4. Coal Mining

Summary

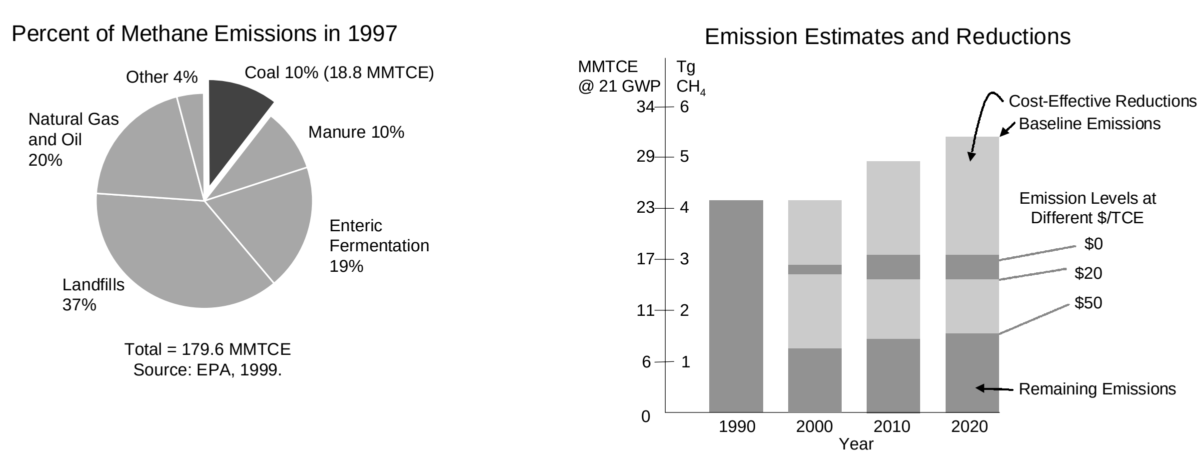
EPA estimates 1997 U.S. methane emissions from coal mines at 18.8 MMTCE (3.3 Tg), accounting for 10 percent of total U.S. anthropogenic methane emissions (see Exhibit 4-1). Methane, formed during coalification, is stored in coal seams and the surrounding strata and released during coal mining. Small amounts of methane are also released during the processing, transport, and storage of coal. Deeper coal seams contain much larger amounts of methane than shallow seams. Accordingly, 65 percent of 1997 U.S. coal mine methane emissions were from underground mines, even though underground mines accounted for only 39 percent of coal production.

EPA expects methane emissions from U.S. coal mines to increase faster than total U.S. coal production because underground coal production – mined at increasingly greater depths – is projected to grow faster than surface production. EPA estimates that methane emissions from coal mines will reach 28.0 MMTCE (4.9 Tg) by 2010, excluding possible Climate Change Action Plan (CCAP) reductions.

Methane emissions from coal mines can be reduced by methane recovery and use projects at underground mines and by the oxidation of methane in ventilation air using new technologies. In 1997, 14 underground U.S. coal mines recovered and used methane, achieving annual reductions of 4.6 MMTCE (0.8 Tg). Methane recovery technologies include vertical wells drilled from the surface or boreholes drilled from inside the mine. Depending on gas quality, methane recovered from underground mines may be sold to natural gas companies, used to generate electricity, used on-site as fuel for drying coal, or sold to nearby industrial or commercial facilities. The oxidization of coal mine ventilation air produces heat that can be used directly on-site or to produce electricity. Coal mines in the U.S. do not currently use the oxidization technology, but it has been successfully demonstrated in Great Britain.

The Coalbed Methane Outreach Program (CMOP), a voluntary EPA-industry partnership, has identified cost-effective technologies and practices that could reduce projected 2010 U.S. coal mine emissions by 10.3 MMTCE (1.8 Tg). EPA estimates that with a value of $20/TCE for abated methane added to the energy market price, U.S. coal mine methane emissions could be reduced by 13.1 MMTCE (2.3 Tg) in 2010 as shown in Exhibit 4-1 below.

Exhibit 4-1: U.S. Methane Emissions from Coal Mining (MMTCE)



1.0 Methane Emissions from Coal Mining

Methane and coal are formed together during coalification, a process in which plant biomass is converted by biological and geological forces into coal. Methane, stored within coal seams and the surrounding strata, is liberated when pressure above or surrounding a coalbed is reduced as a result of natural erosion, faulting, or underground and surface mining. Small amounts of methane also are liberated during the processing, storage, and transport of coal (referred to as post-mining emissions). Abandoned underground coal mines also contribute to the total amount of methane liberated. This section summarizes the sources of methane emissions from coal mining and details the methodologies EPA uses to estimate current and future methane emissions. The uncertainties associated with these estimates are also presented.

1.1 Emission Characteristics

Emissions vary greatly by type of coal mine and mining operations. This section describes the methane emissions resulting from underground mines, surface mines, post-mining operations, and abandoned mines.

Underground Mines. Deeper coal seams and surrounding strata contain much larger volumes of methane than shallow coal seams. Geologic pressure, which increases with depth, holds more methane in place. Additionally, coal mined underground tends to have a higher rank or carbon content, which correlates to a higher methane content.

As a safety precaution, all underground coal mines with detectable methane emissions must use ventilation systems to ensure that methane concentrations remain below one percent methane in the air of mine workings.[1] Methane is explosive at concentrations of five percent or greater; thus for safety reasons mine workings are operated at methane levels well below the five percent threshold. Ventilation systems consist of large fans that draw vast quantities of air into mine workings to lower methane concentrations. The ventilation air (extracted mine air containing low concentrations of methane) is then vented to the atmosphere through ventilation shafts or bleeders.

Degasification systems, which are vertical wells drilled from the surface or boreholes drilled within the mine, remove methane contained in the coal or surrounding strata before or after mining so that it does not enter the mine. In contrast to ventilation systems, degasification systems recover methane in high concentrations ranging from 30 to over 90 percent, depending on the degasification technique and coal geology.

Surface Mines. Surface mining is used to mine coal located at shallow depths. Because the coalbed at surface mines has little overburden, little pressure exists to keep methane in the coal. Hence, coal at surface mines tends to have a low methane content. As overburden is removed and the coal seam is exposed during surface mining, methane is emitted directly to the atmosphere. Although surface mines accounted for over 61 percent of U.S. coal production in 1997, they accounted for only an estimated 14 percent of methane emissions.

Post-Mining Operations. Although a significant amount of methane is released from the coal seam during mining activities, some methane remains in the coal after it is removed from the mine. This methane may be emitted from the coal during processing, storage, and transportation. The rate at which methane is emitted during post-mining activities depends on the characteristics of the coal and the way it is handled. For instance, the highest releases occur when coal is crushed, sized, and dried for industrial and utility uses. Post-mining emissions can continue for months after mining.

Abandoned Mines. Abandoned underground coal mines are also a source of emissions. A few gas developers are recovering and using methane from abandoned mines. EPA is conducting further research into this emission source. The current emission estimates do not include emissions from abandoned mines.

