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COAL IN TRANSITION 1980 - 2000 DEMAND CONSIDERATIONS

Andy S. Kydes and Ellen A. Cherniavsky

DECEMBER 1977

ENERGY DATA AND MODELS GROUP
NATIONAL CENTER FOR ANALYSIS OF ENERGY SYSTEMS

BROOKHAVEN NATIONAL LABORATORY
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Abstract

Eight potential energy futures are examined by focusing on parameters expected to be important in determining the pattern of future coal consumption in the United States. The report describes the methodology, results and conclusions of this study performed by Brookhaven National Laboratory as part of a larger study administered by the Energy Modeling Forum (EMF). The EMF study, addressing the topic "Coal in Transition: 1980-2000", comprises the efforts of modeling groups from a number of organizations.

Model assumptions were chosen by a consensus of modelers, electric utility representatives and policymakers. The cases presented are not to be interpreted as "likely" futures but, rather, as cases which are designed to test the sensitivity of the individual models to the parameters of interest.

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SUMMARY

For the purposes of the "Coal in Transition" study, the usefulness of the Brookhaven model, TESOM, lies in its exploration of the demand side of the energy system. Sectors where coal may be substituted for other energy forms are identified, and attractive technologies are highlighted.

The results of the runs accord well with intuitive expectations. The increasing prices of oil and natural gas usually imply that (a) coal synthetics become increasingly attractive technologies, except in the High Demand and CRUNCH Cases (b) nuclear and Hydro-electric generation are preferred technologies (c) coal steam electric, even with expensive scrubbers, becomes more attractive than oil or gas steam electric by year 1990 (d) fluidized bed combustion for electricity generation is cost effective (with relatively small environmental impacts) when compared to oil, gas and coal steam electric. FBC process steam exhibits similar behavior.

In the High Demand and CRUNCH scenarios, technologies such as solar electric, which are usually not chosen on the basis of cost, enter the solution because meeting demands has become extremely difficult. As the allowed coal expansion rate becomes a limiting factor, coal synthetics manufacturing becomes an unattractive alternative. This is due both to the need for coal electric generation to meet high electricity demand levels, and to the inefficiencies in the manufacturing process. Due to preferred allocation of coal to electricity generation or synthetics, direct coal use is reduced, although this is normally a preferred option.

INTRODUCTION

There are many important attributes of the energy system as a whole that must be considered when examining the limitations on the growth of coal utilization in the United States to the year 2000. Since the coal reserves of the United States are expected to satisfy a significant portion of our future energy needs, it is important to examine (a) the environmental effects of this coal production and utilization, (b) the implications for market penetrations of old and new technologies, (c) the competition among fuels and technologies to meet end-use demands, (d) the implied cost, (e) the potential bottlenecks in the production and transportation infrastructure designed to meet this increased utilization, (f) capacity growth and retirement limitations, and (g) "lifestyle" implications.

The Time-stepped Energy System Optimization Model (TESOM) was employed to address these issues. TESOM, a model of the national energy system, is an extension of BESOM¹. We digress to give a brief description of BESOM. The energy system of a region or nation can be represented in a network format as shown in Figure 1. The network in this case is quantified with energy flows for the year 1976 from alternate resources through the various energy delivery activities to specific end-uses. In view of changing prices, demand levels, and fuel supplies it is desirable to have an analytical model that will indicate optimal fuel mix configurations within resource, environmental and demand constraints that operate on the energy system. BESOM, the linear programming model provides this function. The model is formulated about the classical transportation problem of determining the optimal routing of a product from a set of n supply nodes to m demand nodes where a cost and a set of environmental impacts are identified for

a unit of energy passing over each of the $n \times m$ possible paths. The typical linear programming representation of the transportation problem is modified by the inclusion of efficiency coefficients in the supply and demand constraints and is augmented by additional constraint equations reflecting the environmental factors as well as certain technical features of the energy system. See Appendix C for a brief but more complete description of BESOM. TESOM was conceived and developed to provide (a) an improved, automated, simulation capability and (b) an alternative decision-making tool to DESOM² to assist in the study of the evolution of national energy supply/demand distribution systems. TESOM can be classified as a "myopic" time-phased model in that the optimal levels of the decision variables for any time-step are determined entirely from (a) the optimal levels of the decision variables in the previous time-steps, (b) the assumption of retirement/deterioration rates and average lifetimes of "old" stock, with associated costs, and (c) the "current" assumptions involving energy-related economic and technological factors--potentially including both short-term and long-term supply curves. No knowledge of the future is assumed.

Mathematically, the time-stepped model is formulated as a sequence of expanded linear programming problems representing the national energy systems (BESOM's)¹--one for each time-step. The first time-step problem represented in this sequence replicates a recent historical year (1976). (See Figure 1). The solution derived from the first year, along with the assumptions on retirement rates, average lifetimes, and costs of stock in-place at the end of the first time-step are incorporated as additional constraints to be met in the next time-step. The procedure is repeated until the solutions to all the time-points are determined.

II DRIVING VARIABLES

The key driving variables or parameters³ which affect the use and growth of coal are:

- (1) Environmental Restrictions
- (2) Coal Supply/Price Limitations
- (3) Demand Growth Rates (Overall and Electric)
- (4) Central Station Coal Technology Characteristics
(scrubber options and particulate controls)
- (5) Prices of Alternative Fuels
- (6) Availability of Nuclear Generating Capacity
- (7) Cost of Capital

The realization in TESOM of the general guidelines and the philosophy of costing the various options are given in Tables 1 through 3. Supplementary fuel costs by demand categories reflecting combinations of transportation costs, specialized chemical processing costs (as in gasoline for automobiles or aviation fuel), taxes, and mark-ups are given in Table 4. Control costs are the key mechanism by which alternative emissions standards are represented in the model. The representation of the various technological trajectories available is that used in a variant of the National Energy Plan⁴. The central station efficiencies and costs have been adjusted to be consistent with the EMF model assumptions³; however, end-use efficiencies and technologies permitted were those permitted in the National Energy Plan. EMF 2.3, the document summarizing the study assumptions is given as appendix F.

III. ANALYSIS OF RESULTS

SUPPLY SIDE ANALYSIS

- Use of Nuclear Capacity: Nuclear electric generation was a favored technology in every scenario and every year from 1985-2000. It was most favored in the High Demand and CRUNCH scenarios for the year 2000 while it was least favored in the low Demand scenario.
- Coal Synthetics: Coal synthetics became increasingly attractive with time in every scenario except the CRUNCH and High Demand Cases. In the latter two cases, coal synthetics became increasingly unattractive owing to the severe strains caused by the high electricity and aggregate demand growth rates and the apparent inability to continue coal expansion at the rate desired. Low Btu coal gas, though unattractive in 1990, is more attractive than coal liquefaction. All three synthetics are attractive in the remaining six scenarios in the year 2000 with the exception of liquified coal in the "LOW EAST CASE" where factor prices are escalated at 2% per year. Even in this case, liquified coal is almost a desired technology; the correct interpretation here is that liquified coal may be attractive in certain regions of the U.S. The behavior of synthetics is not surprising in view of the 2.75% per year escalation rate plus \$.50 per million Btu prices for "new" natural gas.
- Oil Steam Electric Generation: Electric generation by oil and gas steam electric plants are always unattractive technologies except in the High Demand and CRUNCH scenarios in 1990 where the combination of coal shortage and high demand requires new oil and

gas-fired plants to be built. Otherwise, the retirement/obsolescence rate governs the level of activity of oil and gas steam electric plants since the model generates no new construction for such plants in these cases. In fact, additional existing capacity would have been retired if permitted.

- Gas Turbine Electric Generation: Electric generation by gas turbines does not exhibit the uniform behavior oil and gas steam electric plants do. Gas turbines show a moderate growth in every 1985 scenario. However, it is the obsolescence or retirement rate which governs the levels of gas turbine activity in 1990 for the Reference and Low Demand Case and additional capacity would have been retired if permitted. In the low Demand Case, total electric demand has not grown enough to support more than the minimal activity required by the carry-over of "old" gas turbines.

The minimal usage of gas turbines in the Reference Case for 1990, in contrast to the remaining six scenarios where moderate growth is seen, is due to the fact that there are no severe coal price dislocations; thus, coal steam supplies a greater share of the electric demand.

- Geothermal Electric: Electric generation by geothermal central stations is a preferred technology in 1985 in the BACT, CRUNCH and LOW WEST cases and continues to be desirable through year 2000. These are the cases where price effects on coal production and/or utilization are most severe. In the BACT case, the assumption that every coal plant must have scrubbers stimulates the production of Geothermal electric plants sufficient to generate $.02 \times 10^{12}$ kWhr/year in 1985, and $.22 \times 10^{12}$ kWhr/year in year 2000 (maximum penetration rates).

Geothermal electricity remains unattractive in the Reference Case and Low Demand Case in 1990 and 2000 since coal steam electricity is cheaper. However, Geothermal electric plants become a preferred technology in 1990 and 2000 in the remaining scenarios.

