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Utilization of a Fuel Cell Power Plant for the Capture and Conversion of GOB Well Gas

Final Report
June - December 1995

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Work Performed Under Contract No.: DE-AC21-95MC32188

For
U.S. Department of Energy
Office of Fossil Energy
Morgantown Energy Technology Center
Morgantown, West Virginia

By
Jim Walter Resources, Inc.
Brookwood, Alabama

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December 1995

ABSTRACT

A preliminary study has been made to determine if a 200 kW fuel cell power plant operating on variable quality coalbed methane can be placed and successfully operated at the Jim Walter Resources No. 4 mine located in Tuscaloosa County, Alabama. The purpose of the demonstration is to investigate the effects of variable quality (50 to 98 percent methane) gob gas on the output and efficiency of the power plant. To date, very little detail has been provided concerning the operation of fuel cells in this environment.

The fuel cell power plant will be located adjacent to the No. 4 mine thermal drying facility rated at 152 M British thermal units per hour. The dryer burns fuel at a rate of 75,000 cubic feet per day of methane and 132 tons per day of powdered coal. The fuel cell power plant will provide 700,000 British thermal units per hour of waste heat that can be utilized directly in the dryer, offsetting coal utilization by approximately 0.66 tons per day and providing an avoided cost of approximately $20 per day. The 200 kilowatt electrical power output of the unit will provide a utility cost reduction of approximately $3,296 each month. The demonstration will be completely instrumented and monitored in terms of gas input and quality, electrical power output, and British thermal unit output. Additionally, real-time power pricing schedules will be applied to optimize cost savings.

The Jim Walter Resources facilities present an ideal testbed for this study because of the availability of virtually unlimited pipeline-quality captured mine methane. This constant supply can be adjusted and regulated for variations in quality to investigate the effects on fuel cell performance. The methane supply available for fuel utilization from gob wells will be far more than adequate for a time period far greater than that of the demonstration phase of the project - over 37 billion cubic feet during the next 15 years.

It is expected that the results of this demonstration can be applied to other underground mining operations in the Warrior basin as well as those operations in the central and northern Appalachian basins or where medium-quality gas is produced from coalbed methane gob wells. Another application is the use of fuel cells with gob wells at or below their economic limit. The remaining methane gas reserves could be used to generate electric power and thus reduce their release to the atmosphere.

ACKNOWLEDGMENTS

The authors wish to acknowledge the support of the U.S. Department of Energy, Morgantown Energy Technology Center (DOE) for their support of the first phase of the project through Contract No. DE-AC21-95MC32188. In particular, the authors appreciate the assistance provided by Mr. Charles Byrer of DOE. The authors also acknowledge the contributions made by Mr. Jerry Sanders and Steve Blackburn of Black Warrior Methane Corp. pertaining to methane resources, production, and utilization.

The authors extend particular gratitude to the International Fuel Cell Corporation for their cooperation and support and the information provided regarding phosphoric acid fuel cell processes.

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EXECUTIVE SUMMARY

Methane released into the atmosphere during coal mining operations is believed to contribute to global warming and represents a waste of a valuable energy source. Coal mining in the United States released an estimated 190 to 300 billion cubic feet of methane into the atmosphere in 1990. Currently, however, less than 7 percent of the methane that is captured and utilized. Improved technology that would lower the capture and utilization costs could make this wasted and environmentally damaging gas an attractive economic operation at many of the coal mines in the U.S. and overseas.

One possible technology that could be applied to the capture and utilization of coal mine methane is the conversion of the methane into electric power via the application of fuel cell conversion. However, for this technology to be attractive, especially during a demonstration project, specific gas source criteria must be met, and certain fuel cell operational factors need to be evaluated.

The gas source criteria were met by the selection of the Jim Walter Resources, Inc. No. 4 Mine (JWR No. 4) located in west central Alabama. This mine targets the methane-rich Mary Lee/Blue Creek coal seam in the eastern Warrior basin. Currently, to control methane emissions, this mine employs 1) a large mine ventilation system that emits about 8.6 million cubic feet of methane per day; 2) a horizontal well degasification system that collects and utilizes about 1.2 million cubic feet per day; 3) a gob well program that captures and utilizes 8.6 million cubic feet per day; and 4) a vertical well degasification program that captures and utilizes about 11.0 million cubic feet per day (this value includes wells producing in the adjacent JWR No. 3, 5, and 7 mines). Projected future production from these four sources of methane for the period 1996 through 2010 is estimated at 153 billion cubic feet of methane. This significant quantity of methane clearly satisfies the first criteria set - sufficient gas source for the demonstration project.

Based on the results of this study, the Jim Walter facility, with its abundant pipeline-quality methane production, will permit the close control of test variables when operating the fuel cells on varying quality methane. In other words, a readily-accessible supply of >97 percent quality methane will be available over any practical test duration on which to control experiments to a degree not available at facilities with less reliable methane supplies.

The fuel cell chosen for demonstration is a 200 kilowatt (kW) phosphoric acid unit. This unit is a complete and self-contained power plant. Hence, all power conversion necessary for utility interconnection is factory installed. The unit is capable of providing 700,000 British thermal units per hour of waste heat. This heat will be utilized in the coal drying process, thus increasing the efficiency of the energy conversion process and further reducing emissions to the atmosphere from the burning of coal.

INTRODUCTION

Methane released to the atmosphere during coal mining operations is believed to contribute to global warming and represents a waste of a valuable energy resource. Coal mining in the United States released an estimated 190 to 300 billion cubic feet (Bcf) of methane into the atmosphere in 1990 [1]. Based on the current trend of increasing coal production and the mining of deeper, methane-rich coal deposits, methane emissions from coal mines have been forecast to rise to about 260 to 450 Bcf by 2010. Yet, largely because of inadequate methane capture technology, less than 7 percent of methane released during coal mining is currently recovered for use. Improved design and technology to lower the costs of methane recovery could make methane recovery economically viable in many more mines, thus providing important environmental and safety benefits while enhancing the nation's natural gas supply.

Atmospheric concentrations of methane, which is believed to be an important greenhouse gas, have doubled over the past two centuries and continue to rise rapidly. The Clinton Administration, recognizing the potential environmental risks of methane emissions, has developed the Climate Change Action Plan to control the growth of greenhouse gasses in the atmosphere [2]. The initial Plan looks for voluntary participation by the mining industry for increased methane capture. Should the voluntary actions be inadequate, it is not inconceivable that these environmental initiatives will require the recovery of methane from coal mines in the future, even though the technology to economically recover methane from coal mines has yet to be demonstrated for most mining situations. Thus, a "time window" exists for the U.S. Department of Energy (USDOE) to assist the mining industry to achieve a successful voluntary effort in coal mine methane capture and use.

The US DOE, through the issuance of the Program Research and Development (PRDA) announcement for research entitled "Recovery and Utilization of Coal Mine Methane," Solicitation No. DE-RA21-95MC32062, specifically addresses the issues raised above. Through the support of research, development, and demonstration projects, the USDOE has the ability to demonstrate to the coal mining industry the potential benefits, both environmental and economic, that could be realized with the application of new or improved technology. The PRDA targets two important aspects of coal mining methane emissions - 1) the need to utilize emission streams that contain varying quantities of methane, ranging from mine ventilation air that typically contains less than 1 percent methane to medium quality gas emission streams from gob wells and/or horizontal boreholes that may contain over 80 percent methane, identified in the PRDA as Demonstration Area 1; and 2) the need to develop techniques to upgrade the lower quality gas emission streams to standard natural gas pipeline specifications, identified in the PRDA as Demonstration Area 2. This report from Jim Walter Resources, Inc. (JWR) documents the work performed under this contract in Demonstration Area 1.

Demonstration Area 1 (Coal Mine Methane Utilization) of this PRDA targets the lower quality gas stream that is currently emitted from degasification operations (gob wells and horizontal boreholes) and coal mine ventilation systems. This report focuses on a feasibility study and conceptual design for a fuel cell-based power plant to capture and convert gob well gas to electrical energy and heat.

Overall, we expect that fuel cell power plant will drastically reduce mining operation utility charges. This will occur because mine power requirements can be partially or fully met with the fuel cell electrical output, and utility demand can be reduced. Furthermore, excess generation can be sold to the electric utility. This may provide a means for the utility shave their peak loads and thus reduce the burn rate at peaking generation sites, which are typically the dirtiest units of all.

Heat is an additional output of the fuel cell. This particular by-product will assist in offsetting the cost of such an installation at a mining site because the heat can be used in the coal drying process. While the electrical output of the fuel cell will reduce mining operation demands on the electric utility directly, the use of waste heat will indirectly reduce utility demand. This concept is graphically represented in Figures 1 and 2. Figure 1 shows the present situation at mining locations. Figure 2 displays the potential situation based on results from this project.

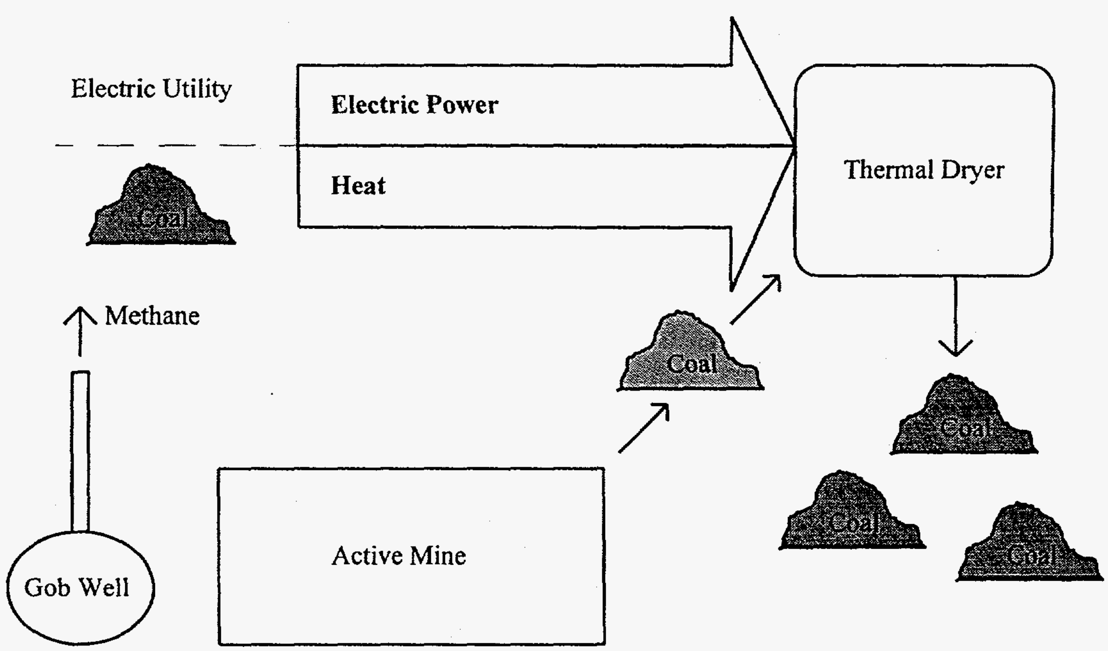

Figure 1. The Present Situation at the Typical Mining Site.

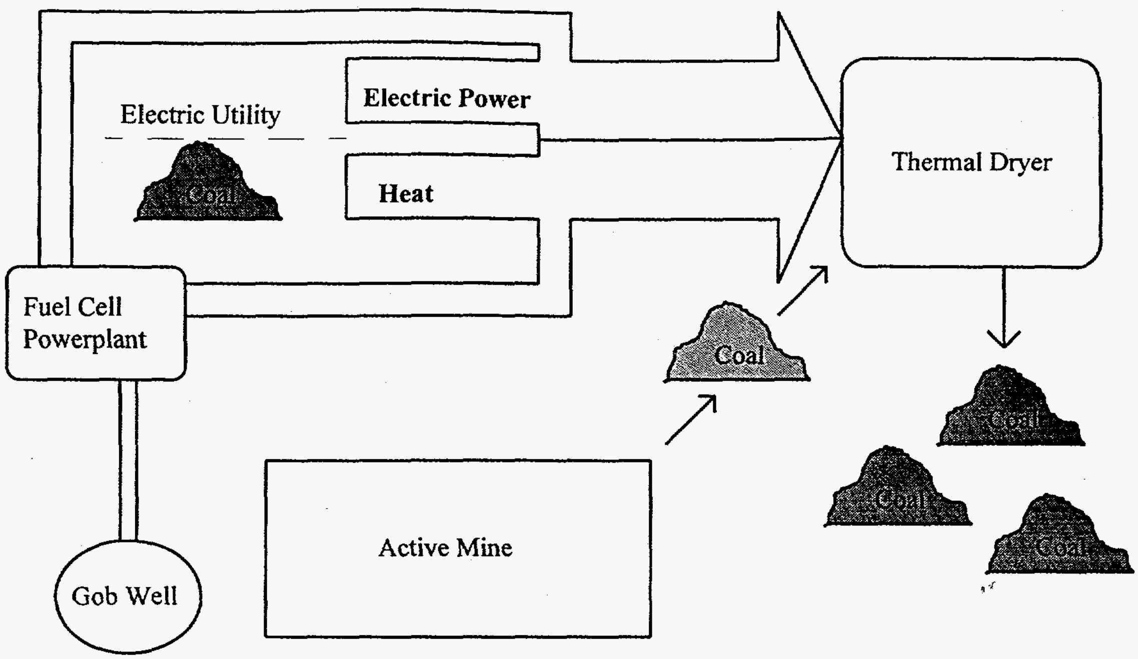

Figure 2. The Proposed Situation at Mining Sites.

To summarize the expected results of this development work, we intend to utilize a fuel cell power plant, supplied with gob well gas, to reduce methane emissions and mining operation utility demands. Surplus generation can be sold to the utility, and waste heat can be utilized in the coal drying process.

This project is highly practical in nature, and thus involves a substantial effort in addressing the issues that will be critical for the adoption of fuel cell power plants at mining facilities. These issues include, but are not limited to, such factors as capital cost, operating cost, installation procedures, utilization of generated power, utilization of produced heat, and utility interconnection.

STUDY PURPOSE

This study investigated the feasibility of operating a 200 kW phosphoric acid fuel cell power plant on variable-quality coalbed methane so as to mitigate the emission of this greenhouse gas into the atmosphere. Besides the obvious advantage of reducing greenhouse emissions, this demonstration would serve as the first of its kind to evaluate the performance of the fuel cell power plant in a low-quality methane/oxygen-rich atmosphere. This area of fuel cell power plant operation must be investigated because its application is far-reaching. For example, many underground coal mining operations in Northern Appalachia and throughout the world are producing considerable quantities of coalbed methane through gob wells with either a quality too low to be sold as pipeline-quality gas, or with no infrastructure available to market this gas. In some cases, the quality of the gas varies such that specifications cannot be guaranteed by the producer and marketing is restricted or prohibited. Therefore, this gas is usually allowed to escape into the atmosphere with deleterious results. Capturing this otherwise-emitted energy resource and converting it into useful electrical energy not only has the potential to be cost-effective, but also preserves the environment.

The fuel cell power plant appears ideal for the application intended in this study. The power plant selected for this demonstration, the ONSI Corporation PC25C fuel cell power plant, is the only commercial unit of its type available at this time, and is capable of direct hook-up and operation. It has a continuous rating of 200 kW/235 kVA, and provides about 700,000 Btu per hour of waste heat. The power plant is grid-connected and operates in parallel with the electric utility grid. It consumes 1,900 standard cubic feet of natural gas per hour at rated load. Its rated load electrical generation efficiency is 40 percent on a lower heating value basis, and electrical efficiency remains at or above this value at loads between one-half and full load. The sound pressure level is 60 dBA at 30 feet from the power module. It is compact, can be transported easily, and can convert coalbed methane directly into electrical energy.

Innumerable locations around the world have a supply of low-quality coalbed methane but no electric-generation capabilities. However, before the fuel cell is viewed as a panacea for these locations, its operational limitations on low-quality gas must be investigated. Included among the variables are the power plant efficiency, fuel consumption, oxygen tolerance, power output, heat generation and utilization, reliability, and operating economics. Also, such peripheral areas as legal, environmental, and regulatory must be thoroughly investigated as an adjunct to the operating demonstration of the power plant. The type of study described in this report can broaden the utilization of the fuel cell power plant such that future cost of acquisition and operation will be reduced to practical levels for widespread use.

BACKGROUND AND PREVIOUS WORK

As is well documented in the literature [3,4,5], methane from coal seams in underground mining environments has been known and documented as a potential hazard ("unwholesome gas") since the late 16th century. Reports from early in the 18th century from Great Britain identify the occurrence of methane explosions in what then were termed deep British mines.

In the United States, methane related mining problems were first identified by a report of a mine explosion in the state of Virginia in 1839 [4]. According to Deul, methane explosions occurred at irregular intervals until 1875 when an increase in the frequency of explosions was reported. This corresponded to the rapid increase in the growth of the eastern U.S. coal mining industry (required to supply the rapidly expanding base metals and other industry) and the trend toward mining deeper coal horizons.

Similar situations were encountered in the coal mining industry throughout Europe and the far east such that beginning in the early 1900's efforts were put forth by various governments and governmental agencies to mitigate the presence of methane in coal mines. Within the U.S., the formation of the U.S. Bureau of Mines (USBM) in 1910 significantly impacted mine safety, primarily through the development and implementation of improved mine ventilation systems, rock dusting procedures, and the use of permissible (safety) explosives, electrical equipment, and cap lamps.

However, even with the adoption of these improved methods and equipment, methane emissions continued to be a source of potential danger. Clearly, supplemental efforts to those described above were required in certain mines, especially the deeper, high gas emission-prone mines. The proposed solution to this problem was the removal of the methane from the coal prior to it's mining or the venting of the methane contained within the mined-out coal areas. This process (degasification, firedamp drainage, demethanation) employed various combinations of in-mine and surface relief techniques to remove the methane. The methods employed were initially developed within the European coal mining industry, beginning in earnest during the 1920's and becoming systematic by the early 1950's with the formation by the Council of Organization for European Economic Cooperation of the technical assistance program on the *"drainage and use of methane from coal mines"* [6]. Similar programs were also developed in what was then the Soviet-influenced eastern European countries and the republics of the Soviet Union.

Efforts in the United States in methane control were initiated by the USBM in 1964, although industry had already begun a development program of it's own by the early 1950's [7]. However, the work of the USBM did not begin in earnest until the passage in 1969 of the Federal Coal Mine Health and Safety Act, which was quickly enacted following the massive Farmington, West Virginia coal mine disaster. Significant government and industry efforts during the 1970's firmly established the techniques for controlling methane, including the use of in-mine horizontal and cross-measure boreholes, gob wells, and vertical, fracced wells, along with other more conventional methane control methods (i.e. ventilation). As should be expected, much of the USBM work (and that of private industry) built upon the earlier work conducted in other parts of the world (especially Europe), with modifications to these techniques for the unique geologic and mining conditions and operations in the U.S.

However, during this entire period, the effort was directed toward removing the methane from the mine environment (to make the mining operation more safe). Only recently was it realized that 1) the methane that was being recovered by certain techniques could be of value as an added energy source; and 2) the methane that was being captured and emitted to the atmosphere was a potent greenhouse gas. Beginning in the early 1980's, capture and utilization of this gas was realized, primarily through the use of vertical wells in advance of mining and gob wells. In these situations of methane capture and use, all of the gas captured was of high methane concentration (>90 percent) and was utilized as a pipeline-grade natural gas.

However, although significant quantities of methane was utilized that would otherwise have been emitted, there still were larger quantities that continued to be emitted to the atmosphere. This was due to the fact that this gas often had large concentrations of mine air mixed with the methane, ranging from 30 to 90 percent for gas captured by degasification methods and 0 to 1 percent for gas captured by the mine's ventilation air. Clearly, any reduction in methane emissions from coal mining required some type of utilization of this less-than-pipeline-quality gas.

At the same time that significant gains were being made in the capture and control of methane in the underground mine environment, substantial efforts were underway to develop and improve a system whereby different gasses could be directly converted to electric energy. In the late 1950s, the first fuel cell power units capable of operating at useful power levels were demonstrated. And, through Federal research funding, the fuel cell reached a level of maturity sufficient to warrant specification in a required power system by the National Aeronautics and Space Administration.

Since the pioneering days in fuel cell technology, the USDOE has been actively supporting research endeavors to advance the field. Of particular interest here are the advances in phosphoric acid fuel cells that are well documented in the yearly proceedings of the Fuel Cells Contractors Review Meetings sponsored by the Morgantown Energy Technology Center. In fact, the complete fuel cell power plant has reached the point of development that it can be applied in modular sense.

As an example, this modular application has been previously demonstrated by researchers at The University of Alabama and with Southern Company Services under USDOE sponsorship. In this project, a 40 kW phosphoric acid cell was employed with near pipeline- quality coalbed methane from an on-site well. The project successfully demonstrated that on-site fuel cell generation works. The problem now at hand is how well does it work with less than pipeline-quality fuel and in an industrial setting where efficiency, logistics, and mobility are crucial.

FEASIBILITY STUDY: TASK RESULTS AND DISCUSSION

INTRODUCTION

Methane released during the mining coal has historically been viewed as a safety hazard because of its explosiveness at low concentrations (5 to 15 percent) in air. Because of this, the control of this gas during the mining of coal has been a major concern to mine operators and miners. Recently, however, the potential of certain gases (including methane) released during anthropogenic activity to have possible effects on global climate has been demonstrated. Accordingly, attention has focused on the emission of methane during the mining of coal and on possible methods to minimize this emission while still maintaining safety in the mining operation.

As discussed above, the possible use of the methane that is emitted by various methane control techniques at coal mines for energy conversion applications is not only technically possible but also economically probable. The emphasis of this project to evaluate the potential of using this emitted (and wasted) methane as a fuel source for fuel cell conversion into electricity closely aligns itself with these important goals - *maintenance of coal mine safety while reducing emissions of methane to the atmosphere.*

The first step of such an evaluation must include a determination if the methane emission source under consideration for conversion will be large enough to both perform the required research and development scheduled for the Demonstration Project. Accordingly, an important aspect of the Phase I work included a determination of the size and quality of the gas resource and the potential producibility of this resource. In addition, preliminary analysis of the application of the proposed technology - *fuel cell conversion of emitted methane from gob wells* - must also be performed to provide 1) an initial indication of the potential for the demonstration project success; and 2) a foundation for the more detailed engineering analysis to be performed during the second phase of the project. This section of the report provides a summary of the work performed during the first phase on these important issues.

TASK 1 - DETERMINATION OF MINE GAS POTENTIAL

Project Location

The site selected for the potential demonstration project is at the Jim Walter Resources Blue Creek No. 4 Mine (JWR No. 4), located in north-central Alabama within eastern

Tuscaloosa County. The JWR No. 4 mine is part of a four-mine underground complex within eastern Tuscaloosa county and western Jefferson county operated by Jim Walter Resources, Inc., Figures 3 and 4. Depths of operations in these four mines (JWR No. 3, No. 4, No. 5, and No. 7) range from 1,300 to 2,100 feet, making these mines some of the deepest operating coal mines in the U.S. Adjacent to these mines are other underground coal mines operated by USS Mining Company (Oak Grove Mine) and Drummond Coal Company (Shoal Creek Mine).

