AN INTRODUCTION TO OPTIONS FOR REDUCING METHANE EMISSIONS FROM COAL MINES

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COAL MINING

1 Background

Methane Production, Storage, and Emissions

Methane is produced during coalification (the process of coal formation) and remains trapped under pressure in the coal seam and surrounding rock strata. This trapped methane is released during the mining process when the coal seam is fractured. Methane released in this fashion will escape into the mine works, and will eventually be emitted into the atmosphere.

The production of methane during coalification may exceed the adsorptive capacity of the coal. For example, although the highest gas content measurements for U.S. anthracite coal are only 21.6 cubic meters per metric ton, 180 cubic meters of methane may be produced during coalification (Diamond et al., 1986). As a result, significant quantities of methane seep into and are stored in the rock surrounding the coal seam. This methane seeps back into the mine working as the coal is mined. Mine air containing methane is removed from the mine workings, and is generally vented directly into the atmosphere.

The quantity of methane emitted per tonne of mined coal depends upon several characteristics of the coal, the most important of which are: 1) gas content, 2) permeability and gas diffusion rates, and 3) method of mining. The gas content of coal depends upon its rank and geological history. Coal rank is a measure of the degree of coalification; as coal rank increases, the amount of methane produced also increases (see Exhibit 4-1). Furthermore, higher ranks of coal have greater adsorptive capacities and will tend to contain more gas. Because pressure increases with depth, deeper coal seams generally contain more methane than shallow coal seams of similar rank. Thus, deeper mines with coal of a higher rank will typically contain larger quantities of methane.

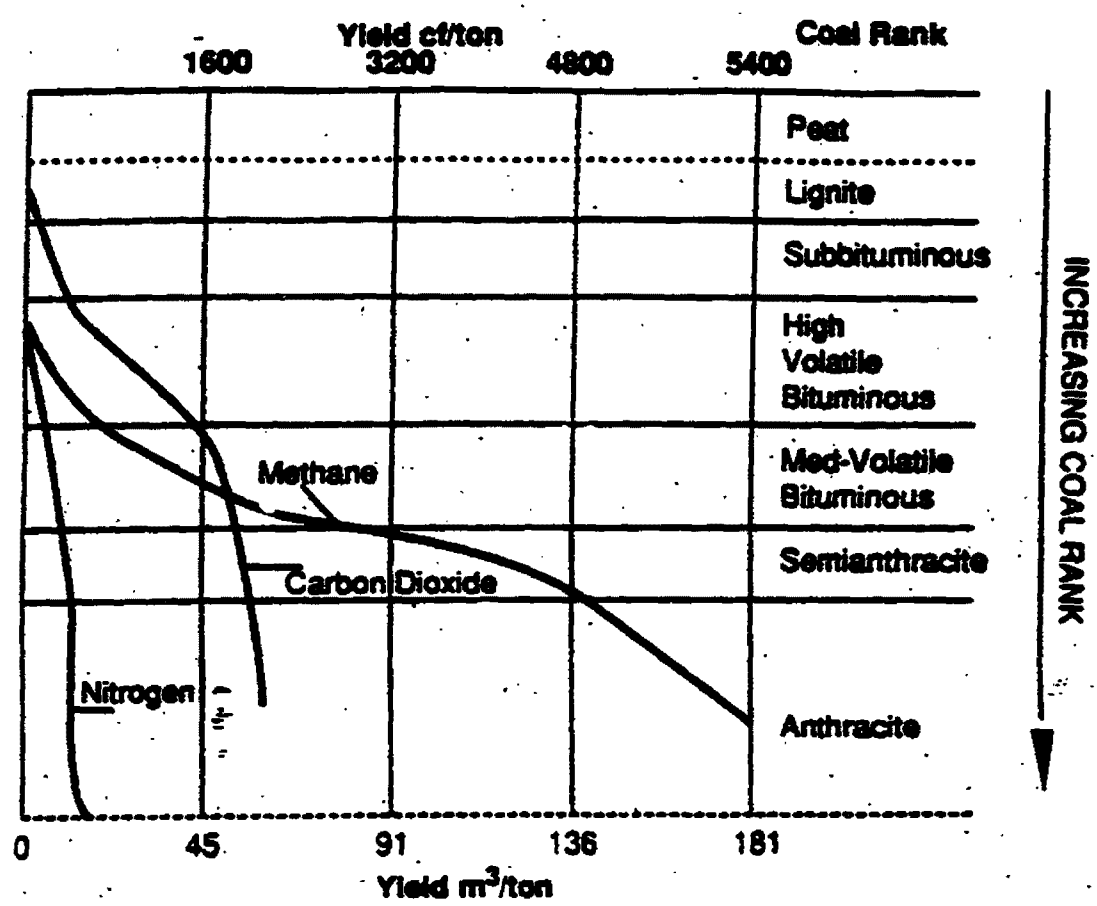
Permeability and diffusion rates are also important because they determine how quickly gas can migrate through the coal and into the mine workings. After coal is mined, the strata overlying the mined coal are allowed to cave in, causing the formation of a rubbleized area, termed a "gob." This fracturing increases the permeability of the methane-containing strata and facilitates the release of methane. Because more coal is removed during longwall mining and fewer pillars remain, the caving associated with longwall mining is generally more extensive, and thus methane released per tonne of coal is generally higher with longwall mining than with room and pillar mining.

Methane Recovery and Utilization Strategies

Techniques for removing methane from underground mine workings have been developed primarily for safety reasons, because methane is highly explosive in air concentrations between 5 and 15 percent. These same techniques can be adapted to recover methane so that the energy value of this fuel is not wasted. Where methane utilization is combined with recovery, methane emissions into the atmosphere are reduced.

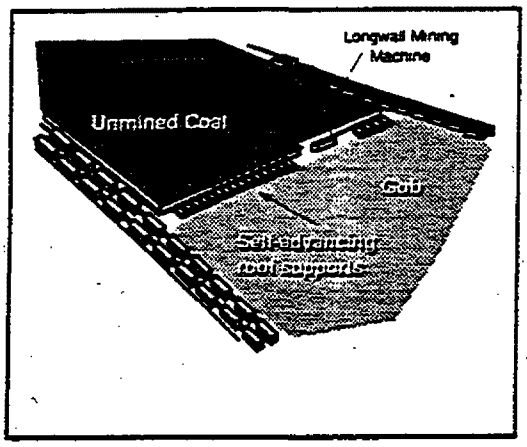
Important factors when considering options for reducing methane emissions from coal mining are: the geologic and reservoir characteristics of the coal basin; mine conditions and mining method; current mine gas recovery systems; potential gas quality and use options; and technical and economic capabilities. In particular, the recovery method largely determines the quality and quantity of gas recovered, which in turn determines the possible utilization options. Developing uses for recovered methane is required if emission reductions are to be achieved. The sale and/or use of methane can offset the costs of recovery in certain cases. Furthermore, improving methane recovery techniques can result in safer, more productive mines, with lower ventilation costs (Dixon, 1987).

Exhibit 4-1
Coal Rank and Methane Production

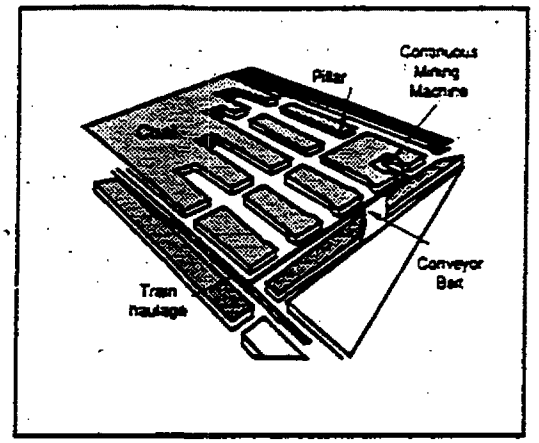


Source: USEPA, 1990.

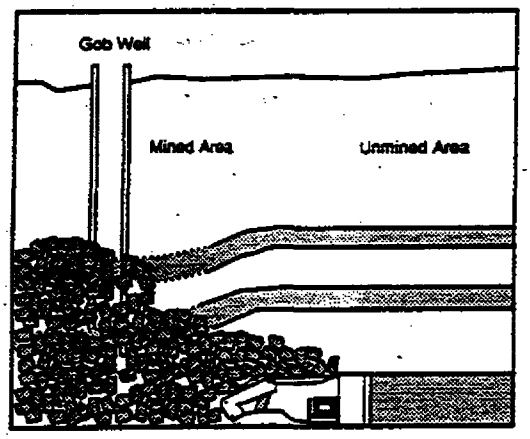
Exhibit 4-2
Coal Mining and Methane Recovery Techniques



