To the Graduate Council:

I am submitting herewith a dissertation written by Robin A. Watson entitled "Uncertainty and the Regional Allocation of Steam Electric Coal in the United States." I recommend that it be accepted in partial fulfillment of the requirements for the degree of Doctor of Philosophy, with a major in Economics.

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UNCERTAINTY AND THE REGIONAL ALLOCATION OF STEAM ELECTRIC COAL IN THE UNITED STATES

A Dissertation

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Doctor of Philosophy

Degree

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ABSTRACT

The uncertainty of demand is expected to continue to be a significant element in the United States coal market. The uncertainty associated with the demand for steam electric coal specifically is largely due to the unsettled prospects for electric demand, the price of coal and other fuels, and environmental regulations. The broad range of possible policy options available to the government is a major reason for the uncertain market.

This research uses a cost minimizing linear programming model to simulate the optimal allocation of United States steam electric coal. The coal sources consist of 23 coal producing districts and the demand regions are the contiguous states. The uncertainty of demand is incorporated by specifying a probability distribution of 1990 coal demand as derived from a two-stage econometric coal demand model. Over or under provision for future coal requirements is penalized through additional costs assessed within the linear programming model.

The results indicate that the optimal allocation of United States coal is noticeably affected by explicitly incorporating the cost of uncertainty in the model. Moreover, it appears that coal users pay a significantly higher price for coal as a result. However, this extra cost is not so great as to suggest that the flexibility of government policies, which increase uncertainty, necessarily should be abandoned.

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CHAPTER I

INTRODUCTION

Coal is generally expected to continue to be a critical fuel in the United States' energy market. Yet, depending upon the assumptions one makes and the forecasting technique one deems appropriate, expected coal use can vary across a very broad range. Specific investigation of the steam electric component of the domestic coal market indicates that the future need for coal primarily depends upon the price of coal, the price of those other fuels for which coal can be a substitute as well as the total amount of electricity consumed. Thus we have chosen to investigate steam coal demand within a classical demand framework where electricity demand stands in for the income element traditionally used. However, each of the factors upon which the level of coal demand depends, whether directly or indirectly, is difficult to predict.

Some of the uncertainty of coal demand is attributable to the myriad unsettled elements which determine electricity demand. Future electricity use will depend on the availability and price of traditional substitutes such as natural gas and oil and unconventional substitutes like solar power. The effectiveness of conservation trends, price induced or otherwise, is unknown. Moreover, technological changes, even over a period of less than ten years, can have a noticeable impact on electricity generation and use.

The price of coal is another of the principal determinants of coal demand and attempting to predict this price requires speculative assessment of many unknowns. Substantial evidence is available which indicates that the coal market is competitive (Gordon, 1975, p. 69; ICF, 1977, p. B-19). This assumption leads to the further inference that coal prices are cost determined. Thus an estimate of future coal prices necessitates investigation of production costs. Yet, the total costs of coal production include both private production costs and external costs. It is thus important to consider both sorts of costs and the degree to which social costs may be incorporated into the selling price of coal.

Private production costs, or those costs which are usually internal to the producer, generally depend on the size of particular coal deposits, the characteristics of the deposit, the costs of the productive factors, and the technology available for recovering the mineral. Surprisingly, neither the magnitude nor the particular characteristics of U.S. coal resources are well known (Gordon, 1978, p. 72). Thus future coal prices, which partly depend on the availability of coal, are imprecisely derived. Moreover, the labor force in the underground industry is generally seen to be particularly unreliable and only available at unpredictable rates of compensation. The uncertainty associated with the labor input is further complicated by the volatile capital markets upon which any expansion must depend. The technology of coal mining is evolving at the same time that the most efficient means of coal use in boilers continues to change. Even the transportation of coal is subject to profound change if such a technique as the coal slurry pipeline is deemed useful (Rieber, 1978).

The means of coal extraction, transportation, and use are subject to stringent government regulation. Sulfur emissions regulations can change several times within a single year, such as occurred in 1978 (<u>Coal Week</u>, September 18, 1978, p. 3; October 2, 1978, p. 7).

The future relative price of coal compared to alternative fuels is the third major element in coal demand. Though relative prices seem certain to leave oil and gas uncompetitive for electricity generation, the magnitude of the capital stock dedicated to their use would indicate that they will continue for some time to substitute for steam coal. Nuclear power may be the most direct substitute for coal, yet uncertainty regarding its cost and availability is manifestly evident. In the choice of fuels government policy is a major source of uncertainty. It is, moreover, an element which might theoretically (though perhaps not always practically), be identified and its variability minimized.

Government action, whether through regulation, subsidization, research support, or general policy focus, has a profound impact on the coal market. The absence of a rigid and predictable government policy can be appreciated as a reticence to adopt a comprehensive policy where definitive knowledge of the ramifications is lacking. That is, one expects that ignorance restrains the policy maker. Gordon suggests that, " . . . we clearly need policies that open many options and allow maximum flexibility. . . ." (Gordon, 1978, p. 197). However, this luxury of postponed policy has a price. Here we investigate an element of that premium--the cost and effects of the uncertainty of coal demand, where demand is the quantity of coal purchased at a prescribed coal price, price of substitutes, and the level of electricity generation. In addition to affecting the cost of coal utilization, the uncertainty of future coal requirements causes coal producers to over or under provide for the uncertain future. This range of effective demand may result in disparate supply responses across the coal-producing districts of the country.

In contrast to existing modeling and projection schemes, we utilize a system which explicitly recognizes uncertainty in the coal market. We suggest that the least-cost allocation of coal is markedly affected by this uncertainty which exists in the market. Moreover, we propose that the cost of providing for an imperfectly known level of coal demand is significantly more than it would be if perfect forecasts were available and widely accepted.

This is not to suggest, however, that perfectly predictable coal demand is a reasonable, achievable, or even an unqualified objective. We recognize that future demand for nearly every commodity is uncertain to varying degrees. We do suggest that the coal producer or entrepreneur is faced with unpredictable elements which may be more severe than those in some other resource markets. Moreover, the unsettled factors which influence future demand for coal are to some degree avoidable because some of them emanate from unsteady public policies.

The existence of uncertainty in the coal market is not an altogether negative factor. The energy market is changing very rapidly. Between 1980 and 1990 we can expect technological change profoundly to affect coal production, transportation, and utilization. Deep mining is currently experimenting with the introduction of long wall mining. Surface mining is still adjusting its capital stock to incorporate larger and more efficient mining and hauling equipment. The unit train has already revolutionized coal hauling by rail and the slurry pipeline may eventually become a significant mode of coal transport. Coal boiler technology constantly changes to glean the maximum heat from coal as it is burned. Finally, emissions control technology in the areas of flue gas desulfurization and fluidized bed combustion may markedly affect the relative attractiveness of coal in various geographic regions.

In facing such an unsettled future, coal entrepreneurs are expected to incorporate uncertainty in their plans. Inflexible commitments to any particular estimate would sacrifice possible opportunities afforded by a changing market. Their optimal strategy is naturally affected by government policies which affect nearly every facet of the market. Policy makers, however, are understandably hesitant to commit the industry to regulations which may become untenable or suboptimal in the future.

Uncertainty in the coal market is an expensive phenomenon, however. Because he must prepare for a range of possible outcomes, the entrepreneur is unable to muster his productive factors in a manner that would be an optimal way of providing for future demand. We will explore the cost of uncertainty thus incurred in what follows. We shall conclude the study by assessing both the allocation and cost effects of uncertainty. That is, we can expect an altered distribution of coal production and consumption relative to a predictable market as the market attempts to minimize the cost of the phenomenon. Moreover, we can expect that the total cost of providing the coal will appear to be greater when we explicitly recognize uncertainty than when it is ignored, as in previous studies. Naturally, the fact that uncertainty has a cost does not necessarily imply that we must make every effort to eliminate it. We merely attempt to provide the policy maker with an assessment of the negative aspect of a phenomenon which has acknowledged benefits.

We recognize that a comprehensive model would be required to assess the general equilibrium impact of uncertainty in the energy market. That is, each alternative fuel is undoubtedly subject to uncertainty, and the partial equilibrium analysis which we employ is unable to attain the broader perspective. An implicit assumption in our analysis is that the impact of certain major factors such as nuclear capacity and air quality standards is primarily upon the level of coal utilization with less profound or less direct impacts on substitute fuel markets. Moreover, we suggest that, though the costs of an uncertain market are significant, the optimal provision for an uncertain future is more efficient than the naive projection which ignores risk entirely. For example, suppose a forecast of future coal demand were available and widely accepted. The expected cost of a universally believed wrong guess (an average of the cost of all possible wrong guesses weighted by their likelihood) is greater than the expected cost of intelligently taking into account the uncertainty that exists. This is because we suppose that the market gravitates toward that level along the range of possibility where error, in either direction, is least expensive. That is, entrepreneurs in the market attempt to minimize the occurrence of the most expensive error.

In the next chapter the economics of coal production, transportation, and utilization will be described. In Chapter II a brief analysis of prospects for growth in the coal market is provided. An overview of several existing modeling options is presented in Chapter III. Most of the existing studies which model the coal market utilize mathematical programming models. This class of model provides an optimizing framework which is not necessarily constrained by historical relationships between coal producers and coal users. We have found this modeling scheme appropriate both as a means of assessing the coal market as if it were characterized by precisely predictable demand, and to be amenable to incorporating uncertainty.

The last four chapters are a succession of steps leading toward a stochastic linear programming model which shows how demand uncertainty affects the coal market. In Chapter IV a linear programming model of steam electric coal allocation is presented. The least-cost allocations generated by the model can be compared to actual market distributions of coal. Up to this point, our analysis is conceptually similar to previous studies, though noticeable improvements in the basic analysis have been attempted by incorporating the best aspects of other models, such as the ICF supply functions and the Schlottmann transportation network.

The next chapter utilizes this deterministic model to generate a projection of 1990 coal allocation under the assumption of perfect knowledge.

Our system of analysis is somewhat unique, however, in that we endogenize econometrically derived coal demand functions in our model. In addition to providing defensible estimates of coal demand on a regional basis, the statistical estimates of future demand are associated with a range of variation about the expected value. The mathematical programming framework is thus modified in Chapters VI and VII explicitly to introduce uncertainty in coal demand.

We assume that we can represent the expectations of coal entrepreneurs regarding the likelihood of different states (levels of coal demand) of the world. A subjective probability weight is assigned to each possible outcome and the degree of uncertainty is reflected in the dispersion of probability weights over the possible states (Hirshleifer and Riley, p. 1376). In other words, we subjectively assign a mean (expected value) and variation (dispersion) based on historical market adaptation to the same demand determinants. This technique was explored by Hadley in the context of, among other problems, a transportation problem similar to the coal model which we employ in our analysis (Hadley, 1964, pp. 158-167). It will be necessary to specify a "consequence function" (Hirshleifer and Riley, p. 1379). This estimate of the consequences of any possible outcome takes the form of penalties for wrong predictions by entrepreneurs. In our analysis we incorporate the information available from "prior round markets" (Hirshleifer and Riley, p. 1380) by both projecting the variance about expected demand from historical experience, and by deriving the consequence function from studies based on historical cost data.

In Chapter VII the necessary foundation will have been laid and the effects of uncertainty on the costs and distribution of steam coal in the United States are described. Then some of the effects of demand uncertainty on the cost and the most efficient allocation of steam coal in the United States can be described.

CHAPTER II

THE DEMAND FOR STEAM ELECTRIC COAL

Introduction

In this chapter we examine the characteristics of the electric utility industry which have most critically influenced utilization and production of steam coal. This discussion of the historical adaptation to evolving conditions provides a useful background for evaluation of the possible range of future adjustments by the industry to a changing environment. The variety of likely scenarios and the range of possible market responses to diverse influences are the source of much of the coal demand uncertainty which is explicitly treated in our model of the coal market in Chapter VII.

Electric utilities increased their consumption of coal to nearly 500 million tons in 1977, a 6.3 percent average annual rate of growth from 69 million tons in 1946 (Gordon, 1978). Even though the share of electricity generation fueled by coal has declined slightly over the period, the 7 percent average annual growth rate in electricity consumption (FEA, 1976, p. 215) has given rise to the extraordinary absolute growth of coal consumption.

Electricity consumption in the United States is expected to grow more rapidly than the average increase in general economic activity or even the growth in total energy use, principally because electricity is a versatile source of energy. Of secondary importance is the relative ease of transport and the apparent absence of serious external costs when used. The versatility of electricity relative to most other fuels would itself assure a larger relative role for this energy source. The next most versatile fuels have been petroleum products. Audubon states that, ". . . It is assumed that the best method of cutting back on the use of oil and gas is to substitute electricity for these fuels and use more coal to produce this electricity" (Audubon, November, 1978, p. 63). The expected direct employments of coal and nuclear power are rigidly circumscribed. This is due mainly to their significant scale economies.

Coal is seldom practical for small scale end use employments such as home heating. Thus, like nuclear power, coal is almost exclusively suited to utilization in large scale steam plants through which the energy becomes finally usable as electricity. Petroleum fuels, especially natural gas, have been utilized for a variety of end-use employments, and the expected scarcity of these fuels seems to prescribe an ever increasing role for versatile electricity as a substitute in the industrial and commercial sectors as well as in the final demand market.

Fuel Choice in Electricity Generation

The peak or maximum demand of electrical power customers may only occur for short periods of the day and a few days per year. The base or continuous level of demand may be much lower than peak. In the United States, the load factor, which measures the ratio of base to peak requirements, has been around 62 percent (Federal Energy Administration, 1976, p. 223). Efficiency requires that the utility employ the generating option with minimal average cost for continuous or base load generation and reserve the most expensive generation options for least extensive, peak power requirements. Base load generators are characterized by low variable cost technologies which minimize the generally higher fixed costs through high rates of utilization. Less intensive generating options used for discontinuous peak generation generally require smaller initial fixed cost and have a higher associated variable (principally fuel) cost. Thus the high capital costs of hydroelectric power stations, nuclear reactors, and coal-fired plants, combined with low operating costs best suit them for extensive utilization as base load plants. Petroleum and natural gas-fueled units with higher variable cost (fuel cost), but significantly lower investment costs, are most economical for brief peak load employment. To the extent that utilities are able to manage the shape of future load curves and minimize radical peaks, they may be able to benefit from minimal average cost. The relative share of base load generation would increase and the need for less efficient peaking units would decline.

This division of electric utility fuel requirements between peak, base, and even middle load requirements, tends to minimize discrete or discontinuous fuel utilization adjustments. The ability to shift expensive generators such as oil and gas to peak load employments leads to smooth, continuous adjustments in the fuel mix. Capital requirements and fuel acquisition rates are codeterminant factors in the shift in consonance with the less than subtle realignments of relative fuel costs imposed by such an effective price setting power as the Organization of Petroleum Exporting Countries.

Electricity Generation Fuel Mix Options

Coal is one of the five major prime movers traditionally available to electric utilities. The other four are nuclear power, oil, gas, and hydroelectric dams. In Table II-1 are shown the changes in electric utility fuel shares since 1955 in the United States. In this table the dynamics of utility fuel choices are apparent and the considerable potential for future adjustments may be inferred.

In Table II-2 the national and regional contribution to electric generation in 1977 is shown. The figures in this table illustrate that national shares belie the marked concentration of fuel use on the regional level and the range of the fuels' relative shares. With the exception of nuclear, each prime mover is significant in at least one region and generally only two fuels effectively compete in any particular utility market. Geography, politics, and economics have thus combined in different ways in the several U.S. census regions to determine the mix of methods employed to generate electricity. What, then, has been the historical importance of the alternative prime movers and what roles might they be expected to fill in the immediate future?

Oil

Oil has historically competed with coal in electricity generation in utilities in the northeast and Florida, and, to a lesser extent, in some eastern utilities (Gordon, 1975, p. 29). In the United States, the economics of oil refining have not favored the production of the cheaper residual fuel oil that can compete with steam coal. However, foreign refineries have produced large quantities of cheaper, low grade oil and the removal of import controls in 1966 made this substitute more available in the U.S. market (Gordon, 1975, p. 17). Significant transportation costs for both oil and coal, however, helped to confine the residual oil market to utility plants located near the east coast.

