ENGINEERING/ECONOMIC ANALYSES OF COAL PREPARATION WITH SO_2 CLEANUP PROCESSES FOR KEEPING HIGHER SULFUR COALS IN THE ENERGY MARKET

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DISCLAIMER

PREFACE

This report was prepared by the Hoffman-Muntner Corporation of Silver Spring, Maryland, under United States Bureau of Mines Contract Number J0155171. The contract was initiated under the Coal Preparation Research Program. It was administered under the technical direction of the Coal Preparation and Analysis Laboratory, with the Chief of the Laboratory, Mr. Albert W. Deurbrouck, acting as the Technical Project Officer. Miss Elizabeth Rexroad was the contract administrator for the Bureau of Mines.

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1.0 INTRODUCTION

Concern for preserving the quality of the environment resulted in the Air Quality Act of 1963, which initiated a concerted effort by Federal, State, and local governments for the preservation of the Nation's air quality. This act called for an expanded Federal research and development program and placed special emphasis on the problem of sulfur oxides emissions from the combustion of fossil fuels in stationary plants.

Coal provides for 18 percent (calendar year 1974) of the total fossil fuel energy consumed by all domestic sources (utility, industrial, commercial, and residential). In the utility industry, 55 percent (calendar year 1975) of the fossil fuel energy requirement is supplied by coal.

Electric power generation has been increasing at around 5 to 8 percent per year. This increasing demand for electrical energy, the sudden increase in the cost of imported oil following the October 1973 oil embargo, the uncertainty of the foreign oil supply, and the delays in constructing and licensing nuclear powerplants have resulted and will continue to result in increasing use of coal as a major source of energy for the utility industry. Coal consumption by utilities was 404 million tons for 1975, may be as high as 700 million tons by 1985, and could be over 1,200 million tons in the year 2000.

Because pollution from fuel combustion has long been recognized as a problem, major emphasis has been placed on the development of methods for controlling sulfur oxides emissions from fossil-fuel-fired combustors. Currently available methods for controlling sulfur oxides emissions from coal-fired stationary combustion sources fall into the following categories:

1. The use of low-sulfur coal, either naturally occurring or physically cleaned;

2. Chemical treatment to extract sulfur from coal;

3. Removal of sulfur oxides from the combustion flue gas;

4. Conversion of coal to clean fuel by such processes as gasification and liquefaction.

Of these methods, for amenable coals, physical removal of pyritic sulfur is the lowest cost and has the most developed technology. Another approach to controlling SO_2 emissions could be the combined use of physical cleaning followed by stack gas scrubbing. Such a combined approach could make it possible to utilize high-sulfur coal with minimal to moderate stack gas scrubbing while continuing to realize the established benefits of coal cleaning such as (1) the availability of a more uniform coal, (2) lower effective transportation costs, (3) reduced maintenance costs, and (4) lower coal pulverizing and ash disposal costs.

Coal is a heterogeneous material containing organic combustible matter and mineral matter. The mineral matter or impurities may be broadly divided into two categories--those that form ash, and those that contribute sulfur. The ash-forming and the sulfur-containing impurities can be further subdivided into two classes: (1) Impurities that are structurally a part of the coal and cannot be removed by physical means, and (2) impurities that can be liberated by crushing and removed by physical means.

Sulfur in coal exists in two principal forms, organic and inorganic. The organic sulfur is bound chemically to the coal substance and cannot be physically removed. However, inorganic sulfur (i.e., pyritic) is not bound chemically with the coal substance and may be removed to varying extents by crushing and physical cleaning. The degree of removal is dependent upon pyrite size and distribution, coal size, and other physical characteristics.

Physical cleaning of coal has been used for many years. Its principal purpose has been to reduce the so-called ash-forming impurities. If any of the impurities are pyrites it would also reduce the total sulfur in the coal. The process in common use for reducing such impurities is a combination of stage crushing and specific gravity separation. Shale and coal having different specific gravities may be separated. Froth flotation, dependent on differences in surface characteristics of coal and refuse, is used for removing impurities from very fine size coal. Existing cleaning processes, while removing impurities from coal, also reduce the total Btu recovery (i.e., a portion of the heat content of the feed will be lost with the refuse). However, the Btu content per unit weight of the processed product increases owing to removal of low-heat-value impurities. In practice, an economic balance must be achieved between the Btu loss and the improvement in coal quality. This balance may be further influenced by environmental considerations.

In 1965, EPA sponsored a study to quantify the impact that coal cleaning, optimized for pyrite removal, could have on the control of sulfur oxide emissions. This study found that it was impossible to quantify the impact of coal cleaning on sulfur oxide emissions because of large gaps in available information. The study identified the following areas where required information was either not available or was inadequate for appraising this impact:

- Knowledge of the distribution of sulfur forms in all major utility-coal-producing coalbeds in the United States;

- Effectiveness of available commercial coal preparation methods for pyrite separation, together with the development or modification of these techniques to maximize sulfur reduction;

- Identification and assessment of processes that could economically utilize coal cleaning reject material for byproduct recovery, thereby aiding the overall cleaning economics and reducing potential air, water, and solid pollution.

The findings of the 1965 study led EPA to proceed with implementation of a comprehensive program designed to define the role of coal cleaning in controlling sulfur oxide emissions from coal-fired sources. An important part of the program was to determine the extent to which the sulfur content of U.S. coals could be reduced by coal cleaning processes based on differences in physical properties. While pyritic sulfur is amenable to removal by such processes, the other major form of sulfur (organic sulfur compounds) is not. A good indicator of the "cleanability" of pyrites from a coal is the specific gravity analysis, or float-and-sink test, in which the crushed coal is tested at various gravities to effect a separation between coal and impurities. Such float-and-sink tests form an important element of the total program by providing the basic data for determining the amount of sulfur removal achieved.

Increased interest in the utilization of coal, together with the realization that substantial quantities of U.S. coals exhibit reasonable sulfur reductions on physical cleaning, has led to consideration of coal preparation as a total or partial step in meeting environmental standards. One approach would be to clean those coals that show significant sulfur reductions at reasonable cost, and then use a minimal, economically attractive, flue gas desulfurization system.

This concept of physical coal cleaning combined with flue gas desulfurization is not new (e.g., Reference 17). For some time there have been discussions, speculations, and some very preliminary assessments addressing the possible benefits of physical coal desulfurization followed by flue gas desulfurization. Past opinions, based on a general appreciation of some of the cost and benefit factors associated with such an approach, have been that economic advantage in many instances could be attained. However, the associated specific economics had not previously been fully addressed.

The Bureau of Mines, therefore, decided to proceed with an analytical assessment that would more fully define the potential economics of physical coal desulfurization followed by flue gas desulfurization as a means for increasing the attractiveness of some of our higher sulfur content coals. The study approach, based on reasonable and realistic study parameters, would for a number of user situations examine the economics of physical cleaning followed by flue gas desulfurization as a means of satisfying environmental-sulfur-related emission standards. Economic paramenters are based on current and past conditions. It should be noted that industry economic factors exhibit considerable spread. In this regard, study values chosen tended to provide conservative (i.e., least attractive) economics of physical cleaning followed by flue gas desulfurization. The development of study factors, parameters, and findings is provided herein.

2.0 GENERAL CONSIDERATIONS AND APPROACH

2.1 General Considerations

For the purpose of this study, reasonable coal source-user combinations were established, and analyses were conducted to determine whether there was any potential economic advantage associated with physical cleaning followed by flue gas desulfurization (FGD) over using FGD alone to meet environmental standards.

Selection of Coal Source Areas

To determine the coal source side of these combinations, it was necessary to determine coal source areas possessing coals that display apparently attractive cleaning potential. Such coals are found in the Northern Appalachian and Eastern Interior Regions.

Selection of Coal Use Areas

Having established general coal source areas, States were identified that have historically been served by these areas. From these, 20 States were selected which have emission regulations in a range compatible with the burning of moderate- and low-sulfur coals (i.e., 1 to 3 percent and less than 1 percent sulfur content, respectively). The considered states were Alabama, Delaware, Illinois, Indiana, Iowa, Kentucky, Maine, Maryland, Massachusetts, Michigan, Minnesota, New Hampshire, New Jersey, New York, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and Wisconsin. A summary of the sulfur emission regulations pertaining to utility coal burning facilities in each of these States is presented in Appendix A hereto. Within each of these States, a wide distribution of actual coal-burning utilities were identified from which a total of 12 were selected for complete analysis. Then, 12 specific coals from the Northern Appalachian and Eastern Interior Regions were individually matched with these 12 selected coal-burning utilities, thus constituting the practical core of the study.

2.2 General Approach

In some coal use areas, some coals can be physically cleaned to a total sulfur content level consistent with governing environmental standards. In some cases this can be accomplished at reasonable cost and reasonable loss in total heat content value (i.e., on a per-ton basis). Even though many coals can be cleaned to provide a substantial reduction in total sulfur, the beneficiated coal product is often too high in sulfur to meet environmental requirements. In many cases, the beneficiated coal is not too far from meeting standards and a small amount of SO_2 emission control would enable the coal to be used in an environmentally acceptable fashion. The required degree of SO_2 emission control can often be achieved by employing either a low removal efficiency SO_x flue gas desulfurization system or a highly efficient flue gas desulfurization system treating only a portion of the total stack gas.

This effort specifically addresses the applicability and the economics of physical desulfurization followed by flue gas desulfurization as a means for keeping our higher sulfur coals in the energy market. The advantage of such an approach would necessarily relate to economics (i.e., cost compared to other options of sulfur removal).

The relationship between flue gas desulfurization cleaning efficiency, portion of the total gas cleaned, and normalized emission level is defined by the following:

$$y = 1 - nx,$$

where y = total SO_2 emitted with FGD/total SO_2 emitted without FDG,

n = flue gas desulfurization efficiency of treated portion of flue gas (expressed as a decimal),

and x = decimal proportion of flue gas cleaned.

Therefore, for a given cleaning efficiency, the relationship between portion of gas cleaned and the normalized emitted SO_x emission level (i.e., y) is defined by a straight line. In a similar manner, the relationship between portion of gas cleaned and the normalized amount removed is also described by a straight line.

For a flue gas desulfurization system with a 90-percent removal efficiency we have--

Percent of Gas Cleaned	SO_2 Emitted (normalized value)	SO_2 Removal (normalized value)
0	1	0
10	0.91	0.09
20	0.82	0.18
30	0.73	0.27
40	0.64	0.36
50	0.55	0.45
60	0.46	0.54
70	0.37	0.63
80	0.28	0.72
90	0.19	0.81
100	0.10	0.90

For a flue gas desulfurization system with an 85-percent removal efficiency we have--

Percent of Gas Cleaned	SO_2 Emitted (normalized value)	SO_2 Removal (normalized value)
0	1	0
10	0.915	0.085
20	0.83	0.17
30	0.745	0.255
40	0.66	0.34
50	0.575	0.425
60	0.49	0.51
70	0.405	0.595
80	0.32	0.68
90	0.235	0.765
100	0.15	0.85

For a flue gas desulfurization system with an 80-percent removal efficiency we have--

Percent of Gas Cleaned	SO_2 Emitted (normalized value)	SO_2 Removal (normalized value)
0	1	0
10	0.92	0.08
20	0.84	0.16
30	0.76	0.24
40	0.68	0.32
50	0.60	0.40
60	0.52	0.48
70	0.44	0.56
80	0.36	0.64
90	0.28	0.72
100	0.20	0.80

Given the ash, Btu, and sulfur contents of a raw coal, related float-sink test data, transportation economics, and SO_2 emission limitations, economic assessments of coal cleaning (to remove sulfur and ash) followed by SO_2 cleanup can be addressed. The addressed economics would cover the various identified costs and benefits directly related to coal beneficiation. These benefits (other than those associated with environmental satisfaction) mainly result from lower coal ash and sulfur content via cleaning. The cleaning costs and benefit assessments can then be modified to encompass the SO_2 cleanup process.

The overall economics will be sensitive to the achieved ash and sulfur reductions, the resulting coal yield, and the cost of physical cleaning. The achievable sulfur reduction on physical cleaning will effectively define the level of sulfur prior to combustion and will therefore define the required degree of flue gas desulfurization to meet a specific standard. In this regard, it should be noted that in general for a given top size, coal exhibits a reasonably sharp break point in attainable sulfur and ash reduction as a function of yield. If coal beneficiation combined with FGD has any attractiveness for a given use situation, the optimum coal beneficiation level would be somewhere in the region where a sharp change in ash and sulfur reduction potential versus yield occurs.

In general, for most of the coals examined, this break point occurs around a 90-percent weight yield. This general condition (for 3/8-inch top size coal) is indicated for Northern Appalachian coals by Figures 1 and 2 (Reference 3). For this effort the 90-percent yield was chosen.

It should be noted that the sharp break indicated on Figures 1 and 2 is exaggerated owing to the fact that the 90-percent point was the first data point. Even so, the maximum change in sulfur and ash reduction potential versus yield occurs in the neighborhood of a 90-percent yield.

Currently, electrostatic precipitators are required with or without an FGD system. Therefore, precipitator-related economics are not considered in this study. Early FGD systems combined particulate and SO_2 removal in the

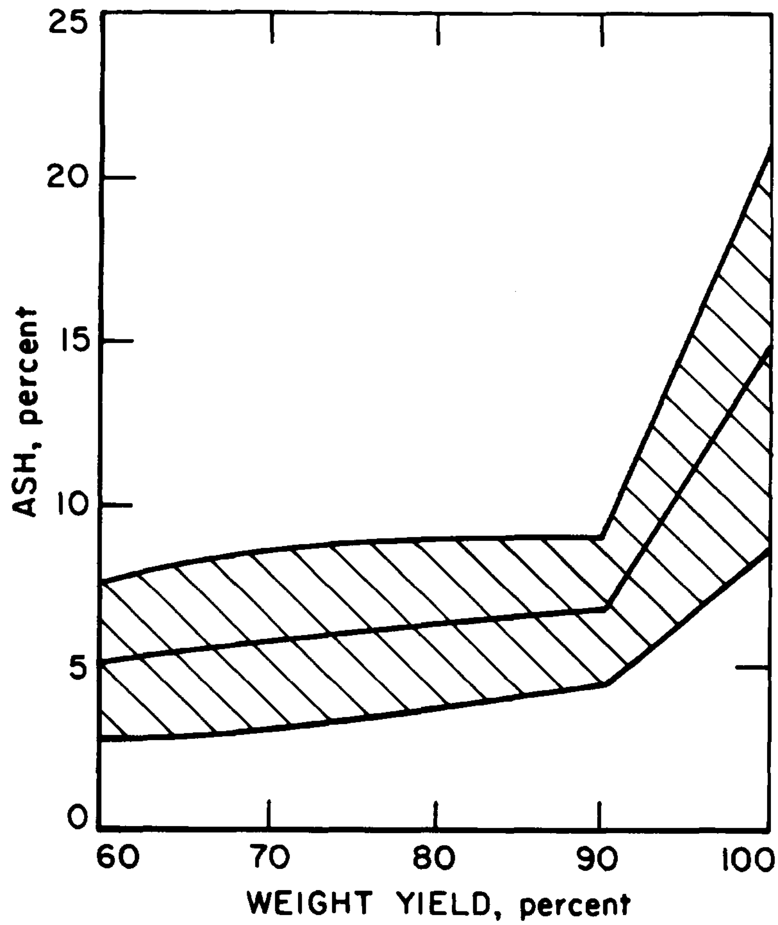

Figure 1-Average ash content, ± 1 standard deviation at 3/8 inch top size, Northern Appalachian region coals.

Source: United States Bureau of Mines RI 7633, 1972 (page 234).

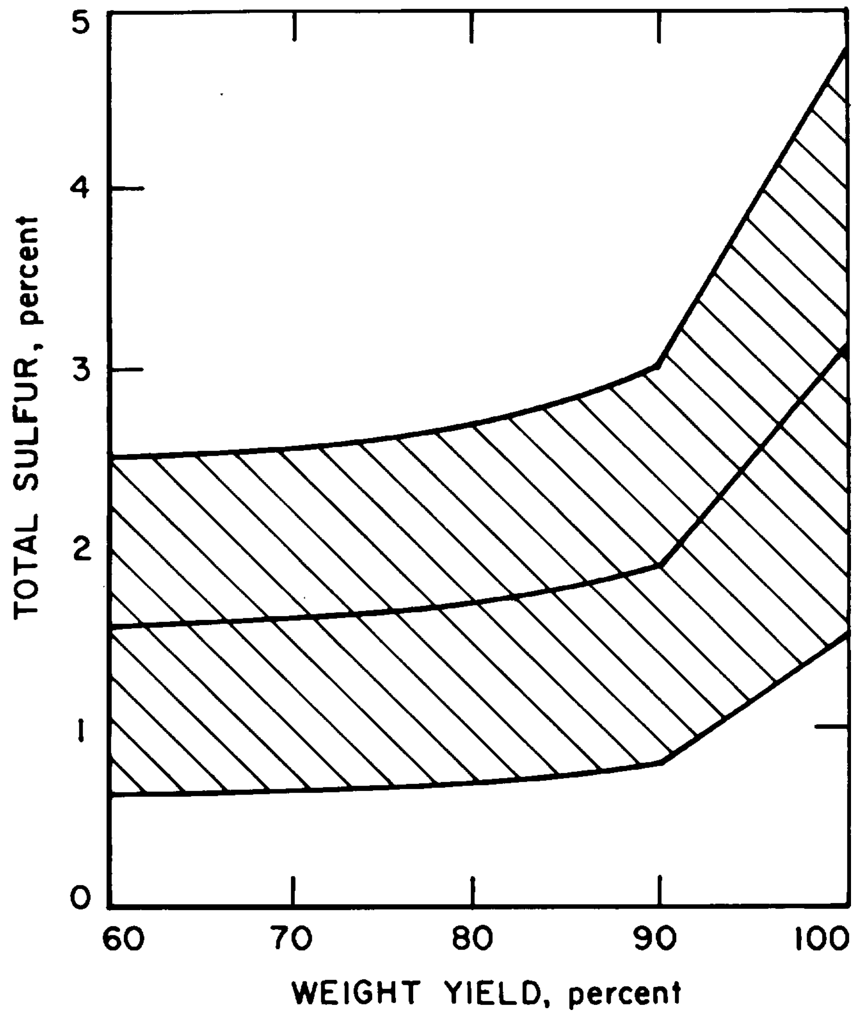

Figure 2–Average total sulfur content, ± 1 standard deviation at $\frac{3}{8}$ inch top size, Northern Appalachian region coals.

Source: United States Bureau of Mines RI 7633, 1972 (page 235).

same scrubber to realize potential cost savings. However, there are a number of problems associated with this combined approach. For example, the fan can no longer be operated dry, which creates corrosion and imbalance potential. Another area of difficulty is the fact that the chemistry of the SO_2 system is affected by the addition of the particulate in the slurry. Further, the SO_2 system cannot be bypassed without also bypassing the precipitator, thus losing the entire particulate removal function. Finally, if the fly ash is collected dry and then mixed with the sludge, there is a higher percent total solids content than if the fly ash is wetted along with the sulfate sludge. As a result of these numerous problems, virtually all new installations are using precipitators followed by dry fans and then followed by SO_2 scrubbers.

2.3 Additional Factors Not Included As Part Of This Study

In addition to the many cost and benefit factors that were included as part of this study, there were several others which were considered but omitted owing to either their inability to be reasonably defined and/or quantified or their inconsequential impact upon the overall findings of the effort. The following is a brief summary of those factors:

1. Crushing and Screening Cost Savings -

   When raw coal is not going to be physically cleaned, it is normal practice in the coal industry to crush and screen to a size of approximately 2 x 0 inches that coal which is to be sold to utility plants. The overall cost of this process including coal loading has been estimated by industry personnel to be as high as $0.60 per ton. When coal is physically cleaned, it is not necessary to perform the crushing and screening separately since these functions are now integrated with the overall cleaning process. For purposes of this study, coal cleaning costs were not reduced by the cost of crushing and screening even though there is a definite savings to the mine operator by not having to perform these separately. If this savings had been considered a benefit by the study, the net cost of physical cleaning would have been reduced, and thus the relative economics of using physically cleaned coal followed by FGD as compared to FGD alone would have been improved.

2. Reduction in FGD Installation Time -

   By using physically cleaned coal, less of the flue gas needs to be processed by the FGD system and therefore fewer or smaller FGD units are required to meet environmental standards. This has not only the benefit (as covered by the study) of reducing the FGD cost, but it also reduces the construction time. Additionally, the total sludge disposal at the plant site is reduced substantially from what it would be in the absence of coal cleaning. This will in some cases reduce the time required for, and the difficulty with, obtaining legal permits and site acquisition for ponding and/or landfill.

3. Stack Gas Reheat Cost Savings -

When many coals are burned which have not been physically cleaned, it may be necessary to process all or nearly all of the flue gas through the FGD system in order to meet environmental standards. In these situations, the stack gas must be reheated following FGD. When only a small portion of the total flue gas is cleaned, reheat would not be required. The absence of reheat would save energy and consequently amount to a benefit for the combined physical cleaning followed by FGD approach.

4. Less Derating of Powerplant Output -

FGD systems require power to operate. The smaller FGD systems that could result from using physically desulfurized coal would require less operating power. This would result in more marketable power for the same powerplant fuel input level.

5. Cost of Working Capital and Land -

When considering the cost of a coal cleaning plant as well as a flue gas desulfurization (FGD) system, neither the cost of the working capital necessary to handle the larger operation nor the cost of the land area to be occupied were included by this study. The reasoning behind this exclusion relates to their very limited impact on a per million Btu basis. Additionally, it is not uncommon to have sufficient land area available at the mine site to handle a coal preparation plant and very little land available at the powerplant for a retrofit FGD installation. This situation would provide additional benefit to the physical cleaning followed by FGD approach.

6. Possible Creation of a Market or the Establishment of a Long-Term Sales Contract -

In many cases the physical cleaning of coal could create markets for coals which are relatively unattractive in their raw form. The providing of beneficiated coals compatible with particular use situations could lead to the creation of long-term sales contracts matching specific cleaned coals with specific users. This arrangement works to the advantage of all concerned by giving the mine operator a long-term source for his product and the utility a predictably uniform product over an extended period which has been efficiently matched to operating requirements.

3.0 EVALUATION OF COSTS ASSOCIATED WITH THE COAL CLEANING PROCESS

Physical cleaning involves the removal of waste products such as shale, pyrite, and roof slate from coal by utilizing differences in the physical properties of the materials. The practice of physically cleaning coal has existed for many years; however, until the current concern with SO_2 emission, the purpose has been to remove the so-called ash-forming impurities. This material is removed to reduce transportation charges and the operating problems and associated expenses that this ash-forming material causes in practically all major uses of coal. About 41 percent of the bituminous coal and lignite produced in 1975 was mechanically cleaned. Cleaning equipment include a variety of jigs, tables, launders, dense-medium and flotation washers, and pneumatic devices, all of which depend upon the difference in specific gravity and froth flotation that depends upon the surface chemistry of fine coal. The specific cleaning method chosen depends on the size of coal to be upgraded, the composition of the raw product, and the chemical-quality specifications imposed by the consumer (Reference 14).

Sulfur is found in raw coal in two major forms: organic and inorganic (pyritic sulfur). The organic sulfur is considered an inherent constituent of the coal and cannot be reduced by use of conventional cleaning methods. The pyritic sulfur occurs in particles of varying size mixed with the coal. By crushing (to liberate the pyritic sulfur) and cleaning (to remove the liberated particles), the total amount of sulfur in the coal may be reduced. The degree of removal of the pyritic sulfur is dependent on the size of the particles of pyrites; the finer the particles, the more difficult to remove by cleaning. The total sulfur reduction, therefore, is dependent on the amount of organic sulfur and the effects of crushing to liberate the pyritic sulfur. The desulfurization process results (as do most beneficiation processes) in some loss in total heat content of the processed coal.

To obtain a low sulfur level (less than 1 percent total sulfur) in the physically cleaned coal requires that the organic sulfur content in the raw coal be less than 1 percent. A summary of washability tests by the Bureau of Mines (Reference 1), based on work done in cooperation with the Office of Air Programs, EPA, shows that the organic sulfur and the effects of crushing and cleaning vary widely, as would be expected, when washability data of coals throughout the United States are considered.

3.1 Cleaning Cost Factors

The cost associated with providing 1 ton of physically cleaned coal at the cleaning plant site (assumed located at mine) is the sum of the following:

- The cleaning plant amortization costs associated with each ton of cleaned coal.
- The cleaning plant operating and maintenance costs associated with each ton of cleaned coal. Operating costs also include the disposal of the refuse associated with the cleaning operations.

- The value of raw coal that is utilized in providing 1 ton of cleaned coal.

- The share of State and local taxes and insurance (on cleaning plant) allocated against each ton of cleaned coal.

3.2 Cleaning Plant Amortization Costs

Mechanical cleaning of coal is possible because of the differences between the physical properties of coal and those of its impurities. For the cleaning process to provide attractive pyrite removal benefits, it is necessary to select coals which possess characteristics amenable to pyrite removal and to have an appropriately designed cleaning plant.

The cost of a coal cleaning plant can vary over a wide range. Plant cost basically depends on plant capacity, equipment composition, and top size of prepared coal, assuming no undue site preparation charges. In general, for a given cleaning plant capacity, the smaller the coal particles, the greater the cleaning plant costs. The increase in plant costs required to clean fine coal is due to both the greater capital equipment cost for cleaning the finer coal and the higher operating and capital cost associated with fines dewatering, especially if thermal drying has to be used.

Data Considerations

Even though some cost data on several existing coal preparation plants are available, the value of such data is questionable. This cautious attitude concerning the utilization of past cost information is due to a number of reasons, including the following:

- Existing plants may not be representative of required coal cleaning plant(s).

- The age of existing plants is not well defined.

- The questionable ability to extrapolate or project current plant costs from plants of different total makeup that were constructed in past years under different economic conditions.

- The intricate details of existing plants are not well known (effectiveness and utilization restrictions).

These factors must be considered when using past plant-cost data to judge the reasonableness of newly acquired plant-cost estimates.

Capital Equipment Costs

The characteristics of the raw coal to be upgraded have to be carefully investigated together with a determination of the finished product before an estimate of cleaning plant configuration and cost can be made. In general, the finer we crush the coal, the more we liberate the impurities. However, as coal size is reduced and finer coal is cleaned, the complexity of the cleaning plant increases along with increased capital cost.

There are four general alternatives that are considered regarding processing of raw coal, as follows:

1. No Cleaning - Steam coals low in sulfur and ash or low in sulfur and high in ash are often utilized near the mine without cleaning. Currently, as in the past, cleaning is principally employed to upgrade coal by removing impurities such as clay, rock, shale, and pyrite. Even so, where the cost of transporting the noncombustibles is not economically significant, coal can often be sold without the benefit of cleaning.

2. Partial Washing (Coarse-Size Coal Plant) - In a coarse-size coal plant only the larger size fractions of coal are treated. Typically, a given coal could contain 50 to 60 percent plus 3/8-inch coal with the fines reasonably low in ash and sulfur. The plus 3/8-inch portion of the feed is washed and mechanically dried to a low moisture content. The separated and untreated minus 3/8-inch portion of the feed is combined with the cleaned coarse coal for shipment.

3. Coarse Washing with Partial Washing of Fines (Coarse-Size and Fine-Size Coal Plant) - In this case all the feed is wetted, but only the plus 48-mesh fraction is washed; the minus 48-mesh material is discarded. All the utilized coal would be mechanically dried. This approach results in the exclusion of the minus 48-mesh material (the most difficult and expensive to dewater) from the product. The use of this concept generally results in a lower yield and often results in higher cost and problems associated with disposal of the tailings.

4. Total Washing - In this case all the feed is wetted and washed. The cost of the plant will vary depending on the top size of coal treated. Such a plant could consist of both coarse (e.g., plus 3/8-inch coal) and fine (e.g., minus 3/8-inch coal) circuits or could be composed entirely of fine coal circuits.

   A plant designed to crush run-of-mine (ROM) coal to 3- to 5-inch top size resulting in 50 to 60 percent plus 3/8-inch (coarse) coal would wash the coarse coal, followed by dewatering to remove the surface moisture. The fines (e.g., minus 3/8-inch coal) would be wet-washed, followed by mechanical dewatering and possibly heat drying. A plant optimized to remove pyritic sulfur and ash from amenable coals would most likely be a total fine coal plant. Such a plant would crush ROM coal to 3/8-inch top size prior to processing. Plants of this type would include tables and/or cyclones, froth flotation units, filters, sizing and dewatering screens, mechanical and/or thermal dryers, and water clarification provisions.

To define current cleaning plant capital costs, engineering companies presently engaged in the design and construction of coal cleaning plants were contacted and cost information requested. Specifically, turnkey cleaning plant cost and plant makeup for 3/8-inch and/or 1/2-inch top size (fine coal) processing of Northern Appalachian and Midwest steam coals were requested. The requested cost and design information were for fine coal processing plants that would provide the capability for removing pyritic sulfur from the more readily cleanable coals. Obtained information from several designers and constructors of coal processing plants indicated that for either Northern Appalachian or Eastern Interior steam coals a fine coal preparation plant would currently cost $16,000 to $18,000 per ton-hour of input capacity for plants with capacities of 500 or more tons per hour. The information was supplied by personnel well aware of the plant capabilities that would be required to beneficiate coals of interest. Such a plant would include tables and/or cyclones, froth flotation units, filters, a range of screen sizes, and mechanical and thermal dryers. The design would provide for drying of fines and would remove the surface moisture from the larger fraction to aid shipping. In addition, included provisions would provide a slurry pond for the fine refuse and a pit for the coarse refuse.

In a previous effort in 1970, we estimated the cost of a medium-high-quality cleaning plant of the general design required to clean the more readily cleanable coals. The estimate was for a plant with an input capacity of 500 tons per hour and containing a combination of tables, cyclone separators, froth flotation units, filters, heat dryers, and sizing and dewatering screens. The cost of the plant was estimated at $4 million, the equivalent of $8,000 per ton-hour of input capacity.

From 1970 through 1975 the Dodge Building Cost Index has increased approximately 200 percent. This index reflects changes in construction costs based on wage and material price trends. The index is based on 60 percent material and 40 percent labor.

Cost increase indexes covering equipment related to coal beneficiation are reported by the Bureau of Labor Statistics. Table 1 provides index ratios between March 1970 and December 1975. From 1970 through 1975, both the Dodge Index and the Bureau of Labor Statistics price trend data support the reasonableness of the 1975 cleaning plant capital cost estimate as being essentially double the 1970 value.

TABLE 1. BUREAU OF LABOR STATISTICS COST ESCALATIONS FOR EQUIPMENT ASSOCIATED WITH COAL BENEFICIATION

Category	Dec. 1975 index/Mar. 1970 index
Crushing, pulverizing, screening machinery	1.77*
Roll Crusher	1.75*
Mining Machinery	1.95*
	Aug. 1975 index/Jan. 1973 index
Flotation machinery	1.80

* Estimate based on Bureau of Labor statistics value through August 1975.

Capital Equipment Amortization

It is assumed that regardless of tax and depreciation considerations, a mine operator would probably finance and amortize a coal preparation plant by means of an equal-payment, self-liquidating loan or its equivalent. Information from designers and constructors of coal preparation plants indicates that the interest rate for a loan for financing a coal cleaning plant would at best be 2 to 3 points above the prime interest rate. The more financially sound borrowers of course would obtain the more attractive rates. If the loan is payable with equal installments, the amount due per period per dollar of loan as a function of the loan period and the interest rate is given by--

$$R = \frac{i\,(1+i)^n}{(1+i)^n - 1},$$

where R = capital recovery per period per dollar invested,

i = interest rate per period expressed as a decimal,

and n = number of periods in the amortization schedule.

Therefore, the factor R multiplied by the amortizable cost yields the per-period fixed cost covering interest and principal.

Industrial-quality coal cleaning plants, when properly maintained, will undoubtedly have a life expentancy of greater than 20 years. Even so, the writeoff or amortization period is usually based strictly on company fiscal policy as constrained or guided by Internal Revenue Service policies and regulations. Reference 2 contains guidelines for depreciable assets used by business in general. Under the category of Mining, defined to include the mining and quarrying of metallic and nonmetallic materials plus the milling, beneficiation, and other preparation of such materials, Reference 2 indicates an 8- to 10-year depreciation period. Even so, discussions with industry indicated that even though a coal cleaning plant can be written off in about 10 years, prudent considerations dictate a writeoff period of 15 years. A 15-year depreciation period therefore was used for analysis purposes.

For a 15-year depreciation period, the monthly installment per dollar of loan value equals:

$$R = \frac{i\ (1 + i)^{180}}{(1 + i)^{180} - 1},$$

where i = monthly interest rate expressed as a decimal.

It is assumed that obtainable loans will bear an interest value that is two points in excess of the prime commercial rate. Therefore we have--

When prime interest rate equals--	i per month becomes--	R per year equals--
6%	(0.06+0.02)/12 = 0.006667	0.11468
7%	(0.07+0.02)/12 = 0.0075	0.12171
8%	(0.08+0.02)/12 = 0.008333	0.12895
9%	(0.09+0.02)/12 = 0.009167	0.13639
10%	(0.10+0.02)/12 = 0.01	0.14402

The yearly amortization costs for various amortization periods and interest rates (on the unpaid balance) are provided in terms of plant cost per ton-hour of input capacity. The share of amortization costs attributable against each plant input ton of coal is merely the per-ton-hour input capacity yearly amortization cost divided by the yearly operating hours. The amortization cost per ton of cleaned coal is simply the cost per plant input ton divided by the recovery (i.e., yield) expressed as a decimal.

The yearly operating hours of a cleaning plant as a function of plant utilization are indicated in Figure 3. For the purposes of this study a plant utilization factor of 38.58 percent was used. This is based upon the cleaning plant operating 260 days per year, 13 hours per day. Although this represents typical current industry practice, greater plant utilization would mean reduced capital amortization contribution per ton of cleaned coal and thus improve the economics associated with physical cleaning.

The per-ton cleaned coal amortization values are given in Figure 4. These values are provided for a range of plant yields and utilization factors and are based on--

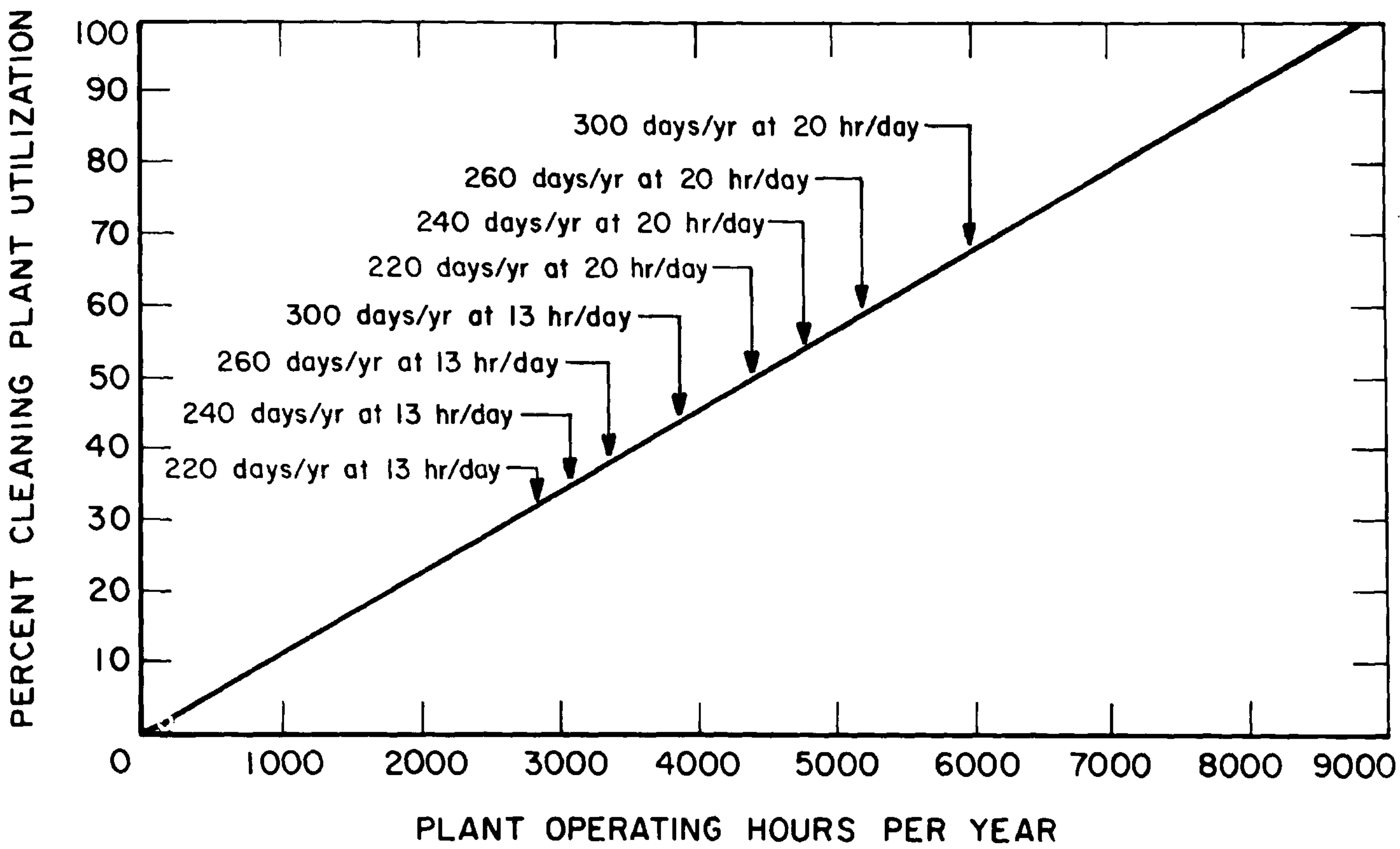

Figure 3—Cleaning plant utilization.

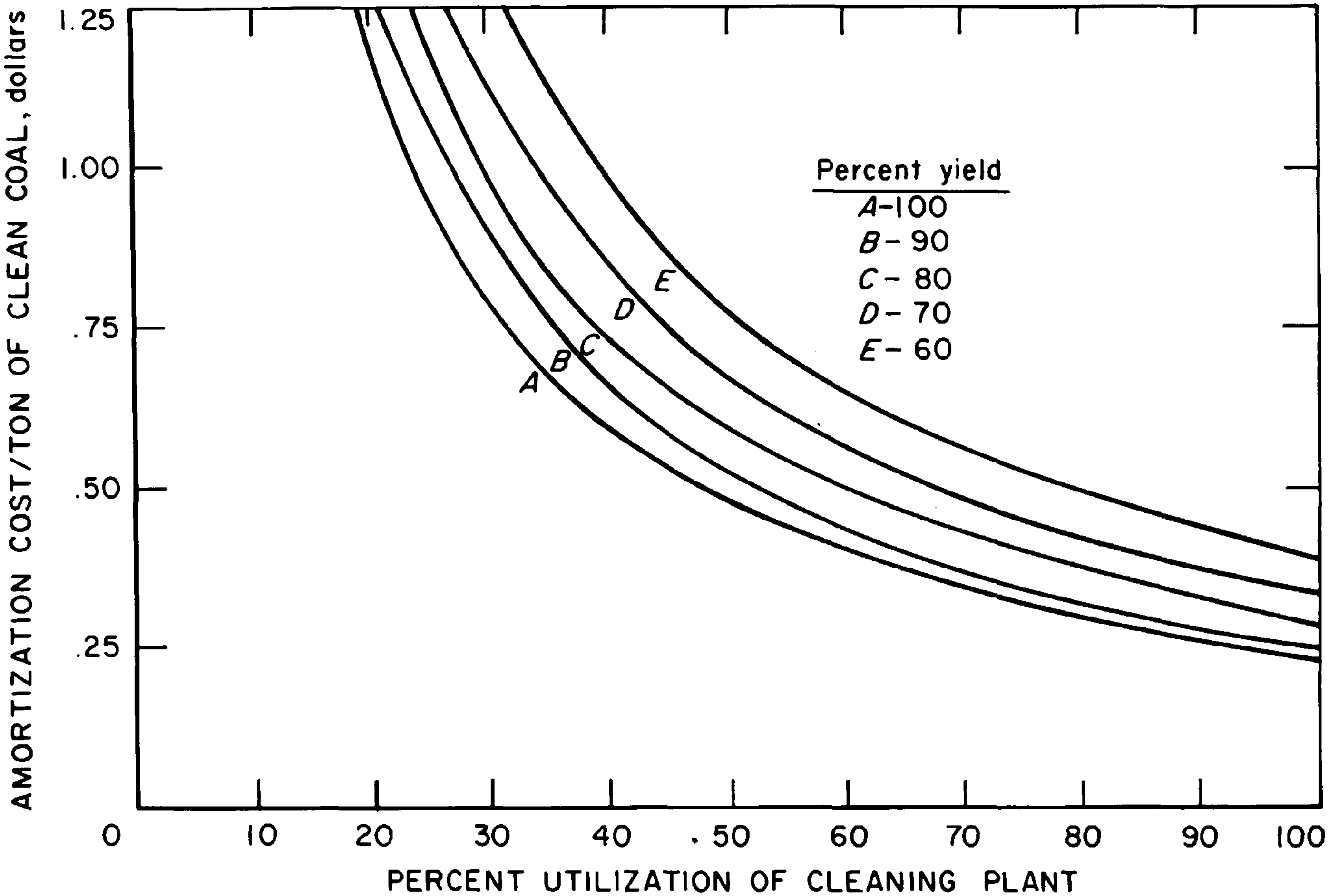

Figure 4–Amortization cost/ton cleaned coal for: plant cost–$18,000 per ton-hour input capacity, interest rate-8%, loan period 15 years.

- A plant costing $18,000 per ton-hour of input capacity
- A 15-year amortization period
- An 8 percent interest (on unpaid balance)

Curves showing the relationships between amortization costs per ton of clean coal for various plant costs, interest rates, plant utilization values, and recovery (yield) values are given in Appendix F.

3.3 Operation and Maintenance Costs

Operation and maintenance (O & M) costs are a function of--

- Coal yield (i.e., weight percent of plant input coal that becomes clean coal)
- Cleaning plant labor requirements and rates
- Maintenance costs
- Cost of operating supplies
- Power costs
- Refuse handling and disposal costs

For a given plant, the throughput time required to produce a ton of "clean" coal depends on yield (i.e., the percentage of raw coal that ends up as cleaned coal). As an example, if a cleaning plant operating at input capacity takes X hours with a given yield to process or provide 1 ton of clean coal, then the same plant when operating at half the previous yield will take essentially 2 X hours to provide 1 ton of clean coal. Therefore, the cleaning plant operating costs attributable to 1 ton of cleaned coal are (essentially) inversely proportional to cleaning plant yield. In like manner, maintenance, supply, and power costs will also be inversely proportional to yield. Refuse handling and disposal costs, however, do not follow this same relationship. This is evident from the fact that for 100 percent yield, refuse will not exist, and therefore refuse costs will be zero.

Operations and maintenance costs can therefore be considered to be composed of the sum of two cost categories. One cost category (i.e., sum of plant labor, maintenance, supplies, and power costs) is inversely proportional to yield, and the other cost category (refuse handling and disposal costs) is directly proportional to the percent of refuse.

Operation and Maintenance Cost Data Considerations

Information on operation and maintenance (O & M) costs is available from various sources.[7,8,12] The basic problem is correlating or projecting past data to reflect current economic conditions. Difficulty in assessing the data is due to various degrees of uncertainty in the following:

- Year of initial data collection
- Plant type, total composition, and capacity
- Year(s) of cleaning plant construction and date of initial operations
- Special operating considerations (i.e., duty, maintenance, etc.)
- Management efficiency of operating company
- Total cost inclusions covered by available cost information

The most detailed information available on O & M costs is contained in Reference 12. Operation and maintenance cost information from the following sources was also examined and evaluated in arriving at anticipated present-day O & M cost values.

Reference 7 contains preparation costs (i.e., operating cost of coal cleaning plant) for a 1,500-ton/hour-capacity plant, designed to produce both metallurgical and utility coal. The article defined O & M costs to be $0.253/ton of coal processed. According to the U.S. Bureau of Labor Statistics, the average hourly earnings for November 1975 for the bituminous coal industry are 241 percent of the average 1961 hourly earnings. Furthermore, the average hourly earnings for the bituminous coal industry were constant for 1959 through 1962. Therefore, the 1961 O & M cost (i.e., $0.253/ton) corrected for November 1975 becomes $0.61/ton of coal.

Table 5-1 on page 5-15 of Reference 8 contains operating costs obtained from extended records of a plant processing over 1 million tons of coal a year at 500 tons per hour with a plant reject of about 15 percent. Total labor, supplies, and power amount to $0.30/ton. Since the information was published in 1968, it is assumed that the provided information was for the 1968 or at worst the 1967 time frame. Depreciation is listed, and the sum of the previously mentioned $0.30/ton figure plus the depreciation associated with each ton is defined as the total cleaning costs. It is therefore assumed that preparation plant maintenance cost is included in the $0.30/ton figure. Correcting the $0.30/ton figure by the ratio of November 1975 to 1967 average hourly earnings in the bituminous coal industry provides a November 1975 O & M cost of $0.60/ton of plant-processed coal. Thus, both References 7 and 8 result in essentially the same adjusted November 1975 O & M cost.

As previously indicated, Reference 12 contains information on a number of coal cleaning plants. The provided data, associated with studies of six different cleaning plants, have been examined as a partial basis for developing current cleaning plant O & M costs per ton of processed coal. These case studies, updated to November 1975 conditions, are in Appendix E.

The development of updated (to November 1975) O & M costs indicates that for examined coal cleaning plants of the general type, class, and costs indicated by practicing engineers, the spread of O & M costs is small. Figure 5

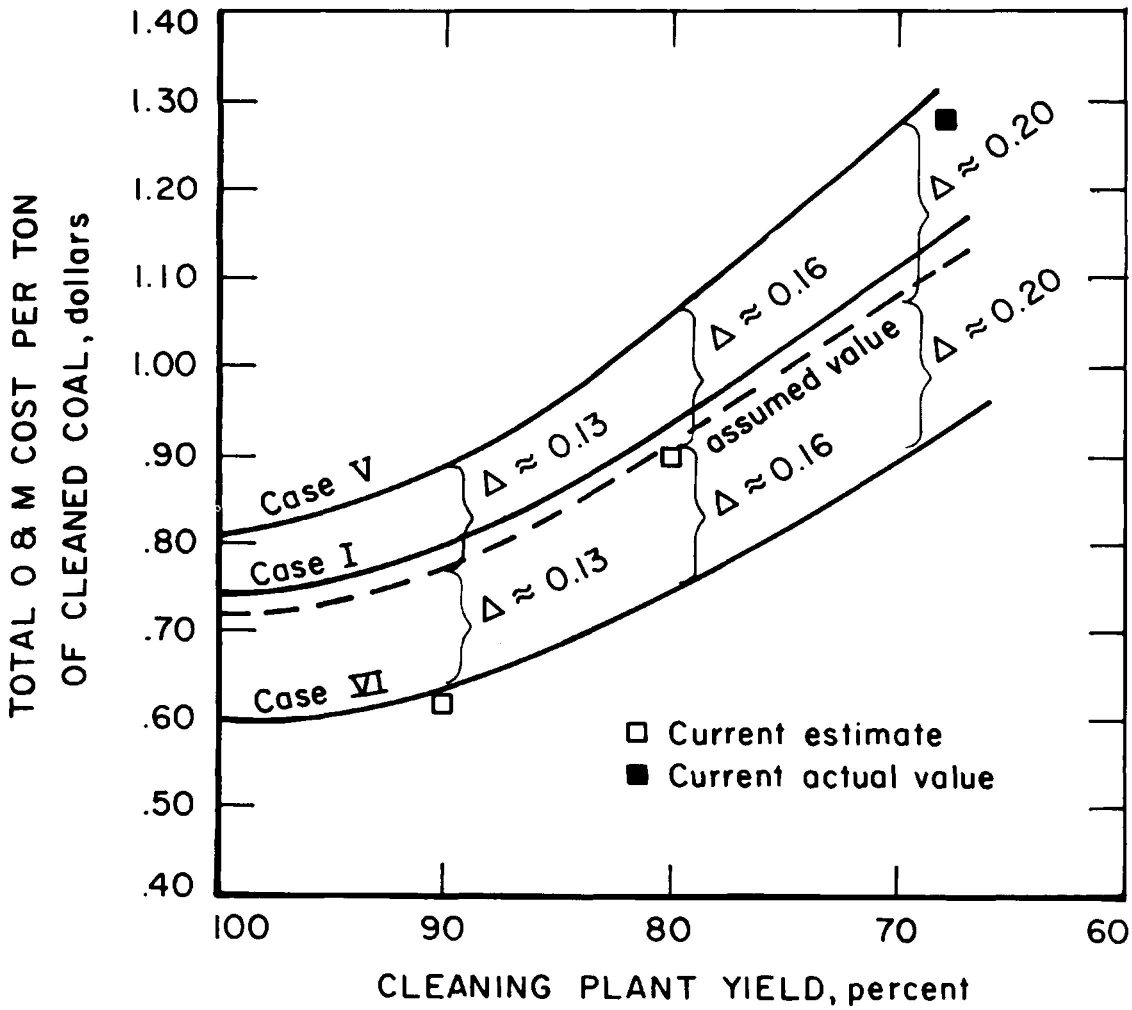

Figure 5—Operation and maintenance cost.

indicates the O & M costs associated with three plants that are believed representative of the expected composition and costs of plants that will be required to clean "readily cleanable" coals. In addition, an average curve of the two extreme cases (i.e., Cases V and VI) is provided. As indicated, the O & M costs for all three cases differ from the average curve (of the extreme cases) by not more than 13 cents for a 90 percent yield, by not more than 16 cents for an 80 percent yield, and by not more than 20 cents for a 70 percent yield. This spread is not unreasonable and could well be partially attributed to differences in plant conditions, plant composition, and management philosophy. In addition, three current industry-supplied values are also indicated on Figure 5. As compared with current industry values, the average assumed values for yields greater than 80 percent appear quite conservative.

For this effort, the values associated with the average curve will be used. The deviations of 13, 16, and 20 cents will be considered to be the uncertainty or maximum possible variation in O & M costs (i.e., for the associated yields).

3.4 Cost of Raw Coal Required Per Ton of Cleaned Coal

Operator's cost is defined as the operator's break-even cost for providing 1 ton of raw coal input to the cleaning plant. Such cost would include all appropriate expenses (e.g., royalties, labor and equipment, fair share of insurance, taxes, and mine development costs). For the purposes of this study, profit was not included in the break-even cost of providing 1 ton of raw coal input to the cleaning plant. This was done since the study treats the mine and the coal preparation plant as an integrated operation under common ownership and therefore the coal is treated as work-in-process until it has been cleaned. However, one might argue that under different business management and/or accounting arrangements profit should be included in the raw coal input cost to the cleaning plant. To allow for such variations, a range of mine operator's costs to provide 1 ton of coal input was used in the analyses.

Since the clean coal yield is less than 100 percent of the raw coal input, it takes more than 1 ton of raw coal to provide 1 ton of cleaned coal. The cost of raw coal that is used to produce 1 ton of cleaned coal is simply equal to the per-ton operator's cost divided by the cleaning plant yield expressed as a decimal. Curves indicating the cost of raw coal required to produce 1 ton of clean coal are given in Figure 6. The "additional" raw coal cost to provide 1 ton of cleaned coal is the cost of the raw coal lost during the cleaning process and is equal to the operator's coal cost required to produce 1 ton of cleaned coal less the operator's per-ton coal cost.

