Identifying Opportunities for Methane Recovery at U.S. Coal Mines:

Profiles of Selected Gassy Underground Coal Mines 1999-2003

EPA COALBED METHANE OUTREACH PROGRAM

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COVER PHOTOGRAPHS (clockwise from top): 1) Two 44 MW Gas-Combustion Turbines Operated by Allegheny Energy and Consol Energy (Photo courtesy of Consol) 2) 850 kW Caterpillar engine at O'Gara #8 abandoned mine in Illinois Basin, Operated by Grayson Hill Farms (Photo Courtesy of Raven Ridge Resources, Incorporated) 3) BCCK Cryogenic Gas Processing Unit at JWR Blue Creek Mines (Photo courtesy of Jim Walters Resources)

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Frequently Used Terms

Coalbed methane: Methane that resides within coal seams.

Coal mine methane: As coal mining proceeds, methane contained in the coal and surrounding strata may be released. This methane is referred to as coal mine methane since its liberation resulted from mining activity. In some instances, methane that continues to be released from the coal bearing strata once a mine is closed and sealed may also be referred to as coal mine methane because the liberated methane is associated with past coal mining activity.

Degasification system: A system that facilitates the removal of methane gas from a mine by ventilation and/or by drainage. However, the term is most commonly used to refer to removal of methane by drainage technology.

Drainage system: A system that drains methane from coal seams and/or surrounding rock strata. These systems include vertical pre-mine wells, gob wells and in-mine boreholes.

Ventilation system: A system that is used to control the concentration of methane within mine working areas. Ventilation systems consist of powerful fans that move large volumes of air through the mine workings to dilute methane concentrations.

Methane drained: The amount of methane removed via a drainage system.

Methane liberated: The total amount of methane that is released, or liberated, from the coal and surrounding rock strata during the mining process. This total is determined by summing the volume of methane emitted from the ventilation system and the volume of methane that is drained.

Methane recovered: The amount of methane that is captured through methane drainage systems and is synonymous with "methane drained."

Methane used: The amount of methane put to productive use (.e.g., natural gas pipeline injection, fuel for power generation, etc)

Methane emissions: This is the total amount of methane that is not used and therefore emitted to the atmosphere. Methane emissions are calculated by subtracting the amount of methane used from the amount of methane liberated (emissions = liberated – recovered/used).

Frequently Used Abbreviations

b	Billion (10^9)
Btu	British Thermal Unit
CAA	Clean Air Act
CAAA	Clean Air Act Amendments
cf	Cubic Feet
CH_4	Methane
CO_2	Carbon Dioxide
DOE	Department of Energy
EIA	Energy Information Administration
EPA	Environmental Protection Agency
FOB	Freight on Board
GWP	Global Warming Potential
m (or M)	Thousand (10^3)
mm (or MM)	Million (10^6)
MSHA	Mine Safety and Health Administration
MW	Megawatt
NA	Not Available (as opposed to Not Applicable)
PUC	Public Utility Commission
t	ton (short tons are used throughout this report)
USBM	U.S. Bureau of Mines
UMWA	United Mine Workers of America

1. Executive Summary

1. Executive Summary

The purpose of this report is to provide information about specific opportunities to develop methane recovery projects at large underground coal mines in the United States. This report contains profiles of 50 U.S. coal mines that may be potential candidates for methane recovery and use, and details on-going recovery projects at 12 of the mines. The United States Environmental Protection Agency (EPA) designed the profiles to help project developers perform an initial screening of potential projects. While the mines profiled in this report appear to be good candidates, a detailed evaluation would need to be done on a site-specific basis in order to determine whether the development of a specific methane recovery project is both technically and economically feasible.

Since the last version of this report was published in July 2004, coalbed and coal mine methane recovery and use are unchanged with 2001 and 2003 methane recovery and use of approximately 40 Bcf/yr in each year (methane recovery/use was up slightly in 2002 to 43 Bcf). Despite the recent trend, coal mine methane recovery and use have grown from an estimated 28 Bcf in 1997. At a gas price of $4.88/mcf, this means that coal mine methane developers increased annual revenues by an estimated $59 million between 1997 and 2003.

Methane Emissions and Recovery Opportunities

Non-CO_2 gases play important roles in efforts to understand and address global climate change. The non-CO_2 gases include a broad category of greenhouse gases other than carbon dioxide (CO_2), such as methane, nitrous oxide and a number of high global warming potential (GWP) gases. The non-CO_2 gases are more potent than CO_2 (per unit weight) and are significant contributors to global warming, thus, reducing emissions of non-CO_2 gases can help prevent global climate change and produce broader economic and environmental benefits.

Methane (CH_4) is a greenhouse gas that exists in the atmosphere for approximately 9-15 years. As a greenhouse gas, CH_4 is over 20 times more effective in trapping heat in the atmosphere than carbon dioxide – over a 100-year period – and is emitted from a variety of natural and human-influenced sources. Human-influenced sources include landfills, natural gas and petroleum systems, agricultural activities, coal mining, stationary and mobile combustion, wastewater treatment, and certain industrial processes.

Methane is also a primary constituent of natural gas and an important energy source. As a result, efforts to prevent or utilize methane emissions can provide significant energy, economic and environmental benefits. In the United States, many companies are working with EPA in voluntary efforts to reduce emissions by implementing cost-effective management methods and technologies.

U.S. industries along with state and local governments collaborate with the U.S. Environmental Protection Agency to implement several voluntary programs that promote profitable opportunities for reducing emissions of methane, an important greenhouse gas. These programs are designed to overcome a wide range of informational, technical, and institutional barriers to reducing methane emissions, while creating profitable activities for the coal, natural gas, petroleum, landfill, and agricultural industries.

CMM Recovery Opportunities

In the U.S., coal mines account for approximately 10% of all man-made methane emissions. Today, there are methane recovery and use projects at mines in Alabama, Colorado, New Mexico, Virginia, and West Virginia. As shown in this report, there are many additional gassy coal mines at which projects have not yet been developed that offer the potential for the profitable recovery of methane.

In addition to the direct financial benefits that may be enjoyed from the sale of coal mine methane, indirect financial and economic benefits may also be achieved. Degasification systems that are used to drain methane prevent gas from escaping into mine working areas, increase methane recovery, improve worker safety, and significantly reduce ventilation costs at several mines. Increased recovery also reduces methane-related mining delays, resulting in increased coal productivity. Furthermore, the development of methane recovery projects has been shown to result in the creation of new jobs, which has helped to stimulate area economies.[1] Additionally, the development of local coal mine methane resources may result in the availability of a potentially low-cost supply of gas that could be used to help attract new industry to a region. For these reasons, encouraging the development of coal mine methane recovery projects is likely to be of growing interest to state and local governments that have candidate mines in their jurisdictions.

For example, some of the mines profiled in this report have methane emissions in excess of ten million cubic feet per day (or nearly 4 billion cubic feet per year). To illustrate the impact of methane recovery, developing a project at a mine recovering two billion cubic feet per year would result in emissions reductions equating to 900,000 tonnes of CO_2.[2] Because of the large environmental benefits that may be achieved, coal mine methane projects may serve as cost-effective alternatives for utilities and others seeking to offset their own greenhouse gas emissions.

To realize continued emission reductions from the coal mining industry, EPA's Coalbed Methane Outreach Program (CMOP) has worked voluntarily with the coal mining industry and associated industries since 1994 to recover and use methane released into and emitted from mines.

CMOP's efforts are directed to assist the mining industry by supporting project development, overcoming institutional, technical, regulatory and financial barriers to implementation, and educating the general public on the benefits of CMM recovery. More specifically, these efforts include:

- identifying, evaluating and promoting methane reduction options including technological innovations and market mechanisms to encourage project implementation;
- workshops to educate the mining sector on the environmental, mine safety and economic benefits of methane recovery;
- preparing and disseminating reports and other materials that address topics ranging from technical and economic analyses to overviews of legal issues;
- interfacing with all facets of the industry to advance real project development;
- conducting pre-feasibility and feasibility studies for U.S. mines that examine a range of end-use options; and
- managing a website that is an important information resource for the coal mine methane industry.

[1] For example, see discussion on this subject in the report "The Environmental and Economic Benefits of Coalbed Methane Development in the Appalachian Region" (USEPA, 1994).

[2] The carbon dioxide equivalent of methane emissions is calculated by determining the weight of methane collected (on a 100% basis), using a density of 19.2 g/cf. The weight is then multiplied by the global warming potential (GWP) of methane, which is 21 times greater than carbon dioxide over a 100 year time period.

Overview of CMM Recovery and Use Techniques

Methane gas (CH_4) and coal are formed together during coalification, a process in which biomass is converted by biological and geological processes into coal. Methane is stored within coal seams and also within the rock strata surrounding the seams. Methane is released when pressure within a coalbed is reduced as a result of natural erosion, faulting, or mining. Deep coal seams tend to have a higher average methane content than shallow coal seams, because the capacity to store methane increases as pressure increases with depth. Accordingly, underground mines release substantially more methane than surface mines, per ton of coal extracted.

Coal mine methane emissions may be mitigated by the implementation of methane recovery projects at underground mines. Mines can use several reliable degasification methods to drain methane. These methods have been developed primarily to supplement mine ventilation systems that were designed to ensure that methane concentrations in underground mines remain within safe concentrations. While these degasification systems are mostly used for safety reasons, they can also recover methane that may be employed as an energy resource. Degasification systems include vertical wells (drilled from the surface into the coal seam months or years in advance of mining), gob wells (drilled from the surface into the coal seam just prior to mining), and in-mine boreholes (drilled from inside the mine into the coal seam or the surrounding strata prior to mining).

The quality (purity) of the gas that is recovered is partially dependent on the degasification method employed, and determines how the gas can be used. For example, only high quality gas (typically greater than 95% methane) can be used for pipeline injection. Vertical wells and horizontal boreholes tend to recover nearly pure methane (over 95% methane). In very gassy mines, gob wells can also recover high-quality methane, especially during the first few months of production. Over time, however, mine air may become mixed with the methane produced by gob wells, resulting in a lower quality gas.

Even lower quality methane can be used as an energy source in various applications. Potential applications that have been demonstrated in the U.S. and other countries include:

- electricity generation (the electricity can be used either on-site or can be sold to utilities);
- as a fuel for on-site preparation plants or mine vehicles, or for nearby industrial or institutional facilities; and,
- cutting-edge applications, such as in fuel cells and ventilation air methane (VAM) technologies.

It is also possible to enrich lower quality gas to pipeline standards using technologies that separate methane from carbon dioxide, oxygen, and/or nitrogen. Several technologies for separating methane are under development. Another option for improving the quality of mine gas is blending, which is the mixing of lower quality gas with higher quality gas whose heating value exceeds pipeline requirements.

Even mine ventilation air, which typically contains less than 1% methane, is being successfully used as combustion air in gas-fired internal combustion engines in Australia. The technology for using mine ventilation air as combustion air in turbines and coal-fired boilers also exists, and research on the use of thermal oxidizers and catalytic reactors to generate heat from methane in mine ventilation air is underway. The first commercial oxidizer in the world is under construction in Australia and is scheduled to begin operating in 2006.

Opportunities for Methane Recovery Projects

While methane recovery projects already are operating at some of the gassiest mines in the U.S., there are numerous additional gassy mines at which recovery projects could be developed. This report profiles 50 mines that are potential candidates for the development of coal mine methane projects. At least 14 currently operate drainage systems, with drainage efficiencies in the range of 25 to 60 percent. Eleven of the draining mines already sell recovered methane.[3] Mines that already use drainage systems may be especially good candidates for the development of cost-effective methane recovery projects. There are also projects at abandoned mines in the U.S.; however, this report only profiles active mines.

Overview of Methane Liberation, Drainage and Use at Profiled Mines

This report profiles mines located in 12 states. West Virginia has the largest number of profiled mines (15), followed by Kentucky (8), and Alabama (6). In 2003, the 50 mines profiled in this report liberated an estimated 347 mmcf/d of methane, or about 127 Bcf/yr (95% of all methane liberated from underground mines). Table 1-1 shows the number of profiled mines and the estimated total methane liberated from these mines, summarizing information presented in the state summaries and individual mine profiles (Chapter 6). Chapter 4 explains how these data were derived.

Table 1-1 shows that about 31% of the total estimated methane liberated from all profiled mines is being used. Table 1-1 also shows estimated annual methane emissions from the mines that are operating but not using methane and the estimated annual methane emissions that would be avoided by implementing methane recovery and use projects at these mines, assuming a 20-60% range of recovery efficiency. Based on these recovery efficiencies, if methane recovery projects were implemented at profiled mines that are currently operating but do not recover methane, an estimated 9-27 Bcf/yr of methane emissions would be avoided. This is equivalent to about 4-12 mmt/yr of CO_2. Moreover, there is significant potential for increased methane recovery at many of the mines that already have recovery projects.

Overview of U.S. Mining Industry Since 2001

Significant changes occurred in the U.S. mining industry between 2001 and 2003. Several noteworthy trends unfolded since the 2001 surge in coal production. In 2003, production levels returned to normal and the year was characterized by a decline in the overall number of mining operations in the U.S. Underlining the consolidation were mine closures and bankruptcy filings concentrated in the Eastern coal markets. Production in the Illinois Basin held steady while Western mines continued to produce at or above record levels.

Regarding the mines profiled in this report, there are 11 mines that did not appear in the previous version of this report. Three new gassy mines have opened since 2001; they include Deep Mine #26 in Virginia, Elk Creek mine in Colorado, and Willow Lake Portal mine in Illinois. The other eight mines profiled in 2003, but not in 2001, generally saw a considerable increase in production, and all eight mines have become gassier. Since 2001, two additional CMM recovery and use projects came online as West Elk (CO) and San Juan South (NW) began recovering methane. As for the eleven mines profiled in 2001, but not in this version of the report, five have closed or been idled, and six are less gassy in 2003 than they were in 2001.

Other developments having a significant impact on mining operations and/or production are highlighted below:

- Fires affected production at three mines since 2001: CONSOL extinguished a fire at Mine No. 84, Loveridge was idled due to a fire in March of 2003, and JWR's No. 5 mine suffered an explosion/fire in September of 2001 (production has since resumed).

[3] Please see Chapter 4 for a more detailed discussion of this issue.

- CONSOL expanded its McElroy mine and spent $180 million to improve prep plant throughput capacity to 2000 tph. CONSOL also signed a 17 year supply deal with First Energy.
- In Utah, Andalex Resources completed a move of longwall mining equipment from its Aberdeen mine to the West Ridge mine.
- During the fall of 2001 U.S. Steel decided against closing its Oak Grove mine in Alabama.
- Anker Coal Group filed for bankruptcy protection in 2002. They restructured debt and reopened the Sentinel Mine which had been idled since May of 2002.
- BHP Billiton's San Juan South mine – originally a surface mine – was added to *Coal Age's* Longwall Census in 2002.
- Baker mine in Kentucky was idled after Lodestar Energy ceased operations at the end of 2003.

Table 1-1: U.S. Summary Table

Number of Profiled Mines and Estimated Methane Liberated and Used in 2003[1]

	Operating but not Using Methane		Operating and Using Methane		All Mines Profiled in This Report		
State	Number of Mines	Total Methane Liberated (mmcf/d)	Number of Mines	Total Methane Liberated (mmcf/d)	Number of Mines	Total Methane Liberated (mmcf/d)	Estimated Methane Use (mmcf/d)
Alabama	1	4.2	5	74.0	6	78.2	28
Colorado	1	1.1	1	27.2	2	28.3	0.1
Illinois	4	7.1	0	0.0	4	7.1	0
Indiana	1	2.4	0	0.0	1	2.4	0
Kentucky	8	7.2	0	0.0	8	7.2	0
New Mexico	0	0	1	3.6	1	3.6	0.1
Ohio	1	1.1	0	0.0	1	1.1	0
Oklahoma	1	1.0	0	0.0	1	1.0	0
Pennsylvania	5	56.9	0	0.0	5	56.9	0
Utah	3	7.0	0	0.0	3	7.0	0
Virginia	1	1.9	2	88.9	3	90.8	76
West Virginia	12	32.4	3	31.2	15	63.6	6
TOTAL[2]:	38	122.2	12	224.9	50	347.1	109

Estimated Emissions and Avoided Emissions of Methane and CO_2 Equivalent from Operating Mines not Currently Using Methane (38 mines):	**Methane (Bcf/y)**	**CO_2 (mmt/y)**
2003 Estimated Total Emissions	44.6	19.8
Estimated Annual Avoided Emissions if Recovery Projects are Implemented	8.9 – 26.8	4.0 – 11.9

[1]Chapter 4 explains how these data were estimated.

[2] Values shown here do not always sum to totals due to rounding.

Summary of Opportunities for Project Development

Most underground coal mines still do not recover and use methane, however, the profiles indicate that many of these mines appear to be strong candidates for cost-effective recovery projects. Furthermore, this report contains information suggesting that substantial environmental, economic, and energy benefits could be achieved if mines that currently emit methane were to recover and use it.

The mines profiled in this report are quite variable in terms of the amount of methane they liberate, their gassiness or "specific emissions" (methane liberated per ton of coal mined), and their annual coal production. The volume of methane liberated from each mine ranges from less than 0.7 mmcf/d to over 40 mmcf/d. Similarly, specific emissions range from 84 cf/ton to approximately 9,000 cf/ton. Annual coal production ranges from approximately 300,000 tons at some mines to nearly 10 million tons per year at others. All these factors are important indicators of the potential profitability of developing a project at an individual mine. Furthermore, as shown in the profiles (Chapter 6), the candidate mines vary with respect to other important factors that affect profitability, such as the distance from the mine to a pipeline or the projected remaining productive life of the mine. Accordingly, the overall feasibility of developing a methane recovery project will likely vary widely among the candidate mines.
Although a number of the mines profiled here show strong potential for profitable projects, methane ventures at these mines are not currently being developed, due to a number of barriers to coal mine methane development. Many of these barriers are being overcome. Gas prices have improved, increasing the economic benefits of coalbed methane recovery. Restructuring of the gas industry has created new market opportunities for coal mine methane, and the potential for distributed generation is increasing as a result of electricity industry restructuring. At the same time, utilities and other industries are seeking opportunities to offset greenhouse gas emissions and to develop "environmentally friendly" projects. If projects are initiated at even a few of the mines profiled here, substantial methane emissions reductions and increased profits for developers could be achieved, thereby benefiting the U.S. economy and the global environment.

The following list summarizes the chapters in this report:

- Chapter 2 provides an introduction to coal mine methane in the U.S., including a discussion of major developments in the burgeoning coal mine methane recovery industry that have transpired since publication of the previous version of this report in 2004.
- Chapter 3 discusses current coal mine methane recovery projects in the U.S.
- Chapter 4 provides a key to evaluating the mine profiles.
- Chapter 5 presents the mine summary tables.
- Chapter 6 lists state summaries and actual mine profiles, which should assist potential investors in assessing the overall potential project profitability.

2. Introduction

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Purpose of Report

This report provides information about specific opportunities to develop methane recovery and use projects at large underground mines in the United States. Groups that may be interested in identifying such opportunities include utilities, natural gas resource developers, independent power producers, and local industries or institutions that could directly use the methane recovered from a nearby mine.

This introduction provides a broad overview of the technical, economic, regulatory, and environmental issues concerning methane recovery from coal mines. The report also presents an overview of existing methane recovery and use projects (Chapter 3). Chapter 4 contains Information that will assist the reader in understanding and evaluating the data presented in Chapters 5 and 6. Chapter 5 contains data summary tables, and finally, Chapter 6 profiles individual underground coal mines that appear to be good candidates for the development of methane recovery projects.

Recent Developments in the Coal Mine Methane Industry

Since the last version of this document was published in July 2004, there have been significant developments in coal mine methane recovery, particularly in the number of active recovery and use projects. The number of mines with active methane recovery and use projects has increased from 10 in 2001 to 12 in 2003. However, the amount of methane recovered has stayed nearly the same as in 2001 at around 40 Bcf (43 Bcf recovered in 2002). At a gas price of $4.88/mcf[4], this means that coal mine methane developers had revenues of $195 million in 2003. The resulting decrease in methane emissions has yielded benefits to the global environment through a greenhouse gas emission reduction of 18 MMT/year of CO_2 in 2003. Figure 2-1 shows the number of mines engaging in coal mine methane recovery since 1994 while Figure 2-2 shows the growth in the amount of gas being recovered.

The growth in the amount of recovered methane since 1990 can be attributed to five primary factors: 1) continued use in natural gas pipelines; 2) use for a variety of purposes besides pipeline injection; 3) legislation concerning ownership issues has been enacted in most coalbed methane producing states; 4) various projects have proven the profit-generating potential of coal mine methane recovery; and 5) growing awareness of the climate change impacts of methane emissions. Also, the issuance of FERC Orders 636 in 1992 and 888 in 1996 continues to remove barriers to free and open competition in the natural gas and electric utility industries, respectively. As a result of these orders, coal mine methane developers have been encountering fewer problems accessing the available capacity of the nation's gas and electric transmission lines.

[4] EIA – average wellhead price for 2003.

Figure 2-1: Mines with Active Coal Mine Methane Recovery Projects

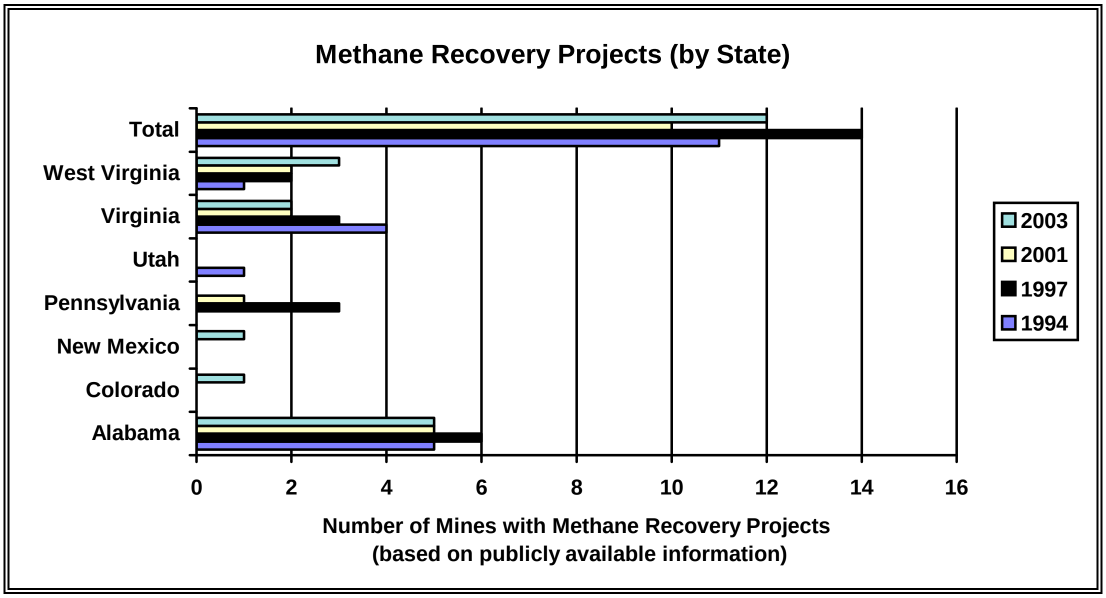
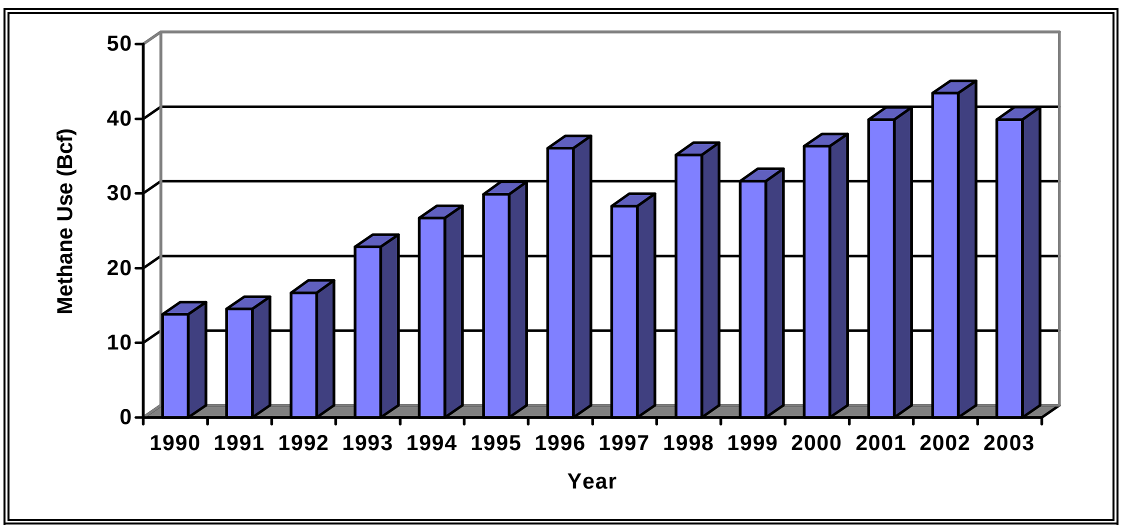


Figure 2-2: Estimated Annual Use of Methane Recovered From U.S. Coal Mines (based on publicly available information)



Overview of Coal Mine Methane

Methane and coal are formed together during coalification, a process in which vegetation is converted by geological and biological forces into coal. Methane is stored in large quantities within coal seams and also within the rock strata surrounding the seams. Two of the most important factors determining the amount of methane that will be stored in a coal seam and the surrounding strata are the rank and the depth of the coal. Coal is ranked by its carbon content; coals of a higher rank have a higher carbon content and generally a higher methane content.[5] The capacity to store methane increases as pressure increases with depth. Thus, within a given coal rank, deep coal seams tend to have a higher methane content than shallow ones.

Methane concentrations typically increase with depth, therefore underground mines tend to release significantly higher quantities of methane per ton of coal mined than do surface mines. In 2003, while only 33 percent of U.S. coal was produced in underground mines, these mines accounted for over 70 percent of estimated methane emissions from coal mining (USEPA, 2005). Although the options for recovering and using methane are primarily available for underground mines, gas recovery at surface mines may also be feasible. Among underground mines, the largest and gassiest mines typically have the best potential for profitable recovery and utilization of methane.

Methane emissions resulting from coal mining activities account for about 10 percent of annual global methane emissions from anthropogenic (man-made) sources. In 2001, The People's Republic of China was the largest emitter of coal mine methane, followed by the United States and then Russia, Ukraine and Australia (USEPA, 2001). In 2003, coal mining emissions were estimated to account for 9.9 percent of total U.S. methane emissions (USEPA, 2005), down from 11.3 percent in 1995.

In underground mines, methane poses a serious safety hazard for miners because it is explosive in low concentrations (5 to 15 percent in air). In the U.S., methane concentrations in the mine may not exceed one percent in mine working areas and two percent in all other locations. In many underground mines, methane emissions can be controlled solely through the use of a ventilation system, which pumps large quantities of air through the mine in order to dilute the methane to safe levels. The coal mine methane (CMM) released to the atmosphere by the mine ventilation system is typically below 1 percent. This methane vented from coal mine exhaust shafts constitutes the largest source of coal mine methane emissions in the U.S. In 2003, for example, 71 billion cubic feet (Bcf) or 56% of the 127 Bcf released from underground mines was released through mine ventilation systems.

In particularly gassy mines, however, the ventilation system must be supplemented with a drainage system. Drainage systems reduce the quantity of methane in the working areas by draining the gas from the coal-bearing strata before, during, or after mining, depending on mining needs. Emissions from drainage systems are estimated to account for approximately one third of the total methane emissions from underground coal mining. At least 17 of the mines profiled in this report have some type of drainage system.

Methane Drainage Techniques

Over the years, mine operators have realized the economic benefits of employing drainage systems. For mines that have drainage systems in place, the cost of ventilation is significantly reduced because the drainage systems recover a significant percentage of the associated methane. Use of methane drainage systems also help reduce production costs, as there are typically fewer methane-related delays at mines that employ drainage systems (Kim and Mutmansky, 1990). Today, methane drainage is a proven technology and much of the gas that is recovered can be used in various applications.

While drainage systems are currently used primarily for economic and safety reasons to ensure that methane concentrations remain below acceptable levels, these systems recover methane that also

[5] In descending order, the ranks of coal are: graphite, anthracite, bituminous, sub-bituminous, and lignite. Most U.S. production is bituminous or sub-bituminous.

can be employed as an energy source. The quantity and quality of the methane recovered will vary according to the method used. The quality of the recovered methane is measured by its heating value. Pure methane has a heating value of about 1000 British Thermal Units per cubic foot (Btu/cf), while a mixture of 50 percent methane and 50 percent air has a heating value of approximately 500 Btu/cf.

Drainage methods include vertical wells (vertical pre-mine), gob wells (vertical gob), longhole horizontal boreholes, and horizontal and cross-measure boreholes. The preferred recovery method will depend, in part, on mining methods and on how the methane will be used. In some cases, an integrated approach using a combination of the above drainage methods will lead to the highest recovery of methane. The key features of the methane recovery methods are discussed in more detail below and are summarized in Table 2-1.

Vertical Pre-Mining Wells

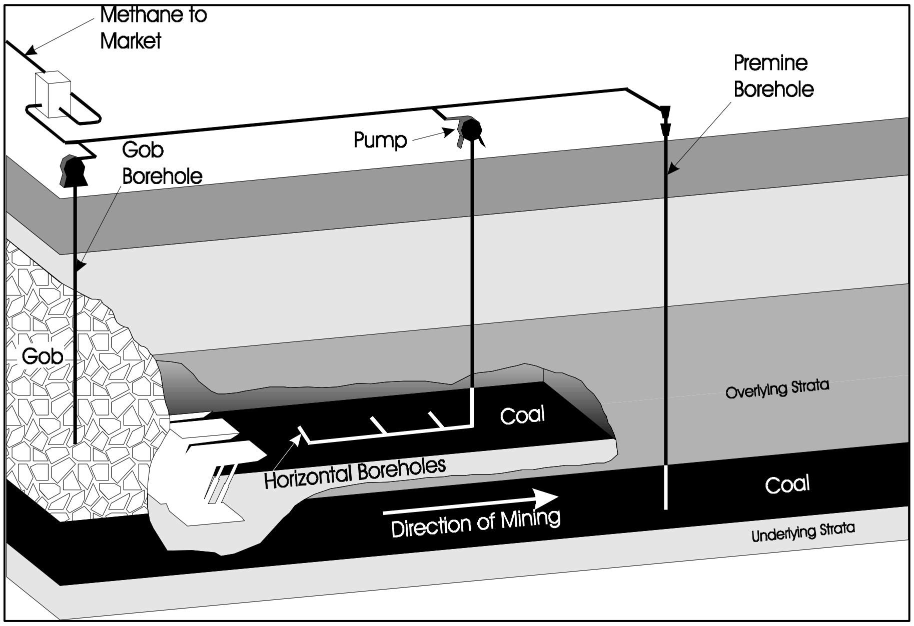
Vertical pre-mining wells are the optimal method for recovering high quality gas from the coal seam and the surrounding strata before mining operations begin. Pre-mine drainage ensures that the recovered methane will not be contaminated with ventilation air from mine working areas. Similar in design to conventional oil and gas wells, vertical wells can be drilled into the coal seam several years in advance of mining. Vertical wells, which may require hydraulic or nitrogen fracturing of the coal seam to activate the flow of methane, typically produce gas of over 90 percent purity. However, these wells may produce large quantities of water and small volumes of methane during the first several months they are in operation. As this water is removed and the pressure in the coal seam is lowered, methane production increases.

The total amount of methane recovered using vertical pre-drainage will depend on site-specific conditions and on the number of years the wells are drilled prior to the start of mining. Recovery of from 50 to over 70 percent of the methane that would otherwise be emitted during mining operations is likely for operations in which vertical degasification wells are drilled more than 10 years in advance of mining. Although not previously used widely in the coal mining industry, vertical wells are increasing in popularity within the coal industry, and are used by numerous stand-alone operations[6] that produce methane from coal seams for sale to natural gas pipelines. In some very low permeability coal seams, vertical wells may not be a cost-effective technology due to limited methane flow. Vertical wells, however, will likely continue to be a viable recovery technology for most underground mines.

Eight underground mines in the U.S. currently use vertical pre-mining wells. A majority of these mines already recover methane for pipeline sales (see section on existing methane recovery projects). Figure 2-3 illustrates a vertical pre-mine well.

[6] The term "stand-alone" refers to coalbed methane operations that recover methane for its own economic value. In most cases, these operations recover methane from deep and gassy coal seams that are not likely to be mined in the near future.

Figure 2-3: Vertical Pre-Mining Gob, and Horizontal Boreholes



Gob Wells

Gob wells are drilled from the surface to a point 10 to 50 feet above the target seam prior to mining. As mining advances under the well, the methane-charged strata that surround the well fracture. Relaxation and collapse of strata surrounding the coal seam creates a fractured zone known as the "gob" area, which is a significant source of methane. Methane emitted from the gob flows into the gob well and up to the surface. A vacuum is frequently used on the gob wells to prevent methane from entering mine working areas.

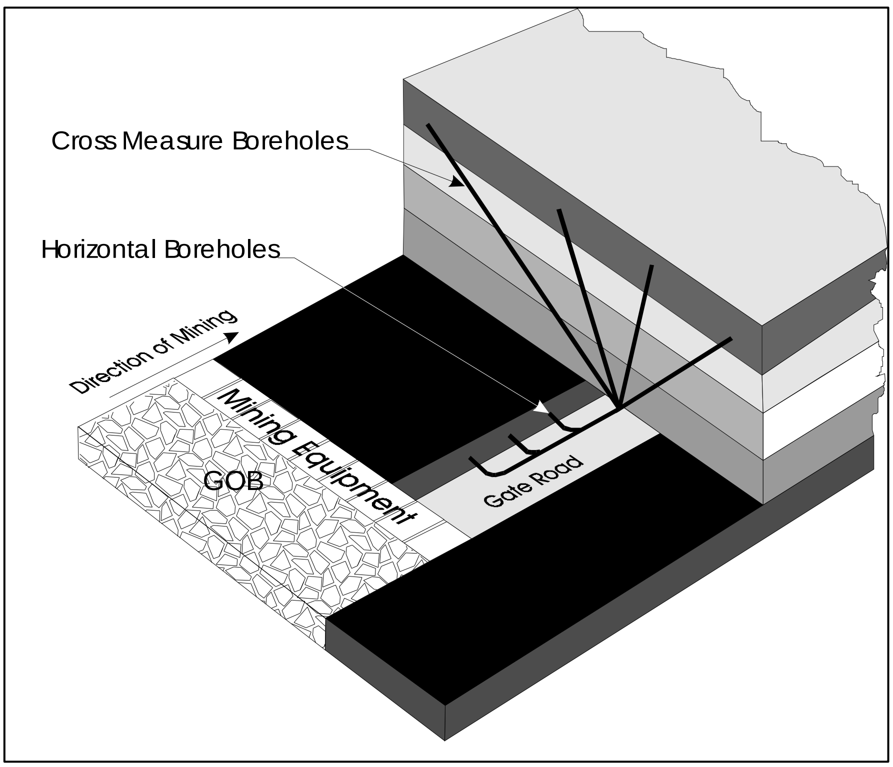
Initially, gob wells produce nearly pure methane. Over time, however, additional amounts of mine air can flow into the gob area and dilute the methane. The heating value of "gob gas" normally ranges between 300 and 800 Btu/cf. In some cases, it is possible to maintain nearly pure methane production from gob wells through careful monitoring and management. Jim Walter Resources, CONSOL, and Peabody are all using techniques for producing high-quality gas from gob wells. Gas production rates from gob wells can be very high, especially immediately following the fracturing of the strata as mining advances under the well. Jim Walter Resources reports that gob wells initially produce at rates in excess of two million cubic feet per day. Over time, production rates typically decline until a relatively stable rate is achieved, typically in the range of 100 mcf/d. Depending on the number and spacing of the wells, gob wells can recover an estimated 30 percent to over 50 percent of methane emissions associated with coal mining (USEPA, 1990).

Seventeen U.S. mines currently use surface gob wells to reduce methane levels in mine working areas. Most mines release methane drained from gob wells into the atmosphere. Figure 2-3 illustrates a vertical gob well.

Horizontal Boreholes

Horizontal boreholes are drilled inside the mine (as opposed to from the surface) and they drain methane from the unmined areas of the coal seam, or from blocked out longwall panels shortly before mining takes place. These boreholes are typically 400 to 800 feet in length. Several hundred boreholes may be drilled within a single mine and connected to an in-mine vacuum piping system, which transports the methane out of the mine and to the surface. Most often, horizontal boreholes are used for short-term methane emissions relief during mining. Because methane drainage only occurs from the mined coal seam (and not from the surrounding strata), the recovery efficiency of this technique is low – approximately 10 to 18 percent of methane that would otherwise be emitted (USEPA, 1990). However, this methane typically can have a heating value of over 950 Btu/cf (USEPA, 1991). Approximately 16 underground mines in the U.S. currently use this technique to reduce the quantity of methane in mine working areas. Figures 2-3 and 2-4 illustrate horizontal boreholes.

Figure 2-4: Horizontal and Cross-Measure Boreholes



Longhole Horizontal Boreholes

Like horizontal boreholes, longhole horizontal boreholes are drilled from inside the mine in advance of mining. They are greater than 1000 feet in length and are drilled in unmined seams using directional drilling techniques. Longhole horizontal boreholes produce nearly pure methane with a recovery efficiency of about 50% and therefore can be used when high quality gas is desired. This technique is most effective for gassy, low permeability coal seams that require long diffusion periods. Both West Elk Mine in Colorado and San Juan South Mine in New Mexico have employed longhole horizontal boreholes in their drainage programs.

Cross-Measure Boreholes

Cross-measure boreholes degasify the overlying and underlying rock strata surrounding the target coal seam. These boreholes are drilled inside the mine and they drain methane with a heating value similar to that of gob wells. Cross-measure boreholes have been used extensively in Europe and Asia but are not widely used in the United States where surface gob wells are preferred. West Elk Mine in Colorado has employed cross-measured boreholes in the past. Figure 2-4 illustrates cross-measure boreholes.

Table 2-1
Summary of Drainage Methods

Method	Description	Gas Quality	Drainage Efficiency[a]	Current Use in U.S. Coal Mines[b]
Vertical Pre-Mine Wells	Drilled from surface to coal seam months or years in advance of mining.	Produces nearly pure methane.	up to 70%	Used by 8 mines.
Gob Wells	Drilled from surface to a few feet above coal seam just prior to mining.	Produces methane that is sometimes contaminated with mine air.	up to 50%	Used by 17 mines.
Horizontal Boreholes	Drilled from inside the mine to degasify the coal seam shortly prior to mining.	Produces nearly pure methane.	up to 20%	Used by 16 mines.
Longhole Horizontal Boreholes	Drilled from inside the mine to degasify the coal seam shortly prior to mining.	Produces nearly pure methane.	up to 50%	Used by at least 2 mines.
Cross-measure Boreholes	Drilled from inside the mine to degasify surrounding rock strata shortly prior to mining.	Produces methane that is sometimes contaminated with mine air.	Up to 20%	Not widely used in the U.S.[c]

Source: USEPA (1993) & USEPA (2005)

[a] Percent of total methane liberated that is drained.

[b] Accurate only at the time of publication of this report, may vary often as mining progresses.

[c] Used at West Elk Mine at one time.

Utilization Options

Once recovered, coal mine methane is an energy source available for many different applications. Potential utilization options are pipeline injection, electricity generation, and direct use in on-site prep-plants or to fuel mine vehicles, or at nearby industrial or institutional facilities. Following is a discussion of various utilization methods. Table 2-2 shows the recovery methods that may be employed for each utilization option.

Table 2-2
Utilization Options for Coalbed Methane

Utilization Options	Range of Btu Quality (Btu/cf)	Recovery Method
Pipeline Injection Power Generation Local Use (at on-site coal prep plant or to fuel mine vehicles, or at nearby industrial or institutional facilities)	> 950	Vertical Wells (Pre-mining degasification)
Pipeline Injection – requires: (1) maintaining pipeline quality, or (2) gas enrichment Power Generation Local Use	300 to 950	Gob Wells
Pipeline Injection Power Generation Local Use	up to 950	In-Mine Boreholes
Use ventilation air methane as combustion air in gas-fired IC engines, gas turbines or coal-fired boilers; thermal oxidation; catalytic reactors; VOC concentrators; lean fuel gas turbines	1 to 20	Ventilation Air

Sources: USEPA (1990); USEPA (1991); USEPA (2005)

Pipeline Injection

Methane liberated during coal mining may be recovered and collected for sale to pipeline companies. The key issues that will determine project feasibility are: 1) whether the recovered gas can meet pipeline quality standards; and 2) whether the costs of production, processing, compression and transportation are competitive with other gas sources.

U.S. experience demonstrates that selling recovered methane to a pipeline can be profitable for mining companies and is by far the most popular use method. As shown in Table 2-3, 11 of the profiled mines currently sell methane from their drainage systems to local pipeline companies. Chapter 3 contains additional information on these projects.

Technical Feasibility

The primary technical consideration involved in collecting coal mine methane for pipeline sales is that the recovered methane must meet the standards for "pipeline quality" gas. First, it must have a methane concentration of at least 95 percent and contain no more than a 2 percent concentration of gases that do not burn (i.e., carbon dioxide, nitrogen, helium). Additionally, any non-methane hydrocarbons are usually removed from the gas stream for other uses. Hydrogen sulfide (which mixes with water to make sulfuric acid) and hydrogen (which makes pipes brittle) must also be removed before the gas is introduced into the pipeline system. Finally, any water or sand produced with the gas must be removed to prevent damage to the system. While coalbed methane requires water removal, it is often free of hydrogen sulfide and other impurities typically found in natural gas.

With proper recovery and treatment, coalbed methane can meet the requirements for pipeline quality gas.

