WHITE PAPER:

OPPORTUNITIES FOR COAL MINE GAS PROJECTS CREATED BY ELECTRIC INDUSTRY RESTRUCTURING

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GLOSSARY OF TERMS USED IN THIS DOCUMENT

Avoided Costs - The costs that an electric utility avoids by purchasing power from an independent producer rather than generating and delivering power itself, purchasing power from another source, or constructing new power plants.

Base Load Units - Generating units which run nearly continuously to serve electricity demand that remains steady.

Bilateral Transaction - A direct-purchase transaction between a buyer and a seller.

British Thermal Unit (Btu) - The amount of energy necessary to raise the temperature of one pound of water one degree Fahrenheit.

Btu Substitution - Substituting different fuels such as coal, gas, wind, etc. depending on the market, to generate electricity.

Demand - The rate at which electric energy or natural gas is delivered to or by a system at a given instant or averaged over a designated period, usually expressed in kilowatts or megawatts (electricity) or cubic feet per second (gas).

Dispatchability - The ability of a generating unit to respond to a signal to increase or decrease its generating capacity or be brought on line or shut down.

Distributed Generation - Power produced away from a central station designed to meet the requirements of that load using on-site small scale generating equipment such as gas turbines, reciprocating engines, fuel cells, and micro-turbines.

Efficiency - A percentage indicating the available Btu input that is converted to useful purposes.

Exempt Wholesale Generator (EWG) - A class of generators defined by the Energy Policy Act of 1992 that includes the owners and/or operators of facilities used to generate electricity exclusively for the wholesale power market or generation capacity that is leased to utilities.

Federal Energy Regulatory Commission (FERC) - A quasi-independent regulatory agency within the Department of Energy having jurisdiction over interstate electricity sales, wholesale electric rates, hydroelectric licensing, natural gas transmission and related pipeline rates and certifications.

Grid - Network of electric or gas transmission and distribution lines along which energy moves.

Hedging - To offset a position with the intent of managing risk. The process of protecting the long-term value of an investment with an offsetting short-term position in a related investment.

Holding Company - A parent company set up to hold shares in other companies.

Independent Power Producer (IPP) - Private entrepreneurs who develop, own, and operate electric power plants fueled by a variety of energy sources.

Independent System Operator (ISO) - An independent system operator handles, in a non-discriminatory manner, all the transmission assets of a fixed geographic area granted through the authority of multiple utilities.

Merchant Plant - Power plants that are outside electric utility rate bases and are without purchase power agreements. Merchant power plants are built to sell power in a deregulated wholesale power market without long-term power purchase agreements.

North American Electric Reliability Council (NERC) - An electric utility council formed in 1968 to promote the reliability and adequacy of bulk power supply in the electric utility systems of North America.

Peak Units - Generating units that run only when demand is highest, such as hot summer afternoons on workdays. Peaking units may operate less than 5% of the time.

Qualifying Facilities (QFs) - A designation created by the 1978 Public Utility Regulatory Policies Act for non-utility power producers that meet certain operating, efficiency, and fuel standards set by the Federal Energy Regulatory Commission. To receive status as a QF, the facility must produce electric energy and "another form of useful thermal energy through the sequential use of energy". QFs may be cogeneration or combined heat and power systems using renewable energy sources.

Real-time metering - Monitoring electricity use in 15 or 30 minute increments to coordinate with hourly price fluctuations in electricity sales.

Retail Wheeling - The ability of end-use customers to purchase electricity generated from anyone other than the local electric utility facilitated by movement of such power over the local utility's transmission or distribution lines.

Spot Market - Commodity transactions in which the transaction commencement is near term (usually within 10 days) and the contract duration is relatively short (usually within 30 days).

Stranded Costs - An investment with a cost recovery that was initially approved by regulatory action that subsequent regulatory action or market forces has rendered not practically recoverable. Electric utilities are currently recovering stranded costs through their rate structure.

Time-of-Use Rates or Pricing - A rate design imposing charges during periods of the day when relatively higher generation and transmission costs are incurred to meet higher than peak demands of electricity. Prices could be based on 30 minute intervals, or less, depending on distribution service.

I. INTRODUCTION

Electric industry restructuring has brought about a transitional market environment where utilities, power marketers, and large industrial customers are developing strategies to gain a competitive edge for the future. Restructuring is creating new opportunities for coal mine gas[1] projects, particularly for those coal mines and energy developers who are innovative and are willing to form strategic alliances. The purpose of this paper is to describe how project developers may be able to take advantage of these opportunities. The potential for profitable coal mine methane projects appears promising, considering the various options available to energy developers.

The extent to which electric industry restructuring encourages the construction of new gas-fueled power generation, and the extent to which coal production increases to meet demand, will have a significant impact on opportunities for coal mine gas use in the future. This, along with the continued evolution of coal mine gas drainage technologies, will determine the degree to which coal mines can benefit from new market opportunities.

Several of the benefits of coal mine gas use include:

1) ability to generate electricity for on-site use at a coal mine and/or sale of electricity to the local grid;
2) lower NO_x and SO_2 emissions for utility companies through cofiring;
3) lower greenhouse gas emissions from coal mines; and
4) bundling of coal, gas, electricity, $SO_{2,}$ and/or NO_x emission credits to maximize opportunities in today's changing energy markets.

Section II of this paper reviews the history of electric industry restructuring to provide a background for readers who may not be familiar with its evolution. Readers with a thorough knowledge of this background may wish to move directly to Section III, which discusses today's electric industry and the potential role of coal mine gas therein.

II. ELECTRIC INDUSTRY RESTRUCTURING HISTORY

Emergence of Electric Utilities

Independent power generators and distributors, competing for customers, began supplying electricity to the public in the early part of this century. The electric industry was divided into three segments, generation, transmission, and distribution, all of which were controlled by a single investor-owned utility. In the 1920s, public enthusiasm for the growth of municipal electric systems resulted in the formation of many large power holding companies, and by the next decade, a handful of large companies controlled the majority of the marketplace. Private investor funds fueled the creation of early electric power production and distribution facilities.

[1] The term “coal mine methane” refers to the gas that is released from coal or surrounding rock strata during the process of coal mining. In addition to methane, this gas may contain other hydrocarbon gases or consituents such as carbon dioxide, nitrogen, or oxygen. Because some readers could construe “coal mine methane” to mean pure methane, this paper will instead use the term “coal mine gas”.

This tradition has continued, as investor-owned utilities provide over 75% of all power generated in the U.S. (Edison Electric Institute, 1998). In response to market abuses by holding companies, which resulted in increased costs paid by consumers, Congress passed the Public Utilities Holding Company Act (PUHCA) in 1935 to regulate finances and corporate structure of holding companies that controlled public utility companies. However, the electric industry continued to evolve in a monopolistic environment where utility companies, assigned to designated geographic areas, produced power at progressively lower rates due to increases in economies of scale, technological improvements, and only moderate increases in fuel prices. By the 1960s, the electric industry developed regional transmission networks, which allowed power plants to be located up to 1,000 miles from consumers. Regulation of the industry proved to be beneficial to both the electric companies and their customers by producing low-cost electricity at a reasonable profit.

Federal Initiatives

During the 1970s, a sharp rise in energy prices due to the oil crises of 1973 and 1979 spurred changes in U.S. energy policy. Because of high fuel costs, rapid inflation, high interest rates, and the need for greater energy security, regulators began to shift their perceptions of traditional rate-based regulation of utilities and as a result, they attempted to encourage competition within the electricity generation market. Three milestones that marked this regulatory shift were the enactment of the Public Utility Regulatory Policies Act of 1978 (PURPA), the Energy Policy Act of 1992 (EPAct), and most recently, the issuance of Federal Energy Regulatory Commission (FERC) Orders 888 and 889 in 1996.

PURPA required utilities to increase energy efficiency and conservation and purchase electricity from certain cogeneration and small power production facilities (termed qualifying facilities, or QFs) that were exempt from the requirements of PUHCA and most state laws governing utility rates. PURPA defined these QFs as non-utility, renewable power generators and cogenerators, and required electric utilities to purchase electricity from QFs at rates not to exceed the avoided energy costs. As a result, the number of QFs in the U.S. grew to 1,200 by 1993 (Mauel, 1996). Prompted by the success of QFs, other independent power producers (IPPs) that were regulated separately from QFs began to build new capacity (primarily with smaller gas-fired plants) to compete in bulk power markets. However, ownership restrictions under PUHCA hindered the development of IPPs.

The passage of EPAct set the stage for competition in the electric utility industry. Its thrust was to promote greater competition in bulk power markets by eliminating some of the obstacles facing IPPs such as the alternative energy fuel requirements. EPAct revised PUHCA by creating a new class of exempt wholesale generators (EWGs) that could be owned by utilities or holding companies. Furthermore, EPAct expanded FERC's authority to approve power producer applications for non-discriminatory transmission access to other utilities' power lines.

