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MODELING SO_2 ABATEMENT COSTS *

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ABSTRACT

A linear programming model is presented for use in calculating the minimal cost to operate power plant SO_2 removal systems. The following fuel related costs were included: coal purchasing, physical coal cleaning, UMW contribution, coal transportation, power plant operation and maintenance, flue gas desulfurization, and ash disposal. The model is bound by demand, environmental, and operational constraints. The model is used to compare alternative methods of achieving a given SO_2 output. The results are sensitive to power plant location, coal purchase costs, and to variations in the variety of coal in the fuel mixture; slightly sensitive to flue gas desulfurization costs; and, insensitive to the other cost factors.

The New Source Performance Standards (NSPS) of the Clean Air Act (PL-91-604) regulate sulfur dioxide (SO_2) emissions from new and refurbished coal fired power plants. Under the present structure, the NSPS mandate an emissions ceiling, and, in addition, coal fired power plants are required to reduce post combustion SO_2 emissions by a certain percentage. The percentage reduction requirement is based on a sliding scale. Percentage reduction can range from 70 to 90 percent when emissions fall below 0.6 lb $SO_2/10^6$ Btu but must equal or exceed 90 percent when emissions range between 0.6 and 1.2 lb $SO_2/10^6$ Btu. The NSPS require the installation of flue gas desulfurization (FGD) systems for SO_2 control. The purpose of this research has been to develop a quantitative procedure for comparing the cost of FGD systems with the cost of alternative

* Original Flue Gas Desulfurization data obtained for this research from: Thomas A. Burnett, Project Leader, Economic Evaluation Section, Pilot-Plant Design and Construction Branch, Energy Design and Operations, Energy Demonstrations and Technology. Data generated from an original TVA cost estimation model which is described in reference [1].

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SO_2 control methods. A linear programming model is developed, the objective of which is to minimize construction and operating costs, including SO_2 control costs, for any new coal fired power plant. This research demonstrates the framework of a methodology which can be used to analyze the costs of alternative methods of SO_2 abatement.

MODEL STRUCTURE

Overview

The procedure followed uses linear programming to determine the least cost mix of coal plus FGD that will meet the NSPS. As noted below, a number of the necessary mathematical relationships are non-linear. In order to circumvent this difficulty, the linear programming model is used after a cash flow model. The latter is used to calculate the cost to solely utilize each coal in the potential fuel mixture. These costs then become the input for the linear program.

Linear Program

Objective Function – The objective of the model is to minimize construction and operating costs, which vary as the fuel mixture changes. The fuel mixture is varied to determine the least cost combination of fuels (SO_2 input) and FGD that satisfies regulations. The fuel mixture choice, therefore, determines the magnitude of costs.

It was assumed that numerous coals of varying characteristics can be purchased and mixed in linear combinations. (The validity of this assumption is subject to debate as noted in a later section.) It was assumed that coals can be cleaned to any technically feasible level, at a cost which can be determined. The cost to utilize (i.e., purchase, clean, transport, burn, etc.) any coal, C_i, is calculated in a cash flow model prior to running the linear program. The cleaned product of a raw coal is treated as an individual coal source. Therefore, the C_i term includes physical coal cleaning (PCC) costs where appropriate. The objective function of the model can be expressed as:

$$\text{Minimize: } z = \sum_{i=1}^{n} \alpha_i C_i + \ldots + \alpha_n C_n + C_{FGD} \qquad (1)$$

where:

z = total construction and operating costs
α_i = decimal fraction of coal i in fuel mix
C_i = cost to solely utilize coals i
C_{FDG} = cost to construct and operate the FGD system.

The linear program is used to determine the optimum fuel mix, i.e., the least cost combination of α_i values. The problem is bound by demand, regulatory, and engineering constraints. It is important to note that because of the structure of linear programming, the number of coals (four) entering the final solution is limited by the number of constraints. FGD costs vary as a function of boiler size, SO_2 flow through (SO_2 input), and SO_2 reduction achieved. Thus, for individual power plants of differing size, an equation that gives FGD costs as a function of SO_2 flow through and percentage reduction is derived by linear regression of known FGD cost data.

The FGD cost equation was developed for a 500 MW power plant using cost data provided by TVA [1]. TVA generated sixteen data points for the hypothetical plant equipped with the wet limestone FGD process. It was necessary that the range of FGD cost data encompass all possible SO_2 inputs, S_{in}, outputs, S_{out}, and ratios of SO_2 output to SO_2 input, S_R. Table 1 lists the selected data, and Figures 1 and 2, the results. The lines indicate cost at any particular combination of SO_2 input and output. Regression of construction and operating costs against S_{in}, S_{out}, and S_R yields:

$$C_{FCC} = 181.774 + 6.82\,S_{in} - 3.03\,S_{out} - 169.03\,S_R \qquad (2)$$

$$C_{FOC} = 1.1276 \times 10^7 + 766560\,S_{in} - 1.4753 \times 10^6\,S_{out} - 8.7256 \times 10^6\,S_R \qquad (3)$$

where

C_{FCC} = FGD construction cost, \$/kW
C_{FOC} = FGD operating cost, \$/yr.

The R^2 values are 0.997 and 0.998 for equations (2) and (3), respectively.

In order to facilitate mathematical modeling of FGD costs, the two equations were simplified, converted to \$ per million Btu, and combined into a single FGD equation which yields annual FGD costs per million Btu. This was accomplished by annualizing the construction cost and converting it to \$ per million Btu, assuming the FGD construction time to be two years. It was further assumed that the FGD system is constructed during the two years preceding the plant start-up date and that half of FGD construction costs are expended during each year. Assuming that the power plant comes on line in 1982, FCC values were inflated to 1982 at a rate of 6 percent per year [2]. Therefore, total FGD construction costs in 1982 dollars for the 500 MW system can be written as:

$$C'_{FCC} = (545900) \times C_{FCC}.$$

Construction costs were annualized using a thirty year amortization period and 10 percent discount rate to provide an annual capital recovery factor of \$0.1061 per dollar. Converting this to annual Btu input basis yields an annual FGD debt repayment of $(2.14 \times 10^{-3})\,(C'_{FCC})$ \$ per 10^6 Btu. Equation (2) thus becomes

Table 1. FGD Data Points

Number	$lb\ SO_2/10^6\ Btu$ Input	$lb\ SO_2/10^6\ Btu$ Output	Percentage Reduction: $(1 - \frac{output}{input})$
1	1.14	1.0	12
2	1.14	0.8	30
3	1.14	0.55	52
4	1.14	0.12	90
5	3.25	1.0	71
6	3.25	0.8	75
7	3.25	0.55	83
8	3.25	0.33	90
9	5.65	1.0	82
10	5.65	0.8	86
11	5.65	0.55	89
12	5.65	0.57	90
13	8.12	1.0	88
14	8.12	0.8	90
15	8.12	0.55	93
16	8.12	0.82	90

$$C(FGD)_c = 0.389 + 0.0146\ S_{in} + 0.00649\ S_{out} + 0.362\ S_R. \tag{5}$$

It is assumed that operating and maintenance costs are constant for each ton of ash plus sulfur (A + S) which passes through the power plant. PEDCo analyzed the operating and maintenance costs at five TVA coal fired power plants of differing size and coal type inputs [3]. The results of that analysis are shown in Figure 3 in which cumulative operating and maintenance costs are plotted against cumulative tons A + S through-put. The plots are approximately linear and all possess nearly the same slope of \$3.90 (1978\$) per ton of A + S. This figure was inflated to \$5.33 (1982\$) [2].