3.5 State and Local Taxes and Insurance Allocated Against Each Ton of Cleaned Coal

Each ton of cleaned coal must support its share of cleaning plant insurance and State and local taxes. For this effort, an overall insurance and tax (I&T) level of 2 percent of the inital cleaning plant cost is employed. The load attributable against each ton of cleaned coal (assuming cleaning plant operates at design capacity) is--

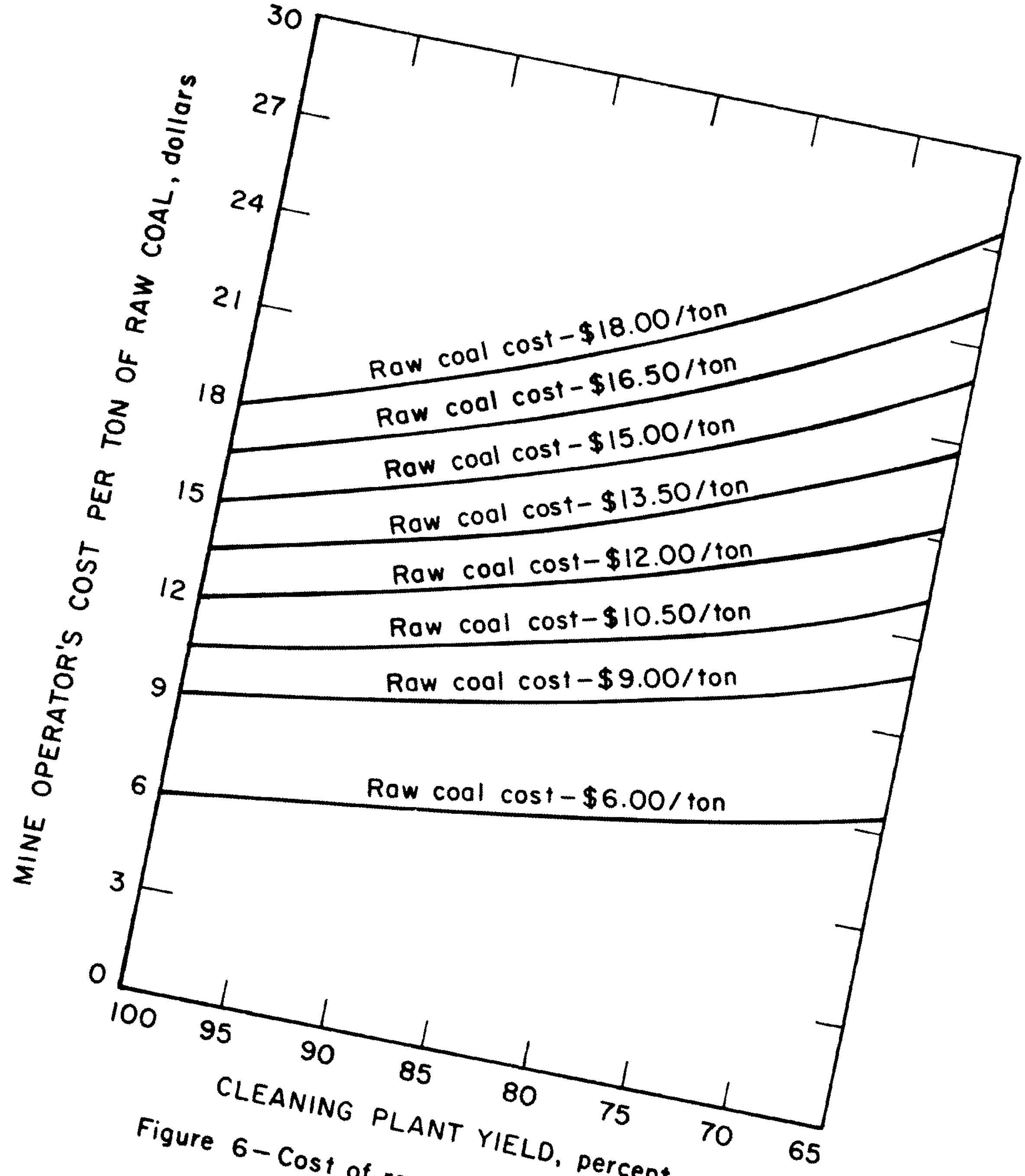

Figure 6—Cost of raw coal required to produce a ton of cleaned coal.

$$\text{I \& T load/ton clean coal} = \frac{\text{cleaning plant cost/ton-hr/input capacity} \times 0.02}{\text{operating hr/year} \times \text{yield (decimal value)}}$$

$$= \frac{\text{cleaning plant cost/ton-hr/input capacity} \times 0.02}{8{,}760 \times \text{utilization (dec.val.)} \times \text{yield (dec.val.)}}$$

Thus, the insurance and tax load allocated against each ton of cleaned coal from a cleaning plant costing \$18,000 per ton-hour of input capacity is--

$$\text{I \& T/ton clean coal} = \frac{360}{8{,}760 \times \text{utilization (dec.val.)} \times \text{yield (dec.val.)}}$$

Figure 7 indicates the insurance and tax burden per ton of clean coal for a plant costing \$18,000 per ton-hour of input capacity. The I & T burden (Figure 7) is a function of plant utilization and plant yield.

4.0 EVALUATION OF ECONOMIC BENEFITS ASSOCIATED WITH THE USE OF CLEANED COAL

4.1 Economic Benefit Factors

The readily identifiable monetary benefits attributable to a powerplant burning cleaned coal (dried to or below the original raw coal moisture content) are as follows:

1. Cleaned coal has a higher heat content per ton than the raw coal from which it is produced. Therefore, less cleaned coal will be required to provide a given heat content value.

2. Less cleaned (higher heat content) coal need be shipped for a given overall heat content value. Therefore, the cost of shipping will be less.

3. Cleaning reduces the ash content of coal. The ash requiring disposal by the utility will be less due both to the lower ash content per ton burned and to the fact that fewer tons of coal will be burned (i.e., for a given heat content value).

4. Less clean coal needs to be pulverized for a given heat content value, thus reducing the pulverizing costs. Further, cleaning often reduces the amount of harder particles in the coal, which should lessen wear on pulverizing equipment. However, the economic impact of this latter factor associated with pulverizing is difficult to quantify and will therefore not be considered.

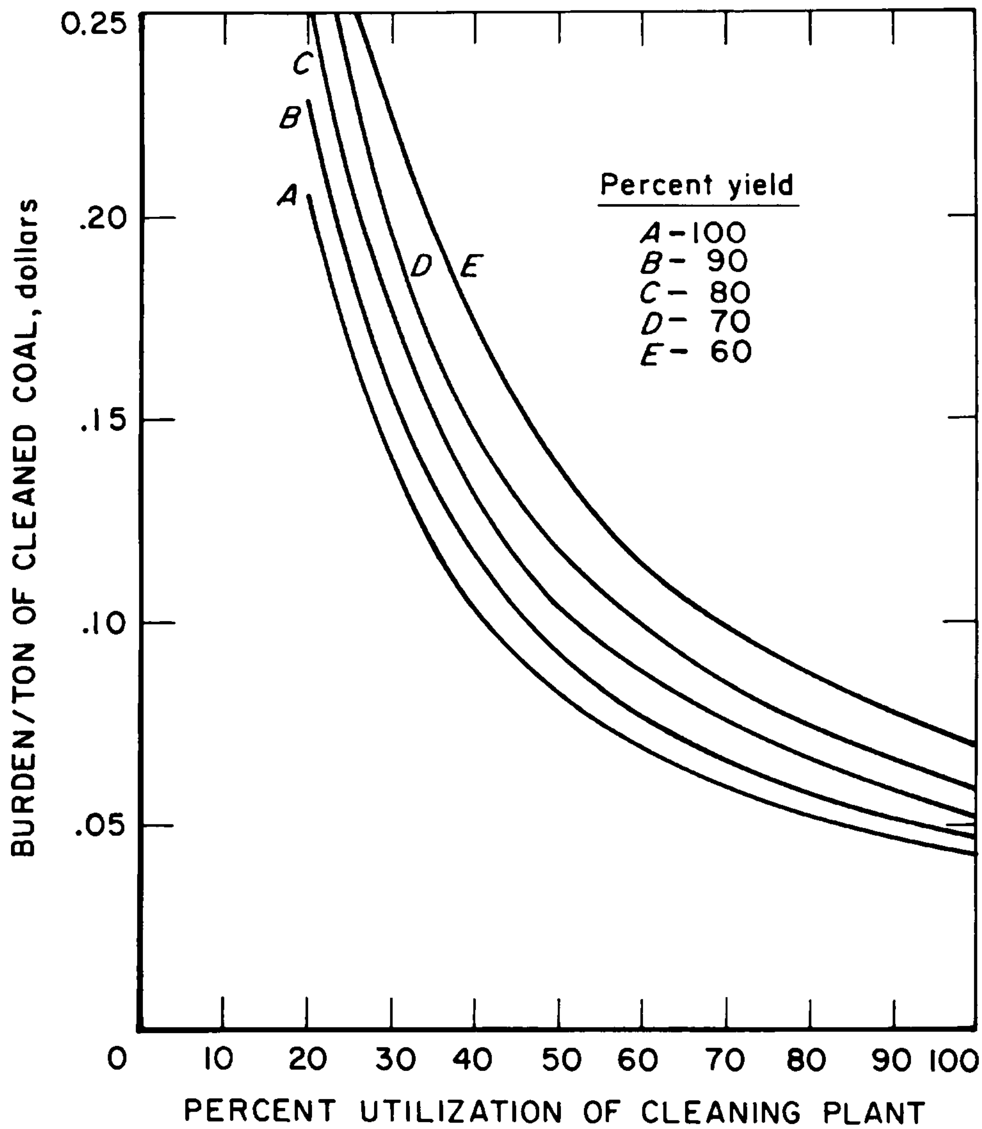

Figure 7–Tax and insurance burden/ton of cleaned coal, plant cost-$18,000 per ton-hour input capacity and tax and insurance rate of 2%.

5. Mine operators pay 74 cents to the Pension and Benefit Trust Fund for each ton of coal shipped from the mine. Cleaning, by raising the heat content of coal, will cause a decrease in the number of tons shipped (for a given heat content). Thereby, a savings equal to 74 cents times the reduction in shipped tonnage will be attained.

6. There is evidence that savings in powerplant maintenance costs will be obtained by using coal with reduced sulfur and ash content. Thus, since physical cleaning reduces the ash and sulfur content of coal, lower powerplant maintenance cost may result. In addition, for a given heat content value, fewer tons of cleaned coal need be handled by the powerplant. Therefore, powerplant units that are tonnage (utilization) limited will have an increased operational life.

7. Utilization of a more uniform coal, obtained by cleaning, results in better plant efficiencies and ease of operation. The economic impact of this factor will not be considered in this report since it has not been quantified separately.

4.2 Increased Heat Content

An economic benefit readily identifiable to the purchaser of cleaned coal is equivalent to the f.o.b. raw coal price (i.e., price of unprepared coal) times the fractional increase in heat value of the cleaned coal over that of the raw coal. This is the equivalent f.o.b. mine raw coal price associated with the amount of coal that provides the equivalent heat increase.

If raw coal has an initial heat content of $\underline{A}$ per ton and if upon physical cleaning the heat content decimal increase is $\underline{x}$, then the physically cleaned coal will have a heat content of A (1 + x) per ton. The increase over the initial value is A (1 + x)-A or $\underline{Ax}$ per ton. The fractional amount of cleaned coal that need not be shipped (i.e., the amount that offsets the heat content increase) is Ax/A (1 + x) or $\frac{x}{1 + x}$. For the purposes of this study the factor $\frac{x}{1 + x}$ shall be termed the multiplier factor $\underline{K}$. Therefore, the per-cleaned-ton benefit gained, a function of the raw coal f.o.b. price and the increase in heat content, is equal to the f.o.b. raw coal price (per ton) times $\frac{x}{1 + x}$. Figure 8 indicates the benefit gained as a function of raw coal f.o.b. mine price and the increase in heat content over the initial value.

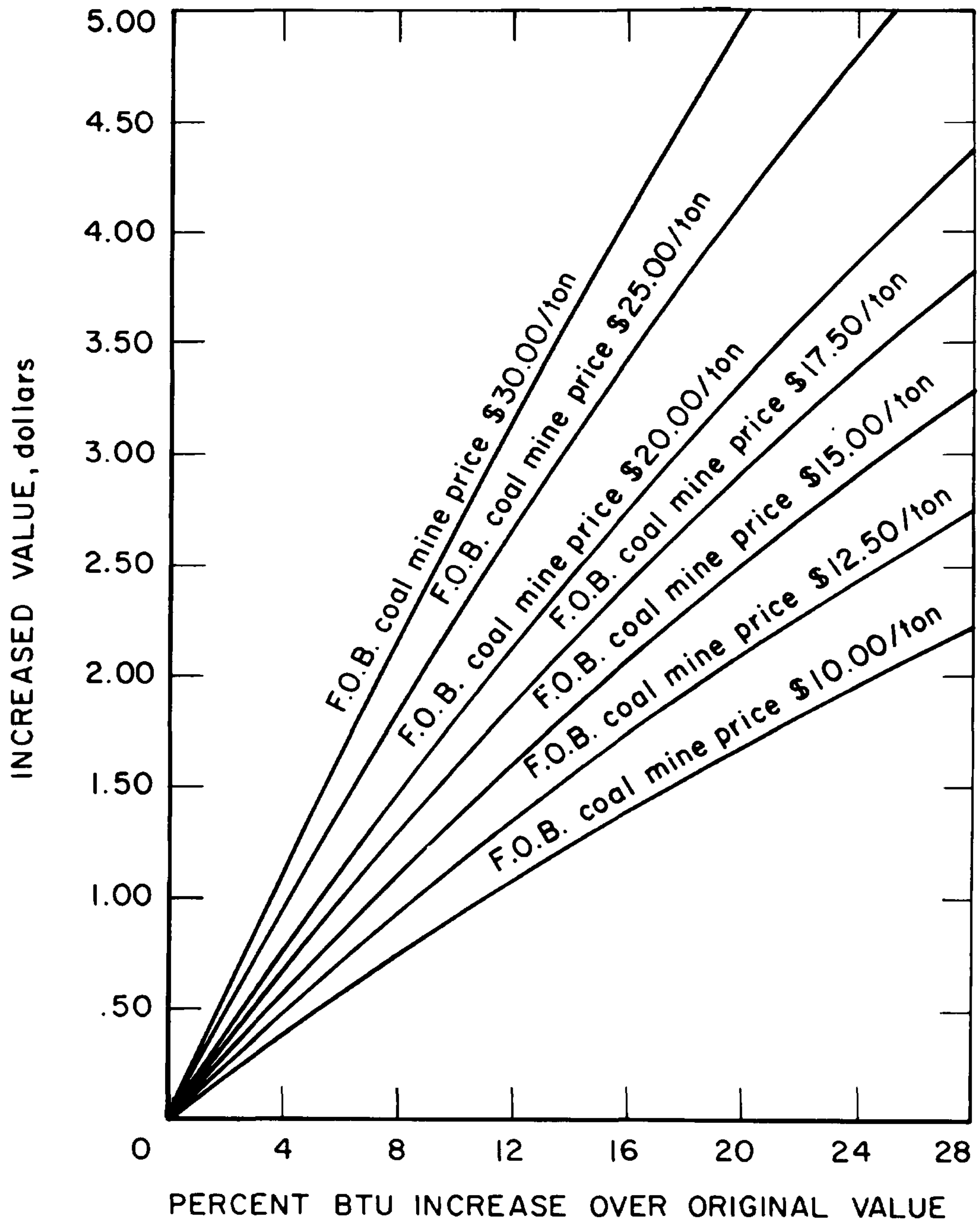

Figure 8—Added coal value due to increase in heat content.

4.3 Savings in Coal Transport Costs

Since cleaning increases the heat content of coal, less cleaned coal need be shipped to supply a given heat value. The amount of transport savings attainable by cleaning is a function of the increase in the coal heat content and the coal shipping costs.

The effective transport saving per ton of coal cleaned is equal to--

$$T.C. \times K,$$

where T.C. = transportation cost per ton of coal,

and K = the multiplier factor $\frac{x}{1 + x}$.

Figure 9 indicates the multiplier factor K as a function of heat content increase.

Coal is currently shipped by train, waterway carrier, truck, and slurry pipeline. The transport mode or combination of modes employed in a given situation is usually determined by overall economic considerations. Coal loaded for shipping in 1973 as reported by mine operators is provided in Table 2.

TABLE 2. COAL LOADED FOR SHIPMENT IN THE UNITED STATES, IN 1973, AS REPORTED BY MINE OPERATORS

	Thousands short tons
Total Railroad shipments	397,158
Total Waterway shipments	68,604
Shipped by truck to final destination	57,268
Coal transported to electric utility plants adjacent to or near mine	64,424
All others*	4,284
Total production	591,738

* Includes coal used at mine for power and heat, made into beehive coke at mine, used by mine employees, used for all other purposes at mine, and shipped by slurry pipeline.

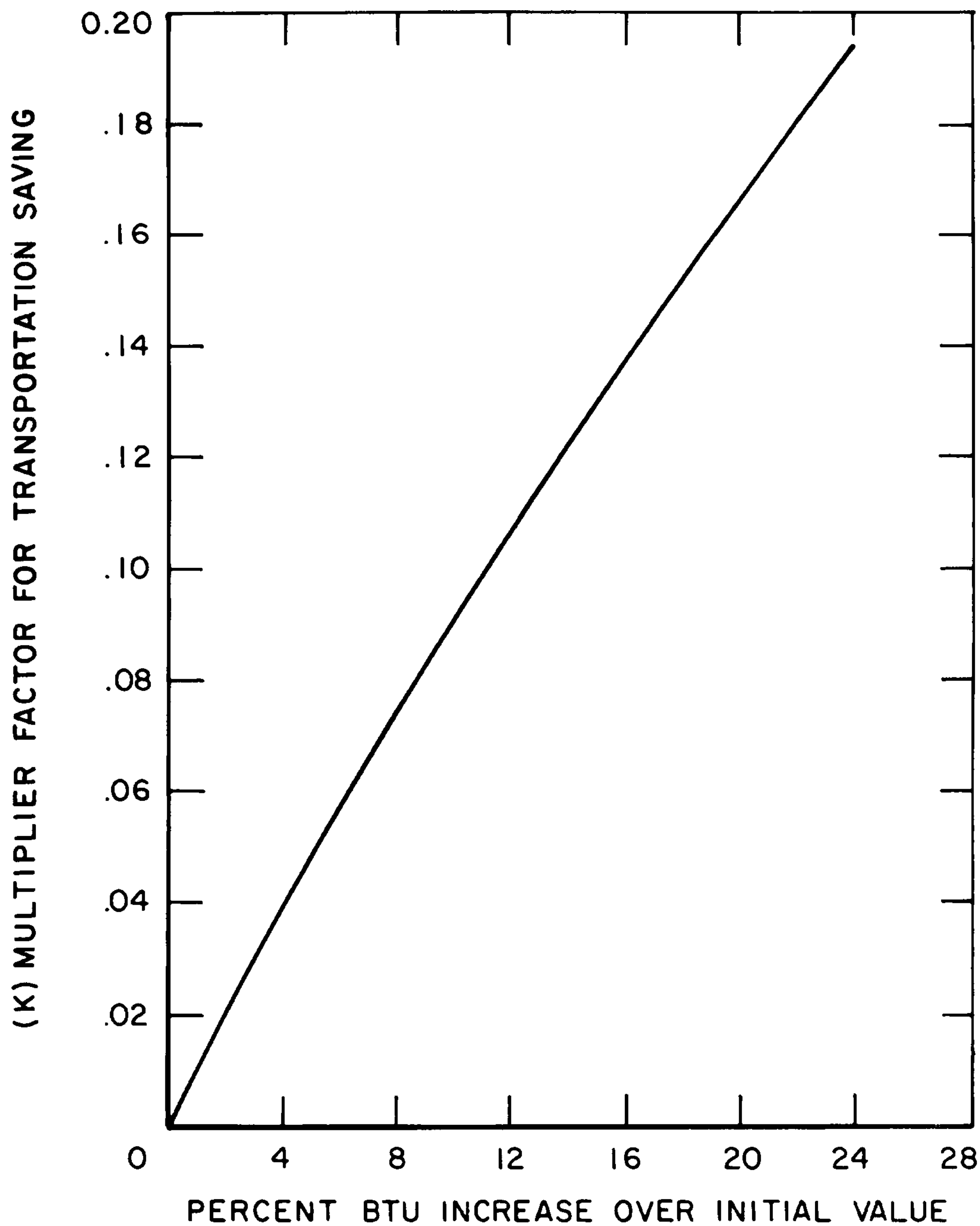

Figure 9—Effective savings in transport cost due to increase in coal heat content (equals shipping cost × K).

As indicated by this Table, the majority of coal is shipped by the railroads. This study therefore only considers the rail mode of shipping. The rail transportation costs used in this study are based on information reported by the Bureau of Mines and the Interstate Commerce Commission. Transportation costs to be realistic must reflect current conditions and practices that tend toward large annual tonnages along with economic train-load tonnage levels. The actual shipping rates used are based on rates for coal shipped in cars owned by the railroad (so as to reflect real costs) as reported by Reference 10 and updated by an appropriate time-cost correction factor so as to reflect current costs. Transportation cost development as based on referenced inputs and study constraints are provided in Appendix G.

4.4 Savings in Ash Disposal Costs

Savings in ash disposal costs will be realized when cleaned coal is used (i.e., as opposed to raw coal). This saving is due to the following two reasons:

- Cleaning lowers the ash content of coal
- The heat content is raised by the cleaning process. Therefore, less coal needs to be burned for a given heat content value.

The effective saving in ash disposal cost per ton of cleaned coal burned is equal to the ash disposal saving per ton of coal burned, resulting from lower ash content, times a multiplier factor to account for the higher heat content of the cleaned coal. This multiplier factor is (1 + x), where (x) is the fractional increase in heat content. Assuming that a (x) fractional increase in heat content results from a (x) fractional reduction in ash content, then the total effective ash disposal savings per ton of coal burned is equal to the disposal cost per ton of ash times x (1 + x).

4.5 Savings in Coal Pulverizing Costs

Evidence exists that in some cases reducing the amount of the harder impurities (e.g., pyrite) makes coal easier to pulverize. However, this effect does not appear to be universal, and the effect on pulverizing cost is not always discernible. It is currently estimated that it costs \$0.50 to pulverize 1 ton of coal, compared with \$0.25 5 years ago. This \$0.50 value is considered the total operation and maintenance cost.

The identifiable saving associated with cleaning coal results from the increased heat content of a ton of cleaned coal since less tonnage need be pulverized to supply a given heat value. The cost savings relationship (on a per ton basis) is--

$$\text{Cost savings} = \$0.50 \text{ times } K,$$

where K = the multiplier factor $\dfrac{x}{1 + x}$.

As an example, consider that cleaning raises the heat content of coal by 10 percent; e.g., from 10,000 to 11,000 Btu per pound. In this case, the fractional decrease in the amount of coal that would compensate for the increase in heat content is $\frac{0.1}{1 + 0.1} = \frac{0.1}{1.1}$. The saving would be (on an equivalent per-ton basis) equal to $0.50 \times \frac{0.1}{1.1}$ or \$0.0454 for each ton of cleaned coal burned.

4.6 Savings in Payment to Trust Fund

The mine operator pays 74 cents to the Pension and Benefit Trust Fund for each ton of coal shipped to a consumer. If by cleaning, the heat content is raised by a decimal increase of x, then to satisfy a given heat content demand $\frac{x}{1 + x}$ less coal need be shipped. The savings attributable to each ton of cleaned coal is then equal to \$0.74 times K.

4.7 Maintenance Savings

Only two data sources have been identified in which operating conditions and collected data are such as to permit a judgment relating sulfur and ash content in coal to powerplant maintenance costs. The two sets of data are for identical steam powerplants which burn coals of different ash and sulfur contents.[5] The available data, however, do not permit firm assessments of variations in maintenance savings with variations in coal ash and sulfur contents.

These data are derived from two Tennessee Valley Authority (TVA) generating boiler units each having 200 Mw generating capacity. These two units, both pulverized-coal-fired boilers, were placed in operation in the middle 1950's. Information on the coal-associated maintenance costs for the two plants is given in Tables 3 and 4. The data cover approximately 74 million tons of consumed coal. The economic data are contained in a February 1969 report (Reference 5) and are assumed to represent economic relationships during 1968. The available maintenance data with conclusions indicate--

- Maintenance costs for all the items listed in Table 4 are greater for the plant burning the higher ash and sulfur coal.

- The difference in maintenance cost during CY 1968 amounted to 11.63 cents per ton of coal. This difference in maintenance cost for the two units is almost two to one. This difference is not accounted for by the 5 percent difference in heat content value between the two coals. The current difference in maintenance cost, as based on escalation cost of skilled labor, is currently estimated to equal 19.8 cents per ton of coal.

TABLE 3. AVERAGE ANALYSES OF "AS-BURNED" COALS UTILIZED IN TWO IDENTICAL STEAM ELECTRIC PLANTS

	Plant A	Plant B
Moisture, percent	4.9	5.1
Volatile matter, percent	32.4	33.8
Fixed carbon, percent	52.1	47.7
Ash, percent	10.8	13.4
Sulfur, percent	1.0	2.7
Btu content (per pound)	12,680	12,053

Source: Reference 5

TABLE 4. COMPARISON OF 1968 MAINTENANCE COSTS IN IDENTICAL POWERPLANTS BURNING COALS OF DIFFERENT ASH AND SULFUR CONTENT

Items with coal associated maintenance costs	Maintenance costs (cents per ton)	
	Plant A	Plant B
Primary coal crushing	0.34	0.76
Coal conveyors	1.24	1.65
Boilers	3.72	6.42
Soot blowers	0.80	2.55
Pulverizers	3.45	5.38
Burners	0.80	1.59
Air preheaters	0.41	0.62
Bottom ash hoppers	0.55	1.73
Fly-ash collectors	0.80	1.52
Ash disposal system	2.70	3.60
Coal piping	0.80	1.42
Totals	15.61	27.24

Source: Reference 5

As indicated in Table 3, the average difference in ash content of the coals consumed by the two plants was 2.6 percent and the average difference in sulfur content was 1.7 percent. No information is available on maintenance costs with variations in ash and sulfur content for a given plant. However, these results suggest that maintenance savings of up to 33 cents per ton of coal burned may be expected in steam plants capable of substituting lower sulfur and ash coal for their current steam coal.

For the purposes of this study, it is assumed that the maintenance savings indicated in Table 5 will be obtained for the listed reductions in total ash and sulfur contents. The assumed savings are based on TVA data (Reference 5) as corrected to reflect current economic conditions.

TABLE 5. ASSUMED MAINTENANCE SAVINGS AS A FUNCTION OF ASH AND SULFUR REDUCTION

Total additive reduction in ash and sulfur	Maintenance savings per ton of coal burned
15 percent and over	$0.33
12 percent to 15 percent	0.30
9 percent to 12 percent	0.27
7 percent to 9 percent	0.24
5 percent to 7 percent	0.20
3 percent to 5 percent	0.17
2 percent to 3 percent	0.13

5.0 EVALUATION OF COSTS ASSOCIATED WITH FLUE GAS DESULFURIZATION

5.1 Flue Gas Desulfurization Plant Costs

For assessment purposes, information on capital cost and related data useable for developing capital-cost-scaling relationships were obtained from References 9 and 13. Discussions with the EPA Energy Process Division and the EPA Office of Planning and Evaluation indicated that cost data contained in Reference 13 appear to reflect current industry conditions; Reference 9 gives cost information for a little earlier time period. Even so, data contained in both references provided the basis for development of the required size-versus-capital cost-scaling relationships.

Capital costs for 12 model plants (Reference 13) are provided in Table 6. Each model plant size was analyzed for two SO_2 control requirements: high-sulfur coal (3.5 percent) with a SO_2 limitation of 1.2 pounds per million Btu (Federal New Source Performance Standard), and low-sulfur coal (0.6 percent sulfur by weight) with a SO_2 limitation of 0.15 pound per million Btu. These equate to SO_2 removal efficiencies (assuming coal containing 23 million Btu per ton) of 80 and 85 percent, respectively. The provided cost per kilowatt of capacity decreases between 10.2 and 13.5 percent (depending on plant category) as size increases from a 250- to a 500-Mw capacity and are constant per kilowatt of capacity for listed plants in excess of 500 Mw capacity. The Environmental Protection Agency, the study sponsor of the Reference 13 report, indicated that 500 Mw was the break point and that a 1,000-Mw plant, from a cost standpoint, would be two 500-Mw plants.

TABLE 6. LIMESTONE MODEL PLANT CAPITAL COSTS

Model plant characteristics	Scrubbing* $/KW	Sludge disposal† $/KW	Indirect costs‡ $/KW	Total $/KW	Total $ MM
<u>250-Mw capacity</u>					
Retrofit, 3.5 pct. S	40	6	35	81	20.2
New, 3.5 pct. S	30	8	28	66	16.5
Retrofit, 0.6 pct. S	38	4	32	74	18.6
New, 0.6 pct. S	29	5	25	59	14.7
<u>500-Mw capacity</u>					
Retrofit, 3.5 pct. S	35	5	30	70	35.1
New, 3.5 pct. S	28	5	25	58	29.2
Retrofit, 0.6 pct. S	34	3	28	65	32.3
New, 0.6 pct. S	27	3	23	53	26.4
<u>1,000-Mw capacity</u>					
Retrofit, 3.5 pct. S	36	4	30	70	69.5
New, 3.5 pct. S	29	4	24	57	56.8
Retrofit, 0.6 pct. S	34	2	28	64	64.4
New, 0.6 pct. S	28	2	22	52	52.0

* Includes limestone preparation system (conveyors, storage silo, ball mills, pumps, motors, and storage tank) and scrubbing system (absorbers, fans, and motors, pumps and motors, tanks, reheaters, soot blowers, ducting, and valves).

† Sludge disposal costs do not include associated indirect charges.

‡ Includes interest during construction, field labor and expenses, contractor's fees and expenses, engineering, freight, spares, taxes, contingency, and allowance for shakedown.

As indicated, other plant cost information was obtained from Reference 9. Capital investment costs provided by that report are given in Table 7. The limestone model plant capital costs according to Table 7 are lower than those indicated by Reference 13. It should be noted that investment costs depend heavily on project definition and the development time period. For example, the capital cost for a 500-Mw coal-fired desulfurization unit would be increased per Reference 9 by an additional $13.50 per kw installed capacity by providing reliability provisions, additional bypass ducts and dampers, and a fly-ash pond including closed-loop provisions.

TABLE 7. FLUE GAS DESULFURIZATION CAPITAL COST ESTIMATES

Plant characteristics	Years of life	Limestone Process $	$/kw
90 percent SO_2 removal; on-site solids disposal			
200 Mw N* 3.5 percent S	30	13,031,000	65.2
200 Mw N 3.5 percent S	20	11,344,000	56.7
500 Mw N 3.5 percent S	25	23,088,000	46.2
500 Mw N 2.0 percent S	30	22,600,000	45.2
500 Mw N 3.5 percent S	30	25,163,000	50.3
500 Mw N 5.0 percent S	30	27,343,000	54.7
1,000 Mw E* 3.5 percent S	25	35,133,000	35.1
1,000 Mw N 3.5 percent S	30	37,725,000	37.7
80 percent SO_2 removal; on-site solids disposal			
500 Mw N 3.5 percent S	30	24,267,000	48.5
90 percent SO_2 removal; off-site solids disposal			
500 Mw N 3.5 percent S	30	20,532,000	41.1
90 percent SO_2 removal; on-site solids disposal (existing unit without existing particulate collection facilities)			
500 Mw E 3.5 percent S	25	29,996,000	60.0

* N-New; E-Existing.

Source: Reference 9.

One would expect that over a limited size range the following plant size-cost relationship to generally hold:

$$\frac{\text{Cost plant A}}{\text{Cost plant B}} = \left(\frac{\text{capacity plant A}}{\text{capacity plant B}}\right)^{x},$$

where x is the capacity-cost exponent and is usually less than 1. For chemical and processing plants the value of x generally falls between 0.7 and 0.9. The values of x as determined from Reference 13 (Table 6) cost values are--

1. For Retrofit Plant Installation and 3.5 Percent Sulfur Coal

$$\frac{35.1}{20.2} = \left(\frac{500}{250}\right)^{x}$$

$$\ln \frac{35.1}{20.2} = x \cdot \ln 2$$

$$x = 0.80$$

2. For New Plant Installation and 3.5 Percent Sulfur Coal

$$\frac{29.2}{16.5} = \left(\frac{500}{250}\right)^{x}$$

$$\ln \frac{29.2}{16.5} = x \cdot \ln 2$$

$$x = 0.82$$

3. For Retrofit Plant Installation and 0.6 Percent Sulfur Coal

$$\frac{32.3}{18.6} = \left(\frac{500}{250}\right)^{x}$$

$$\ln \frac{32.3}{18.6} = x \cdot \ln 2$$

$$x = 0.80$$

4. New Plant Installation and 0.6 Percent Sulfur Coal

$$\frac{26.4}{14.7} = \left(\frac{500}{250}\right)^x$$

$$\ln \frac{26.4}{14.7} = x \cdot \ln 2$$

$$x = 0.84$$

From Table 7, capital cost versus sulfur content data with 90 percent SO_2 removal and on-site solids disposal are--

Plant Characteristics	Costs (in millions of dollars)
500 Mw, New Plant, 2% S Coal	22.6
500 Mw, New Plant, 3.5% S Coal	25.163
500 Mw, New Plant, 5% S Coal	27.343

A plot of the foregoing indicates that for the same removal efficiency the following may be expected:

Sulfur Content Design Level	Capital Cost as Percent of 3.5% S Design Level Cost
3%	96.6
2-1/2%	93.2
2%	89.9
1-1/2%	86.4

Data contained in the same reference indicate that the capital cost for a plant with a 90-percent SO_2 removal efficiency is approximately 4 percent higher than the cost for a plant with an 80-percent removal efficiency.

The FGD systems' capital costs used for assessment purposes are based on Reference 13; cost versus designed-sulfur-content scaling relationships are based on Reference 9.

The assumed capital costs for a 90-percent SO_2 removal FGD system installed as a retrofit are--

Plant Characteristics	Cost (million dollars)
250 Mw, 3.5% S	20.2 x 1.04 = 21.01
250 Mw, 3.0% S	20.2 x 1.04 x 0.966 = 20.29
250 Mw, 2.5% S	20.2 x 1.04 x 0.932 = 19.58
250 Mw, 2.0% S	20.2 x 1.04 x 0.899 = 18.89
250 Mw, 1.5% S	20.2 x 1.04 x 0.864 = 18.15
250 Mw, 1.0% S	20.2 x 1.04 x 0.864 = 18.15
250 Mw, 0.5% S	20.2 x 1.04 x 0.864 = 18.15

The assumed capital costs for a 90-percent SO_2 removal FGD system installed on a new installation are--

Plant Characteristics	Cost (million dollars)
250 Mw, 3.5% S	16.5 x 1.04 = 17.16
250 Mw, 3.0% S	16.5 x 1.04 x 0.966 = 16.58
250 Mw, 2.5% S	16.5 x 1.04 x 0.932 = 15.99
250 Mw, 2.0% S	16.5 x 1.04 x 0.899 = 15.43
250 Mw, 1.5% S	16.5 x 1.04 x 0.864 = 14.83
250 Mw, 1.0% S	16.5 x 1.04 x 0.864 = 14.83
250 Mw, 0.5% S	16.5 x 1.04 x 0.864 = 14.83

Size scaling for plants that differ from 250-Mw capacity are based on--

For Retrofit Installation

$$\frac{\text{Cost X}}{\text{cost 250 Mw size}} = \left(\frac{\text{capacity X in Mw}}{250}\right)^{0.8}$$

For New Installations

$$\frac{\text{Cost X}}{\text{cost 250 Mw size}} = \left(\frac{\text{capacity X in Mw}}{250}\right)^{0.8}$$

Once the capital cost associated with the FGD system (either new or retrofit) is determined based upon the above scaling relationships, it is necessary to properly allocate this cost annually over the reasonable life expectancy of the installation. By updating and expanding information obtained from Reference 9 relative to determining annual capital charges for the power industry, the following cost components were found to apply.

5.2 Annual Capital Charges For Financing

	As Percentage of Original Investment Years Remaining Life				
	28	25	20	15	10
Depreciation-straight (based on useable life of unit)	3.57	4.00	5.00	6.67	10.00
Interim replacement (unit having less than 30-yr life)	0.56	0.40	-	-	-
Insurance	0.50	0.50	0.50	0.50	0.50
Total rate applied to original investment	4.63	4.90	5.50	7.17	10.5

5.2 Annual Capital Charges For Financing (Con.)

	As Percentage of Outstanding Depreciation Base
Cost of Capital (capital structure assumed to be 50% debt and 50% equity)	
Bonds at 9% interest	4.50
Equity at 12% return to stockholder	6.00
Taxes	
Federal (50% of gross return or same as return on equity)	6.00
State (national average for states in relation to Federal rates)	4.80
Total rate applied to depreciation base	21.30
Rate applied on an average basis	10.65

Combining the various annual capital charges for financing gives a set of total annual percentages applied on an average basis for each of the possible installation life expectancies as follows:

For 28 years = 4.63 + 10.65 = 15.28
For 25 years = 4.90 + 10.65 = 15.55
For 20 years = 5.50 + 10.65 = 16.15
For 15 years = 7.17 + 10.65 = 17.82
For 10 years = 10.5 + 10.65 = 21.15

5.3 Flue Gas Desulfurization Costs Per Ton Of Coal Burned

Now, having established the scaling relationships and the other relevant cost components, the FGD system costs on each ton of coal burned can be determined for any given coal-burning installation. The following FGD costs per ton of coal burned are based upon an electric utility heat rate of 10,000 Btu/kwh. In addition, since only a portion of the stack gas would normally be treated, stack gas reheat would not generally be required.

a. Capital Cost Per Ton of Coal =

$$\frac{\text{capital cost (\$) x annual \% of original investment applied on average basis}}{\text{tons of coal burned per year X 100}}$$

b. Fuel and Electricity

Reference 13 indicates a fuel and electricity cost of between 0.27 and 0.30 mill per kwh irrespective of plant size. This value is associated only with flue gas cleaned. The levelized cost ($) per ton coal burned is equal to--

$$\frac{0.29 \text{ Mill/kwh}}{1{,}000 \text{ mill/\$}} \times \frac{\text{Btu per ton coal burned}}{10{,}000 \text{ Btu/kwh}} \times \frac{\text{\% flue gas cleaned}}{100}$$

$$= 2.9 \times 10^{-10} \times \text{Btu per ton coal burned} \times \text{\% flue gas cleaned}$$

$$= 2.9 \times 10^{-4} \times \text{MM Btu per ton coal burned} \times \text{\% flue gas cleaned}$$

c. Raw Materials

Limestone and fixation chemicals costs are scaled directly from cost provided in Reference 13. The amount of limestone or fixation chemicals required per hour essentially varies directly with plant size and the sulfur content of the coal. For each case, the estimated costs per ton of coal burned are as follows:

Limestone cost (\$) per ton of coal burned =

$$\frac{7.543 \times 10^{-4} \times \text{Mw capacity of scrubber} \times \text{\% sulfur} \times \text{\% flue gas cleaned}}{\text{tons coal burned per hour}}$$

$$= 7.543 \times 10^{-5} \times \text{MM Btu per ton coal} \times \text{\% S} \times \text{\% gas cleaned}$$

Fixation chemicals (\$) per ton burned =

$$\frac{6.16 \times 10^{-4} \times \text{Mw capacity of scrubber} \times \text{\% sulfur} \times \text{\% flue gas cleaned}}{\text{tons coal burned per hour}}$$

$$= 6.16 \times 10^{-5} \times \text{MM Btu per ton coal} \times \text{\% S} \times \text{\% gas cleaned}$$

d. Operating Labor

The operating labor estimate is based on two men at \$8 per man-hour and supervision equal to 15 percent of direct labor. The operating labor (\$) per ton coal burned is estimated to equal:

$$\frac{2 \times 1.15 \times \$8\text{/hr} \times 8{,}760 \text{ hr/year}}{\text{tons coal burned per year}}$$

$$= \frac{\$161{,}184}{\text{tons coal burned per year}}$$

e. Maintenance Cost

Maintenance cost per year fall into two categories: (1) Labor and materials, and (2) supplies. Labor and materials per year are estimated at 4 percent of the fixed investment, and supplies are estimated at 15 percent of the labor and materials value (i.e., 0.6 percent of the fixed investment). The cost per ton of coal burned is merely the yearly values divided by the number of tons burned per year.

f. Overhead values are as follows:

Plant - 50 percent of operation and maintenance
Payroll - 20 percent of operating labor

6.0 CASE STUDIES

6.1 Basis and Economic Approach Behind Case Study Analysis

As has been previously stated, the basic objective of this study sponsored by the Bureau of Mines was to perform engineering and economic analyses of coal preparation followed by SO_2 cleanup processes with the intent of establishing the attractiveness of keeping some higher sulfur coals in the energy market. Since the largest user of coal in this country is the electric power generating industry, the study was directed at this economic sector.

Toward this end, studies were made of the cost factors associated with coal cleaning (Section 3 and Appendixes D, E, and F). An analysis of such costs quite logically leads into a study of the many benefits associated with physical cleaning of coal. The major benefits of physical cleaning include reduced transportation cost for the same heat content, higher Btu per unit weight, reduction in pulverizing costs, savings in maintenance cost, reduced payments to miners' benefit fund, and savings in ash disposal costs.

Following the analysis of cleaning cost and benefit factors, an evaluation of the costs associated with flue gas desulfurization (FGD) systems of various sizes was conducted. This evaluation provided reasonable estimates of the capital costs associated with constructing FGD systems, depending on the particular size of the plant, its age, and the sulfur content of the flue gas to be treated. As has been indicated in Section 5 on the economics associated with FGD, a scrubber installed on a new plant is less expensive than one installed as a retrofit to an existing facility. These differences in cost include the inefficiencies of working around existing piping and other obstructions. In addition, details of significant operation and maintenance aspects of FGD systems were considered to arrive at a methodology for estimating such costs for plants of varying sizes burning coal of different sulfur contents.

Having identified the costs and benefits associated with coal cleaning and FGD, the next step was to select a broad range of coal sources which due to their sulfur content typically would require some level of coal preparation and/or flue gas desulfurization to render them environmentally acceptable in many areas of the country. Eight of the 23 coal districts as outlined by the Bituminous Coal Act of 1937 were selected as potential sources. These encompass a number of Appalachian and Interior coals.

The final step before commencing the actual economic analysis on a case-by-case basis was to arrive at reasonable user locations. To accomplish this, we considered the following 20 States: Alabama, Delaware, Illinois, Indiana, Iowa, Kentucky, Maine, Maryland, Massachusetts, Michigan, Minnesota, New Hampshire, New Jersey, New York, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and Wisconsin. These were considered in that they represented reasonable transportation distances from and had been historically served by the previously mentioned Appalachian and Interior Coal sources. In addition to considering these potential user States, it was necessary to do an exhaustive analysis of the environmental regulations governing the emission of sulfur dioxide from large coal-burning installations. Many times these regulations differ for new and existing facilities. These regulations were summarized and appear in Appendix A. Having established the legal emission levels in each of the potential user States, it was possible to determine the extent to which a combination of reasonable cleaning and FGD would suffice. Such analysis was conducted for each source-user combination on the basis of both a new and an existing facility. In addition, each case was analyzed from the standpoint of using FGD exclusively. This provided comparative economics of the two approaches to meeting environmental standards on both new and existing coal-burning utilities.

To determine where within each of the potential user States coal from the selected regions might practically be consumed, publications from the National Coal Association (Reference 11) and the Illinois Geological Survey (Reference 6) and confidential sources were consulted. These gave specific locations of large power generation facilities which were designated as "coal use areas" in each of the case studies. At this point, it was necessary to determine the general locations from which these using locations had historically obtained their coal. To accomplish this, actual utility companies were contacted directly and publications were reviewed such as Bureau of Mines Information Circular 8614 (Reference 10). From these same sources, actual shipping costs on a per-ton basis were extrapolated. So as not to distort the impact of this factor, only large-volume transportation cost information was used. Since this shipping information covered the 1972 period, it was necessary to update these figures to December 1975, using the Bureau of Labor Statistics Index of Coal Transportation by Rail. The procedure for accomplishing this is covered by Appendix G.

6.2 Case Study Analysis - An Example

Now, having given some of the background of the basic ingredients used in each of the case studies, a step-by-step example will attempt to highlight the more significant economic considerations. In the particular example given, the new steam-electric plant is assumed to be burning coal which has been physically cleaned with the flue gas passing through a stack gas scrubbing system (flue gas desulfurization) to the extent necessary to achieve the required sulfur dioxide emission level. This case appears in its entirety as Case Number 12A in Appendix B and for the purposes of explanation, the same numerical headings and nomenclature will be used.

1.0 CASE CONDITIONS - Case Number: 12A   Combined Use of Physical Cleaning Followed by Stack Gas Scrubbing

The case conditions set forth the basic technical, environmental, and economic parameters for the particular situation being examined.

1.1 Coal Use Area: Dickerson (Montgomery County), Maryland

An electric utility currently operates a 580 Mw coal burning plant at this site in Montgomery County, Maryland. According to available information, this plant consumes approximately 1.3 million tons of coal per year.

1.2 Emission Standards: New: 1% Sulfur by Weight
Existing: N/A

Currently, the State of Maryland regulations restrict coal-burning installations in the Washington Metropolitan area, which includes Montgomery County, Maryland, to the use of coal having no more than 1 percent sulfur by weight. This limit has been used for the purpose of case analysis, although it is projected that subsequent limits will more closely follow the Federal New Source Performance Standard of 1.2 pounds of sulfur dioxide per million Btu.

1.3 Coal District of Origin: No. 3   Coalbed: Pittsburgh
State: West Virginia   County: Marion

Within district 3, coal from the Pittsburgh coalbed in Marion County, West Virginia, was selected. This choice is consistent with information obtained relative to the areas from which coal has typically been procured by this user.

1.4 Raw Coal

		Ash: 11.0%
Lb SO_2/MM Btu: 5.70	Sulfur: 3.80%	MM Btu/Ton: 26.66

After selecting a reasonable source for the coal in each case, data were obtained on a specific coal from Bureau of Mines Report of Investigations RI 8118 with the Btu content adjusted for the moisture level of the raw coal.

1.5 Clean Coal

		Ash: 5.9%
Cleaning Plant Yield: 90.0%	Sulfur: 2.16%	MM/Btu/Ton: 28.09
Lb SO_2/MM Btu: 3.08	Btu Recovery: 94.8%	Btu Increase: 5.36%

As indicated in Section 2, General Considerations and Approach, a 90 percent by weight coal cleaning yield will be uniformly applied for the purposes of these analyses. The above data represent Bureau of Mines laboratory results published in the Reference 1 report. For the purpose of treating the influence of moisture content, it is assumed in all cases that the moisture content of the clean coal is the same as that of the raw coal.

1.6 Transportation Mileage: 245 Cost Per Ton: $6.60

Using actual information from industry sources on typical transportation distances and costs to the using facility, as well as historical data on annual coal shipments and costs from coal district 3 to the Maryland area, reasonable estimates were set for purposes of analysis. The distances in rail miles were confirmed using current railroad maps, and the per-ton shipping costs were confirmed to the greatest extent possible from the rail carriers involved.

1.7 Assumed Plant Size Megawatts: 500

For the purposes of this study, all case analyses are based upon a 500-Mw plant size.

1.8 Remaining Life Of Boiler: 25 Yr

In this particular example, a new installation is assumed to have a 25-year life. This factor is important for purposes of amortizing the flue gas desufurization (FGD) system. In other case studies appearing in Appendix B, 15 years is assumed for existing plants where a FGD system retrofit would be appropriate.

1.9 Assumed Ash Disposal Cost: $4.00/Ton

In all case analyses where coal cleaning is considered, $4.00 per ton is assumed for ash disposal cost. Based upon information obtained from industry sources, this is felt to be a realistic estimate on the conservative side. For example, some utilities are paying as much as $7.00 per ton.

1.10 Cleaning Plant Cost: $18,000 Per Ton-Hour Of Input Capacity
Utilization: 38.58%

As explained in Section 3, current estimates of cleaning plant cost range from $16,000 to $18,000 per ton-hour of input capacity. The upper limit of $18,000 has been used in all case analyses where coal cleaning is being considered. As to cleaning plant utilization, it has been assumed in all cases that the plant operates 13 hours per day for 260 days out of the year, or 38.58 percent of the time--

$$\left(\frac{260 \text{ days/yr} \times 13 \text{ hr/day}}{365 \text{ days/yr} \times 24 \text{ hr/day}}\right).$$

1.11 Assumed Annual Capital Scrubber Charges As Percent Of Original Investment: 15.55%

In Section 5, covering the annual capital charges for financing flue gas desulfurization systems, the total annual percentage to be applied on an average basis to the original investment is derived. This percentage is 15.55 percent for a new plant having an expected life of 25 years. For those cases where an existing installation is assumed, a 15-year remaining life is used consistently and an annual percentage of 17.82 percent is applied.

2.0 COAL CLEANING COST FACTORS

Under this part in each of the case analyses, the major cost factors that apply to the particular coal being cleaned are covered.

2.1 Cleaning Plant Costs Amortization: $0.68/Ton O & M: $0.75/Ton

To determine the reasonable amortization on a per-ton basis of the cleaning plant capital cost of $18,000 per ton-hour of input capacity, certain considerations must be given to the manner in which the plant will be operated and the long-term financing market at the time. For all case analyses, it was assumed that cleaning plant owners would be paying approximately two points (2 percent) over the prime interest rate. Assuming a prime interest rate of 6 percent, this gives an effective rate of 8 percent, which yields an annual capital recovery factor of 0.11468 as derived in Section 3. Using this factor and the already given operating parameters of the cleaning plant gives--

$$\frac{18{,}000 \text{ \$/ton-hr} \times 0.11468 \text{ \$/yr/\$ invested}}{3{,}380 \text{ hr/yr} \times 0.90 \text{ cleaning plant yield}} = \$0.68/\text{ton.}$$

The figure of $0.75 per ton for cleaning plant operating and maintenance cost comes from well-established sources, as set forth in Section 3 and taken from Figure 5.

2.2 Additional Cost To Mine Operator To Provide For 1 Ton Of Clean Coal When Mine Operator's Cost Per Ton Of Raw Coal Is--

$ 9.00/Ton, Additional Cost Is $1.00/Ton
$11.00/Ton, Additional Cost Is $1.22/Ton
$13.00/Ton, Additional Cost Is $1.44/Ton

In the cleaning of coal, obviously more than 1 ton of raw coal must be processed in order to achieve 1 ton of clean coal. The amount of additional coal required depends on the level to which the coal is cleaned. For these analyses, it is assumed that the cleaning plant is located at the mine site and is operated by the mine operator. From an economic standpoint, this additional increment of coal lost in the cleaning process represents a cost to the cleaning plant operator which must be considered. In the case of coal cleaning to 90 percent weight yield this cost is equal to--

$$\left(\frac{1}{.90} - 1\right) \text{X mine operator's cost per ton of raw coal.}$$

For the purpose of analysis a reasonable range of possible mine operator's costs per ton of raw coal was established with the use of industry sources, as well as Bureau of Mines, Federal Power Commission, and National Coal Association publications (References 4, 11, and 15).

2.3 Cleaning Plant Tax And Insurance Burden: $0.12/Ton

As covered by Section 3, a reasonable estimate of the tax and insurance burden attributable to each ton of coal cleaned is $0.12.

2.4 Total Differential Production Cost To Mine Operator To Provide A Ton Of Cleaned Coal, When Mine Operator's Cost Per Ton Of Raw Coal Is--

$ 9.00/Ton, Differential Cost Is $2.55/Ton
$11.00/Ton, Differential Cost Is $2.77/Ton
$13.00/Ton, Differential Cost Is $2.99/Ton

This part merely summarizes the various cost factors per ton of coal cleaned as covered by parts 2.1, 2.2, and 2.3 categorized according to estimated mine operator cost levels per ton of raw coal.

3.0 ASSESSABLE BENEFIT FACTORS ASSOCIATED WITH CLEAN COAL

Having considered the cost side of the coal cleaning process, this part assesses the benefits on a per-ton basis.

3.1 Added Coal Value Due To Higher Heat Content Of Coal, When F.O.B. Mine Raw Coal Price Is--

$17.00/Ton, Benefit Is $0.86/Ton
$19.00/Ton, Benefit Is $0.97/Ton
$21.00/Ton, Benefit Is $1.07/Ton

One of the major economic benefits of coal cleaning is the increase in Btu content for the same unit weight. This means a mine operator has a more valuable product to sell since the buyer is purchasing Btu's, not tons. Therefore, as derived in Section 4, the quantification of this benefit is--

$$\frac{\text{decimal Btu increase}}{1 + \text{decimal Btu increase}} \times \text{f.o.b. mine raw coal price.}$$

For the purpose of analysis, a reasonable range of possible f.o.b. mine raw coal prices per ton of cleaned coal was established with the use of industry sources, as well as Bureau of Mines, Federal Power Commission, and National Coal Association publications.

3.2 Transportation Cost Saving Due To Increased Heat Content Of Coal: $0.34/Ton

The same relationship discussed above also leads to a savings in transportation costs since fewer tons of coal need to be shipped to deliver the same quantity of Btu's to the user. On a per ton of coal basis the savings is--

$$\frac{\text{decimal Btu increase}}{1 + \text{decimal Btu increase}} \times \text{ shipping cost per ton.}$$

3.3 Saving In Ash Disposal Cost: $0.23/Ton

Since less ash is generated from the cleaned coal, there are definite savings associated with its disposal. As derived in Section 4, this savings is--

decimal Btu increase x (1 + decimal Btu increase) x ash disposal cost/ton.

3.4 Saving in Pulverizing Cost: $0.03/Ton

Following the same line of reasoning as that applied to the savings in transportation costs, the pulverizing facility at the using location is not required to process as much coal owing to the higher Btu content of the cleaned coal. Therefore, the savings are--

$$\frac{\text{decimal Btu increase}}{1 + \text{decimal Btu increase}} \times \text{ pulverizing cost per ton.}$$

As explained in Section 4, $0.50 per ton is representative of pulverizing costs in the power generating industry.

