a curved path that will enter the coal seam approximately horizontally, and drilling one to two thousand feet horizontally into the coal seam (Figure 5-2).

As in Predrainage Project I, the gas is collected in a pipeline and transported to a central location for processing. The utilization subsystem to be demonstrated by this project is the conversion of methane to ammonia. The ammonia is to be sold as a chemical to producers of fertilizers.

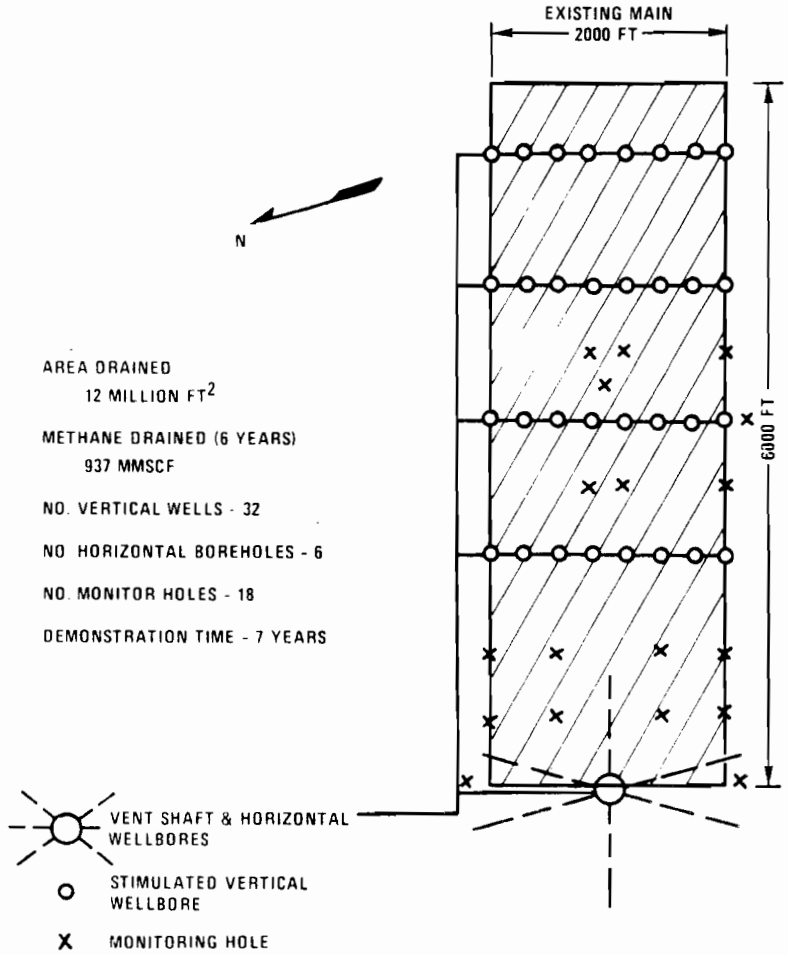


FIGURE 5-1. STIMULATED VERTICAL WELLS AND VENTILATION SHAFT WITH HORIZONTAL BOREHOLES

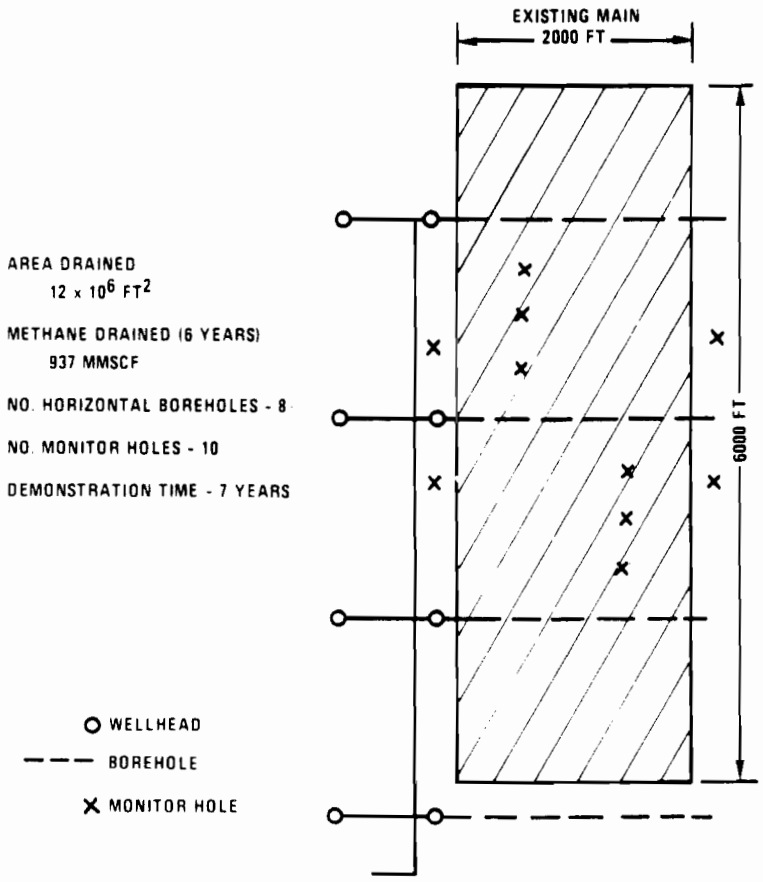


FIGURE 5-2. DIRECTIONAL DRILLED BOREHOLES

Gob Gas Project I - This project provides for recovering methane from gob areas, collecting by means of a gathering pipeline, upgrading and converting to liquefied natural gas (LNG). Recovery of the methane is accomplished with vertical wells. Conversion to LNG is the utilization subsystem to be demonstrated by this project. Figure 5-3 depicts an arrangement suitable for this project.

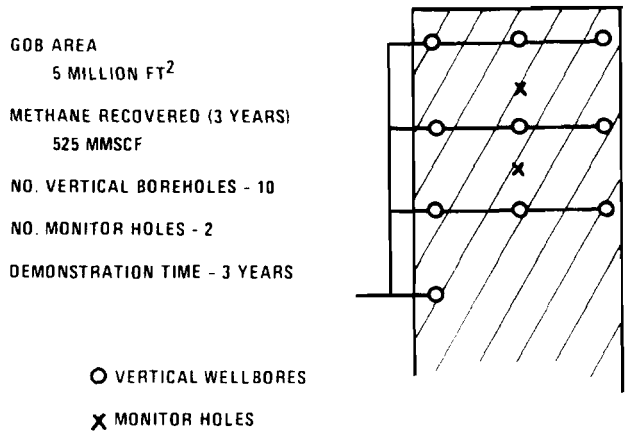


FIGURE 5-3. GOB GAS RECOVERY

Gob Gas Project II - This project provides for recovering methane from gob areas and utilizing it to produce electric power by means of a gas turbine. The power will be used locally for mine operations. Figure 5-3 shows a suitable arrangement of wells for gob gas recovery.

Gob Gas Project III - This project provides for recovering methane from gob areas and utilizing for a direct heating application such as coal drying, building heating, water heating, etc. Figure 5-3 shows a suitable arrangement of wells for gob gas recovery.

The long-term objective of more efficient and economical systems requires hardware development before field demonstration can be considered. As hardware development progresses, future revisions of this document will incorporate appropriate strategy for implementing field demonstration.

5.1.3 Assumptions and Constraints

Implementation of the demonstration projects identified in this plan is contingent upon the following assumptions/constraints:

- Necessary funding will be available on a timely basis when needed.
- Necessary approvals of contract documents, agreements, etc., will be forthcoming when needed.

- Legal questions that may result from project implementation can be resolved so as not to adversely affect the schedule.

- Implementation of projects will in no way adversely affect mining operations or safety.

- Environmental impact is favorable and therefore will not impede implementation.

5.1.4 Program Strategy/Approach

The near-term approach aims at early utilization of methane gas now being wasted as it is released during mining operations. Because of differences in type of mining, site access, availability of commercial transmission pipelines, ownership of surface rights, ownership of gas rights, legal constraints, etc., a number of utilization options must be demonstrated so at least one feasible alternative is possible for any mine in the country. Systems studies conducted under contract, coupled with ERDA in-house analyses, have identified several viable field demonstration projects desirable for utilizing coalbed methane gas.