TABLE II-1

ELECTRICITY GENERATION BY ENERGY SOURCE
(Percent of Total Btus)

Year	Coal	Nuclear	Oil	Gas	Hydro/Other
1955	52.8	--	7.3	18.1	21.3
1960	51.5	--	7.8	21.6	20.1
1965	52.8	0.3	6.5	21.6	18.6
1970	44.7	1.4	12.9	24.7	16.3
1975	44.0	8.2	16.4	15.8	15.6

Source: General Accounting Office, U.S. Coal Development-Promises, Uncertainties, 1977.

TABLE II-2

CONTRIBUTIONS TO TOTAL REGIONAL ELECTRICITY
GENERATION OF MAJOR FUEL SOURCES
Gigawatt-Hours (Percent of Regional Total)

Census Region	Source						
	Hydro	Coal	Oil	Gas	Nuclear	Other	Total
Northeast Region I	4,893 (6.41)	2,523 (3.31)	43,058 (56.45)	273 (0.36)	25,530 (33.47)	1 --	76,278
Middle Atlantic Region II	26,474 (10.19)	105,141 (40.47)	81,799 (31.49)	1,005 (0.39)	45,369 (17.46)	0 --	259,789
East North Central Region III	2,842 (0.75)	303,370 (79.84)	19,051 (5.01)	3,500 (0.92)	50,191 (13.21)	1 --	379,955
West North Central Region IV	10.248 (6.77)	99,201 (65.49)	4,900 (3.21)	15,591 (10.29)	21,503 (14.20)	23 (0.02)	151,466
South Atlantic Region V	15,630 (4.03)	212,145 (54.71)	82,059 (21.16)	13,421 (3.46)	64,536 (16.64)	0 --	387,791
East South Central Region VI	24,039 (11.71)	145,964 (71.08)	12,271 (5.98)	3,547 (1.73)	19,522 (9.51)	0 --	205,343
West South Central Region VII	4,704 (1.73)	22,154 (8.15)	24,430 (8.98)	215,454 (79.23)	5,085 (1.87)	96 (0.04)	271,922

TABLE II-2 (Continued)

Census Region	Source						
	Hydro	Coal	Oil	Gas	Nuclear	Other	Total
Mountain Region VIII	26,035 (19.32)	86,526 (64.23)	6,461 (4.80)	15,429 (11.45)	225 (0.17)	46 (0.03)	134,723
Pacific Region IX	105,570 (40.95)	8,426 (3.27)	83,860 (32.53)	37,138 (14.40)	18,923 (7.34)	3,896 (1.51)	257,812
United States Total	220,435 (10.38)	985,450 (46.39)	357,889 (16.85)	305,357 (14.38)	250,883 (11.81)	4,063 (0.19)	2,124,078

Source: Energy Data Reports, U.S. Department of Energy, May 1978.

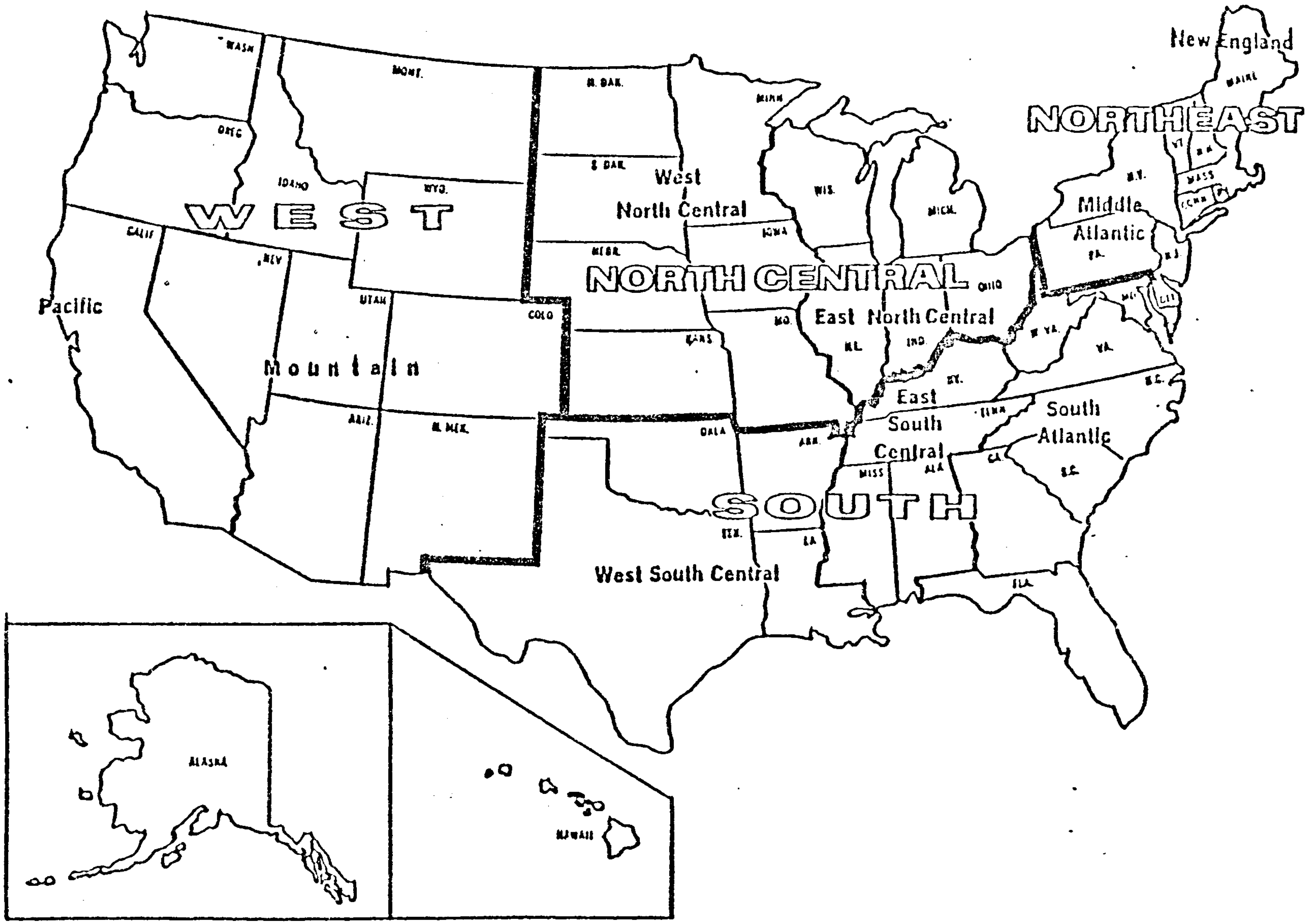

Figure II-1. U.S. Bureau of the Census Regions.

In addition, physical attributes of residual fuel oil (i.e., its high viscosity) restrict its carriers to barges or tankers, further limiting market penetration to coastal regions. The increased attention to sulfur emissions standards during the period may have contributed to the inundation of oil, but simple economics seem to have been sufficient to have caused the shift (Gordon, 1975, p. 29; Schlottmann, 1975, p. 67). Oil has also been an important electric generation fuel in California, but it has not directly competed with coal there.

Gordon concludes that one " . . . firm, long-term conclusion is that oil is not competitive at present prices" (Gordon, 1978, p. 153). We thus expect that oil will fail to provide economical base load electric generation and that alternative fuels will be required to replace oil in the regions noted above where it has been a principal steam generator fuel. Coal and nuclear power are the principal contenders to fill the projected need for a source of a continuously utilized fuel with minimal average cost.

Natural Gas

Natural gas has been a significant fuel in electric generation only in the areas where it is produced--California and the West South Central region. The General Accounting Office has found that, "About 70 percent of all gas used as a utility boiler fuel occurs in the South Central states, which accounts for nearly 90 percent of total U.S. gas production" (General Accounting Office, 1977, p. 2.11). In the future, gas is not expected to be competitive as an electric utility fuel. Deregulation is expected to, ". . . raise prices to levels at which natural gas will no longer be competitive in the electric utility market" (Gordon, 1975, p. 129). The economic penalty attached to such a fuel has thus become severe, and, ". . . by 1983 the baseload generating capacity is expected to be completely coal and nuclear" (General Accounting Office, 1977, p. 2.11).

Nuclear

The continual depletion of petroleum and gas resources has been anticipated for some time, though the abrupt and rapid increase in their prices removed the cherished subtlety of the transition. The difficulty of the transition may have been underestimated since, "The replacement was to be nuclear power, which since the end of World War II had been touted as the energy source of the future" (Audubon, 1978, p. 60). This position has been tempered so that now, " . . . it is generally agreed that all new large generating plants will either have to be coal fired or nuclear" (Wall Street Journal, April 24, 1979, p. 1). In the 1950's and 1960's the electric utility industry and electricity consumers were enamoured with the prospect of cheap power from nuclear plants. However, extraordinary capital costs and extended construction times have eroded the cost advantage perceived earlier. The extraordinary growth of uranium prices in addition to high capital cost has seriously undermined the nuclear cost advantage vis-à-vis coal (General Accounting Office, 1977, p. 2.21). The amended perspective on nuclear powered electricity generation in 1979 was summarized by the Wall Street Journal.

> In those early days it was believed that the electricity produced by nuclear power would be too cheap to meter. Today, that electricity threatens to become so expensive--more than tripling in price over the next decade, even by industry estimates--that some critics believe cost, not safety, is the major hurdle facing the nuclear power industry.. . .

> This cost reflects both inflation and the federally mandated changes in safety design in recent years. It is also the result of critics' delaying tactics that have stretched the time it takes to build and license a plant to eleven years from eight years (Wall Street Journal, April 24, 1979, p. 1).

Though relative cost data are fraught with numerous malleable assumptions, it appears that new nuclear units may only have an economic advantage over coal if coal-fired plants are required to install expensive sulfur emissions controls such as flue gas desulfurization equipment (General Accounting Office, 1977, p. 2.20; Gordon, 1978, p. 127). It seems that nuclear operating cost may be somewhere below scrubbed coal and above unscrubbed (Gordon, 1978, p. 128). Other studies have indicated that " . . . nuclear power seems less expensive for baseload generation than any other alternative . . . ." (Energy Modeling Forum, 1978, p. 10). However, the future availability of nuclear generating capacity depends on extra-market factors which range from confidently held trust to hysterical fear. Thus the projected level of nuclear generation has ranged from an unlikely moratorium on new nuclear plant construction to rapid growth enabling nuclear power to account for as much as 26 percent of electricity generation by 1985 (Federal Energy Administration, 1976, p. xxv). Recent studies of the entire "fuel cycle" have shown coal to involve extraordinarily large non-market costs relative to nuclear power (Fortune, November, 1978, p. 52) and the extent to which the market or the regulatory apparatus begins to assess the user for more of these costs bodes a relatively less rapid growth in the demand for steam electric coal. The uncertainty of the future fuel mix in electricity generation is exemplified by the following statements.

> . . .The plausible range of cost estimates for electricity generation is sufficiently broad that any outcome could occur. However, considerable reason exists to expect that nuclear power ultimately will prove a major threat to coal use in electric utilities (Gordon, 1978, p. 196).
>
> Even if all the government-imposed constraints on nuclear power were lifted--and the utilities convinced of it--it is doubtful that enough plants could be constructed and fueled to serve the needs of the next few decades (Fortune, November, 1978, p. 60).

The analyses cited above indicate that both the future level and the degree of impact of each of the relevant variables affecting the choice between coal and nuclear powered electricity generation are uncertain.

The Supply of Steam Electric Coal

The most important characteristic of steam electric coal in the United States varies considerably between and within the various producing regions. This is because, "[Coal] was created out of so many substances, in so many different situations, that coals from the same region or even the same mine will vary in their composition and thus in their utility" (Audubon, November, 1978, p. 55). The valuable component of coal is its heat content which is in the form of hydrocarbons and measured in Btus. The weight of the coal relative to its heating value is a liability because it is expensive to transport. Coal users, through the coal market, register the relative value of the various coal types. This value is increased, on the one hand, by higher heat content per unit of weight and depressed, on the other hand, by the peculiar negative characteristics of the heat source, which include sulfur, ash, and extraneous components. In fact, "Of all the fuels that man employs, coal produces the most copious and complex array of emissions thought to be damaging to health" (Fortune, November, 1978, p. 51).

Among FPC (Federal Power Commission, now Federal Energy Regulatory Commission) Form 423[1] reported shipments in 1977, the Btu content of steam electric coal varied from 26.3 million Btus per ton for some West Virginia deep-mined coal to 13.1 million Btus per ton for certain shipments of Dakota surface-mined coal. Assuming comparable utilization rates of the heat contained in the coal, at least twice as many tons of the least volatile western coal would be needed to compensate for the heating value of an equal weight of the best eastern coal.

We briefly considered the significance of the sulfur content of steam coal in this chapter and will take quantitative account of its importance when we model the coal market in Chapters V through VII. The sulfur content of U.S. coal varies widely across and within coal districts of the United States. Even when we "normalize" the sulfur content by measuring weight of sulfur per unit of heat content, notable diversity remains. Our analysis of the coal quality reported by electric utilities to the Federal Energy Regulatory Commission indicates that some eastern deep-mined coal and a large share of western coal contain less than 0.2 pounds of sulfur per million Btus. At the other end of the spectrum, a significant portion of U.S. midwestern coal

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[1]The specific Btu and sulfur content of U.S. coal was determined from Federal Energy Regulatory Commission (formerly Federal Power Commission, and thus FPC) reported statistics. A more detailed treatment of this data source is contained in Chapter V.

contains more than 5 pounds of sulfur for every million Btus. We shall present below a model which is intended approximately to duplicate the market preference for lower sulfur coal as a result of sulfur emissions control standards. This market preference leads to an imputed premium on the lower sulfur coals found in some Appalachian sources and in the West.

In addition to variations in heat and sulfur content, U.S. coal shows varying proportions of superfluous materials. Problems associated with the ash content of coal have received considerable attention recently with the advent of the 1976 Resource Conservation and Recovery Act. The ash content of coal is a principal determinant of steam electric plant particulate emissions, and this parameter is expected to attract increased scrutiny and gain even greater economic importance in the future (Fortune, November, 1978, p. 56). However, the rigidity of the expected standards and the effect on future coal demand are unknown.

The chemical composition of coal in combination with the coal combustion methodology determines the level of nitrous oxide emissions from steam plants and thus has become an important variable in the coal market. Nitrous oxide emissions standards have not traditionally existed and the factor has thus not been important in the coal market.

The considerable variation in the important characteristics of coal can be, to some extent, associated with the district of origin, as noted above. Appalachian and midwestern coal tends to be high in heating value, yet midwestern coal is generally very high in sulfur content. Western coal contains a very low percentage of sulfur, yet this advantage is offset, at least in part, by its generally lower heat value. Future utilization of Appalachian coal will necessarily be severely constrained by the necessity to exploit less easily mined sources of the resource. This is a less critical factor in midwestern coal, and western coal supplies are expected to prove fairly elastic (ICF, 1978, Appendix G).

Western Coal

The vast reserves of coal in the West, especially in the Northern Great Plains, are expected to play an increasing role in U.S. energy policy. Though the distinct advantage of western coal by virtue of its lower sulfur content is partially ameliorated by its low heat value, the low sulfur advantage remains.

Another advantage of western coal is the low production cost, principally due to the thick coal seams and the economies afforded by large scale surface mining techniques. Moreover, Gordon states that surface mining legislation may be relatively less severe. " . . . In the West, where the greatest strip mine expansion potential exists, reclamation requirements are likely to prove a minor element in costs" (Gordon, 1975, p. 195). Once more, however, the advantage is partly offset by another factor. That is, western coal fields are located far from the large energy using centers of the Northeast, the South, and even the West Coast. Thus the lower production costs must compensate for high transportation costs which can account for more than half of the delivered cost to distant consumers (Gordon, 1978, p. 95).

Perhaps the most important factor in the expected expansion of western coal production is the sheer magnitude of expected coal needs.

Eastern and midwestern production could meet the extraordinary expected growth in demand only at astronomical prices (ICF, 1978, Appendix G). Moreover, rapid western growth can even be expected with overall conservative expectations of coal demand due to the limited capacity of Eastern and Midwestern coal fields.