3.5 Saving In Benefit Payment: $0.04/Ton

In the mining industry, union contracts require the payment of a fixed sum into a Miners' Benefit Trust Fund for each ton of coal shipped. Currently, this amounts to approximately $0.74 per ton. Since the higher Btu content of the cleaned coal requires the shipment of fewer tons for the same total Btu yield, the savings in this area is--

$$\frac{\text{decimal Btu increase}}{1 + \text{decimal Btu increase}} \times \text{\$0.74 trust fund payment per ton.}$$

3.6 Saving In Maintenance: $0.20/Ton

As was established in Section 4, there is a definite relationship between the reduction in sulfur and ash that occurs during coal cleaning and savings in maintenance cost at the coal-burning facility. This relationship has been summarized in Table 5 on a per-ton of coal burned basis and was utilized in each case analysis where coal cleaning was considered. In this example case, the combined sulfur and ash reduction was 6.74 percent, and therefore a maintenance saving of $0.20 per ton was applied.

3.7 Total Benefits Of Coal Cleaning, When F.O.B. Mine Raw Coal Selling Price Is--

$17.00/Ton, Benefit Is $1.70/Ton
$19.00/Ton, Benefit Is $1.81/Ton
$21.00/Ton, Benefit Is $1.91/Ton

This part merely summarizes the various benefit factors per ton of coal cleaned as covered by parts 3.1 through 3.6 categorized according to estimated f.o.b. mine raw coal prices.

4.0 DIFFERENTIAL CLEANING COST LESS BENEFITS PER TON

		F.O.B. Mine Raw Coal Price (Per Ton)		
		17.00	19.00	21.00
Mine Operator's Cost	9.00	0.85	0.74	0.64
Of Raw Coal (Per Ton)	11.00	1.07	0.96	0.86
	13.00	1.29	1.18	1.08

This portion of the case analysis gives the net cost of cleaning 1 ton of coal. These values are the differences between the costs given in part 2.4 and the benefits summarized in part 3.7. This type of presentation gives the reader an opportunity to observe the net cleaning cost for the selected range of Mine Operator's Cost and F.O.B. Mine Raw Coal Prices.

5.0 STACK GAS COST FACTORS

Under this part, the magnitude of the flue gas desulfurization system necessary to meet the emission requirements of the particular using location is determined along with the capital amortization and operating and maintenance costs associated with such a system.

5.1 Boiler Capacity: 500 Mw

In all case analyses, a 500-Mw electric power generating capacity is assumed.

5.2 Utilization Factor: 7,000 Hr/Yr

According to industry sources and Reference 9, coal-burning electric power generating facilities operate on the order of 80 percent of the time (7,000 hours per year) during the first 10 years following construction. This utilization factor has been used in all case analyses where a new plant is being considered. In those cases where an existing installation is being considered (15 years remaining life), a utilization factor of 57 percent (5,000 hours) is assumed. According to the aforementioned Reference, this utilization factor is maintained for approximately the next 5 years, at which time it reduces still further.

5.3 Tons Of Coal Burned Per Year: 1,245,995 Tons

Given the Btu content of the coal being burned and the total hours the plant operates, the number of tons of coal burned annually by a 500-Mw plant can be calculated as follows:

$$\frac{10 \times 10^6 \text{ Btu/Mw hour} \times \text{hours of operation} \times 500 \text{ Mw of capacity}}{\text{Btu/ton of coal being considered}}$$

For this particular example, the aforementioned value was calculated as follows:

$$\frac{10 \times 10^6 \times 7{,}000 \times 500}{28.09 \times 10^6} = 1{,}245{,}995 \text{ tons per year}$$

5.4 Minimum Scrubber Requirements — Scrubber Rating: 299 Mw; % of Flue Gas Cleaned: 59.7%

Having established the maximum permissible emission level at the using location and the sulfur content of the cleaned coal, the minimum scrubber requirements necessary to meet such an emission standard can then be determined. The minimum scrubber requirements are determined as a function of the percent of flue gas which must be channeled through the flue gas desulfurization (FGD) system to meet the emission standard. This percentage is--

$$\frac{\%\text{ of flue gas cleaned}}{100} = \frac{1 - \dfrac{\text{required emission standard}}{\text{emission from coal prior to FGD}}}{\text{decimal operation efficiency of scrubber}}$$

For this particular case the following applied:

$$\frac{\%\text{ of flue gas cleaned}}{100} = \frac{1 - \dfrac{1\%\text{ sulfur content by weight}}{2.16\%\text{ sulfur content of cleaned coal}}}{0.90}$$

% of flue gas cleaned = 59.7.

This means that for our assumed plant size of 500 Mw, 59.7 percent of the gas must be processed by the FGD system to meet standard. Therefore, minimum scrubber rating is--

$$0.597 \times 500 \text{ Mw} = 299 \text{ Mw}$$

5.5 Design Scrubber Requirements — Scrubber Rating: 344 Mw; % of Flue Gas Cleaned: 68.8%

In order to arrive at conservative design scrubber requirements for purposes of analysis, a 15-percent margin was allowed over the minimum scrubber requirements calculated in 5.4.

5.6 Scrubber Capital Cost: $20,138,140

Now, having established the size of the FGD system necessary to meet existing emission standards, the total capital cost for such an installation is determined by using the scaling relationship derived in Section 5.

As explained, this relationship is based upon the known capital costs of 250-Mw FGD systems and how such costs relate to scrubbing systems of varying sizes treating flue gas of comparable sulfur content. In this particular case analysis, the following applies for a FGD system being installed in a new plant:

$$\frac{\text{capital cost of 344-Mw scrubber}}{\text{capital cost of 250-Mw scrubber}} = \left(\frac{\text{344-Mw capacity}}{\text{250-Mw capacity}}\right)^{0.8}$$

$$\frac{\text{capital cost of 344-Mw scrubber}}{\text{15.61 million}} = \left(\frac{\text{344 Mw}}{\text{250 Mw}}\right)^{0.8}$$

$$\text{Capital cost of 344-Mw scrubber} = \$20,138,140$$

5.7 Scrubber Capital Charges/Yr: $3,131,481

Using the appropriate annual amortization factors discussed in 1.11 above, the scrubber capital charges per year are determined by multiplying this factor times the total capital investment of the scrubber system; i.e., 0.1555 x $20,138,140 = $3,131,481.

5.8 Capital Contribution Per Ton Of Coal: $2.51/Ton

Dividing the scrubber capital charges per year calculated in 5.7 above by the number of tons of coal burned determined in 5.3 gives the capital contribution per ton of coal for the particular installation under consideration. $\left(\frac{\$3,131,481/\text{yr}}{1,245,995\ \text{tons/yr}} = \$2.51/\text{ton}\right)$

5.9 Fuel And Electricity Cost Per Ton Of Coal: $0.56/Ton

As covered by Section 5, a fuel and electricity cost of 0.29 mill per kwh produced regardless of plant size has been used in all case analyses. It should be noted that this amount is attributed only to the FGD system. Specifically, for this case, this cost is determined as follows:

$$\frac{0.29\ \text{mill/kwh produced}}{1,000\ \text{mill/\$}} \times \frac{28.09\text{x}10^{6}\text{Btu of clean coal}}{10,000\ \text{Btu/kwh}} \times 0.688\ \text{of flue gas cleaned}$$

5.10 O & M Costs Per Ton Of Coal

Limestone Cost:	$0.31/Ton	Maintenance Labor & Mat'l:	$0.67/Ton
Fixation Chemical Cost:	$0.26/Ton	Supplies Cost:	$0.10/Ton
Operating Labor Cost:	$0.13/Ton	Overhead Cost:	$0.48/Ton

Using the cost relationships for the operating and maintenance costs of the FGD system covered by Section 5, the above costs on a per-ton of coal burned basis were calculated.

5.11 Total Stack Gas Cost Per Ton Of Coal Burned: $5.02/Ton

Summarizing all of the stack gas cost factors determined in parts 5.8 through 5.10 gives a total scrubber cost on a per-ton-of-coal-burned basis. This means that given the already physically cleaned coal, it will cost an additional $5.02 per ton to bring the sulfur oxides emissions into compliance with existing regulations in the user area selected.

6.0 COST PER TON OF COAL BURNED TO MEET EMISSION STANDARDS

		F.O.B. Mine Raw Coal Price (Per Ton)		
		17.00	19.00	21.00
Mine Operator's Cost	9.00	5.87	5.76	5.66
Of Raw Coal (Per Ton)	11.00	6.09	5.98	5.88
	13.00	6.31	6.20	6.10

This portion of the case analysis gives the total cost per ton of coal burned for cleaning the coal, using stack gas scrubbing to the extent necessary to meet the given emission standards. These values are the sum of the costs given in Parts 2.4 and 5.11 less the benefits given in Part 3.7. This type of presentation gives the reader an opportunity to observe the cost of meeting emission standards for all combinations of assumed mine operator's cost and f.o.b. mine raw coal prices. For example, the above chart of values indicates that at a mine operator's cost of $13.00 per ton of raw coal and a f.o.b. mine selling price of $19.00 per ton, it will cost $6.20 per ton to bring the burning of such coal into compliance with governing emission standards. This cost of $6.20 per ton consists of two major components: physical cleaning at $1.18 and stack gas scrubbing (FGD) at $5.02. Although these costs are initially felt at various points along the path between the mine and final consumption at the utility, the total will ultimately be absorbed by the utility and in turn the consumer.

7.0 COST PER MILLION BTU TO MEET EMISSION STANDARDS

		F.O.B. Mine Raw Coal Price (Per Ton)		
		17.00	19.00	21.00
Mine Operator's Cost	9.00	0.209	0.205	0.201
Of Raw Coal (Per Ton)	11.00	.217	.213	.209
	13.00	.225	.221	.217

For the convenience of the reader, the total costs reflected in Part 6.0 above are converted to a per-million-Btu basis.

8.0 COST PER TON OF RAW COAL TO MEET EMISSION STANDARDS

		F.O.B. Mine Raw Coal Price (Per Ton)		
		17.00	19.00	21.00
Mine Operator's Cost Of Raw Coal (Per Ton)	9.00	5.57	5.47	5.36
	11.00	5.79	5.68	5.57
	13.00	6.00	5.89	5.79

The final portion of the case analysis presents the total cost of the combined use of physical cleaning followed by stack gas scrubbing on the basis of a ton of raw coal.

6.3 Summarization of Case Results

A total of 50 case analyses were performed. All of these cases are provided in their entirety as Appendix B hereto. Each case examines 1 of 12 selected coals and possible use areas from the standpoint of both a new and an existing plant utilizing either combined physical cleaning followed by stack gas scrubbing or sulfur cleanup exclusively by stack gas scrubbing. The cases are grouped according to coal and use area. This permits ease of comparison between like plants using the same coal in the same area but utilizing two different approaches to meeting existing or projected environmental standards. In most cases, the emission standards used were currently applicable as of January 1976. However, where knowledge of projected changes was available, those standards were used and identified accordingly.

Immediately following are summaries of each of the 50 case analyses. These summaries are grouped in sets for comparison of the costs associated with meeting emission standards from the two different approaches. For example, Cases 1A, 1B, 1C, and 1D are based upon an actual coal coming from Sullivan County, Indiana, which is assumed being used in a utility plant in the Knoxville, Tennessee, area. Cases 1A and 1B approach the analysis on the basis of an assumed new facility, whereas Cases 1C and 1D assume an existing facility. However, Cases 1A and 1C address the analysis using a combination of physically cleaned coal followed by stack gas scrubbing, whereas Cases 1B and 1D approach the situation from the standpoint of using stack gas scrubbing alone. As can be readily seen from the summarization of these cases, the cost to meet the applicable sulfur emission standard is less in Cases 1A and 1C, which are the plants using combined physical and flue gas cleaning in new and existing facilities, respectively.

In each set of cases, the relative economic advantage (or disadvantage) is expressed as a percent for comparative purposes. The manner of stating economic advantage (less costly) or disadvantage (more costly) is dependent upon what, if any, action the coal-using plant has taken to meet environmental standards. For example, if, as in the case of IC, the utility is using physically cleaned coal followed by FGD, then economic advantage could be stated as their cost is 25 percent less than by FGD alone. If, as in case 1D, the utility is using FGD alone, then economic disadvantage could be stated as their cost is 33 percent more than by the combined approach.

The summarization of case results referred to above follows (see pages 53 to 65.

SUMMARIZATION OF CASE RESULTS

CASE NUMBERS: 1A, 1B, 1C, and 1D

CASE CONDITIONS

Coal use area: Knoxville (Clinton), Tennessee

Coal source area: Sullivan County, Indiana   Coalbed: Number VII

Raw coal characteristics: 10.5 percent ash, 1.87 percent sulfur

Clean coal characteristics: 7.3 percent ash, 1.11 percent sulfur

CASE RESULTS

Case No.	Type of plant and approach	Emission standard	Cost to meet emission standard	Economic advantage
	Comparison of Costs for New Plant			
1 A	New plant with combined use of physical cleaning followed by stack gas scrubbing (FGD)	1.2 lb SO_2 per MBTU	$ 0.15-0.17 per MBTU	16 pct. less than by FGD alone
1 B	New plant with sulfur clean-up exclusively by stack gas scrubbing	1.2 lb SO_2 per MBTU	$ 0.19 per MBTU	19 pct. more than by PC and FGD
	Comparison of Costs for Existing Plant			
1 C	Existing plant with combined use of physical cleaning followed by stack gas scrubbing (FGD)	1.2 lb SO_2 per MBTU	$ 0.23-0.25 per MBTU	25 pct. less than by FGD alone
1 D	Existing plant with sulfur clean-up exclusively by stack gas scrubbing	1.2 lb SO_2 per MBTU	$ 0.32 per MBTU	33 pct. more than by PC and FGD

SUMMARIZATION OF CASE RESULTS (Continued)

CASE NUMBERS: 2A, 2B, 2C, and 2D

CASE CONDITIONS

Coal use area: Tonawanda (Buffalo), New York

Coal source area: Cambria County, Pennsylvania Coalbed: Lower Freeport

Raw coal characteristics: 11.4 percent ash, 2.4 percent sulfur

Clean coal characteristics: 6.7 percent ash, 1.01 percent sulfur

CASE RESULTS

Case No.	Type of plant and approach	Emission standard	Cost to meet emission standard	Economic advantage
	Comparison of Costs for New Plant			
2 A	New plant with combined use of physical cleaning followed by stack gas scrubbing (FGD)	1.2 lb SO_2 per MBTU	\$ 0.10-0.12 per MBTU	50 pct. less than by FGD alone
2 B	New plant with sulfur clean-up exclusively by stack gas scrubbing	1.2 lb SO_2 per MBTU	\$ 0.22 per MBTU	100 pct. more than by PC and FGD
	Comparison of Costs for Existing Plant			
2 C	Existing plant with combined use of physical cleaning followed by stack gas scrubbing (FGD)	1.4 lb SO_2 per MBTU	\$ 0.06-0.09 per MBTU	50 pct. less than by FGD alone
2 D	Existing plant with sulfur clean-up exclusively by stack gas scrubbing	1.4 lb SO_2 per MBTU	\$ 0.15 per MBTU	100 pct. more than by PC and FGD

SUMMARIZATION OF CASE RESULTS (Continued)

CASE NUMBERS: 3A, 3B, 3C, and 3D

CASE CONDITIONS

Coal use area: Essexville (Saginaw), Michigan

Coal source area: Harrison County, Ohio   Coalbed: Lower Freeport

Raw coal characteristics: 10.4 percent ash, 2.30 percent sulfur

Clean coal characteristics: 4.8 percent ash, 1.26 percent sulfur

CASE RESULTS

Case No.	Type of plant and approach	Emission standard	Cost to meet emission standard	Economic advantage
	Comparison of Costs for New Plant			
3 A	New plant with combined use of physical cleaning followed by stack gas scrubbing (FGD)	1.2 lb SO_2 per MBTU	\$ 0.12-0.14 per MBTU	38 pct. less than by FGD alone
3 B	New plant with sulfur clean-up exclusively by stack gas scrubbing	1.2 lb SO_2 per MBTU	\$ 0.21 per MBTU	62 pct. more than by PC and FGD
	Comparison of Costs for Existing Plant			
3 C	Existing plant with combined use of physical cleaning followed by stack gas scrubbing (FGD)	1.6 lb SO_2 per MBTU	\$ 0.11-0.14 per MBTU	58 pct. less than by FGD alone
3 D	Existing plant with sulfur clean-up exclusively by stack gas scrubbing	1.6 lb SO_2 per MBTU	\$ 0.30 per MBTU	140 pct more than by PC and FGD

SUMMARIZATION OF CASE RESULTS (Continued)

CASE NUMBERS: 4A, 4B, 4C, and 4D

CASE CONDITIONS

Coal use area: Boston, Massachusetts

Coal source area: Clearfield County, Pennsylvania   Coalbed: Upper Kittanning

Raw coal characteristics: 9.3 percent ash, 0.85 percent sulfur

Clean coal characteristics: 7.0 percent ash, 0.45 percent sulfur

CASE RESULTS

Case No.	Type of plant and approach	Emission standard	Cost to meet emission standard	Economic advantage
	Comparison of Costs for New Plant			
4 A	New plant with combined use of physical cleaning followed by stack gas scrubbing (FGD)	0.28 lb SO_2 per MBTU	\$ 0.12-0.14 per MBTU	24 pct. less than by FGD alone
4 B	New plant with sulfur clean-up exclusively by stack gas scrubbing	0.28 lb SO_2 per MBTU	\$ 0.17 per MBTU	31 pct. more than by PC and FGD
	Comparison of Costs for Existing Plant			
4 C	Existing plant with combined use of physical cleaning followed by stack gas scrubbing (FGD)	0.28 lb SO_2 per MBTU	\$ 0.17-0.19 per MBTU	38 pct. less than by FGD alone
4 D	Existing plant with sulfur clean-up exclusively by stack gas scrubbing	0.28 lb SO_2 per MBTU	\$ 0.29 per MBTU	61 pct. more than by PC and FGD

SUMMARIZATION OF CASE RESULTS (Continued)

CASE NUMBERS: 5A, 5B, 5C, and 5D

CASE CONDITIONS

Coal use area: Grand Rapids, Michigan

Coal source area: Preston County, West Virginia   Coalbed: Upper Freeport

Raw coal characteristics: 18.5 percent ash, 2.24 percent sulfur

Clean coal characteristics: 11.9 percent ash, 1.25 percent sulfur

CASE RESULTS

Case No.	Type of plant and approach	Emission standard	Cost to meet emission standard	Economic advantage
	Comparison of Costs for New Plant			
5 A	New plant with combined use of physical cleaning followed by stack gas scrubbing (FGD)	1.6 lb SO_2 per MBTU	\$ 0.07-0.10 per MBTU	53 pct. less than by FGD alone
5 B	New plant with sulfur clean-up exclusively by stack gas scrubbing	1.6 lb SO_2 per MBTU	\$ 0.18 per MBTU	112 pct. more than by PC and FGD
	Comparison of Costs for Existing Plant			
5 C	Existing plant with combined use of physical cleaning followed by stack gas scrubbing (FGD)	1.6 lb SO_2 per MBTU	\$ 0.12-0.14 per MBTU	57 pct. less than by FGD alone
5 D	Existing plant with sulfur clean-up exclusively by stack gas scrubbing	1.6 lb SO_2 per MBTU	\$ 0.30 per MBTU	131 pct. more than by PC and FGD

SUMMARIZATION OF CASE RESULTS (Continued)

CASE NUMBERS: 6A, 6B, 6C, and 6D

CASE CONDITIONS

Coal use area: Springfield, Massachusetts

Coal source area: Armstrong County, Pennsylvania   Coalbed: Upper Freeport

Raw coal characteristics: 13.0 percent ash, 2.53 percent sulfur

Clean coal characteristics: 7.2 percent ash, 1.09 percent sulfur

CASE RESULTS

Case No.	Type of plant and approach	Emission standard	Cost to meet emission standard	Economic advantage
	Comparison of Costs for New Plant			
6 A	New plant with combined use of physical cleaning followed by stack gas scrubbing (FGD)	0.55 lb SO_2 per MBTU	$ 0.11-0.13 per MBTU	48 pct. less than by FGD alone
6 B	New plant with sulfur clean-up exclusively by stack gas scrubbing	0.55 lb SO_2 per MBTU	$ 0.23 per MBTU	92 pct. more than by PC and FGD
	Comparison of Costs for Existing Plant			
6 C	Existing plant with combined use of physical cleaning followed by stack gas scrubbing (FGD)	0.55 lb SO_2 per MBTU	$ 0.18-0.21 per MBTU	49 pct. less than by FGD alone
6 D	Existing plant with sulfur clean-up exclusively by stack gas scrubbing	0.55 lb SO_2 per MBTU	$ 0.38 per MBTU	95 pct. more than by PC and FGD

SUMMARIZATION OF CASE RESULTS (Continued)

CASE NUMBERS: 7A, 7B, 7C, and 7D

CASE CONDITIONS

Coal use area: Lansing, Michigan

Coal source area: Jefferson County, Ohio   Coalbed: Pittsburgh

Raw coal characteristics: 9.8 percent ash, 2.82 percent sulfur

Clean coal characteristics: 6.0 percent ash, 2.03 percent sulfur

CASE RESULTS

Case No.	Type of plant and approach	Emission standard	Cost to meet emission standard	Economic advantage
	Comparison of Costs for New Plant			
7 A	New plant with combined use of physical cleaning followed by stack gas scrubbing (FGD)	1.6 lb SO_2 per MBTU	\$ 0.19-0.22 per MBTU	6.8 pct. less than by FGD alone
7 B	New plant with sulfur clean-up exclusively by stack gas scrubbing	1.6 lb SO_2 per MBTU	\$ 0.22 per MBTU	7.3 pct. more than by PC and FGD
	Comparison of Costs for Existing Plant			
7 C	Existing plant with combined use of physical cleaning followed by stack gas scrubbing (FGD)	1.6 lb SO_2 per MBTU	\$ 0.30-0.32 per MBTU	11 pct. less than by FGD alone
7 D	Existing plant with sulfur clean-up exclusively by stack gas scrubbing	1.6 lb SO_2 per MBTU	\$ 0.35 per MBTU	13 pct. more than by PC and FGD

SUMMARIZATION OF CASE RESULTS (Continued)

CASE NUMBERS: 8A, 8B, 8C, and 8D

CASE CONDITIONS

Coal use area: Nashville (Gallatin), Tennessee

Coal source area: Vigo County, Indiana Coalbed: Number VII

Raw coal characteristics: 12.0 percent ash, 1.54 percent sulfur

Clean coal characteristics: 7.7 percent ash, 0.90 percent sulfur

CASE RESULTS

Case No.	Type of plant and approach	Emission standard	Cost to meet emission standard	Economic advantage
	Comparison of Costs for New Plant			
8 A	New plant with combined use of physical cleaning followed by stack gas scrubbing (FGD)	1.2 lb SO_2 per MBTU	\$ 0.11-0.13 per MBTU	25 pct. less than by FGD alone
8 B	New plant with sulfur clean-up exclusively by stack gas scrubbing	1.2 lb SO_2 per MBTU	\$ 0.16 per MBTU	33 pct. more than by PC and FGD
	Comparison of Costs for Existing Plant			
8 C	Existing plant with combined use of physical cleaning followed by stack gas scrubbing (FGD)	1.2 lb SO_2 per MBTU	\$ 0.16-0.18 per MBTU	39 pct. less than by FGD alone
8 D	Existing plant with sulfur clean-up exclusively by stack gas scrubbing	1.2 lb SO_2 per MBTU	\$ 0.28 per MBTU	65 pct. more than by PC and FGD

SUMMARIZATION OF CASE RESULTS (Continued)

CASE NUMBERS: 9A, 9B, 9C, and 9D

CASE CONDITIONS

Coal use area: Burlington, New Jersey

Coal source area: Garrett County, Maryland   Coalbed: Upper Freeport

Raw coal characteristics: 13.8 percent ash, 2.37 percent sulfur

Clean coal characteristics: 8.8 percent ash, 1.6 percent sulfur

CASE RESULTS

Case No.	Type of plant and approach	Emission standard	Cost to meet emission standard	Economic advantage
	Comparison of Costs for New Plant			
9 A	New plant with combined use of physical cleaning followed by stack gas scrubbing (FGD)	0.30 lb SO_2 per MBTU	This coal will not meet emission standards for new plants in the State of New Jersey even with combined physical and stack gas cleaning.	
9 B	New plant with sulfur clean-up exclusively by stack gas scrubbing	0.30 lb SO_2 per MBTU	This coal will not meet emission standards for new plants in the State of New Jersey using stack gas scrubbing.	
	Comparison of Costs for Existing Plant			
9 C	Existing plant with combined use of physical cleaning followed by stack gas scrubbing (FGD)	1 pct. SO_2 by weight (or equivalent emission)	$ 0.23-0.25 per MBTU	25 pct. less than by FGD alone
9 D	Existing plant with sulfur clean-up exclusively by stack gas scrubbing	1 pct. SO_2 by weight (or equivalent emission)	$ 0.32 per MBTU	33 pct. more than by PC and FGD

SUMMARIZATION OF CASE RESULTS (Continued)

CASE NUMBERS: 10A, 10B, 10C, and 10D

CASE CONDITIONS

Coal use area: Milwaukee, Wisconsin

Coal source area: Franklin County, Illinois Coalbed: Number 6

Raw coal characteristics: 14.8 percent ash, 1.12 percent sulfur

Clean coal Characteristics: 7.1 percent ash, 0.95 percent sulfur

CASE RESULTS

Case No.	Type of plant and approach	Emission standard	Cost to meet emission standard	Economic advantage
	Comparison of Costs for New Plant			
10 A	New plant with combined use of physical cleaning followed by stack gas scrubbing (FGD)	1.2 lb SO_2 per MBTU	$ 0.07-0.10 per MBTU	29 pct. less than by FGD alone
10 B	New plant with sulfur clean-up exclusively by stack gas scrubbing	1.2 lb SO_2 per MBTU	$ 0.12 per MBTU	41 pct. more than by PC and FGD
	Comparison of Costs for Existing Plant			
10 C	Existing plant with combined use of physical cleaning followed by stack gas scrubbing (FGD)	1.2 lb SO_2 per MBTU	$ 0.12-0.15 per MBTU	33 pct. less than by FGD alone
10 D	Existing plant with sulfur clean-up exclusively by stack gas scrubbing	1.2 lb SO_2 per MBTU	$ 0.20 per MBTU	48 pct. more than by PC and FGD

SUMMARIZATION OF CASE RESULTS (Continued)

CASE NUMBERS: 11A, 11B, 11C, and 11D

CASE CONDITIONS

Coal use area: Concord, New Hampshire

Coal source area: Greene County, Pennsylvania Coalbed: Sewickley

Raw coal characteristics: 11.4 percent ash, 3.45 percent sulfur

Clean coal characteristics: 8.1 percent ash, 2.20 percent sulfur

CASE RESULTS

Case No.	Type of plant and approach	Emission standard	Cost to meet emission standard	Economic advantage
	Comparison of Costs for New Plant			
11 A	New plant with combined use of physical cleaning followed by stack gas scrubbing (FGD)	1.5 lb SO_2 per MBTU	$ 0.09-0.11 per MBTU	41 pct. less than by FGD alone
11 B	New plant with sulfur clean-up exclusively by stack gas scrubbing	1.5 lb SO_2 per MBTU	$ 0.17 per MBTU	70 pct. more than by PC and FGD
	Comparison of Costs for Existing Plant			
11 C	Existing plant with combined use of physical cleaning followed by stack gas scrubbing (FGD)	1.5 lb SO_2 per MBTU	$ 0.12-0.14 per MBTU	54 pct. less than by FGD alone
11D	Existing plant with sulfur clean-up exclusively by stack gas scrubbing	1.5 lb SO_2 per MBTU	$ 0.28 per MBTU	115 pct. more than by PC and FGD

SUMMARIZATION OF CASE RESULTS (Continued)

CASE NUMBERS: 11E and 11F

CASE CONDITIONS

Coal use area: Concord, New Hampshire

Coal source area: Greene County, Pennsylvania Coalbed: Sewickley

Raw coal characteristics: 11.4 percent ash, 3.45 percent sulfur

Clean coal characteristics: 8.1 percent ash, 2.20 percent sulfur

CASE RESULTS

Case No.	Type of plant and approach	Emission standard	Cost to meet emission standard	Economic advantage
	Comparison of Costs for New Plant			
11 E	New plant with combined use of physical cleaning followed by stack gas scrubbing (FGD)	1.2 lb SO_2 per MBTU (projected standard)	$ 0.25-0.28 per MBTU	2 pct. less than by FGD alone
11 F	New plant with sulfur clean-up exclusively by stack gas scrubbing	1.2 lb SO_2 per MBTU (projected standard)	$ 0.27 per MBTU	2 pct. more than by PC and FGD

SUMMARIZATION OF CASE RESULTS (Continued)

CASE NUMBERS: 12A, 12B, 12C, and 12D

CASE CONDITIONS:

Coal use area: Dickerson (Montgomery County), Maryland

Coal source area: Marion County, West Virginia   Coalbed: Pittsburgh

Raw coal characteristics: 11.0 percent ash, 3.80 percent sulfur

Clean coal characteristics: 5.9 percent ash, 2.16 percent sulfur

CASE RESULTS

Case No.	Type of plant and approach	Emission standard	Cost to meet emission standard	Economic advantage
	Comparison of Costs for New Plant			
12 A	New plant with combined use of physical cleaning followed by stack gas scrubbing (FGD)	1 pct. SO_2 by weight	\$ 0.20-0.23 per MBTU	20 pct. less than by FGD alone
12 B	New plant with sulfur clean-up exclusively by stack gas scrubbing	1 pct. SO_2 by weight	\$ 0.27 per MBTU	26 pct more than by PC and FGD
	Comparison of Costs for Existing Plant			
12 C	Existing plant with combined use of physical cleaning followed by stack gas scrubbing (FGD)	1 pct. SO_2 by weight	\$ 0.32-0.34 per MBTU	23 pct. less than by FGD alone
12 D	Existing plant with sulfur clean-up exclusively by stack gas scrubbing	1 pct. SO_2 by weight	\$ 0.43 per MBTU	30 pct. more than by PC and FGD

7.0 CONCLUSIONS

The economic analyses covering physical desulfurization of coal followed by flue gas desulfurization and flue gas desulfurization used alone for selected coal source-user combinations indicate that economic generalizations must be approached with caution. The range of variability is such that each case must be individually assessed.

In general, available data indicate that many coals can be beneficiated to remove ash and sulfur at an attractive net cost. These coals with reduced ash and sulfur content levels are often not too far removed from the sulfur content levels required to meet environmental standards in some areas traditionally served by these coals.

When coal can be physically cleaned to a level not too far removed from that required to meet emission standards, flue gas desulfurization treating only a portion of the flue gas would satisfy environmental constraints. In many cases the net cost of physical desulfurization followed by flue gas desulfurization is substantially less than that of flue gas desulfurization alone. This is due to the net economics associated with physically cleaning coal combined with the substantially lower flue gas desulfurization costs. In essence, the net cost (i.e., costs less benefits) associated with physical desulfurization would be less than the additional cost if flue gas desulfurization was used alone.

For existing powerplants, the real costs for flue gas desulfurization systems are especially expensive owing both to higher capital costs and to the shorter economic lives of the systems. In many such cases, the use of physical desulfurization followed by flue gas desulfurization can be particularly attractive.

The provided case studies indicate that for many potential situations the economic advantage of a combined approach is quite significant. Key elements in economic advantage relate to (1) the availability of coals capable of significant reductions in ash and sulfur at reasonable weight yields, and (2) a beneficiated-coal sulfur level that is compatible with significantly less than full-scale scrubbing requirements. Even so, the range of variables is such that each source-user combination must be individually assessed. In this regard, it should be noted, the results can be weighted unrealistically to indicate excessively attractive economics by employing unrealistic factors (e.g., shipping coal farther than is normally warranted).

The assessments imply that the attractiveness of many of our medium- to high-sulfur content coals can be enhanced by cleaning to provide an assured supply of coal that could be used with more economic flue gas desulfurization. This is true for many as-mined medium-sulfur content coals and some higher sulfur content coals that could serve areas with less restrictive environmental standards.

The overall study findings covering the combined use of physical cleaning followed by flue gas desulfurization indicated a savings of 2 percent to 112 percent as compared with flue gas desulfurization alone when applied to new steam coal utilities. The results were even more impressive for existing plants, where study assessments indicated a 13 percent to 140 percent savings for physical cleaning followed by flue gas desulfurization as compared with FGD alone.

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APPENDIX A

SO_x EMISSION REGULATIONS FOR SELECTED STATES

Sulfur regulations (for solid fuel) for selected States are provided in this section. The States chosen are those that have emission regulations compatible with the usage of moderate- and low-sulfur coals and are serviced by coal districts that possess coals of apparently attractive cleaning potential. Specifically, coals that have the required cleaning potential are from the Northern Appalachian Region and the States of Illinois, Indiana, and Kentucky (western) in the Eastern Interior Region. The selected States having regulations consistent with usage of moderate- and low-sulfur coals are Alabama, Delaware, Illinois, Indiana, Iowa, Kentucky, Maine, Maryland, Massachusetts, Michigan, Minnesota, New Hampshire, New Jersey, New York, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and Wisconsin.

The cognizant regulatory agency within each of the selected States was contacted to determine their most recent sulfur compound emission standards. These regulations were abstracted with emphasis on larger fuel-burning installations--those having rated capacities of 250 million Btu heat input or greater. Although it is acknowledged that regulations of this type are subject to revision, the standards given below were current as of February 1976.

Alabama

The Alabama Air Pollution Control Commission regulates the emission of sulfur compounds by limiting the amount of sulfur dioxide that can be emitted in pounds per million Btu heat input. For the purpose of such regulations, counties are placed in one of two categories where the emission standards are as follows:

Category I Counties -

> No fuel-burning installation can operate in such a way to emit in excess of 1.8 pounds of sulfur dioxide per million Btu of heat input.

Category II Counties -

> No fuel-burning installation can operate in such a way to emit in excess of 4.0 pounds of sulfur dioxide per million Btu of heat input.

Delaware

The Delaware Department of Natural Resources and Environmental Control makes the general provision that the emission of sulfur dioxide from fuel-burning equipment shall be controlled to a limit that shall meet the ambient air quality requirements. The only specification standard is established for New Castle County, where the sulfur content of fuel used by fuel-burning equipment is limited to 1.0 percent by weight. Higher sulfur content is allowed if emission controls give results equivalent to that achieved when burning fuel meeting the 1-percent limit.

Illinois

a. For new solid fuel combustion with actual heat inputs greater than 250 million Btu per hour: not to exceed 1.2 pounds of SO_2 per million Btu in any 1-hour period.

b. For existing solid fuel combustion in the Chicago, St. Louis (Illinois), and Peoria Major Metropolitan Areas (MMA): not to exceed 1.8 pounds of sulfur dioxide per million Btu of actual heat input.

c. For existing solid fuel combustion sources located outside the Chicago, St. Louis (Illinois), and Peoria Major Metropolitan Areas: (1) not to exceed 6.0 pounds of SO2 per million Btu of actual heat input, and (2) 1.8 pounds of SO_2 per million Btu of actual heat input from sources located within any MMA other than Chicago, Peoria, and St. Louis (Illinois) that measures an annual arithmetic average SO_2 level greater than

60 ug/M^3 (0.02 ppm) for any year ending prior to May 30, 1976, or

45 ug/M^3 (0.015 ppm) for any year ending on or after May 30, 1976.

Compliance with (c)(2) shall be on or after 3 years from the date upon which the Board promulgates an Order for Compliance.

Indiana

The Indiana Air Pollution Control Board regulates sulfur dioxide emission by specifying limits on pounds per million Btu fuel heat input and pounds per hour as well as setting maximum hourly ground level concentration with respect to distance and at the critical wind speed for level terrain resulting from the point source. In discussions with a representative of the Board on January 28, 1976, we were advised that the following regulations were current, but were under consideration for possible revision.

Emission Standards -

For existing sources maximum sulfur dioxide emission is the lesser of

$$E_m = 17.0\ Q_m^{-0.33} \text{ or } E_p = 17.0\ Q_m^{0.67}$$

$$\text{where } E_p = E_m \times Q_m$$

E_m is the maximum allowable sulfur dioxide emissions in pounds per million Btu fuel heat input.

E_p is the maximum allowable sulfur dioxide emissions in pounds per hour.

Q_m is total combustion equipment capacity rating, fuel heat input in millions of Btu per hour.

The value of E_m shall not exceed 6.0 pounds of sulfur dioxide, nor shall it be required that E_m be reduced below 1.2 pounds of sulfur dioxide per million Btu of heat input. When the heat input value is for material other than Indiana coal, Q_m shall be modified by the ratio of the dry stoichiometric effluent gas volume in cubic feet per million Btu heat input of the material to be burned and the corresponding dry stoichiometric effluent gas volume for average Indiana coal (9,850 cubic feet per million Btu of heat input at standard conditions).

Needless to say, this regulation hits hardest at the larger power plants which might typically have a fuel input rating of 5,000 million Btu per hour. This is the capacity necessary to produce 500 megawatts of electric power $(\frac{10 \times 10^3 \text{ Btu}}{\text{kwh}} \times 500 \times 10^3 \text{ kwh} = 5{,}000 \times 10^6 \text{ Btu})$. For example, if E_m (maximum allowable SO_2 emission in pounds per 10^6 Btu) and E_p (maximum allowable SO_2 emission in pounds per hour) are calculated for such a case, the results would be as follows:

$$E_m = 17.0\ Q_m^{-0.33} \doteq 17.0 \times 5{,}000^{-0.33}$$

$$E_m = 17.0 \times 0.06016 = 1.023 \text{ lb } SO_2 \text{ per million Btu}$$

Adjusted to the minimum level $E_m = \underline{1.2 \text{ lb } SO_2}$ per million Btu

$$E_p = 17.0\ Q_m^{0.67} = 17.0 \times 5{,}000^{0.67}$$

$$E_p = 17.0 \times 300.82 = \underline{5{,}114 \text{ lb}}\ SO_2 \text{ per hour}$$

Ground Level Concentration -

Maximum hourly ground level concentration of sulfur dioxide contributed by any source cannot exceed 200 micrograms per cubic meter in Lake County and 500 micrograms in Dearborn, Marion, and Warrick Counties. These latter counties may delay compliance until May 1978, if they install interim controls including monitoring, reporting, and burning low-sulfur fuel during adverse meteorological conditions. Existing sources in all other counties within the State are not subject to ground level concentration regulation. Ground level hourly concentration (Cmax) is calculated by

$$\text{Cmax} = \frac{90 S_f\ Q_m^{0.75} n^{0.25}}{a h_s},$$

where S_f is the pounds of sulfur dioxide emitted per million Btu of heat input value of the fuel,

Q_m is as defined above,

n is the number of stacks or chimneys in fuel-burning operations,

a is the plume rise factor of 0.7,

and h_s is the stack height in feet.

Iowa

The Iowa Department of Environmental Quality, Air Quality Commission, has established limits on the emission of sulfur dioxide from coal-burning facilities which became effective August 1, 1975. In addition, more stringent regulations have been formulated which go into effect August 1, 1978.

Currently, solid-fuel-burning installations must not emit during any 2-hour period more than an average of 6 pounds of sulfur dioxide per million Btu of heat input. Beginning August 1, 1978, this 2-hour average limit is revised to not more than 5 pounds of sulfur dioxide per million Btu of heat input. In this latter case, it is necessary that an emission reduction program be submitted to the Air Quality Commission by fuel-burning installations having a rated capacity of 250 million Btu per hour heat input or more. These reduction programs, which were due by December 31, 1975, were to indicate how the facilities intended to meet the revised future standard.

Although the above regulations were the latest enacted by Iowa as of February 1976, the Air Quality Commission is currently studying the feasibility of varying emission standards according to the actual conditions present at particular locations within the State rather than limiting emission on a single uniform statewide basis. This possible change in approach to emission control procedures was precipatated by a study of actual coal users in various parts of the State. The conclusion of this study was that more restrictive regulation was required in some areas, whereas more relaxed standards could be observed in other areas without creating dangerous environmental conditions. If such changes are adopted, greater amounts of higher sulfur content coal could be used in numerous locations.

Kentucky

The Division of Air Pollution of the Kentucky Department for Natural Resources and Environmental Protection has, for the purpose of air quality control, classified all areas of the State within one of nine air quality control regions. These regions are in turn classified according to one of five priorities for the purpose of specifying limits on the emission of sulfur dioxide and other contaminants.

Kentucky's air pollution control regulations give performance standards for new and existing indirect heat exchanges. Coal-burning power generating facilities fall within this category for the purpose of such regulations. The limitations listed below apply to facilities having a rated heat input capacity of 250 million Btu per hour or more.

New Facilities (operational on or after April 9, 1972)

Priority Classifications I-V (i.e., Statewide)
1.2 pounds of sulfur dioxide per million Btu heat input.

Existing Facilities (operational prior to April 9, 1972)

The following standards must be met no later than July 1, 1977:

Priority Classification I - Jefferson and McCracken Counties
1.2 pounds of sulfur dioxide per million Btu heat input.

Priority Classification II - Bell, Clark, and Woodford Counties
1.8 pounds of sulfur dioxide per million Btu heat input.

Priority Classification III - Pulaski County
3.2 pounds of sulfur dioxide per million Btu heat input.

Priority Classification IV - Muhlenberg, Webster and Hancock Counties
5.2 pounds of sulfur dioxide per million Btu heat input.

Priority Classification V - All other counties
6.0 pounds of sulfur dioxide per million Btu heat input.

Maine

Regulations set down by the Maine Department of Environmental Protection control the emission of sulfur oxides by restricting the use of fuels according to their sulfur content by weight. Specifically,

1. In the Central Maine, Downeast, Aroostook County, and Northwest Maine Air Quality Control Regions (AQCR), no fuel may be used having a sulfur content greater than 2.5 percent by weight.

2. In the Metropolitan Portland AQCR outside the Portland Peninsula AQCR, no fuel may be used having a sulfur content greater than 2.5 percent by weight.

3. In the Portland Peninsula AQCR no fuel may be used having a sulfur content greater than 1.5 percent by weight. This is scheduled to be decreased to 1.0 percent after November 1, 1985. Additionally, in the Portland Peninsula AQCR, construction or expansion of any fuel-burning facility after June 1, 1975, is restricted to those burning number 2 fuel oil or its equivalent in sulfur and ash content.

Pollution control equipment may be used in order to gain exemption from the sulfur content limitations. This is accomplished if a source installs sulfur collecting devices that reduce the sulfur dioxide emissions to the equivalent level allowed in the particular air quality control region.

Maryland

In Maryland, sulfur emission standards are established by the Environmental Health Administration of the Department of Health and Mental Hygiene. These Standards are set forth by specific regions within the State. In Regions III and IV, which comprise the Baltimore and Washington Metropolitan Areas, respectively, sulfur emission is controlled by prohibiting the use of coal having a sulfur content of greater than 1.0 percent by weight. The balance of the State, consisting of Regions I, II, V, and VI, which are more rural, are covered by an emission standard limiting the discharge of sulfur dioxide to not more than 3.5 pounds per million Btu actual heat input per hour.

Coal containing sulfur in excess of that necessary to meet the above standards may be used provided pollution control equipment to desulfurize the stack gases has been installed or other methods or devices are employed by the user such that the discharge of sulfur dioxide to the atmosphere does not exceed that which would have occurred if fuels meeting the above requirements had been burned.

Massachusetts

The Massachusetts Department of Environmental Quality Engineering Air Quality Control limits the emission of sulfur oxides by establishing maximum sulfur content by weight of the coal consumed in the various Air Pollution Control Districts (APCD).

For the Metropolitan Boston APCD, including the cities and towns of Arlington, Belmont, Boston, Brookline, Cambridge, Chelsea, Everett, Malden, Medford, Newton, Somerville, Waltham, and Watertown, the use of coal is limited to that not having sulfur content in excess of 0.28 pound per million Btu heat release potential. Higher sulfur content coals may be used if it is shown that through the use of pollution control equipment the total emission of sulfur dioxide will not exceed that occurring under the use of the 0.28 fuel.

All other facilities located within the State not mentioned above are limited to coal not having a sulfur content in excess of 0.55 pound per million Btu heat release potential unless it can be demonstrated that through the use of pollution control devices the total emission of sulfur oxides would not exceed that experienced using the 0.55 content fuel.

Michigan

The Air Pollution Division of the Michigan Department of Natural Resources restricts the emission of sulfur dioxide caused by coal-burning powerplants through establishing limits on the sulfur content of the fuel used or the amount of sulfur dioxide emitted per hour if pollution control devices are used.

Currently, those installations having a total steam production capacity of 500,000 pounds per hour or less are restricted to using coal having no more than 2.0 percent sulfur by weight. Beginning July 1, 1978, such plants will be restricted to coal of 1.5 percent or less sulfur content. However, if pollution control equipment is used, such plants can now emit up to 3.2 pounds of sulfur dioxide per million Btu of heat input. On July 1, 1978, this figure will be lowered to 2.4 pounds of sulfur dioxide per million Btu of heat input.

For installations having a total steam production capacity of more than 500,000 pounds per hour, sulfur content of the coal is currently limited to a maximum of 1.5 percent. On July 1, 1978, this sulfur content limit will become 1.0 percent. When pollution control equipment is installed, powerplants may elect to be regulated on the basis of not emitting more than 2.4 pounds of sulfur dioxide per million Btu of heat input. After July 1, 1978, this hourly limit will be placed at 1.6 pounds of sulfur dioxide per million Btu of heat input.

Minnesota

The regulations set down by the Minnesota Pollution Control Agency apply to fuel-burning installations utilized for the primary purpose of producing steam, hot water, hot air, or other indirect heating of liquids, gases, or solids where the products of combustion do not have direct contact with process materials.

a. Within the Minneapolis-St. Paul Air Quality Control Region (AQCR) no person shall burn in any installations of greater than 250 million Btu/hour a fuel or blend of fuels of greater than 1.5 percent sulfur content by weight.

b. Outside the Minneapolis-St. Paul AQCR, no fuel-burning installation of greater than 250 million Btu/hour shall burn a fuel or blend of fuels whose sulfur content by weight exceeds 2.0 percent.

c. A fuel-burning installation is exempt from the above regulations if the fuel being consumed contains no more than 1.75 pounds of SO_2 per million Btu actual heat input. As used in the context, "heat input" is the aggregate heat content of fuels whose combustion products pass through a stack or stacks. The heat input value used shall be the equipment manufacturer's or designer's guaranteed maximum input, whichever is greater.

New Hampshire

The New Hampshire Air Pollution Control Agency has established sulfur dioxide emission standards on the basis of sulfur content per million Btu gross heat content. These standards apply separately to new as well as existing stationary combustion installations.

1. In the case of installations which were in existence prior to April 15, 1970, coal may not be used which has a sulfur content greater than 2.8 pounds per million Btu gross heat content. However, there is the further provision that the weighted average of all coal received during a trimonthly period for use in that installation to generate heat or power does not exceed 1.5 pounds of sulfur per million Btu gross heat content.

2. With regard to installations placed in service to generate heat or power on or after April 15, 1970, coal usage is restricted to that having 1.5 pounds or less of sulfur per million Btu gross heat content. Prior to Revision III of Regulation No. 5, new installations were additionally required to only burn coal having a weighted average over a trimonthly period of 1.0 pounds of sulfur or less per million Btu gross heat input. This requirement was deleted by Revision III, leaving the 1.5-pounds-of-sulfur limit without regard to time. Coal having a higher sulfur content may be used if pollution control apparatus continuously restricts the sulfur oxide emissions to levels permitted by the regulations for uncontrolled burning of coal.

New Jersey

The New Jersey Department of Environmental Protection has established standards to limit the emission of sulfur dioxide from coal-burning facilities. These standards, which cover both the sulfur content of the coal and the pounds of sulfur dioxide emitted, are as follows:

1. Existing Coal-Burning Facilities Prior to May 6, 1968 -

   Bituminous and anthracite coals may not be used which have a sulfur content by weight in excess of 0.2 percent.

   Exceptions -

   a. User of such coals can be exempted from the 0.2-percent limitation if through the use of pollution control equipment the sulfur dioxide emission can be kept to 0.30 pound per million Btu gross heat input or less.

   b. In the case of a coal-fired steam and/or electric power generating facility having a rated hourly capacity equal to or greater than 200 million Btu gross heat input, or a group of such facilities at one location having a combined rated hourly capacity equal to or greater than 450 million Btu gross heat input, the limit on sulfur content by weight may be increased upon approval to 1.0 percent for bituminous and 0.70 percent for anthracite. If coals meeting these latter standards cannot be burned successfully, the authorities may grant permission to use bituminous coal having as much as 1.5 percent sulfur content by weight.

c. Coal-burning installations in the New Jersey counties of Atlantic, Cape May, Cumberland, Hunterdon, Ocean, Sussex, and Warren that were in existence prior to May 6, 1968, are permitted to use bituminous coal having up to 1.0 percent sulfur by weight or anthracite having up to 0.7 percent sulfur by weight.

2. Coal-Burning Installations Expanded, Reconstructed, or Constructed On or After May 6, 1968 -

These facilities are limited to using coal having a sulfur content of not more than 0.2 percent by weight unless through the use of pollution control equipment, emissions can be kept to 0.3 pound of sulfur dioxide or less per million Btu gross heat input.

New York

The New York State Department of Environmental Conservation, Division of Air Resources has prepared regulations governing not only sulfur oxide emission from existing coal-burning installations but also those plants that are considering making a conversion from gas or oil to coal.

Emission Standards Applicable To Existing Facilities -

Coal having 0.6 pound of sulfur per million Btu gross heat content is the maximum permissible in the Suffolk County towns of Babylon, Brookhaven, Huntington, Islip, and Smithtown.

In Erie and Niagara Counties, the maximum permissible is 1.7 pounds, but the installation must also adhere to a 1.4-pound average computed by dividing the total sulfur content by the total gross heat content of all coal received during any consecutive 3-month period.

For New York City and the counties of Nassau, Rockland, and Westchester, the limit is 0.20 pound per million Btu gross heat content. The balance of the State is covered by a 2.5-pound maximum coupled with a 1.9-pound average computed as stated above over a trimonthly period.

Emission Standards Applicable To Conversions -

If a plant changes from the use of fuel oil or gas to coal, it may not use coal which has a sulfur content in pounds per million Btu in excess of the product of 0.55 times the maximum sulfur content for oil in percent by weight permitted in the particular location.

Exception -

The installation of acceptable pollution control equipment can permit a facility to utilize coal exceeding the sulfur content restrictions.

Ohio

Since July 1, 1975, the Ohio Environmental Protection Agency has had one uniform standard regarding the emission of sulfur dioxide from fuel-burning installations whose primary purpose is to produce heat or power by indirect heat transfer. This regulation, which applies equally to new and existing installations, limits the maximum allowable mass rate of emission of sulfur compounds (measured as sulfur dioxide) to 1.0 pound per million Btu heat input per hour. Under this standard, the capacity of any installation is determined to be the manufacturer's or designer's guaranteed maximum heat input rate.

Pennsylvania

The Pennsylvania Department of Environmental Resources, Bureau of Air Quality and Noise Control, regulates sulfur compound emissions by general categories:

A. For all combustion units falling within the heat input categories below which are not located in the Allegheny County, Beaver Valley, Monongahela Valley, and Southeast Pennsylvania air basins, the following regulations apply:

   1. For combustion units having heat input greater than 2.5 million Btu per hour but less than 50 million Btu per hour, a limit of 3.0 pounds of sulfur dioxide per million Btu of input applies.

   2. For combustion units having heat input equal to or greater than 50 but less than 2,000 million Btu per hour, the allowable emission rate must not exceed

$$A = 5.1\ E^{-0.14}$$

   where A is the allowable emissions in pounds per million Btu heat input,

   and E is the heat input to the combustion unit in million Btu per hour.

   3. For combustion units having heat input equal to or greater than 2,000 million Btu per hour, the maximum permissible rate of emission is 1.8 pounds of sulfur dioxide per million Btu of heat input.

B. For all combustion units falling within the heat input categories below which are located in the Allegheny County, Beaver Valley, Monongahela Valley, and Southeast Pennsylvania air basins, the following regulations apply:

   1. For combustion units having heat input of greater than 2.5 million Btu per hour but less than 50 million Btu per hour, a limit of 1.0 pound of sulfur dioxide per million Btu of input applies.

2. For combustion units having heat input equal to or greater than 50 but less than 2,000 million Btu per hour, the allowable emission rate must not exceed

$$A = 1.7\ E^{-0.14}$$

where A is the allowable emissions in pounds per million Btu heat input,

and E is the heat input to the combustion unit in million Btu per hour.

3. For combustion units having heat input equal to or greater than 2,000 million Btu per hour, the maximum permissible rate of emission is 0.6 pound of sulfur dioxide per million Btu of heat input.