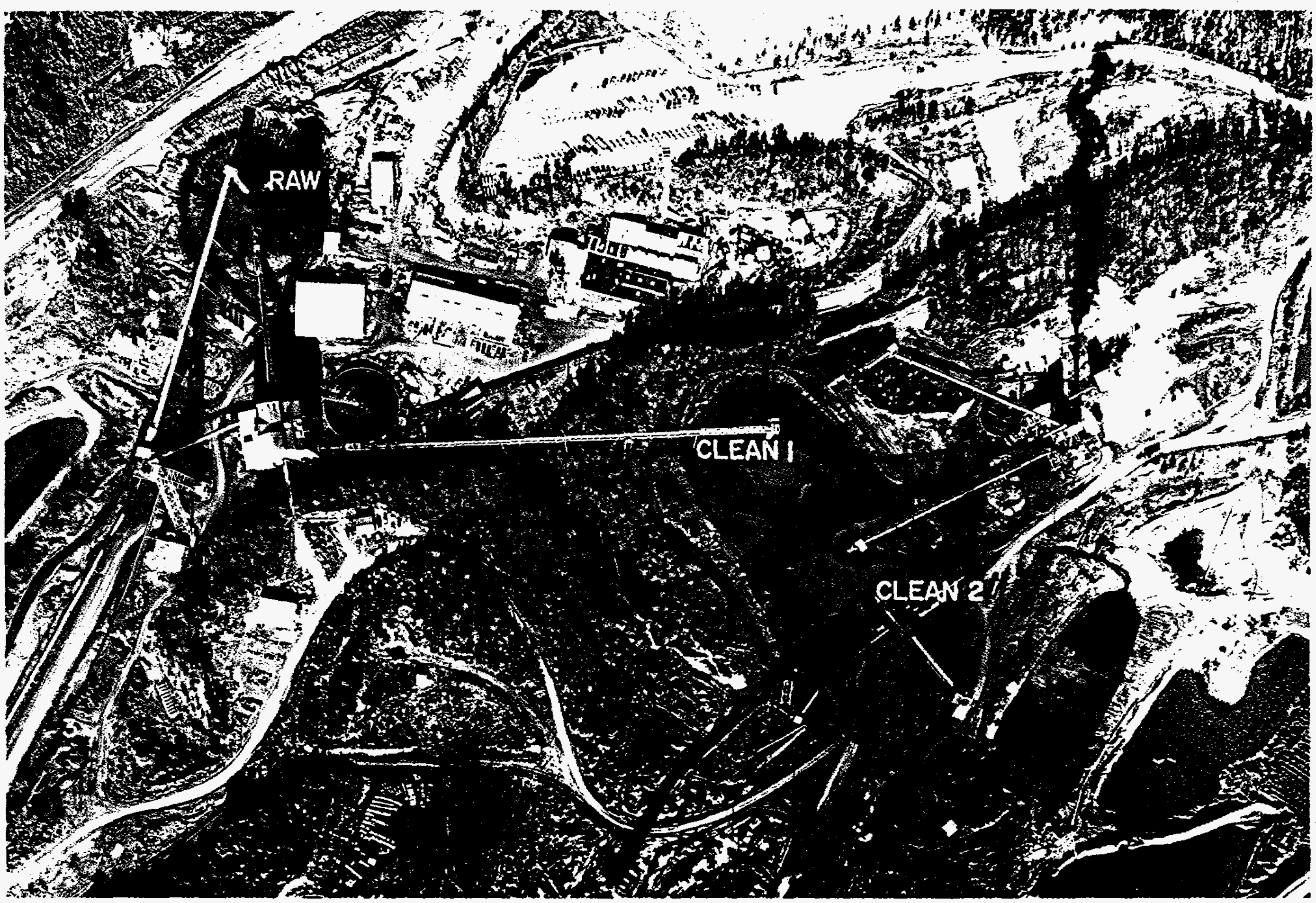

Figure 3. Aerial View of the JWR No. 4 Mine showing (from left to right) Mine Shaft, Preparation Plant, Coal Storage Piles, and Thermal Dryer (w/ steam plume).

The mine site is easily accessible via state highway Route 216 and is 25 miles from the Adger interchange on U.S. Interstate Highway I-59/20. In addition to the well-developed county road system in the area, the mining operations maintain extensive all-weather roads for access to ventilation shafts, mine degasification gob and vertical wells, and other facilities throughout the surface area of the mine.

Topographically, the area is a dissected Appalachian plateau with an average vertical relief of 50 feet. A more pronounced topographic relief (up to 200 feet) can occur in the vicinity of stream valleys, such as the Davis Creek valley which is located east and north of the JWR No. 4 mine area. The closest major population centers are Birmingham, Alabama (50 miles to the northeast on I-59/20) and Tuscaloosa, Alabama (25 miles to the west-southwest on I-59/20), although numerous towns and villages are present within the mining area. Surface use in the area is composed of timber cutting, surface facilities for underground mining operations, surface (strip) mining, and limited agriculture.

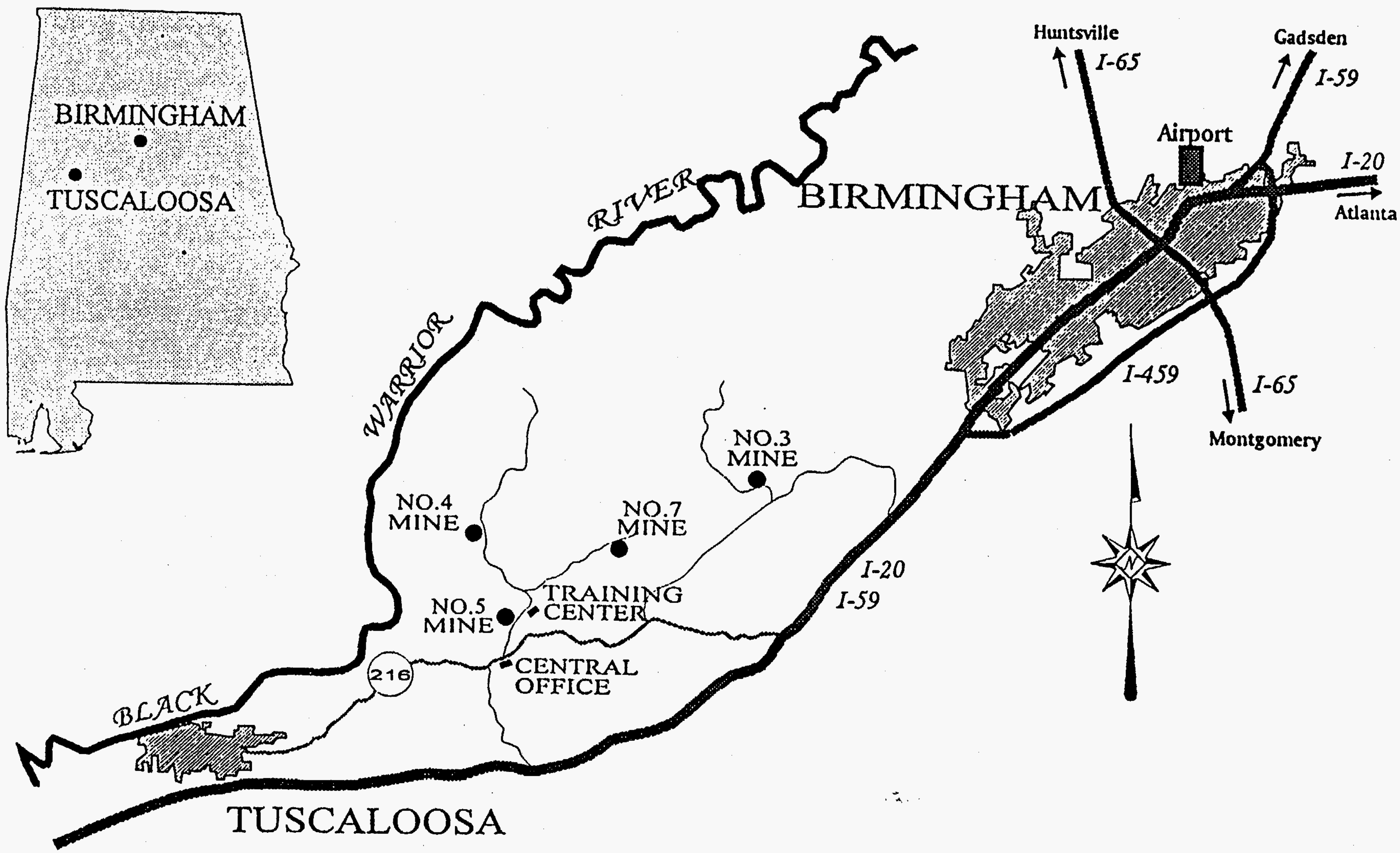

Figure 4. Demonstration Site Location.

Geologic Setting of the JWR No. 4 Mine

The JWR No. 4 mine is located within and along the eastern edge of the Warrior basin. The Warrior basin is the southernmost of a series of Pennsylvanian-age basins of the Appalachian plateau in the eastern U.S. The basin is principally a triangular wedge of sedimentary rock that is structurally bounded on the east and southeast by steeply dipping strata of the Appalachian orogenic belt and on the southwest by the deeply buried Ouachita structural trend, Figure 5. The northern edge of the basin is stratigraphically defined by the updip limit of Pennsylvanian-age rocks [8].

The easternmost part of the Warrior basin (the area of the project site) is characterized as a structurally complex foreland basin [9]. The eastern margin of the basin is a large thrust structure formed during the Alleghenian orogeny. While extensive folding and faulting of the early Paleozoic strata is more commonly associated with this compressional orogenic event, the eastern Warrior basin is characterized by more broad and low amplitude folds and little evidence of thrust faulting. However, numerous enechelon normal faults are present within this area of the basin, possibly due to tensional pull-apart structures formed during basal decollement in the Alleghenian orogeny [10], Figure 6.

Within the specific area of the JWR No. 4 mine, the geologic structure consists of a series of northwest-southeast trending normal faults with stratigraphic throws ranging from a few feet to over 100 feet, Figure 7. The primary target coal seam (Mary Lee/Blue Creek) dips gently to the west across most of the mine area. Southeast of the mine area the structure is dominated by the main Appalachian overthrust, such that the dip of the strata changes rapidly from near horizontal to near vertical.

The coal-bearing strata of the Warrior basin occur in the Lower Pennsylvanian Pottsville formation and consist primarily of sandstone, siltstone, and shale with minor amounts of coal. Repeated sedimentary cycles, each of which correspond to a major coal group, are common throughout the basin [11]. Eight coal groups are present within the eastern portion of the Warrior basin (from oldest to youngest): 1) Black Creek; 2) Mary Lee; 3) Gillespy/Curry; 4) Pratt; 5) Cobb; 6) Gwin; 7) Utley; and 8) Brookwood [8,9,10], Figure 8. Coal groups (and the subject coal seams) generally cap the regressive, coarsening-upward sedimentary cycles. The cycles have as much as 350 feet of marine mudstone at the base and typically coarsen upward into sandstone. At the top of each cycle is the interbedded mudstone, sandstone, underclay, and coal that makes up a coal group [9]. Within the Warrior basin the Mary Lee and Blue Creek coal seams of the Mary Lee group are the primary target zones for coal mining. Locally, the Pratt seams within the Pratt Group are also underground mining targets.

The JWR No. 4 mining operation primarily targets the Blue Creek coal seam. In addition, the overlying Mary Lee seam is also mined if the rock parting between the two coal seams is too thin and cannot be supported by normal roof control techniques. Coal seams of the other seven coal groups discussed above are present within the mine area, as shown in the typical well stratigraphic section for the mine area, Figure 9. However, individual coal seams within these groups often are not continuous across the mine area.

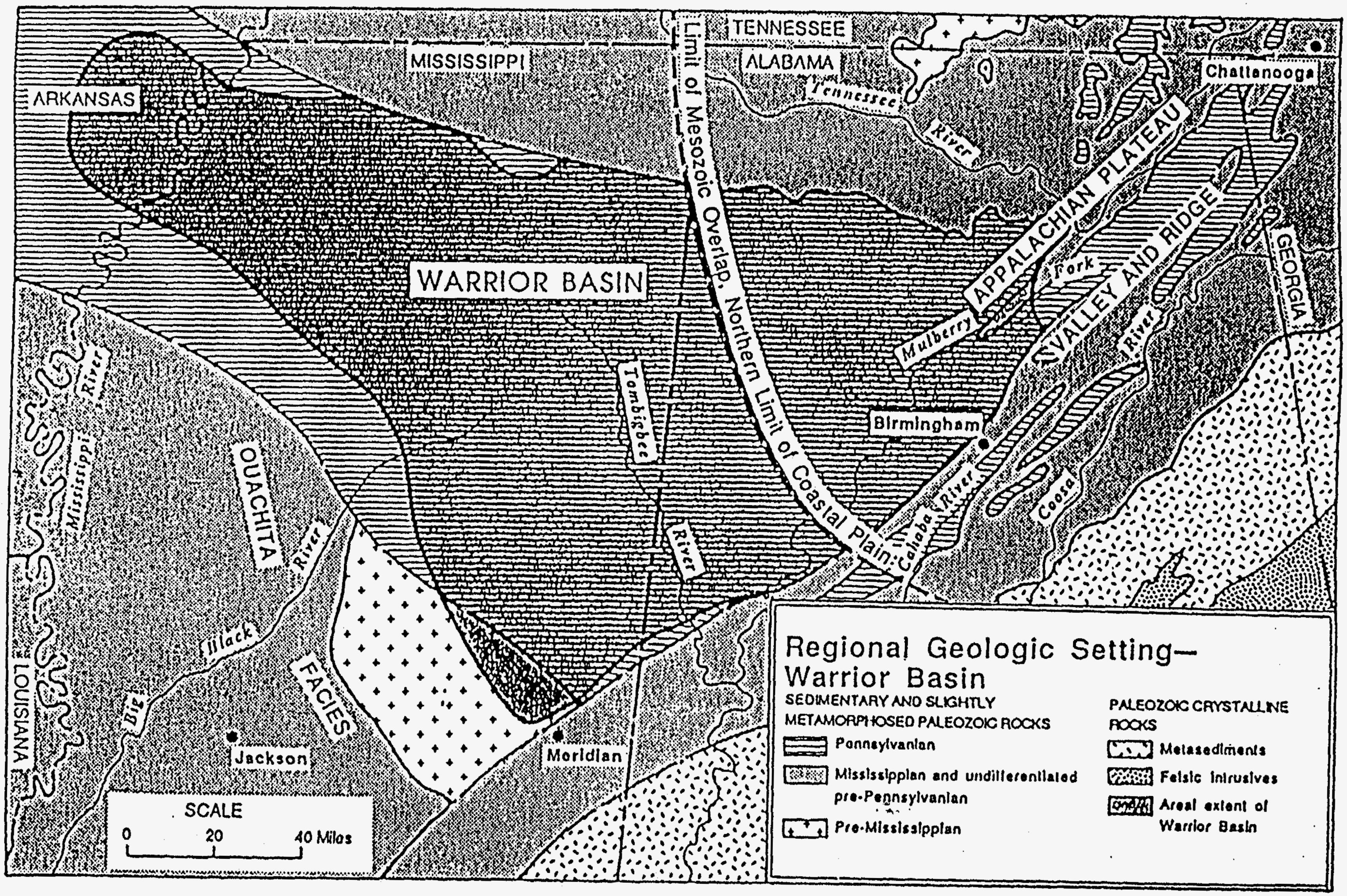

Figure 5. Geologic Setting of the Warrior Basin.

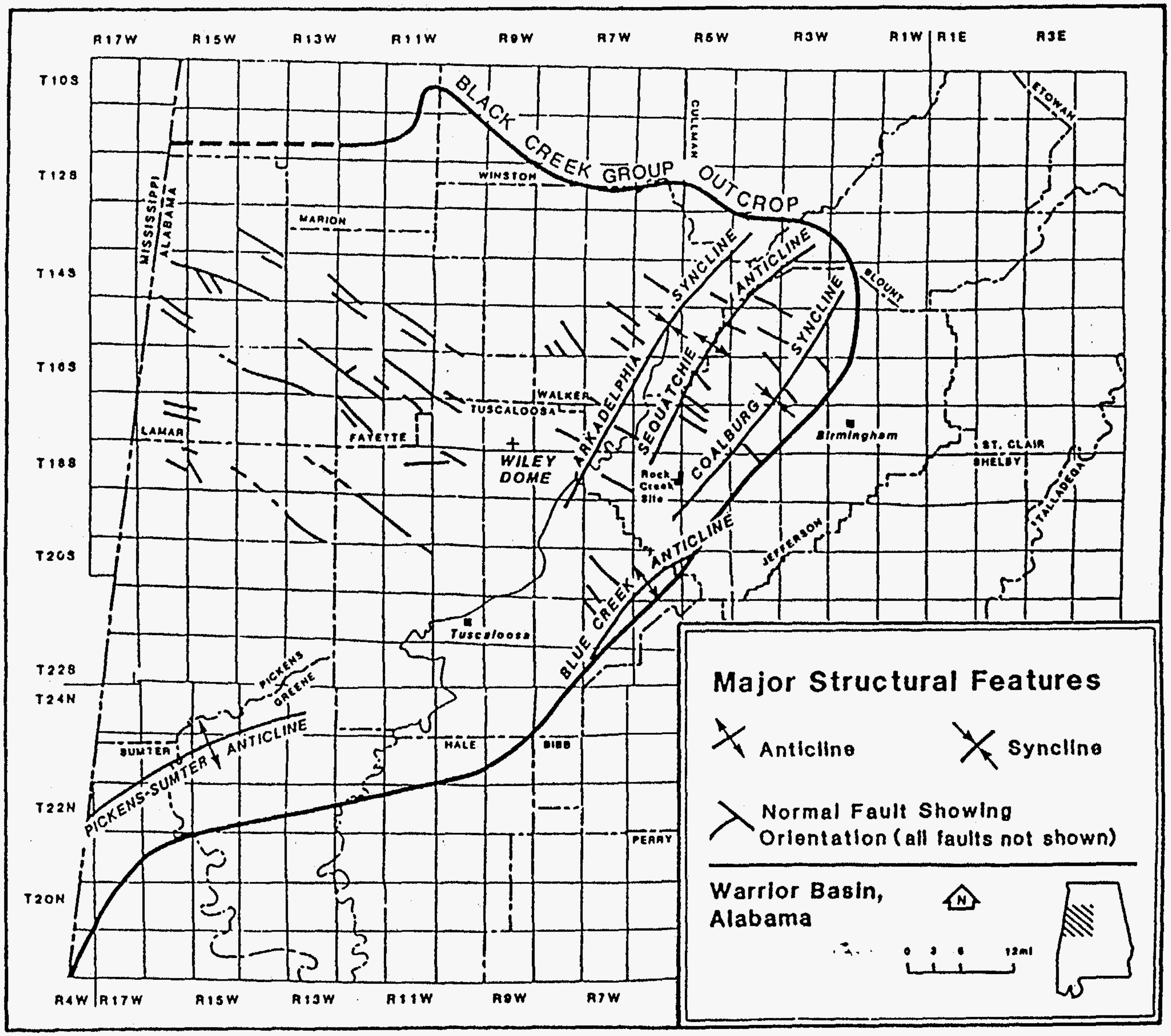

Figure 6. Major Structural Features of the Eastern Warrior Basin.

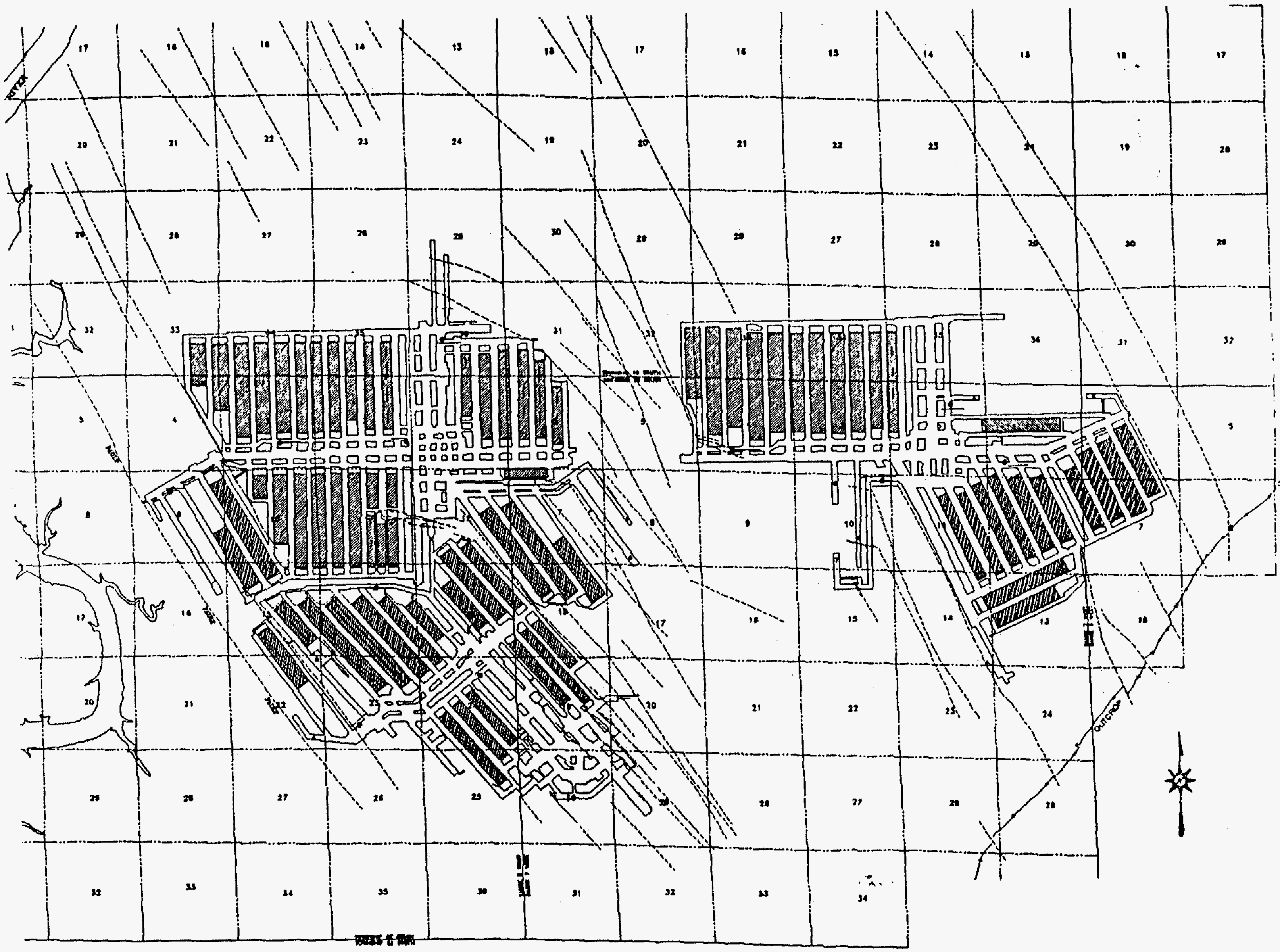

Figure 7. Structural Features of the JWR Mine Area.