Issuance of FERC Orders 888 and 889

An increasing number of IPPs, EWGs, and power marketers were created during the mid-1990s due to low natural gas prices and the ability to obtain non-discriminatory transmission access by FERC. The issuance of FERC Orders 888 and 889 on April 24, 1996 opened wholesale power sales to competition by requiring public utilities that own, control, or operate transmission lines to offer others the same transmission services they provide themselves, under comparable terms and conditions.

FERC Order 888 also allows public utilities and transmitting utilities to recover 100% of "stranded costs". These are expenditures that investor-owned utilities have invested in power plants (most notably nuclear power plants) and are still paying off, and may not recover in a restructured market. Currently, individual state utility commissions and courts are grappling with stranded costs decisions that shape the future of restructuring. While utilities lobby to recover stranded costs, citizen action groups have been fighting to assure that decisions are fair to consumers.[2]

The second rule, FERC Order 889, requires public utilities to implement a Standard of Conduct and develop an Open Access Same-time Information System (OASIS) to electronically communicate information about their transmission systems and services to all potential customers at the same time. This ensures that transmission owners will not have an unfair competitive advantage in selling power as a result of inside information regarding transmission availability.

The overall impact of FERC Orders 888 and 889, as well as legislation that created PURPA and the Energy Policy Act of 1992, has been to create an industry in which generation, transmission and distribution are unbundled. Because the vertically integrated utilities have traditionally bundled the price of services, restructuring requires utilities to demonstrate that each function remains competitive. Most industry analysts agree that unbundling services, coupled with opening the utilities' transmission lines, facilitates open competition.

Ongoing Federal Actions

From 1996 through 1998 during the 104th and 105th Congresses, several members of the U.S. Congress introduced legislative initiatives that were aimed at protecting consumers by giving them the right to choose among competitive providers of electricity. However, no Federal legislation has been passed to date that applies directly to electric industry restructuring. The House and Senate are still debating several bills that cover a wide range of restructuring actions. Major issues being debated include energy efficiency and conservation, the use of renewable sources of energy, specific dates for mandated customer choice, FERC's authority, and the repeal of PUHCA. It will be up to the 106th Congress to address these proposals.

The Clinton Administration proposed a bill to Congress on June 27, 1998 called the Comprehensive Electricity Competition Act (CECA). The bill includes a flexible mandate requiring full retail competition by 2003, but allows states to opt out of retail competition if FERC determines that deregulation would have a negative impact on a class of customers. Also included is a requirement that power providers produce at least 5.5% of their electricity from renewable sources (excluding hydropower) by 2009. The proposed bill seeks to fund $3 billion to promote consumer education and energy conservation and efficiency programs for states. Finally, CECA would allow U.S. EPA to impose a NO_x allowance cap on states whose emissions are transported via air currents to other states, thereby making it difficult for those states to attain ambient air quality standards.

[2] Citizens of California (which was the first state to allow retail competition in March 1998) and Massachusetts gathered enough signatures to place initiatives on their November 1998 ballots to repeal recently implemented state restructuring laws. The California petition argued that the $28 billion bailout of California utilities through a transmission surcharge impeded fair retail competition. However, voters in both states overwhelmingly rejected the ballot initiatives, thereby endorsing the existing restructuring laws. Nevertheless, consumer groups nationwide are vowing to continue fighting the utilities' recovery of stranded costs from ratepayers in other states.

Current State Initiatives

While power generation at the wholesale level is open to competition, the U.S. Congress left it up to the individual states to implement their own rights to retail competition. State legislatures must first pass legislation that authorizes deregulation so that the State regulatory commissions can then implement restructuring plans. In March 1998 California led the way by implementing restructuring legislation that requires retail competition, and most states have at least begun addressing electric industry changes. As of January 1999, 18 states[3] (including the five Appalachian coal mining states) had mandated retail restructuring by passing legislation.

Over the next two years, policies and legislation relating to deregulation will have major impacts on the long-term development of restructuring. Appendix A contains a partial list of public utility commissions that can provide current restructuring information for the 11 gassy coal mine states.

III. TODAY'S ELECTRIC POWER INDUSTRY

Today's electric power industry is characterized by traditional, large, investor-owned and public utilities as well as a smaller, but growing, class of independent power producers that are taking advantage of changes in the industry. The electric industry is becoming increasingly market-driven, and innovative power producers can profit from these changes. In particular, the emerging market-based system provides new opportunities for using coal mine gas within the power sector such as on-site electricity generation, peak shaving, and electricity sales to the grid. The impact of electric industry restructuring on new gas-fired power plants depends on a number of factors, including the speed and success of the transition to a competitive market, gas prices, electricity demand, access to the grid, and how states calculate and treat stranded costs for utilities. Although FERC 888 lays the groundwork for accelerated competition, restructuring may proceed slower than expected due to a reluctance to legislate retail competition at the state level and delays in court decisions addressing stranded cost recovery.

Recovered coal mine gas is an energy source available for many different applications. Potential utilization methods include pipeline injection, direct use on-site in prep plants or mine vehicles, cofiring in boilers, or electricity generation through the use of internal combustion engines or gas turbines. The opportunities that arise for the sale, transportation, and delivery of electricity generated from coal mine gas depend heavily on the direction in which market forces will drive *new* investment in power generation. New technological advances in electricity production should produce market niches for gas-fired generating units even in areas where electric capacity is already built and electricity prices are low.

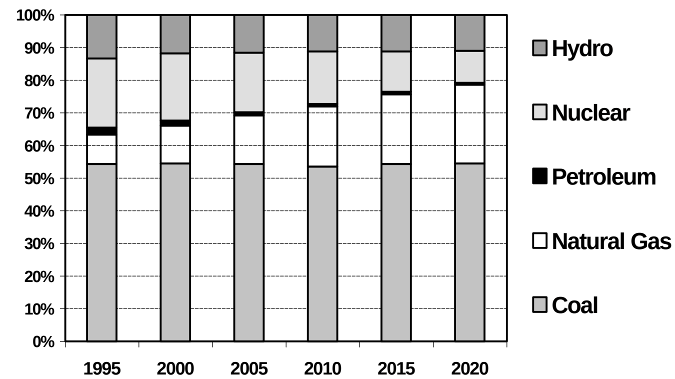
Electricity Demand

Electricity consumption in the U.S. has been, and will continue to be, closely tied to growth in the nation's economy. Current projections by the U.S. DOE's Energy Information Administration (EIA) indicate that overall electricity demand will grow by 1.3-1.5% per year through 2020 (EIA 1998a). Both the coal and gas industries will benefit considerably from this increased demand since over 90% of *new* generation capacity is expected to be either coal or gas-fired (Gas Research Institute, 1997a). This expected increase in demand would provide opportunities for new coal and gas-fired generating capacity, with the potential for 300 GW of additional electricity.

[3] The 18 states are Arizona, California, Connecticut, Illinois, Maine, Maryland, Massachusetts, Michigan, Montana, Nevada, New Hampshire, New Jersey, New York, Oklahoma, Pennsylvania, Rhode Island, Vermont, and Virginia.

One reason for the increased need for new coal and gas-fired capacity is that no new nuclear power plants are planned over the next 20 years, while during the same time, 65 units totaling 52 GW are scheduled to be retired (EIA 1998a). As a result, nuclear powered generation will decline from 22% (GRI, 1997a) of net U.S. electricity generation to about 9% (Figure 1). In addition, hydroelectric power contributes nearly 11% of U.S. electrical generation today, but the lack of available sites limits any potential increase in hydropower generation.

Figure 1 - Projected Energy Sources for Electric Utilities



According to the EIA (1998a), gas-fired electricity generation is expected to increase from 9% to 24% of the total net generation by the year 2020 (Figure 1). Coal will remain the primary fuel for electricity generation even though its market share will decrease slightly by the year 2020. Moreover, coal consumption is expected to rise in the near-term as electric restructuring leads to increased utilization of existing plants.

Increases in peak demand are not expected to keep pace with net increases in total electricity demand. When consumers face seasonal or diurnal variations in electricity prices, they are likely to respond by reducing their demand in high cost periods and increasing it in low cost periods (EIA, 1997). Studies indicate that the average annual price of electricity will be relatively low, with a moderate consumer response to time-of-use pricing, as compared with no time-of-use pricing. In view of this, time-of-use prices are expected to gain acceptance under restructuring.

Market Structure

As restructuring continues, decisions concerning which electric generating systems are dispatched will be based on a combination of wholesale contracts and short-term spot market bids made by generating companies. These transactions will take place in regional Power Exchanges, where electricity futures are traded. Contracts between generating companies and those who purchase the power will be governed by inter-utility agreements that are independent of generating companies. On a regional basis, Independent System Operators (ISOs) ensure suppliers have equal access to transmission lines. Ultimately, distribution companies are responsible for procuring an adequate electricity supply for their end-users, and thus will generally rely on *base load* units even though it could be cheaper at times to purchase power from spot market bids.