Table 2-3
Current Coal Mine Methane Pipeline Projects at Profiled Mines

Mining Company	Number of Active Mines	State
Jim Walter Resources	3	Alabama
U.S. Steel Mining	2	Alabama, West Virginia
Drummond Coal	1	Alabama
CONSOL	1	West Virginia/Pennsylvania*
Eastern Associated Coal (Peabody)	1	West Virginia
BHP Billiton	1	New Mexico
CONSOL Coal Group	2	Virginia

* While the main entries for this mine and two abandoned mines (which are part of a single methane recovery project) are located in West Virginia, significant portions of the mines extend into Pennsylvania, and most of the gas production is from Pennsylvania.

Vertical degas wells are the preferred recovery method for producing pipeline quality methane from coal seams because pre-mining drainage ensures that the recovered methane is not contaminated with ventilation air from the working areas of the mine. Gob wells, in contrast, generally do not produce pipeline quality gas as the methane is frequently mixed with ventilation air. In certain cases, however, it is possible to maintain a higher and more consistent gas quality through careful monitoring and adjustment of the vacuum pressure in gob wells.

It is also possible to enrich gob gas to pipeline quality by using technologies that separate methane from carbon dioxide, oxygen, and/or nitrogen. Several technologies for separating methane are under development and may prove to be economically attractive and technically feasible with additional research (USEPA Technical Option Series). One such project currently operating is at the Blue Creek #4, #5, and #7 mines operated by JWR where a cryogenic gas processing unit was installed in 2000 to upgrade medium-quality gas, recovered from gob wells, to pipeline quality gas. Pressure swing adsorption is also being utilized.

Another option for improving the quality of mine gas is blending, which is the mixing of lower Btu gas with higher Btu gas whose heating value exceeds pipeline requirements. As a result of blending, the Btu content of the overall mixture can meet acceptable levels for pipeline injection. For example, CONSOL is blending gob gas recovered from the VP #8 and Buchanan mines in Virginia with coalbed methane production for pipeline injection.

Horizontal boreholes and longhole horizontal boreholes also can produce pipeline quality gas when the integrity of the in-mine piping system is closely monitored. However, the amount of methane produced from these methods is sometimes not large enough to warrant investments in the necessary surface facilities. In cases where mines are developing utilization strategies for larger amounts of gas recovered from vertical or gob wells, it may be possible to use the gas recovered from in-mine boreholes to supplement production.

Profitability

The overall profitability of recovering methane for pipeline injection will depend on a number of factors. These factors include the amount and quality of methane recovered (as discussed above), the capital and operating costs for wells, water disposal, compression and gathering systems, and most importantly, the price at which the recovered gas may be sold.

The costs for disposal of production water from vertical wells may be a significant factor in determining the economic viability of a project, as discussed later in this chapter ("Production Characteristics of Coalbed Methane Wells"). The cost of gas gathering lines is another consideration. Because costs for laying gathering lines are high, proximity to existing commercial pipelines is a significant factor in determining the economic viability of a coalbed methane project. Most coal mines are located within 20 miles of a commercial pipeline (See Chapter 6). However, in some cases, existing pipelines may have limited capacity for transporting additional gas supplies. Costs for laying gathering lines vary widely depending, in part, on terrain. The hilly and mountainous terrain in many mining areas increases the difficulty, and thus the cost, of installing gathering lines.

Another determinant of the overall profitability of a pipeline injection project is a mine's ability to find a purchaser for its recovered gas. A methane recovery project will also need to demonstrate that its recovered methane is of the requisite pipeline quality.

Power Generation

Coalbed methane may also be used as a fuel for power generation. Unlike pipeline injection, power generation does not require pipeline quality methane. Gas turbines can generate electricity using methane that has a heat content of 350 Btu/cf. Mines can use electricity generated from recovered methane to meet their own on-site electricity requirements and can sell electricity generated in excess of on-site needs to utilities. An example is an 88 MW power generation station developed by CONSOL Energy and Allegheny Energy, placed near the VP #8 and Buchanan mines, fueled by coalbed methane and coal mine methane. Power generated is sold to the competitive wholesale market. The 88 MW project, though, is currently the world's largest CMM-fired power plant. More typical are projects in the 1-10 MW range, and there is currently a 1.2 MW project using internal combustion engines at the Federal No. 2 Mine in West Virginia. In addition to the two U.S. projects, power generation projects are reported to be operating at coal mines in several other countries including China, Australia, UK and Germany.

Technical Feasibility

A methane/air mixture with a heating value of at least 350 Btu/cf is a suitable gaseous fuel for electricity generation. Accordingly, vertical degas wells, gob wells, and in-mine boreholes are all acceptable methods of recovering methane for generating power. Gas turbines, internal combustion (IC) engines, and boiler/steam turbines can all be adapted to generate electricity from coalbed methane. Fuel cells may also prove to be a promising option and are currently being tested at the Nelms Portal Mine[7] in Ohio where a 250 kW Direct FuelCell®, manufactured by FuelCell Energy, Inc., will be set up to deliver power to the local utility. This project is being cost-shared by the Department of Energy.

[7] Not profiled in this edition of the report.

Currently, the most likely generator choice for a coalbed methane project would be either a gas turbine or an IC engine. Boiler/steam turbines are generally not cost effective in sizes below 30 MW, while gas turbines are not the optimal choice for projects requiring 1.5 MW or less. However, when used in the right applications gas turbines are smaller and lighter than IC engines and historically have had lower operation and maintenance costs.

While maintaining pipeline quality gas output from gob wells can be difficult, the heating value of gob gas is generally compatible with the combustion needs of gas turbines. One potential problem with using gob gas is that production, methane concentration, and rate of flow are generally not predictable; wide variations in the Btu content of the fuel may create operating difficulties. Equipment for blending the air and methane may be needed to ensure that variations in the heating value of the fuel remain within an acceptable range – approximately ten percent allowable variability for gas turbines.

A potential advantage of using vertical pre-mine wells as the recovery method for power generation is that the quantity and quality of methane produced is more consistent than that of gob wells. Thus, problems stemming from variations in the heating value of the fuel would be minimized where vertical wells are employed. Another option is to blend high quality gas from vertical wells with lower quality gas from gob wells to ensure consistent quality. Horizontal boreholes also can produce gas of consistently high quality. The limited quantity of gas produced by this method would likely need to be supplemented by larger quantities of methane from vertical or gob wells, however.

The level of electric capacity that may be generated depends on the amount of methane recovered and the "heat rate" (i.e., Btu to kWh conversion) of the generator. For example, simple cycle gas turbines typically have heat rates in the range of 10,000 Btu/kWh, while combined cycle gas turbines could have heat rates of 7,000 Btu/kWh. Assuming a conservative heat rate of 11,000 Btu/kWh and assuming that mines could recover 35 percent of total emissions, the level of electric capacity that could be sustained by the top twenty methane-emitting mines would likely exceed 10 MW per mine.

Profitability: Power Generation for On-Site Use

Given their large energy requirements, coal mines may realize significant economic savings by generating power from recovered methane. Nearly every piece of equipment in an underground mine operates on electricity, including mining machines, conveyor belts, ventilation fans, and elevators. Much of the equipment at typical mines is operated 250 days a year, two shifts per day. Ventilation systems, however, must run 24 hours a day, 365 days a year, and they demand a considerable amount of electricity – up to 60 percent of the mine's total needs (USBM, 1992).

A mine's total electricity needs can exceed 24 kWh per ton of coal mined. Since many of the largest underground mines in the U.S. produce more than 3 million tons of coal annually, they may purchase over 72 million kWh of electricity annually. At average industrial electricity rates of five cents per kWh, a mine's electricity bill can exceed several million dollars a year.

Coal preparation plants, which are frequently located near large mines, also consume a great deal of energy. Preparation involves crushing, cleaning, and drying the coal before its final sale. Coal drying operations require thermal energy, which could be generated by a turbine or engine in a cogeneration cycle. Coal preparation generally requires an additional 6 kWh per ton of coal (ICF Resources, 1990a). CONSOL currently recovers approximately 2 mmcf/d from the VP #8 and Buchanan mines for use in their thermal dryer.

Among the main factors in determining the economic viability of generating power for on-site use are the total amount and flow of the methane recovered, the capital costs of the generator, the expected lifetime of the project, and the price the mine pays for the electricity it uses. A mine would need to be fairly large to recover an amount of methane that would justify the capital expenditures for a generator and other equipment needed for utilizing power on-site. Moreover, because the $/kW capital cost of a generator is relatively high in terms of the overall economics of a coalbed methane power project, the mine would need to generate power for several years in order to justify the capital investment. A final economic consideration is the cost of back-up power, which is typically supplied by a utility and is essential for mining operations given their safety considerations.

Profitability: Off-Site Sale to a Utility

Large and gassy coal mines may be able to generate electric power from recovered methane in excess of their own power requirements. In such cases, a mine may be able to profit from selling power to a nearby utility. Additionally, under some circumstances, a mine might arrange to sell electricity to a utility, but continue to purchase electricity from the utility for its own on-site use. The economic feasibility of selling power off-site would depend on the amount of electricity that could be generated, the incremental costs of selling power to a utility, and the price received for the electricity.

If a mine is generating power to meet its own electricity needs, the incremental costs of selling excess power off-site are relatively low. Normally, a coal mine already has a large transmission line running from a main transmission line to the mine substation. In most cases, this same line could be used to transmit power from the mine back to the utility. For some mines, an interconnection facility or line upgrades may be needed to feed this additional power into the main line.

Ventilation Air Methane Use Technologies

Ventilation air methane (VAM) is now recognized as an unused source of energy and a potent atmospheric greenhouse gas (GHG). A host of recently introduced technologies can reduce ventilation air methane emissions, while harnessing methane's energy, and can offer significant benefits to the world community.

USEPA (2000) identified two technologies for destroying or beneficially using the methane contained in ventilation air: the VOCSIDIZER,[8] a thermal flow-reversal reactor developed by MEGTEC Systems (De Pere, Wisconsin, United States), and a catalytic flow-reversal reactor developed expressly for mine ventilation air by Canadian Mineral and Energy Technologies (CANMET—Varennes, Quebec, Canada). Both technologies employ similar principles to oxidize methane contained in mine ventilation airflows. Based on laboratory and field experience, both units can sustain operation (i.e., can maintain oxidation) with ventilation air having uniform methane concentrations down to approximately 0.1 percent. For practical field applications where methane concentrations are likely to vary over time, however, this analysis assumes that a practical average lower concentration limit at which oxidizers will function reliably is 1.5 percent.

In addition, a variety of other technologies such as boilers, engines, and turbines may use ventilation airflows as combustion air. At least two other technology families may also prove to be viable candidates for beneficially using VAM. These are VOC concentrators and new lean fuel gas turbines.

[8] VOCSIDIZER is a registered trademark of MEGTEC Systems.

Thermal Flow Reversal Reactor

Figure 2.5 shows a schematic of the Thermal Flow Reversal Reactor (TFRR). The equipment consists of a bed of silica gravel or ceramic heat-exchange medium with a set of electric heating elements in the center. The TFRR process employs the principle of regenerative heat exchange between a gas and a solid bed of heat-exchange medium. To start the operation, electric heating elements preheat the middle of the bed to the temperature required to initiate methane oxidation (above 1,000°C [1,832°F]) or hotter. Ventilation air at ambient temperature enters and flows through the reactor in one direction and its temperature increases until oxidation of the methane takes place near the center of the bed.

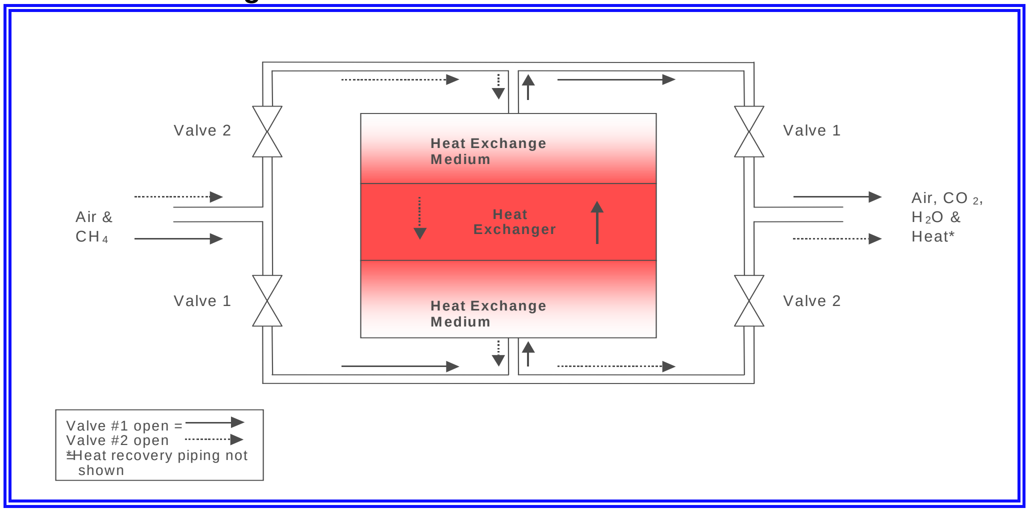
The hot products of oxidation continue through the bed, losing heat to the far side of the bed in the process. When the far side of the bed is sufficiently hot, the reactor automatically reverses the direction of ventilation airflow. The ventilation air now enters the far (hot) side of the bed, where it encounters auto-oxidation temperatures near the center of the bed and then oxidizes. The hot gases again transfer heat to the near (cold) side of the bed and exit the reactor. Then, the process again reverses.

TFRR units are effectively employed worldwide to oxidize industrial VOC streams. Recently, their ability to oxidize VAM has been demonstrated in the field.

Catalytic Flow Reversal Reactor

Catalytic flow reversal reactors adapt the thermal flow reversal technology described above by including a catalyst to reduce the auto-oxidation temperature of methane by several hundred degrees Celsius (to as low as 350°C [662°F]). CANMET has demonstrated this system in pilot plants and is now in the process of licensing Neill and Gunter of Dartmouth, Nova Scotia, to commercialize the design (under the name VAMOX).

Figure 2-5. Thermal Flow-Reversal Reactor



CANMET is also studying energy recovery options for profitable turbine electricity generation. Injecting a small amount of methane (gob gas or other source) increases the methane concentration in ventilation air and can make the turbine function more efficiently. Waste heat from the oxidizer is also used to pre-heat the compressed air before it enters the expansion side of the gas turbine.

Energy Conversion from a Flow-Reversal Reactor

There are several methods of converting the heat of oxidation from a flow-reversal reactor to electric power, which is the most marketable form of energy in most locations. The two methods being studied by MEGTEC and CANMET are:

- *Use water as a working fluid.* Pressurize the water and force it through an air-to-water heat exchanger in a section of the reactor that will provide a non-destructive temperature environment (below 800°C [1472°F]). Flash the hot pressurized water to steam and use the steam to drive a steam turbine-generator. If a market for steam or hot water is available, send exhausted steam to that market. If none is available, condense the steam and return the water to the pump to repeat the process.
- *Use air as a working fluid.* Pressurize ventilation air or ambient air and send it through an air-to-air heat exchanger that is embedded in a section of the reactor that stays below 800°C (1472°F). Direct the compressed hot air through a gas turbine-generator. If gob gas is available, use it to raise the temperature of the working fluid to more nearly match the design temperature of the turbine inlet. Use the turbine exhaust for cogeneration, if thermal markets are available.

Since affordable heat exchanger temperature limits are below those used in modern prime movers, efficiencies for both of the energy conversion strategies listed above will be fairly modest. The use of a gas turbine, the second method listed, is the energy conversion technology assumed for the cost estimates in this report. At a VAM concentration of 0.5 percent one vendor expects an overall plant efficiency in the neighborhood of 17 percent after accounting for power allocated to drive the fans that force ventilation air through the reactor.

Other Technologies

USEPA has also identified other technologies that may be able to play a role in and enhance opportunities for VAM oxidation projects. These are briefly described below.

Concentrators

Volatile organic compound (VOC) concentrators offer another possible economical option for application to VAM. During the past 10 years the use of such units to raise the concentration of VOCs in industrial-process air exhaust streams that are sent to VOC oxidizers has increased. Smaller oxidizer units are now used to treat these exhaust streams, which in turn has reduced capital and operating costs for the oxidizer systems. Ventilation air typically contains about 0.5 percent methane concentration by volume. Conceivably, a concentrator might be capable of increasing the methane concentration in ventilation airflows to about 20 percent. The highly reduced gas volume with a higher concentration of methane might serve beneficially as a fuel in a gas turbine, reciprocating engine, etc. Concentrators also may prove effective in raising the methane concentration of very dilute VAM flows to levels that will support oxidation in a TFRR or CFRR.

Lean Fuel Gas Turbines

A number of engineering teams are striving to modify selected gas turbine models to operate directly on VAM or on VAM that has been enhanced with more concentrated fuels, including concentrated VAM (see “Concentrator” section above) or gob gas. These efforts include:

- ***Carbureted gas turbine.*** A carbureted gas turbine (CGT) is a gas turbine in which the fuel enters as a homogeneous mixture via the air inlet to an aspirated turbine. It requires a fuel/air mixture of 1.6 percent by volume, so most VAM sources would require enrichment. Combustion takes place in an external combustor where the reaction is at a lower temperature (1200°C [2192°F]) than for a normal turbine thus eliminating any NOx emissions. Energy Developments Limited (EDL) of Australia is testing the CGT on ventilation air at the Appin coal mine in New South Wales, Australia.

- ***Lean-fueled turbine with catalytic combustor.*** CSIRO Exploration & Mining of Australia, a government research organization, is developing a catalytic combustion gas turbine (CCGT) that can use methane in coal mine ventilation air. The CCGT technology being developed oxidizes VAM in conjunction with a catalyst. The turbine compresses a very lean fuel/air mixture and combusts it in a catalytic combustor. CSIRO hopes to operate the system on a 1.0 percent methane mixture to minimize supplemental fuel requirements.

- ***Lean-fueled catalytic microturbine.*** Two U.S. companies, FlexEnergy and Capstone Turbine Corporation, are jointly developing a line of microturbines, starting at 30 kW that will operate on a methane-in-air mixture of 1.3 percent.

- ***Hybrid coal and VAM-fueled gas turbine.*** CSIRO is also developing an innovative system to oxidize and generate electricity with VAM in combination with waste coal. CSIRO is constructing a 1.2-MW pilot plant that cofires waste coal and VAM in a rotary kiln, captures the heat in a high-temperature air-to-air heat exchanger, and uses the clean, hot air to power a gas turbine. Depending on site needs and economic conditions, VAM can provide from about 15 to over 80 percent (assuming a VAM mixture of 1.0 percent) of the system’s fuel needs, while waste coal provides the remainder.

VAM Used as an Ancillary Fuel

VAM can also be used as an ancillary or supplemental fuel. Such technologies rely on a primary fuel other than VAM and are able to accept VAM as all or part of their combustion air to replace a small fraction of the primary fuel. The largest example of ancillary VAM use occurred at the Appin Colliery in Australia, where 54 one-MW Caterpillar engines used mine ventilation air containing VAM as combustion air. Similarly, the Australian utility, Powercoal, is installing a system to use VAM as combustion air for a large coal-fired steam power plant. In addition, the U.S. Department of Energy funded a research project to use VAM in concentrations up to 0.5 percent as combustion air in a turbine manufactured by Solar. Even the CSIRO hybrid coal and VAM project described in the preceding paragraph falls in the category of ancillary VAM use when waste coal combustion is maximized and VAM use is limited to prescribed levels of combustion air.

Project Economics for Ventilation Air Methane Use Technologies

Many of the technologies for VAM use are still in the developmental stage, and cost information is still limited. The costs for simply using the VAM as combustion air either in reciprocating engines or turbines is negligible, the only costs being construction and operation of equipment to move the air to the generator sets. Additional maintenance of the engines or turbines may be necessary if excess moisture and dust are present in the mine ventilation air. Developers of the lean-burn turbines are reporting that they can produce 30-100 kW units for about $1,000-2,000 per kW while commercial production of larger scale units (200 kW – 2 MW) would drive down the costs significantly to $600-$1,000 per kW.

The majority of economic data available is for the flow reversal reactors. Field-scale and bench-scale tests of the MEGTEC TFRR and the CANMET CFRR, respectively, have provided more reliable cost data than other technologies. In 2003, EPA released the report, "Assessment of the Worldwide Potential for Oxidizing Coal Mine Ventilation Air Methane," the most comprehensive assessment to date of the marginal abatement costs of VAM use technologies. With methane abatement costs at $3.00 per tonne of CO2e, VAM-derived power projects in the U.S. could theoretically create 457 MW of net useable capacity. If the equipment value for each project were rounded to $10 million, the total equipment market estimate for the U.S. would be over $1.2 billion. Finally, the annual revenues that could accrue from such power sales in the country could amount to over $120 million (USEPA, 2003).

Local Use

In addition to pipeline injection, power generation, and ventilation air methane use, coal mine methane may be used as a fuel in on-site preparation plants or vehicle refueling stations, or it can be transported to a nearby coal-fired boiler or other industrial or institutional facilities for direct use.

Nearly all large underground coal mines have preparation plants located nearby. Mines have traditionally used their own coal to fuel these plants, but there is the potential to use recovered methane instead. Currently, CONSOL uses recovered methane to fuel the thermal dryer in one of its preparation plants. In Poland, several coal mines have used recovered methane to fuel their coal drying plants.

Another option for on-site methane use may be as a fuel for mine vehicles. Natural gas is much cheaper and cleaner than diesel fuel or gasoline, and internal combustion engines burn it more efficiently.

In addition to on-site methane use, selling recovered methane to a nearby industrial or institutional facility may be a promising option for some mines. An ideal gas customer would be located near the coal mine (within five miles) and would have a continuous demand for gaseous fuel. Coal mine methane could be used to fuel a cogeneration system, to fire boilers or chillers, or to provide space heating. In some cases, local communities may find that the availability of an inexpensive fuel source from their local mine can help them attract industry and generate additional jobs.

Additionally, there are numerous international examples of mine gas being used for industrial purposes. For example, in Ukraine and Russia, recovered methane is used in coal-fired boilers located at the mine-site. In the Czech Republic, coal mine methane is used in nearby metallurgical plants. In Poland, recovered methane is used as a feed-stock fuel in a chemical plant. In China, methane has been used in carbon black plants.

Finally, co-firing methane with coal in a boiler is another potential utilization option, particularly for mines that are located in close proximity to a power plant. A few of the mines profiled in this report are located within a few miles of a coal-fired plant (for example, Robinson Run is located about three miles from Allegheny Power's Harrison Plant).

Flaring

Environmentally, flaring methane is nearly as beneficial as utilizing the methane as fuel, since flaring changes the majority of the methane to carbon dioxide. Emitting carbon dioxide is much less harmful in terms of the impact on global warming than is the direct emission of methane. For purposes of greenhouse gas reductions, the value of recovering one ton of methane and using it to generate energy (in lieu of burning natural gas from a traditional source) is equivalent to a 21 ton reduction in carbon dioxide emissions. If mine emissions are flared without using the combustion to displace energy from other sources, flaring yields greenhouse gas reductions equal to 87.5% of those achievable through recovery and use (Lewin, 1997).

Although there are flares at a closed mine in the U.S., to date, flaring has not been implemented at active mines in the U.S. The principal concern expressed by the coal industry is that it is not safe to pipe the gas to a point where it would be flared because of the potential for the flame to propagate back down to the mine and to cause an underground explosion (Lewin, 1995). If agreement on the safe practice of flaring methane recovered from coal mines is reached, flaring could become an additional option for mitigating methane emissions, however, the flaring option still requires acceptance of miners, MSHA, union parties, and mine owners. Through a series of reports, EPA has outlined the benefits of flaring and addressed these concerns by offering a conceptual flare design (USEPA, 1999).

Green Pricing Projects

With the advent of competition in the electric utility industry, utilities are recognizing the need to provide new services to customers. One such service is "green pricing". Under green pricing, customers can choose the type of electricity they purchase. Customers can choose conventional power, which they can purchase at a standard rate, or they can purchase green power at a slightly higher rate. As part of the green pricing program, for every customer who commits to pay the higher rate, the utility pledges to buy enough "environmentally friendly" energy to completely offset the customer's share of conventionally generated electricity. In 2000, the State of Pennsylvania Public Utility Commissions included CMM as a renewable energy source as part of their green pricing program.

Another result of electric utility industry deregulation is the emergence of laws and regulations to encourage investment in renewables. Twenty-one States and the District of Columbia have enacted “renewable portfolio standards” (RPS), which require electric utilities to generate a portion of their electricity through qualifying renewable technologies by a specific date in the future. The requirements under the various standards and the definition of renewable energy vary by state. Currently, Pennsylvania is the only state with an RPS to include CMM as a qualifying renewable source.

Barriers to the Recovery and Use of Coal Mine Methane

While a number of U.S. coal mines are already selling recovered methane to pipelines, numerous seemingly profitable projects have not been undertaken at other mines. Currently, a number of problems and disincentives exist that distort the economics of coal mine methane projects, with the result that many potentially profitable investments are not being developed. These obstacles include unresolved legal issues concerning ownership of the coalbed methane resource, power prices and pipeline capacity constraints, among other technical challenges.

Ownership of Coalbed Methane

Unresolved legal issues concerning the ownership of coalbed methane resources have constituted one of the most significant barriers to coalbed methane recovery. Ambiguity in certain state legal systems provides a disincentive for investment in coalbed methane projects because of the uncertainties as to which parties may demand compensation for development of the resource. Although ownership legislation has improved the investment climate, coalbed methane industry forums have still identified ownership issues as serious obstacles to methane recovery. Courts are being called upon on a case-by-case basis to determine the ownership of coalbed methane in situations where mining and mineral rights have been severed from land ownership. The issue is simply whether the owner of the rights to the coal and/or gas also owns the coalbed methane rights. Resolution can happen only after all the facts are considered in each case.

Power Prices

Another factor contributing to the slow development of CMM-fueled power generation is the low prices of electricity in many U.S. coal producing regions. When comparing the economics of power generation to other alternatives, low electricity prices have resulted in power projects not being as attractive, regardless of the designated end-use for the power, whether it be on-site at the mine to offset electricity purchases, or to sell the power to the local utility.

Production Characteristics of Coalbed Methane Wells

<u>Gas Production</u>

Coalbed methane degasification wells have production characteristics that differ from conventional gas wells in a variety of respects. One important difference is the amount of control the developer has in terms of the gas flow. With conventional gas wells, the gas flow may be controlled, or completely halted, at the discretion of the operator. This provides the operator with flexibility as to when the gas is sold. Vertical pre-mine degasification wells can be controlled as their production is not directly related to mining activities. In-seam and gob wells, however, are not subject to the same control by virtue of their purpose. These wells are used primarily to drain a mine of methane for safety reasons. As such, the feasibility of turning off and on an in-seam or gob well depends on safety first and gas production second.

The production characteristics of coalbed methane wells present difficulties in the context of the natural gas and pipeline industries. Much of the consumer demand for natural gas is seasonal in nature. In addition, in situations of limited pipeline capacity, local pipelines may not be able to accept the gas supplied from coalbed methane projects on a continuous, uninterrupted basis. In particular, some areas of the Appalachian region have limited pipeline capacity. Storage of coalbed methane in depleted natural gas reservoirs or abandoned mines is an excellent means of overcoming problems related to fluctuations in demand or pipeline capacity. EPA has investigated the potential for storing methane recovered from active coal mines in nearby abandoned coal mines, concluding that if the abandoned mine were to meet certain criteria a project could be sustainable (USEPA, 1998).

Water Production

Another area in which technical challenges may arise is water disposal. In many instances, vertical coalbed methane wells will produce water from the coal seam and surrounding strata. Water is also produced during conventional mining operations, but some states have adopted separate regulations for water produced in association with coalbed methane operations and for water produced as a result of mining operations. For mines located near fresh water bodies or other vulnerable areas, surface water disposal may not be environmentally acceptable. Several alternative disposal and treatment methods are in use or under development, including deep well injection and other surface treatment approaches. These treatments may have higher costs associated with them, and in some cases additional research is needed to address technical issues.

3. Overview of Existing Coal Mine Methane Projects

3. Overview of Existing Coal Mine Methane Projects

Coal mine methane recovery and use is a proven technology. This chapter discusses methane recovery and use projects at 12 mines profiled in Chapter 6. In 2003, total methane sales from coal mine methane projects at profiled mines was nearly 40 billion cubic feet, which is the equivalent of nearly 18 million tons of carbon dioxide.[9] At the current wellhead gas price of roughly $6 per thousand cubic feet[10], and assuming that all recovered gas was sold to a pipeline, these projects collectively will have grossed approximately $240 million dollars in annual revenues. Additionally, by working to maximize the amount of gas recovered from their drainage systems, these projects have greatly reduced mine ventilation costs and have improved safety conditions for miners.

The projects in Alabama, Colorado, New Mexico, Pennsylvania, Virginia, and West Virginia employ a variety of degasification techniques, including vertical wells (pre-mining degasification), gob wells, and in-mine boreholes. Regardless of the degasification system employed, all mines have been able to recover large quantities of gas suitable for use in various applications. Following is a brief overview of the existing projects, arranged by location. Table 3-1, at the end of this chapter, summarizes the major characteristics of the existing projects.

Alabama

Five mines in Alabama recover and sell methane: Blue Creek No. 4, Blue Creek No. 5, Blue Creek No. 7, Oak Grove and Shoal Creek. The Blue Creek No. 4, No. 5 and No. 7 mines are owned by Jim Walter Resources (JWR), while the Oak Grove Mine is owned by U.S. Steel Mining, and the Shoal Creek Mine is owned by Drummond Coal.

Jim Walter Resources (JWR)

Blue Creek No. 4, No. 5, and No. 7 Mines

Located in Jefferson County, Alabama, the JWR mines are among the deepest and gassiest mines in the country. Opened in the early to mid-1970's, the mines cover an 80,000 acre area and have vertical shafts ranging from 1,300 to 2,100 feet in depth. The in-situ gas content of coal is about 500 to 600 cubic feet per ton and the total amount of methane liberated from these mines is estimated to be between 1,800 – 3,900 cubic feet per ton of coal produced.

JWR has been a leader in the development of coal mine methane recovery projects in the United States. The company's Blue Creek mines – the Nos. 4, 5, and 7 mines – are currently recovering and selling approximately 23 million cubic feet of gas per day. Methane is produced using three recovery methods: 1) vertical degasification (holes drilled from the surface into the virgin coalbed); 2) horizontal degasification (holes drilled in the coalbed from active workings inside the mine); and 3) a gob degasification program (holes drilled from the surface into the caved area behind the longwall faces).

Since the late 1980s, JWR has been producing between 25 – 35 mmcf/d of methane. As of December 2001, there were 256 wells producing approximately 27 mmcf/d. Since then, production has declined to 23 mmcf/d in 2003. The quantity of methane recovered in 2003 represents 46 percent of total methane liberated from the mines. Depending on the mine, recovery from vertical pre-mine wells in

[9] Methane emissions may be converted to a measure equivalent to carbon dioxide, since methane is 21 times more potent than carbon dioxide over a 100 year time frame.

[10] EIA - Average price for July 2005.

2003 made up approximately 5 - 25 percent of production, while gob wells and in-mine boreholes made up the remaining 75 - 95 percent of production.

U.S. Steel Mining

Oak Grove Mine

U.S. Steel Mining's (USM's) Oak Grove Mine produces methane for pipeline sales. USM is a subsidiary of USX, Incorporated (formerly U.S. Steel Corporation). Oak Grove is located in the east-central portion of the Black Warrior Basin of Jefferson County, Alabama. The target seam for mining is the Blue Creek bed of the Mary Lee coal group. The coal is mined at a depth of approximately 1,150 feet.

The effectiveness of a large-scale pattern of stimulated vertical wells in reducing the gas content of a coalbed was first demonstrated at the Oak Grove Mine in 1977. This was the first large-scale coal seam degasification project in the United States using vertical wells, as well as one of the first coalbed methane production projects. After 10 years, the original wells had produced a total of 3.2 Bcf (billion cubic feet) of methane that will never need to be controlled in the underground mine environment. Most of the wells in the field, however, are well beyond the near-term mine plan. In 2003, pre-drainage wells that are scheduled to be mined-through during the next few years produced nearly 4 mmcf/d. In addition to the vertical wells drilled in advance of mining, Oak Grove Mine also has utilized both horizontal and gob wells for methane drainage, primarily to increase the safety of the underground mine. Since 1997, as many as 15 gob and horizontal wells have been in production in a given year. In 2003, nine of these wells remained in production, producing 150 mcf/day.

Because the sole goal of other companies drilling in the Oak Grove Degasification Field is commercial methane production, rather than reducing emissions from future mining operations, most of the wells drilled since 1985 have been spaced on a 160-acre (or greater) pattern. While these wells do drain methane from the area to be mined, the wider well spacing does not drain the coal as effectively as would a true vertical pre-mine drainage program.

Drummond Coal

Shoal Creek Mine

Drummond Coal's Shoal Creek Mine began producing coal in 1994. The mine entry is located in the Oak Grove Field, but mining will progress into the White Oak Field. Currently, Shoal Creek is using vertical pre-mine, horizontal and gob wells to drain methane. The pre-mine wells in the White Oak Field are operated by Saga Petroleum, Amoco Production Co., McKenzie Methane Co., Kukui Operating Co., and El Paso Production Co. Nearly 37 wells produced about 1 mmcf of methane per day for pipeline sales in 2003. In 2003, there were six gob wells, which produced 415 mcf/d, in addition to 31 horizontal wells that produced 580 mcf/d.

Colorado

There is one methane recovery and use project underway in Colorado. The project is taking place at the West Elk mine, which is owned by Mountain Coal.

Mountain Coal (a subsidiary of Arch Coal Co,)

West Elk

West Elk began recovering methane in 2003 to heat mine ventilation air on site.

New Mexico

There is one methane recovery and use project underway in New Mexico. The project involves the San Juan South mine, which is owned by a subsidiary of BHP Billiton.

San Juan Coal Co. (a subsidiary of BHP Billiton)

San Juan South

This longwall mine opened in 2002 and initiated methane recovery for pipeline sales in 2003. San Juan South represents a surface mine that decided to continue operations underground.

Pennsylvania

There is one methane recovery and use project underway in Pennsylvania. The project involves three mines owned by CONSOL. Because the main portals for these mines are in West Virginia, they are categorized as West Virginia mines in Chapter 6 (the individual mine profiles section of this document). However, significant sections of the mines extend into Pennsylvania, and the majority of the gas produced is from coal and strata in Pennsylvania, therefore this methane recovery and use project is classified as a Pennsylvania project. Of the three mines, two are abandoned; therefore this report will only focus on the active mine.

Consolidation Coal Company (a subsidiary of CONSOL Energy)

Blacksville No. 2

CONSOL and CBE Inc. are undertaking a gas enrichment and sales project at the Blacksville No. 2 Mine. In 1997, CBE began selling enriched gas directly to the pipeline. The project captured as much as 4 mmcf/day from the mine, and removed carbon dioxide, oxygen and nitrogen from the gas using catalytic, amine and cryogenic processes respectively. Columbia Energy Services purchases the resulting pipeline-quality gas. The enrichment plant is able to process 5-6 mmcf/d of gas whose methane content (prior to enrichment) is about 80-85%. The project can be expanded to process 10-12 mmcf/d. Operational problems in 2000 and 2001 have kept the project from maintaining its maximum output. Since that time, CONSOL has assumed full responsibility for the project and expects to optimize the production.

Virginia

The commercial potential of coalbed methane recovery in Virginia has long been recognized, but complicated issues regarding gas ownership, as well as the lack of pipeline capacity in southwest Virginia, delayed commercial coalbed methane recovery in this area until the early 1990's. There are two methane recovery and use projects currently underway in Virginia. These projects are taking place at the Buchanan and VP No. 8 mines. The CONSOL Coal Group owns both mines.

CONSOL

CONSOL recovers methane from two of the gassiest mines in the southwestern region of Virginia: Buchanan and VP No. 8. One of these mines, VP No. 8 was born out of the consolidation of the VP No. 5 and VP No. 6 mines in 1994. CONSOL has operated the adjacent Buchanan No. 1 Mine since 1983. The company has developed extensive degasification programs on both their properties, and continues to invest in vertical pre-mine wells. Although more gas can be successfully drained if a vertical pre-mine well has been in place for a long period, CONSOL has been opting for an advance drainage time frame that adequately balances the risk of investing in a vertical pre-mine drainage system with that of the company's mining plans. Thus, the company uses a three to five year advance degasification program to the extent that this can be feasibly coordinated with the company's overall mining strategies.

Currently, CONSOL produces gas for pipeline sales, on site use, and power generation. The total methane drained at the two CONSOL Virginia mine properties totaled nearly 76 mmcf/d in 2003. This number significantly exceeds ventilation emissions of 15 mmcf/d, which indicates that much of the produced gas comes from virgin coals that CONSOL may mine in the future, and/or that recovery efficiencies are higher than standard EPA assumptions.

Of the 76 mmcf/d of methane that CONSOL currently recovers, approximately 74 mmcf/d can be attributed to emissions reduction at the mines, with an additional 2 mmcf/d being used on-site in a thermal dryer. Of the total recovered methane, gob wells and in-mine horizontal boreholes account for approximately 67 percent of methane production at the mines. Vertical pre-mine wells that have been mined through and impact emissions reductions at the mines account for the remaining 33 percent. This production from the vertical wells represents only about one third of the total gas sales occurring in the coals being drained ahead of mining.

Buchanan Mine

A deep and gassy mine, Buchanan is actively mining at a depth of about 1,500 feet and has an in-situ gas content of about 3,318 cf/ton. Beginning in May 1995, Buchanan began using recovered methane, instead of coal, as fuel in its thermal dryer. As of May 1997, the thermal dryer consumed approximately 1.5 mmcf/d, or 547.5 mmcf/year (CONSOL, 1997). In addition, over 7 mmcf/d was recovered from gob and horizontal wells at the mine in 2001. After 2001, CONSOL began reporting methane recovered from the Buchanan and VP No. 8 projects together.

VP No. 8 Mine

Gas sales started in May 1992 at a rate of 3 mmcf/d. Over the next twelve months, production had grown to more than 30 mmcf/d (about 11 Bcf per year). In 2001, gas sales exceeded 60 mmcf/d via three methods, vertical pre-drainage wells, horizontal boreholes, and gob wells. Additionally, CONSOL recovers methane from abandoned areas at the VP and Buchanan mines. Once a methane drainage program from an abandoned area is completed, that area is sealed and no further methane extraction takes place (CONSOL, 1997). After 2001, CONSOL began reporting methane recovered from the Buchanan and VP No. 8 projects together.

West Virginia

There are two methane recovery and use projects currently underway in West Virginia[11]. These projects are taking place at the Federal No. 2 and Pinnacle No. 50 mines. The Federal No. 2 Mine is owned by Peabody Coal and the Pinnacle No. 50 Mine is owned by U.S. Steel Mining.

Peabody Energy

Federal No. 2 Mine

Federal No. 2 currently drains methane using vertical gob wells. The mine markets gas recovered from some higher quality gob wells to a natural gas pipeline. This gas project is a joint venture with Dominion Gas Company. Dominion recovered approximately 0.8 mmcf/d in 2003. The project at Federal No. 2 continues to expand as more sealed longwall panels become available to drain.

Eastern Associated Coal and Northwest Fuel Development are involved in a Department of Energy funded effort to evaluate the use of an integrated power generation system comprised of IC engines and gas turbines (USDOE, 2000). This combination of equipment will allow low quality and variable quality gob gas to be used as a fuel. The electricity produced will power CNG's existing coalbed methane pipeline injection operations at the mine site. A generation capacity of 1.2 MW is planned.

The Federal No. 2 power project will build upon an aggressive coalbed methane degasification and commercialization project that likely will involve in-seam horizontal boreholes, gob wells, and vertical pre-mine wells.

U.S. Steel Mining Co. (a subsidiary of USX Corp.)

Pinnacle No. 50 Mine

USM's Pinnacle No. 50 Mine, located in West Virginia, produces methane for pipeline sale. Currently, the mine sells recovered coal mine gas to a local pipeline company. Until recently, methane recovery in the area had been hindered by high road and location costs. As a result, CDX Gas, LLC now uses a unique horizontal borehole drainage system called the Z-Pinnate Horizontal Drilling and Completion technology. Under this dual system approach, a vertical well was drilled first and the target coal seam was cavitated. Then a horizontal hole was kicked off from a second well, which intersected the cavity of the first well. The cavity acts as a down-hole water separator, retaining water while gas flows to the production well. Finally, a lateral well was drilled through the cavity along the coal seam for up to 4800 feet. When the drill was pulled back along this main branch, paired branches were drilled at 45 degrees to the main, yielding a “barbed” appearance from a plan view. This process continued back toward the production well, creating a series of barbed branches that CDX calls a “pinnate” drilling pattern. Four of these patterns can be drilled from a central well.

In 2003 the Pinnacle Mine recovered and sold approximately 1.5 mmcf/d of gas from its pre-mine drainage wells. In addition, the mine uses gob vent boreholes to drain methane, but currently does not recover this gas.

[11] Another project involving three West Virginia mines is discussed under the "Pennsylvania" section earlier in this chapter, for reasons explained in therein.

Summary

Table 3-1 summarizes the methane recovery and use projects discussed in this chapter.

Table 3-1: Summary of Existing Methane Recovery and Use Projects

Mine Name	Mine Location (State)	Approximate Amount of Gas Used in 2003	Methane Use Option	Notes
Blue Creek No. 4 Blue Creek No. 5 Blue Creek No. 7	Alabama	23 mmcf/day	Pipeline Sales	The three mines collectively produced 23 mmcf/day of gas in 2003.
Oak Grove	Alabama	4 mmcf/day	Pipeline Sales	Most of the production in the Oak Grove Field is beyond the limits of the mine plan.
Shoal Creek	Alabama	1 mmcf/day	Pipeline Sales	Most of the production from the White Oak Field is outside the limits of the mine plan.
West Elk	Colorado	110 mcf/day	On-Site Use Heaters	Began recovering methane in 2003.
San Juan South	New Mexico	110 mcf/day	Pipeline Sales	Mine opened in 2002 and methane recovery began in 2003.
Buchanan VP #8	Virginia	76 mmcf/day	Pipeline Sales On-Site Use Power Generation	These two mines collectively produced 76 mmcf/day of gas in 2003, of which 74 mmcf/d contributes to emissions reduction at the mines. A small portion (2 mmcf/d) of the total gas production is used on-site in a thermal dryer.
Blacksville No. 2	Pennsylvania	3 mmcf/day	Pipeline Sales	Gas is produced from two abandoned mines that are part of the project, but over 3 mmcf/d is from the active mine alone.
Federal No. 2	West Virginia	820 mcf/day	Pipeline Sales	Project continues to expand as more longwall panels become available to drain.
Pinnacle No. 50	West Virginia	2 mmcf/day	Pipeline Sales	A unique, horizontal pre-mine drainage program is utilized.