Sulfur Emissions Standards

Sulfur emissions standards have historically varied across time and across regions of the country with the general trend toward tighter standards. Concurrent with the recent interest in greater coal use we have entered a new phase in the application of sulfur standards. Several alternative strategies have emerged which seek to minimize the amount of sulfur oxides released by coal-burning plants.

The traditional control technique has been to mandate maximum permissible sulfur dioxide emissions per unit of coal heat utilized. The effort has thus been to establish a maximum allowable quantity of emitted sulfur per Btu extracted. Fortune has noted that the standard has not always been scientifically determined. "With science largely mute as to what such thresholds might be, the permissible levels were determined by the political process" (Fortune, November, 1978, p. 51). A frequently employed ceiling has been 1.2 pounds of sulfur per million Btus. Other jurisdictions have specified maximum percent sulfur levels of the coal burned (Environmental Protection Agency, 1977, p. 2-1). Aubudon notes that no hard evidence backs even this practice. "The standards are to some degree arbitrary, simply because . . . we do not know precisely how much of the pollutants and what mix of them we can tolerate" (Audubon, November, 1978, p. 69).

A more recent strategy would require the maximum reasonable reduction of sulfur on a percentage basis regardless of the sulfur content of the coal burned. Standards as high as 90 percent removal of sulfur have been proposed (ICF, 1978, p. 7), with associated floors and ceilings on sulfur emissions per unit of coal or heat utilized. This strategy is an attempt to take advantage of the best available control technology, BACT, often referred to as scrubbers. However, the viability of this control option over the long run has been questioned. They [scrubbers] can extract well over 90 percent of the sulfur dioxide, but their reliability in continuous operation is still unproved (Fortune, November, 1978, p. 57).

Not surprisingly, the effort to control sulfur emissions has been joined by interest groups with motives unrelated to clean air. Fortune has noted that,

> . . . emissions regulations can be motivated by considerations unrelated to environmental protection. The [clean air] legislation and the EPA's proposed regulations reflect not so much rampant fanaticism about sulfur emissions as they do political pressures from eastern states where high-sulfur coal is mined. . . . The governments insistence that all plants must scrub alike . . . deliberately diminishes the attractiveness of Western coal. . . . (Fortune, November, 1978, p. 56).

As we shall see in Chapter VII and Appendix A, however, universal scrubbing can lead to expensive inefficiencies. Such a strategy garners support from midwestern, high sulfur coal producers, who are pleased to neutralize the advantage of western coal. Moreover, Gordon adds that ". . . the move to best available control technology clearly makes the nuclear as well as the eastern coal option more attractive relative to western coal. It is not clear that the boost to eastern coal is sufficient to overcome the impacts of rising costs" (Gordon, 1978, pp. 195-196).

A more recent control strategy proposed by the utility industry would impose a sliding scale standard. ". . . (ranging) from 85% removal on coal with uncontrolled emissions of 0.8 lb. SO_2/ mmBtu to 20% on coal with uncontrolled emissions of 0.1 lb. SO_2/mm Btu" (Coal Week, September 18, 1978, p. 3). Little enthusiasm outside the utility industry itself has been shown for such a strategy.

Obviously, there are numerous factors operating which will ultimately determine the sulfur control strategy. Thus, in attempting to arrive at the least costly allocation of coal, the market is somewhat hampered by the unsettled state of sulfur emissions standards. The range of possible control options not only affects total coal demand, but the various strategies can be expected to have an uneven impact on the regions of the country which produce differing qualities of coal. For example, the potential Midwestern high sulfur coal producer can expect his market to be constricted by a severe standard which strictly limits total sulfur emitted. On the other hand, a percentage removal standard would not necessarily undermine the marketability of his high sulfur coal relative to other sources.

Coal Transportation

Coal has traditionally been transported from the mine to the ultimate user by either rail, barge, or truck. The extraordinarily rapid increase in truck transportation cost as a function of distance has generally left barge and rail transportation as the principal means of long distance shipment. Where available, barge shipment has generally been the cheapest alternative. Naturally, geographic realities have left rail as the predominant carrier, occasionally combined, where feasible, with barge shipment.

In 1975, nearly 65 percent of the coal produced in the U.S. was shipped by rail. Of the remainder, 10.7 percent was shipped by water, 12.2 percent was shipped by truck, 11.3 percent was used by mine-mouth plants, and 1.3 percent went by other means (General Accounting Office, 1977, p. 5.4). In 1975 transportation costs ranged from less than $.50 to $10.00 per ton and accounted for up to 75 percent of the delivered cost of coal (General Accounting Office, 1977, pp. 5.4-5.5).

A possible alternative to rail transport of coal is the much discussed coal slurry pipeline option. Relative to marginal coal transportation costs by rail, some studies have projected that costs per ton mile by the slurry pipeline may be 50 percent less. (Coal Week, January 16, 1978). Severe environmental considerations coupled with railroad resistance to the potential competitor have clouded the propects of the slurry pipeline alternative.[2]

Summary

The brief review of the U.S. steam electric coal market presented in this chapter has highlighted aspects of the industry which seem to prescribe an unsettled industry for the next decade. Two important

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[2]For a comprehensive discussion of the slurry pipeline controversy, see Michael Rieber, "Coal Transportation Models: The Use, Misuse, and Abuse of Data," Center for Advanced Computation, University of Illinois, Urbana/Champaign.

reasons for this uncertain future are the unsettled role of nuclear power, the major alternative to coal-fired electricity generation, and environmental policy, especially sulfur emissions standards. Sulfur emissions standards cut with a two-edged blade. On the one hand, stringent and universal coal emissions standards add to the overall cost of the coal option and thus detract from its economic appeal. On the other hand, alternative strategies have a different effect on the marketability of coals with varying sulfur content and thus have an uneven impact upon the various coal mining regions. Compounding the unpredictability of future emissions standards is the fact that changeable government regulation acts as the vehicle for effecting the social estimation of any policy option. Future coal production costs will be profoundly affected by the eventual land reclamation requirements. Variation in reclamation standards not only affects the cost of coal relative to other fuels but has different impacts in the several producing regions of the country.[3]

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[3]An explicit treatment of the impact of reclamation requirements is given in Alan Schlottmann and Robert S. Spore, "Economic Impact of Surface Mine Reclamation," Land Economics, 52, 3 (August, 1976), pp. 265-277.

CHAPTER III

ALTERNATIVE MODELS OF THE STEAM ELECTRIC COAL MARKET

Introduction

Optimization techniques such as mathematical programming models have been extensively employed in efforts to simulate quantitatively the behavior of the U.S. coal market. Thus the mathematical programming model which we employ in the several succeeding chapters has several notable precedents. Of the several which we discuss below, each has distinctive features and is representative of the range of efforts which exist in published form.

The National Coal Model

The National Coal Model (NCM) (ICF, Inc., 1978) is an outgrowth of the Project Independence Evaluation System (PIES). NCM was developed by ICF, Incorporated, for the Federal Energy Administration. The major tool of analysis in the NCM is a linear programming algorithm whose parameters are derived from engineering-type studies and not statistically estimated as in the case of an econometric study.

NCM disaggregates coal supply into 30 supply districts, maintaining both state and Bureau of Mines (BOM) coal district integrity. Thirty-five demand districts are used.

The model functions to distribute coal from the supply to demand districts through a least-cost mathematical programming algorithm. It accounts for differences in heat content (Btus) and sulfur content through categorization across these two dimensions. The NCM generates estimates of coal-fired steam plant capacity, and environmental characteristics exogenous to the optimization model.

Coal production capacity from each supply district is derived by first adjusting current output by an assumed rate of mine closings. Expected new capacity, derived from BOM estimates of coal reserves, is then added. A major change incorporated in NCM compared to earlier PIES models is the variety of coal supply functions. For each type of coal in each region a step function relates increasing costs to increasing output. This is intended to account more fully for the higher costs of output due to the various production conditions rather than to assume constant costs, a necessary, but severe shortcoming of some earlier models. Due to the general lack of accurate data on mining costs in specific coal producing regions, extraction costs are based on two model mines, one surface and one underground. These base case costs are adjusted to account for regional differences in overburden ratio, seam thickness, seam depth, and mine size. The base case cost figures were developed by the United States Bureau of Mines and TRW, Incorporated from existing mine cost studies (ICF, Inc., 1977, p. III-47).

Coal demand, for the most part, is a direct function of electricity demand. Electricity demand for 1974 in the demand districts is expanded by a constant annual growth rate to arrive at the amount assumed to be required in any future year. A rather complex algorithm distributes this total demand among base, peak, and intermediate loads and assigns generation to prime movers according to efficiency criteria. A regional requirement for coal is thus established. Non-utility coal demand, both industrial and coking, are accounted by exogenous point estimates. A final equilibrating process is employed when discrepancies in coal supply cost and demand price occur. The process reconciles any differences by further shifts in coal supply and shipments.

NCM employs a fairly simple transportation grid. Distances are derived from Federal Railroad Administration data and one of four linear transportation cost-generating functions is employed, depending on location (Appalachia, Midwest, West, and West to East) to determine transportation costs.

The model identifies coal quality in two dimensions--sulfur content and heat content (Btus). Heat content is divided into eight categories and sulfur content into five categories. Though 40 types of coal are thus possible, only six Btu and three sulfur categories are actually utilized. Supply regions possess an average of six to seven categories each.

The Argonne Coal Model

The Argonne Coal Market Model, developed for the United States Energy Research and Development Administration by the Argonne National Laboratory, employs a quadratic programming algorithm (Dux, *et al*., 1977). The advantage of the non-linear programming approach is its ability to model continuous coal supply functions which exhibit increasing costs with higher levels of output.[4]

The Argonne Coal Market Model (ACM) uses nine supply regions which are compatible with the Bureau of Mines districts. Demand centroids

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[4] *Linear* programming algorithms can account for increasing (or decreasing) functions only in discrete steps. Essentially, the technique involves adding a new activity at each "jump" in the function.

are modeled for 25 utility and 25 industrial coal users, 15 of which coincide in space. Coal types from the nine supply districts are disaggregated according to sulfur content into 14 district supply sources. Only one Btu content level is possible in each region. Allocations must be less than or equal to supply limits in a region. Demand constraints must be met at each of the 35 demand centroids.

The model does not attempt to treat long-term contracted coal--only new and non-contracted, an inherent stabilizing factor which one would expect to de-emphasize rapid adjustments. The supply functions are actually continuous, linear approximations to the step function coal supply estimates made by ICF, Inc. for the National Coal Model discussed above. Coal demand is derived by applying engineering parameters which generate coal requirements as a function of FEA electricity demand estimates. Transportation costs are estimated from a linear function which depends on distance, annual volume and a shipper-owned dummy variable.

The Schlottmann Coal Model

The Schlottmann Coal Model (Schlottmann, 1975) employs a transportation model framework to optimize the distribution of U.S. steam coal from 23 producing districts to the 48 contiguous states, the demand districts. Besides the source and demand district dimensions, coal is differentiated according to heat content (Btus) and five grades of sulfur content.

The model is specified to minimize the cost of mining and transportation of coal subject to capacity, demand, and sulfur emissions constraints. Regional coal demand is calculated by an allocation scheme which uses regional power plant construction and FPC projected regional growth rates in electricity demand.

The producing districts' capacity is a function of labor availability in the district. Btu values and sulfur content are derived from Federal Power Commission Form 423 data which account for 98 percent of all coal shipments to utilities. The transportation costs are derived from a meticulously derived railroad distance matrix from supply to demand centroids over actual routes.

Without the artificial device of constraining coal shipments *à priori* to actual patterns, the model fairly accurately predicts coal shipments on a census region level of aggregation. Thus validated, the model is used to simulate coal shipments in 1978.

One characteristic of the model's specifications is its ability to provide policy simulations and thus gauge the different impacts on regional coal distribution and use of various policy options. The sulfur characteristic dimension of coal enables the model to predict shifts in shipments as a result of sulfur restrictions and different rates of taxation on sulfur emissions. Moreover, the impact of other policies such as the once contemplated 20° slope angle restriction on strip mining can be modeled.

The Iowa Coal Model

One of the most recent programming models of the coal industry was developed at Iowa State University (Libbin and Boehlj, 1977). The Iowa Coal Model (ICM) is noteworthy principally because of its multiperiod nature.

The ICM minimizes the cost of mining, washing, transport, land reclamation, and building new mines subject to supply, demand, sulfur emissions, and capital availability constraints. Sixty-four coal quality categories are utilized. Twenty-one supply regions and 18 demand regions are specified.

The inter-temporal nature of the model reflects analysis for four time periods: 1967-77, 1978-80, 1981-85, and 1986-90. Capacity for the various periods is derived by adjusting current capacity by both a mine depletion factor and a rate of new mine openings. Projected coal demand is derived from PIES estimates for 1974.

Another useful aspect of the ICM is the detailed treatment of coal washing. The availability or viability of midwestern and some Appalachian coal is assumed dependent on the degree to which sulfur levels can be reduced by this technique.

The Gordon Coal "Model"

Richard L. Gordon utilizes a coal "model" [his quotes] which he calls a bookkeeping tool by which data are assembled and synthesized. His system uses rather detailed data on the nature of electricity generating capacity. It also makes projections of the nature of electricity capacity; necessarily employing several alternative scenarios to treat the uncertainty associated with future capacity additions (Gordon, 1976).

A rather complicated procedure is employed to distribute assumed electricity demand among peak, intermediate, and base-generating load. Then another algorithm determines any needed new capacity and its identity based on an equally complex capital budgeting-investment procedure.

The system is disaggregated into eight regions based mainly upon utility group service areas. The optimization technique of the model involves only hand calculations. However, this may not necessarily be seen as a comparative disadvantage since the procedure when coupled with a set of best available assumptions, can provide a degree of "reasonableness" not guaranteed elsewhere. Gordon notes that considerable refinement based on regional eccentricities would be useful though not yet attempted.

Summary

Several of the existing models of the United States coal industry have been explored in this chapter. The model to be developed and employed in subsequent chapters borrows heavily from these earlier formulations, especially that of Schlottmann. The model developed below is designed to simulate accurately the interaction of the most relevant factors in the coal market. The formulation is also intended to provide a framework which is adaptable to the eventual inclusion of uncertainty as an important market characteristic. Moreover, the extensive data requirements have reinforced the motivation to follow existing research where extensive efforts to refine the data base have already been undertaken. For example, ICF, Inc. has meticulously formulated coal supply functions as an integral element of their National Coal Model reviewed in this chapter.

CHAPTER IV

A DETERMINISTIC LINEAR PROGRAMMING MODEL OF THE U.S. STEAM ELECTRIC COAL MARKET

Introduction

In this chapter a linear programming model will be introduced which seeks to minimize the total cost of production and transportation of U.S. steam electric coal. This simplest form of the model will be used to generate estimates of the minimum cost shipment pattern of U.S. coal production in 1977. This will be compared to actual shipments in order to establish how well the assumptions embodied in the model approximate actual market conditions. The next chapter will project 1990 coal shipments with the same model extensively modified to reflect changes in the coal market which are expected in the interim. In Chapter VII we shall be able to relax the rather unrealistic assumption of perfect knowledge which we utilize in this chapter and the next.

The model introduced here is an extension of that developed by Schlottmann (Schlottmann, 1975). The Schlottmann model is itself an extension of Henderson's 1947 application of the classic transportation problem to the coal industry (Henderson, 1955). The classic transportation model distributes an identical product from spatially separate supply locations to various demand locations in a way that minimizes total transportation cost. In applying the model to coal, both production costs, which vary noticeably across supply regions, and transportation cost are minimized.

A Model of the Steam Electric Coal Market

It is assumed that electric utilities attempt to minimize the cost of acquiring coal. The mathematical programming model is constrained to satisfy regional demands for the heat (Btus) contained in coal. In meeting this demand, the model results can neither exceed productive capacity of any supply region nor exceed sulfur emissions standards of the demand regions.

The model disaggregates coal demand among the individual contiguous states. Coal supply is disaggregated among the 23 coal producing districts as specified by the Bureau of Mines. These are shown in Table IV-1 and Figure IV-1. Each coal producing region's capacity is identified across two dimensions; six possible sulfur levels and whether the coal is surface or deep mined. The average Btu content is computed for each distinct category.