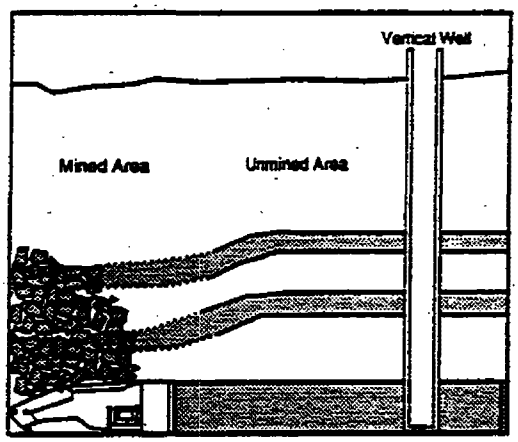
(a) Longwall Mining



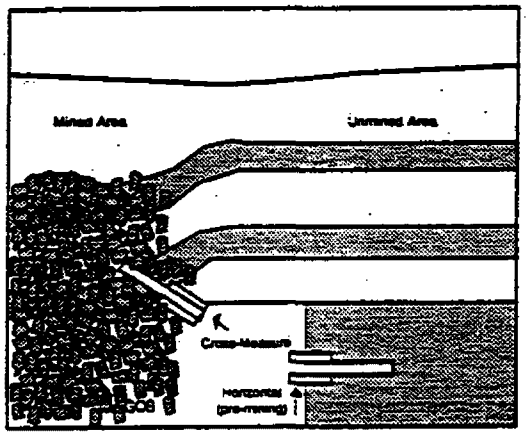
(b) Room-and-pillar Mining



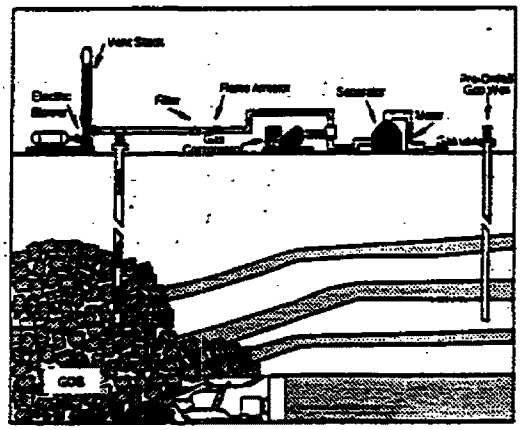
(c) Vertical Gob Well



(d) Vertical Degasification Well



(e) Cross Measure and Horizontal Boreholes



(f) Surface Equipment

Because the quality of gas that is recovered determines the possible gas utilization options, each of the four techniques presented here is a complete project based on a particular recovery method and its associated utilization options. Additionally, these strategies are structured according to technological and economic criteria and overall applicability. The four strategies presented are:

- Enhanced Gob Well Recovery;
- Pre-Mining Degasification;
- Ventilation Air Utilization; and
- Integrated Recovery.

Enhanced Gob Well Recovery: This strategy recovers methane from the gob area of a coal mine – the highly fractured area of coal and rock that is created by the caving of the mine roof after the coal is removed. Gob areas can release significant quantities of methane into the mine, and if this gas is recovered before entering the mine, ventilation requirements can be reduced (see Exhibit 4-2, Coal Mining and Methane Recovery Techniques). Typically, gob gas is diluted by mine air during production so a medium quality gas is obtained (300-800 Btu/cf; 11-29 MJ/m^3). This type of gas can be used in a variety of applications, including on-site power generation, gas distribution systems, and industrial heating. Enhanced gob well recovery can involve in-mine and/or surface wells using existing technology that is currently employed in many countries. In many cases, the capital requirements for methane recovery are low compared to the amount of gas that may be produced. The capital cost associated with gas utilization can vary significantly, being quite high for electricity generation, particularly where gas turbines are used.

Pre-Mining Degasification: This strategy recovers methane before coal is mined. Pre-mining degasification can be attractive where geologic conditions are appropriate because the methane is removed before the air from the mine workings can mix with it. Pre-mining degasification typically recovers a higher quality gas (900-1000 Btu/cf; 32-37 MJ/m^3) which can be used as a chemical feedstock in addition to being used for power generation and industrial or residential applications. Pre-mining degasification can be an in-mine or surface operation. When done inside the mine, boreholes can be drilled anywhere from six months to several years in advance of mining. Surface drilled vertical wells can be drilled anywhere from 2 to more than 10 years in advance of mining. Pre-mining degasification requires more advanced technology and equipment than enhanced gob well recovery, and therefore has higher capital costs.

Ventilation Air Utilization: Most mine gas is released to the atmosphere in the ventilation air used in the mine. Ventilation, necessary in underground coal mines for safety reasons, is achieved with large fans which blow air through the mine. The recovery technology is basic, but the operating costs of running the fans can be high if the mine is gassy. The methane content of the vented air must be below 5 percent for safety reasons, and is frequently as low as 0.5 percent to comply with relevant regulations. In spite of its low concentration, it appears that there may be opportunities to use ventilation air as combustion air in turbines or boilers (Granatstein et al., 1991; ESA, 1991). However, the technical and economic feasibility has not yet been demonstrated.

Integrated Recovery: The most significant methane emission reductions are likely to occur by employing a combination of methane recovery options. Indeed, many US coal mines currently use a combination of in-mine and surface recovery methods both before mining and from gob areas (Soot, 1990). The technological and capital requirements of such integrated systems are likely to be moderately high, but it is possible that the additional opportunities for gas utilization, as well as the enhanced mine safety, could justify the required investment.

Exhibit 4-3 summarizes information on these four coalbed methane recovery and utilization strategies. The four strategies are described in more detail in the individual technological assessments.

The assessments consist of the following sections:

- Recovery Technology Descriptions;
- Utilization Technology Descriptions;
- Costs;
- Availability;
- Applicability;
- Barriers; and
- Benefits.

Exhibit 4-3
Summary of Options for Reducing Methane Emissions from Coal Mining

Considerations	Enhanced Gob Well Recovery	Pre-Mining Degasification	Ventilation Air Utilization	Integrated Recovery *combined strategies*
Recovery Techniques	• In-Mine Boreholes • Vertical Gob Wells	• Vertical Wells • In-Mine Boreholes	• Fans	• All Techniques
Support Technologies	• In-Mine Drills and/or Basic Surface Rigs • Compressors, Pumps, and other support facilities	• In-Mine Drills and/or Advanced Surface Rigs • Compressors, Pumps, and other support facilities	• Surface Fans and Ducting	• All Technologies • Ability to Optimize Degasification Using Combined Strategies
Gas Quality	• Medium Quality (11-29 MJ/m^3) (300-800 Btu/cf) (approx. 30-80% CH_4)	• High Quality (32-37 MJ/m^3) (900-1000 Btu/cf) (above 90% CH_4)	• Low Quality (<1% CH_4; usually below 0.5%)	• All Qualities
Use Options	• On-Site Power Generation • Gas Distribution Systems • Industrial Use	• Chemical Feedstocks *in addition to those uses listed for medium quality gas*	• Combustion Air for On-Site/Nearby Turbines and Boilers	• All Uses
Availability	• Currently Available	• Currently Available	• Requires demonstration	• Currently Available
Capital Requirements	• Low	• Medium/High	• Low/Medium	• Medium/High
Technical Complexity	• Low	• Medium/High	• Medium/High	• High
Applicability	• Widely Applicable • Site Dependent	• Technology, Finance, and Site Dependent	• Nearby Utilization • Site Dependent	• Technology, Finance, and Site Dependent
Methane Reductions[1]	• Up to 50%	• Up to 70%	• 10-90% recovery	• 80-90% recovery

1 These reductions are achievable at specific sites or systems.

2 Enhanced Gob Well Recovery

Enhanced Gob Well Recovery is an approach that seeks to improve and augment methane recovery techniques that are already in place at a mine so that recovery is more efficient. This strategy builds on local experience and methods of operation.

Gob areas consist of fractured rock and coal that have collapsed into mined-out areas. Since these areas are considerably more permeable than intact coal and rock, methane stored above and below the coal seam is released during and after the creation of this gob area. The proximity of the gob area to the lower pressure of the mine can result in the flow of significant quantities of methane into the mine workings. This released methane is typically emitted into the atmosphere, rather than being utilized.

In many deep coal mines, methane concentrations in the mine air cannot be maintained at safe levels through ventilation alone without reducing coal production. Coal mine operators seek to maximize the amount of coal they can safely produce by employing additional methane removal techniques to supplement ventilation. These systems are quite common; for example, 100 state-owned underground mines in China, 18 Polish mines, at least 145 Russian and Ukrainian mines, and about 35 U.S. mines use some type of advanced methane recovery technique (JP International, 1990; Pilcher et al., 1991; Zabourdyaev, 1992; USEPA, 1993a). Mines in many other countries -- including Czechoslovakia, Germany, Canada, the United Kingdom, Japan, Australia, South Africa and India -- also use these techniques.

The most common of these techniques are performed during mining operations (as opposed to pre-mining degasification), and include vertical gob wells drilled from the surface and boreholes drilled from in-mine workings into gob areas. Enhanced Gob Well Recovery will improve the efficiency of existing recovery systems and expand the use of these techniques. Based on reported emissions data from a variety of countries, it appears that anywhere from 10 to 50 percent of the total methane emissions may be recovered with these technologies, depending upon the site-specific geologic conditions, and the design of the degasification program.

Recovery Technology Description

The two techniques described here are cross-measure boreholes and vertical gob wells. These techniques are carried out in conjunction with active mining operations, and, as shown in Figure 2, they recover gas from the caved-in or "gob" area. Removing methane from the gob area can be technically complex and must be integrated with mining operations. Because the gob area is located within the mine and is surrounded by ventilated mine workings, medium-quality gas is typically produced using these techniques.

In-Mine Boreholes: Boreholes have been used in coal mining since the 1800's. This technology consists of drilling boreholes from the mine workings into unmined areas of the coal seam and surrounding rock. Cross-measure boreholes, angled into the rock and coal strata above and below the mine workings, are used to recover methane from the gob areas. These boreholes are typically tens to hundreds of meters in length. The boreholes

are connected to an in-mine vacuum piping system, through which recovered methane is transported out of the mine (USEPA, 1990).

To maximize gas production the boreholes are operated under negative pressure, and in the process mine air is drawn into the gob area and ultimately into the gas stream. The quality of gas recovered will vary greatly depending on such factors as local geology, coal rank, and the efficiency of the recovery system. Previous experience indicates that medium quality gas (300-800 Btu/cf; 11-30 MJ/m^3) will be recovered. Total methane production will vary according to local factors and the length of the borehole. Various experiments in the U.S. have yielded production rates of 800 m^3/day to 2,800 m^3/day for boreholes of 100 to 200 meters in length (Garcia and Cervik, 1985; Baker et al., 1986). Typically, 20 to 50 percent of the methane contained in the gob area may be recovered through the use of in-mine boreholes (USEPA, 1990).

Japan and other countries practice a variant of this method of gob well recovery (Higuchi, personal communication). When a longwall panel (typically 150-250 m wide and several hundred meters long; 500-825 ft by 3000 ft) is completed, the resulting collapsed gob area is sealed to reduce methane leakage into the mine workings. A steel pipe is inserted into this sealed area and connected to an in-mine piping system enabling large quantities of methane to be recovered.