The majority of methane emissions from coal mining are from a few very large and gassy, i.e., high-emitting, underground mines. The most gassy 125 (of 573) underground coal mines account for over 97 percent of underground methane liberated and about 65 percent of methane liberated from all coal mines. Future trends at these gassy mines, including the potential for methane recovery and use, will have a large impact on future emission levels.

1.2 Emission Estimation Method

Total methane emissions from coal mining are estimated by summing methane emissions from underground mines, surface mines, and post-mining activities.

1.2.1 Underground Mines

Methane liberated from coal mines includes emissions from ventilation and degasification systems. Some coal mines recover and use the methane collected from degasification systems. Accordingly, this portion is subtracted from total methane liberated to determine methane emitted from underground mines.

Ventilation Systems. As mentioned previously, all underground coal mines with detectable methane emissions must use ventilation systems to ensure that methane concentrations remain within safe levels. Ventilation air typically contains methane concentrations below one percent. The Mine Safety and Health Administration (MSHA) measures methane emissions from ventilation systems on a quarterly basis. Based on these measurements, MSHA estimates average daily methane emissions for each underground mine (MSHA, 1998). For 1997, MSHA compiled the average daily methane emissions for all mines with detectable methane emissions into a single database, which provides the basis for EPA's method of estimating methane emissions from ventilation systems. First, EPA estimates annual methane emissions for each mine by multiplying the daily average by 365 days per year. Next, total annual methane emissions from ventilation systems were estimated by summing annual ventilation emissions from individual mines.

The 1997 MSHA database includes methane emission data for over 500 of the estimated 950 underground mines in the United States. Those mines not listed in the MSHA database do not have detectable levels of methane and the emissions from this group of mines are assumed to be negligible.

The methodology for estimating ventilation emissions for the years prior to 1997 is slightly different than the approach used for 1997 (see Exhibit 4-2). The 1997 MSHA database contains data for all mines with detectable methane emissions, and, consequently, reports on 100 percent of all ventilation emissions (MSHA, 1998). The MSHA data indicates that 97.8 percent of ventilation emissions come from mines emitting at least 0.1 million cubic feet per day (MMcf/d) and 94.1 percent of total emissions come from mines emitting at least 0.5 MMcf/day. EPA uses these estimates to prorate other data that are only representative of the mines emitting methane above these levels. For example, the estimates for 1990, 1993, and 1994 are based on a U.S. Bureau of Mines database that reported mine-specific information for all mines emitting at least 0.1 MMcf/d from their ventilation systems (DOI, 1995). Similarly,

Exhibit 4-2: Approach Used to Estimate Ventilation Emissions

Year	Data/Method Used
1990	U.S. Bureau of Mines database listing all mines with ventilation emissions greater than 0.1 MMcf/d. EPA adjusted total emissions to account for mines not included in the database. Assumed to account for 97.8% of total emissions.
1991	Total underground coal mining emissions are estimated by using emission factors developed in 1990 and multiplying those factors by 1991 coal production. Annual ventilation data are unavailable.
1992	Same approach as 1991, using 1992 coal production data.
1993	Same approach as 1990, using 1993 data. Assumed to account for 97.8% of total emissions.
1994	Same approach as 1990, using 1994 data. Assumed to account for 97.8% of total emissions.
1995	Obtained data from MSHA for all mines emitting at least 0.5 MMcf/d. Total was then adjusted to account for mines for which data were not collected. Assumed to account for 94.1% of total emissions.
1996	Same approach as 1995, using 1996 data. Assumed to account for 94.1% of total emissions.
1997	MSHA database containing ventilation emissions for all underground coal mines with detectable emissions. Assumed to account for 100% of total.

the 1995 and 1996 data are based on MSHA mine-specific ventilation emissions for all mines emitting at least 0.5 MMcf/d. Due to a lack of mine-specific emissions for 1991 and 1992, EPA estimates total underground emissions by multiplying emission factors, based on 1990 data, by coal production in the relevant year.

Degasification Systems. In 1997, 24 U.S. coal mines used degasification systems as a supplement to their ventilation systems. In the U.S., the three most common types of degasification methods are vertical wells and horizontal boreholes, drilled in advance of mining, and gob wells, drilled post mining. MSHA reports the coal mines that are employing degasification systems and the type of degasification systems used. However, MSHA does not measure or report the amount of methane liberated from degasification systems. Some U.S. coal mines provide EPA with information about their emissions from degasification systems. In other cases, EPA estimates the amount of methane liberated based on the type of degasification system employed and mine characteristics. Exhibit 4-3 shows U.S. coal mines employing degasification systems, the type of system employed, and the estimated amount of methane liberated and used.

Methane Used. Coal mines first began large scale use of methane recovered from degasification systems in the late 1970s. Since that time, methane recovery and use has increased substantially. In 1997, 14 active U.S. coal mines recovered and used or sold some or all of the methane recovered by their degasification systems. For each of these mines, the quantity of methane recovered is indicated in Exhibit 4-3. All of these active mines sell methane to natural gas companies, since methane is the principal component of natural gas. In addition, one of the mines uses a portion of the meth-

Exhibit 4-3: Mines Employing Degasification Systems and Methane Use Projects in 1997

Mine Name	Type of Degasification System Used	Methane Liberated from Degas System (MMcf/year)	Methane Used (MMcf/year)
Buchanan No. 1	Vertical, Horizontal, Gob	10,706	10,050
VP No. 8	Vertical, Horizontal, Gob	7,951	7,687
VP No. 3	Vertical, Horizontal, Gob	7,160	6,922
Blue Creek No. 7	Vertical, Horizontal, Gob	4,883	4,883
Blue Creek No. 4	Vertical, Horizontal, Gob	3,603	3,603
Blue Creek No. 3	Vertical, Horizontal, Gob	3,057	3,057
Blue Creek No. 5	Vertical, Horizontal, Gob	2,573	2,573
Pinnacle No. 50	Vertical, Horizontal, Gob	2,356	522
Enlow Fork	Gob	2,356	-
Cumberland	Vertical, Horizontal, Gob	2,341	-
Blacksville No. 2	Horizontal, Gob	2,074	149
Bailey	Gob	1,681	-
Oak Grove	Vertical, Horizontal, Gob	1,657	1,408
Emerald No. 1	Horizontal, Gob	1,351	-
Federal No. 2	Vertical, Horizontal, Gob	1,105	197
Loveridge No. 22	Horizontal, Gob	988	74
Dilworth	Gob	827	-
Robinson Run No. 95	Horizontal, Gob	750	-
Shoal Creek	Vertical, Horizontal, Gob	489	440
McElroy	Gob	299	-
Shoemaker	Gob	261	-
Maple Meadow	Gob	170	-
Baker	Gob	83	-
Humphrey No. 7	Horizontal, Gob	19	2

Note: Although all of the mines listed above liberated methane in 1997, not all of them sold (used) the methane recovered.