4. A Key to Evaluating Mine Profiles

4. A Key to Evaluating Mine Profiles

This report contains profiles of coal mines that are potential candidates for the development of methane recovery and use projects. Also included are mines that already have installed methane recovery and use systems. The mines that are profiled were selected primarily on the basis of their annual methane emissions from ventilation systems as recorded in a Mine Safety and Health Administration database (MSHA, 2004). While this report is thought to contain a comprehensive listing of the best candidates for cost-effective methane recovery projects, it is possible that some promising candidate mines have not yet been identified.

The mine profiles presented in this report are designed to assist interested parties in identifying mines that can sustain a profitable methane recovery and use project. Each mine profile is comprised of the following sections:

- geographic data
- corporate information
- mine address
- general information
- production, ventilation and drainage data
- energy and environmental value of emission reductions
- power generation potential
- pipeline sales potential
- other utilization possibilities

The mine profiles are ordered alphabetically by state, then by mine name. Following this chapter are summary tables that list key data elements shown in the mine profiles. Summary Table 1 lists all profiled mines in alphabetical order. The individual mine profiles follow the summary tables.

Operating Status

Each mine's operating status as of December 2003 is listed at the top right-hand corner of each profile. The operating status may be listed as described below:

Active: These mines are currently producing coal.

Idle: A mine that is open but not currently producing coal.

The current operating status was determined by reviewing coal industry publications that track the production status of coal mines, and through discussions with MSHA district offices and sources in the coal industry. No closed or abandoned mines are included in this report.

Geographic Data

The first section of each profile gives the geographic location of the mine, including the state, county, coal basin where the mine is located, and the coalbed(s) from which it produces coal. The sources for this information were MSHA (2004) and the Keystone Coal Industry Manual (Keystone, 2004).

State: Mines included in this report are located in the following states -- Alabama, Colorado, Illinois, Indiana, Kentucky, New Mexico, Ohio, Oklahoma, Pennsylvania, Utah, Virginia, or West Virginia. Summary Table 2 shows the mines listed by state.

County: A relatively small number of counties contain a majority of the gassy mines in the country. Summary Table 2 shows the mines listed by state and by county.

Coal Basin: Mines are located in one of five major coal producing regions: the Black Warrior Basin, the Central Appalachian Basin, the Northern Appalachian Basin, the Illinois Basin, or one of the "Western basins" (Central Rockies, San Juan, or Uinta Basin), which are located in the states of Colorado, Utah and New Mexico. Major geological characteristics of coal seams, including methane content, sulfur content, depth, and permeability tend to vary by basin. Summary Table 3 lists the mines by basin and 2003 estimated specific emissions per ton of coal mined for each listed mine.

Coalbed: Substantial and detailed information has been published on the geological and mining characteristics of major coalbeds occurring in the United States. Summary Table 4 lists mines according to the seam from which they produce their coal.

Corporate Information

Current Owner: Current owner refers to the mining company that owns the mine. Summary Table 5 lists mines by mining company. The sources for this information were the MSHA database (MSHA, 2004) and the Keystone Coal Industry Manual (Keystone, 2004).

Parent Company: Many coal companies are owned by a parent company. In addition to showing the coal companies, Summary Table 5 also shows the parent corporation of the mining company. This information was taken from Keystone (2004).

Previous Owner: The names of previous mine owners are useful as some of the coal mines profiled here have had numerous owners. This information, along with the previous or alternate name of the mine, is based on previous editions of the Keystone Coal Industry Manual.

Previous or Alternate Name: Mines frequently undergo name changes, particularly when they are purchased by a new company. This section lists previous or alternate mine names.

Mine Address

This section includes the phone number and mailing address of the mine and a contact name. The principal source of this information was the Keystone Coal Industry Manual. The phone numbers and mailing addresses are believed to be current. The contact names, however, may be somewhat out of date because the most recent editions of the Keystone Coal Industry Manual have not included this information for all of the mines. If contact information was not available in the Keystone Coal Industry Manual, contact information from the Energy Information Administration's (EIA) Coal Production Data Files for the year 2003 was used (EIA, 2003).

General Information

Number of Employees: This field shows the number of people employed by the mine, as reported in the Keystone Coal Industry Manual. If employment information was not listed in the Keystone Coal Industry Manual, the MSHA Data Retrieval System was consulted and the number of employees corresponding to year 2003 was used.

Year of Initial Production: Year of initial production indicates the age of the mine, as reported in the Keystone Coal Industry Manual.

Life Expectancy Life expectancy can be an important factor in determining whether a mine is a good candidate for a methane recovery and use project. Information on life expectancy was collected from various Keystone Coal Industry Manuals. However, given the difficulty in predicting mine life this statistic is perhaps only marginally useful, and care should be exercised in basing decisions on this factor.

Prep Plant Located On Site: The profile indicates whether a preparation plant is located at the mine, based on the Keystone Coal Industry Manual's and *Coal Age* magazine's annual prep plant surveys. At the preparation plant, coal is crushed, cleaned and dried. Most large mines have a prep plant located within close proximity. In some cases, a prep plant will process coal not only from the on-site mine, but also from other nearby mines. Information regarding whether the mine has a prep plant, and the amount of coal processed, is of importance in determining the mine's total electricity and fuel demands.

Mining Method: Mines are classified as longwall or continuous (room-and-pillar), based on *Coal Age* magazine's annual longwall survey and on information in coal industry publications. The mining method used is important for several reasons. First, longwall mines tend to emit more methane than do room-and-pillar mines, as the longwall technique tends to cause a more extensive collapse of, and relaxation of the methane-rich strata surrounding the coal seam. Furthermore, longwall mining has higher up-front capital costs. Thus, a company is not likely to invest in a longwall at a mine that is not expected to have a fairly long life. Finally, while continuous mining is the more common method, the number of longwall mines is growing. In fact, the longwall technique seems to be the preferred mining method at the largest and gassiest mines. All mines not listed on the longwall survey were assumed to be continuous. Summary Table 6 lists mines by mining method.

Primary Coal Use: Coal may be used for steam and/or metallurgical purposes. Steam coal is used by utilities to produce electricity, while metallurgical coal is used to produce coke. The primary coal use is based on information in the Keystone Coal Industry Manual. Summary Table 7 lists mines by primary coal use.

Btus/lb: Btus (British Thermal Units) per pound of coal produced indicates the heating value of the coal. This statistic, which was taken from the Keystone Coal Industry Manual, is used in comparing the energy value of the coal to the energy value of the methane recovered (see section on Environmental and Energy benefits below). Heating values were not available for all mines. Where coal analysis for individual mines was not available, mean heating values for the basin/seam were used.

Production, Ventilation and Drainage Data

This section presents the quantity of methane emitted from, and the amount of coal produced by, the profiled mines for each of the years 1999 to 2003.

Coal Production:[12] Most of the mines profiled in this report are large, with production exceeding one million tons per year. Annual coal production is an important factor in determining a mine's potential for profitable methane recovery. Generally, larger mines will be better candidates because of the potential for high methane production and because they are more likely to be able to finance the large capital investments required for a methane recovery and utilization project. Coal production was based primarily on annual Energy Information Administration (EIA) reports, but was supplemented

[12] In the July 2004 edition of this report the coal production values listed in the Profiled Mines Section (Section 6) for year 2001 were actually production values for year 2000. However, the coal production values in Table 8 were correct. This error has been corrected in the current report.

with data from coal producing states. Summary Table 8 lists the coal mines by the amount of coal they produced in 2003.

Estimated Total Methane Liberated: Methane liberation is the total volume of methane that is removed from the mine by ventilation and drainage. Liberation differs from emissions in that the term emissions, as used in this report, refers to methane that is not used and is therefore emitted to the atmosphere. Estimated total methane liberated is the sum of "emissions from ventilation systems" and "estimated methane drained." For mines that do not use or sell any of their methane, estimated total methane liberated equals estimated methane emissions to the atmosphere. The volume of methane liberated is shown for the years 1999-2003. Summary Table 10 shows mines listed by their estimated total daily methane liberation for 2003.

Emissions from Ventilation Systems: Methane released to the atmosphere from ventilation systems is emitted in very low concentrations (typically less than one percent in air). MSHA field personnel test methane emissions rates at each coal mine on a quarterly basis. Testing is performed underground at the same location each time. However, MSHA does not necessarily conduct the tests at precise three-month intervals, nor are they always taken at the same time of day. The ventilation emissions data for a given year are therefore averages of the four quarterly tests, and are accurate to the extent that the data collected at those four times are representative of actual emissions. Summary Table 11 lists the mines by their 2003 ventilation emissions, based on MSHA data.

Estimated Methane Drained: Mines that employ degasification systems emit large quantities of methane in high concentrations. Summary Table 12 lists mines according to the estimated methane drained. In contrast to ventilation emissions, no agency requires mines to report the amount of methane they drain, and actual methane drainage data are therefore unavailable. Thus, EPA has estimated the volume of methane drained based on estimated drainage efficiency, as defined below. Based on information obtained from MSHA district offices, EPA has developed a list of 17 U.S. mines that have drainage systems in place. A list of the mines that have drainage systems is shown in Summary Table 9. For the purpose of estimating emissions from drainage systems, if a mine is listed as having a drainage system in place, it was assumed that the system was in place from 1993 onward.

Specific Emissions:[13] "Specific emissions" refer to the total amount of methane liberated per ton of coal that is mined. Specific emissions are an important indicator of whether a mine is a good candidate for a methane recovery project. In general, mines with higher specific emissions tend to have stronger potential for methane recovery. Summary Table 13 shows a list of mines ordered according to specific emissions. Note that the coal production and methane liberation values shown in this report have been rounded, whereas the data actually used to calculate the specific emissions values have not been rounded. Therefore, the specific emissions data shown in this report may differ from results that the reader would obtain by dividing the methane liberation values by the coal production values. This difference is strictly due to rounding, and does not reflect any error in the calculation of methane recovered.

Estimated Current Drainage Efficiency: In order to estimate the amount of methane emitted at mines that are believed to have drainage systems, it was assumed that these emissions would represent from 20-60 percent of total methane liberated from the mine. Thus, for mines that have drainage systems, ventilation emissions were assumed to equal 40-80 percent of total liberation, with emissions from drainage systems accounting for the remaining 20-60 percent. For mines that do not

[13] In the July 2004 edition of this report the specific emissions listed in the Profiled Mines Section (Section 6) for years 1997-2001 were incorrect. However, the specific emissions reported in Table 13 were correct. This error has been corrected in the current report.

already have drainage systems in place, ventilation emissions are assumed to equal 100 percent of total methane liberation.

The assumption that methane drainage accounts for 40 percent of total methane liberation is probably conservative for some mines, but optimistic for others. Therefore, drainage estimates of 20, 40, and 60% were calculated for each mine profile. Accordingly, the drainage efficiency of 40 percent is merely an arbitrarily chosen value, and may not reflect actual conditions at any one mine.

Drainage System Used: Seventeen of the mines profiled in this report use some type of drainage (or degasification) system to capture coal mine methane. Drainage systems used include vertical pre-mine (drilled in advance of mining), vertical gob wells, long-hole horizontal pre-mine, and horizontal pre-mine. Summary Table 9 lists mines by drainage system used.

Energy and Environmental Value of Emissions Reduction

This section presents information on the environmental and energy benefits that may be achieved by developing a methane recovery project at a mine.

CO_2 Equivalent of CH_4 Emissions Reductions (mmt/yr). This statistic shows the carbon dioxide (CO_2) equivalent of the *annual* methane emissions reductions that may potentially be achieved at each mine. The CO_2 equivalent of the potential methane emissions reductions is shown in order to facilitate the comparison of the environmental benefits of coal mine methane recovery projects to other greenhouse gas mitigation projects. The potential quantity of methane that may be recovered from a mine – which represents the emissions reductions that may be achieved – is converted to a CO_2 equivalent as follows:

CO_2 equivalent
(million tons/yr) = [CH_4 liberated (mmcf/yr) x recovery efficiency (20%, 40% and 60%) x 19.2 g CH_4/cf x 21 g CO_2/ 1 g CH_4 x 1 lb / 453.59 g x 1 ton / 2000 lbs]

where: 21 is the global warming potential (GWP) of emitting 1 gram of methane compared to emitting 1 gram of carbon dioxide over a 100 year time period[14]

19.2 g/cf is the density of methane at 60 degrees F and atmospheric pressure

The CO_2 equivalent is shown assuming a 20%, 40% and 60% recovery efficiencies (i.e., the portion of total methane emissions that are recovered and utilized). Summary Table 14 shows the CO_2 equivalent of the potential methane emissions reductions that may be achieved at each mine.

CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion: This ratio shows the reduction in CO_2 emissions from the combustion of methane instead of coal produced at the mine. The ratio is calculated by converting the methane recovered into a CO_2 equivalent (as described above) and dividing by the annual CO_2 emitted from the combustion of coal produced at the mine. In order to calculate the CO_2 emissions from coal combustion, the annual coal production is multiplied by the Btu value of the coal (see general information section for Btu value). Next, this value

[14] For further information on the global warming potential of various greenhouse gases see Intergovernmental Panel on Climate Change (1997).

is multiplied by an emissions factor of from 203 to 210 lbs CO_2 per million Btu.[15] Finally, the value is multiplied by 99 percent to account for the fraction oxidized. The formula is as follows:

> [CO_2 equivalent of potential annual CH_4 emissions reductions (lbs)] / [annual coal production (tons) x Btus/ton x lbs CO_2 emitted / Btu x 99% (fraction oxidized)].

The ratio is calculated assuming a 20%, 40% and 60% recovery efficiencies.

Btu Value of Recovered Methane/Btu Value of Coal Produced: In order to calculate this ratio, the potential annual quantity of methane recovered is multiplied by a value of 1000 Btus/cf. Annual coal production is multiplied by the Btus/ton value for the mine. The ratio of the energy value of the methane recovered to the energy value of the coal produced is then calculated. The formula is as follows:

> [Recovered methane (cf/yr) x 1000 Btus/cf] / [coal production (tons) x Btus/ton]

As with the other statistics in this section, the ratio is calculated assuming a 20%, 40% and 60% recovery efficiencies. In comparison with the first ratio (CO_2 equivalent of methane/ CO_2 emissions from coal combustion), the energy value of the methane emissions is a much smaller fraction of the energy value of the coal production.

Power Generation Potential

This section presents data relevant to the examination of whether the mine is a good candidate for an on-site electricity generation project.

Utility Electricity Supplier: The utility that supplies electricity to the mine is listed here, based on the service areas reported in the *North American Electric Power Atlas, 2001 Edition* (Electric Power, 2002). Summary Table 15 lists the utilities that sell power to the profiled mines.

Parent of Utility: The parent company of the local electric utility is also shown. This information is also based on the *North American Electric Power Atlas, (Electric Power, 2002).*

Total Electricity Demand (MW): The annual electricity demand – including the electricity demands of the mine plus the additional electricity load of the preparation plant – is calculated as follows:

Mine Electricity Demand Assumptions:

- Total annual electricity needs are estimated by assuming that 24 kWh are needed for each ton of coal mined.
- Ventilation systems are run 24 hours a day, 365 days a year (8760 hours a year) and account for about 25% of total electricity needs.
- Other mine operations run 16 hours a day for 220 days a year (3520 hours a year) and account for 75% of total electricity needs.

[15] The emissions factor used is based on average state values reported in Energy Information Administration (1992). For the states examined in this report, values range from about 203 to 210 lbs CO_2/mm Btu.

Demand (kWh/yr): 24 kWh/ton x tons mined/yr = kWhs/yr
Demand (kW): [(75% x kWhs/yr)/(3520 hours)] + [(25% x kWhs/yr)/8760 hours)]
(mine operations) + *(mine ventilation)*

Prep Plant Electricity Demand Assumptions:

Prep plants require 6 kWh/ton of coal processed
Prep plants are operated 16 hours a day, 220 days a year (3520 hours)
Demand (kWh/yr): 6 kWh/ton x tons/year
Demand (kW): [kWh/yr / 3520 hours]

Electricity Demand (GWh/year): The annual continuous electricity demand – including the electricity demands of the mine plus the additional electricity load of the preparation plant – is calculated as follows:

Mine Electricity Demand Assumptions:

Total annual electricity needs are estimated by assuming that 24 kWh are needed for each ton of coal mined.

Demand (kWh/yr): 24 kWh/ton x tons mined/yr = kWhs/yr

Demand (GWh/year): [Demand (kWh/yr)]/ 10^6

Prep Plant Electricity Demand Assumptions:

Prep plants require 6 kWh/ton of coal processed

Demand (kWh/yr): 6 kWh/ton x tons/year

Demand (GWh/year): [Demand (kWh/yr)]/ 10^6

Potential Electric Generating Capacity (kW):[16] The potential electric generating capacity (i.e., the amount of electricity that could be generated from recovered coal mine methane) is estimated by assuming that there are 1000 Btus/cf of methane recovered and that the heat rate of a generator would be about 11,000 Btu/kWh, which is a conservative assumption for a heat rate given that a gas turbine would likely be used for such a project. (Other technologies such as internal combustion engines may also be used to generate electricity). The capacity is estimated based on 20%, 40% and 60% recovery efficiencies (i.e. percentage of total emissions recovered). The formula is:

Generating Capacity (kW): CH_4 liberated in cf/day x 1 day/24 hours x 1000 Btus/cf x kWh/11,000 Btus.

Summary Table 16 lists the mines according to their potential electric generating capacity in MW.

[16] In the July 2004 edition of this report the range provided for the potential electric generating capacity in Table 16 was incorrect. Table 16 stated an assumed recovery efficiency of 20% – 60%. However, the range provided actually corresponded to a recovery efficiency of 20% - 40%. This error has been corrected in the current report.

Pipeline Potential

This section presents data that are useful in determining whether a mine is a good candidate for a pipeline sales project.

Potential Annual Gas Sales: Potential annual gas sales are estimated by multiplying total daily methane liberated by 365 days per year and then multiplying that value by the assumed recovery efficiency. Potential annual gas sales are calculated for 20%, 40%, and a 60% assumed recovery efficiencies and are presented in billion cubic feet. The estimated amount of gas that could be produced for sale to a pipeline at each candidate mine is shown in Summary Table 17.

Description of Surrounding Terrain: The terrain surrounding the mine is described, as this is an important factor in determining the costs of laying gathering lines for the project. While many mines in Appalachia are located in hilly or mountainous terrain, mines in the Illinois Basin tend to be located on relatively flat plains.

Transmission Pipeline in County: A "yes" indicates that an existing commercial pipeline runs through the county.

Owner of Nearest Pipeline: The corporate owner of the pipeline located closest to the mine is provided. If a mine is utilizing methane it is assumed that the owner of the nearest pipeline is the mine itself. The mine’s pipeline would connect the mine to a commercial pipeline.

Distance to Pipeline: The estimated distance from the closest pipeline to the mine is provided. Some western coal mines may be more than 20 miles from the nearest pipeline. In contrast, most eastern coal mines are located within ten miles of a commercial pipeline. However, while a mine may be located within close proximity to an existing gas pipeline, there are no guarantees that the pipeline will have enough capacity to take the gas produced from a coal mine. In particular, the Appalachian region tends to have limited pipeline capacity. If a mine is using methane it is assumed that the distance to the nearest commercial pipeline is zero, since the mine would have to have a pipeline in place to transport the gas.

Pipeline Diameter: The diameter (in inches) of the nearest pipeline is provided.

Other Utilization Possibilities

This section addresses the possibility of using methane in a nearby coal-fired power plant.

Name of Nearby Coal Fired Power Plant: A few of the mines profiled here are located less than ten miles from a coal-fired power plant. For these mines, the name of the nearby power plant is listed. The source of this information, along with the estimated distance to the power plant and the plant capacity is taken from the *North American Electric Power Atlas, (Electric Power, 2002).*

Distance to Plant: The profile shows the estimated distance between the mine and the nearby power plant.

Comments: This section briefly describes any other important information about the mine that is not listed in any other section.

Ventilation Air Methane Emissions

Table 18 in Chapter 5 summarizes certain characteristics of ventilation air methane (VAM) emissions that were derived for each mine from Mine Safety and Health Administration (MSHA) quarterly sampling data. For each shaft at gassy mines, MSHA samples methane concentration and ventilation airflow. The shaft-specific data were aggregated to derive weighted average methane emissions for each mine. The most current MSHA shaft emissions data available were used.

5. Mine Summary Tables

List of Summary Tables:

Table 1: Mines Listed Alphabetically

Mine Name	State	Mine Name	State
Aberdeen	UT	Justice #1	WV
American Eagle Mine	WV	Loveridge No. 22	WV
Bailey Mine	PA	Mc Elroy Mine	WV
Baker	KY	Mine #1	KY
Beckley Crystal	WV	No. 3 Mine	KY
Blacksville No. 2	WV	North River Mine	AL
Blue Creek No. 4	AL	Oak Grove Mine	AL
Blue Creek No. 5	AL	Pinnacle No. 50	WV
Blue Creek No. 7	AL	Pollyanna No. 8	OK
Buchanan Mine	VA	Pontiki No. 2	KY
Cardinal	KY	Powhatan No. 6 Mine	OH
Clean Energy No. 1	KY	RAG Cumberland Mine	PA
Dakota No. 2	WV	RAG Emerald Mine	PA
Deep Mine #26	VA	Robinson Run No. 95	WV
Dugout Canyon Mine	UT	San Juan South	NM
E3RF	KY	Sentinel Mine	WV
Eagle Mine	WV	Shoal Creek	AL
Eighty-Four Mine	PA	Shoemaker Mine	WV
Elk Creek Mine	CO	Upper Big Branch - South	WV
Elkhart Mine	IL	Virginia Pocahontas No. 8	VA
Enlow Fork Mine	PA	Wabash	IL
Federal No. 2	WV	West Elk Mine	CO
Freedom Energy No.1	KY	West Ridge Mine	UT
Galatia	IL	Whitetail Kittanning Mine	WV
Gibson	IN	Willow Lake Portal	IL

Table 2: Mines Listed by State and County

Mine Name	State	County	Mine Name	State	County
North River Mine	AL	Fayette	Enlow Fork Mine	PA	Greene
Oak Grove Mine	AL	Jefferson	RAG Cumberland Mine	PA	Greene
Shoal Creek	AL	Jefferson	RAG Emerald Mine	PA	Greene
Blue Creek No. 4	AL	Tuscaloosa	Eighty-Four Mine	PA	Washington
Blue Creek No. 5	AL	Tuscaloosa	Aberdeen	UT	Carbon
Blue Creek No. 7	AL	Tuscaloosa	Dugout Canyon Mine	UT	Carbon
Elk Creek Mine	CO	Gunnison	West Ridge Mine	UT	Carbon
West Elk Mine	CO	Gunnison	Buchanan Mine	VA	Buchanan
Galatia	IL	Saline	Virginia Pocahontas No. 8	VA	Buchanan
Willow Lake Portal	IL	Saline	Deep Mine #26	VA	Wise
Elkhart Mine	IL	Sangamon	Sentinel Mine	WV	Barbour
Wabash	IL	Wabash	Dakota No. 2	WV	Boone
Gibson	IN	Gibson	Justice #1	WV	Boone
Cardinal	KY	Hopkins	Robinson Run No. 95	WV	Harrison
E3RF	KY	Knott	American Eagle Mine	WV	Kanawha
Pontiki No. 2	KY	Martin	Eagle Mine	WV	Kanawha
Clean Energy No. 1	KY	Pike	Loveridge No. 22	WV	Marion
Freedom Energy No.1	KY	Pike	Mc Elroy Mine	WV	Marshall
Mine #1	KY	Pike	Blacksville No. 2	WV	Monongalia
No. 3 Mine	KY	Pike	Federal No. 2	WV	Monongalia
Baker	KY	Webster	Shoemaker Mine	WV	Ohio
San Juan South	NM	San Juan	Whitetail Kittanning Mine	WV	Preston
Powhatan No. 6 Mine	OH	Belmont	Beckley Crystal	WV	Raleigh
Pollyanna No. 8	OK	Le Flore	Upper Big Branch - South	WV	Raleigh
Bailey Mine	PA	Greene	Pinnacle No. 50	WV	Wyoming

Table 3: Mines Listed by Coal Basin

Coal Basin/ Mine Name	Estimated Specific Emissions (cf/ton)
Arkoma	
Pollyanna No. 8	929
Black Warrior	
Blue Creek No. 4	1,856
Blue Creek No. 5	3,791
Blue Creek No. 7	3,942
North River Mine	437
Oak Grove Mine	2,666
Shoal Creek	1,200
Central Appalachian	
American Eagle Mine	435
Beckley Crystal	1,809
Buchanan Mine	3,318
Cardinal	136
Clean Energy No. 1	265
Dakota No. 2	366
Deep Mine #26	619
E3RF	149
Eagle Mine	240
Freedom Energy No.1	211
Mine #1	156
No. 3 Mine	217
Pinnacle No. 50	2,064
Pontiki No. 2	132
Upper Big Branch - South	347
Virginia Pocahontas No. 8	8,992
Central Rockies	
Dugout Canyon Mine	267
Illinois	
Baker	898
Elkhart Mine	152
Galatia	238
Gibson	355
Wabash	279
Willow Lake Portal	138
Northern Appalachian	
Bailey Mine	223
Blacksville No. 2	571
Eighty-Four Mine	467
Enlow Fork Mine	382
Federal No. 2	725
Justice #1	565
Loveridge No. 22	6,402
Mc Elroy Mine	88
Powhatan No. 6 Mine	84
RAG Cumberland Mine	1,418
RAG Emerald Mine	631
Robinson Run No. 95	314
Sentinel Mine	1,114
Shoemaker Mine	206
Whitetail Kittanning Mine	265
San Juan	
San Juan South	223
Uinta	
Aberdeen	995
Elk Creek Mine	91
West Elk Mine	1,528
West Ridge Mine	443

Table 4: Mines Listed by Coalbed

Mine Name	Coalbed	Mine Name	Coalbed
West Elk Mine	B Seam	Eighty-Four Mine	Pittsburgh
Blue Creek No. 7	Blue Creek	Mc Elroy Mine	Pittsburgh
Oak Grove Mine	Blue Creek	Bailey Mine	Pittsburgh
Blue Creek No. 5	Blue Creek	Loveridge No. 22	Pittsburgh
Shoal Creek	Blue Creek, Mary Lee	Robinson Run No. 95	Pittsburgh
Blue Creek No. 4	Blue Creek, Mary Lee	Shoemaker Mine	Pittsburgh
Elk Creek Mine	D-seam	Federal No. 2	Pittsburgh
Eagle Mine	Eagle, Big Eagle	Powhatan No. 6 Mine	Pittsburgh No. 8
American Eagle Mine	Eagle, Big Eagle	Blacksville No. 2	Pittsburgh No. 8
Upper Big Branch - South	Eagle, Powellton	RAG Emerald Mine	Pittsburgh No. 8
Dugout Canyon Mine	Gilson, Rock Canyon	RAG Cumberland Mine	Pittsburgh No. 8
Pollyanna No. 8	Hartshorne	Dakota No. 2	Pittsburgh No. 8
Willow Lake Portal	Illinois No. 5 & 6	Virginia Pocahontas No. 8	Pocahontas No. 3
Whitetail Kittanning Mine	Kittanning	Buchanan Mine	Pocahontas No. 3
Sentinel Mine	Kittanning	Pinnacle No. 50	Pocahontas No. 3
Cardinal	KY No. 11	Freedom Energy No.1	Pond Creek
Aberdeen	L. Sunnyside, Gilson, Aber.	Pontiki No. 2	Pond Creek
West Ridge Mine	Lower Sunnyside	Clean Energy No. 1	Pond Creek
No. 3 Mine	NA	Justice #1	Powellton, Buffalo Crk
Beckley Crystal	NA	North River Mine	Pratt
Mine #1	NA	Wabash	Springfield No. 5
E3RF	NA	Elkhart Mine	Springfield No. 5
San Juan South	No 9, No. 8	Galatia	Springfield No. 5
Deep Mine #26	Norton, Upper Banner	Gibson	Springfield No. 5
Enlow Fork Mine	Pittsburgh	Baker	W. Kentucky No. 13

Table 5: Mines Listed by Company

Parent Company	Owner	Mine Name
ABC Coke Division -		
	Drummond Co., Inc.	Shoal Creek
Alliance Resource Partners		
	Warrior Coal, LLC	Cardinal
Alliance Resource Partners		
	Excel Mining	Pontiki No. 2
	Excel Mining LLC	No. 3 Mine
Alliance Resources Partners		
	Gibson County Coal, LLC	Gibson
Alpha Natural Resources LLC		
	Paramount Coal Corp.	Deep Mine #26
American Coal Company		
	The American Coal Co.	Galatia
Andalex Resources, Inc.		
	Andalex Resources, Inc.	Aberdeen
	West Ridge Resources	West Ridge Mine
Anker Energy Corp.		
	Anker West Virginia Mining Co.	Sentinel Mine
Arch Coal Co.		
	Canyon Fuel Co., LLC	Dugout Canyon Mine
	Mountain Coal Co.	West Elk Mine
BHP/Billitton		
	San Juan Coal Co.	San Juan South
Bluegrass Coal Devel. Co.		
	Turris Coal Company	Elkhart Mine
Chevron Texaco		
	Pittsburg & Midway Coal Mining	North River Mine

Table 5: Mines Listed by Company (cont.)

Parent Company	Owner	Mine Name
CONSOL Energy		
	Consol Energy Inc.	Bailey Mine
	Consol Energy Inc.	Blacksville No. 2
	Consol Energy Inc.	Buchanan Mine
	Consol Energy Inc.	Enlow Fork Mine
	Consol Energy Inc.	Loveridge No. 22
	Consol Energy Inc.	Mc Elroy Mine
	Consol Energy Inc.	Robinson Run No. 95
	Consol Energy Inc.	Shoemaker Mine
	Consol Energy Inc.	Virginia Pocahontas No. 8
	Consol of Kentucky, Inc.	E3RF
	Eighty-Four Mining Co.	Eighty-Four Mine
El Paso Corporation		
	Coastal Coal Co., LLC	Whitetail Kittanning Mine
James O. Bunn; Frank D.		
	Newtown Energy, Inc.	Eagle Mine
Lodestar Energy, Inc.		
	Lodestar Energy, Inc	Baker
Massey Energy Co.		
	Freedom Energy Mining Co.	Freedom Energy No.1
	Independence Coal Co., Inc.	Justice #1
	Massey Energy Co.	Clean Energy No. 1
	Performance Coal Co.	Upper Big Branch - South
	Rockhouse Energy Mining	Mine #1
Murray Energy Corporation		
	Ohio Valley Coal Co.	Powhatan No. 6 Mine
Oxbow Carbon & Materials		
	Oxbow Mining, Inc.	Elk Creek Mine
Peabody Energy Corp.		
	Big Ridge Inc	Willow Lake Portal
	Peabody Energy/Federal	Federal No. 2

Table 5: Mines Listed by Company (cont.)

Parent Company	Owner	Mine Name
RAG American Coal Co.		
	RAG Cumberland Resources, LP	RAG Cumberland Mine
	RAG Emerald Resources, LP	RAG Emerald Mine
	Wabash Mine Holding Co.	Wabash
Rainbow Trout Coal LLC		
	Dakota Mining, Inc.	Dakota No. 2
Robert L. Worley		
	Baylor Mining, Inc.	Beckley Crystal
South Central Coal Company		
	Sunrise Coal Co., LLC	Pollyanna No. 8
Timothy G. Elliott		
	Speed Mining, Inc.	American Eagle Mine
USX Corp.		
	U.S. Steel Mining Co., L.L.C.	Oak Grove Mine
	U.S. Steel Mining Co., L.L.C.	Pinnacle No. 50
Walter Industries, Inc.		
	Jim Walter Resources, Inc.	Blue Creek No. 4
	Jim Walter Resources, Inc.	Blue Creek No. 5
	Jim Walter Resources, Inc.	Blue Creek No. 7

Table 6: Mines Listed by Mining Method

Mine Name	Method	Mine Name	Method
American Eagle Mine	Continuous	Baker	Longwall/Continuous
Beckley Crystal	Continuous	Blacksville No. 2	Longwall/Continuous
Cardinal	Continuous	Blue Creek No. 4	Longwall/Continuous
Clean Energy No. 1	Continuous	Blue Creek No. 5	Longwall/Continuous
Dakota No. 2	Continuous	Blue Creek No. 7	Longwall/Continuous
Deep Mine #26	Continuous	Buchanan Mine	Longwall/Continuous
E3RF	Continuous	Dugout Canyon Mine	Longwall/Continuous
Eagle Mine	Continuous	Eighty-Four Mine	Longwall/Continuous
Elkhart Mine	Continuous	Enlow Fork Mine	Longwall/Continuous
Freedom Energy No.1	Continuous	Federal No. 2	Longwall/Continuous
Gibson	Continuous	Justice #1	Longwall/Continuous
Mine #1	Continuous	Loveridge No. 22	Longwall/Continuous
No. 3 Mine	Continuous	Mc Elroy Mine	Longwall/Continuous
Pollyanna No. 8	Continuous	North River Mine	Longwall/Continuous
Pontiki No. 2	Continuous	Oak Grove Mine	Longwall/Continuous
Sentinel Mine	Continuous	Pinnacle No. 50	Longwall/Continuous
Wabash	Continuous	Powhatan No. 6 Mine	Longwall/Continuous
Whitetail Kittanning Mine	Continuous	RAG Cumberland Mine	Longwall/Continuous
Willow Lake Portal	Continuous	RAG Emerald Mine	Longwall/Continuous
Elk Creek Mine	Longwall	Robinson Run No. 95	Longwall/Continuous
Galatia	Longwall	Shoal Creek	Longwall/Continuous
San Juan South	Longwall	Shoemaker Mine	Longwall/Continuous
West Ridge Mine	Longwall	Upper Big Branch - South	Longwall/Continuous
Aberdeen	Longwall/Continuous	Virginia Pocahontas No. 8	Longwall/Continuous
Bailey Mine	Longwall/Continuous	West Elk Mine	Longwall/Continuous

Table 7: Mines Listed by Primary Coal Use

Mine Name	Primary Use	Mine Name	Primary Use
Blue Creek No. 4	Metallurgical	Pontiki No. 2	Steam
Pinnacle No. 50	Metallurgical	Powhatan No. 6 Mine	Steam
Upper Big Branch - South	Metallurgical	RAG Cumberland Mine	Steam
Beckley Crystal	NA	Robinson Run No. 95	Steam
E3RF	NA	San Juan South	Steam
Eagle Mine	NA	Shoal Creek	Steam
Elk Creek Mine	NA	Shoemaker Mine	Steam
No. 3 Mine	NA	Wabash	Steam
Willow Lake Portal	NA	West Elk Mine	Steam
Aberdeen	Steam	West Ridge Mine	Steam
Baker	Steam	Whitetail Kittanning Mine	Steam
Blacksville No. 2	Steam	American Eagle Mine	Steam, Metallurgical
Cardinal	Steam	Bailey Mine	Steam, Metallurgical
Dakota No. 2	Steam	Blue Creek No. 5	Steam, Metallurgical
Dugout Canyon Mine	Steam	Buchanan Mine	Steam, Metallurgical
Elkhart Mine	Steam	Clean Energy No. 1	Steam, Metallurgical
Enlow Fork Mine	Steam	Deep Mine #26	Steam, Metallurgical
Federal No. 2	Steam	Eighty-Four Mine	Steam, Metallurgical
Galatia	Steam	Freedom Energy No.1	Steam, Metallurgical
Gibson	Steam	Justice #1	Steam, Metallurgical
Loveridge No. 22	Steam	Oak Grove Mine	Steam, Metallurgical
Mc Elroy Mine	Steam	RAG Emerald Mine	Steam, Metallurgical
Mine #1	Steam	Sentinel Mine	Steam, Metallurgical
North River Mine	Steam	Virginia Pocahontas No. 8	Steam, Metallurgical
Pollyanna No. 8	Steam	Blue Creek No. 7	Steam, Metallurgical, Ind.