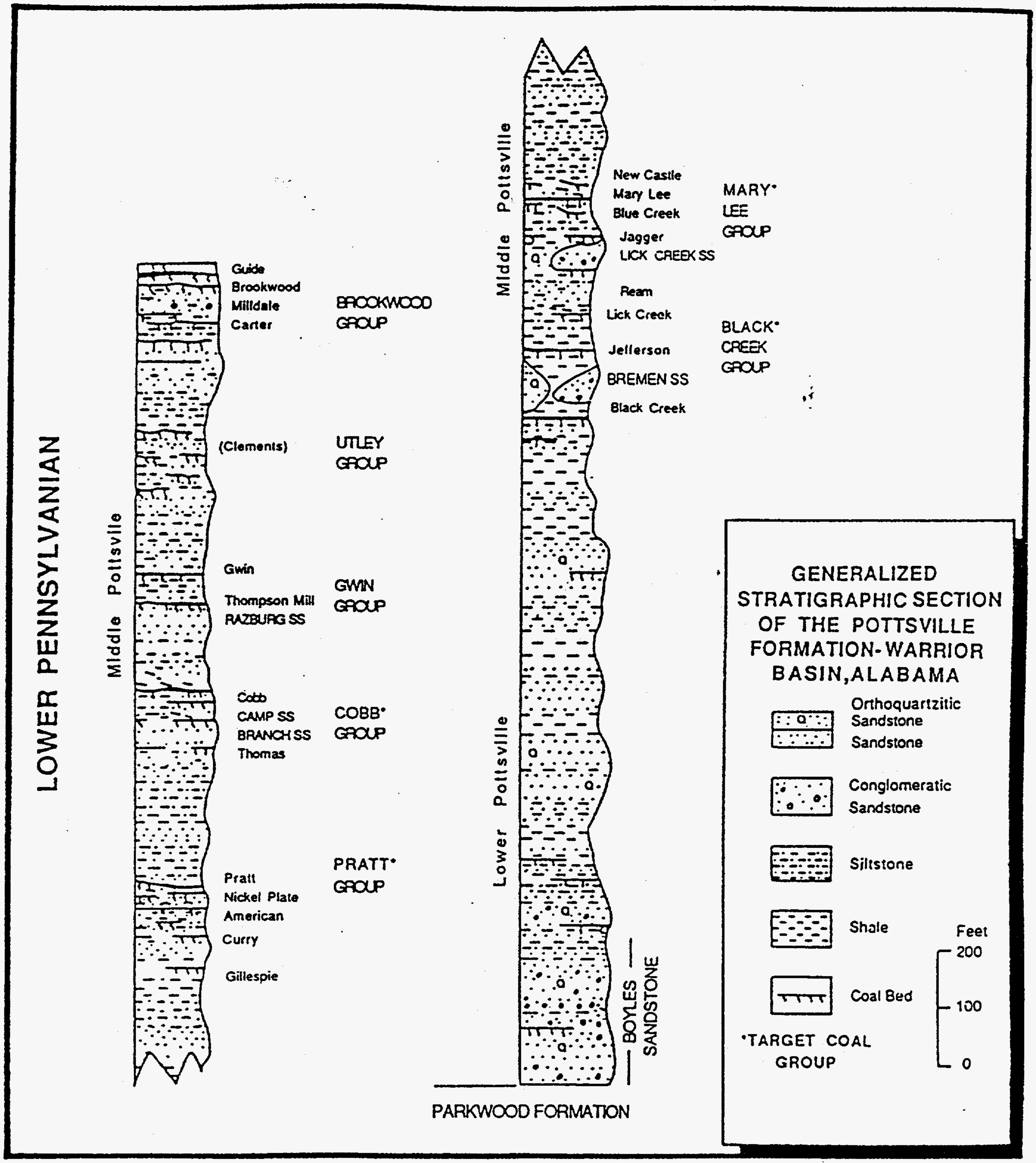

Figure 8. Generalized Stratigraphic Section for the Eastern Warrior Basin.

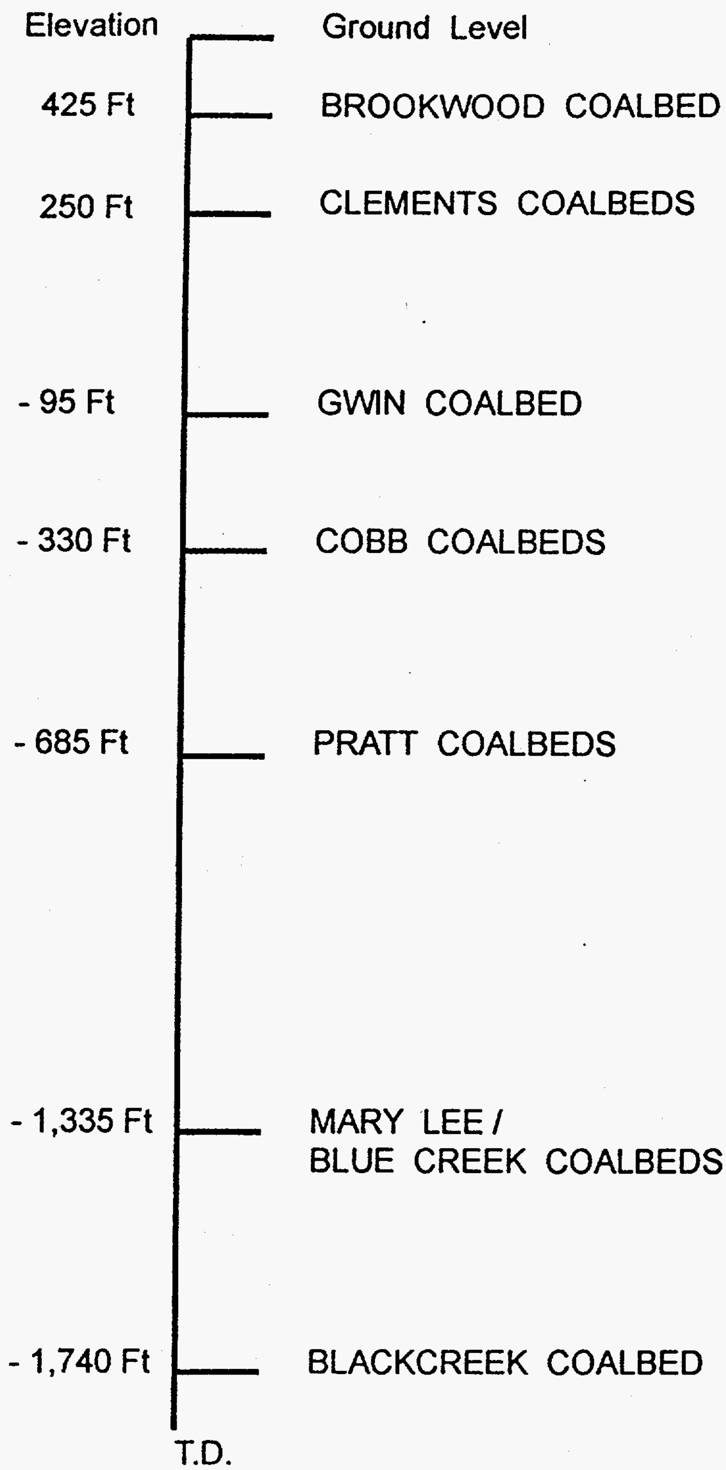

Figure 9. Generalized Stratigraphic Section for the JWR No. 4 Mine.

Mining Operations at the JWR No. 4 Mine

The mining operations at the JWR No. 4 mine target the Mary Lee and Blue Creek coal seam at a depth ranging from 1,900 to 2,100 feet. Continuous mining sections (there are 5 sections operating at the JWR No. 4 mine) develop the mine main entries and sub-main entries and the headgate/tailgate/bleeder entries surrounding the planned longwall panels. The mine mains and sub-mains typically consist of 4 to 6 entries with yield and barrier pillar support systems employed. The mains and sub-mains are designed to effectively create a long-term access/egress route within the mine for ventilation, personnel, and coal production movement.

Once the continuous mining sections have developed the headgate/tailgate/bleeder entries surrounding planned longwall panels, shearing-type longwall mining equipment utilizing four-leg roof support units are installed for longwall mining operations. Longwall panels originally were 600 to 750 feet in width but current operations utilize panel widths of 850 to 950 feet. Panel lengths are dependent upon local mining conditions, especially the presence of the numerous high-angle normal faults that are present within the mining area. Typical panel lengths of 5,500 to 6,500 feet are currently employed by the mining operations. At present, 2 longwall units are in operation at the JWR No. 4 mine.

Coal produced from the continuous and longwall operations is transported from the working face area via shuttle-car haulage and conveyor systems to underground storage bunkers located near the bottom of the production shafts. Balanced hoisting skips transport the coal from the temporary storage bunkers to the surface, transporting 20 to 25 tons of mined coal per lift [12].

The active portion of Mine No. 4 is illustrated in the mine map of Figure 10. The crosshatched areas of the map indicate the gob areas of the mined-out longwall panels. Further inspection of Figure 10 shows that future mining at the JWR No. 4 mine will be in the west and north areas of the mine. The life-of-mine map shows mining activity to the Year 2029. This tremendous coal reserve assures adequate coalbed methane for any conceivable need.

Mine Ventilation Operations at the JWR No. 4 Mine

The goal of a coal-mine ventilation system is to provide healthy and safe atmospheric conditions for the mine workers. To achieve this goal, the ventilation system must supply an adequate amount of fresh air and dilute toxic, noxious, and explosive gases and dusts to harmless levels while removing them from the mine. In coal mines, the required quantities of air are generally dictated by the amount of fresh air necessary to dilute methane concentrations well below their combustion threshold.

To accomplish this at the JWR No. 4 mine, two exhaust shafts coupled with four intake shafts are used for ventilating the mine, and are located on the mine map shown in Figure 10. At each exhaust shaft, two fans are connected in parallel and provide the means of exhausting air

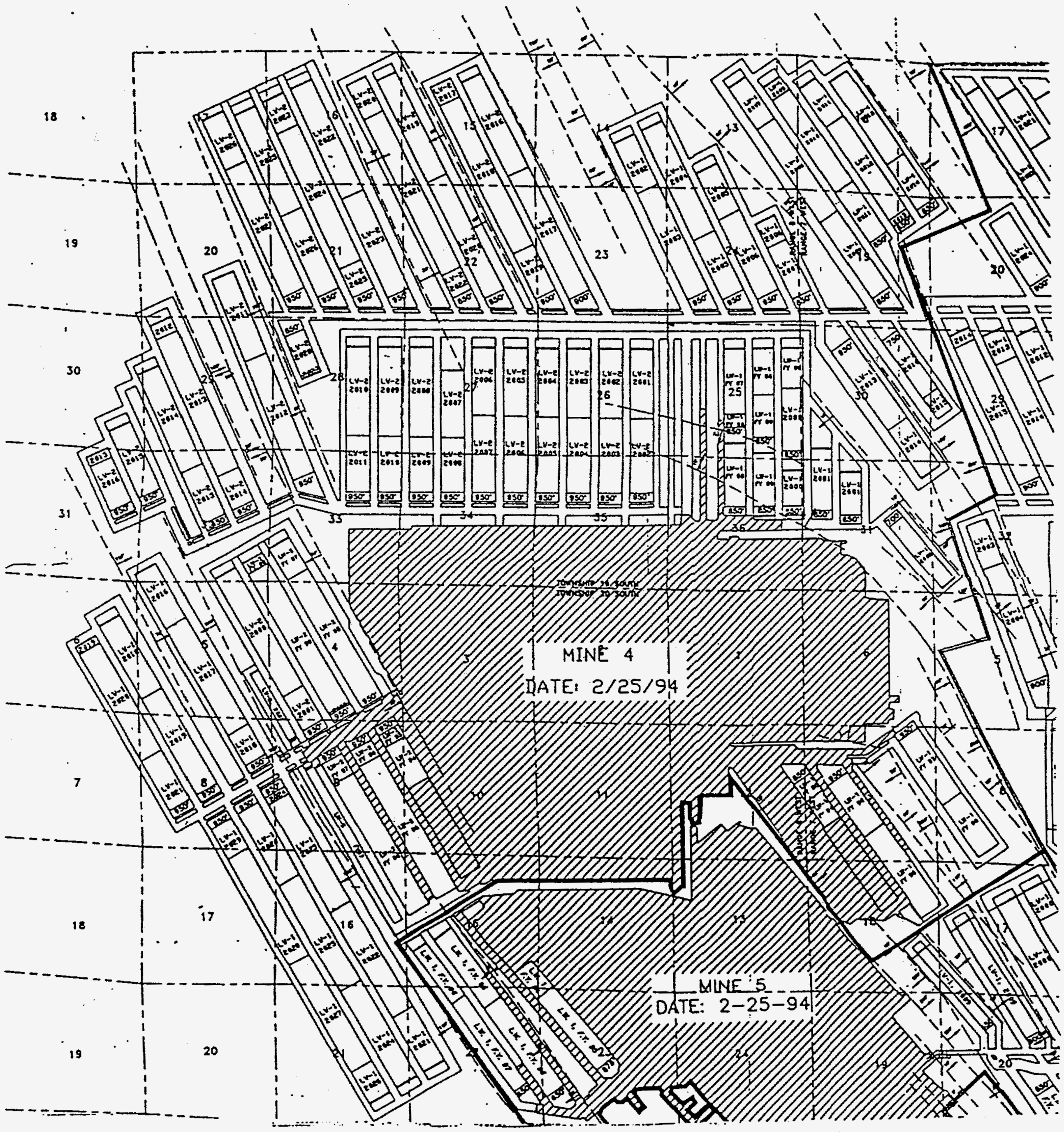

Figure 10. Mine Map of the JWR No. 4 Mine Showing Mined-Out and Future Mining Areas.

from the mine workings. Each fan is 12-feet in diameter and is powered by a 3,500-horsepower electric motor.

Figure 11 shows the ventilation exhaust and Figure 12 shows the total methane liberation rates from the two exhaust fans at the JWR No. 4 mine. The south fan shaft produces an average exhaust flow of about 1,750,000 standard cubic feet per minute, with an average methane content of 0.29 percent. The north shaft exhausts about 1,690,000 standard cubic feet per minute, with an average methane content of 0.05 percent. During the period October 1994 through June 1995 these two fan shafts emitted an average total daily volume of 8.6 million cubic feet of methane.

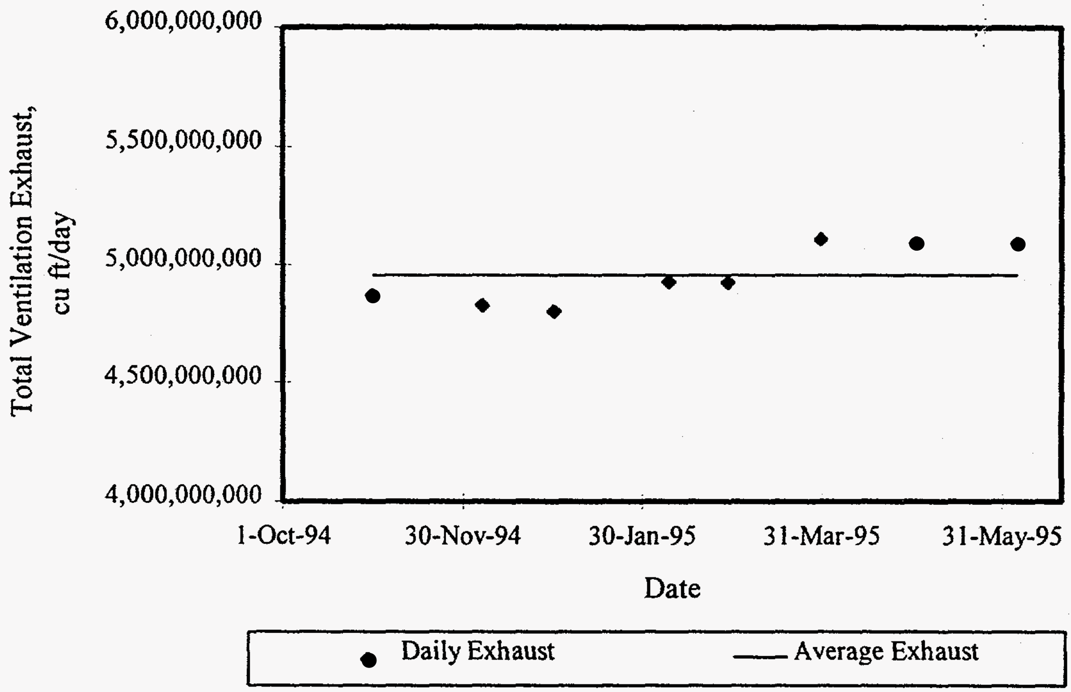

Figure 11. No. 4 Mine Ventilation Exhaust (Oct 1994 - June 1995).

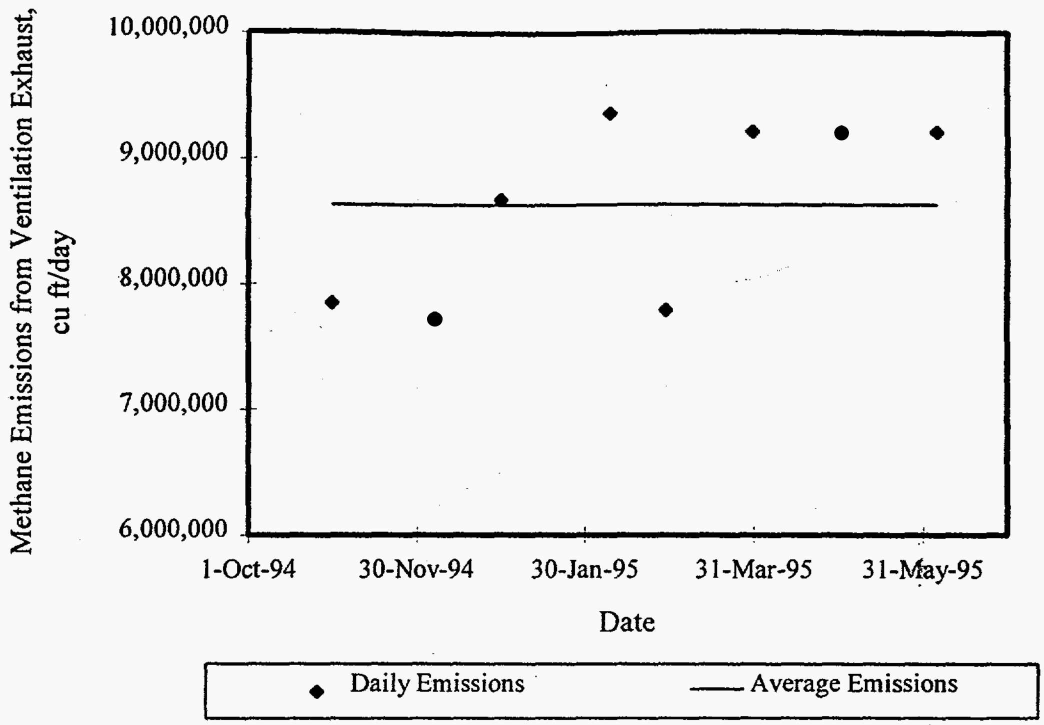

Figure 12. No. 4. Mine Methane Emissions from Ventilation Exhaust (Oct 1994 - June 1995).

Mine Degasification Operations at the JWR No. 4 Mine

Introduction

Because of the high methane content of the coal mined at the JWR mines (discussed in more detail later) in the Warrior basin, methane drainage techniques are used to supplement the normal mine ventilation system. These methane drainage systems employ vertical pre-mining wells, in-mine horizontal wells, and gob wells. Each of these systems are described in more detail below.

Vertical Pre-Mine Drainage Wells

JWR, along with other mining companies in the Warrior and Appalachian basins, utilize vertical wells drilled into the unmined coal areas as an effective means of removing the methane from the coal prior to its mining. This type of well, drilled and completed in a method similar to conventional natural gas wells, is the primary basis for the large U.S. coalbed methane industry in which over 6,700 wells were producing 2.2 billion cubic feet of methane per day at the end of 1994.

Vertical wells at the JWR mines in the Warrior basin initially only targeted the seams that were being mined - the Mary Lee/Blue Creek. However, with improved drilling and completion techniques, current wells target all primary coal gas horizons in the well, including the coal seams of the Black Creek, Mary Lee, Gillespie/Curry, Pratt, and Cobb coal groups. Figure 13 illustrates a typical vertical well completed into one coal zone. In this figure, water that is co-produced with the coalbed methane is pumped from the well through a central tubing string, whereas the gas flows naturally in the annular area between the tubing and the well casing. To enhance the gas flow from the typically lower permeability coal formations, the coal seams are hydraulically stimulated. Generally, three to four stimulation treatments are performed in each well. Figures 14 and 15 illustrate the surface equipment configurations for vertical wells using two different types of dewatering systems. Shown in these photographs is the surface pumping unit (either the pump jack for the sucker-rod pump or the progressive-cavity pump surface drive unit), the gas-water separator, surface gas and water piping, and flow metering instruments.

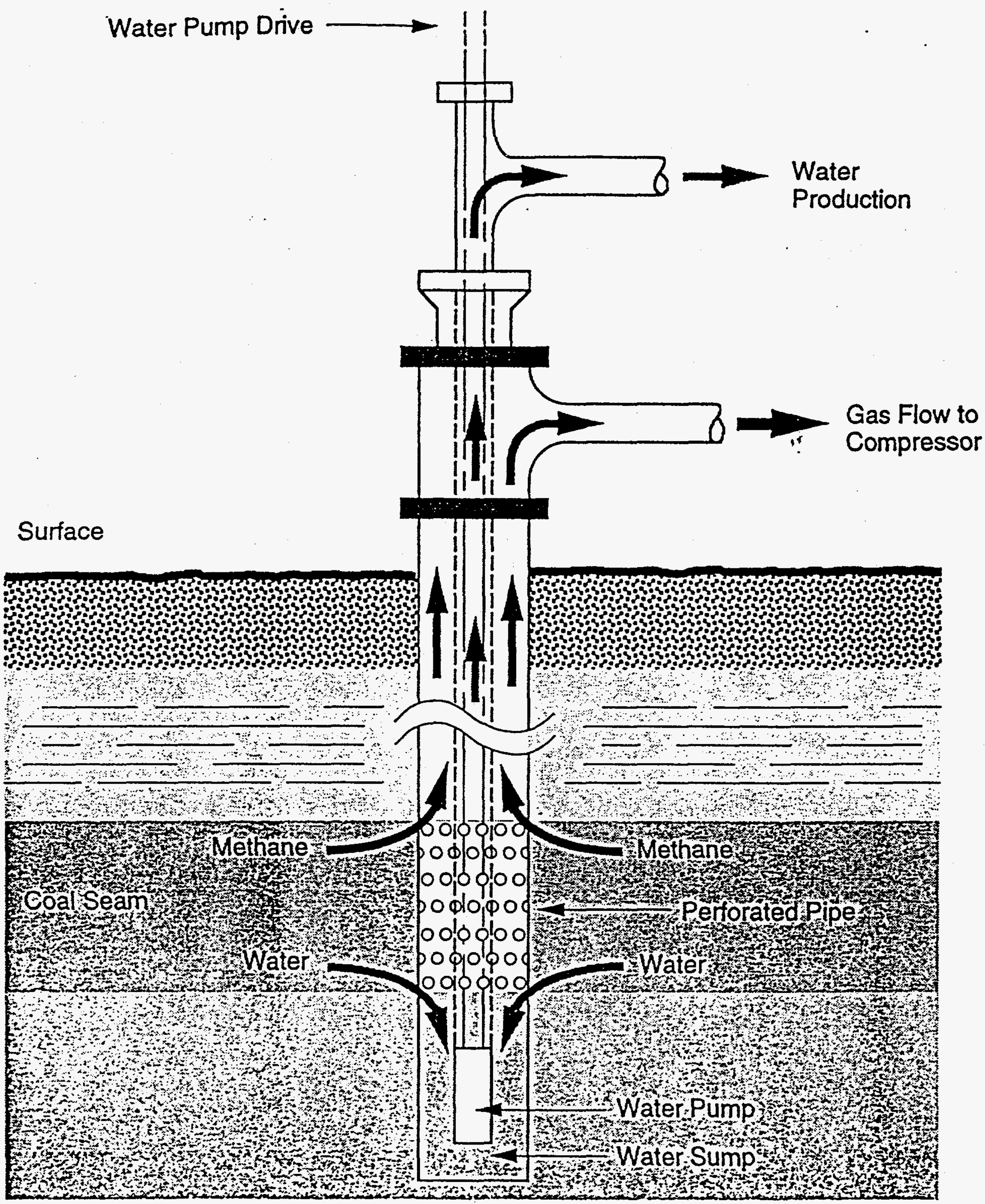

Figure 13. Schematic Diagram of a Fracced, Vertical Well.