Source: MSHA, 1998; Mine Owners and Operators; State Petroleum and Natural Gas Agencies' Gas Sales Data; EPA, 1997a.

ane recovered from gob wells as fuel for an on-site gas-fired coal dryer.

EPA estimates methane emissions avoided over time for each U.S. recovery and use project. All of the projects must report methane sales to state agencies responsible for monitoring sales of natural gas. EPA uses gas sales information reported by state agencies, as well as information supplied by the coal mines, to estimate the emission reductions for a particular year. For coal mines that recover methane while mining, the emission reductions are estimated as the reported gas sales amount, adjusted for additional methane use in gas-fired compressors.

For projects that recover methane in advance of mining, estimating emission reductions is more complex. For these projects, the emission reductions are counted during the year in which the methane would otherwise have been emitted, i.e., the year during which the well is mined-through. The estimates are calculated based on reported gas sales over time, the portion of gas sales coming from pre-mining degasification systems, and the number of years in advance of mining that methane is recovered. In some cases, the amount of gas sold or used does not equal the amount liberated from degasification systems since part of the gas (up to 20 percent) is simply vented (see Buchanan No. 1 in Exhibit 4-3 for one example). Currently, U.S. coal mines only use methane that has been recovered from degasification systems; however, in the future, U.S. coal mines could potentially use methane from ventilation systems (EPA, 1999b).[2]

1.2.2 Surface Mines

With the exception of a few field studies, methane emissions from surface mines have not been measured or estimated on a mine-specific basis. Methane emissions from surface mines are estimated by multiplying surface coal production for each coal basin by a basin-specific emission factor. This factor is calculated by multiplying the average methane in-situ content of surface-mined coals by a factor of two to account for methane contained in overlying or underlying coal seams or other strata (EPA, 1993).

1.2.3 Post-Mining

Post-mining emissions are estimated by multiplying basin-specific coal production for surface and underground mines by a factor equal to 33 percent of the average basin-specific in-situ content of the coal. Different average methane in-situ values are used for surface mines and for underground mines (EPA, 1993).

1.2.4 Methodology for Estimating Future Methane Liberated

To estimate the amount of methane that will be liberated from coal production in the future, emission factors are multiplied by estimates of future coal production. Emission factors have been developed for underground mines, surface mines, and post-mining activities using 1997 data. These emission factors are then multiplied by projected surface and underground coal production levels to estimate future emissions. The opening and closing of very gassy mines is also taken into account since these changes significantly impact overall emissions.[3]

1.3 Emission Estimates

This section presents estimated methane emissions from coal mining from 1990 through 1997 and projected methane emissions through 2020.

1.3.1 Current Emissions and Trends

EPA estimates that the U.S. coal mining industry emitted 18.8 MMTCE (3.3 Tg) of methane in 1997. Mining in deep coal seams accounted for 65 percent of methane emitted from coal mining in 1997, totaling 12.3 MMTCE (2.1 Tg). As shown in Exhibit 4-4, methane emissions from coal mining declined from 1990 to 1997. This decline is due to three main factors. First, several gassy mines closed. These closures are due in part to reduced demand for high-sulfur coal in response to the Clean Air Act, which places strict requirements on utilities to reduce their sulfur dioxide emissions. Other mines closed due to declining coal prices, while others simply reached the end of their productive lifetime. Second, methane recovery and use has increased significantly at underground mines; EPA estimates that the amount of emissions avoided increased from 1.6 MMTCE (0.3 Tg) in 1990 to 4.6

Exhibit 4-4: Methane Emissions from Coal Mining (MMTCE)								
Activity	**1990**	**1991**	**1992**	**1993**	**1994**	**1995**	**1996**	**1997**
Underground Liberated	18.8	18.1	17.8	16.0	16.3	17.7	16.5	16.8
Underground Used	(1.6)	(1.7)	(2.1)	(2.7)	(3.2)	(3.4)	(3.8)	(4.6)
Net Underground Emissions	17.1	16.4	15.6	13.3	13.1	14.2	12.6	12.3
Surface Emissions	2.8	2.6	2.6	2.5	2.6	2.4	2.5	2.6
Post-Mining Emissions (Underground)	3.6	3.4	3.3	3.0	3.3	3.3	3.4	3.5
Post-Mining Emissions (Surface)	0.5	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Total	**24.0**	**22.8**	**22.0**	**19.2**	**19.4**	**20.3**	**18.9**	**18.8**

Totals may not sum due to independent rounding.
Source: EPA, 1999a.

MMTCE (0.8 Tg) in 1997. Third, although total coal production has increased, the percentage of total production from underground mines has declined slightly. Since underground production drives the total quantity of methane liberated from coal mines, a decline in underground production leads to a decline in methane liberated. Appendix IV, Exhibit IV-1 provides historical and projected coal production data.

1.3.2 Future Emissions and Trends

Although the amount of methane liberated from coal mining decreased over the past ten years, it is projected to increase between 2000 and 2020, as Exhibit 4-5 indicates. This projection is based on forecasted levels of coal production for both underground and surface mines developed by the Energy Information Administration of the U.S. Department of Energy (EIA, 1998b). Estimates for 2000 may overstate underground liberated emissions because of the closure of some very gassy mines in 1998 and 1999 that have not yet been taken into account.

1.4 Emission Estimate Uncertainties

The level of uncertainty associated with the emission estimates varies for each of the emission sub-sources.

Underground Ventilation Systems. As described above, methane emissions from ventilation systems are based on quarterly measurements taken by MSHA at individual mines. To the extent that the average of the four quarterly measurements are not representative of the true average at a given mine, average emissions at a particular mine may be over- or under-estimated. In addition, there are some limited uncertainties associated with the potential for measurement and reporting errors.

Underground Degasification Systems. MSHA reports which mines employ degasification systems and the type of degasification system used, but the agency does not record the quantity of methane liberated from degasification systems. Although coal mines are not required to publish methane liberation data, some have provided it to EPA. For other mines, EPA has estimated methane liberated based on the type of degasification system employed. The uncertainty is higher for those mines where EPA has estimated the amount of methane liberated. However, EPA has more data from gassy mines than from less gassy mines, thereby reducing overall uncertainty.

Exhibit 4-5: Projected Baseline Methane Emissions from Coal Mining (MMTCE)					
Activity	**2000**	**2005**	**2010**	**2015**	**2020**
Underground Liberated	17.1	19.3	20.4	21.5	22.1
Surface Liberated	2.8	2.8	2.9	3.0	3.2
Post-Mining Liberated (Underground)	3.5	4.0	4.2	4.5	4.6
Post-Mining Liberated (Surface)	0.5	0.5	0.5	0.5	0.5
Total	**23.9**	**26.6**	**28.0**	**29.5**	**30.4**

Totals may not sum due to independent rounding.

