COAL TRANSPORTATION AND THE DEVELOPMENT OF THE INTERNATIONAL STEAM COAL MARKET: AN ECONOMIC AND POLICY ANALYSIS

by

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DANIEL ALEC SARGENT

Submitted to the Department of Urban Studies and Planning
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ABSTRACT

This dissertation is an economic and policy study of supply, demand, and transportation variables that are important to the development of the international steam coal market. The study analyzes in detail specific economic and policy components of this developing market and, by integrating the analyses of these component parts, explains the importance of supply, demand, and transportation variables, and inter-temporal changes in these variables, to the development of international steam coal trade. Given this close correspondence between energy markets and government policies, this analysis is especially useful for determining effective government policies for international steam coal market developments.

The dissertation is divided into two main parts. Part A is a detailed analysis of coal transportation economics and regulation, both inland and ocean-borne. The analysis contributes as much to the understanding of domestic coal markets as to the understanding of the international steam coal market. The first three chapters analyze the economics of railroad transportation of coal in the United States. Particular attention is directed to the estimation of long-run marginal costs of railroad transportation of coal, the existence of monopoly rents on coal shipments, and the effect of Interstate Commerce Commission regulations on railroad tariffs. Chapter IV analyzes the economics of two alternative modes: barges and trucks. Chapter IV also analyzes the economics of potential U.S. steam coal export routes. Chapter V considers three major factors that could affect the economics of U.S. coal transportation in the long-run: coal-slurry pipelines, railroad deregulation, and long-run transportation capacity expansion.

Chapter VI analyzes coal transportation in Canada, Australia, South Africa, and, to a lesser extent, in Western Europe and Japan. The chapter attempts to estimate costs and to determine the difference

between marginal costs and coal tariffs as a function of institutional structures and coal market economics. The approach is similar to that for the U.S. chapters, but the analysis is more limited due to data non-availability. Chapter VII analyzes the economics of ocean transportation of coal.

Part B focuses more specifically on the international steam coal market. Chapter I analyzes coal supply in Australia, Canada, South Africa, and the United States. The chapter estimates current coal prices at the mine, as well as prospective changes in these prices. Chapter II integrates the supply and transportation analyses to determine cost-minimizing steam coal trade patterns based on existing economics and government policies. In addition, the effects of previously discussed non-incremental shifts in transportation and supply variables on future trade patterns are analyzed.

Chapters III through V analyze steam coal demand in Western Europe and Japan to the year 2000. The existing structure of steam coal demand is described in Chapter III. Recent estimates of steam coal demand are criticized in Chapter IV. In Chapter V, we develop additional estimates of steam coal demand for two major potential importers, France and Japan.

The conclusions summarize the results of the analysis and further discuss critical transportation, supply, and demand variables underlying the future development of international steam coal trade. Particular attention is paid to the prospects for U.S. steam coal exports. In conjunction with this, the concluding remarks comment on possible future government involvement in the development of steam coal trade.

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LIST OF ABBREVIATIONS

Btu	British Thermal Units
CIF	Cost including freight and insurance
DWT	Deadweight tons (metric)
FOB	free on board
GW	Gigawatt = billion watts
k	kilo = thousand
kcal	kilocalories
kg	kilograms
km	kilometers
kWh	kilowatt hour
M	mega = million
MBtu	million Btu
MT	million metric tons
MTCE	million metric tons of coal equivalent
MTOE	million metric tons of oil equivalent
MW	megawatts = million watts
TW	Tetawatt = trillion watts

LIST OF CONVERSIONS

one large calorie = 3.968 Btu = 4168 joules

metric ton = 1000 kilograms = 2,204 lbs = 1.1023 x short ton

MTCE = 7×10^{12} kcal = 27.8 MBtu

MTOE = 10^{13} kcal

one kwh = 3413 Btu

If power station thermal efficiency is 35 percent, the heat rate (the number of Btus required to produce one kwh) is:

$$\frac{3413}{.35} = 9751$$

One million Btu would produce approximately:

$$\frac{1,000,000}{9751} = 102.5 \text{ kwh}$$

Source: Energy Reference Handbook, Government Institutes, Inc., Washington, D.C., 1974.