The operating cost equation (Eq. 3) was converted to \$ per million Btu, resulting in

$$C(FGD)_o = 0.417 + 2.834 \times 10^{-2}\ (S_{in}) - 5.454 \times 10^{-2}\ (S_{out}) - 3.226 \times 10^{-1}\ S_R, \tag{6}$$

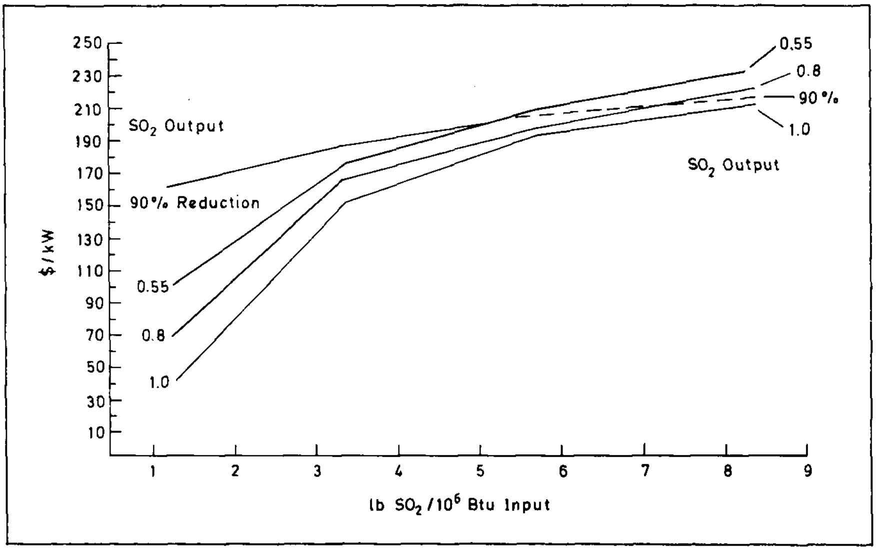

Figure 1. Flue gas desulfurization construction costs, $/kW.

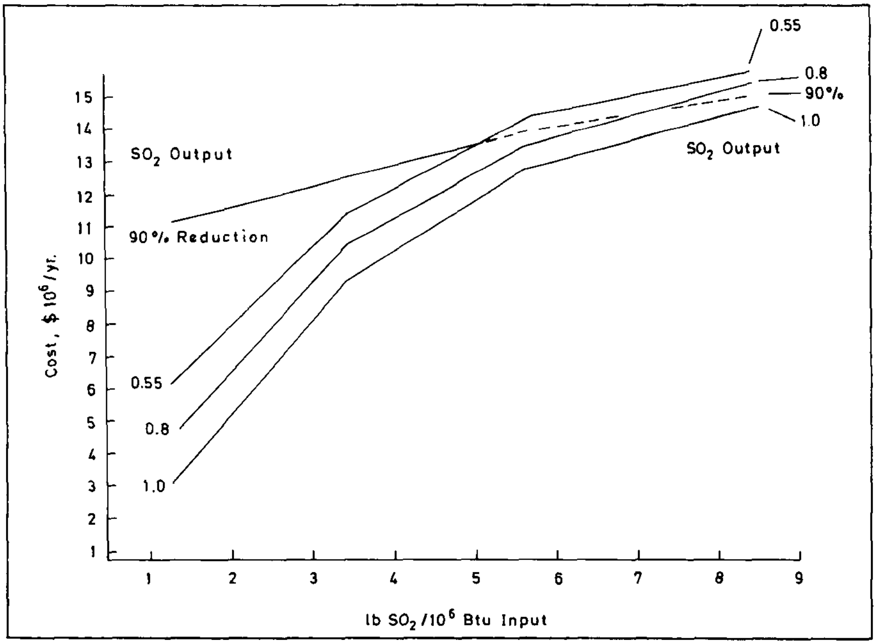

Figure 2. Flue gas desulfurization operating costs, million dollars per year.

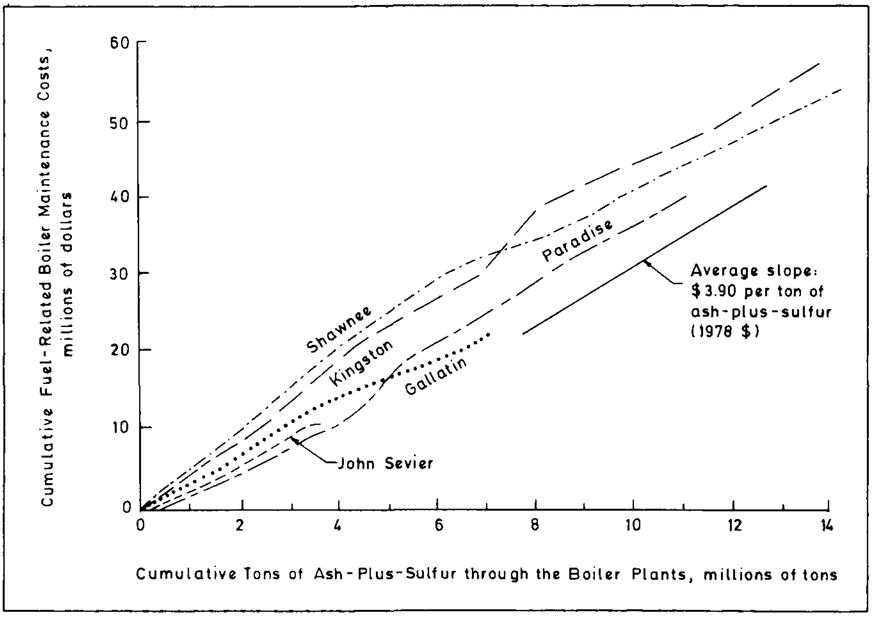

Figure 3. Relationship between fuel-related boiler maintenance costs and the ash plus sulfur content of the coal [3].

where $C(FGD)_0$ is the operating cost in $\$/10^6$ Btu.

Equations (5) and (6) are added to yield

$$C_{FGD} = 0.806 + 0.0429\,(S_{in}) - 0.0481\,(S_{out}) - 0.6846\,S_R. \tag{7}$$

The optimal SO_2 output is determined by the linear program. The SO_2 output term must, therefore, be eliminated from the FGD cost equation before the model is run. This was done as follows:

$$C_{FGD} = 0.806 + 0.0429\,(S_{in}) - 0.0481\,(S_{out})\,(\frac{S_{in}}{S_{in}}) - 0.6846\,(S_R)$$

or

$$C_{FGD} = 0.806 + [0.0429 - 0.0481\,(S_R)]\;[S_{in}] - 0.6846\,(S_R) \tag{8}$$

thus expressing C_{FGD} in terms of S_{in} and S_R.

The ratio S_R is non-linear and causes difficulties in using the linear programming algorithm. The non-linearity problem was overcome by utilizing an iterative procedure. The model was run repeatedly, determining a least cost solution (fuel mixture) for every reasonable S_R (FGD system size). An optimal SBR which indicated an optimal SO_2 output and fuel mixture, was chosen from this series of results. This was performed by adding C_{FGD} to each C_i term for each S_R. Note that within each S_R, FGD costs differ for each C_i term because SO_2 input values differ among the coals. The new C_i terms, called C'_i, denote the cost to solely utilize and desulfurize each coal for each S_R. With the FGD equation eliminated, the C_i terms were combined in the linear program to determine the optimal SO_2 input and resulting SO_2 output for each S_R.

The above procedure yields a set of results which can provide data to examine the trade-offs incurred when methods of SO_2 removal are varied. This function displays the least cost fuel mixture at each level of desulfurization. When S_R is high, lower sulfur fuels will be purchased to comply with regulations. The fuel mixture will probably contain a higher sulfur level when lower S_R values are employed. This hypothesis is based on the assumption that higher sulfur coal is less expensive to purchase than low sulfur coal and that the cost penalties incurred from burning higher sulfur coal (i.e., increased FGD costs) do not outweigh the differences in raw coal prices when resources have already been spent on FGD.