The structure of the basic model is as follows:

$$\text{minimize } \sum_{ljik}\sum\sum\sum(C_{ji} + t_{lj})X_{ljik}$$

subject to

$$\sum_{l} X_{ljik} \leq K_{jik} \text{ for all i, j, k}$$

$$\sum_{jik}\sum\sum b_{jik}X_{ljik} \geq D_l \text{ for all l}$$

$$\sum_{jik}\sum\sum S_{ljik}X_{ljik} \leq S_l \text{ for all l}$$

where C_{ji} = unit extraction cost of the ith mining method in supply region j

t_{lj} = unit transporation cost from supply region j to demand region l

TABLE IV-1

DEFINITIONS OF BITUMINOUS COAL AND LIGNITE PRODUCING DISTRICTS

DISTRICT 1.

Maryland–
All mines in the State

Pennsylvania–
All mines in the following counties:

Bedford	Centre	Forest	McKean
Blair	Clarion	Fulton	Mifflin
Bradford	Clearfield	Huntingdon	Potter
Cambria	Clinton	Jefferson	Somerset
Cameron	Elk	Lycoming	Tioga

Selected mines in the following counties:
Armstrong County (part).-All mines east of the Allegheny River, and those mines served by the Pittsburgh & Shawmut Railroad located on the west bank of the river.
Fayette County (part).-All mines located on and east of the line of Indian Creek Valley branch of the Baltimore & Ohio Railroad.
Indiana County (part).-All mines not served by the Saltsburg branch of the CONSOLIDATED RAIL CORPORATION.
Westmoreland County (part).-All mines served by the CONSOLIDATED RAIL CORPORATION from Torrance,east.

West Virginia–
All mines in the following counties:

Grant	Mineral	Tucker

DISTRICT 2.

Pennsylvania–
All mines in the following counties:

Allegheny	Butler	Lawrence	Venango
Beaver	Greene	Mercer	Washington

Selected mines in the following counties:
Armstrong County (part).-All mines west of the Allegheny River except those mines served by the Pittsburgh & Shawmut Railroad.
Fayette County (part).-All mines except those on and east of the line of Indian Creek Valley branch of the Baltimore & Ohio Railroad.
Indiana County (part).-All mines served by the Saltsburg branch of the CONSOLIDATED RAIL CORPORATION.
Westmoreland County (part).-All mines except those served by the CONSOLIDATED RAIL CORPORATION from Torrance, east.

DISTRICT 3.

West Virginia–
All mines in the following counties:

Barbour	Jackson	Randolph	Webster
Braxton	Lewis	Ritchie	Wetzel
Calhoun	Marion	Roane	Wirt
Doddridge	Monongalia	Taylor	Wood
Gilmer	Pleasants	Tyler	
Harrison	Preston	Upshur	

Selected mines in the following county:
Nicholas County (part).-All mines served by or north of the Baltimore & Ohio railroad.

DISTRICT 4.

Ohio–
All mines in the State.

DISTRICT 5.

Michigan–
All mines in the State.

DISTRICT 6.

West Virginia–
All mines in the following counties:

Brooke	Hancock	Marshall	Ohio

DISTRICT 7.

Virginia–
All mines in the following counties:

Montgomery	Pulaski	Wythe	Giles	Craig

Selected mines in the following counties:
Buchanan County (part).-All mines in that portion of the county served by the Richlands-Jewell Ridge branch of the Norfolk & Western Railroad and in that portion on the headwaters of Dismal Creek east of Lynn Camp Creek (a tributary of Dismal Creek).
Tazewell County (part).-All mines in those portions of the county served by the Dry Fork branch to Cedar Bluff and from Bluestone Junction to Boissevain branch of the Norfolk & Western Railroad and Richlands-Jewell Ridge branch of the Norfolk & Western Railroad.

West Virginia–
All mines in the following counties:

Greenbrier	Mercer	Monroe	Pocahontas	Summers

Definition of Bituminous, Subbituminous, and Lignite Coal Producing Districts

DISTRICT 7. Continued

West Virginia– (continued)

Selected mines in the following counties:
Fayette County (part).-All mines east of Gauley River and all mines served by the Gauley River branch of the Chesapeake & Ohio Railroad and mines served by the Norfolk & Western Railroad.
McDowell County (part).-All mines in that portion of the county served by the Dry Fork branch of the Norfolk & Western Railroad and east thereof.
Raleigh County (part).-All mines except those on the Coal River branch of the Chesapeake & Ohio Railroad and north thereof.
Wyoming County (part).-All mines in that portion served by the Guyandot branch of the Norfolk & Western Railroad lying east of the mouth of Skin Fork of Guyandot River and in that portion served by the Virginia division main line of the Norfolk & Western Railroad.

DISTRICT 8.

Kentucky–
All mines in the following counties in eastern Kentucky:

Bell	Greenup	Lawrence	Morgan
Boyd	Harlan	lee	Owsley
Breathitt	Jackson	Leslie	Perry
Carter	Johnson	Letcher	Pike
Clay	Knott	McCreary	Rockcastle
Elliott	Knox	Magoffin	Wayne
Floyd	Laurel	Martin	Whitley

North Carolina–
All mines in the State.

Tennessee–
All mines in the following counties:

Anderson	Cumberland	Overton
Campbell	Fentress	Roane
Claiborne	Morgan	Scott

Virginia–
All mines in the following counties:

Dickinson	Russell	Wise
Lee	Scott	

Selected mines in the following counties:
Buchanan County (part):-All mines in the county, except in that portion on the headwaters of Dismal Creek, east of Lynn Camp Creek (a tributary of Dismal Creek) and in that portion served by the Richlands-Jewell Ridge branch of the Norfolk & Western Railroad.
Tazewell County (part).-All mines in the county except in those portions served by the Dry Fork branch of the Norfolk & Western Railroad and branch from Bluestone Junction to Boissevain of Norfolk & Western Railroad and Richlands-Jewell Ridge branch of the Norfolk & Western Railroad.

West Virginia–
All mines in the following counties:

Boone	Kanawha	Mason	Wayne
Cabell	Lincoln	Mingo	
Clay	Logan	Putnam	

Selected mines in the following counties:
Fayette County (part).-All mines west of the Gauley River except mines served by the Gauley River branch of the Chesapeake & Ohio Railroad.
McDowell County (part).-All mines west of and not served by the Dry Fork branch of the Norfolk & Western Railroad.
Nicholas County (part).-All mines in that part of the county south of and not served by the Baltimore & Ohio Railroad.
Raleigh County (part).-All mines on the Coal River branch of the Chesapeake & Ohio Railroad and north thereof.
Wyoming County (part).-All mines in that portion served by the Guyandot branch of the Norfolk & Western Railroad and lying west of the mouth of Skin Fork of Guyandot River.

DISTRICT 9.

Kentucky–
All mines in the following counties in western Kentucky:

Butler	Hancock	McLean	Todd
Christian	Henderson	Muhlenberg	Union
Crittenden	Hopkins	Ohio	Warren
Daviess	Logan	Simpson	Webster

DISTRICT 10

Illinois–
All mines
in the State.

DISTRICT 11

Indiana–
All mines
in the State.

DISTRICT 12

Iowa–
All mines
in the State.

DISTRICT 13.

Alabama–
All mines in the State.

Georgia–
All mines in the State.

Tennessee–
All mines in the following counties:

Bledsoe	Marion	Sequatchie	White
Grundy	McMinn	Van Buren	
Hamilton	Rhea	Warren	

DISTRICT 14.

Arkansas–
All mines in the State.

Oklahoma–
All mines in the following counties:

Haskell	Le Flore	Sequoyah

DISTRICT 15.

Kansas–
All mines in the State.

Missouri–
All mines in the State.

Oklahoma–
All mines in the following counties:

Coal	Latimer	Okmulgee	Rogers	Wagoner
Craig	Muskogee	Pittsburg	Tulsa	

Texas–
All mines in the State.

DISTRICT 16.

Colorado–
All mines in the following counties:

Adams	Douglas	Jackson	Larimer
Arapahoe	Elbert	Jefferson	Weld
Boulder	El Paso		

DISTIRCT 17.

Colorado–
All mines except those included in District 16.

New Mexico–
All mines except those included in District 18.

DISTRICT 18.

Arizona–
All mines in the State.

California–
All mines in the State.

New Mexico–
All mines in the following counties:

Grant	McKinley	Sandoval	San Miguel	Socorro
Lincoln	Rio Arriba	San Juan	Santa Fe	

DISTRICT 19.

Idaho–
All mines in the State.

Wyoming–
All mines in the State.

DISTRICT 20.

Utah–
All mines in the State.

DISTRICT 21.

North Dakota–
All mines in the State.

South Dakota–
All mines in the State.

DISTRICT 22.

Montana–
All mines in the State.

DISTRICT 23.

Alaska–
All mines in the State.

Oregon–
All mines in the State.

Washington–
All mines in the State.

Source: Energy Information Administration, U.S. Department of Energy

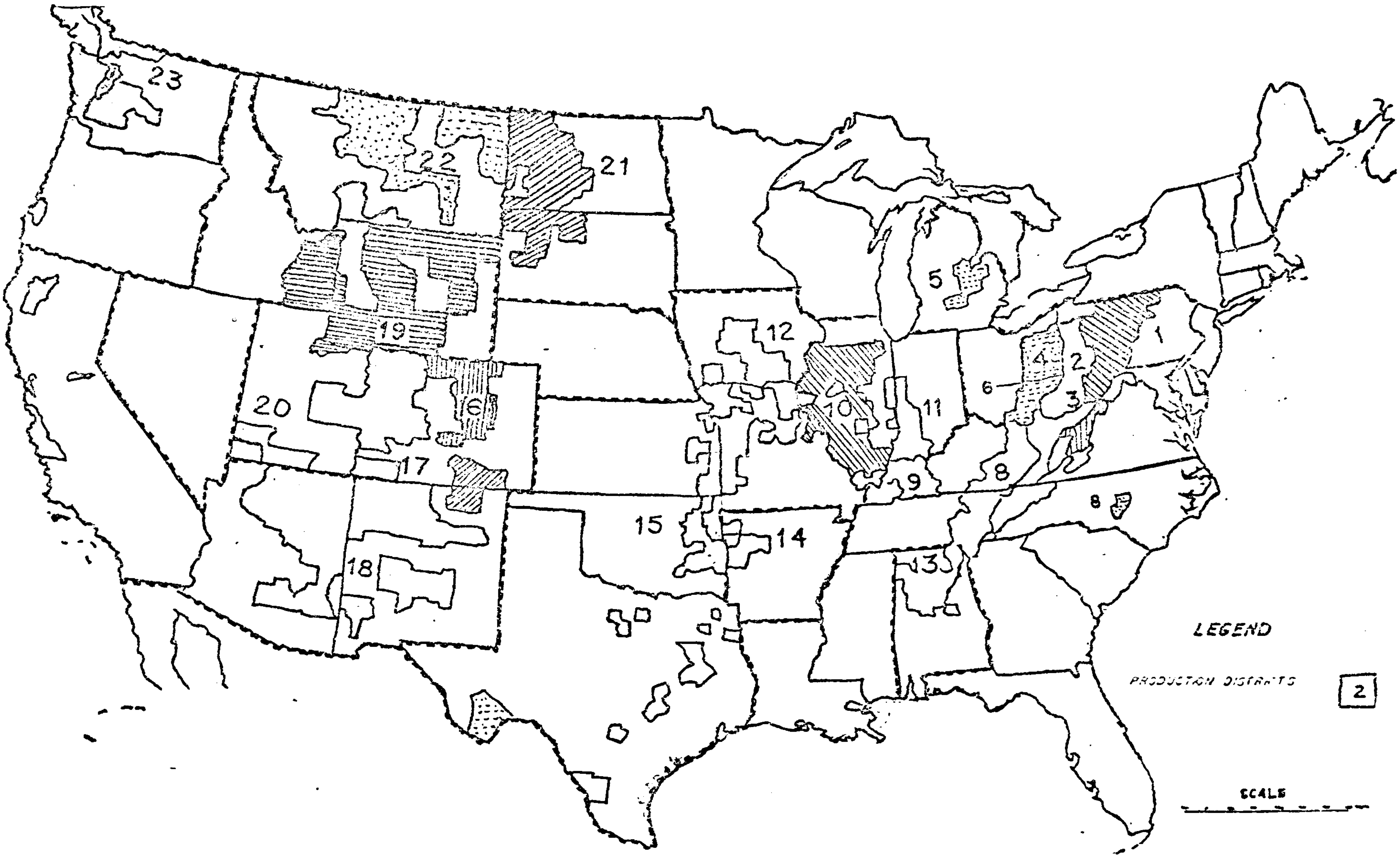

Figure IV-1. U.S. Bureau of Mines Coal Producing Districts.

Source: Energy Information Administration, U.S. Department of Energy.

X_{ljik} = shipment from region j to l of coal extracted by the ith method with sulfur level k

K_{ijk} = capacity of coal district j for coal mined by technique i with sulfur level k

b_{jik} = average energy value in Btus of the specific coal type in 1977

D_l = total Btu demand in region l

S_{ljik} = the average contribution to total sulfur emissions in region l per unit of coal from district j, mining method i, and sulfur category k. This is equal to $(b_{ijk} * S_{ijk})/D_l$ where S_{ijk} is equal to the percent sulfur by weight contained in the coal and

S_l = maximum allowable sulfur emission level per million Btu in region l

The objective function expresses the behavioral assumption of the model; that the market will seek the lowest cost allocation of coal which meets the constraints. That is, in attempting to satisfy the total Btu requirements of each state, the model will prefer a supply district whose delivered price is lower than a competing district's. This delivered price advantage is a composite of both transportation and extraction cost differeces. The optimal solution occurring at minimum cost imitates that which would occur in a perfectly competitive market where perfect knowledge exists. In other words, a perfectly informed coal broker would not be able to make a profit by rearranging the shipment pattern generated by the model.

Thus specified, the model is capable of simulating some of the complex interactions which take place in the real world. The minimum cost solution of this model will vary as a result of changes in transportation costs, regional demands, regional sulfur emissions standards, extraction costs and supply district capacities. When one of these variables changes, for whatever reason, that change can affect many other regions in addition to the one directly altered as the model arrives at a new optimal solution. For example, if demand in one state increases, this entails increased shipments from at least one of this state's least cost suppliers. The shipment pattern of the states formerly utilizing this reallocated coal must be adjusted accordingly. These adjustments continue until the market as a whole cannot lower total cost by further rearranging shipments. The assumption that perfect knowledge exists is thus implicit in the model.

The primary data source for coal market characteristics as they existed in 1977 is a data tape which consists of all reported shipments of coal to electric utilities during the year. It is thought that reported shipments reflect about 98 percent of actual (Schlottmann, 1975, p. 238). Figure IV-2 is a reproduction of the form utilities are required to submit.

These data make it possible to achieve a high degree of resolution in the relevant characteristics of steam electric coal. We have been able to identify, for each region, the average heat content of the coal shipped broken down by both mining method and sulfur content. This detailed specification of Btu content is a significant improvement over those techniques which divide average Btu values into several categories and require the model to operate on some average value within each range (ICF, 1977). Sulfur content was disaggregated to provide a unique value for each possible combination of supply district, mining method, and sulfur level. Demand and supply constraints were set equal to total shipments in 1977 from each supply district, j, or to each state, l.