While the specifics are uncertain, most analysts predict that electric restructuring will take place at a varying pace depending on the state, and will be generally, but not completely, successful in creating an open market. This is because utility regulatory commissions and legislatures in all 50 states are currently in different stages of the implementation process. Some states are still studying the idea informally, others are drafting restructuring legislation, and several implemented retail competition in 1998. Through activities of these regulators and lawmakers, the implications of restructuring are becoming more evident:

Electricity Market Participants

Electricity Producers**:** Generate electricity and sell it wholesale to energy brokers and power marketers at competitive rates.
The Power Exchange**:** The spot market for the buying and selling of energy within a region.
Energy Brokers**:** Buy energy from energy suppliers and then re-market it to power marketers or retailers.
Power Marketers**:** Buy energy wholesale from energy producers or brokers for resale to retailers, or directly to consumers.
Distribution Companies**:** Distribute electricity and/or gas to consumers.

- there will be considerable variation from state to state;
- the transmission and distribution sectors will still be regulated but are likely to be subjected to performance-based rates;
- utilities will get out of existing high cost electricity purchase and fuel contracts;
- wholesale and retail electricity prices will vary widely based on time-of-day, time of year, and region;
- electric utility profits will drive new investment in power generation;
- resolution of stranded cost recovery mechanisms will remain controversial and vary from state to state;
- power marketers could market green electricity produced from renewable or clean energy fuels; and
- power produced from coal mine gas can be marketed to consumers as part of an environmentally friendly energy portfolio.

Restructured Marketplace in States with Coal Mine Gas Resources

As of January 1, 1999, three states have opened their retail electricity markets to competition: California, Massachusetts and Rhode Island. In addition, Pennsylvania (a state with coal mine gas reserves) has implemented the nation's largest pilot program. The strategies that coal mines undertake for the sale, transportation, and delivery of electricity generated from coal mine gas depend heavily on the rate at which restructuring occurs in that state. The North American Electricity Reliability Council divides the United States into power market regions. There are consumers in several of these regions that could directly benefit from power generated from increased coal mine gas recovery and use, however regulatory and legislative activity varies greatly between the states containing gassy coal mines due to existing market parameters.

With a restructured market in place, the proximity of high-demand and higher-priced electricity markets to coal mine gas sources is a key factor in the potential profitability of a coal mine's production and sale of power fueled by recovered coal mine gas. The principle coal mine regions with large coal mine gas resources are located in the north and central Appalachian, central Illinois, Alabama, and south-central Rocky Mountain regions. Energy markets near these regions vary greatly (Figure 2).

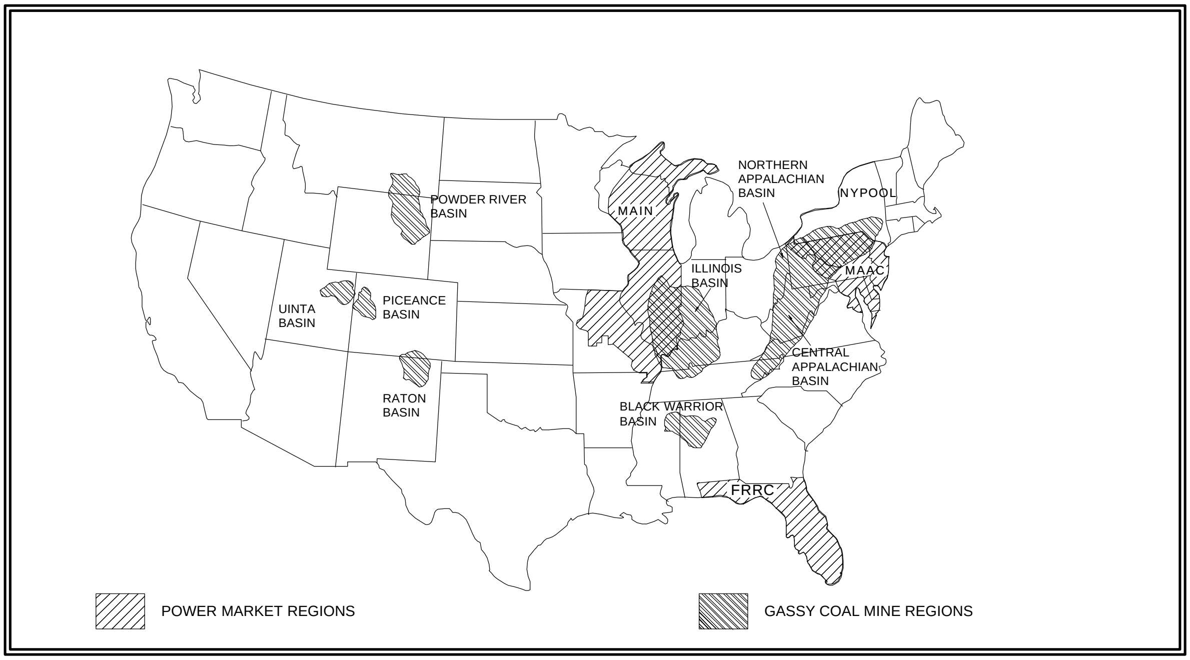


Figure 2 – Potentially Profitable Power Markets Located Near Gassy Coal Mines

Following is a restructuring and market summary as of January 1, 1999 for the regions containing the greatest coal mine methane resources. Appendix A contains a list of organizations where more up-to-date information on state restructuring activities can be obtained.

Northern Appalachian Region

Pennsylvania began its pilot program in July 1998, and within four months nearly two million customers signed up. All customers received a minimum 8% rate reduction and began receiving power from the supplier of their choice in January 1999. Additionally, the Pennsylvania Public Utility Commission has defined coal mine methane as a renewable resource, thus opening the renewable energy market to coal mine gas projects (which CECA encourages). In Ohio, representatives from the five major investor-owned utilities have been developing a consensus framework for a restructuring proposal. The proposal includes retail choice for all consumers by January 2001. Two of the nation's energy markets yielding the highest revenues for electricity sales are the Northeast and Mid-Atlantic regions. Northern Appalachian coal mining regions in Pennsylvania and Ohio could access these markets, although constraints exist via current transmission systems.

Central Appalachian Region

The West Virginia Public Service Commission has designed a deregulation plan for its state and presented it to the legislature in January 1999. In Virginia, the State legislature has passed a bill establishing a Regional Power Exchange and an ISO, as well as competition by 2002. The Mid-Atlantic Area Council (MAAC) region includes Pennsylvania, New Jersey, Maryland, Delaware and Washington D.C. MAAC relies heavily on coal generation from the central Appalachian states and unfortunately for new generation, the line capacity tends to be fully loaded. Due to high operating and maintenance charges, New Jersey consumers paid the highest rates in the region. Central Appalachian coal mines producing electricity could begin selling electricity to this high-demand region once increased line capacity is installed.

Midwest Region
The state of Illinois has enacted a restructuring bill that 1) required a 15% rate reduction beginning August 1998, 2) allows some commercial and industrial retail choice by October 1999, and 3) allows residential customers full choice for their generation supplier by mid-year of 2002. Illinois introduced additional legislation to add environmental provisions to the current law. In Indiana, the State legislature defeated a bill to allow retail access by 2004. Indiana plans to revisit restructuring issues in 1999.

Mid-America Interconnected Network (MAIN) includes Illinois, Wisconsin, and northern Michigan. The regions are heavily dominated by low cost coal generation due to their proximity to coal producing areas of the Illinois Basin. With high demand, however, electricity rates in Illinois are above the national average. Again, coal mines could sell coal mine gas-fueled electricity competitively to this nearby high priced power region.

Rocky Mountain Region
Colorado has failed to pass bills allowing retail competition. However, the legislature passed a bill to study whether retail competition will benefit the state's customers and will report its findings by November 1999. In Utah, the State voted to recommend no restructuring in 1998. A task force issued a draft report favoring restructuring legislation for 1999 using a "go slow" approach.

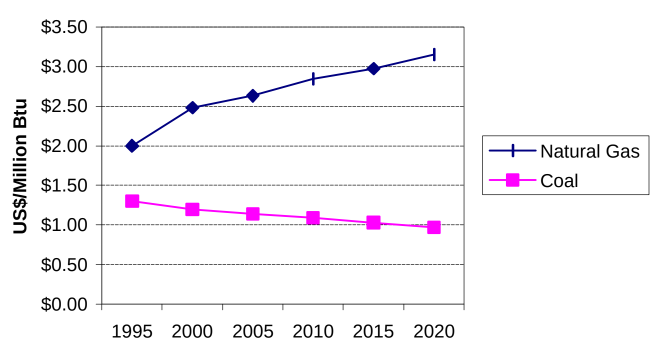
Southeast Region
The state of Alabama has appointed a task force that is preparing a report on restructuring. Some of the largest coal mine gas recovery systems in the nation are located in Alabama's Black Warrior Basin, and are currently used for gas pipeline injection. Alabama residents pay some of the lowest electricity rates in the nation, but Florida consumers pay above average prices. External transmission lines to Florida's market are well interconnected with the Southeastern Regional Council, which operates with little constraint. This situation presents a potential opportunity for Black Warrior Basin coal mines to generate electricity for sale to the Florida market.