Demand constraint – It was assumed that a specified number of kilowatts (kW) will be produced annually. Therefore, the same Btu requirement to produce this electricity is implied within each C'_i term, although the tons of fuel, ash, and sulfur vary with the various coals. Since each C'_i term satisfies demand, any coal mixture for which the α_i values sum to one also satisfies demand. The demand constraint can be written as

$$\sum_{i=1}^{n} \alpha_i + \ldots + \alpha_n = 1. \tag{9}$$

SO_2 constraint – The NSPS regulations are represented in Figure 4, where SO_2 input is plotted against SO_2 output. The solid line denotes the required percentage reduction of potential SO_2 emissions given any particular SO_2 input. When S_{in} is six to twelve lb $SO_2/10^6$ Btu, at least 90 percent SO_2 removal is required and the resulting S_{out} will range from 0.6 to 1.2 lb $SO_2/10^6$ Btu (line segment AB). When S_{in} is two to six lb $SO_2/10^6$ Btu, required reduction ranges from 70 to 90 percent so that S_{out} will be 0.6 lb $SO_2/10^6$ Btu (line segment BC). Finally, when S_{in} is less than two lb $SO_2/10^6$ Btu, the required percentage reduction is 70 percent and S_{out} ranges from 0.2 (regulated emission floor) to 0.6 lb $SO_2/10^6$ Btu.

The SO_2 bypass ratio (S_R) occurs again in the SO_2 emissions ceiling and floor constraints. SO_2 emissions must be less than or equal to the regulated ceiling. This can be written as:

$$S_{out} = (S_R)(S_{in}) \leqslant S_{max} \tag{10}$$

or,

$$S_{in} \leqslant \frac{S_{max}}{S_R} \tag{11}$$

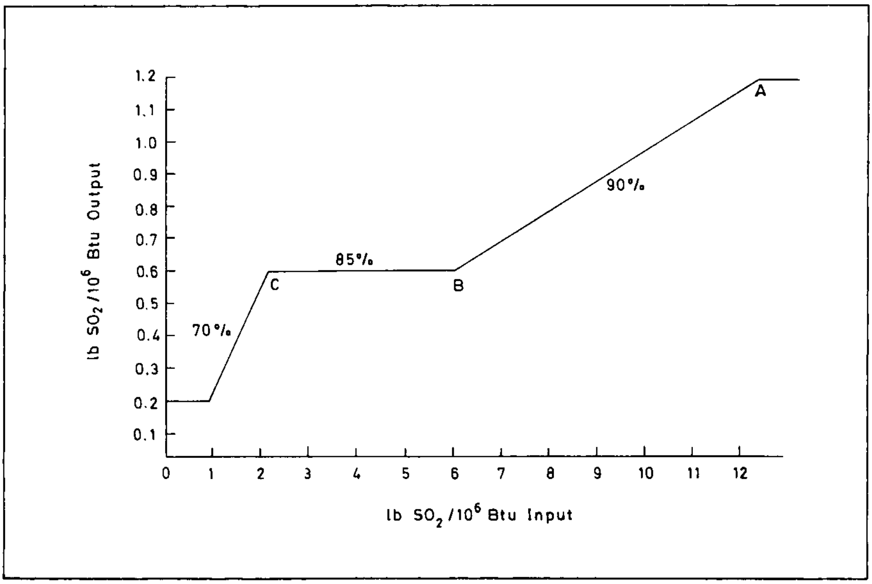

Figure 4. Schematic of new source performance standards for SO_x.

where S_{max} = Emission ceiling.

Since S_{in} is comprised of the SO_2 inputs of each coal in the fuel mixture, Equation (11) can be rewritten as:

$$\sum_{i=1}^{n} \alpha_i S_i + \ldots + \alpha_n S_n \leqslant \frac{S_{max}}{S_R} \tag{12}$$

where

S_i through S_n are the SO_2 levels of each coal, lb $SO_2/10^6$ Btu.

In addition, SO_2 emissions are not required to fall below 0.2 lb $SO_2/10^6$ Btu. This "emissions floor" constraint can be written as:

$$\sum_{i=1}^{n} \alpha_i S_i + \ldots + \alpha_n S_n \geqslant \frac{0.2}{S_R} \ . \tag{13}$$

The emissions constraints, which are non-linear, also necessitate the use of the iterative procedure described above.

The solution of the linear programming problem was developed in two stages. First, the optimal abatement procedure under the NSPS was determined. This was done as follows for the 0.6 lb $SO_2/10^6$ Btu-70 to 90 percent regulation. The emissions ceiling, S_{max} was set to 0.6 and the linear program was run repeatedly for each S_R between 0.3 and 0.1 in increments of 0.01. This process was repeated for the 1.2 lb $SO_2/10^6$ Btu - 90 percent regulation when S_R between 0.1 and 0.05 was tested. This procedure produced a function (thirty-five points) giving the minimum cost to operate the power plant at each allowable level of desulfurization while satisfying the emissions ceiling. One or more of these points are optima, indicating the minimum cost solution under the NSPS. This solution also indicates the optimal level of desulfurization and fuel mixture under the NSPS.

The second stage of the linear programming problem was to determine if the level of SO_2 abatement achieved under the NSPS can be attained for less cost (or, if the same expenditure can purchase more SO_2 abatement) by a smaller FGD system in conjunction with coal cleaning and the use of low sulfur coal. This was accomplished as follows. The regulated ceiling was set to equal the emissions output attained in the NSPS optimal solution. The S_R was varied from the lowest feasible level to 70 percent ($S_R = 0.3$). The lowest S_R was determined by calculating the percentage emission reduction required to attain the NSPS SO_2 output determined previously, when the lowest sulfur coal in the potential fuel mixture is burned. The result of this two stage procedure was a function which gives the costs incurred when trading-off between FGD, low sulfur coal, and coal cleaning to achieve a given emissions reduction.

Operational constraints – The engineering constraints which are relevant to this analysis involve characteristics of the fuel mixture. For example, power plants are often designed to handle a maximum quantity of ash, sulfur, and other impurities per time period [3-6]. The power plant may have to shut down when the impurity level surpasses a threshold because failures occur in power systems components, such as the pulverizer, ash conveyor, and electrostatic precipitator.

Power plant construction and operating costs vary as the characteristics of the fuel mixture change. Many of the fuel mixture related costs are non-linear. It has been estimated that in order to produce a given quantity of electricity, power plant capacity (MW) must be increased by 1 percent for each percentage point the proportion of A + S in the fuel mixture exceeds 17.5 percent [4, 5]. Operating costs generally are linear when A + S does not exceed 17.5 percent. Therefore, for ease of analysis, it was assumed that A + S in the fuel mixture cannot exceed 17.5 percent. This constraint can be expressed as follows:

$$\sum_{i=1}^{n} \alpha_i (A_i + S_i') + \ldots + \alpha_n (A_n + S_n') \leqslant 17.5 \tag{14}$$

where

A_i = the percent ash content of coal i
S_i' = percent S content of coal i.

A related engineering constraint involves the calorific content of the coal feed. Power plants are designed to handle a maximum quantity (tonnage) of coal. More fuel is required to satisfy a given demand as the heat value of the fuel decreases. However, a minimum Btu/lb constraint was not imposed in this analysis because the coals chosen for the case study were bituminous and contained relatively high calorific contents. Such a constraint could, of course, be added to the model. It was assumed that plant construction costs do not change as the calorific content of the fuel mixture increases [3]. Operating costs do change as the calorific content of the fuel mixture varies and these costs are described later.

Cash Flow Model

The purpose of the cash flow model is to calculate the cost to solely utilize each coal in the potential fuel mixture. The results become the C_i terms in the objective function of the linear program (Equation (1)). The components of the cash flow model are the costs which differ among the coals of the potential fuel mixture. These are: raw coal costs, coal transportation, PCC, UMW contribution, power plant operating and maintenance, and ash disposal. All costs were taken to inflate at the same rate, and were annualized and converted to (1982) dollars per million Btu of input ($\$/10^6$ Btu).