INTRODUCTION

In the past few years, as oil prices have rapidly increased and nuclear power development has been stalled by public concern with health and safety, the probability of a major transition from oil to coal-fired power generation has increased substantially. In certain nations with large technically and economically recoverable coal reserves, for example the United States, the transition is far along. New power plants are almost exclusively coal-fired, and conversions of existing oil-fired plants to coal are ubiquitous. In other cases, for example Western Europe and Japan, the transition is in the early stages, and the extent of the transition is less certain. Nevertheless, these countries are generally committed to a movement away from OPEC oil supplies, and towards nuclear- or coal-fired power. If technological and political uncertainties continue to pervade nuclear power generation, coal will continue to be a likely alternative. Furthermore, since Japan and most Western European nations have negligible domestic coal reserves, and since in the Western European nations that have substantial coal reserves (for example, the United Kingdom and West Germany) domestic coal prices are dramatically higher than imported coal prices, an increase in demand will yield a substantial increase in international steam coal trade.

The development of the international steam coal market will, in significant part, be determined by government. Existing government policies and regulations in the transportation, coal supply, and electric

utility sectors will affect the developing coal markets, and new policies may evolve as the importance of coal markets increases. In both cases, a thorough understanding of the economic and policy variables affecting the development of the international steam coal market is essential for effective government planning.

This dissertation attempts to provide this understanding. It is an economic and policy study of supply, demand, and transportation issues that are important to the development of international steam coal trade. The study is limited in scope to four potential net exporting countries--the United States, Canada, Australia, and South Africa--and to two potential importing areas--Western Europe and Japan. These countries will probably account for most steam coal exports and imports into the 21st century. The purpose is not to forecast the future prices and quantities traded in international steam coal markets, but rather to analyze in detail specific economic and policy components of this developing market, and by integrating the analyses of these component parts, to explain the importance of supply, demand, and transportation variables, and intertemporal changes in these variables, to the development of international steam coal trade. The focus is not on the specific future role of a given country in the international steam coal market, but rather on the variables, and on the interrelationships between the variables, that will determine this role. For example, we are not as concerned with the magnitude and price of Australian steam coal exports to Japan in the year 2000 as we are with the systematic explanation of why Australian coal might cost less than United States or

Canadian coal: because of locational, geological, regulatory, or some other factors. And, just as important, what factors might change in the long run, how might governments affect these changes, and what will be the consequent effect on the patterns of international steam coal trade.

The dissertation is separated into two main parts. Part A is a detailed analysis of coal transportation economics and regulation, both inland and ocean-borne. Coal transportation is very expensive relative to coal prices, in fact, it is often the determining influence on patterns of coal trade. It also accounts for the fundamental difference between domestic and international markets. The analysis of coal transportation is critical to understanding the development of both domestic and international coal markets.

Part A is organized as follows. The first three chapters analyze the economics of coal transportation by railroad in the United States. Railroads currently carry the vast majority of coal shipments, and they will probably maintain this role in the future. The objectives are: 1) to determine the long-run marginal costs of railroad transportation; 2) to determine the difference between existing railroad tariffs and long-run marginal costs; and 3) to explain this difference as a function of Interstate Commerce Commission (ICC) regulations and coal market economics. The effect of ICC regulations on railroad transportation of coal has been the subject of extensive attention in the past few years. The analysis of these effects is critical to understanding both domestic and international coal markets, and it serves as an interesting case study in both transportation economics and government regulation. Note

that these sections are highly specific. The reader primarily interested in international steam coal markets may choose to bypass large segments of the material.