IV. POTENTIAL OPPORTUNITIES FOR INCREASED COAL MINE GAS USE

Delivered Cost of Fuel

According to EIA (1998b), gas prices should increase by 50% (from $2/mmBtu to $3/mmBtu) by the year 2015 (Figure 3), mostly due to increased wellhead production costs. The Gas Research Institute predicts a similar gas price increase over the same time period. Coal prices have decreased over the past decade and U.S. DOE predicts they will follow that trend in the future. Natural gas prices are also subject to more seasonal fluctuation than coal.

Figure 3 - Energy Prices for Electricity Generation



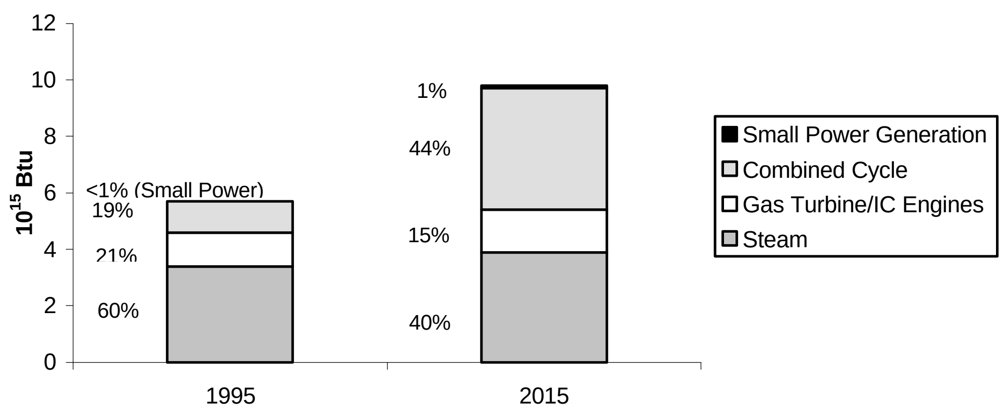
Higher gas prices mean coal mine gas projects could become more economically viable. Medium-quality coal mine gas is an attractive supplement/alternative fuel for power generation, particularly in light of the fact that it does not require upgrading to pipeline quality. In addition, most of the new merchant power plants currently planned or under construction employ highly efficient gas-fueled power generation technologies that could use this medium quality gas.

Delivered fuel costs are a significant part of the total cost of generating electricity from a fossil-fueled generating unit. Incremental fuel costs include: the cost of fuel at the source (mine, wellhead, or refinery), transportation and handling costs, off-site storage costs, and broker or marketer premiums. The delivered fuel cost, which is a major component of the cost of producing a kilowatt-hour of electricity, generally determines whether or not a generating unit is economically competitive. In the case of coal mine gas, the unit cost of gas used on-site or to fuel *nearby* gas-fired electric utilities could be significantly lower than conventional natural gas because of reduced transmission and distribution costs. In view of this, siting new merchant power plants adjacent to coal mines with this low-cost fuel supply provides an excellent opportunity for the power plant to compete in a restructured market. Table 1 in Appendix A lists the potential for gas supplies from 31 of the gassiest coal mines in the U.S.

The Increased Role of Gas-Fired Electric Generation Technologies

Several improved gas-fired technologies are now affecting the structure of electric generating markets, and may provide opportunities for coal mine gas use, if coal mine gas production remains competitive with conventional natural gas. Coal-fired base load units could cofire or reburn gas to yield environmental as well as economic benefits. Small gas turbine developments may afford coal mine operators the option of on-site power generation during peak pricing periods. In addition, the development of new technologies that reduce the cost of producing, storing and transporting gas may increase the role of coal mine gas usage as well. Total gas use in power generation, including on-site industrial cogeneration, is expected to grow from 5.6 quadrillion (10^{15}) Btus in 1995 to 9.7 quadrillion Btus by the year 2015 (Figure 4), with combined-cycle turbines accounting for most of the increase (GRI, 1997a).

Figure 4 - Gas Use by Technology



The evolution of a competitive electricity market structure should produce market niches for coal mine gas-fired generation technologies. The development of small-scale gas turbines, combined cycle cogeneration systems, fuel cells, microturbines and other distributed generation processes has moved beyond the research and development stage, and these technologies are now commercially available. The success of these technologies, together with current usage of gas turbines and internal combustion engines in the electricity marketplace, is increasing the potential for coal mine gas use. U.S. EPA's Coalbed Methane Outreach Program (CMOP) has published a Technical Options Series of case studies that provides more information about these technologies. Appendix B lists these and other CMOP publications.

Fuel Switching Generating Units

Electric power generating companies generally prefer to have generating units that can use more than one fuel so that they can take advantage of supply and price differentials between fuels. A coal-fired unit may include fuel-switching capabilities that allow it to burn oil or natural gas (including coal mine gas). Gas-fired generating units using today's turbine technology also have the capability to switch to distillate fuel oil or diesel, which would allow them to continue generating power if coal mine gas supplies were disrupted. In this case, the generator would have to invest capital for on-site fuel storage equipment.

In a restructured market, generating units located at or near a coal mine could use coal mine gas piped directly from the mine. There would be several economic advantages to both parties, one being little or no charges for transporting the gas. Electricity produced with minimal transmission costs could be sent directly back to the mine for on-site use. When considering fuel switching, a power producer would have to evaluate performance, capital cost, operating cost, and utilization rates.

Peak Period Sales

Generally occurring on hot summer afternoons, peak time periods provide coal mines with a window of opportunity to sell coal mine gas-fueled electricity when prices are at their highest. In June 1998 in the Midwest (a partially deregulated market) prices soared as high as $7,500 per MWhr. With the development of real-time metering, short-term, hourly electricity sales (or on-site use to offset purchases of peak electricity) can be maximized by coal mines. As competition increases, coal mine gas developers should seek opportunities for using coal mine gas to fuel peak power units during maximum load periods. Gas-fired combustion turbines tend to be ideal for coal mine gas fuel and peak service use. To be economically attractive, however, such coal mine gas projects must be able to sell the gas to a pipeline or use it on-site during the off-peak power months.

This type of collaborative effort could benefit both parties involved. For example, power marketers look to spot market sales of electricity to supplement their base loads during the summer months. Traditionally, pipeline gas prices are lowest during these months, so operating coal mine gas-fueled electric generators would maximize profits during this time. A gas storage facility could improve the economics of operating a peak load unit at a coal mine, or could supply gas to larger-scale peaking units. A storage facility would also give a mine the ability to maximize gas sales during the winter months when gas prices are at their peak[4]. Utilities may have several peak period markets to which they can supply electricity, if available. Therefore, utilities could maximize their profits by having the additional capacity to reach as many high-priced, peak period customers as possible during short time periods.

[4] Select abandoned coal mines could be suitable for storing coal mine gas from active mines, and could provide significant economic advantages to coal mine gas projects. Gas storage can be particularly advantageous to larger coal mine gas projects (U.S. EPA, 1998g).

Distributed Power Generation

"Distributed generation" is defined as the integrated use of small, modular power generation systems typically ranging from a few kilowatts up to 25 MW. It differs from self-generation in that power units are placed close to a limited number of consumers to enhance the capability of the existing power grid. Large-scale power systems, in contrast, require direct access to large quantities of fuel and serve larger populations than distributed generation systems. Areas where the cost of power delivered to the point of use is high and/or those areas with high peak-period electricity prices will benefit from distributed power generation systems. Figure 5 shows examples of the distributed power generation process, showing how internal combustion engines, gas-fired turbines, and fuel cells might be used for distributed generation.

Both local utilities and coal mines can benefit from distributed power systems. To illustrate, local utilities could substitute a distributed generation system for needed upgrades or additions to existing generating capacity, transmission, or distribution systems. They may be able to reduce their SO_2 and NO_x emissions by supporting coal mines in producing clean power for sectors which are now supplied by older, less efficient power systems. As part of a distributed power generation system, coal mines could generate electricity for themselves and sell power to nearby industrial plants, commercial centers, or residential customers. In addition, any excess electricity could be sold back to the local grid for commercial or industrial customers that are currently on power systems that may be near capacity. Moreover, if a power producer arranges a distributed power generation system for a coal mine and industrial customers, it could benefit utilities by allowing them to shift electricity sales to higher-priced markets such as residential consumers.