- Solar Electric: Solar electric is an undesirable technology in every scenario except in the High Demand and CRUNCH cases. Here, the combination of high demand and the inability to build additional nuclear or fossil fuel electric generating capacity made solar electricity a desirable technology which penetrates the market to the maximum levels permitted in 1990 and 2000.
- Total Energy Systems: Total Energy Systems, decentralized systems which can provide both electricity and heating for residential/commercial uses, is a preferred technology in both 1990 and 2000 of the High Demand and CRUNCH cases, but unattractive in all other cases. Again, the rising prices of oil and natural gas dictate this behavior.
- Solar Direct: Solar direct, either for space heating or water heating, is never a preferred technology although it becomes increasingly attractive, especially in the High Demand, CRUNCH, and BACT cases.

It is interesting to note that the average delivered price of electricity in the year 2000 is bracketed by the CRUNCH Case, \$54.35/1000 kWhr, at the upper extreme and by the LOW DEMAND Case, \$44.01/1000 kWhr, at the other extreme. See Figure 2. Further, the average price actually decreases very slightly for the LOW DEMAND Case. Except for the CRUNCH and High Demand Cases, the average price of electricity remains relatively stable between 1985 and 2000 owing to the slightly decreased demand growth rate for electricity in the interval 1990 to 2000.

Coal use by electric utilities is bracketed by the CRUNCH Case (47.72 Quads) and the Low Demand Case (18.32 Quads). See Figure 3. Finally, it is worth pointing to Tables 5 through 7 which illustrate the fact that the CRUNCH and High Demand Cases place the most severe strains on coal production and transportation since these imply massive changes in the transportation infrastructure and significant investments in mining capital.

Figure 2. Average price of delivered electricity

Figure 3. Coal use by electric utilities

DEMAND SIDE ANALYSIS

Here we address interfuel substitution effects across all scenarios for Residential/Commercial SPACE HEAT, WATER HEAT and INDUSTRIAL PROCESS STEAM. Four scenarios were selected to perform a cursory "lifestyles" analysis. Appendix A presents the methodology for this analysis.

- Space Heat: Natural gas and electric resistance heating are preferred end-use technologies in 1976 through 1985 across all scenarios and penetrate the market to maximum permitted levels (see Tables 8 through 11 for lifestyle implications). The heat pump is slightly unattractive but is forced in to generate the additional electric demand. Again, the implication is that the heat pump might be cost effective in certain regions where conventional electric resistance heating was used. Use of oil for home heating grows but at a moderate rate.

In 1985 through 1990, natural gas penetrates the space heat market to maximum level only in the BACT, LOW WEST and Low Demand Cases. The reference Case, 1/2 NSPS Case, and Low East Coal Case show moderate growth between 1985 and 1990 whereas natural gas use in the CRUNCH and High Demand Cases is the minimum permitted from the carry-over of old stock. The trend away from maximum permitted penetration of natural gas heating between 1985 and 1990 occurs because of the rapidly increasing costs of natural gas relative to electric resistance and oil heat. Electric resistance heating penetrates the market to the maximum permitted levels between 1985 and 1990 in all cases except the CRUNCH Case and the Low West Case. Electricity prices are highest in the CRUNCH Case and growth in electric resistance heating is reduced to zero between 1985 and 1990.

The trend for the CRUNCH Case continues through 2000. The Low East Case shows growth in electrically heated homes; however, the attractiveness of natural gas relative to electricity prices, the level of heat pump usage again forced in 1990 and the required carryover of oil burners prevented electric resistance heating from taking over more of the space heating market.

In 1990-2000 the level of natural gas usage in homes remains stable for all cases except the High Demand and CRUNCH Case. There the need for additional electricity brought in the development of total energy systems. Hence, waste heat from these systems satisfy the portion of the demand which would have been captured by natural gas. Conventional electric resistance heating becomes unattractive for the High Demand, CRUNCH, Low East and BACT Cases, while the heat pump remains slightly unattractive for all cases.

Tables 13 through 16 summarize the implications of the demand growth rate assumptions on the Aluminum and Steel Industries, while Tables 17 and 18 summarize the implications of auto travel assumptions for the Reference Case, CRUNCH, High Demand Case and Low Demand Cases.

- Water Heat: Natural gas for residential/commercial water heating is a favored technology through 1990 in all scenarios, capturing as much as possible of the permitted market. However, the price of natural gas outstrips that of oil by 2000 and makes it less attractive than either oil or electric water heaters. Electric water heaters show a moderate rate of growth across all scenarios while never penetrating the market to the maximum level permitted. It should be noted that

part of the attractiveness of electric water heat is due to the fact that electric water heat is used as a peak leveling demand which does not usually require the installation of additional generating capacity.

FLUIDIZED BED COMBUSTION (FBC) ELECTRIC UTILITY

Here we discuss the potential penetration of fluidized bed coal steam plants in each of the eight scenarios for the year 2000. Most likely market penetration assumptions were based on the MOPPS study⁵, which indicated very small penetrations to 1990 (.8 GW installed capacity) but potential rapid expansion thereafter. See Appendix B for the cost, technological and environmental summary of the FBC technology. Assuming a .70 utilization factor for coal steam electric plants and a .65 utilization factor for FBC utilities we obtain the annualized plant cost of generating a million Btu of electricity (excluding fuel costs):

	Cost (\$/MMBtu(e))
Conventional Coal Steam with Partial Scrub:	5.56
Conventional Coal Steam with Full Scrub:	6.50
Fluidized Bed:	3.83

The break-even cost (at which a technology becomes competitive) of FBC electric utilities in year 2000 is determined by the cost of competing generation technologies. However, since oil and gas steam electric plants are already at the minimum levels permitted by retirement in all but the High Demand and CRUNCH cases, the actual cost at which FBC would become competitive in these cases is determined by the cost of generating electricity by conventional coal steam electric plants. The actual break-even cost of FBC electricity generated, excluding transmission, distribution and fuel costs is:

$$\begin{aligned}\text{Breakeven FBC} &= \frac{\text{conversion eff of FBC}}{\text{conversion eff of coal steam}} * \text{cost coal steam} \\ &= \frac{.39}{.35} * 5.56 = \$6.20/\text{MMBtu (e)}\end{aligned}$$

For the High Demand and CRUNCH cases the break-even costs are, in fact, determined by the costs of oil and gas steam electric plants. For a utilization factor of .70 for oil and gas steam electric plants, the cost (including fuels, transmission and distribution and mark-ups) for the year 2000 is (\$/MMBtu)

gas steam:	21.53
oil steam:	21.41
coal steam:	
(a) (partial scrub):	11.68
High Demand	
(b) CRUNCH Case:	14.48

Evidently, the real break-even cost of FBC, in these two cases is 21.53. The substitutions which would result initially, however, would be FBC electric utility for conventional coal steam electric, thereby releasing coal for process steam which would reduce in turn gas and oil use for process steam, where possible. The secondary effects would be substitution of FBC for conventional coal steam electric and oil and gas steam electric (since coal supplies are limited).

Further, if the sulfur content (by weight) is less than 2.1% then FBC will satisfy both the BACT and 1/2 NSPS environmental restrictions; coal with sulfur content in excess of 4.5% can be used for which the BACT and NSPS restrictions will be satisfied.

Gas steam and oil steam electric plants are at the minimum levels permitted by retirement in all cases except the High Demand and CRUNCH Cases. LWR, Hydroelectric are more desirable than coal steam electric for all cases.

PROCESS STEAM APPLICATIONS

We assume that the capital costs in Appendix B apply (\$125/KW(e)). The cost assumptions become

Capital Cost (\$/10 ⁶ Btu delivered) (CRF = .13)	
Fluidized bed	= .24
Heat Exchangers (\$/10 ⁶ Btu delivered	= .02
(assumes 1/3 cost of conventional gas equipment for process heat)	
O & M (\$/10 ⁶ Btu delivered)	= .30
TOTAL (\$/10 ⁶ Btu delivered)	.56
- excluding fuel costs	

The cost (including annualized end use devices) per million Btu of refined fuel input to the end-use device is given by the table below.

PROCESS STEAM COSTS* (\$/10⁶ Btu Refined Fuel Input)

	1990				2000			
	OIL (1)	NG (1)	COAL (2)	FBC (2)	OIL (1)	NG (1)	COAL (2)	FBC (2)
SET 1 (3)	4.06	3.87	1.34	1.72	5.20	5.32	1.50	1.88
CRUNCH	4.06	3.87	1.72	2.10	5.20	5.32	1.97	2.35
SET 2 (4)	4.06	3.87	1.39	1.77	5.20	5.32	1.50	1.88

(1) Oil and natural gas prices do not vary across scenarios for a particular year.

(2) Cheapest coal available is assumed used.

(3) SET 1: Reference, High Demand, BACT, Low EAST, Low Demand Cases.

(4) Set 2: Low West and 1/2 NSPS Cases.

NOTE: These costs include the annualized cost of end-use devices used for process steam.