Methane Used at Underground Mines. As mentioned previously, all coal mines must report gas sales to state agencies responsible for monitoring gas production. While little uncertainty exists associated with the reported gas sales, uncertainty exists associated with the timing of the emission reductions. For coal mines that recover methane in advance of mining, the emission reduction is accounted for in the year in which the coal seam is mined-through. Thus, without knowing the exact timing of operations, there is uncertainty associated with estimating the timing of methane emissions avoided.

Surface Mines. Previous studies have indicated that methane emissions from surface mines are likely to be from one to three times greater than the in-situ content of the coal. EPA's emission estimation methodology assumes a value of two times the in-situ content of the coal. Additional uncertainty is related to the estimated average in-situ content for each basin.

Post-Mining Emissions. The uncertainties related to post-mining emissions are similar to those for surface mining emissions since a similar methodology is used.

Uncertainties Associated with Future Emissions. Future emissions are estimated for different sub-sources by multiplying the average emissions per ton of coal by projected future coal production levels. Accordingly, two additional sources of uncertainty are associated with the emission projections. First, the average emissions per ton of coal may change over time. Second, actual coal production levels may vary from projected coal production levels.

2.0 Emission Reductions

This section surveys the technologies and practices available for reducing coalbed methane emissions, analyzes the cost of implementing three "model" projects that integrate these abatement options, and highlights which options are most achievable and cost-effective through the development of a marginal abatement curve (MAC).

2.1 Technologies for Reducing Methane Emissions

Methane emissions from coal mines can be reduced through the implementation of the methane recovery and use projects described below.

2.1.1 Methane Recovery

Coal mines already employ a range of technologies for recovering methane. These methods have been developed primarily for safety reasons, as a supplement to ventilation systems. The major degasification techniques used at U.S. coal mines are vertical wells, longhole and shorthole horizontal boreholes, and gob wells. Exhibit 4-6 summarizes these technologies. Vertical wells and in-mine horizontal boreholes, which recover methane in advance of mining, produce nearly pure methane. In contrast, gob wells, which recover post-mining methane, may recover methane that has been mixed with mine air. The quality of the gas determines how it may be used.

Even where degasification systems are used, mines still emit significant quantities of methane via ventilation systems. Currently, technologies are in development that catalytically oxidize the low concentrations of methane in ventilation air producing usable thermal heat as a by-product.

2.1.2 Methane Use

Methane recovered from degasification can be used for the purposes described below.

Pipeline Injection. Natural gas companies may purchase methane recovered from coal mines. Most pipeline companies require gas with a methane concentration of at least 97 percent. Since gas recovered in advance of mining is nearly pure methane, the only processing required may be dehydration.

Gob gas, however, typically does not have a methane concentration greater than 97 percent. U.S. coal mines have developed different approaches for selling gob gas to natural gas companies. Two major projects, involving several coal mines in Alabama and Virginia, recover methane from gob wells for sale to a natural gas company. These coal mines have developed

Exhibit 4-6: Summary of Degasification Techniques

Method	Description	Methane Quality	Recovery Efficiency[a]	Current Use in U.S. Coal Mines
Vertical Wells	Drilled from the surface to coal seam several years in advance of mining.	Recovers nearly pure methane.	Up to 60%	Used by at least 3 U.S. mining companies in about 11 mines.
Gob Wells	Drilled from the surface to a few feet above coal seam just prior to mining.	Recovers methane that is sometimes contaminated with mine air.	Up to 50%	Used by more than 21 U.S. mines.
Shorthole Horizontal Boreholes	Drilled from inside the mine to degasify the coal seam just prior to mining.	Recovers nearly pure methane.	Up to 20%	Used by approximately 16 U.S. mines.
Longhole Horizontal Boreholes	Drilled from inside the mine to degasify the coal seam up to several years before mining.	Recovers nearly pure methane.	Up to 50%	Used by over 10 U.S. mines.
Cross-Measure Boreholes	Drilled from inside the mine to degasify surrounding rock strata.	Recovers methane that is sometimes contaminated with mine air.	Up to 60%	Not widely used in the U.S.

[a] Percent of total methane liberated that is recovered by degasification systems.

Source: EPA 1993, 1997b, and 1999a; Expert comments.

strategies for controlling the amount of air entering the gob and annually monitor gas quality in the well. These methods are highly effective, especially during the early stages of the productive lifetime of an individual gob well.

Power Generation. Coal mine methane is also used to generate electricity. In contrast to pipeline injection, power generation does not require nearly pure methane. Accordingly, methane recovered from gob wells may be used directly as fuel for a power generation project. At present, only one active U.S. mine uses recovered methane for power generation. In addition, an abandoned coal mine in Ohio also recovers methane to generate electricity for a neighboring, active coal mine.[4]

The methane contained in ventilation air may be used as combustion air in a turbine or internal combustion (IC) engine. Currently, BHP has developed a power generation project at the Appin and Tower coal mines in Australia. The project involves using methane recovered from degasification systems as the main fuel for 94 internal combustion engines rated at one MW each. The project uses about 1.3 million cubic feet a day of methane from ventilation air for this purpose (EPA, 1998). The thermal energy recovered from the oxidation of mine ventilation air can also be used in a steam turbine to generate power (CANMET, 1998; EPA, 1999b).

On-Site Use in a Thermal Coal Drying Facility. As with power generation, a thermal dryer does not require pure methane. Currently, one coal mine in Virginia uses methane recovered from gob wells as fuel for its thermal coal dryer. The thermal energy recovered from the oxidation of mine ventilation air may also be used for on-site drying operations.

Sale to Nearby Commercial or Industrial Facilities. Another option is for coal mines to sell recovered methane to nearby commercial or industrial facilities with a high demand for natural gas. In the early 1990s, gas recovered from coal mines in northern West Virginia was sold to a glass factory.

2.2 Cost Analysis of Emission Reductions

EPA estimates potential emission reductions by evaluating the ability of coal mines to cost-effectively build and operate systems for recovering and using, or oxidizing coal mine methane. EPA developed a MAC by evaluating a range of energy prices along with a range of emission reduction values. To determine cost-effectiveness, EPA assumes that in addition to the value of the energy produced, the mine owner/operator receives income equal to the emission reduction value, in $/ton of carbon equivalent ($/TCE), multiplied by the amount of methane abated. The cost-effectiveness of various options is estimated by comparing the value of the energy and the emission reduction to the costs of the system. The analysis is described below.

Step 1: Define the Current Underground Mines. The analysis is performed on underground mines that released at least 0.5 MMcf/d of methane from ventilation systems in 1997. These 58 mines account for about 94 percent of the methane released from U.S. underground coal mining (MSHA, 1998). EPA characterizes these mines in terms of coal basin, annual coal production, methane released from the ventilation system, existence of degasification system, methane recovered by the degasification system (if one is present), and mining method, i.e., longwall or room and pillar (EPA, 1999a). Where applicable, EPA estimates the amount of methane recovered from existing degasification systems. Using these data, EPA calculates the amount of methane liberated per ton of coal mined. EPA uses this liberation rate to estimate the amount of gas available for recovery per ton of coal mined.