MONTHLY REPORT OF COST AND QUALITY OF FUELS FOR ELECTRIC PLANTS

1. Company-Plant Code	2. Report For: NO. YR.	3. Reporting Company	4. Page Number OF
5. Plant Name		6. Plant Location	
7. Name, Title and Address of person to be contacted concerning data entered on this form			Telephone No. Area Code ( ) Extension:
8. Signature of Official submitting this report		Title	Date Completed

Line No.	TYPE PLANT & IC GT (0)	PURCHASES: TYPE use code (1)	PURCHASES: CONTRACT EXPIRES WITHIN 24 Mos. (Yes-No) (2)	FUEL TYPE use code (3)	COAL MINES ONLY: TYPE use code (4)	COAL MINES ONLY: DISTRICT Number & State (5)	SOURCE For coal, show name of mine and county from which coal originated, if available. For oil, show suplier and refinery or port of entry. For gas, show pipeline (supplier) or distributor, producing area by state, or port of entry. (6)	QUANTITY RECEIVED 1000 Tons 1000 Barrels 1000 Mcf (7)	QUALITY (AS RECEIVED): Average Btu of: Coal per lb. Oil per gal. Gas per cu. ft. (8)	QUALITY (AS RECEIVED): Sulfur To Nearest 0.01% (9)	QUALITY (AS RECEIVED): Ash To Nearest 0.1% (10)	COST IN ¢ PER MILLION Btu (to nearest 0.1 cent) (11)
1												
2												
3												
4												
5												
6												
7												
8												
9												
10												

Figure IV-2. Monthly Report of Cost and Quality of Fuels for Electric Plants.

Source: Federal Energy Commission.

Sulfur emissions standards were set equal to state implementation plan (SIP) regulations for every state as reported by the Environmental Protection Agency (EPA, 1977). In several states, such as Indiana, Kansas, Tennessee, and Wisconsin, actual shipments in 1977 could not have met these statutory standards. It was assumed that effective regulations must have been less stringent than the statutory standard and in these cases the emission level used in the model was raised to account for this disparity. The Department of Energy has found that over 30 percent of 1977 coal shipments violated existing standards (EPA, 1977, pp. xxviii). This confirms the occasional disparity between statutory and de facto emissions standards. Though some flue gas desulfurization systems were operational in 1977, their total coal capacity was an insignificant proportion of the market (Federal Energy Regulatory Commission, part V, p. 42).

The prices reported on FPC Form 423 are delivered prices. This enables us to specify the term $(C_{jik} + t_{lj})$ as one term, Ct_{ljik} in the 1977 simulation. A more accurate representation of delivered cost, the relevant decision variable to the programming problem, is possible because it is thus not necessary to specify separately both extraction and transportation costs.

The linear programming model described above seems to imitate the actual coal market fairly closely. The optimal shipments generated by the model are shown in Table IV-2. Table IV-3 indicates how these "predictions" differ from the actual shipments of steam electric coal in 1977. Overall, the model misallocates some 35 million tons, or about seven percent of total shipments. This resolution is fairly

TABLE IV-2

PREDICTED STEAM COAL SHIPMENTS, 1977, DETERMINISTIC MODEL
(Millions of Tons)

	Destination[1]				
Supply Region[2]	East	South	Midwest	West	Total
Northern Appalachia	65.98	24.46	0.0	0.0	90.44
Mid Appalachia	49.48	75.71	0.0	0.0	125.19
Southern Appalachia	--	14.17	0.0	0.0	14.17
Midwest	58.28	43.67	40.36	0.0	142.31
West	23.88	0.0	39.09	52.92	115.89
Total	197.62	158.54	79.45	52.72	488

[1]East includes New England, Middle Atlantic and East North Central Census Regions; South includes South Atlantic and East South Central Census Regions; Midwest includes West North Central and West South Central Census Regions; West includes Mountain and Pacific Census Regions.

[2]Northern Appalachia includes coal producing districts 1, 2, and 4; Mid-Appalachia includes districts 3, 6, 7, and 8; Southern Appalachia includes district 13; Midwest includes districts 5, 9, 10, 11, 12, 14, and 15; the West includes districts 16, 17, 18, 19, 20, 21, 22, and 23.

TABLE IV-3

MODEL DISCREPANCIES RELATIVE TO ACTUAL SHIPMENTS, 1977
(Millions of Tons)

Supply Region	Destination			
	East	South	Midwest	West
Northern Appalachia	-14.04	14.15	-.12	--
Mid Appalachia	16.03	-15.32	-.73	--
Southern Appalachia	-.03	.06	-.03	--
Midwest	.57	.11	-.68	--
West	-1.95	-.13	1.60	.46

precise in view of the several important institutional factors which are not accounted in such an optimization system.

The model ships coal in the cheapest manner subject to severe constraints and the optimal allocation could deviate substantially as a result of ignoring less quantitatively amenable economic or institutional factors. Since we cannot hope to model every such factor, it is illuminating to trace the reverberations which our exclusions imply. Since the model is a highly integrated and interrelated system, it is an arbitrary choice of which disparity starts the adjustment process. The model would indicate more coal shipment than the actual market from mid-Appalachia to the East, and consequently the East would require less coal from northern Appalachia. This would leave less mid-Appalachian coal available to the South, which would make up the shortage by purchasing coal from northern Appalachia.

Summary

We have presented a mathematical programming model in this chapter which simulates the allocation of steam coal in the United States. The model reproduces actual coal distribution with a fair degree of accuracy. The chapters that follow will modify this model to predict coal allocations in 1990 under variously specified scenarios.

CHAPTER V

PROJECTING COAL ALLOCATIONS WITH THE DETERMINISTIC MODEL

Introduction

In this chapter we modify and expand the linear programming model of Chapter IV in order to analyze the coal market projected for 1990. The optimization technique remains essentially the same but forecasts of the relevant variables instead of the historical data available for 1977 simulations are used. We have thus attempted to improve our linear programming allocation model by including a complementary econometrically estimated demand equation.

Coal Demand

To project total energy requirements from coal in 1990 econometric estimates from a simple simultaneous equation system are used. Alternative forecasts of coal demand for the model constraints are available from several sources (ICF, 1977; Mount, Chapman and Tyrrell, 1973; Argonne National Laboratory, 1977) but the model here is estimated in order to generate the variance about the estimate of demand which we utilize in Chapter VII, and to allow a degree of flexibility in the specification of the independent variables. The estimates are generally consistent with other studies, however (ICF, 1978; Gordon, 1976B). The model is a simple simultaneous equation system. The simultaneous equation bias is recognized by using a two-stage estimation procedure.

The general specification of a demand function includes own price, income, and prices of substitutes. The function used here to estimate electricity demand is described by,

$$Qe = B_1 + B_2Y + B_3Pe + B_4P_s + B_sR_i + E \tag{1}$$

where: Qe = quantity of electricity

Y = regional personal income

Pe = price of electricity

P_s = price of substitute, gas

R_i = a region specific dummy variable

E = stochastic disturbance

The demand for coal is specified as derived from the demand for electricity. The methodology is similar to that used by Bohm and Watson (Bohm and Watson).

$$Qc = \alpha_1 + \alpha_2\hat{Qe} + \alpha_3Pc + \alpha_4Ps' + \alpha_5R_i + E' \tag{2}$$

where: Qc = quantity of coal

$\hat{Qe}$ = "predicted" quantity of electricity from equation (1)

Pc = price of coal

Ps'= price of substitute, oil

R_i = a region specific dummy variable

E' = stochastic disturbance

Table V-1 shows the regression model estimated as specified above.[5] Both of the equations yield elasticities which are consistent with their hypothesized values. In the electricity demand equation, the price of electricity is slightly inelastic and highly significant and the price elasticity of a substitute is positive and significant.

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[5]Though autocorrelation and heteroscedasticity are probably extant in the data, third-stage estimates of the coefficients were not very different from those presented here.

TABLE V-1

THE DEMAND FOR COAL

$$Qe = 5.849 + \underset{(21.3)}{1.253}\ Y - \underset{(7.9)}{0.828}\ Pe + \underset{(4.2)}{0.198}\ Ps$$

$$-\underset{(6.7)}{0.989}\ R2 - \underset{(5.9)}{0.787}\ R3 - \underset{(5.0)}{0.520}\ R4 - \underset{(4.4)}{0.467}\ R5 - \underset{(1.3)}{0.063}\ R8$$

$R^2 = 0.9795$

$$Qc = 1.364 + \underset{(18.2)}{1.175}\ \hat{Qe} - \underset{(6.3)}{0.739}\ Pc + \underset{(3.0)}{0.226}\ Ps'$$

$$+ \underset{(0.5)}{0.046}\ R2 + \underset{(2.9)}{0.224}\ R3 - \underset{(1.9)}{0.146}\ R4 + \underset{(1.1)}{0.103}\ R5 - \underset{(12.0)}{0.889}\ R8$$

$R^2 = 0.95(*)$

---

* R^2 is not a dependable statistic when predicted values are used as independent variables and should not be interpreted in the usual sense.

't' values are shown in parentheses.

[114 observations (19 years, 6 regions)], 1958-1977.

Both equations were estimated in double-log form, and thus the coefficients can be interpreted as elasticities.

Income is very elastic in equation (1), consistent with the contention that electricity is a superior good.

The coal demand equation is consistent with our expectations. Own price is slightly inelastic and the coefficient of the price of a substitute is positive and significant. Also, the second stage coefficient estimate on electricity demand is greater than one, suggesting that the elasticity of coal demand with respect to electricity demand is somewhat elastic. The regional dummy variables confirm signficant regional diversity in the electricity and coal markets.

The demand model was estimated over the six census regions where coal has been a significant fuel over the 20-year period (1958-1977) of the model. Both the electric utility industry and the fuels markets have been subject to varying degrees of government regulation over this period. Thus, data on relative prices may introduce distortions into the analysis. Moreover, the 1973-74 oil embargo may have fundamentally altered traditional market relationships. Yet it would not seem appropriate to reject the energy market information that exists, especially in an analysis such as this where uncertainty is an acknowledged factor (Bohm and Watson, p. 4). Table V-2 shows the projected 1990 demand for electricity and coal as generated by the model in these six regions and the average annual growth rates that these results imply. Electricity demand is expected to increase between 3.7 and 5.3 percent per year, which leads to a growth in coal demand ranging from 2.4 to over 5 percent per year. ICF demand estimates for New England, the West South Central, and West census regions were used since historically the utilization of coal in these regions has been insignificant, and thus existing data were insufficient for econometric estimation.

TABLE V-2

PROJECTED REGIONAL ELECTRICITY AND COAL DEMAND, 1990

Census Region	Electricity Demand (10^6 KWH)	Average Annual Growth Rate	Coal Demand (10^9 Btus)	Average Annual Growth Rate
Middle Atlantic	413990.01	3.69	2214661.49	5.03
South Atlantic	736848.06	4.97	6011088.33	4.85
East North Central	254293.60	4.30	1407373.97	2.85
East South Central	675534.88	4.40	4073990.27	5.06
West North Central	373976.49	5.10	2095069.68	2.40
Mountain	256208.70	5.28	1081282.55	2.65

Estimates of coal demand for census regions were distributed among the individual states according to the particular state's share of regional coal demand in 1977. Relative populations were used to allocate coal demand in the three regions for which ICF estimates were used.

The overriding purpose of the present study is to assess the cost and impact of uncertainty in the allocation of coal. The merit of such a study is partly due to the scant treatment of this crucial factor elsewhere. The absolute level of coal demand in the "deterministic" forecast, to which the estimates under uncertainty are compared, is thus of secondary importance. The relevant consideration here is the distortion and higher cost which ensues as a consequence of uncertainty--not the absolute level of the forecast. It would be ludicrous to attach a particular significance to projected coal consumption when a principal contention is that uncertainty is a major factor. Indeed, an ability to predict with any confidence would obviate a substantial part of the present analysis.

The projections of independent variables were made by expanding 1976 values by assumed average annual growth rates. The growth rates are shown in Table V-3. It is notable that some of the variables, such as income and electricity prices, are expected to exhibit varying growth rates across the regions, and this is one important determinant of expected shifts in the future coal market.

Coal Supply

Projections of coal supply in the future are subject to uncertainty nearly to the extent coal demand is unknown. However, the coal market

TABLE V-3

AVERAGE ANNUAL PERCENT REAL GROWTH RATES ASSUMED
TO PROJECT 1990 ELECTRICITY AND COAL DEMAND BY REGION

Region	Income	Electricity Price	Gas Price	Coal Price	Oil Price
Middle Atlantic	3.2	0.0	3.7	1.0	0.9
South Atlantic	3.0	0.0	4.5	1.0	1.0
East North Central	3.1	0.0	5.3	1.0	1.1
East South Central	4.1	0.3	3.2	1.0	0.6
West North Central	3.8	1.5	4.6	1.0	1.0
Mountain	3.7	0.5	5.0	1.0	0.8

Source: National Energy Outlook, 1976.

is generally conceded to be demand constrained. That is, most analysts expect that supplies will expand to meet any feasible level of expected demand (Energy Modeling Forum, 1978, p. iii). The imprecision is primarily focused on the cost and therefore the prices which will be necessary to coax requisite production. Certainly any reasonable demand for coal could be met if prices were high enough. The uncertainty associated with coal supply is centered on the amount of coal available at a given price and how much higher price must rise in order to insure greater supply. The problem becomes more interesting and more complex when it is recognized that this supply function varies across supply districts, mining methods, and coal characteristics.

Our data have enabled us to utilize step supply functions to reflect increasing costs within a linear programming framework. This allows the model to incorporate the increased cost of significantly expanded coal supply of a specific type in each region. The 1977 capacities utilized in the last chapter when appropriately adjusted for depletion provide the first step in the supply function. Subsequent capacity steps and the requisite price were derived from ICF (ICF, 1978, Appendix G). Figure V-1 illustrates one of the ICF supply functions. Many of the ICF functions exhibit much coarser steps than the one here and often we have aggregated several steps in order to keep the size of the transportation matrix within reasonable bounds. Thus the "steps" we have utilized represent up to $5 increments for some specific coal sources.

Coal Transportation

Transportation costs employed in the model were primarily those used by Schlottmann. Though several alternative sources of transportation

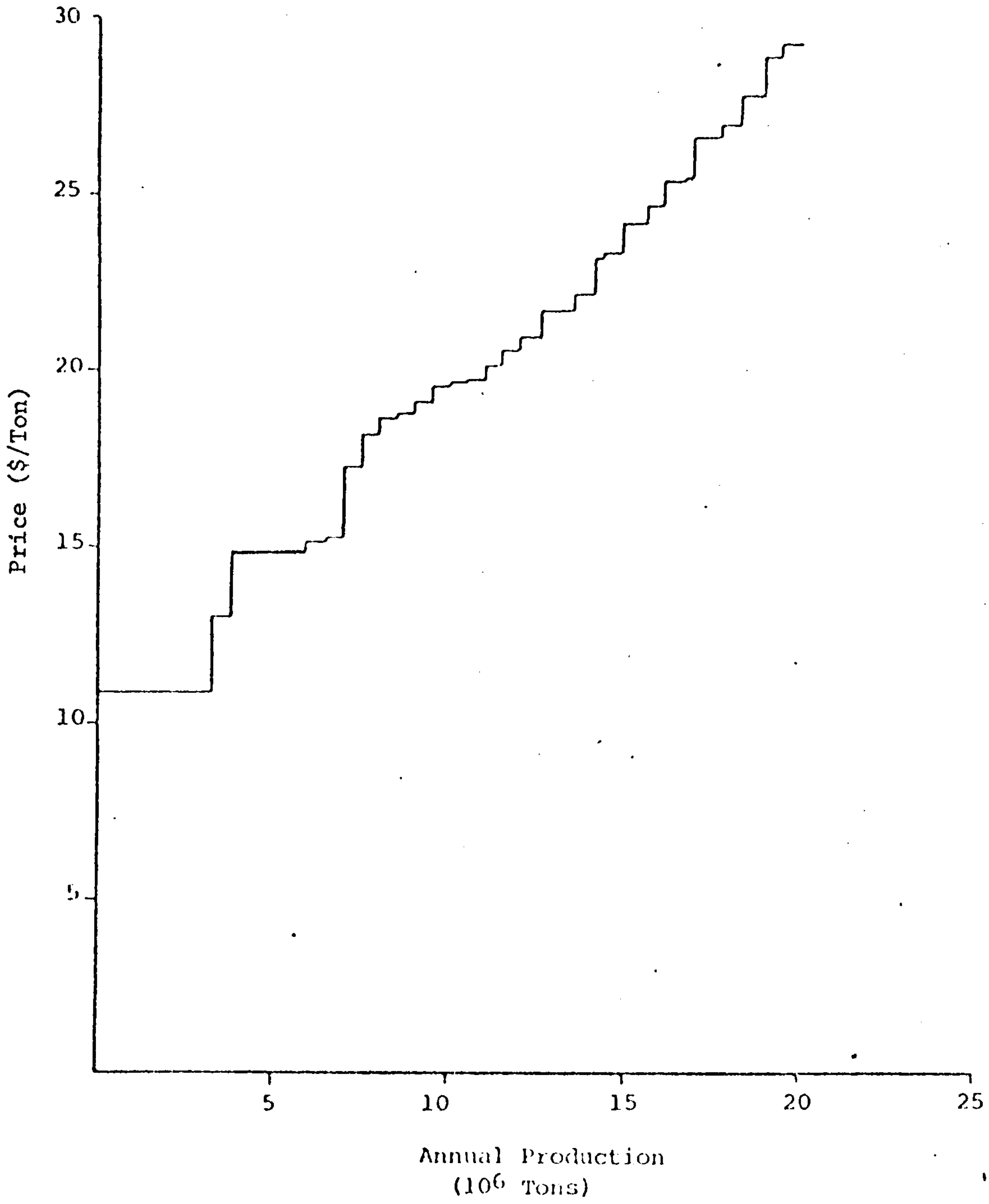

Figure V-1. Coal Supply Curve.