Table 8: Mines Listed by 2003 Coal Production

Mine Name	MM Tons	Mine Name	MM Tons
Enlow Fork Mine	9.9	Gibson	2.4
Bailey Mine	9.4	Cardinal	2.4
Mc Elroy Mine	6.8	Whitetail Kittanning Mine	2.4
RAG Emerald Mine	6.6	Elkhart Mine	2.1
West Elk Mine	6.5	Pontiki No. 2	2.0
RAG Cumberland Mine	6.2	Mine #1	1.9
Galatia	6.0	E3RF	1.9
San Juan South	5.9	Virginia Pocahontas No. 8	1.9
Robinson Run No. 95	5.7	Blue Creek No. 7	1.9
Blacksville No. 2	5.4	Justice #1	1.8
Powhatan No. 6 Mine	4.9	Oak Grove Mine	1.7
Buchanan Mine	4.7	Wabash	1.6
Elk Creek Mine	4.6	No. 3 Mine	1.5
Federal No. 2	4.4	Dakota No. 2	1.5
American Eagle Mine	4.1	Eagle Mine	1.5
Eighty-Four Mine	4.0	Blue Creek No. 5	1.4
Shoemaker Mine	3.8	Freedom Energy No.1	1.4
Shoal Creek	3.8	Deep Mine #26	1.1
North River Mine	3.5	Clean Energy No. 1	1.0
Upper Big Branch - South	3.3	Baker	0.6
West Ridge Mine	3.0	Beckley Crystal	0.5
Dugout Canyon Mine	2.9	Aberdeen	0.4
Willow Lake Portal	2.9	Pollyanna No. 8	0.4
Blue Creek No. 4	2.8	Loveridge No. 22	0.3
Pinnacle No. 50	2.5	Sentinel Mine	0.3

Table 9: Mines Employing Methane Drainage Systems

Mine Name	Type of Drainage System	Estimated Current Drainage Efficiency
Blacksville No. 2	Vertical Gob, Horizontal Pre-Mine	45%
Blue Creek No. 4	Vertical Pre-Mine, Vertical Gob, Horizontal Pre-Mine	39%
Blue Creek No. 5	Vertical Pre-Mine, Vertical Gob, Horizontal Pre-Mine	46%
Blue Creek No. 7	Vertical Pre-Mine, Vertical Gob, Horizontal Pre-Mine	51%
Buchanan Mine	Vertical Pre-Mine, Vertical Gob, Horizontal Pre-Mine	83%
Federal No. 2	Vertical Gob, Horizontal Pre-Mine	13%
Loveridge No. 22	Vertical Gob, Horizontal Pre-Mine	82%
Oak Grove Mine	Vertical Pre-Mine, Vertical Gob	33%
Pinnacle No. 50	Directional Pre-Mine, Vertical Gob, Horizontal Pre-Mine	30%
RAG Cumberland Mine	Vertical Pre-Mine, Vertical Gob, Horizontal Pre-Mine	59%
RAG Emerald Mine	Vertical Gob, Horizontal Pre-Mine	35%
Robinson Run No. 95	Vertical Gob, Horizontal Pre-Mine	20%
San Juan South	Vertical Gob, Horizontal Pre-mine	65%
Shoal Creek	Vertical Pre-Mine, Vertical Gob, Horizontal Pre-Mine	35%
Shoemaker Mine	Vertical Gob, Horizontal Pre-Mine	15%
Virginia Pocahontas No. 8	Vertical Pre-Mine, Vertical Gob, Horizontal Pre-Mine	83%
West Elk Mine	Vertical Gob, Horizontal Pre-Mine	50%

Table 10: Mines Listed by Estimated Total Methane Liberated in 2003

Mine Name	MMCF/D	Mine Name	MMCF/D
Virginia Pocahontas No. 8	46.3	Gibson	2.4
Buchanan Mine	42.6	Beckley Crystal	2.3
West Elk Mine	27.2	Shoemaker Mine	2.2
RAG Cumberland Mine	24.3	Dugout Canyon Mine	2.2
Blue Creek No. 7	20.1	Deep Mine #26	1.9
Blue Creek No. 5	14.4	Whitetail Kittanning Mine	1.7
Blue Creek No. 4	14.2	Mc Elroy Mine	1.6
Pinnacle No. 50	14.0	Baker	1.5
Oak Grove Mine	12.6	Dakota No. 2	1.5
Shoal Creek	12.6	Aberdeen	1.2
RAG Emerald Mine	11.5	Wabash	1.2
Enlow Fork Mine	10.3	Elk Creek Mine	1.1
Federal No. 2	8.7	Powhatan No. 6 Mine	1.1
Blacksville No. 2	8.5	Willow Lake Portal	1.1
Bailey Mine	5.7	Pollyanna No. 8	1.0
Loveridge No. 22	5.3	Eagle Mine	1.0
Eighty-Four Mine	5.1	No. 3 Mine	0.9
Robinson Run No. 95	4.9	Sentinel Mine	0.9
American Eagle Mine	4.9	Elkhart Mine	0.9
North River Mine	4.2	Cardinal	0.9
Galatia	3.9	Mine #1	0.8
West Ridge Mine	3.6	Freedom Energy No.1	0.8
San Juan South	3.6	E3RF	0.8
Upper Big Branch - South	3.1	Clean Energy No. 1	0.8
Justice #1	2.8	Pontiki No. 2	0.7

Table 11: Mines Listed by Daily Ventilation Emissions in 2003

Mine Name	MMCF/D	Mine Name	MMCF/D
West Elk Mine	13.6	Dugout Canyon Mine	2.2
Enlow Fork Mine	10.3	Deep Mine #26	1.9
RAG Cumberland Mine	9.9	Shoemaker Mine	1.8
Pinnacle No. 50	9.8	Whitetail Kittanning Mine	1.7
Blue Creek No. 7	9.8	Mc Elroy Mine	1.6
Blue Creek No. 4	8.7	Baker	1.5
Oak Grove Mine	8.5	Dakota No. 2	1.5
Shoal Creek	8.2	San Juan South	1.3
Virginia Pocahontas No. 8	7.9	Aberdeen	1.2
Blue Creek No. 5	7.8	Wabash	1.2
Federal No. 2	7.6	Elk Creek Mine	1.1
RAG Emerald Mine	7.4	Powhatan No. 6 Mine	1.1
Buchanan Mine	7.3	Willow Lake Portal	1.1
Bailey Mine	5.7	Pollyanna No. 8	1.0
Eighty-Four Mine	5.1	Eagle Mine	1.0
American Eagle Mine	4.9	Loveridge No. 22	0.9
Blacksville No. 2	4.7	No. 3 Mine	0.9
North River Mine	4.2	Sentinel Mine	0.9
Robinson Run No. 95	4.0	Elkhart Mine	0.9
Galatia	3.9	Cardinal	0.9
West Ridge Mine	3.6	Mine #1	0.8
Upper Big Branch - South	3.1	Freedom Energy No.1	0.8
Justice #1	2.8	E3RF	0.8
Gibson	2.4	Clean Energy No. 1	0.8
Beckley Crystal	2.3	Pontiki No. 2	0.7

Table 12: Mines Listed by Estimated Daily Methane Drained in 2003

Mine Name	MMCF/D	Mine Name	MMCF/D
Virginia Pocahontas No. 8	38.4	Deep Mine #26	0.0
Buchanan Mine	35.3	Dugout Canyon Mine	0.0
RAG Cumberland Mine	14.4	E3RF	0.0
West Elk Mine	13.6	Eagle Mine	0.0
Blue Creek No. 7	10.3	Eighty-Four Mine	0.0
Blue Creek No. 5	6.6	Elk Creek Mine	0.0
Blue Creek No. 4	5.6	Elkhart Mine	0.0
Shoal Creek	4.4	Enlow Fork Mine	0.0
Loveridge No. 22	4.4	Freedom Energy No.1	0.0
Pinnacle No. 50	4.2	Galatia	0.0
Oak Grove Mine	4.1	Gibson	0.0
RAG Emerald Mine	4.0	Justice #1	0.0
Blacksville No. 2	3.8	Mc Elroy Mine	0.0
San Juan South	2.3	Mine #1	0.0
Federal No. 2	1.1	No. 3 Mine	0.0
Robinson Run No. 95	1.0	North River Mine	0.0
Shoemaker Mine	0.3	Pollyanna No. 8	0.0
Aberdeen	0.0	Pontiki No. 2	0.0
American Eagle Mine	0.0	Powhatan No. 6 Mine	0.0
Bailey Mine	0.0	Sentinel Mine	0.0
Baker	0.0	Upper Big Branch - South	0.0
Beckley Crystal	0.0	Wabash	0.0
Cardinal	0.0	West Ridge Mine	0.0
Clean Energy No. 1	0.0	Whitetail Kittanning Mine	0.0
Dakota No. 2	0.0	Willow Lake Portal	0.0

Table 13: Mines Listed by Estimated Specific Emissions in 2003

Mine Name	CF/Ton	Mine Name	CF/Ton
Virginia Pocahontas No. 8	8,992	Enlow Fork Mine	382
Loveridge No. 22	6,402	Dakota No. 2	366
Blue Creek No. 7	3,942	Gibson	355
Blue Creek No. 5	3,791	Upper Big Branch - South	347
Buchanan Mine	3,318	Robinson Run No. 95	314
Oak Grove Mine	2,666	Wabash	279
Pinnacle No. 50	2,064	Dugout Canyon Mine	267
Blue Creek No. 4	1,856	Whitetail Kittanning Mine	265
Beckley Crystal	1,809	Clean Energy No. 1	265
West Elk Mine	1,528	Eagle Mine	240
RAG Cumberland Mine	1,418	Galatia	238
Shoal Creek	1,200	Bailey Mine	223
Sentinel Mine	1,114	San Juan South	223
Aberdeen	995	No. 3 Mine	217
Pollyanna No. 8	929	Freedom Energy No.1	211
Baker	898	Shoemaker Mine	206
Federal No. 2	725	Mine #1	156
RAG Emerald Mine	631	Elkhart Mine	152
Deep Mine #26	619	E3RF	149
Blacksville No. 2	571	Willow Lake Portal	138
Justice #1	565	Cardinal	136
Eighty-Four Mine	467	Pontiki No. 2	132
West Ridge Mine	443	Elk Creek Mine	91
North River Mine	437	Mc Elroy Mine	88
American Eagle Mine	435	Powhatan No. 6 Mine	84

Table 14: Mines Listed by CO_2 Equivalent of Potential Annual CH_4 Emissions Reductions

(Assuming 20% - 60% Recovery Efficiency)

Mine Name	MM Tons CO_2/Yr	Mine Name	MM Tons CO_2/Yr
Virginia Pocahontas No. 8	1.50 - 4.51	Gibson	0.08 - 0.23
Buchanan Mine	1.38 - 4.15	Beckley Crystal	0.08 - 0.23
West Elk Mine	0.88 - 2.65	Shoemaker Mine	0.07 - 0.21
RAG Cumberland Mine	0.79 - 2.36	Dugout Canyon Mine	0.07 - 0.21
Blue Creek No. 7	0.65 - 1.96	Deep Mine #26	0.06 - 0.19
Blue Creek No. 5	0.47 - 1.40	Whitetail Kittanning Mine	0.06 - 0.17
Blue Creek No. 4	0.46 - 1.38	Mc Elroy Mine	0.05 - 0.16
Pinnacle No. 50	0.45 - 1.36	Baker	0.05 - 0.15
Oak Grove Mine	0.41 - 1.23	Dakota No. 2	0.05 - 0.14
Shoal Creek	0.41 - 1.23	Aberdeen	0.04 - 0.12
RAG Emerald Mine	0.37 - 1.11	Wabash	0.04 - 0.12
Enlow Fork Mine	0.34 - 1.01	Elk Creek Mine	0.04 - 0.11
Federal No. 2	0.28 - 0.85	Powhatan No. 6 Mine	0.04 - 0.11
Blacksville No. 2	0.28 - 0.83	Willow Lake Portal	0.04 - 0.11
Bailey Mine	0.19 - 0.56	Pollyanna No. 8	0.03 - 0.10
Loveridge No. 22	0.17 - 0.52	Eagle Mine	0.03 - 0.09
Eighty-Four Mine	0.16 - 0.49	No. 3 Mine	0.03 - 0.09
Robinson Run No. 95	0.16 - 0.48	Sentinel Mine	0.03 - 0.09
American Eagle Mine	0.16 - 0.48	Elkhart Mine	0.03 - 0.09
North River Mine	0.14 - 0.41	Cardinal	0.03 - 0.09
Galatia	0.13 - 0.38	Mine #1	0.03 - 0.08
West Ridge Mine	0.12 - 0.35	Freedom Energy No.1	0.03 - 0.08
San Juan South	0.12 - 0.35	E3RF	0.02 - 0.07
Upper Big Branch - South	0.10 - 0.30	Clean Energy No. 1	0.02 - 0.07
Justice #1	0.09 - 0.27	Pontiki No. 2	0.02 - 0.07

Table 15: Mines Listed by Electric Utility Supplier

Utility Parent Company / Mine Name	Utility Company
Eagle Mine	NA
E3RF	NA
American Eagle Mine	NA
Dakota No. 2	NA
Deep Mine #26	NA
Elk Creek Mine	NA
Willow Lake Portal	NA
Elkhart Mine	NA
No. 3 Mine	NA
Mine #1	NA
Beckley Crystal	NA
Allegheny Power Systems, Inc.	
Whitetail Kittanning Mine	Monongahela Power Co.
Blacksville No. 2	Monongahela Power Co.
Loveridge No. 22	Monongahela Power Co.
Robinson Run No. 95	Monongahela Power Co.
Federal No. 2	Monongahela Power Co.
Eighty-Four Mine	West Penn Power Co.
Enlow Fork Mine	West Penn Power Co.
RAG Emerald Mine	West Penn Power Co.
Bailey Mine	West Penn Power Co.
RAG Cumberland Mine	West Penn Power Co.
American Electric Power Co., Inc.	
Buchanan Mine	Appalachian Power Co.
Virginia Pocahontas No. 8	Appalachian Power Co.
Pinnacle No. 50	Appalachian Power Co.
Justice #1	Appalachian Power Co.
Upper Big Branch - South	Appalachian Power Co.
Pontiki No. 2	Kentucky Power Co.
Shoemaker Mine	Wheeling Power Co.
Mc Elroy Mine	Wheeling Power Co.

Table 15: Mines Listed by Electric Utility Supplier (cont.)

Utility Parent Company Mine Name	Utility Company
Cinergy	
Gibson	PSI
CIPSCO, Inc.	
Galatia	Central Illinois Public Service
DPL Inc.	
Powhatan No. 6 Mine	The Dayton Power & Light Co.
KU Energy	
Freedom Energy No.1	Kentucky Utilities Co.
Baker	Kentucky Utilities Co.
Clean Energy No. 1	Kentucky Utilities Co.
Municipal Owned	
Sentinel Mine	Philippi Municipal Electric
OGE Energy Corp.	
Pollyanna No. 8	OGE Energy Corp
Pacificorp	
Dugout Canyon Mine	Pacificorp
West Ridge Mine	Pacificorp
Aberdeen	Price City Utilities, Utah Power & Light
Public Service of New Mexico	
San Juan South	Public Service of New Mexico
The Southern Co.	
Shoal Creek	Alabama Power Co.
Oak Grove Mine	Alabama Power Co.
Blue Creek No. 5	Alabama Power Co.
North River Mine	Alabama Power Co.
Blue Creek No. 4	Alabama Power Co.
Blue Creek No. 7	Alabama Power Co.
Touchstone Energy Cooperatives	
West Elk Mine	Delta Montrose Elec. Assoc./Gunnison County Elec.
Cardinal	Kenergy Corp
Wabash	Wayne White Counties Elec. Coop./Norris Elec.

Table 16: Mines Listed by Potential Electric Generating Capacity
(Assuming 20% - 60% Recovery Efficiency)

Mine Name	Megawatts	Mine Name	Megawatts
Virginia Pocahontas No. 8	35.1 - 105.2	Gibson	1.8 - 5.4
Buchanan Mine	32.3 - 96.8	Beckley Crystal	1.8 - 5.3
West Elk Mine	20.6 - 61.8	Shoemaker Mine	1.6 - 4.9
RAG Cumberland Mine	18.4 - 55.1	Dugout Canyon Mine	1.6 - 4.9
Blue Creek No. 7	15.2 - 45.7	Deep Mine #26	1.4 - 4.3
Blue Creek No. 5	10.9 - 32.7	Whitetail Kittanning Mine	1.3 - 3.9
Blue Creek No. 4	10.8 - 32.3	Mc Elroy Mine	1.2 - 3.7
Pinnacle No. 50	10.6 - 31.7	Baker	1.1 - 3.4
Oak Grove Mine	9.6 - 28.7	Dakota No. 2	1.1 - 3.4
Shoal Creek	9.6 - 28.7	Aberdeen	0.9 - 2.8
RAG Emerald Mine	8.7 - 26.0	Wabash	0.9 - 2.7
Enlow Fork Mine	7.8 - 23.5	Elk Creek Mine	0.9 - 2.6
Federal No. 2	6.6 - 19.9	Powhatan No. 6 Mine	0.9 - 2.6
Blacksville No. 2	6.5 - 19.4	Willow Lake Portal	0.8 - 2.5
Bailey Mine	4.3 - 13.0	Pollyanna No. 8	0.8 - 2.3
Loveridge No. 22	4.0 - 12.1	Eagle Mine	0.7 - 2.2
Eighty-Four Mine	3.8 - 11.5	No. 3 Mine	0.7 - 2.1
Robinson Run No. 95	3.7 - 11.2	Sentinel Mine	0.7 - 2.0
American Eagle Mine	3.7 - 11.2	Elkhart Mine	0.7 - 2.0
North River Mine	3.2 - 9.6	Cardinal	0.7 - 2.0
Galatia	3.0 - 8.9	Mine #1	0.6 - 1.9
West Ridge Mine	2.7 - 8.2	Freedom Energy No.1	0.6 - 1.8
San Juan South	2.7 - 8.2	E3RF	0.6 - 1.7
Upper Big Branch - South	2.4 - 7.1	Clean Energy No. 1	0.6 - 1.7
Justice #1	2.1 - 6.4	Pontiki No. 2	0.5 - 1.6

Table 17: Mines Listed by Potential Annual Gas Sales*
(Assuming 20% - 60% Recovery Efficiency)

Mine Name	BCF/Yr	Mine Name	BCF/Yr
Virginia Pocahontas No. 8	3.4 -10.1	Gibson	0.2 - 0.5
Buchanan Mine	3.1 - 9.3	Beckley Crystal	0.2 - 0.5
West Elk Mine	2.0 - 6.0	Shoemaker Mine	0.2 - 0.5
RAG Cumberland Mine	1.8 - 5.3	Dugout Canyon Mine	0.2 - 0.5
Blue Creek No. 7	1.5 - 4.4	Deep Mine #26	0.1 - 0.4
Blue Creek No. 5	1.1 - 3.2	Whitetail Kittanning Mine	0.1 - 0.4
Blue Creek No. 4	1.0 - 3.1	Mc Elroy Mine	0.1 - 0.4
Pinnacle No. 50	1.0 - 3.1	Baker	0.1 - 0.3
Oak Grove Mine	0.9 - 2.8	Dakota No. 2	0.1 - 0.3
Shoal Creek	0.9 - 2.8	Aberdeen	0.1 - 0.3
RAG Emerald Mine	0.8 - 2.5	Wabash	0.1 - 0.3
Enlow Fork Mine	0.8 - 2.3	Elk Creek Mine	0.1 - 0.2
Federal No. 2	0.6 - 1.9	Powhatan No. 6 Mine	0.1 - 0.2
Blacksville No. 2	0.6 - 1.9	Willow Lake Portal	0.1 - 0.2
Bailey Mine	0.4 - 1.3	Pollyanna No. 8	0.1 - 0.2
Loveridge No. 22	0.4 - 1.2	Eagle Mine	0.1 - 0.2
Eighty-Four Mine	0.4 - 1.1	No. 3 Mine	0.1 - 0.2
Robinson Run No. 95	0.4 - 1.1	Sentinel Mine	0.1 - 0.2
American Eagle Mine	0.4 - 1.1	Elkhart Mine	0.1 - 0.2
North River Mine	0.3 - 0.9	Cardinal	0.1 - 0.2
Galatia	0.3 - 0.9	Mine #1	0.1 - 0.2
West Ridge Mine	0.3 - 0.8	Freedom Energy No.1	0.1 - 0.2
San Juan South	0.3 - 0.8	E3RF	0.1 - 0.2
Upper Big Branch - South	0.2 - 0.7	Clean Energy No. 1	0.1 - 0.2
Justice #1	0.2 - 0.6	Pontiki No. 2	0.1 - 0.2

* Mine's actual gas sales may differ from the potential

Table 18: Mine Shaft Emissions (2001)

Mine Name	Shaft Name	Shaft Vent Air Flow CFM	Shaft Methane Flow CFM	Shaft Methane Conc. %	Weighted Mine Methane Conc. %
Aberdeen	Aberdeen	517,249	2,608	0.50	0.50
Bailey	Bleeder 12A	193,738	577	0.30	
Bailey	Bleeder 1E	219,398	2,230	1.02	0.61
Bailey	Bleeder 7B	150,385	634	0.42	
Baker	Baker	738,685	1,718	0.23	0.23
Blacksville	#2	3,001,534	4,930	0.16	0.16
Blue Creek No. 4	#4, North fan	2,023,813	6,915	0.34	0.34
Blue Creek No. 5	#5, 5-7 fan	1,656,540	7,766	0.47	0.47
Blue Creek No. 7	#7, South fan	1,563,218	6,165	0.39	0.34
Blue Creek No. 7	#7, South fan	1,904,878	5,678	0.30	
Bowie No. 2	No.2	423,768	85	0.02	0.02
Buchanan	#1	3,101,292	8,278	0.27	0.27
Cadiz Portal		245,339	932	0.38	0.38
Camp #11	#11	500,176	844	0.17	0.17
Cardinal No. 2	#2	162,322	410	0.25	0.25
Clean Energy No. 1	#1	473,924	1,264	0.27	0.27
Cumberland	#1	308,439	1,344	0.44	
Cumberland	#6	540,459	2,130	0.39	
Cumberland	Bleeder #1	167,909	2,614	1.56	0.64
Cumberland	Bleeder #2	104,608	1,306	1.25	
Cumberland	Bleeder #3	197,806	1,071	0.54	
Dugout Canyon		395,517	119	0.03	0.03
Eighty-Four Mine	Lang	130,365	917	0.70	
Eighty-Four Mine	Smith	157,370	1,389	0.88	0.38
Eighty-Four Mine	Zediker	538,793	853	0.16	
Emerald	Bleeder #4	206,017	1,806	0.88	0.35
Emerald	Emerald #7	684,012	1,318	0.19	
Enlow Fork	A11 bleeder	270,518	2,178	0.80	
Enlow Fork	B6 bleeder	255,353	1,735	0.68	0.79
Enlow Fork	E1 bleeder	238,607	2,126	0.89	
Federal No. 2	#2	2,018,301	6,259	0.31	0.31
Galatia	Galatia	1,788,102	5,802	0.32	0.32
Gibson	Gibson	208,240	469	0.23	0.23
Harris No. 1	#1	444,809	618	0.14	0.14

Table 18: Mine Shaft Emissions (cont.)

Mine Name	Shaft Name	Shaft Vent Air Flow CFM	Shaft Methane Flow CFM	Shaft Methane Conc. %	Weighted Mine Methane Conc. %
Justice #1	Licks bleeder	222,761	546	0.24	0.41
Justice #1	Whites Br bleeder	206,935	1,226	0.59	
Leeco No. 68		387,748	318	0.08	0.08
Loveridge No. 22	22	1,405,850	3,576	0.25	0.25
McElroy	McElroy	1,425,538	4,610	0.32	0.32
Mine #1	#1	605,988	685	0.11	0.11
Monterey No. 1	#1	764,901	673	0.09	0.09
North River	Cedar Cr	422,891	1,118	0.26	0.36
North River	Tyro Cr	509,182	2,249	0.44	
Oak Grove	#1	680,844	683	0.10	
Oak Grove	#4	610,557	2,552	0.42	0.24
Oak Grove	#5	463,871	1,030	0.22	
Pattiki	Pattiki	361,495	1,681	0.47	0.47
Pinnacle	Pinnacle	199,051	434	0.22	0.22
Pollyanna No. 8	No.8	185,939	182	0.10	0.10
Pontiki No. 2	#2	294,519	215	0.07	0.07
Powhatan No. 6	#6	871,079	784	0.09	0.09
Rend Lake		1,620,913	1,572	0.10	0.10
Robinson Run	Robinson Run	1,347,678	2,808	0.21	0.21
San Juan South	South	90,807	6	0.01	0.01
Sanborn Creek	Sanborn Creek	636,551	3,683	0.58	0.58
Sentinel	Sentinel	867,540	1,211	0.14	0.14
Shoal Creek	#2	514,181	1,538	0.30	0.27
Shoal Creek	#4	470,259	1,081	0.23	
Shoemaker		1,672,768	3,178	0.19	0.19
Tiller No. 1	#1	19,070	0	0.00	0.00
U.S. Steel No. 50	8A	353,691	2,477	0.70	
U.S. Steel No. 50	Dale	396,627	2,496	0.63	0.50
U.S. Steel No. 50	South Fork	649,707	1,967	0.30	
Upper Big Branch	Upper Big Branch	275,127	777	0.28	0.28
VP No. 8	#8	2,693,001	5,852	0.22	0.22
Wabash		1,063,658	1,106	0.10	0.10
West Elk	West Elk	1,519,703	7,231	0.48	0.48
West Ridge		190,696	19	0.01	0.01
Whitetail Kittanning		381,391	381	0.10	0.10

6. Profiled Mines (continued)

States with Candidate and Utilizing Mines:

Alabama

Colorado

Illinois

Indiana

Kentucky

New Mexico

Ohio

Oklahoma

Pennsylvania

Utah

Virginia

West Virginia

6. Profiled Mines

Data Summary

Below is a state-by-state summary of data pertaining to coal mine methane at the mines profiled in this report. Chapter 4 explains how these data were derived. Following this data summary section are individual mine profiles, in alphabetical order by state.

Alabama

Of the twelve profiled U.S. mines that already recover and use methane, five are located in Alabama. Three of these mines are owned by Jim Walter Resources (JWR), one mine is owned by U.S. Steel, and one mine is owned by Drummond Coal. All five mines sell methane to pipelines. Based on information obtained from MSHA (2004), these five mines recovered and sold an average of 28 mmcf/d in 2003. This recovery was drained from areas that are currently or will eventually be mined.

In addition to these mines, Alabama has one other large gassy mine that appears to be a good candidate for a methane recovery project. North River has been in operation since 1974 and uses the longwall mining method. Table 6-1 shows that the implementation of a methane recovery and use project at the North River Mine could reduce annual methane emissions by 0.3 – 0.9 Bcf/yr.

Table 6-1: Alabama Mines

Mine	Company	2003 Coal Production (mm tons)	2003 Ventilation, Drainage and Use Data[1]				
			Ventilation Emissions (mmcf/d)	Estimated Methane Drained (mmcf/d)	Estimated Total Methane Liberated (mmcf/d)	Estimated Specific Emissions (cf/ton)	Estimated Methane Used (mmcf/d)
Mines Using Methane (mines at which recovery and use projects have already been developed):							
Blue Creek No. 4	Jim Walter Res.	2.8	8.7	5.6	14.2	1,856	5.5
Blue Creek No. 5	Jim Walter Res.	1.4	7.8	6.6	14.4	3,791	6.6
Blue Creek No. 7	Jim Walter Res.	1.9	9.8	10.3	20.1	3,942	10.3
Oak Grove	U.S. Steel	1.7	8.5	4.1	12.6	2,666	4.1
Shoal Creek	Drummond	3.8	8.2	4.4	12.6	1,200	1.0
Total for All Mines Using Methane		**11.6**	**43.0**	**31.0**	**74.0**	**-**	**27.6**
Operating But Not Using Methane:							
North River	Pitts. & Midway	3.5	4.2	0.0	4.2	437	0.0
TOTAL:[2]		**15.1**	**47.2**	**31.0**	**78.2**	**-**	**27.6**

Estimated Emissions and Avoided Emissions of Methane and CO_2 Equivalent From Operating Mines Not Currently Using Methane (North River):	**Methane (Bcf/yr)**	**CO_2 (mmt/yr)**
2003 Estimated Total Emissions	1.5	0.7
Estimated Annual Avoided Emissions if Recovery Project is Implemented[3]	0.3 - 0.9	0.1 – 0.4

[1] Chapter 4 explains how these were estimated.
[2] Values shown here do not always sum to totals due to rounding.
[3] Range calculated assuming 20% - 60% of total liberated methane could be recovered.

Colorado

Colorado has a number of underground mines with relatively low methane emissions, but there are also several deep and gassy mines with high emissions; these mines present potential opportunities for those interested in developing a methane recovery project in the West.

Of the two Colorado mines profiled in this report, West Elk began recovering methane in 2003 for use onsite (heaters). Table 6-2 shows coal production, methane ventilation, and drainage data. In 2003, West Elk liberated an estimated 27.2 mmcf/d (9.9 Bcf/yr), while recovering 0.1 mmcf/d (0.04 Bcf/yr).

Colorado has three additional mines that are potential candidates for methane recovery: Elk Creek, Bowie No. 2, and Sanborn Creek. Among the three mines, only Elk Creek is profiled in this report[17]. Elk Creek had methane emissions totaling 1.1 mmcf/d in 2003. Table 6-2 shows that the implementation of methane recovery and use project at Elk Creek could reduce annual methane emissions by 0.1 – 0.2 Bcf/yr.

Table 6-2: Colorado Mines

Mine	Company	2003 Coal Production (mm tons)	2003 Ventilation, Drainage and Use Data[1]				
			Ventilation Emissions (mmcf/d)	Estimated Methane Drained (mmcf/d)	Estimated Total Methane Liberated (mmcf/d)	Estimated Specific Emissions (cf/ton)	Estimated Methane Used (mmcf/d)
Mines Using Methane (mines at which recovery and use projects have already been developed):							
West Elk	Mountain Coal	6.5	13.6	13.6	27.2	1,528	0.1
Operating But Not Using Methane:							
Elk Creek	Oxbow Mining	4.6	1.1	0.0	1.1	91	0.0
TOTAL:[2]		**11.1**	**14.7**	**13.6**	**28.3**	**-**	**0.1**

Estimated Emissions and Avoided Emissions of Methane and CO_2 Equivalent From Operating Mines Not Currently Using Methane (Elk Creek):	**Methane (Bcf/yr)**	**CO_2 (mmt/yr)**
2003 Estimated Total Emissions	0.4	0.2
Estimated Annual Avoided Emissions if Recovery Project is Implemented[3]	0.1 – 0.2	0.0 – 0.1

[1] Chapter 4 explains how these were estimated.
[2] Values shown here do not always sum to totals due to rounding.
[3] Range calculated assuming 20% - 60% of total liberated methane could be recovered.

Illinois

In general, Illinois mines tend to be less gassy than mines in other regions of the country. These mines tend to have lower specific emissions, but many have high total methane emissions depending on their yearly coal production. Accordingly, emissions reductions may be achieved at several of these mines. Coal production and methane ventilation and drainage data on these mines are shown in Table 6-3.

Four operating Illinois mines are considered to be potential candidates for methane recovery projects. None of the featured Illinois mines have a degasification system in place. Table 6-3 shows that methane emissions from the four Illinois mines totaled an estimated 2.6 Bcf in 2003. Table 6-3 shows that the implementation of methane recovery and use projects at the four profiled mines that are

[17] Bowie No. 2 Mine is not profiled in this report because it did not emit large volumes of methane to the atmosphere in 2003. Sanborn Creek Mine was closed in 2003. Both of these mines are examples of potential recovery projects in addition to the one highlighted in Table 6-2.

operating but not currently using methane could reduce annual methane emissions by 0.5 – 1.6 Bcf/yr.

Table 6-3: Illinois Mines

Mine	Company	2003 Coal Production (mm tons)	2003 Ventilation and Drainage Data[1] Ventilation Emissions (mmcf/d)	Estimated Methane Drained (mmcf/d)	Estimated Total Methane Liberated (mmcf/d)	Estimated Specific Emissions (cf/ton)
Operating But Not Using Methane:						
Elkhart	Turris Coal	2.1	0.9	0.0	0.9	152
Galatia	American Coal Co.	6.0	3.9	0.0	3.9	238
Wabash	Wabash Mne. Hld.	1.6	1.2	0.0	1.2	279
Willow Lake Portal	Big Ridge Inc.	2.9	1.1	0.0	1.1	138
TOTAL[2]:		**12.6**	**7.1**	**0.0**	**7.1**	**-**

Estimated Emissions and Avoided Emissions of Methane and CO_2 Equivalent From Operating Mines Not Currently Using Methane (four mines):	**Methane (Bcf/yr)**	**CO_2 (mmt/yr)**
2003 Estimated Total Emissions	2.6	1.2
Estimated Annual Avoided Emissions if Recovery Projects are Implemented[3]	0.5 – 1.6	0.2 – 0.7

[1] Chapter 4 explains how these data were estimated.
[2] Values shown here do not always sum to totals due to rounding.
[3] Range calculated assuming 20% - 60% of total liberated methane could be recovered.

Indiana

A single Indiana mine, the Gibson Mine, is profiled in this report. This room-and-pillar operation, which opened in 2000, is currently considered the gassiest underground mine in Indiana. The mine produced 2.4 million tons of coal in 2003. Gibson Mine reported total methane emissions of approximately 0.88 billion cubic feet in 2003, and is not equipped with a degasification system. Based on these emissions, a methane use project may remain viable at the Gibson Mine.

Kentucky

Kentucky has eight operating mines that are good candidates for the development of methane recovery projects. The Baker Mine, which is located in the western Kentucky portion of the Illinois Coal Basin, is the gassiest in the state and the only one with methane emissions greater than 1 mmcf/d. The other seven mines are located in the in eastern Kentucky, in the Central Appalachian Basin.

Table 6-4 shows that methane emissions from the eight Kentucky mines totaled an estimated 2.6 Bcf in 2003. Implementation of methane recovery and use projects at these eight mines could reduce annual methane emissions by an estimated 0.5 - 1.6 Bcf/yr.

Table 6-4: Kentucky Mines							
Mine	Company	2003 Coal Production (mm tons)	2003 Ventilation and Drainage Data[1]			
			Ventilation Emissions (mmcf/d)	Estimated Methane Drained (mmcf/d)	Estimated Total Methane Liberated (mmcf/d)	Estimated Specific Emissions (cf/ton)
Operating But Not Using Methane:						
Baker	Lodestar Energy	0.6	1.5	0.0	1.5	898
Cardinal	Warrior Coal	2.4	0.9	0.0	0.9	136
Clean Energy No. 1	Massey Energy	1.0	0.8	0.0	0.8	265
E3RF[2]	CONSOL of KY	1.9	0.8	0.0	0.8	149
Freedom Energy No. 1	Frdm. Engy. Mng.	1.4	0.8	0.0	0.8	211
Mine #1	Rockhouse	1.9	0.8	0.0	0.8	156
No. 3 Mine	Excel Mining	1.5	0.9	0.0	0.9	217
Pontiki No. 2	Excel Mining	2.0	0.7	0.0	0.7	132
TOTAL:[3]		**12.7**	**7.2**	**0.0**	**7.2**	**-**
Estimated Emissions and Avoided Emissions of Methane and CO_2 Equivalent From Operating Mines Not Currently Using Methane (8 mines):					**Methane (Bcf/yr)**	**CO_2 (mmt/yr)**
2003 Estimated Total Emissions					2.6	1.2
Estimated Annual Avoided Emissions if Recovery Projects are Implemented[4]					0.5 – 1.6	0.2 – 0.7

[1] Chapter 4 explains how these data were estimated.

[2] Mine listed as permanently abandoned by EIA. However, according to the MSHA Data Retrieval System mine is currently active and never stopped producing coal. Mine listed as "No. 10 mine" operated by Ember Contracting.

[3] Values shown here do not always sum to totals due to rounding.

[4] Range calculated assuming 20% - 60% of total liberated methane could be recovered.

New Mexico

The San Juan Mine, which is owned by the BHP Billiton, is the only New Mexico mine profiled in this report. This longwall mine opened in 2002 and methane recovery began in 2003. San Juan produced ventilation emissions of 1.3 mmcf/d in 2003, and total methane liberated was 3.6 mmcf/d (1.3 Bcf/yr) in 2003. The mine employs a degasification system which uses both vertical gob vent boreholes and in-mine, horizontal, pre-drainage boreholes. The mine recovered 40 mmcf/yr in 2003.

Ohio

As with the Illinois mines, Ohio mines tend to be less gassy than mines in other regions of the country. One operating Ohio mine is profiled in this report, the Powhatan No. 6 Mine. The mine produced 4.9 million tons in 2003 and had ventilation emissions of 1.1 mmcf/d. As of 2003, Powhatan No. 6 had no drainage system in place. The implementation of a methane recovery and use project at this Ohio mine could reduce annual methane emissions by 0.1 - 0.2 Bcf/yr.

Oklahoma

A single Oklahoma mine, the Pollyanna No. 8 Mine, is profiled in this report. This room-and-pillar operation, which opened in 1996, is currently considered the gassiest underground mine in Oklahoma. In 2003, the mine produced 0.4 million tons annually and reported total methane emissions of approximately 0.37 billion cubic feet in 2003. Based on these emissions, and a history of gassy mines in the Arkoma Basin, a coalmine methane project may be viable at the Pollyanna No. 8 Mine.

Pennsylvania

Five operating Pennsylvania mines are good candidates for methane recovery and use and are profiled in this report. Several of the mines profiled in the previous edition of this report have recently closed. These mines may also be candidates for methane projects. Coal production, ventilation, and drainage data on these mines are shown in Table 6-5.

In 2003, the five mines shown in Table 6-5 liberated about 56.9 mmcf/d (20.8 Bcf/yr) of methane. Several of these mines are located in Greene County, Pennsylvania. In fact, Greene County is the location of the two largest underground mines in the United States, CONSOL's Bailey and Enlow Fork mines. These mines are adjacent to one another and are often referred to as the Bailey-Enlow Fork complex.

Two other large and gassy mines are also located in Greene County, RAG America's Emerald and Cumberland mines. As with Bailey and Enlow Fork, Emerald and Cumberland are located in close proximity to each other. Both mines already have drainage systems in place, although the methane is not being used at present.

Table 6-5 shows that the implementation of recovery and use projects at the five profiled Pennsylvania mines that are currently operating could reduce annual methane emissions by 4.2 – 12.5 Bcf/yr.

Table 6-5: Pennsylvania Mines

Mine	Company	2003 Coal Production (mm tons)	2003 Ventilation and Drainage Data[1]			
			Ventilation Emissions (mmcf/d)	Estimated Methane Drained (mmcf/d)	Estimated Total Methane Liberated (mmcf/d)	Estimated Specific Emissions (cf/ton)
Operating But Not Using Methane:						
Bailey	CONSOL	9.4	5.7	0.0	5.7	223
Eighty-Four	84 Mining	4.0	5.1	0.0	5.1	467
Enlow Fork	CONSOL	9.9	10.3	0.0	10.3	382
RAG Cumberland	RAG Resources	6.2	9.9	14.4	24.3	1,418
RAG Emerald	RAG Resources	6.6	7.4	4.0	11.5	631
TOTAL:[2]		**36.1**	**38.4**	**18.4**	**56.9**	**-**

Estimated Emissions and Avoided Emissions of Methane and CO_2 Equivalent From Operating Mines Not Currently Using Methane (five mines):	Methane (Bcf/yr)	CO_2 (mmt/yr)
2003 Estimated Total Emissions	20.8	9.2
Estimated Annual Avoided Emissions if Recovery Projects are Implemented[3]	4.2 – 12.5	1.8 – 5.5

[1] Chapter 4 explains how these data were estimated.
[2] Values shown here do not always sum to totals due to rounding.
[3] Range calculated assuming 20% - 60% of total liberated methane could be recovered.

Utah

Utah has a number of underground mines with relatively low methane emissions along the Wasatch Plateau, but it also has several deep and gassy mines with high methane emissions located nearby in the Uinta Basin. As with Colorado, these mines present potential opportunities for those interested in developing a methane recovery project in the West. Three operating Utah mines are good candidates for methane recovery and use and are profiled in this report[18].

The Aberdeen Mine is currently the gassiest in the state with 2003 estimated specific emissions of 995 cf/ton. However, West Ridge and Dugout Canyon liberated a total of 3.6 mmcf/d and 2.2 mmcf/d in 2003, respectively. These Utah mines tend to have high specific emissions, and have produced high total methane emissions depending on their yearly coal production. Table 6-6 shows that the implementation of methane recovery and use projects at these three operating Utah mines could reduce annual methane emissions by 0.5 – 1.5 Bcf/yr.

Table 6-6: Utah Mines

Mine	Company	2003 Coal Production (mm tons)	2003 Ventilation and Drainage Data[1]			
			Ventilation Emissions (mmcf/d)	Estimated Methane Drained (est.) (mmcf/d)	Estimated Total Methane Liberated (mmcf/d)	Estimated Specific Emissions (cf/ton)
Operating But Not Using Methane:						
Aberdeen	Andalex Resources	0.4	1.2	0.0	1.2	995
Dugout Canyon	Canyon Fuel Co.	2.9	2.2	0.0	2.2	267
West Ridge	Andalex Resources	3.0	3.6	0.0	3.6	443
TOTAL:[2]		**6.4**	**7.0**	**0.0**	**7.0**	**-**
Estimated Emissions and Avoided Emissions of Methane and CO_2 Equivalent From Operating Mines Not Currently Using Methane (three mines):					**Methane (Bcf/yr)**	**CO_2 (mmt/yr)**
2003 Estimated Total Emissions					2.5	1.1
Estimated Annual Avoided Emissions if Recovery Projects are Implemented[3]					0.5 – 1.5	0.2 – 0.7

[1] Chapter 4 explains how these data were estimated.
[2] Values shown here do not always sum to totals due to rounding.
[3] Range calculated assuming 20% - 60% of total liberated methane could be recovered.

Virginia

As Table 6-7 demonstrates, two of the mines at which successful methane recovery and use projects have already been developed are located in Virginia. The Buchanan and the VP No. 8 mines are both longwall operations, and are owned by subsidiaries of CONSOL. The total methane drained at the two CONSOL Virginia mine properties equaled 76 mmcf/d in 2003. This number significantly exceeds ventilation emissions of 15 mmcf/d, which indicates that recovery efficiencies (greater that 80% at VP No.8) are higher than standard EPA assumptions. Table 6-7 shows that CONSOL operates the largest active methane recovery project in the United States.

[18] Pinnacle mine, which closed in the Fall of 2003 as a consequence of ventilation problems, may also be potential candidate for a methane use and recovery project.

Table 6-7: Virginia Mines								
Mine	Company	2003 Coal Production (mm tons)	2003 Ventilation, Drainage and Use Data[1]				
			Ventilation Emissions (mmcf/d)	Estimated Methane Drained (mmcf/d)	Estimated Total Methane Liberated (mmcf/d)	Estimated Specific Emissions (cf/ton)	Estimated Methane Used (mmcf/d)
Mines Using Methane (mines at which recovery and use projects have already been developed):							
Buchanan	CONSOL	4.7	7.3	35.3	42.6	3,318	36.4
VP No. 8	CONSOL	1.9	7.9	38.4	46.3	8,992	39.5
Total for All Mines Using Methane		**6.6**	**15.2**	**73.7**	**88.9**	**-**	**75.9**
Operating But Not Using Methane:							
Deep Mine #26	Paramount Coal	1.1	1.9	0.0	1.9	619	0.0
TOTAL:[2]		**7.7**	**17.1**	**73.7**	**90.8**	**-**	**75.9**

Estimated Emissions and Avoided Emissions of Methane and CO_2 Equivalent From Operating Mines Not Currently Using Methane (Deep Mine #26):	Methane (Bcf/yr)	CO_2 (mmt/yr)
2003 Estimated Total Emissions	0.7	0.3
Estimated Annual Avoided Emissions if Recovery Project is Implemented[3]	0.1 – 0.4	0.1 – 0.2

[1] Chapter 4 explains how these were estimated.
[2] Values shown here do not always sum to totals due to rounding.
[3] Range calculated assuming 20% - 60% of total liberated methane could be recovered.

West Virginia

Of the 50 mines profiled in this report, 15 are located in West Virginia. Of these mines, three are currently recovering methane for sale. Coal production, methane ventilation, and drainage data on these mines are shown in Table 6-8.

The three profiled mines that are recovering methane for sale are the Blacksville No. 2, Federal No. 2, and Pinnacle No. 50 mines. (The methane recovery project involving the Blacksville No. 2, Humphrey No. 7, and Loveridge No. 22 mines is often considered a Pennsylvania project, for reasons explained in Chapter 3). In 2003, these mines liberated an estimated 31.2 mmcf/d (11.4 Bcf/yr), while recovering 5.6 mmcf/d (2.0 Bcf/yr). Federal No. 2 recovered and sold about 0.3 Bcf of methane in 2003, while Pinnacle No. 50 sold about 0.5 Bcf of methane to a gas marketing company, and the project at Blacksville No. 2 sold about 1.2 Bcf in 2003.

Nine of the West Virginia mines profiled in this report are located in the Northern Appalachian Basin; five of these are owned by subsidiaries of CONSOL. The remaining six operating mines that are profiled are located in the Central Appalachian Basin. Table 6-8 shows that the implementation of methane recovery and use projects at the twelve operating mines that do not already use methane could reduce annual methane emissions by 2.4 – 7.1 Bcf/yr.

Table 6-8: West Virginia Mines

Mine	Company	2003 Coal Production (mm tons)	2003 Ventilation, Drainage and Use Data[1]: Ventilation Emissions (mmcf/d)	Estimated Methane Drained (mmcf/d)	Estimated Total Methane Liberated (mmcf/d)	Estimated Specific Emissions (cf/ton)	Estimated Methane Used (mmcf/d)
Mines Using Methane (mines at which recovery and use projects have already been developed):							
Blacksville No. 2	CONSOL	5.4	4.7	3.8	8.5	571	3.3
Federal No. 2	Peabody Energy	4.4	7.6	1.1	8.7	725	0.8
Pinnacle No. 50	U.S. Steel	2.5	9.8	4.2	14.0	2,064	1.5
Total for All Mines Using Methane		**12.3**	**22.1**	**9.1**	**31.2**	**-**	**5.6**
Operating But Not Using Methane:							
American Eagle	Speed Mining	4.1	4.9	0.0	4.9	435	0.0
Beckley Crystal	Baylor Mining	0.5	2.4	0.0	2.3	1,809	0.0
Dakota No. 2	Dakota Mining	1.5	1.5	0.0	1.5	366	0.0
Eagle	Newtown Energy	1.5	1.0	0.0	1.0	240	0.0
Justice #1	Independence	1.8	2.8	0.0	2.8	565	0.0
Loveridge No. 22	CONSOL	0.3	0.9	4.4	5.3	6,402	0.0
Mc Elroy	CONSOL	6.8	1.6	0.0	1.6	88	0.0
Robinson Run No. 95	CONSOL	5.7	4.0	1.0	4.9	314	0.0
Sentinel	Anker WV Mining	0.3	0.9	0.0	0.9	1,114	0.0
Shoemaker	CONSOL	3.8	1.8	0.3	2.2	206	0.0
Upper Big Branch So.	Performance	3.3	3.1	0.0	3.1	347	0.0
Whitetail-Kittanning	Coastal Coal	2.4	1.7	0.0	1.7	265	0.0
TOTAL:[2]		**44.3**	**48.8**	**14.8**	**63.6**	**-**	**5.6**

Estimated Emissions and Avoided Emissions of Methane and CO_2 Equivalent From Operating Mines Not Currently Using Methane (12 Mines):	**Methane (Bcf/yr)**	**CO_2 (mmt/yr)**
2003 Estimated Total Emissions	11.8	5.2
Estimated Annual Avoided Emissions if Recovery Project is Implemented[3]	2.4 – 7.1	1.0 – 3.1

[1] Chapter 4 explains how these were estimated.
[2] Values shown here do not always sum to totals due to rounding.
[3] Range calculated assuming 20% - 60% of total liberated methane could be recovered.