The annual Btu requirement for the given output (kWh) is calculated as:

$$E_{in} = kW \times HR \times CF \times AF \times 8760, \tag{15}$$

where

E_{in} = energy input, Btu/year.

kW indicates the plant size, or capacity, in kilowatts. HR stands for heat rate, measured in Btu/kWh. CF, denoting capacity factor, indicates the fraction of plant capacity which is used while the plant is in operation. AF, denoting availability factor, indicates the fraction of time the plant operates. The model was tested by a case study using a 500 MW base-load plant. Therefore, CF was assumed to be one. The availability factor was assumed to be 0.65 and the heat rate, 9500 Btu/kWh [1, 3]. The resulting Btu requirement is 2.705×10^7 million Btu/year.

Coal consumption – Different quantities (tons) of each coal in the potential fuel mixture could satisfy the annual Btu requirement, because the calorific content of coal varies. Several of the fuel related cost factors depend upon the quantity of coal that is consumed. The maximum potential annual consumption of each coal must, therefore, be calculated (the linear program, of course, will be used to determine the actual quantity of each coal that is consumed). Maximum potential annual consumption of each was calculated as follows:

$$F_i = \frac{E_{in}}{H_i}, \tag{16}$$

for F_i = Annual fuel consumption, tons coal i/yr.
H_i = Heat value of coal i, 10^6 Btu/ton
E_{in} = Annual Btu requirement, 10^6 Btu/yr.

Coal purchase costs – Coal purchase costs were calculated differently for raw and cleaned coals. The purchase cost for each raw coal was calculated as follows:

$$P_{Ri} = \frac{(P_i)(F_i)}{(E_{in})} \tag{17}$$

where P_{Ri} = purchase cost of raw coal i, \$/10^6 Btu
P_i = unit price of raw coal i, \$/ton.

The cost to purchase cleaned coal is calculated differently because a portion of the coal is discarded at the PCC plant. PCC costs are comprised of raw coal costs and plant operating and construction costs. It was assumed that these costs are spread equally among each ton of sold coal and that customers are found for every ton which is produced. Thus, the power plant can purchase any portion of the PCC plant's output. The purchase cost of cleaned coal must be adjusted to account for the portion of the raw coal that is discarded at the PCC plant (PCC operating and construction costs will be added separately). This was calculated for each cleaned coal as follows:

$$P_{Ci} = \frac{(P_i)(F_i)}{(W)(E_{in})} \tag{18}$$

where P_{Ci} = purchase cost of cleaned coal i, \$/10^6 Btu
W = weight recovery at PCC plant, fraction.

PCC costs – PCC costs are based on a report by Versar, Inc. [7]. Versar developed PCC costs for a variety of coals representative of several distinct geographical regions. Construction expenses are annualized over the life of the plant. For simplicity, it was assumed that the PCC plant begins operation concurrently with the power plant. Construction costs were annualized with the standard annual capital recovery factor, using a thirty year plant life and 10 percent real interest rate.

Several changes were made in Versar's methodology [7]. In this analysis, it was assumed that land costs are recovered while the plant operates, and that the value of the land (and equipment) is zero when the plant closes permanently. Second, Versar included the interest expense of the loan for construction working capital as an expense separate from the construction loan. Working capital was included as a construction cost in this analysis.

PCC costs were calculated for each cleaned coal as follows:

$$PCC_i = \frac{(R)(CC) + AE}{(TP)(H_i)} \tag{19}$$

where

R = Capital Recovery Factor, \$/\$ yr.
CC = Capital Costs, \$
AE = Annual Expense, \$/yr.
TP = Tons Produced at PCC Plant, tons coal/year
PCC_i = Total PCC costs, $\$/10^6$ Btu.

UMW contribution – The UMW pension fund receives a contribution of \$1.51 for each ton of coal sold [8]. It was assumed that the PCC plant is located at the mine mouth and that the coal is sold after cleaning. Thus, the UMW contribution will decrease for cleaned coal because fewer tons of such coal will be purchased in comparison to the raw coal feed. The UMW contribution was calculated for each coal, UMW_i, $\$/10^6$ Btu, as follows:

$$UMW_i = \frac{\$1.51}{H_i}. \tag{20}$$

Transportation costs – Transportation costs vary as a function of heat values, H_i. PCC reduces transportation costs by increasing H_i, thereby decreasing coal tonnages. Transportation costs were calculated as

$$T_i = \frac{(TC_i)(D_i)}{H_i} \tag{21}$$

where,

T_i = Transportation costs for coal i, $\$/10^6$ Btu
TC_i = Unit transport cost for coal i, \$/ton-mi
D_i = Transport distance for coal i, mi.

Operations and maintenance – Operating and maintenance costs are largely a function of fuel impurities which are a primary cause of wear and malfunction. It has been shown that, within a certain range, boiler operating and maintenance costs are a linear function of A + S [3]. Boiler operating and maintenance costs were, therefore, calculated as follows:

$$BC_i = \frac{(K)(F_i)(A_i + S_i')}{E_{in}} \tag{22}$$

where,

BC_i = Boiler O&M cost for coal i, $\$/10^6$ Btu
K = PEDCo [3] O&M cost, \$/ton A + S.

Ash disposal – It was assumed that ash is disposed of in on-site sanitary landfills. Ash disposal costs are reduced by PCC because ash is removed at the PCC plant. The fixed charge per ton of ash was calculated as:

$$AD_i = \frac{(AC)(F_i)(A_i)}{E_{in}} \tag{23}$$

where,

AD_i = ash disposal cost for coal i, $\$/10^6$ Btu
AC = unit charge for ash disposal, \$/ton ash.

Base Case Analysis

Although the model is a general one, it involves site-specific characteristics and, therefore, it is necessary to define a site or region in order to determine the proper value of those parameters.

The hypothetical power plant was located approximately fifty miles west of Pittsburgh, Pennsylvania, near the town of Sewickley on the Ohio River. This area was chosen for several reasons. First, the variety of coal is typical of Appalachia. Second, data were accessible for this region. Finally, the area chosen is classified as "Class II' by the regional EPA office, and it is thus more likely that a new power plant in this region will be subjected to the NSPS. The characteristics of the selected coals from this area are presented in Table 2.

Characteristics of physically cleaned coal are summarized in Table 3. It is interesting to note how the raw coal characteristics influence the effectiveness of the cleaning processes. The Butler coal cleaning processes are significantly more effective than the other cleaning processes. This is particularly evident since the percentage reductions of A + S achieved in the Butler coal cleaned to level 2 are greater than the reductions achieved in all the other coals, which were cleaned to levels 3 and 4. This occurred because of the differences in coal characteristics among the coals; the Butler coal contains very high proportions of ash and pyritic sulfur. PCC is moderately effective in removing impurities from the Cambria and Tucker coal. Note that even after cleaning, the Tucker coal contains more than 17.5 percent A + S. Thus, in order to be consumed, the Tucker coal will have to be mixed with other coals of greater purity. PCC is least effective in the Dickensen coal, which is inherently very pure.

Raw Coal Price

Raw coal prices are based on published long term contract baseline prices which are then corrected for variations in Btu, sulfur, and ash content [9]. A sulfur premium/penalty of \$0.00375 per ton of coal for each 0.1 percent sulfur deviation, and an ash penalty/premium of \$0.0025 per ton of coal for each 1 percent ash deviation was used. The calculated raw coal prices, PR_i, are summarized in Table 2.