Source: ICF Incorporated.

costs exist (ICF, 1978; Zimmerman, 1975; Federal Railway Administration, 1977), the Schlottmann data are thought to most accurately reflect costs of actual routes utilized. Whereas common practice is to use crowflight distances or rail distances shown in the Federal Railroad Administration's Short Line Mileage System for the U.S. Railroad Networks (ICF, 1977, p. III-iii), Schlottmann was meticulous in assuring that the minimum distance routes chosen were capable of handling coal trains. This important consideration is often ignored. The Schlottmann formulation also accounts for the possibility of shipping coal by barge where available. The Schlottmann costs in 1972 dollars were inflated to 1977 dollars with the Bureau of Labor statistics price index for coal shipments by railroad (Bureau of Labor Statistics, 1978).

A shortcoming of the Schlottmann transportation cost matrix arose for shipments to regions which have not been significant coal users in the past. The model needed additional transportation cost entries, primarily for coal shipments to Western states. These possible routes were integrated into the model by using ICF estimates of transportation costs, which, as a whole, were generally comparable to the Schlottmann figures (ICF, 77, pp. III-124).

Sulfur Emissions Standards

Sulfur emissions standards will probably continue to be an important and unpredictable element in the coal market. The standards vary markedly among and even within the individual states. The Environmental Protection Agency (EPA) has been the source of maximum emissions standards which may be tightened further by SIPs. Much of the variation and imprecision associated with sulfur emissions standards emanate from the fact that the effects of sulfur emissions (and sulfur's associated compounds) are not clearly understood. We are not really sure of the effects caused by higher concentrations of sulfur, i.e., the costs, nor are we at all well informed of the future cost of controlling such emissions. Flue gas desulfurization systems were once thought to be a reliable, cost effective technology, but even this control option has been questioned (Gordon, 1975, p. 131). Deep cleaning or coal washing, a technique for removing pyritic or superficial sulfur, is a viable sulfur control technology. However, its maximum removal efficiency with specific types of coal is, at most, 30 percent (Gordon, 1975, p. 130).

Complicating the issue is the highly political nature of any sulfur emission control option. Some policy makers seem to believe that the prosperity of their constituents requires artificial constraints or at a minimum, sulfur standards which may not be most efficient, but which insure a continued market for their constituents' coal. Fortune, for example, states that, ". . . Regulations reflect not so much rampant fanaticism about sulfur emissions as they do political pressure from eastern states where high-sulfur coal is mined" (Fortune, November, 1978, p. 56).

Sulfur standards for "old" coal burning facilities are fairly well established, however, and the suggested changes in emissions standards are expected to affect new coal burning facilities (Coal Age, September, 1978, p. 9). Old source performance standards (OSPS) were reviewed in Chapter VI. These existing standards, which apply to existing sources, are assumed to continue through 1990. We assume that the increased costs of capital coupled with significantly higher costs of meeting new source performance standards will be a strong stimulus to utilize old sources to a maximum extent through 1990. Thus coal burning capacity which existed in 1977 is projected to remain effective in 1990 and to be subject to sulfur emissions standards as they existed in the earlier period.

The difference in total coal demand projected for 1990 and that which existed in 1977 is assumed subject to new source performance standards, NSPS. In our model we have assumed that the standards proposed in November of 1978 by the EPA will be effective for subsequent additions to coal burning capacity. Therefore, all new coal demand will have to be treated to remove 90 percent of the sulfur emissions unless a level of 0.2 pounds of sulfur dioxide per million Btus can be achieved at a lower sulfur removal efficiency. An absolute ceiling of 1.2 pounds per million Btus is assumed. "But any new standard based on a percentage reduction precludes the use of low sulfur coal without FGD" (Environmental Protection Agency, 1978, p. 2-1). Appendix A investigates an alternative specification of the sulfur standard, 0.5 pounds/mm Btu with no restriction on how the standard is met.

New emissions standards which unequivocally mandate the use of FGD, involve considerably higher cost. A recent study for the EPA indicates scrubbing cost of up to $15 per ton of coal burned when their costs per kwh are translated to dollars per ton (Environmental Protection Agency, 1978, p. 4-17). However, the EPA study was based on an updated TVA study of scrubbing costs. The most recent data from TVA indicate that FGD costs per ton are more likely to be in the $6 to $9 per ton range, depending primarily upon the percent of sulfur content of the scrubbed coal.[6] In our model, scrubbing costs are set at $8.60/ton for coal that exceeds 3 percent sulfur, $6.24/ton for coal which is less than 2 percent sulfur, and $7.57/ton for that in between. Scrubbing to 90 percent also involves a 4.5 percent energy penalty which is assessed in the model.

The 90 percent removal case where all coal must be scrubbed minimizes the premium on low sulfur coal and thus largely precludes the marketability of western coal merely on the basis of its low sulfur level.

Deterministic Model Results

The deterministic model of the United States allocation of steam electric coal is computationally similar to the model of 1977 presented in Chapter V, and few changes were required. A new demand constraint for each state's projected increased requirement for coal between 1977 and 1990 is added. All new coal requiremnts are further constrained to meet NSPS. The single price and corresponding capacity for each type of coal supplied from each producing district in the 1977 simulation is replaced by the step-like supply functions discussed above where each "step" enters the model as a distinct constraint. Additional capacity for a particular type of coal from a supply district enters the model at a higher price. Thus the 252 row, 694 column matrix of Chapter V is replaced by a 447 row, 8,667 column matrix which requires over one thousand iterations to solve for the optimum.

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[6]The scrubbing costs estimates were graciously supplied by Susannah Tomlinson of TVA, Muscle Shoals, Alabama in a phone conversation.

Table V-4 shows the optimal regional shipments in the U.S. steam electric coal market as projected for 1990. There is a marked expansion in coal shipments from the West to every demand region. The 683 million tons of Western coal represents an average growth rate in Western coal producing capacity of nearly 15 percent per year. However, this extraordinary projected growth rate seems quite reasonable in light of recent experience. Between 1973 and 1977 the five largest western coal-producing states experienced average growth rates of 25 to 40 percent per year. This extraordinary growth rate is partly due to the very small initial value. Though coal production in nearly every supply district is expected to expand markedly, the West is projected to increase its share of U.S. steam coal to 60 percent of total tons shipped. This proportion is considerably less on a Btu basis, however, since western coal contains two-thirds to three-quarters of the heat in eastern coals on a tonnage basis.[7]

This projection of extraordinary expansion in western coal-producing capacity is a direct result of the supply functions utilized. Specifically, ICF, Inc. projects a greatly expanded supply of Wyoming coal at prices so low that the formidable transportation premium to markets in the East can be overcome (ICF, 1978, Appendix G). This phenomenon is roughly consistent with other studies of future coal allocations (Gordon, 1978; ICF, 1978). We make no claim of precision in these predictions, however. The magnitudes in our reference scenario are useful primarily in so far as they provide a reasonable base from which to gauge the cost and impact of uncertainty, which we explore in the remaining two chapters.

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[7]Based on Btu content of coal shipped in 1977 and reflected in FPC form 423 data.

TABLE V-4

PROJECTED U.S. COAL SHIPMENTS IN 1990; THE DETERMINISTIC CASE
(Millions of Tons)

From	To			
	East	South	Midwest	West
Northern Appalachia	100.85	1.37	0.00	0.00
Middle Appalachia	7.43	102.51	0.00	0.00
Southern Appalachia	0.00	5.80	0.00	0.00
Midwest	70.08	77.17	71.35	0.00
West	319.31	102.84	167.29	93.59
Total	497.67	289.69	238.64	93.59

Summary

Chapter V has presented the several modifications to the linear programming model of the last chapter which allow us to project future steam coal allocations in the United States. We have incorporated an econometrically derived coal demand system. Thus projections of coal demand, supply, sulfur emissions standards, and transportation costs are incorporated into our programming model to estimate regional allocations of steam coal in 1990. In the next chapter, we incorporate an estimate of the cost of uncertainty in the coal market and assess the impact of uncertainty on the steam coal market.

CHAPTER VI

INCORPORATING THE UNCERTAINTY OF COAL DEMAND IN A COAL MARKET MODEL

Introduction

The models we have utilized thus far have implicitly assumed that future demand for coal in each region is deterministic. Substantial region specific investments in coal mining capacity will be necessary prior to 1990 in order for producers to meet expected coal demand. We have thus far implicitly assumed that the market knows with certitude what future requirements to purchase electricity from coal will be. However, in actual practice, no such perfect knowledge exists.

In Chapter II it was indicated that the future demand for coal depends on many unpredictable factors. The future role of other fossil fuels such as gas and oil are not known. Moreover, the level of nuclear generation is manifestly uncertain and yet practically every kilowatt hour produced by fusion (or fission) means one less kilowatt hour needed from coal.

It was also noted that the level of coal emissions standards is subject to severe government constraints. Yet these constraints may well change as more knowledge is gained regarding their need and impact. Finally, neither production cost nor the closely related matter of coal availability is precisely predictable. This cost not only includes extraction and transportation cost of coal but the imperfect estimates of the cost of cleaning the fuel.

Compounding the problem introduced by uncertainty is the considerable lead time necessary to provide coal. The decision to open a deep mine comes at least two and one-half and sometimes more than seven years before production is realized (U.S. General Accounting Office 1977, p. 4.12). Thus, the expectation of coal demand in 1990 is a signal to coal market entrepreneurs some time between 1983 and 1988. The entrepreneurs presumably weigh all of the information available to them which influences 1990 demand. Yet, precise future requirements are not well known and only a most likely magnitude is discernible from the limited and often contradictory signals available.

Associated with the most likely expected value of future coal demand is the possibility that eventual requirements may surpass or fall short of it. The implicit assumption is that near the equilibrium price and quantity in any particular year, long-run supply is very elastic and short-run supply is nearly inelastic. But what if the entrepreneur fails to predict accurately? In order to assess the impact of inaccurate demand forecasts, we infer how the market penalizes shortfalls or excess capacity. The situation has been stated in general terms as follows,

> An entrepreneur for example may have to decide *ex ante* whether to commit resources that could turn out to be inappropriate *ex post*; thus, as events would have it, an unproductive and unmarketable sunk cost. On the other hand, the decision not to commit could result in an opportunity foregone, since the ability to seize such opportunities may depend upon having some sort of resource structure already in place. (Balch, *et al*., p. 1).

If the entreprenuer fails to provide enough coal to meet eventual demand in 1990, he forfeits, as an opportunity cost, the foregone profits.

That is, he loses the chance to make a profit on every ton of coal that might have been sold had it been available. These are profits in the economic sense in that capital costs or interest costs are considered a cost of production. There is thus a strong impetus to at least meet expected demand.

What sort of penalty does the market exact for overinvestment or the provision of too much coal? Since it is expensive to allocate capital to any employment, if its cost is not reimbursed through final sales the entrepreneur would absorb it. The coal producer is thus penalized for overprovision of capacity since he must pay for any idle capital. Presumably, the variable costs are avoidable.[8] The market may thus over or under allocate; it does, however, assess an extra cost when future needs are unassured which varies with the degree of the uncertainty.

If the imprecision associated with the most likely level of coal demand were small, the extent of over or underproduction and the magnitude of the associated penalties would be correspondingly smaller, approaching zero as the expected level of demand becomes more assured. On the other hand, the magnitude of this extra cost of uncertainty increases with the level of imprecision. When the likelihood of, say, greatly exceeding expected demand is large, the significance of the opportunity cost incurred by underestimated sales is correspondingly

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[8] Thus we have assumed that capital costs are a good proxy for fixed costs. To the extent, however, that we ignore the proposition that part of the labor input is a fixed factor, we underestimate this cost.

large. A similarly significant expected cost is incurred by underutilized capacity when uncertainty is a major factor.

Uncertainty in Alternative Models

Heretofore, perhaps the most widely used techniques for dealing with uncertainty have been the least quantitative. This is suggested partly because mathematical techniques often imply a degree of precision that is neither intended nor justified. Thus, the coal allocation framework presented by Gordon and reviewed in Chapter III may have been the most useful in an uncertain environment (Gordon, 1978, pp. 155-192). His technique relies less upon precise mathematical relationships and more on informed, judgmental distribution. Implicit and conscious account of the wide variation inherent in coal demand estimation can be thus accounted through the specification of multiple scenarios.

The avowed purpose of the Gordon "model," is to present,

> . . . combinations of assumptions equivalent to almost any case of interest . . . they consider a far wider range of relative cost positions than have yet been treated by other models. This provides a demonstration that the reasonable ranges of estimates of values of key determinants of electric utility fuel use are so broad that many plausible futures can be projected (Gordon, 1978, p. 155).

Yet Gordon admits that he has failed to exhaust all possible situations that might arise.

Without doubt, these alternative scenarios provide policy makers with valuable information. They are not able to assess the impact of uncertainty itself, however, and seldom make any such pretension. Each scenario is presented as if the outcome were deterministic.

We have noted earlier that econometric models of future coal utilization are severely hampered in so far as they project historical relationships into the future. This is generally true of econometric analysis where the historical relationships among variables are expected to continue. However, a potentially useful aspect of the econometric technique is seldom exploited. Regression equations simultaneously generate a measure of the variation associated with the most likely estimate of a variable. This variation about the mean expected value could give policy makers a crude measure of the imprecision of a projection. This econometrically derived measure of the variability associated with demand is based on historical experience rather than present reality or possible future trends. Despite this shortcoming, however, the technique affords an indication of reasonable bounds of a forecast which should be more useful than an arbitrarily assigned range.

Occasionally scenario analysis is used to gauge the cost and/or impact of several policy options. It might often be the case that two alternative scenarios may not really be significantly different when the researcher allows for the inexactitude in each scenario which undoubtedly exists (Mayer, 1979, p. 18).

Several of the optimization or mathematical programming models which exist were reviewed in Chapter III. These techniques are not restricted to historical patterns in the same way that econometric models can be. However, optimization models require, as inputs, estimates of demand, supply, extraction costs, transport costs, and other such variables as they are expected to exist in a later period. Yet, once these predicted parameters are chosen, they become, in essence, precise magnitudes in a deterministic scenario. The modelers' lack of confidence in their exact value is generally evident in the range of alternative scenarios chosen. As we have seen above, this technique, however valuable, ignores the impact of uncertainty itself.