6. Profiled Mines (continued)

Alabama Mines

Blue Creek No. 4
Blue Creek No. 5
Blue Creek No. 7
North River
Oak Grove
Shoal Creek

Updated: 08/01/2005 **Status:** Active

Blue Creek No. 4

GEOGRAPHIC DATA

Basin: Black Warrior **State:** AL

Coalbed: Blue Creek, Mary Lee **County:** Tuscaloosa

CORPORATE INFORMATION

Current Owner: Jim Walter Resources, Inc.

Parent Company: Walter Industries, Inc. **Parent Company Web Site:** www.jimwalterresources.com

Previous Owner(s): None in last 10 years **Previous or Alternate Name of Mine:** No. 4 Mine

MINE ADDRESS

Contact Name: Keith Shalvey, Mine Mgr. **Phone Number:** (205) 554-6450

Mailing Address: 14730 Lock 17 Rd.

City: Brookwood **State:** AL **ZIP:** 35444

GENERAL INFORMATION

Number of Employees at Mine: 394 **Mining Method:** Longwall/Continuous

Year of Initial Production: 1975 **Primary Coal Use:** Metallurgical

Life Expectancy: 2020 **Sulfur Content of Coal Produced:** 0.75% - 0.95%

Prep Plant Located on Site? Yes **BTUs/lb of Coal Produced:** 14,200

Depth to Seam (ft): 2,000 **Seam Thickness (ft):** 6.5

PRODUCTION, VENTILATION AND DRAINAGE DATA

	1999	2000	2001	2002	2003
Coal Production (million short tons/year):	2.0	2.4	2.5	2.8	2.8
Estimated Total Methane Liberated (million cf/day):	19.6	21.4	15.9	23.8	14.2
Emission from Ventilation Systems:	12.0	11.0	8.0	11.7	8.7
Estimated Methane Drained:	7.6	10.3	8.0	12.1	5.6
Estimated Specific Emissions (cf/ton):	3526	3295	2290	3077	1856
Methane Recovered (million cf/day):	7.8	10.3	7.9	8.4	5.5

Estimated Current Drainage Efficiency: 39%

Drainage System Used: Vertical Pre-Mine, Vertical Gob, Horizontal Pre-Mine

Blue Creek No. 4 (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

	Assumed Potential Recovery Efficiency		
(Based on 2003 Data)	20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons):	0.5	0.9	1.4
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	5.7%	11.3%	17.0%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	1.3%	2.6%	3.9%

Power Generation Potential

Utility Electric Supplier: Alabama Power Co.

Parent Corporation of Utility: The Southern Co.

	MW	GWh/year
Total Electricity Demand (2003 data):	22.2	83.9
Mine Electricity Demand:	17.4	67.1
Prep Plant Electricity Demand:	4.8	16.8
Potential Generating Capacity (2003 data)		
Assuming 20% Recovery Efficiency:	10.8	94.4
Assuming 40% Recovery Efficiency:	21.6	188.9
Assuming 60% Recovery Efficiency:	32.3	283.3

Pipeline Sales Potential

Potential Annual Gas Sales (2003 data)	Bcf
Assuming 20% Recovery (Bcf):	1.0
Assuming 40% Recovery (Bcf):	2.1
Assuming 60% Recovery (Bcf):	3.1

Description of Surrounding Terrain: Open Hills/Open High Hills

Transmission Pipeline in County? Yes

Owner of Nearest Pipeline: Mine owns pipeline that connects to trans. line

Distance to Pipeline (miles): 0.0 **Pipeline Diameter (inches):** NA

Owner of Next Nearest Pipeline: NA

Distance to Next Nearest Pipeline (miles): 8.3 **Pipeline Diameter (inches):** 24.0

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: None **Distance to Plant (miles):** NA

Comments: Not yet researched.

Updated: 08/01/2005 **Status:** Active

Blue Creek No. 5

GEOGRAPHIC DATA

Basin: Black Warrior **State:** AL

Coalbed: Blue Creek **County:** Tuscaloosa

CORPORATE INFORMATION

Current Owner: Jim Walter Resources, Inc.

Parent Company: Walter Industries, Inc. **Parent Company Web Site:** www.jimwalterresources.com

Previous Owner(s): None in last 10 years **Previous or Alternate Name of Mine:** No. 5 Mine

MINE ADDRESS

Contact Name: Trent Thrasher, Mine Mgr. **Phone Number:** (205) 554-6550

Mailing Address: 12972 Lock 17 Rd.

City: Brookwood **State:** AL **ZIP:** 35444

GENERAL INFORMATION

Number of Employees at Mine: 389 **Mining Method:** Longwall/Continuous

Year of Initial Production: 1978 **Primary Coal Use:** Steam, Metallurgical

Life Expectancy: 2006 **Sulfur Content of Coal Produced:** 0.72% - 0.8%

Prep Plant Located on Site? Yes **BTUs/lb of Coal Produced:** 13,300

Depth to Seam (ft): 2,140 **Seam Thickness (ft):** 8.3

PRODUCTION, VENTILATION AND DRAINAGE DATA

	1999	2000	2001	2002	2003
Coal Production (million short tons/year):	1.7	2.0	1.5	0.7	1.4
Estimated Total Methane Liberated (million cf/day):	22.7	23.9	23.6	12.0	14.4
Emission from Ventilation Systems:	14.3	14.0	13.2	6.3	7.8
Estimated Methane Drained:	8.4	10.0	10.4	5.8	6.6
Estimated Specific Emissions (cf/ton):	4772	4410	5865	6451	3791
Methane Recovered (million cf/day):	8.3	9.9	9.4	5.8	6.6

Estimated Current Drainage Efficiency: 46%

Drainage System Used: Vertical Pre-Mine, Vertical Gob, Horizontal Pre-Mine

Blue Creek No. 5 (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

(Based on 2003 Data)	Assumed Potential Recovery Efficiency 20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons):	0.5	0.9	1.4
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	12.3%	24.7%	37.0%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	2.9%	5.7%	8.6%

Power Generation Potential

Utility Electric Supplier: Alabama Power Co.

Parent Corporation of Utility: The Southern Co.

	MW	GWh/year
Total Electricity Demand (2003 data):	11.0	41.6
Mine Electricity Demand:	8.6	33.3
Prep Plant Electricity Demand:	2.4	8.3
Potential Generating Capacity (2003 data)		
Assuming 20% Recovery Efficiency:	10.9	95.6
Assuming 40% Recovery Efficiency:	21.8	191.1
Assuming 60% Recovery Efficiency:	32.7	286.7

Pipeline Sales Potential

Potential Annual Gas Sales (2003 data)	Bcf
Assuming 20% Recovery (Bcf):	1.1
Assuming 40% Recovery (Bcf):	2.1
Assuming 60% Recovery (Bcf):	3.2

Description of Surrounding Terrain: Open Hills/Open High Hills

Transmission Pipeline in County? Yes

Owner of Nearest Pipeline: Mine owns pipeline that connects to trans. line

Distance to Pipeline (miles): 0.0 **Pipeline Diameter (inches):** NA

Owner of Next Nearest Pipeline: NA

Distance to Next Nearest Pipeline (miles): 10.0 **Pipeline Diameter (inches):** 24.0

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: None **Distance to Plant (miles):** NA

Comments: Not yet researched.

Updated: 08/01/2005 **Status:** Active

Blue Creek No. 7

GEOGRAPHIC DATA

Basin: Black Warrior **State:** AL

Coalbed: Blue Creek **County:** Tuscaloosa

CORPORATE INFORMATION

Current Owner: Jim Walter Resources, Inc.

Parent Company: Walter Industries, Inc. **Parent Company Web Site:** www.jimwalterresources.com

Previous Owner(s): None in last 10 years **Previous or Alternate Name of Mine:** No. 7 Mine

MINE ADDRESS

Contact Name: Leon Robertson, Mine Mgr. **Phone Number:** (205) 554-6750

Mailing Address: 18069 Hannah Creek

City: Brookwood **State:** AL **ZIP:** 35444

GENERAL INFORMATION

Number of Employees at Mine: 407 **Mining Method:** Longwall/Continuous

Year of Initial Production: 1975 **Primary Coal Use:** Steam, Metallurgical, Ind.

Life Expectancy: 2039 **Sulfur Content of Coal Produced:** 0.58% -0.75%

Prep Plant Located on Site? Yes **BTUs/lb of Coal Produced:** 14,500

Depth to Seam (ft): 1790 **Seam Thickness (ft):** 5.1

PRODUCTION, VENTILATION AND DRAINAGE DATA

	1999	2000	2001	2002	2003
Coal Production (million short tons/year):	2.1	2.4	1.8	2.0	1.9
Estimated Total Methane Liberated (million cf/day):	25.2	26.1	24.5	22.9	20.1
Emission from Ventilation Systems:	16.9	16.9	14.7	11.0	9.8
Estimated Methane Drained:	8.3	9.2	9.8	11.9	10.3
Estimated Specific Emissions (cf/ton):	4467	3905	4881	4218	3942
Methane Recovered (million cf/day):	8.4	9.3	9.9	11.9	10.3

Estimated Current Drainage Efficiency: 51%

Drainage System Used: Vertical Pre-Mine, Vertical Gob, Horizontal Pre-Mine

Blue Creek No. 7 (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

	Assumed Potential Recovery Efficiency		
(Based on 2003 Data)	20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons):	0.7	1.3	2.0
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	11.8%	23.5%	35.3%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	2.7%	5.4%	8.2%

Power Generation Potential

Utility Electric Supplier: Alabama Power Co.

Parent Corporation of Utility: The Southern Co.

	MW	GWh/year
Total Electricity Demand (2003 data):	14.8	55.8
Mine Electricity Demand:	11.6	44.7
Prep Plant Electricity Demand:	3.2	11.2
Potential Generating Capacity (2003 data)		
Assuming 20% Recovery Efficiency:	15.2	133.4
Assuming 40% Recovery Efficiency:	30.5	266.8
Assuming 60% Recovery Efficiency:	45.7	400.2

Pipeline Sales Potential

Potential Annual Gas Sales (2003 data)	Bcf
Assuming 20% Recovery (Bcf):	1.5
Assuming 40% Recovery (Bcf):	2.9
Assuming 60% Recovery (Bcf):	4.4

Description of Surrounding Terrain: Open Hills/Open High Hills

Transmission Pipeline in County? Yes

Owner of Nearest Pipeline: Mine owns pipeline that connects to trans. line

Distance to Pipeline (miles): 0.0 **Pipeline Diameter (inches):** NA

Owner of Next Nearest Pipeline: NA

Distance to Next Nearest Pipeline (miles): 13.3 **Pipeline Diameter (inches):** 24.0

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: None **Distance to Plant (miles):** NA

Comments: Not yet researched.

Updated: 08/01/2005 **Status:** Active

North River Mine

GEOGRAPHIC DATA

Basin: Black Warrior **State:** AL

Coalbed: Pratt **County:** Fayette

CORPORATE INFORMATION

Current Owner: Pittsburg & Midway Coal Mining

Parent Company: Chevron Texaco **Parent Company Web Site:** www.chevron.com

Previous Owner(s): None in last 10 years **Previous or Alternate Name of Mine:** North River No. 1

MINE ADDRESS

Contact Name: Mark Premo, Gen. Mine Mgr. **Phone Number:** (205) 333-5000

Mailing Address: 12398 New Lexington

City: Berry **State:** AL **ZIP:** 35546

GENERAL INFORMATION

Number of Employees at Mine: 353 **Mining Method:** Longwall/Continuous

Year of Initial Production: 1974 **Primary Coal Use:** Steam

Life Expectancy: NA **Sulfur Content of Coal Produced:** 1.5% - 1.85%

Prep Plant Located on Site? Yes **BTUs/lb of Coal Produced:** 12,000

Depth to Seam (ft): 516 **Seam Thickness (ft):** 4.7

PRODUCTION, VENTILATION AND DRAINAGE DATA

	1999	2000	2001	2002	2003
Coal Production (million short tons/year):	2.3	2.6	3.2	3.4	3.5
Estimated Total Methane Liberated (million cf/day):	5.2	3.8	5.6	5.1	4.2
Emission from Ventilation Systems:	5.2	3.8	5.6	5.1	4.2
Estimated Methane Drained:	0.0	0.0	0.0	0.0	0.0
Estimated Specific Emissions (cf/ton):	819	528	629	547	437
Methane Recovered (million cf/day):	-	-	-	-	-

Estimated Current Drainage Efficiency: 0%

Drainage System Used: None

North River Mine (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

(Based on 2003 Data)	Assumed Potential Recovery Efficiency 20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons):	0.1	0.3	0.4
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	1.6%	3.1%	4.7%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	0.4%	0.7%	1.1%

Power Generation Potential

Utility Electric Supplier: Alabama Power Co.

Parent Corporation of Utility: The Southern Co.

	MW	GWh/year
Total Electricity Demand (2003 data):	27.9	105.5
Mine Electricity Demand:	21.9	84.4
Prep Plant Electricity Demand:	6.0	21.1
Potential Generating Capacity (2003 data)		
Assuming 20% Recovery Efficiency:	3.2	27.9
Assuming 40% Recovery Efficiency:	6.4	55.9
Assuming 60% Recovery Efficiency:	9.6	83.8

Pipeline Sales Potential

Potential Annual Gas Sales (2003 data)	Bcf
Assuming 20% Recovery (Bcf):	0.3
Assuming 40% Recovery (Bcf):	0.6
Assuming 60% Recovery (Bcf):	0.9

Description of Surrounding Terrain: Open Hills/Open High Hills

Transmission Pipeline in County? No

Owner of Nearest Pipeline: City Of Berry

Distance to Pipeline (miles): 0.4 **Pipeline Diameter (inches):** 2.0

Owner of Next Nearest Pipeline: SNG Intrastate Pipeline

Distance to Next Nearest Pipeline (miles): 14.2 **Pipeline Diameter (inches):** 24.0

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: None **Distance to Plant (miles):** NA

Comments: Not yet researched.

Updated: 08/01/2005 **Status:** Active

Oak Grove Mine

GEOGRAPHIC DATA

Basin: Black Warrior **State:** AL

Coalbed: Blue Creek **County:** Jefferson

CORPORATE INFORMATION

Current Owner: U.S. Steel Mining Co., L.L.C.

Parent Company: USX Corp. **Parent Company Web Site:** www.uss.com/ussteel/Index.html

Previous Owner(s): None in last 10 years **Previous or Alternate Name of Mine:** None

MINE ADDRESS

Contact Name: John Hedrick **Phone Number:** (205) 497-3602

Mailing Address: 8800 Oak Grove Mine

City: Adger **State:** AL **ZIP:** 35006

GENERAL INFORMATION

Number of Employees at Mine: 450 **Mining Method:** Longwall/Continuous

Year of Initial Production: 1974 **Primary Coal Use:** Steam, Metallurgical

Life Expectancy: 2023 **Sulfur Content of Coal Produced:** 0.5% - 0.55%

Prep Plant Located on Site? No **BTUs/lb of Coal Produced:** 14,000

Depth to Seam (ft): 1,100 **Seam Thickness (ft):** 5.8

PRODUCTION, VENTILATION AND DRAINAGE DATA

	1999	2000	2001	2002	2003
Coal Production (million short tons/year):	2.1	2.1	1.8	1.9	1.7
Estimated Total Methane Liberated (million cf/day):	12.6	10.4	8.8	12.7	12.6
Emission from Ventilation Systems:	9.6	6.7	6.3	5.1	8.5
Estimated Methane Drained:	3.0	3.7	2.5	7.6	4.1
Estimated Specific Emissions (cf/ton):	2135	1803	1751	2385	2666
Methane Recovered (million cf/day):	2.9	3.0	2.5	9.7	4.1

Estimated Current Drainage Efficiency: 33%

Drainage System Used: Vertical Pre-Mine, Vertical Gob

Oak Grove Mine (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

(Based on 2003 Data)	Assumed Potential Recovery Efficiency 20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons):	0.4	0.8	1.2
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	8.2%	16.5%	24.7%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	1.9%	3.8%	5.7%

Power Generation Potential

Utility Electric Supplier: Alabama Power Co.

Parent Corporation of Utility: The Southern Co.

	MW	GWh/year
Total Electricity Demand (2003 data):	13.7	51.9
Mine Electricity Demand:	10.8	41.5
Prep Plant Electricity Demand:	2.9	10.4
Potential Generating Capacity (2003 data)		
Assuming 20% Recovery Efficiency:	9.6	83.9
Assuming 40% Recovery Efficiency:	19.2	167.8
Assuming 60% Recovery Efficiency:	28.7	251.7

Pipeline Sales Potential

Potential Annual Gas Sales (2003 data)	Bcf
Assuming 20% Recovery (Bcf):	0.9
Assuming 40% Recovery (Bcf):	1.8
Assuming 60% Recovery (Bcf):	2.8

Description of Surrounding Terrain: Open Hills/Open High Hills

Transmission Pipeline in County? Yes

Owner of Nearest Pipeline: Mine owns pipeline that connects to trans. line

Distance to Pipeline (miles): 0.0 **Pipeline Diameter (inches):** NA

Owner of Next Nearest Pipeline: SNG Intrastate Pipeline

Distance to Next Nearest Pipeline (miles): 3.8 **Pipeline Diameter (inches):** 12.0

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: None **Distance to Plant (miles):** NA

Comments: Not yet researched.

Updated: 08/01/2005 **Status:** Active

Shoal Creek

GEOGRAPHIC DATA

Basin: Black Warrior **State:** AL

Coalbed: Blue Creek, Mary Lee **County:** Jefferson

CORPORATE INFORMATION

Current Owner: Drummond Co., Inc.

Parent Company: ABC Coke Division - Drummond **Parent Company Web Site:** www.drummondco.com

Previous Owner(s): None in last 10 years **Previous or Alternate Name of Mine:** None

MINE ADDRESS

Contact Name: Jay Vilseck **Phone Number:** (205) 491-6200

Mailing Address: P.O. Box 1549

City: Jasper **State:** AL **ZIP:** 35501

GENERAL INFORMATION

Number of Employees at Mine: 830 **Mining Method:** Longwall/Continuous

Year of Initial Production: 1994 **Primary Coal Use:** Steam

Life Expectancy: NA **Sulfur Content of Coal Produced:** 0.63% - 1.1%

Prep Plant Located on Site? Yes **BTUs/lb of Coal Produced:** 12,464

Depth to Seam (ft): 1,180 **Seam Thickness (ft):** 7.5, 2.0

PRODUCTION, VENTILATION AND DRAINAGE DATA

	1999	2000	2001	2002	2003
Coal Production (million short tons/year):	4.1	4.2	4.1	4.0	3.8
Estimated Total Methane Liberated (million cf/day):	6.8	6.0	6.9	7.4	12.6
Emission from Ventilation Systems:	6.6	5.7	6.6	6.7	8.2
Estimated Methane Drained:	0.2	0.3	0.3	0.7	4.4
Estimated Specific Emissions (cf/ton):	604	520	615	681	1200
Methane Recovered (million cf/day):	0.2	0.3	0.5	0.7	1.0

Estimated Current Drainage Efficiency: 35%

Drainage System Used: Vertical Pre-Mine, Vertical Gob, Horizontal Pre-Mine

Shoal Creek (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

(Based on 2003 Data)	Assumed Potential Recovery Efficiency 20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons):	0.4	0.8	1.2
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	4.2%	8.3%	12.5%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	1.0%	1.9%	2.9%

Power Generation Potential

Utility Electric Supplier: Alabama Power Co.

Parent Corporation of Utility: The Southern Co.

	MW	GWh/year
Total Electricity Demand (2003 data):	30.4	115.2
Mine Electricity Demand:	23.9	92.2
Prep Plant Electricity Demand:	6.5	23.0
Potential Generating Capacity (2003 data)		
Assuming 20% Recovery Efficiency:	9.6	83.8
Assuming 40% Recovery Efficiency:	19.1	167.5
Assuming 60% Recovery Efficiency:	28.7	251.3

Pipeline Sales Potential

Potential Annual Gas Sales (2003 data)	Bcf
Assuming 20% Recovery (Bcf):	0.9
Assuming 40% Recovery (Bcf):	1.8
Assuming 60% Recovery (Bcf):	2.8

Description of Surrounding Terrain: Open Hills/High Hills

Transmission Pipeline in County? Yes

Owner of Nearest Pipeline: SNG Intrastate Pipeline

Distance to Pipeline (miles): NA **Pipeline Diameter (inches):** NA

Owner of Next Nearest Pipeline: NA

Distance to Next Nearest Pipeline (miles): NA **Pipeline Diameter (inches):** NA

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: None **Distance to Plant (miles):** NA

Comments: Not yet researched.

6. Profiled Mines (continued)

Colorado Mines

Elk Creek
West Elk

Updated: 08/01/2005 **Status:** Active

Elk Creek Mine

GEOGRAPHIC DATA

Basin: Uinta **State:** CO

Coalbed: D-seam **County:** Gunnison

CORPORATE INFORMATION

Current Owner: Oxbow Mining, Inc.

Parent Company: Oxbow Carbon & Materials Inc. **Parent Company Web Site:** www.oxbow.com

Previous Owner(s): NA **Previous or Alternate Name of Mine:** NA

MINE ADDRESS

Contact Name: James Cooper **Phone Number:** (970) 929-5122

Mailing Address: P.O. Box 535

City: Somerset **State:** CO **ZIP:** 81434

GENERAL INFORMATION

Number of Employees at Mine: 258 **Mining Method:** Longwall

Year of Initial Production: 2001 **Primary Coal Use:** NA

Life Expectancy: 2011 **Sulfur Content of Coal Produced:** 0.5% - 0.8%

Prep Plant Located on Site? No **BTUs/lb of Coal Produced:** 11,750

Depth to Seam (ft): NA **Seam Thickness (ft):** NA

PRODUCTION, VENTILATION AND DRAINAGE DATA

	1999	2000	2001	2002	2003
Coal Production (million short tons/year):	0.0	0.0	0.0	0.6	4.6
Estimated Total Methane Liberated (million cf/day):	0.0	0.0	0.0	0.1	1.1
Emission from Ventilation Systems:	0.0	0.0	0.0	0.1	1.1
Estimated Methane Drained:	0.0	0.0	0.0	0.0	0.0
Estimated Specific Emissions (cf/ton):	-	-	-	31	91
Methane Recovered (million cf/day):	-	-	-	-	-

Estimated Current Drainage Efficiency: 0%

Drainage System Used: None

Elk Creek Mine (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

	Assumed Potential Recovery Efficiency		
(Based on 2003 Data)	20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons):	0.0	0.1	0.1
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	0.3%	0.7%	1.0%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	0.1%	0.2%	0.2%

Power Generation Potential

Utility Electric Supplier:

Parent Corporation of Utility:

	MW	GWh/year
Total Electricity Demand (2003 data):	36.4	137.9
Mine Electricity Demand:	28.6	110.3
Prep Plant Electricity Demand:	7.8	27.6
Potential Generating Capacity (2003 data)		
Assuming 20% Recovery Efficiency:	0.9	7.6
Assuming 40% Recovery Efficiency:	1.7	15.1
Assuming 60% Recovery Efficiency:	2.6	22.7

Pipeline Sales Potential

Potential Annual Gas Sales (2003 data)	Bcf
Assuming 20% Recovery (Bcf):	0.1
Assuming 40% Recovery (Bcf):	0.2
Assuming 60% Recovery (Bcf):	0.2

Description of Surrounding Terrain:

Transmission Pipeline in County?

Owner of Nearest Pipeline:

Distance to Pipeline (miles): **Pipeline Diameter (inches):**

Owner of Next Nearest Pipeline:

Distance to Next Nearest Pipeline (miles): **Pipeline Diameter (inches):**

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: **Distance to Plant (miles):**

Comments:

Updated: 08/01/2005 **Status:** Active

West Elk Mine

GEOGRAPHIC DATA

Basin: Uinta **State:** CO

Coalbed: B Seam **County:** Gunnison

CORPORATE INFORMATION

Current Owner: Mountain Coal Co.

Parent Company: Arch Coal, Inc. **Parent Company Web Site:** www.archcoal.com

Previous Owner(s): Atlantic Richfield/ITOCHU Corp. **Previous or Alternate Name of Mine:** Mt. Gunnison

MINE ADDRESS

Contact Name: Gene DiClaudio, Pres. & G.M. **Phone Number:** (970) 929-5015

Mailing Address: P.O. Box 591

City: Somerset **State:** CO **ZIP:** 81434

GENERAL INFORMATION

Number of Employees at Mine: 341 **Mining Method:** Longwall/Continuous

Year of Initial Production: 1982 **Primary Coal Use:** Steam

Life Expectancy: 2020 **Sulfur Content of Coal Produced:** 0.36% - 0.78%

Prep Plant Located on Site? Yes **BTUs/lb of Coal Produced:** 11,700

Depth to Seam (ft): 1,000 - 2,000 **Seam Thickness (ft):** 12

PRODUCTION, VENTILATION AND DRAINAGE DATA

	1999	2000	2001	2002	2003
Coal Production (million short tons/year):	7.1	3.4	5.0	6.6	6.5
Estimated Total Methane Liberated (million cf/day):	11.8	15.7	16.1	19.8	27.2
Emission from Ventilation Systems:	11.8	11.8	12.1	9.9	13.6
Estimated Methane Drained:	0.0	3.9	4.0	9.9	13.6
Estimated Specific Emissions (cf/ton):	607	1711	1169	1100	1528
Methane Recovered (million cf/day):	-	-	-	-	0.1

Estimated Current Drainage Efficiency: 50%

Drainage System Used: Vertical Gob, Horizontal Pre-Mine

West Elk Mine (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

(Based on 2003 Data)	Assumed Potential Recovery Efficiency 20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons):	0.9	1.8	2.6
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	5.6%	11.3%	16.9%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	1.3%	2.6%	3.9%

Power Generation Potential

Utility Electric Supplier: Delta Montrose Elec. Assoc./Gunnison County Elec. Assoc.
Parent Corporation of Utility: Touchstone Energy Cooperatives

	MW	GWh/year
Total Electricity Demand (2003 data):	51.5	194.7
Mine Electricity Demand:	40.4	155.8
Prep Plant Electricity Demand:	11.1	38.9
Potential Generating Capacity (2003 data)		
Assuming 20% Recovery Efficiency:	20.6	180.4
Assuming 40% Recovery Efficiency:	41.2	360.8
Assuming 60% Recovery Efficiency:	61.8	541.1

Pipeline Sales Potential

Potential Annual Gas Sales (2003 data)	Bcf
Assuming 20% Recovery (Bcf):	2.0
Assuming 40% Recovery (Bcf):	4.0
Assuming 60% Recovery (Bcf):	6.0

Description of Surrounding Terrain: Hilly/Mountainous

Transmission Pipeline in County? Yes

Owner of Nearest Pipeline: Rocky Mountain Natural Gas

Distance to Pipeline (miles): < 25.0 **Pipeline Diameter (inches):** 8.0

Owner of Next Nearest Pipeline: NA

Distance to Next Nearest Pipeline (miles): NA **Pipeline Diameter (inches):** NA

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: None **Distance to Plant (miles):** NA

Comments: Hospital and other institutional facilities.

6. Profiled Mines (continued)

Illinois Mines

Elkhart
Galatia
Wabash
Willow Lake Portal

Updated: 08/01/2005 **Status:** Active

Elkhart Mine

GEOGRAPHIC DATA

Basin: Illinois **State:** IL

Coalbed: Springfield No. 5 **County:** Sangamon

CORPORATE INFORMATION

Current Owner: Turris Coal Company

Parent Company: Bluegrass Coal Devel. Co. **Parent Company Web Site:** NA

Previous Owner(s): NA **Previous or Alternate Name of Mine:** NA

MINE ADDRESS

Contact Name: C. Lane **Phone Number:** (606) 923-2934

Mailing Address: 8100 E. Main

City: Williamsville **State:** IL **ZIP:** 62693

GENERAL INFORMATION

Number of Employees at Mine: 219 **Mining Method:** Continuous

Year of Initial Production: 1982 **Primary Coal Use:** Steam

Life Expectancy: NA **Sulfur Content of Coal Produced:** 3.0% - 3.2%

Prep Plant Located on Site? Yes **BTUs/lb of Coal Produced:** 10,454

Depth to Seam (ft): 290 **Seam Thickness (ft):** 5.7

PRODUCTION, VENTILATION AND DRAINAGE DATA

	1999	2000	2001	2002	2003
Coal Production (million short tons/year):	2.3	2.0	2.1	1.8	2.1
Estimated Total Methane Liberated (million cf/day):	0.5	0.5	0.5	0.6	0.9
Emission from Ventilation Systems:	0.5	0.5	0.5	0.6	0.9
Estimated Methane Drained:	0.0	0.0	0.0	0.0	0.0
Estimated Specific Emissions (cf/ton):	79	101	93	122	152
Methane Recovered (million cf/day):	-	-	-	-	-

Estimated Current Drainage Efficiency: 0%

Drainage System Used: None

Elkhart Mine (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

(Based on 2003 Data)	Assumed Potential Recovery Efficiency 20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons):	0.0	0.1	0.1
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	0.6%	1.3%	1.9%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	0.1%	0.3%	0.4%

Power Generation Potential

Utility Electric Supplier:

Parent Corporation of Utility:

	MW	GWh/year
Total Electricity Demand (2003 data):	16.9	64.0
Mine Electricity Demand:	13.3	51.2
Prep Plant Electricity Demand:	3.6	12.8
Potential Generating Capacity (2003 data)		
Assuming 20% Recovery Efficiency:	0.7	5.9
Assuming 40% Recovery Efficiency:	1.3	11.8
Assuming 60% Recovery Efficiency:	2.0	17.7

Pipeline Sales Potential

Potential Annual Gas Sales (2003 data)	Bcf
Assuming 20% Recovery (Bcf):	0.1
Assuming 40% Recovery (Bcf):	0.1
Assuming 60% Recovery (Bcf):	0.2

Description of Surrounding Terrain:

Transmission Pipeline in County?

Owner of Nearest Pipeline:

Distance to Pipeline (miles): **Pipeline Diameter (inches):**

Owner of Next Nearest Pipeline:

Distance to Next Nearest Pipeline (miles): **Pipeline Diameter (inches):**

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: **Distance to Plant (miles):**

Comments:

Updated: 08/01/2005 **Status:** Active

Galatia

GEOGRAPHIC DATA

Basin: Illinois **State:** IL

Coalbed: Springfield No. 5 **County:** Saline

CORPORATE INFORMATION

Current Owner: The American Coal Co.

Parent Company: American Coal Company **Parent Company Web Site:** NA

Previous Owner(s): Kerr-McGee Coal Corp. **Previous or Alternate Name of Mine:** None

MINE ADDRESS

Contact Name: Maynard St. John, Mine Mgr. **Phone Number:** (618) 268-6311

Mailing Address: P.O. Box 727

City: Harrisburg **State:** IL **ZIP:** 62946

GENERAL INFORMATION

Number of Employees at Mine: 585 **Mining Method:** Longwall

Year of Initial Production: 1983 **Primary Coal Use:** Steam

Life Expectancy: NA **Sulfur Content of Coal Produced:** 1.2%

Prep Plant Located on Site? Yes **BTUs/lb of Coal Produced:** 12,000

Depth to Seam (ft): 400 **Seam Thickness (ft):** 7.0

PRODUCTION, VENTILATION AND DRAINAGE DATA

	1999	2000	2001	2002	2003
Coal Production (million short tons/year):	6.5	7.3	7.0	6.3	6.0
Estimated Total Methane Liberated (million cf/day):	8.6	10.3	8.4	6.1	3.9
Emission from Ventilation Systems:	8.6	10.3	8.4	6.1	3.9
Estimated Methane Drained:	0.0	0.0	0.0	0.0	0.0
Estimated Specific Emissions (cf/ton):	483	509	436	354	238
Methane Recovered (million cf/day):	-	-	-	-	-

Estimated Current Drainage Efficiency: 0%

Drainage System Used: None

Galatia (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

(Based on 2003 Data)	Assumed Potential Recovery Efficiency 20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons):	0.1	0.3	0.4
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	0.9%	1.7%	2.6%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	0.2%	0.4%	0.6%

Power Generation Potential

Utility Electric Supplier: Central Illinois Public Service

Parent Corporation of Utility: CIPSCO, Inc.

	MW	GWh/year
Total Electricity Demand (2003 data):	47.7	180.3
Mine Electricity Demand:	37.4	144.3
Prep Plant Electricity Demand:	10.2	36.1
Potential Generating Capacity (2003 data)		
Assuming 20% Recovery Efficiency:	3.0	26.0
Assuming 40% Recovery Efficiency:	5.9	52.0
Assuming 60% Recovery Efficiency:	8.9	78.0

Pipeline Sales Potential

Potential Annual Gas Sales (2003 data)	Bcf
Assuming 20% Recovery (Bcf):	0.3
Assuming 40% Recovery (Bcf):	0.6
Assuming 60% Recovery (Bcf):	0.9

Description of Surrounding Terrain: Open Hills/Irregular Plains

Transmission Pipeline in County? Yes

Owner of Nearest Pipeline: Texas Eastern Transmission Co.

Distance to Pipeline (miles): 0.8 **Pipeline Diameter (inches):** 24.0

Owner of Next Nearest Pipeline: Trunkline

Distance to Next Nearest Pipeline (miles): 8.0 miles **Pipeline Diameter (inches):** 26"

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: None **Distance to Plant (miles):** NA

Comments: Apparel, fertilizers, trusses, and mine equipment manufacturing.

Updated: 08/01/2005 **Status:** Active

Wabash

GEOGRAPHIC DATA

Basin: Illinois **State:** IL

Coalbed: Springfield No. 5 **County:** Wabash

CORPORATE INFORMATION

Current Owner: Wabash Mine Holding Co.

Parent Company: RAG American Coal Co. **Parent Company Web Site:** http://www.rag-american.com/

Previous Owner(s): Amax Coal Co. **Previous or Alternate Name of Mine:** None

MINE ADDRESS

Contact Name: William Kelly, Gen. Mine Mgr. **Phone Number:** (618) 298-2394

Mailing Address: P.O. Box 144, 1000

City: Keensburg **State:** IL **ZIP:** 62852

GENERAL INFORMATION

Number of Employees at Mine: 234 **Mining Method:** Continuous

Year of Initial Production: 1973 **Primary Coal Use:** Steam

Life Expectancy: NA **Sulfur Content of Coal Produced:** 1.5%

Prep Plant Located on Site? Yes **BTUs/lb of Coal Produced:** 11,000

Depth to Seam (ft): NA **Seam Thickness (ft):** NA

PRODUCTION, VENTILATION AND DRAINAGE DATA

	1999	2000	2001	2002	2003
Coal Production (million short tons/year):	1.3	1.5	1.5	1.5	1.6
Estimated Total Methane Liberated (million cf/day):	0.8	1.2	1.5	0.8	1.2
Emission from Ventilation Systems:	0.8	1.2	1.5	0.8	1.2
Estimated Methane Drained:	0.0	0.0	0.0	0.0	0.0
Estimated Specific Emissions (cf/ton):	220	298	382	189	279
Methane Recovered (million cf/day):	-	-	-	-	-

Estimated Current Drainage Efficiency: 0%

Drainage System Used: None

Wabash (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

(Based on 2003 Data)	Assumed Potential Recovery Efficiency 20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons):	0.0	0.1	0.1
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	1.1%	2.2%	3.3%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	0.3%	0.5%	0.8%

Power Generation Potential

Utility Electric Supplier: Wayne White Counties Elec. Coop./Norris Elec. Coop.

Parent Corporation of Utility: Touchstone Energy Cooperatives

	MW	GWh/year
Total Electricity Demand (2003 data):	12.4	47.0
Mine Electricity Demand:	9.8	37.6
Prep Plant Electricity Demand:	2.7	9.4
Potential Generating Capacity (2003 data)		
Assuming 20% Recovery Efficiency:	0.9	8.0
Assuming 40% Recovery Efficiency:	1.8	15.9
Assuming 60% Recovery Efficiency:	2.7	23.9

Pipeline Sales Potential

Potential Annual Gas Sales (2003 data)	Bcf
Assuming 20% Recovery (Bcf):	0.1
Assuming 40% Recovery (Bcf):	0.2
Assuming 60% Recovery (Bcf):	0.3

Description of Surrounding Terrain: Irregular Plains

Transmission Pipeline in County? No

Owner of Nearest Pipeline: Texas Eastern Transmission Co.

Distance to Pipeline (miles): 4.2 **Pipeline Diameter (inches):** 24.0

Owner of Next Nearest Pipeline: NA

Distance to Next Nearest Pipeline (miles): NA **Pipeline Diameter (inches):** NA

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: None **Distance to Plant (miles):** NA

Comments: Not yet researched.

Updated: 08/01/2005 **Status:** Active

Willow Lake Portal

GEOGRAPHIC DATA

Basin: Illinois **State:** IL

Coalbed: Illinois No. 5 & 6 **County:** Saline

CORPORATE INFORMATION

Current Owner: Big Ridge Inc

Parent Company: Peabody Energy **Parent Company Web Site:** NA

Previous Owner(s): Arclar Co., LLC **Previous or Alternate Name of Mine:** Willow Lake Mine

MINE ADDRESS

Contact Name: Mike Fourney **Phone Number:** (314) 342-7699

Mailing Address: 420 Long Lane Rd

City: Equality **State:** IL **ZIP:** 62934

GENERAL INFORMATION

Number of Employees at Mine: 307 **Mining Method:** Continuous

Year of Initial Production: NA **Primary Coal Use:** NA

Life Expectancy: NA **Sulfur Content of Coal Produced:** 2% - 5%

Prep Plant Located on Site? No **BTUs/lb of Coal Produced:** 12,200

Depth to Seam (ft): NA **Seam Thickness (ft):** 4.5 - 5

PRODUCTION, VENTILATION AND DRAINAGE DATA

	1999	2000	2001	2002	2003
Coal Production (million short tons/year):	0.0	0.0	0.0	2.1	2.9
Estimated Total Methane Liberated (million cf/day):	0.0	0.0	0.0	0.5	1.1
Emission from Ventilation Systems:	0.0	0.0	0.0	0.5	1.1
Estimated Methane Drained:	0.0	0.0	0.0	0.0	0.0
Estimated Specific Emissions (cf/ton):	-	-	-	86	138
Methane Recovered (million cf/day):	-	-	-	-	-

Estimated Current Drainage Efficiency: 0%

Drainage System Used: None

Willow Lake Portal (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

(Based on 2003 Data)	Assumed Potential Recovery Efficiency 20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons):	0.0	0.1	0.1
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	0.5%	1.0%	1.5%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	0.1%	0.2%	0.3%

Power Generation Potential

Utility Electric Supplier:

Parent Corporation of Utility:

	MW	GWh/year
Total Electricity Demand (2003 data):	22.6	85.6
Mine Electricity Demand:	17.8	68.5
Prep Plant Electricity Demand:	4.9	17.1
Potential Generating Capacity (2003 data)		
Assuming 20% Recovery Efficiency:	0.8	7.2
Assuming 40% Recovery Efficiency:	1.6	14.3
Assuming 60% Recovery Efficiency:	2.5	21.5

Pipeline Sales Potential

Potential Annual Gas Sales (2003 data)	Bcf
Assuming 20% Recovery (Bcf):	0.1
Assuming 40% Recovery (Bcf):	0.2
Assuming 60% Recovery (Bcf):	0.2

Description of Surrounding Terrain:

Transmission Pipeline in County?

Owner of Nearest Pipeline:

Distance to Pipeline (miles): **Pipeline Diameter (inches):**

Owner of Next Nearest Pipeline:

Distance to Next Nearest Pipeline (miles): **Pipeline Diameter (inches):**

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: **Distance to Plant (miles):**

Comments:

Indiana Mines

Gibson

Updated: 08/01/2005 **Status:** Active

Gibson

GEOGRAPHIC DATA

Basin: Illinois **State:** IN

Coalbed: Springfield No. 5 **County:** Gibson

CORPORATE INFORMATION

Current Owner: Gibson County Coal, LLC

Parent Company: Alliance Resources Partners **Parent Company Web Site:** www.arlp.com

Previous Owner(s): Alliance Resources Holdings **Previous or Alternate Name of Mine:** None

MINE ADDRESS

Contact Name: NA **Phone Number:** (812) 385-1816

Mailing Address: P.O.Box 1269

City: Princeton **State:** IN **ZIP:** 47670

GENERAL INFORMATION

Number of Employees at Mine: 153 **Mining Method:** Continuous

Year of Initial Production: 2000 **Primary Coal Use:** Steam

Life Expectancy: NA **Sulfur Content of Coal Produced:** 0.6% - 7.2%

Prep Plant Located on Site? Yes **BTUs/lb of Coal Produced:** 12,800

Depth to Seam (ft): NA **Seam Thickness (ft):** NA

PRODUCTION, VENTILATION AND DRAINAGE DATA

	1999	2000	2001	2002	2003
Coal Production (million short tons/year):	0.0	0.0	1.7	1.9	2.4
Estimated Total Methane Liberated (million cf/day):	0.0	0.0	1.3	2.2	2.4
Emission from Ventilation Systems:	0.0	0.0	1.3	2.2	2.4
Estimated Methane Drained:	0.0	0.0	0.0	0.0	0.0
Estimated Specific Emissions (cf/ton):	-	0	291	406	355
Methane Recovered (million cf/day):	-	-	-	-	-

Estimated Current Drainage Efficiency: 0%

Drainage System Used: None

Gibson (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

(Based on 2003 Data)	Assumed Potential Recovery Efficiency 20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons):	0.1	0.2	0.2
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	1.2%	2.4%	3.6%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	0.3%	0.6%	0.8%

Power Generation Potential

Utility Electric Supplier: PSI

Parent Corporation of Utility: Cinergy

	MW	GWh/year
Total Electricity Demand (2003 data):	19.4	73.4
Mine Electricity Demand:	15.2	58.7
Prep Plant Electricity Demand:	4.2	14.7
Potential Generating Capacity (2003 data)		
Assuming 20% Recovery Efficiency:	1.8	15.8
Assuming 40% Recovery Efficiency:	3.6	31.6
Assuming 60% Recovery Efficiency:	5.4	47.4

Pipeline Sales Potential

Potential Annual Gas Sales (2003 data)	Bcf
Assuming 20% Recovery (Bcf):	0.2
Assuming 40% Recovery (Bcf):	0.3
Assuming 60% Recovery (Bcf):	0.5

Description of Surrounding Terrain:

Transmission Pipeline in County? Yes

Owner of Nearest Pipeline: Texas Gas Transmission Co.