Table 2. Raw Coal Characteristics and Estimated Prices

Coal Seam (County, State)	*Sulfur %*	*Lb $SO_2/10^6$ Btu*	*Ash %*	*Btu/lb*	*Coal Week Price (\$/ton)*	*Adjusted Raw Coal Price (\$/ton after application of Btu premium/penalty)*	*Estimated Raw Coal Price, P_i (\$/ton)*	*Raw Coal Price, PR_i (\$/10^6 Btu)*
Upper Freeport Butler, PA	3.45	5.99	23.9	11,510	28.49	26.23	22.32	.97
Lower Kittanning Cambria, PA	1.86	2.75	12.8	13,508	28.49	30.79	35.61	1.32
Bakerstown Tucker, WV	0.92	1.71	28.7	10.750	24.49	21.40	25.28	1.18
Clintwood Dickensen, VA	0.87	1.25	11.2	13,891	29.49	33.58	36.77	1.22

Table 3. Characteristics of Cleaned Coal

Coal Seam (County, State)	Level of Cleaning	Lb $SO_2/10^6$ Btu			% Ash			Btu/Lb			% Weight Recovery	% Btu Recovery
		ROM[a] Coal	Clean Coal	% Reduction	ROM[a] Coal	Clean Coal	% Reduction	ROM[a] Coal	Clean Coal	% Increase		
Upper Freeport Butler, PA #1	2	5.99	3.41	43	23.9	14.4	40	11,510	12,971	13	83.6	94.2
Upper Freeport Butler, PA #2	3	5.99	2.30	62	23.9	9.7	59	11,510	13,704	19	74.5	88.7
Lower Kittanning Cambria, PA	3	2.75	1.72	37	12.8	8.7	32	13,508	14,139	5	92.6	96.9
Bakerstown Tucker, WV	4	1.71	1.35	22	28.7	19.9	31	10,750	12,072	12	80.5	90.3
Clintwood Dickensen, VA	4	1.25	1.15	8	11.2	8.1	28	13,891	14,382	4	89.9	93.0

[a] ROM stands for run-of-mine.

PCC Costs

Table 4 shows the costs of cleaning each coal. These costs include construction (annualized) and operating expenses. The cost of coal cleaning ranges from \$0.089 to \$0.189 per 10^6 Btu of output (\$2.52 to \$4.55 per ton produced). More significant are the measures of cost effectiveness given in the last two columns of Table 4. As expected, cleaning of the Butler coal is most cost effective. This is evidenced by the fact that SO_2 removal is forty-five times as costly for the Dickensen coal as for the Butler coal cleaned to level 2. This is due primarily to the differences in the proportions of pyritic sulfur in the two coals. It is also interesting to note the differences in the cost per ton A + S removed by the various processes. PCC applied to Butler coal is most effective due to the high levels of A + S. While cleaning the Cambria coal is more cost effective in SO_2 removal than cleaning the Bakerstown coal, the latter is more cost effective in A + S removal. This results primarily from the comparatively high ash content of the Bakerstown coal. These differences highlight the case-specific nature of PCC.

Ash Disposal Costs

Ash is disposed of by the on-site land fill method, the cost of which was approximately \$2.00 per ton of refuse in 1979 [3, 4, 10, 11]. This figure was inflated to \$2.82 (1982\$) using the Chemical Engineering Plant Cost Index [2].

Transportation Costs

It should be noted that, given the appropriate data, the method presented here can be readily expanded to include any site-specific transportation costs. However, for simplicity, it was assumed that coal is shipped via unit trains at a rate which was inflated to mid-1982 dollars [11]. The calculated average cost to ship coal is 0.027¢/ton-mi. It was assumed that each coal is produced near a town close to other mines producing coal from that seam and that each coal is shipped over the shortest distance from mine to power plant: 30, 75, 112, and 265 miles for the Upper Freeport, Lower Kittanning, Bakerstown, and Clintwood coal seams, respectively.

RESULTS OF THE BASE CASE ANALYSIS

The results of the case study are shown in Figure 5. The least cost solution occurs with an FGD system that captures 74 percent of potential SO_2 emissions. The power plant operates under the 0.6/60-90 percent NSPS emissions constraint, and emissions are 0.6 lb $SO_2/10^6$ Btu. Ninety-eight percent of the fuel mixture is comprised of Coal 3, the highly cleaned Butler coal. The remaining 1.5 percent is comprised of Coal 2. Coal 3 was chosen because of the high cost effectiveness of cleaning it. The optimal fuel mixture contains less

Table 4. Physical Coal Cleaning Costs

Coal Seam (County, State)	Construction Costs	Annual Capital Recovery	Operating Costs	Total Annual Expenditures	Cost: $ Per Ton of Product	Cost: $ Per 10^6 Btu	Cost: $ Per Lb SO_2 Removed	Cost: $ Per Ton of Ash Plus Sulfur Removed
Upper Freeport Butler, PA	10,806,000	1,145,000	3,641,000	4,786,000	$2.86	$.1104	$ .056	$ 26.63
Upper Freeport Butler, PA	16,409,000	1,739,000	5,042,000	6,781,000	$4.55	$.1661	$ .061	$ 28.30
Lower Kittanning Cambria, PA	11,444,000	1,213,000	3,460,000	4,673,000	$2.52	$.0892	$ .10	$ 53.17
Bakerstown Tucker, WV	14,598,000	1,547,000	5,783,000	7,330,000	$4.55	$.1887	$1.14	$ 51.12
Clintwood Dickensen, VA	19,572,000	2,077,000	5,396,000	7,473,000	$4.16	$.1445	$2.60	$132.48

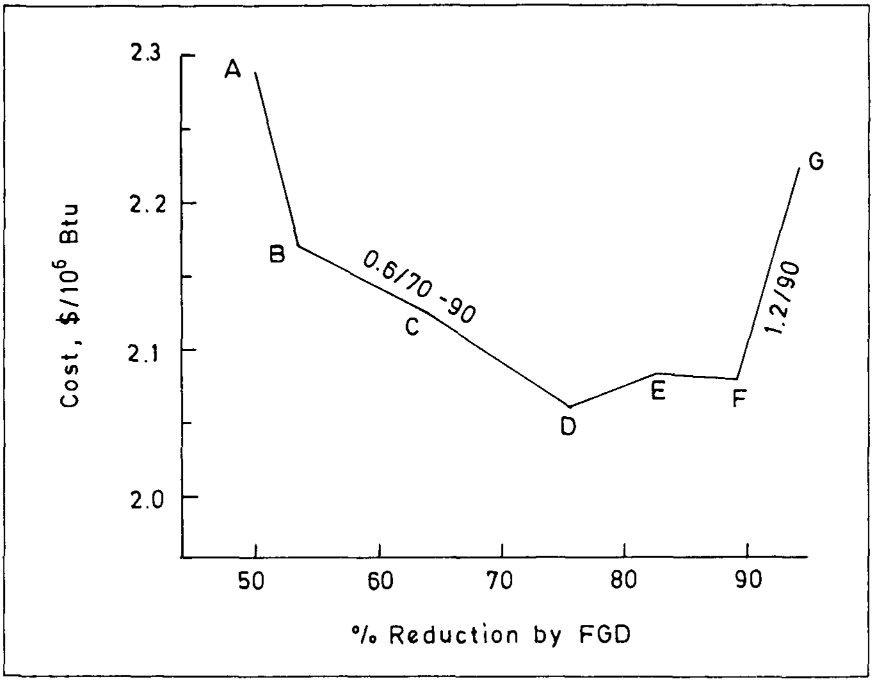

Figure 5. Base case results.

than 17.5 percent A + S. Thus, the operational constraint did not alter the final solution.

The shape of the optimal fuel mixture/FGD curve (Figure 5) warrants further discussion. As the percentage reduction achieved by FGD decreases, lower sulfur fuels must be consumed to satisfy the regulations. Thus, when percentage reduction is between 50 and 52 percent (line segment AB), the optimal fuel mixture contains Coals 8 and 9, the lowest sulfur fuels. Total costs are highest in this percentage reduction range because these are the most expensive fuels. Hence, the savings due to reduced FGD do not outweigh the costs of purchasing low sulfur coal in this range. Emissions are 0.6 lb $SO_2/10^6$ Btu in this range, and the proportion of ash plus sulfur in the fuel mixture is well below 17.5 percent.

Coals 6 and 8 dominate the fuel mixture when percentage reduction is between 53 and 63 percent (interval BC). Costs decrease throughout this range, while the sulfur content of the fuel mixture increases, indicating that it is less expensive to burn higher sulfur fuel and use more FGD to satisfy regulations. Coal 7 does not enter into the solution, indicating that this PCC process is not cost effective in this specific case study. Due to the operational constraint, Coal 6 never comprises more than 33 percent of the fuel mixture. Emissions continue to be 0.6 lb $SO_2/10^6$ Btu throughout this range.