Vertical Gob Wells: A second method of removing the methane from the gob area is to drill vertical wells into the gob from the surface. Prior to mining, wells are drilled to a point 2 to 15 vertical meters above the coal seam (USEPA, 1990). As the working face passes under the well, the methane-charged coal and rock strata collapse to form the gob. The methane can be recovered under vacuum, rather than being released into the mine workings. The main advantage of this technique is that it avoids the difficulties of working in the mine, and possibly interfering with the mine operations. However, the use of vertical gob wells requires relatively advanced drilling techniques and may be difficult to integrate with multiple seam coal extraction.

Typically, the gas quality is similar to that of the in-mine systems, although it may be easier to produce high quality methane using vertical gob wells. As with in-mine boreholes, surface gob wells can be operated under negative pressure, drawing mine air into the gob and diluting the recovered methane. Through careful monitoring of the gas quality, and adjustment of the vacuum pressure, it is possible to maintain a higher and more consistent gas quality (one company's mines in Alabama, U.S., produce gas with over 95 percent methane from the gob wells) (Dixon, 1989). Over time, the quality will decline as air from the mine workings seeps into the gob area. Vertical gob wells alone may recover 30 to 40 percent of the methane contained in the gob area (USEPA, 1990). Typical production figures are 2,800 m^3 per day (100,000 cf), but are highly dependent on site-specific factors (Baker at al., 1988; USEPA, 1990). One mining operation in Alabama, U.S., recovers 849,000 m^3 per day from 80 surface gob wells (Dixon, 1987).

The choice between in-mine and surface recovery techniques depends upon site-specific factors that affect how cost-effective and appropriate these two techniques are for a particular mine. These factors include mine depth, mining method, drilling costs, availability of technology, surface activities, and terrain.

Where the techniques described above are already in place, it is often possible to increase the recovery efficiency and improve gas quality through improved drilling techniques, improved pumping and in-mine piping systems, and the use of more advanced monitoring and control systems.

Drilling Techniques: Inappropriate drilling technology can slow the drilling of gob wells and boreholes to the point where it is no longer feasible to implement these technologies. However, adequate technology currently exists, and is in use in many countries. Where improvements would be useful, those countries with oil and gas industries may be able to adapt existing drilling capabilities; otherwise this technology must be imported, raising project costs. Drilling improvements may include the use of diamond bits for rock, and the capacity to drill bore holes with larger diameters and longer lengths.

In-Mine Piping: In some mines, the overall quality of the in-mine piping system can be improved to reduce leakage. One important improvement is to ensure the integrity of the piping by installing safety devices to shut down the system in the event of mining accidents. In some cases, increasing the capacity of the piping system will increase the quantity of methane that can feasibly be recovered.

Pumping: Gas pumps with higher pressures and greater capacities increase the efficiency of methane recovery. In general any improvements in reliability and lifetime will be beneficial.

Monitoring: The placement and spacing of boreholes and vertical wells is extremely important for the effectiveness of a recovery program. Monitoring the recovery system in operation can also improve the efficiency of the system. Both of these important factors involve relatively low-technology solutions. For example, each borehole can be equipped with a shutoff device that activates when the gas quality drops below 25 percent CH_4. Many monitoring techniques are currently available and in use.

Utilization Technology Description

There are four main options for utilizing medium quality gas: on-site power generation with turbines, on-site power generation with internal combustion engines, sale to a distribution system, and industrial use in boilers. In each case, the sale or direct use of energy can often justify the initial investment in generating equipment. The anticipated gas flow rate and gas quality (e.g., impurity levels and methane concentration) are particularly important in selecting the appropriate utilization option.

On-site Gas Turbines: Gas turbine systems can use medium quality gas to generate power for on-site use or for sale to nearby electricity users or supply companies. Selection can be made from among several gas turbine system configurations, depending on factors such as energy needs, technical capabilities, and capital availability.

Simple cycle gas turbine systems can operate with efficiencies ranging from 15 to 40 percent, increasing in efficiency as size increases (Williams and Larson, 1990). Combined cycle turbine systems use the exhaust heat from a gas turbine to produce steam in a boiler, which is then used to power a steam turbine. Alternatively, or in addition, waste

heat can be used for various local heating needs (i.e., co-generation). When combined with a heat recovery system, energy efficiencies can exceed 80 percent. Energy efficiencies in the region of 50 percent can be achieved in combined cycle systems without heat recovery.

Gas turbine systems have certain properties which make them a particularly attractive utilization option for coal mines: 1) turbines come in a range of sizes, depending on the required generating capacity; 2) the turbine combustion process is continuous, which results in a high combustion efficiency and greater tolerance to deviations in fuel quality; and 3) waste heat from the turbines can be used for industrial purposes, such as coal drying at the mine. Gas turbines usually require higher gas flows in order to be economical, and typical applications at coal mines would use one or more 1 to 5 MW turbines (Sturgill, 1991). Gas turbines are running on medium quality mine gas in Australia, China, Germany, and Japan.

On-site Internal Combustion Engines: Internal combustion (IC) engines provide an alternative method for burning medium quality mine gas for power generation. A stationary engine can turn a generator which produces electric energy, with operating efficiencies ranging from 25 percent to 35 percent. With a heat recovery system, energy efficiencies can reach as high as 80 percent (Williams and Larson, 1990). IC engines are widely used to generate power from medium quality gas, and they tend to be better suited than turbines to low gas flows or irregular use. Although variations in methane concentration previously caused some problems with the use of mine gas in IC engines, modern integrated control systems allow fluctuations in gas quality to be accommodated in the operation in the engine (Pilcher et al., 1991). IC engines are available in sizes from around 30 kW up to several MW, but are typically rated at several hundred kW.

Gas Distribution System: In developing countries, as well as some other regions, medium quality mine gas can be distributed in residential and commercial gas supply networks and used for cooking and heating. Many mines in China, for example, currently transport medium quality methane short distances to residential consumers (JP International, 1990). The system can be very simple, consisting of pipes and rudimentary stoves which can burn natural gas. High efficiency gas burners will use fuel more efficiently and will also reduce the emissions of uncombusted methane. Care should be taken in the construction of new pipelines so that leakage is minimized.

In some countries, such as Poland, it may also be possible to distribute coalbed methane in low-methane natural gas (LMNG) or coke-oven gas pipeline systems (Pilcher et al., 1991). These medium quality gas pipelines are extremely attractive because they can be used to transport gas that would not otherwise be considered "pipeline quality," (e.g., pipeline quality gas must be 95 percent methane in the U.S.) In general, these types of systems transport gas that is 50 to 70 percent methane.

Industrial Use: Medium quality gas may also be used as a combustion fuel for industrial boilers. The gas can be supplied to nearby industries and used on its own or in conjunction with other fuels in a boiler. Medium quality methane from coal mines is used by local industries in several countries, including Czechoslovakia, Poland, and Ukraine. The use of medium quality gas may require minimal conversion of existing boiler equipment, but in many cases requires no significant changes.

Costs

Preliminary figures for the costs of recovery and utilization options are presented below. The prices are U.S. figures and do not reflect the added cost of importing technology, lower labor costs in developing countries, or other local factors. All costs are in U.S. dollars.

Recovery Costs: Recovery costs will vary depending on the recovery technique being used and various site-specific factors such as mining depth and coal permeability. Per well recovery costs are presented below for vertical gob recovery projects. The full costs associated with hypothetical U.S. vertical gob well and cross-measure borehole projects are also summarized. The costs are based on U.S. conditions and U.S. state-of-the-art technology. Simpler technologies may require less capital investment, but may also incur larger operating costs. Furthermore, improvements in existing technology may be significantly less expensive than indicated by the costs below.

- Vertical Gob Wells. Exhibit 4-4 summarizes the potential range of capital costs on a per well basis for vertical gob wells in various U.S. coal basins. The number of wells drilled by a given mine will depend on site specific conditions. In addition, the capital costs for vertical gob wells vary between and within coal basins due to differences in well depths (drilling costs), equipment costs, and costs for surface rights (which can vary significantly on a site-specific basis depending on terrain and land use in the area).

  Vertical gob wells are assumed to have fixed annual operating costs associated with recovering -- but not utilizing -- methane. Recovery costs include all manpower, materials, and power costs for the operations, maintenance, and administration of producing wells. The likely range of operating costs for vertical gob wells is $4,000 to $8,000 per well (ICF, 1992).

  Project costs for hypothetical methane recovery projects using vertical gob wells in different U.S. coal basins have been estimated by the U.S. Bureau of Mines (Baker, 1988). These costs are for complete methane recovery projects associated with five years of coal mining. Specific characteristics of the projects, such as the depth of the wells, the number of wells per longwall panel, the rate of mining, and the productive life of the wells, were assumed to vary by coal basin. Estimated project costs include all planning, site development, equipment, drilling and subsequent operating costs, and general overhead for each project. These costs include only the recovery portion of the project. Exhibit 4-5 summarizes the total costs of these hypothetical projects in the selected coal basins (Baker, 1988). No gas production values are provided, so the USBM study cannot be used to determine production costs on a $/mcf basis.

  Based on potential capital and operating costs, however, and with some assumptions about gas production over the life of the wells, it is possible to make rough estimates of methane recovery costs in terms of $/mcf. In general, the costs for vertical gob well recovery could range from a low of $0.50/mcf to levels of $3.00/mcf or higher. Some U.S. vertical gob well projects have reported costs on the order of $0.75/mcf to $1.00/mcf, not including the value of cost savings in the mining operations.

Exhibit 4-4
Capital Costs for Gob Wells (per well costs)

Basin	Low	Medium	High
Central Appalachian	$80,000	$130,000	$190,000
Northern Appalachian	$60,000	$110,000	$170,000
Illinois	$50,000	$100,000	$160,000
Warrior	$90,000	$140,00	$200,000
Western	$100,000	$150,000	$210,000

Note: Capital costs for gob wells include all costs for surface drilling rights, site development and preparation, and costs for drilling, completing and equipping the wells.