Distance to Pipeline (miles): < 5.0 **Pipeline Diameter (inches):** 4.0

Owner of Next Nearest Pipeline: Texas Eastern Transmission Co.

Distance to Next Nearest Pipeline (miles): < 10.0 miles **Pipeline Diameter (inches):** 20"

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: **Distance to Plant (miles):**

Comments:

6. Profiled Mines (continued)

Kentucky Mines

Baker
Cardinal
Clean Energy No. 1
E3RF
Freedom Energy No. 1
Mine #1
No. 3 Mine
Pontiki No. 2

Updated: 08/01/2005 **Status:** Active

Baker

GEOGRAPHIC DATA

Basin: Illinois **State:** KY

Coalbed: W. Kentucky No. 13 **County:** Webster

CORPORATE INFORMATION

Current Owner: Lodestar Energy, Inc

Parent Company: Lodestar Energy, Inc. **Parent Company Web Site:** www.lodestarenergy.com

Previous Owner(s): The Renco Group **Previous or Alternate Name of Mine:** Pyro/Baker

MINE ADDRESS

Contact Name: David Wineberger, Mine Mgr. **Phone Number:** (270) 667-7025

Mailing Address: P.O. Box 448

City: Clay **State:** KY **ZIP:** 42404

GENERAL INFORMATION

Number of Employees at Mine: 390 **Mining Method:** Longwall/Continuous

Year of Initial Production: NA **Primary Coal Use:** Steam

Life Expectancy: 2005 **Sulfur Content of Coal Produced:** 1.9% - 3.0%

Prep Plant Located on Site? Yes **BTUs/lb of Coal Produced:** 9,400

Depth to Seam (ft): 850 **Seam Thickness (ft):** 6.0

PRODUCTION, VENTILATION AND DRAINAGE DATA

	1999	2000	2001	2002	2003
Coal Production (million short tons/year):	4.5	4.3	3.4	2.9	0.6
Estimated Total Methane Liberated (million cf/day):	2.2	2.2	3.4	2.3	1.5
Emission from Ventilation Systems:	2.0	2.2	3.4	2.3	1.5
Estimated Methane Drained:	0.2	0.0	0.0	0.0	0.0
Estimated Specific Emissions (cf/ton):	179	187	366	289	898
Methane Recovered (million cf/day):	-	-	-	-	-

Estimated Current Drainage Efficiency: 0%

Drainage System Used: None

Baker (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

	Assumed Potential Recovery Efficiency		
(Based on 2003 Data)	20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons):	0.0	0.1	0.1
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	4.2%	8.4%	12.5%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	1.0%	1.9%	2.9%

Power Generation Potential

Utility Electric Supplier: Kentucky Utilities Co.

Parent Corporation of Utility: KU Energy

	MW	GWh/year
Total Electricity Demand (2003 data):	4.9	18.4
Mine Electricity Demand:	3.8	14.7
Prep Plant Electricity Demand:	1.0	3.7
Potential Generating Capacity (2003 data)		
Assuming 20% Recovery Efficiency:	1.1	10.0
Assuming 40% Recovery Efficiency:	2.3	20.0
Assuming 60% Recovery Efficiency:	3.4	30.1

Pipeline Sales Potential

Potential Annual Gas Sales (2003 data)	Bcf
Assuming 20% Recovery (Bcf):	0.1
Assuming 40% Recovery (Bcf):	0.2
Assuming 60% Recovery (Bcf):	0.3

Description of Surrounding Terrain: Open Hills

Transmission Pipeline in County? No

Owner of Nearest Pipeline: Texas Gas Transmission

Distance to Pipeline (miles): 8.3 **Pipeline Diameter (inches):** 26.0

Owner of Next Nearest Pipeline: NA

Distance to Next Nearest Pipeline (miles): NA **Pipeline Diameter (inches):** NA

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: None **Distance to Plant (miles):** NA

Comments: Not yet researched.

Updated: 08/01/2005 **Status:** Active

Cardinal

GEOGRAPHIC DATA

Basin: Central Appalachian **State:** KY

Coalbed: KY No. 11 **County:** Hopkins

CORPORATE INFORMATION

Current Owner: Warrior Coal, LLC

Parent Company: Alliance Resource Partners **Parent Company Web Site:** www.alrp.com

Previous Owner(s): Roberts Brothers Coal Co., Inc. **Previous or Alternate Name of Mine:** Cardinal No. 2

MINE ADDRESS

Contact Name: Brian Kelley, Manager of **Phone Number:** (270) 249-3100

Mailing Address: 57 J.E. Ellis

City: Madisonville **State:** KY **ZIP:** 42431

GENERAL INFORMATION

Number of Employees at Mine: 220 **Mining Method:** Continuous

Year of Initial Production: 1993 **Primary Coal Use:** Steam

Life Expectancy: 2012 **Sulfur Content of Coal Produced:** 3.29% - 4.27%

Prep Plant Located on Site? No **BTUs/lb of Coal Produced:** 11,440

Depth to Seam (ft): 600 **Seam Thickness (ft):** 6.0

PRODUCTION, VENTILATION AND DRAINAGE DATA

	1999	2000	2001	2002	2003
Coal Production (million short tons/year):	1.5	1.6	1.8	1.6	2.4
Estimated Total Methane Liberated (million cf/day):	0.4	0.8	0.7	0.6	0.9
Emission from Ventilation Systems:	0.4	0.8	0.7	0.6	0.9
Estimated Methane Drained:	0.0	0.0	0.0	0.0	0.0
Estimated Specific Emissions (cf/ton):	112	177	140	148	136
Methane Recovered (million cf/day):	-	-	-	-	-

Estimated Current Drainage Efficiency: 0%

Drainage System Used: None

Cardinal (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

(Based on 2003 Data)	Assumed Potential Recovery Efficiency 20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons):	0.0	0.1	0.1
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	0.5%	1.0%	1.6%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	0.1%	0.2%	0.4%

Power Generation Potential

Utility Electric Supplier: Kenergy Corp

Parent Corporation of Utility: Touchstone Energy Cooperatives

	MW	GWh/year
Total Electricity Demand (2003 data):	18.8	71.1
Mine Electricity Demand:	14.7	56.9
Prep Plant Electricity Demand:	4.0	14.2
Potential Generating Capacity (2003 data)		
Assuming 20% Recovery Efficiency:	0.7	5.8
Assuming 40% Recovery Efficiency:	1.3	11.7
Assuming 60% Recovery Efficiency:	2.0	17.5

Pipeline Sales Potential

Potential Annual Gas Sales (2003 data)	Bcf
Assuming 20% Recovery (Bcf):	0.1
Assuming 40% Recovery (Bcf):	0.1
Assuming 60% Recovery (Bcf):	0.2

Description of Surrounding Terrain:

Transmission Pipeline in County? Yes

Owner of Nearest Pipeline: ANR Pipeline Company

Distance to Pipeline (miles): < 3.0 **Pipeline Diameter (inches):** 30.0

Owner of Next Nearest Pipeline:

Distance to Next Nearest Pipeline (miles): **Pipeline Diameter (inches):**

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: **Distance to Plant (miles):**

Comments:

Updated: 08/01/2005 **Status:** Active

Clean Energy No. 1

GEOGRAPHIC DATA

Basin: Central Appalachian **State:** KY

Coalbed: Pond Creek **County:** Pike

CORPORATE INFORMATION

Current Owner: Massey Energy Co.

Parent Company: Massey Energy Co. **Parent Company Web Site:** www.masseyenergyco.com

Previous Owner(s): Sidney Coal Co., Clean Energy **Previous or Alternate Name of Mine:** None

MINE ADDRESS

Contact Name: Barry Dotson **Phone Number:** (804) 788-1800

Mailing Address: 29501 Mayo Trail

City: Cattlesburg **State:** KY **ZIP:** 41129

GENERAL INFORMATION

Number of Employees at Mine: 92 **Mining Method:** Continuous

Year of Initial Production: 1994 **Primary Coal Use:** Steam, Metallurgical

Life Expectancy: NA **Sulfur Content of Coal Produced:** NA

Prep Plant Located on Site? No **BTUs/lb of Coal Produced:** 13,200

Depth to Seam (ft): NA **Seam Thickness (ft):** NA

PRODUCTION, VENTILATION AND DRAINAGE DATA

	1999	2000	2001	2002	2003
Coal Production (million short tons/year):	1.2	1.1	1.3	1.1	1.0
Estimated Total Methane Liberated (million cf/day):	1.2	1.0	0.9	0.9	0.8
Emission from Ventilation Systems:	1.2	1.0	0.9	0.9	0.8
Estimated Methane Drained:	0.0	0.0	0.0	0.0	0.0
Estimated Specific Emissions (cf/ton):	377	332	231	277	265
Methane Recovered (million cf/day):	-	-	-	-	-

Estimated Current Drainage Efficiency: 0%

Drainage System Used: None

Clean Energy No. 1 (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

	Assumed Potential Recovery Efficiency		
(Based on 2003 Data)	20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons):	0.0	0.0	0.1
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	0.9%	1.7%	2.6%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	0.2%	0.4%	0.6%

Power Generation Potential

Utility Electric Supplier: Kentucky Utilities Co.

Parent Corporation of Utility: KU Energy

	MW	GWh/year
Total Electricity Demand (2003 data):	8.3	31.4
Mine Electricity Demand:	6.5	25.1
Prep Plant Electricity Demand:	1.8	6.3
Potential Generating Capacity (2003 data)		
Assuming 20% Recovery Efficiency:	0.6	5.0
Assuming 40% Recovery Efficiency:	1.2	10.1
Assuming 60% Recovery Efficiency:	1.7	15.1

Pipeline Sales Potential

Potential Annual Gas Sales (2003 data)	Bcf
Assuming 20% Recovery (Bcf):	0.1
Assuming 40% Recovery (Bcf):	0.1
Assuming 60% Recovery (Bcf):	0.2

Description of Surrounding Terrain: Hills

Transmission Pipeline in County? Yes

Owner of Nearest Pipeline: Columbia Gas of Kentucky, Inc.

Distance to Pipeline (miles): < 2.0 **Pipeline Diameter (inches):** 10.0

Owner of Next Nearest Pipeline: NA

Distance to Next Nearest Pipeline (miles): NA **Pipeline Diameter (inches):** NA

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: NA **Distance to Plant (miles):** NA

Comments: Not yet researched.

Updated: 08/01/2005 **Status:** Active

E3RF

GEOGRAPHIC DATA

Basin: Central Appalachian **State:** KY

Coalbed: NA **County:** Knott

CORPORATE INFORMATION

Current Owner: Consol of Kentucky, Inc.

Parent Company: CONSOL Energy **Parent Company Web Site:** www.consolenergy.com

Previous Owner(s): NA **Previous or Alternate Name of Mine:** NA

MINE ADDRESS

Contact Name: Richard Liberatore **Phone Number:** (412) 831-4212

Mailing Address: PO Box 1500

City: Pikesville **State:** KY **ZIP:** 41502

GENERAL INFORMATION

Number of Employees at Mine: 175 **Mining Method:** Continuous

Year of Initial Production: NA **Primary Coal Use:** NA

Life Expectancy: NA **Sulfur Content of Coal Produced:** 0.5% - 5.2%

Prep Plant Located on Site? No **BTUs/lb of Coal Produced:** 12,500

Depth to Seam (ft): NA **Seam Thickness (ft):** NA

PRODUCTION, VENTILATION AND DRAINAGE DATA

	1999	2000	2001	2002	2003
Coal Production (million short tons/year):	0.3	1.1	2.7	2.1	1.9
Estimated Total Methane Liberated (million cf/day):	0.0	0.2	0.5	0.6	0.8
Emission from Ventilation Systems:	0.0	0.2	0.5	0.6	0.8
Estimated Methane Drained:	0.0	0.0	0.0	0.0	0.0
Estimated Specific Emissions (cf/ton):	0	52	64	105	149
Methane Recovered (million cf/day):	-	-	-	-	-

Estimated Current Drainage Efficiency: 0%

Drainage System Used: None

E3RF (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

	Assumed Potential Recovery Efficiency		
(Based on 2003 Data)	20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons):	0.0	0.0	0.1
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	0.5%	1.0%	1.6%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	0.1%	0.2%	0.4%

Power Generation Potential

Utility Electric Supplier:

Parent Corporation of Utility:

	MW	GWh/year
Total Electricity Demand (2003 data):	14.9	56.5
Mine Electricity Demand:	11.7	45.2
Prep Plant Electricity Demand:	3.2	11.3
Potential Generating Capacity (2003 data)		
Assuming 20% Recovery Efficiency:	0.6	5.1
Assuming 40% Recovery Efficiency:	1.2	10.2
Assuming 60% Recovery Efficiency:	1.7	15.3

Pipeline Sales Potential

Potential Annual Gas Sales (2003 data)	Bcf
Assuming 20% Recovery (Bcf):	0.1
Assuming 40% Recovery (Bcf):	0.1
Assuming 60% Recovery (Bcf):	0.2

Description of Surrounding Terrain:

Transmission Pipeline in County?

Owner of Nearest Pipeline:

Distance to Pipeline (miles): **Pipeline Diameter (inches):**

Owner of Next Nearest Pipeline:

Distance to Next Nearest Pipeline (miles): **Pipeline Diameter (inches):**

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: **Distance to Plant (miles):**

Comments:

Updated: 08/01/2005 **Status:** Active

Freedom Energy No.1

GEOGRAPHIC DATA

Basin: Central Appalachian **State:** KY

Coalbed: Pond Creek **County:** Pike

CORPORATE INFORMATION

Current Owner: Freedom Energy Mining Co.

Parent Company: Massey Energy Co. **Parent Company Web Site:** www.masseyenergyco.com

Previous Owner(s): Aero Energy Co., Inc. **Previous or Alternate Name of Mine:** Mine #1

MINE ADDRESS

Contact Name: Nick Pope **Phone Number:** (304) 235-4290

Mailing Address: P.O. Box 299

City: Sydney **State:** KY **ZIP:** 41564

GENERAL INFORMATION

Number of Employees at Mine: 123 **Mining Method:** Continuous

Year of Initial Production: NA **Primary Coal Use:** Steam, Metallurgical

Life Expectancy: NA **Sulfur Content of Coal Produced:** 1.67%

Prep Plant Located on Site? No **BTUs/lb of Coal Produced:** 12,822

Depth to Seam (ft): NA **Seam Thickness (ft):** NA

PRODUCTION, VENTILATION AND DRAINAGE DATA

	1999	2000	2001	2002	2003
Coal Production (million short tons/year):	1.5	1.5	1.9	1.9	1.4
Estimated Total Methane Liberated (million cf/day):	1.1	1.1	1.0	0.8	0.8
Emission from Ventilation Systems:	1.1	1.1	1.0	0.8	0.8
Estimated Methane Drained:	0.0	0.0	0.0	0.0	0.0
Estimated Specific Emissions (cf/ton):	257	281	202	151	211
Methane Recovered (million cf/day):	-	-	-	-	-

Estimated Current Drainage Efficiency: 0%

Drainage System Used: None

Freedom Energy No.1 (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

(Based on 2003 Data)	Assumed Potential Recovery Efficiency 20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons):	0.0	0.1	0.1
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	0.7%	1.4%	2.1%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	0.2%	0.3%	0.5%

Power Generation Potential

Utility Electric Supplier: Kentucky Utilities Co.

Parent Corporation of Utility: KU Energy

	MW	GWh/year
Total Electricity Demand (2003 data):	10.7	40.5
Mine Electricity Demand:	8.4	32.4
Prep Plant Electricity Demand:	2.3	8.1
Potential Generating Capacity (2003 data)		
Assuming 20% Recovery Efficiency:	0.6	5.2
Assuming 40% Recovery Efficiency:	1.2	10.4
Assuming 60% Recovery Efficiency:	1.8	15.5

Pipeline Sales Potential

Potential Annual Gas Sales (2003 data)	Bcf
Assuming 20% Recovery (Bcf):	0.1
Assuming 40% Recovery (Bcf):	0.1
Assuming 60% Recovery (Bcf):	0.2

Description of Surrounding Terrain: Hills

Transmission Pipeline in County? Yes

Owner of Nearest Pipeline: Columbia Gas of Kentucky, Inc.

Distance to Pipeline (miles): < 2.0 **Pipeline Diameter (inches):** 10.0

Owner of Next Nearest Pipeline: NA

Distance to Next Nearest Pipeline (miles): NA **Pipeline Diameter (inches):** NA

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: NA **Distance to Plant (miles):** NA

Comments: Not yet researched.

Updated: 08/01/2005 **Status:** Active

Mine #1

GEOGRAPHIC DATA

Basin: Central Appalachian **State:** KY

Coalbed: NA **County:** Pike

CORPORATE INFORMATION

Current Owner: Rockhouse Energy Mining

Parent Company: Massey Energy Company **Parent Company Web Site:** www.masseyenergyco.com

Previous Owner(s): NA **Previous or Alternate Name of Mine:** NA

MINE ADDRESS

Contact Name: Nick Pope **Phone Number:** (304) 235-4290

Mailing Address: P.O. Box 299

City: Sidney **State:** KY **ZIP:** 41564

GENERAL INFORMATION

Number of Employees at Mine: 129 **Mining Method:** Continuous

Year of Initial Production: 1995 **Primary Coal Use:** Steam

Life Expectancy: NA **Sulfur Content of Coal Produced:** 0.8% - 1.4%

Prep Plant Located on Site? No **BTUs/lb of Coal Produced:** 13,440

Depth to Seam (ft): NA **Seam Thickness (ft):** NA

PRODUCTION, VENTILATION AND DRAINAGE DATA

	1999	2000	2001	2002	2003
Coal Production (million short tons/year):	0.6	1.0	0.7	1.8	1.9
Estimated Total Methane Liberated (million cf/day):	0.4	0.3	0.3	0.4	0.8
Emission from Ventilation Systems:	0.4	0.3	0.3	0.4	0.8
Estimated Methane Drained:	0.0	0.0	0.0	0.0	0.0
Estimated Specific Emissions (cf/ton):	243	129	167	86	156
Methane Recovered (million cf/day):	-	-	-	-	-

Estimated Current Drainage Efficiency: 0%

Drainage System Used: None

Mine #1 (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

	Assumed Potential Recovery Efficiency		
(Based on 2003 Data)	20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons):	0.0	0.1	0.1
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	0.5%	1.0%	1.5%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	0.1%	0.2%	0.3%

Power Generation Potential

Utility Electric Supplier:

Parent Corporation of Utility:

	MW	GWh/year
Total Electricity Demand (2003 data):	15.2	57.6
Mine Electricity Demand:	11.9	46.1
Prep Plant Electricity Demand:	3.3	11.5
Potential Generating Capacity (2003 data)		
Assuming 20% Recovery Efficiency:	0.6	5.4
Assuming 40% Recovery Efficiency:	1.2	10.9
Assuming 60% Recovery Efficiency:	1.9	16.3

Pipeline Sales Potential

Potential Annual Gas Sales (2003 data)	Bcf
Assuming 20% Recovery (Bcf):	0.1
Assuming 40% Recovery (Bcf):	0.1
Assuming 60% Recovery (Bcf):	0.2

Description of Surrounding Terrain:

Transmission Pipeline in County?

Owner of Nearest Pipeline:

Distance to Pipeline (miles): **Pipeline Diameter (inches):**

Owner of Next Nearest Pipeline:

Distance to Next Nearest Pipeline (miles): **Pipeline Diameter (inches):**

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: **Distance to Plant (miles):**

Comments:

Updated: 08/01/2005 **Status:** Active

No. 3 Mine

GEOGRAPHIC DATA

Basin: Central Appalachian **State:** KY

Coalbed: NA **County:** Pike

CORPORATE INFORMATION

Current Owner: Excel Mining LLC

Parent Company: Alliance Resource Partners LP **Parent Company Web Site:** www.arlp.com

Previous Owner(s): NA **Previous or Alternate Name of Mine:** NA

MINE ADDRESS

Contact Name: Judy Magee **Phone Number:** (918) 295-7635

Mailing Address: 4126 St. Hwy. 194 W.

City: Pikeville **State:** KY **ZIP:** 41501

GENERAL INFORMATION

Number of Employees at Mine: 193 **Mining Method:** Continuous

Year of Initial Production: 1977 **Primary Coal Use:** NA

Life Expectancy: NA **Sulfur Content of Coal Produced:** 0.8% - 1.4%

Prep Plant Located on Site? No **BTUs/lb of Coal Produced:** 13,440

Depth to Seam (ft): NA **Seam Thickness (ft):** NA

PRODUCTION, VENTILATION AND DRAINAGE DATA

	1999	2000	2001	2002	2003
Coal Production (million short tons/year):	0.9	0.8	1.2	1.3	1.5
Estimated Total Methane Liberated (million cf/day):	0.9	0.5	0.4	0.8	0.9
Emission from Ventilation Systems:	0.9	0.5	0.4	0.8	0.9
Estimated Methane Drained:	0.0	0.0	0.0	0.0	0.0
Estimated Specific Emissions (cf/ton):	364	237	139	227	217
Methane Recovered (million cf/day):	-	-	-	-	-

Estimated Current Drainage Efficiency: 0%

Drainage System Used: None

No. 3 Mine (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

(Based on 2003 Data)	Assumed Potential Recovery Efficiency 20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons):	0.0	0.1	0.1
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	0.7%	1.4%	2.1%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	0.2%	0.3%	0.5%

Power Generation Potential

Utility Electric Supplier:

Parent Corporation of Utility:

	MW	GWh/year
Total Electricity Demand (2003 data):	12.3	46.4
Mine Electricity Demand:	9.6	37.1
Prep Plant Electricity Demand:	2.6	9.3
Potential Generating Capacity (2003 data)		
Assuming 20% Recovery Efficiency:	0.7	6.1
Assuming 40% Recovery Efficiency:	1.4	12.2
Assuming 60% Recovery Efficiency:	2.1	18.3

Pipeline Sales Potential

Potential Annual Gas Sales (2003 data)	Bcf
Assuming 20% Recovery (Bcf):	0.1
Assuming 40% Recovery (Bcf):	0.1
Assuming 60% Recovery (Bcf):	0.2

Description of Surrounding Terrain:

Transmission Pipeline in County?

Owner of Nearest Pipeline:

Distance to Pipeline (miles): **Pipeline Diameter (inches):**

Owner of Next Nearest Pipeline:

Distance to Next Nearest Pipeline (miles): **Pipeline Diameter (inches):**

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: **Distance to Plant (miles):**

Comments:

Updated: 08/01/2005 **Status:** Active

Pontiki No. 2

GEOGRAPHIC DATA

Basin: Central Appalachian **State:** KY

Coalbed: Pond Creek **County:** Martin

CORPORATE INFORMATION

Current Owner: Excel Mining

Parent Company: Alliance Resource Partners LP **Parent Company Web Site:** www.arlp.com

Previous Owner(s): Pontiki Coal Co. **Previous or Alternate Name of Mine:** None

MINE ADDRESS

Contact Name: John Small **Phone Number:** (606) 395-5352

Mailing Address: P.O. Box 802

City: Lovely **State:** KY **ZIP:** 41231

GENERAL INFORMATION

Number of Employees at Mine: 220 **Mining Method:** Continuous

Year of Initial Production: NA **Primary Coal Use:** Steam

Life Expectancy: NA **Sulfur Content of Coal Produced:** 0.6% - 0.73%

Prep Plant Located on Site? No **BTUs/lb of Coal Produced:** 12,900

Depth to Seam (ft): 425 **Seam Thickness (ft):** NA

PRODUCTION, VENTILATION AND DRAINAGE DATA

	1999	2000	2001	2002	2003
Coal Production (million short tons/year):	0.8	0.6	1.2	1.8	2.0
Estimated Total Methane Liberated (million cf/day):	0.6	0.5	0.6	0.4	0.7
Emission from Ventilation Systems:	0.6	0.5	0.6	0.4	0.7
Estimated Methane Drained:	0.0	0.0	0.0	0.0	0.0
Estimated Specific Emissions (cf/ton):	283	335	182	83	132
Methane Recovered (million cf/day):	-	-	-	-	-

Estimated Current Drainage Efficiency: 0%

Drainage System Used: None

Pontiki No. 2 (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

(Based on 2003 Data)	Assumed Potential Recovery Efficiency 20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons):	0.0	0.0	0.1
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	0.4%	0.9%	1.3%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	0.1%	0.2%	0.3%

Power Generation Potential

Utility Electric Supplier: Kentucky Power Co.

Parent Corporation of Utility: American Electric Power Co., Inc.

	MW	GWh/year
Total Electricity Demand (2003 data):	15.8	59.6
Mine Electricity Demand:	12.4	47.7
Prep Plant Electricity Demand:	3.4	11.9
Potential Generating Capacity (2003 data)		
Assuming 20% Recovery Efficiency:	0.5	4.8
Assuming 40% Recovery Efficiency:	1.1	9.6
Assuming 60% Recovery Efficiency:	1.6	14.3

Pipeline Sales Potential

Potential Annual Gas Sales (2003 data)	Bcf
Assuming 20% Recovery (Bcf):	0.1
Assuming 40% Recovery (Bcf):	0.1
Assuming 60% Recovery (Bcf):	0.2

Description of Surrounding Terrain: High Hills/Low Mountains

Transmission Pipeline in County? Yes

Owner of Nearest Pipeline: Columbia Gas Transmission Co.

Distance to Pipeline (miles): 2.0 **Pipeline Diameter (inches):** 6.0

Owner of Next Nearest Pipeline: NA

Distance to Next Nearest Pipeline (miles): NA **Pipeline Diameter (inches):** NA

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: None **Distance to Plant (miles):** NA

Comments: Not yet researched.

6. Profiled Mines (continued)

New Mexico Mines

San Juan South

Updated: 08/01/2005 **Status:** Active

San Juan South

GEOGRAPHIC DATA

Basin: San Juan **State:** NM

Coalbed: No 9, No. 8 **County:** San Juan

CORPORATE INFORMATION

Current Owner: San Juan Coal Co.

Parent Company: BHP/Billiton **Parent Company Web Site:** www.bhpbilliton.com

Previous Owner(s): NA **Previous or Alternate Name of Mine:** None

MINE ADDRESS

Contact Name: Scott Langley **Phone Number:** (505) 598-2000

Mailing Address: P.O. Box 561

City: Waterflow **State:** NM **ZIP:** 87421

GENERAL INFORMATION

Number of Employees at Mine: 280 **Mining Method:** Longwall

Year of Initial Production: 1997 **Primary Coal Use:** Steam

Life Expectancy: NA **Sulfur Content of Coal Produced:** 0.8%

Prep Plant Located on Site? Yes **BTUs/lb of Coal Produced:** 9,500

Depth to Seam (ft): 300 - 1,000 **Seam Thickness (ft):** 4.2 - 14.6

PRODUCTION, VENTILATION AND DRAINAGE DATA

	1999	2000	2001	2002	2003
Coal Production (million short tons/year):	0.1	0.0	0.7	1.8	5.9
Estimated Total Methane Liberated (million cf/day):	0.0	0.0	0.3	2.0	3.6
Emission from Ventilation Systems:	0.0	0.0	0.3	1.5	1.3
Estimated Methane Drained:	0.0	0.0	0.0	0.5	2.3
Estimated Specific Emissions (cf/ton):	0	0	166	425	223
Methane Recovered (million cf/day):	-	-	-	-	0.1

Estimated Current Drainage Efficiency: 65%

Drainage System Used: Vertical Gob, Horizontal Pre-mine

San Juan South (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

(Based on 2003 Data)	Assumed Potential Recovery Efficiency 20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons):	0.1	0.2	0.4
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	1.0%	2.0%	3.0%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	0.2%	0.5%	0.7%

Power Generation Potential

Utility Electric Supplier: Public Service of New Mexico

Parent Corporation of Utility: Public Service of New Mexico

	MW	**GWh/year**
Total Electricity Demand (2003 data):	46.7	176.7
Mine Electricity Demand:	36.7	141.4
Prep Plant Electricity Demand:	10.0	35.3
Potential Generating Capacity (2003 data)		
Assuming 20% Recovery Efficiency:	2.7	23.9
Assuming 40% Recovery Efficiency:	5.5	47.8
Assuming 60% Recovery Efficiency:	8.2	71.7

Pipeline Sales Potential

Potential Annual Gas Sales (2003 data)	Bcf
Assuming 20% Recovery (Bcf):	0.3
Assuming 40% Recovery (Bcf):	0.5
Assuming 60% Recovery (Bcf):	0.8

Description of Surrounding Terrain:

Transmission Pipeline in County? Yes

Owner of Nearest Pipeline: Western/Chuska

Distance to Pipeline (miles): < 10.0 **Pipeline Diameter (inches):** 16.0

Owner of Next Nearest Pipeline:

Distance to Next Nearest Pipeline (miles): **Pipeline Diameter (inches):**

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: **Distance to Plant (miles):**

Comments:

Ohio Mines

Powhatan No. 6

Updated: 08/01/2005 **Status:** Active

Powhatan No. 6 Mine

GEOGRAPHIC DATA

Basin: Northern Appalachian **State:** OH

Coalbed: Pittsburgh No. 8 **County:** Belmont

CORPORATE INFORMATION

Current Owner: Ohio Valley Coal Co.

Parent Company: Murray Energy Corporation **Parent Company Web Site:** www.ohiovalleycoal.com

Previous Owner(s): None in last ten years **Previous or Alternate Name of Mine:** None

MINE ADDRESS

Contact Name: Roy A. Heidelbach, Mine Supt. **Phone Number:** (740) 926-1351

Mailing Address: 56854 Pleasant Ridge

City: Alledonia **State:** OH **ZIP:** 43902

GENERAL INFORMATION

Number of Employees at Mine: 415 **Mining Method:** Longwall/Continuous

Year of Initial Production: 1972 **Primary Coal Use:** Steam

Life Expectancy: 2018 **Sulfur Content of Coal Produced:** 3.8% - 4.5%

Prep Plant Located on Site? Yes **BTUs/lb of Coal Produced:** 12,600

Depth to Seam (ft): 270 **Seam Thickness (ft):** 5.3

PRODUCTION, VENTILATION AND DRAINAGE DATA

	1999	2000	2001	2002	2003
Coal Production (million short tons/year):	4.4	4.6	4.6	3.9	4.9
Estimated Total Methane Liberated (million cf/day):	1.0	1.1	1.4	1.2	1.1
Emission from Ventilation Systems:	1.0	1.1	1.4	1.2	1.1
Estimated Methane Drained:	0.0	0.0	0.0	0.0	0.0
Estimated Specific Emissions (cf/ton):	84	89	114	116	84
Methane Recovered (million cf/day):	-	-	-	-	-

Estimated Current Drainage Efficiency: 0%

Drainage System Used: None

Powhatan No. 6 Mine (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

(Based on 2003 Data)	Assumed Potential Recovery Efficiency 20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons):	0.0	0.1	0.1
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	0.3%	0.6%	0.9%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	0.1%	0.1%	0.2%

Power Generation Potential

Utility Electric Supplier: The Dayton Power & Light Co.

Parent Corporation of Utility: DPL Inc.

	MW	**GWh/year**
Total Electricity Demand (2003 data):	38.7	146.6
Mine Electricity Demand:	30.4	117.3
Prep Plant Electricity Demand:	8.3	29.3
Potential Generating Capacity (2003 data)		
Assuming 20% Recovery Efficiency:	0.9	7.5
Assuming 40% Recovery Efficiency:	1.7	15.0
Assuming 60% Recovery Efficiency:	2.6	22.5

Pipeline Sales Potential

Potential Annual Gas Sales (2003 data)	Bcf
Assuming 20% Recovery (Bcf):	0.1
Assuming 40% Recovery (Bcf):	0.2
Assuming 60% Recovery (Bcf):	0.2

Description of Surrounding Terrain: Hills/High Hills

Transmission Pipeline in County? Yes

Owner of Nearest Pipeline: Columbia Gas Transmission Co.

Distance to Pipeline (miles): 0.1 **Pipeline Diameter (inches):** 4.0

Owner of Next Nearest Pipeline: Texas Eastern Transmission

Distance to Next Nearest Pipeline (miles): 1.4 **Pipeline Diameter (inches):** 30.0

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: None **Distance to Plant (miles):** NA

Comments: Not yet researched.

6. Profiled Mines (continued)

Oklahoma Mines

Pollyanna No. 8

Updated: 08/01/2005 **Status:** Active

Pollyanna No. 8

GEOGRAPHIC DATA

Basin: Arkoma **State:** OK

Coalbed: Hartshorne **County:** Le Flore

CORPORATE INFORMATION

Current Owner: Sunrise Coal Co., LLC

Parent Company: South Central Coal Company **Parent Company Web Site:** NA

Previous Owner(s): NA **Previous or Alternate Name of Mine:** Sunrise Coal

MINE ADDRESS

Contact Name: Paul Matlock **Phone Number:** (918) 962-9402

Mailing Address: P. O. Box 100

City: Spiro **State:** OK **ZIP:** 74959

GENERAL INFORMATION

Number of Employees at Mine: 36 **Mining Method:** Continuous

Year of Initial Production: 1995 **Primary Coal Use:** Steam

Life Expectancy: NA **Sulfur Content of Coal Produced:** 1.0%

Prep Plant Located on Site? No **BTUs/lb of Coal Produced:** 14,190

Depth to Seam (ft): NA **Seam Thickness (ft):** NA

PRODUCTION, VENTILATION AND DRAINAGE DATA

	1999	2000	2001	2002	2003
Coal Production (million short tons/year):	0.2	0.2	0.4	0.5	0.4
Estimated Total Methane Liberated (million cf/day):	0.0	0.5	0.9	1.2	1.0
Emission from Ventilation Systems:	0.0	0.5	0.9	1.2	1.0
Estimated Methane Drained:	0.0	0.0	0.0	0.0	0.0
Estimated Specific Emissions (cf/ton):	0	787	827	945	929
Methane Recovered (million cf/day):	-	-	-	-	-

Estimated Current Drainage Efficiency: 0%

Drainage System Used: None

Pollyanna No. 8 (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

(Based on 2003 Data)	Assumed Potential Recovery Efficiency 20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons):	0.0	0.1	0.1
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	2.8%	5.7%	8.5%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	0.7%	1.3%	2.0%

Power Generation Potential

Utility Electric Supplier: OGE Energy Corp

Parent Corporation of Utility: OGE Energy Corp.

	MW	GWh/year
Total Electricity Demand (2003 data):	3.1	11.8
Mine Electricity Demand:	2.4	9.4
Prep Plant Electricity Demand:	0.7	2.4
Potential Generating Capacity (2003 data)		
Assuming 20% Recovery Efficiency:	0.8	6.6
Assuming 40% Recovery Efficiency:	1.5	13.3
Assuming 60% Recovery Efficiency:	2.3	19.9

Pipeline Sales Potential

Potential Annual Gas Sales (2003 data)	Bcf
Assuming 20% Recovery (Bcf):	0.1
Assuming 40% Recovery (Bcf):	0.1
Assuming 60% Recovery (Bcf):	0.2

Description of Surrounding Terrain:

Transmission Pipeline in County? Yes

Owner of Nearest Pipeline: Arkansas Oklahoma Gas Co.

Distance to Pipeline (miles): 2.0 **Pipeline Diameter (inches):** 6.0

Owner of Next Nearest Pipeline:

Distance to Next Nearest Pipeline (miles): **Pipeline Diameter (inches):**

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: **Distance to Plant (miles):**

Comments:

6. Profiled Mines (continued)

Pennsylvania Mines

Bailey
Eighty-Four Mine
Enlow Fork
RAG Cumberland
RAG Emerald

Updated: 08/01/2005 **Status:** Active

Bailey Mine

GEOGRAPHIC DATA

Basin: Northern Appalachian **State:** PA

Coalbed: Pittsburgh **County:** Greene

CORPORATE INFORMATION

Current Owner: Consol Energy Inc.

Parent Company: CONSOL Energy **Parent Company Web Site:** www.consolenergy.com

Previous Owner(s): None in last 10 years **Previous or Alternate Name of Mine:** None

MINE ADDRESS

Contact Name: Roy Pride **Phone Number:** (724) 663-4781

Mailing Address: 192 Crabapple

City: Wind Ridge **State:** PA **ZIP:** 15377

GENERAL INFORMATION

Number of Employees at Mine: 540 **Mining Method:** Longwall/Continuous

Year of Initial Production: 1984 **Primary Coal Use:** Steam, Metallurgical

Life Expectancy: NA **Sulfur Content of Coal Produced:** 1.03% -2.41%

Prep Plant Located on Site? Yes **BTUs/lb of Coal Produced:** 13,200

Depth to Seam (ft): 800 **Seam Thickness (ft):** NA

PRODUCTION, VENTILATION AND DRAINAGE DATA

	1999	2000	2001	2002	2003
Coal Production (million short tons/year):	8.5	9.9	10.3	9.7	9.4
Estimated Total Methane Liberated (million cf/day):	8.6	7.6	6.8	7.1	5.7
Emission from Ventilation Systems:	6.9	7.6	6.7	7.1	5.7
Estimated Methane Drained:	1.7	0.1	0.1	0.1	0.0
Estimated Specific Emissions (cf/ton):	371	282	241	270	223
Methane Recovered (million cf/day):	-	-	-	-	-

Estimated Current Drainage Efficiency: 0%

Drainage System Used: None

Bailey Mine (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

(Based on 2003 Data)	Assumed Potential Recovery Efficiency 20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons):	0.2	0.4	0.6
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	0.7%	1.5%	2.2%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	0.2%	0.3%	0.5%

Power Generation Potential

Utility Electric Supplier: West Penn Power Co.

Parent Corporation of Utility: Allegheny Power Systems, Inc.

	MW	GWh/year
Total Electricity Demand (2003 data):	74.5	281.7
Mine Electricity Demand:	58.4	225.4
Prep Plant Electricity Demand:	16.0	56.3
Potential Generating Capacity (2003 data)		
Assuming 20% Recovery Efficiency:	4.3	38.1
Assuming 40% Recovery Efficiency:	8.7	76.2
Assuming 60% Recovery Efficiency:	13.0	114.3

Pipeline Sales Potential

Potential Annual Gas Sales (2003 data)	Bcf
Assuming 20% Recovery (Bcf):	0.4
Assuming 40% Recovery (Bcf):	0.8
Assuming 60% Recovery (Bcf):	1.3

Description of Surrounding Terrain: High Hills/Open High Hills

Transmission Pipeline in County? Yes

Owner of Nearest Pipeline: Carnegie Natural Gas

Distance to Pipeline (miles): 6.0 **Pipeline Diameter (inches):** 20.0

Owner of Next Nearest Pipeline: NA

Distance to Next Nearest Pipeline (miles): NA **Pipeline Diameter (inches):** NA

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: None **Distance to Plant (miles):** NA

Comments: Television components, apparel, and metal manufacturing; hospitals, schools and other municipal buildings.

Updated: 08/01/2005 **Status:** Active

Eighty-Four Mine

GEOGRAPHIC DATA

Basin: Northern Appalachian **State:** PA

Coalbed: Pittsburgh **County:** Washington

CORPORATE INFORMATION

Current Owner: Eighty-Four Mining Co.

Parent Company: CONSOL Energy **Parent Company Web Site:** www.consolenergy.com

Previous Owner(s): Beth Energy Mines **Previous or Alternate Name of Mine:** Ellsworth or Livingston

MINE ADDRESS

Contact Name: Eric Schubel **Phone Number:** (724) 250-1577

Mailing Address: P.O. Box 284

City: Eighty Four **State:** PA **ZIP:** 15330

GENERAL INFORMATION

Number of Employees at Mine: 499 **Mining Method:** Longwall/Continuous

Year of Initial Production: NA **Primary Coal Use:** Steam, Metallurgical

Life Expectancy: NA **Sulfur Content of Coal Produced:** 1.33% - 1.71%

Prep Plant Located on Site? No **BTUs/lb of Coal Produced:** 13,307

Depth to Seam (ft): 625 **Seam Thickness (ft):** 7.5

PRODUCTION, VENTILATION AND DRAINAGE DATA

	1999	2000	2001	2002	2003
Coal Production (million short tons/year):	5.8	4.2	1.6	4.0	4.0
Estimated Total Methane Liberated (million cf/day):	6.0	6.1	4.6	4.9	5.1
Emission from Ventilation Systems:	6.0	6.1	4.6	4.9	5.1
Estimated Methane Drained:	0.0	0.0	0.0	0.0	0.0
Estimated Specific Emissions (cf/ton):	379	531	1022	445	467
Methane Recovered (million cf/day):	-	-	-	-	-

Estimated Current Drainage Efficiency: 0%

Drainage System Used: None

Eighty-Four Mine (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

	Assumed Potential Recovery Efficiency		
(Based on 2003 Data)	20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons):	0.2	0.3	0.5
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	1.5%	3.0%	4.5%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	0.4%	0.7%	1.1%

Power Generation Potential

Utility Electric Supplier: West Penn Power Co.

Parent Corporation of Utility: Allegheny Power Systems, Inc.