Coal 3 enters the solution when percentage reduction is 57 percent, and slowly replaces Coals 6 and 8 as the percentage reduction increases. Coal 3 comprises nearly all of the fuel mixture when percentage reduction is 74 percent. Thus, through this range, costs continue to decrease as sulfur content and FGD increase. The regulatory constraint is binding through this range; emissions continue to be 0.6 lb $SO_2/10^6$ Btu. The operational constraint is non-binding. Coal 5 does not enter the solution indicating that the cleaning process for this coal is not cost-effective in this example.

Coal 3 is slowly replaced by Coals 2 and 1 as the percentage reduction increases to 89.9 percent (the maximum percentage reduction under the 0.6/70-90 percent constraint). Between 74 and 83 percent reduction (segment DE) costs increase as sulfur content and FGD increase. This indicates that it is no longer cost effective to satisfy regulations by switching to higher sulfur fuels and more desulfurization; the decreased fuel purchase costs no longer out-weigh increased FGD costs. Emissions continue to equal 0.6 lb $SO_2/10^6$ Btu in this range, and the operational constraint is non-binding. When percentage reduction is between 86 and 89.9 percent, the optimal fuel mixture does not vary from 92 percent Coal 2 and 8 percent Coal 1 because the operational constraint prevents further consumption of Coal 1 which contains 4.3 lb $SO_2/10^6$ Btu. Because of this, emissions fall below 0.6 lbs $SO_2/10^6$ Btu as percentage reduction increases; the operational constraint forces the power plant to consume a fairly low sulfur fuel mixture, because the highest sulfur fuel also contains a high proportion of ash. The power plant, therefore, purchases more SO_2 abatement than required within this percentage reduction range. Costs increase because an increasing quantity of FGD is purchased, as well as a fuel mixture that is fairly low in sulfur.

The binding operational constraint helps to explain why it is not optimal to reduce emissions by 90 percent or more with FGD and emit more than 0.6 and less than 1.2 lb $SO_2/10^6$ Btu. This is illustrated by line segment FG. At the highest levels of desulfurization, the power plant continues to purchase the fuel mixture described above (92 percent Coal 2, 8 percent Coal 1), but spends more on FGD. Emissions continue to decrease, rather than increase. Several requirements must be satisfied before the 1.2/90 percent emission constraint can become binding. First, a fuel containing more than 6 lb $SO_2/10^6$ Btu must be placed in the potential fuel mixture. The plant cannot emit more than 0.6 lb $SO_2/10^6$ Btu when the available coal contains less than 6 lb $SO_2/10^6$ Btu, due to the 90 percent reduction requirement. Second, the higher sulfur fuel, or the fuel mixture in which it is placed, must satisfy the operational constraint. Finally, it will be optimal to consume a higher sulfur fuel only when such a fuel is properly priced. The cost difference must equal or exceed the increased FGD costs incurred when consuming the higher sulfur level.

To summarize, the base case results indicate that it is optimal to consume the highly cleaned Butler coal and reduce potential emissions by 74 percent with

FGD. This indicates that the benefits of the Butler cleaning process outweigh the costs. However, several other cleaning processes were shown to be uneconomical.

SENSITIVITY ANALYSIS

Sensitivity analyses have been performed to test the strengths of the model's components. These analyses were made using the post optimal analysis technique. They centered on the effect on the optimal result of the various cost inputs, and constraints.

Sensitivity to UMW, Transportation, Operating and Maintenance, and Ash Disposal Costs

Post optimal analysis demonstrated that the results are highly insensitive to variations in UMW, transportation, operating and maintenance, and ash disposal costs. UMW costs can be increased by 92 percent or decreased by 78 percent without affecting the optimal solution. Transportation costs can vary by over 150 percent without affecting the optimal solution. Operating and maintenance costs can range approximately 200 percent, while ash disposal costs can range over 450 percent without altering the optimal solution. These results are due to the relatively small share that each of these cost components contribute to the total cost.

Sensitivity to PCC Costs

The base case results are fairly insensitive to variations in PCC costs. Post optimal analysis showed that PCC costs for the Butler coal can be decreased by nearly 75 percent without changing the optimal solution. Also, any decrease in PCC costs would favor the Butler coal, since the Butler coal cleaning processes were favored in the Base Case.

PCC costs for the Butler coal can be increased by 25 percent without changing the optimal solution. PCC cost increases greater than 25 percent will cause the optimal fuel mixture to rely more heavily on Coal 2 since the cleaning process used to produce Coal 2 was nearly as cost effective as its counterpart.

Sensitivity to the Operational Constraint

The 17.5 percent A + S constraint was relaxed. This did not alter the optimal result but it did alter the results at the highest levels of desulfurization. When the operational constraint is relaxed, the power plant will consume Coal 1, the highest sulfur coal, entirely when desulfurization exceeds 85 percent. This result again exhibits the tendency for the power plant to consume the highest sulfur coal when high levels of desulfurization are required.

Sensitivity to FGD Costs

The results are fairly sensitive to FGD costs. Post optimal analysis showed that FGD costs can range approximately 6 percent without altering the optimal solution. An increase in FGD costs would favor low sulfur coal, since such an increase would disproportionately increase the cost of consuming high sulfur coal. The opposite would occur as the result of an FGD cost decrease.

These results must be qualified. The post optimal analysis indicated whether the optimal solution would vary when FGD costs change only for the coals in the optimal fuel mixture. In other words, post optimal analysis varies FGD costs for each coal separately. This is perhaps unrealistic, since the same equation was used to calculate FGD costs for each coal. It might be more realistic to vary FGD costs simultaneously for all coals. This was accomplished in this analysis by varying FGD costs ±30 percent, in increments of 5 percent.

The results showed that a 30 percent increase in FGD costs will not alter the optimal solution. Coal 3 is so inexpensive that it would continue to dominate the optimal solution. A decrease in FGD costs of approximately 25 percent would alter the optimal solution. The resulting new optimal solution would contain 95 percent coal 2 and 5 percent coal 1. FGD percentage reduction would be 83 percent and emissions would continue to be 0.6 lb $SO_2/10^6$ Btu. Lower FGD costs lessen the cost of consuming high sulfur fuel and the new optimal coal mix would contain 3.53 rather than 2.5 lb $SO_2/10^6$ Btu. Thus, viewed in this light, the Base Case results are fairly insensitive to FGD cost variations.

Sensitivity to Plant Location

The optimal results change dramatically by relocating the power plant nearer to the low sulfur coal. In the Base Case, it costs approximately 0.22¢/10^6 Btu more to transport the low sulfur Dickensen coal than the high sulfur Butler coal. Thus, by relocating the power plant near the Dickensen coal the cost difference between utilizing the Dickensen and Butler coals will be reduced by approximately 0.44¢/10^6 Btu.

Figure 6 shows the results of this sensitivity analysis. The maximum SO_2 output was set at 0.6 lb $SO_2/10^6$ Btu, the level achieved in the base case. The new optimal conditions are 97.5 percent Coal 8 and 2.5 percent Coal 9; 52 percent desulfurization; and SO_2 output of 0.6 lb $SO_2/10^6$ Btu. The operational constraint is nonbinding. None of the physically cleaned coals were chosen for consumption, because Coal 8 dominated the solution. The NSPS would not allow the 52 percent desulfurization level. Rather, a minimum of 70 percent desulfurization would be required, costing approximately 7 percent more than the 52 percent solution described above.