Sources used to develop ranges: 1) USEPA 1990; 2) ICF Resources, 1990b; 3) Baker, Garcia, and Cervik *Cost Comparison of Gob Hole and Cross-Measure Borehole Systems to Control Methane in Gobs* (USBM Report of Investigations, 1988).

Exhibit 4-5
Total Vertical Gob Project Costs in Various U.S. Coal Basins

Location	Capital Cost ($ millions)	Operating Cost ($ millions)	Project Cost ($ millions)
Central Pennsylvania	1.0	0.3	1.3
Northern West Virginia	1.1	0.3	1.4
Southern Virginia	6.1	0.2	7.2
Northern Alabama	3.8	0.5	4.2

Note: Costs are undiscounted and represent the sum of all costs incurred over the life of the project, which was assumed to be five years and one year of development.

Source: Baker, 1988.

- Cross-Measure Boreholes. In general, cross-measure borehole recovery projects will have lower capital costs but higher operating costs than vertical gob recovery, as a result of the greater complexity of drilling within the mine. Cross-measure boreholes are not a common degasification technique in the United States, although they are widely used in other countries.

No costs from actual U.S. cross-measure boreholes projects have been published. In general, costs for in-mine piping systems will be similar to those for horizontal boreholes, or about $5/foot of pipe (ICF Resources, 1990a). Drilling costs may be lower than for horizontal boreholes, however, because the holes are shorter and less powerful drilling equipment can be used. On the other hand, the shorter cross-measure boreholes require proportionately more setup time and, because they are drilled through hard strata rather than coal, could have slower penetration and higher drill bit wear rates.

The U.S. Bureau of Mines has investigated the costs of hypothetical cross-measure boreholes systems in four U.S. locations: central Pennsylvania, northern West Virginia, southern Virginia, and northern Alabama (Baker, 1988). Costs for each area were specific to anticipated local methane production rates and to local labor and material costs. The USBM benefitted from some information provided to them by mining operators in these regions. However, this study only estimated investment and operating costs over a five-year period for a system with fixed methane capacity. No estimate of actual production from the boreholes over time was provided. Therefore, it is not possible to evaluate the economic viability of such a system using the USBM costs alone. The results of the USBM analysis are summarized in Exhibit 4-6.

Exhibit 4-6
Total Cross-Measure Borehole Project Costs in Various U.S. Coal Basins

Location	Capital Cost ($ millions)	Operating Cost ($ millions)	Project Cost ($ million)
Central Pennsylvania	0.3	1.2	1.5
Northern West Virginia	0.4	1.2	1.6
Southern Virginia	1.8	3.6	5.4
Northern Alabama	1.2	1.5	2.8

Note: Costs are undiscounted and represent the sum of all costs incurred over the life of the project, which was assumed to be five years and one year of development.
Source: Baker, 1988.

Utilization Costs: Utilization costs are presented for four options: power generation using gas turbines; power generation using IC engines; pipeline injection; and use in industrial boilers. The costs are presented in U.S. dollars, based on U.S. applications and technology. Costs in other countries could vary significantly depending on specific conditions.

- Power Generation in Turbines. The cost of using methane from coal mines in gas turbines could range from $0.04/kwh to $0.07/kwh or higher. Key variables are the size of the turbine, its efficiency, and the market for waste heat. The cost of fuel

supplied to the turbine can also be an important cost item; where coal mine methane is used, however, it is assumed that the only fuel costs are those associated with transporting and preparing the methane for use.

The equipment required for on-site power generation includes a turbine generator and the gathering lines between the wellhead and the generator. For off-site sale of power to a utility, transmission line upgrades or an interconnection facility may be needed to feed power generated at the mine into the main transmission line. A range of capital costs for power generation are shown in Exhibit 4-7.

Exhibit 4-7
Capital Costs for Power Generation

Equipment	Low	Medium	High
Gathering lines between wellhead and generator	$10,000 per well	$25,000 per well	$40,000 per well
Gas Turbine[1]	$800 per kw installed	$1,000 per kw installed	$1,200 per kw installed
Off-site Transmission[2]	$100,000 per project	$300,000 per project	$500,000 per project

1 Both IC engines and gas turbines were examined in the analysis. However, for sizes above 4 MW, it was assumed that a mine would prefer a gas turbine. Since projects less than 4 MW were not shown to be profitable, IC engine costs are not included here.
2 Off-site transmission costs are for costs of an interconnection facility and/or line up-grades. The low costs assume that an interconnection facility would not be needed and that line up-grades would be minimal.
Sources used to develop ranges: 1) Carl Sturgill *Power Generation: On-site Use and Sale to Utilities* (Prepared for USEPA April, 1991); 2) "Opportunities for Power Generation from Methane Recovered During Coal Mining" (Draft Report Prepared for USEPA by ICF Resources, 1990a); 3) Bill Wolfe and Greg Maxwell, "Commercial Landfill Gas Recovery Operation: Technology and Economics" in Klass, *Energy from Biomass and Wastes XII* (Institute of Gas Technology, 1990); 4) Personal Communication with Allison Gas Turbines.

- Power Generation in IC Engines. The cost of generating power using IC engines is likely to be slightly lower than for turbines. In general, the capital costs of IC engines are lower, with estimates ranging from $350 to $500 per kilowatt (Soot, 1991; Anderson, 1991). Operation and maintenance costs are generally higher than for turbines, however, typically around $0.02/kwh.

  IC engines are best suited to smaller power generation projects, with typical sizes ranging from a few hundred kilowatts to 2 or 3 MW. Project financial analyses in the U.S. have indicated that the most economic coal mine generation projects would range in size from 4 MW to 20 MW. For projects of greater than 4 MW it appears that mines would prefer gas turbines.

- Pipeline Distribution. The costs associated with pipeline distribution will include: (1) the gas gathering system, between the wellheads and the central compression/processing location; (2) compression; (3) processing; (4) enrichment, if necessary; and (5) the transportation system from the compression point to the

commercial pipeline. Capital and operating costs for each of these components are discussed below, based on U.S. experience.

The capital costs for gathering lines, compression, and processing and treatment of the recovered gas are summarized in Exhibit 4-8. As the table shows, for certain system components capital costs are presented in terms of the gas production ($/mcf) because gas production will determine the size of these components.

Exhibit 4-8
Capital Costs for Pipeline Injection All Equipment Needed Between the Wellhead and a Central Compressor

Equipment	Low	Medium	High
Gathering lines between wellhead and Central Compressor	$10,000 per well	$45,000 per well	$100,000 per well
Compressor(s)	$180 per mcf/day	$190 per mcf/day	$200 per mcf/day
Processing/Treatment	$10 per mcf/day	$20 per mcf/day	$30 per mcf/day

Note: Capital costs for compressor and processing/treatment are based on maximum gas production per day. Equipment costs for enrichment of gob gas are included in the total $/mcf operating costs.

Sources used to develop ranges: 1) USEPA 1990; 2) *A Technical and Economic Assessment of Methane Recovery from Coal Seams* (Prepared for USEPA by ICF Resources Inc., 1990b); 3) *The Potential Recovery of Methane from Coal Mining for Use in the U.S. Natural Gas System* (Prepared by ICF Resources, Inc. for USEPA, 1990); 4) W.W. Sykes "Gathering Systems Concepts-Planning, Design and Construction" *Proceedings of the 1989 Coalbed Methane Symposium* (The University of Alabama at Tuscaloosa); Warren R. True "Pipeline Economics" *Oil & Gas Journal Special* (November 26, 1990).

In addition to capital costs, there will also be operating costs associated with compression and processing, as shown in Exhibit 4-9. These operating costs are based on annual gas production.

The capital costs for the gas pipelines that transport gas from the point of compression to the commercial pipeline are presented in terms of their cost per mile. Costs will vary between or within coal basins depending primarily on terrain and land use patterns. Exhibit 4-10 presents a range of costs, which reflects pipeline construction experience in several U.S. coal basins.

Finally, in some countries or at some mines it may be necessary to enrich gob gas before it can be injected into pipelines. This will be the case in situations where medium quality pipelines do not exist and where the mine cannot maintain pipeline quality gas through monitoring and management of the gob recovery system. Enrichment costs are quite uncertain and there has been limited experience with the

Exhibit 4-9
Operating Costs for Pipeline Injection
All Equipment Needed Between the Wellhead and a Central Compressor

Equipment	Low	Medium	High
Compressor(s)	$.06 per mcf	$.07 per mcf	$.08 per mcf
Processing/Treatment	$.02 per mcf	$.03 per mcf	$.04 per mcf

Sources used to develop ranges: 1) ICF Resources 1990a; 2) Warren R. True "Pipeline Economics" *Oil & Gas Journal Special* (November 26, 1990).

Exhibit 4-10
Capital Costs for Pipeline Injection
Gathering Lines to Main Commercial Pipeline

Basin	Dollars per Mile		
	Low	Medium	High
Central Appalachian	$650,000	$750,000	$850,000
Northern Appalachian	$450,000	$550,000	$650,000
Illinois	$200,000	$300,000	$400,000
Warrior	$500,000	$600,000	$700,000
Western	$650,000	$800,000	$950,000

Sources used to develop ranges: 1) ICF Resources 1990; 2) Warren R. True "Pipeline Economics" *Oil & Gas Journal Special* (November 26, 1990).

enrichment of mine gas. Current estimates for these costs range from $1.00/mcf to $2.00/mcf for various enrichment approaches. Some new technologies are under development that could have lower costs of $0.50/mcf, but these have not been demonstrated.

- Industrial Boilers. The cost of adding capacity for gas combustion at industrial facilities will depend on the site and the retrofit requirements. Retrofits for full boiler conversion (to 100 percent capacity with gas) can range from $1,500/kJ to $3,000/kJ, with sizes ranging from 40 kJ to 250 kJ (Glickert, 1992). It would thus cost about $200,000 to convert an average sized boiler rated at 120 kJ to gas. Additional costs would

include the gathering of the gas, any necessary compression and processing, and transportation from the point of compression to the boiler site.