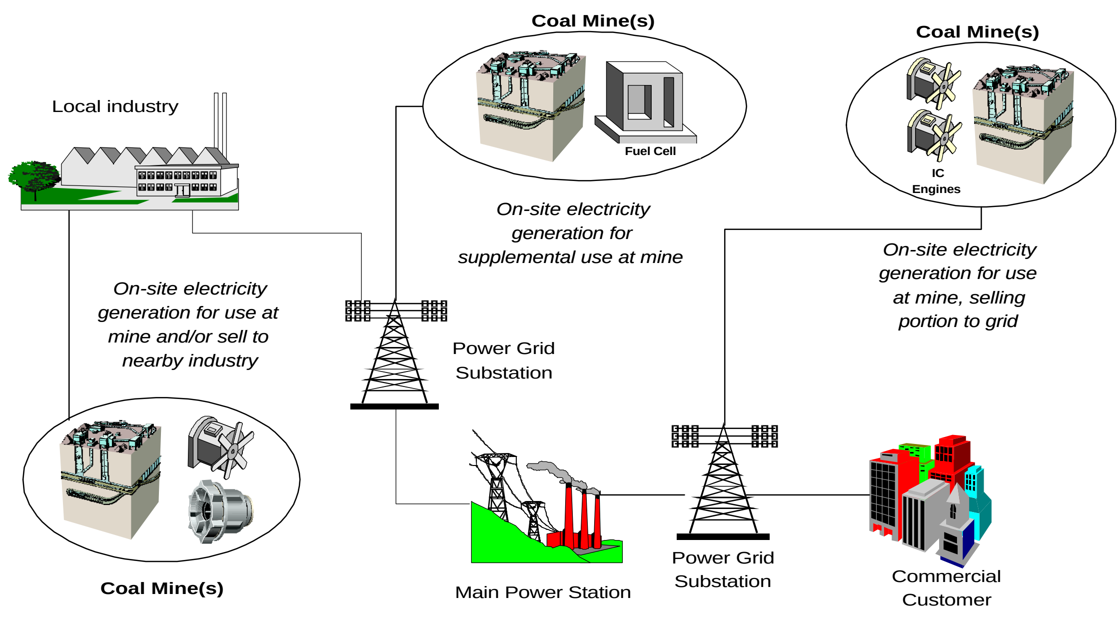


Figure 5: Examples Of Distributed Generation Systems Using Coal Mine Gas

Based on estimates of electricity demands of mines profiled in U.S. EPA's *Identifying Opportunities for Methane Recovery at U.S. Coal Mines*, a power generating unit ranging in capacity from 5-25 MW would meet the needs of 80% of the gassiest underground coal mines in the U.S. (U.S. EPA, 1997). At a 60% methane recovery rate, 12 of the 25 gassiest coal mines in the U.S. could produce enough coal mine gas to supply 100% of their power requirements, and in addition, provide electricity for market sales. An additional eight of the 25 mines would be capable of producing as least two thirds of their energy needs. Overall, these gassy coal mines have the potential to produce 10 to 30 MW each of electric generating capacity, while reducing their greenhouse gas emissions. Table 1 in Appendix A lists the potential generating capacity for each of these 25 mines.

Opportunities for Coal Mine Gas Use Resulting from Environmental Regulations

Title IV of the 1990 Clean Air Act Amendments (CAAA) sets as its primary goal the reduction of SO_2 and NO_x emissions, mostly from coal-fired utility and industrial boilers. As a result, Title IV has given industry the impetus to produce and commission new coal-fueled advanced power systems, such as low-emission boilers and pressurized fluidized bed combustion. Title IV provides a significant opportunity for coal mine gas to play a cost-effective role in the electricity generating sector, in that utilities can reduce emissions by cofiring coal mine gas in coal-fired utility boilers. In particular, U.S. EPA's recent ozone rule may negate the price advantage currently enjoyed by Midwestern coal-fired utilities. A restructured market may make it easier for such utilities to use coal mine gas as part of an alternative fuel strategy.

Below is a brief description of each type of environmental benefit associated with increased coal mine gas use.

Sulfur Dioxide Emissions Allowances. U.S. EPA's Acid Rain Program introduced an SO_2 allowance trading system that harnessed the incentives of the free market to reduce emissions of this pollutant. Under this system, the law sets a permanent cap on emissions nationwide. Utilities are given a set number of allowances. Those that reduce emissions through energy efficiency, pollution control devices, or renewable energy are able to sell or bank their surplus allowances, while those that exceed their allowed emissions must buy additional allowances. U.S. EPA has instituted an electronic record keeping and notification system called the Allowance Tracking System to track transactions and the status of allowance accounts. The market price of an SO_2 allowance as of December 1998 was $196/ton (Cantor Fitzgerald, 1998).

Use of coal mine gas as a fuel for electricity generation, whether through co-firing, combustion air or supplemental power systems, could be economically beneficial to a utility by reducing its SO_2 allowance purchases. Based on the current value of SO_2 allowances, a utility would realize an offset value of $0.11/MM Btu of gas fired. As Phase II of the program begins in the year 2000, U.S. EPA will lower the cap on SO_2 emissions on all utility units, thus increasing allowance trading and possibly prices, which will increase the value of coal mine gas for SO_2 emission reductions.

Nitrogen Oxide Emissions Allowances. Phase II of the Acid Rain Program will subject *all* utility boilers to further reductions in NO_x emissions (a precursor to ground-level ozone formation) in the year 2000. The NO_x program embodies many of the same principles of the SO_2 trading program; however, it does not cap NO_x emissions as does the SO_2 program, nor does it employ an allowance trading system. Compliance is based on individual emission rates for boilers using "reasonably achievable control technology" (RACT), which gives utilities more flexibility to meet emissions limitations in the most cost-effective way.

As an addition to the Acid Rain Program, U.S. EPA published the proposed rule in May 1998 to implement a program aimed at further reducing emissions of NO_x to less than half of the 1990 baseline levels (U.S. EPA, 1998d). U.S. EPA proposed the rule under the Ozone Transport Commission (OTC) NO_x Program. Like the SO_2 allowance trading program, the OTC rule will use a "cap and trade" system to reduce ground-level ozone in 22 states[5], thus affecting all existing fossil-fuel fired boilers with an output greater than 15 MW. Individual states that adopt the program will allocate the NO_x allowances and ensure that sources are in compliance through a State Implementation Plan (SIP), while U.S. EPA will operate the only allowance and emissions tracking systems for the program. The NO_x reductions will be implemented in two phases, the first phase beginning May 1999 and the second phase in May 2003. The market price of OTC NO_x credits during 1998 ranged from $1,500 to $3,400/ton, depending on the month, state, and air quality designation (Cantor Fitzgerald, 1998).

Cofiring coal mine gas with coal in boilers can prove to be an economical strategy for helping utilities comply with NO_x regulations under Phase II of the U.S. EPA's Acid Rain Program and the more recent OTC program. Utilities affected by these programs are responsible for demonstrating compliance with the requirements of both programs. For existing power plants, the calculated value of NO_x reductions, based on OTC NO_x offset values ranging from $1,500 to $3,400/ton, is $1.69 to $3.74/MM Btu of gas co-fired with coal, respectively (U.S. EPA, 1998b). Although, the cost of implementing this post-combustion technology is approximately $1500/ton NOx removed, the emissions offset value can easily exceed the value of the avoided coal consumption and cost of implementing the technology.

Greenhouse Gas Emissions. Methane is a greenhouse gas, and when coal mines emit it to the atmosphere, rather than using it as fuel, it contributes to global warming. In fact, methane significantly contributes to global warming because it is approximately 21 times more potent (as a greenhouse gas) than carbon dioxide (CO_2). U.S. EPA estimates that recovering and using just 1 BCF of coal mine methane is equivalent (in terms of global warming reduction) to taking nearly 90,000 cars off the road (U.S. EPA, 1998e).

Congress's passage of Title XVI, Sec.1605(b) of the Energy Policy Act of 1992 directed the DOE's Energy Information Administration to establish a database for voluntary greenhouse gas emissions reductions. The benefit of reporting reductions in greenhouse gas emissions is that participating companies have a formal record of their efforts to reduce greenhouse gas emissions. Although a trading system for greenhouse gas reductions has not been implemented, governments worldwide are examining proposals for domestic and international greenhouse gas trading systems. Recently, the Dutch government and the state of New Jersey signed a "letter of intent" in June 1998 to design a prototype greenhouse gas emissions trading system (U.S. EPA, 1998f). U.S. EPA has developed several Voluntary Programs that allow companies, agencies, and other organizations to report the results of actions taken to reduce or offset greenhouse gas emissions. U.S. EPA's Coalbed Methane Outreach Program (CMOP) works with coal mines to encourage the recovery and use of coal mine gas that would otherwise be emitted to the atmosphere during mining operations.