Five projects are identified for implementation in this plan. Collectively, they will demonstrate three different techniques for gas recovery and five different utilizations of the methane. Demonstration results are expected to show that a suitable alternative is available for accommodating almost any local differences affecting the use of methane. In order to provide the necessary data base for adapting a demonstrated system to a particular commercial site, monitor wells and additional instrumentation are included in the demonstration projects that will be unnecessary in the commercial application by private interests. Data acquired by the additional equipment will permit accurate documentation and assessment of the demonstration projects and provide the information needed by others to implement similar projects.

Because of these data requirements, and the fact that certain existing technical, economic, institutional, and legal risks are greater than those acceptable to a commercial concern, government cost-sharing of the demonstration projects is provided. Conservation of methane gas is of national concern, will benefit the nation as a whole, and justifies government sharing of the risks to expedite commercial application on a broad basis. By making demonstration results available to all mine owners by wide dissemination of reports, seminars, worshops, etc., it is expected that they will implement similar projects when presented with tangible evidence of the advantages.

Figure 5-4 shows the schedule for project implementation. As shown, data and information useful to others will be made available to them at the earliest possible time and will continue to be furnished as the project progresses to completion. This will assist early planning and implementation by others.

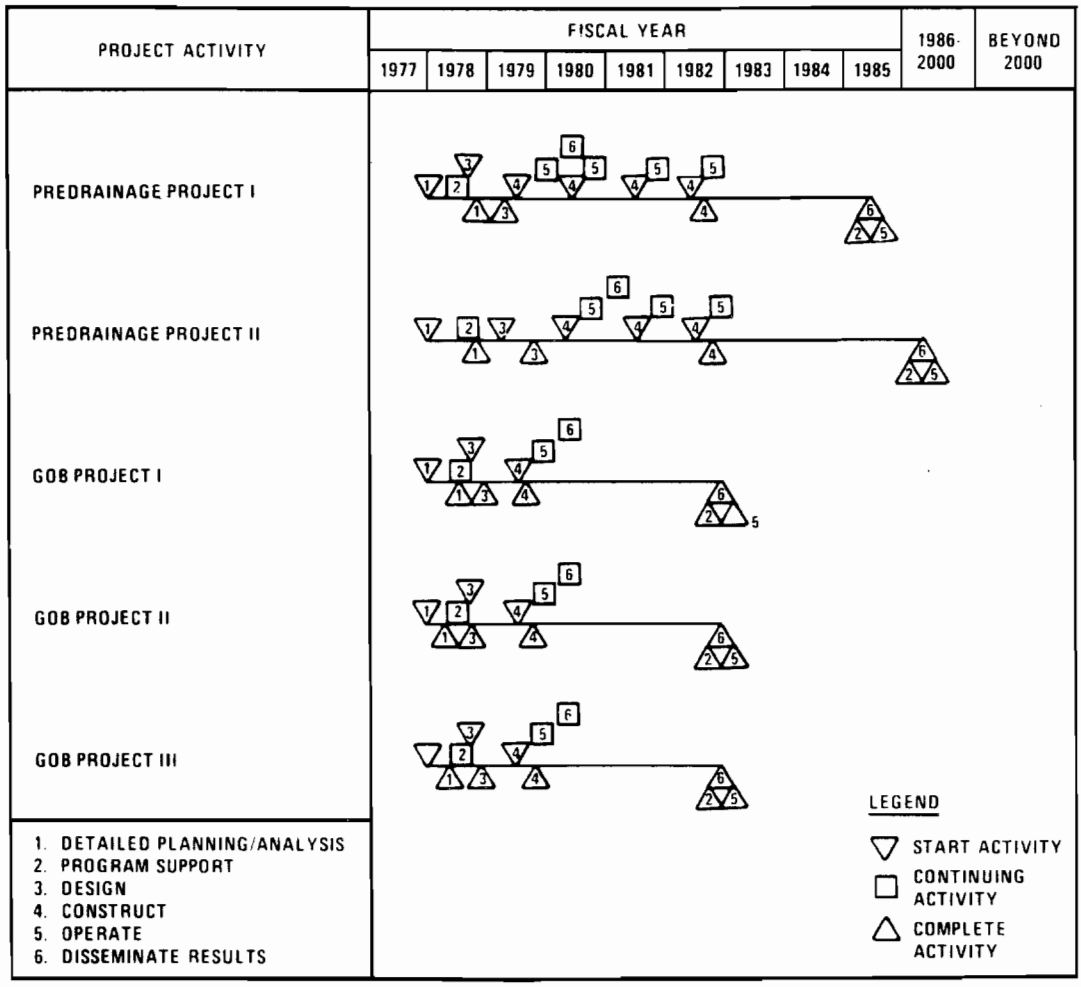


FIGURE 5-4. FIELD DEMONSTRATION PROJECT SCHEDULE

5.1.5 Program Structure

The program structure for implementing the five demonstration projects defined in Section 2.0 is shown in Figure 5-5. Sections 5.1, 5.2, 5.3, 5.4, and 5.5 discuss details of a project's major elements and tasks associated with each element.