Chapter IV analyzes coal transportation economics via two alternative modes, barge and truck. Direct regulations are not important to the economics of these modes, but they are indirectly important to these modes as potential competitors with the railroads. In Chapter IV we also assemble the United States inland transportation cost estimates, and analyze the economics of steam coal export routes. Chapter V considers three interdependent factors that could affect U.S. steam coal transportation patterns in the future: 1) the commercialization of coal-slurry pipelines; 2) the deregulation of U.S. railroads; and 3) the long-run ability of the railroads to finance capacity expansion. Government policy is critical to all three factors, and in turn to the development of steam coal markets.

Having analyzed coal transportation practices and problems in the United States, Chapter VI analyzes coal transportation in Australia, Canada, South Africa, and, to a lesser extent, Western Europe. The objective is similar to that of the United States sections: to determine the long-run marginal cost of coal transportation, and to explain the difference between coal tariffs and long-run marginal costs as a function of institutional structures and coal market economics. However, the approach is constrained by data limitations, and subjects that were analyzed rigorously for the United States can only be treated generally for these other countries. Nonetheless, the section develops estimates

of coal transportation rates for comparison with United States coal rates, approximates where possible the relationship of rates to costs, and considers the institutions that affect rate-cost relationships.

In Chapter VII we analyze ocean transportation. In this case, regulation is of minor importance. The primary purpose is to develop estimates of ocean transportation costs for major potential steam coal trade routes. The effects of port ship-size constraints, changes in ship technologies, and return cargo possibilities on steam coal trade patterns are assessed.

Part B focuses more specifically on the international steam coal market. Chapter I analyzes coal supply in Australia, Canada, the United States, and Australia. The emphasis is on current coal prices and on prospective changes in these prices as coal output cumulates and markets and government policies develop. Chapter II integrates supply price information with the transportation cost information developed in part A to determine cost-minimizing trade patterns on the basis of existing economics and government policy. The relative importance of critical supply and transportation variables to the patterns of international steam coal trade will be assessed. In addition, the effect of previously discussed non-incremental structural shifts in transportation and supply variables on future trade patterns is appraised.

Chapters III through V analyze steam coal demand to the year 2000. The existing structure of steam coal demand is described in Chapter III. Recent estimates of steam coal demand are criticized in Chapter IV, and, based both on the delivered price estimates developed in Chapter II and

on a detailed analysis of the structure of steam coal demand, additional estimates of coal demand for electricity generation in two major potential importing countries, Japan and France, are developed in Chapter V. Finally, the last chapter summarizes the results of the previous sections and further discusses the critical transportation, supply, and demand factors underlying the future development of the international steam coal market. In conjunction with this, we will discuss possible future government participation in the development of the international steam coal market.

PART A

AN ANALYSIS OF COAL TRANSPORTATION: ECONOMICS AND REGULATION

INTRODUCTION

Transportation costs for coal are as much as ten times higher per Btu/mile than transportation costs for competing fuels. Coal-supply districts are often remote from major port facilities. Capital requirements for the expansion of the coal transportation infrastructure are enormous. In addition to the cost burden, transportation regulation has distorted the efficient provision of inland coal transportation services. Combined, these factors are an overwhelming handicap to the development of coal markets in general, and international coal trade in particular.

However, transportation cost is only one of the many variables in the coal demand function. Therefore, these negative factors do not preclude international steam coal trade. Rather, they indicate that transportation costs will be a critical factor in determining the patterns of international steam coal trade.

The first part of this dissertation is a detailed analysis of coal transportation, both inland and ocean-borne. The primary purpose is to explain the economics of coal transportation as it relates to the development of international steam coal markets. However, while Part B integrates the results of Part A with supply and demand variables and focuses specifically on international steam coal markets, Part A is equally important to understanding the development of domestic coal markets, especially in the United States. Furthermore, in addition to explaining the interaction between coal transportation and international

or domestic markets, Part A provides an interesting case study in transportation economics and regulation.

Part A is organized as follows. In Chapters I through V, we will analyze the economics of coal transportation in the United States. In the first three chapters, we analyze the economics of railroad movements of coal. Our purpose is dualfold: 1) to approximate the long-run marginal costs of coal railroad transportation; 2) to analyze the existence or non-existence of monopoly rents in railroad coal rates, and the effects of Interstate Commerce Commission (ICC) regulations on rate-cost relationships. The effect of ICC regulations on coal movements has been the subject of extensive concern in the past few years. An understanding of these effects is critical to understanding coal markets.