C. For all combustion units not covered by the above regulations, sulfur dioxide emission must not exceed 4.0 pounds per million Btu of heat input per hour.

Tennessee

The Air Pollution Control Division of the Tennessee Department of Public Health groups counties into three major classes for the purpose of regulating the emission of sulfur compounds from coal-burning installations having a rated capacity of 250 million Btu per hour or less heat input.

1. In the Class I counties of Polk, Sullivan, Roane, and Maury, the average emission measured over any 2-hour period from a fuel-burning source is limited to not more than 1.6 pounds of sulfur dioxide per million Btu heat input.

2. In the Class II county of Humphreys, the average emission measured over any 2-hour period from a fuel-burning source is limited to not more than 3.0 pounds of sulfur dioxide per million Btu heat input.

3. In the Class III counties, which include the balance of the State, the average emission measured over any 2-hour period from a fuel-burning source is limited to not more than 4.0 pounds of sulfur dioxide per million Btu heat input.

Additionally, since January 1, 1973, coal-burning sources constructed after April 3, 1972, that have a capacity of more than 250 million Btu per hour heat input are limited to an average hourly emission of 1.2 pounds of sulfur dioxide per million Btu heat input measured over any 2-hour period.

In the case of fuel-burning installations having a rated capacity of more than 1,000 million Btu heat input, several additional requirements must be met. The installation must--

1. Demonstrate that the installation will not interfere with attainment and maintenance of any primary or secondary ambient air quality standard,

2. Demonstrate that the installation will not result in air quality concentrations in excess of 50 percent of the primary ambient air quality standard, and

3. Demonstrate that the installation will not increase emissions to the extent that resulting air quality concentrations will be greater than those concentrations (either measured or calculated) which existed in 1972 or those concentrations which existed during the first year of operation of the installation if it began operating after January 1, 1972.

Although the above regulations were in effect as of February 1976, revised emission standards were pending at that time which would establish six classifications of counties as follows:

Class I - Polk
Class II - Humphreys, Maury, and Roane
Class III - Sullivan
Class IV - Shelby
Class V - Anderson, Davidson, Hamilton, Hawkins, Knox, and Rhea
Class VI - All other counties

Under the proposed changes, the allowable sulfur dioxide emissions for fuel-burning installations according to rated capacity by county classification would be--

Rated capacity in million Btu per hour heat input	Maximum emission level in pounds of SO_2					
	Class I	Class II	Class III	Class IV	Class V	Class VI
Greater than 1,000	1.2	1.2	2.4	4.0	4.0	5.0
Less than 1,000	1.6	5.0	2.4	4.0	4.0	5.0

Virginia

The State Air Pollution Control Board of Virginia limits the emission from any source operation of sulfur dioxide in an in-stack concentration exceeding 2,000 parts per million (ppm) by volume except that emissions of sulfur dioxide from any combustion installation are governed by the following formulas:

1. S = 2.64 K For Air Quality Control Regions (AQCR) 1 through 6

2. S = 1.06 K For AQCR 7 (National Capital Interstate AQCR which includes the counties of Arlington, Fairfax, Loudoun, and Prince William).

where S = allowable emissions of sulfur dioxide expressed in lb/hr,

and K = actual heat input at total capacity expressed in Btu x 10^6 per hour.

Where there are one or more combustion installation units at a facility, and where the facility can be shown, to the satisfaction of the Board, to be in compliance when the facility is operating at total capacity, the facility will be deemed to be still in compliance if the facility is operated at reduced load or one or more units are shut down for maintenance or repair. This paragraph is applicable only if the remaining unit(s) continues to burn the same type of fuel with the same sulfur content, or an equivalent, that was shown above to allow compliance when the facility was operating at maximum load and if the actual emissions when operating at reduced load do not exceed the maximum allowable emissions.

West Virginia

As of February 1976, the West Virginia Air Pollution Commission regulated the emission of sulfur dioxide from fuel-burning units according to Air Quality Control Regions having Priority Classifications of either I, II, or III. Under such regulations, fuel-burning installations whose primary purpose is to produce electric power for sale are categorized as Type "a" units. For Type "a" units the following limits apply:

All Air Quality Control Regions Having Priority Classification I or II--

> Beginning June 30, 1975, the total pounds of sulfur dioxide emitted per hour cannot exceed 2.7 times the total design heat input of all units located at any particular plant expressed in millions Btu per hour.
>
> Effective June 30, 1978, the limit is changed to 2.0 times the total design heat input, with the additional requirement that the total emission from the entire plant cannot exceed 45,000 pounds of sulfur dioxide per hour.

Air Quality Control Region IV (Kanawha Valley AQCR, which includes Kanawha County, Putnam County, and Falls and Kanawha Magisterial Districts of Fayette County)--

> Beginning January 1, 1973, the total pounds of sulfur dioxide emitted per hour cannot exceed 1.6 times the total design heat input of all units located at any particular plant expressed in millions Btu per hour provided that no more than 45,000 pounds per hour of sulfur dioxide shall be discharged into the open air from the entire plant.

All Air Quality Control Regions Having Priority Classification III except Region IV--

Beginning June 30, 1975, the total pounds of sulfur dioxide emitted per hour cannot exceed 3.2 times the total design heat input of all units located at any particular plant, expressed in millions Btu per hour.

Effective June 30, 1978, the limit is changed to 2.0 times the total design heat input with the additional requirement that the total emission from the plant cannot exceed 45,000 pounds of sulfur dioxide per hour.

Wisconsin

The Wisconsin Department of Natural Resources has established one statewide limitation on the emission of sulfur dioxide from coal-fired steam generating facilities having a rated capacity of over 250 million Btu per hour. However, this limitation is written to cover "new or modified fossil fuel-fired steam generators" and appears to exempt facilities in existance prior to April 1, 1972. Such regulation simply restricts emission to not more than 1.2 pounds of sulfur dioxide per million Btu heat input.

In addition to this general restriction, coal-burning power generating facilities may be required during conditions of severe air pollution to burn coal not having a sulfur content of more than 1.5 percent. Such lower sulfur content fuel is maintained by the coal-burning facility on a standby basis for use under these conditions so that the plant can continue operations.

APPENDIX B

DETAILED CASE ANALYSES

CASE NUMBER: 1A

1.0 CASE CONDITIONS — Combined Use of Physical Cleaning Followed by Stack Gas Scrubbing

1.1 Coal Use Area: Knoxville (Clinton), Tennessee

1.2 Emission S ındards: New: 1.2 lb SO_2 Per MM Btu
Existing:

1.3 Coal District of Origin: No. 11 Coalbed: No. VII
State: Indiana County: Sullivan

1.4 Raw Coal* Ash: 10.5%
Lb SO_2/MM Btu: Sulfur: 1.87% MM Btu/Ton: 24.97

1.5 Clean Coal Ash: 7.3%
Cleaning Plant Yield: 90.0% Sulfur: 1.11% MM Btu/Ton: 25.80
Lb SO_2/MM Btu: 1.72 Btu Recovery: 93.0% Btu Increase: 3.3%

1.6 Transportation Mileage: 454 Cost Per Ton: $7.41

1.7 Assumed Plant Size Megawatts: 500

1.8 Remaining Life of Boiler: 25 Yr

1.9 Assumed Ash Disposal Cost: $4.00/Ton

1.10 Cleaning Plant Cost: $18,000 Per Ton-Hour Input Capacity**
Utilization: 38.58%***

1.11 Assumed Annual Capital Scrubber Charges as Percent of Original Investment: 15.55%

2.0 COAL CLEANING COST FACTORS

2.1 Cleaning Plant Costs Amortization: $0.68/Ton O & M: $0.75/Ton

2.2 Additional Cost to Mine Operator to Provide for One Ton of Clean Coal, When Mine Operator's Cost is:

$ 7.00/Ton, Additional Cost is $0.78/Ton
$ 9.00/Ton, Additional Cost is $1.00/Ton
$11.00/Ton, Additional Cost is $1.22/Ton

2.3 Cleaning Plant Tax and Insurance Burden: $0.12/Ton

2.4 Total Differential Production Cost to Mine Operator to Provide a Ton of Cleaned Coal, when Mine Operator's Cost is

$ 7.00/Ton, Differential Cost is $2.33/Ton****
$ 9.00/Ton, Differential Cost is $2.55/Ton
$11.00/Ton, Differential Cost is $2.77/Ton

3.0 ASSESSABLE BENEFIT FACTORS ASSOCIATED WITH CLEAN COAL

3.1 Added Coal Value Due to Higher Heat Content of Coal, When F.O.B. Mine Raw Coal Price is

$12.00/Ton, Benefit is $0.38/Ton
$14.00/Ton, Benefit is $0.45/Ton
$16.00/Ton, Benefit is $0.51/Ton

3.2 Transportation Cost Saving Due to Increased Heat Content of Coal: $0.24/Ton

3.3 Saving in Ash Disposal Cost: $0.14/Ton

3.4 Saving in Grinding Cost: $0.02/Ton

3.5 Saving in Benefit Payment: $0.02/Ton

3.6 Saving in Maintenance: $0.17/Ton

3.7 Total Benefits of Coal Cleaning, When F.O.B. Mine Raw Coal Selling Price is

$12.00/Ton, Benefit is $0.97/Ton
$14.00/Ton, Benefit is $1.04/Ton
$16.00/Ton, Benefit is $1.10/Ton

4.0 DIFFERENTIAL CLEANING COST LESS BENEFITS PER TON

		F.O.B. Mine Raw Coal Price (Per Ton)		
		12.00	14.00	16.00
Mine Operator's Cost of Raw Coal (Per Ton)	7.00	1.36	1.29	1.23
	9.00	1.58	1.51	1.45
	11.00	1.80	1.73	1.67

5.0 STACK GAS COST FACTORS

5.1 Boiler Capacity: 500 Mw

5.2 Utilization Factor: 7,000 Hr/Yr

5.3 Tons of Coal Burned Per Year: 1,356,590 Tons

5.4 Minimum Scrubber Requirements — Scrubber Rating: 168 Mw
% of Flue gas Cleaned: 33.6%

5.5 Design Scrubber Requirements — Scrubber Rating: 193 Mw
% of Flue Gas Cleaned: 38.6%

5.6 Scrubber Capital Cost: $12,032,492

5.7 Scrubber Capital Charges/Yr: $1,871,053

5.8 Capital Contribution Per Ton of Coal: $1.38/Ton

5.9 Fuel and Electricity Cost Per Ton of Coal: $0.29/Ton

5.10 O & M Costs Per Ton of Coal

Limestone Cost: $0.08/Ton
Maintenance Labor & Material: $0.35/Ton
Fixation Chemical Cost: $0.07/Ton
Supplies Cost: $0.05/Ton
Operating Labor Cost: $0.12/Ton
Overhead Cost: $0.28/Ton

5.11 Total Stack Gas Cost Per Ton of Coal Burned: $2.62/Ton

6.0 COST PER TON OF COAL BURNED TO MEET EMISSION STANDARDS

		F.O.B. Mine Raw Coal Price (Per Ton)		
		12.00	14.00	16.00
Mine Operator's Cost of Raw Coal (Per Ton)	7.00	3.98	3.91	3.85
	9.00	4.20	4.13	4.07
	11.00	4.42	4.35	4.29

7.0 COST PER MILLION BTU TO MEET EMISSION STANDARDS

		F.O.B. Mine Raw Coal Price (Per Ton)		
		12.00	14.00	16.00
Mine Operator's Cost of Raw Coal (Per Ton)	7.00	0.154	0.152	0.149
	9.00	.163	.160	.158
	11.00	.171	.169	.166

8.0 COST PER TON OF RAW COAL TO MEET EMISSION STANDARDS

		F.O.B. Mine Raw Coal Price (Per Ton)		
		12.00	14.00	16.00
Mine Operator's Cost of Raw Coal (Per Ton)	7.00	3.85	3.80	3.72
	9.00	4.07	4.00	3.95
	11.00	4.27	4.22	4.15

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* As-received values.
** Amortized over 15 years, 8% interest on unpaid blance.
*** Based upon 260 days/yr at 13 hr/day - 3,380 hr/yr.
**** This represents the total of all coal-cleaning cost factors at the respective operator cost levels as covered in Section 2.0 above.

CASE NUMBER: 1B

1.0 CASE CONDITIONS — Sulfur Clean-up Exclusively by Stack Gas Scrubbing

1.1 Coal Use Area: Knoxville (Clinton), Tennessee

1.2 Emission Standards — New: 1.2 lb of SO_2 Per MM Btu
Existing:

1.3 Coal District of Origin: No. 11 — Coalbed: Number VII
State: Indiana — County: Sullivan

1.4 Raw Coal — Ash: 10.5%
Lb $SO_2/10^6$ Btu: 3.0 — Sulfur: 1.87% — MM Btu/Ton: 24.97*

1.5 Assumed Plant Size: 500 Mw

1.6 Remaining Life of Boiler: 25 Yr

1.7 Assumed Annual Capital Scrubber Charges as Percent of Original Investment: 15.55%

2.0 STACK GAS COST FACTORS

2.1 Boiler Capacity: 500 Mw

2.2 Utilization Factor: 7,000 Hr/Yr

2.3 Tons of Coal Burned Per Year: 1,401,682 Tons

2.4 Minimum Scrubber Requirements — Scrubber Rating: 335 Mw
% of Flue Gas Cleaned: 67%

2.5 Design Scrubber Requirements — Scrubber Rating: 385 Mw
% of Flue Gas Cleaned: 77%

2.6 Scrubber Capital Cost: $21,796,287

2.7 Scrubber Capital Charges/Yr: $3,389,323

2.8 Capital Contribution Per Ton of Coal: $2.42/Ton

2.9 Fuel and Electricity Cost Per Ton of Coal: $0.56/Ton

2.10 O & M Costs Per Ton of Coal

Limestone Cost $0.27/Ton
Maintenance Labor & Material: $0.62/Ton
Fixation Chemical Cost: $0.22/Ton
Supplies Cost: $0.09/Ton
Operating Labor Cost: $0.11/Ton
Overhead Cost: $0.43/Ton

2.11 Total Cost Per Ton of Coal Burned to Meet Emission Standards: $4.72/Ton

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* This value has been adjusted for raw coal moisture content.

CASE NUMBER: 1C

1.0 CASE CONDITIONS — Combined Use of Physical Cleaning Followed by Stack Gas Scrubbing

1.1 Coal Use Area: Knoxville (Clinton), Tennessee

1.2 Emission Standards — New:
Existing: 1.2 lb SO_2 Per MM Btu

1.3 Coal District of Origin: No. 11 — Coalbed: Number VII
State: Indiana — County: Sullivan

1.4 Raw Coal* — Ash: 10.5%
Lb SO_2/MM Btu: 3.0 — Sulfur: 1.87% — MM Btu/Ton: 24.97

1.5 Clean Coal — Ash: 7.3%
Cleaning Plant Yield: 90.0% — Sulfur: 1.11% — MM Btu/Ton: 25.80
Lb SO_2/MM Btu: 1.72 — Btu Recovery: 93.0% — Btu Increase: 3.3%

1.6 Transportation — Mileage: 454 — Cost Per Ton: $7.41

1.7 Assumed Plant Size — Megawatts: 500

1.8 Remaining Life of Boiler: 15 Yr

1.9 Assumed Ash Disposal Cost: $4.00/Ton

1.10 Cleaning Plant — Cost: $18,000 Per Ton-Hour Input Capacity**
Utilization: 38.58%***

1.11 Assumed Annual Capital Scrubber Charges as Percent of Original Investment: 17.82%

2.0 COAL CLEANING COST FACTORS

2.1 Cleaning Plant Costs — Amortization: $0.68/Ton — O & M: $0.75/Ton

2.2 Additional Cost to Mine Operator to Provide for One Ton of Clean Coal, When Mine Operator's Cost is

$ 7.00/Ton, Additional Cost is $0.78/Ton
$ 9.00/Ton, Additional Cost is $1.00/Ton
$11.00/Ton, Additional Cost is $1.22/Ton

2.3 Cleaning Plant Tax and Insurance Burden: $0.12/Ton

2.4 Total Differential Production Cost to Mine Operator to Provide a Ton of Cleaned Coal, When Mine Operator's Cost is

$ 7.00/Ton, Differential Cost is $2.33/Ton****
$ 9.00/Ton, Differential Cost is $2.55/Ton
$11.00/Ton, Differential Cost is $2.77/Ton

3.0 ASSESSABLE BENEFIT FACTORS ASSOCIATED WITH CLEAN COAL

3.1 Added Coal Value Due to Higher Heat Content of Coal, When F.O.B. Mine Raw Coal Price is

$12.00/Ton, Benefit is $0.38/Ton
$14.00/Ton, Benefit is $0.45/Ton
$16.00/Ton, Benefit is $0.51/Ton

3.2 Transportation Cost Saving Due to Increased Heat Content of Coal: $0.24/Ton

3.3 Saving in Ash Disposal Cost: $0.14/Ton

3.4 Saving in Grinding Cost: $0.02/Ton

3.5 Saving in Benefit Payment: $0.02/Ton

3.6 Saving in Maintenance: $0.17/Ton

3.7 Total Benefits of Coal Cleaning When F.O.B. Mine Raw Coal Selling Price is

$12.00/Ton, Benefit is $0.97/Ton
$14.00/Ton, Benefit is $1.04/Ton
$16.00/Ton, Benefit is $1.10/Ton

4.0 DIFFERENTIAL CLEANING COST LESS BENEFITS PER TON

		F.O.B. Mine Raw Coal Price (Per Ton)		
		12.00	14.00	16.00
Mine Operator's Cost of Raw Coal (Per Ton)	7.00	1.36	1.29	1.23
	9.00	1.58	1.51	1.45
	11.00	1.80	1.73	1.67

5.0 STACK GAS COST FACTORS

5.1 Boiler Capacity: 500 Mw

5.2 Utilization Factor: 5,000 Hr/Yr

5.3 Tons of Coal Burned Per Year: 968,993 Tons

5.4 Minimum Scrubber Requirements — Scrubber Rating: 168 Mw
% of Flue Gas Cleaned: 33.6%

5.5 Design Scrubber Requirements — Scrubber Rating: 193 Mw
% of Flue Gas Cleaned: 38.6%

5.6 Scrubber Capital Cost: $15,121,915

5.7 Scrubber Capital Charges/Yr: $2,694,726

5.8 Capital Contribution Per Ton of Coal: $2.78/Ton

5.9 Fuel and Electricity Cost Per Ton of Coal: $0.29/Ton

5.10 O & M Costs Per Ton of Coal

Limestone Cost: $0.08/Ton
Maintenance Labor & Material: $0.62/Ton
Fixation Chemical Cost: $0.07/Ton
Supplies Cost: $0.09/Ton
Operating Labor Costs: $0.17/Ton
Overhead Cost: $0.47/Ton

5.11 Total Stack Gas Cost Per Ton of Coal Burned: $4.57/Ton

6.0 COST PER TON OF COAL BURNED TO MEET EMISSION STANDARDS

		F.O.B. Mine Raw Coal Price (Per Ton)		
		12.00	14.00	16.00
Mine Operator's Cost of Raw Coal (Per Ton)	7.00	5.93	5.86	5.80
	9.00	6.15	6.08	6.02
	11.00	6.37	6.30	6.24

7.0 COST PER MILLION BTU TO MEET EMISSION STANDARDS

		F.O.B. Mine Raw Coal Price (Per Ton)		
		12.00	14.00	16.00
Mine Operator's Cost of Raw Coal (Per Ton)	7.00	0.230	0.227	0.225
	9.00	.238	.236	.233
	11.00	.247	.244	.242

8.0 COST PER TON OF RAW COAL TO MEET EMISSION STANDARDS

		F.O.B. Mine Raw Coal Price (Per Ton)		
		12.00	14.00	16.00
Mine Operator's Cost of Raw Coal (Per Ton)	7.00	5.74	5.67	5.62
	9.00	5.94	5.89	5.82
	11.00	6.17	6.09	6.04

* As-received values.
** Amortized over 15 years, 8% interest on unpaid balance.
*** Based upon 260 days/yr at 13 hr/day - 3,380 hrs/yr.
**** This represents the total of all coal cleaning cost factors at the respective operator cost levels as covered in Section 2.0 above.

CASE NUMBER 1D

1.0 CASE CONDITIONS — Sulfur Clean-up Exclusively by Stack Gas Scrubbing

1.1 Coal Use Area: Knoxville (Clinton), Tennessee

1.2 Emission Standards — New:
Existing: 1.2 lb of SO_2 Per MM Btu

1.3 Coal District of Origin: No. 11 — Coalbed: No. VII
State: Indiana — County: Sullivan

1.4 Raw Coal — Ash: 10.5%
Lb $SO_2/10^6$ Btu: 3.0 — Sulfur: 1.87% — MM Btu/Ton: 24.97*

1.5 Assumed Plant Size: 500 Mw

1.6 Remaining Life of Boiler: 15 Yr

1.7 Assumed Annual Capital Scrubber Charges as Percent of Original Investment: 17.82%

2.0 STACK GAS COST FACTORS

2.1 Boiler Capacity: 500 Mw

2.2 Utilization Factor: 5,000 Hr/Yr

2.3 Tons of Coal Burned Per Year: 1,001,202 Tons

2.4 Minimum Scrubber Requirements — Scrubber Rating: 335 Mw
% of Flue Gas Cleaned: 67%

2.5 Design Scrubber Requirements — Scrubber Rating: 385 Mw
% of Flue Gas Cleaned: 77%

2.6 Scrubber Capital Cost: $26,683,853

2.7 Scrubber Capital Charges/Yr: $4,755,063

2.8 Capital Contribution Per Ton of Coal: $4.75/Ton

2.9 Fuel and Electricity Cost Per Ton of Coal: $0.56/Ton

2.10 O & M Costs Per Ton of Coal

Limestone Cost: $0.27/Ton
Maintenance Labor & Material: $1.07/Ton
Fixation Chemical Cost: $0.22/Ton
Supplies Cost: $0.16/Ton
Operating Labor Cost: $0.16/Ton
Overhead Cost: $0.73/Ton

2.11 Total Cost Per Ton of Coal Burned to Meet Emission Standards: $7.92/Ton

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* This value has been adjusted for raw coal moisture content.

CASE NUMBER 2A

1.0 CASE CONDITIONS — Combined Use of Physical Cleaning Followed by Stack Gas Scrubbing

1.1 Coal Use Area: Tonawanda (Buffalo), New York

1.2 Emission Standards — New: 1.2 lb SO_2 Per MM Btu
Existing:

1.3 Coal District of Origin: No. 1 — Coalbed: Lower Freeport
State: Pennsylvania — County: Cambria

1.4 Raw Coal* — Ash: 11.4%
Lb SO_2/MM Btu: 3.56 — Sulfur: 2.4% — MM Btu/Ton: 26.96

1.5 Clean Coal — Ash: 6.7%
Cleaning Plant Yield: 90.0% — Sulfur: 1.01% — MM Btu/Ton: 28.29
Lb SO_2/MM Btu: 1.43 — Btu Recovery: 94.4% — Btu Increase: 4.9%

1.6 Transportation — Mileage: 300 — Cost Per Ton: $6.35

1.7 Assumed Plant Size — Megawatts: 500

1.8 Remaining Life of Boiler: 25 Yr

1.9 Assumed Ash Disposal Cost: $4.00/Ton

1.10 Cleaning Plant — Cost: $18,000 Per Ton-Hour Input Capacity**
Utilization: 38.58%***

1.11 Assumed Annual Capital Scrubber Charges as Percent of Original Investment: 15.55%

2.0 COAL CLEANING COST FACTORS

2.1 Cleaning Plant Costs — Amortization: $0.68/Ton — O & M: $0.75/Ton

2.2 Additional Cost to Mine Operator to Provide for One Ton of Clean Coal, When Mine Operator's Cost is

$14.00/Ton, Additional Cost is $1.56/Ton
$16.00/Ton, Additional Cost is $1.78/Ton
$18.00/Ton, Additional Cost is $2.00/Ton

2.3 Cleaning Plant Tax and Insurance Burden: $0.12/Ton

2.4 Total Differential Production Cost to Mine Operator to Provide a Ton of Cleaned Coal, When Mine Operator's Cost is

$14.00/Ton, Differential Cost is $3.11/Ton****
$16.00/Ton, Differential Cost is $3.33/Ton
$18.00/Ton, Differential Cost is $3.55/Ton

3.0 ASSESSABLE BENEFIT FACTORS ASSOCIATED WITH CLEAN COAL

3.1 Added Coal Value Due to Higher Heat Content of Coal, When F.O.B. Mine Raw Coal Price is

$26.00/Ton, Benefit is $1.21/Ton
$28.00/Ton, Benefit is $1.31/Ton
$30.00/Ton, Benefit is $1.40/Ton

3.2 Transportation Cost Saving Due to Increased Heat Content of Coal: $0.30/Ton

3.3 Saving in Ash Disposal Cost: $0.21/Ton

3.4 Saving in Grinding Cost: $0.02/Ton

3.5 Saving in Benefit Payment: $0.03/Ton

3.6 Saving in Maintenance: $0.20/Ton

3.7 Total Benefits of Coal Cleaning, When F.O.B. Mine Raw Coal Selling Price is

$26.00/Ton, Benefit is $1.97/Ton
$28.00/Ton, Benefit is $2.07/Ton
$30.00/Ton, Benefit is $2.16/Ton

4.0 DIFFERENTIAL CLEANING COST LESS BENEFITS PER TON

		F.O.B. Mine Raw Coal Price (Per Ton)		
		26.00	28.00	30.00
Mine Operator's Cost of Raw Coal (Per Ton)	14.00	1.14	1.04	0.95
	16.00	1.36	1.26	1.17
	18.00	1.58	1.48	1.39

5.0 STACK GAS COST FACTORS

5.1 Boiler Capacity: 500 Mw

5.2 Utilization Factor: 7,000 Hr/Yr

5.3 Tons of Coal Burned Per Year: 1,237,187 Tons

5.4 Minimum Scrubber Requirements — Scrubber Rating: 89.5 Mw
% of Flue Gas Cleaned: 17.9%

5.5 Design Scrubber Requirements — Scrubber Rating: 103 Mw
% of Flue Gas Cleaned: 20.6%

5.6 Scrubber Capital Cost: $7,280,807

5.7 Scrubber Capital Charges/Yr: $1,132,166

5.8 Capital Contribution Per Ton of Coal: $0.92/Ton

5.9 Fuel and Electricity Cost Per Ton of Coal: $0.17/Ton

5.10 O & M Costs Per Ton of Coal

Limestone Cost: $0.04/Ton
Maintenance Labor & Material: $0.24/Ton
Fixation Chemical Cost: $0.04/Ton
Supplies Cost: $0.04/Ton
Operating Labor Costs: $0.13/Ton
Overhead Cost: $0.23/Ton

5.11 Total Stack Gas Cost Per Ton of Coal Burned: $1.81/Ton

6.0 COST PER TON OF COAL BURNED TO MEET EMISSION STANDARDS

		F.O.B. Mine Raw Coal Price (Per Ton)		
		26.00	28.00	30.00
Mine Operator's Cost of Raw Coal (Per Ton)	14.00	2.95	2.85	2.76
	16.00	3.17	3.07	2.98
	18.00	3.39	3.29	3.20

7.0 COST PER MILLION BTU TO MEET EMISSION STANDARDS

		F.O.B. Mine Raw Coal Price (Per Ton)		
		26.00	28.00	30.00
Mine Operator's Cost of Raw Coal (Per Ton)	14.00	0.104	0.101	0.098
	16.00	.112	.109	.105
	18.00	.120	.116	.113

8.0 COST PER TON OF RAW COAL TO MEET EMISSION STANDARDS

		F.O.B. Mine Raw Coal Price (Per Ton)		
		26.00	28.00	30.00
Mine Operator's Cost of Raw Coal (Per Ton)	14.00	2.80	2.72	2.64
	16.00	3.02	2.94	2.83
	18.00	3.24	3.13	3.05

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* As-received values.
** Amortized over 15 years, 8% interest on unpaid balance.
*** Based upon 260 days/yr at 13 hr/day - 3,380 hr/yr.
**** This represents the total of all coal cleaning cost factors at the respective operator cost levels as covered in Section 2.0 above.

CASE NUMBER 2B

1.0 CASE CONDITIONS — Sulfur Clean-up Exclusively by Stack Gas Scrubbing

1.1 Coal Use Area: Tonawanda (Buffalo), New York

1.2 Emission Standards — New: 1.2 lb SO_2 Per MM Btu
Existing:

1.3 Coal District of Origin: No. 1 — Coalbed: Lower Freeport
State: Pennsylvania — County: Cambria

1.4 Raw Coal — Ash: 11.4%
Lb $SO_2/10^6$ Btu: 3.56 — Sulfur: 2.4% — MM Btu/Ton: 26.96*

1.5 Assumed Plant Size: 500 Mw

1.6 Remaining Life of Boiler: 25 Yr

1.7 Assumed Annual Capital Scrubber Charges as Percent of Original Investment: 15.55%

2.0 STACK GAS COST FACTORS

2.1 Boiler Capacity: 500 Mw

2.2 Utilization Factor: 7,000 Hr/Yr

2.3 Tons of Coal Burned Per Year: 1,298,220 Tons

2.4 Minimum Scrubber Requirements — Scrubber Rating: 369 Mw
% of Flue Gas Cleaned: 73.7%

2.5 Design Scrubber Requirements — Scrubber Rating: 424 Mw
% of Flue Gas Cleaned: 84.8%

2.6 Scrubber Capital Cost: $24,399,962

2.7 Scrubber Capital Charges/Yr: $3,794,194

2.8 Capital Contribution Per Ton of Coal: $2.92/Ton

2.9 Fuel and Electricity Cost Per Ton of Coal: $0.66/Ton

2.10 O & M Costs Per Ton of Coal

Limestone Cost: $0.41/Ton
Maintenance Labor & Material: $0.75/Ton
Fixation Chemical Cost: $0.34/Ton
Supplies Cost: $0.11/Ton
Operating Labor Cost: $0.12/Ton
Overhead Cost: $0.51/Ton

2.11 Total Cost Per Ton of Coal Burned to Meet Emission Standards: $5.82/Ton

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* This value has been adjusted for raw coal moisture content.

CASE NUMBER: 2C

1.0 CASE CONDITIONS — Combined Use of Physical Cleaning Followed by Stack Gas Scrubbing

1.1 Coal Use Area: Tonawanda (Buffalo), New York

1.2 Emission Standards — New:
Existing: 1.4 lb S Per MM Btu (2.8 lb SO_2)

1.3 Coal District of Origin: No. 1 — Coalbed: Lower Freeport
State: Pennsylvania — County: Cambria

1.4 Raw Coal* — Ash: 11.4%
Lb SO_2/MM Btu: 3.56 — Sulfur: 2.4% — MM Btu/Ton: 26.96

1.5 Clean Coal — Ash: 6.7%
Cleaning Plant Yield: 90.0% — Sulfur: 1.01% — MM Btu/Ton: 28.29
Lb SO_2/MM Btu: 1.43 — Btu Recovery: 94.4% — Btu Increase: 4.9%

1.6 Transportation — Mileage: 300 — Cost Per Ton: $6.35

1.7 Assumed Plant Size — Megawatts: 500

1.8 Remaining Life of Boiler: 15 Yr

1.9 Assumed Ash Disposal Cost: $4.00/Ton

1.10 Cleaning Plant — Cost: $18,000 Per Ton-Hour Input Capacity**
Utilization: 38.58%***

1.11 Assumed Annual Capital Scrubber Charges as Percent of Original Investment: 17.82%

2.0 COAL CLEANING COST FACTORS

2.1 Cleaning Plant Costs — Amortization: $0.68/Ton — O & M: $0.75/Ton

2.2 Additional Cost to Mine Operator to Provide for One Ton of Clean Coal, When Mine Operator's Cost is

$14.00/Ton, Additional Cost is $1.56/Ton
$16.00/Ton, Additional Cost is $1.78/Ton
$18.00/Ton, Additional Cost is $2.00/Ton

2.3 Cleaning Plant Tax and Insurance Burden: $0.12/Ton

2.4 Total Differential Production Cost to Mine Operator to Provide a Ton of Cleaned Coal, When Mine Operator's Cost is

$14.00/Ton, Differential Cost is $3.11/Ton****
$16.00/Ton, Differential Cost is $3.33/Ton
$18.00/Ton, Differential Cost is $3.55/Ton

3.0 ASSESSABLE BENEFIT FACTORS ASSOCIATED WITH CLEAN COAL

3.1 Added Coal Value Due to Higher Heat Content of Coal, When F.O.B. Mine Raw Coal Price is

$26.00/Ton, Benefit is $1.21/Ton
$28.00/Ton, Benefit is $1.31/Ton
$30.00/Ton, Benefit is $1.40/Ton

3.2 Transportation Cost Saving Due to Increased Heat Content of Coal: $0.30/Ton

3.3 Saving in Ash Disposal Cost: $0.21/Ton

3.4 Saving in Grinding Cost: $0.02/Ton

3.5 Saving in Benefit Payment: $0.03/Ton

3.6 Saving in Maintenance: $0.20/Ton

3.7 Total Benefits of Coal Cleaning, When F.O.B. Mine Raw Coal Selling Price is

$26.00/Ton, Benefit is $1.97/Ton
$28.00/Ton, Benefit is $2.07/Ton
$30.00/Ton, Benefit is $2.16/Ton

4.0 DIFFERENTIAL CLEANING COST LESS BENEFITS PER TON

		F.O.B. Mine Raw Coal Price (Per Ton)		
		26.00	28.00	30.00
Mine Operator's Cost of Raw Coal (Per Ton)	14.00	1.14	1.04	0.95
	16.00	1.36	1.26	1.17
	18.00	1.58	1.48	1.39

5.0 STACK GAS COST FACTORS

5.1 Boiler Capacity: 500 Mw

5.2 Utilization Factor: 5,000 Hr/Yr

5.3 Tons of Coal Burned Per Year: 883,705 Tons

5.4 Minimum Scrubber Requirements — Scrubber Rating: 12 Mw; % of Flue Gas Cleaned: 2.3%

5.5 Design Scrubber Requirements — Scrubber Rating: 14 Mw; % of Flue Gas Cleaned: 2.8%

5.6 Scrubber Capital Cost: $1,853,803

5.7 Scrubber Capital Charges/Yr: $330,348

5.8 Capital Contribution Per Ton of Coal: $0.37/Ton

5.9 Fuel and Electricity Cost Per Ton of Coal: $0.02/Ton

5.10 O & M Costs Per Ton of Coal

Limestone Cost: $0.01/Ton
Maintenance Labor and Material: $0.08/Ton
Fixation Chemical Cost: $0.01/Ton
Supplies Cost: $0.01/Ton
Operating Labor Cost: $0.18/Ton
Overhead Cost: $0.17/Ton

5.11 Total Stack Gas Cost Per Ton of Coal Burned: $0.85/Ton

6.0 COST PER TON OF COAL BURNED TO MEET EMISSION STANDARDS

		F.O.B. Mine Raw Coal Price (Per Ton)		
		26.00	28.00	30.00
Mine Operator's Cost of Raw Coal (Per Ton)	14.00	1.99	1.89	1.80
	16.00	2.21	2.11	2.02
	18.00	2.43	2.33	2.24

7.0 COST PER MILLION BTU TO MEET EMISSION STANDARDS

		F.O.B. Mine Raw Coal Price (Per Ton)		
		26.00	28.00	30.00
Mine Operator's Cost of Raw Coal (Per Ton)	14.00	0.070	0.067	0.064
	16.00	.078	.075	.071
	18.00	.086	.082	.079

8.0 COST PER TON OF RAW COAL TO MEET EMISSION STANDARDS

		F.O.B. Mine Raw Coal Price (Per Ton)		
		26.00	28.00	30.00
Mine Operator's Cost of Raw Coal (Per Ton)	14.00	1.89	1.81	1.73
	16.00	2.10	2.02	1.91
	18.00	2.32	2.21	2.13

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* As-received values.
** Amortized over 15 years, 8% interest on unpaid balance.
*** Based upon 260 days/yr at 13 hr/day - 3,380 hr/yr.
**** This represents the total of all coal cleaning cost factors at the respective operator cost levels as covered in Section 2.0 above.

CASE NUMBER: 2D

1.0 CASE CONDITIONS — Sulfur Clean-up Exclusively by Stack Gas Scrubbing

1.1 Coal Use Area: Tonawanda (Buffalo), New York

1.2 Emission Standards — New:
Existing: 1.4 lb S Per MM Btu (2.8 lb SO_2)

1.3 Coal District of Origin: No. 1 — Coalbed: Lower Freeport
State: Pennsylvania — County: Cambria

1.4 Raw Coal — Ash: 11.4%
Lb $SO_2/10^6$ Btu: 3.56 — Sulfur: 2.4% — MM Btu/Ton: 26.96*

1.5 Assumed Plant Size: 500 Mw

1.6 Remaining Life of Boiler: 15 Yr

1.7 Assumed Annual Capital Scrubber Charges as Percent of Original Investment: 17.82%

2.0 STACK GAS COST FACTORS

2.1 Boiler Capacity: 500 Mw

2.2 Utilization Factor: 5,000 Hr/Yr

2.3 Tons of Coal Burned Per Year: 927,300 Tons

2.4 Minimum Scrubber Requirements — Scrubber Rating: 119 Mw
% of Flue Gas Cleaned: 23.7%

2.5 Design Scrubber Requirements — Scrubber Rating: 137 Mw
% of Flue Gas Cleaned: 27.4%

2.6 Scrubber Capital Cost: $12,014,916

2.7 Scrubber Capital Charges/Yr: $2,141,058

2.8 Capital Contribution Per Ton of Coal: $2.31/Ton

2.9 Fuel and Electricity Cost Per Ton of Coal: $0.21/Ton

2.10 O & M Costs Per Ton of Coal

Limestone Cost: $0.13/Ton
Maintenance Labor & Material: $0.52/Ton
Fixation Chemical Cost: $0.11/Ton
Supplies Cost: $0.08/Ton
Operating Labor Cost: $0.17/Ton
Overhead Cost: $0.42/Ton

2.11 Total Cost Per Ton of Coal Burned to Meet Emission Standards: $3.95/Ton

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* This value has been adjusted for raw coal moisture content.

CASE NUMBER: 3A

1.0 CASE CONDITIONS — Combined Use of Physical Cleaning Followed by Stack Gas Scrubbing

1.1 Coal Use Area: Essexville (Saginaw), Michigan

1.2 Emission Standards — New: 1.2 lb SO_2 Per MM Btu (Anticipated Standard)
Existing:

1.3 Coal District of Origin: No. 4 — Coalbed: Lower Freeport
State: Ohio — County: Harrison

1.4 Raw Coal* — Ash: 10.4%
Lb SO_2/MM Btu: 3.54 — Sulfur: 2.30% — MM Btu/Ton: 25.97

1.5 Clean Coal — Ash: 4.8%
Cleaning Plant Yield: 90.0% — Sulfur: 1.26% — MM Btu/Ton: 27.51
Lb SO_2/MM Btu: 1.83 — Btu Recovery: 95.3% — Btu Increase: 5.9%

1.6 Transportation — Mileage: 375 — Cost Per Ton: \$6.19

1.7 Assumed Plant Size — Megawatts: 500

1.8 Remaining Life of Boiler: 25 Yr

1.9 Assumed Ash Disposal Cost: \$4.00/Ton

1.10 Cleaning Plant — Cost: \$18,000 Per Ton-Hour Input Capacity**
Utilization: 38.58%***

1.11 Assumed Annual Capital Scrubber Charges as Percent of Original Investment: 15.55%

2.0 COAL CLEANING COST FACTORS

2.1 Cleaning Plant Costs — Amortization: \$0.68/Ton — O & M: \$0.75/Ton

2.2 Additional Cost to Mine Operator to Provide for One Ton of Clean Coal, When Mine Operator's Cost is

\$ 7.00/Ton, Additional Cost is \$0.78/Ton
\$ 9.00/Ton, Additional Cost is \$1.00/Ton
\$11.00/Ton, Additional Cost is \$1.22/Ton

2.3 Cleaning Plant Tax and Insurance Burden: \$0.12/Ton

2.4 Total Differential Production Cost to Mine Operator to Provide a Ton of Cleaned Coal, When Mine Operator's Cost is

\$ 7.00/Ton, Differential Cost is \$2.33/Ton****
\$ 9.00/Ton, Differential Cost is \$2.55/Ton
\$11.00/Ton, Differential Cost is \$2.77/Ton

3.0 ASSESSABLE BENEFIT FACTORS ASSOCIATED WITH CLEAN COAL

3.1 Added Coal Value Due to Higher Heat Content of Coal, When F.O.B. Mine Raw Coal Price is

$13.00/Ton, Benefit is $0.72/Ton
$15.00/Ton, Benefit is $0.84/Ton
$17.00/Ton, Benefit is $0.95/Ton

3.2 Transportation Cost Saving Due to Increased Heat Content of Coal: $0.34/Ton

3.3 Saving in Ash Disposal Cost: $0.25/Ton

3.4 Saving in Grinding Cost: $0.03/Ton

3.5 Saving in Benefit Payment: $0.04/Ton

3.6 Saving in Maintenance: $0.20/Ton

3.7 Total Benefits of Coal Cleaning, When F.O.B. Mine Raw Coal Selling Price is

$13.00/Ton, Benefit is $1.58/Ton
$15.00/Ton, Benefit is $1.70/Ton
$17.00/Ton, Benefit is $1.81/Ton

4.0 DIFFERENTIAL CLEANING COST LESS BENEFITS PER TON

		F.O.B. Mine Raw Coal Price (Per Ton)		
		13.00	15.00	17.00
Mine Operator's Cost of Raw Coal (Per Ton)	7.00	0.75	0.63	0.52
	9.00	.97	.85	.74
	11.00	1.19	1.07	.96

5.0 STACK GAS COST FACTORS

5.1 Boiler Capacity: 500 Mw

5.2 Utilization Factor: 7,000 Hr/Yr

5.3 Tons of Coal Burned Per Year: 1,272,265 Tons

5.4 Minimum Scrubber Requirements — Scrubber Rating: 192 Mw; % of Flue Gas Cleaned: 38.3%

5.5 Design Scrubber Requirements — Scrubber Rating: 220 Mw; % of Flue Gas Cleaned: 44%

5.6 Scrubber Capital Cost: $13,374,816

5.7 Scrubber Capital Charges/Yr: $2,079,784

5.8 Capital Contribution Per Ton of Coal: $1.63/Ton

5.9 Fuel and Electricity Cost Per Ton of Coal: $0.35/Ton

5.10 O & M Costs Per Ton of Coal

Limestone Cost: $0.12/Ton
Maintenance Labor & Material: $0.42/Ton
Fixation Chemical Cost: $0.09/Ton
Supplies Cost: $0.06/Ton
Operating Labor Cost: $0.13/Ton
Overhead Cost: $0.33/Ton

5.11 Total Stack Gas Cost Per Ton of Coal Burned: $2.71/Ton

6.0 COST PER TON OF COAL BURNED TO MEET EMISSION STANDARDS

		F.O.B. Mine Raw Coal Price (Per Ton)		
		13.00	15.00	17.00
Mine Operator's Cost of Raw Coal (Per Ton)	7.00	3.46	3.34	3.23
	9.00	3.68	3.56	3.45
	11.00	3.90	3.78	3.67

7.0 COST PER MILLION BTU TO MEET EMISSION STANDARDS

		F.O.B. Mine Raw Coal Price (Per Ton)		
		13.00	15.00	17.00
Mine Operator's Cost of Raw Coal (Per Ton)	7.00	0.126	0.121	0.117
	9.00	.134	.129	.125
	11.00	.142	.137	.133

8.0 COST PER TON OF RAW COAL TO MEET EMISSION STANDARDS

		F.O.B. Mine Raw Coal Price (Per Ton)		
		13.00	15.00	17.00
Mine Operator's Cost of Raw Coal (Per Ton)	7.00	3.27	3.14	3.04
	9.00	3.48	3.35	3.25
	11.00	3.69	3.56	3.45

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* As-received values.
** Amortized over 15 years, 8% interest on unpaid balance.
*** Based upon 260 days/yr at 13 hr/day - 3,380 hr/yr.
**** This represents the total of all coal cleaning cost factors at the respective operator cost levels as covered in Section 2.0 above.

CASE NUMBER: 3B

1.0	CASE CONDITIONS	Sulfur Clean-up Exclusively by Stack Gas Scrubbing

1.1 Coal Use Area: Essexville (Saginaw), Michigan

1.2 Emission Standards — New: 1.2 lb SO_2 Per MM Btu (Anticipated Standard)
Existing:

1.3 Coal District of Origin: No. 4 — Coalbed: Lower Freeport
State: Ohio — County: Harrison

1.4 Raw Coal — Ash: 10.4%
Lb $SO_2/10^6$ Btu: 3.54 — Sulfur: 2.30% — MM Btu/Ton: 25.97*

1.5 Assumed Plant Size: 500 Mw

1.6 Remaining Life of Boiler: 25 Yr

1.7 Assumed Annual Capital Scrubber Charges as Percent of Original Investment: 15.55%

2.0 STACK GAS COST FACTORS

2.1 Boiler Capacity: 500 Mw

2.2 Utilization Factor: 7,000 Hr/Yr

2.3 Tons of Coal Burned Per Year: 1,347,709 Tons

2.4 Minimum Scrubber Requirements — Scrubber Rating: 367 Mw
% of Flue Gas Cleaned: 73.4%

2.5 Design Scrubber Requirements — Scrubber Rating: 422 Mw
% of Flue Gas Cleaned: 84.4%

2.6 Scrubber Capital Cost: $23,973,401

2.7 Scrubber Capital Charges/Yr: $3,727,864

2.8 Capital Contribution Per Ton of Coal: $2.77/Ton

2.9 Fuel and Electricity Cost Per Ton of Coal: $0.64/Ton

2.10 O & M Costs Per Ton of Coal

Limestone Cost: $0.38/Ton
Maintenance Labor & Material: $0.71/Ton
Fixation Chemical Cost: $0.31/Ton
Supplies Cost: $0.11/Ton
Operating Labor Cost: $0.12/Ton
Overhead Cost: $0.49/Ton

2.11 Total Cost Per Ton of Coal Burned to Meet Emission Standards: $5.53/Ton

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* This value has been adjusted for raw coal moisture content.

CASE NUMBER: 3C

1.0 CASE CONDITIONS — Combined Use of Physical Cleaning Followed by Stack Gas Scrubbing

1.1 Coal Use Area: Essexville (Saginaw), Michigan

1.2 Emission Standards — New:
Existing: 1.6 lb SO_2 Per MM Btu

1.3 Coal District of Origin: No. 4 — Coalbed: Lower Freeport
State: Ohio — County: Harrison

1.4 Raw Coal* — Ash: 10.4%
Lb SO_2/MM Btu: 3.54 — Sulfur: 2.30% — MM Btu/Ton: 25.97

1.5 Clean Coal — Ash: 4.8%
Cleaning Plant Yield: 90.0% — Sulfur: 1.26% — MM Btu/Ton: 27.51
Lb SO_2/MM Btu: 1.83 — Btu Recovery: 95.3% — Btu Increase: 5.9%

1.6 Transportation — Mileage: 375 — Cost Per Ton: $6.19

1.7 Assumed Plant Size — Megawatts: 500

1.8 Remaining Life of Boiler: 15 Yr

1.9 Assumed Ash Disposal Cost: $4.00/Ton

1.10 Cleaning Plant — Cost: $18,000 Per Ton-Hour Input Capacity**
Utilization: 38.58%***

1.11 Assumed Annual Capital Scrubber Charges as Percent of Original Investment: 17.82%

2.0 COAL CLEANING COST FACTORS

2.1 Cleaning Plant Costs — Amortization: $0.68/Ton — O & M: $0.75/Ton

2.2 Additional Cost to Mine Operator to Provide for One Ton of Clean Coal, When Mine Operator's Cost is

$ 7.00/Ton, Additional Cost is $0.78/Ton
$ 9.00/Ton, Additional Cost is $1.00/Ton
$11.00/Ton, Additional Cost is $1.22/Ton

2.3 Cleaning Plant Tax and Insurance Burden: $0.12/Ton

2.4 Total Differential Production Cost to Mine Operator to Provide a Ton of Cleaned Coal, When Mine Operator's Cost is

$ 7.00/Ton, Differential Cost is $2.33/Ton****
$ 9.00/Ton, Differential Cost is $2.55/Ton
$11.00/Ton, Differential Cost is $2.77/Ton

3.0 ASSESSABLE BENEFIT FACTORS ASSOCIATED WITH CLEAN COAL

3.1 Added Coal Value Due to Higher Heat Content of Coal, When F.O.B. Mine Raw Coal Price is

$13.00/Ton, Benefit is $0.72/Ton
$15.00/Ton, Benefit is $0.84/Ton
$17.00/Ton, Benefit is $0.95/Ton

3.2 Transportation Cost Saving Due to Increased Heat Content of Coal: $0.34/Ton

3.3 Saving in Ash Disposal Cost: $0.25/Ton

3.4 Saving in Grinding Cost: $0.03/Ton

3.5 Saving in Benefit Payment: $0.04/Ton

3.6 Saving in Maintenance: $0.20/Ton

3.7 Total Benefits of Coal Cleaning, When F.O.B. Mine Raw Coal Selling Price is

$13.00/Ton, Benefit is $1.58/Ton
$15.00/Ton, Benefit is $1.70/Ton
$17.00/Ton, Benefit is $1.81/Ton

4.0 DIFFERENTIAL CLEANING COST LESS BENEFITS PER TON

		F.O.B. Mine Raw Coal Price (Per Ton)		
		13.00	15.00	17.00
Mine Operator's Cost of Raw Coal (Per Ton)	7.00	0.75	0.63	0.52
	9.00	.97	.85	.74
	11.00	1.19	1.07	.96

5.0 STACK GAS COST FACTORS

5.1 Boiler Capacity: 500 Mw

5.2 Utilization Factor: 5,000 Hr/Yr

5.3 Tons of Coal Burned Per Year: 908,761 Tons

5.4 Minimum Scrubber Requirements — Scrubber Rating: 70 Mw; % of Flue Gas Cleaned: 14%

5.5 Design Scrubber Requirements — Scrubber Rating: 80 Mw; % of Flue Gas Cleaned: 16%

5.6 Scrubber Capital Cost: $7,475,375

5.7 Scrubber Capital Charges/Yr: $1,332,112

5.8 Capital Contribution Per Ton of Coal: $1.47/Ton

5.9 Fuel and Electricity Cost Per Ton of Coal: $0.13/Ton

5.10 O & M Costs Per Ton of Coal

Limestone Cost: $0.04/Ton
Maintenance Labor & Material: $0.33/Ton
Fixation Chemical Cost: $0.03/Ton
Supplies Cost: $0.05/Ton
Operating Labor Cost: $0.18/Ton
Overhead Cost: $0.32/Ton

5.11 Total Stack Gas Cost Per Ton of Coal Burned: $2.55/Ton

6.0 COST PER TON OF COAL BURNED TO MEET EMISSION STANDARDS

		F.O.B. Mine Raw Coal Price (Per Ton)		
		13.00	15.00	17.00
Mine Operator's Cost of Raw Coal (Per Ton)	7.00	3.30	3.18	3.07
	9.00	3.52	3.40	3.29
	11.00	3.74	3.62	3.51

7.0 COST PER MILLION BTU TO MEET EMISSION STANDARDS

		F.O.B. Mine Raw Coal Price (Per Ton)		
		13.00	15.00	17.00
Mine Operator's Cost of Raw Coal (Per Ton)	7.00	0.120	0.116	0.112
	9.00	.128	.124	.120
	11.00	.136	.132	.128

8.0 COST PER TON OF RAW COAL TO MEET EMISSION STANDARDS

		F.O.B. Mine Raw Coal Price (Per Ton)		
		13.00	15.00	17.00
Mine Operator's Cost of Raw Coal (Per Ton)	7.00	3.12	3.01	2.91
	9.00	3.32	3.22	3.12
	11.00	3.53	3.43	3.32

* As-received values.
** Amortized over 15 years, 8% interest on unpaid balance.
*** Based upon 360 days/yr at 13 hr/day - 3,380 hr/yr.
**** This represents the total of all coal cleaning cost factors at the respective operator cost levels as covered in Section 2.0 above.