5.1.5.1 Detailed Planning/Analysis for System/Site Selection

Systems studies have identified several candidate sites and subsystems for the recovery, collection, and utilization of coalbed methane. These studies have been general in nature; they discuss average coal thickness and gas content per ton of coal, identify candidate sites based solely on reported methane disposed of during current mining activity, determine cost-benefits using average data, etc., to show the feasibility of a broad conservation program. Due to variations in specific mines, the final matching of systems/sites must result from detailed planning/analysis discussed in the following sections.

5.1.5.1.1 Technical and Equipment Requirements

This task will address all aspects of technical and equipment requirements that must be identified and provided for in each project. Requirements for such things as access roads, surveys, site preparation, equipment size, equipment performance, equipment reliability, etc., will be analyzed and specific recommendations made. Field tests, samples, etc., required to support the analyses will be provided.

5.1.5.1.2 Environmental Requirements

All environmental requirements applicable at the local, state, and federal levels will be identified and appropriate recommendations made for compliance.

5.1.5.1.3 Safety Requirements

All safety requirements applicable at local, state, and federal levels will be identified and appropriate recommendations made for compliance.

5.1.5.1.4 Regulatory Requirements

This task involves making a thorough review of each project to ascertain if there are any other local, state, or federal regulations that apply. This will include regulations regarding transportation of LNG and ammonia, highway limitations on the weight and size of load that may be transported, interstate commerce regulations, FEA regulations, etc. Appropriate action will be recommended for compliance.