At least two companies have already engaged in a greenhouse gas emissions trade. In March 1998, Suncor Energy of Canada made an initial purchase of 100,000 metric tons of CO_2 emission reductions from Niagara Mohawk Power Corp. of the U.S., with an option to purchase up to an additional 10 million metric tons over a ten-year period. The trade, potentially worth $U.S. 6 million, establishes Suncor and Niagara Mohawk as leaders in emissions credit trading. Currently, Alternative Fuels Corporation operates the Green Valley Coalbed Methane Power Plant that generates 1.2 MW of electricity using coal mine gas from an abandoned mine near Terre Haute, Indiana. The project reports approximately 38,000 tons per year of CO_2 equivalent credits per megawatt of generation. The Chicago Board of Trade lists the current market value

[5] The states that will be subject to this action are: Alabama, Connecticut, District of Columbia, Delaware, Georgia, Illinois, Indiana, Kentucky, Massachusetts, Maryland, Michigan, Missouri, North Carolina, New Jersey, New York, Ohio, Pennsylvania, Rhode Island, South Carolina, Tennessee, Virginia, Wisconsin, and West Virginia.

of greenhouse gas credits, based on their carbon dioxide equivalent, as approximately $1 per metric ton (Cantor Fitzgerald, 1998) depending on the industry, country, type of project, and ability to validate the reduction.

Cofiring Gas in Coal Boilers to Reduce SO_2, NO_x, and GHG Emissions. The ease of boiler conversion and low capital cost make cofiring a low-risk approach to using coal mine gas. Cofiring improves ash quality, reduces slag buildup, and can slightly increase boiler efficiency. The gas input may vary from less than 3% to 100% of the total fuel input, increasing the short-term peaking capability of the coal-fired boiler. One cofiring technology termed "gas reburning" can achieve a NO_x reduction of 5% for each 1% of gas heat input (U.S. EPA, 1998b). The value of NO_x benefits is not linear with the percentage of coal mine gas cofired, as it peaks at about 7% heat input. As a result, a coal mine gas cofiring rate of 7% is able to reduce entire boiler emissions by over 40%, making this NO_x control technology an economically attractive gas use option in some cases.

Approximately 370 utility boilers in the U.S. now have cofiring capability, of which many are situated near gassy coal mines. In order to determine which boilers would be ideal for cofiring with coal mine gas, operators must consider gas demand and availability, pipeline distance, and boiler conversion costs. Cofiring is an ideal application for variable quality coal mine gas. U.S. EPA is researching the economic potential of siting new coal-fired boilers at gassy coal mines to employ coal, coal mine gas, and ventilation air as fuels. If successful, these new boilers could assure the future sales of coal *and* coal mine gas for coal mine operators.

***Economics of Cofiring with Coal Mine Gas*.** The economics of cofiring gas at coal-fired industrial and utility boilers makes a compelling argument for coal mine gas use, especially at power plants located at coal mines. As competition in the electric industry serves the lowest-cost producer, the use of low emissions technologies will become increasingly important to utilities. In addition, emission credits and avoided penalties can substantially improve the economics of most coal mine gas projects, therefore stabilizing coal use for utilities that can achieve low-cost environmental compliance. Cofiring coal mine gas with coal can therefore help utilities comply with environmental regulations without having to switch entirely from coal to gas. Table 1 illustrates the potential value of coal mine gas when SO_2, NO_x, and greenhouse gas reduction values are taken into account.

Table 1 – Estimated Value of Coal Mine Gas Based on Emissions Reductions Achievable by Gas Reburning in Coal-Fired Boilers at Electric Utilities (modified from U.S. EPA 1998d)

BENEFIT	Coal Replacement[1]	Reduced OTC NO_x Emissions[2]	Reduced SO_2 Emissions[3]	Reduced CH_4 Emissions[4]	Total
GAS VALUE ($/MM Btu)	$1.27	$1.69-$3.74	$0.11	$0.40	$3.09-$5.52

[1] Avoided cost of coal based on 1997 U.S. average coal purchase prices
[2] Assumes OTC NO_X credit value of $1500-$3,400/ton and a 5% NO_x reduction for each 1% of gas fired
[3] Assumes SO_2 credit value of $196/ton SO_2 , and 1.5% sulfur content in coal combusted
[4] Assumes greenhouse gas credit value of $1/metric ton CO_2 equivalent (or $3.67/ton of carbon) and does not include additional offset for reduced carbon emissions resulting from reduced combustion of coal

In summary, environmental regulations are compelling utilities to find least-cost options for reducing SO_X and NO_X emissions. Opportunities arising from restructuring, such as bundling of energy services and advances in distributed power generation technologies, should make it more feasible than ever before for utilities to use coal mine methane for this purpose.

Green Energy Marketing

Green energy marketing capitalizes on an expressed public preference for cleaner energy options, such as energy derived from renewable sources. Currently, power marketers advertising green energy are suggesting to consumers that *they* can make a difference in protecting the environment by purchasing electricity generated from “green” sources. Several companies are offering premium electricity rates based on 10, 25 or 50% of a consumer's power coming from renewable or green sources. New energy companies use names like "Green Mountain" or "Earth Source" to promote their environmentally-friendly image. Pilot programs in several states have shown customers are willing to pay a 1-2 cent per kilowatt-hour premium for green power (Swezey, 1997), and utilities in fifteen states, including Colorado and Indiana, have developed or are developing green pricing programs.

Green marketing has the potential to expand domestic markets for renewable energy technologies, although critics argue that the current marketing of green energy is merely repackaging electricity from existing sources at higher rates without additional benefits to the environment (Public Citizen, 1998). While some states classify green power as only that which is generated by renewable (e.g. wind or solar) power, several states, such as Pennsylvania, New Hampshire, and Massachusetts have broadly defined green power to include other energy sources. An expanded definition that includes coal mine gas-generated power may attract a larger market segment, and better serve to heighten environmental awareness of greenhouse gas emissions. Based on recent electricity marketing approaches, it appears the reduction in greenhouse gas emissions resulting from coal mine gas use could be attractive to the environmentally conscious consumer or business. Consumers may be willing to pay a premium for coal mine gas-generated power even if it does not receive an official “green” classification.

The degree to which power marketers can sell electricity in a given market determines the success of a green energy program. If state restructuring rules are "market friendly" such that power marketers can compete, green energy marketing will be present. However, restructuring in states like California and Massachusetts has made it difficult for power marketers to compete with local utilities, therefore making green energy marketing difficult as well. According to U.S. DOE's Green Power Network (Houston, 1998), the fact that Pennsylvania's restructuring rules are favorable to power marketers make it the most friendly state toward green power marketing. This, coupled with the state's designation of coal mine methane as a renewable resource, make Pennsylvania an ideal green energy market for coal mine gas-fueled electricity projects.

Power producers that use coal mine gas should strive to be a part of this new, environmentally-friendly marketing approach. Under this marketing scenario, the higher rates that customers would be willing to pay for electricity produced from coal mine gas could make recovery and use projects more attractive. Under restructuring, the customer or end-user would not even have to be located near gassy coal mine regions to take advantage of this energy source.

V. TAKING ADVANTAGE OF RESTRUCTURED POWER MARKETS

There are several ways in which restructuring creates potential opportunities for increased coal mine gas use. The bundling of energy services can allow for coal mine gas to be sold as part of a coal sales contract, pipeline gas sales, or with electricity. The convergence of the gas, coal and electricity industries may facilitate these opportunities. In addition, the electric industry's shift to cleaner-burning, gas-fired power generation will provide opportunities for coal mine gas use as fuel (in cofiring for example) and as a means of reducing NO_x and SO_2 emissions. As a result, restructuring may encourage coal mines to form relationships with energy producers, power marketers, or local utilities that could spawn joint ventures or alliances that can provide the capital investment required to construct new co-fired or gas-fueled power systems. In many cases, the mutual benefits of forming alliances may overcome the advantages of energy company mergers. The following subsections discuss how coal mine operators can take advantage of restructured power markets by bundling energy services through mergers or alliances, developing strategic partnerships with other energy companies, and planning gas-use strategies with other investors based on changing market conditions.

Bundling of Energy Services

With the evolution of natural gas industry restructuring, competitive-based natural gas contracts are becoming more target-oriented toward specific industries and regions of the country. Electric industry restructuring is envisioned to follow the same path, therefore, the link between market prices for gas and power may become stronger. Integration of gas producers, pipeline companies, and power producers supports further convergence of the gas and electric industries, therefore broadening markets for coal mine gas.

Bundling of coal, gas, and electricity sales along with SO_2, NO_x, greenhouse gas credits and avoided penalties can maximize the value of coal mine gas. Already, there are marketing groups that offer "total Btu packages", meaning that they can offer services that would meet all of a consumer's energy needs, whether they require coal, gas, fuel oil, electricity, or any combination of these fuels. In addition, Btu bundling can also occur at the wholesale level, such that a coal mine could offer to sell coal, coal mine gas for cofiring, or coal mine gas-fired electricity to a utility company. In addition, a utility can purchase emission reduction credits generated through coal mine gas use in cofiring or electricity generation.