In Chapter IV, the economics of barge and truck movements are analyzed. Regulation is not directly important to the economics of these modes, but it is indirectly important to them as competitors with the railroads for coal shipments. Also, Chapter IV assembles the United States inland transportation cost estimates, and analyzes potential steam coal export routes. Chapter V considers three additional interdependent factors that could affect U.S. steam coal transportation patterns in the long run: coal-slurry pipelines, railroad deregulation, and capacity expansion.

Chapter VI analyzes coal transportation economics in Australia, Canada, South Africa, and to a lesser extent, Western Europe. The objective is similar to that of the U.S. chapters: to determine the long-run marginal costs of coal transportation, and the effect of the

institutional structure on transportation rates. However, due to data limitations, the subjects that we analyzed extensively for the United States can only be treated roughly for other countries.

Chapter VII analyzes the economics of ocean-borne coal transportation. The primary purpose is to develop estimates of ocean transportation costs for major potential steam coal trade markets.

It should be noted that much of Part A is extremely detailed. Readers who are not specifically interested in the intricacies of coal transportation economics and regulation may choose to skim much of the material, or head directly to Part B where the results of Part A will be integrated with the analyses of international steam coal supply and demand.

CHAPTER 1

UNITED STATES INLAND COAL TRANSPORTATION: INTRODUCTION, SUMMARY OF INLAND TRANSPORTATION PATTERNS, AND ANALYSIS OF UNITED STATES RAILROAD COAL RATES

INTRODUCTION

The following five chapters analyze coal transportation economics and regulation in the United States. Our purpose is threefold. First, transportation, as will be shown below, is a critical economic factor in the development of steam coal exports. On certain potentially important export routes, inland transportation costs are as much as three times the cost of coal at the mine. An analysis of the economic and regulatory factors underlying United States coal transportation is essential to projecting the United States role in international steam coal trade. Second, transportation of coal for export is in large part interdependent with domestic coal transportation. Consequently, the analysis is equally important to understanding the complex present and future problems of United States domestic coal transportation. Third, beyond our direct concerns with steam coal export and domestic transportation, the analysis should serve as an interesting case study in transportation economics and regulation. To date, the literature is full of studies on coal transportation, and studies on transportation economics and regulation. Very few, however, have attempted to merge an understanding of the intricacies of a particular commodity, coal in this case, with the general principles of transportation economics and regulation.

The chapters are organized as follows. In this first chapter, past and present coal transportation patterns in the United States will be summarized, and the existing railroad rate structures for coal transportation, domestic and export, steam and metallurgical, will be

presented and analyzed. This will show that steam coal domestic railroad rates are increasing at a rapid rate throughout the country, and raise the question of whether these changes are explained by cost increases or monopoly rent increases.

In Chapter II, railroad costs will be analyzed. The bulk of the analysis will focus on the evidence presented in the recent coal rate cases. Though significant uncertainties exist, our conclusion will be that long-run marginal transport costs are substantially less than existing steam coal rates.

In Chapter III we analyze rents from a different perspective. Where in Chapter II we estimate the costs of coal transportation in order to estimate the level of rents, in this chapter we analyze qualitatively the regulatory process itself, and the implicit or explicit allowance for rents by the Interstate Commerce Commission (ICC). First, the current competitive environment in coal consumption and transportation is evaluated. The firm conclusion will be that the opportunity for realizing high rents exists. Second, the ICC's role as a possible constraint on rents will be evaluated. We will see that the ICC has not been and is not likely to be an effective constraint on the railroads' appropriation of monopoly rents, and, though some justification for rates exceeding long-run marginal costs may exist, the railroads' and the ICC's arguments for rates exceeding costs are seriously flawed.