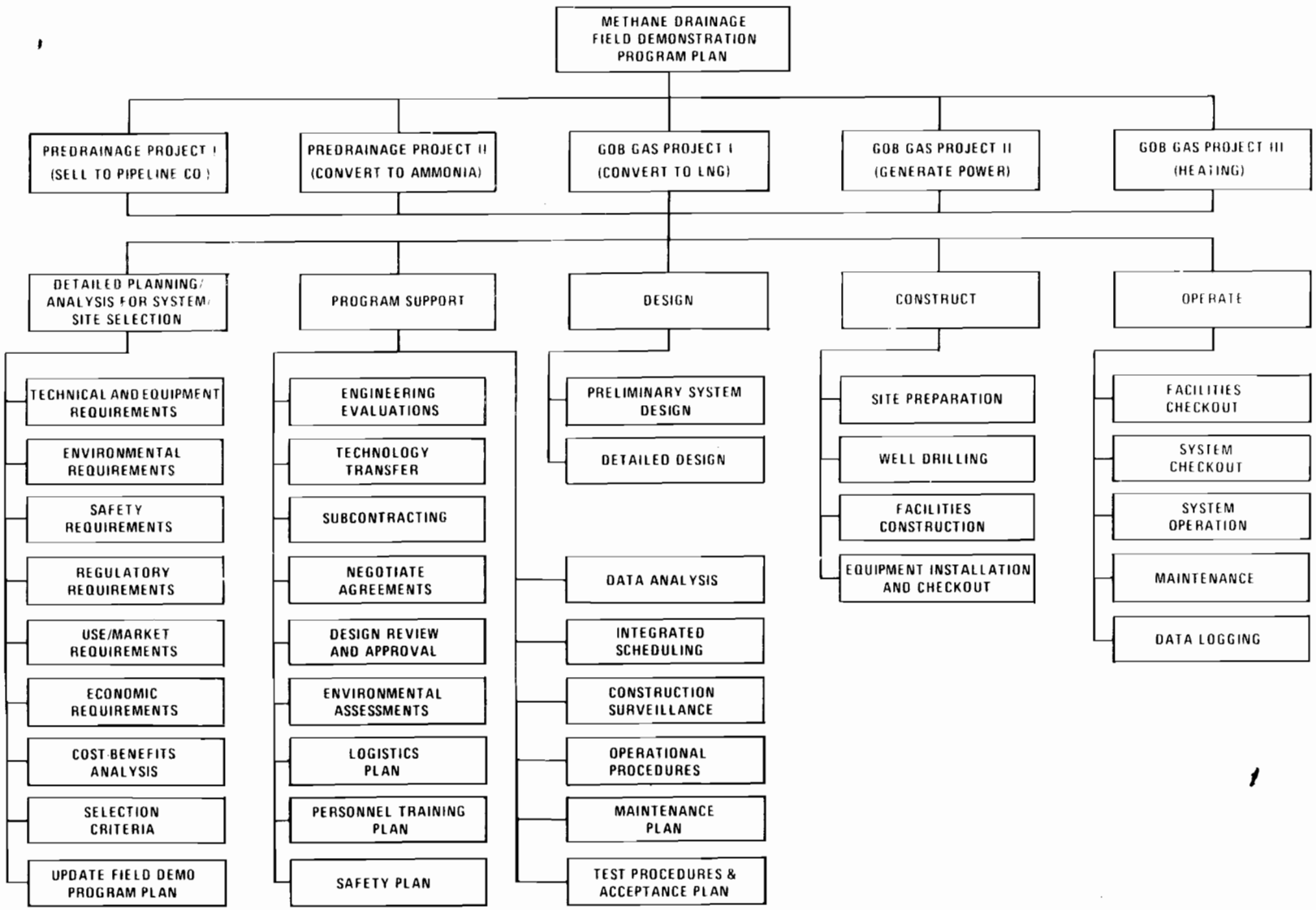


FIGURE 5-5. FIELD DEMONSTRATION PROGRAM STRUCTURE

5.1.5.1.5 Use/Market Requirements

The current status of the intended use/market of the methane gas will be ascertained and sufficient analysis performed to predict what may be anticipated during the project's planned life.

5.1.5.1.6 Economic Requirements

The government funding, private capital required, expected revenue, etc., will be assessed for project impact and planning.

5.1.5.1.7 Cost-Benefits Analysis

A detailed cost-benefits analysis will be performed for each candidate system/site under consideration for implementation. Appropriate tradeoffs will be made to assure optimum selections.

5.1.5.1.8 Selection Criteria

Evaluation criteria for each candidate system/site will be developed under this task. Consideration will be given to such matters as cost-benefit results, mine owner cooperation, legal constraints, ease of access, etc. Final system/site projects will be selected as a result of these evaluations.

5.1.5.1.9 Update Field Demonstration Program Plan

This task provides for updating the Field Demonstration Program Plan to incorporate required changes resulting from detailed analysis/planning and selection of the system/site for each project.

5.1.5.2 Program Support

This activity will integrate and implement the complex requirements to design, construct and operate the field demonstration projects. It will also evaluate results and disseminate the information enabling others to implement similar projects commercially.

Tasks that will be performed as program support are identified in the following paragraphs.

5.1.5.2.1 Engineering Evaluations

This task provides for support to evaluate equipment proposals, changes that may be required during the course of construction due to field conditions, the most cost-effective mode of operation, design alternatives, etc.

5.1.5.2.2 Technology Transfer

The progressive transfer of project data and information to other interested parties is essential to expedite implementation of similar projects on a commercial basis. This task will provide for dissemination of progress reports, setting up symposia and workshops conducive to information transfer, and establishment of two-way communications necessary to assure that data is understood. It also will provide other techniques for assuring that the project results are available to all concerned private interests.

5.1.5.2.3 Subcontracting

This task provides required support for contracting with other organizations as necessary during project implementation. It will include such things as A-E design services, well drilling, facilities construction, equipment installation, consultants, etc. Procurement of long-lead items will also be accomplished under this task.

5.1.5.2.4 Negotiate Agreements

This task provides support for preparing, negotiating, and obtaining approval of the concerned parties, of agreements necessary for each project. This may include agreements for such matters as sale of the product, mine owner/equipment suppliers, regulatory requirements, etc.