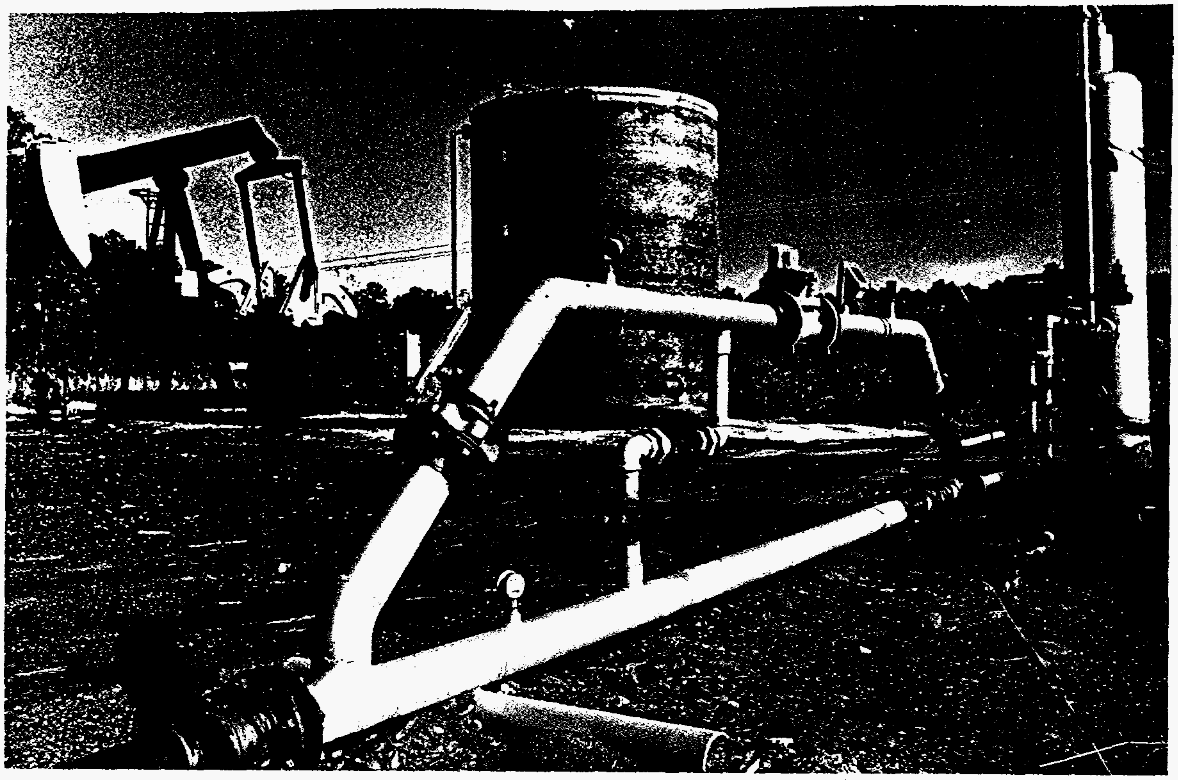

Figure 14. Vertical well at the JWR No. 4 Mine Utilizing a Sucker-Rod Dewatering Pump.

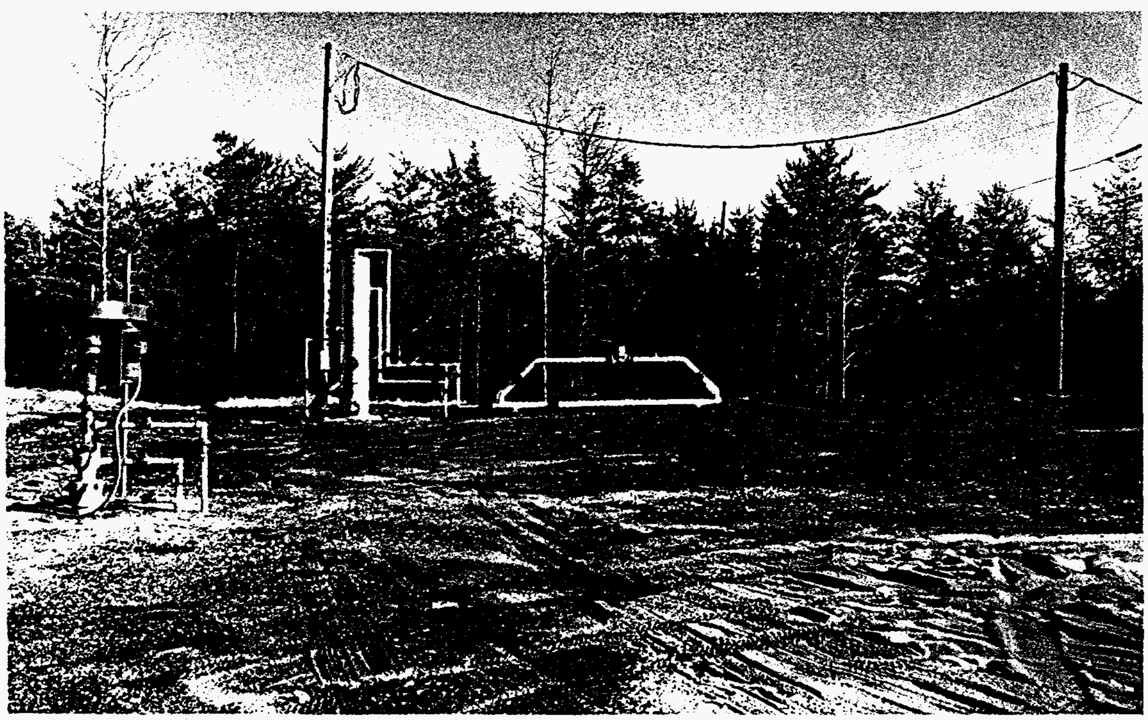

Figure 15. Vertical Well at the JWR No. 4 Mine Utilizing a
Progressive Cavity Dewatering Pump.

One of the advantages of vertical, fracced wells is that the gas that is produced is unaffected by the mining operations. This causes the gas quality to be that which is found naturally in the coal seam and in the JWR mine areas, the gas is principally methane (95 to 98 percent) with minor amounts of nitrogen, carbon dioxide, and other hydrocarbons.

As shown in Figure 16, daily production from the vertical, fracced wells in the JWR mining area has slowly increased during the past three years. Increased emphasis by the mining company on vertical well drainage and improved completion practices has led to increased activity in this type of methane recovery. Current production from the 110 vertical wells in the JWR mining area averaged 11 million cubic feet per day during June 1995, for an average per well daily production of 100,000 cubic feet. It should be noted, however, that the average daily rate includes new wells still undergoing dewatering (gas production is increasing), wells that are at their peak production, and older wells that have begun their production decline phase.

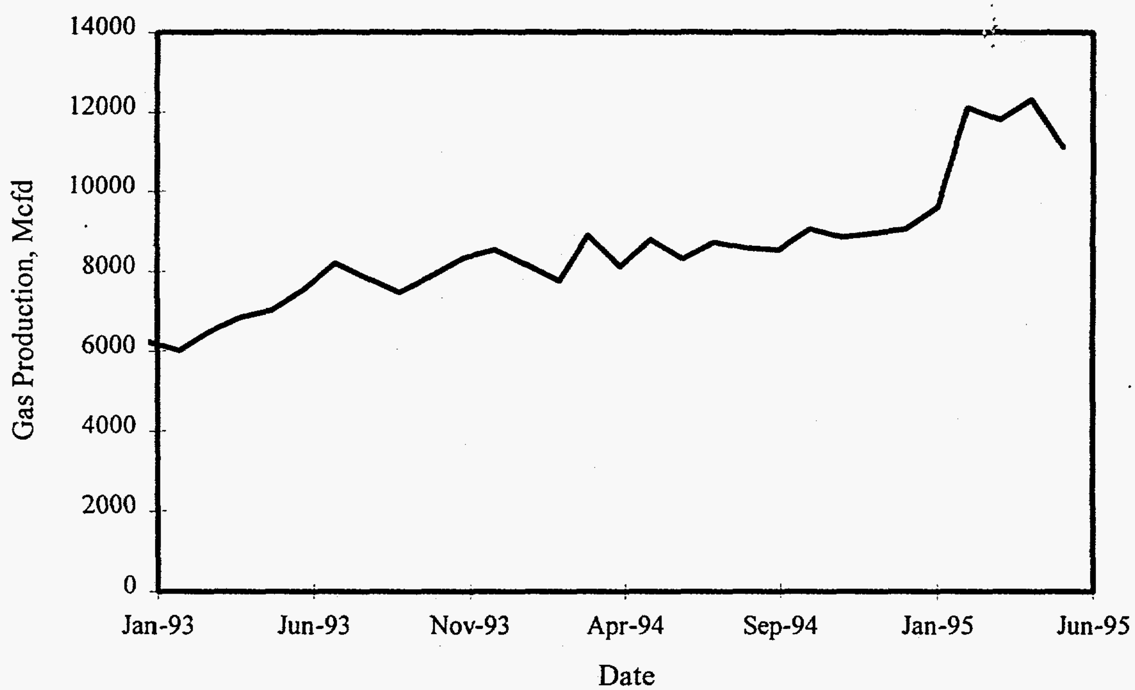

Figure 16. JWR Area Vertical Well Production History.

Horizontal Wells

Horizontal wells have been used in the JWR mines since the late 1970's as an effective means of removing methane from unmined longwall panels. The wells are drilled from the active mine workings (the longwall panel headgate road) across the width of the panel for a typical length of 700 feet. These wells are connected to an underground piping system that transports the methane through the mine to a collection point where a vertical well then transports the methane to the surface, Figure 17.

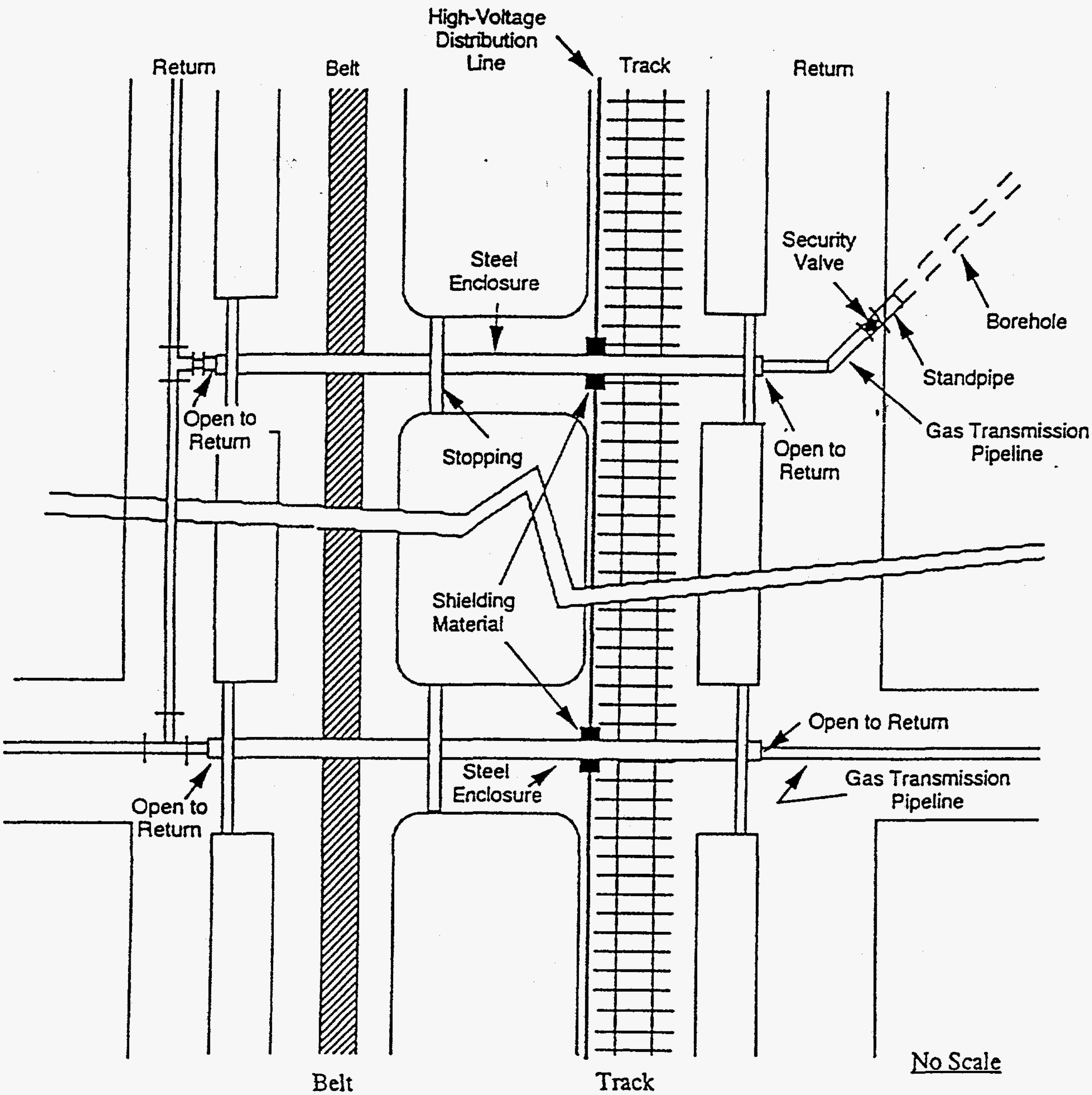

Figure 17. Horizontal Methane Well.

Although an effective method to degasify the mined coal seam immediately prior to its mining, the short production life of these wells causes their total production to be small when compared to a vertical fracced well. Figure 18 displays the production history for horizontal wells at each of the four JWR mines. As shown in this figure, the production rates can be highly variable, due to changes in mining rates and operations. As can also be seen in Figure 18, there is a general decreasing trend in production rate from the horizontal wells at the four mines. This is due in part to the effect of the pre-mining vertical wells and an emphasis to rely more heavily on these vertical wells to degasify the coal prior to mining. It is anticipated that as future mining occurs, fewer horizontal wells will be required and therefore the production decline should continue.

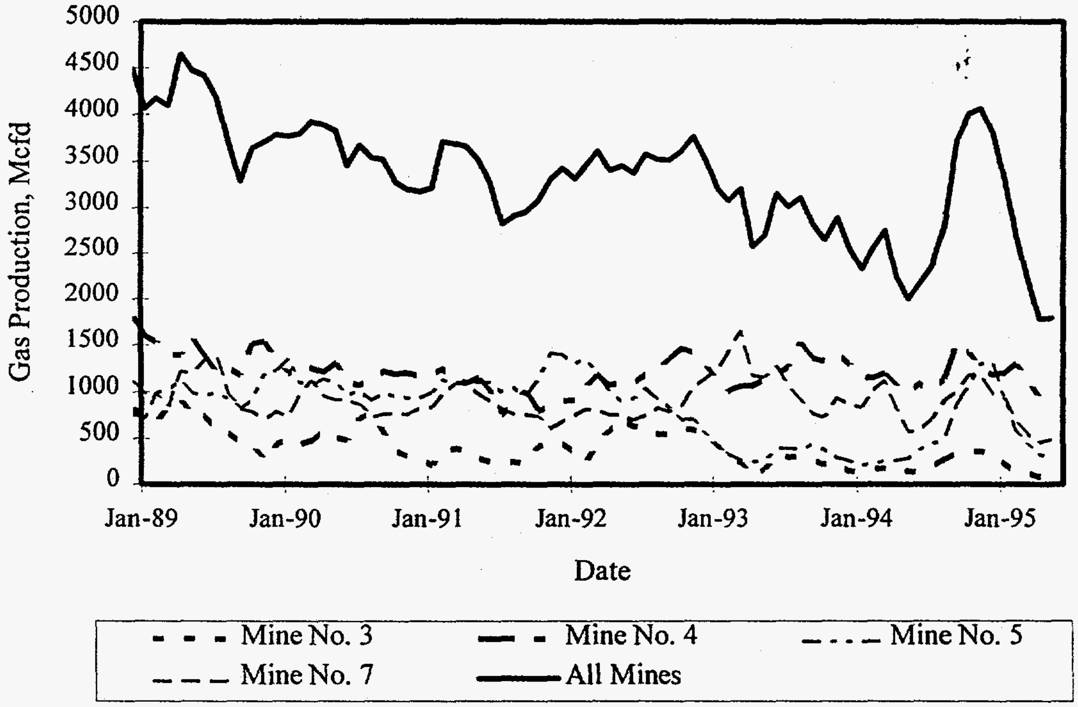

Figure 18. Horizontal Well Production History.

Figure 19 displays the horizontal well production from the JWR No. 4 mine, the location of the current project. As can be seen, there is also a general decline in production from horizontal wells due to fewer number of wells being required for methane control and a slowing of mining operations.

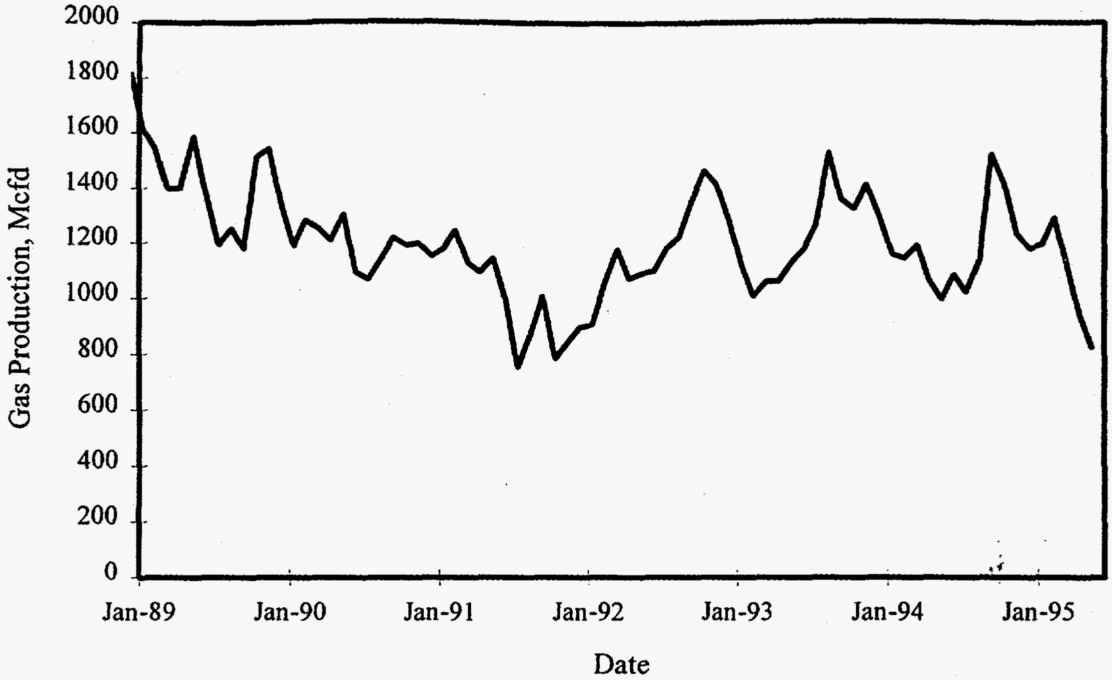

Figure 19. No. 4 Mine Horizontal Well Production History.

Gob Wells

Gob wells are the primary method of methane control at the JWR mines, following the mine's normal ventilation system. Gob wells are drilled from the surface into the area above a planned longwall panel, Figure 20. Following the mining of the coal by the longwall mining operation, the immediate roof fails and collapses into the void behind the mining operation. This collapse creates a lower zone of rock and coal rubble, an intermediate zone of fractured rock and coal, and an upper zone of fractured and sagging coal and rock strata. This zone of disturbed strata (referred to as the gob) has a very high surface area, high permeability, and low reservoir pressure. Because of this, the methane that is contained in the affected coal seams (including some seams below the mined seam which are affected due to stress relief fracturing) flows into the created voids. Without the presence of gob wells, this released methane would enter the active mine workings. However, the gob wells act as low pressure points within the gob such that the methane flows toward and into these wells, thus eliminating the flow of the methane into the mine workings.

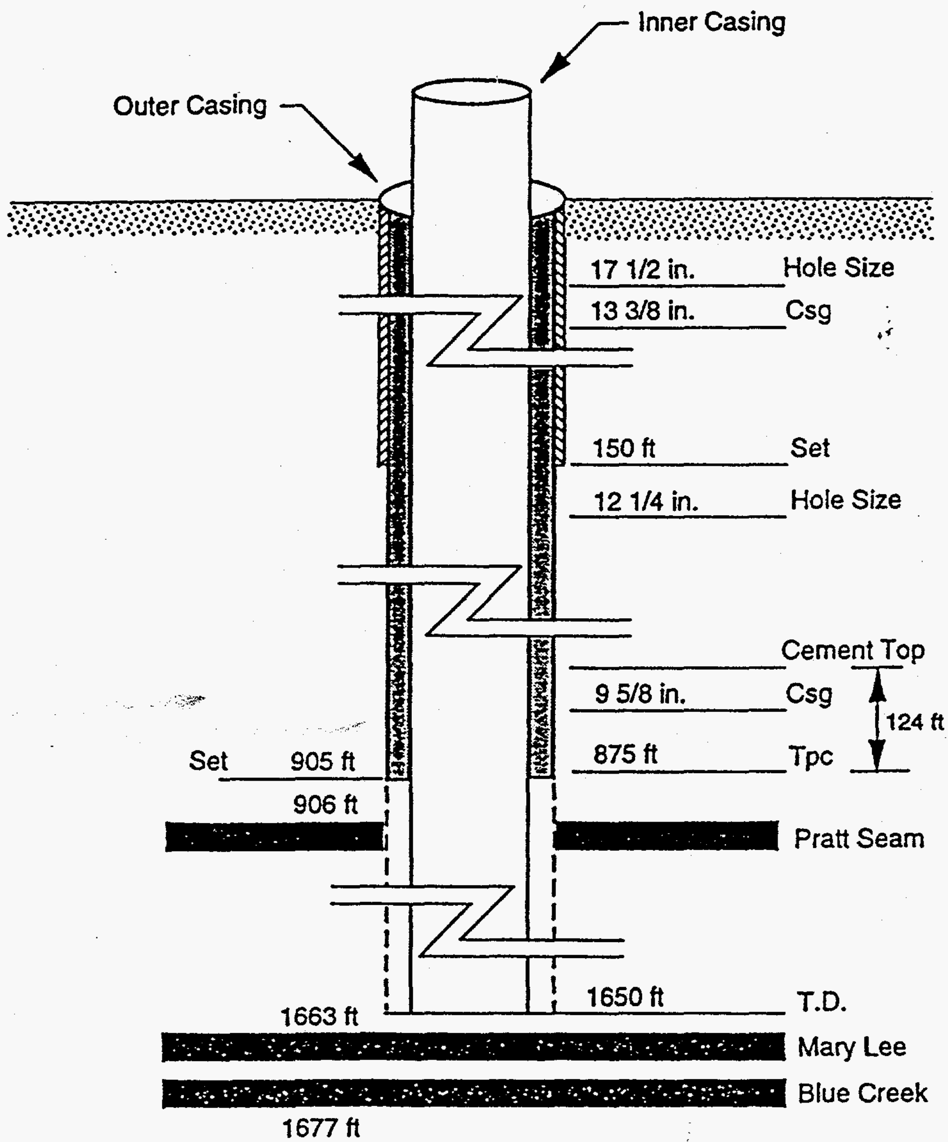

Figure 20. Typical Cross-Section of a Gob Well in the Warrior Basin.

The JWR mines in the Warrior basin have not only been a leader in the mining industry in the use of gob wells for effective methane control during longwall mining, but have also been at the forefront of operation of the gob wells to ensure that the gas that is produced is primarily the gas that is released from the affected coal seams. If insufficient draw (vacuum) is placed on the wells, some of the methane released from the coal flows into the mine workings. If excess draw is placed on the well, the gas that is produced is a mixture of the gas from the coal seams and the gas (air) that is in the underground mine environment. The optimum condition is whereby sufficient draw is placed on the well to prevent the flow of the methane into the mine workings but is not sufficient to draw the mine air into the upper gob area. JWR mines utilize an interactive underground/surface operating system to maximize the methane concentration in the produced gob well gas while preventing methane influx into the mine workings. Figures 21 and 22 illustrate the surface equipment configurations for gob wells at the JWR No. 4 Mine.