Availability

All of the above technologies are commercially available and are in use in various countries. In countries where the equipment is not locally manufactured it may be possible to import used equipment or modify existing equipment.

Applicability

Enhanced gob well recovery, when combined with suitable utilization options, is an appropriate strategy for mines where more advanced techniques are not already in use or are found to be impractical. In many cases, recovery and utilization techniques will build upon existing practices.

Medium quality gas can be used in many countries for a wide range of utilization options. Some countries, especially developed countries, may have gas quality standards which prohibit the distribution of a medium quality gas for residential fuel use and therefore reduce the overall marketability of non-pipeline quality gas. In these countries, power generation or on-site industrial uses (e.g., coal-drying) may be the most feasible options. In countries with fewer restrictions on medium quality gas use, the full range of options may be applicable.

Barriers

Barriers to the development of these recovery and use options will depend on the country and the technology used, but frequently include: investment capital shortages, lack of resources, difficulties in maintaining gas quality, and regulatory or institutional barriers related to a country's coal mining or energy sector. To address the technical difficulties, methane content can be carefully monitored and methods to compensate for heat value variations can be implemented. Overcoming regulatory, legal or institutional barriers may require changing legislative or legal frameworks. To the extent that particular policies have reduced the economic attractiveness of projects, moreover, it may be necessary to remove energy subsidies, rationalize prices, and/or provide incentives to encourage methane utilization.

Benefits

In addition to the reduction of methane emissions into the atmosphere, other benefits will be seen from the recovery and use of coalbed methane:

- Mine safety will be improved. Because methane drainage is improved with the enhanced gob well recovery strategy, the methane concentration in the mine is reduced, which may result in fewer methane-related accidents at mines.

- Ventilation costs will decrease. One mining company in Alabama, U.S. has been able to increase coal production while decreasing ventilation costs by using improved methane recovery techniques. This mine has estimated that capital expenditures of $15 million would have been required for additional ventilation shafts and fans necessary to ventilate the same amount of methane which is now being recovered at a profit (Dixon, 1989).

- A more efficient energy source will be used. Methane can be a more efficient fuel than coal, particularly in residential cooking and heating end-uses. Many countries, including China, use coal extensively for residential purposes (JP International, 1990). Coal combustion cannot respond efficiently to low load operation, nor is it easy to start and stop operation as the heating load swings. In comparison, gas can respond instantaneously to heat demand and can be used for low load operation, thereby providing a more efficient fuel source.

- Less SO_2, NO_x, and particulate emissions will be produced by the displacement of coal with gas. Natural gas combustion produces virtually no SO_2 emissions, no particulate emissions, and lower NO_x emissions. A 10 percent increase in gas use in a retrofitted coal-fired burner will result in a 10 percent decrease in SO_2 and particulate emissions. In many countries, expanded natural gas use is being aggressively pursued in response to serious local air pollution problems (Pilcher et al., 1991; Bibler et al., 1992).

Enhanced Gob Well Recovery and Utilization

- up to 50% methane reduction
- improved mine safety
- improved mine productivity
- competitive with alternative gas sources
- augments existing practices
- technology currently available
- clean energy source

3 Pre-Mining Degasification

Pre-Mining Degasification is a strategy that produces methane from targeted coal seams prior to active mining. Unmined coal of high rank, such as bituminous coal, may contain as much as 10 to 20 cubic meters of methane per metric ton of coal (Kim, 1977). Additionally, larger quantities of methane are stored in the surrounding rock strata. During mining operations, this methane can also flow into the mine workings where it may create a severe safety hazard. Conventional methods for removing mine gas dilute the gas and vent it into the atmosphere. Pre-mining degasification recovers this otherwise wasted resource before mining begins, thereby increasing utilization options and reducing the methane emissions associated with future mining activities.

Recovery Technology Description

The two primary recovery technologies are in-mine horizontal boreholes and vertical wells drilled from the surface. Both techniques can be implemented anywhere from six months to several years prior to the commencement of active mining operations, depending upon the amount of degasification required and various geologic factors such as the methane content and permeability (USEPA, 1990). Drilling horizontal boreholes is an in-mine technique; vertical wells are drilled from the surface. Both techniques remove methane from areas of the coal seam that are not yet exposed to ventilated mine workings, and as a result typically produce higher quality gas than the "Enhanced Gob Well Recovery" approach. Furthermore, unlike gob gas recovery, pre-mining degasification does not depend on active mining operation to stimulate methane emissions. As a result, gas production can be more reliable over longer periods of time.

Horizontal Boreholes: Horizontal boreholes have been used extensively for methane drainage, especially in the United States and some European countries. These boreholes are drilled into the unmined coal seam itself, in contrast to cross-measure boreholes which are angled up into coal and rock strata at the boundary of the gob area (see "Enhanced Gob Well Recovery"). The boreholes are typically a few hundred meters long. All horizontal boreholes are drilled and produce methane prior to mining.

In general, horizontal boreholes are longer than cross-measure boreholes and therefore require more powerful drilling equipment. They can be drilled in two ways: 1) into the longwall panel, or 2) into mine development areas prior to the preparation of panels for mining. In the first case, horizontal boreholes are drilled across the width of a developed longwall panel and typically produce gas for a period of several months until they are mined through. These boreholes are generally a few meters shorter than the width of the longwall panel. In the second case, much longer boreholes can be drilled into the coal reserves from development headings and drain gas for several years in advance of mining.

As with cross-measure boreholes, horizontal boreholes are connected to an in-mine piping system often operated under negative pressure to remove the gas. However, the gas quality is higher, typically over 95 percent methane. Production volumes vary with local geology and borehole length, and have ranged from 700 to 5,000 m^3/day (Trevits and Finfinger, 1986; Baker et al., 1986; Kline et al., 1987). Useful production lifetimes are

reported to be from six months to several years. The production lifetime is limited by how far in advance the mine is developed or the longwall panels are defined and laid out.

Horizontal boreholes are not as effective for degasification when coal seams are steeply inclined or have very low permeability, as is the case in many of the world's coal producing countries such as Japan and China. In these countries, pre-mining degasification is carried out using cross-measure boreholes drilled from a gallery under the coal seam (Higuchi, personal communication). Boring stations are typically located every 50 to 100 m (160 to 330 ft) along the gallery, and a number of boreholes are drilled from each station. Borehole spacing depends on coal and geologic characteristics, and they are usually spaced 10 to 25 m (30 to 80 ft) apart.

Vertical Wells: Degasification using vertical wells drilled from the surface is a more recently developed technology that has been commercially demonstrated in independent gas production and coal mining operations. Vertical degasification wells are similar to conventional oil and gas wells and are drilled into the coal seam several years in advance of active mining. This technology is more advanced than the use of in-mine boreholes because of the greater depth of drilling, the need to drill through rock rather than coal, and the need to stimulate the reservoir in order to produce gas. Despite this, suitable technologies have been developed and are widely available. The advantages of drilling from the surface include avoiding working in the mine, and the ability to degasify the coal seam many years prior to mining.

Because of the vertical orientation of the well, only a few meters of the coal seam will be exposed (i.e., the height of the coal seam), in contrast to the hundreds of meters exposed to an in-mine borehole. Depending on the permeability of the coal seam this may limit the desorption rate of the methane into the well, thereby limiting overall recovery potential. In order to overcome this, fractures can be induced in the seam by hydraulic fracturing (or stimulation), a process in which a sand and water mixture is pumped under pressure into the wellbore. This fracturing process increases the permeability of the seam by creating pathways through which the gas can flow.

Care must be exercised in the design and execution of hydraulic fracturing to ensure that the future mineability of the coal is not jeopardized. Many coal miners are concerned that uncontrolled fracturing could weaken roof rocks and reduce mine safety when the area is mined through. Experiments in U.S. mining regions have shown that hydraulic fractures can be controlled and should not adversely affect future mining (Deul, 1986). In fact, several coal mines in the U.S. are using vertical degasification and hydraulic fracturing to recover methane in advance of mining (Consolidation Coal Company, 1992; Oxy USA, 1992). When these technologies are used in other basins, however, care must be taken to protect the integrity of the coal.

After fracturing, water must be removed from the coal formation in order to produce gas. Removing water (which is naturally occurring and also added during hydraulic stimulation) decreases the hydrostatic pressure on the coal seams, thereby allowing gas to desorb from the coal. Coalbed methane wells usually produce substantial quantities of water during the first year of production, after which water production decreases and stabilizes over a long period of time. Methane production peaks after the initial dewatering, and declines slowly (10-20 percent/yr) over the lifetime of the well (USEPA, 1990). Recovered water

must be disposed of by direct land application, discharge into streams or rivers, deep well injection, or in evaporation pits.

The quality of produced water varies depending on geologic characteristics; in some cases the water is potable, while in other cases it has high concentrations of dissolved salts and other solids. The quantity and quality of the produced water, as well as applicable regulations, will determine what disposal or treatment method is required. Where large quantities of water, poor quality, or local regulations necessitate advanced treatment (such as deep well injection or desalination) the disposal costs can be substantial.

Pre-mining degasification using vertical wells may be a very effective method of reducing the methane content of coal seams and could consequently reduce the emissions from mining operations. Recovery rates of up to 70 percent over a 10 year period have been documented using this technique (USEPA, 1990). Gas quality is high (over 90 percent methane) because the methane is not diluted with ventilation air. Production rates depend on reservoir and geological factors, the success of hydraulic stimulation, coal rank, and well spacing.

Where the techniques described above are already in place, it is often possible to increase recovery efficiency through improved drilling techniques, improved pumping and in-mine piping systems, and the use of more advanced monitoring and control systems. These improvements have been discussed above (see "Enhanced Gob Well Recovery").