5.1.5.2.5 Design Review and Approval

This task provides technical support required to perform all necessary review and approval of proposed system designs.

5.1.5.2.6 Environmental Assessments

This task provides for a thorough review of each project with regard to environmental requirements and an impact assessment. Required environmental impact assessments of regulatory agencies will be prepared and submitted under this task.

5.1.5.2.7 Logistics Plan

This task requires preparation of a logistics plan to include all aspects of equipment supply, spare parts inventory, consumable supplies, product disposition, support services, etc., necessary for construction and continued operation of the installed system.

5.1.5.2.8 Personnel Training Plan

This task provides for a review of each project to ascertain the manpower requirements for operation and maintenance. A training plan will then be prepared to include training materials to be used, extent of training, timing of personnel training to meet schedules, and methods for evaluating trainees to assure they are competent for their contemplated assignments.

5.1.5.2.9 Safety Plan

This task provides for preparation of a safety plan to identify all potential hazards and precautions that must be observed to assure safety of personnel and property. The task scope includes all aspects of the project from construction through operation.

5.1.5.2.10 Data Analysis

This task is established to identify the data needed, when needed, for what it is needed, how it will be used, and to perform those analyses required to support intended use. Both technical and economic data analyses are envisioned for this task.

5.1.5.2.11 Integrated Scheduling

This task provides for a comprehensive integrated schedule of all activities required for project implementation. It will include procurement, subcontracting, program support, design, construction, and operation. Milestones will be identified and interrelationships shown of the various activities. The impact of schedule change in one activity will be readily apparent on other related activities, assuring immediate action to minimize adverse effects or to take full advantage of favorable effects.

5.1.5.2.12 Construction Surveillance

This task provides support to assure that construction conforms with the intent of the drawings and specifications, and that all acceptance testing is performed in accordance with, and meets, specifications. All equipment will be tested for conformance with performance criteria.

5.1.5.2.13 Operational Procedures

Those procedures that provide the instructions and operating mode of individual equipment and the system as a whole will be prepared under this task. They will include normal operation and, in addition, emergency instructions for the safest possible course of action to deal with foreseeable contingencies.

5.1.5.2.14 Maintenance Plan

This task will prepare a maintenance plan to assure that individual equipment items are maintained in accordance with manufacturers' recommendations and that the system as a whole is maintained efficiently and economically. Manufacturers' maintenance manuals, preventive maintenance requirements and schedules, supplementary maintenance instructions required for the system, special tools required, and any other information needed to assure adequate planning for this function will be provided as part of the plan.

5.1.5.2.15 Test Procedures and Acceptance Plan

This task provides for preparation of the test procedures to assure compliance with applicable codes and that all equipment meets performance specifications. The acceptance plan will assure that all test procedures have been satisfactorily performed and that all specified conditions have been met.

5.1.5.3 Design

This activity will perform the design necessary to support alternative choice decisions and will prepare the detailed drawings and specifications necessary for construction.

5.1.5.3.1 Preliminary System Design

This task will provide for the preparation of general arrangement system drawings, overall flow diagrams, etc., as necessary, to support decisionmaking on the exact system configuration for which detailed drawings and specifications should be prepared.

5.1.5.3.2 Detailed Design

This task will provide for preparation of the detailed drawings and specifications required for construction of facilities and installation of equipment.

5.1.5.4 Construct

This activity will provide the requirements for field construction.

5.1.5.4.1 Site Preparation

This task will provide for site clearing, access roads, underground utilities, etc., needed for facilities construction and equipment installation.

5.1.5.4.2 Well Drilling

This task will provide all services, samples, analyses, etc., and the drilling equipment and crews for drilling of specified wells. This includes vertical wells, horizontal boreholes, and directional (slant) wells.

5.1.5.4.3 Facilities Construction

This task will provide for all services, material, equipment, and construction of all specified facilities.

5.1.5.4.4 Equipment Installation and Checkout

This task will provide for all services, specified materials, installation equipment and installation of all required project equipment.

5.1.5.5 Operate

This activity will provide for system operation and maintenance.

5.1.5.5.1 Facilities Checkout

This task will provide the services, material, test equipment, etc., and perform required tests to verify that the facility meets specified requirements and is capable of supporting overall system operation and maintenance.