Step 2: Future Coal Production and Future Mines. The Energy Information Administration estimates that coal production will increase 16 percent by 2010 and 26 percent by 2020 relative to 1997 production (EIA, 1998a). See Appendix IV, Exhibit IV-1 for details. Several characteristics of existing mines are assumed to be the same for future mines, such as the methane liberation rate per ton of coal. Therefore, the data set of current mines is used to represent future mines, with the exception that coal production at each mine is scaled over time to correspond with projected changes in underground U.S. coal production.

Step 3: Define "Model" Projects. The three types of modeled recovery and use options analyzed are described below and are also outlined in Exhibit 4-7.

- **Option 1: Degasification and Pipeline Injection.** Under this option, coal mines recover methane using vertical wells drilled five years in advance of mining, horizontal boreholes drilled one year in advance of mining, and gob wells. All of the gas recovered is sold to a pipeline. However, only the high-quality gas produced during the early stages of production from gob wells is assumed to be sold due to the declining gas quality over time. Methane recovery and use under this option varies by basin. EPA assumes that the technology to recover methane will improve over time, leading to increased methane recovery. (See Appendix IV, Exhibit IV-3 for a table of baseline coal basin recovery efficiencies by year.)
- **Option 2: Enhanced Degasification, Gas Enrichment, and Pipeline Injection.** This option consists of gas recovery-and-use incremental to Option 1. As in Option 1, EPA assumes that coal mines recover methane using vertical wells drilled five years in advance of mining, horizontal boreholes drilled one year in advance of mining, and gob wells drilled just prior to mining and that gas is sold to a pipeline. However, well spacing is tightened to increase recovery efficiency. Additionally, mines invest in enrichment technologies to enhance gob gas for sale to natural gas companies. This combination of tightened well spacing and gas enrichment increases recovery efficiency by 20 percent above what could have been achieved in Option 1. Accordingly, Option 2 results in an additional 20 percent of gas that is available for pipeline sale.

Exhibit 4-7: Summary of Options Included in the U.S. Coal Mine Cost Analysis of Methane Emission Reductions

Option	Technologies	Assumptions
1	Degasification and Pipeline Injection	All gas recovered from vertical wells and in-mine boreholes is sold to a pipeline. Only high quality gob gas is sold to the pipeline.
2	Enhanced Degasification, Gas Enrichment, and Pipeline Injection	Incremental to Option 1 with tightened well spacing and gas enrichment. Recovery and use efficiency increases 20% over Option 1.
3	Catalytic Oxidation	Ventilation air is oxidized.

- **Option 3: Catalytic Oxidation.** Under this option, coal mines eliminate methane in their ventilation air using a catalytic oxidizer system with a maximum capacity of 211,860 standard cubic feet per minute (scf/min). The catalytic oxidizer is estimated to oxidize up to 98 percent of the methane that passes through the system. This option can be implemented alone or in conjunction with either of the other two options. Although the heat produced by the system could potentially be used to produce electricity, EPA did not model this option due to the current lack of operational data.

As shown in Appendix IV, Exhibit IV-4, the number of wells required for any option is a function of the amount of coal mined. The size and cost of other equipment is driven by the amount of gas produced, which depends on the amount of coal mined, the rate of methane liberated per ton of coal produced, and the recovery efficiency. For those mines that already have degasification systems in place, these costs were considered sunk costs and were not included. Costs for royalty payments are also not included.

Step 4: Calculate Break-Even Emission Reduction Values. EPA performs a discounted cash flow analysis to calculate the break-even emission reduction values for Options 1, 2, and 3 for each of the 58 mines in 2000, 2010, and 2020. Exhibit 4-8 shows the financial assumptions. Costs are estimated for each mine using these assumptions and the data defined in Step 3. Project costs include only the incremental costs of methane recovery and use. For example, to the extent that a coal mine would already employ degasification systems as part of normal mining practices, the cost of drilling degasification wells or boreholes would not be an incremental cost of a methane use project. EPA estimates the revenue associated with the project as the gas price times the amount of gas recovered and sold.

Step 5: Estimate Emission Reductions for Each Option. The final step is to estimate cost-effective national emission reductions for 2000, 2010, and 2020 within a range of gas prices and emission reduction values in $/TCE. The base gas price is $2.53/MMBtu, which is the average 1996 wellhead gas price in Alabama, Indiana, Kentucky, and Ohio (EIA, 1997).[5] The additional emission reduction values, expressed in $/TCE, range from $0/TCE to $200/TCE. The emission reduction values are translated into gas prices using a global warming potential (GWP) for methane of 21 and a methane energy content of 1,000 Btu/cubic foot.[6] If the break-even gas price for the mine is equal to or less than the sum of the estimated gas price plus the emission reduction value, the emissions can be reduced cost-effectively. For Options 1 and 2, EPA estimates total emission reductions to be the sum of the emissions that can be recovered cost-effectively at the 58 mines for each combination of gas price and emission reduction value. For Option 3, the break-even emission reduction value is used to define the cases in which this option is cost-effective. The emission reduction is applied to all underground mining ventilation emissions that are calculated to be cost-effective.

2.3 Achievable Emission Reductions and Marginal Abatement Curve

This analysis indicates that projected 2010 methane emissions from U.S. coal mining can be reduced by approximately 10.3 MMTCE (1.8 Tg) or 37 percent below baseline projections by implementing currently available technologies that are cost-effective at energy market prices alone. Additional reduction options are cost-effective at carbon equivalent values greater than

Exhibit 4-8: Financial Assumptions for Emission Reduction Analysis

	Description	
Parameters	**Options 1 and 2**	**Option 3**
Base Gas Price (1996 US$)	$2.53/MMBtu	Not applicable
Discount Rate	15 percent real	15 percent real
Project Lifetime	15 years	10 years
Tax Rate	40 percent	40 percent
Depreciation Period	15 years	5 years

$0/TCE. At $20/TCE, baseline emissions in 2010 from U.S. coal mines could be reduced by 13.1 MMTCE (2.3 Tg) or 47 percent.

Exhibit 4-9 presents the cumulative emission reductions at selected values of carbon equivalent in 2000, 2010, and 2020. Exhibit 4-10 provides a schedule of selected emission reduction options for U.S. coal mines for 2010. Option 1 has a lower break-even price (lower cost) than Option 2 for any given mine. For example, the break-even price for Option 1 at Buchanan No. 1 is $0.54/MMBtu compared to $1.63/MMBtu for Option 2. The same methane reduction option becomes cost-effective at different break-even gas prices for different mines depending on the incremental amount of methane that can be recovered and used and the costs of methane recovery.