	MW	GWh/year
Total Electricity Demand (2003 data):	31.4	118.9
Mine Electricity Demand:	24.7	95.1
Prep Plant Electricity Demand:	6.8	23.8
Potential Generating Capacity (2003 data)		
Assuming 20% Recovery Efficiency:	3.8	33.6
Assuming 40% Recovery Efficiency:	7.7	67.3
Assuming 60% Recovery Efficiency:	11.5	100.9

Pipeline Sales Potential

Potential Annual Gas Sales (2003 data)	Bcf
Assuming 20% Recovery (Bcf):	0.4
Assuming 40% Recovery (Bcf):	0.7
Assuming 60% Recovery (Bcf):	1.1

Description of Surrounding Terrain: Open High Hills/High Hills

Transmission Pipeline in County? Yes

Owner of Nearest Pipeline: Columbia Gas of Pennsylvania, Inc.

Distance to Pipeline (miles): 6.0 **Pipeline Diameter (inches):** 20.0

Owner of Next Nearest Pipeline: NA

Distance to Next Nearest Pipeline (miles): NA **Pipeline Diameter (inches):** NA

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: None **Distance to Plant (miles):** NA

Comments: Steel, plastics, apparel, glass, fertilizers, and other types of manufacturing; municipal buildings.

Updated: 08/01/2005 **Status:** Active

Enlow Fork Mine

GEOGRAPHIC DATA

Basin: Northern Appalachian **State:** PA

Coalbed: Pittsburgh **County:** Greene

CORPORATE INFORMATION

Current Owner: Consol Energy Inc.

Parent Company: CONSOL Energy **Parent Company Web Site:** www.consolenergy.com

Previous Owner(s): None in last 10 years **Previous or Alternate Name of Mine:** None

MINE ADDRESS

Contact Name: Dave Hudson **Phone Number:** (724) 663-3101

Mailing Address: Rte. 231

City: East Finley **State:** PA **ZIP:** 15377

GENERAL INFORMATION

Number of Employees at Mine: 504 **Mining Method:** Longwall/Continuous

Year of Initial Production: 1990 **Primary Coal Use:** Steam

Life Expectancy: NA **Sulfur Content of Coal Produced:** 1.00% -2.41%

Prep Plant Located on Site? No **BTUs/lb of Coal Produced:** 13,000

Depth to Seam (ft): 800 **Seam Thickness (ft):** 5.7 - 6.0

PRODUCTION, VENTILATION AND DRAINAGE DATA

	1999	2000	2001	2002	2003
Coal Production (million short tons/year):	9.8	9.5	10.3	9.6	9.9
Estimated Total Methane Liberated (million cf/day):	13.9	11.1	9.8	9.1	10.3
Emission from Ventilation Systems:	11.1	11.0	9.7	9.0	10.3
Estimated Methane Drained:	2.8	0.1	0.1	0.1	0.0
Estimated Specific Emissions (cf/ton):	514	426	346	346	382
Methane Recovered (million cf/day):	-	-	-	-	-

Estimated Current Drainage Efficiency: 0%

Drainage System Used: None

Enlow Fork Mine (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

(Based on 2003 Data)	Assumed Potential Recovery Efficiency 20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons):	0.3	0.7	1.0
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	1.3%	2.5%	3.8%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	0.3%	0.6%	0.9%

Power Generation Potential

Utility Electric Supplier: West Penn Power Co.

Parent Corporation of Utility: Allegheny Power Systems, Inc.

	MW	GWh/year
Total Electricity Demand (2003 data):	78.4	296.7
Mine Electricity Demand:	61.5	237.3
Prep Plant Electricity Demand:	16.9	59.3
Potential Generating Capacity (2003 data)		
Assuming 20% Recovery Efficiency:	7.8	68.6
Assuming 40% Recovery Efficiency:	15.7	137.2
Assuming 60% Recovery Efficiency:	23.5	205.9

Pipeline Sales Potential

Potential Annual Gas Sales (2003 data)	Bcf
Assuming 20% Recovery (Bcf):	0.8
Assuming 40% Recovery (Bcf):	1.5
Assuming 60% Recovery (Bcf):	2.3

Description of Surrounding Terrain: Open Hills/Open High Hills

Transmission Pipeline in County? Yes

Owner of Nearest Pipeline: Columbia Gas Transmission Co.

Distance to Pipeline (miles): 6.0 **Pipeline Diameter (inches):** 20.0

Owner of Next Nearest Pipeline: NA

Distance to Next Nearest Pipeline (miles): NA **Pipeline Diameter (inches):** NA

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: NA **Distance to Plant (miles):** NA

Comments: Television components, apparel, and metal manufacturing; hospitals, schools and other municipal buildings.

Updated: 08/01/2005 **Status:** Active

RAG Cumberland Mine

GEOGRAPHIC DATA

Basin: Northern Appalachian **State:** PA

Coalbed: Pittsburgh No. 8 **County:** Greene

CORPORATE INFORMATION

Current Owner: RAG Cumberland Resources, LP

Parent Company: RAG American Coal Co. **Parent Company Web Site:** http://www.rag-american.com/

Previous Owner(s): Cyprus Amax, U. S. Steel **Previous or Alternate Name of Mine:** Cumberland

MINE ADDRESS

Contact Name: Mike Misha, Pres. **Phone Number:** (724) 852-7781

Mailing Address: P.O. Box 1020

City: Waynesburg **State:** PA **ZIP:** 15370

GENERAL INFORMATION

Number of Employees at Mine: 574 **Mining Method:** Longwall/Continuous

Year of Initial Production: 1972 **Primary Coal Use:** Steam

Life Expectancy: 2023 **Sulfur Content of Coal Produced:** 2.4%

Prep Plant Located on Site? Yes **BTUs/lb of Coal Produced:** 13,000

Depth to Seam (ft): 900 **Seam Thickness (ft):** 6.5 - 7.0

PRODUCTION, VENTILATION AND DRAINAGE DATA

	1999	2000	2001	2002	2003
Coal Production (million short tons/year):	6.6	6.5	6.7	6.6	6.2
Estimated Total Methane Liberated (million cf/day):	10.7	17.4	16.2	11.1	24.3
Emission from Ventilation Systems:	9.1	12.9	11.7	9.6	9.9
Estimated Methane Drained:	1.6	4.5	4.5	1.5	14.4
Estimated Specific Emissions (cf/ton):	594	975	888	609	1418
Methane Recovered (million cf/day):	-	-	-	-	-

Estimated Current Drainage Efficiency: 59%

Drainage System Used: Vertical Pre-Mine, Vertical Gob, Horizontal Pre-Mine

RAG Cumberland Mine (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

	Assumed Potential Recovery Efficiency		
(Based on 2003 Data)	20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons):	0.8	1.6	2.4
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	4.7%	9.4%	14.1%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	1.1%	2.2%	3.3%

Power Generation Potential

Utility Electric Supplier: West Penn Power Co.

Parent Corporation of Utility: Allegheny Power Systems, Inc.

	MW	GWh/year
Total Electricity Demand (2003 data):	49.5	187.4
Mine Electricity Demand:	38.9	149.9
Prep Plant Electricity Demand:	10.6	37.5
Potential Generating Capacity (2003 data)		
Assuming 20% Recovery Efficiency:	18.4	161.0
Assuming 40% Recovery Efficiency:	36.8	322.0
Assuming 60% Recovery Efficiency:	55.1	483.0

Pipeline Sales Potential

Potential Annual Gas Sales (2003 data)	Bcf
Assuming 20% Recovery (Bcf):	1.8
Assuming 40% Recovery (Bcf):	3.5
Assuming 60% Recovery (Bcf):	5.3

Description of Surrounding Terrain: High Hills

Transmission Pipeline in County? Yes

Owner of Nearest Pipeline: Texas Eastern Transmission Co.

Distance to Pipeline (miles): 0.2 **Pipeline Diameter (inches):** 24.0

Owner of Next Nearest Pipeline: NA

Distance to Next Nearest Pipeline (miles): NA **Pipeline Diameter (inches):** NA

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: NA **Distance to Plant (miles):** NA

Comments: Television components, apparel, and metal manufacturing; hospitals, schools and other municipal buildings.

Updated: 08/01/2005 **Status:** Active

RAG Emerald Mine

GEOGRAPHIC DATA

Basin: Northern Appalachian **State:** PA

Coalbed: Pittsburgh No. 8 **County:** Greene

CORPORATE INFORMATION

Current Owner: RAG Emerald Resources, LP

Parent Company: RAG American Coal Co. **Parent Company Web Site:** http://www.rag-american.com/

Previous Owner(s): Cyprus Amax **Previous or Alternate Name of Mine:** Emerald No. 1

MINE ADDRESS

Contact Name: Mike Misha, Pres. **Phone Number:** (724) 852-1200

Mailing Address: 212 Mine Rd., Rte. 218

City: Waynesburg **State:** PA **ZIP:** 15370

GENERAL INFORMATION

Number of Employees at Mine: 549 **Mining Method:** Longwall/Continuous

Year of Initial Production: 1977 **Primary Coal Use:** Steam, Metallurgical

Life Expectancy: 2013 **Sulfur Content of Coal Produced:** 2.4%

Prep Plant Located on Site? Yes **BTUs/lb of Coal Produced:** 13,000

Depth to Seam (ft): 650 **Seam Thickness (ft):** NA

PRODUCTION, VENTILATION AND DRAINAGE DATA

	1999	2000	2001	2002	2003
Coal Production (million short tons/year):	4.3	6.4	6.7	6.6	6.6
Estimated Total Methane Liberated (million cf/day):	8.3	7.5	7.6	9.1	11.5
Emission from Ventilation Systems:	5.0	5.8	5.9	6.6	7.4
Estimated Methane Drained:	3.3	1.6	1.7	2.5	4.0
Estimated Specific Emissions (cf/ton):	696	425	410	508	631
Methane Recovered (million cf/day):	-	-	-	-	-

Estimated Current Drainage Efficiency: 35%

Drainage System Used: Vertical Gob, Horizontal Pre-Mine

RAG Emerald Mine (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

(Based on 2003 Data)	Assumed Potential Recovery Efficiency 20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons):	0.4	0.7	1.1
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	2.1%	4.2%	6.3%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	0.5%	1.0%	1.5%

Power Generation Potential

Utility Electric Supplier: West Penn Power Co.

Parent Corporation of Utility: Allegheny Power Systems, Inc.

	MW	GWh/year
Total Electricity Demand (2003 data):	52.5	198.6
Mine Electricity Demand:	41.2	158.9
Prep Plant Electricity Demand:	11.3	39.7
Potential Generating Capacity (2003 data)		
Assuming 20% Recovery Efficiency:	8.7	76.0
Assuming 40% Recovery Efficiency:	17.3	152.0
Assuming 60% Recovery Efficiency:	26.0	228.0

Pipeline Sales Potential

Potential Annual Gas Sales (2003 data)	Bcf
Assuming 20% Recovery (Bcf):	0.8
Assuming 40% Recovery (Bcf):	1.7
Assuming 60% Recovery (Bcf):	2.5

Description of Surrounding Terrain: High Hills/Open High Hills

Transmission Pipeline in County? Yes

Owner of Nearest Pipeline: Texas Eastern Transmission Co.

Distance to Pipeline (miles): 0.2 **Pipeline Diameter (inches):** 24.0

Owner of Next Nearest Pipeline: NA

Distance to Next Nearest Pipeline (miles): NA **Pipeline Diameter (inches):** NA

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: None **Distance to Plant (miles):** NA

Comments: Television components, apparel, and metal manufacturing; hospitals, schools and other municipal buildings.

6. Profiled Mines (continued)

Utah Mines

Aberdeen
Dugout Canyon
West Ridge

Updated: 08/01/2005 **Status:** Active

Aberdeen

GEOGRAPHIC DATA

Basin: Uinta **State:** UT

Coalbed: L. Sunnyside, Gilson, Aber. **County:** Carbon

CORPORATE INFORMATION

Current Owner: Andalex Resources, Inc.

Parent Company: Andalex Resources, Inc. **Parent Company Web Site:** www.andalex.com

Previous Owner(s): None **Previous or Alternate Name of Mine:** Tower Division

MINE ADDRESS

Contact Name: Garth Neilsen **Phone Number:** (435) 637-5385

Mailing Address: P.O. Box 902

City: Price **State:** UT **ZIP:** 84501

GENERAL INFORMATION

Number of Employees at Mine: 31 **Mining Method:** Longwall/Continuous

Year of Initial Production: 1980 **Primary Coal Use:** Steam

Life Expectancy: NA **Sulfur Content of Coal Produced:** NA

Prep Plant Located on Site? Yes **BTUs/lb of Coal Produced:** 11,991

Depth to Seam (ft): NA **Seam Thickness (ft):** 6.0 - 8.0

PRODUCTION, VENTILATION AND DRAINAGE DATA

	1999	2000	2001	2002	2003
Coal Production (million short tons/year):	1.5	1.6	0.5	0.0	0.4
Estimated Total Methane Liberated (million cf/day):	4.4	4.4	1.2	0.8	1.2
Emission from Ventilation Systems:	4.4	4.4	1.2	0.8	1.2
Estimated Methane Drained:	0.0	0.0	0.0	0.0	0.0
Estimated Specific Emissions (cf/ton):	1037	1020	848	8484	995
Methane Recovered (million cf/day):	-	-	-	-	-

Estimated Current Drainage Efficiency: 0%

Drainage System Used: None

Aberdeen (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

(Based on 2003 Data)	Assumed Potential Recovery Efficiency 20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons):	0.0	0.1	0.1
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	3.6%	7.2%	10.8%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	0.8%	1.7%	2.5%

Power Generation Potential

Utility Electric Supplier: Price City Utilities, Utah Power & Light

Parent Corporation of Utility: Pacificorp

	MW	GWh/year
Total Electricity Demand (2003 data):	3.5	13.3
Mine Electricity Demand:	2.8	10.7
Prep Plant Electricity Demand:	0.8	2.7
Potential Generating Capacity (2003 data)		
Assuming 20% Recovery Efficiency:	0.9	8.0
Assuming 40% Recovery Efficiency:	1.8	16.1
Assuming 60% Recovery Efficiency:	2.8	24.1

Pipeline Sales Potential

Potential Annual Gas Sales (2003 data)	Bcf
Assuming 20% Recovery (Bcf):	0.1
Assuming 40% Recovery (Bcf):	0.2
Assuming 60% Recovery (Bcf):	0.3

Description of Surrounding Terrain: Tablelands; Open High/Low Mountains

Transmission Pipeline in County? Yes

Owner of Nearest Pipeline: Questar Pipeline Company

Distance to Pipeline (miles): ~5.0 **Pipeline Diameter (inches):** 20.0

Owner of Next Nearest Pipeline: NA

Distance to Next Nearest Pipeline (miles): NA **Pipeline Diameter (inches):** NA

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: Carbon **Distance to Plant (miles):** NA

Comments: Not yet researched.

Updated: 08/01/2005 **Status:** Active

Dugout Canyon Mine

GEOGRAPHIC DATA

Basin: Central Rockies **State:** UT

Coalbed: Gilson, Rock Canyon **County:** Carbon

CORPORATE INFORMATION

Current Owner: Canyon Fuel Co., LLC

Parent Company: Arch Coal Co. **Parent Company Web Site:** www.archcoal.com

Previous Owner(s): NA **Previous or Alternate Name of Mine:** NA

MINE ADDRESS

Contact Name: R.W. Olsen, Mine Mgr. **Phone Number:** (435) 636-2860

Mailing Address: P.O. Box 1029

City: Wellington **State:** UT **ZIP:** 84542

GENERAL INFORMATION

Number of Employees at Mine: 175 **Mining Method:** Longwall/Continuous

Year of Initial Production: 1998 **Primary Coal Use:** Steam

Life Expectancy: 2115 **Sulfur Content of Coal Produced:** 0.4% - 0.75%

Prep Plant Located on Site? No **BTUs/lb of Coal Produced:** 11,700

Depth to Seam (ft): 1400 **Seam Thickness (ft):** 7.5 - 8.0

PRODUCTION, VENTILATION AND DRAINAGE DATA

	1999	2000	2001	2002	2003
Coal Production (million short tons/year):	0.8	0.5	2.0	2.1	2.9
Estimated Total Methane Liberated (million cf/day):	0.1	0.1	0.6	1.1	2.2
Emission from Ventilation Systems:	0.1	0.1	0.6	1.1	2.2
Estimated Methane Drained:	0.0	0.0	0.0	0.0	0.0
Estimated Specific Emissions (cf/ton):	62	103	103	195	267
Methane Recovered (million cf/day):	-	-	-	-	-

Estimated Current Drainage Efficiency: 0%

Drainage System Used: None

Dugout Canyon Mine (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

(Based on 2003 Data)	Assumed Potential Recovery Efficiency 20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons):	0.1	0.1	0.2
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	1.0%	2.0%	3.0%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	0.2%	0.5%	0.7%

Power Generation Potential

Utility Electric Supplier: Pacificorp

Parent Corporation of Utility: Pacificorp

	MW	GWh/year
Total Electricity Demand (2003 data):	23.3	88.2
Mine Electricity Demand:	18.3	70.6
Prep Plant Electricity Demand:	5.0	17.6
Potential Generating Capacity (2003 data)		
Assuming 20% Recovery Efficiency:	1.6	14.3
Assuming 40% Recovery Efficiency:	3.3	28.5
Assuming 60% Recovery Efficiency:	4.9	42.8

Pipeline Sales Potential

Potential Annual Gas Sales (2003 data)	Bcf
Assuming 20% Recovery (Bcf):	0.2
Assuming 40% Recovery (Bcf):	0.3
Assuming 60% Recovery (Bcf):	0.5

Description of Surrounding Terrain:

Transmission Pipeline in County? Yes

Owner of Nearest Pipeline: Questar Pipeline Company

Distance to Pipeline (miles): < 5.0 **Pipeline Diameter (inches):** 20.0

Owner of Next Nearest Pipeline:

Distance to Next Nearest Pipeline (miles): **Pipeline Diameter (inches):**

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: **Distance to Plant (miles):**

Comments:

Updated: 08/01/2005 **Status:** Active

West Ridge Mine

GEOGRAPHIC DATA

Basin: Uinta **State:** UT

Coalbed: Lower Sunnyside **County:** Carbon

CORPORATE INFORMATION

Current Owner: West Ridge Resources

Parent Company: Andalex Resources, Inc. **Parent Company Web Site:** www.andalex.com/westridge.html

Previous Owner(s): NA **Previous or Alternate Name of Mine:** NA

MINE ADDRESS

Contact Name: Gary Gray **Phone Number:** (435) 564-4015

Mailing Address: P.O. Box 1077

City: Price **State:** UT **ZIP:** 84501

GENERAL INFORMATION

Number of Employees at Mine: 76 **Mining Method:** Longwall

Year of Initial Production: 2001 **Primary Coal Use:** Steam

Life Expectancy: NA **Sulfur Content of Coal Produced:** 1.09%

Prep Plant Located on Site? No **BTUs/lb of Coal Produced:** 12,648

Depth to Seam (ft): 1200 **Seam Thickness (ft):** 8-14

PRODUCTION, VENTILATION AND DRAINAGE DATA

	1999	2000	2001	2002	2003
Coal Production (million short tons/year):	0.0	0.5	2.3	2.8	3.0
Estimated Total Methane Liberated (million cf/day):	0.0	0.0	0.8	2.5	3.6
Emission from Ventilation Systems:	0.0	0.0	0.8	2.5	3.6
Estimated Methane Drained:	0.0	0.0	0.0	0.0	0.0
Estimated Specific Emissions (cf/ton):	-	0	120	316	443
Methane Recovered (million cf/day):	-	-	-	-	-

Estimated Current Drainage Efficiency: 0%

Drainage System Used: None

West Ridge Mine (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

(Based on 2003 Data)	Assumed Potential Recovery Efficiency 20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons):	0.1	0.2	0.4
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	1.5%	3.1%	4.6%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	0.4%	0.7%	1.1%

Power Generation Potential

Utility Electric Supplier: Pacificorp

Parent Corporation of Utility: Pacificorp

	MW	GWh/year
Total Electricity Demand (2003 data):	23.6	89.2
Mine Electricity Demand:	18.5	71.4
Prep Plant Electricity Demand:	5.1	17.8
Potential Generating Capacity (2003 data)		
Assuming 20% Recovery Efficiency:	2.7	24.0
Assuming 40% Recovery Efficiency:	5.5	47.9
Assuming 60% Recovery Efficiency:	8.2	71.9

Pipeline Sales Potential

Potential Annual Gas Sales (2003 data)	Bcf
Assuming 20% Recovery (Bcf):	0.3
Assuming 40% Recovery (Bcf):	0.5
Assuming 60% Recovery (Bcf):	0.8

Description of Surrounding Terrain:

Transmission Pipeline in County? Yes

Owner of Nearest Pipeline: Questar Pipeline Co.

Distance to Pipeline (miles): < 10.0 **Pipeline Diameter (inches):** 20.0

Owner of Next Nearest Pipeline:

Distance to Next Nearest Pipeline (miles): **Pipeline Diameter (inches):**

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: **Distance to Plant (miles):**

Comments:

6. Profiled Mines (continued)

Virginia Mines

Buchanan
Deep Mine #26
Virginia Pocahontas No. 8

Updated: 08/01/2005 **Status:** Active

Buchanan Mine

GEOGRAPHIC DATA

Basin: Central Appalachian **State:** VA

Coalbed: Pocahontas No. 3 **County:** Buchanan

CORPORATE INFORMATION

Current Owner: Consol Energy Inc.

Parent Company: CONSOL Energy **Parent Company Web Site:** www.consolenergy.com

Previous Owner(s): None in last 10 years **Previous or Alternate Name of Mine:** Buchanan No. 1

MINE ADDRESS

Contact Name: Terry Suder **Phone Number:** (276) 498-6900

Mailing Address: Rte. 680

City: Keen Mountain **State:** VA **ZIP:** 24624

GENERAL INFORMATION

Number of Employees at Mine: 392 **Mining Method:** Longwall/Continuous

Year of Initial Production: 1983 **Primary Coal Use:** Steam, Metallurgical

Life Expectancy: NA **Sulfur Content of Coal Produced:** 0.73%

Prep Plant Located on Site? Yes **BTUs/lb of Coal Produced:** 13,831

Depth to Seam (ft): NA **Seam Thickness (ft):** 5.4

PRODUCTION, VENTILATION AND DRAINAGE DATA

	1999	2000	2001	2002	2003
Coal Production (million short tons/year):	4.7	4.5	4.5	4.1	4.7
Estimated Total Methane Liberated (million cf/day):	19.5	21.6	17.9	48.2	42.6
Emission from Ventilation Systems:	12.3	11.8	10.3	9.5	7.3
Estimated Methane Drained:	7.2	9.8	7.5	38.7	35.3
Estimated Specific Emissions (cf/ton):	1520	1766	1463	4330	3318
Methane Recovered (million cf/day):	7.0	9.8	7.5	38.8	36.4

Estimated Current Drainage Efficiency: 83%

Drainage System Used: Vertical Pre-Mine, Vertical Gob, Horizontal Pre-Mine

Buchanan Mine (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

	Assumed Potential Recovery Efficiency		
(Based on 2003 Data)	20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons):	1.4	2.8	4.1
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	10.3%	20.7%	31.0%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	2.4%	4.8%	7.2%

Power Generation Potential

Utility Electric Supplier: Appalachian Power Co.

Parent Corporation of Utility: American Electric Power Co., Inc.

	MW	GWh/year
Total Electricity Demand (2003 data):	37.2	140.6
Mine Electricity Demand:	29.2	112.5
Prep Plant Electricity Demand:	8.0	28.1
Potential Generating Capacity (2003 data)		
Assuming 20% Recovery Efficiency:	32.3	282.7
Assuming 40% Recovery Efficiency:	64.5	565.4
Assuming 60% Recovery Efficiency:	96.8	848.1

Pipeline Sales Potential

Potential Annual Gas Sales (2003 data)	Bcf
Assuming 20% Recovery (Bcf):	3.1
Assuming 40% Recovery (Bcf):	6.2
Assuming 60% Recovery (Bcf):	9.3

Description of Surrounding Terrain: Open Low Mountains/Low Mountains

Transmission Pipeline in County? No

Owner of Nearest Pipeline: Mine owns pipeline that connects to dist. line

Distance to Pipeline (miles): 0.0 **Pipeline Diameter (inches):** NA

Owner of Next Nearest Pipeline: Consolidated Natural Gas Supply Co. (CNG)

Distance to Next Nearest Pipeline (miles): 1.0 **Pipeline Diameter (inches):** 8.0

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: None **Distance to Plant (miles):** NA

Comments: Not yet researched.

Updated: 08/01/2005 **Status:** Active

Deep Mine #26

GEOGRAPHIC DATA

Basin: Central Appalachian **State:** VA

Coalbed: Norton, Upper Banner **County:** Wise

CORPORATE INFORMATION

Current Owner: Paramount Coal Corp.

Parent Company: Alpha Natural Resources LLC **Parent Company Web Site:** www.alphanr.com

Previous Owner(s): NA **Previous or Alternate Name of Mine:** Virginia Commonwealth 5

MINE ADDRESS

Contact Name: Robert Hutton **Phone Number:** (276) 619-4476

Mailing Address: 179 E. Jackson St.

City: Gate City **State:** VA **ZIP:** 24251

GENERAL INFORMATION

Number of Employees at Mine: 133 **Mining Method:** Continuous

Year of Initial Production: NA **Primary Coal Use:** Steam, Metallurgical

Life Expectancy: NA **Sulfur Content of Coal Produced:** 0.75% - 0.87%

Prep Plant Located on Site? Yes **BTUs/lb of Coal Produced:** 13,620

Depth to Seam (ft): NA **Seam Thickness (ft):** 4-7

PRODUCTION, VENTILATION AND DRAINAGE DATA

	1999	2000	2001	2002	2003
Coal Production (million short tons/year):	0.0	0.0	0.0	0.3	1.1
Estimated Total Methane Liberated (million cf/day):	0.0	0.0	0.0	0.5	1.9
Emission from Ventilation Systems:	0.0	0.0	0.0	0.5	1.9
Estimated Methane Drained:	0.0	0.0	0.0	0.0	0.0
Estimated Specific Emissions (cf/ton):	-	-	-	629	619
Methane Recovered (million cf/day):	-	-	-	-	-

Estimated Current Drainage Efficiency: 0%

Drainage System Used: None

Deep Mine #26 (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

(Based on 2003 Data)	Assumed Potential Recovery Efficiency 20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons):	0.1	0.1	0.2
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	2.0%	3.9%	5.9%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	0.5%	0.9%	1.4%

Power Generation Potential

Utility Electric Supplier:

Parent Corporation of Utility:

	MW	GWh/year
Total Electricity Demand (2003 data):	8.9	33.8
Mine Electricity Demand:	7.0	27.0
Prep Plant Electricity Demand:	1.9	6.8
Potential Generating Capacity (2003 data)		
Assuming 20% Recovery Efficiency:	1.4	12.7
Assuming 40% Recovery Efficiency:	2.9	25.4
Assuming 60% Recovery Efficiency:	4.3	38.0

Pipeline Sales Potential

Potential Annual Gas Sales (2003 data)	Bcf
Assuming 20% Recovery (Bcf):	0.1
Assuming 40% Recovery (Bcf):	0.3
Assuming 60% Recovery (Bcf):	0.4

Description of Surrounding Terrain:

Transmission Pipeline in County?

Owner of Nearest Pipeline:

Distance to Pipeline (miles): **Pipeline Diameter (inches):**

Owner of Next Nearest Pipeline:

Distance to Next Nearest Pipeline (miles): **Pipeline Diameter (inches):**

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: **Distance to Plant (miles):**

Comments:

Updated: 08/01/2005 **Status:** Active

Virginia Pocahontas No. 8

GEOGRAPHIC DATA

Basin: Central Appalachian **State:** VA

Coalbed: Pocahontas No. 3 **County:** Buchanan

CORPORATE INFORMATION

Current Owner: Consol Energy Inc.

Parent Company: CONSOL Energy **Parent Company Web Site:** www.consolenergy.com

Previous Owner(s): None in last 5 years **Previous or Alternate Name of Mine:** VP No. 8

MINE ADDRESS

Contact Name: Neil Made **Phone Number:** (276) 498-7800

Mailing Address: Rte. 624

City: Rowe **State:** VA **ZIP:** 24646

GENERAL INFORMATION

Number of Employees at Mine: NA **Mining Method:** Longwall/Continuous

Year of Initial Production: 1994 **Primary Coal Use:** Steam, Metallurgical

Life Expectancy: NA **Sulfur Content of Coal Produced:** 0.75%

Prep Plant Located on Site? No **BTUs/lb of Coal Produced:** 14,013

Depth to Seam (ft): 2050 **Seam Thickness (ft):** 5.0 -5.1

PRODUCTION, VENTILATION AND DRAINAGE DATA

	1999	2000	2001	2002	2003
Coal Production (million short tons/year):	1.4	2.3	2.3	2.2	1.9
Estimated Total Methane Liberated (million cf/day):	53.7	59.8	70.6	43.0	46.3
Emission from Ventilation Systems:	6.2	7.9	7.3	8.5	7.9
Estimated Methane Drained:	47.5	51.8	63.3	34.6	38.4
Estimated Specific Emissions (cf/ton):	14489	9651	11063	7225	8992
Methane Recovered (million cf/day):	46.3	51.5	63.0	34.5	39.5

Estimated Current Drainage Efficiency: 83%

Drainage System Used: Vertical Pre-Mine, Vertical Gob, Horizontal Pre-Mine

Virginia Pocahontas No. 8 (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

	Assumed Potential Recovery Efficiency		
(Based on 2003 Data)	20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons):	1.5	3.0	4.5
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	27.7%	55.3%	83.0%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	6.4%	12.8%	19.2%

Power Generation Potential

Utility Electric Supplier: Appalachian Power Co.

Parent Corporation of Utility: American Electric Power Co., Inc.

	MW	GWh/year
Total Electricity Demand (2003 data):	14.9	56.4
Mine Electricity Demand:	11.7	45.1
Prep Plant Electricity Demand:	3.2	11.3
Potential Generating Capacity (2003 data)		
Assuming 20% Recovery Efficiency:	35.1	307.3
Assuming 40% Recovery Efficiency:	70.2	614.7
Assuming 60% Recovery Efficiency:	105.2	922.0

Pipeline Sales Potential

Potential Annual Gas Sales (2003 data)	Bcf
Assuming 20% Recovery (Bcf):	3.4
Assuming 40% Recovery (Bcf):	6.8
Assuming 60% Recovery (Bcf):	10.1

Description of Surrounding Terrain: Open Low Mountains/Low Mountains

Transmission Pipeline in County? No

Owner of Nearest Pipeline: Mine owns pipeline that connects to dist. line

Distance to Pipeline (miles): 0.0 **Pipeline Diameter (inches):** NA

Owner of Next Nearest Pipeline: Consolidated Natural Gas Supply Co. (CNG)

Distance to Next Nearest Pipeline (miles): 1.0 **Pipeline Diameter (inches):** 6.0

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: None **Distance to Plant (miles):** NA

Comments: Not yet researched.

6. Profiled Mines (continued)

West Virginia Mines

American Eagle
Beckley Crystal
Blacksville No. 2
Dakota No. 2
Eagle
Federal No. 2
Justice #1
Loveridge No. 22
McElroy
Pinnacle No. 50
Robinson Run No. 95
Sentinel
Shoemaker
Upper Big Branch - South
Whitetail Kittanning

Updated: 08/01/2005 **Status:** Active

American Eagle Mine

GEOGRAPHIC DATA

Basin: Central Appalachian **State:** WV

Coalbed: Eagle, Big Eagle **County:** Kanawha

CORPORATE INFORMATION

Current Owner: Speed Mining, Inc.

Parent Company: Timothy G. Elliott **Parent Company Web Site:** NA

Previous Owner(s): NA **Previous or Alternate Name of Mine:** NA

MINE ADDRESS

Contact Name: Scott Pettry **Phone Number:** (304) 461-3050

Mailing Address: 325 Harper Park Dr.

City: Beckley **State:** WV **ZIP:** 25801

GENERAL INFORMATION

Number of Employees at Mine: 132 **Mining Method:** Continuous

Year of Initial Production: NA **Primary Coal Use:** Steam, Metallurgical

Life Expectancy: NA **Sulfur Content of Coal Produced:** <1.5%

Prep Plant Located on Site? No **BTUs/lb of Coal Produced:** 13,500

Depth to Seam (ft): NA **Seam Thickness (ft):** NA

PRODUCTION, VENTILATION AND DRAINAGE DATA

	1999	2000	2001	2002	2003
Coal Production (million short tons/year):	0.2	0.0	0.9	3.3	4.1
Estimated Total Methane Liberated (million cf/day):	0.3	0.0	0.5	2.5	4.9
Emission from Ventilation Systems:	0.3	0.0	0.5	2.5	4.9
Estimated Methane Drained:	0.0	0.0	0.0	0.0	0.0
Estimated Specific Emissions (cf/ton):	534	-	199	282	435
Methane Recovered (million cf/day):	-	-	-	-	-

Estimated Current Drainage Efficiency: 0%

Drainage System Used: None

American Eagle Mine (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

	Assumed Potential Recovery Efficiency		
(Based on 2003 Data)	20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons):	0.2	0.3	0.5
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	1.4%	2.8%	4.1%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	0.3%	0.6%	1.0%

Power Generation Potential

Utility Electric Supplier:

Parent Corporation of Utility:

	MW	GWh/year
Total Electricity Demand (2003 data):	32.7	123.8
Mine Electricity Demand:	25.7	99.1
Prep Plant Electricity Demand:	7.0	24.8
Potential Generating Capacity (2003 data)		
Assuming 20% Recovery Efficiency:	3.7	32.7
Assuming 40% Recovery Efficiency:	7.5	65.3
Assuming 60% Recovery Efficiency:	11.2	98.0

Pipeline Sales Potential

Potential Annual Gas Sales (2003 data)	Bcf
Assuming 20% Recovery (Bcf):	0.4
Assuming 40% Recovery (Bcf):	0.7
Assuming 60% Recovery (Bcf):	1.1

Description of Surrounding Terrain:

Transmission Pipeline in County?

Owner of Nearest Pipeline:

Distance to Pipeline (miles): **Pipeline Diameter (inches):**

Owner of Next Nearest Pipeline:

Distance to Next Nearest Pipeline (miles): **Pipeline Diameter (inches):**

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: **Distance to Plant (miles):**

Comments:

Updated: 08/01/2005 **Status:** Active

Beckley Crystal

GEOGRAPHIC DATA

Basin: Central Appalachian **State:** WV

Coalbed: NA **County:** Raleigh

CORPORATE INFORMATION

Current Owner: Baylor Mining, Inc.

Parent Company: Robert L. Worley **Parent Company Web Site:** NA

Previous Owner(s): NA **Previous or Alternate Name of Mine:** NA

MINE ADDRESS

Contact Name: Sam Hatcher **Phone Number:** (304) 732-6422

Mailing Address: P.O. Box 577

City: Mabscott **State:** WV **ZIP:** 25871

GENERAL INFORMATION

Number of Employees at Mine: 55 **Mining Method:** Continuous

Year of Initial Production: NA **Primary Coal Use:** NA

Life Expectancy: NA **Sulfur Content of Coal Produced:** <1.5%

Prep Plant Located on Site? No **BTUs/lb of Coal Produced:** 12,000

Depth to Seam (ft): NA **Seam Thickness (ft):** NA

PRODUCTION, VENTILATION AND DRAINAGE DATA

	1999	2000	2001	2002	2003
Coal Production (million short tons/year):	0.0	0.0	0.2	0.6	0.5
Estimated Total Methane Liberated (million cf/day):	0.0	0.0	0.7	1.0	2.3
Emission from Ventilation Systems:	0.0	0.0	0.7	1.0	2.3
Estimated Methane Drained:	0.0	0.0	0.0	0.0	0.0
Estimated Specific Emissions (cf/ton):	-	-	1169	646	1809
Methane Recovered (million cf/day):	-	-	-	-	-

Estimated Current Drainage Efficiency: 0%

Drainage System Used: None

Beckley Crystal (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

	Assumed Potential Recovery Efficiency		
(Based on 2003 Data)	20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons):	0.1	0.2	0.2
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	6.5%	12.9%	19.4%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	1.5%	3.0%	4.5%

Power Generation Potential

Utility Electric Supplier:

Parent Corporation of Utility:

	MW	GWh/year
Total Electricity Demand (2003 data):	3.8	14.2
Mine Electricity Demand:	3.0	11.4
Prep Plant Electricity Demand:	0.8	2.8
Potential Generating Capacity (2003 data)		
Assuming 20% Recovery Efficiency:	1.8	15.6
Assuming 40% Recovery Efficiency:	3.6	31.2
Assuming 60% Recovery Efficiency:	5.3	46.8

Pipeline Sales Potential

Potential Annual Gas Sales (2003 data)	Bcf
Assuming 20% Recovery (Bcf):	0.2
Assuming 40% Recovery (Bcf):	0.3
Assuming 60% Recovery (Bcf):	0.5

Description of Surrounding Terrain:

Transmission Pipeline in County?

Owner of Nearest Pipeline:

Distance to Pipeline (miles): **Pipeline Diameter (inches):**

Owner of Next Nearest Pipeline:

Distance to Next Nearest Pipeline (miles): **Pipeline Diameter (inches):**

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: **Distance to Plant (miles):**

Comments:

Updated: 08/01/2005 **Status:** Active

Blacksville No. 2

GEOGRAPHIC DATA

Basin: Northern Appalachian **State:** WV

Coalbed: Pittsburgh No. 8 **County:** Monongalia

CORPORATE INFORMATION

Current Owner: Consol Energy Inc.

Parent Company: CONSOL Energy **Parent Company Web Site:** www.consolenergy.com

Previous Owner(s): None in last 10 years **Previous or Alternate Name of Mine:** None

MINE ADDRESS

Contact Name: Byron Payne **Phone Number:** (304) 662-6128

Mailing Address: P.O. Box 24

City: Wana **State:** WV **ZIP:** 26590

GENERAL INFORMATION

Number of Employees at Mine: 479 **Mining Method:** Longwall/Continuous

Year of Initial Production: 1971 **Primary Coal Use:** Steam

Life Expectancy: NA **Sulfur Content of Coal Produced:** 1.97%

Prep Plant Located on Site? No **BTUs/lb of Coal Produced:** 13,419

Depth to Seam (ft): 1375 **Seam Thickness (ft):** 6.5

PRODUCTION, VENTILATION AND DRAINAGE DATA

	1999	2000	2001	2002	2003
Coal Production (million short tons/year):	4.6	5.2	5.0	4.8	5.4
Estimated Total Methane Liberated (million cf/day):	11.1	11.9	9.1	8.2	8.5
Emission from Ventilation Systems:	6.7	7.1	6.7	5.7	4.7
Estimated Methane Drained:	4.4	4.8	2.4	2.4	3.8
Estimated Specific Emissions (cf/ton):	873	843	658	619	571
Methane Recovered (million cf/day):	3.4	1.1	2.1	3.3	3.3

Estimated Current Drainage Efficiency: 45%

Drainage System Used: Vertical Gob, Horizontal Pre-Mine

Blacksville No. 2 (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

(Based on 2003 Data)	Assumed Potential Recovery Efficiency 20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons):	0.3	0.6	0.8
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	1.8%	3.6%	5.5%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	0.4%	0.9%	1.3%

Power Generation Potential

Utility Electric Supplier: Monongahela Power Co.

Parent Corporation of Utility: Allegheny Power Systems, Inc.

	MW	GWh/year
Total Electricity Demand (2003 data):	43.2	163.5
Mine Electricity Demand:	33.9	130.8
Prep Plant Electricity Demand:	9.3	32.7
Potential Generating Capacity (2003 data)		
Assuming 20% Recovery Efficiency:	6.5	56.5
Assuming 40% Recovery Efficiency:	12.9	113.1
Assuming 60% Recovery Efficiency:	19.4	169.6

Pipeline Sales Potential

Potential Annual Gas Sales (2003 data)	Bcf
Assuming 20% Recovery (Bcf):	0.6
Assuming 40% Recovery (Bcf):	1.2
Assuming 60% Recovery (Bcf):	1.9

Description of Surrounding Terrain: Open Low Mountains/High Hills

Transmission Pipeline in County? Yes

Owner of Nearest Pipeline: Consolidated Natural Gas Supply Co. (CNG)

Distance to Pipeline (miles): 0.4 **Pipeline Diameter (inches):** 10.0

Owner of Next Nearest Pipeline: NA

Distance to Next Nearest Pipeline (miles): NA **Pipeline Diameter (inches):** NA

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: None **Distance to Plant (miles):** NA

Comments: Pharmaceuticals, chemicals, apparel, and glass manufacturing; hospitals, university, and other municipal buildings.

Updated: 08/01/2005 **Status:** Active

Dakota No. 2

GEOGRAPHIC DATA

Basin: Central Appalachian

State: WV

Coalbed: Pittsburgh No. 8

County: Boone

CORPORATE INFORMATION

Current Owner: Dakota Mining, Inc.

Parent Company: Rainbow Trout Coal LLC

Parent Company Web Site: NA

Previous Owner(s): NA

Previous or Alternate Name of Mine: NA

MINE ADDRESS

Contact Name: Amanda Lawson

Phone Number: (304) 461-3049

Mailing Address: 430 Harper Park, Ste. A

City: Beckley **State:** WV **ZIP:** 25801

GENERAL INFORMATION

Number of Employees at Mine: 165

Mining Method: Continuous

Year of Initial Production: 1996

Primary Coal Use: Steam

Life Expectancy: NA

Sulfur Content of Coal Produced: <1.5%

Prep Plant Located on Site? No

BTUs/lb of Coal Produced: 13,500

Depth to Seam (ft): NA

Seam Thickness (ft): NA

PRODUCTION, VENTILATION AND DRAINAGE DATA

	1999	2000	2001	2002	2003
Coal Production (million short tons/year):	1.6	1.6	1.2	1.5	1.5
Estimated Total Methane Liberated (million cf/day):	0.5	0.5	0.4	1.0	1.5
Emission from Ventilation Systems:	0.5	0.5	0.4	1.0	1.5
Estimated Methane Drained:	0.0	0.0	0.0	0.0	0.0
Estimated Specific Emissions (cf/ton):	119	107	129	235	366
Methane Recovered (million cf/day):	-	-	-	-	-

Estimated Current Drainage Efficiency: 0%

Drainage System Used: None

Dakota No. 2 (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

(Based on 2003 Data)	Assumed Potential Recovery Efficiency 20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons):	0.0	0.1	0.1
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	1.2%	2.3%	3.5%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	0.3%	0.5%	0.8%

Power Generation Potential

Utility Electric Supplier:

Parent Corporation of Utility:

	MW	GWh/year
Total Electricity Demand (2003 data):	11.7	44.2
Mine Electricity Demand:	9.2	35.4
Prep Plant Electricity Demand:	2.5	8.8
Potential Generating Capacity (2003 data)		
Assuming 20% Recovery Efficiency:	1.1	9.8
Assuming 40% Recovery Efficiency:	2.2	19.6
Assuming 60% Recovery Efficiency:	3.4	29.5

Pipeline Sales Potential

Potential Annual Gas Sales (2003 data)	Bcf
Assuming 20% Recovery (Bcf):	0.1
Assuming 40% Recovery (Bcf):	0.2
Assuming 60% Recovery (Bcf):	0.3

Description of Surrounding Terrain:

Transmission Pipeline in County?