CASE NUMBER: 3D

1.0 CASE CONDITIONS — Sulfur Clean-up Exclusively by Stack Gas Scrubbing

1.1 Coal Use Area: Essexville (Saginaw), Michigan

1.2 Emission Standards — New:
Existing: 1.6 lb SO_2 Per MM Btu

1.3 Coal District of Origin: No. 4 — Coalbed: Lower Freeport
State: Ohio — County: Harrison

1.4 Raw Coal — Ash: 10.4%
Lb $SO_2/10^6$ Btu: 3.54 — Sulfur: 2.30% — MM Btu/Ton: 25.97*

1.5 Assumed Plant Size: 500 Mw

1.6 Remaining Life of Boiler: 15 Yr

1.7 Assumed Annual Capital Scrubber Charges as Percent of Original Investment: 17.82%

2.0 STACK GAS COST FACTORS

2.1 Boiler Capacity: 500 Mw

2.2 Utilization Factor: 5,000 Hr/Yr

2.3 Tons of Coal Burned Per Year: 962,650 Tons

2.4 Minimum Scrubber Requirements — Scrubber Rating: 305 Mw
% of Flue Gas Cleaned: 61%

2.5 Design Scrubber Requirements — Scrubber Rating: 351 Mw
% of Flue Gas Cleaned: 70.2%

2.6 Scrubber Capital Cost: $25,240,547

2.7 Scrubber Capital Charges/Yr: $4,497,866

2.8 Capital Contribution Per Ton of Coal: $4.67/Ton

2.9 Fuel and Electricity Cost Per Ton of Coal: $0.53/Ton

2.10 O & M Costs Per Ton of Coal

Limestone Cost: $0.32/Ton
Maintenance Labor & Material: $1.05/Ton
Fixation Chemical Cost: $0.26/Ton
Supplies Cost: $0.16/Ton
Operating Labor Cost: $0.17/Ton
Overhead Cost: $0.72/Ton

2.11 Total Cost Per Ton of Coal Burned to Meet Emission Standards: $7.88/Ton

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* This value has been adjusted for raw coal moisture content.

CASE NUMBER: 4A

1.0 CASE CONDITIONS — Combined Use of Physical Cleaning Followed by Stack Gas Scrubbing

1.1 Coal Use Area: Boston, Massachusetts

1.2 Emission Standards — New: 0.28 lb of Sulfur Per MM Btu
Existing:

1.3 Coal District of Origin: No. 1 — Coalbed: Upper Kittanning
State: Pennsylvania — County: Clearfield

1.4 Raw Coal* — Ash: 9.3%
Lb SO_2/MM Btu: 1.31 — Sulfur: 0.85% — MM Btu/Ton: 25.94

1.5 Clean Coal — Ash: 7.0%
Cleaning Plant Yield: 90:0% — Sulfur: 0.45% — MM Btu/Ton: 26.55
Lb SO_2/MM Btu: 0.68 — Btu Recovery: 92.1% — Btu Increase: 2.35%

1.6 Transportation — Mileage: 551 — Cost Per Ton: $8.75

1.7 Assumed Plant Size — Megawatts: 500

1.8 Remaining Life of Boiler: 25 Yr

1.9 Assumed Ash Disposal Cost: $4.00/Ton

1.10 Cleaning Plant — Cost: $18,000 Per Ton-Hour Input Capacity**
Utilization: 38.58%***

1.11 Assumed Annual Capital Scrubber Charges as Percent of Original Investment: 15.55%

2.0 COAL CLEANING COST FACTORS

2.1 Cleaning Plant Costs — Amortization: $0.68/Ton — O & M: $0.75/Ton

2.2 Additional Cost to Mine Operator to Provide for One Ton of Clean Coal, When Mine Operator's Cost is

$ 8.00/Ton, Additional Cost is $0.89/Ton
$10.00/Ton, Additional Cost is $1.11/Ton
$12.00/Ton, Additional Cost is $1.33/Ton

2.3 Cleaning Plant Tax and Insurance Burden: $0.12/Ton

2.4 Total Differential Production Cost to Mine Operator to Provide a Ton of Cleaned Coal, When Mine Operator's Cost is

$ 8.00/Ton, Differential Cost is $2.44/Ton****
$10.00/Ton, Differential Cost is $2.66/Ton
$12.00/Ton, Differential Cost is $2.88/Ton

3.0 ASSESSABLE BENEFIT FACTORS ASSOCIATED WITH CLEAN COAL

3.1 Added Coal Value Due to Higher Heat Content of Coal, When F.O.B. Mine Raw Coal Price is

$16.00/Ton, Benefit is $0.37/Ton
$20.00/Ton, Benefit is $0.46/Ton
$24.00/ton, Benefit is $0.55/Ton

3.2 Transportation Cost Saving Due to Increased Heat Content of Coal: $0.20/Ton

3.3 Saving in Ash Disposal Cost: $0.10/Ton

3.4 Saving in Grinding Cost: $0.01/Ton

3.5 Saving in Benefit Payment: $0.02/Ton

3.6 Saving in Maintenance: $0.13/Ton

3.7 Total Benefits of Coal Cleaning, When F.O.B. Mine Raw Coal Selling Price is

$16.00/Ton, Benefit is $0.83/Ton
$20.00/Ton, Benefit is $0.92/Ton
$24.00/Ton, Benefit is $1.01/Ton

4.0 DIFFERENTIAL CLEANING COST LESS BENEFITS PER TON

		F.O.B. Mine Raw Coal Price (Per Ton)		
		16.00	20.00	24.00
Mine Operator's Cost of Raw Coal (Per Ton)	8.00	1.61	1.52	1.43
	10.00	1.83	1.74	1.65
	12.00	2.05	1.96	1.87

5.0 STACK GAS COST FACTORS

5.1 Boiler Capacity: 500 Mw

5.2 Utilization Factor: 7,000 Hr/Yr

5.3 Tons of Coal Burned Per Year: 1,318,268 Tons

5.4 Minimum Scrubber Requirements — Scrubber Rating: 97 Mw
% of Flue Gas Cleaned: 19.3%

5.5 Design Scrubber Requirements — Scrubber Rating: 112 Mw
% of Flue Gas Cleaned: 22.4%

5.6 Scrubber Capital Cost: $7,732,853

5.7 Scrubber Capital Charges/Yr: $1,202,549

5.8 Capital Contribution Per Ton of Coal: $0.91/Ton

5.9 Fuel and Electricity Cost Per Ton of Coal: $0.17/Ton

5.10 O & M Costs Per Ton of Coal

Limestone Cost $0.02/Ton
Maintenance Labor & Material: $0.23/Ton
Fixation Chemical Cost: $0.02/Ton
Supplies Cost: $0.03/Ton
Operating Labor Cost: $0.12/Ton
Overhead Cost: $0.21/Ton

5.11 Total Stack Gas Cost Per Ton of Coal Burned: $1.71/Ton

6.0 COST PER TON OF COAL BURNED TO MEET EMISSION STANDARDS

		F.O.B. Mine Raw Coal Price (Per Ton)		
		16.00	20.00	24.00
Mine Operator's Cost of Raw Coal (Per Ton)	8.00	3.32	3.23	3.14
	10.00	3.54	3.45	3.36
	12.00	3.76	3.67	3.58

7.0 COST PER MILLION BTU TO MEET EMISSION STANDARDS

		F.O.B. Mine Raw Coal Price (Per Ton)		
		16.00	20.00	24.00
Mine Operator's Cost of Raw Coal (Per Ton)	8.00	0.125	0.122	0.118
	10.00	.133	.130	.127
	12.00	.142	.138	.135

8.0 COST PER TON OF RAW COAL TO MEET EMISSION STANDARDS

		F.O.B. Mine Raw Coal Price (Per Ton)		
		16.00	20.00	24.00
Mine Operator's Cost of Raw Coal (Per Ton)	8.00	3.24	3.16	3.06
	10.00	3.45	3.37	3.29
	12.00	3.68	3.58	3.50

* As-received values.
** Amortized over 15 years, 8% interest on unpaid balance.
*** Based upon 260 days/yr at 13 hr/day - 3,380 hr/yr
**** This represents the total of all coal cleaning cost factors at the respective operator cost levels as covered in Section 2.0 above.

CASE NUMBER: 4B

1.0 CASE CONDITIONS — Sulfur Clean-up Exclusively by Stack Gas Scrubbing

1.1 Coal Use Area: Boston, Massachusetts

1.2 Emission Standards — New: 0.28 lb of Sulfur Per MM Btu; Existing:

1.3 Coal District of Origin: No. 1 — Coalbed: Upper Kittanning
State: Pennsylvania — County: Clearfield

1.4 Raw Coal — Ash: 9.3%
Lb $SO_2/10^6$ Btu: 1.31 — Sulfur: 0.85% — MM Btu/Ton: 25.94*

1.5 Assumed Plant Size: 500 Mw

1.6 Remaining Life of Boiler: 25 Yr

1.7 Assumed Annual Capital Scrubber Charges as Percent of Original Investment: 15.55%

2.0 STACK GAS COST FACTORS

2.1 Boiler Capacity: 500 Mw

2.2 Utilization Factor: 7,000 Hr/Yr

2.3 Tons of Coal Burned Per Year: 1,349,268 Tons

2.4 Minimum Scrubber Requirements — Scrubber Rating: 318 Mw; % of Flue Gas Cleaned: 63.6%

2.5 Design Scrubber Requirements — Scrubber Rating: 366 Mw; % of Flue Gas Cleaned: 73.2%

2.6 Scrubber Capital Cost: $20,076,804

2.7 Scrubber Capital Charges/Yr: $3,121,943

2.8 Capital Contribution Per Ton of Coal: $2.31/Ton

2.9 Fuel and Electricity Cost Per Ton of Coal: $0.55/Ton

2.10 O & M Costs Per Ton of Coal

Limestone Cost: $0.12/Ton
Maintenance Labor & Material: $0.60/Ton
Fixation Chemical Cost: $0.10/Ton
Supplies Cost: $0.09/Ton
Operating Labor Cost: $0.12/Ton
Overhead Cost: $0.43/Ton

2.11 Total Cost Per Ton of Coal Burned to Meet Emission Standards: $4.32/Ton

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* This value has been adjusted for raw coal moisture content.

CASE NUMBER: 4C

1.0 CASE CONDITIONS — Combined Use of Physical Cleaning Followed by Stack Gas Scrubbing

1.1 Coal Use Area: Boston, Massachusetts

1.2 Emission Standards — New:
Existing: 0.28 lb of Sulfur per MM Btu

1.3 Coal District of Origin: No. 1 — Coalbed: Upper Kittanning
State: Pennsylvania — County: Clearfield

1.4 Raw Coal* — Ash: 9.3 %
Lb SO_2/MM Btu: 1.31 — Sulfur: 0.85% — MM Btu/Ton: 25.94

1.5 Clean Coal — Ash: 7.0%
Cleaning Plant Yield: 90.0% — Sulfur: 0.45% — MM Btu/Ton: 26.55
Lb SO_2/MM Btu: 0.68 — Btu Recovery: 92.1% — Btu Increase: 2.35%

1.6 Transportation — Mileage: 551 — Cost Per Ton: $8.75

1.7 Assumed Plant Size — Megawatts: 500

1.8 Remaining Life of Boiler: 15 Yr

1.9 Assumed Ash Disposal Cost: $4.00/Ton

1.10 Cleaning Plant — Cost: $18,000 Per Ton-Hour Input Capacity**
Utilization: 38.58%***

1.11 Assumed Annual Capital Scrubber Charges as Percent of Original Investment: 17.82%

2.0 COAL CLEANING COST FACTORS

2.1 Cleaning Plant Costs — Amortization: $0.68/Ton — O & M: $0.75/Ton

2.2 Additional Cost to Mine Operator to Provide for One Ton of Clean Coal, When Mine Operator's Cost is

$ 8.00/Ton, Additional Cost is $0.89/Ton
$10.00/Ton, Additional Cost is $1.11/Ton
$12.00/Ton, Additional Cost is $1.33/Ton

2.3 Cleaning Plant Tax and Insurance Burden: $0.12/Ton

2.4 Total Differential Production Cost to Mine Operator to Provide a Ton of Cleaned Coal, When Mine Operator's Cost is

$ 8.00/Ton, Differential Cost is $2.44/Ton****
$10.00/Ton, Differential Cost is $2.66/Ton
$12.00/Ton, Differential Cost is $2.88/Ton

3.0 ASSESSABLE BENEFIT FACTORS ASSOCIATED WITH CLEAN COAL

3.1 Added Coal Value Due To Higher Heat Content of Coal, When F.O.B. Mine Raw Coal Price is

$16.00/Ton, Benefit is $0.37/Ton
$20.00/Ton, Benefit is $0.46/Ton
$24.00/Ton, Benefit is $0.55/Ton

3.2 Transportation Cost Saving Due to Increased Heat Content of Coal is $0.20/Ton

3.3 Saving in Ash Disposal Cost: $0.10/Ton

3.4 Saving in Grinding Cost: $0.01/Ton

3.5 Saving in Benefit Payment: $0.02/Ton

3.6 Saving in Maintenance: $0.13/Ton

3.7 Total Benefits of Coal Cleaning, When F.O.B. Mine Raw Coal Selling Price is

$16.00/Ton, Benefit is $0.83/Ton
$20.00/Ton, Benefit is $0.92/Ton
$24.00/Ton, Benefit is $1.01/Ton

4.0 DIFFERENTIAL CLEANING COST LESS BENEFITS PER TON

		F.O.B. Mine Raw Coal Price (Per Ton)		
		16.00	20.00	24.00
Mine Operator's Cost of Raw Coal (Per Ton)	8.00	1.61	1.52	1.43
	10.00	1.83	1.74	1.65
	12.00	2.05	1.96	1.87

5.0 STACK GAS COST FACTORS

5.1 Boiler Capacity: 500 Mw

5.2 Utilization Factor: 5,000 Hr/Yr

5.3 Tons of Coal Burned Per Year: 941,620 Tons

5.4 Minimum Scrubber Requirements — Scrubber Rating: 97 Mw; % of Flue Gas Cleaned: 19.3%

5.5 Design Scrubber Requirements — Scrubber Rating: 112 Mw; % of Flue Gas Cleaned: 22.4%

5.6 Scrubber Capital Cost: $9,784,427

5.7 Scrubber Capital Charges/Yr $1,743,585

5.8 Capital Contribution Per Ton of Coal: $1.85/Ton

5.9 Fuel and Electricity Cost Per Ton of Coal: $0.17/Ton

5.10 O & M Costs Per Ton of Coal

Limestone Cost: $0.02/Ton
Maintenance Labor & Materials: $0.42/Ton
Fixation Chemical Cost: $0.02/Ton
Supplies Cost: $0.06/Ton
Operating Labor Cost: $0.17/Ton
Overhead Cost: $0.36/Ton

5.11 Total Stack Gas Cost Per Ton of Coal Burned: $3.07/Ton

6.0 COST PER TON OF COAL BURNED TO MEET EMISSION STANDARDS

		F.O.B. Mine Raw Coal Price (Per Ton)		
		16.00	20.00	24.00
Mine Operator's Cost of Raw Coal (Per Ton)	8.00	4.68	4.59	4.50
	10.00	4.90	4.81	4.72
	12.00	5.12	5.03	4.94

7.0 COST PER MILLION BTU TO MEET EMISSION STANDARDS

		F.O.B. Mine Raw Coal Price (Per Ton)		
		16.00	20.00	24.00
Mine Operator's Cost of Raw Coal (Per Ton)	8.00	0.176	0.173	0.169
	10.00	.185	.181	.178
	12.00	.193	.189	.186

8.0 COST PER TON OF RAW COAL TO MEET EMISSION STANDARDS

		F.O.B. Mine Raw Coal Price (Per Ton)		
		16.00	20.00	24.00
Mine Operator's Cost of Raw Coal (Per Ton)	8.00	4.57	4.49	4.38
	10.00	4.80	4.70	4.62
	12.00	5.01	4.90	4.82

* As received values.
** Amortized over 15 years, 8% interest on unpaid balance.
*** Based upon 260 days/yr at 13 hr/day - 3,380 hr/yr.
**** This represents the total of all coal cleaning cost factors at the respective operator cost levels as covered in Section 2.0 above.

CASE NUMBER: 4D

1.0 CASE CONDITIONS — Sulfur Clean-up Exclusively by Stack Gas Scrubbing

1.1 Coal Use Area: Boston, Massachusetts

1.2 Emission Standards
New:
Existing: 0.28 lb of Sulfur Per MM Btu

1.3 Coal District of Origin: No. 1 — Coalbed: Upper Kittanning
State: Pennsylvania — County: Clearfield

1.4 Raw Coal — Ash: 9.3%
Lb $SO_2/10^6$ Btu: 1.31 — Sulfur: 0.85% — MM Btu/Ton: 25.94*

1.5 Assumed Plant Size: 500 Mw

1.6 Remaining Life of Boiler: 15 yr

1.7 Assumed Annual Capital Scrubber Charges as Percent of Original Investment: 17.82%

2.0 STACK GAS COST FACTORS

2.1 Boiler Capacity: 500 Mw

2.2 Utilization Factor: 5,000 Hr/Yr

2.3 Tons of Coal Burned Per Year: 963,763 Tons

2.4 Minimum Scrubber Requirements
Scrubber Rating: 318 Mw
% of Flue Gas Cleaned: 63.6%

2.5 Design Scrubber Requirements
Scrubber Rating: 366 Mw
% of Flue Gas Cleaned: 73.2%

2.6 Scrubber Capital Cost: $25,231,659

2.7 Scrubber Capital Charges/Yr: $4,496,282

2.8 Capital Contribution Per Ton of Coal: $4.67/Ton

2.9 Fuel and Electricity Cost Per Ton of Coal: $0.55/Ton

2.10 O & M Costs Per Ton of Coal

Limestone Cost: $0.12/Ton
Maintenance Labor & Materials: $1.05/Ton
Fixation Chemical Cost: $0.10/Ton
Supplies Cost: $0.16/Ton
Operating Labor Cost: $0.17/Ton
Overhead Cost: $0.72/Ton

2.11 Total Cost Per Ton of Coal Burned to Meet Emission Standards: $7.54/Ton

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* This value has been adjusted for raw coal moisture content.

CASE NUMBER: 5A

1.0 CASE CONDITIONS — Combined Use of Physical Cleaning Followed by Stack Gas Scrubbing

1.1 Coal Use Area: Grand Rapids, Michigan

1.2 Emission Standards — New: 1.6 lb of SO_2 Per MM Btu; Existing:

1.3 Coal District of Origin: No. 3 — Coalbed: Upper Freeport
State: West Virginia — County: Preston

1.4 Raw Coal* — Ash: 18.5%
Lb SO_2/MM Btu: 3.66 — Sulfur: 2.24% — MM Btu/Ton: 24.5

1.5 Clean Coal — Ash: 11.9%
Cleaning Plant Yield: 90.0% — Sulfur: 1.25% — MM Btu/Ton: 26.23
Lb SO_2/MM Btu: 1.91 — Btu Recovery: 96.4% — Btu Increase: 7.1%

1.6 Transportation — Mileage: 575 — Cost Per Ton: $5.41

1.7 Assumed Plant Size — Megawatts: 500

1.8 Remaining Life of Boiler: 25 Yr

1.9 Assumed Ash Disposal Cost: $4.00/Ton

1.10 Cleaning Plant — Cost: $18,000 Per Ton-Hour Input Capacity**
Utilization: 38.58%***

1.11 Assumed Annual Capital Scrubber Charges as Percent of Original Investment: 15.55%

2.0 COAL CLEANING COST FACTORS

2.1 Cleaning Plant Costs — Amortization: $0.68/Ton — O & M: $0.75/Ton

2.2 Additional Cost to Mine Operator to Provide for One Ton of Clean Coal, When Operator's Cost is

$ 8.00/Ton, Additional Cost is $0.89/Ton
$10.00/Ton, Additional Cost is $1.11/Ton
$12.00/Ton, Additional Cost is $1.33/Ton

2.3 Cleaning Plant Tax and Insurance Burden: $0.12/Ton

2.4 Total Differential Production Cost to Mine Operator to Provide a Ton of Cleaned Coal, When Mine Operator's Cost is

$ 8.00/Ton, Differential Cost is $2.44/Ton****
$10.00/Ton, Differential Cost is $2.66/Ton
$12.00/Ton, Differential Cost is $2.88/Ton

3.0 ASSESSABLE BENEFIT FACTORS ASSOCIATED WITH CLEAN COAL

3.1 Added Coal Value Due to Higher Heat Content of Coal, When F.O.B. Mine Raw Coal Price is

$16.00/Ton, Benefit is $1.06/Ton
$18.00/Ton, Benefit is $1.19/Ton
$20.00/Ton, Benefit is $1.33/Ton

3.2 Transportation Cost Saving Due to Increased Heat Content of Coal: $0.36/Ton

3.3 Saving in Ash Disposal Cost: $0.30/Ton

3.4 Saving in Grinding Cost: $0.03/Ton

3.5 Saving in Benefit Payment: $0.05/Ton

3.6 Saving in Maintenance: $0.24/Ton

3.7 Total Benefits of Coal Cleaning, When F.O.B. Mine Raw Coal Selling Price is

$16.00/Ton, Benefit is $2.04/Ton
$18.00/Ton, Benefit is $2.17/Ton
$20.00/Ton, Benefit is $2.31/Ton

4.0 DIFFERENTIAL CLEANING COST LESS BENEFITS PER TON

		F.O.B. Mine Raw Coal Price (Per Ton)		
		16.00	18.00	20.00
Mine Operator's Cost of Raw Coal (Per Ton)	8.00	0.40	0.27	0.13
	10.00	.62	.49	.35
	12.00	.84	.71	.57

5.0 STACK GAS COST FACTORS

5.1 Boiler Capacity: 500 Mw

5.2 Utilization Factor: 7,000 Hr/Yr

5.3 Tons of Coal Burned Per Year: 1,334,350 Tons

5.4 Minimum Scrubber Requirements — Scrubber Rating: 90 Mw
% of Flue Gas Cleaned: 18.0%

5.5 Design Scrubber Requirements — Scrubber Rating: 104 Mw
% of Flue Gas Cleaned: 20.8%

5.6 Scrubber Capital Cost: $7,344,739

5.7 Scrubber Capital Charges/Yr: $1,142,107

5.8 Capital Contribution Per Ton of Coal: $0.86/Ton

5.9 Fuel and Electricity Cost Per Ton of Coal: $0.16/Ton

5.10 O & M Costs Per Ton of Coal

Limestone Cost: $0.05/Ton
Maintenance Labor & Materials: $0.22/Ton
Fixation Chemical Cost: $0.04/Ton
Supplies Cost: $0.03/Ton
Operating Labor Cost: $0.12/Ton
Overhead Cost: $0.21/Ton

5.11 Total Stack Gas Cost Per Ton of Coal Burned: $1.69/Ton

6.0 COST PER TON OF COAL BURNED TO MEET EMISSION STANDARDS

		F.O.B. Mine Raw Coal Price (Per Ton)		
		16.00	18.00	20.00
Mine Operator's Cost of Raw Coal (Per Ton)	8.00	2.09	1.96	1.82
	10.00	2.31	2.18	2.04
	12.00	2.53	2.40	2.26

7.0 COST PER MILLION BTU TO MEET EMISSION STANDARDS

		F.O.B. Mine Raw Coal Price (Per Ton)		
		16.00	18.00	20.00
Mine Operator's Cost of Raw Coal (Per Ton)	8.00	0.080	0.075	0.069
	10.00	.088	.083	.078
	12.00	.096	.091	.086

8.0 COST PER TON OF RAW COAL TO MEET EMISSION STANDARDS

		F.O.B. Mine Raw Coal Price (Per Ton)		
		16.00	18.00	20.00
Mine Operator's Cost of Raw Coal (Per Ton)	8.00	1.96	1.84	1.69
	10.00	2.16	2.03	1.91
	12.00	2.35	2.23	2.11

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* As received values.
** Amortized over 15 years, 8% interest on unpaid balance.
*** Based upon 260 days/yr at 13 hr/day - 3,380 hr/yr.
**** This represents the total of all coal cleaning cost factors at the respective operator cost levels as covered in Section 2.0 above.

1.0 CASE CONDITIONS — Sulfur Clean-up Exclusively by Stack Gas Scrubbing

1.1 Coal Use Area: Grand Rapids, Michigan

1.2 Emission Standards — New: 1.6 lb of SO_2 Per MM Btu; Existing:

1.3 Coal District of Origin: No. 3 — Coalbed: Upper Freeport
State: West Virginia — County: Preston

1.4 Raw Coal — Ash: 18.5%
Lb $SO_2/10^6$ Btu: 3.66 — Sulfur: 2.24% — MM Btu/Ton: 24.5*

1.5 Assumed Plant Size: 500 Mw

1.6 Remaining Life of Boiler: 25 Yr

1.7 Assumed Annual Capital Scrubber Charges as Percent of Original Investment: 15.55%

2.0 STACK GAS COST FACTORS

2.1 Boiler Capacity: 500 Mw

2.2 Utilization Factor: 7,000 Hr/Yr

2.3 Tons of Coal Burned Per Year: 1,428,572 Tons

2.4 Minimum Scrubber Requirements — Scrubber Rating: 313 Mw; % of Flue Gas Cleaned: 62.5%

2.5 Design Scrubber Requirements — Scrubber Rating: 360 Mw; % of Flue Gas Cleaned: 72.0%

2.6 Scrubber Capital Cost: $19,833,148

2.7 Scrubber Capital Charges/Yr: $3,084,055

2.8 Capital Contribution Per Ton of Coal $2.16/Ton

2.9 Fuel and Electricity Cost Per Ton of Coal: $0.51/Ton

2.10 O & M Costs Per Ton of Coal

Limestone Cost: $0.30/Ton
Maintenance Labor & Materials: $0.56/Ton
Fixation Chemical Cost: $0.24/Ton
Supplies Cost: $0.08/Ton
Operating Labor Cost: $0.11/Ton
Overhead Cost: $0.40/Ton

2.11 Total Cost Per Ton of Coal Burned to Meet Emission Standards: $4.36/Ton

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* This value has been adjusted for raw coal moisture content.

CASE NUMBER: 5C

1.0 CASE CONDITIONS — Combined Use of Physical Cleaning Followed by Stack Gas Scrubbing

1.1 Coal Use Area: Grand Rapids, Michigan

1.2 Emission Standards — New:
Existing: 1.6 lb SO_2 Per MM Btu

1.3 Coal District of Origin: No. 3 — Coalbed: Upper Freeport
State: West Virginia — County: Preston

1.4 Raw Coal* — Ash: 18.5 %
SO_2/MM Btu: 3.66 — Sulfur: 2.24% — MM Btu/Ton: 24.5

1.5 Clean Coal — Ash: 11.9%
Cleaning Plant Yield: 90.0% — Sulfur: 1.25% — MM Btu/Ton: 26.23
Lb SO_2/MM Btu: 1.91 — Btu Recovery: 96.4% — Btu Increase: 7.1%

1.6 Transportation — Mileage: 575 — Cost Per Ton: $5.41

1.7 Assumed Plant Size — Megawatts: 500

1.8 Remaining Life of Boiler: 15 Yr

1.9 Assumed Ash Disposal Cost: $4.00/Ton

1.10 Cleaning Plant — Cost: $18,000 Per Ton-Hour Input Capacity**
Utilization: 38.58%***

1.11 Assumed Annual Capital Scrubber Charges as Percent of Original Investment: 17.82%

2.0 COAL CLEANING COST FACTORS

2.1 Cleaning Plant Costs — Amortization: $0.68/Ton — O & M: $0.75/Ton

2.2 Additional Cost to Mine Operator to Provide for One Ton of Clean Coal, When Mine Operator's Cost is

$ 8.00/Ton, Additional Cost is $0.89/Ton
$10.00/Ton, Additional Cost is $1.11/Ton
$12.00/Ton, Additional Cost is $1.33/Ton

2.3 Cleaning Plant Tax and Insurance Burden: $0.12/Ton

2.4 Total Differential Production Cost to Mine Operator to Provide a Ton of Cleaned Coal, When Mine Operator's Cost is

$ 8.00/Ton, Differential Cost is $2.44/Ton****
$10.00/Ton, Differential Cost is $2.66/Ton
$12.00/Ton, Differential Cost is $2.88/Ton

3.0 ASSESSABLE BENEFIT FACTORS ASSOCIATED WITH CLEAN COAL

3.1 Added Coal Value Due to Higher Heat Content of Coal, When F.O.B. Mine Raw Coal Price is

$16.00/Ton, Benefit is $1.06/Ton
$18.00/Ton, Benefit is $1.19/Ton
$20.00/Ton, Benefit is $1.33/Ton

3.2 Transportation Cost Saving Due to Increased Heat Content of Coal: $0.36/Ton

3.3 Saving in Ash Disposal Cost: $0.30/Ton

3.4 Saving in Grinding Cost: $0.03/Ton

3.5 Saving in Benefit Payment: $0.05/Ton

3.6 Saving in Maintenance: $0.24/Ton

3.7 Total Benefits of Coal Cleaning, When F.O.B. Mine Raw Coal Selling Price is

$16.00/Ton, Benefit is $2.04/Ton
$18.00/Ton, Benefit is $2.17/Ton
$20.00/Ton, Benefit is $2.31/Ton

4.0 DIFFERENTIAL CLEANING COST LESS BENEFITS PER TON

		F.O.B. Mine Raw Coal Price (Per Ton)		
		16.00	18.00	20.00
Mine Operator's Cost of Raw Coal (Per Ton)	8.00	0.40	0.27	0.13
	10.00	.62	.49	.35
	12.00	.84	.71	.57

5.0 STACK GAS COST FACTORS

5.1 Boiler Capacity: 500 Mw

5.2 Utilization Factor: 5,000 Hr/Yr

5.3 Tons of Coal Burned Per Year: 953,108 Tons

5.4 Minimum Scrubber Requirements — Scrubber Rating: 90 Mw
% of Flue Gas Cleaned: 18.0%

5.5 Design Scrubber Requirements — Scrubber Rating: 104 Mw
% of Flue Gas Cleaned: 20.8%

5.6 Scrubber Capital Cost: $9,221,204

5.7 Scrubber Capital Charges/Yr: $1,643,219

5.8 Capital Contribution Per Ton of Coal: $1.72/Ton

5.9 Fuel and Electricity Cost Per Ton of Coal: $0.16/Ton

5.10 O & M Costs Per Ton of Coal

Limestone Cost: $0.05/Ton
Maintenance Labor & Materials: $0.39/Ton
Fixation Chemical Cost: $0.04/Ton
Supplies Cost: $0.06/Ton
Operating Labor Cost: $0.17/Ton
Overhead Cost: $0.34/Ton

5.11 Total Stack Gas Cost Per Ton of Coal Burned: $2.93/Ton

6.0 COST PER TON OF COAL BURNED TO MEET EMISSION STANDARDS

		F.O.B. Mine Raw Coal Price (Per Ton)		
		16.00	18.00	20.00
Mine Operator's Cost of Raw Coal (Per Ton)	8.00	3.33	3.20	3.06
	10.00	3.55	3.42	3.28
	12.00	3.77	3.64	3.50

7.0 COST PER MILLION BTU TO MEET EMISSION STANDARDS

		F.O.B. Mine Raw Coal Price (Per Ton)		
		16.00	18.00	20.00
Mine Operator's Cost of Raw Coal (Per Ton)	8.00	0.127	0.122	0.117
	10.00	.135	.130	.125
	12.00	.144	.139	.133

8.0 COST PER TON OF RAW COAL TO MEET EMISSION STANDARDS

		F.O.B. Mine Raw Coal Price (Per Ton)		
		16.00	18.00	20.00
Mine Operator's Cost of Raw Coal (Per Ton)	8.00	3.11	2.99	2.87
	10.00	3.31	3.19	3.06
	12.00	3.53	3.41	3.26

* As received values.

** Amortized over 15 years, 8% interest on unpaid balance.

*** Based upon 260 days/yr at 13 hr/day - 3,380 hr/yr.

**** This represents the total of all coal cleaning cost factors at the respective operator cost levels as covered in Section 2.0 above.

CASE NUMBER: 5D

1.0 CASE CONDITIONS — Sulfur Clean-up Exclusively by Stack Gas Scrubbing

1.1 Coal Use Area: Grand Rapids, Michigan

1.2 Emission Standards — New:
Existing: 1.6 lb of SO_2 Per MM Btu

1.3 Coal District of Origin: No. 3 — Coalbed: Upper Freeport
State: West Virginia — County: Preston

1.4 Raw Coal — Ash: 18.5%
Lb $SO_2/10^6$ Btu: 3.66 — Sulfur: 2.24% — MM Btu/Ton: 24.5*

1.5 Assumed Plant Size: 500 Mw

1.6 Remaining Life of Boiler: 15 Yr

1.7 Assumed Annual Capital Scrubber Charges as Percent of Original Investment: 17.82%

2.0 STACK GAS COST FACTORS

2.1 Boiler Capacity: 500 Mw

2.2 Utilization Factor: 5,000 Hr/Yr

2.3 Tons of Coal Burned Per Year: 1,020,409 Tons

2.4 Minimum Scrubber Requirements — Scrubber Rating: 313 Mw
% of Flue Gas Cleaned: 62.5%

2.5 Design Scrubber Requirements — Scrubber Rating: 360 Mw
% of Flue Gas Cleaned: 72.0%

2.6 Scrubber Capital Cost: $24,900,206

2.7 Scrubber Capital Charges/Yr: $4,437,217

2.8 Capital Contribution Per Ton of Coal: $4.35/Ton

2.9 Fuel and Electricity Cost Per Ton of Coal: $0.51/Ton

2.10 O & M Costs Per Ton of Coal

Limestone Cost: $0.30/Ton
Maintenance Labor & Materials: $0.98/Ton
Fixation Chemical Cost: $0.24/Ton
Supplies Cost: $0.15/Ton
Operating Labor Cost: $0.16/Ton
Overhead Cost: $0.68/Ton

2.11 Total Cost Per Ton of Coal Burned to Meet Emission Standards: $7.37/Ton

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* This value has been adjusted for raw coal moisture content.

CASE NUMBER: 6A

1.0 CASE CONDITIONS — Combined Use of Physical Cleaning Followed by Stack Gas Scrubbing

1.1 Coal Use Area: Springfield, Massachusetts

1.2 Emission Standards — New: 0.55 Lb of Sulfur Per MM Btu; Existing:

1.3 Coal District of Origin: No. 2 — Coalbed: Upper Freeport
State: Pennsylvania — County: Armstrong

1.4 Raw Coal*
Lb SO_2/MM Btu: 3.86 — Sulfur: 2.53% — Ash: 13.0% — MM Btu/Ton: 26.21

1.5 Clean Coal
Cleaning Plant Yield: 90.0% — Sulfur: 1.09% — Ash: 7.2% — MM Btu/Ton: 27.82
Lb SO_2/MM Btu: 1.57 — Btu Recovery: 95.5% — Btu Increase: 6.14%

1.6 Transportation — Mileage: 659 — Cost Per Ton: $9.01

1.7 Assumed Plant Size — Megawatts: 500

1.8 Remaining Life of Boiler: 25 Yr

1.9 Assumed Ash Disposal Cost: $4.00/Ton

1.10 Cleaning Plant — Cost: $18,000 Per Ton-Hour Input Capacity**
Utilization: 38.58%***

1.11 Assumed Annual Capital Scrubber Charges as Percent of Original Investment: 15.55%

2.0 COAL CLEANING COST FACTORS

2.1 Cleaning Plant Costs — Amortization: $0.68/Ton — O & M: $0.75/Ton

2.2 Additional Cost to Mine Operator to Provide for One Ton of Clean Coal, When Mine Operator's Cost is

$ 7.00/Ton, Additional Cost is $0.78/Ton
$ 9.00/Ton, Additional Cost is $1.00/Ton
$11.00/Ton, Additional Cost is $1.22/Ton

2.3 Cleaning Plant Tax and Insurance Burden: $0.12/Ton

2.4 Total Differential Production Cost to Mine Operator to Provide a Ton of Cleaned Coal, When Mine Operator's Cost is

$ 7.00/Ton, Differential Cost is $2.33/Ton****
$ 9.00/Ton, Differential Cost is $2.55/Ton
$11.00/Ton, Differential Cost is $2.77/Ton

3.0 ASSESSABLE BENEFIT FACTORS ASSOCIATED WITH CLEAN COAL

3.1 Added Coal Value Due to Higher Heat Content of Coal, When F.O.B. Mine Raw Coal Price is

$14.00/Ton, Benefit is $0.81/Ton
$16.00/Ton, Benefit is $0.93/Ton
$18.00/Ton, Benefit is $1.04/Ton

3.2 Transportation Cost Saving Due to Increased Heat Content of Coal: $0.52/Ton

3.3 Saving in Ash Disposal Cost: $0.26/Ton

3.4 Saving in Grinding Cost: $0.03/Ton

3.5 Saving in Benefit Payment: $0.04/Ton

3.6 Saving in Maintenance: $0.24/Ton

3.7 Total Benefits of Coal Cleaning, When F.O.B. Mine Raw Coal Selling Price is

$14.00/Ton, Benefit is $1.90/Ton
$16.00/Ton, Benefit is $2.02/Ton
$18.00/Ton, Benefit is $2.13/Ton

4.0 DIFFERENTIAL CLEANING COST LESS BENEFITS PER TON

		F.O.B. Mine Raw Coal Price (Per Ton)		
		14.00	16.00	18.00
Mine Operator's Cost of Raw Coal (Per Ton)	7.00	0.43	0.31	0.20
	9.00	.65	.53	.42
	11.00	.87	.75	.64

5.0 STACK GAS COST FACTORS

5.1 Boiler Capacity: 500 Mw

5.2 Utilization Factor: 7,000 Hr/Yr

5.3 Tons of Coal Burned Per Year: 1,258,088 Tons

5.4 Minimum Scrubber Requirements — Scrubber Rating: 166 Mw; % of Flue Gas Cleaned: 33.2%

5.5 Design Scrubber Requirements — Scrubber Rating: 191 Mw; % of Flue Gas Cleaned: 38.2%

5.6 Scrubber Capital Cost: $11,932,637

5.7 Scrubber Capital Charges/Yr: $1,855,525

5.8 Capital Contribution Per Ton of Coal: $1.48/Ton

5.9 Fuel and Electricity Cost Per Ton of Coal: $0.31/Ton

5.10 O & M Costs Per Ton of Coal

Limestone Cost: $0.09/Ton
Maintenance Labor & Material: $0.38/Ton
Fixation Chemical Cost: $0.07/Ton
Supplies Cost: $0.06/Ton
Operating Labor Cost: $0.13/Ton
Overhead Cost: $0.31/Ton

5.11 Total Stack Gas Cost Per Ton of Coal Burned: $2.83/Ton

6.0 COST PER TON OF COAL BURNED TO MEET EMISSION STANDARDS

		F.O.B. Mine Raw Coal Price (Per Ton)		
		14.00	16.00	18.00
Mine Operator's Cost of Raw Coal (Per Ton)	7.00	3.26	3.14	3.03
	9.00	3.48	.3.36	3.25
	11.00	3.70	3.58	3.47

7.0 COST PER MILLION BTU TO MEET EMISSION STANDARDS

		F.O.B. Mine Raw Coal Price (Per Ton)		
		14.00	16.00	18.00
Mine Operator's Cost of Raw Coal (Per Ton)	7.00	0.117	0.113	0.109
	9.00	.125	.121	.117
	11.00	.133	.129	.125

8.0 COST PER TON OF RAW COAL TO MEET EMISSION STANDARDS

		F.O.B. Mine Raw Coal Price (Per Ton)		
		14.00	16.00	18.00
Mine Operator's Cost of Raw Coal (Per Ton)	7.00	3.07	2.96	2.86
	9.00	3.28	3.17	3.07
	11.00	3.49	3.38	3.28

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* As received values.
** Amortized over 15 years, 8% interest on unpaid balance.
*** Based upon 260 days/yr at 13 hr/day - 3,380 hr/yr
**** This represents the total of all coal cleaning cost factors at the respective operator cost levels as covered in Section 2.0 above.

CASE NUMBER: 6B

1.0 CASE CONDITIONS — Sulfur Clean-up Exclusively by Stack Gas Scrubbing

1.1 Coal Use Area:

1.2 Emission Standards — New: 0.55 Lb of Sulfur Per MM Btu
Existing:

1.3 Coal District of Origin: No. 2 — Coalbed: Upper Freeport
State: Pennsylvania — County: Armstrong

1.4 Raw Coal — Ash: 13.0%
Lb $SO_2/10^6$ Btu: 3.86 — Sulfur: 2.53% — MM Btu/Ton: 26.21*

1.5 Assumed Plant Size: 500 Mw

1.6 Remaining Life of Boiler: 25 Yr

1.7 Assumed Annual Capital Scrubber Charges as Percent of Original Investment: 15.55%

2.0 STACK GAS COST FACTORS

2.1 Boiler Capacity: 500 Mw

2.2 Utilization Factor: 7,000 Hr/Yr

2.3 Tons of Coal Burned Per Year: 1,335,369 Tons

2.4 Minimum Scrubber Requirements — Scrubber Rating: 397 Mw
% of Flue Gas Cleaned: 79.4%

2.5 Design Scrubber Requirements — Scrubber Rating: 457 Mw
% of Flue Gas Cleaned: 91.4%

2.6 Scrubber Capital Cost: $25,907,734

2.7 Scrubber Capital Charges/Yr: $4,028,653

2.8 Capital Contribution Per Ton of Coal: $3.02/Ton

2.9 Fuel and Electricity Cost Per Ton of Coal: $0.69 Ton

2.10 O & M Costs Per Ton of Coal

Limestone Cost: $0.46/Ton
Maintenance Labor & Material: $0.78/Ton
Fixation Chemical Cost: $0.37/Ton
Supplies Cost: $0.12/Ton
Operating Labor Cost: $0.12/Ton
Overhead Cost: $0.53/Ton

2.11 Total Cost Per Ton of Coal Burned to Meet Emission Standards: $6.09/Ton

* This value has been adjusted for raw coal moisture content.

CASE NUMBER: 6C

1.0 CASE CONDITIONS — Combined Use of Physical Cleaning Followed by Stack Gas Scrubbing

1.1 Coal Use Area: Springfield, Massachusetts

1.2 Emission Standards — New:
Existing: 0.55 Lb of Sulfur Per MM Btu

1.3 Coal District of Origin: No. 2 — Coalbed: Upper Freeport
State: Pennsylvania — County: Armstrong

1.4 Raw Coal*
Lb SO_2/MM Btu: 1.57 — Sulfur: 2.53% — Ash: 13.0%
MM Btu/Ton: 26.21

1.5 Clean Coal
Cleaning Plant Yield: 90.0% — Sulfur: 1.09% — Ash: 7.2%
MM Btu/Ton: 27.82
Lb SO_2/MM Btu: 1.57 — Btu Recovery: 95.5% — Btu Increase: 6.14%

1.6 Transportation — Mileage: 659 — Cost Per Ton: $9.01

1.7 Assumed Plant Size — Megawatts: 500

1.8 Remaining Life of Boiler: 15 Yr

1.9 Assumed Ash Disposal Cost: $4.00/Ton

1.10 Cleaning Plant — Cost: $18,000 Per Ton-Hour Input Capacity**
Utilization: 38.58%***

1.11 Assumed Annual Capital Scrubber Charges as Percent of Original Investment: 17.82%

2.0 COAL CLEANING COST FACTORS

2.1 Cleaning Plant Costs — Amortization: $0.68/Ton — O & M: $0.75/Ton

2.2 Additional Cost to Mine Operator to Provide for One Ton of Clean Coal, When Mine Operator's Cost is

$ 7.00/Ton, Additional Cost is $0.78/Ton
$ 9.00/Ton, Additional Cost is $1.00/Ton
$11.00/Ton, Additional Cost is $1.22/Ton

2.3 Cleaning Plant Tax and Insurance Burden: $0.12/Ton

2.4 Total Differential Production Cost to Mine Operator to Provide a Ton of Cleaned Coal, When Mine Operator's Cost is

$ 7.00/Ton, Differential Cost is $2.33/Ton****
$ 9.00/Ton, Differential Cost is $2.55/Ton
$11.00/Ton, Differential Cost is $2.77/Ton

3.0 ASSESSABLE BENEFIT FACTORS ASSOCIATED WITH CLEAN COAL

3.1 Added Coal Value Due to Higher Heat Content of Coal, When F.O.B. Mine Raw Coal Price is

$14.00/Ton, Benefit is $0.81/Ton
$16.00/Ton, Benefit is $0.93/Ton
$18.00/Ton, Benefit is $1.04/Ton

3.2 Transportation Cost Saving Due to Increased Heat Content of Coal: $0.52/Ton

3.3 Saving in Ash Disposal Cost: $0.26/Ton

3.4 Saving in Grinding Cost: $0.03/Ton

3.5 Saving in Benefit Payment: $0.04/Ton

3.6 Saving in Maintenance: $0.24/Ton

3.7 Total Benefits of Coal Cleaning, When F.O.B. Mine Raw Coal Selling Price is

$14.00/Ton, Benefit is $1.90/Ton
$16.00/Ton, Benefit is $2.02/Ton
$18.00/Ton, Benefit is $2.13/Ton

4.0 DIFFERENTIAL CLEANING COST LESS BENEFITS PER TON

		F.O.B. Mine Raw Coal Price (Per Ton)		
		14.00	16.00	18.00
Mine Operator's Cost of Raw Coal (Per Ton)	7.00	0.43	0.31	0.20
	9.00	.65	.53	.42
	11.00	.87	.75	.64

5.0 STACK GAS COST FACTORS

5.1 Boiler Capacity: 500 Mw

5.2 Utilization Factor: 5,000 Hr/Yr

5.3 Tons of Coal Burned Per Year: 898,635 Tons

5.4 Minimum Scrubber Requirements — Scrubber Rating: 166 Mw
% of Flue Gas Cleaned: 33.2%

5.5 Design Scrubber Requirements — Scrubber Rating: 191 Mw
% of Flue Gas Cleaned: 38.2%

5.6 Scrubber Capital Cost: $14,996,442

5.7 Scrubber Capital Charges/Yr: $2,672,363

5.8 Capital Contribution Per Ton of Coal: $2.97/Ton

5.9 Fuel and Electricity Cost Per Ton of Coal: $0.31/Ton

5.10 O & M Costs Per Ton of Coal

Limestone Cost: $0.09/Ton
Maintenance Labor & Materials: $0.67/Ton
Fixation Chemical Cost: $0.07/Ton
Supplies Cost: $0.10/Ton
Operating Labor Cost: $0.18/Ton
Overhead Cost: $0.51/Ton

5.11 Total Stack Gas Cost Per Ton of Coal Burned: $4.90/Ton

6.0 COST PER TON OF COAL BURNED TO MEET EMISSION STANDARDS

		F.O.B. Mine Raw Coal Price (Per Ton)		
		14.00	16.00	18.00
Mine Operator's Cost of Raw Coal (Per Ton)	7.00	5.33	5.21	5.10
	9.00	5.55	5.43	5.32
	11.00	5.77	5.65	5.54

7.0 COST PER MILLION BTU TO MEET EMISSION STANDARDS

		F.O.B. Mine Raw Coal Price (Per Ton)		
		14.00	16.00	18.00
Mine Operator's Cost of Raw Coal (Per Ton)	7.00	0.192	0.187	0.183
	9.00	.200	.195	.191
	11.00	.207	.203	.199

8.0 COST PER TON OF RAW COAL TO MEET EMISSION STANDARDS

		F.O.B. Mine Raw Coal Price (Per Ton)		
		14.00	16.00	18.00
Mine Operator's Cost of Raw Coal (Per Ton)	7.00	5.03	4.90	4.80
	9.00	5.24	5.11	5.01
	11.00	5.43	5.32	5.22

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* As received values.

** Amortized over 15 years, 8% interest on unpaid balance.

*** Based Upon 260 days/yr at 13 hr/day - 3,380 hrs/yr

**** This represents the total of all coal cleaning cost factors at the respective operator cost levels as covered in Section 2.0 above.

CASE NUMBER: 6D

1.0 CASE CONDITIONS — Sulfur Clean-up Exclusively by Stack Gas Scrubbing

1.1 Coal Use Area: Springfield, Massachusetts

1.2 Emission Standards — New:
Existing: 0.55 Lb of Sulfur Per MM Btu

1.3 Coal District of Origin: No. 2 — Coalbed: Upper Freeport
State: Pennsylvania — County: Armstrong

1.4 Raw Coal — Ash: 13.0%
Lb $SO_2/10^6$ Btu: 3.86 — Sulfur: 2.53% — MM Btu/Ton: 26.21*

1.5 Assumed Plant Size: 500 Mw

1.6 Remaining Life of Boiler: 15 Yr

1.7 Assumed Annual Capital Scrubber Charges as Percent of Original Investment: 17.82%

2.0 STACK GAS COST FACTORS

2.1 Boiler Capacity: 500 Mw

2.2 Utilization Factor: 5,000 Hr/Yr

2.3 Tons of Coal Burned Per Year: 953,835 Tons

2.4 Minimum Scrubber Requirements — Scrubber Rating: 397 Mw
% of Flue Gas Cleaned: 79.4%

2.5 Design Scrubber Requirements — Scrubber Rating: 457 Mw
% of Flue Gas Cleaned: 91.4%

2.6 Scrubber Capital Cost: $31,724,417

2.7 Scrubber Capital Charges/Yr: $5,653,292

2.8 Capital Contribution Per Ton of Coal: $5.93/Ton

2.9 Fuel and Electricity Cost Per Ton of Coal: $0.69/Ton

2.10 O & M Costs Per Ton of Coal

Limestone Cost: $0.46/Ton
Maintenance Labor & Materials: $1.33/Ton
Fixation Chemical Cost: $0.37/Ton
Supplies Cost: $0.20/Ton
Operating Labor Cost: $0.17/Ton
Overhead Cost: $0.88/Ton

2.11 Total Cost Per Ton of Coal Burned to Meet Emission
Standards: $10.03/Ton

* This value has been adjusted for raw coal moisture content.

CASE NUMBER: 7A

1.0 CASE CONDITIONS — Combined Use of Physical Cleaning Followed by Stack Gas Scrubbing

1.1 Coal Use Area: Lansing, Michigan

1.2 Emission Standards — New: 1.6 Lb SO_2 Per MM Btu
Existing:

1.3 Coal District of Origin: No. 4 — Coalbed: Pittsburgh
State: Ohio — County: Jefferson

1.4 Raw Coal* — Ash: 9.8%
Lb SO_2/MM Btu: 4.29 — Sulfur: 2.82% — MM Btu/Ton: 26.32

1.5 Clean Coal — Ash: 6.0%
Cleaning Plant Yield: 90.0% — Sulfur: 2.03% — MM Btu/Ton: 27.36
Lb SO_2/MM Btu: 2.97 — Btu Recovery: 93.56% — Btu Increase: 3.95%

1.6 Transportation — Mileage: 323 — Cost Per Ton: $3.87

1.7 Assumed Plant Size — Megawatts: 500

1.8 Remaining Life of Boiler: 25 Yr

1.9 Assumed Ash Disposal Cost: $4.00/Ton

1.10 Cleaning Plant — Cost: $18,000 Per Ton-Hour Input Capacity**
Utilization: 38.58%***

1.11 Assumed Annual Capital Scrubber Charges as Percent of Original Investment: 15.55%

2.0 COAL CLEANING COST FACTORS

2.1 Cleaning Plant Costs — Amortization: $0.68/Ton — O & M: $0.75/Ton

2.2 Additional Cost to Mine Operator to Provide for One Ton of Cleaned Coal, When Mine Operator's Cost is

$ 6.00/Ton, Additional Cost is $0.67/Ton
$ 8.00/Ton, Additional Cost is $0.89/Ton
$10.00/Ton, Additional Cost is $1.11/Ton

2.3 Cleaning Plant Tax and Insurance Burden: $0.12/Ton

2.4 Total Differential Production Cost to Mine Operator to Provide a Ton of Cleaned Coal, When Mine Operator's Cost is

$ 6.00/Ton, Differential Cost is $2.22/Ton****
$ 8.00/Ton, Differential Cost is $2.44/Ton
$10.00/Ton, Differential Cost is $2.66/Ton

3.0 ASSESSABLE BENEFIT FACTORS ASSOCIATED WITH CLEAN COAL

3.1 Added Coal Value Due to Higher Heat Content of Coal, When F.O.B. Mine Raw Coal Price is

$12.00/Ton, Benefit is $0.46/Ton
$14.00/Ton, Benefit is $0.53/Ton
$16.00/Ton, Benefit is $0.61/Ton

3.2 Transportation Cost Saving Due to Increased Heat Content of Coal: $0.15/Ton

3.3 Saving in Ash Disposal Cost: $0.16/Ton

3.4 Saving in Grinding Cost: $0.02/Ton

3.5 Saving in Benefit Payment: $0.03/Ton

3.6 Saving in Maintenance: $0.17/Ton

3.7 Total Benefits of Coal Cleaning, When F.O.B. Mine Raw Coal Selling Price is

$12.00/Ton, Benefit is $0.99/Ton
$14.00/Ton, Benefit is $1.06/Ton
$16.00/Ton, Benefit is $1.14/Ton

4.0 DIFFERENTIAL CLEANING COST LESS BENEFITS PER TON

		F.O.B. Mine Raw Coal Price (Per Ton)		
		12.00	14.00	16.00
Mine Operator's Cost of Raw Coal (Per Ton)	6.00	1.23	1.16	1.08
	8.00	1.45	1.38	1.30
	10.00	1.67	1.60	1.52

5.0 STACK GAS COST FACTORS

5.1 Boiler Capacity: 500 Mw

5.2 Utilization Factor: 7,000 Hr/Yr

5.3 Tons of Coal Burned Per Year: 1,279,240 Tons

5.4 Minimum Scrubber Requirements — Scrubber Rating: 266 Mw
% of Flue Gas Cleaned: 51.3%

5.5 Design Scrubber Requirements — Scrubber Rating: 295 Mw
% of Flue Gas Cleaned: 59.0%

5.6 Scrubber Capital Cost: $17,614,550

5.7 Scrubber Capital Charges/Yr: $2,739,063

5.8 Capital Contribution Per Ton of Coal: $2.14/Ton

5.9 Fuel and Electricity Cost Per Ton of Coal: $0.47/Ton

5.10 O & M Costs Per Ton of Coal

Limestone Cost: $0.25/Ton
Maintenance Labor & Material: $0.55/Ton
Fixation Chemical Cost: $0.20/Ton
Supplies Cost: $0.08/Ton
Operating Labor Cost: $0.13/Ton
Overhead Cost: $0.41/Ton

5.11 Total Stack Gas Cost Per Ton of Coal Burned: $4.23/Ton

6.0 COST PER TON OF COAL BURNED TO MEET EMISSION STANDARDS

		F.O.B. Mine Raw Coal Price (Per Ton)		
		12.00	14.00	16.00
Mine Operator's Cost of Raw Coal (Per Ton)	6.00	5.46	5.39	5.31
	8.00	5.68	5.61	5.53
	10.00	5.90	5.83	5.75

7.0 COST PER MILLION BTU TO MEET EMISSION STANDARDS

		F.O.B. Mine Raw Coal Price (Per Ton)		
		12.00	14.00	16.00
Mine Operator's Cost of Raw Coal (Per Ton)	6.00	0.200	0.197	0.194
	8.00	.208	.205	.202
	10.00	.216	.213	.210

8.0 COST PER TON OF RAW COAL TO MEET EMISSION STANDARDS

		F.O.B. Mine Raw Coal Price (Per Ton)		
		12.00	14.00	16.00
Mine Operator's Cost of Raw Coal (Per Ton)	6.00	5.26	5.19	5.11
	8.00	5.47	5.40	5.32
	10.00	5.69	5.61	5.53

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* As received values.
** Amortized over 15 years, 8% interest on unpaid balance.
*** Based upon 260 days/yr at 13 hr/day - 3,380 hr/yr
**** This represents the total of all coal cleaning cost factors at the respective operator cost levels as covered in Section 2.0 above.