Our purpose is not to demean the popular technique of exploring several eventualities. Recognizing that uncertainty is a major factor in the coal market by projecting several possible levels of coal demand is far superior to a naive model in which a prediction is treated as if it were the only possible outcome. We have, however, gone a step further and included uncertainty as an explicit parameter in a model of the coal industry. This enables us to simulate the response of the market to unpredictable demand. We can thus gauge the magnitude of the extra costs which an uncertain coal market imposes and discern the regional permutations of the market which result but are otherwise poorly explained or ignored. For example, let us suppose that future coal demand is very uncertain and that the likelihood of our prediction being high or low is the same. Suppose also that we expect to sacrifice $10 for every ton of coal required that we have not provided. That is if we underestimate demand, we forego a profit, over and above our total costs of production, of $10 per ton. On the other hand, if we have extra coal producing capacity on hand, the depreciation cost of the extra capital equipment averages $1 per excess ton available. This might be the cost of idle structures and equipment that we are committed to pay for even if it is not used. The same costs are normally incurred, but when we overestimate how much capacity is required, these depreciation costs are uncompensated by sales. In the face of such a dilemma brought on by uncertainty, we suggest that the rational entrepreneur would tend to overinvest in order to be less apt to incur the higher penalty. If the entire market responds this way, greater demand for the most desirable sources would be expected to alter allocation patterns as well.[9]

The Stochastic Programming Model

In the remainder of this chapter we shall show how the deterministic model presented in Chapter VI can be modified to account explicitly for uncertainty. We shall first identify mathematical representations for the costs associated with imprecise estimates of future coal demand. Then, we shall be in a position to alter the objective function such that we may simultaneously minimize the uncertainty premium while distributing coal in the least expensive way.

For each possible level of coal demand we shall present a fairly straightforward procedure to obtain a measure of the associated uncertainty cost. We do this by assigning specific costs for each ton of coal which we under or overestimate actual demand. We can then calculate a weighted average of this cost of uncertainty over all possible levels of demand, using the probability density function of demand as a factor to weight each eventuality. This weighted average of the cost of every possible level of demand gives the expected cost (Hadley,

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[9] One further analogy might be illuminating. Consider the host of a large cocktail party. He certainly appreciates that his estimate of the number of guests may be either high or low and thus he contemplates a range of possible liquor requirements. If he provides too much, he absorbs the extra cost of too much liquor, probably a nominal expense. On the other hand, if he buys too little, he can expect embarassment and other undesirable consequences. Most often, the prudent host liberally overprovides in order to decrease the chance of the least desirable possibility.

1964, p. 160). The market problem, simulated by the model, is to determine the set of coal shipments which meet these expected levels of demand at the least possible cost.

The regression model of Chapter VI predicts the most likely values of regional coal demand in 1990. A particularly useful aspect of that model for the present analysis is that it also generates a measure of the historical variation associated with the predicted values. That is, we infer the likelihood of exceeding or falling short of expected coal demand by any given amount. This variation about estimated demand is an element conspicuously ignored by most other studies (Mayer 1979, p. 18).

The estimate of the standard deviation about the expected value generated by the demand model is equal to approximately 20 percent of the mean value. Utilizing the normal distribution, this implies that there is about a 16 percent chance of actual demand being more than 20 percent less or 20 percent greater than the expected value. This estimate of the variance associated with expected coal demand is quite useful in assessing the cost of uncertainty. It is this probability density function which allows us to assign probability weights to possible levels of future coal demand.

Presumably, we can be fairly well assured that 1977 coal burning capacity will be fully utilized in 1990. This is a result of both the greater expense of building new capacity and the ability to operate "old" sources under less stringent "old source performance standards," OSPS, as they were effective in 1977.

It is therefore assumed here that the uncertainty of coal demand is only associated with the extra coal burning capacity coming on line after 1977, i.e., NSPS coal. Though the standard deviation is derived as a fraction of total projected demand, the variation is only associated with new, NSPS demand. OSPS coal capacity is maintained at the 1977 level and continues to enter the model as a deterministic magnitude.

The probability distribution of coal demand $\Phi_1(V_1)$, is fully specified by its mean, μ_1, and standard deviation, σ_1. The relevant programming variable is the expected value of coal demand. This expected value, V_1, is thus:

$$\int_{-\infty}^{+\infty} V_1 \Phi_1 (V_1) dV_1 \tag{1}$$

Here the subscript 1 refers to the specific demand region. For simplicity of exposition, only one subscript is used though we continue to recognize the several dimensions across which coal demand (and supply) vary.

First we shall investigate the cost incurred when actual coal demand exceeds the expected value. The opportunity cost of having provided less coal than that which is actually needed is equal to the profit that would have been earned by the entrepreneur had this coal been available. The deterministic model of the previous chapter generates dual variables or shadow prices of each constraint.[10] The dual variable corresponding to each state's demand for NSPS coal measures

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[10] An illuminating discussion of dual variables in transportation problems is contained in Benjamin H. Stevens, "Linear Programming and Location Rent," Journal of Regional Science, III, 2, 1961, pp. 15-26.

the cost of the extra ton of coal demand. If, for example, another scenario were cast in which the demand in region l were set at one unit more (less), the dual variable or shadow price tells us the precise amount by which the total cost of supplying this new market would increase (decrease). One further example may be illuminating. Suppose one discovers a heretofore unknown ton of coal. The dual variable associated with the demand constraint tells us the maximum price a coal consumer would willingly pay for that coal. The assumption here is that only a portion of this revenue accrues to the entrepreneur. ICF and Bureau of Mines studies indicate that profit is 14 to 17 percent of the total price of coal produced (ICF, Inc., 1977, p. III-51).[11] We have used 15 percent of the coal price as the estimate of the profit foregone (opportunity cost) by the entrepreneur in failing to provide all the coal needed by the market.

Thus the expected cost of failing to meet demand enters the objective function as:

$$\sum_{l} r_l \int_{Y_l}^{\infty} (V_l - Y_l)\Phi_l(V_l)\,dV_l \tag{2}$$

Where r_l is the cost of a shortfall per ton in region l, V_l is the expected value of demand, and Y_l is the total of actual shipments to region l.

If, on the other hand, provision is made for more demand in state l than is actually realized, a different kind of cost is incurred by the entrepreneur. We assess the cost of overage as the cost of the

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[11]The ICF coal price estimates are cost figures based on their model mine studies, which were noted in Chapter III.

capital investment necessary to provide the unneeded coal. We have assumed that non-capital costs are avoidable. There may, however, be other unavoidable expenses in addition to capital investment such as labor recruitment, training, and other "sunk" costs. Thus the cost of exceeding expected demand is:

$$S_1\int_o^{Y_1}(Y_1-V_1)\Phi_1(V_1)dV_1 = S_1(Y_1-\mu_1) + S_1\int_o^{Y_1}(V_1-Y_1)\Phi_1(V_1)dV_1 \tag{3}$$

Where S_1 is the depreciation cost of excess capital investment and μ_1 is the mean expected value of coal demand in region 1.

We can combine the cost of overage and underage, denoted by F_1, as follows:

$$F_1 = S_1(Y_1-\mu_1) + (S_1 + r_1)\int_{Y_1}^{\infty}(V_1-Y_1)\Phi(V_1)dV_1 \tag{4}$$

Thus F_1 is a representation of the cost of uncertainty. This expression enters the objective function as an additional cost to be minimized.

The capacity constraints relative to each production point remain as previously specified. However, the demand constraints which were considered in Chapter VII no longer enter in the same form. The deterministic constraint is replaced by a requirement that total shipments to each state equal the least costly level of demand as specified in F_1. Therefore instead of the constraint:

$$\sum_j X_{1j} = b_1 \tag{5}$$

We require that:

$$\sum_j X_{lj} - Y_l = 0 \text{ for every } l = 1, \ldots, n. \tag{6}$$

With the addition of F_l, the optimization model has become a nonlinear programming problem; in general, much more difficult to solve than a purely linear formulation.

Computation Technique

Each non-linear expected cost function $f_l(Y_l)$, is replaced by a piecewise linear approximating function, $\hat{f}_l(Y_l)$, by choosing T grid points $Y_l^1, Y_l^2, \ldots, Y_l^T$ and computing the corresponding values of $f_l(Y_l)$. The approximating function, $\hat{f}_l(Y_l)$, is formed by linear interpolation between adjacent computed values $f_l(Y_l^t)$, $t=1, \ldots, T$.

For each of the T intervals between grid points we calculate the value,

$$DY_{tl} = Y_l^t - Y_l^{t-1} \tag{7}$$

and the corresponding change in expected costs,

$$DF_{tl} = f_l(Y_l^t) - f_l(Y_l^{t-1}). \tag{8}$$

Then, since we can choose Y_l^o equal to zero, the value of Y_l in the pth interval may be expressed as

$$\sum_t^T DY_{tl} X_{tl} \text{ (for } 0 \leq p \leq T) \tag{9}$$

where

$X_{tl} = 1$ if $t < p$

$0 \leq X_{tl} \leq 1$ if $t = p$

and $X_{tl} = 0$ if $t > p$

These values of X_{tl} give the corresponding approximation of $f_l(Y_l)$,

$$\hat{f}_l(Y_l^o) = f_l(Y_l) + \sum_t^T DF_{tl} X_{tl}. \tag{10}$$

This approximates $f_l(Y_l)$ by an initial value (a constant) and the sum of the changes from that value. The non-linear function is thus approximated by linear terms that can be used in a linear formulation. The initial value, $f_l(Y_l^o)$, corresponds to a minimum level of activity, Y_l^o, is thus a constant amount in the objective function for any level of the activity. For convenience, we can ignore the value of $f_l(Y_l^o)$ for each state during the computations. This is possible because any constant value is irrelevant in an optimizing procedure.

Having established a linear approximation of the expected cost function, the model can be estimated in the following form.

$$\text{minimize } \sum_{ljikmn}\sum\sum\sum\sum\sum (C_{jikm} + t_{lj}) X_{ljikmn} + \sum_{tl}\sum DF_{tl} Y_{lt} \tag{11}$$

subject to:

$$\sum_{nl}\sum X_{ljikmn} \leq Kjikm \tag{12}$$

$$\sum_{mjik}\sum\sum\sum b_{jikn} X_{ljikmn} - \sum\sum DY_{tl} X_{tl}, \text{ for every } l \text{ and } n \tag{13}$$

$$X_{ljikmn} \geq 0,$$

and $0 \leq X_{tl} \leq 1$, all t, l.

Furthermore, it is a necessary restriction that $X_{t1} > 0$ only if $X_{p,1} = 1$, $p = 1, \ldots, t-1$. Since $f_1(Y_1)$ is convex (Hadley 1964:89) for any interval t and t+1,

$$\frac{DF_{t,1}}{DY_{t,1}} \leq \frac{DF_{t+1,1}}{DY_{t+1,1}} \tag{14}$$

Thus larger values of Y_1 are associated with smaller decreases in $\hat{f}_1(Y_1)$. The unit contribution to minimizing the objective function becomes smaller as Y_1 increases. The simplex algorithm will not allow X_{t+1}, 1 to enter the solution until $X_{t,1}$ can be made no larger. We have restricted $X_{t,1}$ to a maximum of one, and have thus satisfied the necessary restriction. Otherwise, it would be necessary to append the "restricted basis entry" option to insure the condition.

As applied in this case the linear programming model described above is a transportation algorithm with 447 rows, 100 demand constraints, and 346 distinct supply sources, and a total of nearly 36,000 elements. It requires nearly 40,000 iterations to arrive at an optimal solution.

Summary

This chapter has presented a methodology for assessing the cost of uncertain demand in the United States steam electric coal market. We have thus explicitly introduced uncertainty as an important factor in the market. In the next chapter we investigate how the inclusion of uncertainty in a optimization model affects the most efficient allocation of coal. Uncertainty can be expected to affect the level of coal utilization, the regional patterns of production, and the total cost of coal production and allocation.

CHAPTER VII

PROJECTING COAL ALLOCATIONS WITH THE STOCHASTIC MODEL

Introduction

This chapter explores the cost of uncertain demand in the coal market and indicates how the optimal allocation of domestically produced coal is affected. The results obtained from the stochastic model are compared to the optimal solution of the deterministic model developed in Chapter V. Finally, the significance of our results is examined as indicative of the cost of uncertainty in the coal market whether the uncertainty emanates from a generally unsettled future or from contradictory or noncommittal government policies. We also examine our results as an indication of adjustments made in the market which might not otherwise appear expedient.

The expected cost of uncertainty is the difference between the expected cost of mining and shipping coal when future demands are known and when they are not. However, to derive a measure of the expected cost under certainty would require that we average the total cost of every possible set of demands using their joint probability as a weighting factor in calculating the average (Hadley, 1964, p. 179). Such a procedure would be extraordinarily difficult. Instead, the deterministic solution presented in Chapter V is used to represent the total cost of coal allocation in a predictable market. Comparisons of total costs and the permutations in regional coal shipments which result will use the deterministic model as a base and the model presented in Chapter VI to represent the minimum cost and optimal allocation of coal under uncertainty.

Results

Table VII-1 shows optimal coal shipments which are generated by the stochastic model of the last chapter. Perhaps the most obvious change relative to the deterministic solution of Table VI-4 is the net increase in total shipments. Whereas shipments under a predictable scenario were 1,120 million tons, the stochastic model projects that a total of 1,145 million tons would be provided, 2.2 percent more. This provision for additional capacity, though prudent in accordance with our assumptions, involves extra capital costs relative to the predictable scenario attributable to uncertainty in the coal market.[12] Moreover, the relatively larger magnitude of the difference is in individual producing regions. For example, the model results indicate a much greater relative increase in the West as a result of uncertainty. Relatively smaller additional output is forthcoming from the East due to the assumed extraordinarily high cost of additional output. In Chapter VI we assumed that the optimal level of coal demand for each demand region is determined by minimizing the expected cost of possible discrepancies between actual and forecast demand. Thus the net increase

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[12] Our cost framework depends upon the cost function as specified above which implies Leontief-type production in which there is no factor substitution. Thus, no provision has been made for the short-term possibility of increasing output by singly increasing one factor. Even if explicitly accounted, however, if we assume that the producer would normally operate with an optimal factor mix, increasing only the variable factors of production would be a less than optimal, more costly course.

TABLE VII-1

PROJECTED U.S. COAL SHIPMENTS IN 1990: THE STOCHASTIC MODEL
(Millions of Tons)

Supply Region	Destination East	South	Midwest	West	Total
Northern Appalachia	101.46	0.75	0.00	0.00	102.21
Mid Appalachia	5.25	104.38	0.00	0.00	109.63
Southern Appalachia	0.00	6.80	0.00	0.00	6.80
Midwest	101.63	93.30	41.57	0.00	236.50
West	295.44	89.45	210.77	93.90	689.56
Total	503.78	294.68	252.34	93.90	1,144.70

in expected demand is a result of the higher penalty assessed for failing to meet actual demand relative to the lesser cost of excess capacity.

There is a noticeable variation in the effect of uncertainty across the regions; from little net impact in the West to an increased allocation of nearly 6 percent in the Midwest. This regional variation is a result of the relative magnitudes of overage and underage costs. For example, coal prices to consumers in the South and Midwest are relatively high and thus the greater opportunity costs of failing to provide these regional demands tend to encourage extraordinarily conservative provision for expected demand. On the other hand, coal costs for western coal consumers are relatively much lower, and the opportunity cost associated with production shortfalls is consequently much smaller. Accordingly, less precautionary capacity is expected to exist in the region.

Table VII-2 shows the changes in regional shipments which occur when account is taken of the stochastic component of coal demand. For example, shipments under uncertainty indicate that the Midwest would acquire an additional 43 million tons of western coal. This is partly a precaution in the presence of uncertainty. It is also partly necessary to make up for the significantly increased utilization of midwestern coal in the East and South. Though net shipments of coal only increase by some 2 percent; over 9 percent of total steam-electric coal or nearly 100 million tons, is allocated differently as a result of the stochastic specification of demand.