Chapter IV will analyze the movement of coal by barge, the most realistic alternative to railroads on long-haul, high-volume shipments, and truck, limited in use to short hauls, primarily as a connecting

mode. Furthermore, transfer costs will be estimated to complete the data base required for the integration of supply, demand, and transportation cost variables below.

Also in Chapter IV, the results of both the economic and regulatory analyses will be applied to United States coal exports. Potential routes will be identified, costs will be estimated for the various transportation options, and the effect of ICC regulations on coal export shipments will be discussed.

The last chapter on United States coal transportation will focus on long-term developments in transportation patterns. Three major issues will be confronted. First, will railroads and barges be able to finance the expansion of long-run capacity in order to handle the rapidly increasing volume of coal carried? Second, will railroad transportation be deregulated partially or fully, and what effects will this have on domestic and export coal shipments? Third, and closely related to the second, will coal slurry pipelines be allowed to compete with existing coal transportation modes? If so, what effects will this have on future domestic and export coal transportation patterns?

SUMMARY OF UNITED STATES INLAND TRANSPORTATION PATTERNS

In 1978, approximately 640 million short tons of bituminous coal and lignite were moved from United States mines; 600 million short tons were destined for U.S. consumers, and the remaining 40 million short tons (6.8 percent) were destined for Canada (14.8 million short tons), Mexico, and

overseas consumers. Of the 600 million short tons destined for U.S. consumers, 471 million short tons (78.5 percent) were consumed by electric utilities, and the remainder was allocated between industrial consumers and coking plants. With the exception of Canada, where 8.8 of the 14.8 million short tons imports were used for steam raising, virtually all remaining exports were used for metallurgical and industrial purposes.[1]

The movement of coal from U.S. mines is broken down by transport mode in Table 1. Approximately 86 percent of the coal carried from U.S. mines to U.S. consumers is moved by barge, truck, or rail.[2] Of these three modes, railroads are the major carriers with approximately 63 percent of the total tonnage. Barges and trucks carried 19 percent and 18 percent, respectively.[3] Approximately 82 percent of the coal destined for ports is carried by rail, the remainder allocated between tidewater ships, trucks, and barges.[4]

Table 1 also shows that since 1974, these modal-shares have not significantly shifted.[5] Barge and rail carriers have lost some traffic to trucks, as railroads have abandoned small spur lines and barges have reduced short-haul shipments.

Although the railroads have maintained their position as the dominant coal carrier, the geographic importance of rail transportation has shifted. Since 1967, eastern traffic has decreased, southern traffic has increased slowly, while western traffic has increased rapidly (see Tables 2 through 5). Burlington-Northern, for example, carried 66.2 million short tons in 1978 relative to only 30 million short tons in 1974.[6]

Table 1

Distribution of Bituminous Coal and Lignite from United States Mines by Specific Method of Movement, 1974-1978 1/

Method of Movement	Thousand Short Tons					Percent of Total				
	1974	1975	1976	1977 2/	1978	1974	1975	1976	1977 2/	1978
All-rail	298,731	320,140	331,048	339,382	324,252	53.8	54.3	54.0	53.2	52.8
River and ex-river	102,517	107,025	107,503	106,844	96,301	18.4	18.2	17.5	16.8	15.7
Great Lakes	32,083	33,963	33,029	31,595	30,200	5.8	5.8	5.4	5.0	4.9
Tidewater	6,259	5,353	5,344	4,535	3,813	1.1	.9	.9	.7	.6
Truck	71,497	69,679	69,410	85,609	93,531	12.9	11.8	11.3	13.4	15.2
Tramway, conveyor, and private railroad	44,636	53,373	66,667	69,564	65,893	8.0	9.1	10.9	10.9	10.7
Total 3/	555,723	589,533	613,001	637,529	613,992	100.0	100.0	100.0	100.0	100.0

1/ Final destinations include Canada and Mexico. Mexican consumption is negligible. Canadian consumption in 1978 amounted to 14.78 million short tons, 14.03 of which were moved via the Great Lakes. Excludes railraod fuel, vessel fuel, Great Lakes commercial docks, coal used at mines and sales to employees, net change in mine inventory, and overseas exports (excluding Canada and Mexico).