If the end use conversion efficiencies in year 2000 for process steam are

• oil	.78
• gas	.73
• conventional coal	.80
• FBC	.95

then the cost of delivered energy for process steam is

• oil	\$6.67/MMBtu
• gas	\$7.28/MMBtu
• conventional coal	\$1.88 (best)
	\$2.46 (worst)
• FBC	\$1.98 (best)
	\$2.47 (worst)

Clearly the FBC technology is a technology preferred to oil or gas for process steam and nearly competitive to conventional coal process steam.

ENVIRONMENTAL EFFECTS

Table 23 summarizes the inventory of air quality environmental effects for the Reference Case where as Tables 19 through 22 summarize the SO_2 , Particulate, NO_x and Hydrocarbon effluents as they vary across scenarios. For a given level of demands and control devices, the SO_2 emissions are not very sensitive to the pricing strategies--showing less than a 2% fluctuation. However, when either the 1/2 NSPS or BACT environmental assumptions are imposed overall, SO_2 emissions drop by more than 51% over the Reference Case levels. Similar comments apply for particulates except that particulate emissions are reduced by more than 50% for similar demands but different BACT or 1/2 NSPS emission standards.

This is not surprising in view of the fact that overall coal use is not sensitive to the levels of price perturbations postulated for coal, given the price increases for oil and gas postulated by the study. The study indicates that the most effective way to reduce effluents is through conservation. Tables 24 - 26 compare six potential alternate objective functions for the eight scenarios. The environmental index, a weighted average of the levels environmental effluents, reinforces this conclusion; a 16% reduction in resources used in the Reference Case leads to a 30% improvement in the Environmental Index and a 13% decrease in the annual system cost.

IV. Conclusions

The Electric Power Research Institute created the Energy Modeling Forum (EMF) to improve the practical application of energy models to policy issues and planning. Administered by the Stanford University Institute for Energy Studies, the EMF operates through a series of working groups of energy model developers and users conducting comparative tests of a variety of energy models. Models are examined in the context of an important topic in energy decision making. The present study pursues the application of several models in the analysis of coal use during the period from 1980 to 2000.

The working group included technical teams or experts associated with each model. The group developed a common set of assumptions and scenarios for analysis to compare the results of the models. The comparisons are conducted to uncover differences and similarities in the models' treatment of the major forces affecting the coal transition, e.g., the effects of different air pollution standards.

The results obtained by TESOM from the common set of assumptions are entirely intuitive.

The total demand for coal will rise substantially over the next twenty years given the studies assumed rise in the price of oil and the assumed maximum level of nuclear power generation. Under these conditions there is a strong economic advantage for coal over oil and gas in all new base load electricity generation plants - even in the presence of environmental standards as strict as the use of "Best Available Control Technology."

The potential for substitution moderates the changes in the cost of electric power across different scenarios. However, the gradual introduction of higher capital cost new plants, the retirement of old plants and the increasing prices of all crude fuels produces an upward trend in the price of electricity demand.

There are environmental problems associated with coal utilization which we have been unable to treat in this study. For example, the translation of air pollutant emissions into health effects has not been done here because at present, the relation of aggregate emissions to regional air quality is not fully understood.

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APPENDIX A

APPENDIX A -- METHODOLOGY FOR COMPUTING LIFESTYLE IMPLICATIONS

I. RESIDENTIAL - COMMERCIAL SPACE HEAT

A fifty-fifty split was assumed for space heating demands between the residential and commercial sectors. For residential space heating demands, population projections were taken from estimates by the BUREAU OF CENSUS, SERIES 2⁽⁶⁾ and household projections were taken from Series C⁷.

	POPULATION (millions)	PEOPLE PER HOUSEHOLD
1985	234.7	2.80
1990	245.1	2.70
2000	262.5	2.60

Then the number of households utilizing each type of heating unit in each year is

$$\text{No. Households Using Fuel (i)} = \frac{\text{Fuel Input}_i \cdot \text{Efficiency}_i \cdot \text{Total Households}}{\text{Total Space Heat Demand}}$$

II. COMMERCIAL FLOOR SPACE INVENTORY

Commercial floor space was assumed to grow in a manner proportional to the growth in space heating demand.

III. INDUSTRIAL SECTOR

ALUMINUM: Growth in aluminum production was assumed to be proportional to the growth in energy demand by the sector. Further, in the period 1976 through 1985 25% of aluminum is assumed to be produced from scrap metal while the fraction rises to 33.3% thereafter.

STEEL PRODUCTION: The production of steel was proportional to the increase in the aggregate fuel specific demands by the steel industry.

IV. AUTOMOBILE DEMANDS

The energy content per gallon of gasoline, the miles per gallon for the average fleet vehicle and the average miles traveled per vehicle yield

IV. AUTOMOBILE DEMANDS (Cont'd)

$$\text{Miles Traveled} = \text{Btu INPUT} * \frac{\text{gals}}{\text{gal}} * \frac{\text{miles}}{\text{gal}}$$

$$\text{No. Vehicles} = \text{Miles Traveled} \div \frac{10,200 \text{ miles}}{\text{vehicle}}$$

The vehicles per person over 16 requires the number of people aged sixteen or greater.

1985 : 176.3

1990 : 183.3

2000 : 199.6

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APPENDIX B

APPENDIX B

COSTS AND TECHNICAL PARAMETERS ASSOCIATED WITH FBC POWER PLANT

1. Plant Type:	Pressurized Fluidized Boiler Combined Cycle Regenerative, Limestone-Dolomite System, 600 MWe
2. Capital Cost (\$kWe):	
(i) Boiler Plant Equipment ^a	
Boiler	20.16
Related Equipment (coal Handling & Feeding, Par- ticulate Removal, Piping/Ducts, etc.)	53.76
TOTAL	73.92
(ii) Two Step Limestone-Dolomite Regenerative System ^b	51.52
(iii) Other ^c (Turbines, Generators, Land, Structures, etc.)	<u>183.68</u>
SUBTOTAL	309.12
TOTAL (Including escalation, interest during construc- tion, etc.-45% ^c)	448.00
3. Energy Cost (\$10 ⁶ BTU(e)), bus bar costs	
Fixed Charges	3.45
O & M Cost ^e	.38
TOTAL (excluding coal cost and transmission and distribution costs)	3.83

a. Adopted from Reference 8, p. 25 and escalated to 1975 dollars. Escalation factor (1.42) was obtained by comparing our 1985 \$ cost estimates with those of Reference 8, p. 10 for conventional coal steam electric plant with scrubber.

b. Reference 9, p. 500.

c. Reference 8, p. 25.

For the sake of comparison we include the cost ($\$/10^6 \text{Btu(e)}$) of generating electricity excluding transmission, distribution and fuel costs. We assume a 70% plant factor for conventional coal fired and coal combined cycle plants and a 65% utilization factor for the fluidized bed combustors to account for the extra maintenance time anticipated.

COST
($\$/\text{MMBtu(e)}$)

Conventional Coal Steam	
with Partial Scrubbers:	5.56
Conventional Coal Steam	
with Full Scrubbers:	6.50
Fluidized Bed Combustion:	3.83

"Most likely" market penetrations for fluidized bed combustion in electric utilities were taken from the MOPPS study³ which indicated very small penetrations to 1990 (.8 GW installed capacity) but rapid expansion thereafter (5.6 GW installed capacity in 2000).

Evidently, fluidized bed combustion power plants easily satisfy the NSPS and BACT (90% removal) environmental standards for coal combustion for coal containing sulfur in excess of 4%. However, to satisfy the 1/2 NSPS environmental standard, the sulfur content must be less than 2.1% which is not severe enough to necessitate a premium on low sulfur coal. Further, additional particulate controls are never required.

Efficiency:

Coal combustion efficiency = 0.90 - 0.98

Overall Coal-to Electric efficiency -

 Pressurized FBC ^f = 0.41

 Atmospheric FBC ^f = 0.35

-
- d. Annual fired charge rate of 15% and plant factor equal to .65 has been used in computing this cost.

Emissions

- (i) Nitrogen Oxides^g
 - Pressurized FBC -
 No_x ranges between 0.30 to 0.73 lb/10⁶ Btu (e)
 - Atmospheric FBC -
 No_x ranges between 0.71 to 1.71 lb/10⁶ Btu (e)
- (ii) Sulfur Oxides^h
 - It varies with sulfur content of coal.
 - High Sulfur Coal -
 $\text{SO}_x = 2.15 \text{ lbs}/10^6 \text{ Btu (e)}$
 - Low Sulfur Coal -
 $\text{SO}_x = .35 \text{ lbs}/10^6 \text{ Btu (e)}$
- (iii) Particulatesⁱ
 - Particulate emission depends on sulfur content of coal.
 - High Sulfur Coal -
 $\text{Particulates} = 0.05 \text{ lbs}/10^6 \text{ Btu(e)}$
 - Low Sulfur Coal -
 $\text{Particulates} = 0.04 \text{ lbs}/10^6 \text{ Btu(e)}$

-
- e. This cost is derived by escalating the value on P. VI-7 of Ref. 10 by 24% to convert 1972 \$ to 1975 \$. This value includes cost of limestone at \$5.40/ton. The regenerative system cuts down the requirement of limestone from 0.2 ton/ton of coal to .05 ton/ton of coal. Good agreement is found between this figure and the one given on p. 10 of Ref. 5 after escalation, if adjustment is made for regenerative limestone system in the latter figure.
 - f. Reference 11, p. 69.
 - g. Reference 11, p. 70.
 - h. Derived from table on p. VI-7 of reference 10. Variation with respect to pressurized and atmospheric FBC is small. The value in the table corresponds to the larger of the two.
 - i. Derived from table on p. VI-7 of reference 10.