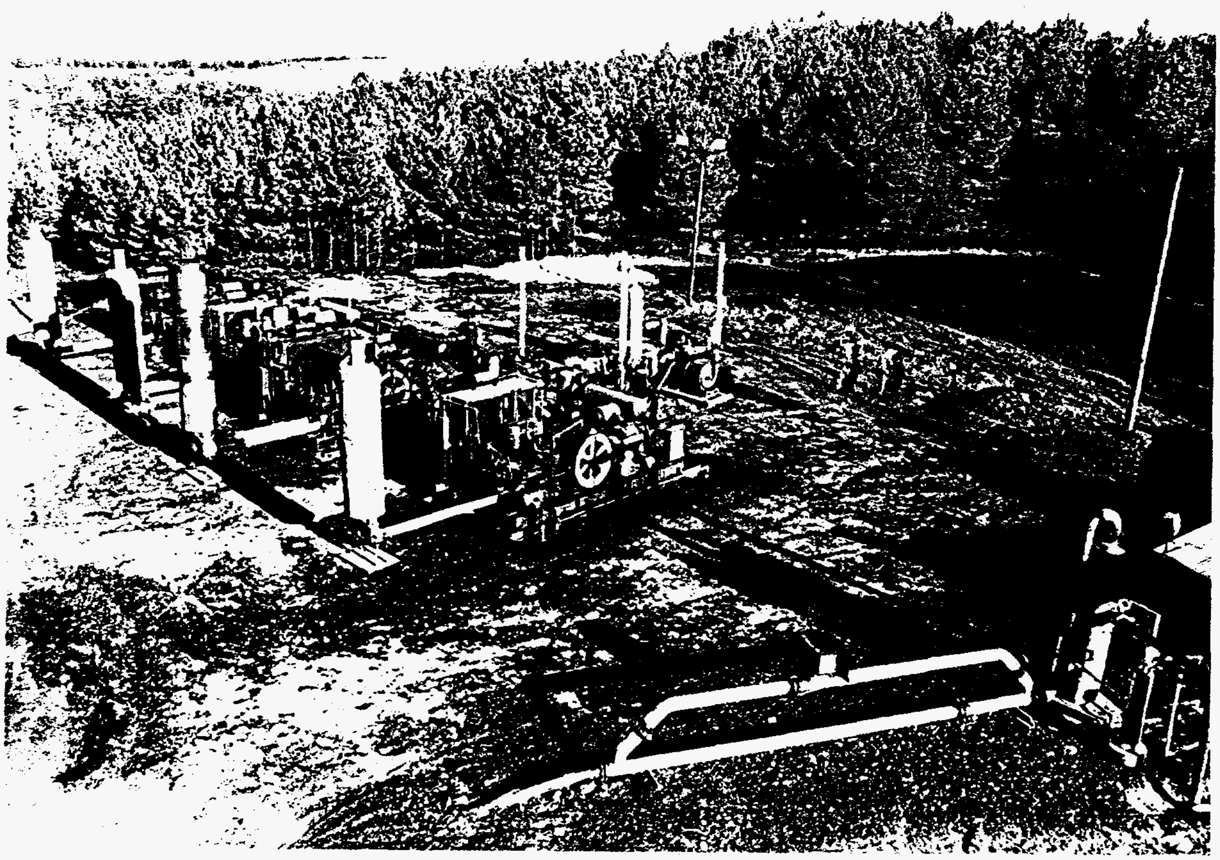

Figure 21. Surface Equipment Configuration for a High Production-Rate (2.6 MMcfd) Gob Well, Showing Compressors Used to Place Vacuum on the Gob Well and Compress the Gas for Movement to Central Compression Facility

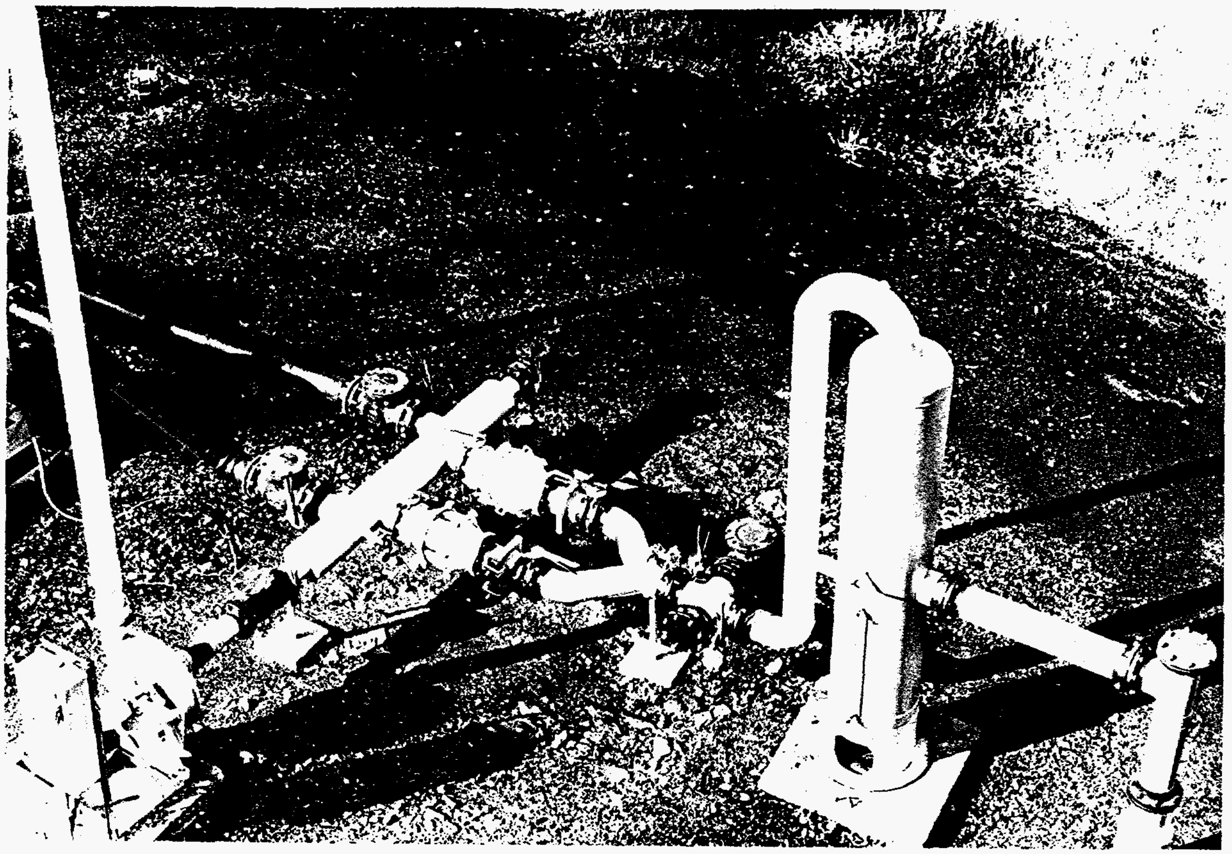

Figure 22. Surface Equipment Configuration for a High Production-Rate (1.2 MMcfd) Gob Well, With Compression Equipment Located Off-Site

Figure 23 details the daily production from gob wells in the four JWR mines during the period 1988 through 1995. As shown, total gob well production, while variable, has typically ranged from 20 million to 35 million cubic feet per day during this period. In comparison to the previously displayed production from horizontal and vertical wells, the gob well production is clearly the dominant form of methane capture at the JWR mines. Methane production from the gob wells currently contributes about 68 percent of the total methane produced and captured, while vertical wells contribute about 28 percent followed by horizontal wells at 4 percent.

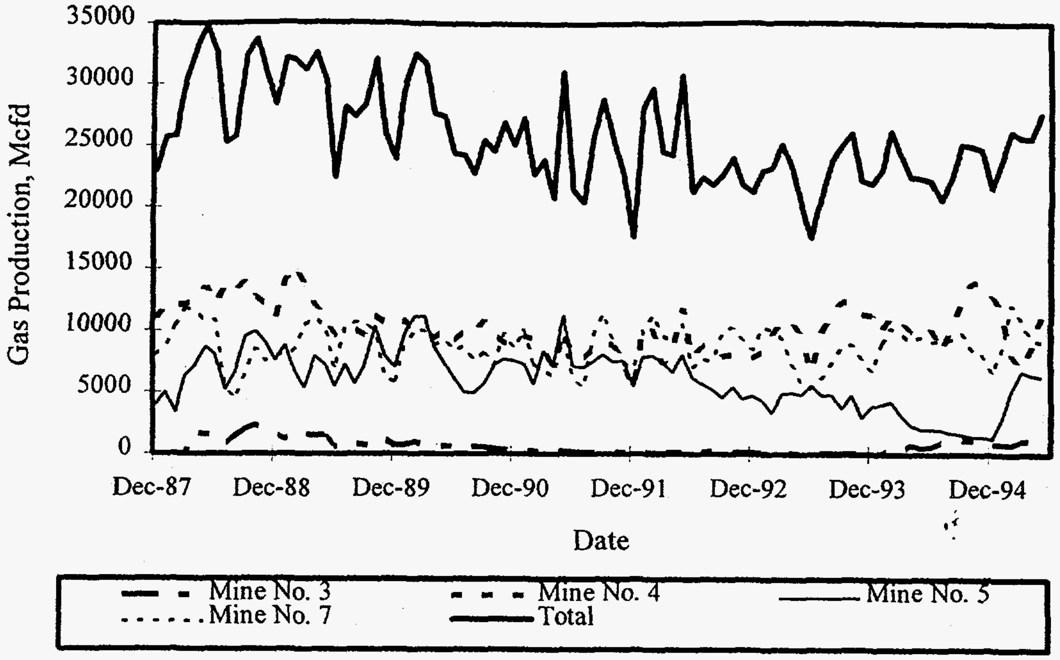

Figure 23. Gob Well Production History.

Specific gob well production from the JWR No. 4 mine is shown in Figure 24. The production trend is similar to that seen in the horizontal wells in which there was a general decline in production during the period 1991 to 1994 followed by an increase in production to the previous level of about 11 million cubic feet per day. As discussed earlier, the decline was due to a combination of factors, including mining rate and operations. The increase in production observed during the period 1993 through 1995 is due the increase in mining rate and the development of new longwall panels (and the concomitant development of new gob wells).

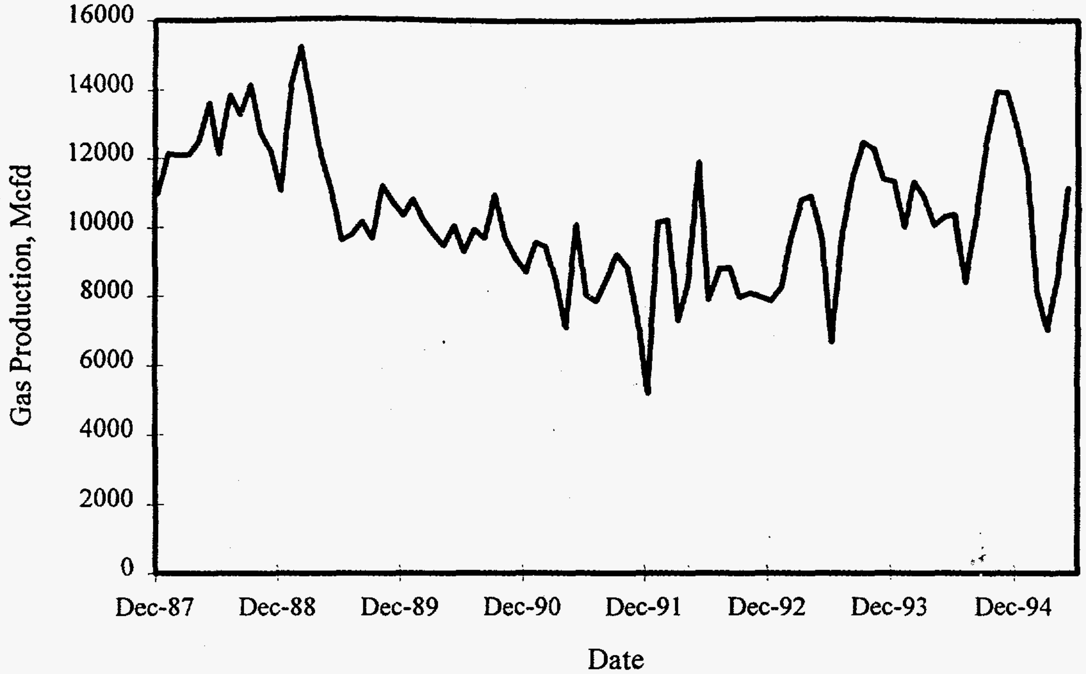

Figure 24. No. 4 Mine Gob Well Production History.

Coal Seam Geologic and Reservoir Conditions at the JWR No. 4 Mine

As discussed previously, the coal seams present within the JWR No. 4 mine area are Pennsylvanian-age and bituminous in rank. The coal type is typical of that found within the Warrior and Appalachian basins and generally consists of clairain and vitrain with a total vitrinite content of 70 to 75 percent. Ash content is low, typically 5 to 10 percent and is generally described as disseminated to fine laminar mineral matter. The primary coal seam (Mary Lee/Blue Creek) has a vitrinite reflectance averaging 1.25 percent (R_0) which is indicative of a rank of medium-volatile bituminous. Coal rank varies within the JWR mine area, ranging from low volatile bituminous (R_0 1.55) at the JWR No. 3 mine, northeast of the JWR No. 4 mine to high-volatile bituminous A (R_0 1.17) within the northwestern sections of the JWR No. 4 mine.

Within the area of the JWR No. 4 mine, numerous coal seams occur above and below the mined Mary Lee/Blue Creek coal seam. A representative geologic stratigraphic section highlighting the primary coal seams within the JWR No. 4 mine area is shown in Table 1. Coal seams from seven coal groups are present within the stratigraphic section with a cumulative coal thickness of 35.25 feet. As can be seen, the Mary Lee/Blue Creek coal seams represent 30 percent of the total coal thickness within this interval. However, significant coal thickness (and potential gas reservoir) exists above and below the mined interval.

Table 1. Representative Coal Seam Stratigraphy for the JWR No. 4 Mine - Well S-0545-S.

COAL GROUP	COAL SEAM	DEPTH, FT (TOP)	THICKNESS, FT
Utley	Clements	323.50	0.15
	Clements	350.00	1.50
	Subtotal	-	**1.65**
Gwin	Gwin	666.50	0.75
	Subtotal	-	**0.75**
Cobb	Upper Cobb	892.00	0.35
	Upper Cobb	893.00	0.50
	Subtotal	-	**0.85**
Pratt	Pratt	1243.00	1.00
	Pratt	1254.65	0.35
	Pratt	1263.00	0.40
	Pratt	1263.65	0.35
	Pratt	1265.00	1.00
	Nickel Plate	1299.50	0.75
	America	1325.00	1.40
	America	1355.00	0.15
	Subtotal	-	**5.40**
Curry/Gillespie	Curry	1478.50	0.25
	Gillespie	1543.00	0.25
	Subtotal	-	**1.60**
Mary Lee	Marker	1860.00	0.75
	Upper New Castle	1867.50	1.35
	Lower New Castle	1878.00	0.85
	Mary Lee	1916.85	1.61
	Blue Creek	1919.65	4.60
	Subtotal	-	**9.16**
Black Creek	Lick Creek	2126.00	1.15
	Lick Creek	2137.00	0.25
	Jefferson	2235.00	0.15
	Jefferson	2237.00	0.20
	Murphy	2286.50	0.35
	Black Creek	2350.60	3.06
	Subtotal	-	**5.16**
	TOTAL	-	**24.57**

Of particular importance to this project and to the mining operations at the JWR mines is the methane content of the coal. Numerous gas content measurements have been performed on coal core recovered during exploratory drilling. Gas content measurements were made utilizing the U.S. Bureau of Mines Direct Method [13]. Based on the collected gas desorption results, average gas contents were determined for each of the seven coal groups present within the JWR Mine No. 4 area and are presented below in Table 2.

Table 2. Average Coal Seam Gas Content for Seven Coal Groups in the No. 4 Mine Area.

COAL GROUP	GAS CONTENT, cubic feet per ton
Utley	150
Gwin	300
Cobb	350
Pratt	400
Gillespie/Curry	400
Mary Lee	500
Black Creek	550

Limited measurements of other coal seam reservoir properties exist for the coal seams within the JWR mine area. From tests performed in areas adjacent to this area, it can be extrapolated that the virgin reservoir pressure is near hydrostatic (0.39 to 0.41 psi/ft) and the permeability is in the range of 5 to 20 millidarcy [14].

Methane Resources and Resource Categories for the JWR No. 4 Mine

Using the collected geologic and coal seam reservoir data, preliminary estimates of the gas resource contained in the coal seams within the JWR No. 4 mine area were made. However, it is appropriate to further discuss the reality of estimating coalbed methane resources within an area where active mining is occurring before presenting the summary results.

Gas resource (natural gas, coalbed methane, shale gas, etc.) estimates are an integral part of the conventional natural gas industry. These estimates provide an initial indication of the quantity of gas resource that is present within the rock formations and provide an important input into estimating potential recovery of that gas. The estimation of gas resource is generally a function of void space (porosity) within the rock units, the pressure of the gas within the void space, and specific gas properties of the captured gas. This method is modified slightly for the unique characteristics of gas storage in coal (sorption), but nonetheless it is an attempt to measure the volume of gas that is contained within a certain volume of reservoir rock.

For gas reservoirs (including coal seams) the determination of the quantity of gas that is stored is therefore a straightforward process. However, this assumes that the reservoir has been unaffected by any man-made operation. If the reservoir is disturbed (for example, if part of the reservoir has been produced via producing gas wells) then the determination of gas resource in-place becomes much more difficult. This problem escalates rapidly for coal seams that have been affected by underground mining operations.

In the case of coalbed methane resource present within a mining area, generally three resource types need to be considered. The first type, and often the easiest to determine, is the quantity of gas resource that is present within the coal outside the current influence of the mining activity. This resource could be considered similar to a gas resource in a virgin state because the reservoir properties (primarily reservoir pressure) have not been impacted by the mining operation. Accordingly, the gas resource is estimated using the standard volume relationships described above (i.e. gas content [in cubic feet per ton of coal) x unmined coal resource [tons] = gas resource [cubic feet]).

The second type of gas resource is that which is contained within the unmined coal that is present within the active mining areas. This resource is primarily contained within the unmined pillars in the mining area and in the coal seams above and below the mined seam. While the method of determining the gas resource is the same as that for the unmined virgin coal reservoir areas, the major problem is determining the gas content of the coal in these disturbed areas. It can easily be seen that the gas content of the coal should be lower than that originally in-place. However, there has been little work performed to date to quantify this volume. Importantly, the percentage of gas that remains in this type of coal reservoir will be very dependent upon not only the reservoir properties of the coal (especially permeability, reservoir pressure, and initial gas content) but also will be dependent upon the impact of the mining operation on these properties. Therefore, estimating the gas resource that is in-place within the active mining area is difficult and open to a large degree of uncertainty.

The final type of gas resource that is present is the free gas (and to a lesser degree the sorbed gas) that exists within the gob areas above and below extracted longwall panels. This third type of resource is the most difficult to estimate due to the uncertainty associated with 1) the pore volume within the gob area; 2) the amount of gas that has been lost from the gob area into the mine's ventilation system; and 3) the source and quantity of gas that has migrated (or is migrating) into the gob's pore space. Some attempts have been made to estimate the maximum volume of the gas that could originally be contained within a gob, but this has basically been to determine the amount of gas-in-place in the virgin, unmined coal. Clearly the current amount of gas that is in place is somewhat less than this and with time this quantity should continue to decrease.

Therefore, to determine the gas resource that is present within the JWR No. 4 mine area, it was decided to only evaluate the gas resource within the unmined coal areas. The authors recognize that there is a significant quantity of gas present within the other two resource categories, but that limited data precludes any reasonable estimate of this gas volume. However, it should be noted that while estimates of resource volume within these two categories were not determined, the potential reserves (i.e. future recoverable resource) of these can be estimated. These volumes (including the methodology for determination) are presented later in this report.

Using the average gas contents, typical thickness for the coal seams present, and a coal density of 1,800 tons per acre-foot, estimates of gas resource in-place within the JWR No. 4 mine area were made. Presented in Table 3 below are the average gas resource estimates (per square mile of reservoir) by coal group.

Table 3. Coalbed Methane Resource for the Unmined Areas of the JWR No. 4 Mine.

COAL GROUP	THICKNESS, ft	GAS CONTENT, cu ft/ton	GAS RESOURCE, billion cu ft/sq mi
Utley	1.65	150	0.285
Gwin	0.75	300	0.259
Cobb	0.85	350	0.343
Pratt	5.40	400	2.488
Gillespie/Curry	1.60	400	0.737
Mary Lee	9.16	500	5.276
Black Creek	5.16	550	3.269
TOTAL	24.57	-	12.657

TASK 2 - EVALUATION OF THE COAL MINE METHANE RESERVES

Potential Methane Reserve Area and Area Logistics

Potential Reserve Area

The potential coalbed methane reserve area established for this project consists of the area of past, present, and future mining at the JWR No. 4 mine. As seen in Figure 10, the potential reserve area covers approximately 20 square miles (12,800 acres). This area has been established by JWR as the project site and reserve area, such that all data presented later in this section applies to this total area. Within this 20 square mile area, different types of reserve areas have been developed that correspond to the different methane capture methods (ventilation, vertical wells, horizontal wells, and gob wells).

Area Logistics

As discussed previously, the JWR No. 4 mine is part of a four-mine underground complex within eastern Tuscaloosa county and western Jefferson county operated by Jim Walter Resources, Inc. Because of the extensive underground mining operations in this area, access to the proposed sites for the demonstration project is relatively easily. The mine site is easily accessible via state highway Route 216 and is 25 miles from the Adger interchange on U.S. Interstate Highway I-59/20. In addition to the well-developed state and county road system in the area, the mining operations maintain extensive all-weather roads for access to ventilation shafts, mine degasification gob and vertical wells, and other surface facilities throughout the surface area of the mine. This existing access should provide the project with ease of movement of equipment (especially the fuel cell and associated equipment) and personnel throughout the mine area.

Surface access for transporting the produced electric power should also be relatively easy within the JWR No. 4 mine area. In addition to all-weather roads accessing the gob wells and surface facilities, extensive power right-of-ways (including installed transmission service for gob well operation) also exist within the mine area.

Environmental Considerations in the Methane Reserve Area

The impact of the fuel cell power plant operation on the surrounding environment will be negligible. In fact, the net environmental impact of power plant installation will be a reduction of greenhouse gas emissions. The proposed unit emissions are well below any Federal, state, or local requirements. Typical emission and environmental impact data are provided in Table 4. The units are very quiet, and should not pose any problems related to noise pollution.

Table 4. Emission and Sound Pressure Levels.

QUANTITY	EMISSIONS @ 200 kW (ppmv, 15% O_2, Dry)	CALIFORNIA STANDARDS FOR COMBUSTION ENGINES
NO_x	1	36
SO_x	Negligible	(no standard)
Particulates	Negligible	(no standard)
Smoke	None	(no standard)
CO	5	2000
Non-Methane Hydrocarbons	1	250 (reactive organic gases)
Noise	60 dBA at 30 ft from the power module	

Gas Ownership in the Methane Reserve Area

From the onset of development of coalbed methane, there have been conflicting claims of ownership to the resource [15]. Owners of the mineral interest in coal claim that coalbed methane is included in the ownership of the coal or the right to extract the coal because it was produced from or is contained within the coal. The basis of the claim by owners of the mineral interest in oil and natural gas generally is that coalbed methane is physically and chemically indistinguishable from natural gas. Methane is, in fact, the principal constituent of natural gas, often constituting more than 90 percent of its gaseous fractions. The Federal government takes that latter position - essentially that "gas is gas" - with regard to the extraction of minerals owned by the United States [16]. Finally, in cases where the coal interest and the interest in oil and gas have been severed or separately conveyed, there are occasional claims by the owners of the reserved or residual mineral interest that coalbed methane is not part of either the coal or oil and gas estates.

There have been numerous court cases involving conflicting ownership claims to coalbed methane. Most of these cases have been in Alabama or Appalachia [15]. There has also been legislation passed by a few states in attempts to resolve the ownership issues sufficiently to encourage development [17]. A full discussion of these cases and statutes is beyond the scope of this report. However, any person considering the utilization of coalbed methane as outlined in this report must realize that the legal question of ownership of coalbed methane is a threshold issue which must be addressed early in the evaluation of a potential project. The issue may be capable of resolution through legal or administrative means or through the design and operation of the project. If ownership can be resolved, there may arise questions of whether a royalty or other payment due upon severance of a mineral is owed and how such payments may be computed. This is discussed below.