CASE NUMBER: 7B

1.0 CASE CONDITIONS — Sulfur Clean-up Exclusively by Stack Gas Scrubbing

1.1 Coal Use Area: Lansing, Michigan

1.2 Emission Standards — New: 1.6 lb SO_2 Per MM Btu
Existing:

1.3 Coal District of Origin: No. 4 — Coalbed: Pittsburgh
State: Ohio — County: Jefferson

1.4 Raw Coal — Ash: 9.8%
Lb $SO_2/10^6$ Btu: 4.29 — Sulfur: 2.82% — MM Btu/Ton: 26.32*

1.5 Assumed Plant Size: 500 Mw

1.6 Remaining Life of Boiler: 25 Yr

1.7 Assumed Annual Capital Scrubber Charges as Percent of Original Investment: 15.55%

2.0 STACK GAS COST FACTORS

2.1 Boiler Capacity: 500 Mw

2.2 Utilization Factor: 7,000 Hr/Yr

2.3 Tons of Coal Burned Per Year: 1,329,788 Tons

2.4 Minimum Scrubber Requirements — Scrubber Rating: 349 Mw
% of Flue Gas Cleaned: 69.7%

2.5 Design Scrubber Requirements — Scrubber Rating: 401 Mw
% of Flue Gas Cleaned: 80.2%

2.6 Scrubber Capital Cost: $23,846,001

2.7 Scrubber Capital Charges/Yr: $3,708,054

2.8 Capital Contribution Per Ton of Coal: $2.79/Ton

2.9 Fuel and Electricity Cost Per Ton of Coal: $0.61/Ton

2.10 O & M Costs Per Ton of Coal

Limestone Cost: $0.45/Ton
Maintenance Labor & Material: $0.72/Ton
Fixation Chemical Cost: $0.37/Ton
Supplies Cost: $0.11/Ton
Operating Labor Cost: $0.12/Ton
Overhead Cost: $0.50/Ton

2.11 Total Cost Per Ton of Coal Burned to Meet Emission Standards: $5.67/Ton

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* This value has been adjusted for raw coal moisture content.

CASE NUMBER: 7C

1.0 CASE CONDITIONS — Combined Use of Physical Cleaning Followed by Stack Gas Scrubbing

1.1 Coal Use Area: Lansing, Michigan

1.2 Emission Standards — New:
Existing: 1.6 Lb SO_2 Per MM Btu

1.3 Coal District of Origin: No. 4 — Coalbed: Pittsburgh
State: Ohio — County: Jefferson

1.4 Raw Coal* — Ash: 9.8%
Lb SO_2/MM Btu: 4.29 — Sulfur: 2.82% — MM Btu/Ton: 26.32

1.5 Clean Coal — Ash: 6.0%
Cleaning Plant Yield: 90.0% — Sulfur: 2.03% — MM Btu/Ton: 27.36
Lb SO_2/MM Btu: 2.97 — Btu Recovery: 93.56% — Btu Increase: 3.95%

1.6 Transportation — Mileage: 323 — Cost Per Ton: $3.87

1.7 Assumed Plant Size — Megawatts: 500

1.8 Remaining Life of Boiler: 15 Yr

1.9 Assumed Ash Disposal Cost: $4.00/Ton

1.10 Cleaning Plant — Cost: $18,000 Per Ton-Hour Input Capacity**
Utilization: 38.58%***

1.11 Assumed Annual Capital Scrubber Charges as Percent of Original Investment: 17.82%

2.0 COAL CLEANING COST FACTORS

2.1 Cleaning Plant Costs — Amortization: $0.68/Ton — O & M: $0.75/Ton

2.2 Additional Cost to Mine Operator to Provide for One Ton of Cleaned Coal When Mine Operator's Cost is

$ 6.00/Ton, Additional Cost is $0.67/Ton
$ 8.00/Ton, Additional Cost is $0.89/Ton
$10.00/Ton, Additional Cost is $1.11/Ton

2.3 Cleaning Plant Tax and Insurance Burden: $0.12/Ton

2.4 Total Differential Production Cost to Mine Operator to Provide a Ton of Cleaned Coal, When Mine Operator's Cost is

$ 6.00/Ton, Differential Cost is $2.22/Ton****
$ 8.00/Ton, Differential Cost is $2.44/Ton
$10.00/Ton, Differential Cost is $2.66/Ton

3.0 ASSESSABLE BENEFIT FACTORS ASSOCIATED WITH CLEAN COAL

3.1 Added Coal Value Due to Higher Heat Content of Coal, When F.O.B. Mine Raw Coal Price is

$12.00/Ton, Benefit is $0.46/Ton
$14.00/Ton, Benefit is $0.53/Ton
$16.00/Ton, Benefit is $0.61/Ton

3.2 Transportation Cost Saving Due to Increased Heat Content of Coal: $0.15/Ton

3.3 Saving in Ash Disposal Cost: $0.16/Ton

3.4 Saving in Grinding Cost: $0.02/Ton

3.5 Saving in Benefit Payment: $0.03/Ton

3.6 Saving in Maintenance: $0.17/Ton

3.7 Total Benefits of Coal Cleaning, When F.O.B. Mine Raw Coal Selling Price is

$12.00/Ton, Benefit is $0.99/Ton
$14.00/Ton, Benefit is $1.06/Ton
$16.00/Ton, Benefit is $1.14/Ton

4.0 DIFFERENTIAL CLEANING COST LESS BENEFITS PER TON

		F.O.B. Mine Raw Coal Price (Per Ton)		
		12.00	14.00	16.00
Mine Operator's Cost of Raw Coal (Per Ton)	6.00	1.23	1.16	1.08
	8.00	1.45	1.38	1.30
	10.00	1.67	1.60	1.52

5.0 STACK GAS COST FACTORS

5.1 Boiler Capacity: 500 Mw

5.2 Utilization Factor: 5,000 Hr/Yr

5.3 Tons of Coal Burned Per Year: 913,743 Tons

5.4 Minimum Scrubber Requirements — Scrubber Rating: 266 Mw; % of Flue Gas Cleaned: 51.3%

5.5 Design Scrubber Requirements — Scrubber Rating: 295 Mw; % of Flue Gas Cleaned: 59.0%

5.6 Scrubber Capital Cost: $21,564,410

5.7 Scrubber Capital Charges/Yr: $3,842,778

5.8 Capital Contribution Per Ton of Coal: $4.21/Ton

5.9 Fuel and Electricity Cost Per Ton of Coal: $0.47/Ton

5.10 O & M Costs Per Ton of Coal

Limestone Cost: $0.25/Ton
Maintenance Labor and Materials: $0.94/Ton
Fixation Chemical Cost: $0.20/Ton
Supplies Cost: $0.14/Ton
Operating Labor Cost: $0.18/Ton
Overhead Cost: $0.67/Ton

5.11 Total Stack Gas Cost Per Ton of Coal Burned: $7.06/Ton

6.0 COST PER TON OF COAL BURNED TO MEET EMISSION STANDARDS

		F.O.B. Mine Raw Coal Price (Per Ton)		
		12.00	14.00	16.00
Mine Operator's Cost of Raw Coal (Per Ton)	6.00	8.29	8.22	8.14
	8.00	8.51	8.44	8.36
	10.00	8.73	8.66	8.58

7.0 COST PER MILLION BTU TO MEET EMISSION STANDARDS

		F.O.B. Mine Raw Coal Price (Per Ton)		
		12.00	14.00	16.00
Mine Operator's Cost of Raw Coal (Per Ton)	6.00	0.303	0.300	0.298
	8.00	.311	.308	.306
	10.00	.319	.317	.314

8.0 COST PER TON OF RAW COAL TO MEET EMISSION STANDARDS

		F.O.B. Mine Raw Coal Price (Per Ton)		
		12.00	14.00	16.00
Mine Operator's Cost of Raw Coal (Per Ton)	6.00	7.97	7.90	7.84
	8.00	8.19	8.11	8.05
	10.00	8.40	8.34	8.26

* As received values.

** Amortized over 15 years, 8% interest on unpaid balance.

*** Based upon 260 days/yr at 13 hr/day - 3,380 hr/yr.

**** This represents the total of all coal cleaning cost factors at the respective operator cost levels as covered in Section 2.0 above.

CASE NUMBER: 7D

1.0 CASE CONDITIONS — Sulfur Clean-up Exclusively by Stack Gas Scrubbing

1.1 Coal Use Area: Lansing, Michigan

1.2 Emission Standards — New:
Existing: 1.6 Lb SO_2 Per MM Btu

1.3 Coal District of Origin: No. 4 — Coalbed: Pittsburgh
State: Ohio — County: Jefferson

1.4 Raw Coal — Moisture: 1.4% — Ash: 9.8%
Lb $SO_2/10^6$ Btu: 4.29 — Sulfur: 2.82% — MM Btu/Ton: 26.32*

1.5 Assumed Plant Size: 500 Mw

1.6 Remaining Life of Boiler: 15 Yr

1.7 Assumed Annual Capital Scrubber Charges as Percent of Original Investment: 17.82%

2.0 STACK GAS COST FACTORS

2.1 Boiler Capacity: 500 Mw

2.2 Utilization Factor: 5,000 Hr/Yr

2.3 Tons of Coal Burned Per Year: 949,849 Tons

2.4 Minimum Scrubber Requirements — Scrubber Rating: 349 Mw
% of Flue Gas Cleaned: 69.7%

2.5 Design Scrubber Requirements — Scrubber Rating: 401 Mw
% of Flue Gas Cleaned: 80.2%

2.6 Scrubber Capital Cost: $29,198,946

2.7 Scrubber Capital Charges/Yr: $5,203,253

2.8 Capital Contribution Per Ton of Coal: $5.48/Ton

2.9 Fuel and Electricity Cost Per Ton of Coal: $0.61/Ton

2.10 O & M Costs Per Ton of Coal

Limestone Cost: $0.45/Ton
Maintenance Labor & Material: $1.23/Ton
Fixation Chemical Cost: $0.37/Ton
Supplies Cost: $0.18/Ton
Operating Labor Cost: $0.17/Ton
Overhead Cost: $0.82/Ton

2.11 Total Cost Per Ton of Coal Burned to Meet Emission Standards: $9.31/Ton

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* This value has been adjusted for raw coal moisture content.

CASE NUMBER: 8A

1.0 CASE CONDITIONS — Combined Use of Physical Cleaning Followed by Stack Gas Scrubbing

1.1 Coal Use Area: Nashville (Gallatin), Tennessee

1.2 Emission Standards — New: 1.2 lb SO_2 Per MM Btu
Existing:

1.3 Coal District of Origin: No. 11 — Coalbed: Number VII
State: Indiana — County: Vigo

1.4 Raw Coal* — Ash: 12.0%
Lb SO_2/MM Btu: 2.57 — Sulfur: 0.90% — MM Btu/Ton: 23.99

1.5 Clean Coal — Ash: 7.7%
Cleaning Plant Yield: 90.0% — Sulfur: 0.90% — MM Btu/Ton: 25.07
Lb SO_2/MM Btu: 1.44 — Btu Recovery: 94.04% — Btu Increase: 4.5%

1.6 Transportation — Mileage: 288 — Cost Per Ton: $4.03

1.7 Assumed Plant Size — Megawatts: 500

1.8 Remaining Life of Boiler: 25 Yr

1.9 Assumed Ash Disposal Cost: $4.00/Ton

1.10 Cleaning Plant — Cost: $18,000 Per Ton-Hour Input Capacity**
Utilization: 38.58%***

1.11 Assumed Annual Capital Scrubber Charges as Percent of Original Investment: 15.55%

2.0 COAL CLEANING COST FACTORS

2.1 Cleaning Plant Costs — Amortization: $0.68/Ton — O & M: $0.75/Ton

2.2 Additional Cost to Mine Operator to Provide for One Ton of Cleaned Coal, When Mine Operator's Cost is

$ 7.00/Ton, Additional Cost is $0.78/Ton
$ 9.00/Ton, Additional Cost is $1.00/Ton
$11.00/Ton, Additional Cost is $1.22/Ton

2.3 Cleaning Plant Tax and Insurance Burden: $0.12/Ton

2.4 Total Differential Production Cost to Mine Operator to Provide a Ton of Cleaned Coal, When Mine Operator's Cost is

$ 7.00/Ton, Differential Cost is $2.33/Ton****
$ 9.00/Ton, Differential Cost is $2.55/Ton
$11.00/Ton, Differential Cost is $2.77/Ton

3.0 ASSESSABLE BENEFIT FACTORS ASSOCIATED WITH CLEAN COAL

3.1 Added Coal Value Due to Higher Heat Content of Coal, When F.O.B. Mine Raw Coal Price is

$12.00/Ton, Benefit is $0.52/Ton
$14.00/Ton, Benefit is $0.60/Ton
$16.00/Ton, Benefit is $0.69/Ton

3.2 Transportation Cost Saving Due to Increased Heat Content of Coal: $0.17/Ton

3.3 Saving in Ash Disposal Cost: $0.19/Ton

3.4 Saving in Grinding Cost: $0.02/Ton

3.5 Saving in Benefit Payment: $0.03/Ton

3.6 Saving in Maintenance: $0.17/Ton

3.7 Total Benefits of Coal Cleaning, When F.O.B. Mine Raw Coal Selling Price is

$12.00/Ton, Benefit is $1.10/Ton
$14.00/Ton, Benefit is $1.18/Ton
$16.00/Ton, Benefit is $1.27/Ton

4.0 DIFFERENTIAL CLEANING COST LESS BENEFITS PER TON

		F.O.B. Mine Raw Coal Price (Per Ton)		
		12.00	14.00	16.00
Mine Operator's Cost of Raw Coal (Per Ton)	7.00	1.23	1.15	1.06
	9.00	1.45	1.37	1.28
	11.00	1.67	1.59	1.50

5.0 STACK GAS COST FACTORS

5.1 Boiler Capacity: 500 Mw

5.2 Utilization Factor: 7,000 Hr/Yr

5.3 Tons of Coal Burned Per Year: 1,396,091 Tons

5.4 Minimum Scrubber Requirements — Scrubber Rating: 93 Mw; % of Flue Gas Cleaned: 18.5%

5.5 Design Scrubber Requirements — Scrubber Rating: 107 Mw; % of Flue Gas Cleaned: 21.4%

5.6 Scrubber Capital Cost: $7,506,142

5.7 Scrubber Capital Charges/Yr: $1,167,205

5.8 Capital Contribution Per Ton of Coal: $0.84/Ton

5.9 Fuel and Electricity Cost Per Ton of Coal: $0.16/Ton

5.10 O & M Costs Per Ton of Coal

Limestone Cost: $0.04/Ton
Maintenance Labor & Material: $0.22/Ton
Fixation Chemical Cost: $0.03/Ton
Supplies Cost: $0.03/Ton
Operating labor Cost: $0.12/Ton
Overhead Cost: $0.21/Ton

5.11 Total Stack Gas Cost Per Ton of Coal Burned: $1.65/Ton

6.0 COST PER TON OF COAL BURNED TO MEET EMISSION STANDARDS

		F.O.B. Mine Raw Coal Price (Per Ton)		
		12.00	14.00	16.00
Mine Operator's Cost of Raw Coal (Per Ton	7.00	2.88	2.80	2.71
	9.00	3.10	3.02	2.93
	11.00	3.32	3.24	3.15

7.0 COST PER MILLION BTU TO MEET EMISSION STANDARDS

		F.O.B. Mine Raw Coal Price (Per Ton)		
		12.00	14.00	16.00
Mine Operator's Cost of Raw Coal (Per Ton)	7.00	0.115	0.112	0.108
	9.00	.124	.120	.117
	11.00	.132	.129	.126

8.0 COST PER TON OF RAW COAL TO MEET EMISSION STANDARDS

		F.O.B. Mine Raw Coal Price (Per Ton)		
		12.00	14.00	16.00
Mine Operator's Cost of Raw Coal (Per Ton)	7.00	2.76	2.69	2.59
	9.00	2.97	2.88	2.81
	11.00	3.17	3.09	3.02

* As received values.
** Amortized over 15 years, 8% interest on unpaid balance.
*** Based upon 260 days/yr at 13 hr/day - 3,380 hr/yr
**** This represents the total of all coal cleaning cost factors at the respective operator cost levels as covered in Section 2.0 above.

CASE NUMBER: 8B

1.0 CASE CONDITIONS — Sulfur Clean-up Exclusively by Stack Gas Scrubbing

1.1 Coal Use Area: Nashville (Gallatin), Tennessee

1.2 Emission Standards — New: 1.2 Lb SO_2 Per MM Btu; Existing:

1.3 Coal District of Origin: No. 11 — Coalbed: Number VII
State: Indiana — County: Vigo

1.4 Raw Coal — Ash: 12.0%
Lb $SO_2/10^6$ Btu: 2.57 — Sulfur: 1.54% — MM Btu/Ton: 23.99*

1.5 Assumed Plant Size: 500 Mw

1.6 Remaining Life of Boiler: 25 Yr

1.7 Assumed Annual Capital Scrubber Charges as Percent of Original Investment: 15.55%

2.0 STACK GAS COST FACTORS

2.1 Boiler Capacity: 500 Mw

2.2 Utilization Factor: 7,000 Hr/Yr

2.3 Tons of Coal Burned Per Year: 1,458,942 Tons

2.4 Minimum Scrubber Requirements — Scrubber Rating: 2.96 Mw; % of Flue Gas Cleaned: 59.2%

2.5 Design Scrubber Requirements — Scrubber Rating: 341 Mw; % of Flue Gas Cleaned: 68.2%

2.6 Scrubber Capital Cost: $19,010,461

2.7 Scrubber Capital Charges/Yr: $2,956,127

2.8 Capital Contribution Per Ton of Coal: $2.03/Ton

2.9 Fuel and Electricity Cost Per Ton of Coal: $0.47/Ton

2.10 O & M Costs Per Ton of Coal

Limestone Cost: $0.19/Ton
Maintenance Labor & Material: $0.52/Ton
Fixation Chemical Cost: $0.16/Ton
Supplies Cost: $0.08/Ton
Operating Labor Cost: $0.11/Ton
Overhead Cost: $0.38/Ton

2.11 Total Cost Per Ton of Coal Burned to Meet Emission Standards: $3.94/Ton

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* This value has been adjusted for raw coal moisture content.

CASE NUMBER: 8C

1.0 CASE CONDITIONS — Combined Use of Physical Cleaning Followed by Stack Gas Scrubbing

1.1 Coal Use Area: Nashville (Gallatin), Tennessee

1.2 Emission Standards — New:
Existing: 1.2 Lb SO_2 Per MM Btu

1.3 Coal District of Origin: No. 11 — Coalbed: Number VII
State: Indiana — County: Vigo

1.4 Raw Coal* — Ash: 12.0%
Lb SO_2/MM Btu: 2.57 — Sulfur: 1.54% — MM Btu/Ton: 23.99

1.5 Clean Coal — Ash: 7.7%
Cleaning Plant Yield: 90.0% — Sulfur: 0.90% — MM Btu/Ton: 25.07
Lb SO_2/MM Btu: 1.44 — Btu Recovery: 94.04% — Btu Increase: 4.5%

1.6 Transportation — Mileage: 288 — Cost Per Ton: $4.03

1.7 Assumed Plant Size — Megawatts: 500

1.8 Remaining Life of Boiler: 15 Yr

1.9 Assumed Ash Disposal Cost: $4.00/Ton

1.10 Cleaning Plant — Cost: $18,000 Per Ton-Hour Input Capacity**
Utilization: 38.58%***

1.11 Assumed Annual Capital Scrubber Charges as Percent of Original Investment: 17.82%

2.0 COAL CLEANING COST FACTORS

2.1 Cleaning Plant Costs — Amortization: $0.68/Ton — O & M: $0.75/Ton

2.2 Additional Cost to Mine Operator to Provide for One Ton of Cleaned Coal, When Mine Operator's Cost is

$ 7.00/Ton, Additional Cost is $0.78/Ton
$ 9.00/Ton, Additional Cost is $1.00/Ton
$11.00/Ton, Additional Cost is $1.22/Ton

2.3 Cleaning Plant Tax and Insurance Burden: $0.12/Ton

2.4 Total Differential Production Cost to Mine Operator to Provide a Ton of Cleaned Coal, When Mine Operator's Cost is

$ 7.00/Ton, Differential Cost is $2.33/Ton****
$ 9.00/Ton, Differential Cost is $2.55/Ton
$11.00/Ton, Differential Cost is $2.77/Ton

3.0 ASSESSABLE BENEFIT FACTORS ASSOCIATED WITH CLEAN COAL

3.1 Added Coal Value Due to Higher Heat Content of Coal, When F.O.B. Mine Raw Coal Price is

$12.00/Ton, Benefit is $0.52/Ton
$14.00/Ton, Benefit is $0.60/Ton
$16.00/Ton, Benefit is $0.69/Ton

3.2 Transportation Cost Saving Due to Increased Heat Content of Coal: $0.17/Ton

3.3 Saving in Ash Disposal Cost: $0.19/Ton

3.4 Saving in Grinding Cost: $0.02/Ton

3.5 Saving in Benefit Payment: $0.03/Ton

3.6 Saving in Maintenance: $0.17/Ton

3.7 Total Benefits of Coal Cleaning, When F.O.B. Mine Raw Coal Selling Price is

$12.00/Ton, Benefit is $1.10/Ton
$14.00/Ton, Benefit is $1.18/Ton
$16.00/Ton, Benefit is $1.27/Ton

4.0 DIFFERENTIAL CLEANING COST LESS BENEFITS PER TON

		F.O.B. Mine Raw Coal Price (Per Ton)		
		12.00	14.00	16.00
Mine Operator's Cost of Raw Coal (Per Ton)	7.00	1.23	1.15	1.06
	9.00	1.45	1.37	1.28
	11.00	1.67	1.59	1.50

5.0 STACK GAS COST FACTORS

5.1 Boiler Capacity: 500 Mw

5.2 Utilization Factor: 5,000 Hr/Yr

5.3 Tons of Coal Burned Per Year: 997,208 Tons

5.4 Minimum Scrubber Requirements — Scrubber Rating: 93 Mw
% of Flue Gas Cleaned: 18.5%

5.5 Design Scrubber Requirements — Scrubber Rating: 107 Mw
% of Flue Gas Cleaned: 21.4%

5.6 Scrubber Capital Cost: $9,433,394

5.7 Scrubber Capital Charges/Yr: $1,681,031

5.8 Capital Contribution Per Ton of Coal: $1.69/Ton

5.9 Fuel and Electricity Cost Per Ton of Coal: $0.16/Ton

5.10 O & M Costs Per Ton of Coal

Limestone Cost: $0.04/Ton
Maintenance Labor & Material: $0.38/Ton
Fixation Chemical Cost: $0.03/Ton
Supplies Cost: $0.06/Ton
Operating Labor Cost: $0.16/Ton
Overhead Cost: $0.33/Ton

5.11 Total Stack Gas Cost Per Ton of Coal Burned: $2.85/Ton

6.0 COST PER TON OF COAL BURNED TO MEET EMISSION STANDARDS

		F.O.B. Mine Raw Coal Price (Per Ton)		
		12.00	14.00	16.00
Mine Operator's Cost of Raw Coal (Per Ton)	7.00	4.08	4.00	3.91
	9.00	4.30	4.22	4.13
	11.00	4.52	4.44	4.35

7.0 COST PER MILLION BTU TO MEET EMISSION STANDARDS

		F.O.B. Mine Raw Coal Price (Per Ton)		
		12.00	14.00	16.00
Mine Operator's Cost of Raw Coal (Per Ton)	7.00	0.163	0.160	0.156
	9.00	.172	.168	.165
	11.00	.180	.177	.174

8.0 COST PER TON OF RAW COAL TO MEET EMISSION STANDARDS

		F.O.B. Mine Raw Coal Price (Per Ton)		
		12.00	14.00	16.00
Mine Operator's Cost of Raw Coal (Per Ton)	7.00	3.91	3.84	3.74
	9.00	4.13	4.03	3.96
	11.00	4.32	4.25	4.17

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* As received values.

** Amortized over 15 years, 8% interest on unpaid balance.

*** Based upon 260 days/yr at 13 hr/day - 3,380 hr/yr

**** This represents the total of all coal cleaning cost factors at the respective operator cost levels as covered in Section 2.0 above.

CASE NUMBER: 8D

1.0 CASE CONDITIONS — Sulfur Clean-up Exclusively by Stack Gas Scrubbing

1.1 Coal Use Area: Nashville (Gallatin), Tennessee

1.2 Emission Standards — New:
Existing: 1.2 Lb SO_2 Per MM Btu

1.3 Coal District of Origin: No. 11 — Coalbed: Number VII
State: Indiana — County: Vigo

1.4 Raw Coal — Ash: 12.0%
Lb $SO_2/10^6$ Btu: 2.57 — Sulfur: 1.54% — MM Btu/Ton: 23.99*

1.5 Assumed Plant Size: 500 Mw

1.6 Remaining Life of Boiler: 15 Yr

1.7 Assumed Annual Capital Scrubber Charges as Percent of Original Investment: 17.82%

2.0 STACK GAS COST FACTORS

2.1 Boiler Capacity: 500 Mw

2.2 Utilization Factor: 5,000 Hr/Yr

2.3 Tons of Coal Burned Per Year: 1,042,101 Tons

2.4 Minimum Scrubber Requirements — Scrubber Rating: 296 Mw
% of Flue Gas Cleaned: 59.2%

2.5 Design Scrubber Requirements — Scrubber Rating: 341 Mw
% of Flue Gas Cleaned: 68.2%

2.6 Scrubber Capital Cost: $23,843,195

2.7 Scrubber Capital Charges/Yr: $4,248,858

2.8 Capital Contribution Per Ton of Coal: $4.08/Ton

2.9 Fuel and Electricity Cost Per Ton of Coal: $0.47/Ton

2.10 O & M Costs Per Ton of Coal

Limestone Cost: $0.19/Ton
Maintenance Labor & Material: $0.92/Ton
Fixation Chemical Cost: $0.16/Ton
Supplies Cost: $0.14/Ton
Operating Labor Cost: $0.15/Ton
Overhead Cost: $0.64/Ton

2.11 Total Cost Per Ton of Coal Burned to Meet Emission Standards: $6.75/Ton

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* This value has been adjusted for raw coal moisture content.

CASE NUMBER: 9A

1.0 CASE CONDITIONS — Combined Use of Physical Cleaning Followed by Stack Gas Scrubbing

1.1 Coal Use Area: Burlington, New Jersey

1.2 Emission Standards — New: 0.30 Lb SO_2 Per MM Btu
Existing:

1.3 Coal District of Origin: No. 1 — Coalbed: Upper Freeport
State: Maryland — County: Garrett

1.4 Raw Coal* — Ash: 13.8%
Lb SO_2/MM Btu: 3.59 — Sulfur: 2.37% — MM Btu/Ton: 26.4

1.5 Clean Coal — Ash: 8.8%
Cleaning Plant Yield: 90.0% — Sulfur: 1.6% — MM Btu/Ton: 27.79
Lb SO_2/MM Btu: 2.30 — Btu Recovery: 94.7% — Btu Increase: 5.27%

1.6 Transportation — Mileage: 302 — Cost Per Ton: $6.66

1.7 Assumed Plant Size — Megawatts: 500

1.8 Remaining Life of Boiler: 25 Yr

1.9 Assumed Ash Disposal Cost: $4.00/Ton

1.10 Cleaning Plant — Cost: $18,000 Per Ton-Hour Input Capacity**
Utilization: 38.58%***

1.11 Assumed Annual Capital Scrubber Charges as Percent of Original Investment: 15.55%

2.0 COAL CLEANING COST FACTORS

2.1 Cleaning Plant Costs — Amortization: $0.68/Ton — O & M: $0.75/Ton

2.2 Additional Cost to Mine Operator to Provide for One Ton of Cleaned Coal, When Mine Operator's Cost is

$ 8.00/Ton, Additional Cost is $0.89/Ton
$10.00/Ton, Additional Cost is $1.11/Ton
$12.00/Ton, Additional Cost is $1.33/Ton

2.3 Cleaning Plant Tax and Insurance Burden: $0.12/Ton

2.4 Total Differential Production Cost to Mine Operator to Provide a Ton of Cleaned Coal, When Mine Operator's Cost is

$ 8.00/Ton, Differential Cost is $2.44/Ton****
$10.00/Ton, Differential Cost is $2.66/Ton
$12.00/Ton, Differential Cost is $2.88/Ton

3.0 ASSESSABLE BENEFIT FACTORS ASSOCIATED WITH CLEAN COAL

3.1 Added Coal Value Due to Higher Heat Content of Coal, When F.O.B. Mine Raw Coal Price is

$19.00/Ton, Benefit is $0.95/Ton
$21.00/Ton, Benefit is $1.05/Ton
$23.00/Ton, Benefit is $1.15/Ton

3.2 Transportation Cost Saving Due to Increased Heat Content of Coal: $0.33/Ton

3.3 Saving in Ash Disposal Cost: $0.21/Ton

3.4 Saving in Grinding Cost: $0.03/Ton

3.5 Saving in Benefit Payment: $0.04/Ton

3.6 Saving in Maintenance: $0.20/Ton

3.7 Total Benefits of Coal Cleaning, When F.O.B. Mine Raw Coal Selling Price is

$19.00/Ton, Benefit is $1.76/Ton
$21.00/Ton, Benefit is $1.86/Ton
$23.00/Ton, Benefit is $1.96/Ton

4.0 DIFFERENTIAL CLEANING COST LESS BENEFITS PER TON

		F.O.B. Mine Raw Coal Price (Per Ton)		
		19.00	21.00	23.00
Mine Operator's Cost of Raw Coal (Per Ton)	8.00	0.68	0.58	0.48
	10.00	.90	.80	.70
	12.00	1.12	1.02	.92

5.0 STACK GAS COST FACTORS

5.1 Boiler Capacity: 500 Mw

5.2 Utilization Factor: 7,000 Hr/Yr

5.3 Tons of Coal Burned Per Year: 1,259,446 Tons

5.4 Minimum Scrubber Requirements — Scrubber Rating:
% of Flue Gas Cleaned: 96.6%

The use of this particular coal, cleaned to 90% yield, in the State of New Jersey in a facility expanded or constructed on or after May 6, 1968, is impractical. This is due to the fact that the State Department of Environmental Protection limits sulfur emission from bituminous coal burning facilities to not more than 0.3 pound of SO_2 per MM Btu gross heat input. Since following cleaning to 90% yield this coal would still emit 2.30 pounds of SO_2 per MM Btu, the stack gas scrubbing installation would have to clean a minimum of 96.6% of the flue gas. This leaves only a 3.5% margin in the design even if 100% of the flue gas were to be cleaned, which is not recommended. Therefore, this particular coal, cleaned to 90% yield, only has economic utility in New Jersey facilities in existence prior to May 6, 1968, where 1% sulfur coal may be burned.

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* As received values.

** Amortized over 15 years, 8% interest on unpaid balance.

*** Based upon 260 days/yr at 13 hr/day - 3,380 hr/yr.

**** This represents the total of all coal cleaning cost factors at the respective operator cost levels as covered in Section 2.0 above.

CASE NUMBER: 9B

1.0 CASE CONDITIONS — Sulfur Clean-up Exclusively by Stack Gas Scrubbing

1.1 Coal Use Area: Burlington, New Jersey

1.2 Emission Standards — New: 0.30 lb of SO_2 Per MM Btu; Existing:

1.3 Coal District of Origin: No. 1 — Coalbed: Upper Freeport
State: Maryland — County: Garrett

1.4 Raw Coal — Ash: 13.8%
Lb $SO_2/10^6$ Btu: 3.59 — Sulfur: 2.37% — MM Btu/Ton: 26.4*

1.5 Assumed Plant Size: 500 Mw

1.6 Remaining Life of Boiler: 25 Yr

1.7 Assumed Annual Capital Scrubber Charges as Percent of Original Investment: 15.55%

2.0 STACK GAS COST FACTORS

2.1 Boiler Capacity: 500 Mw

2.2 Utilization Factor: 7,000 Hr/Yr

2.3 Tons of Coal Burned Per Year: 1,325,758 Tons

2.4 Minimum Scrubber Requirements — Scrubber Rating:
% of Flue Gas Cleaned: 101.18%

When only stack gas scrubbing is used to reduce sulfur emission, the burning of this particular coal in the State of New Jersey in facilities expanded or constructed on or after May 6, 1968, is unacceptable. This is due to the fact that the State Department of Environmental Protection limits sulfur emission from bituminous coal burning facilities to not more than 0.3 pound of SO_2 per MM Btu gross heat input. Since the raw coal emits 3.59 pounds of SO_2 per MM Btu, it would be necessary for the scrubber to clean over 100% of the flue gas, which is impossible. Therefore, this particular coal only has economic utility in New Jersey facilities in existence prior to May 6, 1968, where 1% sulfur coal may be burned.

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* This value has been adjusted for raw coal moisture content.

CASE NUMBER: 9C

1.0 CASE CONDITIONS — Combined Use of Physical Cleaning Followed by Stack Gas Scrubbing

1.1 Coal Use Area: Burlington, New Jersey

1.2 Emission Standards — New:
Existing: 1% Sulfur by Weight

1.3 Coal District of Origin: No. 1 — Coalbed: Upper Freeport
State: Maryland — County: Garrett

1.4 Raw Coal* — Ash: 13.0%
Lb SO_2/MM Btu: 3.59 — Sulfur: 2.37% — MM Btu/Ton: 26.4

1.5 Clean Coal — Ash: 8.8%
Cleaning Plant Yield: 90.0% — Sulfur: 1.6% — MM Btu/Ton: 27.79
Lb SO_2/MM Btu: 2.30 — Btu Recovery: 94.7% — Btu Increase: 5.27%

1.6 Transportation — Mileage: 302 — Cost Per Ton: $6.66

1.7 Assumed Plant Size — Megawatts: 500

1.8 Remaining Plant Life of Boiler: 15 Yr

1.9 Assumed Ash Disposal Cost: $4.00/Ton

1.10 Cleaning Plant — Cost: $18,000 Per Ton-Hour Input Capacity**
Utilization: 38.58%***

1.11 Assumed Annual Capital Scrubber Charges as Percent of Original Investment: 17.82%

2.0 COAL CLEANING COST FACTORS

2.1 Cleaning Plant Costs — Amortization: $0.68/Ton — O & M: $0.75/Ton

2.2 Additional Cost to Mine Operator to Provide for One Ton of Cleaned Coal, When Mine Operator's cost is

$ 8.00/Ton, Additional Cost is $0.89/Ton
$10.00/Ton, Additional Cost is $1.11/Ton
$12.00/Ton, Additional Cost is $1.33/Ton

2.3 Cleaning Plant Tax and Insurance Burden: $0.12/Ton

2.4 Total Differential Production Cost to Mine Operator to Provide a Ton of Cleaned Coal, When Mine Operator's Cost is

$ 8.00/Ton, Differential Cost is $2.44/Ton****
$10.00/Ton, Differential Cost is $2.66/Ton
$12.00/Ton, Differential Cost is $2.88/Ton

3.0 ASSESSABLE BENEFIT FACTORS ASSOCIATED WITH CLEAN COAL

3.1 Added Coal Value Due to Higher Heat Content of Coal, When F.O.B. Mine Raw Coal Price is

$19.00/Ton, Benefit is $0.95/Ton
$21.00/Ton, Benefit is $1.05/Ton
$23.00/Ton, Benefit is $1.15/Ton

3.2 Transportation Cost Saving Due to Increased Heat Content of Coal: $0.33/Ton

3.3 Saving in Ash Disposal Cost: $0.21/Ton

3.4 Saving in Grinding Cost: $0.03/Ton

3.5 Saving in Benefit Payment: $0.04/Ton

3.6 Saving in Maintenance: $0.20/Ton

3.7 Total Benefits of Coal Cleaning, When F.O.B. Mine Raw Coal Selling Price is

$19.00/Ton, Benefit is $1.76/Ton
$21.00/Ton, Benefit is $1.86/Ton
$23.00/Ton, Benefit is $1.96/Ton

4.0 DIFFERENTIAL CLEANING COST LESS BENEFITS PER TON

		F.O.B. Mine Raw Coal Price (Per Ton)		
		19.00	21.00	23.00
Mine Operator's Cost	8.00	0.68	0.58	0.48
of Raw Coal (Per Ton)	10.00	.90	.80	.70
	12.00	1.12	1.02	.92

5.0 STACK GAS COST FACTORS

5.1 Boiler Capacity: 500 Mw

5.2 Utilization Factor: 5,000 Hr/Yr

5.3 Tons of Coal Burned Per Year: 899,605 Tons

5.4 Minimum Scrubber Requirements — Scrubber Rating: 209 Mw; % of Flue Gas Cleaned: 41.7%

5.5 Design Scrubber Requirements — Scrubber Rating: 240 Mw; % of Flue Gas Cleaned: 48%

5.6 Scrubber Capital Cost: $18,002,381

5.7 Scrubber Capital Charges/Yr: $3,208,025

5.8 Capital Contribution Per Ton of Coal: $3.57/Ton

5.9 Fuel and Electricity Cost Per Ton of Coal: $0.39/Ton

5.10 O & M Costs Per Ton of Coal

Limestone Cost: $0.16/Ton
Maintenance Labor & Material: $0.80/Ton
Fixation Chemical Cost: $0.13/Ton
Supplies Cost: $0.12/Ton
Operating Labor Cost: $0.18/Ton
Overhead Cost: $0.59/Ton

5.11 Total Stack Gas Cost Per Ton of Coal Burned: $5.94/Ton

6.0 COST PER TON OF COAL BURNED TO MEET EMISSION STANDARDS

		F.O.B. Mine Raw Coal Price (Per Ton)		
		19.00	21.00	23.00
Mine Operator's Cost of Raw Coal (Per Ton)	8.00	6.62	6.52	6.42
	10.00	6.84	6.74	6.64
	12.00	7.06	6.96	6.86

7.0 COST PER MILLION BTU TO MEET EMISSION STANDARDS

		F.O.B. Mine Raw Coal Price (Per Ton)		
		19.00	21.00	23.00
Mine Operator's Cost of Raw Coal (Per Ton)	8.00	0.238	0.235	0.231
	10.00	.246	.243	.239
	12.00	.254	.250	.247

8.0 COST PER TON OF RAW COAL TO MEET EMISSION STANDARDS

		F.O.B. Mine Raw Coal Price (Per Ton)		
		19.00	21.00	23.00
Mine Operator's Cost of Raw Coal (Per Ton)	8.00	6.28	6.20	6.10
	10.00	6.49	6.42	6.31
	12.00	6.71	6.60	6.52

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* As received values.
** Amortized over 15 years, 8% interest on unpaid balance.
*** Based upon 260 days/yr at 13 hr/day - 3,380 hr/yr.
**** This represents the total of all coal cleaning cost factors at the respective operator cost levels as covered in Section 2.0 above.

CASE NUMBER: 9D

1.0 CASE CONDITIONS — Sulfur Clean-up Exclusively by Stack Gas Scrubbing

1.1 Coal Use Area: Burlington, New Jersey

1.2 Emission Standards — New:
Existing: 1% Sulfur by Weight

1.3 Coal District of Origin: No. 1 — Coalbed: Upper Freeport
State: Maryland — County: Garrett

1.4 Raw Coal — Ash: 13.8%
Lb $SO_2/10^6$ Btu: 3.59 — Sulfur: 2.37% — MM Btu/Ton: 26.4*

1.5 Assumed Plant Size: 500 Mw

1.6 Remaining Life of Boiler: 15 Yr

1.7 Assumed Annual Capital Scrubber Charges as Percent of Original Investment: 17.82%

2.0 STACK GAS COST FACTORS

2.1 Boiler Capacity: 500 Mw

2.2 Utilization Factor: 5,000 Hr/Yr

2.3 Tons of Coal Burned Per Year: 946,970 Tons

2.4 Minimum Scrubber Requirements — Scrubber Rating: 321 Mw
% of Flue Gas Cleaned: 64.2%

2.5 Design Scrubber Requirements — Scrubber Rating: 369 Mw
% of Flue Gas Cleaned: 73.8%

2.6 Scrubber Capital Cost: $2,543,938

2.7 Scrubber Capital Charges/Yr: $4,730,130

2.8 Capital Contribution Per Ton of Coal: $5.00/Ton

2.9 Fuel and Electricity Cost Per Ton of Coal: $0.57/Ton

2.10 O & M Costs Per Ton of Coal

Limestone Cost: $0.35/Ton
Maintenance Labor & Material: $1.12/Ton
Fixation Chemical Cost: $0.28/Ton
Supplies Cost: $0.17/Ton
Operating Labor Cost: $0.17/Ton
Overhead Cost: $0.76/Ton

2.11 Total Cost Per Ton of Coal Burned to Meet Emission Standards: $8.42/Ton

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* This value has been adjusted for raw coal moisture content.

CASE NUMBER: 10A

1.0 CASE CONDITIONS — Combined Use of Physical Cleaning Followed by Stack Gas Scrubbing

1.1 Coal Use Area: Milwaukee, Wisconsin

1.2 Emission Standards — New: 1.2 Lb of SO_2 Per MM Btu
Existing:

1.3 Coal District of Origin: No. 10 — Coalbed: Number 6
State: Illinois — County: Franklin

1.4 Raw Coal* — Ash: 14.8%
Lb SO_2/MM Btu: 1.87 — Sulfur: 1.12% — MM Btu/Ton: 23.9

1.5 Clean Coal — Ash: 7.1%
Cleaning Plant Yield: 90.0% — Sulfur: 0.95% — MM Btu/Ton: 25.89
Lb SO_2/MM Btu: 1.47 — Btu Recovery: 97.5% — Btu Increase: 8.33%

1.6 Transportation — Mileage: 375 — Cost Per Ton: \$3.43

1.7 Assumed Plant Size — Megawatts: 500

1.8 Remaining Life of Boiler: 25 Yr

1.9 Assumed Ash Disposal Cost: \$4.00/Ton

1.10 Cleaning Plant — Cost: \$18,000 Per Ton-Hour Input Capacity**
Utilization: 38.58%***

1.11 Assumed Annual Capital Scrubber Charges as Percent of Original Investment: 15.55%

2.0 COAL CLEANING COST FACTORS

2.1 Cleaning Plant Costs — Amortization: \$0.68/Ton — O & M: \$0.75/Ton

2.2 Additional Cost to Mine Operator to Provide for One Ton of Cleaned Coal When Mine Operator's Cost is

\$ 7.00/Ton, Additional Cost is \$0.78/Ton
\$ 9.00/Ton, Additional Cost is \$1.00/Ton
\$11.00/Ton, Additional Cost is \$1.22/Ton

2.3 Cleaning Plant Tax and Insurance Burden: \$0.12/Ton

2.4 Total Differential Production Cost to Mine Operator to Provide a Ton of Cleaned Coal, When Mine Operator's Cost is

\$ 7.00/Ton, Differential Cost is \$2.33/Ton****
\$ 9.00/Ton, Differential Cost is \$2.55/Ton
\$11.00/Ton, Differential Cost is \$2.77/Ton

3.0 ASSESSABLE BENEFIT FACTORS ASSOCIATED WITH CLEAN COAL

3.1 Added Coal Value Due to Higher Heat Content of Coal, When F.O.B. Mine Raw Coal Price is

$13.00/Ton, Benefit is $1.00/Ton
$15.00/Ton, Benefit is $1.15/Ton
$17.00/Ton, Benefit is $1.31/Ton

3.2 Transportation Cost Saving Due to Increased Heat Content of Coal: $0.26/Ton

3.3 Saving in Ash Disposal Cost: $0.36/Ton

3.4 Saving in Grinding Cost: $0.04/Ton

3.5 Saving in Benefit Payment: $0.06/Ton

3.6 Saving in Maintenance: $0.24/Ton

3.7 Total Benefits of Coal Cleaning When F.O.B. Mine Raw Coal Selling Price is

$13.00/Ton, Benefit is $1.96/Ton
$15.00/Ton, Benefit is $2.11/Ton
$17.00/Ton, Benefit is $2.27/Ton

4.0 DIFFERENTIAL CLEANING COST LESS BENEFITS PER TON

		F.O.B. Mine Raw Coal Price (Per Ton)		
		13.00	15.00	17.00
Mine Operator's Cost of Raw Coal (Per Ton)	7.00	0.37	0.22	0.06
	9.00	.59	.44	.28
	11.00	.81	.66	.50

5.0 STACK GAS COST FACTORS

5.1 Boiler Capacity: 500 Mw

5.2 Utilization Factor: 7,000 Hr/Yr

5.3 Tons of Coal Burned Per Year: 1,351,874 Tons

5.4 Minimum Scrubber Requirements — Scrubber Rating: 102 Mw; % of Flue Gas Cleaned: 20.4%

5.5 Design Scrubber Requirements — Scrubber Rating: 118 Mw; % of Flue Gas Cleaned: 23.6%

5.6 Scrubber Capital Cost: $8,117,370

5.7 Scrubber Capital Charges/Yr: $1,262,251

5.8 Capital Contribution Per Ton of Coal: $0.93/Ton

5.9 Fuel and Electricity Cost Per Ton of Coal: $0.18/Ton

5.10 O & M Costs Per Ton of Coal

Limestone Cost: $0.04/Ton
Maintenance Labor and Material: $0.24/Ton
Fixation Chemical Cost: $0.04/Ton
Supplies Cost: $0.04/Ton
Operating Labor Cost: $0.12/Ton
Overhead Cost: $0.22/Ton

5.11 Total Stack Gas Cost Per Ton of Coal Burned: $1.81/Ton

6.0 COST PER TON OF COAL BURNED TO MEET EMISSION STANDARDS

		F.O.B. Mine Raw Coal Price (Per Ton)		
		13.00	15.00	17.00
Mine Operator's Cost of Raw Coal (Per Ton)	7.00	2.18	2.03	1.87
	9.00	2.40	2.25	2.09
	11.00	2.62	2.47	2.31

7.0 COST PER MILLION BTU TO MEET EMISSION STANDARDS

		F.O.B. Mine Raw Coal Price (Per Ton)		
		13.00	15.00	17.00
Mine Operator's Cost of Raw Coal (Per Ton)	7.00	0.084	0.078	0.072
	9.00	.093	.087	.081
	11.00	.101	.095	.089

8.0 COST PER TON OF RAW COAL TO MEET EMISSION STANDARDS

		F.O.B. Mine Raw Coal Price (Per Ton)		
		13.00	15.00	17.00
Mine Operator's Cost of Raw Coal (Per Ton)	7.00	2.01	1.86	1.72
	9.00	2.22	2.08	1.94
	11.00	2.41	2.27	2.13

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* As received values.
** Amortized over 15 years, 8% interest on unpaid balance.
*** Based upon 260 days/yr at 13 hr/day - 3,380 hr/yr.
**** This represents the total of all coal cleaning cost factors at the respective operator cost levels as covered in Section 2.0 above.

CASE NUMBER: 10B

1.0	CASE CONDITIONS	Sulfur Clean-up Exclusively by Stack Gas Scrubbing

1.1 Coal Use Area: Milwaukee, Wisconsin

1.2 Emission Standards — New: 1.2 Lb of SO_2 Per MM Btu; Existing:

1.3 Coal District of Origin: No. 10 — Coalbed: Number 6
State: Illinois — County: Franklin

1.4 Raw Coal — Ash: 14.8%
Lb $SO_2/10^6$ Btu: 1.87 — Sulfur: 1.12% — MM Btu/Ton: 23.9*

1.5 Assumed Plant Size: 500 Mw

1.6 Remaining Life of Boiler: 25 Yr

1.7 Assumed Annual Capital Scrubber Charges as Percent of Original Investment: 15.55%

2.0 STACK GAS COST FACTORS

2.1 Boiler Capacity: 500 Mw

2.2 Utilization Factor: 7,000 Hr/Yr

2.3 Tons of Coal Burned Per Year: 1,464,436 Tons

2.4 Minimum Scrubber Requirements — Scrubber Rating: 199 Mw
% of Flue Gas Cleaned: 39.8%

2.5 Design Scrubber Requirements — Scrubber Rating: 229 Mw
% of Flue gas Cleaned: 45.8%

2.6 Scrubber Capital Cost: $13,796,792

2.7 Scrubber Capital Charges/Yr: $2,145,402

2.8 Capital Contribution Per Ton of Coal: $1.47/Ton

2.9 Fuel and Electricity Cost Per Ton of Coal: $0.32/Ton

2.10 O & M Costs Per Ton of Coal

Limestone Cost: $0.09/Ton
Maintenance Labor & Material: $0.38/Ton
Fixation Chemical Cost: $0.08/Ton
Supplies Cost: $0.06/Ton
Operating Labor Cost: $0.11/Ton
Overhead Cost: $0.30/Ton

2.11 Total Cost Per Ton of Coal Burned to Meet Emission Standards: $2.81/Ton

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* This value has been adjusted for raw coal moisture content.