APPENDIX C

APPENDIX C

DESCRIPTION OF BESOM

The energy system, on a regional or national level, may be represented in a network format as shown in Figure 1. The network in this case is quantified with the energy flows for the year 1976 from alternate resources through the various energy conversion and delivery activities to specific end uses. Each link in the network represents a process or mix of processes used for a given activity such as the refining of crude oil. Costs and environmental effects may be assigned to each link. Similar energy system diagrams have been developed for the purpose of technology assessment for selected future years.¹² Examination of the energy demand sectors at the right-hand side of the diagram indicates the degree of disaggregation that is required in the demand sectors. To evaluate the potential benefits of a high-efficiency air-conditioner, for example, it is necessary to define the demand level for this specific end use and to estimate the degree of implementation of the improved system whether such implementation comes about purely from competitive market forces or from a policy or regulatory decision. It is also necessary, particularly in the example of the air-conditioner, to establish the electrical load-duration characteristics of the demand sectors, as the type of generating equipment installed to serve that demand depends strongly on the load factor.

It is possible to develop energy system diagrams by specifying the fuel mix and technology mix at some future point in time on the basis of available forecasts and trend analysis. In view of changing prices, demand levels, and fuel supplies it is desirable to have an analytical model that will indicate optimal fuel mix configurations within the resource, environmental, and

demand constraints that operate on the energy system. The linear programming model provides this function. Rather than using a network algorithm for further analysis and optimization, the energy system diagrams may be transformed to a simpler structure. Figure 4 indicates that a given resource may be converted to electricity and one, or in some instances several, general-purpose fuels. Rather than to reflect these in a network structure it is convenient in the linear program to consider them as alternate supply categories subject, when appropriate, to a single resource constraint.

The model is formulated about the classical transportation problem of determining the optimal routing of a product, in this case an intermediate energy form, from a set of n supply nodes to m demand nodes where a cost and a set of environmental impacts are identified for a unit of energy passing over each of the $n \times m$ possible paths. The typical linear programming representation of the transportation problem is modified by the inclusion of efficiency coefficients in the supply and demand constraints and is augmented by additional constraint equations reflecting the environmental factors as well as certain technical features of the energy system.

The n supply nodes and m demand nodes can include all supply and demand categories. To provide a feasible path between a supply and demand category, both a supply and utilizing technology must be identified. For a given path, j , a resource S_u is converted to intermediate energy form, x_j , at an efficiency, e_{uj} . In turn, the intermediate energy form is used to satisfy demand D_v at an efficiency d_{vj} . A cost c_j and set of environmental effects, included in f_j , are also defined per unit of intermediate energy form.

In the model the intermediate energy form is defined at the point just before end-use, i.e., on the line between decentralized conversion and the utilizing device on the Reference Energy

System (Figure 1). Intermediate energy forms include transmitted and distributed electricity, gasoline in an automobile, oil in a home oil tank, for example. The supply efficiency is calculated by multiplying together all the supply efficiencies on the path from the resource to the intermediate energy form; similarly the demand efficiency is calculated by multiplying together all the demand efficiencies on the path from the intermediate energy form to final demand. The efficiencies and environmental impacts associated with each activity in the Reference Energy System are taken from the Energy Model Data Base¹³. An activity such as extraction may have several processes associated with it, such as strip-mining or underground mining of coal. Each process has certain impacts. The Energy Model Data Base specifies the fraction of the total activity each process represents, so that total impacts for each activity can be calculated and summed up along the path from resource to demand. The resulting efficiency and environmental effect coefficients are input to the linear programming model.

The mathematical formulation of the model is as follows:
Minimize

$$\sum_{j=1}^P c_j x_j ,$$

subject to

$$\sum_j \frac{1}{e_{uj}} x_j \leq S_u \quad u = 1, n ,$$

$$\sum_j d_{vj} x_j = D_v \quad v = 1, m ,$$

$$\sum_j f_{wj} x_j \leq B_w \quad w = 1, \ell$$

where f_{wj} are the unit emissions per unit energy delivered and B_w is the maximum permitted level.

and

$$x_j \geq 0. \quad (1)$$

The summation in each constraint equation is over only those indices j that represent admissible intermediate energy forms for the supply category, demand category, or other constraint. The full linear program array thus has $k = n+m+l$ constraints and these may be represented as:

$$\sum_{j=1}^p a_{ij} x_j \leq b_i \quad i = 1, k, \quad (2)$$

where the a_{ij} include e_{uj} , d_{vj} , and f_{wj} in the previous formulation and the b_i correspond to the S_u , D_v , and B_w . See Reference 1 for a more complete description.

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APPENDIX D

TABLE 1: CENTRAL STATION CHARACTERISTICS*

	Capital Cost \$/kW	Conversion Efficiency		O&M (mills/kWhr)
		<u>1985</u>	<u>2000</u>	
Coal Steam	558**	.34**	.35**	3.53**
Coal Combined Cycle	375	.44	.45	4.61
Oil Steam Electric	435	.33	.33	1.69
Gas Turbines	203	.28	.30	2.31
Gas Steam Electric	391	.33	.33	1.54
Total Energy Systems	478	.25	.30	4.88
LWR	848	.34	.34	1.20
Hydroelectric	449	.34	.34	.92
Geothermal Electric	1217	.34	.34	2.31
Solar Electric	1739	.34	.34	2.31
Pumped Storage	290	.75	.75	.92

* These characteristics refer to the Reference Case, High Demand Case, Low East Case, Low West Case, Low Demand Case and the 1/2 NSPS Case.

** Includes partial scrub costs and effects.

TABLE 2: CENTRAL STATION CHARACTERISTICS*

	Capital Cost \$/KW	Conversion Efficiency		O&M (mills/kWhr)
		1985	2000	
Coal Steam	627**	.33**	.34**	5.05**
Coal Combined Cycle	375	.44	.45	4.61
Oil Steam Electric	435	.33	.33	1.69
Gas Turbines	203	.28	.30	2.31
Gas Steam Electric	391	.33	.33	1.54
Total Energy Systems	478	.25	.30	4.88
LWR	848	.34	.34	1.20
Hydroelectric	449	.34	.34	.92
Geothermal Electric	1217	.34	.34	2.31
Solar Electric	1739	.34	.34	2.31
Pumped Storage	290	.75	.75	.92

* These characteristics refer to the CRUNCH and BACT cases.

** These include full scrubbing options.

TABLE 3: CRUDE FUEL COSTS

	Oil (\$/MMBtu)	Natural Gas (\$/MMBtu)	Nuclear (\$/MMBtu)
1985	2.95	2.60	.50
1990	3.38	3.30	.52
2000	4.43	4.63	.65

CRUDE COAL COSTS (\$/MMBtu)

	<u>Underground</u>			<u>Stripmined</u>		
	<u>1985</u>	<u>1990</u>	<u>2000</u>	<u>1985</u>	<u>1990</u>	<u>2000</u>
Reference Case	1.02	1.07	1.18	.95	1.02	1.18
High Demand	1.02	1.07	1.18	.95	1.02	1.18
BACT Case	1.02	1.07	1.18	.95	1.02	1.18
Low East	1.21	1.40	1.88	.95	1.02	1.18
CRUNCH Case	1.21	1.40	1.88	1.33	1.43	1.65
Low West	1.02	1.07	1.18	1.33	1.43	1.65
Low Demand	1.02	1.07	1.18	.95	1.02	1.18
1/2 NSPs	1.02	1.07	1.18	1.20	1.26	1.40

TABLE 4: SUPPLEMENTARY FUEL COSTS

(\$/MMBtu)

	<u>Residential/Comm. and Transportation</u>	<u>Utility</u>	<u>Industrial</u>
Gasoline	3.02		
Distillate	1.29	0.95	1.20
Residual		0.95	1.20
Kerosene	1.44		
Coal		0.32	0.46
Natural Gas	0.89	1.45	1.45

TABLE 5:

ANNUAL GROWTH IN COAL CONSUMPTION RATES FOR COAL STEAM ELECTRIC (%/YEAR)

	<u>1976-1985</u>	<u>1985-1990</u>	<u>1990-2000</u>
Reference Case	6.6	3.6	3.5
High Demand	8.1	11.0	3.1
BACT Case	6.9	2.6	1.8
Low East Coal	6.6	3.0	2.0
CRUNCH Case	8.3	11.1	2.9
Low West Coal	6.5	2.6	3.0
Low Demand	4.4	3.3	0.4
1/2 NSPS Case	6.6	3.0	2.7

TABLE 6: OVERALL GROWTH RATES IN PRODUCTION OF COAL (%/YEAR)