Exhibit 4-9: Emission Reductions at Selected Values of Carbon Equivalent in 2000, 2010, and 2020 (MMTCE)

	2000	2010	2020
Baseline Emissions	23.9	28.0	30.4
Cumulative Reductions			
at $0/TCE	7.1	10.3	12.5
at $10/TCE	8.0	12.0	13.9
at $20/TCE	8.2	13.1	15.3
at $30/TCE	16.8	20.0	21.7
at $40/TCE	16.8	20.0	21.7
at $50/TCE	16.8	20.0	21.7
at $75/TCE	16.8	20.0	21.7
at $100/TCE	16.8	20.0	21.7
at $125/TCE	16.8	20.0	21.7
at $150/TCE	16.8	20.0	21.7
at $175/TCE	16.8	20.0	21.7
at $200/TCE	16.8	20.0	21.7
Remaining Emissions	7.1	8.0	8.7

Exhibit 4-11 presents the MAC which is derived by a rank order of cost-effective individual opportunities at each combination of gas price and carbon equivalent emission reduction value, i.e., the cost per emission reduction amount. The options shown in Exhibit 4-10 are labeled along the MAC at increasing break-even prices through to $29.70/TCE.

At $29.70/TCE the catalytic oxidizer technology becomes cost-effective.[7] The MAC becomes inelastic because all methane emissions from ventilation air can be reduced cost-effectively.[8] The maximum amount of emission reductions that can be achieved in 2010 assuming that the catalytic oxidizer is used is 20.0 MMTCE (3.5 Tg), or 71 percent of all methane liberated from coal mines in the U.S., which is equivalent to nearly all methane liberated from underground mines in the U.S.

2.4 Reduction Estimate Uncertainties and Limitations

Overall, this analysis is limited by the lack of detailed site-specific assessments. Coal mine methane recovery and use is greatly affected by site-specific conditions. In general, average industry costs are used along with conservative assumptions, so as not to overestimate emission reductions that could be achieved.

The cost analysis only considers recovering methane in advance of mining and selling the gas to natural gas companies or oxidizing the methane in ventilation air. For some smaller, less gassy mines, more limited recovery and use options may be cost-effective. Consequently, the analysis is conservative in that additional emission reduction opportunities may exist.

The analysis does not account for the incremental benefits that will accrue from the installation of degasification systems, such as decreased ventilation costs or increased productivity. Thus, the analysis is conservative to the extent that mines realize significant financial benefits to their mining operations from the installation of degasification projects.

Finally, uncertainty exists regarding the capital and operation and maintenance (O&M) costs for the technologies. In particular, the catalytic oxidation technology at coal mines is under development and limited data are available to estimate costs. Consequently, EPA bases the unit costs on an existing demonstration project and assumes that the costs for catalytic oxidation are proportional to the methane ventilated from underground mines. Given that the cost is based on only one project, EPA cannot assess the extent to which the costs are being over- or under-estimated.

Exhibit 4-10: Schedule of Emission Reduction Options in 2010

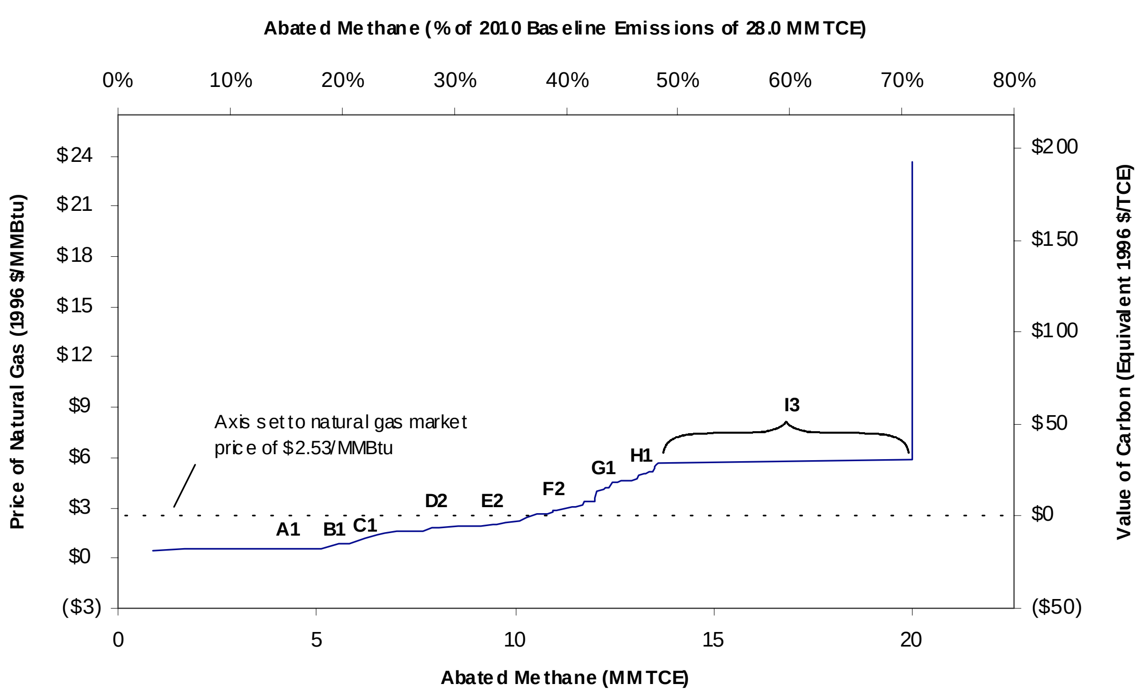
	Sample Coal Mines					National		
Option Used[a]	Representative Mine[b]	Coal Production (Million Short Tons/yr)	Break-Even Gas Price ($/MMBtu)	Value of Carbon Equivalent ($/TCE)	Emission Reductions (MMTCE)	Incremental Reductions (MMTCE)	Cumulative Reductions (MMTCE)	Label on MAC
1	Buchanan No. 1	5.26	$0.54	$(18.05)	1.22	4.05	4.05	A1
1	Blue Creek No. 3	2.78	$0.60	$(17.51)	0.48	1.05	5.10	B1
1	Oak Grove	3.17	$0.85	$(15.23)	0.25	0.72	5.82	C1
2	Buchanan No. 1	5.26	$1.63	$(8.14)	0.41	1.61	7.42	D2
2	Blue Creek No. 3	2.78	$1.94	$(5.32)	0.19	1.69	9.12	E2
2	Sanborn Creek	1.94	$3.33	$7.32	0.07	2.63	11.74	F2
1	McElroy	6.48	$4.59	$18.78	0.16	1.08	12.83	G1
1	Maple Creek	2.27	$5.63	$28.24	0.05	0.75	13.58	H1
3	*All Underground Mines*	NA[c]	$5.79	$29.70	20.00	6.42	20.00	I3

[a] Option 1 = Degasification and Pipeline Injection; Option 2 = Enhanced Degasification, Gas Enrichment, and Pipeline Injection; Option 3 = Catalytic Oxidation of Ventilation Air Emissions.

[b] This representative sample of coal mines existed in 1997. Although EPA uses data from these mines to model future emission reductions, EPA does not evaluate whether any specific mine would be operating in 2010.

[c] Not Applicable.