5.1.5.5.2 System Checkout

This task will provide the services, material, test equipment, etc., and will perform the tests for systems checkout to verify that specifications and performance requirements have been met.

5.1.5.5.3 System Operation

This task will provide the services, tools, equipment, etc., for continued operation of the system after checkout and acceptance.

5.1.5.5.4 Maintenance

This task will provide the services, tools, materials, equipment, etc., required to perform both preventive and repair maintenance of the system.

5.1.5.5.5 Data Logging

This task will provide the services required to acquire specified data and to transmit it to the program support activity for analysis and evaluation.

6.0 CONCLUSIONS

The conclusions listed below are made as a result of those analyses and evaluations performed during the study effort.

- Utilization of coalbed methane gas is practical and economically favorable.

- Drainage of methane in advance of mining, and from gob areas subsequent to mining, decreases the quantity of methane now being released into the mine environment. Such drainage reduces ventilation requirements and the hazards of removing methane by this technique. Therefore, a severe hazard is significantly reduced, greatly enhancing underground mine safety.

- Differences in type of mining, site access, availability of commercial gas transmission pipelines, ownership of surface rights, ownership of gas rights, legal constraints, etc., require several different techniques for gas recovery and several variant uses for the recovered methane gas.

- Cost-sharing of demonstration projects between government and private interests is necessary to expedite early commercial applications and end waste of this resource.

- Legal problems and possible litigation may result when coal-bed methane gas is recovered and utilized in a profitable venture. Coal rights agreements vary in mining ventures, and when they do not specifically state or imply the right to recover gas released in conjunction with mining requirements, litigation to recover royalties is likely to result.

7.0 RECOMMENDATIONS

The recommendations listed below are considered necessary to implement a comprehensive coalbed methane gas conservation program. They are designed to end waste of this precious resource at the earliest possible time. Their implementation also will improve mine safety to a significant degree by recovering large quantities of methane otherwise contributing to fire and explosion hazards if released during mining activity.

- Approve the detailed planning/analysis necessary for final site/system selection and expanding the preliminary program plan into a detailed program plan suitable for efficient project implementation.

- Approve implementation of the five field demonstration projects identified in the Methane Drainage Field Demonstration Program Plan contained in Section 5.0 of this report.

- Provide the necessary funding to accelerate implementation to what is attainable on a sound engineering basis. If additional FY 77 funding is made available, approximately six to eight months could be gained without sacrificing quality or altering total project costs.

- Approve government cost-sharing of the projects with flexibility to negotiate an equitable basis following detailed planning/analysis, when the projects are fully defined, and cost-benefits determined for the specific system/site under consideration.

- If possible, select sites where the mine owner has the right to recover gas contained in the coalbed.

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17. PRIVATE COMMUNICATIONS

1. Maurice Deul and Kurt Elder, U.S. Bureau of Mines, Coal Degasification Project, supplied a complete set of USBM research documents on the subject, provided background information on USBM field demonstrations on coal gas pre-drainage, and identified major contractors for future field work.

2. S. Cortis and Tom Alexander, Pennsylvania Department of Environmental Resources, Bureau of Land Protection, Division of Mines Subsidence Regulations, provided information on available state publications pertaining to the project, and supplied original drawings of state mine maps.

3. Carl Smith, West Virginia Geological Survey, Coal Division, supplied illustrative material on underground coal mining, and advice on coal gas rights legislation.

4. Russel Allison, West Virginia Department of Mines, supplied background information on mine portal coordinates and abandoned mines. He made and provided original mine maps for the specific mines of concern in the project, and identified appropriate state agencies and individuals having information relating to specific needs of this project.

5. William Litle and R. Piotrowski, Pennsylvania Geological Survey, Oil and Gas Division, supplied gas pipeline maps and gas industry background information for Northern Appalachia.

6. Richard DeLong, Ohio Geological Survey, Coal Division, supplied coordinates of Ohio coal mine portals, methane emission rates of Ohio coal mines, and general geological background of the Pittsburgh Coalbed in Ohio.

7. Jeff Huston, United Technologies, Fuel Cell Division, provided information on the current state of development of fuel cell technology and on specifications of gas feedstock requirements.