	<u>1976-1985</u>	<u>1985-1990</u>	<u>1990-2000</u>
Reference Case	7.0	5.2	4.7
High Demand	8.3	10.0	4.4
BACT Case	7.1	4.6	4.2
Low East Coal	7.0	4.8	3.8
CRUNCH Case	8.5	9.6	4.4
Low West Coal	6.9	4.6	4.4
Low Demand	5.3	3.7	2.0
1/2 NSPS Case	7.0	4.8	4.2

TABLE 7: TOTAL COAL CONSUMPTION (10^{15} Btu)

	<u>1985</u>	<u>1990</u>	<u>2000</u>
Reference Case	26.03	35.58	53.03
High Demand	29.00	46.68	72.00
BACT Case	26.43	33.02	49.73
Low East Coal	26.03	32.93	47.89
CRUNCH Case	29.47	46.68	71.99
Low West Coal	25.88	32.41	49.82
Low Demand	22.56	27.06	32.89
1/2 NSPS Case	26.03	32.93	49.82

1976 - all cases 14.17 Quads

TABLE 8:

RESIDENTIAL SPACE HEAT BY FUEL TYPE, REFERENCE CASE (10^6 HOUSEHOLDS)

	<u>1976</u>	<u>1985</u>	<u>1990</u>	<u>2000</u>
Gas	38.0	44.9	46.9	47.1
Oil	26.9	24.4	21.5	34.7
Elect. Resistance	5.7	8.3	11.1	12.3
Heat Pump	-	6.6	10.6	7.6
Coal	1.4	-	-	-
Total	72.0	84.2	90.1	101.8

TABLE 9:

RESIDENTIAL SPACE HEAT BY FUEL TYPE, BACT CASE (10^6 HOUSEHOLDS)

	<u>1976</u>	<u>1985</u>	<u>1990</u>	<u>2000</u>
Gas	38.0	44.9	48.8	47.0
Oil	26.9	24.5	21.4	40.6
Elect. Resistance	5.7	8.4	9.3	6.6
Heat Pump	-	6.6	10.6	7.7
Coal	1.4	-	-	-
TES	-	-	-	-
Total	72.0	84.2	90.1	101.8

TABLE 10: RESIDENTIAL SPACE HEAT BY FUEL TYPE, CRUNCH CASE,
HIGH DEMAND (10⁶ HOUSEHOLDS)

	<u>1976</u>	<u>1985</u>	<u>1990</u>	<u>2000</u>
Gas	38.0	42.6	36.5	29.6
Oil	26.9	26.6	35.9	58.7
Elect. Resistance	5.7	8.9	7.0	4.8
Heat Pump	-	6.1	10.7	7.5
TES	-	-	-	1.2
Coal	1.4	-	-	-
Total	<u>72.0</u>	<u>84.2</u>	<u>90.1</u>	<u>101.8</u>

TABLE 11: RESIDENTIAL SPACE HEAT BY FUEL TYPE, LOW DEMAND (10⁶ HOUSEHOLDS)

	<u>1976</u>	<u>1985</u>	<u>1990</u>	<u>2000</u>
Gas	38.0	48.8	50.6	49.8
Oil	26.9	18.1	16.9	31.6
Elect. Resistance	5.7	10.2	11.5	12.4
Heat Pump	-	7.1	11.1	8.0
Coal	1.4	-	-	-
Total	<u>72.0</u>	<u>84.2</u>	<u>90.1</u>	<u>101.8</u>

TABLE 12: COMMERCIAL INVENTORY (10^9 Sq Ft)

	<u>1976</u>	<u>1985</u>	<u>1990</u>	<u>2000</u>
Reference Case	25.3	32.9	36.2	42.0
CRUNCH Case	25.3	34.7	38.7	46.6
Low Demand	25.3	30.3	34.8	39.7
High Demand	25.3	34.7	38.7	46.6

TABLE 13

ALUMINUM PRODUCTION - REFERENCE CASE

	<u>1985</u>	<u>1990</u>	<u>2000</u>
Total* Production (10^9 lbs.)	27.7	32.8	50.3
Primary Production (10^9 lbs.)	20.8	22.0	33.7

* 25% of total aluminum production is produced from scrap in 1985 and 1/3 thereafter

STEEL PRODUCTION - REFERENCE CASE

	<u>1985</u>	<u>1990</u>	<u>2000</u>
Production (10^6 tons)	166	178	255

TABLE 14.

ALUMINUM PRODUCTION - HIGH DEMAND

	<u>1985</u>	<u>1990</u>	<u>2000</u>
Total* Production (10 ⁹ lbs.)	31.2	60.1	74.3
Primary Production (10 ⁹ lbs.)	23.4	40.3	49.8

* 25% of total aluminum production is produced from scrap in 1985 and 1/3 thereafter.

STEEL PRODUCTION - HIGH DEMAND

	<u>1985</u>	<u>1990</u>	<u>2000</u>
Production (10 ⁶ tons)	185	245	331

TABLE 15

ALUMINUM PRODUCTION - CRUNCH CASE

	<u>1985</u>	<u>1990</u>	<u>2000</u>
Total* Production (10 ⁹ lbs.)	29.3	52.5	83.1
Primary Production (10 ⁶ lbs)	22.0	35.2	55.7

* 25% of total aluminum production is produced from scrap in 1985 and 1/3 thereafter.

STEEL PRODUCTION - CRUNCH CASE

	<u>1985</u>	<u>1990</u>	<u>2000</u>
Production (10 ⁶ tons)	185	247	347

TABLE 16
ALUMINUM PRODUCTION - LOW DEMAND CASE

	<u>1985</u>	<u>1990</u>	<u>2000</u>
Total* Production (10 ⁹ lbs.)	25.4	31.7	36.1
Primary Production (10 ⁹ lbs.)	19.0	21.3	24.2

* 25% of total aluminum production is produced from scrap in 1985 and 1/3 thereafter.

STEEL PRODUCTION - LOW DEMAND CASE

	<u>1985</u>	<u>1990</u>	<u>2000</u>
Production (10 ⁶ tons)	146	158	227

TABLE 17
AUTOMOBILE

REFERENCE CASE	<u>1985</u>	<u>1990</u>	<u>2000</u>
Fuel Economy (mpg)	20.9	25.0	28.4
Miles/Vehicle	10,200	10,200	10,200
Vehicles/Population over 16	.70	.88	.96
Total Vehicles (millions)	116.4	161.6	191.0
Total VMT (billions)	1,187.6	1,648.6	1,947.9

CRUNCH CASE

Fuel Economy (mpg)	20.9	25.0	28.4
Miles/Vehicle	10,200	10,200	10,200
Vehicles/Population over 16	.74	.90	1.01
Total Vehicles (millions)	131.2	165.4	201.61
Total VMT (billions)	1,338.1	1,686.6	2,056.1

TABLE 18
AUTOMOBILE

LOW DEMAND	<u>1985</u>	<u>1990</u>	<u>2000</u>
Fuel Economy (mpg)	20.9	25.0	28.4
Miles/Vehicle	10,200	10,200	10,200
Vehicles/Population over 16	.66	.81	.85
Total Vehicles (MILLIONS)	116.4	148.5	169.8
Total VMT (billions)	1,187.6	1,514.6	1,731.9

HIGH DEMAND

Fuel Economy (mpg)	20.9	25.0	28.4
Miles/Vehicle	10,200	10,200	10,200
Vehicles/Population over 16	.74	.90	1.01
Total Vehicles (millions)	131.2	165.4	201.61
Total VMT (billions)	1,338.1	1,686.6	2,056.1

TABLE 19: INVENTORY OF SO₂
SO₂ EMISSIONS (10⁶ TONS)

	1985			1990			2000		
	<u>CNTRL</u>	<u>DCNTR</u>	<u>TOTAL</u>	<u>CNTRL</u>	<u>DCNTR</u>	<u>TOTAL</u>	<u>CNTRL</u>	<u>DCNTR</u>	<u>TOTAL</u>
REF. CASE	4.92	6.13	11.05	5.38	7.99	13.37	7.02	12.78	19.73
HIGH DEMAND	5.45	6.96	12.41	8.66	9.58	18.24	10.89	15.97	26.85
BACT CASE*	2.50	3.07	5.57	2.74	3.96	6.69	3.25	6.39	9.64
LOW EAST COAL	4.92	6.27	11.19	5.45	7.88	13.33	6.13	13.02	19.15
CRUNCH CASE	2.77	3.41	6.19	4.44	4.72	9.16	5.52	7.92	13.44
LOW WEST COAL	4.89	6.13	11.02	5.34	8.07	13.41	6.51	12.83	19.34
LOW DEMAND	4.17	4.85	9.01	4.47	6.08	10.55	4.45	8.78	13.23
1/2 NSPS*	2.46	3.07	5.53	2.73	3.94	6.67	3.26	6.44	9.70

*NOTE: The BACT Case and the 1/2 NSPS Case are indistinguishable in the model.