Utilization Technology Description

Pre-mining degasification typically yields high quality gas, with a heat value greater than 32 MJ/m^3 (950 Btu/cf). The recovered gas can be used in any of the applications described above for medium quality gas (in "Enhanced Gob Well Recovery"), including electricity generation, gas distribution systems, and industrial heating. High quality gas will be a preferred fuel because it does not cause some of the technical problems associated with burning fuel with a lower heat value. In addition to the previously described uses, gas that consistently contains 95 percent methane is "pipeline quality," and can be sold in high quality pipeline systems (e.g., in the U.S.). This high quality gas may be transported long distances or used as a chemical feedstock, in addition to its other uses.

Pipeline Distribution: Conventional natural gas is generally processed, gathered, and compressed on its way from the wellhead to the pipeline. As with conventional gas production, methane recovered from coal mines will also require these steps, although the specifics of these activities may differ slightly.

Processing involves the removal of impurities. For most coalbed methane, the principal contaminants are water and sand, which can be easily removed. Some coal seams may also contain significant concentrations of CO_2, which must also be removed from the gas prior to pipeline injection. In cases where rare trace gases (e.g., helium) are found, separation techniques can be used to remove the gases and these by-products can then be sold. Water and sand are removed at the wellhead; trace gases and CO_2 are usually separated at a central processing location after the gas is gathered. Gathering lines are laid between the wellhead and the processing plant of pipeline.

The gas is compressed and propelled through the gathering lines to the pipeline. The required compression is a function of the compressor's inlet pressure, outlet pressure, and rated capacity. Pressures typically range from 200 to 800 psi (ICF Resources, 1990c).

Chemical Feedstock: Methane is a feedstock (i.e., a raw material) in several important chemical processes, such as the synthesis of ammonia, methanol, and acetic acid. In very gassy areas, pre-mining degasification can recover the large quantities of consistently high quality methane required to supply chemical plants. The smallest plants typically require about 5 to 10 million standard cubic feet per day (280,000 cubic meters)(Xytel Technologies, 1992), although smaller plants may be feasible. Alternatively, coalbed methane from several mines could be collected at a central location in order to meet this required volume.

Costs

Total project costs will include both the costs associated with methane recovery and the costs associated with gas utilization. A range of costs associated the two pre-mining recovery technologies -- vertical wells and in-mine boreholes -- are summarized below. Many of the utilization costs have already been presented in the discussion of gob well costs, but those costs associated with unique utilization options, such as chemical feedstock, are also presented in this section.

Recovery Costs: The costs associated with recovering methane in advance of mining using vertical wells and in-mine horizontal boreholes are summarized below. These costs are based on U.S. experiences and technology and they are presented in U.S. dollars.

- Vertical Wells. The costs associated with recovering methane in advance of mining using vertical wells are higher than for gob wells, because these wells require additional completion and hydraulic stimulation and because it is necessary to dispose of the produced water. As with vertical gob wells, the capital costs will vary between and within basins depending on the depth of the wells and site specific conditions, which can influence the completion method used, the type of stimulation, the amount of water produced, and the method of water disposal required.

  Exhibit 4-11 summarizes the capital costs associated with vertical well drilling, completion and stimulation in the United States. The costs of surface rights and site development are also included in these figures. The costs associated with coal basins in the eastern United States tend to be lower as compared to western basins because the eastern basins are usually shallow.

  The operating costs of vertical wells will depend on the number of wells in operation and on annual gas and water production. The per well recovery costs are associated with the operation, maintenance and administration of the producing wells. They should be quite similar to those for vertical gob wells and are assumed to remain fixed over the lifetime of the well regardless of the amount of methane recovered. The operating costs could range from $4,000 per well to $8,000 per well, depending on site specific conditions (ICF, 1992).

Exhibit 4-11
Capital Costs for Vertical Wells (per well costs)

Basin	Low	Medium	High
Central Appalachian	$60,000	$140,000	$225,000
Northern Appalachian	$50,000	$125,000	$205,000
Illinois	$45,000	$115,000	$195,000
Warrior	$90,000	$190,000	$290,000
Western	$320,000	$450,000	$580,000

Note: Capital costs for vertical wells include all costs for surface drilling rights, site development and preparation, drilling, completing and equipping the wells and hydraulic fracture treatment.

Sources used to develop ranges: 1) USEPA 1990; 2) *A Technical and Economic Assessment of Methane Recovery from Coal Seams* (Prepared by ICF Resources, Inc. for USEPA, 1990); 3) *The Coalbed Methane Resource and the Mechanisms of Gas Production* (Gas Research Institute, 1989); 4) *Economics and Financing of Coalbed Methane Ventures* (Ammonite Resources, 1991); 5) Hunt and Steele *Coalbed Methane Technology Development in the Appalachian Basin* (prepared for Gas Research Institute, 1991); *Market Study of Future Coalbed Methane Activity* (Spears and Associates, 1991).

Vertical wells typically produce significant quantities of water during the first months of operation, which must be disposed of in an environmentally safe manner. Water disposal costs will vary for individual mines depending on geologic conditions and applicable environmental regulations.

The capital costs for water disposal systems can range from $0.30/barrel of water to $3.30/barrel of water. The low end of this range is associated with stream discharge with little treatment, a practice that is sometimes practiced in the Warrior basin. Medium costs of $0.90/barrel of water would be associated with stream discharge with treatment, or land application with treatment, as is practiced in the Warrior basin. The high end of this range is associated with the cost of disposal wells or evaporation pits, which are often necessary, as is the case in the Western U.S.

The operating costs for water disposal can vary significantly depending on the disposal method used. Generally, the stream or river discharge disposal method has the lowest operating costs. Evaporation pits, surface application, and stream or river discharge with treatment, deep well injection and commercial off-site disposal have higher operating costs. Operating costs for water disposal can range from $0.40/barrel of water to $1.00/barrel.

The methane production costs (in $/mcf) will vary significantly depending upon numerous site-specific factors, such as depth of drilling, completion and stimulation methods used, water disposal requirements, and gas production. Low costs could be

in the range of $1.00/mcf, and high costs could reach $3.50/mcf or more. As production costs increase, project economics become less attractive.

- In-Mine Boreholes. The costs for in-mine horizontal boreholes have been estimated by the U.S. Bureau of Mines and others (Baker, 1986; ICF Resources, 1990a). The total system costs associated with several U.S. projects -- including the boreholes, methane collection system, gas transmission system, and methane sensing system --are reported to range from $25/foot of borehole to $35/foot of borehole. These costs include both amortized investment and system operating costs. Capital and operating costs for drilling alone are reported to range from $10 to $15 per foot of borehole. The cost of in-mine piping systems may be about $5/foot of pipe.

  The costs of in-mine systems will of course be highly site-specific. Conditions within the mine will determine the number of boreholes drilled and their gas production rates. Likely gas production costs could range from $1.00/mcf to $4.00/mcf or higher.

Utilization Costs: The utilization costs for several options -- including power generation with turbines and IC engines, pipeline distribution, and use in industrial boilers -- were summarized in the section on gob well recovery. One additional utilization option may be attractive where high-quality methane is recovered: the use of methane as a chemical feedstock. The costs for this option will include the costs associated with the process, as well as costs related to collecting and transmitting the methane to the point of use. These costs will be highly variable depending upon the feedstock process selected and the amount of gas to be processed.

Availability

All of the above technologies are commercially available, but may not be feasible in certain regions for technical or economic reasons. In countries where the equipment is not locally manufactured, it may be possible to import used equipment or modify existing equipment. Factors affecting applicability and barriers to implementation are discussed in the following sections.

Applicability

Pre-Mining Degasification is an appropriate strategy for very gassy mines where more advanced techniques are already in use, or may be easily introduced. In many cases, recovery and utilization techniques will build upon existing practices.

High quality gas is a valuable energy source or raw material that can be used in many countries. Developed countries, in particular, are likely to have pipeline infrastructures which would allow the distribution of high quality gas for commercial sale and/or residential fuel use. The price for natural gas varies considerably from region to region, however, and can have a large effect on the applicability of commercial sale as an option (including use as a chemical feedstock). Using high quality gas as a chemical feedstock would be attractive for gassy mines in countries with substantial domestic petrochemical markets (e.g., China and India are both increasing their domestic demand for ammonium fertilizers).

Barriers

Barriers to the development of these recovery and use options will depend on the country and the technology used. Frequently encountered barriers include investment capital shortages, lack of local resources, lack of technical experience, low gas prices, and legal or regulatory constraints. Some of the barriers can be overcome through technology demonstration, training, and technical assistance in regulatory development. In other cases, it may be necessary to restructure energy sectors, rationalize energy prices, and provide assistance in the development of viable gas markets. Additionally, because the use of recovered methane as a feedstock requires transport to the point of sale, feasible proximity to commercial users must be considered.

Benefits

In addition to reducing methane emissions into the atmosphere, pre-mining degasification will result in several other benefits:

- Mine safety will be improved. Because methane drainage is greatly improved through pre-mining degasification, the methane concentration in the mine is reduced, which may result in fewer methane-related accidents.

- Ventilation costs will decrease. One mining company in Alabama, U.S. has been able to increase coal production while decreasing ventilation costs by using improved methane recovery techniques. This mine has estimated that capital expenditures of $15 million would have been required for additional ventilation shafts and fans necessary to ventilate the same amount of methane which is now being recovered at a profit (Dixon, 1989).

- A more efficient energy source will be used. Methane can be a more efficient fuel than coal, particularly in residential cooking and heating end-uses. Many countries, including China, use coal extensively for residential purposes (JP International, 1990). Coal combustion cannot respond efficiently to low load operation, nor is it easy to start and stop operation as the heating load swings. In comparison, gas can respond instantaneously to heat demand and can be used for low load operation, thereby providing a more efficient fuel source.

- Less SO_2, NO_x, and particulate emissions will be produced by the displacement of coal with gas. Natural gas combustion produces virtually no SO_2 emissions, no particulate emissions, and lower NO_x emissions. A 10 percent increase in gas use in a retrofitted coal-fired burner will result in a 10 percent decrease in SO_2 and particulate emissions. In many countries, expanded natural gas use is being aggressively pursued in response to serious local air pollution problems (Pilcher et al., 1991; Bibler et al., 1992).