Convergence of Energy Industries

The unbundling of gas and electricity services and rates is contributing to a convergence of energy industries, where markets may soon be defined by a "Btu of energy service" rather than by a kilowatt-hour of electricity or a thousand cubic feet (mcf) of natural gas. Participants in the new market will be able to offer customers functions and services from both industries, such as Btu substitution and real-time metering for end-users, along with various types of "full service" functions such as load management services and energy efficient equipment.

Many gas and electric companies that have merged over the past year are venturing into "one-stop shopping" for consumers. For example, Atlanta-based Southern Company and Houston-based Vastar Resources joined forces to create Southern Company Energy Marketing. Similarly, Puget Sound Power & Light Co. acquired Washington Energy Company to form Puget Sound Energy. Energy companies such as these could utilize and market coal mine gas as a fuel and/or as gas-fueled electricity.

There are indications that economic conditions in some regional energy markets may foster the convergence of the coal industry with the gas and electricity industries. If a coal mine has access to gas pipelines and electric transmission lines through its parent company, coal mine gas projects could become more accessible to energy markets. A good example of this merging of industries is PacifiCorp's[6] recent attempt to buy Britain's largest supplier of electricity, The Energy Group PLC (which is the parent company of Peabody Coal, the world's largest private coal producer).

[6] Pacificorp owns two large electric utilities, Pacific Power and Utah Power, lists PacifiCorp Power Marketing as a subsidiary, owns five coal mines in the western U.S., and has alliances with several gas marketers.

PacifiCorp's interest in acquiring The Energy Group apparently included a long-term strategy with Peabody Coal (Ludwigson, 1997). These intentions became clear when PacifiCorp announced a willingness to renegotiate the coal contracts held by Peabody Coal in exchange for the right to sell additional electricity produced by the plants bound by these contracts. PacifiCorp's scheme was to acquire access to prime generating capacity by lowering coal prices to those plants. If successful, this merger would have redefined vertical mergers and added a new dimension to coal/energy industry convergence, but an investor-owned holding company, Texas Utilities Company, bought The Energy Group in May 1998 by outbidding PacifiCorp. In December 1998, Pacificorp merged with another leading British multi-utility company, ScottishPower.

Developing Strategic Partnerships

Coal mine operators considering coal mine gas recovery and use projects must weigh the risks and benefits to their mining operations. In addition to increased mining efficiency, benefits may include long-term relationships with utilities, royalty payments from gas revenues, increased cash flow, and greenhouse gas credits. The key to maximizing benefits from coal mine gas-fueled power projects is the development of strategic partnerships or alliances between coal mine operators and energy producers, marketers, or utilities. Table 2 in Appendix A lists methane drainage systems currently employed at U.S. coal mines.

Coal mines with drainage systems in place are in a strong position to seek out partners for joint ventures, equity investments, and debt financing for electric power project development. Mutual interest between a merchant power plant developer and an anchor tenant like a coal mine makes a power project near a coal mine very attractive for both parties. For example, a power producer may be able to take advantage of the availability of both coal and a coal mine's gob gas. In turn, the coal mine may be able to purchase a portion of the electricity at a rate that would be attractive for long term, on-site use. Also, the two parties could include the greenhouse gas credits generated by reduced greenhouse gas emissions in the transaction.

Coal Mine/Utility Partnerships. Electric utilities are looking for better ways to serve (and keep) their clients. A utility that ventures into an agreement with a coal mine that allows the mine to self-generate part of its electricity needs can profit by 1) retaining the coal mine as a customer, 2) redirecting electricity sales from the coal mine to residential or commercial customers, who pay higher rates (traditionally, utilities sell electricity to coal mines at low industrial rates), and 3) possibly reducing capacity constraints of certain transmission lines. Furthermore, a utility may profit from financing a power project sited at a mine, where the mine supplies the gas and uses a portion of the power, and the utility sells the remaining electricity to other customers. A coal company could become a total power supplier in this case, including the potential for saleable emissions reductions credits.

Some coal suppliers have been reluctant to develop coal mine methane fueled power generation projects because 1) they fear that this could jeopardize coal sales, since utilities are the main customers of coal suppliers, and 2) it would compete with their own coal sales. However, in this age of restructuring and merging of energy industries, there could be many cases where a coal supplier could self-generate power, or sell power to the grid, without necessarily alienating a utility customer. Furthermore, in becoming a “total Btu provider”, the “coal supplier” becomes an *energy* supplier, capable of selling coal or gas in whatever combination is most profitable.

Coal Mine/Gas Developer Partnerships. A restructured market will encourage bilateral transactions between gassy coal mines and different parties within the electric power market. In some cases, agreements may involve participation of gas developers that supply gas to electric utilities, and may provide the best avenue for connecting coal mines with gas-fired power generators.

In addition to producing saleable gas, coal mine operators can realize economic benefits from gas drainage projects through reduced mine ventilation costs and fewer methane-related production delays. Recent research (Mutmansky, 1997) has shown that the use of coal mine methane drainage systems before or during the mining process can significantly lower mining costs and/or increase coal production, particularly if the levels of methane in the seam being mined are relatively high.

Coal mining companies that do not have corporate ties to gas developers can also look toward independent gas developers to help finance coal mine gas recovery projects. If the mine is not interested in operating the project itself, it can turn over project operations to the gas developer who will determine the best use of the gas. Coal mine operators may be able to obtain financing for the project based on the economic benefits of increased coal production, in addition to gas sales. U.S. EPA has prepared several publications that can provide the reader with more information regarding financing of coal mine gas projects (Appendix B).

When entering into agreements between coal mines and gas industry partners, it is important to consider the coal mine's existing relationship with a coal-fired power producer and the future of its coal contracts. Table 2 lists several strategic partnerships that could develop from restructuring, along with their associated benefits.

Table 2 - Mutual Benefits of Various Partnerships

PARTNERSHIPS	OPTIONS	MUTUAL BENEFITS
Coal Mine and Coal-fired Utility	Cofiring, On-site use	Decreased SO_2, NOx & GHG emissions adds value to gas Existing agreements may be in place
Coal Mine and Gas Developer	Gas sales to pipeline Gas sales to gas-fired power plant	Revenues from gas sales GHG reduction credits may be bundled with coal sales or traded separately
Coal Mine and Merchant Power Developer	Cofiring on site Gas-fired power plant on site	Reduced on-site electricity costs and GHG emissions Fuel to supply low-emissions power plant
Coal Mine and Power Distribution Company	Distributed generation power system On-site use	Revenues from electricity sales & GHG credits Reduced on-site electricity costs
Coal Mine and Power Marketer	Electricity sales to off-site markets	Revenues from electricity sales & GHG credits Market green energy to consumers

Recommended Coal Mine Gas Use Strategies

Developers of coal mine gas-fueled electricity projects must choose the gas-use strategies that best suit the needs of the mine(s) supplying the gas, and must also consider the influence of the regional power market on gas sales. This subsection discusses six different recommended gas-use strategies that could be mutually beneficial to the parties involved. Table 3 summarizes these strategies, along with their potential benefits and issues.

Table 3 - Benefits and Potential Issues of Various Gas Use Options

GAS USE OPTIONS	BENEFITS	POTENTIAL ISSUES
- **Sell coal mine gas** to coal-fired utility for co-firing	- Could bundle gas with coal sales - Emissions reduction for both parties	- Gas pipeline system may be needed - Cost of boiler conversion
- **Sell electricity wholesale** to power marketer to wheel over transmission lines	- Long-term recovery solution for coal mine gas - Electricity sales can be used to generate revenue - Reduce load on system	- Capital costs - Profits depend on regional market
- **Produce distributed power** or produce and consume on-site electricity	- Electricity can be used to meet coal mine's needs - Excess electricity can be sold to local consumers	- Capital costs - Higher O&M costs for smaller projects - Electricity is dependent on consistent gas flow
- **Bundling of coal, gas and electricity** sales to power producer	- Long term recovery solution for coal mine gas - Could maximize value of each commodity through bilateral contract with power producer	- Capital costs - Managing both electric generating unit and gas pipeline system
- **Sell coal mine gas-generated electricity** to power marketer for green energy sales	- Added value to electricity - Generate revenue	- Capital costs
- **Sell either coal mine gas or coal mine gas-generated electricity** depending on market prices	- Maximize gas value - Capture market for both peak sales	- Capital costs - Gas must be stored, used or sold separately at different times of year

1. **Selling coal mine gas directly to a coal-fired utility** for cofiring or fuel switching is one of the simplest strategies. This arrangement benefits both the coal producer and coal customer, and with the possible exception of an independent gas developer, no new companies would need to enter into the relationship. As discussed earlier, both parties can reap the economic benefits of reduced emissions.