TABLE 20: INVENTORY OF PARTICULATES

PARTICULATE EMISSIONS (10^5 TONS)

	1985			1990			2000		
	<u>CNTRL</u>	<u>DCNTR</u>	<u>TOTAL</u>	<u>CNTRL</u>	<u>DCNTR</u>	<u>TOTAL</u>	<u>CNTRL</u>	<u>DCNTR</u>	<u>TOTAL</u>
REF. CASE	4.95	65.29	70.24	5.44	92.65	98.09	7.14	193.47	200.61
HIGH DEMAND	5.47	71.20	76.68	8.73	90.77	99.50	11.23	220.45	231.68
BACT CASE*	1.68	21.76	23.44	1.83	30.83	32.66	2.20	63.99	66.27
LOW EAST COAL	4.95	65.40	70.35	5.47	92.46	97.93	6.21	192.78	198.99
CRUNCH CASE	1.86	23.72	25.58	2.99	26.23	29.22	3.81	70.63	74.45
LOW WEST COAL	4.92	65.22	70.14	5.37	92.67	98.04	6.61	193.73	200.33
LOW DEMAND	4.20	61.07	65.27	4.52	61.00	65.52	4.53	96.07	100.61
1/2 NSPS*	1.65	21.75	23.40	1.83	30.83	32.66	2.21	64.63	66.83

*NOTE: The BACT Case and the 1/2 NSPS Case are indistinguishable in the model.

TABLE 21: INVENTORY OF NO_xNO_x EMISSIONS (10⁶ TONS)

	1985			1990			2000		
	<u>CNTRL</u>	<u>DCNTR</u>	<u>TOTAL</u>	<u>CNTRL</u>	<u>DCNTR</u>	<u>TOTAL</u>	<u>CNTRL</u>	<u>DCNTR</u>	<u>TOTAL</u>
REF. CASE	8.44	17.91	26.36	9.40	17.28	26.68	12.52	20.49	33.01
HIGH DEMAND	9.37	17.78	27.16	15.08	19.30	34.89	19.79	23.54	43.34
BACT CASE	8.59	17.92	26.51	9.41	17.71	27.12	11.46	20.55	32.01
LOW EAST COAL	8.44	17.90	26.35	9.37	17.57	26.95	10.79	20.70	31.50
CRUNCH CASE	9.59	18.39	27.94	15.47	19.77	35.24	20.20	23.58	43.78
LOW WEST COAL	8.39	17.87	26.27	9.18	17.71	26.90	11.49	20.56	32.06
LOW DEMAND	7.14	15.22	22.37	7.79	15.69	23.48	7.86	17.30	25.17
1/2 NSPS	8.44	17.88	26.32	9.37	17.57	26.95	11.49	20.58	32.08

TABLE 22: INVENTORY OF HYDROCARBONS

	HYDROCARBON EMISSIONS (10^5 TONS)								
	1985			1990			2000		
	<u>CNTRL</u>	<u>DCNTR</u>	<u>TOTAL</u>	<u>CNTRL</u>	<u>DCNTR</u>	<u>TOTAL</u>	<u>CNTRL</u>	<u>DCNTR</u>	<u>TOTAL</u>
REF. CASE	2.26	41.19	43.45	2.35	45.90	48.26	4.87	60.35	65.22
HIGH DEMAND	2.41	42.31	44.73	3.71	51.68	55.39	10.20	66.98	77.19
BACT CASE	2.52	41.21	43.74	2.60	46.47	49.08	8.24	57.64	65.88
LOW EAST COAL	2.26	41.16	43.42	2.59	46.65	49.25	8.13	59.18	67.31
CRUNCH CASE	2.68	42.99	45.68	3.77	51.58	55.63	10.38	67.11	77.50
LOW WEST COAL	2.49	41.18	43.68	2.56	46.59	49.16	8.24	60.98	69.23
LOW DEMAND	2.04	35.80	37.84	2.08	38.73	40.81	4.09	53.91	58.01
1/2 NSPS	2.26	41.19	43.45	2.59	46.65	49.25	8.24	61.07	69.32

TABLE 23: ENVIRONMENTAL EFFECTS

INVENTORY FOR EMF REFERENCE CASE

	<u>1985</u>	<u>1990</u>	<u>2000</u>
CENTRALIZED AIR POLLUTANTS			
Carbon Dioxide (CO ₂) 10 ⁸ Tons	24.78	27.84	37.54
Carbon Monoxide (CO) 10 ⁶ Tons	.37	.45	6.41
Nitrogen Oxides (NO _x) 10 ⁶ Tons	8.45	9.40	12.52
Sulfur Dioxide (SO ₂) 10 ⁶ Tons	16.80	14.22	7.02
Particulates 10 ⁵ Tons	8.86	8.38	7.14
Hydrocarbons 10 ⁶ Tons	.23	.24	.49
DECENTRALIZED AIR POLLUTANTS			
Carbon Dioxide (CO ₂) 10 ⁸ Tons	35.39	37.44	45.25
Carbon Monoxide (CO) 10 ⁶ Tons	12.50	12.16	13.84
Nitrogen Oxides (NO _x) 10 ⁶ Tons	17.92	17.29	20.49
Sulfur Dioxide (SO ₂) 10 ⁶ Tons	6.13	7.99	12.71
Particulates 10 ⁵ Tons	65.29	92.64	193.46
Hydrocarbons 10 ⁶ Tons	4.19	4.59	6.04
TOTAL AIR POLLUTANTS			
Carbon Dioxide (CO ₂) 10 ⁸ Tons	60.17	65.29	82.80
Carbon Monoxide (CO) 10 ⁶ Tons	12.87	12.61	14.48
Nitrogen Oxides (NO _x) 10 ⁶ Tons	26.36	26.69	33.01
Sulfur Dioxide (SO ₂) 10 ⁶ Tons	22.93	22.21	19.31
Particulates 10 ⁵ Tons	74.15	101.02	200.62
Hydrocarbons 10 ⁶ Tons	4.35	4.83	6.52

TABLE 24: ALTERNATE OBJECTIVE FUNCTIONS, YEAR 1985

	Imported plus Domestic Oil (10^{15} Btu)	Total System Cost W/EUD (\$ 10^9)	Resources Used (10^{15} Btu)	Capital Cost W/EUD (\$ 10^9)	Capital Cost W/O EUD (\$ 10^9)	Environmental Index
Reference Case	37.41	559.4	95.8	1850	589.0	496.2
High Demand	40.49	588.9	101.9	1932	629.0	529.0
BACT Case*	37.41	565.9	96.4	1852	591.0	≤ 497
Low East Coal	37.41	561.8	95.8	1850	589.2	496.9
CRUNCH	40.49	604.3	102.5	1931	627.6	$\leq 520^*$
Low West Coal	37.41	563.4	95.8	1851	590.0	494.6
Low Demand	31.10	495.0	86.05	1641	533.9	424.2
1/2 NSPS	37.41	562.2	95.8	1850	589.2	397.1*

NOTE: The BACT Case and the 1/2 NSPS Case are indistinguishable for SO_2 and Particulates. We assume that BACT implies at least NSPS standards are met.

TABLE 25: ALTERNATE OBJECTIVE FUNCTIONS, YEAR 1990

	Imported plus Domestic Oil (10^{15} Btu)	Total System Cost W/EUD (\$ 10^9)	Resources Used (10^{15} Btu)	Capital Cost W/EUD (\$ 10^9)	Capital Cost W/O EUD (\$ 10^9)	Environmental Index
Reference Case	37.79	630.4	106.7	2023	736.6	517.2
High Demand	48.68	756.6	131.1	2368	972.3	669.7
BACT Case	38.46	638.0	107.3	1999	713.0	$\leq 520.0^*$
Low East Coal	38.87	635.4	106.9	2015	727.9	518.5
CRUNCH	49.85	789.4	132.3	2368	972.9	$\leq 670.0^*$
Low West Coal	38.87	635.8	106.6	2004	717.5	518.7
Low Demand	32.96	572.5	95.7	1852	669.7	425.0
1/2 NSPS	38.87	633.7	106.9	2009	722.6	405.5^*

NOTE: The BACT Case and 1/2 NSPS Case are indistinguishable in the model with respect to SO_2 and Particulates. We assume BACT implies that at least the NSPS continue to be met.

TABLE 26: ALTERNATE OBJECTIVE FUNCTIONS, YEAR 2000

	Imported plus Domestic Oil (10 ¹⁵ Btu)	Total System Cost W/EUD (\$10 ⁹)	Resources Used (10 ¹⁵ Btu)	Capital Cost W/EUD (\$10 ⁹)	Capital Cost W/O EUD (\$10 ⁹)	Environmental Index
Reference Case	38.16	834.6	135.6	2664	1121	644.3
High Demand	50.07	1035.0	171.2	3153	1505	810.4
BACT Case	39.44	847.1	135.7	2612	1069	≤ 628*
Low East Coal	40.35	848.5	134.5	2620	1080	628.5
CRUNCH	51.69	1099.5	172.7	3152	1504	≤ 810*
Low West Coal	39.29	842.7	135.3	2642	1099	638.0
Low Demand	36.17	729.8	113.5	2293	8900	450.4
1/2 NSPS	39.29	838.6	135.3	2638	1095	529.1

*Note: The BACT Case and the 1/2 NSPS Case are indistinguishable for SO₂ and particulates. We assume that BACT implies at least NSPS standards are met.