Exhibit 4-11: Marginal Abatement Curve for Methane Emissions from Coal Mining in 2010



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4.0 Explanatory Notes

[1] The Mine Safety and Health Administration (MSHA) records coal mine methane readings with concentrations greater than 50 ppm (parts per million) methane. Readings below this threshold are considered non-detectable.

[2] One coal mine in Australia has recovered and used ventilation air as a fuel for a series of internal combustion engine-driven generators. In addition, a British coal mine reported successful demonstration of oxidation technology.

[3] In 1998 and 1999, the VP No. 3, VP No. 8, and Blue Creek No. 3 mines closed. These closures will significantly reduce total U.S. methane emissions.

[4] Additionally, coal mines in Australia, China, Germany, and the United Kingdom have successfully developed power generation projects at active underground mines.

[5] Gas prices in key coal mine states, e.g., West Virginia, Virginia, Pennsylvania, and Illinois, are assumed to fall within the range of prices represented by the states with available data.

[6] Equation to calculate the equivalent gas price for a given value of carbon equivalent:

$$\frac{\$}{TCE} x \frac{10^6\ TCE}{MMTCE} x \frac{5.73\,MMTCE}{Tg\ CH_4} x \frac{Tg}{10^{12}\ g} x \frac{19.2\ g\ CH_4}{ft^3\ CH_4} x \frac{ft^3}{1{,}000\ Btu} x \frac{10^6\ Btu}{MMBtu} = \frac{\$}{MMBtu}$$

Where: 5.73 MMTCE/Tg CH_4 = 21 CO_2/CH_4 x (12 C / 44 CO_2)
Density of CH_4 = 19.2 g/ft^3
Btu content of CH_4 = 1,000 Btu/ft^3

[7] Although at this price, the catalytic oxidizer technology is cost-effective, a mine may still need to implement Options 1 and 2 for technical and safety reasons.

[8] At the less gassy mines, the low methane concentration make self-sustained oxidation impossible and supplemental gas is required to combust the gas. Because EPA's analysis is based on the more gassy mines, the assumption that all methane emissions from ventilation air can be reduced cost-effectively does not have a major impact on the MAC results.

Appendix IV: Supporting Material for the Analysis of Coal Mining

This appendix presents the coal mine data that EPA used to develop methane emission forecasts and to estimate methane emission reduction costs. The exhibits are described below:

- **Exhibit IV-1: Historical and Projected Coal Production.** This exhibit details historic and projected coal production data for surface and underground mines. These data underlie projections of the quantity of methane liberated from coalbeds. Historical data are shown for the period 1990-1997. Projected data are provided for the years 2000, 2005, 2010, 2015, and 2020.
- **Exhibit IV-2: Coal Mine Methane Liberation Estimates by Year.** The estimates of methane liberated from coal mining in 1997 are presented in this exhibit. Projections of methane liberated are also provided, based on the production data in Exhibit IV-1. These estimates are the basis for determining achievable and cost-effective emission reductions.
- **Exhibit IV-3: Coal Basin Recovery Efficiencies by Year.** This exhibit summarizes the methane recovery efficiencies by coal basin and by year. Methane recovery efficiencies vary by coal basin. In addition, EPA assumes that the technology to recover methane will improve over time, leading to increased methane recovery.
- **Exhibit IV-4: Cost Data and Assumptions Used in the Coal Mine Analysis.** The assumptions and data underlying the cost analysis of methane recovery and use techniques are summarized in this exhibit. Data are arranged by type of cost (well, compression, processing, etc.) and option number.
- **Exhibit IV-5: Schedule of Emission Reduction Options for 2010.** This exhibit provides a schedule of emission reduction data by option and individual mine for 2010. Data include annual coal production, liberated methane, projected "break-even" gas price, the value of carbon equivalent ($/TCE), and the cumulative amount of emissions reduced.

Exhibit IV-1: Historical and Projected Coal Production (Million Short Tons)													
	Historical								Projected				
	1990	1991	1992	1993	1994	1995	1996	1997	2000	2005	2010	2015	2020
Underground	425	407	407	351	399	396	410	421	427	482	510	537	552
Surface	605	589	590	594	634	636	654	669	718	725	756	789	824
Total Production	1,029	996	998	945	1,034	1,033	1,064	1,090	1,145	1,207	1,265	1,326	1,376
Underground (% of Total)	41%	41%	41%	37%	39%	38%	39%	39%	37%	40%	40%	41%	40%
Surface (% of Total)	59%	59%	59%	63%	61%	62%	61%	61%	63%	60%	60%	59%	60%

Source: EIA, 1998a and 1998b.

Exhibit IV-2: Coal Mine Methane Liberation Estimates by Year			
Year	Total Methane Liberated (MMcf)	Methane Liberated from Underground Mining (MMcf)	Underground Mining (% of Total)
1997	212,312	153,203	72.2
2000	217,142	155,570	71.6
2005	241,501	175,490	72.7
2010	254,966	185,614	72.8
2015	268,377	195,592	72.9
2020	276,454	201,091	72.7

MMcf = million cubic feet

Source: Projections based on EPA, 1999a, and EIA, 1998b.

Exhibit IV-3: Coal Basin Recovery Efficiencies by Year						
Basin	1997	2000	2005	2010	2015	2020
Warrior	45.0%	45.0%	47.5%	50.0%	52.5%	55.0%
Illinois	50.0%	50.0%	52.5%	55.0%	57.5%	60.0%
Northern Appalachian	55.0%	55.0%	57.5%	60.0%	62.5%	65.0%
Central Appalachian	55.0%	55.0%	57.5%	60.0%	62.5%	65.0%
Western	50.0%	50.0%	52.5%	55.0%	57.5%	60.0%

Source: Experience with existing coal mine methane projects, and EPA, 1997b.

Exhibit IV-4: Cost Data and Assumptions Used in the Coal Mine Analysis		
Cost Item	**Number or Size of Units Needed**	**Cost Per Unit**
	Costs for Wells	
Vertical Well	Option 1: 1 well for every 250,000 tons of coal mined	$150,000/well
	Option 2: 1 well for every 1 million tons of coal mined [a]	
Gob Wells	Option 1: 1 well for every 500,000 tons of coal mined	$30,000/well
	Option 2: 1 well for every 1 million tons of coal mined [a]	
In-Mine Boreholes	Option 1: 1 well for every 500,000 tons of coal mined	$75,000/well
	Option 2: 1 well for every 1 million tons of coal mined [a]	
Well Water Disposal Costs (Vertical Wells Only)	1 barrel of water is produced per Mcf (thousand cubic feet) of gas produced	$0.50 per barrel per year
	Compression Costs	
Wellhead Compressor	1 per well at 200 HP/MMcfd	Capital costs: $600/HP; O&M costs: $20/HP
Satellite Compressor	1 per project at 150 HP/MMcfd	
Sales Compressor	1 per project at 150 HP/MMcfd	
Gathering Lines from Wellhead to Satellite	Length of gathering lines from each well to satellite = 2000 ft	$10/ft
Gathering Lines from Satellite to Point of End-Use	Length of gathering lines from satellite to point of end-use = 26,400 ft (5 miles)	$15/ft
Cost of Moving Gathering Lines		$5/ft per year
	Gas Processing Costs	
Dehydrator	1 per project	Capital Cost: $40,000; O&M cost: $3,000
Gas Enrichment (Fixed Capital Cost) $/project	Required for Option 2 only	$1,888,500
Gas Enrichment (Variable Capital Cost) $/MMCFD	Required for Option 2 only	$526,000
Gas Enrichment (Fixed Annual Operating Cost) $/year	Required for Option 2 only	$132,000
Gas Enrichment (Operating Cost Based on Maximum Gas Production) $/MMCFD	Required for Option 2 only	$37,167
	Oxidizer Costs	
Oxidizer (Without Electricity Generation)	Option 3 only	Capital Cost: $6.2 million; O&M costs: $541,740[b]

[a] Option 1 is degasification and pipeline injection. Option 2 is degasification and pipeline injection incremental to Option 1. Option 3 is catalytic oxidation.