Pre-Mining Degasification

- up to 70% methane reduction
- high quality gas
- long production lifetime
- improved mine safety
- improved mine productivity (up to 25% at gassy mines)
- competitive with other gas sources
- technology currently available
- clean energy source

4 Ventilation Air Utilization

Ventilation air utilization presents an opportunity to use the considerable volume of mine gas that is currently vented into the atmosphere in low concentrations from all underground mines. Developing uses for ventilation air can significantly reduce methane emissions to the atmosphere from coal mining.

The release of methane into the mine workings presents a safety hazard for all deep coal mines, because methane is explosive at concentrations of 5 percent to 15 percent in air. Most countries have regulations which require that methane concentrations be kept below 1 percent. The most common method of achieving this safety level is to dilute the methane through the ventilation of the mine with large fans. Although additional techniques can be used, ventilation is a necessity in all underground mines. As a result, large quantities of air are removed which contain methane at an average concentration of about 0.5 percent methane. At gassy U.S. mines, between 5 and 23 tons of air may be ventilated per ton of coal mined (Skow et al., 1980). Total methane emissions in ventilation air range from 0.5 to 15.0 million cubic feet a day of methane for gassy U.S. mines (Trevits et al., 1991). Recent estimates for the U.S. indicate that the venting of mine gas accounts for 50 to 75 percent of all methane releases from coal mining, and 75 percent of emissions from underground mines (USEPA, 1993a).

Although the methane in ventilation air is dilute, its energy value may still be profitably recovered. Efforts to reduce methane emissions from this source must focus on developing uses for air that contains low concentrations of methane. The utilization techniques described here involve using ventilation air as a supplemental or secondary fuel for the generation of electricity in steam boilers and gas turbines. Depending on its concentration and the generator technology, ventilation air could supply between 7 percent and 15 percent of a generator's energy (or higher if methane concentrations are in excess of 0.5 percent), thereby reducing primary fuel requirements and contributing to the electricity need of the mining operation (ESA, 1991).

Recovery Technology Descriptions

Recovery of the methane is not a factor in this strategy. As noted above, ventilation of the mine will occur as a matter of course in any underground mine, and utilizing the ventilation air should have no negative economic or practical effect on mining operations. Since this utilization option has not yet been demonstrated, however, it is important to design the system in a manner that does not jeopardize the ability of the mine to dilute and remove the methane from the mine workings. In addition, this option must be implemented in a manner consistent with mine safety regulations.

Utilization Technology Description

The utilization option discussed in this section involves substituting low concentrations of methane in air for combustion air in coal-fired boilers or gas turbines. In either case the basic concept is the same: generators obtain energy by burning a fuel/air mixture, with the fuel being coal or gas. Because ventilation air from coal mines contains methane, it has a heat energy value which could reduce the amount of fuel required to create an explosive fuel/air mix of combustion in a boiler or turbine.

For both coal-fired boilers and gas turbines, the ventilation air must be ducted from the ventilation shaft to the generating facility. Preliminary technical analyses indicate that the air supply system can be readily constructed from galvanized steel ducts, typically 7 to 12 feet (2 to 4 m) in diameter (ESA, 1991). Fans and motors will likely be necessary if the supply distance is over 1000 feet (300 m). The energy needs of the fan motors must be balanced against the energy value of the mine gas -- at some point, depending on duct length, capacity, and pressure, more energy will be required to transport the gas to the generating facility than can be recovered during combustion. It appears that this distance is on the order of 3 miles (5 km).

Coal-Fired Boilers: Coal-fired boilers burn pulverized coal mixed with large amounts of combustion air to produce steam, which in turn is used to generate electricity. Typically, 13 pounds of air are needed for every pound of coal that is burned (i.e., a 13:1 mass ratio). This translates to approximately 140 standard cubic feet (4 m^3) of combustion air per hour for each kilowatt (SCFH/kW) of generating capacity, but the ratio will vary with coal type, boiler efficiency, and the amount of excess air used in combustion (ESA, 1991).

Preliminary technical feasibility studies indicate that ventilation air can be transported through the air ducts of most types of boilers without compromising safety or otherwise affecting standard operation. The methane should therefore be easily introduced into the boiler, where it will burn and produce heat. 140 standard cubic feet of ventilation air (i.e., the approximate amount needed to produce 1 kWh of electricity), containing 0.5 percent methane, has a heat value of 700 Btu (740 kJ). Ventilation air containing 0.5 percent methane could provide 7 percent of the boiler's energy (ESA, 1991). Replacing the primary fuel, coal, with methane could also improve boiler economics through reduced fuel purchasing, handling, and preparation costs, less furnace slagging and ash production, and lower emissions of particulates, sulfur dioxide and nitrogen oxides.

Gas Turbines: A gas turbine uses heat obtained from the combustion of a fuel/air mixture to raise the temperature of compressed air. The hot compressed gas powers a turbine which generates electricity. Gas turbines use large quantities of combustion air in the fuel/air mixture, typically 350 SCFH per kW of generating capacity for turbines with capacities between 1 and 100 MW. Based on ventilation air containing 0.5 percent methane, 350 SCFH would provide 1750 Btu/kWh, or about 15 percent of a typical turbine's energy requirements (ESA, 1991).

Because turbines use larger quantities of combustion air than coal-fired boilers, and thus gain a higher energy contribution from ventilation air they are an attractive option for ventilation air use. Additionally, the simpler technology, lower capital and maintenance costs, shorter construction lead times, and the large range in available generating capacities make turbines extremely suitable for use at coal mines.

The applicability of these techniques must be determined by an analysis of many site-specific factors, including the compatibility of the volume of ventilation air with combustion air requirements, the mine operation power requirements and/or local energy markets, and the proximity and design of the generating plant. A discussion of relative energy costs is presented in the following section.

Costs

The underlying factor in choosing to use ventilation air as combustion air is the relative energy cost of supplying ventilation air. If low concentration methane is to replace some percentage of the primary fuel requirements for electricity generation, the ventilation air must be supplied at a lower cost per unit of energy than the primary fuel.

In terms of fuel costs, supplying low quality methane is attractive if the combustion devices are located in close proximity to the mine. In this situation, the capital costs of the ducting should be low and the operating costs associated with running fan motors minimized. For a range of air flows from 2 MMSCFH to 80 MMSCFH (compatible with turbine sizes of 5 MW to 230 MW respectively), costs are estimated to be $0.08 to over $1.60 per MMBtu, depending on the distance and methane concentration (ESA, 1991). To the extent that new ventilation shafts are opened as mining proceeds, it may be necessary to move the fans and ducting every few years, which could increase costs. In comparison to current U.S. costs of $1.50 to $4.00/MMBtu for conventional turbine fuels (e.g., natural gas and #2 fuel oil) the economics of supplying ventilation air to mine-site gas turbines appear attractive in many cases (ESA, 1991).

Energy costs rise when the ventilation air is transported some distance from the mine site. In this situation, higher methane concentrations and flow rates will increase the overall attractiveness of the project. For example, supplying air containing 0.5 percent methane at a flow rate of 40 MMSCFH (compatible with a 285 MW coal-fired boiler) would cost approximately $1.25 MMBtu at a distance of 3 miles (ESA, 1991). In comparison, delivered coal costs are approximately $1.50/MMBtu in the U.S., rising to $1.75- $2.00/MMBtu if costs for preparation, pollution control and ash disposal are included. Exhibit 4-12 shows estimated break-even energy costs for ventilation air use based on duct length, methane content, and air flow.

Exhibit 4-12
Break-Even Energy Costs for Mine Ventilation Air

Distance (miles)	Concentration (% CH_4)	Gas Flow (mmscfh)	2	20	40	80
		Turbine Capacity (MW)	6	57	114	229
		Boiler Capacity (MW)	14	143	286	572
			Break-Even Energy Cost ($/mmbtu)			
< 0.5	0.5		0.8	0.25	0.18	0.13
1.0	0.5		> 1.6	0.55	0.35	0.28
3.0	0.5		> 1.6	> 1.6	1.25	1.25
< 0.5	0.25		n/a	n/a	0.5	n/a
1.0	0.25		n/a	n/a	0.8	n/a
< 0.5	1.0		n/a	n/a	0.08	0.08
1.0	1.0		n/a	n/a	0.18	0.13
3.0	1.0		n/a	n/a	0.5	0.42

Source: ESA, 1991.

Availability

The recovery, transportation, and combustion of ventilation air uses equipment and technology that is commercially available and accessible. However, this concept has not yet been demonstrated and pilot projects should be undertaken to determine if this strategy is feasible.

Applicability

Large quantities of ventilation air are vented by every operating underground mine. These emissions constitute an untapped energy resource that can potentially be utilized. If a technical demonstration is successful, the utilization of ventilation air should be considered for every mine. However, there are economic and practical requirements that will limit the number of feasible project locations. The crucial factors are whether the methane in the ventilation air can be reliably supplied to the combustion device in sufficient quantity at an energy cost lower than the primary fuel, and whether the project can be implemented in a technically feasible manner that does not adversely affect mine safety or the safety of powerplant operation.

Ventilation air use may be economically attractive in certain locations if it is proven technically feasible. Additionally, where primary fuel is available and electricity demand is expected to

grow, meeting this demand by installing gas turbines in the vicinity of underground coal mines may be a feasible strategy that more efficiently utilizes local resources.

Barriers

Despite the potential for utilizing this resource, there are several barriers to implementation. Most importantly, the technical viability of this utilization option has yet to be demonstrated. Institutional interest and awareness of the potential is often lacking, as are incentives to consider ventilation air as an energy source. In addition, the massive volume of low quality gas that is produced is itself a barrier. Generally, utilizing all the ventilation air produced by a mine would necessitate a larger generator than is required for mine operations alone. As a result, full utilization of mine ventilation air requires external electricity markets and a transmission infrastructure; this reliance on specific conditions in other sectors of the local energy market may present a barrier to project implementation.