2/ Beginning with the fourth quarter of 1977, the transportation mode of shipments to Mexico and shipments within Alaska were excluded from total figures to avoid disclosure of individual respondent data.

3/ Data may not add to totals shown because of independent rounding.

Source of data: Bituminous Coal and Lignite Distribution,Calendar year 1978, U.S. Department of Energy, Energy Data Reports, pp. 85

Table 2

RAILROAD TRANSPORTATION OF COAL--UNITED STATES

Year	Tons Originated (Millions)	Percent*	Freight Revenues ($ Millions)	Percent
1965	363	26	1128	12
1967	385	27	1152	12
1969	383	26	1190	11
1971	360	26	1135	11
1973	375	24	1425	10
1975	408	29	2146	13
1977	415	30	2698	14

*U.S. coal tonnage as a percentage of total U.S. freight tonnage.

SOURCE: Moody's Transportation Manual, 1979. New York: Moody's Investors Service, Inc., 1979, pp. A13-A16.

Table 3

RAILROAD TRANSPORTATION OF COAL--EASTERN DISTRICT

Year	Tons Originated (Millions)	Percent of Total Eastern Railroad Tonnage	Freight Revenues ($ Millions)	Percent of Total Eastern Railroad Revenues
1965	253	44	852	24
1967	253	46	861	24
1969	252	44	869	22
1971	214	43	897	21
1973	208	39	920	19
1975	209	45	1271	24
1977	191	44	1384	23

SOURCE: Moody's Transportation Manual, 1979. New York: Moody's Investors Service, Inc., 1979, pp. A13-A16.

Table 4

RAILROAD TRANSPORTATION OF COAL--SOUTHERN DISTRICUT

Year	Tons Originated (Millions)	Percent of Total Southern Railroad Tonnage	Freight Revenues ($ Millions)	Percent of Total Southern Railroad Revenues
1965	75	25	180	13
1967	89	27	201	13
1969	90	26	220	12
1971	97	28	271	13
1972	106	28	284	11
1975	112	32	408	15
1977	114	31	547	16

SOURCE: Moody's Transportation Manual, 1979. New York: Moody's Investors Service, Inc., 1979, pp. A13-A16.

Table 5

RAILROAD TRANSPORTATION OF COAL--WESTERN DISTRICT

Year	Tons Originated (Millions)	Percent of Total Western Railroad Tonnage	Freight Revenues ($ Millions)	Percent of Total Western Railroad Revenues
1965	35	7	96	2
1967	37	7	90	2
1969	41	7	101	2
1971	49	9	167	3
1973	61	10	221	3
1975	87	15	446	6
1977	98	17	572	6

SOURCE: Moody's Transportation Manual, 1979. New York: Moody's Investors Service, Inc., 1979, pp. A13-A16.

Similarly, the relative importance of coal to the railroads (see Tables 2 through 5) has remained roughly constant in the East and South, while it has increased rapidly for the West. Nevertheless, the eastern and southern railroads still generate a larger percentage of their total revenues through coal than do the western roads.

Coal transportation by rail is dominated by a few roads in each Interstate Commerce Commission (ICC) region.[7] Table 6 shows that 3 or 4 railroads control 85 percent of the coal traffic originating in each region. The most striking concentration of power is in the West where the Burlington-Northern railroad controlled 40 percent of all western-originating coal flows in 1977.