2. **Selling coal mine gas-generated electricity wholesale to power marketers** can generate revenue for the coal mine. A restructured market allows electricity sales to customers anywhere in the U.S., provided there is transmission capacity available. As previously discussed, there are highly prospective regional markets located near several gassy underground coal mine regions.

3. **Producing coal mine gas-generated electricity for use on-site with a distributed power generation system** has many advantages, especially if a coal mine is currently located in a high-priced region. Electricity costs to the coal mine will decrease and any excess power can be sold back to the grid. Joint ventures with coal mines may be attractive to utilities if the reduced load on the utilities' system allows increased sales (from their existing capacity) to higher-priced end users.

4. **Bundling of coal, gas, and electricity sales along with SO_2, NO_x, and greenhouse gas credits** would maximize the value of coal mine gas. Coal mines that sell coal to a nearby power plant with fuel switching or cofiring capability could negotiate a combined gas and coal sales contract. Electricity produced by the coal mine could also be bundled into the sales agreement, and greenhouse gas credits could be incorporated into an agreement as well.

5. **Marketing coal mine gas as green energy** can prove to be an excellent strategy for a power marketer. Environmentally conscious customers are choosing green power over conventionally produced power and are willing to pay a premium for it. Power marketers and consumers will likely embrace the opportunity to reduce greenhouse gas emissions via coal mine gas recovery and use.

VI. CONCLUSIONS

It is clear that restructuring of the electricity industry will have far-reaching implications for all energy sources, including coal mine gas. The outcome is difficult to predict at this early stage of restructuring. Most indicators show an increased dependence on gas for electricity generation over the next few decades, where competition will most likely favor the low-cost electricity producer. Coal mine gas producers who can supply low-cost fuel may become an essential part of this equation.

The following areas appear to present key opportunities for coal mine gas producers:

- *On-site power generation*. On-site power generation eliminates distribution and transmission costs, and gas-fired electric generating units have low capital costs relative to coal-fired units. Medium-quality coal mine gas is ideal for fueling power generation units.

- *Bundling of energy services*. The convergence of the gas and electric industries will allow for Btu substitution, such as combined coal, gas and electricity sales, which will open the door for greater flexibility in coal mine gas use options. Coal mines could sell either coal, gas or electricity to an integrated power market based on energy prices, seasonal or diurnal demand, and regional demands. Greenhouse gas emission credits can be incorporated into energy contracts as well.

- *Advances in distributed power generation technologies*. Distributed generation systems are expected to account for over 20% of all new electricity generation capacity. Several advanced gas technologies such as fuel cells, micro turbines, and IC engines are ideal options for distributed power or on-site use at coal mines. Coal mine gas-fired power generation can supplement distributed power systems, while restructuring will enable coal mines to sell power locally.

- *Cofiring coal mine gas with coal.* Cofiring can reduce overall SO_2 and NO_X emissions and would be particularly cost effective in states located within the Ozone Transport Corridor. By siting at coal mines, new merchant power plants could assure both coal and coal mine gas sales.

- *Electricity sales in high-priced markets.* Many gassy coal mines are located in regions of the country with relatively high-priced electricity markets that will need additional power generation capacity. In some instances, utilities may allow coal mines to produce on-site power at peak periods, reducing electricity costs for the mine while allowing the utility to sell the displaced electricity to higher priced markets.

The U.S. energy marketplace is dynamic and complex. Coal mines and project developers can best capitalize on opportunities in the present marketplace by forming strategic alliances with other energy industry partners. Ideal partners are those that are well-positioned to help the coal mine or project developer meet its short- and long-term goals.

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Appendix A

LISTING OF PUBLIC UTILITIES COMMISSIONS
IN STATES WITH GASSY COAL MINES

Alabama Public Service Commission
P.O. Box 991
Montgomery, AL 36101-0991
Telephone: 334 242-5025
Web site: www.psc.state.al.us

Colorado Public Utilities Commission
1580 Logan Street
Office Level 2
Denver, CO 80203
Telephone: 303 894-2000
Web site:
http://www.jpuc.state.co.us/pucsites.html

Illinois Commerce Commission
527 E. Capitol Avenue
P.O. Box 19280
Springfield, IL 62794-9280
Telephone:
Springfield: 217 782-7295
Chicago: 312 814-2850
Web site: http://icc.state.il.us/

Indiana Utility Regulatory Commission
302 West Washington St. – Suite E306
Indianapolis, IN 46204
Telephone: 800 851-4268
Web site: http://www.ai.org/iurc/index.html

Kentucky Public Service Commission
730 Schenkel Lane
P.O. Box 615
Frankfort, KY 40602-0615
Telephone: 502 564-3940
Fax: 502 564-3460
Web site: http://www.psc.state.ky.us

New Mexico Public Utility Commission
224 East Palace Ave., Marian Hall
Santa Fe, NM 87501
Telephone: 505 827-6940
Fax: 505 827-6973
Web site: http://WWW.PUC.STATE.NM.US/

Public Utilities Commission of Ohio
180 E. Broad St.
Columbus, Ohio 43215-3793
Telephone: 614 466-3292
Web site:
http://www.puc.ohio.gov/CONSUMER/RT/RT_INDEX.HTML

Pennsylvania Public Utility Commission
P.O. Box 3265
Harrisburg, PA 17105-3265
Web site:
http://puc.paoline.com/com_info/consmrinfo.htm

Utah Division of Public Utilities
4th Floor, Heber M. Wells Bldg.
160 East 300 South
Box 146751
Salt Lake City, UT 84114-6751
Telephone: 801 530-6651
Fax: 801 530-6512
Web site:
http://www.commerce.state.ut.us/web/commerce/pubutls/dpuhp1.htm

Virginia State Corporation Commission
Division of Energy Regulation
4th Floor – Tyler Building
1300 E Main Street
P.O. Box 1197
Richmond, VA 23218
Telephone: 804 371-9611
Web site:
http://www.state.va.us/scc/division/pue/index.htm

Public Service Commission of West Virginia
201 Brooks Street
Charleston, WV 25323
Telephone: 800 642-8544
Web site:
http://www.state.wv.us/psc/psccons.htm

Appendix B

Related Publications

EPA has published many coal mine methane reports, including:

Technical and Economic Assessment of Coal Mine Methane Use in Coal-Fired Utility and Industrial Boilers in Northern Appalachia and Alabama, April 1998. Provides information about potential opportunities of cofiring coal mine methane in coal-fired utility and industrial boilers.

White Paper: The Impacts of FERC Order 636 on Coal Mine Gas Project Development, March 1998. Provides information about opportunities for coal mine methane use resulting from the passage of FERC Order 636.

***Identifying Opportunities for Methane Recovery at U.S. Coal Mines: Draft Profiles of Selected Gassy Underground Coal Mines* - Office of Air and Radiation, September 1997.** Provides information about specific opportunities to develop methane recovery projects at large underground coal mines in the United States.

***A Guide to Financing Coalbed Methane Projects* - Office of Air and Radiation, January 1997**. Addresses issues related to coalbed methane project finance.

***A Guide for Methane Mitigation Projects: Gas-to-Energy at Coal Mines* - Office of Air and Radiation, February 1996.** Provides guidance for developing programs to reduce methane emissions from coal mines through coal mine methane recovery and use.

***Finance Opportunities for Coal Mine Methane Projects: A Guide for West Virginia* - Office of Air and Radiation, August 1995.** Provides information regarding financial assistance opportunities available in West Virginia.

***Finance Opportunities for Coal Mine Methane Projects: A Guide for Southwestern Pennsylvania* - Office of Air and Radiation, June 1995.** Provides information regarding financial assistance opportunities available in Southwestern Pennsylvania.

***Economic Assessment of the Potential for Profitable Use of Coal Mine Methane: Case Studies of Three Hypothetical U.S. Mines* - Office of Air and Radiation, May 1995.** Provides information on the economics of methane use.

Finance Opportunities for Coal Mine Methane Projects: A Guide to Federal Assistance, March 1996. Provides information regarding financial assistance opportunities available through federal agencies.

Coalbed Methane Outreach Program Technical Options Series, October 1997 - July 1998. Provides information on how to maximize a coal mine's methane resource.

To order these reports, or to obtain a list of other coal mine methane publications, call 1-888-STAR-YES (1-888-782-7937).

For More Information

To learn more about coal mine methane opportunities, please contact:

Coalbed Methane Outreach Program
U.S. EPA (6202J)
401 M Street, SW
Washington, DC 20460 USA
Tel: (202) 564-9468 or (202) 564-9481
Fax: (202) 565-2077

e-mail: fernandez.roger@epa.gov
schultz.karl@epa.gov

Internet: www.epa.gov/coalbed