Benefits

In addition to the reduction of methane emissions into the atmosphere, other benefits will be seen from the utilization of ventilation air:

- Reduced use of primary energy sources and/or increased generating capacity. The use of ventilation air in electricity generation can reduce primary energy source use by up to 30 percent. This is a more efficient use of energy resources, and can reduce reliance on foreign energy sources.

- Less SO_2, NO_x, and particulate emissions will be produced by the displacement of coal with gas. Natural gas combustion produces virtually no SO_2 emissions, no particulate emissions, and lower NO_x emissions. A 10 percent increase in gas use in a retrofitted coal-fired burner will result in a 10 percent decrease in SO_2 and particulate emissions. In many countries, expanded natural gas use is being aggressively pursued in response to serious local air pollution problems (Pilcher et al., 1991; Bibler et al., 1992).

Ventilation Air Utilization

- 10-90% methane reductions
- efficient use of energy resources
- competitive energy costs
- augments existing practices
- technology currently available
- demonstration projects necessary
- clean energy source

Integrated Recovery

An integrated system of methane recovery and utilization can take full advantage of all the available strategies for reducing methane emissions from coal mining. In many mines, using two or more methane recovery approaches (e.g., pre-mining degasification with horizontal boreholes and vertical gob wells) can: 1) optimize mine degasification, achieving the maximum improvements in mine safety and productivity; and 2) realize economies of scale as fixed costs are shared (Exhibit 4-13).

Recovery Technology Description

Developing the capability to implement a variety of methane recovery techniques enables an optimal response to site-specific field conditions. The available methane recovery technologies have each been described in the technical assessments above. Each technology can effectively reduce methane concentrations in mines. Nevertheless due to certain geological or technological factors it may be desirable to implement a combination of strategies. For example, if methane reductions of 50 percent are required to maintain coal production most economically while ensuring mine safety, an optimal strategy may be to combine gob well recovery with pre-mining drainage. This has been the experience of at least one mining operation in the United States (Dixon, 1987), and many mines in the U.S. and throughout the world use a variety of degasification techniques to optimize methane recovery. In addition to technical advantages, economies of scale may be realized in integrated projects.

Utilization Technology Description

As with recovery technologies, the utilization technologies that have been previously described may be combined to optimize gas use. The compatible combination of end uses can improve technical and economic feasibility.

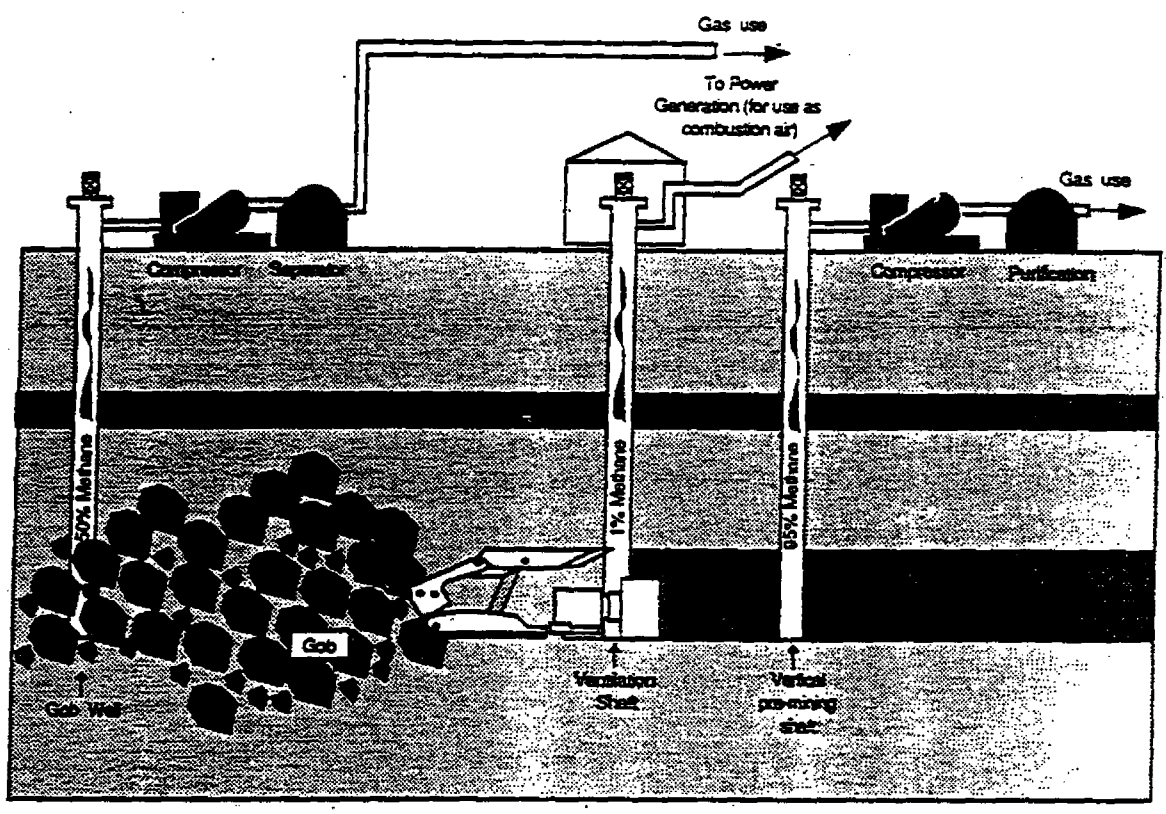
Costs

Integrated recovery projects will typically be larger than projects employing single strategies; capital costs are expected to be correspondingly larger. However, unit costs may be lower due to economies arising from the implementation of mutually beneficial technologies.

Economies of Scale: Several of the techniques use similar technology, equipment, or drilling practices, and require similar technical capabilities. In-mine piping and surface gathering and processing equipment are often compatible with different projects. Therefore, certain fixed costs associated with capital expenditures, support facilities, training, and maintenance may be spread over several types of methane recovery. Even where this is not the case, common costs of project planning and overhead can be shared for integrated strategies.

Economies of Scope: The most promising potential for integrated systems lies in the mutual benefits of coordinating utilization strategies. For example, one of the significant barriers to utilizing ventilation air as a supplementary combustion fuel is the supply of competitively priced primary fuel for gas turbines (see "Ventilation Air Utilization"). Conventional supplies of gas turbine fuel, natural gas or #2 fuel oil, can cost between $1.50 and $4.00 per MMBtu, which is often enough to make the installation of a turbine uneconomical. However, coordination of a degasification or gob well recovery project with the combustion of ventilation air can provide a significantly less costly supply of primary fuel; medium quality gas (as low as 30 percent methane) is sufficient to power a gas turbine. The integrated recovery and use of both low and medium/high quality gas provides a direct demand for the medium quality gas, and removes a barrier to utilizing ventilation air; independent of one another, these projects may not be feasible.

Exhibit 4-13
Integrated Recovery



Note: not drawn to scale

Mutual advantages may also exist for issues of technical feasibility. Active gob gas recovery will reduce the volume of ventilation air necessary to maintain mine safety. As a result, a smaller and less costly turbine can be used, or a more significant proportion of the ventilation air can be consumed. Coordinating the production from both projects can optimize total project economics and feasibility.

Availability

Technologies for reducing methane emissions are available. However, certain countries may need technical assistance in assessing the trade-offs between approaches for developing optimal integrated systems.

Applicability

There are significant benefits associated with developing integrated methane recovery and utilization projects. However, it is important to realize that these benefits are attained through the implementation of larger and more technically advanced projects. This fact has a direct impact on the suitability of integrated recovery projects. It is likely that integrated projects will only be suitable for large mining operations working in relatively gassy coal seams. The current trend in coal mining is towards deeper, and thus gassier mines, making the implementation of integrated projects increasingly likely.

Barriers

The barriers for integrated recovery will be similar to those facing any methane recovery project, though larger because of the additional scope, cost, and complexity. As a direct result of the size and technical sophistication of these larger projects, capital expenditures and operating costs will be correspondingly higher even though the long-term economics may be more favorable. Similarly, equipment and training needs will be more advanced, as will technical and planning expertise. Integrated projects will likely only be implemented by mining operations that have significant previous experience, or with technology transfer assistance.

Benefits

In addition to the reduction of methane emissions into the atmosphere, other benefits will be seen from the integrated recovery and use of coalbed methane:

- Mine safety will be improved. Because methane drainage is improved with the enhanced gob well recovery strategy, the methane concentration in the mine is reduced, which may result in fewer methane-related accidents at mines.

- Ventilation costs will decrease. One mining company in Alabama, U.S. has been able to increase coal production while decreasing ventilation costs by using improved methane recovery techniques. This mine has estimated that capital expenditures of $15 million would have been required for additional ventilation shafts and fans

necessary to ventilate the same amount of methane which is now being recovered at a profit (Dixon, 1989).

- A more efficient energy source will be used. Methane can be a more efficient fuel than coal, particularly in residential cooking and heating end-uses. Many countries, including China, use coal extensively for residential purposes (JP International, 1990). Coal combustion cannot respond efficiently to low load operation, nor is it easy to start and stop operation as the heating load swings. In comparison, gas can respond instantaneously to heat demand and can be used for low load operation, thereby providing a more efficient fuel source.

- Less SO_2, NO_x, and particulate emissions will be produced by the displacement of coal with gas. Natural gas combustion produces virtually no SO_2 emissions, no particulate emissions, and lower NO_x emissions. A 10 percent increase in gas use in a retrofitted coal-fired burner will result in a 10 percent decrease in SO_2 and particulate emissions. In many countries, expanded natural gas use is being aggressively pursued in response to serious local air pollution problems (Pilcher et al., 1991; Bibler et al., 1992).

- Degasification will be optimized. The integrated use of suitable recovery technologies can result in up to 90 percent methane reduction. Greater reductions can be achieved while improving project economics.

Integrated Systems

- up to 90% methane reduction
- optimization of degasification
- economies of scale
- economies of scope
- augments existing practices
- technology currently available
- clean energy source

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