This can be contrasted to the competitive structure in barge and truck transport, where a large number of firms carry the traffic. For example, in barge transport 34 for-hire carriers are listed as coal carriers. Although four companies account for 25 percent of the total barge tonnage, the large number of firms and the option to provide one's own service create a relatively competitive structure.[8]

Finally, transportation of coal has increasingly relied on unit trains, strictly defined as "a complete train of dedicated cars operating on a regularly scheduled cycle movement between a single origin and a single destination", in contrast to past methods in which many commodities are mixed and remixed in one train as they are shipped from many origins to many destinations.[9] The appeal of the unit train service is that it is far more efficient in terms of equipment utilization than is conventional rail freight service. In 1965, approximately 25 percent of the coal tonnage transported was moved by rail. In 1978, approximately

Table 6

BITUMINOUS COAL HANDLED BY MAJOR CLASS I RAILROADS--1977

	Tons Originated (1,000 short tons)	Percentage of District Total
Eastern District:	189353	100
Chessie	71115	38
Conrail	40285	21
Norfolk and Western	62484	33
Southern District:	114073	100
Louisville and Nashville	59989	53
Southern	27315	24
Illinois Central Gulf	19413	17
Western District:	109403	
Burlington Northern	50549	46
Denver and Rio Grande	13210	12
Missouri Pacific	12801	12
Union Pacific	16115	15

SOURCE: Coal Traffic Annual, 1978, National Coal Association, 1979, p. II-11.

50 percent was moved in unit trains, and the ICC estimates that 85 percent will be moved in unit trains by 1985.[10]

To conclude, large and increasing volumes of coal are being moved by railroads, barges, and trucks. Railroads account for the majority of coal flows, and railroads' markets are highly concentrated. Coal flows in the East and South have been relatively stable in the past few years, but rapid increases have obtained in the West. The next section will focus on the existing rate structures in railroad coal transportation.

UNITED STATES RAILROAD COAL RATES

As the demand for coal rail transportation has increased in recent years, rail rates and the controversies surrounding them have simultaneously increased. In this section we evaluate the existing coal rate structure and review recent changes.

The rate structure has several dimensions: type of coal (steam or metallurgical), type of service (single-car, trainload, unit train), and origins and destinations.[11]

Based on these dimensions, three rate categories warrant our attention:

1) steam coal, domestic unit trains.
2) metallurgical coal, domestic unit trains and trainload.
3) metallurgical coal and steam coal exports, single car and trainload (unit-train rates do not exist for export shipments).

STEAM COAL DOMESTIC RATES

The most complex and controversial rates are for steam coal domestic unit-train shipments. Prior to the 1960's coal was exclusively shipped under single-car or trainload rates. However, given the pressures from competing modes and alternative fuels, the ICC ultimately allowed the railroads to post unit-train rates.[12]

Today, approximately 50 percent of steam coal domestic shipments are carried by unit trains, and the Interstate Commerce Commission estimates that by 1985, 85 percent of these shipments will be unit trains.[13]

Unit-train rates can best be classified in three groups, according to cost variations and different competitive environments. First, shipments destined to the East and the South, originating for the most part in Appalachia and Eastern Kentucky coal fields. Second, shipments destined for the Midwest, largely originating in Western Kentucky and Southern Illinois. Third, shipments destined for consumers in the Midwest and West, originating from western coal fields.

The sample of rates that has been analyzed for all those groups includes 1970, 1975, and 1979 rates. The first two samples were provided by Peabody Coal Company, supplemented for 1975 by additional western rates from the Burlington-Northern, Union Pacific, and Denver-Rio Grande Railroads. The 1979 sample was developed by Mobil's traffic division for internal purposes.[14]

East, South, Midwest Rates

Table 7 summarizes the 1979 rates for the East/South and Midwest regions.[15] Southern and midwestern rail rates for railroad-owned

Table 7

MIDWESTERN AND SOUTHERN/EASTERN UNIT-TRAIN RATES (January 1, 1979)

	Mean	Standard Deviation	Minimum	Maximum
Tariff per ton-mile (in cents)1				
MW Shipper	.0128	.0022	.0101	.0169
MW Rail	.0210	.0056	.0160	.0320
S/E Shipper	.0128	.0012	.0106	.0141
S/E Rail	.0190	.0032	.0150	.0250
One-Way Mileage				
MW Shipper	287	168	81	519
MW Rail	115	24	92	145
S/E Shipper	504	124	333	695
S/E Rail	439	118	217	695
Loading plus Unloading Times				
MW Shipper	18	10	8	36
MW Rail	16	14	7	48
S/E Shipper	10	4	8	16
S/E Rail	30	22	8	64
Minimum Annual Tonnage (1/million short tons)				
MW Shipper	.79	.60	.17	2.50
MW Rail	.71	.45	.25	1.67
S/E Shipper	.89	.60	.33	2.00
S/E Rail	.79	.50	.33	2.08

Table 7 (continued)

NOTES: Rates are through ex parte 357, 12/15/78.