APPENDIX E

REFERENCE ENERGY SYSTEMS

Figure 4. Reference energy system, year 1985 reference case

Figure 5. Reference energy system, year 1990 reference case

Figure 6. Reference energy system, year 2000 reference case

Figure 7. Reference energy system, year 1985 BACT case

Figure 8. Reference energy system, year 1990 BACT case

Figure 9. Reference energy system, year 2000 BACT case

Figure 10. Reference energy system, year 1985 CRUNCH case

Figure 12. Reference energy system, year 2000 CRUNCH case

Figure 13. Reference energy system, year 1985 high demand case

Figure 14. Reference energy system, year 1990 high demand case

Figure 15. Reference energy system, year 2000 high demand case

Figure 16. Reference energy system, year 1985 low demand case

Figure 17. Reference energy system, year 1990 low demand case

Figure 18. Reference energy system, year 2000 low demand case

APPENDIX F

EMF WORKING PAPER 2.3

DRIVING VARIABLES

- * Base year and base dollars are all set in 1975.
- * All conditions a,b,c, etc. for a given level of a driving variable are assumed to be imposed SIMULTANEOUSLY.
- * Unless otherwise stated all assumptions are to be input to ALL models; both the coal supply and energy sector models.

ENVIRONMENTAL

(1) Electric Utility Emissions Standards (*)

Two alternatives to the existing new source performance standards are seriously being considered at the present time. One (1/2 NSPS) would simply halve the maximum absolute sulfur emissions per million Btu of fuel input allowed under existing regulations. The other (90%) would require that the best available control technology be used regardless of the sulfur content of the input fuel. Given present technology this would imply 90% RELATIVE sulfur removal. Although the 1/2 NSPS option would preclude some low sulfur western coal from being burned without controls it would not completely eliminate the comparative advantage of transporting western coals which will emit less than .6 lb of SO₂/million Btu burnt or low sulfur western coal which would only require partial scrubbing to the east and burning it without controls as the 90% case would. Thus, the impact of the two alternative kinds of more stringent standards would be expected to have quite different impacts on regional coal development.

REFERENCE: New Source Performance Standards (NSPS)
(a) 1.2 lbs SO₂/million Btu burned (**)
(b) .1 lb particulates/million Btu
(c) State Implementation Plans (***)

-
- * Tom Schrader of EPA has suggested the following explicit timetable for the imposition of environmental control standards.
 - 1) Plants that were introduced into service before Jan. 1, 1977: State Implementation Plans.
 - 2) Plants entering service between Jan. 1, 1977 and Dec. 31, 1982: Federal New Source Performance Standards or State Implementation Plans, whichever are more stringent.
 - 3) Plants entering service after Dec. 31, 1982: (NSPS, 1/2 NSPS or 90% as specified) or State Implementation Plans, whichever are more stringent.

- 1/2 NSPS: One half of New Source Performance Standards
- a) .6 lbs SO₂/million Btu burned (**)
 - b) .033 lb particulates/million Btu
 - c) State Implementation Plans (***)
- 90%: Best available control technology
- a) 90% of sulfur removal (**)
 - b) .033 lb particulates/million Btu
 - c) State Implementation Plans (***)

SUPPLY

Parameters to which the distribution of coal production between eastern and western sources is particularly sensitive were chosen as supply side driving variables.

** Since EPA emissions standards are enforced by stack gas monitoring, Tom Schrader has suggested that in the absence of any scrubbing it be assumed that the following percentages of the sulfur in the coal enters the stack gas.

- 1) Lignite: 75%
- 2) All other coals: 95%

*** Interpretations of SO₂ regulations for existing coal-fired by power plants proposed in the State Implementation Plans were sent to you directly by Tom Schrader's office at EPA. ICF has supplied the following list of areas where the State Implementation Plans for new sources are more stringent than the Federal New Source Performance Standards (1.2 lbs SO₂/million Btu).

Mass, Conn, R.I. and California:	.5% sulfur content by weight
Downstate New York, New Jersey, and Eastern Pennsylvania:	.3 lb SO ₂ /million Btu
Ohio:	1.0 lb "
Montana, Wyoming and Idaho:	.2 lb "
Utah, Nevada:	.15 lb "
Colorado:	.22 lb "
Arizona, New Mexico	.34 lb "

ICF's definitions of Downstate New York and Eastern Pennsylvania have been sent to you.

(2) Mine Factor Input Costs

Increasing factor input costs for eastern mines would tend to lead to an increase in the use of western coal.

REFERENCE: Constant real input factor unit costs
(eastern and western)

HIGH: 2% annual increase in the real unit cost of input factors for eastern coal over that of 1975 (1975 factor input costs left to the discretion of the modeler.). No change for western coal.

(3) Surface Mine Taxes and Costs

Increasing surface mine severance taxes and reclamation costs in the west tend to increase the use of eastern coal.

REFERENCE: Continuation of current (as of August 1, 1977) conditions, including the existing severance taxes in Wyoming and Montana.

HIGH: (a) Step percentage increase in 1982 in the price of western coal due to reclamation requirements or severance taxes or both. (tentatively 40%)
(b) Restrictions on the amount of recoverable reserves of coal from the west (the Northern Great Plains" and "other west" supply regions) due to a lack of a federal leasing program. Since about half of the western coal resources are on federal lands, it is assumed that this fraction of the western coal resources are unavailable. (*)

(4) Freight Rates (are imbedded in each model)

The freight rates are important in determining the regional distribution of coal supply, but the differences in model definitions and classifications precludes standardization of individual values. The freight cost structures for 1975 are interpreted as generic characteristics of the models.

REFERENCE: No change in the future in the real freight rate structures assumed for 1975.

- * Hoff Stauffer has calculated that base on current stripmine laws restrictions on the amount of recoverable reserves of coal from the alluvial basin in the Northern Great Plains region will be minimal. Therefore, to retain the intent of this part of the scenario he has suggested replacing them with the restriction on western coal availability.

DEMAND

- (5) Demands: The aggregate energy demands specified here are required only for the energy sector models. The electricity, industrial steam-coal, and synfuels growth rates given here are NOT to be used to constrain the results of those models. The industrial steam-coal requirements exclude demands for metallurgical coal, which are left up to the discretion of the individual modelers. In 1975, industrial steam coal demand was 64 million tons, while metallurgical coal demand was 83 million tons for a total industrial demand of 146 million tons.
- For models which require demands by region, the modelers are requested to select a reasonable reference forecast and to scale the demands so as to match the national totals specified here.

REFERENCE:

- a) Aggregate energy: 2.5% annual growth rate
- b) Electricity: 5.6% annual growth rate through 1985 and 4% thereafter
- c) Industrial steam coal: 8% annual growth rate
- d) Synfuels: 3 quads of coal required by year 2000
- e) Exports: 50 million tons of metallurgical coal exports per year increasing linearly to 70 million tons per year in 2000 and 10 million tons of steam coal exports in 1975 increasing linearly to 30 million tons per year in 2000.

HIGH:

- a) Aggregate energy: 3.5% annual growth rate
- b) Electricity: 7% annual growth rate through 1985 and 6% thereafter
- c) Industrial steam coal: 10% annual growth rate
- d) Synfuels: 5 quads of coal required by year 2000
- e) Exports: Same as for REFERENCE.

- LOW:
- a) Aggregate energy: 1.5% annual growth rate
 - b) Electricity: 4% annual growth rate through 1985 and 2% thereafter
 - c) Industrial steam coal: 6% annual growth rate
 - d) Synfuels: 1 quad of coal required by year 2000
 - e) Exports: Same as for REFERENCE.

(6) Power Plant Capital Costs, OM Costs (in 1975 \$) and Heat Rates

A capital cost, OM cost and heat rate are specified only for a "reference" power plant. The modelers are requested to maintain the proportions between the characteristics of this reference power plant and those of other types of power plants in other regions already embedded in their models. Characteristics of a combined power plant are specified in view of its status as a relatively new technology.

- REFERENCE:
- a) Bituminous coal-fired plant in the east central region (exclusive of scrubber, but with AFDC)
Capital cost = \$500/kW
OM cost = 2 mills/kWhr
Heat rate = 9500 Btu/kWhr
 - b) Combined cycle power plant in the east central region (does not include coal gasification facilities)
Capital cost = \$325/kW
Heat rate = 8100 Btu/kWhr
 - c) Other: maintain proportions with characteristics of (a) already in models.

(7) Power Plant Emission Control Costs

Control costs are the key mechanism by which the impacts of alternative emission standards are represented in the models. The control costs determine the premium that utilities should be willing to pay for low sulfur coal delivered to the power plant.