CASE NUMBER: 10C

1.0 CASE CONDITIONS — Combined Use of Physical Cleaning Followed by Stack Gas Scrubbing

1.1 Coal Use Area: Milwaukee, Wisconsin

1.2 Emission Standards — New:
Existing: 1.2 lb of SO_2 Per MM Btu

1.3 Coal District of Origin: No. 10 — Coalbed: Number 6
State: Illinois — County: Franklin

1.4 Raw Coal*
Lb SO_2/MM Btu: 1.87 — Sulfur: 1.12% — Ash: 14.8% — MM Btu/Ton: 23.9

1.5 Clean Coal
Cleaning Plant Yield: 90.0% — Sulfur: 0.95% — Ash: 7.1% — MM Btu/Ton: 25.89
Lb SO_2/MM Btu: 1.47 — Btu Recovery: 97.5% — Btu Increase: 8.33%

1.6 Transportation — Mileage: 375 — Cost Per Ton: $3.43

1.7 Assumed Plant Size — Megawatts: 500

1.8 Remaining Life of Boiler: 15 Yr

1.9 Assumed Ash Disposal Cost: $4.00/Ton

1.10 Cleaning Plant — Cost: $18,000 Per Ton-Hour Input Capacity**
Utilization: 38.58%***

1.11 Assumed Annual Capital Scrubber Charges as Percent of Original Investment: 17.82%

2.0 COAL CLEANING COST FACTORS

2.1 Cleaning Plant Cost — Amortization: $0.68/Ton — O & M: $0.75/Ton

2.2 Additional Cost to Mine Operator to Provide for One Ton of Clean Coal, When Mine Operator's Cost is

$ 7.00/Ton, Additional Cost is $0.78/Ton
$ 9.00/Ton, Additional Cost is $1.00/Ton
$11.00/Ton, Additional Cost is $1.22/Ton

2.3 Cleaning Plant Tax and Insurance Burden: $0.12/Ton

2.4 Total Differential Production Cost to Mine Operator to Provide a Ton of Cleaned Coal, When Mine Operator's Cost is

$ 7.00/Ton, Differential Cost is $2.33/Ton****
$ 9.00/Ton, Differential Cost is $2.55/Ton
$11.00/Ton, Differential Cost is $2.77/Ton

3.0 ASSESSABLE BENEFIT FACTORS ASSOCIATED WITH CLEAN COAL

3.1 Added Coal Value Due to Higher Heat Content of Coal, When F.O.B. Mine Raw Coal Price is

$13.00/Ton, Benefit is $1.00/Ton
$15.00/Ton, Benefit is $1.15/Ton
$17.00/Ton, Benefit is $1.31/Ton

3.2 Transporation Cost Saving Due to Increased Heat Content of Coal: $0.26/Ton

3.3 Saving in Ash Disposal Cost: $0.36/Ton

3.4 Saving in Grinding Cost: $0.04/Ton

3.5 Saving in Benefit Payment: $0.06/Ton

3.6 Saving in Maintenance: $0.24/Ton

3.7 Total Benefits of Coal Cleaning, When F.O.B. Mine Raw Coal Selling Price is

$13.00/Ton, Benefit is $1.96/Ton
$15.00/Ton, Benefit is $2.11/Ton
$17.00/Ton, Benefit is $2.27/Ton

4.0 DIFFERENTIAL CLEANING COST LESS BENEFITS PER TON

		F.O.B. Mine Raw Coal Price (Per Ton)		
		13.00	15.00	17.00
Mine Operator's Cost of Raw Coal (Per Ton)	7.00	0.37	0.22	0.06
	9.00	.59	.44	.28
	11.00	.81	.66	.50

5.0 STACK GAS COST FACTORS

5.1 Boiler Capacity: 500 Mw

5.2 Utilization Factor: 5,000 Hr/Yr

5.3 Tons of Coal Burned Per Year: 965,624 Tons

5.4 Minimum Scrubber Requirements — Scrubber Rating: 102 Mw; % of Flue Gas Cleaned: 20.4%

5.5 Design Scrubber Requirements — Scrubber Rating: 118 Mw; % of Flue Gas Cleaned: 23.6%

5.6 Scrubber Capital Cost: $10,201,559

5.7 Scrubber Capital Charges/Yr: $1,817,918

5.8 Capital Contribution Per Ton of Coal: $1.88/Ton

5.9 Fuel and Electricity Cost Per Ton of Coal: $0.18/Ton

5.10 O & M Costs Per Ton of Coal

Limestone Cost: $0.04/Ton
Maintenance Labor & Material: $0.42/Ton
Fixation Chemical Cost: $0.04/Ton
Supplies Cost: $0.06/Ton
Operating Labor Cost: $0.17/Ton
Overhead Cost: $0.36/Ton

5.11 Total Stack Gas Cost Per Ton of Coal Burned: $3.15/Ton

6.0 COST PER TON OF COAL BURNED TO MEET EMISSION STANDARDS

		F.O.B. Mine Raw Coal Price (Per Ton)		
		13.00	15.00	17.00
Mine Operator's Cost of Raw Coal (Per Ton)	7.00	3.52	3.37	3.21
	9.00	3.74	3.59	3.43
	11.00	3.96	3.81	3.65

7.0 COST PER MILLION BTU TO MEET EMISSION STANDARDS

		F.O.B. Mine Raw Coal Price (Per Ton)		
		13.00	15.00	17.00
Mine Operator's Cost of Raw Coal (Per Ton)	7.00	0.136	0.130	0.124
	9.00	.144	.139	.132
	11.00	.153	.147	.141

8.0 COST PER TON OF RAW COAL TO MEET EMISSION STANDARDS

		F.O.B. Mine Raw Coal Price (Per Ton)		
		13.00	15.00	17.00
Mine Operator's Cost of Raw Coal (Per Ton)	7.00	3.25	3.11	2.96
	9.00	3.44	3.32	3.15
	11.00	3.66	3.51	3.37

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* As received values.
** Amortized over 15 years, 8% interest on unpaid balance.
*** Based upon 260 days/yr at 13 hr/day - 3,380 hr/yr.
**** This represents the total of all coal cleaning cost factors at the respective operator cost levels as covered in Section 2.0 above.

CASE NUMBER: 10D

1.0 CASE CONDITIONS — Sulfur Clean-up Exclusively by Stack Gas Scrubbing

1.1 Coal Use Area: Milwaukee, Wisconsin

1.2 Emission Standards — New:
Existing: 1.2 lb of SO_2 Per MM Btu

1.3 Coal District of Origin: No. 10 — Coalbed: No. 6
State: Illinois — County: Franklin

1.4 Raw Coal — Ash: 14.8%
Lb $SO_2/10^6$ Btu: 1.87 — Sulfur: 1.12% — MM Btu/Ton: 23.9*

1.5 Assumed Plant Size: 500 Mw

1.6 Remaining Life of Boiler: 15 Yr

1.7 Assumed Annual Capital Scrubber Charges as Percent of Original Investment: 17.82%

2.0 STACK GAS COST FACTORS

2.1 Boiler Capacity: 500 Mw

2.2 Utilization Factor: 5,000 Hr/Yr

2.3 Tons of Coal Burned Per Year: 1,046,026 Tons

2.4 Minimum Scrubber Requirements — Scrubber Rating: 199 Mw
% of Flue Gas Cleaned: 39.8%

2.5 Design Scrubber Requirements — Scrubber Rating: 229 Mw
% of Flue Gas Cleaned: 45.8%

2.6 Scrubber Capital Cost: $17,339,211

2.7 Scrubber Capital Charges/Yr: $3,089,848

2.8 Capital Contribution Per Ton of Coal: $2.95/Ton

2.9 Fuel and Electricity Cost Per Ton of Coal: $0.32/Ton

2.10 O & M Costs Per Ton of Coal

Limestone Cost: $0.09/Ton
Maintenance Labor and Material: $0.66/Ton
Fixation Chemical Cost: $0.08/Ton
Supplies Cost: $0.10/Ton
Operating Labor Cost: $0.15/Ton
Overhead Cost: $0.49/Ton

2.11 Total Cost Per Ton of Coal Burned to Meet Emission Standards: $4.84/Ton

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* This value has been adjusted for raw coal moisture content.

CASE NUMBER: 11A

1.0 CASE CONDITIONS — Combined Use of Physical Cleaning Followed by Stack Gas Scrubbing

1.1 Coal Use Area: Concord, New Hampshire

1.2 Emission Standards — New: 1.5 lb of Sulfur Per MM Btu; Existing:

1.3 Coal District of Origin: No. 2 — Coalbed: Sewickley
State: Pennsylvania — County: Greene

1.4 Raw Coal* — Ash: 11.4%
Lb SO_2/MM Btu: 5.25 — Sulfur: 3.45% — MM Btu/Ton: 26.3

1.5 Clean Coal — Ash: 8.1%
Cleaning Plant Yield: 90.0% — Sulfur: 2.20% — MM Btu/Ton: 27.2
Lb SO_2/MM Btu: 3.24 — Btu Recovery: 93.07% — Btu Increase: 3.42%

1.6 Transportation — Mileage: 745 — Cost Per Ton: $9.31

1.7 Assumed Plant Size — Megawatts: 500

1.8 Remaining Life of Boiler: 25 Yr

1.9 Assumed Ash Disposal Cost: $4.00/Ton

1.10 Cleaning Plant — Cost: $18,000 Per Ton-Hour Input Capacity**
Utilization: 38.58%***

1.11 Assumed Annual Capital Scrubber Charges as Percent of Original Investment: 15.55%

2.0 COAL CLEANING COST FACTORS

2.1 Cleaning Plant Costs — Amortization: $0.68/Ton — O & M: $0.75/Ton

2.2 Additional Cost to Mine Operator to Provide for One Ton of Clean Coal, When Mine Operator's Cost is

$12.00/Ton, Additional Cost is $1.33/Ton
$14.00/Ton, Additional Cost is $1.56/Ton
$16.00/Ton, Additional Cost is $1.78/Ton

2.3 Cleaning Plant Tax and Insurance Burden: $0.12/Ton

2.4 Total Differential Production Cost to Mine Operator to Provide a Ton of Cleaned Coal, When Mine Operator's Cost is

$12.00/Ton, Differential Cost is $2.88/Ton****
$14.00/Ton, Differential Cost is $3.11/Ton
$16.00/Ton, Differential Cost is $3.33/Ton

3.0 ASSESSABLE BENEFIT FACTORS ASSOCIATED WITH CLEAN COAL

3.1 Added Coal Value Due to Higher Heat Content of Coal, When F.O.B. Mine Raw Coal Price is

$22.00/Ton, Benefit is $0.73/Ton
$24.00/Ton, Benefit is $0.79/Ton
$26.00/Ton, Benefit is $0.86/Ton

3.2 Transportation Cost Saving Due to Increased Heat Content of Coal: $0.31/Ton

3.3 Saving in Ash Disposal Cost: $0.14/Ton

3.4 Saving in Grinding Cost: $0.02/Ton

3.5 Saving in Benefit Payment: $0.02/Ton

3.6 Saving in Maintenance: $0.17/Ton

3.7 Total Benefits of Coal Cleaning, When F.O.B. Mine Raw Coal Selling Price is

$22.00/Ton, Benefit is $1.39/Ton
$24.00/Ton, Benefit is $1.45/Ton
$26.00/Ton, Benefit is $1.52/Ton

4.0 DIFFERENTIAL CLEANING COST LESS BENEFITS PER TON

		F.O.B. Mine Raw Coal Price (Per Ton)		
		22.00	24.00	26.00
Mine Operator's Cost of Raw Coal (Per Ton)	12.00	1.49	1.43	1.36
	14.00	1.72	1.66	1.59
	16.00	1.94	1.88	1.81

5.0 STACK GAS COST FACTORS

5.1 Boiler Capacity: 500 Mw

5.2 Utilization Factor: $7,000 Hr/Yr

5.3 Tons of Coal Burned Per Year: 1,286,765 Tons

5.4 Minimum Scrubber Requirements — Scrubber Rating: 41 Mw; % of Flue Gas Cleaned: 8.2%

5.5 Design Scrubber Requirements — Scrubber Rating: 48 Mw; % of Flue Gas Cleaned: 9.6%

5.6 Scrubber Capital Cost: $4,211,848

5.7 Scrubber Capital Charges/Yr: $654,943

5.8 Capital Contribution Per Ton of Coal: $0.51/Ton

5.9 Fuel and Electricity Cost Per Ton of Coal: $0.08/Ton

5.10 O & M Costs Per Ton of Coal

Limestone Cost: $0.04/Ton
Maintenance Labor & Material: $0.13/Ton
Fixation Chemical Cost: $0.04/Ton
Supplies Cost: $0.02/Ton
Operating Labor Cost: $0.13/Ton
Overhead Cost: $0.17/Ton

5.11 Total Stack Gas Cost Per Ton of Coal Burned: $1.12/Ton

6.0 COST PER TON OF COAL BURNED TO MEET EMISSION STANDARDS

		F.O.B. Mine Raw Coal Price (Per Ton)		
		22.00	24.00	26.00
Mine Operator's Cost of Raw Coal (Per Ton)	12.00	2.61	2.55	2.48
	14.00	2.84	2.78	2.71
	16.00	3.06	3.00	2.93

7.0 COST PER MILLION BTU TO MEET EMISSION STANDARDS

		F.O.B. Mine Raw Coal Price (Per Ton)		
		22.00	24.00	26.00
Mine Operator's Cost of Raw Coal (Per Ton)	12.00	0.096	0.094	0.091
	14.00	.104	.102	.100
	16.00	.113	.110	.108

8.0 COST PER TON OF RAW COAL TO MEET EMISSION STANDARDS

		F.O.B. Mine Raw Coal Price (Per Ton)		
		22.00	24.00	26.00
Mine Operator's Cost of Raw Coal (Per Ton)	12.00	2.52	2.47	2.39
	14.00	2.74	2.68	2.63
	16.00	2.97	2.89	2.84

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* As received values.
** Amortized over 15 years, 8% interest on unpaid balance.
*** Based upon 260 days/yr at 13 hr/day - 3,380 hr/yr.
**** This represents the total of all coal cleaning cost factors at the respective operator cost levels as covered in Section 2.0 above.

1.0 CASE CONDITIONS — Sulfur Clean-up Exclusively by Stack Gas Scrubbing

1.1 Coal Use Area: Concord, New Hampshire

1.2 Emission Standards — New: 1.5 lb of Sulfur Per MM Btu
Existing:

1.3 Coal District of Origin: No. 2 — Coalbed: Sewickley
State: Pennsylvania — County: Greene

1.4 Raw Coal — Ash: 11.4%
Lb $SO_2/10^6$ Btu: 5.25 — Sulfur: 3.45% — MM Btu/Ton: 26.3*

1.5 Assumed Plant Size: 500 Mw

1.6 Remaining Life of Boiler: 25 Yr

1.7 Assumed Annual Capital Scrubber Charges as Percent of Original Investment: 15.55%

2.0 STACK GAS COST FACTORS

2.1 Boiler Capacity: 500 Mw

2.2 Utilization Factor: 7,000 Hr/Yr

2.3 Tons of Coal Burned Per Year: 1,330,799 Tons

2.4 Minimum Scrubber Requirements — Scrubber Rating: 238 Mw
% of Flue Gas Cleaned: 47.6%

2.5 Design Scrubber Requirements — Scrubber Rating: 274 Mw
% of Flue Gas Cleaned: 54.8%

2.6 Scrubber Capital Cost: $18,465,698

2.7 Scrubber Capital Charges/Yr: $2,871,416

2.8 Capital Contribution Per Ton of Coal: $2.16/Ton

2.9 Fuel and Electricity Cost Per Ton of Coal: $0.42/Ton

2.10 O & M Costs Per Ton of Coal

Limestone Cost: $0.38/Ton
Maintenance Labor & Material: $0.56/Ton
Fixation Chemical Cost: $0.31/Ton
Supplies Cost: $0.08/Ton
Operating Labor Cost: $0.12/Ton
Overhead Cost: $0.40/Ton

2.11 Total Cost Per Ton of Coal Burned to Meet Emission Standards: $4.43/Ton

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* This value has been adjusted for raw coal moisture content.

CASE NUMBER: 11C

1.0 CASE CONDITIONS — Combined Use of Physical Cleaning Followed by Stack Gas Scrubbing

1.1 Coal Use Area: Concord, New Hampshire

1.2 Emission Standards — New:
Existing: 1.5 lb of Sulfur Per MM Btu

1.3 Coal District of Origin: No. 2 — Coalbed: Sewickley
State: Pennsylvania — County: Greene

1.4 Raw Coal* — Ash: 11.4%
Lb SO_2/MM Btu: 5.25 — Sulfur: 3.45% — MM Btu/Ton: 26.3

1.5 Clean Coal — Ash: 8.1%
Cleaning Plant Yield: 90.0% — Sulfur: 2.20% — MM Btu/Ton: 27.2
Lb SO_2/MM Btu: 3.24 — Btu Recovery: 93.07% — Btu Increase: 3.42%

1.6 Transportation — Mileage: 745 — Cost Per Ton: $9.31

1.7 Assumed Plant Size — Megawatts: 500

1.8 Remaining Life of Boiler: 15 Yr

1.9 Assumed Ash Disposal Cost: $4.00/Ton

1.10 Cleaning Plant — Cost: $18,000 Per Ton-Hour Input Capacity**
Utilization: 38.58%***

1.11 Assumed Annual Capital Scrubber Charges as Percent of Original Investment: 17.82%

2.0 COAL CLEANING COST FACTORS

2.1 Cleaning Plant Costs — Amortization: $0.68/Ton — O & M: $0.75/Ton

2.2 Additional Cost to Mine Operator to Provide for One Ton of Clean Coal, When Mine Operator's Cost is

$12.00/Ton, Additional Cost is $1.33/Ton
$14.00/Ton, Additional Cost is $1.56/Ton
$16.00/Ton, Additional Cost is $1.78/Ton

2.3 Cleaning Plant Tax and Insurance Burden: $0.12/Ton

2.4 Total Differential Production Cost to Mine Operator to Provide a Ton of Cleaned Coal, When Mine Operator's Cost is

$12.00/Ton, Differential Cost is $2.88/Ton****
$14.00/Ton, Differential Cost is $3.11/Ton
$16.00/Ton, Differential Cost is $3.33/Ton

3.0 ASSESSABLE BENEFIT FACTORS ASSOCIATED WITH CLEAN COAL

3.1 Added Coal Value Due to Higher Heat Content of Coal, When F.O.B. Mine Raw Coal Price is

$22.00/Ton, Benefit is $0.73/Ton
$24.00/Ton, Benefit is $0.79/Ton
$26.00/Ton, Benefit is $0.86/Ton

3.2 Transportation Cost Saving Due to Increased Heat Content of Coal: $0.31/Ton

3.3 Saving in Ash Disposal Cost: $0.14/Ton

3.4 Saving in Grinding Cost: $0.02/Ton

3.5 Saving in Benefit Payment: $0.02/Ton

3.6 Saving in Maintenance: $0.17/Ton

3.7 Total Benefits of Coal Cleaning, When F.O.B. Mine Raw Coal Selling Price is

$22.00/Ton, Benefit is $1.39/Ton
$24.00/Ton, Benefit is $1.45/Ton
$26.00/Ton, Benefit is $1.52/Ton

4.0 DIFFERENTIAL CLEANING COST LESS BENEFITS PER TON

		F.O.B. Mine Raw Coal Price (Per Ton)		
		22.00	24.00	26.00
Mine Operator's Cost of Raw Coal (Per Ton)	12.00	1.49	1.43	1.36
	14.00	1.72	1.66	1.59
	16.00	1.94	1.88	1.81

5.0 STACK GAS COST FACTORS

5.1 Boiler Capacity: 500 Mw

5.2 Utilization Factor: 5,000 Hr/Yr

5.3 Tons of Coal Burned Per Year: 919,118 Tons

5.4 Minimum Scrubber Requirements — Scrubber Rating: 41 Mw; % of Flue Gas Cleaned: 8.2%

5.5 Design Scrubber Requirements — Scrubber Rating: 48 Mw; % of Flue Gas Cleaned: 9.6%

5.6 Scrubber Capital Cost: $5,138,615

5.7 Scrubber Capital Charges/Yr: $915,702

5.8 Capital Contribution Per Ton of Coal: $1.00/Ton

5.9 Fuel and Electricity Cost Per Ton of Coal: $0.08/Ton

5.10 O & M Costs Per Ton of Coal

Limestone Cost: $0.04/Ton
Maintenance Labor & Material: $0.22/Ton
Fixation Chemical Cost: $0.04/Ton
Supplies Cost: $0.03/Ton
Operating Labor Cost: $0.18/Ton
Overhead Cost: $0.25/Ton

5.11 Total Stack Gas Cost Per Ton of Coal Burned: $1.84/Ton

6.0 COST PER TON OF COAL BURNED TO MEET EMISSION STANDARDS

		F.O.B. Mine Raw Coal Price (Per Ton)		
		22.00	24.00	26.00
Mine Operator's Cost of Raw Coal (Per Ton)	12.00	3.33	3.27	3.20
	14.00	3.56	3.50	3.43
	16.00	3.78	3.72	3.65

7.0 COST PER MILLION BTU TO MEET EMISSION STANDARDS

		F.O.B. Mine Raw Coal Price (Per Ton)		
		22.00	24.00	26.00
Mine Operator's Cost of Raw Coal (Per Ton)	12.00	0.122	0.120	0.118
	14.00	.131	.129	.126
	16.00	.139	.137	.134

8.0 COST PER TON OF RAW COAL TO MEET EMISSION STANDARDS

		F.O.B. Mine Raw Coal Price (Per Ton)		
		22.00	24.00	26.00
Mine Operator's Cost of Raw Coal (Per Ton)	12.00	3.21	3.16	3.10
	14.00	3.45	3.39	3.31
	16.00	3.66	3.60	3.52

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* As received values.
** Amortized over 15 years, 8% interest on unpaid balance.
*** Based upon 260 days/yr at 13 hr/day - 3,380 hr/yr.
**** This represents the total of all coal cleaning cost factors at the respective operator cost levels as covered in Section 2.0 above.

CASE NUMBER: 11D

1.0 CASE CONDITIONS — Sulfur Clean-up Exclusively by Stack Gas Scrubbing

1.1 Coal Use Area: Concord, New Hampshire

1.2 Emission Standards — New:
Existing: 1.5 lb of Sulfur Per MM Btu

1.3 Coal District of Origin: No. 2 — Coalbed: Sewickley
State: Pennsylvania — County: Greene

1.4 Raw Coal — Ash: 11.4%
Lb $SO_2/10^6$ Btu: 5.25 — Sulfur: 3.45% — MM Btu/Ton: 26.3*

1.5 Assumed Plant Size: 500 Mw

1.6 Remaining Life of Boiler: 15 Yr

1.7 Assumed Annual Capital Scrubber Charges as Percent of Original Investment: 17.82%

2.0 STACK GAS COST FACTORS

2.1 Boiler Capacity: 500 Mw

2.2 Utilization Factor: 5,000 Hr/Yr

2.3 Tons of Coal Burned Per Year: 950,571 Tons

2.4 Minimum Scrubber Requirements — Scrubber Rating: 238 Mw
% of Flue Gas Cleaned: 47.6%

2.5 Design Scrubber Requirements — Scrubber Rating: 274 Mw
% of Flue Gas Cleaned: 54.8%

2.6 Scrubber Capital Cost: $22,608,643

2.7 Scrubber Capital Charges/Yr: $4,028,861

2.8 Capital Contribution Per Ton of Coal: $4.24/Ton

2.9 Fuel and Electricity Cost Per Ton of Coal: $0.42/Ton

2.10 O & M Costs Per Ton of Coal

Limestone Cost: $0.38/Ton
Maintenance Labor & Materials: $0.95/Ton
Fixation Chemical Cost: $0.31/Ton
Supplies Cost: $0.14/Ton
Operating Labor Cost: $0.17/Ton
Overhead Cost: $0.66/Ton

2.11 Total Cost Per Ton of Coal Burned to Meet Emission Standards: $7.27/Ton

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* This value has been adjusted for raw coal moisture content.

CASE NUMBER: 11E

1.0 CASE CONDITIONS — Combined Use of Physical Cleaning Followed by Stack Gas Scrubbing

1.1 Coal Use Area: Concord, New Hampshire

1.2 Emission Standards — New: 1.2 lb of SO_2 Per MM Btu (Projected Standard)
Existing:

1.3 Coal District of Origin: No. 2 — Coalbed: Sewickley
State: Pennsylvania — County: Greene

1.4 Raw Coal* — Ash: 11.4%
Lb SO_2/MM Btu: 5.25 — Sulfur: 3.45% — MM Btu/Ton: 26.3

1.5 Clean Coal — Ash: 8.1%
Cleaning Plant Yield: 90.0% — Sulfur: 2.20% — MM Btu/Ton: 27.2
Lb SO_2/MM Btu: 3.24 — Btu Recovery: 93.07% — Btu Increase: 3.42%

1.6 Transportation — Mileage: 745 — Cost Per Ton: $9.31

1.7 Assumed Plant Size — Megawatts: 500

1.8 Remaining Life of Boiler: 25 Yr

1.9 Assumed Ash Disposal Cost: $4.00/Ton

1.10 Cleaning Plant — Cost: $18,000 Per Ton-Hour Input Capacity**
Utilization: 38.58%***

1.11 Assumed Annual Capital Scrubber Charges as Percent of Original Investment: 15.55%

2.0 COAL CLEANING COST FACTORS

2.1 Cleaning Plant Costs — Amortization: $0.68/Ton — O & M: $0.75/Ton

2.2 Additional Cost to Mine Operator to Provide for One Ton of Clean Coal, When Mine Operator's Cost is

$12.00/Ton, Additional Cost is $1.33/Ton
$14.00/Ton, Additional Cost is $1.56/Ton
$16.00/Ton, Additional Cost is $1.78/Ton

2.3 Cleaning Plant Tax and Insurance Burden: $0.12/Ton

2.4 Total Differential Production Cost to Mine Operator to Provide a Ton of Cleaned Coal, When Mine Operator's Cost is

$12.00/Ton, Differential Cost is $2.88/Ton****
$14.00/Ton, Differential Cost is $3.11/Ton
$16.00/Ton, Differential Cost is $3.33/Ton

3.0 ASSESSABLE BENEFIT FACTORS ASSOCIATED WITH CLEAN COAL

3.1 Added Coal Value Due to Higher Heat Content of Coal, When F.O.B. Mine Raw Coal Price is

$22.00/Ton, Benefit is $0.73/Ton
$24.00/Ton, Benefit is $0.79/Ton
$26.00/Ton, Benefit is $0.86/Ton

3.2 Transportation Cost Saving Due to Increased Heat Content of Coal: $0.31/Ton

3.3 Saving in Ash Disposal Cost: $0.14/Ton

3.4 Saving in Grinding Cost: $0.02/Ton

3.5 Saving in Benefit Payment: $0.02/Ton

3.6 Saving in Maintenance: $0.19/Ton

3.7 Total Benefits of Coal Cleaning, When F.O.B. Mine Raw Coal Selling Price is

$22.00/Ton, Benefit is $1.39/Ton
$24.00/Ton, Benefit is $1.45/Ton
$26.00/Ton, Benefit is $1.52/Ton

4.0 DIFFERENTIAL CLEANING COST LESS BENEFITS PER TON

		F.O.B. Mine Raw Coal Price (Per Ton)		
		22.00	24.00	26.00
Mine Operator's Cost of Raw Coal (Per Ton)	12.00	1.49	1.43	1.36
	14.00	1.72	1.66	1.59
	16.00	1.94	1.88	1.81

5.0 STACK GAS COST FACTORS

5.1 Boiler Capacity: 500 Mw

5.2 Utilization Factor: 7,000 Hr/Yr

5.3 Tons of Coal Burned Per Year: 1,286,765 Tons

5.4 Minimum Scrubber Requirements — Scrubber Rating: 350 Mw
% of Flue Gas Cleaned: 70.0%

5.5 Design Scrubber Requirements — Scrubber Rating: 403 Mw
% of Flue Gas Cleaned: 80.6%

5.6 Scrubber Capital Cost: $23,105,945

5.7 Scrubber Capital Charges/Yr: $3,592,975

5.8 Capital Contribution Per Ton of Coal: $2.79/Ton

5.9 Fuel and Electricity Cost Per Ton of Coal: $0.64/Ton

5.10 O & M Costs Per Ton of Coal

Limestone Cost: $0.36/Ton
Maintenance Labor & Material: $0.72/Ton
Fixation Chemical Cost: $0.30/Ton
Supplies Cost: $0.11/Ton
Operating Labor Cost: $0.13/Ton
Overhead Cost: $0.51/Ton

5.11 Total Stack Gas Cost Per Ton of Coal Burned: $5.56/Ton

6.0 COST PER TON OF COAL BURNED TO MEET EMISSION STANDARDS

		F.O.B. Mine Raw Coal Price (Per Ton)		
		22.00	24.00	26.00
Mine Operator's Cost of Raw Coal (Per Ton)	12.00	7.05	6.99	6.92
	14.00	7.28	7.22	7.15
	16.00	7.50	7.44	7.37

7.0 COST PER MILLION BTU TO MEET EMISSION STANDARDS

		F.O.B. Mine Raw Coal Price (Per Ton)		
		22.00	24.00	26.00
Mine Operator's Cost of Raw Coal (Per Ton)	12.00	0.259	0.257	0.254
	14.00	.268	.265	.263
	16.00	.276	.274	.271

8.0 COST PER TON OF RAW COAL TO MEET EMISSION STANDARDS

		F.O.B. Mine Raw Coal Price (Per Ton)		
		22.00	24.00	26.00
Mine Operator's Cost of Raw Coal (Per Ton)	12.00	6.81	6.76	6.68
	14.00	7.05	6.97	6.92
	16.00	7.26	7.21	7.13

* As received values.
** Amortized over 15 years, 8% interest on unpaid balance.
*** Based upon 260 days/yr at 13 hr/day - 3,380 hr/yr.
**** This represents the total of all coal cleaning cost factors at the respective operator cost levels as covered in Section 2.0 above.

CASE NUMBER: 11F

1.0 CASE CONDITIONS — Sulfur Clean-up Exclusively by Stack Gas Scrubbing

1.1 Coal Use Area: Concord, New Hampshire

1.2 Emission Standards — New: 1.2 lb of SO_2 Per MM Btu (Projected Standard)
Existing:

1.3 Coal District Of Origin: No. 2 — Coalbed: Sewickley
State: Pennsylvania — County: Greene

1.4 Raw Coal — Ash: 11.4%
Lb $SO_2/10^6$ Btu: 5.25 — Sulfur: 3.45% — MM Btu/Ton: 26.3*

1.5 Assumed Plant Size: 500 Mw

1.6 Remaining Life of Boiler: 25 Yr

1.7 Assumed Annual Capital Scrubber Charges as Percent of Original Investment: 15.55%

2.0 STACK GAS COST FACTORS

2.1 Boiler Capacity: 500 Mw

2.2 Utilization Factor: 7,000 Hr/Yr

2.3 Tons of Coal Burned Per Year: 1,330,799 Tons

2.4 Minimum Scrubber Requirements — Scrubber Rating: 429 Mw
% of Flue Gas Cleaned: 85.7%

2.5 Design Scrubber Requirements — Scrubber Rating: 493 Mw
% of Flue Gas Cleaned: 98.6%

2.6 Scrubber Capital Cost: $29,542,199

2.7 Scrubber Capital Charges/Yr: $4,593,812

2.8 Capital Contribution Per Ton of Coal: $3.45/Ton

2.9 Fuel and Electricity Cost Per Ton of Coal: $0.75/Ton

2.10 O & M Costs Per Ton of Coal

Limestone Cost: $0.67/Ton
Maintenance Labor & Material: $0.89/Ton
Fixation Chemical Cost: $0.55/Ton
Supplies Cost: $0.13/Ton
Operating Labor Cost: $0.12/Ton
Overhead Cost: $0.59/Ton

2.11 Total Cost Per Ton of Coal Burned to Meet Emission Standards: $7.15/Ton

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* This value has been adjusted for raw coal moisture content.

CASE NUMBER: 12A

1.0 CASE CONDITIONS — Combined Use of Physical Cleaning Followed by Stack Gas Scrubbing

1.1 Coal Use Area: Dickerson (Montgomery County), Maryland

1.2 Emission Standards — New: 1% Sulfur by Weight; Existing:

1.3 Coal District of Origin: No. 3 — Coalbed: Pittsburgh
State: West Virginia — County: Marion

1.4 Raw Coal* — Ash: 11.0%
Lb SO_2/MM Btu: 5.70 — Sulfur: 3.80% — MM Btu/Ton: 26.66

1.5 Clean Coal — Ash: 5.9%
Cleaning Plant Yield: 90.0% — Sulfur: 2.16% — MM Btu/Ton: 28.09
Lb SO_2/MM Btu: 3.08 — Btu Recovery: 94.8% — Btu Increase: 5.36%

1.6 Transportation — Mileage: 245 — Cost Per Ton: $6.60

1.7 Assumed Plant Size — Megawatts: 500

1.8 Remaining Life of Boiler: 25 Yr

1.9 Assumed Ash Disposal Cost: $4.00/Ton

1.10 Cleaning Plant — Cost: $18,000 Per Ton-Hour Input Capacity**
Utilization: 38.58%***

1.11 Assumed Annual Capital Scrubber Charges as Percent of Original Investment: 15.55%

2.0 COAL CLEANING COST FACTORS

2.1 Cleaning Plant Costs — Amortization: $0.68/Ton — O & M: $0.75/Ton

2.2 Additional Cost to Mine Operator to Provide for One Ton of Clean Coal, When Mine Operator's Cost is

$ 9.00/Ton, Additional Cost is $1.00/Ton
$11.00/Ton, Additional Cost is $1.22/Ton
$13.00/Ton, Additional Cost is $1.44/Ton

2.3 Cleaning Plant Tax and Insurance Burden: $0.12/Ton

2.4 Total Differential Production Cost to Mine Operator to Provide a Ton of Cleaned Coal, When Mine Operator's Cost is

$ 9.00/Ton, Differential Cost is $2.55/Ton****
$11.00/Ton, Differential Cost is $2.77/Ton
$13.00/Ton, Differential Cost is $2.99/Ton

3.0 ASSESSABLE BENEFIT FACTORS ASSOCIATED WITH CLEAN COAL

3.1 Added Coal Value Due to Higher Heat Content of Coal, When F.O.B. Mine Raw Coal Price is

$17.00/Ton, Benefit is $0.86/Ton
$19.00/Ton, Benefit is $0.97/Ton
$21.00/Ton, Benefit is $1.07/Ton

3.2 Transportation Cost Saving Due to Increased Heat Content of Coal: $0.34/Ton

3.3 Saving in Ash Disposal Cost: $0.23/Ton

3.4 Saving in Grinding Cost: $0.03/Ton

3.5 Saving in Benefit Payment: $0.04/Ton

3.6 Saving in Maintenance: $0.20/Ton

3.7 Total Benefits of Coal Cleaning, When F.O.B. Mine Raw Coal Selling Price is

$17.00/Ton, Benefit is $1.70/Ton
$19.00/Ton, Benefit is $1.81/Ton
$21.00/Ton, Benefit is $1.91/Ton

4.0 DIFFERENTIAL CLEANING COST LESS BENEFITS PER TON

		F.O.B. Mine Raw Coal Price (Per Ton)		
		17.00	19.00	21.00
Mine Operator's Cost of Raw Coal (Per Ton	9.00	0.85	0.74	0.64
	11.00	1.07	.96	.86
	13.00	1.29	1.18	1.08

5.0 STACK GAS COST FACTORS

5.1 Boiler Capacity: 500 Mw

5.2 Utilization Factor: 7,000 Hr/Yr

5.3 Tons of Coal Burned Per Year: 1,245,995 Tons

5.4 Minimum Scrubber Requirements — Scrubber Rating: 299 Mw
% of Flue Gas Cleaned: 59.7%

5.5 Design Scrubber Requirements — Scrubber Rating: 344 Mw
% of Flue Gas Cleaned: 68.8%

5.6 Scrubber Capital Cost: $20,138,140

5.7 Scrubber Capital Charges/Yr: $3,131,481

5.8 Capital Contribution Per Ton of Coal: $2.51/Ton

5.9 Fuel and Electricity Cost Per Ton of Coal: $0.56/Ton

5.10 O & M Costs Per Ton of Coal

Limestone Cost: $0.31/Ton
Maintenance Labor & Material: $0.67/Ton
Fixation Chemical Cost: $0.26/Ton
Supplies Cost: $0.10/Ton
Operating Labor Cost: $0.13/Ton
Overhead Cost: $0.48/Ton

5.11 Total Stack Gas Cost Per Ton of Coal Burned: $5.02/Ton

6.0 COST PER TON OF COAL BURNED TO MEET EMISSION STANDARDS

		F.O.B. Mine Raw Coal Price (Per Ton)		
		17.00	19.00	21.00
Mine Operator's Cost of Raw Coal (Per Ton)	9.00	5.87	5.76	5.66
	11.00	6.09	5.98	5.88
	13.00	6.31	6.20	6.10

7.0 COST PER MILLION BTU TO MEET EMISSION STANDARDS

		F.O.B. Mine Raw Coal Price (Per Ton)		
		17.00	19.00	21.00
Mine Operator's Cost of Raw Coal (Per Ton)	9.00	0.209	0.205	0.201
	11.00	.217	.213	.209
	13.00	.225	.221	.217

8.0 COST PER TON OF RAW COAL TO MEET EMISSION STANDARDS

		F.O.B. Mine Raw Coal Price (Per Ton)		
		17.00	19.00	21.00
Mine Operator's Cost of Raw Coal (Per Ton)	9.00	5.57	5.47	5.36
	11.00	5.79	5.68	5.57
	13.00	6.00	5.89	5.79

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* As received values.
** Amortized over 15 years, 8% interest on unpaid balance.
*** Based upon 260 days/yr at 13 hr/day - 3,380 hr/yr.
**** This represents the total of all coal cleaning cost factors at the respective operator cost levels as covered in Section 2.0 above.

CASE NUMBER: 12B

1.0 CASE CONDITIONS — Sulfur Clean-up Exclusively by Stack Gas Scrubbing

1.1 Coal Use Area: Dickerson (Montgomery County), Maryland

1.2 Emission Standards — New: 1% Sulfur by Weight; Existing:

1.3 Coal District of Origin: No. 3 — Coalbed: Pittsburgh
State: West Virginia — County: Marion

1.4 Raw Coal — Ash: 11.0%
Lb $SO_2/10^6$ Btu: 5.70 — Sulfur: 3.80% — MM Btu/Ton: 26.66*

1.5 Assumed Plant Size: 500 Mw

1.6 Remaining Life of Boiler: 25 Yr

1.7 Assumed Annual Capital Scrubber Charges as Percent of Original Investment: 15.55%

2.0 STACK GAS COST FACTORS

2.1 Boiler Capacity: 500 Mw

2.2 Utilization Factor: 7,000 Hr/Yr

2.3 Tons of Coal Burned Per Year: 1,312,829 Tons

2.4 Minimum Scrubber Requirements — Scrubber Rating: 410 Mw; % of Flue Gas Cleaned: 81.9%

2.5 Design Scrubber Requirements — Scrubber Rating: 472 Mw; % of Flue Gas Cleaned: 94.4%

2.6 Scrubber Capital Cost: $28,531,124

2.7 Scrubber Capital Charges/Yr: $4,436,590

2.8 Capital Contribution Per Ton of Coal: $3.38/Ton

2.9 Fuel and Electricity Cost Per Ton of Coal: $0.73/Ton

2.10 O & M Costs Per Ton of Coal

Limestone Cost: $0.72/Ton
Maintenance Labor & Material: $0.87/Ton
Fixation Chemical Cost: $0.59/Ton
Supplies Cost: $0.13/Ton
Operating Labor Cost: $0.12/Ton
Overhead Cost: $0.58/Ton

2.11 Total Cost Per Ton of Coal Burned to Meet Emission Standards: $7.12/Ton

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* This value has been adjusted for raw coal moisture content.

CASE NUMBER: 12C

1.0 CASE CONDITIONS — Combined Use of Physical Cleaning Followed by Stack Gas Scrubbing

1.1 Coal Use Area: Dickerson (Montgomery County), Maryland

1.2 Emission Standards — New:
Existing: 1% Sulfur by Weight

1.3 Coal District of Origin: No. 3 — Coalbed: Pittsburgh
State: West Virginia — County: Marion

1.4 Raw Coal* — Ash: 11.0%
Lb SO_2/MM Btu: 5.70 — Sulfur: 3.80% — MM Btu/Ton: 26.66

1.5 Clean Coal — Ash: 5.9%
Cleaning Plant Yield: 90.0% — Sulfur: 2.16% — MM Btu/Ton: 28.09
Lb SO_2/MM Btu: 3.08 — Btu Recovery: 94.8% — Btu Increase: 5.36%

1.6 Transportation — Mileage: 245 — Cost Per Ton: $6.60

1.7 Assumed Plant Size — Megawatts: 500

1.8 Remaining Life of Boiler: 15 Yr

1.9 Assumed Ash Disposal Cost: $4.00/Ton

1.10 Cleaning Plant — Cost: $18,000 Per Ton-Hour Input Capacity**
Utilization: 38.58%***

1.11 Assumed Annual Capital Scrubber Charges as Percent of Original Investment: 17.82%

2.0 COAL CLEANING COST FACTORS

2.1 Cleaning Plant Costs — Amortization: $0.68/Ton — O & M: $0.75/Ton

2.2 Additional Cost to Mine Operator to Provide for One Ton of Clean Coal, When Mine Operator's Cost is

$ 9.00/Ton, Additional Cost is $1.00/Ton
$11.00/Ton, Additional Cost is $1.22/Ton
$13.00/Ton, Additional Cost is $1.44/Ton

2.3 Cleaning Plant Tax and Insurance Burden: $0.12/Ton

2.4 Total Differential Production Cost to Mine Operator to Provide a Ton of Cleaned Coal, When Mine Operator's Cost is

$ 9.00/Ton, Differential Cost is $2.55/Ton****
$11.00/Ton, Differential Cost is $2.77/Ton
$13.00/Ton, Differential Cost is $2.99/Ton

3.0 ASSESSABLE BENEFIT FACTORS ASSOCIATED WITH CLEAN COAL

3.1 Added Coal Value Due to Higher Heat Content of Coal, When F.O.B. Mine Raw Coal Price is

$17.00/Ton, Benefit is $0.86/Ton
$19.00/Ton, Benefit is $0.97/Ton
$21.00/Ton, Benefit is $1.07/Ton

3.2 Transportation Cost Saving Due to Increased Heat Content of Coal: $0.34/Ton

3.3 Saving in Ash Disposal Cost: $0.23/Ton

3.4 Saving in Grinding Cost: $0.03/Ton

3.5 Saving in Benefit Payment: $0.04/Ton

3.6 Saving in Maintenance: $0.20/Ton

3.7 Total Benefits of Coal Cleaning, When F.O.B. Mine Raw Coal Selling Price is

$17.00/Ton, Benefit is $1.70/Ton
$19.00/Ton, Benefit is $1.81/Ton
$21.00/Ton, Benefit is $1.91/Ton

4.0 DIFFERENTIAL CLEANING COST LESS BENEFITS PER TON

		F.O.B. Mine Raw Coal Price (Per Ton)		
		17.00	19.00	21.00
Mine Operator's Cost of Raw Coal (Per Ton)	9.00	0.85	0.74	0.64
	11.00	1.07	.96	.86
	13.00	1.29	1.18	1.08

5.0 STACK GAS COST FACTORS

5.1 Boiler Capacity: 500 Mw

5.2 Utilization Factor: 5,000 Hr/Yr

5.3 Tons of Coal Burned Per Year: 889,997 Tons

5.4 Minimum Scrubber Requirements — Scrubber Rating: 299 Mw
% of Flue Gas Cleaned: 59.7%

5.5 Design Scrubber Requirements — Scrubber Rating: 344 Mw
% of Flue Gas Cleaned: 68.8%

5.6 Scrubber Capital Cost: $24,669,221

5.7 Scrubber Capital Charges/Yr: $4,396,056

5.8 Capital Contribution Per Ton of Coal: $4.94/Ton

5.9 Fuel and Electricity Cost Per Ton of Coal: $0.56/Ton

5.10 O & M Costs Per Ton of Coal

Limestone Cost: $0.31/Ton
Maintenance Labor & Material: $1.11/Ton
Fixation Chemical Cost: $0.26/Ton
Supplies Cost: $0.17/Ton
Operating Labor Cost: $0.18/Ton
Overhead Cost: $0.77/Ton

5.11 Total Stack Gas Cost Per Ton of Coal Burned: $8.30/Ton

6.0 COST PER TON OF COAL BURNED TO MEET EMISSION STANDARDS

		F.O.B. Mine Raw Coal Price (Per Ton)		
		17.00	19.00	21.00
Mine Operator's Cost of Raw Coal Per Ton	9.00	9.15	9.04	8.94
	11.00	9.37	9.26	9.16
	13.00	9.59	9.48	9.38

7.0 COST PER MILLION BTU TO MEET EMISSION STANDARDS

		F.O.B. Mine Raw Coal Price (Per Ton)		
		17.00	19.00	21.00
Mine Operator's Cost of Raw Coal (Per Ton)	9.00	0.326	0.322	0.318
	11.00	.334	.330	.326
	13.00	.341	.337	.334

8.0 COST PER TON OF RAW COAL TO MEET EMISSION STANDARDS

		F.O.B. Mine Raw Coal Price (Per Ton)		
		17.00	19.00	21.00
Mine Operator's Cost of Raw Coal (Per Ton)	9.00	8.69	8.58	8.48
	11.00	8.90	8.80	8.69
	13.00	9.09	8.98	8.90

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* As received values.
** Amortized over 15 years, 8% interest on unpaid balance.
*** Based upon 260 days/yr at 13 hr/day - 3,380 hr/yr.
**** This represents the total of all coal cleaning cost factors at the respective operator cost levels as covered in Section 2.0 above.

CASE NUMBER: 12D

1.0 CASE CONDITIONS — Sulfur Clean-up Exclusively by Stack Gas Scrubbing

1.1 Coal Use Area: Dickerson (Montgomery County), Maryland

1.2 Emission Standards — New:
Existing: 1% Sulfur by Weight

1.3 Coal District of Origin: No. 3 — Coalbed: Pittsburgh
State: West Virginia — County: Marion

1.4 Raw Coal — Ash: 11.0%
Lb $SO_2/10^6$ Btu: 5.70 — Sulfur: 3.80% — MM Btu/Ton: 26.66*

1.5 Assumed Plant Size: 500 Mw

1.6 Remaining Life of Boiler: 15 Yr

1.7 Assumed Annual Capital Scrubber Charges as Percent of Original Investment: 17.82%

2.0 STACK GAS COST FACTORS

2.1 Boiler Capacity: 500 Mw

2.2 Utilization Factor: 5,000 Hr/Yr

2.3 Tons of Coal Burned Per Year: 937,735 Tons

2.4 Minimum Scrubber Requirements — Scrubber Rating: 410 Mw
% of Flue Gas Cleaned: 81.9%

2.5 Design Scrubber Requirements — Scrubber Rating: 472 Mw
% of Flue Gas Cleaned: 94.4%

2.6 Scrubber Capital Cost: $34,932,338

2.7 Scrubber Capital Charges/Yr: $6,224,943

2.8 Capital Contribution Per Ton of Coal: $6.64/Ton

2.9 Fuel and Electricity Cost Per Ton of Coal: $0.73/Ton

2.10 O & M Costs Per Ton of Coal

Limestone Cost: $0.72/Ton
Maintenance Labor & Material: $1.49/Ton
Fixation Chemical Cost: $0.59/Ton
Supplies Cost: $0.22/Ton
Operating Labor Cost: $0.17/Ton
Overhead Cost: $0.97/Ton

2.11 Total Cost Per Ton of Coal Burned to Meet Emission Standards: $11.53/Ton

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* This value has been adjusted for raw coal moisture content.

APPENDIX C

COST COMPONENTS AND COST ESTIMATES FOR FULL-SCALE FLUE GAS DESULFURIZATION SYSTEMS

Total costs of flue gas desulfurization (FGD) systems include both capital and annualized costs. Capital costs are direct and indirect. Direct capital costs cover plant equipment, instrumentation, piping, electrical and structural materials, site work, insulation, painting, pilings, and the associated costs of installation or application. Indirect capital costs cover, but are not limited to, interest assessed during construction; contractors' fees and expenses; engineering, freight, and off-site expenses; and taxes, allowances, and contingencies.

The annualized operating costs include both fixed and variable components. Variable costs include utilities, labor, maintenance, and in some cases overhead. Fixed costs include depreciation, interim replacement, insurance, taxes, and capital charges.

Generally, flue gas desulfurization systems can be broken down into four major areas, each of which has direct and indirect cost components. The four areas are--

- SO_2 Emission Control
- Particulate Emission Control
- Sludge Disposal
- Replacement Power

Our analysis excludes consideration of particulate emission control, since particulate emission control requirements are separate from SO_2 emission considerations. Sludge disposal, being a necessary part of SO_2 control, is necessarily included. Cost of replacement power or "capacity penalty" is also covered.

CAPITAL COST COMPONENTS

The major capital cost components of a flue gas desulfurization system consist of plant equipment, installation, site development, and indirect costs.

Plant Equipment and Installation for SO_2 Control

Installation of plant equipment requires foundations, steel work for support; buildings; piping and ducting for effluents, slurries, sludge, steam, overflows, acid, drainage, and make-up water; control panels; instrumentation; insulation of ducting, buildings, piping, and other equipment; painting; and in some instances piling. Site development includes right of way for sludge disposal; site clearing and grading; construction of access roads and walkways; establishment of rail, barge, or truck facilities and parking facilities; and landscaping and fencing.

ANNUAL OPERATING COSTS

Annual operating costs of a flue gas desulfurization system comprise--

Raw materials, including those required by the FGD process for sulfur dioxide control, system loss, and sludge fixation.

Utilities, including water for slurries, cooling and cleaning; electricity for pumps, fans, valves, lighting controls, conveyors, and mixers; fuel for reheating of flue gases; and steam for processing.

Operating labor, including the supervisory and skilled and unskilled labor required to operate, monitor, and control the FGD process.

Maintenance and repairs, consisting of both manpower and materials to keep the unit operating efficiently. The function of maintenance is both preventive and corrective to keep outages to a minimum.

Overhead, a business expense that is not charged directly to a particular part of a process, but is allocated to it. Overhead costs include administrative, safety, engineering, legal, and medical services; payroll; employee benefits; recreation; and public relations.

Fixed charges, which continue for the estimated life of the process, include costs of the following:

- Depreciation - the charge for losses in assets due to time/use deterioration and other factors, such as technical and/or regulatory changes making the physical assets obsolete.
- Interim replacement - costs expended for temporary or provisional replacement(s) of equipment that has failed or malfunctioned.
- Insurance - costs of protection from loss by a specified contingency, peril, or unforeseen event. Required coverage could include but not be limited to losses due to fire, personal injury or death, property damage, embezzlement, explosion, and lightning.
- Taxes, including franchise, excise, and property taxes levied by a city, county, State, or Federal government.
- Interest on borrowed funds (averaged over economic life).
- Return on investment (averaged over economic life).

REPLACEMENT CAPACITY AND ENERGY PENALTIES

There is both a replacement and an energy capacity penalty associated with flue gas desulfurization systems. Replacement capacity is the additional power-generating capacity required to compensate for the power used by the flue gas desulfurization system. The energy penalty is the increased number of Btu's required to produce a kilowatt-hour of electricity.

For a FGD system treating the total flue gas, approximately 1.5 to 4 percent of a plant's gross energy input is required to run a flue gas desulfurization system; an additional 1 to 2 percent may be required for particulate emission control using venturi scrubbers. In contrast (for particulate emission control), less than 0.5 percent would be required if an electrostatic precipitator was used in place of the venturi scrubber. Even so, as previously indicated, particulate emission control is not and should not be treated by this effort.

The power requirement for a full FGD system is approximately equivalent to the power required to run the boiler feed pumps and fans in the powerplant. Thus, to generate a net of 1,000 Mw, a plant must have a gross rating of approximately 1,080 Mw (allowing 40 Mw to run the plant and 40 Mw to run the FGD system).

In general, for a full FGD system, the energy consumed by the FGD system is about equally split between energy for stack gas reheat and electricity to run the process equipment (of which about half is to overcome the system pressure drop and the remainder is for operation of pumps, ball mills, and the like). The amount of energy consumed for stack gas reheat varies with the amount of reheat required and also somewhat with the type of reheat system used. Some types of reheat systems will not cause the plant to be derated in terms of kilowatt-hours of electricity produced (i.e., there will be only an energy penalty, not a capacity penalty). For example, if the plant power production is turbine limited (as opposed to boiler limited), the excess steam produced by the boiler can be used to reheat the stack gases. Similarly, if a direct-fired reheater is used, plant capacity will not be derated although the energy consumption per kilowatt-hour generated will increase in the same manner as if the unit was derated. Furthermore, many plants may operate without flue gas reheat or combine scrubbed and unscrubbed flue gases to attain desired reheat temperatures. When reheat is not required, the economics associated with FGD are enhanced.

The capital and annualized costs of flue gas desulfurization systems can vary significantly depending upon design philosophy and site-specific factors. Factors having a major cost impact are plant size, remaining life, and capacity factor; flue gas desulfurization (FGD) process and design; sulfur content and heating values of the coal; maximum allowable SO_2 emission rate; particulate control requirements (if included); and replacement power requirements.

To present unencumbered cost estimates and illustrate the impact of site and process factors on total installed and annualized costs of limestone FGD systems, model plants were defined by Reference 13 and cost estimates prepared for each (Table C-1). The 12 model plants analyzed for FGD costs were selected to incorporate varying cost factors (i.e., plant size, installation status, and degree of SO_2 control required). Boiler capacities of 250 Mw, 500 Mw, and 1,000 Mw were selected to cover a range representative of U.S. powerplant boilers. Both new and existing FGD systems applications were considered for each boiler size. Also, each plant size was analyzed for two SO_2 limitations; one of 1.2 lb/10^6 Btu (Federal New Source Performance Standard) using high-sulfur coal (3.5 percent), and the other of 0.15 lb/10^6 Btu using low-sulfur coal (0.6 percent).