The origins of the conflicting claims of ownership is the fact that mineral interests have in the past been conveyed without discussion of the ownership of or right to exploit coalbed methane. Generally speaking, this was due to the fact that the economic production of coalbed methane is a relatively recent phenomenon. Therefore the methane contained in the coal or surrounding strata was viewed as, at best, a non-commercial mineral and, at worst, a serious hazard to underground mining. The lack of any indication that coalbed methane was or could become a commercial resource meant that most conveyances or leases of oil and gas or coal were silent or ambiguous with regard to the transfer of or right to develop coalbed methane. When commercial production of coalbed methane was finally attempted and achieved, this potential for conflict led to legal actions being taken in several states. Not only did these actions impede development of the projects involved, but widespread knowledge of the suits served to stifle development in areas where potential conflicts in ownership were readily apparent and not easily resolvable

The potential for conflict should be expected in any situation where the conveyance of the mineral interest in coal does not discuss the beneficial use or commercial sale of coalbed methane by the coal miner. This expectation should be greater in coal basins where oil or conventional natural gas has also been produced. This will be due to the fact that in basins with production of liquid or gaseous hydrocarbons there will be a heightened awareness in the legal community and the general public of the possibilities of revenue from the production of gas.

For any person acquiring mineral interests for the purpose of opening or expanding an underground coal mine, it is imperative that the grant of the new mineral interest conveys the right to the commercial sale or beneficial use of coalbed methane. In the case of the commercial sale of the gas or its conversion to some other marketable product, such as electric power, the computation and allocation of royalties should be addressed through lease clauses which take into account the peculiar problems which occur when gas is produced in conjunction with coal mining. Where the gas is used exclusively on the mine premises with no commercial sale, it may not be unreasonable to expect the mineral owner to convey this right without a royalty requirement. This would be much in the same fashion as the grant to the miner of the right to use for the purpose of facilitating mining and without fee or royalty, minerals or resources, such as water or sand and gravel, which may be found on the leasehold. However, if the grantor of the coal does not own the rights to coalbed methane, any use of the coalbed methane by the miner will likely carry with it a royalty obligation.

In the acquisition of the mineral interests or prior to production of methane, serious thought must be given to mechanisms for pooling or unitizing the royalty interests. Otherwise the computation of royalties may become cumbersome or lead to conflicts. This possibility would be most pronounced in the case of utilization of gob gas or gas taken from ventilation outlets. For example, a longwall panel 900 feet wide by 6,000 feet long covers an area of approximately 124 acres. Analysis may indicate that all or most of the gas which might be produced from the panel's gob comes from strata immediately above or below the gob. However, if the miner attempts to limit the allocation of royalty to those mineral owners of the 124 acres overlying the panel, as might be done in the case of coal production, it may provide an open invitation to adjoining mineral owners to assert their claims. Unitizing all or a portion of the mine and pooling production from all gob wells within the unitized area provides the simplest method for dealing with conflicts in advance. Pooling and unitization also have the advantage of being methods which are familiar to the regulatory agencies and courts in states with oil and gas production. Black Warrior Methane Corp., the company which operates the degasification system for Jim Walter Resources, Inc., relies upon the laws and regulations of the State of Alabama and the Alabama Oil and Gas Board regarding the pooling and unitization of mineral interests affected by mine degasification [18].

The laws and regulations in Alabama regarding pooling and unitization follow generally a model based on oil and gas experience. This model may not be the best guidance with regard to production of either gob gas or utilization of ventilation gas. The Virginia statute may provide a better example of the direction regulation should take for mine gas development and utilization. The Virginia law requires that drilling units follow the mine plan, if there is one, and that well spacing conform to mine operations. This approach makes much more sense than to unitize on the conventional oil and gas model. Oil and gas units generally conform to governmental units, i.e., 40 acre, 80 acre, 160 acre, etc., sized drilling units. It would be the most unlikely happenstance if a mine plan conformed to such units.

Potential Future Methane Production at the JWR No. 4 Mine

An important aspect of the proposed project is the confirmation that sufficient feedstock exists for the demonstration of the reduction of methane emissions by conversion via fuel cell to electric power. While it has been recognized that the coal seams of the Warrior basin contain significant quantities of methane, the potential for recovering this methane is highly variable. Variations in reservoir properties, recovery methods, and duration of production all contribute to this variability.

Within the oil and gas industry, various analytical techniques and methods have been developed for estimating the potential for recovering hydrocarbons from geologic formations [19]. These methods have been modified to account for the unique properties of coal seam gas reservoirs, but nonetheless the basic principles still apply [20]. The analytical solutions provide a means of estimating total recoverable gas and in some cases the rate of recovery. However, the method of estimating future recovery from coal seams have been primarily applied to the vertical coalbed methane wells not affected by underground mining operations. Little work has been performed in the area of estimating future recovery from other methane capture systems, such as horizontal wells, gob wells, or mine ventilation.

To assess the potential recovery of methane from the JWR No. 4 mine area, different techniques were applied to each of the four methane capture systems. Results of this assessment are an estimate of the future gas production rate and cumulative gas production for the period 1996 through 2010.

Mine Ventilation System

The potential future production of methane from the JWR No. 4 mine's ventilation system is dependent primarily upon future mining rates and the methane content of the coal that will be mined in the future. Current projections indicate that future mining will proceed at a rate similar to the most recent past. Accordingly, the methane emission rate into the ventilation system should be at a rate similar to that currently encountered. Because of this, it was determined to utilize the current average emission rate as a basis for projecting the future emission rate.

However, current plans also call for an increased use of pre-mining vertical wells within the JWR No. 4 mine area to recover the methane from the coal. This is expected to lead to a decreased level of gas content in the coal, such that when mining of this coal occurs reduced methane emissions will be encountered. Projections of future mining areas and vertical well degasification rates indicate that 1) the mine will begin to enter the area of degasification in about five years; and 2) the vertical wells will recover about 50 percent of the methane in-place in about 10 years. Based on this, future projections of methane emissions from the mine were modified to account for the reduced methane content of the coal and the expected reduced methane emission rate.

Figure 25 displays the historic methane emission rate that was used as a basis for estimating the near-term future rate of approximately 8.6 million cubic feet per day. As shown in the figure, the emission rate begins to decline in about 5 years and continues to decline until the year 2007. Emission rate at this time was estimated to be 50 percent of the original average rate or about 4.3 million cubic feet per day. The estimated emission rate shown in Figure 25 results in a cumulative methane emission volume for the 15 year study period of 39.5 billion cubic feet.

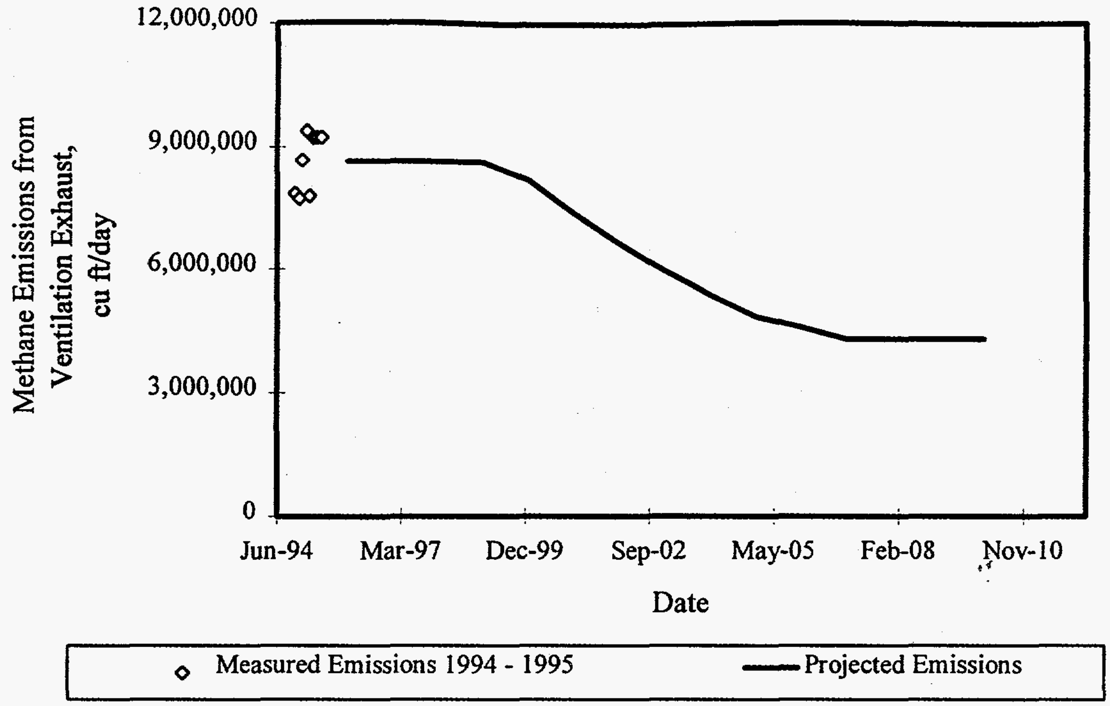

Figure 25. JWR No. Mine Projected Future Methane Emissions from Ventilation Exhaust (1996 - 2010).

Horizontal Degasification Wells

Future production from horizontal wells in the JWR No. 4 mine was estimated also using past historical performance as a basis for projecting future recovery. As with the mine ventilation methane emissions, the horizontal wells will also be impacted by the effect of the vertical well degasification. In addition, with increased per-mining degasification from these vertical wells, the need to install horizontal wells in the future will decline. Therefore, it was projected that horizontal well production will begin to decline within the next five years and continue to decline throughout the 15 year study period.

Figure 26 shows the historic methane production rate from the horizontal wells at the JWR No. 4 mine and from this an average initial future methane production rate of approximately 1.2 million cubic feet per day was estimated. Because of the effect of vertical well degasification and reduction in the number of horizontal wells used, the average future production rate was reduced at an average rate of 10 percent per year for the study period, such that by the end of the production projection, horizontal well recovery rate was 300,000 cubic feet per day. Cumulative methane recovery for the 15 year period, based on this projection, was estimated at 3.8 billion cubic feet.

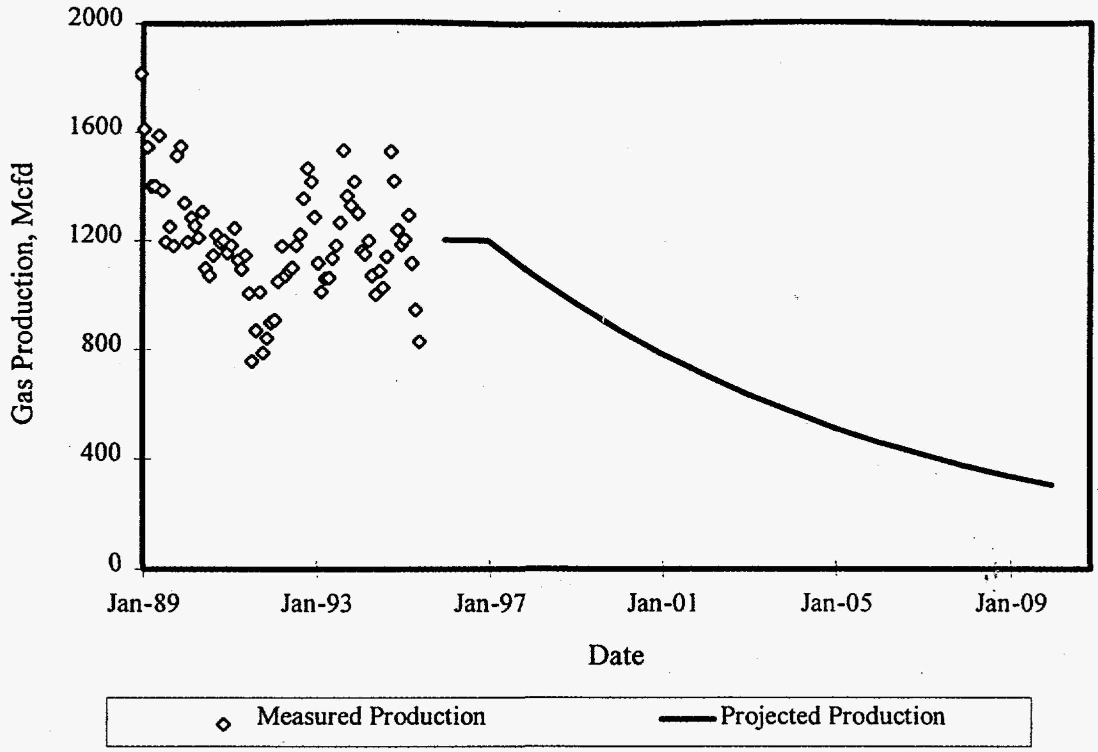

Figure 26. JWR No. 4 Mine Projected Horizontal Well Production (1996 - 2010).

Gob Wells

Using the methodology employed for the mine ventilation system and horizontal wells, the projection of future production from the planned gob wells was determined. The planned vertical well degasification will effectively reduce the methane content not only in the mined coal seam (Mary Lee/Blue Creek) but also in the overlying and underlying coal seams. Because of this, it is expected that the future production rate from the planned gob wells will also decrease in the future. As with the mine ventilation system, current plans expect that within the next five years a production rate decline will be observed such that within ten years the production rate from the future gob wells will be 50 percent of the current rate.

As shown in Figure 27, near-term future production from the gob wells was estimated to be approximately 8.6 million cubic feet per day. Production rate decline was forecast to begin in 1999 such that by the year 2006 average methane production rate from the gob wells at the JWR No. 4 mine was estimated at 4.3 million cubic feet per day. For the 15 year study period, cumulative production from the gob wells was estimated at 37.7 billion cubic feet.

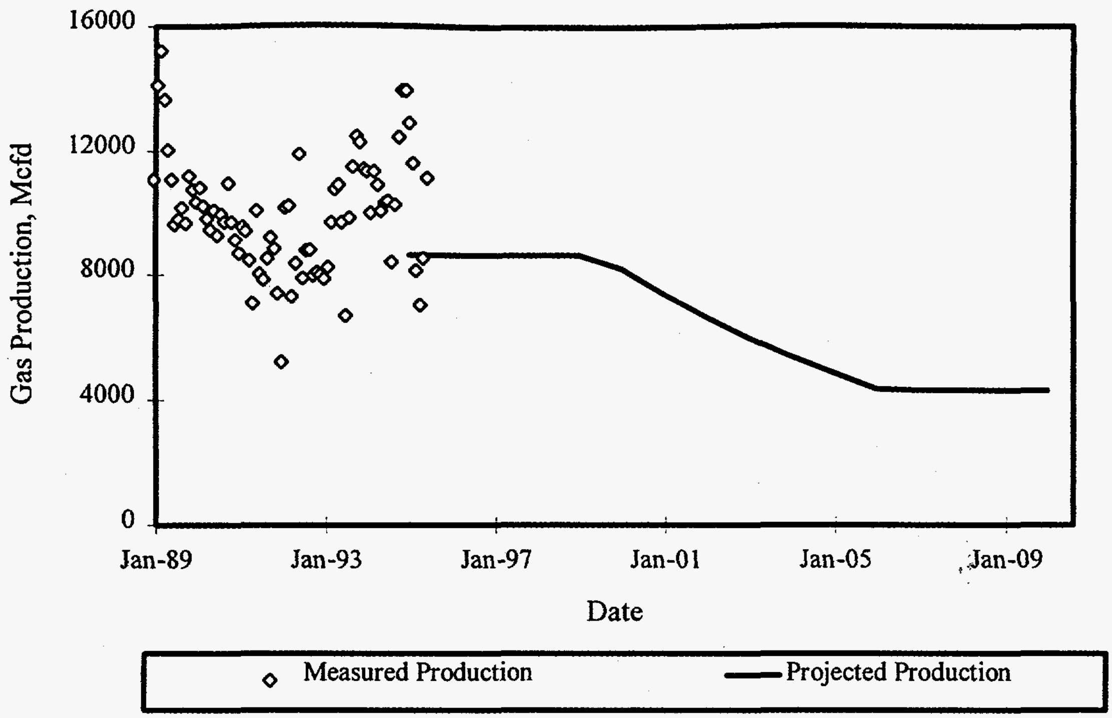

Figure 27. JWR No. 4 Mine Projected Future Gob Well Production (1996 - 2010).

Vertical Wells

The projection of future production from vertical wells in advance of mining could not rely upon past experience. Recently improved completion practices and additional targeted reservoirs has resulted in higher production rates from these newer wells. because of this, a different technique was employed for estimating the future production from the planned vertical well program.

Based on recent production data, a typical production type-curve was developed for a single vertical well within the JWR No. 4 mine area. Figure 28 shows the expected production rate from this single well. As shown, peak production of 300,000 cubic feet per day is expected to occur in the second year of operation followed by a hyperbolic decline leading to a well life of 15 years.

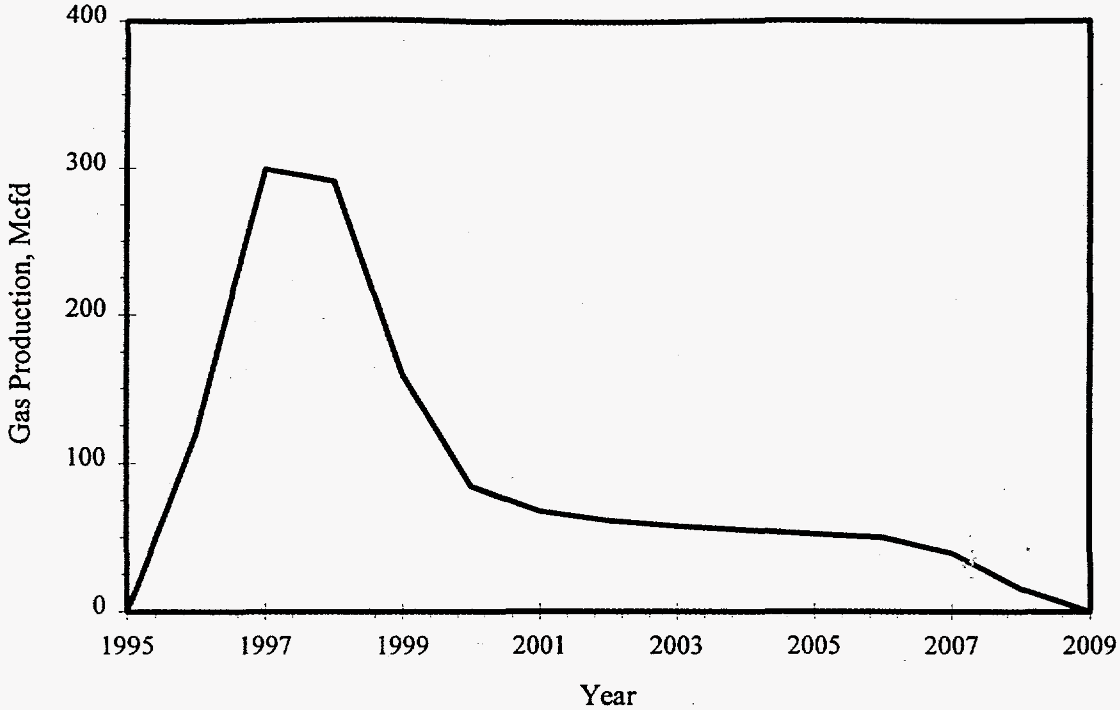

Figure 28. Projected Future Gas Production from a Single Well - JWR No. 4 Mine.

Within the JWR No. 4 mine area, it was projected that at least 150 vertical wells could be drilled. Assuming an installation rate of 25 wells per year for the next six years, 150 wells will be in production by the year 2002. Using the projected single well type-curve and the planned well installation schedule, a projected future production rate from vertical wells was developed, Figure 29. As shown, production peaks in year 2001 at a rate of approximately 26 million cubic feet per day. Projected cumulative methane production from the planned vertical wells was estimated at 72.3 billion cubic feet.

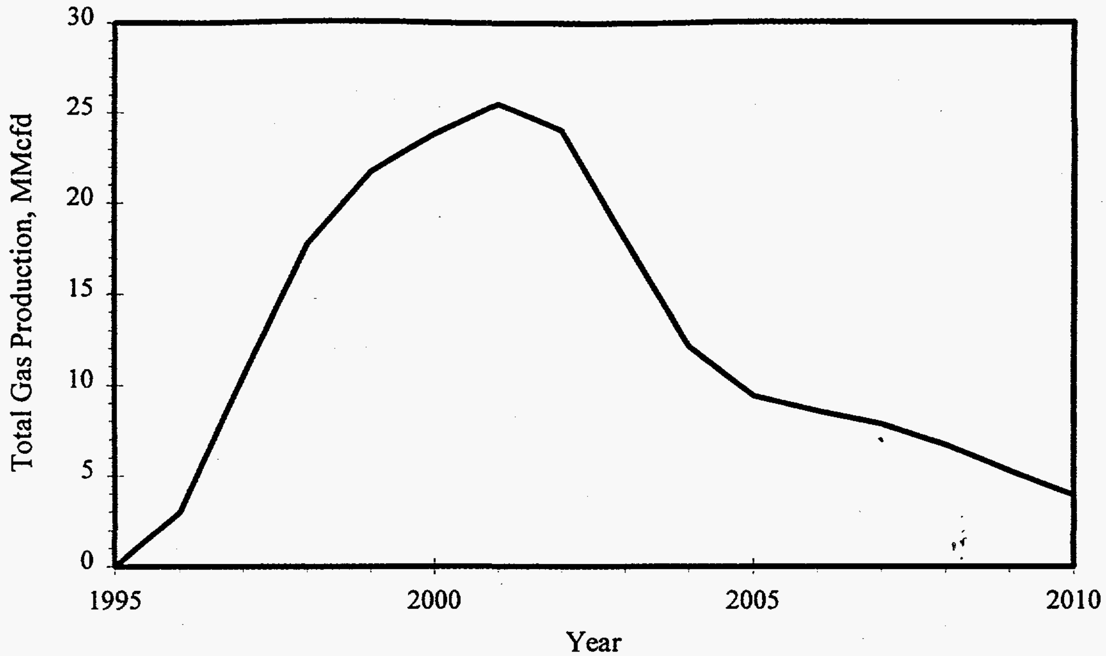

Figure 29. Projected Future Gas Production from 150 Vertical Well - JWR No. 4 Mine.

Summary

As discussed above, four different flow streams describe the potential future methane production from the JWR No. 4 mine. For the 15 year study period, cumulative methane recovered by these four systems are summarized below in Table 5. Based on these results it is evident that a sufficient gas resource volume and quality exists for use in the fuel cell demonstration phase of this project.

Table 5. Potential Recoverable Resources from the JWR No. 4 Mine.

RECOVERY SYSTEM	CUMULATIVE RECOVERY, Bcf
Mine Ventilation	39.5
Horizontal Wells	3.8
Gob Wells	37.7
Vertical Wells	72.3
TOTAL	153.3

TASK 3 - APPLICATION OF THE TECHNOLOGY OF FUEL CELL CONVERSION OF GOB GAS

Introduction

The specific fuel cell power plant to be utilized in the demonstration project is the ONSI PC25 Model C phosphoric acid stack produced by International Fuel Cell Corporation (IFC), Figure 30. This unit is the only commercially available fuel cell power plant for direct utility connection manufactured in the world today, and it is a mobile unit. Electrical specifications for the unit can be found in Table 6 and fuel requirement data is listed in Table 7. Table 7 provides a launching point for this feasibility study.