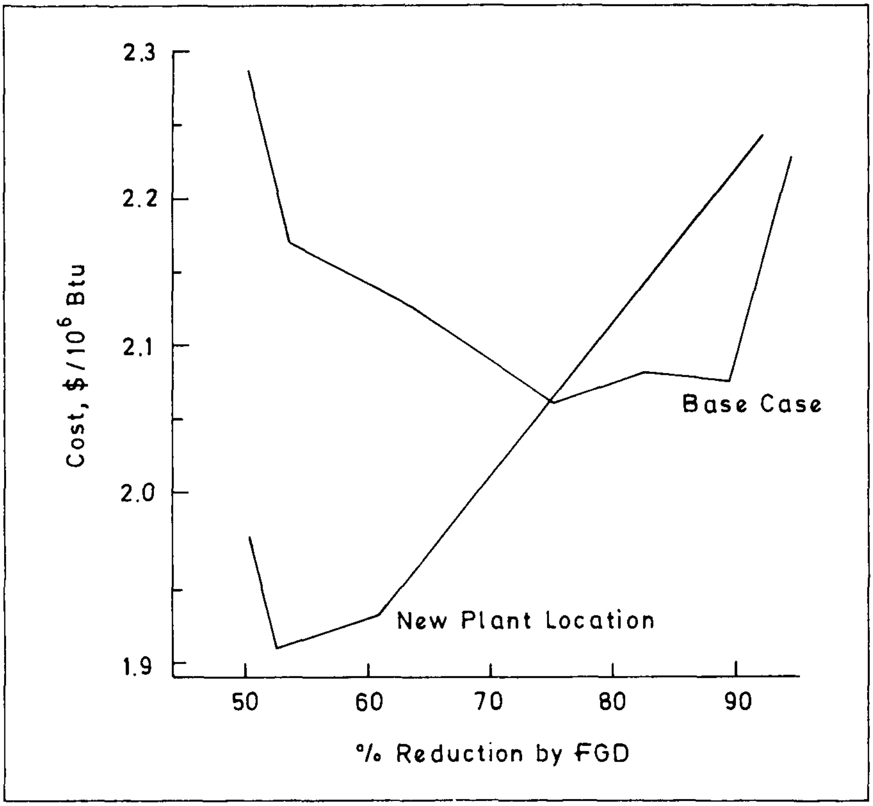

Figure 6. Sensitivity of results to plant location.

Sensitivity Analysis: Relative Coal Prices

It is useful to determine how the Base Case results are affected by lessening the relative differences between the purchase prices of the high and low sulfur coal because coal purchase costs dominate total costs. Post optimal analysis showed that the optimal solution changes when the price of Coal 3 increases by more than 4 percent. The optimal solution will also change when the price of Coal 8 decreases by more than 15 percent. The following procedure was followed to determine the precise fuel mixture resulting from such price changes. Coals 6, 7, 8, and 9 were grouped together as low sulfur coals. Coals 1 through 5 were grouped as high sulfur coals. The model was re-run six times. In three cases, the purchase prices of the low sulfur coals were adjusted downwards by 10, 20, and 30 percent, while the purchase prices of the high sulfur coals were held constant. High sulfur coal prices were increased 10, 20, and 30 percent in the remaining three cases, while lower sulfur coal prices were held constant. The results for the ±10 percent cases are shown in Figure 7.

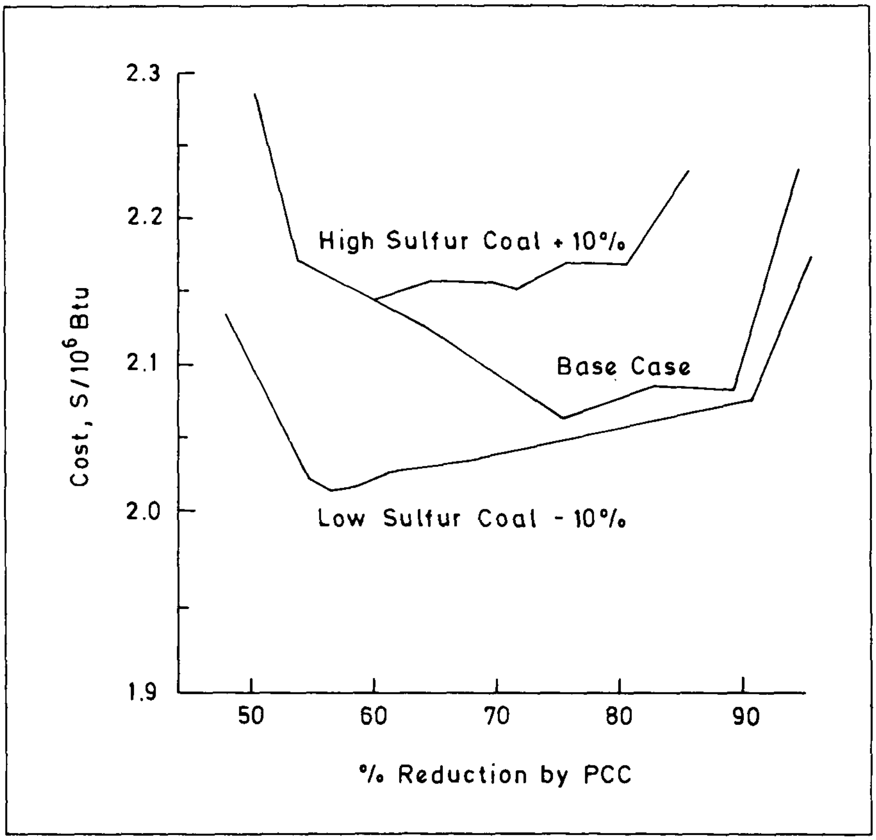

Figure 7. Sensitivity of results to relative coal price.

The Base Case results changed significantly as a result of fairly small changes in coal purchase prices. A 10 percent reduction in low sulfur coal prices reduced the optimal level of desulfurization to 57 percent, from 74 percent. The resulting fuel mixture contained 69 percent Coal 8 and 31 percent Coal 6. Emissions were 0.6 lb $SO_2/10^6$ Btu and the operational constraint was binding.

Similar results were obtained by increasing the high sulfur coal prices. The optimal solution contained 69 percent Coal 8 and 31 percent Coal 6. The optimal level of desulfurization was 57 percent and emissions were 0.6 lb $SO_2/10^6$ Btu.

Discussion of Assumptions

Coal mixing – It was assumed that various coals can be mixed at the power plant. In fact, there are engineering and environmental constraints which limit the extent of coal mixing. Wide fluctuations in coal characteristics can cause certain power plant components to malfunction [3, 4, 6]. In addition, the sulfur content of the coal must be fairly uniform to ensure proper functioning of the FGD system and compliance with SO_2 regulations.

Avoiding such variations in fuel characteristics requires thorough mixing which can be provided by machinery which is used by many power plants [12]. The cost of such equipment was not included here. Since coal purchase and FGD costs dominated all other costs, the exclusion of coal mixing equipment costs would not alter the results.

Utilization of small quantities of coal – It may not be economically or technically feasible to use small quantities (less than 5% of annual coal consumption) of a particular coal. It was assumed that coal in any amount could be purchased at the long term contract price and transported at the unit-train rate. Because of economies of scale, the unit cost to purchase and transport a small quantity of coal is greater than it is for larger quantities. It is reasonable to assume that the cost versus quantity functions are non-linear and, therefore, cannot be integrated into the model. The model therefore underestimates the cost of small quantities of coal and is biased against large quantities.

For a variety of operational reasons, it seems likely that a power plant will avoid using a small quantity of coal. Numerous economies of scale favor the use of large quantities of coal. In the future, therefore, it may be desirable to add a constraint to the model which imposes a floor on the size of coal shipments.

Power plant size – The model was tested using a hypothetical 500 MW base load power plant. It would have been ideal to test the model with numerous plant sizes, because economies of scale exist in power plants. Economies of scale are especially critical in FGD. It is estimated that FGD costs twice as much for each pound of SO_2 removed at a 250 MW power plant than at a 500 MW plant [13-17]. These economies of scale are less pronounced for larger FGD systems. FGD costs 20 percent less for each pound of SO_2 removed at a 1000 MW power plant than at a 500 MW plant [15, 17]. The potential impact of power plant size was not determined in this study.