[b] Costs are for a system capable of handling 211,860 scf/min of ventilation air at 0.5% methane; for each mine, the cost was scaled based on the mine's flow rate relative to 211,860 scf/min.

Source: EPA 1997a, b, and c; CANMET, 1998.

Exhibit IV-5: Schedule of Emission Reductions for 2010						
Mine Name	Option[a]	Coal Production (MM short tons/yr)	Total Methane Liberated (MMcf/yr)	Break-Even Cost ($/MMBtu)	Additional Value of Methane ($/TCE)	Cumulative Emissions Avoided (MMTCE/yr)
VP No. 8	1	1.60	13,237	0.47	(18.69)	0.87
VP No. 3	1	2.69	11,919	0.52	(18.23)	1.66
Blue Creek No. 5	1	1.44	7,352	0.54	(18.05)	2.06
Blue Creek No. 7	1	3.17	13,953	0.54	(18.05)	2.83
Buchanan No. 1	1	5.26	18,523	0.54	(18.05)	4.05
Blue Creek No. 4	1	2.75	10,296	0.57	(17.78)	4.62
Blue Creek No. 3	1	2.78	8,736	0.60	(17.51)	5.10
Pinnacle No.50 (Gary)	1	6.46	7,135	0.84	(15.32)	5.57
Oak Grove	1	3.17	4,460	0.85	(15.23)	5.82
Blacksville No. 2	1	4.18	6,281	1.13	(12.69)	6.23
VP No. 8	2	1.60	13,237	1.41	(10.14)	6.52
Sanborn Creek	1	1.94	3,121	1.54	(8.96)	6.71
Blue Creek No. 7	2	3.17	13,953	1.60	(8.41)	7.02
Buchanan No. 1	2	5.26	18,523	1.63	(8.14)	7.42
VP No. 3	2	2.69	11,919	1.64	(8.05)	7.69
Blue Creek No. 4	2	2.75	10,296	1.77	(6.87)	7.91
Blue Creek No. 5	2	1.44	7,352	1.79	(6.68)	8.07
Enlow Fork	1	10.15	7,135	1.88	(5.87)	8.55
Shoal Creek	1	4.86	1,976	1.90	(5.68)	8.65
Emerald No. 1	1	5.85	4,091	1.91	(5.59)	8.92
Blue Creek No. 3	2	2.78	8,736	1.94	(5.32)	9.12
Cumberland	1	7.71	5,004	2.01	(4.68)	9.45
Maple Meadow	1	1.28	1,370	2.03	(4.50)	9.54
Federal No. 2	1	5.32	3,347	2.09	(3.96)	9.76
Bailey	1	9.11	5,093	2.26	(2.41)	10.09
Loveridge No. 22	1	5.82	2,992	2.45	(0.68)	10.29
Mine 84	1	5.80	4,028	2.66	1.23	10.56
Soldier Canyon	1	1.39	1,164	2.66	1.23	10.63
Dilworth	1	5.38	2,506	2.67	1.32	10.79
Blacksville No. 2	2	4.18	6,281	2.77	2.23	10.93
Roadside North Portal	1	0.52	483	2.84	2.86	10.96
Sentinel Mine	1	1.39	973	2.86	3.05	11.02
Galatia Mine No. 56-1	1	6.03	4,094	2.92	3.59	11.27
Robinson Run No. 95	1	5.79	2,272	3.09	5.14	11.42
Oak Grove	2	3.17	4,460	3.11	5.32	11.52
Pinnacle No.50 (Gary)	2	6.46	7,135	3.14	5.59	11.68
Sanborn Creek	2	1.94	3,121	3.33	7.32	11.74
West Elk Mine	1	6.93	3,975	3.37	7.68	11.99
McClure No. 2 Mine	1	0.44	306	3.56	9.41	12.01
Bowie #1 Mine	1	0.92	506	4.01	13.50	12.04
Tanoma	1	0.65	350	4.03	13.69	12.06
Enlow Fork	2	10.15	7,135	4.11	14.41	12.22
Aberdeen	1	2.27	1,077	4.18	15.05	12.28
Boone No. 1	1	1.03	586	4.19	15.14	12.31
Bay Beck Mine	1	1.19	552	4.20	15.23	12.35

Exhibit IV-5: Schedule of Emission Reductions for 2010 (continued)							
Mine Name	**Option[a]**	**Coal Production (MM short tons/yr)**	**Total Methane Liberated (MMcf/yr)**	**Break-Even Cost ($/MMBtu)**	**Additional Value of Methane ($/TCE)**	**Cumulative Emissions Avoided (MMTCE/yr)**
Emerald No. 1	2	5.85	4,091	4.54	18.32	12.44
Brushy Creek Mine	1	1.07	501	4.56	18.51	12.47
Cumberland	2	7.71	5,004	4.57	18.60	12.58
Mine 84	2	5.80	4,028	4.58	18.69	12.67
McElroy	1	6.48	2,415	4.59	18.78	12.83
Galatia Mine No. 56-1	2	6.03	4,094	4.63	19.14	12.92
Shoemaker	1	5.79	2,111	4.70	19.78	13.06
North River	1	2.41	1,035	4.98	22.33	13.11
Bailey	2	9.11	5,093	5.03	22.78	13.23
Federal No. 2	2	5.32	3,347	5.06	23.05	13.30
Pattiki Mine	1	2.43	918	5.13	23.69	13.36
West Elk Mine	2	6.93	3,975	5.16	23.96	13.44
Wabash Mine	1	1.92	711	5.32	25.42	13.49
Urling No. 1 Mine	1	0.73	271	5.50	27.05	13.50
Maple Meadow	2	1.28	1,370	5.55	27.51	13.53
Maple Creek	1	2.27	711	5.63	28.24	13.58
All Mines	3			5.79	29.70	20.00

[a] Option 1 is degasification and pipeline injection. Option 2 is degasification and pipeline injection incremental to Option 1. Option 3 is catalytic oxidation.

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