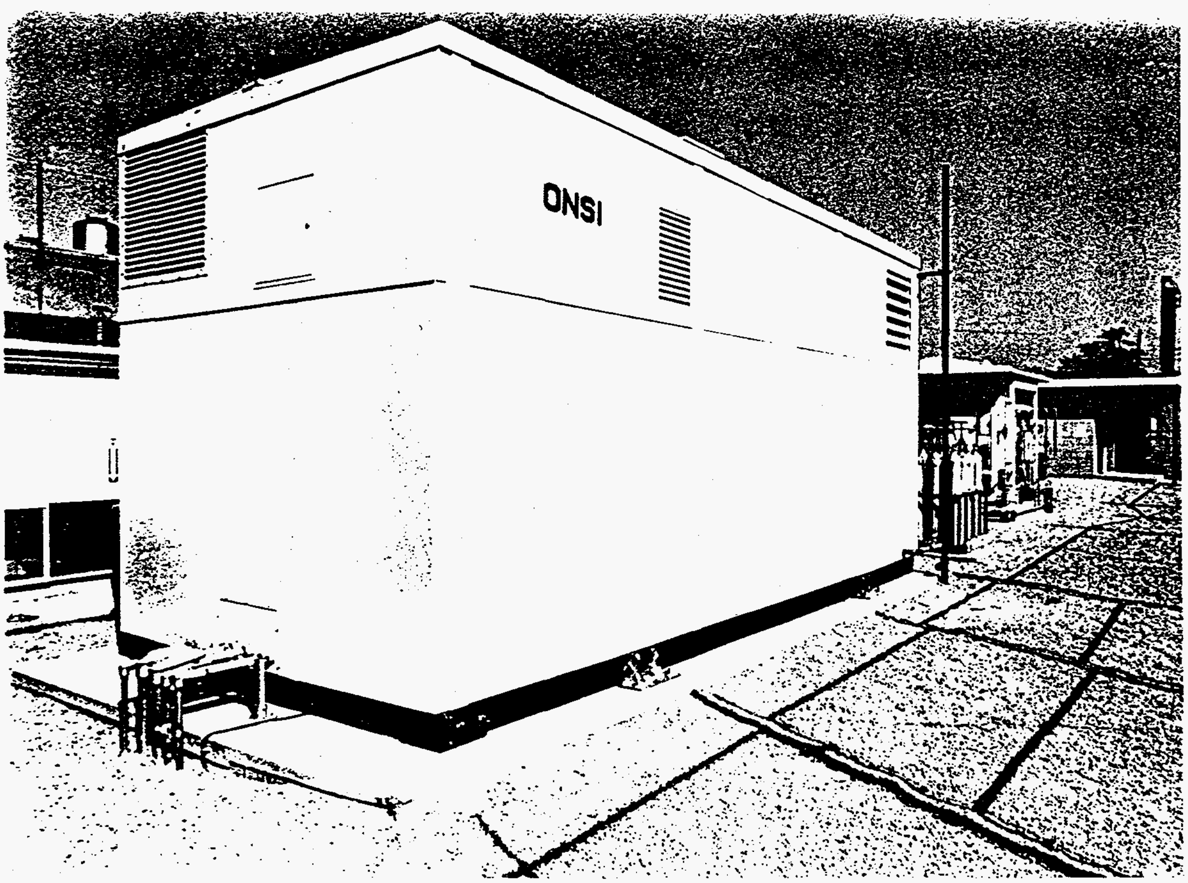

Figure 30. ONSI PC25 Model C Phosphoric Acid Fuel Cell

Table 6. Fuel Cell Power Plant Electrical Specifications.

Power Plant Rating	
Rated Capacity - net	200 kW/235 kVA
Voltage and Frequency - Standard Configuration	480/277 Volts, 3-Phase, 3-Wire, 60-Hz
Electrical Characteristics	
Power Factor Range (at normal line voltage)	0.85 lag/lead to 1.0 (adjustable)
Fault Current	110% of rated RMS current integrated over 1 cycle
Maximum Line Voltage Deviation From Nominal	±5% at rated power; +10% to-20% operating with kVA derated
Line Voltage Unbalance	2 percent line-to-line at rated kVA
Voltage Harmonics	THD <3% at rated power when operating into standard impedance*
Operating Features	10 kW to 100% of rated power
Interruption/Disconnection	Power plant interrupts if abnormal grid condition detected. Power plant disconnects if interrupt duration is excessive or interrupts are repeated too frequently, e.g., abnormal conditions that last for more than one-half second or more than three interruptions in less than fifteen seconds.
Reconnection	Power plant reconnects automatically after a disconnect if grid is normal for a continuous zero to ten minute period (adjustable).
Protection Parameters	• ac overvoltage • ac undervoltage • ac voltage unbalance • abnormal frequency • ac overcurrent, instantaneous • ac overcurrent, inverse time • ac current unbalance • loss of synchronization Field adjustment and testing of protection functions Input port for site-specific protection parameters

* Standard impedance is defined as a 4% inductive shunted by a 56% resistive load.

Table 7. Fuel Requirement Specifications.

	Maximum Allowable Percent Volume
Composition	
Methane	100
Ethanes	10
Propane	5
Butanes	1.25
Pentanes, Hexanes, C_{6+}	0.5
CO_2	3
O_2	0.2
N_2	4.0
Total Sulfur	30 ppmv (6 ppmv average)
Ammonia	1 ppmv
Chlorine	0.05 ppm (weight basis)
Supply Pressure	4 to 14 inches water
Fuel Heating Value	980 to 1200 Btu/scf

Fuel Quality Assessment

Table 8 is a gas analysis of the gas sold at pipeline quality (spec gas) by Black Warrior Methane Corporation. The gas recovered from gob wells will be between 40 and 98 percent spec gas, by volume with the remainder being air. Thus, it becomes readily obvious that the oxygen content in the gob well gas will almost always exceed that allowable for the cell, as dictated in Table 7.

The solution to this issue that is most probable for demonstration is the inclusion of a catalytic converter in the fuel supply line. This solution is illustrated schematically in Figure 31. Within the converter, the methane and oxygen from the air will react to form carbon dioxide and water. The reaction is provided in (1).

$$CH_4 + 2O_2 \rightarrow CO_2 + 2H_2O \tag{1}$$

Note from (1), that one mole of methane will be burned to remove two moles of O_2. Thus, we must assess the impact of the reaction on fuel concentration. This assessment will be based on the assumption that molar and volumetric ratios of all constituent components are equal.

We define the spec gas content in the gob well gas as X. For pure spec gas, X = 1. Thus, the air content will be 1-X. Assuming an oxygen content in the air of 20 percent, the oxygen content in the gob well gas will be Y, as defined in (2).

$$Y = 0.2(1 - X) \tag{2}$$

Table 8. Spec Gas Analysis.

COMPONENT		MOLE %	GPM
Hexanes	C6+	<0.01	<0.001
Propane	C3H8	0.07	0.02
Iso-Butane	i-C4H10	<0.01	<0.001
Normal Butane	n-C4H10	<0.01	<0.001
Iso-Pentane	i-C5H12	<0.01	<0.001
Normal Pentane	n-C5H12	<0.01	<0.001
Carbon Dioxide	CO2	0.34	-
Ethane	C2H6	0.25	0.068
Oxygen	O2	0.15	-
Nitrogen	N2	2.97	-
Methane	CH4	96.22	-
Carbon Monoxide	CO	<0.01	-

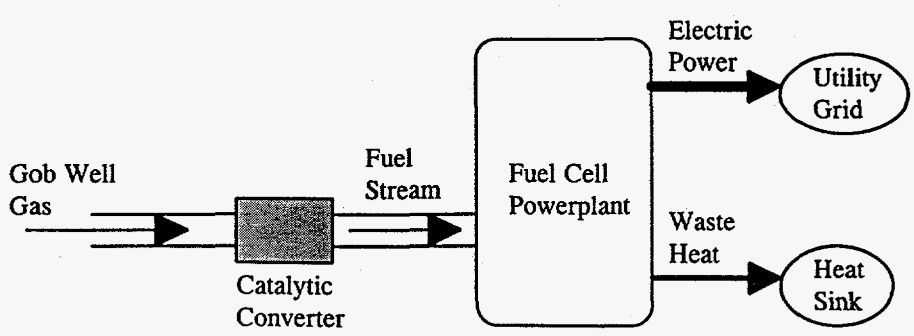

Figure 31. Schematic Diagram with Catalytic Converter.

The methane that will be used for conversion of the oxygen, X_c, is provided by (3).

$$X_c = \frac{Y}{2} \tag{3}$$

The methane remaining after conversion will be X_r, which is defined in (4).

$$X_r = X - X_c \tag{4}$$

The methane concentration entering the fuel cell is plotted in Figure 32 versus the air content in the gob well gas. As illustrated, and defined in (2) through (4) above, the decrease is linear. The anticipated cutoff for methane content in the fuel stream entering the cell is 45 percent. Analysis of the foregoing mathematics shows that this corresponds to an air concentration in the gob well gas of 50 percent and this cutoff point is defined on Figure 26. Thus, as currently designed, the fuel cell unit can be applied to many low production rate wells with varying gas quality.

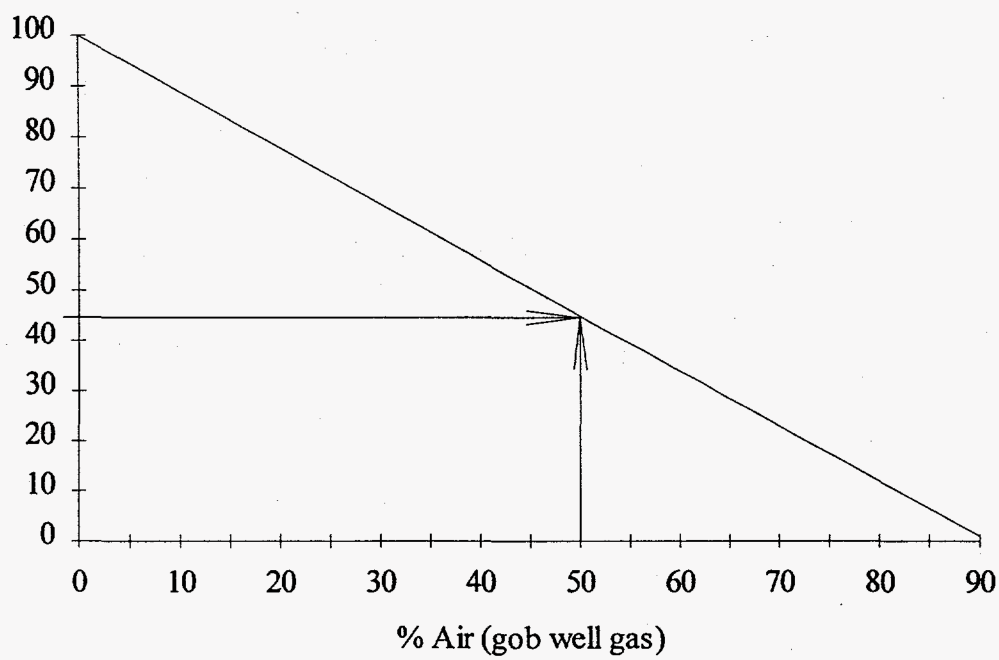

Figure 32. Fuel Stream Methane Concentration.

Fuel Cell Electrical Power Output Assessment

The electrical power output of the fuel cell is a function of methane content in the fuel stream. IFC has previously operated a similar model power plant on landfill gas from a site in California. IFC expects the power plant to operate at full power output from 100 down to 65 percent methane content in the fuel stream. At concentrations below that, a first-order approximation to power output is a linear decrease passing through the 45 percent methane 130 kW point. This point has been experimentally determined based on performance results of the landfill installation. The methane content in the fuel stream is expressible (Figure 31) as a function of methane content in the gob well gas. Thus, a first-order approximation to and input/output curve is calculable and is presented in Figure 33.

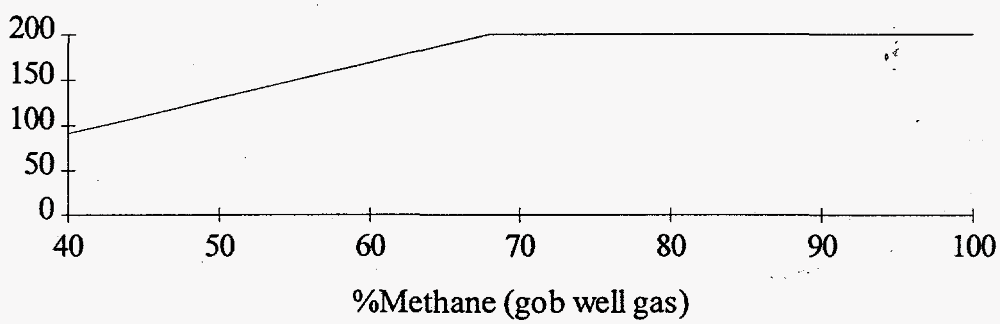

Figure 33. Power Output of Fuel Cell Power Plant.

The power rolloff at methane concentrations in the fuel stream less than 65 percent (which is equivalent to 68 percent in the gob well gas) is dictated by physical device operating range limitations rather than chemical processes. Redesign is likely to greatly improve the full power operating range of the power plant by allowing operation in the presence of the pressure drop that will occur from the increased fuel flow necessary with the lower methane concentrations. Such issues will be addressed in detail during Phase II of this project. However, the current approach will be to employ the commercially available unit, without redesign or modification.

While Phase II will include a detailed theoretical assessment of the I/O curve and possible manufacturing variations that can be implemented to improve the range of rated power output operation, a detailed economic impact will also be considered. Specifically, the impact of design variations on capital investment for adopting fuel cell technology for gob well gas capture and conversion will be defined. It is expected that initial investment variations resulting from such design changes will be negligible. The demonstration phase will provide the first experimental data on fuel cell output and efficiency versus methane content. The JWR mining and degasification facility is unique in that it has the capacity and willingness to supply fuel with gas content at virtually any desired value for an indefinite length of time. Furthermore, the methane reserves are sufficient to operate many fuel cell power plants simultaneously.

Heat Recovery Assessment

The PC25 power plant is equipped to facilitate the removal of waste heat to user processes. Of particular interest is the application to the coal drying process. Under rated conditions, the PC25 will produce in excess of 700,000 Btu/hr. This heat can be collected from a heat exchanger in a propylene glycol-water loop. Pertinent specifications on the thermal dryer are provided in Table 9 and Figure 34 shows the proposed thermal dryer location at the JWR No. 4 Mine.

Table 9. Thermal Dryer Specifications.

Electrical Requirements	
Apparent Power (kVA)	2600
Lagging Power Factor (%)	99
Average Energy (kWh/mo)	1,200,000
Thermal Requirements	
Heat Input (MBtu/hr)	152
Average Coal Burn (ton/hr)	5.5
Process Air Intake (cfm)	132,000
Combustion Air Intake (cfm)	3,200

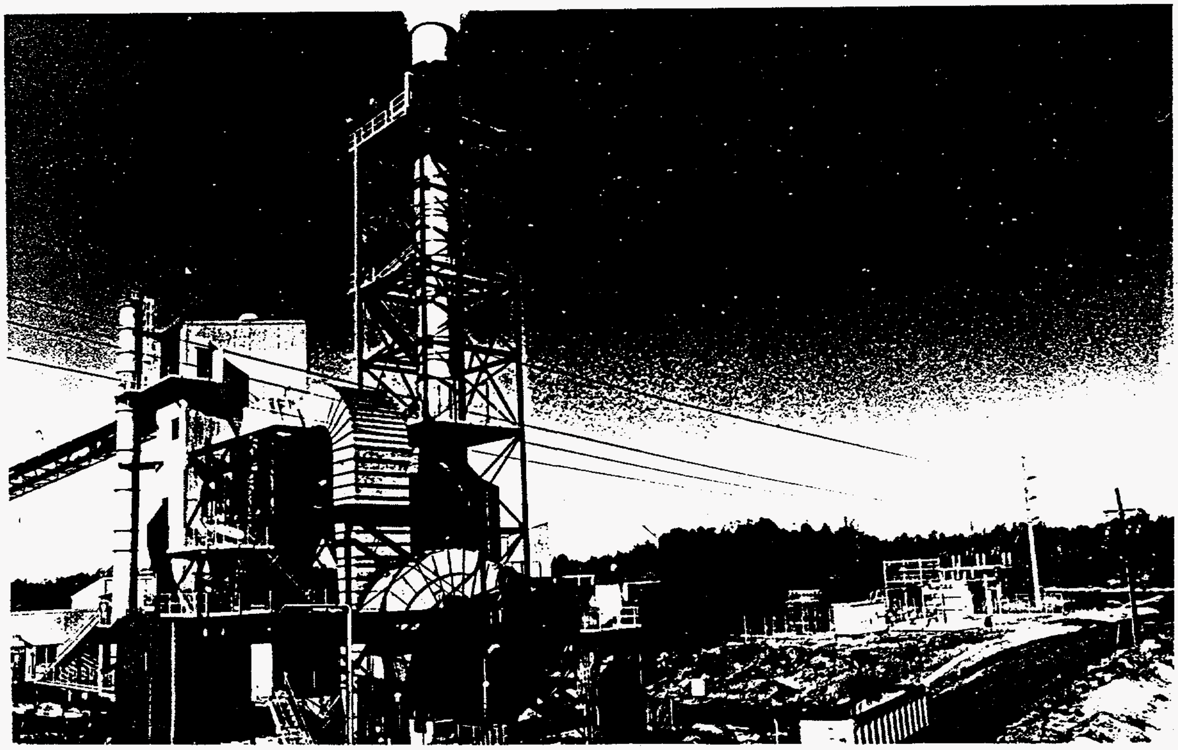

Figure 34. View of the Thermal Coal Dryer at the JWR No. 4 Mine.

The fuel cell heat rejection could be utilized to provide heat to the process air. In this capacity, the fuel cell could provide only 0.5 percent of the total heat required. This would offset 0.5 percent of the coal burned for drying. The average burn rate is 5.5 tons/hr. Thus, 0.0275 tons/hr could be saved. At an estimated $30.00/ton, this yields a savings of $0.83/hr which is approximately $20/day. For the large operation at JWR, this is a negligible effect on the process air. Additionally, however, the reduction in coal burning does provide some reduction in net emissions from the facility.

Another source of heat utilization is to preheat the combustion air. This will result in increased combustion efficiency. The combustion intake of 3,200 cfm corresponds to 15,590.4 lb/hr of air. With a specific heat of 0.25 Btu/(lb °F) for air, the 700,000 Btu/hr of power plant waste heat could elevate the combustion air by 180 °F, in the ideal case. Figure 35 provides the recoverable heat from the power plant as a function of water flow rate, supply temperature, and return temperature.

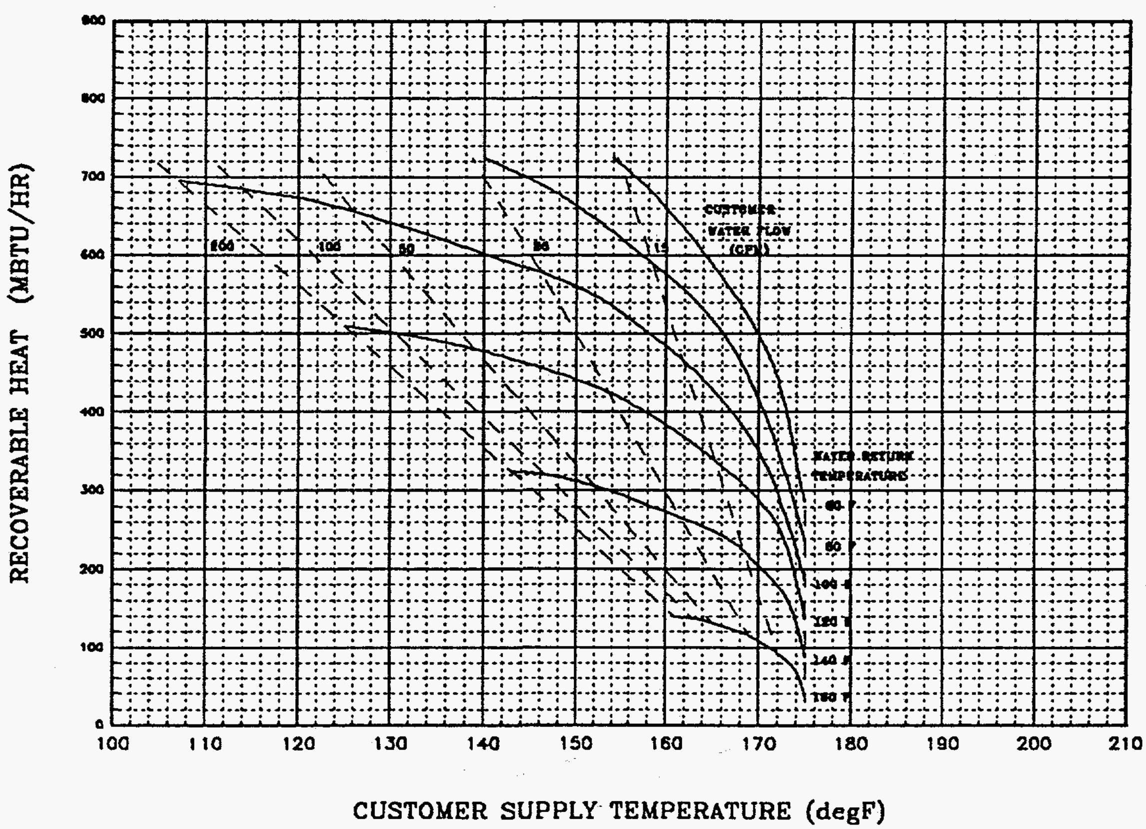

Figure 35. Heat Recovery for the PC25 Power Plant.

Regardless of the process into which the waste heat from the power plant is rejected, waste heat utilization increases the efficiency of the power plant in two ways. First, utilizing the waste heat defines the heat energy as an output rather than a loss. Second, utilization of the waste heat eliminates the need for a cooling unit which requires electrical service which, in turn, decreased the power input to the plant. Additionally, utilization in the process air stream would provide reduced emissions from the coal burning associated with thermal drying.

Electric Grid Interface and Power Production

The Jim Walter Resources mining operation operates their electrical distribution network at two different voltage levels: 115 kV and 4160 V. The PC25 standard configuration supports coupling at a 480/277 V bus. However, an optional configuration can be employed to provide output at 4160 V.

The thermal dryer facility at JWR is independently metered by Alabama Power Company. From metering data, the average electrical demand was found to be approximately 2600 kVA at a 99 percent lagging average power factor. Hence, for this study, we are assuming a real power consumption of 2600 kW for the dryer. At full output, the fuel cell power plant will supply approximately 8 percent of the total dryer demand. Dryer metering information from March 25, 1995 through April 24, 1995 was gathered and analyzed to estimate savings in utility costs. During this period, 1,200,000 kWh were consumed. Operating 5 days/wk at 24 hours per day, to meet the dryer operation schedule, the fuel cell plant would produce 100,800 kWh. Thus, the power plant will be capable of providing 8.4 percent of the total dryer electrical demand. Since JWR operates under a real-time pricing schedule, their utility rate varies on a continuous basis. The average rate was determined during the month under study to be 3.27 cents/kWh. Hence, the net savings available with the fuel cell implementation is approximately $3,296.16 /month.

For research and development, JWR can directly connect to a 480 V bus within the dryer facility. Alternatively, they can isolate a dedicated load for power plant testing during the demonstration phase. In the case of load isolation for testing, a remotely activated power transfer switch will be installed to guarantee continuous operation.

The direct current (dc) output of the fuel cell stack within the PC25 power plant is power electronically converted to 60 Hz alternating current (ac). As with any power electronic conversion process, harmonic distortion is introduced. In this application, harmonics will be injected into the power distribution network, but the total harmonic distortion in the voltage is specified to be within guidelines established by IEEE-519. This standard has been adopted by Alabama Power Company for all industrial customers. However, even though the power plant is in compliance with IEEE-519, special attention must be paid to system resonances. When power factor correction capacitors are present within a distribution network, as is the case at JWR, resonance can exist due to distribution inductance and power factor correction capacitance. If the power plant produces harmonics at or near one of the resonant frequencies, amplification can occur. This can result in overvoltages, capacitor tripping, neutral overloading, electromagnetic interference, and other problems. Proper analysis can ensure that such issues are not problematic, and such analysis will be performed in this case prior to demonstration.

Emissions Reduction

The primary beneficial aspect of the proposed project is the conversion of methane to carbon dioxide. Methane is believed to have a global warming potential 21 times greater than CO_2 [21]. Using the unit described in this report, 15,812,000 cubic feet of methane emissions are converted to CO_2 each year. If the market for fuel cells is as described in this report determined by the approximately 74 MMcfd emitted by one half of the mines identified in [21], full utilization of this methane for fuel cells would convert that amount of methane to the less harmful CO_2.