PCC reduces FGD costs not only through sulfur reduction, but also through reduction of sulfur variability. As sulfur variability increases, FGD system size must also increase in order to maintain emissions at an acceptable level when the sulfur level of the coal varies significantly above the average. PCC significantly reduces a coal's sulfur variability. This analysis does not include reductions in FGD costs resulting from reduced sulfur variability because appropriate data were not available. This limitation will not significantly hinder the model's results as the conservative assumption is made.

PCC plant output – It was assumed that any portion of the PCC plant's output could be purchased. However, over-production at the PCC plant is a potential problem, because PCC plants frequently produce more coal than required by large power plants. For example, a 500 MW power plant typically consumes between 1,000,000 and 1,200,000 tons of coal annually while a medium sized PCC plant produces between 1,400,000 and 1,800,000 tons per year. The PCC plant would have to be reduced in size if customers could not be found for the excess coal, and this would increase PCC unit costs. Post-optimal analysis demonstrated that the results are fairly insensitive to variation in PCC costs. It can, therefore, be safely assumed that the results are probably insensitive to variations in the size of the PCC plant. Additional questions raised by potential PCC over-production are cause for further investigation.

Implications of the operational constraint – This constraint was imposed to limit the quantity of A + S in the fuel mixture because fuel related operation and maintenance costs become non-linear when A + S exceeds 17.5 percent. The optimal results of the base case analysis and the sensitivity analyses were not constrained by this constraint, perhaps because the coals chosen had relatively low A + S contents and were also inexpensive. It is possible that some coals containing more than 17.5 percent A + S are so inexpensive that they will be chosen in the absence of the engineering constraint. On the other hand, it is likely that if increased costs resulting from the higher impurity level are included, most new power plants will burn fuel mixtures containing less than 17.5 percent A + S. TVA estimates that in order to maintain power output, plant capacity must increase 1 percent for each percent A + S above 17.5 [4, 5]. Therefore, in order to maintain power output, an additional 25 MW of capacity would have to be added to a 500 MW power plant if the impurity content of the fuel increased from less than 17.5 percent to 20.5 percent. At $870 per kW [18], and using the same capital recovery and power plant efficiency assumptions as before, the additional 25 MW will add 0.08¢ per million Btu to costs. In addition, fuel related operation and maintenance costs will increase as a result of the increased impurity content. These combined costs will likely outweigh the benefit of purchasing the dirtier coal.

Discount rate and amortization period – A 10 percent real discount rate and thirty-year amortization period were used to calculate PCC and FGD construction costs. This discount rate is high, and therefore increased costs; the amortization period is longer than average and therefore reduced costs. Post-optimal analysis demonstrated that the results were insensitive to variations in PCC costs, and only fairly sensitive to variations in FGD costs. Since construction costs comprise half of annual FGD costs, it was determined that any reasonable variation of the discount and amortization rates would not change the optimal result.

Constant dollars – It was assumed that all prices inflate at the same rate, because it is difficult to accurately predict how relative prices will change. Sensitivity analysis showed that relatively small changes in FGD and coal costs will alter the results. Thus, it is worth determining if the prices of these factors will change at rates other than the general price level. FGD costs have decreased in real terms during the past ten years [14]. It is likely that these costs will decrease somewhat more in the future as experience with the technology increases. Since post-optimal analysis showed that the model is fairly insensitive to decreases in FGD costs, it is, therefore, safe to assume that the results will not change if future FGD cost decreases are not significant.

It was assumed that coal prices remain unchanged. This assumption was unrealistic. Zimmerman demonstrated that high and low sulfur coal prices will increase at different rates in the future, depending on the coal production area [19]. Low sulfur western and high sulfur eastern and mid-western coals are abundant. Zimmerman predicts that the prices of these coals will increase at equal rates during the next thirty years. Low sulfur eastern coal is less abundant and, therefore, will increase in price at a somewhat faster rate than that of the other coals. Zimmerman predicts that the price of low sulfur eastern coal will increase 3 percent more in real terms than high sulfur eastern coal during the next thirty years. The model, therefore, under-estimated the cost of low sulfur coal. The inclusion of this price difference will not alter the results since post-optimal analysis demonstrated that the price of low sulfur coal will have to increase more than 10 percent to alter the optimal results. These price differences could be included in the model by using present discounted value (PDV) calculations rather than the constant dollar assumption. It will be useful to use the PDV method in future analyses.

SUMMARY AND CONCLUSIONS

A linear programming model was designed to minimize power plant operating costs. The model was used to calculate the minimum cost to operate the power plant with any sized FGD system. In addition, the optimal SO_2 output was calculated for every FGD system size. The following fuel related costs were included: coal purchasing, physical coal cleaning, UMW contribution, coal transportation, power plant operation and maintenance, FGD, and ash disposal. The model was bound by demand, environmental, and operational constraints. The model had two stages of operation. First, the least cost expenditure and resulting SO_2 output were determined for the power plant subjected to the NSPS. Second, the minimum cost of obtaining this level of pollution was then determined when the model was freed from the FGD constraint imposed by the NSPS.

A case study was designed in which a hypothetical 500 MW power plant was analyzed. The plant was located in Western Pennsylvania, near Pittsburgh. A variety of coals were chosen for the potential fuel mixture. The calorific and impurity contents of the coals were similar to those of typical eastern coal. The base case results demonstrated a situation in which the most efficient abatement technique would be sanctioned by the NSPS. A single coal dominated the results. This coal was inexpensive to purchase and clean, and, in addition, was mined near the power plant.

A variety of sensitivity analyses were performed. The results were shown to be insensitive to variations in the following cost factors: UMW contribution, transportation, physical coal cleaning, operating and maintenance, and ash disposal. The results were only slightly sensitive to variations in FGD costs. The results were highly sensitive to power plant location, coal purchase costs, and to variations in the variety of coal in the potential fuel mixture.

APPENDIX

Definitions of Notations Used

AC	=	unit cost for ash disposal, \$/ton/ash
AD_i	=	ash disposal cost for coals i, \$/10^6 Btu
AE	=	PCC annual expenses, \$/yr
AF	=	availability factor
A_i	=	the percent ash content of coal i
BC_i	=	Boiler O + M Cost for coal i, \$/10^6 Btu
C_{FCC}	=	FGD construction cost, \$/kW
$C(FGD)_o$	=	FGD operating cost, \$/10^6 Btu
C_{FGD}	=	cost to construct and operate the FGD system
$C(FGD)_c$	=	FGD construction cost, \$/10^6 Btu
C_{FOC}	=	FGD operating cost, \$/yr
CC	=	PCC capital cost, \$
CF	=	capacity factor
C_i	=	cost to solely utilize coal i
D_i	=	transportation distance for coal i, miles
E_{in}	=	energy input at power plant, Btu/yr.
F_i	=	annual fuel consumption, tons coal i per year
H_i	=	heat value of coal i, 10^6 Btu/ton
HR	=	heat rate, Btu/KWH
K	=	PEDCo O + M Cost, \$/ton A + S
PCC_i	=	PCC cost at plant i, \$/10^6 Btu
PC_i	=	purchase cost of cleaned coal i \$/10^6 Btu
P_i	=	unit price of coal i, \$/ton
PR_i	=	purchase cost of raw coal i, \$/10^6 Btu
R	=	the capital recovery factor: payment per period per dollar invested
S_R	=	S_{out}/S_{in}
S_i	=	SO_2 content of coal i, lb $SO_2/10^6$ Btu
S_i'	=	the percent sulfur content of coal i
S_{in}	=	SO_2 input, lb $SO_2/10^6$ Btu
S_{out}	=	SO_2 output, lb $SO_2/10^6$ Btu
S_{max}	=	emission ceiling, lb $SO_2/10^6$ Btu
TC_i	=	unit transportation cost for coal i, \$/ton/mi
T_i	=	transportation cost for coals i, \$/10^6 Btu

TP	=	tons of coal produced at PCC plant per year
UMW_i	=	UMW contribution for coal i, $\$/10^6$ Btu
W	=	weight recovery at PCC plant, fraction
α_i	=	percentage of fuel mixture composed of coal i

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