In addition to the distribution phenomenon, which is costly relative to a more predictable market, there is a profound effect on the

TABLE VII-2

DIFFERENCES IN REGIONAL COAL SHIPMENTS, DETERMINISTIC VERSUS STOCHASTIC MODEL

Supply Region	Destination				
	East	South	Midwest	West	Total Change
Northern Appalachia	.61	-.62	--	--	--
(Percentage Change)	(0.6)	(43.3)			
Mid Appalachia	-2.18	1.87	--	--	-.31
(Percentage Change)	(-29.)	(01.8)			(0.3)
Southern Appalachia	--	1.0	--	--	1.0
(Percentage Change)		(17.2)			(14.7)
Midwest	31.55	16.13	-29.8	--	18.05
(Percentage Change)	(45.0)	(20.9)	(-41.7)		(7.6)
West	-23.87	-13.4	43.48		6.21
(Percentage Change)	(-7.5)	(-13.0)	(26.0)	--	(0.9)
Total Change	6.11	4.98	13.68	--	
(Percentage Change)	(1.2)	(3.5)	(5.8)	--	24.78

cost of coal supplied. The stochastic model of Chapter VI includes an additional term in the objective function to be optimized. Thus, in addition to minimizing the cost of mining and transporting steam coal, the stochastic model minimizes the cost of uncertainty as we have represented it by the term:

$$F = S_l(Y_l - U_l) + (S_l + r_l) \int_{Y_l}^{\infty} (V_l - Y_l)\Phi(V_l)dV_l. \tag{1}$$

In the optimal solution, we sum the magnitude of this term for every region, l, and find that the cost of uncertainty thus specified amounts to \$760 million. This amount represents the total additional cost to the coal market of uncertainty as we have specified it versus a situation where 1990 coal demand was accurately and assuredly predictable. This is an average of \$.66 per ton of total coal allocations in 1990. If we assess this premium only on the increase in coal demand between 1977 and 1990, the cost per ton is nearly \$1.00; about 4 percent of average coal cost in the deterministic scenario.[13]

This extra cost of coal directly attributable to demand uncertainty is more significant in those consuming regions where the variance associated with projected demand is large. Thus, the uncertainty premium can range from over 10 percent of total coal costs in some western states to around 3 percent in Pennsylvania. This result suggests that the cost of uncertainty is most profound in consuming regions

[13]This premium is largely a result of the extra cost we have included to represent uncertainty and little affected by the discrete changes in the step supply function which may occur at a greater total allocation level.

where expected demand is least assured. Once more the average cost over the total market glosses over disparate effects across the individual regions.

The price of coal enters our analysis in the regression model of Chapter V which projects the expected value of coal demand in 1990. The regional requirements thus generated are input to the linear programming model as perfectly inelastic demands. Thereafter the price of coal is a relevant parameter only in the determination of the least-cost supply district and demand is no longer price sensitive. This means that the optimizing model does not itself internally adjust coal demand in accordance with the higher price uncertainty indicates. It is, however, perfectly reasonable to presume that the uncertainty premium is an active component of the coal price which partly determines demand and that demand is consequently less than it might otherwise have been. The regression equations in the demand component of the model thus account for any decreased coal utilization which relatively higher costs dictate. The own price elasticity of .75 generated by our regression model suggests diminished coal consumption on the order of 3 percent, or something over thirty million tons. Quite disparate impacts could be expected, however, within individual regions where the elasticity of demand implies decreased coal demand of up to 8 percent where the uncertainty premium is greatest.

The extra cost of coal utilization discussed above might be expected to undermine the competitive position of coal *vis-à-vis* alternative fuels and the optimal mix of fuels might be consequently distorted. However, uncertainty surely exists to some extent in the market for every prime mover in electricity generation save perhaps hydropower. Thus the direction in which the optimal mix of fuels has been skewed relative to a "perfect knowledge" situation is not readily apparent. That society pays a net premium for electricity as a consequence is, however, a reasonable expectation.[14] Though significant penalties are an associated result from the uncertainty in the coal market, confidently held though incorrect predictions could be even more costly.

Summary

This chapter has presented the optimal steam electric coal shipments generated by the stochastic programming model of Chapter VI. These results are indicative of the additional costs experienced in an uncertain coal market and the changed pattern of shipments which result. Thus the model provides a plausible explanation for why the coal market may tend toward a state of excess capacity.

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[14] We have attempted to represent explicitly this uncertainty premium by including an additional term to the entrepreneurs' cost function. *Ceteris paribus*, in minimizing costs subject to a similar range of constraints, total cost is necessarily greater.

CHAPTER VIII

SUMMARY AND CONCLUSIONS

The purpose of this analysis has been to examine the impact of uncertain demand on the United States steam-electric coal market. That is, what effect does uncertainty have upon the optimal allocation of coal and the delivered price of coal. Furthermore, with an assessment of the extra cost imposed by uncertainty in the coal market, policymakers should be better able to assess the net cost or benefit of policies which lead to uncertainty.

Crucial is an understanding of what uncertainty means in this kind of study which uses a mathematical programming model to simulate the least cost allocation of United States steam-electric coal. The future demand for any commodity, even presuming that its future price and some of the other important demand determinants are known, can be expected to fall within a range of probability. Naturally, the breadth of this expected range depends upon the certainty associated with expected demand. Also, there is generally one level of demand within this range which is most likely. As we consider possibilities in either direction along the range which are progressively farther from this most likely value, the likelihood of their occurrence steadily diminishes until we reach the fringes of the range where such a level of demand is very unlikely. Of course, the breadth of the reasonable range narrows and the likelihood of actual demand occurring close to the expected value increases as confidence in the forecast increases. Our confidence in any particular forecast is dependent upon the importance of those determinants of demand which are excluded from the projection.

We have not attempted to deal with uncertainty in the broadest sense of the term. The more restricted range of uncertainty which we consider ignores phenomena which are unprecedented in recent (since 1957) experience, because we estimate and project uncertainty from historical demand fluctuations. Yet a broader range would include the possibility of a nuclear holocaust or the discovery of a nearly free source of energy. Either event, however unlikely, would obviate the present analysis. So our analysis of the more restrictive sense of uncertainty presumes a continuity of experience and does not pretend to encompass the discontinuity implied by an unprecedented catastrophe or windfall.

The impact of uncertain demand on the pattern of allocation and delivered cost in the kind of market we consider depends largely upon the flexibility of the entrepreneur in reacting to various levels of demand. If additional supply can be quickly called forth from any source without significantly increasing average cost, this impact would be small. However, if considerable lead times are required to provide the commodity and if the market is characterized by a diversity of supply sources or inflexible demand characteristics considerable costs may be incurred if forecasts are wrong. Where high opportunity costs are associated with insufficient capacity for example, entrepreneurs could be reasonably expected to invest liberally in order to profit from higher demand, should it occur. The cost associated with incorrect forecasts thus determines the cost of uncertainty. In such a market, an inability to predict demand confidently could be an expensive phenomenon.

Our specific investigation of the steam electric coal market within this framework has used an econometrically derived demand function to estimate the expected value or most likely level of future steam electric coal demand. This demand function explicitly considers coal prices, electricity demand, and the price of substitute fuels. Though it has been impractical to include many other important determinants of coal demand in the quantitative demand function, such factors as nuclear capacity, emissions standards, technological innovation, and the availability of alternative fuels are certain to influence future levels of coal utilization. Their influence is, however, implicitly included in the stochastic element of the formulation, and thus provide the basis for projecting the variance about the most likely level of demand.

The decade of the seventies was an era of rapidly changing government energy policy. Though most markets are probably affected by uncertainty to some degree, changing government policies has been one of the factors making the coal market especially unpredictable. The goals of public policy are numerous and sometimes conflicting and this has been especially true in the case of energy policy. Energy independence is a stated policy goal, and increased exploitation of massive domestic coal reserves could further this goal. However, legitimate concern regarding the possible emissions which could ensue from a whole-hearted effort to exploit domestic coal has been expressed. As illustrated in the appendix, the allocation of United States steam electric coal is influenced by the particular sulfur emissions control strategy adopted. However, as noted in Chapter II, the EPA has thus far been unsuccessful in promulgating a strategy which can be expected to endure. Moreover, the role of nuclear generation of electricity is a frequently debated issue. Yet, since added nuclear capacity directly supplants the need for coal burning facilities, the uncertain future of the nuclear option directly translates into uncertain coal demand.

Yet, the apparently cautious character of government policy can be reasonably interpreted as a hesitance to commit the country to one course when all of the costs and benefits are not well known or well understood. The safety of nuclear plants is hotly debated, the reliability and expense of scrubbers can only be approximated, the effect of substantially increased carbon dioxide in the atomosphere is not well understood, the economic viability of alternative energy sources such as solar power are subject to constant reassessment, and the total costs of continued dependence on foreign oil may become unaffordable. Such an environment restrains the policymaker from making firm decisons which may become burdensome when all of their effects are known or evolving technology makes another alternative much less expensive.

We have investigated the impact of uncertainty on the steam-electric coal market, and one primary source of this uncertainty is the noncommittal course of government policies affecting the coal market. The benefits of postponing these decisions may be more clearly understood and appreciated than the more subtle factors we have examined which recognize other costs associated with unpredictable energy policy. The acknowledged advantages of a thoroughly considered energy policy may thus be at least partially offset by the expense of prolonged uncertainty.

We have considered the cost of uncertainty in the narrower sense of the term as distinguished at the beginning of this chapter.

Specifically, we have suggested that as a partial consequence of uncertainty in the coal market, the future price of coal can be expected to be higher by perhaps a dollar per ton in constant 1977 dollars. This would amount to 4 percent of the average delivered cost of coal projected in 1990. The total additional cost of providing the nation's coal needs would be about $760 million. There is a tendency to overprovide capacity in attempting to minimize the cost associated with an uncertain market. This is principally because excess capacity is less expensive per ton than the considerable opportunity cost of not having sufficient capacity available if needed. Moreover, we have demonstrated how the optimal pattern of coal shipments can be expected to be distorted as a consequence of market uncertainty. We have thus provided a plausible explanation for why the coal market may tend toward an otherwise difficult to explain state of excess capacity and it is quite reasonable to expect the coal market to arrive at an optimal allocation of coal which might not seem prudent based on a deterministic framework.

None of these consequences, however, implies that coal demand uncertainty is an uncompensated cost that must be eradicated without further deliberation. There may be significant benefits to postponing policy decisions and the best strategy may be to leave many options open. For example, the decade of the seventies was a period in which the benefits of rapidly expanded nuclear capacity were qualified by widespread concern for the costs which may be incurred. Yet these problems may yet be resolved. Naturally, policymakers would hesitate to undermine the United States' ability to capitalize on the benefits of nuclear power in case of such an eventuality. The benefits of deferred action are especially difficult to analyze because technological breakthroughs are, by definition, unprecedented.

We have concluded that the uncertainty associated with such a flexible policy has a cost. Moreover, our analysis has shown that while this cost is a significant component of the total cost of coal, it is not so great as to make the flexibility prohibitively expensive. Thus, in considering an energy option that reserves several alternatives, and perpetuates uncertainty in the coal market, the legislator might well factor in higher coal costs and the impact on allocation patterns that we have indicated. On the other hand, policies designed to give precise direction to energy policy in an attempt to avoid the costs associated with uncertainty do so at the risk of incurring substantial opportunity costs if another course is later seen to be superior. We have not attempted to assess a specific measure of the benefits associated with noncommittal policies and presume that they are better understood. We have only set out to make an entry in the other side of the ledger. That is, uncertainty is one cost that should be considered, and our analysis has provided a methodology for assessing the cost and an estimate of its magnitude.

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APPENDIX

APPENDIX

The new source performance standards based on best available control technology (BACT) were discussed in Chapter II and assumed in the model of Chapter VI. The motivation for the BACT is apparently a combination of regional interests[1] and extraordinary regulatory zeal. Not surprisingly, however, the control strategy is vulnerable to criticism (Time, April 2, 1979, p. 66) because of its inefficiency and inherent tendency to bring about U.S. sulfur emissions levels that are insignificantly improved, if improved at all relative to less expensive control options (ICF, 1978, pp. 3-4).

This appendix will consider one frequently proposed control alternative to the BACT stragegy in order to gauge the different response expected in the coal market in 1990. The comparison is to be made between the expected allocations under a 90 percent sulfur removal standard as presented in Chapter VI, and a popular alternative control strategy which mandates a final sulfur emission level of 0.5 pounds of sulfur dioxide per million Btu's of coal burned. Whereas the BACT strategy mandates a fixed percent sulfur removal, the standard considered here would permit the coal user to vary the ultimate percent sulfur removal as a function of the sulfur content of the coal burned. For example, coal which would emit two pounds of sulfur per million Btu's unscrubbed would be subject to an implicit 75 percent removal standard, while coal which emitted less than 0.5 pounds per million Btu's would need no scrubbing. Moreover, the Btu's would need no scrubbing.

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[1]See the discussion in Chapter II regarding the perceived guarantee to midwestern coal interests of such an emissions control scheme.

Moreover, the infinite combination possible by mixing coals of various qualities and partial scrubbing would be viable strategies. This standard falls between the floor and ceiling expected under BACT, but the possible response stragegy is thus vastly different. If the 0.5 pounds of sulfur dioxide per million Btu's standard were in effect, the average sulfur content of coal burned could not exceed 2.5 lbs./mm Btu if 90 percent effective scrubbers were employed. Under BACT, however, coal containing up to 6 lbs./mm Btu could be burned and the resulting emissions would reach the proposed 1.2 lbs./mm Btu ceiling; 140 percent higher than the alternative examined here. In addition to the extraordinary expense of requiring universal scrubbing at around 90 percent, the reliability of the present technology under continuous utilization is suspect (Fortune, November, 1978, p. 56). The expected response to such a standard would be expected to alter the relative value of the several types of available coal and lead to a pattern of coal allocation markedly different from the response projected in Chapter VII.

This alternative strategy would thus maintain the premium value of low sulfur coal reserves and indirectly assess a penalty on higher sulfur reserves. For example, coal containing more than 2.5 pounds of sulfur per million Btus would only be burnable when mixed with lower sulfur coal. The expectation, therefore, is that the 0.5 pounds per million Btus standard would elicit more low sulfur western coal production at the expense of midwestern high sulfur supplies.

This alternative new source performance standard was substituted for the 90 percent sulfur removal standard in the model presented in Chapter VI. The projected steam electric coal allocations in 1990 under a 0.5 lbs./mm Btu sulfur emissions standard are presented in Table A-1.

TABLE A-1

PROJECTED COAL SHIPMENTS IN 1990 UNDER A .5 POUNDS SULFUR PER MILLION BTU STANDARD

	East	South	Midwest	West	Total
Northern Appalachia	78.28 (-22.4)	5.88	00.00	--	84.16
Middle Appalachia	8.01	73.41	00.00	--	81.42
Southern Appalachia	0.00	5.88	00.00	--	5.88
Midwest	74.86	67.97	39.33	--	182.16
West	323.19	140.31	202.10	89.66	755.26
Total	484.34	293.45	241.43	89.66	1,108.88

TABLE A-2

DIFFERENCE IN STEAM ELECTRIC COAL SHIPMENTS BETWEEN
A 90 PERCENT REDUCTION AND A .5 POUNDS PER MILLION BTU STANDARD

	East	South	Midwest	West	Total
Northern Appalachia	-22.57 (22.4)	4.51 329.2)	--	--	-18.04 (-17.7)
Middle Appalachia	.58 (7.8)	-29.1 -28.4)	--	--	-28.5 (-25.9)
Southern Appalachia	--	.08 (1.4)	--	--	--
Midwest	4.78 (6.8)	-9.20 (-11.9)	-32.02 (-49.9)	--	-36.44 (16.7)
West	3.88 (1.2)	37.47 (36.4)	34.81 (20.8)	-3.93 (4.2)	72.33 (10.5)
Total Change	-13.33	3.76	2.79	-3.93	
Total Percent Change	(-2.7)	(1.3)	(1.2)	(4.2)	

Table A-2 shows the difference in this scenario relative to expected allocations under the assumptions of Chapters VII and VIII.

The expected increase in the utilization of lower sulfur western coal at the expense of higher sulfur midwestern coal is evident in the tables. The West is projected to ship 72.23 million tons more coal, 10.5 percent more, under the alternate standard. The largest share of this increase in western coal production comes at the expense of midwestern coal production which is 36.44 million tons or nearly 17 percent lower. A noticeable decline in Appalachian shipments is also evident.

Moreover, another more subtle factor is evident in comparing the two solutions. The alternate control stragegy apparently requires about 10 million tons of coal less to provide the same Btu value. This is a result of the reduced impact of the minimal employment of scrubbers. This means that less of the coal burned is subjected to the 5 percent energy penalty associated with scrubbers (Environmental Protection Agency, 1978, pp. 4-21). In this particular formulation, this influence slightly overrides the contrary tendency to utilize a greater quantity of lower Btu western coal. The difference here is less than 1 percent of total steam coal shipped. The precise relative magnitude of the two tendencies will depend critically on the exogenous parameters assumed, and no claim is made here to have exactly determined the relative importance of one over the other.

VITA

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