TABLE C-1

LIMESTONE MODEL PLANTS CAPITAL COSTS

Model Plant Characteristics	Scrubbing[a] $/KW	Sludge Disposal[b] $/KW	Indirect Costs[c] $/KW	Total $/KW	Total $ MM
250-Mw Capacity					
Retrofit, 3.5% S	40	6	35	81	20.2
New, 3.5% S	30	8	28	66	16.5
Retrofit, 0.6% S	38	4	32	74	18.6
New, 0.6% S	29	5	25	59	14.7
500-Mw Capacity					
Retrofit, 3.5% S	35	5	30	70	35.1
New, 3.5% S	28	5	25	58	29.2
Retrofit, 0.6% S	34	3	28	65	32.3
New, 0.6% S	27	3	23	53	26.4
1,000-Mw Capacity					
Retrofit, 3.5% S	36	4	30	70	69.5
New, 3.5% S	29	4	24	57	56.8
Retrofit, 0.6% S	34	2	28	64	64.4
New, 0.6% S	28	2	22	52	52.0

[a] Includes limestone preparation system (conveyors, storage silo, ball mills, pumps, motors, and storage tank) and scrubbing system (absorbers, fans and motors, pumps and motors, tanks, reheaters, soot blowers, ducting, and valves).

[b] Sludge disposal costs do not include associated indirect charges.

[c] Includes interest during construction, field labor and expenses, contractor's fees and expenses, engineering, freight, spares, taxes, contingency, and allowance for shakedown.

Other variables such as remaining plant life and plant capacity factor were selected to be representative of each model plant. Operating costs for such components as raw materials and utilities, which vary with geographical location, were selected to be representative of a Midwest location.

Factors Affecting Capital Cost

Capital costs can be substantially modified by varying SO_2 removal requirements and flue gas rates, difficulty of retrofit, conditions of terrain and subsurface, system redundancy, remaining boiler plant life, cost escalation, effluent disposal requirements, etc. The impact of these factors on capital costs is discussed, and Table C-2 provides a summary of capital cost variations for site specific conditions.

Flue Gas Flow Rate

Flue gas flow rate varies primarily with boiler design, including such factors as operating temperature and exit gas temperature, percent excess air, and efficiency; coal characteristics, including ash, sulfur and moisture contents, and heating value; and size and age of the boiler. The flow rate directly affects the size of the required FGD system.

Installation Status (new and retrofit applications)

Higher capital costs are often required for application of FGD systems to existing plants than for application to similar new plants. Unlike a new plant, a retrofit application requires that the system be adapted to the rigid configurations of the existing plant. The retrofit system must be built within fixed space limitations and in a manner that does not interfere with operation of the plant. This often results in unusual and awkward configurations.

Other capital cost components that can be increased because of space restrictions are construction labor and expenses, interest charges during construction (because of longer construction periods), contractor fees and expenses, and allowances for shakedown.

Condition of Terrain and Subsurface

The terrain of the powerplant site affects the capital cost of the FGD system as well as the cost of the entire powerplant due to the site work and structural requirements it imposes. Hilly terrain requires considerable grading and filling to prepare the site for construction of foundations and possible additional structural components. Subsoil characteristics in many cases necessitate substantial additional foundation work with related costs.

Sludge Disposal Options (nonregenerative processes)

The amount of sludge generated by a given plant is a function of the sulfur and ash contents of the coal, coal usage, load factor, mole ratio of additive, SO_2 removal efficiency, composition of the sludge, and moisture content of the sludge. Several methods are now used for disposal of scrubber sludge. The most common are ponding of untreated sludge and landfilling of treated and untreated sludge.

TABLE C-2

TYPICAL CAPITAL COST VARIATIONS
FOR SITE SPECIFIC CONDITIONS*

Factor	Typical Total Capital Cost Impact
SO_x removal requirements	15% to 20%
Flue gas flow rate	10% to 30%
Installation status (new vs. retrofit)	10% to 40%
Conditions of terrain and subsurface	3% to 15%
FGD system redundancy	10% to 40%
Particulate control requirements	25% to 35%
Sludge disposal requirements (nonregenerative processes)	10% to 30%

* Variations in capital cost for 250 to 1,000-Mw model plants.

Remaining Life of Plant and Related Capacity Factor

Boiler life is generally estimated to be about 30 years. Capacity factor is defined as the ratio of the average load for the period of time considered (usually 1 year) to the capacity rating of the plant.

In general, capacity factor of a powerplant decreases with age owing to increased maintenance burdens of the older plant as compared to newer boilers.

Escalation

Installation of an FGD system from initial design through construction and subsequent acceptance tests requires approximately 3 years. Price escalation during this period directly affects the total capital cost of the project. Cost estimates generally consider projected increases.

Factors Affecting Operating Costs

Operating costs are directly affected by the costs of raw materials, utilities, and operating labor. Cost of raw materials contribute 3 to 15 percent of the total operating costs for limestone systems and depend primarily on the quantity of SO_2 to be removed. Costs of utilities contribute 5 to 10 percent of the annual operating costs (i.e., for limestone systems). Utility costs depend primarily on the cost of electricity, amount of SO_2 to be removed, and the process water and horsepower requirement. Operating labor contributes 1 to 5 percent of the total operating costs and depends primarily on the size of the system.

Other operating costs covering maintenance, overhead, and fixed costs are basically dependent on the fixed investment of the FGD system and the costs for operating labor and raw materials. Depreciation, a fixed cost, varies with the life of the FGD system.

The following factors also affect operating costs:

SO_2 Removal Requirements

The amount of SO_2 to be removed affects operating costs appreciably, since it is the major factor that affects the cost of raw materials and utilities. In addition, since capital costs are also affected by SO_2 removal requirements, this impact is reflected in the fixed charges.

Two member companies of Industrial Gas Cleaning Institute provided estimates of limestone flue gas desulfurization costs. Table C-3 provides a summary of these estimates.

As indicated by a comparison of Tables C-1 and C-3, the manufacturers' capital cost estimates for new plants are slightly lower than the 12 model plant estimates developed in reference 13.

TABLE C-3

SUMMARY OF MANUFACTURER ESTIMATES OF LIMESTONE FGD SYSTEM COSTS

Model Plant Characteristics	Range of Capital Costs $/KW	Annualized Costs mills/KWH
250-Mw Capacity		
Retrofit, 3.5% S	61 - 78	4.30
New, 3.5% S	56 - 74	4.27
Retrofit, 0.6% S	55 - 58	3.33
New, 0.6% S	50 - 57	3.41
500-Mw Capacity		
Retrofit, 3.5% S	55 - 68	3.66
New, 3.5% S	49 - 68	3.76
Retrofit, 0.6% S	49 - 51	2.80
New, 0.6% S	43 - 51	2.91
1,000-Mw Capacity		
Retrofit, 3.5% S	48 - 66	3.47
New, 3.5% S	43 - 62	3.37
Retrofit, 0.6% S	42 - 48	2.88
New, 0.6% S	37 - 48	2.67

APPENDIX D

AMORTIZATION PAYMENT DATA

This appendix indicates cleaning plant self-liquidating - yearly mortgage payments per ton-hour plant input capacity. These values are provided for various plant costs and unpaid balance interest rates.

TABLE D-1

SELF-LIQUIDATING MORTGAGE PAYMENT (IN DOLLARS) PER $1,000 OF LOAN YEARLY COST--BASED ON EQUAL MONTHLY PAYMENTS

Interest Rate	7%	8%	8-1/2%	9%	9-1/2%	10%
Loan Period Years						
8	163.69	169.72	172.78	175.88	179.00	182.16
10	139.41	145.67	148.86	152.08	155.35	158.65
12	123.48	129.97	133.28	136.63	140.03	143.48
15	107.93	114.75	118.23	121.78	125.37	129.02
20	93.10	100.44	104.20	108.03	111.92	115.87

TABLE D-2

SELF-LIQUIDATING YEARLY MORTGAGE PAYMENT (IN DOLLARS) PER TON-HOUR PLANT INPUT CAPACITY. PAYMENTS BASED ON PLANT COST OF $15,000 PER TON-HOUR INPUT CAPACITY AND EQUAL MONTHLY PAYMENTS

Interest Rate	7%	8%	8-1/2%	9%	9-1/2%	10%
Loan Period Years						
8	2455.35	2545.80	2591.70	2638.20	2685.00	2732.40
10	2091.15	2185.05	2232.90	2281.20	2330.25	2379.75
12	1852.20	1949.55	1999.20	2049.45	2100.45	2152.20
15	1618.95	1721.25	1773.45	1826.70	1880.55	1935.30
20	1396.50	1506.60	1563.00	1620.45	1678.80	1738.05

TABLE D-3

SELF-LIQUIDATING YEARLY MORTGAGE PAYMENT (IN DOLLARS) PER TON-HOUR PLANT INPUT CAPACITY. PAYMENTS BASED ON PLANT COST OF $16,000 PER TON-HOUR INPUT CAPACITY AND EQUAL MONTHLY PAYMENTS

Interest Rate	7%	8%	8-1/2%	9%	9-1/2%	10%
Loan Period Years						
8	2619.04	2715.52	2764.48	2814.08	2864.00	2914.56
10	2230.56	2330.72	2381.76	2433.28	2485.60	2538.40
12	1975.68	2079.52	2132.48	2186.08	2240.48	2295.68
15	1726.88	1836.00	1891.68	1948.48	2005.92	2064.32
20	1489.60	1607.04	1667.20	1728.48	1790.72	1853.92

TABLE D-4

SELF-LIQUIDATING YEARLY MORTGAGE PAYMENT (IN DOLLARS) PER TON-HOUR PLANT INPUT CAPACITY. PAYMENTS BASED ON PLANT COST OF $17,000 PER TON-HOUR INPUT CAPACITY AND EQUAL MONTHLY PAYMENTS

Interest Rate	7%	8%	8-1/2%	9%	9-1/2%	10%
Loan Period Years						
8	2782.73	2885.24	2937.26	2989.96	3043.00	3096.72
10	2369.97	2476.39	2530.62	2585.36	2640.95	2697.05
12	2099.16	2209.49	2265.76	2322.71	2380.51	2439.16
15	1834.81	1950.75	2009.91	2070.26	2131.29	2193.34
20	1582.70	1707.48	1771.40	1836.51	1902.64	1969.79

TABLE D-5

SELF-LIQUIDATING YEARLY MORTGAGE PAYMENT (IN DOLLARS) PER TON-HOUR PLANT INPUT CAPACITY. PAYMENTS BASED ON PLANT COST OF $18,000 PER TON-HOUR INPUT CAPACITY AND EQUAL MONTHLY PAYMENTS

Interest Rate	7%	8%	8-1/2%	9%	9-1/2%	10%
Loan Period Years						
8	2946.42	3054.96	3110.04	3165.84	3222.00	3278.88
10	2509.38	2622.06	2679.48	2737.44	2796.30	2855.70
12	2222.64	2339.46	2399.04	2459.34	2520.54	2582.64
15	1942.74	2065.50	2128.14	2192.04	2256.66	2322.36
20	1675.80	1807.92	1875.60	1949.40	2014.56	2085.66

APPENDIX E

COAL CLEANING PLANT OPERATION AND MAINTENANCE COST ESTIMATES

Information contained in the 1965 Paul Weir study was examined as a basis for developing current O & M cleaning plant costs attributable to 1 ton of cleaned coal. As indicated in the main body of this report, current anticipated O & M costs for various plant yields were derived from available 1965 data. The projections from the 1965 data follow.

These projections were checked against very recent (late 1975) O & M cleaning cost information obtained from a firm that designs, constructs, and operates coal cleaning plants. Three O & M values were obtained. One was an actual current value, and two are current estimated values for not-yet-operating plants. The obtained information relates to cleaning plants of the same general complexity as that necessary to clean the considered coals. As indicated, in the range of considered yields (80 percent), the assumed cleaning costs are higher than the recent industry value. Even so, it must be recognized that due to many factors, in actual practice there will be a spread in cleaning cost. This is due to variations in management concept, individual plant design, maintenance philosophy, refuse disposal requirements, and other factors.

Figure E-1 (also in main body of report) indicates the anticipated O & M costs for plants of the variety believed required to clean the more readily cleanable coals. The three industry-supplied values are also indicated. The indicated maximum deviations (Δ's) are the maximum anticipated O & M cost variations that may arise due to variations in plant characteristics and management concepts.

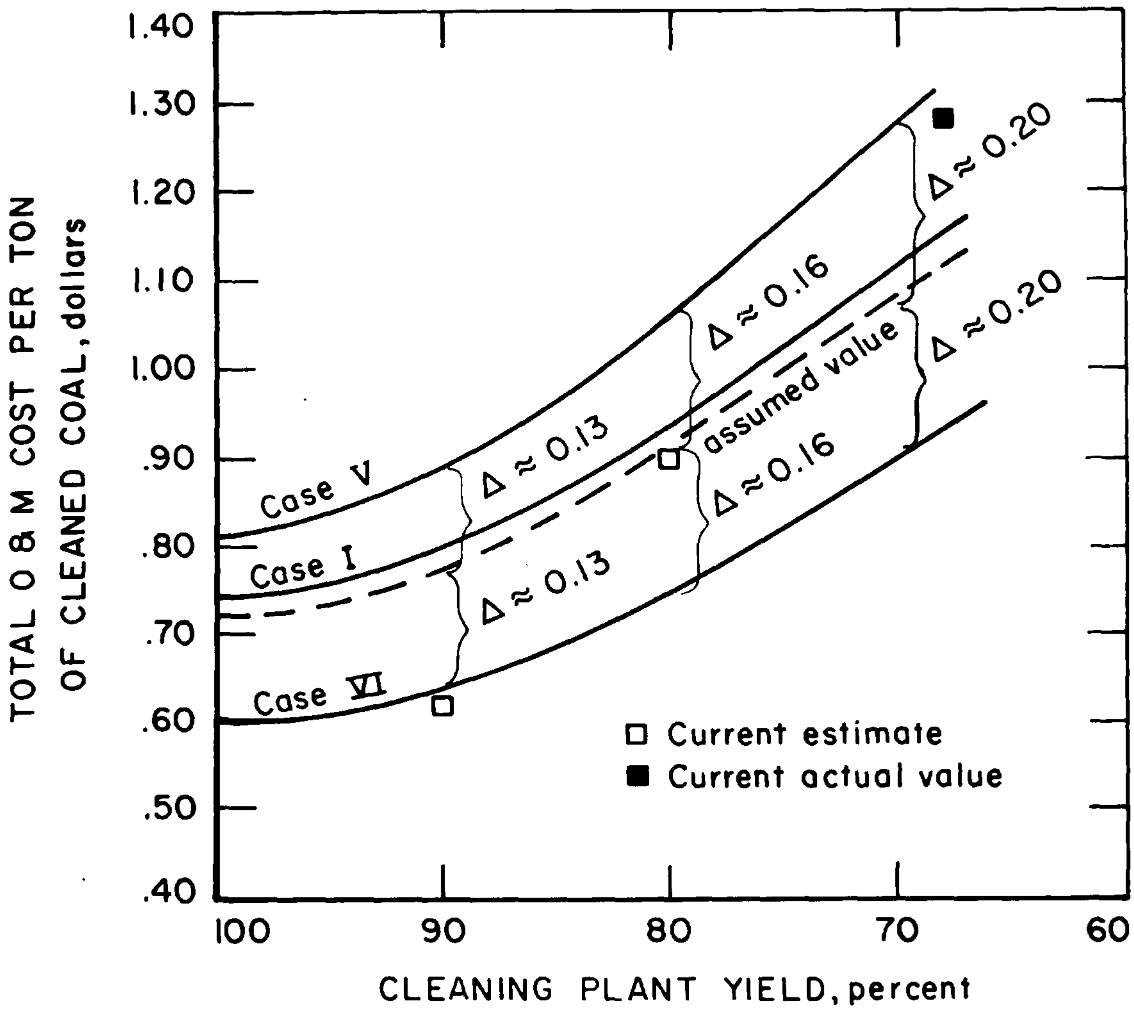

Figure E-1—Operation and maintenance cost.

CASE I

MINE - ILLINOIS NO. 6 BED, FRANKLIN COUNTY, ILL.
(Cost estimates based on available data)

Plant cost	$2,560,000
Plant Capacity	700 tons per hour raw coal feed
Date Constructed	1960 (completed)
Plant Type	Heavy media process for coarse coal, Deister tables for fine sizes, and thermal dryers
Original Plant Cost Per Ton-Hour Input Capacity	$3,660

<u>1965 O & M Cost</u>

If coal is washed to produce 90% yield

Plant O & M cost (less refuse handling)	$0.344/ton
Refuse handling	0.025/ton
Total	$0.369/ton

If coal is washed to produce 80% yield

Plant O & M cost (less refuse handling) (=0.344 x 0.90/0.80)	$0.387/ton
Refuse handling (=0.025 x 2)	0.050/ton
Total	$0.437/ton

If coal is washed to produce 70% yield

Plant O & M cost (less refuse handling) (=0.344 x 0.90/0.70)	$0.442/ton
Refuse handling (=0.025 x 3)	0.075/ton
Total	$0.517/ton

<u>December 1975 O & M Cost</u>
(Based on December 1975 hourly earnings as compared to 1965 hourly earnings. Source; U.S. Bureau of Labor Statistics)

At 90% yield = 0.369 x 7.51/3.49 = $0.794/ton
At 80% yield = 0.437 x 7.51/3.49 = $0.940/ton
At 70% yield = 0.517 x 7.51/3.49 = $1.11/ton

CASE II

MINE - ILLINOIS NO. 6 BED, MONTGOMERY COUNTY, ILL.
(Cost estimates based on available data)

Plant Cost	$2,200,000
Plant Capacity	800 tons per hour raw coal feed
Date Constructed	Not known - older plant
Plant Type	Uses a combination of wet washing and air tables for cleaning. Plant is not capable of cleaning coal at densities lower than 1.60.
Original Plant Cost Per Ton-Hour Input Capacity	$2,750

1965 O & M Cost

If coal is washed to produce 90% yield

Plant O & M cost (less refuse handling)	$0.272
Refuse handling	0.017
Total	$0.289/ton

If coal is washed to produce 80% yield

Plant O & M cost (less refuse handling)	$0.306
Refuse handling	0.035
Total	$0.341/ton

Due to equipment type, this plant is not capable of cleaning at lower densities; for the characteristics of coal processed, 80% yield appears to be the cleaning limit.

December 1975 O & M Cost
(Based on December 1975 hourly earnings as compared to 1965 hourly earnings. Source: U.S. Bureau of Labor Statistics)

At 90% yield = 0.289 x 7.51/3.49 = $0.622/ton
At 80% yield = 0.341 x 7.51/3.49 = $0.734/ton

CASE III

MINE - ILLINOIS NO. 5 BED, FULTON COUNTY, ILL.
(Cost estimates based on available data)

Plant Cost	$2,700,000
Plant Capacity	800 tons per hour raw coal feed
Date Constructed	Not known
Plant Type	Basically Baum jigs for cleaning. Contains two jigs for 6 inch x 0, one for 2 inch x 0, and a middling jig. The 1/4 inch x 0 is rewashed in a Rheolavour launder system. The 3/4 x 1/8 inch product is heat-dried.
Original Plant Cost Per Ton-Hour Input Capacity	$3,380

1965 O & M Cost

If coal is washed to produce 90% yield

Plant O & M cost (less refuse handling)	$0.222/ton
Refuse handling	0.017/ton
Total	$0.239/ton

If coal is washed to produce 80% yield

Plant O & M cost (less refuse handling)	$0.250/ton
Refuse handling	0.034/ton
Total	$0.284/ton

If coal is washed to produce 70% yield

Plant O & M cost (less refuse handling)	$0.285/ton
Refuse handling	0.051/ton
Total	$0.336/ton

December 1975 O & M Cost
(Based on December 1975 hourly earnings as compared to 1965 hourly earnings. Source: U.S. Bureau of Labor Statistics)

At 90% yield = 0.239 x 7.51/3.49 = $0.514/ton
At 80% yield = 0.284 x 7.51/3.49 = $0.611/ton
At 70% yield = 0.336 x 7.51/3.49 = $0.723/ton

CASE IV

MINE - WEST KENTUCKY NO. 9 BED, UNION COUNTY, KY.
(Cost estimates based on available data)

Plant Cost	$1,850,000
Plant Capacity	1,000 tons per hour raw coal feed
Date Constructed	Not known
Plant Type	Basically consists of two parallel Baum-type jigs, and a smaller piston-type jig for cleaning 28 mesh x 0. No heat dryers.
Original Plant Cost Per Ton-Hour Input Capacity	$1,850

1965 O & M Cost

If coal is washed to produce 90% yield

Plant O & M cost (less refuse handling)	$0.152/ton
Refuse handling	0.033/ton
Total	$0.185/ton

If coal is washed to produce 80% yield

Plant O & M cost (less refuse handling)	$0.171/ton
Refuse handling	0.066/ton
Total	$0.237/ton

If coal is washed to produce 70% yield

Plant O & M cost (less refuse handling)	$0.195/ton
Refuse handling	0.100/ton
Total	$0.295/ton

December 1975 O & M Cost
(Based on December 1975 hourly earnings as compared to 1965 hourly earnings. Source: U.S. Bureau of Labor Statistics)

At 90% yield = 0.185 x 7.51/3.49 = $0.398/ton
At 80% yield = 0.237 x 7.51/3.49 = $0.510/ton
At 70% yield = 0.295 x 7.51/3.49 = $0.635/ton

CASE V

MINE - PITTSBURGH BED, GREENE COUNTY, PA.
(Cost estimates based on available data)

Plant Cost	\$3,500,000
Plant Capacity	500 tons per hour raw coal feed
Date Constructed	Completed 1964 or 1965
Plant Type	Employs separator screens, sink and float screens, flotation cells, Deister tables, magnetite separators, and heat dryers.
Original Plant Cost Per Ton-Hour Input capacity	\$7,000

1965 O & M Cost

If coal is washed to produce 90% yield

Plant O & M cost (less refuse handling)	\$0.380/ton
Refuse handling	0.035/ton
Total	\$0.415/ton

If coal is washed to produce 80% yield

Plant O & M cost (less refuse handling)	\$0.428/ton
Refuse handling	0.070/ton
Total	\$0.498/ton

If coal is washed to produce 70% yield

Plant O & M cost (less refuse handling)	\$0.488/ton
Refuse handling	0.105/ton
Total	\$0.593/ton

December 1975 O & M Cost
(Based on December 1975 hourly earnings as compared to 1965 hourly earnings. Source: U.S. Bureau of Labor Statistics)

At 90% yield = 0.415 x 7.51/3.49 = \$0.893/ton
At 80% yield = 0.498 x 7.51/3.49 = \$1.072/ton
At 70% yield = 0.593 x 7.51/3.49 = \$1.276/ton

CASE VI

MINE - OHIO NO. 8 BED, HARRISON AND BELMONT COUNTIES, OHIO
(Cost estimates based on available data)

Plant Cost	$7,500,000
Plant Capacity	1,500 tons per hour raw coal feed
Date Constructed	Not known
Plant Type	Essentially consists of Baum-type jigs, Chance dense media cones, Deister tables, and heat dryers.
Original Plant Cost Per Ton-Hour Input Capacity	$5,000

1965 O & M Cost

If coal is washed to produce 90% yield

Plant O & M cost (less refuse handling)	$0.277/ton
Refuse handling	0.018/ton
Total	$0.295/ton

If coal is washed to produce 80% yield

Plant O & M cost (less refuse handling)	$0.311/ton
Refuse handling	0.036/ton
Total	$0.347/ton

If coal is washed to produce 70% yield

Plant O & M cost (less refuse handling)	$0.356/ton
Refuse handling	0.054/ton
Total	$0.410/ton

December 1975 O & M Cost
(Based on December 1975 hourly earnings as compared to 1965 hourly earnings. Source: U.S. Bureau of Labor Statistics)

At 90% yield = 0.295 x 7.51/3.49 = $0.635/ton
At 80% yield = 0.347 x 7.51/3.49 = $0.747/ton
At 70% yield = 0.410 x 7.51/3.49 = $0.882/ton

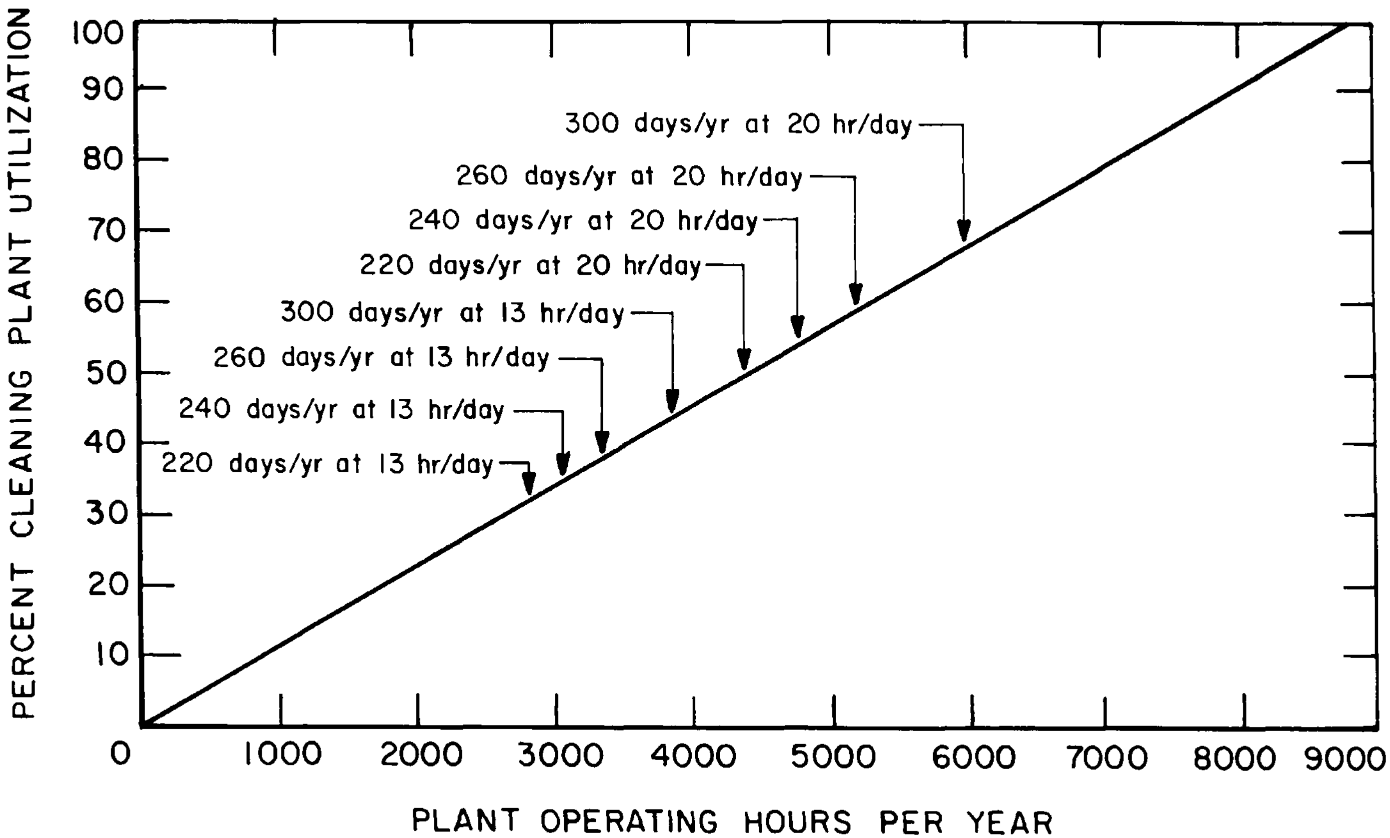

Figure F-1—Cleaning plant utilization.

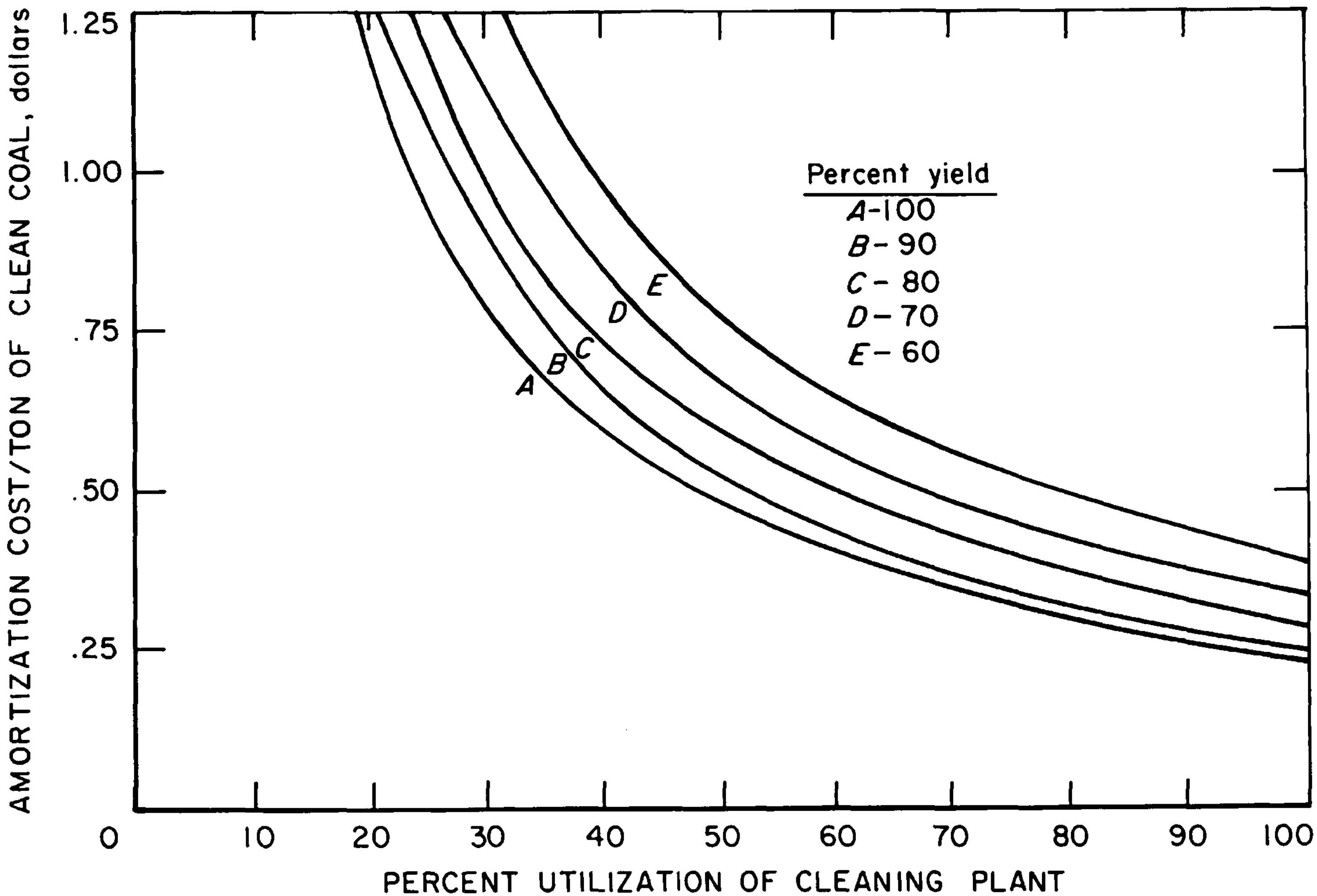

Figure F-2–Amortization cost/ton cleaned coal for: plant cost–$18,000 per ton-hour input capacity, interest rate–8%, loan period 15 years.

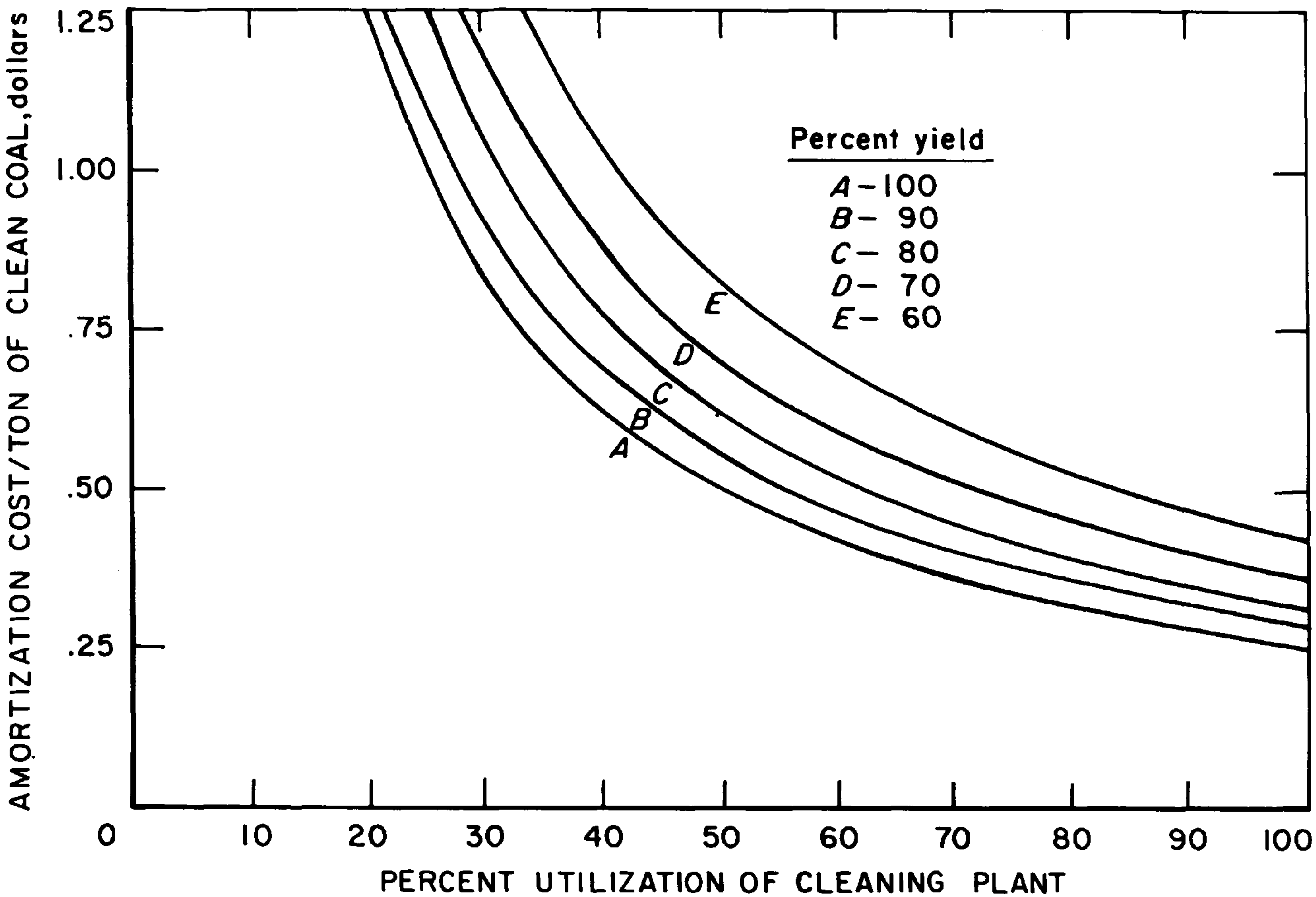

Figure F-3–Amortization cost/ton cleaned coal for: plant cost–$18,000 per ton-hour input capacity, interest rate–9%, loan period 15 years.

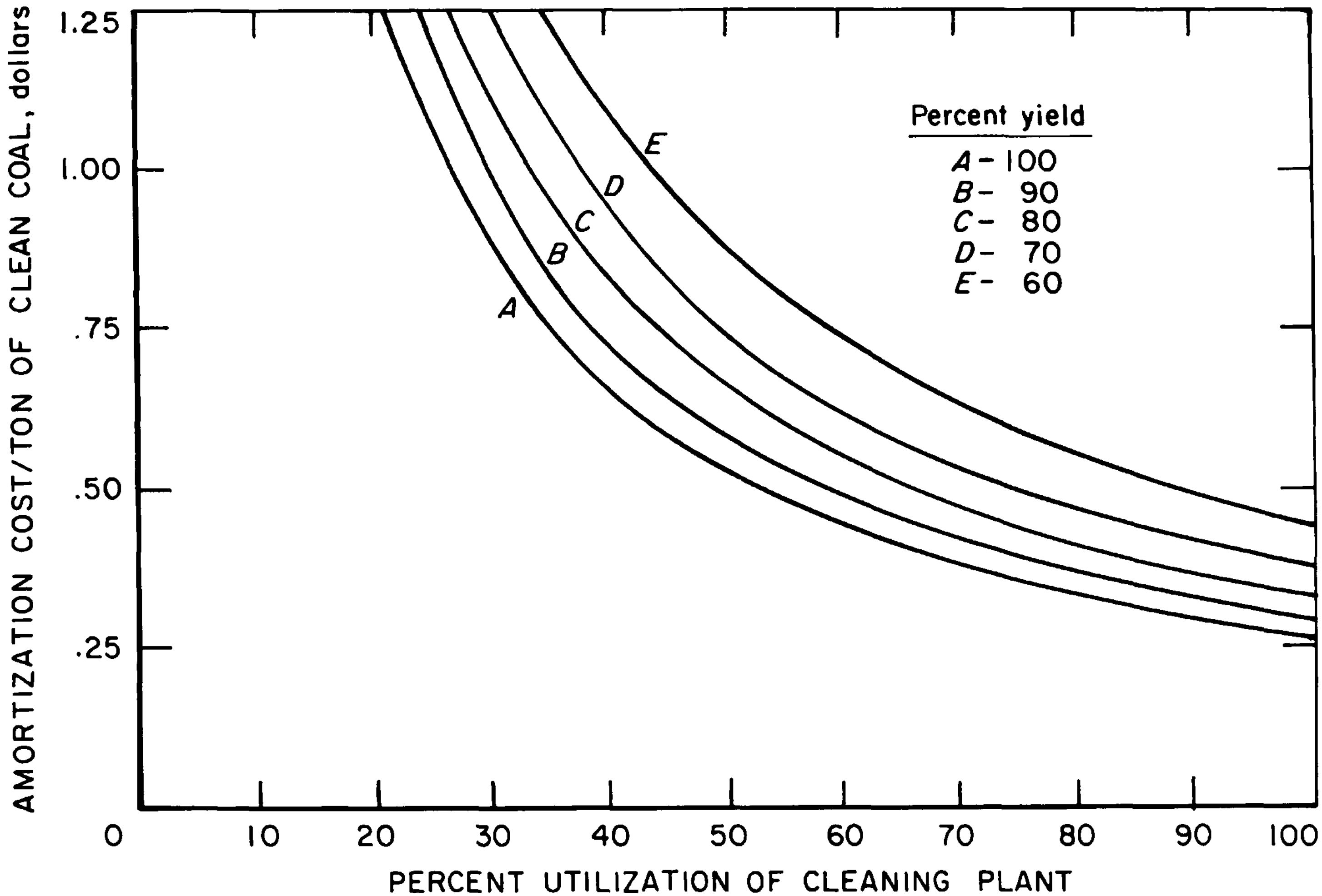

Figure F-4–Amortization cost/ton cleaned coal for: plant cost-$18,000 per ton-hour input capacity, interest rate-10%, loan period 15 years.

APPENDIX G

TRANSPORTATION OF COAL

Importance of Transportation Costs

Because of its bulk, the cost of transporting coal has historically been an important part of the total cost to the consumer. However, this relationship has not remained constant and today rail transportation costs are of declining importance in the marketing of coal. In 1932 rail rates amounted to 63.3 percent of the destination value of bituminous coal. By 1973 rail rates had declined to 30.4 percent of the destination value. This decline in the component of cost associated with transportation has tended to lessen the importance of location in competition between coal-producing regions. The most important competitive factor in the utilities market is the final price per Btu. This price may vary greatly depending not only on the amount of transportation required but also upon the production methods used, the type of coal produced, and the type and amount of labor used.

Movement of Bituminous Coal From the Mines

Water -

At present, water carriers transport about 11 percent of coal traffic. A single tow of 20 barges can carry 20,000 to 30,000 tons of coal. Coal is a major item of traffic along the Ohio River and its tributaries. Coal also moves down the Mississippi River, and large tonnages are transferred near the river mouth to ocean-going barges which cross the Gulf of Mexico to powerplants in Florida. Barge lines are also linked to rail loading points in an efficient, integrated transportation network, so that coal which moves part way to market by water may move to its ultimate destination by rail. More than 100 million tons of coal in the United States presently move each year over rivers. The Great Lakes are another waterway for coal. Lake Erie ports like Toledo and Sandusky receive coal, mostly by rail, and load it into freighters for consumers in Canada or for U.S. destinations on the upper lakes, such as Duluth, Minnesota. At Norfolk and Newport News, Virginia, supercolliers built especially for this trade take on as much as 100,000 tons of coal in a matter of hours for delivery to destinations as distant as Japan.

Truck -

Trucks also carry millions of tons of coal - about 11 percent of all coal is transported over public highways. Trucks are the prime method of moving coal from strip mines to preparation plants, rail, or water loading points, or mine-mouth electric generating stations. Some off-highway motor vehicles with power units at each end carry 240 tons of coal.

Conveyor Belt -

Conveyor belts deliver coal for distances as much as 10 miles. One system in operation in western Kentucky is designed to carry about 140,000 tons of coal a week from mines to a barge loading dock on the Ohio River. River tows take the coal to a powerplant.

Pipeline -

The transportation of coal by pipeline is in slurry form. This consists of a mixture of water and finely ground coal. At present there is only one coal slurry pipeline operating in the United States. This pipeline is 275 miles long and is the longest coal slurry pipeline in the world. It connects the Black Mesa, Arizona, coalfields with a thermal powerplant on the Colorado River in Nevada. Much longer coal slurry pipelines are being considered in the Western United States. Currently, there are proposals to build pipelines from Montana to the Great Lakes and from Wyoming to Arkansas. However, these longer pipelines are receiving much objection from the railroads, which feel it would injure their revenue base, and from conservationists and environmentalists.

The alternative to delivering coal to market is mine-mouth powerplants. A cluster of these generating plants in western Pennsylvania sends power to markets as distant as New York City, using 500,000-volt lines. Other mine-mouth powerplants in West Virginia, Kentucky, Ohio, and other States use coal from nearby mines to generate power for distant markets. In the West, where coal reserves are rich but remote from electrical load centers, high-voltage lines send coal-generated electricity from the Four Corners area of New Mexico to consumers in southern California.

Rail -

The great preponderance of coal - over 60 percent - moves by rail. The railroads derive more revenue from it than any other commodity - over $1.2 billion annually, or about 10 percent of their total freight revenue. The hauling of bituminous coal has long been the single most important commodity for Eastern railroads. During 1974, the Penn Central railroad alone handled 73.4 million tons of coal which constituted 27 percent of its overall freight volume, bringing in $240 million in gross revenues. On a nationwide basis, the railroads carried 391 million tons of coal, which accounted for 13.6 percent of all rail freight tonnage. Over 20 percent of all coal mined moves in unit trains.

Types of Rail Freight Rates on Bituminous Coal

Bituminous coal is rated class 17-1/2 in the governing Uniform ICC Freight Classification. However, extremely little, if any, coal moves at class rates, although at some shipping points class rates are the only rates available. For example, effective June 28, 1974, a unit-train rate applicable on bituminous coal over the lines of the Kansas City Southern Railway Company from Heavener, Oklahoma, to Steeltown, Texas, was canceled. The cancellation notice provided that class rates would apply.

There are numerous types of commodity rates applying on bituminous coal. Those that are necessary for understanding the freight rate structure follow:

Single-car rates, multiple-car rates, trainload rates, and unit-train rates are those based essentially on the number of cars used. In many instances the rates are not listed as single-car, multiple-car, trainload, or unit-train rates, and the terminology is not always uniformly defined by carriers and shippers. A single-car rate is one that is published based on tonnage requiring the use of one car only. This tonnage is usually 100 tons or less, and is frequently based on the marked capacity of the car. Multiple-car rates are rates based on a sufficient tonnage to require the use of two or more cars, moving from one point of origin to one point of destination at one time. A multiple-car rate differs from a trainload rate in that the required tonnage is less than the amount necessary to make up an entire trainload as hereafter defined. A frequently maintained condition for multiple-car rates is 1,500 tons. A trainload rate is a rate that is published based on a sufficient tonnage to make up an entire train, usually 5,000 tons or more. The railroad equipment is usually furnished by the carrier and the movement does not have a predetermined continuously scheduled cycle. A unit-train rate is one that is published to apply on traffic moving in a sufficient set number of railroad cars and a given number of motive units dedicated to one unit between one point of loading and one point of unloading and moving in continuously scheduled cycles. The cars may or may not be permanently coupled. The equipment and motive power are not taken out of the movement, and in a number of instances the cars are shipper-owned.

Annual volume and conditional rates are those based primarily on the stipulation of the movement of a stated tonnage over a specific time period. A frequent annual-volume requirement is that 1 million tons of bituminous coal be tendered during one calendar year. There are single-car annual-volume rates, multiple-car annual-volume rates, trainload annual-volume rates, and unit-train annual-volume rates, depending upon the conditions of the published tariff.

There are certain types of rates based substantially on geographic considerations. These include concentration rates, gathering rates, tidewater rates, export rates, river rates, lake-cargo rates, and refund rates. Concentration rates are rates in connection with which it is provided that coal may originate at various separate mines, concentrated by the customer at one specific common point, thus permitting the movement of the cars beyond the concentration point in blocks so that from the place of concentration to the final destination the movement is multiple-car, trainload, or unit-train service. Gathering rates are rates from mines or stations to a concentration point such as Appalachia, Virginia, for rail movement beyond in multiple-car, trainload, or unit-train service. Tidewater rates normally refer to rates applying on coal moved by rail from the Appalachian fields to the ports of New York, Philadelphia, Baltimore, and Hampton Roads, for movement beyond by water to destinations in the United States. At times the coal movements destined to Baltimore and Hampton Roads for export are referred to as "tidewater coal" or "tidewater movements." This coal moves at export rates. An export rate is one specially established for application on export traffic. River rates are those that are published on traffic having a prior or subsequent movement via barge. Lake-cargo rates are those that are published on traffic having a prior or subsequent movement over one or more of the Great Lakes. Under certain conditions, a refund is provided in the tariffs after traffic has moved from the lake ports and the specified conditions are met. In some instances, rates applicable to a specific movement may consist of more than one of these types of rates.

It is expected that by 1980 more than 85 percent of the domestic coal traffic will move under annual-volume, concentration, trainload, or unit-train concepts. Discussions of these rates follow.

The Annual-Volume and Concentration Rate Concepts

Annual volume rates have been used mainly as a competitive tool of the carriers in their efforts to thwart the use of alternative energy sources, such as natural gas, and the use of other forms of coal or energy transport, such as slurry pipelines or high-voltage wires. Also, the annual-volume concept has sometimes been coupled with other transportation conditions designed to achieve economies in coal handling. In this way, the carriers have attempted to offset, to the extent possible, the effect of revenue losses from downward adjustments necessitated by competition.

Although the cost of large equipment exceeds that of smaller cars, there are savings in transportation effort flowing from the use of large cars. The principle involved is clear when assuming 100 tons of coal is being carried in one 100-ton car versus two 50-ton cars. The handling of one carload is saved, and the car miles are cut in half. Because the tare weight of a 100-ton car is less than that of two 50-ton cars, the amount of deadweight per ton of coal carried is reduced.

In addition to annual-volume provisions, the railroads have established rates substantially lower than their single-car rates when the customer concentrates shipments at a common point. This permits the movement of the cars beyond the concentration point in blocks, so that from the place of concentration to the final destination the movement is multiple-car, trainload, or unit-train service.

A relatively new concept in the distribution of coal by railroad in unit trains was put into operation in September 1966. One of the problems that develops in the inauguration of unit trains comes about by virtue of the fact that coal often originates at many small mines, no single one of which can produce and load out a trainload in one day. A past solution to this problem has been to store coal in large piles from which trainloads can be originated. But, coal does deteriorate to some extent when stored in the open. The loss of coal resulting from open-air storage has been found to make the construction of closed storage silos economically feasible.

The concept is that coal from small-volume mines can be brought to the transloader in a gathering operation, making use of small hoppers and gondolas. The small equipment can be economically operated in a short-haul gathering function, whereas it is largely obsolete for long-haul transportation of volume movements. The cars feed the transloader silos. The silos in turn feed the unit train.

There is a definite difference between trainload and unit-train service. Although these terms are often loosely used to describe any trainload shipment of coal, the services involved are completely different. Some railroads operate trainloads, using ordinary equipment in single moves at random times without reference to any scheduled operation. This type of service should be called trainload, and the applicable rates referred to as trainload rates.

On the other hand, unit trains involve a shuttle service concept with the train operating on a predetermined schedule and in assigned equipment. Specifically, a unit train is a management technique that permits efficient planning through long-range contractual commitment of producer and consumer and dedication of the equipment. A unit train consists of a dedicated set of haulage equipment loaded at one origin, unloaded at one destination each trip, and moving in both directions on a predetermined schedule. Although the origin and destination are not necessarily the same for each trip, the shipment is never split for any trip.

In terms of the tariff, or freight rate, a unit train is not a unit train until so designated by the carrier. Thus, the success of a unit train depends on cooperation between shipper, carrier, and consumer. In fixing tariff rates, the lowest cost usually is realized when a unit train is limited to a single-line haul. When more than one carrier is involved, additional capital cost and additional operating costs are reflected in the tariff rates. The tariff rates specify the haulage cost to the consumer on a net ton basis. Three parties--the railroad, the producer, and the consumer--must negotiate the conditions and the rates (coal and transport) for unit-train service.[16]

Bureau of Labor Statistics Index For The Transportation of Coal By Rail

The Bureau of Labor Statistics (BLS) has developed a new set of price indexes for transportation of railroad freight. The new index is designed to measure changes in prices of shipping goods by rail in the United States. It reflects the price changes for all railroad shipments.

The index is intended to measure "pure" price change between two periods of time; that is, to measure price changes not influenced by changes in quantity, shipping terms, type of service, product mix, or other factors. Therefore, identical shipments of commodities are used in the periods compared. For this purpose, the shipments included in the index are defined by precise specifications which incorporate the principal price-determining factors such as type of commodity, origin, destination, quantity, routing, service provided, and type of rail car. Thus, the prices used in the index conform with the concept of the railroad's price for shipping a fixed set of commodities under specified conditions. The prices used to calculate the index are the rates in effect on the 15th of each month for identical shipments of commodities.

The railroads are required by law to establish rates that are just and reasonable, publish them, and adhere to them. These rates, and changes in them, covering both interstate and intrastate shipments, are published by the railroads in schedules referred to as tariffs. The regulations governing the publication of interstate rail freight tariffs are prescribed by the Interstate Commerce Commission. There are approximately 45,000 tariffs in current use, containing millions of rates. Each month the tariff, applicable increase tariffs, and supplements are checked by the BLS for each shipment to determine the applicable rate as of the 15th of that month. This procedure was adopted to minimize the railroads' burden of reporting specific rates each month and to simplify quality control.

The detailed information necessary to select a sample of shipments to be priced is available on railroad waybills. A waybill moves with the shipment and contains all the information necessary for the railroads to transport a shipment and to prepare a bill. The information needed for the construction of the BLS index was abstracted from the waybills. The commodity shipped, origin, and destination of the shipment, railroads involved in the movement (routing), size of shipment, type of service provided, type of railcar used, and the rate at which the freight charge was calculated were obtained from each waybill used.

The BLS used the ICC 1 percent waybill sample to select the shipments to be priced for the railroad freight index. Because of resource constraints, however, the BLS could not determine the prices for the full 1 percent sample of waybills every month. After determining that about 500 waybills would provide a reasonably accurate price index for all rail freight, probability techniques were used to select a sample of shipments from the ICC sample.

The BLS provided indexes for railroad coal transport from 1969 through 1976 are given in Table G-1. Through the use of this index, known rates for prior periods can be adjusted to give a reasonable approximation of the current cost of shipping a ton of coal. For example, a 1972 rate of \$4.86 per ton could be adjusted to April 1976 as follows:

$$\frac{\text{April 1976 index } (201.2)}{\text{1972 average index } (128.8)} \times \$4.86/\text{ton} = \$7.59/\text{ton}$$

TABLE G-1

PRICE INDEXES FOR RAILROAD COAL TRANSPORT

(1969 Standard Transportation Commodity Code 11)

Year	Month												Annual Average
	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	
1969	99.5	99.5	99.5	99.5	99.5	99.5	99.6	99.7	99.7	99.7	99.7	104.9	100.0
1970	105.2	105.2	105.2	105.2	105.2	109.1	109.3	109.5	109.7	109.8	109.8	119.5	108.6
1971	119.9	119.6	119.9	125.1	124.8	125.2	125.1	125.2	125.5	125.5	125.5	125.5	123.9
1972	125.5	128.4	128.5	128.7	128.7	128.7	128.9	128.8	128.9	128.9	130.5	130.5	128.8
1973	130.5	130.5	130.6	130.6	130.6	130.6	130.6	130.8	134.3	136.8	137.1	137.1	132.5
1974	138.4	140.9	146.8	147.8	148.1	148.7	162.6	163.2	164.6	165.3	165.3	165.3	154.8
1975	164.8	164.8	164.8	164.8	175.2	175.2	183.3	184.3	184.7	189.1	189.7	189.8	177.5
1976	189.9	189.9	189.9	201.2	202.2	202.8	203.1	203.1	203.1	203.2	203.3	203.3	199.6
1977	209.4												