REFERENCE:

a) Scrubber Costs

Flue Gas Desulfurization Costs for New Plants (90% sulfur removal)

Plant size (MW)	Base Inc. Capital cost ('75\$/kW	Base Inc. OM cost ('75 mills per kWhr	Energy Penalty (%)
25 or less	214	7.14	5
100	157	4.29	5
200	121	3.57	4
500 or more	86	2.86	4

- To get the total incremental capital and OM costs account must be taken of the energy penalty which represents the portion of the heat generated at the plant that is used to run the scrubber and reheat the stack gas. To get the total incremental capital cost, the capital cost for the plant to be fitted with the scrubber times the energy penalty expressed as a fraction must be added to the base incremental capital cost. Thus, for the reference (1000 MW) plant the total incremental capital cost would be \$86 plus (\$500 times .04) yields \$106/kW. To get the total operating cost the OM cost for the plant without the scrubber plus the base incremental OM cost must be escalated by the energy penalty. Thus, for the reference plant with a scrubber the total OM cost is $(2.00 + 2.86) (1.04) = 5.05$ mills/kWhr. The heat rate for the base plant must be escalated by the energy penalty to account for the scrubber. Thus for the reference plant the heat rate would be $(9500) (1.04) = 9880$ Btu/kWhr with a scrubber.
- To handle the partial scrub option for a plant with capacity C, we assume that we can scrub a fraction X of the flue gas, which would lead to removal of .90X % of the sulfur. To get the incremental capital and OM costs multiply those for 90% sulfur removal for an XC MW plant by X.

The heat rate would be equal to (the heat rate for the plant without a scrubber times (1-X)) plus (the heat rate for an XC MW plant with 90% sulfur removal times X).

Flue Gas Desulfurization Costs for Existing Plants (90% sulfur removal)

Plant Size (MW)	Increment. Capital Cost ('75\$/kW)	Increment. Nonfuel OM Cost ('75 mills per kWhr)	Energy Penalty (%)
25 or less	268	7.14	5
100	196	4.29	5
200	151	3.57	4
500 or more	108	2.86	4

- The base capital costs are assumed to be 25% higher for a retrofit than for a new plant. For existing plants the effect of the energy penalty is to derate the plant. That is, if the plant is assumed to generate a certain amount of electricity without a scrubber, it will generate a percentage equal to the energy penalty less with a scrubber. Additionally, the energy penalty again escalates the heat rate.
- The calculations for the partial scrub option in the retrofit case are the same as those described for the new plant case.

b) Coal Cleaning Costs

Due to differences in the way coal cleaning is represented in the models, particularly in terms of accounting conventions, it was decided to leave the specification of the coal cleaning options up to the individual modelers. A good discussion of coal cleaning options will be available in a forthcoming EPRI report entitled "Coal Preparation for Combustion and Conversion," prepared by Bibbs and Hill, Inc. Some preliminary data from that study have been published in the April 14, 1977 issue of Public Utilities Fortnightly as "Fixing up Coal: What It

Can Cost," by Phillips and De Rienzo. The reduction in sulfur content attributable to washing is very sensitive to the sulfur characteristics of the input coal, depending in particular on the breakdown between pyritic and organic sulfur content. As much as 25% of the sulfur can be washed out of some coals. Therefore, from the point of view of sulfur removal, cleaning and partial scrubbing may have similar impacts. Another possible benefit of coal cleaning, however, is the reduction in transportation costs that result because of the removal of refuse and trash from the coal. Some processes can reduce the weight of a given type of coal 20-30% while only reducing its Btu content 5-12%. For consistency, it is requested that coal supply quantities and prices be reported after washing. This will make cleaning part of the coal supply functions built into the models.

- c) Particulate control costs: A \$10/kW penalty for additional particulate control equipment for the 1/2 NSPS and 90% electric utility emissions standards cases should be added to the capital cost for the reference plant.

(8) Prices of Alternative Fuels

REFERENCE: a) Crude Oil:

- (i) Imports: \$13/bbl landed price in 1975 and 2.75% real annual price increase thereafter.
- (ii) Domestic Price: Linear increase from the current price to the world price in 1980.
- (iii) Fuel Switching: Left to economic calculations included in the models: Do not include mandatory fuel switching or restrictions on switching like those under consideration in the National Energy Plan.
- (iv) To calibrate individual model assumptions on the margins between the price of crude oil and the price of petroleum products, the price of 2% sulfur residual should be taken as equal to the price of crude oil.

- b) Natural Gas: Price of natural gas at Btu equivalent price of domestic crude oil plus \$.50 per million Btu.

- (9) Maximum Nuclear Power Plant Capacity (with an assumed capacity factor of 65%)

REFERENCE: a) 125 GW (.71 trillion kWhr in 1985
b) 200 GW (1.13 trillion kWhr in 1990
c) 380 GW (2.16 trillion kWhr in 2000

- (10) Cost of Capital

REFERENCE: pre-tax (for use in pricing and investment decisions in the energy sector) 13% real rate.

- (11) Contribution of Hydroelectric Generation

- a) .34 trillion kWhr in 1985.
- b) .37 trillion kWhr in 2000.

It was decided to be explicit about hydroelectric generation assumptions to prevent these from driving the inter-model differences.

SCENARIOS (*)

None of these scenarios are intended to be forecasts. Rather, the focus of this study is on using models to explore potential limitations on the nation's production of coal with special attention paid to the regional nature of the problem. There are many potential limitations which are difficult to address in the models. Examples include transportation bottlenecks, secondary industries, and infrastructure development. The scenarios listed here will be examined ex post using the Bechtel facilities model and other analyses to quantify these effects.

(1) **REFERENCE:** All driving variables at their reference levels

The reference scenario is designed to examine the ease with which the reference demands can be met under the assumption that conditions in the coal mining and electric utility industry remain unchanged between now and the end of the century. In particular, it is assumed that current strip-mining regulations, air pollution emissions standards, labor costs, and emissions control technology costs persist through the year 2000 and that industrial coal conversion efforts are very successful. This will provide a reference scenario which can be subjected to further analysis to indicate requirements for infrastructure expansion, new facilities and the measurement of environmental impacts. More stringent electric utility emissions standards have already been proposed, western states are beginning to impose sizable severance taxes on their coal resources used in the interstate commerce, and the United Mine Workers Union is very powerful. Consequently, most of the other scenarios are designed to investigate the implications of conditions less favorable for the expansion of coal production on total and regional coal use by electric utilities.

(2) **HIGH DEMAND:** Demands at high level

The high demands scenario assumes the same favorable conditions for coal mining and use posited in the reference scenario, but presumes higher demand levels. In fact, higher demands than those posited here were felt to be extremely unlikely by the working group. This scenario should, thus, provide an upper bound on infrastructure and facilities requirements, as well as the extent of the environmental impact due to the mining, transport, and burning of coal.

* Driving variables not specified in each scenario are assumed to be at reference level.

- (3) DE-EMPHASIS ON EASTERN COAL: mine factor input costs at high level

This scenario is designed to explore the impact of higher factor input costs on the supply of eastern coal. Depending on the interaction between transportation costs and coal availability by region and sulfur level, this should tend to cause western coal to be substituted for eastern coal in eastern markets.

- (4) DE-EMPHASIS ON WESTERN COAL: surface mine taxes and costs at high level

This scenario is designed to explore the impact of higher surface mine reclamation costs and/or severance taxes on the supply of western coal. Depending on the interaction between transportation costs and coal availability by region and sulfur level this should tend to cause eastern coal to be substituted for western coal in eastern markets.

- (5) 1/2 NSPS: Electric utility emissions standards at 1/2 NSPS level.

This scenario is designed to explore the impact of the enactment of one of the two major alternative electric utility sulfur emission standards currently being considered by Congress: lowering the permissible SO₂ emissions per million Btu of fuel input to the power plant from the level set in the currently existing New Source Performance Standards (1.2 lbs) by 50% to .6 lbs. This would remove the premium on western coals which will emit between .6 and 1.2 lbs of SO₂ per million Btu burned and, thus, would be expected to decrease the role of western coal in western markets somewhat.

- (6) 90%: Electric utility emissions standards at 90% level

This scenario is designed to explore the impact of the enactment of the other major alternative electric utility sulfur emission standard currently being considered by Congress, requiring that the best available control technology (BACT) be utilized regardless of the sulfur content of the input fuel. Since currently available stack gas scrubbing technology (although not yet of sufficient reliability) is capable of removing about 90 percent of the sulfur from the stack gas, this level of cleanup is used as the operational definition of the BACT regulation. This type of

RELATIVE sulfur removal regulation would eliminate the premium on low sulfur western coal and, thus, would be expected to decrease the role of western coal much more than the 1.2 NSPS alternative (scenario 5).

- (7) CRUNCH: Demands at high level
Mine factor input costs a high level
Surface mine taxes and costs at high level
Electric utility emission standards at 90% level

The crunch scenario is designed to represent conditions that are the most unfavorable to the development of the nation's coal resources relative to factors whose impacts can be adequately represented in the models. Additionally, the high level of demands is posited. Thus, coal prices would be expected to increase dramatically, with the impact on the regional distribution of coal production not predictable on a priori grounds.

- (8) LOW DEMANDS: Demands at low level

The low demands scenario is designed to explore the impact of low demands under the assumption of a continuation of current conditions in the coal mining and electric utility industries. Thus, it could be interpreted as an attempt to examine how the structure of the coal mining and electric utility industries might evolve in response to a very successful conservation program.

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