Owner of Nearest Pipeline:

Distance to Pipeline (miles): **Pipeline Diameter (inches):**

Owner of Next Nearest Pipeline:

Distance to Next Nearest Pipeline (miles): **Pipeline Diameter (inches):**

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: **Distance to Plant (miles):**

Comments:

Updated: 08/01/2005 **Status:** Active

Eagle Mine

GEOGRAPHIC DATA

Basin: Central Appalachian **State:** WV

Coalbed: Eagle, Big Eagle **County:** Kanawha

CORPORATE INFORMATION

Current Owner: Newtown Energy, Inc.

Parent Company: James O. Bunn; Frank D. **Parent Company Web Site:** NA

Previous Owner(s): NA **Previous or Alternate Name of Mine:** NA

MINE ADDRESS

Contact Name: John Dunlap **Phone Number:** (304) 837-8587

Mailing Address: 13905 McCorkle Ave,

City: Chesapeake **State:** WV **ZIP:** 25315

GENERAL INFORMATION

Number of Employees at Mine: 143 **Mining Method:** Continuous

Year of Initial Production: NA **Primary Coal Use:** NA

Life Expectancy: NA **Sulfur Content of Coal Produced:** <1.5%

Prep Plant Located on Site? No **BTUs/lb of Coal Produced:** 13,500

Depth to Seam (ft): NA **Seam Thickness (ft):** NA

PRODUCTION, VENTILATION AND DRAINAGE DATA

	1999	2000	2001	2002	2003
Coal Production (million short tons/year):	0.0	0.5	1.5	1.2	1.5
Estimated Total Methane Liberated (million cf/day):	0.0	0.0	0.4	0.8	1.0
Emission from Ventilation Systems:	0.0	0.0	0.4	0.8	1.0
Estimated Methane Drained:	0.0	0.0	0.0	0.0	0.0
Estimated Specific Emissions (cf/ton):	-	0	96	263	240
Methane Recovered (million cf/day):	-	-	-	-	-

Estimated Current Drainage Efficiency: 0%

Drainage System Used: None

Eagle Mine (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

(Based on 2003 Data)	Assumed Potential Recovery Efficiency 20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons):	0.0	0.1	0.1
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	0.8%	1.5%	2.3%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	0.2%	0.4%	0.5%

Power Generation Potential

Utility Electric Supplier:

Parent Corporation of Utility:

	MW	GWh/year
Total Electricity Demand (2003 data):	11.7	44.2
Mine Electricity Demand:	9.2	35.4
Prep Plant Electricity Demand:	2.5	8.8
Potential Generating Capacity (2003 data)		
Assuming 20% Recovery Efficiency:	0.7	6.4
Assuming 40% Recovery Efficiency:	1.5	12.9
Assuming 60% Recovery Efficiency:	2.2	19.3

Pipeline Sales Potential

Potential Annual Gas Sales (2003 data)	Bcf
Assuming 20% Recovery (Bcf):	0.1
Assuming 40% Recovery (Bcf):	0.1
Assuming 60% Recovery (Bcf):	0.2

Description of Surrounding Terrain:

Transmission Pipeline in County?

Owner of Nearest Pipeline:

Distance to Pipeline (miles): **Pipeline Diameter (inches):**

Owner of Next Nearest Pipeline:

Distance to Next Nearest Pipeline (miles): **Pipeline Diameter (inches):**

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: **Distance to Plant (miles):**

Comments:

Updated: 08/01/2005 **Status:** Active

Federal No. 2

GEOGRAPHIC DATA

Basin: Northern Appalachian **State:** WV

Coalbed: Pittsburgh **County:** Monongalia

CORPORATE INFORMATION

Current Owner: Peabody Energy/Federal

Parent Company: Peabody Energy Corp. **Parent Company Web Site:** www.peabodyenergy.com

Previous Owner(s): Eastern Associated Coal **Previous or Alternate Name of Mine:** None

MINE ADDRESS

Contact Name: John Kucish, Mine Mgr. **Phone Number:** (304) 449-1911

Mailing Address: 1044 Miracle Run Rd.

City: Fairview **State:** WV **ZIP:** 26570

GENERAL INFORMATION

Number of Employees at Mine: 425 **Mining Method:** Longwall/Continuous

Year of Initial Production: 1968 **Primary Coal Use:** Steam

Life Expectancy: 2011 **Sulfur Content of Coal Produced:** 2.0% - 3.2%

Prep Plant Located on Site? Yes **BTUs/lb of Coal Produced:** 13,330

Depth to Seam (ft): 800 - 1250 **Seam Thickness (ft):** 7.0

PRODUCTION, VENTILATION AND DRAINAGE DATA

	1999	2000	2001	2002	2003
Coal Production (million short tons/year):	4.6	4.3	4.9	5.0	4.4
Estimated Total Methane Liberated (million cf/day):	15.3	12.8	17.9	12.0	8.7
Emission from Ventilation Systems:	9.1	7.7	10.7	10.6	7.6
Estimated Methane Drained:	6.1	5.1	7.1	1.4	1.1
Estimated Specific Emissions (cf/ton):	1198	1096	1336	876	725
Methane Recovered (million cf/day):	0.2	1.0	1.0	0.4	0.8

Estimated Current Drainage Efficiency: 13%

Drainage System Used: Vertical Gob, Horizontal Pre-Mine

Federal No. 2 (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

(Based on 2003 Data)	Assumed Potential Recovery Efficiency 20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons):	0.3	0.6	0.9
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	2.3%	4.7%	7.0%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	0.5%	1.1%	1.6%

Power Generation Potential

Utility Electric Supplier: Monongahela Power Co.

Parent Corporation of Utility: Allegheny Power Systems, Inc.

	MW	GWh/year
Total Electricity Demand (2003 data):	34.9	131.9
Mine Electricity Demand:	27.4	105.5
Prep Plant Electricity Demand:	7.5	26.4
Potential Generating Capacity (2003 data)		
Assuming 20% Recovery Efficiency:	6.6	58.0
Assuming 40% Recovery Efficiency:	13.2	116.0
Assuming 60% Recovery Efficiency:	19.9	174.0

Pipeline Sales Potential

Potential Annual Gas Sales (2003 data)	Bcf
Assuming 20% Recovery (Bcf):	0.6
Assuming 40% Recovery (Bcf):	1.3
Assuming 60% Recovery (Bcf):	1.9

Description of Surrounding Terrain: Open Low Mountains/High Hills

Transmission Pipeline in County? Yes

Owner of Nearest Pipeline: Consolidated Natural Gas Supply Co. (CNG)

Distance to Pipeline (miles): 0.9 **Pipeline Diameter (inches):** 10.0

Owner of Next Nearest Pipeline: NA

Distance to Next Nearest Pipeline (miles): NA **Pipeline Diameter (inches):** NA

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: None **Distance to Plant (miles):** NA

Comments: Pharmaceuticals, chemicals, apparel, and glass manufacturing; hospitals, university, and other municipal buildings.

Updated: 08/01/2005 **Status:** Active

Justice #1

GEOGRAPHIC DATA

Basin: Northern Appalachian **State:** WV

Coalbed: Powellton, Buffalo Crk **County:** Boone

CORPORATE INFORMATION

Current Owner: Independence Coal Co., Inc.

Parent Company: Massey Energy Co. **Parent Company Web Site:** www.masseyenergyco.com

Previous Owner(s): NA **Previous or Alternate Name of Mine:** NA

MINE ADDRESS

Contact Name: Dwayne Francisco, Pres. **Phone Number:** (304) 369-7103

Mailing Address: HC 78, Box 1800

City: Madison **State:** WV **ZIP:** 25130

GENERAL INFORMATION

Number of Employees at Mine: 117 **Mining Method:** Longwall/Continuous

Year of Initial Production: NA **Primary Coal Use:** Steam, Metallurgical

Life Expectancy: NA **Sulfur Content of Coal Produced:** <1.5%

Prep Plant Located on Site? Yes **BTUs/lb of Coal Produced:** 13,500

Depth to Seam (ft): NA **Seam Thickness (ft):** NA

PRODUCTION, VENTILATION AND DRAINAGE DATA

	1999	2000	2001	2002	2003
Coal Production (million short tons/year):	1.8	3.0	3.4	2.6	1.8
Estimated Total Methane Liberated (million cf/day):	1.4	2.0	2.5	3.3	2.8
Emission from Ventilation Systems:	1.4	2.0	2.5	3.3	2.8
Estimated Methane Drained:	0.0	0.0	0.0	0.0	0.0
Estimated Specific Emissions (cf/ton):	283	245	275	460	565
Methane Recovered (million cf/day):	-	-	-	-	-

Estimated Current Drainage Efficiency: 0%

Drainage System Used: None

Justice #1 (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

	Assumed Potential Recovery Efficiency		
(Based on 2003 Data)	20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons):	0.1	0.2	0.3
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	1.8%	3.6%	5.4%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	0.4%	0.8%	1.3%

Power Generation Potential

Utility Electric Supplier: Appalachian Power Co.

Parent Corporation of Utility: American Electric Power Co., Inc.

	MW	GWh/year
Total Electricity Demand (2003 data):	14.4	54.6
Mine Electricity Demand:	11.3	43.7
Prep Plant Electricity Demand:	3.1	10.9
Potential Generating Capacity (2003 data)		
Assuming 20% Recovery Efficiency:	2.1	18.7
Assuming 40% Recovery Efficiency:	4.3	37.4
Assuming 60% Recovery Efficiency:	6.4	56.1

Pipeline Sales Potential

Potential Annual Gas Sales (2003 data)	Bcf
Assuming 20% Recovery (Bcf):	0.2
Assuming 40% Recovery (Bcf):	0.4
Assuming 60% Recovery (Bcf):	0.6

Description of Surrounding Terrain:

Transmission Pipeline in County? Yes

Owner of Nearest Pipeline: Columbia Gas Transmission Co.

Distance to Pipeline (miles): < 1.0 **Pipeline Diameter (inches):** 8.0

Owner of Next Nearest Pipeline:

Distance to Next Nearest Pipeline (miles): **Pipeline Diameter (inches):**

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: **Distance to Plant (miles):**

Comments:

Updated: 08/01/2005 **Status:** Active

Loveridge No. 22

GEOGRAPHIC DATA

Basin: Northern Appalachian **State:** WV

Coalbed: Pittsburgh **County:** Marion

CORPORATE INFORMATION

Current Owner: Consol Energy Inc.

Parent Company: CONSOL Energy **Parent Company Web Site:** www.consolenergy.com

Previous Owner(s): None in last 10 years **Previous or Alternate Name of Mine:** None

MINE ADDRESS

Contact Name: John Higgins **Phone Number:** (304) 285-2223

Mailing Address: P.O. Box 40

City: Fairview **State:** WV **ZIP:** 26570

GENERAL INFORMATION

Number of Employees at Mine: 184 **Mining Method:** Longwall/Continuous

Year of Initial Production: 1953 **Primary Coal Use:** Steam

Life Expectancy: NA **Sulfur Content of Coal Produced:** 2.69%

Prep Plant Located on Site? No **BTUs/lb of Coal Produced:** 13,175

Depth to Seam (ft): 1250 **Seam Thickness (ft):** 7.8

PRODUCTION, VENTILATION AND DRAINAGE DATA

	1999	2000	2001	2002	2003
Coal Production (million short tons/year):	1.1	0.0	1.1	0.0	0.3
Estimated Total Methane Liberated (million cf/day):	0.0	2.7	5.8	3.3	5.3
Emission from Ventilation Systems:	0.0	2.7	3.5	2.0	0.9
Estimated Methane Drained:	0.0	0.1	2.3	1.3	4.4
Estimated Specific Emissions (cf/ton):	0	-	1835	-	6402
Methane Recovered (million cf/day):	-	-	-	-	-

Estimated Current Drainage Efficiency: 82%

Drainage System Used: Vertical Gob, Horizontal Pre-Mine

Loveridge No. 22 (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

(Based on 2003 Data)	Assumed Potential Recovery Efficiency 20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons):	0.2	0.3	0.5
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	20.9%	41.7%	62.6%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	4.9%	9.7%	14.6%

Power Generation Potential

Utility Electric Supplier: Monongahela Power Co.

Parent Corporation of Utility: Allegheny Power Systems, Inc.

	MW	GWh/year
Total Electricity Demand (2003 data):	2.4	9.1
Mine Electricity Demand:	1.9	7.3
Prep Plant Electricity Demand:	0.5	1.8
Potential Generating Capacity (2003 data)		
Assuming 20% Recovery Efficiency:	4.0	35.4
Assuming 40% Recovery Efficiency:	8.1	70.9
Assuming 60% Recovery Efficiency:	12.1	106.3

Pipeline Sales Potential

Potential Annual Gas Sales (2003 data)	Bcf
Assuming 20% Recovery (Bcf):	0.4
Assuming 40% Recovery (Bcf):	0.8
Assuming 60% Recovery (Bcf):	1.2

Description of Surrounding Terrain: Open Low Mountains/High Hills

Transmission Pipeline in County? Yes

Owner of Nearest Pipeline: Consolidated Natural Gas Supply Co. (CNG)

Distance to Pipeline (miles): 0.9 **Pipeline Diameter (inches):** 10.0

Owner of Next Nearest Pipeline: Kentucky West Virginia Gas Company

Distance to Next Nearest Pipeline (miles): NA **Pipeline Diameter (inches):** 6"

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: None **Distance to Plant (miles):** NA

Comments: Lighting products, temperature control equipment, hospital and other municipal buildings.

Updated: 08/01/2005 **Status:** Active

Mc Elroy Mine

GEOGRAPHIC DATA

Basin: Northern Appalachian **State:** WV

Coalbed: Pittsburgh **County:** Marshall

CORPORATE INFORMATION

Current Owner: Consol Energy Inc.

Parent Company: CONSOL Energy **Parent Company Web Site:** www.consolenergy.com

Previous Owner(s): Consolidation Coal Co. **Previous or Alternate Name of Mine:** None

MINE ADDRESS

Contact Name: Dave Eraskovich, Supt. **Phone Number:** (304) 843-3700

Mailing Address: Rd. 1

City: Glen Easton **State:** WV **ZIP:** 26039

GENERAL INFORMATION

Number of Employees at Mine: 568 **Mining Method:** Longwall/Continuous

Year of Initial Production: 1968 **Primary Coal Use:** Steam

Life Expectancy: NA **Sulfur Content of Coal Produced:** 3.98% -4.42%

Prep Plant Located on Site? Yes **BTUs/lb of Coal Produced:** 12,300

Depth to Seam (ft): 600 - 1200 **Seam Thickness (ft):** 5.0 - 5.4

PRODUCTION, VENTILATION AND DRAINAGE DATA

	1999	2000	2001	2002	2003
Coal Production (million short tons/year):	7.0	6.8	6.6	4.8	6.8
Estimated Total Methane Liberated (million cf/day):	8.0	6.4	6.9	7.4	1.6
Emission from Ventilation Systems:	6.8	6.4	6.9	7.4	1.6
Estimated Methane Drained:	1.2	0.0	0.0	0.0	0.0
Estimated Specific Emissions (cf/ton):	417	345	382	565	88
Methane Recovered (million cf/day):	-	-	-	-	-

Estimated Current Drainage Efficiency: 0%

Drainage System Used: None

Mc Elroy Mine (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

	Assumed Potential Recovery Efficiency		
(Based on 2003 Data)	20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons):	0.1	0.1	0.2
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	0.3%	0.6%	0.9%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	0.1%	0.1%	0.2%

Power Generation Potential

Utility Electric Supplier: Wheeling Power Co.

Parent Corporation of Utility: American Electric Power Co., Inc.

	MW	GWh/year
Total Electricity Demand (2003 data):	53.8	203.8
Mine Electricity Demand:	42.3	163.0
Prep Plant Electricity Demand:	11.6	40.8
Potential Generating Capacity (2003 data)		
Assuming 20% Recovery Efficiency:	1.2	10.9
Assuming 40% Recovery Efficiency:	2.5	21.8
Assuming 60% Recovery Efficiency:	3.7	32.7

Pipeline Sales Potential

Potential Annual Gas Sales (2003 data)	Bcf
Assuming 20% Recovery (Bcf):	0.1
Assuming 40% Recovery (Bcf):	0.2
Assuming 60% Recovery (Bcf):	0.4

Description of Surrounding Terrain: High Hills/Hills

Transmission Pipeline in County? Yes

Owner of Nearest Pipeline: Columbia Gas Transmission Co.

Distance to Pipeline (miles): 0.0 **Pipeline Diameter (inches):** 10.0

Owner of Next Nearest Pipeline: NA

Distance to Next Nearest Pipeline (miles): NA **Pipeline Diameter (inches):** NA

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: Ohio Power Kammer Plant **Distance to Plant (miles):** 10.0

Comments: Not yet researched.

Updated: 08/01/2005 **Status:** Active

Pinnacle No. 50

GEOGRAPHIC DATA

Basin: Central Appalachian **State:** WV

Coalbed: Pocahontas No. 3 **County:** Wyoming

CORPORATE INFORMATION

Current Owner: U.S. Steel Mining Co., L.L.C.

Parent Company: USX Corp. **Parent Company Web Site:** www.uss.com/ussteel/index.html

Previous Owner(s): None in last 10 years **Previous or Alternate Name of Mine:** Gary No. 50, U.S. Steel No.

MINE ADDRESS

Contact Name: Jack Shroder, GM Pinnacle **Phone Number:** (304) 732-5200

Mailing Address: C/O U.S. Steel Mining,

City: Pineville **State:** WV **ZIP:** 24824

GENERAL INFORMATION

Number of Employees at Mine: 540 **Mining Method:** Longwall/Continuous

Year of Initial Production: 1969 **Primary Coal Use:** Metallurgical

Life Expectancy: NA **Sulfur Content of Coal Produced:** 0.75%

Prep Plant Located on Site? Yes **BTUs/lb of Coal Produced:** 14,900

Depth to Seam (ft): NA **Seam Thickness (ft):** 4.2

PRODUCTION, VENTILATION AND DRAINAGE DATA

	1999	2000	2001	2002	2003
Coal Production (million short tons/year):	3.9	3.7	3.1	3.5	2.5
Estimated Total Methane Liberated (million cf/day):	18.4	16.0	14.8	15.8	14.0
Emission from Ventilation Systems:	14.8	11.0	7.7	8.0	9.8
Estimated Methane Drained:	3.7	5.0	7.1	7.8	4.2
Estimated Specific Emissions (cf/ton):	1735	1594	1721	1636	2064
Methane Recovered (million cf/day):	2.3	3.5	5.6	5.6	1.5

Estimated Current Drainage Efficiency: 30%

Drainage System Used: Directional Pre-Mine, Vertical Gob, Horizontal Pre-Mine

Pinnacle No. 50 (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

	Assumed Potential Recovery Efficiency		
(Based on 2003 Data)	20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons):	0.5	0.9	1.4
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	5.9%	11.9%	17.8%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	1.4%	2.8%	4.2%

Power Generation Potential

Utility Electric Supplier: Appalachian Power Co.

Parent Corporation of Utility: American Electric Power Co., Inc.

	MW	GWh/year
Total Electricity Demand (2003 data):	19.6	74.1
Mine Electricity Demand:	15.4	59.3
Prep Plant Electricity Demand:	4.2	14.8
Potential Generating Capacity (2003 data)		
Assuming 20% Recovery Efficiency:	10.6	92.7
Assuming 40% Recovery Efficiency:	21.2	185.4
Assuming 60% Recovery Efficiency:	31.7	278.1

Pipeline Sales Potential

Potential Annual Gas Sales (2003 data)	Bcf
Assuming 20% Recovery (Bcf):	1.0
Assuming 40% Recovery (Bcf):	2.0
Assuming 60% Recovery (Bcf):	3.1

Description of Surrounding Terrain: Low Mountains

Transmission Pipeline in County? Yes

Owner of Nearest Pipeline: Mine owns pipeline that connects to trans. line

Distance to Pipeline (miles): 0.0 **Pipeline Diameter (inches):** NA

Owner of Next Nearest Pipeline: Cabot

Distance to Next Nearest Pipeline (miles): 0.5 **Pipeline Diameter (inches):** NA

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: None **Distance to Plant (miles):** NA

Comments: Mining equipment manufacturing, quarries, municipal buildings.

Updated: 08/01/2005 **Status:** Active

Robinson Run No. 95

GEOGRAPHIC DATA

Basin: Northern Appalachian **State:** WV

Coalbed: Pittsburgh **County:** Harrison

CORPORATE INFORMATION

Current Owner: Consol Energy Inc.

Parent Company: CONSOL Energy **Parent Company Web Site:** www.consolenergy.com

Previous Owner(s): None in last 10 years **Previous or Alternate Name of Mine:** No. 95

MINE ADDRESS

Contact Name: Jimmy Brock **Phone Number:** (304) 795-4421

Mailing Address: Rte. 2, P.O. Box 152

City: Mannington **State:** WV **ZIP:** 26582

GENERAL INFORMATION

Number of Employees at Mine: NA

Mining Method: Longwall/Continuous

Year of Initial Production: 1968

Primary Coal Use: Steam

Life Expectancy: NA

Sulfur Content of Coal Produced: 2.95% - 3.14%

Prep Plant Located on Site? No

BTUs/lb of Coal Produced: 13,100

Depth to Seam (ft): 700

Seam Thickness (ft): 6.5

PRODUCTION, VENTILATION AND DRAINAGE DATA

	1999	2000	2001	2002	2003
Coal Production (million short tons/year):	5.3	6.0	4.9	5.0	5.7
Estimated Total Methane Liberated (million cf/day):	6.9	5.1	5.0	5.6	4.9
Emission from Ventilation Systems:	4.1	4.1	4.0	4.5	4.0
Estimated Methane Drained:	2.8	1.0	1.0	1.1	1.0
Estimated Specific Emissions (cf/ton):	474	308	375	410	314
Methane Recovered (million cf/day):	-	-	-	-	-

Estimated Current Drainage Efficiency: 20%

Drainage System Used: Vertical Gob, Horizontal Pre-Mine

Robinson Run No. 95 (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

	Assumed Potential Recovery Efficiency		
(Based on 2003 Data)	20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons):	0.2	0.3	0.5
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	1.0%	2.1%	3.1%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	0.2%	0.5%	0.7%

Power Generation Potential

Utility Electric Supplier: Monongahela Power Co.

Parent Corporation of Utility: Allegheny Power Systems, Inc.

	MW	GWh/year
Total Electricity Demand (2003 data):	45.5	172.2
Mine Electricity Demand:	35.7	137.7
Prep Plant Electricity Demand:	9.8	34.4
Potential Generating Capacity (2003 data)		
Assuming 20% Recovery Efficiency:	3.7	32.8
Assuming 40% Recovery Efficiency:	7.5	65.6
Assuming 60% Recovery Efficiency:	11.2	98.4

Pipeline Sales Potential

Potential Annual Gas Sales (2003 data)	Bcf
Assuming 20% Recovery (Bcf):	0.4
Assuming 40% Recovery (Bcf):	0.7
Assuming 60% Recovery (Bcf):	1.1

Description of Surrounding Terrain: Open Low Mountains

Transmission Pipeline in County? Yes

Owner of Nearest Pipeline: Equitable Gas

Distance to Pipeline (miles): 0.2 **Pipeline Diameter (inches):** 10.0

Owner of Next Nearest Pipeline: Consolidated Gas Supply

Distance to Next Nearest Pipeline (miles): 3.0 **Pipeline Diameter (inches):** 12.0

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: Harrison **Distance to Plant (miles):** 3.0

Comments: Aircraft, glass, and casket manufacturing; FBI facility, shopping malls, and municipal buildings.

Updated: 08/01/2005 **Status:** Active

Sentinel Mine

GEOGRAPHIC DATA

Basin: Northern Appalachian **State:** WV

Coalbed: Kittanning **County:** Barbour

CORPORATE INFORMATION

Current Owner: Anker West Virginia Mining Co.

Parent Company: Anker Energy Corp. **Parent Company Web Site:** NA

Previous Owner(s): NA **Previous or Alternate Name of Mine:** Ryanstone #1

MINE ADDRESS

Contact Name: Robby Mundy **Phone Number:** (304) 457-1895

Mailing Address: Rte. 3, Box 146

City: Philippi **State:** WV **ZIP:** 26416

GENERAL INFORMATION

Number of Employees at Mine: 182 **Mining Method:** Continuous

Year of Initial Production: 1974 **Primary Coal Use:** Steam, Metallurgical

Life Expectancy: 2013 **Sulfur Content of Coal Produced:** 0.96% - 1.34%

Prep Plant Located on Site? Yes **BTUs/lb of Coal Produced:** 13,234

Depth to Seam (ft): 425 **Seam Thickness (ft):** NA

PRODUCTION, VENTILATION AND DRAINAGE DATA

	1999	2000	2001	2002	2003
Coal Production (million short tons/year):	0.9	0.5	0.4	0.3	0.3
Estimated Total Methane Liberated (million cf/day):	1.7	1.6	1.4	0.9	0.9
Emission from Ventilation Systems:	1.7	1.6	1.4	0.9	0.9
Estimated Methane Drained:	0.0	0.0	0.0	0.0	0.0
Estimated Specific Emissions (cf/ton):	689	1177	1208	1087	1114
Methane Recovered (million cf/day):	-	-	-	-	-

Estimated Current Drainage Efficiency: 0%

Drainage System Used: None

Sentinel Mine (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

(Based on 2003 Data)	Assumed Potential Recovery Efficiency 20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons):	0.0	0.1	0.1
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	3.6%	7.2%	10.8%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	0.8%	1.7%	2.5%

Power Generation Potential

Utility Electric Supplier: Philippi Municipal Electric

Parent Corporation of Utility: Municipal Owned

	MW	GWh/year
Total Electricity Demand (2003 data):	2.3	8.8
Mine Electricity Demand:	1.8	7.1
Prep Plant Electricity Demand:	0.5	1.8
Potential Generating Capacity (2003 data)		
Assuming 20% Recovery Efficiency:	0.7	6.0
Assuming 40% Recovery Efficiency:	1.4	11.9
Assuming 60% Recovery Efficiency:	2.0	17.9

Pipeline Sales Potential

Potential Annual Gas Sales (2003 data)	Bcf
Assuming 20% Recovery (Bcf):	0.1
Assuming 40% Recovery (Bcf):	0.1
Assuming 60% Recovery (Bcf):	0.2

Description of Surrounding Terrain: Open Low Mountains

Transmission Pipeline in County? Yes

Owner of Nearest Pipeline: Hope Gas

Distance to Pipeline (miles): 0.5 **Pipeline Diameter (inches):** NA

Owner of Next Nearest Pipeline: NA

Distance to Next Nearest Pipeline (miles): NA **Pipeline Diameter (inches):** NA

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: None **Distance to Plant (miles):** NA

Comments: Not yet researched.

Updated: 08/01/2005 **Status:** Active

Shoemaker Mine

GEOGRAPHIC DATA

Basin: Northern Appalachian **State:** WV

Coalbed: Pittsburgh **County:** Ohio

CORPORATE INFORMATION

Current Owner: Consol Energy Inc.

Parent Company: CONSOL Energy **Parent Company Web Site:** www.consolenergy.com

Previous Owner(s): None in last 10 years **Previous or Alternate Name of Mine:** None

MINE ADDRESS

Contact Name: Rock Harris **Phone Number:** (304) 238-1500

Mailing Address: Rd. 1 Box 62 A

City: Dallas **State:** WV **ZIP:** 26036

GENERAL INFORMATION

Number of Employees at Mine: 376 **Mining Method:** Longwall/Continuous

Year of Initial Production: NA **Primary Coal Use:** Steam

Life Expectancy: NA **Sulfur Content of Coal Produced:** 3.3%

Prep Plant Located on Site? No **BTUs/lb of Coal Produced:** 12,172

Depth to Seam (ft): 650 **Seam Thickness (ft):** 5.0 - 5.5

PRODUCTION, VENTILATION AND DRAINAGE DATA

	1999	2000	2001	2002	2003
Coal Production (million short tons/year):	4.4	3.6	4.1	3.4	3.8
Estimated Total Methane Liberated (million cf/day):	5.2	4.3	4.2	3.4	2.2
Emission from Ventilation Systems:	4.4	3.6	3.5	2.9	1.8
Estimated Methane Drained:	0.8	0.6	0.6	0.5	0.3
Estimated Specific Emissions (cf/ton):	428	435	372	371	206
Methane Recovered (million cf/day):	-	-	-	-	-

Estimated Current Drainage Efficiency: 15%

Drainage System Used: Vertical Gob, Horizontal Pre-Mine

Shoemaker Mine (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

(Based on 2003 Data)	Assumed Potential Recovery Efficiency 20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons):	0.1	0.1	0.2
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	0.7%	1.5%	2.2%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	0.2%	0.3%	0.5%

Power Generation Potential

Utility Electric Supplier: Wheeling Power Co.

Parent Corporation of Utility: American Electric Power Co., Inc.

	MW	GWh/year
Total Electricity Demand (2003 data):	30.5	115.3
Mine Electricity Demand:	23.9	92.2
Prep Plant Electricity Demand:	6.6	23.1
Potential Generating Capacity (2003 data)		
Assuming 20% Recovery Efficiency:	1.6	14.4
Assuming 40% Recovery Efficiency:	3.3	28.8
Assuming 60% Recovery Efficiency:	4.9	43.2

Pipeline Sales Potential

Potential Annual Gas Sales (2003 data)	Bcf
Assuming 20% Recovery (Bcf):	0.2
Assuming 40% Recovery (Bcf):	0.3
Assuming 60% Recovery (Bcf):	0.5

Description of Surrounding Terrain: High Hills/Hills

Transmission Pipeline in County? Yes

Owner of Nearest Pipeline: Columbia Gas Transmission Co.

Distance to Pipeline (miles): 0.2 **Pipeline Diameter (inches):** 10.0

Owner of Next Nearest Pipeline: NA

Distance to Next Nearest Pipeline (miles): NA **Pipeline Diameter (inches):** NA

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: None **Distance to Plant (miles):** NA

Comments: Not yet researched.

Updated: 08/01/2005 **Status:** Active

Upper Big Branch - South

GEOGRAPHIC DATA

Basin: Central Appalachian **State:** WV

Coalbed: Eagle, Powellton **County:** Raleigh

CORPORATE INFORMATION

Current Owner: Performance Coal Co.

Parent Company: Massey Energy Co. **Parent Company Web Site:** www.masseyenergyco.com

Previous Owner(s): NA **Previous or Alternate Name of Mine:** None

MINE ADDRESS

Contact Name: Homer Wallace **Phone Number:** (304) 854-1761

Mailing Address: P.O. Box

City: Naoma **State:** WV **ZIP:** 25140

GENERAL INFORMATION

Number of Employees at Mine: 216 **Mining Method:** Longwall/Continuous

Year of Initial Production: NA **Primary Coal Use:** Metallurgical

Life Expectancy: 2018 **Sulfur Content of Coal Produced:** <1.5%

Prep Plant Located on Site? No **BTUs/lb of Coal Produced:** 12,000

Depth to Seam (ft): NA **Seam Thickness (ft):** NA

PRODUCTION, VENTILATION AND DRAINAGE DATA

	1999	2000	2001	2002	2003
Coal Production (million short tons/year):	5.1	4.0	2.9	3.4	3.3
Estimated Total Methane Liberated (million cf/day):	1.0	1.2	1.0	1.5	3.1
Emission from Ventilation Systems:	1.0	1.2	1.0	1.5	3.1
Estimated Methane Drained:	0.0	0.0	0.0	0.0	0.0
Estimated Specific Emissions (cf/ton):	70	108	125	164	347
Methane Recovered (million cf/day):	-	-	-	-	-

Estimated Current Drainage Efficiency: 0%

Drainage System Used: None

Upper Big Branch - South (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

(Based on 2003 Data)	Assumed Potential Recovery Efficiency 20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons):	0.1	0.2	0.3
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	1.2%	2.5%	3.7%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	0.3%	0.6%	0.9%

Power Generation Potential

Utility Electric Supplier: Appalachian Power Co.

Parent Corporation of Utility: American Electric Power Co., Inc.

	MW	GWh/year
Total Electricity Demand (2003 data):	25.9	98.1
Mine Electricity Demand:	20.4	78.5
Prep Plant Electricity Demand:	5.6	19.6
Potential Generating Capacity (2003 data)		
Assuming 20% Recovery Efficiency:	2.4	20.6
Assuming 40% Recovery Efficiency:	4.7	41.3
Assuming 60% Recovery Efficiency:	7.1	61.9

Pipeline Sales Potential

Potential Annual Gas Sales (2003 data)	Bcf
Assuming 20% Recovery (Bcf):	0.2
Assuming 40% Recovery (Bcf):	0.5
Assuming 60% Recovery (Bcf):	0.7

Description of Surrounding Terrain:

Transmission Pipeline in County? Yes

Owner of Nearest Pipeline: Columbia Gas Transmission Co.

Distance to Pipeline (miles): < 3.0 **Pipeline Diameter (inches):** 8.0

Owner of Next Nearest Pipeline:

Distance to Next Nearest Pipeline (miles): **Pipeline Diameter (inches):**

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: **Distance to Plant (miles):**

Comments:

Updated: 08/01/2005 **Status:** Active

Whitetail Kittanning Mine

GEOGRAPHIC DATA

Basin: Northern Appalachian **State:** WV

Coalbed: Kittanning **County:** Preston

CORPORATE INFORMATION

Current Owner: Coastal Coal Co., LLC

Parent Company: El Paso Corporation **Parent Company Web Site:** www.elpaso.com

Previous Owner(s): Kingwood Coal Co. **Previous or Alternate Name of Mine:** NA

MINE ADDRESS

Contact Name: Richard L. Craig **Phone Number:** (304) 568-2460

Mailing Address: Rte. 1, Box 249C

City: Newburg **State:** WV **ZIP:** 26410

GENERAL INFORMATION

Number of Employees at Mine: 209 **Mining Method:** Continuous

Year of Initial Production: NA **Primary Coal Use:** Steam

Life Expectancy: NA **Sulfur Content of Coal Produced:** 1.5% - 1.7%

Prep Plant Located on Site? No **BTUs/lb of Coal Produced:** 13,150

Depth to Seam (ft): NA **Seam Thickness (ft):** NA

PRODUCTION, VENTILATION AND DRAINAGE DATA

	1999	2000	2001	2002	2003
Coal Production (million short tons/year):	0.0	0.3	2.4	2.4	2.4
Estimated Total Methane Liberated (million cf/day):	0.0	0.1	0.9	1.7	1.7
Emission from Ventilation Systems:	0.0	0.1	0.9	1.7	1.7
Estimated Methane Drained:	0.0	0.0	0.0	0.0	0.0
Estimated Specific Emissions (cf/ton):	-	158	142	256	265
Methane Recovered (million cf/day):	-	-	-	-	-

Estimated Current Drainage Efficiency: 0%

Drainage System Used: None

Whitetail Kittanning Mine (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

(Based on 2003 Data)	Assumed Potential Recovery Efficiency 20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons):	0.1	0.1	0.2
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	0.9%	1.7%	2.6%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	0.2%	0.4%	0.6%

Power Generation Potential

Utility Electric Supplier: Monongahela Power Co.

Parent Corporation of Utility: Allegheny Power Systems, Inc.

	MW	**GWh/year**
Total Electricity Demand (2003 data):	18.8	71.1
Mine Electricity Demand:	14.7	56.8
Prep Plant Electricity Demand:	4.0	14.2
Potential Generating Capacity (2003 data)		
Assuming 20% Recovery Efficiency:	1.3	11.4
Assuming 40% Recovery Efficiency:	2.6	22.8
Assuming 60% Recovery Efficiency:	3.9	34.2

Pipeline Sales Potential

Potential Annual Gas Sales (2003 data)	Bcf
Assuming 20% Recovery (Bcf):	0.1
Assuming 40% Recovery (Bcf):	0.3
Assuming 60% Recovery (Bcf):	0.4

Description of Surrounding Terrain:

Transmission Pipeline in County? Yes

Owner of Nearest Pipeline: Columbia Gas Transmission Co.

Distance to Pipeline (miles): ~10.0 **Pipeline Diameter (inches):** 10.0

Owner of Next Nearest Pipeline:

Distance to Next Nearest Pipeline (miles): **Pipeline Diameter (inches):**

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: **Distance to Plant (miles):**

Comments:

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References and Calculations Used in the Mine Profiles

Data Item	Sources	Calculations
Geographic Data (State, County, Basin, Coalbed)	Keystone (2004)	
Corporate Information:		
Current Owner	Past versions of Keystone Coal Manual and recent coal industry publications	
Previous Owner	Past versions of Keystone Coal Manual and Coal Magazine Annual Longwall Surveys	
Parent Company	Past versions of Keystone Coal Manual and recent coal industry publications	
Phone/Address/Contact Information	Past versions of Keystone Coal Manual and EIA reports.	
General Information:		
Number of Employees	Past versions of Keystone Coal Manual	
Year of Initial Production	MSHA; Past versions of Keystone Coal Manual and articles in coal industry publications	
Life Expectancy:	Past versions of Keystone Coal Manual	
Sulfur Content	Past versions of Keystone Coal Manual	
Mining Method	Past versions of Keystone Coal Manual and Coal Magazine Longwall Survey	
Primary Use	Past versions of Keystone Coal Manual	
Production, Ventilation, and Drainage Data		
Coal Production	MSHA (2004), EIA (2003)	
Emissions from Ventilation Systems	MSHA (1997 - 2004)	
Estimated Methane Drained	The number of mines assumed to have drainage systems is based on calls to individual MSHA districts.	Drainage emissions are estimated by assuming that they are 40% of total liberation, unless otherwise noted.

Data Item	Sources	Calculations
Estimated Total Methane Liberated		Sum of "emissions from ventilation systems" and "estimated methane drained."
Degasification Information		
Drainage system Used	Based on calls to individual MSHA districts offices.	
Estimated Current Drainage Efficiency		Assumed to be 40% unless otherwise noted for mines where the drainage efficiency is known.
Energy and Environmental Value		
CO_2 Equivalent of Methane Emissions Reductions (mm tons)	Global Warming Potential of Methane Compared to CO_2 based on IPCC (1997). GWP is 21 over 100 years.	Estimated 2003 CH_4 liberated (mmcf/yr) x recovery efficiency x 19.2 g/cf x 21 g CO_2/1 g CH_4 x 1 lb / 453.59 g x 1 ton / 2000 lbs
CO_2 Equivalent of Methane Emissions Reductions/CO_2 Emissions from Coal Combustion	CO_2/BTU ratio based on average state values in EIA (1992)	Fraction = [CO_2 equivalent of CH_4 emissions reductions (lbs)] / [2003 coal production (tons) x BTUs/ton x CO_2 emitted lbs/BTU x 99% (fraction oxidized)
BTU Value of Recovered Methane/BTU Value of Coal Produced	BTU/ton value for coal production based on information in Keystone or on average state values from EIA (1992)	Fraction = [2003 CH_4 liberated (cf/yr) x rec. efficiency x 1000 BTUs/cf] / [2003 coal production (tons) x BTUs/ton]
Power Generation Potential		
Electricity Supplier	Directory of Electric Utilities	
Potential Electric Generating Capacity		Capacity = Estimated CH_4 liberated in cf/day x recovery efficiency x 1 day/24 hours x 1000 BTUs/cf x kWh/11000 BTUs
Mine Electricity Demand	Mine electricity needs (24 kWh/ton) is based on ICF Resources (1990a) Ventilation systems are assumed to account for 25% of total electricity demand and to run 24 hours a day (8760 hours/year). Other mine operations are assumed to account	Demand (MW) = Demand from Ventilation Systems + Demand from Mine Operations + Demand from Prep Plant Demand (MW) ventilation systems = [25% x 24 kWh/ton x tons/year]/

Data Item	Sources	Calculations
	for 75% of electricity demand and to run 16 hours a day 220 days per year (3520 hours/year).	[8760 hours/year] Demand (MW) mine operations = [75% x 24 kWh/ton x tons/year]/ [3520 hours/year] Demand (GWh/year) = Demand from Mine + Demand from Prep. Plant Demand from Mine = [24 kWh/ton x tons/year]/ 10^6 Demand from Prep. Plant = [6 kWh/ton x tons/year]/ 10^6
Prep Plant Electricity Demand	Based on Keystone Coal Manual (2004) and Coal magazine annual Prep Plant surveys. If tons processed per year at the prep plant is available in the Keystone, then that value is used. Otherwise, coal processed is assumed to be equal to mine production. Prep plant electric needs of 6 kWh/ton based on ICF Resources (1990a). Prep plants are assumed to operate 3520 hours/year.	Demand (MW) prep plant = [6 kWh/ton x tons/year]/ 3520 hours/year]
Pipeline Potential		
Potential Annual Gas Sales		Estimated methane liberated (mmcf/d) x 365 days/yr x recovery efficiency
All other information	ICF Resources (1990b)	
Other Utilization Potential		
Name of Coal Fired Boiler Located Near Mine (if any)	Electric Power (2002)	
Distance to Boiler	Electric Power (2002)	