8. Norman Gatti, Ohio Department of Industrial Relations, Division of Mines, provided methane emission rates in Ohio coal mines.

9. Walter Miller and Carl Kinty, West Virginia Department of Mines, Northern Division, provided mining practice data for all West Virginia coal mines studies in the project, with particular emphasis on mine design, equipment, and potential mine design improvements, as a result of predrainage.

10. Burkey Lilly, Hope Natural Gas, provided a list of coal gas producers selling coal gas to Hope.

11. Bob Reed, John Salveti, Martin Patterson, and Dan Weaver, Bethlehem Mines Co., Cambria Division, presented the current stage of gob drainage technology in Bethlehem Cambria mines. They also supplied mine design data, organized a field visit through a coal preparation plant and demonstrated wellhead equipment of operating vertical degasification boreholes.

12. Herb Steinman, R. Thomas, Bruce Leavitt, Jim Hott and Adam Bronakosky, Jones and Laughlin Steel Co., Mining Division, presented coal gas drainage developmental work and production history in J&L mines. They also provided mine design data and developed a comprehensive data base for application of the cost-benefit analysis of this report, on selective panels of the Gateway mine.

13. Kenneth Stewart, Mid-Atlantic Oil Field Service Co., provided the work track-record of Mid-Atlantic on deviated well drilling, lists of company hardware and technical capabilities, and supplied cost scales on equipment and services.

14. Wallace Darden, Halliburton Services, provided work track-records of Halliburton in hydro- and foam-stimulation of coal gas producing wells in Appalachia, furnished cost scales, and general company capabilities.

15. John Gardner and Jim Fritz, Paramount Exploration, provided the work track-record of Paramount on drilling deviated wells, and furnished cost scales and general company capabilities in hardware and technical expertise.

16. Sam Sprague and Gary Readers, Bethlehem Mines Co., Ellsworth Division, provided mine design data, methane drainage and collection plans, and identified potential sites for cooperative methane drainage demonstrations.

17. Don Holbert, Consulting Petroleum Engineer, provided work track-records in drilling deviated wells, cost scales, and general capability data.

18. Howard Ward, Dyna Drill, assisted in identifying appropriate borehole diameters for future drainage demonstrations. He also outlined specifications of down-hole surveillance and steering tools, and provided a list of major equipment manufacturers and drilling contractors.

19. Bob Johnson, Sperry Sun Co., provided breakdown schedules of surveillance and control activities in drilling deviated wells, furnished specifications of Sperry Sun tools, outlined cost scales and submitted general capability statements.

20. Rick Duenez, Humphrey Instruments Inc., provided work track - records of Humphrey, presented types of vertical and horizontal surveillance instruments manufactured and rented by Humphrey, and outlined price scales.

21. David Lemke, Scientific Drilling Controls, presented the company's work track-record, and lists of available products and services in deviated wells surveillance and control.

22. Jim Sexton, Tom Butler, Bill Black, Eastman-Whipstock, provided work track-records on drilling, surveying and controlling deviated wells. They also outlined cost scales and furnished specifications lists of available tools and services, in addition to making a preliminary cost study for drilling a deviated well in the Gateway mine.

23. Paul Averitt, U.S. Geological Survey, Denver, Colorado, provided a list of references on Appalachian coalbed reserves and characteristics.

24. Gordon Wood, U.S. Geological Survey, Reston, Virginia, discussed coalbed structural and tectonic characteristics.

25. Bill Gillespie, West Virginia Department of Agriculture, provided references and information sources for woodland expansion in Northern Appalachia and its potential obstruction in laying gathering gas pipelines during coal gas drainage demonstrations.

26. Vicki Suomela, U.S. Geological Survey, Reston, Virginia, furnished map lists and aerial high-and low-altitude photographs on woodland expansions in Northern Appalachia.

27. Bob Dodd, West Virginia Department of Mines, Gas Division, provided legal opinions on the possession of coal gas rights in Northern Appalachia.

28. John Northeimer, West Virginia Department of Natural Resources, Industrial Waste Section, Permits Branch, provided state legislative information on industrial process waste environmental regulations.

29. Jim Tilton, Equitable Gas, assisted in identifying major owners of natural gas rights per mine in Northern Appalachia.