Each unit described in this report utilizes 15,812,000 cubic feet of methane per year of operation. If, as discussed in this report, a market for 1,500 of these units can be developed in the U.S., and if it is assumed that, on average, each ton of coal mined results in the release of 500 cubic feet of methane, then full employment of fuel cells would result in an additional 423 mmcf annual reduction in mine methane emissions. Finally, a further reduction in greenhouse effects is achieved due to the substitution of methane for coal as a fuel for power generation. This is due to the fact that the combustion of methane results in the production of 35 percent of the CO_2 that would be produced by the combustion of coal for an equivalent amount of heat energy [22].

Economic Analysis

The economic analysis which follows is based upon an International Fuel Cell Corporation (IFC) 200 kW phosphoric acid fuel cell. The factors for maintenance cost, unit availability, rated capacity and fuel usage are from data provided by IFC. Royalty and severance taxes are based upon the "market value" of natural gas at the wellhead. The rates chosen for each are assumed to be reasonable averages of the rates which would be encountered in areas for which projects as discussed in this proposal would be appropriate. "Market Value" is the computed gross revenue from potential gas sales less all post-production operating expenses. Fuel gas price is based upon present trends in the spot market price of natural gas and is held flat for the life of the analysis. The method of market value calculation is derived from accounting methods for conventional gas production. In the examples, LOE is the only expense charged against royalty and severance tax.

The inclusion and method of calculation of royalty and severance tax charges against revenue is not an opinion that the applicability of royalties and severance taxes are determined by the same criteria, or that royalties and severance taxes might be owed for any or all of the cases examined in the economic analyses, or that the method of computation is the only method by which royalties and severance taxes might be fairly and legally calculated. The authors recognize that the issue of whether royalty or severance tax are due requires the application of different standards. Royalties are payable by contract, generally a document identified as a "mineral lease". While such contracts can be as varied as the skill of the draftsmen and the limits of the law allow, a typical provision might read:

> "As royalty, lessee covenants and agrees . . . to pay lessor on gas and casinghead gas produced from said land (1) when sold by lessee, one-eighth of the net proceeds derived

from such sale, or (2) when used by lessee off said land or in the manufacture of gasoline or other products, the market value, at the mouth of the well, of one-eighth of such gas and casinghead gas, lessor's interest, in either case, to bear one-eighth of the cost of compressing, dehydrating and otherwise treating such gas or casinghead gas to render it marketable or usable and one-eighth of the cost of gathering and transporting such gas and casinghead gas from the mouth of the well to the point of sale or use (emphasis added)."

On the other hand, the payment of severance tax is established by law, and is generally payable for any severed mineral sold or used in any beneficial fashion, whether on or off the premises. The possibility that either might be due for gob methane used beneficially by the miner and a sense of fiscal conservatism suggest that both be included in the cost items of the analyses. The inclusion of all costs incurred from the wellhead to the point of use appears fair and supportable. The exclusion of depreciation on, or a rate of return for, the gathering system or pipeline is not intended as a comment on whether such items can be charged against either royalty or severance tax.

The capital cost of the unit at present is nominally \$600,000. However, a \$1,000 kW subsidy is available for this type of unit thereby reducing the present net cost to \$400,000, *see* Congressional Record - House, p. H 9652 (Sept. 26, 1994). Therefore, \$400,000 is used for the "Cost of Unit" in the Base Case.

Fuel cells for commercial generation of electric power are a very new enterprise, and the fuel cell described in this report is the only type of fuel presently available for commercial power generation. The technology is not fully developed for that application. As a result, the present capital cost of a unit is very high relative to other types of electric power generating equipment - approximately \$3,000/kW excluding the value of federal subsidies. However, it is anticipated by the unit's manufacturer, IFC, that the cost of a single unit can be reduced to \$1,500/kW by 1997 with sufficient sales and mature production cost, *telephone conversations with* William J. Lueckel, Vice President, Marketing and Governmental Affairs, IFC (July & Aug., 1995). Additionally, the power generating section of the unit can be stacked without the need to duplicate the control sections. The applications for fuel cells described in this report appear to be suitable for the stacking of several power units, thereby eliminating the cost of duplicate control sections and reducing installation costs. Therefore, \$300,000 is used as the "Cost of Unit" in the Cases 2 through 4. This cost excludes the effect of the present subsidy and assumes that the production costs will be reduced substantially with maturation of the market and that cost savings will occur with the employment of multiple power units.

The fuel cost is assumed to be the cost to gather and transport the fuel gas to the fuel cell. This cost is identified in the analysis as "LOE" (lease operating expenses), which is the term commonly used in the oil and gas industry for post production expenses. LOE for the gob gas used by the fuel cell is based upon a system of pipelines and compressors designed to handle gas down to 45% methane with no dehydration other than mechanical. LOE covers all costs incurred in producing, treating, transporting and compressing the gas. LOE expenses for gob gas are based upon the experience of Black Warrior Methane Corp. (BWMC) with two significant differences. The post-production costs incurred by BWMC include a substantial charge for compression to a delivery pressure of approximately 700 psi and for the operating costs associated with permanent gathering lines. In the cases analyzed here, it is assumed that gas will be gathered in low pressure lines and boosted to lowest pressure sufficient for operation of the fuel cell. The fuel cell described in this proposal requires a minimal pressure (approximately 1 psi) for fuel gas at the unit. Additionally, it is assumed that a large portion of the gathering lines will be temporary, low-pressure polyethylene lines which can be laid on the surface of the ground and later reused. Therefore, the LOE expense used in the economic evaluations of this report is 5¢/mcf. LOE does not include the cost to drill and complete wells. It is assumed that the project has an existing ventilation program which utilizes vertical gob wells drilled from the surface

All the cases analyzed assume that the fuel cell will derive its fuel from gob wells which produce gas varying from 80% to 45% methane. 45% was chosen as the lower limit for gob methane because there appears to be a significant decrease in power output below that level. The revenue lines in the computation block are actually the cost savings in avoided electricity purchases or coal used to generate heat in a thermal dryer.

The inclusion of a tax credit for methane emission reductions is speculative. The use of a credit is to demonstrate the possible effect on the profitability of fuel cells if laws are enacted to tax emissions or reward emission reductions. A tax credit was used as the accounting vehicle for ease of calculation and based upon the precedent of the Nonconventional Energy Tax Credit under § 29 of the Internal Revenue code. Net cash flow is income after taxes with a recapture of depreciation. A discount factor of 10% was used for calculation of net present values.

Base Case

Royalty and severance taxes are charged against the gob gas. The Base Case uses an electric power cost of 5¢/kWh, which is assumed to be the average industrial electric power rate at the time and in the areas where this technology will be applied.

Case # 2, Reduced Unit and Maintenance Costs

This case assumes that the cost of the unit will be reduced as previously discussed and that maintenance costs can be cut in half from the Base Case. Because there is no experience in operations of fuel cells utilizing mine-generated gases, the Base Case uses the best available figure for maintenance cost of 7¢/kWh. It is not unreasonable to assume that maintenance costs may decrease with experience. This case is therefore intended to show the sensitivity of the economics to a decrease in maintenance costs.

Case # 3, Reduced Unit and Maintenance Costs and High Electric Power Cost

This case is intended to show the economics of the unit in areas where electric costs are higher than the norm. This case indicates that electric power costs to the mine may be the most significant factor in determining the economic feasibility of fuel cell utilization.

Case # 4, Reduced Unit and Maintenance Costs and no Royalty or Severance Tax

This case shows the effect of eliminating payment of royalties and severance tax for the gob gas used by the fuel cell. This case indicates that the effect is minimal. In the actual case, sensitivity analysis would be significant in determining the relative merits of incurring the cost to resolve royalty and severance issues in advance of production and including charges for royalty and severance tax in the revenue stream. This case appears to indicate that such costs would probably be less than the cost of a contingency reserve for potential claims or litigation by royalty owners or state revenue agencies.

Table 10. Economic Analysis - 200 kW Fuel Cell.

Base Case

Assumptions:

Cost of Unit	$400,000	Inflation factor	5.00%
Installation Cost	$15,000	Unit Availability (hrs/yr)	8,322
Maintenance cost ($/kWh)	$0.0070	Elec. power cost/value ($/kWh)	$0.05
Fuel gas price ($/mcf)	$1.75	Rated Capacity (kW)	200
Gob Gas LOE	$0.05	Fuel useage (mcf/hr)	1.9
Royalty (as % of mkt val)	12.5%	Value of waste heat ($/hr)	$0.76
Severance tax (as % of mkt val)	5.0%	Tax credit ($/mcf)	$0.00

Results:	year 1	year 2	year 3	year 4	year 5	year 6	year 7	year 8	year 9	year 10
displaced electric costs	$83,220	$87,381	$91,750	$96,338	$101,154	$106,212	$111,523	$117,099	$122,954	$129,102
value of waste heat	$4,755	$4,993	$5,243	$5,505	$5,780	$6,069	$6,373	$6,691	$7,026	$7,377
fuel cost	($791)	($830)	($872)	($915)	($961)	($1,009)	($1,059)	($1,112)	($1,168)	($1,226)
royalty & severance tax	($4,704)	($4,939)	($5,186)	($5,445)	($5,718)	($6,004)	($6,304)	($6,619)	($6,950)	($7,297)
maint. cost	($11,651)	($12,233)	($12,845)	($13,487)	($14,162)	($14,870)	($15,613)	($16,394)	($17,214)	($18,074)
installation cost	($15,000)	$0	$0	$0	$0	$0	$0	$0	$0	$0
total cost	($32,145)	($18,003)	($18,903)	($19,848)	($20,840)	($21,882)	($22,976)	($24,125)	($25,332)	($26,598)
net revenue	$55,830	$74,372	$78,090	$81,995	$86,094	$90,399	$94,919	$99,665	$104,648	$109,881
depreciation	($40,000)	($40,000)	($40,000)	($40,000)	($40,000)	($40,000)	($40,000)	($40,000)	($40,000)	($40,000)
taxable income	$15,830	$34,372	$38,090	$41,995	$46,094	$50,399	$54,919	$59,665	$64,648	$69,881
tax	($5,382)	($11,686)	($12,951)	($14,278)	($15,672)	($17,136)	($18,672)	($20,286)	($21,980)	($23,759)
tax credit	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
income after taxes	$10,448	$22,685	$25,139	$27,716	$30,422	$33,263	$36,247	$39,379	$42,668	$46,121
net cash flow	$50,448	$62,685	$65,139	$67,716	$70,422	$73,263	$76,247	$79,379	$82,668	$86,121
cumulative net cash flow	$50,448	$113,133	$178,272	$245,989	$316,411	$389,675	$465,921	$545,300	$627,968	$714,089

Net present value	$20,328
Internal rate of return	11%

Table 11. Economic Analysis - 200 kW Fuel Cell.

Case #2, Reduced Unit and Maintenance Costs

Assumptions:

Cost of Unit	$300,000	Inflation factor	5.00%
Installation Cost	$15,000	Unit Availability (hrs/yr)	8,322
Maintenance cost ($/kWh)	$0.0035	Elec. power cost/value ($/kWh)	$0.05
Fuel gas price ($/mcf)	$1.75	Rated Capacity (kW)	200
Gob Gas LOE	$0.05	Fuel useage (mcf/hr)	1.9
Royalty (as % of mkt val)	12.5%	Value of waste heat ($/hr)	$0.76
Severance tax (as % of mkt val)	5.0%	Tax credit ($/mcf)	$0.25

Results:	year 1	year 2	year 3	year 4	year 5	year 6	year 7	year 8	year 9	year 10
displaced electric costs	$83,220	$87,381	$91,750	$96,338	$101,154	$106,212	$111,523	$117,099	$122,954	$129,102
value of waste heat	$4,755	$4,993	$5,243	$5,505	$5,780	$6,069	$6,373	$6,691	$7,026	$7,377
fuel cost	($791)	($830)	($872)	($915)	($961)	($1,009)	($1,059)	($1,112)	($1,168)	($1,226)
royalty & severance tax	($4,704)	($4,939)	($5,186)	($5,445)	($5,718)	($6,004)	($6,304)	($6,619)	($6,950)	($7,297)
maint. cost	($5,825)	($6,117)	($6,423)	($6,744)	($7,081)	($7,435)	($7,807)	($8,197)	($8,607)	($9,037)
installation cost	($15,000)	$0	$0	$0	$0	$0	$0	$0	$0	$0
total cost	($26,320)	($11,886)	($12,480)	($13,104)	($13,760)	($14,448)	($15,170)	($15,928)	($16,725)	($17,561)
net revenue	$61,655	$80,488	$84,513	$88,738	$93,175	$97,834	$102,726	$107,862	$113,255	$118,918
depreciation	($30,000)	($30,000)	($30,000)	($30,000)	($30,000)	($30,000)	($30,000)	($30,000)	($30,000)	($30,000)
taxable income	$31,655	$50,488	$54,513	$58,738	$63,175	$67,834	$72,726	$77,862	$83,255	$88,918
tax	($10,763)	($17,166)	($18,534)	($19,971)	($21,480)	($23,064)	($24,727)	($26,473)	($28,307)	($30,232)
tax credit	$3,953	$3,953	$3,953	$3,953	$3,953	$3,953	$3,953	$3,953	$3,953	$3,953
income after taxes	$24,846	$37,275	$39,931	$42,720	$45,649	$48,723	$51,952	$55,342	$58,901	$62,639
net cash flow	$54,846	$67,275	$69,931	$72,720	$75,649	$78,723	$81,952	$85,342	$88,901	$92,639
cumulative net cash flow	$54,846	$122,121	$192,052	$264,772	$340,421	$419,144	$501,096	$586,438	$675,339	$767,978

Net present value	$140,330
Internal rate of return	20%

Table 12. Economic Analysis - 200 kW Fuel Cell.

Case #3, Reduced Unit and Maintenance Costs and High Electric Power Cost

Assumptions:

Cost of Unit	$300,000	Inflation factor	5.00%
Installation Cost	$15,000	Unit Availability (hrs/yr)	8,322
Maintenance cost ($/kWh)	$0.0035	Elec. power cost/value ($/kWh)	$0.06
Fuel gas price ($/mcf)	$1.75	Rated Capacity (kW)	200
Gob Gas LOE	$0.05	Fuel useage (mcf/hr)	1.9
Royalty (as % of mkt val)	12.5%	Value of waste heat ($/hr)	$0.76
Severance tax (as % of mkt val)	5.0%	Tax credit ($/mcf)	$0.25

Results:	year 1	year 2	year 3	year 4	year 5	year 6	year 7	year 8	year 9	year 10
displaced electric costs	$99,864	$104,857	$110,100	$115,605	$121,385	$127,455	$133,827	$140,519	$147,545	$154,922
value of waste heat	$4,755	$4,993	$5,243	$5,505	$5,780	$6,069	$6,373	$6,691	$7,026	$7,377
fuel cost	($791)	($830)	($872)	($915)	($961)	($1,009)	($1,059)	($1,112)	($1,168)	($1,226)
royalty & severance tax	($4,704)	($4,939)	($5,186)	($5,445)	($5,718)	($6,004)	($6,304)	($6,619)	($6,950)	($7,297)
maint. cost	($5,825)	($6,117)	($6,423)	($6,744)	($7,081)	($7,435)	($7,807)	($8,197)	($8,607)	($9,037)
installation cost	($15,000)	$0	$0	$0	$0	$0	$0	$0	$0	$0
total cost	($26,320)	($11,886)	($12,480)	($13,104)	($13,760)	($14,448)	($15,170)	($15,928)	($16,725)	($17,561)
net revenue	$78,299	$97,964	$102,863	$108,006	$113,406	$119,076	$125,030	$131,282	$137,846	$144,738
depreciation	($30,000)	($30,000)	($30,000)	($30,000)	($30,000)	($30,000)	($30,000)	($30,000)	($30,000)	($30,000)
taxable income	$48,299	$67,964	$72,863	$78,006	$83,406	$89,076	$95,030	$101,282	$107,846	$114,738
tax	($16,422)	($23,108)	($24,773)	($26,522)	($28,358)	($30,286)	($32,310)	($34,436)	($36,668)	($39,011)
tax credit	$3,953	$3,953	$3,953	$3,953	$3,953	$3,953	$3,953	$3,953	$3,953	$3,953
income after taxes	$35,831	$48,809	$52,042	$55,437	$59,001	$62,743	$66,673	$70,799	$75,131	$79,680
net cash flow	$65,831	$78,809	$82,042	$85,437	$89,001	$92,743	$96,673	$100,799	$105,131	$109,680
cumulative net cash flow	$65,831	$144,640	$226,682	$312,119	$401,120	$493,863	$590,536	$691,335	$796,466	$906,146

Net present value	$214,627
Internal rate of return	25%

Table 13. Economic Analysis - 200 kW Fuel Cell.

Case #4, Reduced Unit and Maintenance Costs and no Royalty or Severance Tax

Assumptions:

Cost of Unit	$300,000	Inflation factor	5.00%
Installation Cost	$15,000	Unit Availability (hrs/yr)	8,322
Maintenance cost ($/kWh)	$0.0035	Elec. power cost/value ($/kWh)	$0.05
Fuel gas price ($/mcf)	$1.75	Rated Capacity (kW)	200
Gob Gas LOE	$0.05	Fuel useage (mcf/hr)	1.9
Royalty (as % of mkt val)	0.0%	Value of waste heat ($/hr)	$0.76
Severance tax (as % of mkt val)	0.0%	Tax credit ($/mcf)	$0.25

Results:	year 1	year 2	year 3	year 4	year 5	year 6	year 7	year 8	year 9	year 10
displaced electric costs	$83,220	$87,381	$91,750	$96,338	$101,154	$106,212	$111,523	$117,099	$122,954	$129,102
value of waste heat	$4,755	$4,993	$5,243	$5,505	$5,780	$6,069	$6,373	$6,691	$7,026	$7,377
fuel cost	($791)	($830)	($872)	($915)	($961)	($1,009)	($1,059)	($1,112)	($1,168)	($1,226)
royalty & severance tax	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
maint. cost	($5,825)	($6,117)	($6,423)	($6,744)	($7,081)	($7,435)	($7,807)	($8,197)	($8,607)	($9,037)
installation cost	($15,000)	$0	$0	$0	$0	$0	$0	$0	$0	$0
total cost	($21,616)	($6,947)	($7,294)	($7,659)	($8,042)	($8,444)	($8,866)	($9,309)	($9,775)	($10,264)
net revenue	$66,359	$85,427	$89,699	$94,184	$98,893	$103,838	$109,029	$114,481	$120,205	$126,215
depreciation	($30,000)	($30,000)	($30,000)	($30,000)	($30,000)	($30,000)	($30,000)	($30,000)	($30,000)	($30,000)
taxable income	$36,359	$55,427	$59,699	$64,184	$68,893	$73,838	$79,029	$84,481	$90,205	$96,215
tax	($12,362)	($18,845)	($20,298)	($21,822)	($23,424)	($25,105)	($26,870)	($28,724)	($30,670)	($32,713)
tax credit	$3,953	$3,953	$3,953	$3,953	$3,953	$3,953	$3,953	$3,953	$3,953	$3,953
income after taxes	$27,950	$40,535	$43,354	$46,314	$49,422	$52,686	$56,112	$59,710	$63,488	$67,455
net cash flow	$57,950	$70,535	$73,354	$76,314	$79,422	$82,686	$86,112	$89,710	$93,488	$97,455
cumulative net cash flow	$57,950	$128,485	$201,839	$278,154	$357,576	$440,262	$526,374	$616,084	$709,573	$807,027

Net present value	$161,328
Internal rate of return	21%

Market Issues

For power generation as outlined in this study, the potential market in the United States appears to be very large. Outside the U.S. it appears to be much larger although far more difficult to evaluate. USEPA recently completed a study of the potential for economic utilization of mine methane in the U.S. [21]. Seventy-four mines were identified as candidates for economically using mine emissions. If the mines identified which emit methane from degasification systems are considered the market for fuel cell power generation, the total available methane for fuel gas is 148.6 MMcfd [21] This amount of gas would fuel approximately 3,000 of the units described in this report. Many of these mines may not be candidates for fuel cell projects for many reasons, including: ownership questions may be discouraging; there may be no gob gas production (many of the 57 mines are room-and-pillar; others have no reported gob production); no reasonable access to pipelines; the mine may lack or be reluctant to advance the capital needed for the project; the remaining life of the mine may be too short to justify the capital costs; local utilities may deter alternate energy production. However, if only half of the available methane could be used, 1,500 fuel cells could be employed in the U.S.

There are several aspects of fuel cells which may give them an advantage in certain market niches related to power generation from coal mine methane. The units are readily portable and relatively easy to set up. They may therefore be suitable for use in situations where a gob well is brought into production but full use of the gas cannot be made immediately. Fuel cells may allow early gas production to be used for power generation until gas gathering and production facilities are established. The portability of the units may allow them to be used in cases where wells which produce low levels of medium quality methane, which cannot currently be commercially utilized. For example, in the area of the JWR mines, there are approximately 100 gob wells which are not produced commercially. These wells are capable of producing between 50 and 100 Mcfd of 40 to 80 percent methane [24]. The operating cost and gas quality of these wells renders them uneconomic for pipeline-quality gas production. However, these wells would be ideal as sources of gas for fuel cells. The portability of the units means that they can be easily moved from well to well as gas production declines below minimum limits.

The minimal effect which a fuel cell has on air quality limitations may make fuel cells suitable as a gas utilization option in situations where existing permits for emissions of NO_X or other air pollutants are a factor which may delay or prohibit other end uses for the gas. The low noise levels of fuel cells can give them an advantage over other gas utilization options where demographics make noise pollution a substantial consideration in exploiting mine methane.

Evaluating the market outside the U.S. is more problematic. There are, to the best of our knowledge, no analogous studies of power generation potential for mines outside the U.S. The information that is available indicates that it is not unreasonable to assume that the overseas market is greater than the U.S. market by an order of magnitude or more. It has been estimated that approximately 1,825 Bcf/yr (5,000 MMcfd) of methane is emitted in the nine countries (excluding the U.S.) with the most coal mine emissions[25]. Many of the countries identified as significant sources of mine methane emissions also have substantial needs for expanded electric power generating capacity [26]. If it is assumed that 35 percent of total mine emissions are from degasification systems, then 1,750 MMcfd may be available as fuel gas.

Regulatory Issues

The regulatory issues most likely to be arise in a project as described in this report will involve MSHA regulations concerning mine ventilation [27]. As a matter of practice, flame arresters are installed at all gob wells at the JWR mines which are producing gas. The reason for this installation is to prevent any ignition at the surface from propagating down the well into the mine works [18, 28].

CONCLUSIONS AND RECOMMENDATIONS FOR FUTURE WORK

The conversion of medium-quality gob gas to electric power using existing fuel cell technology appears to be technically feasible. Certain operating parameters, such as the effect of varying methane concentration and the presence of other gasses in the input flow stream, however, are not well understood. Evaluation of these operating parameters under controlled yet varying conditions will greatly enhance the viability of the utilization of existing fuel cell technology to 1) recover mine methane that otherwise may be emitted to the atmosphere; and 2) convert a gas that is often wasted into a new source of environmentally-friendly energy.

The site selected for the demonstration of this technology has a source of coalbed methane from gob wells that is both of high quality and sustainable. Current produced gob gas is of pipeline-quality and is injected into natural gas pipeline systems for sale. This provides for a constant quality flow stream that can be varied under controlled conditions to represent the type of gas quality (high to medium) often produced from gob wells in the U.S. In addition, the extensive coal reserves and the large mining complex of JWR provides a long-term supply of methane for the proposed test facility.

The demonstration project will utilize the only commercial fuel cell power plant available at this time, so assessment of its performance under varying quality coalbed methane flow streams can be transferred in real-time to other areas and facilities. This use of existing "off the shelf" technology means that the field-scale demonstration project will be able to concentrate on proving the viability of the technology as opposed to developing new fuel cell technology. This translates into a very realistic demonstration and the rapid transference of the results to the U.S. and international coal mining industries. In addition, a major factor in operating the fuel cell with coalbed methane in a demonstration is the dedication of electrical load. Such electrical load is available at the test site and ease of access for waste heat utilization is also present at the test site.

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