Number of Observations: MW Shipper = 12; MW Rail = 9; S/E Shipper = 9; S/E Rail = 29.

SOURCE: "Unit Train and Annual Volume Coal Rates," Mobil Oil Corporation, Traffic Department, Jan. 15, 1979.

equipment averaged 09 mills and 20 mills per short ton-mile, respectively. For shipper-owned equipment, the corresponding rates are approximately 03 mills in both regions. Note however that the midwestern routes are on average far shorter in distance. We would expect some costs of railroad shipments to be unrelated to mileage (for example, costs incurred at loading and unloading stations). Accordingly, if we normalized for mileages, the southern rates should be lower on economic grounds.

By regressing the rates on important cost-determining variables, the variations in Table 7 can be mostly explained. A variety of models have been estimated to explain unit-train rates. This study employs a modified version of the model specified by Zimmerman.[06]

Zimmerman assumes that a railroad has a total cost of performing the unit train service of the following form:

$$TC = \alpha_{FS} + \alpha_M(M.MTT.V) + \alpha_L(L.MTT.V)$$

where

TC = total cost of performing the service

α_{FS} = fixed costs pertaining to the service

α_M = costs per short ton-mile

α_L = cost per incremental unit of loading time

V = number of trains per year

MTT = tonnage per train, in millions

M = one-way miles

L = loading and unloading times in hours.

He then assumed that the cost reflected in the tariff would be the

average cost (AC) of providing this service, i.e.,

$$AC = \frac{\alpha FS}{V.MTT} + \alpha_M M + \alpha_L L$$

Miles shipped reflect line-haul costs; loading and unloading times influence rates, since faster times mean better equipment utilization and lower capital costs; annual tonnage reflects the fixed costs, and since AC is a charge per ton, the higher the tonnage, the lower the fixed costs per ton.

For our purposes, the southern and midwestern samples have been pooled. A chow test allows us to accept the hypothesis that the slope coefficients are equal at 99 percent confidence level, but reject the hypothesis that the intercepts are equal.[07] A dummy variable (DUMR) is used to adjust for this factor. The dummy variable takes on the value 0 for southern rates, and 0 for midwestern rates.

Where Zimmerman used only railroad-owned equipment rates, in this case shipper-owned equipment rates have been included. The difference should reflect the number of cars needed (capital costs) and the utilization per car (maintenance costs). We hypothesize that:

1. required cars = (number of cars per train x number of required trains) x (reserve factor for stand-by cars)

2. number of required trains = $\frac{\text{required number of trainloads per year}}{\text{number of trips per train per year}}$

3. required number of trainloads per year = $\frac{\text{annual tonnage to be shipped}}{\text{tons per trainload}}$

4. number of trips per train per year = $\frac{24 \text{ x number of operating days per train per year}}{\text{number of hours required per round trip}}$

We also assume that travel times per long-haul mile and that tons per trainload are uniform. Then the equipment costs should be mostly related to distance and loading-unloading times. Tonnage is of minor importance in that doubling of tonnage should not yield significant increased requirements for cars per ton.

The equipment costs are not, however, strictly proportional to miles. That is, as miles double, equipment requirements do not double, given loading and unloading delays. A reasonable specification therefore is a fixed component, DUMEQ, and a dummy variable on miles, DM.

It should be noted that an important component of tariffs is rent, as opposed to costs. To this point we have made only casual reference to rent. Given the existence of rents, omitting a rent variable(s) might well bias coefficient estimates, unless the rent is uncorrelated with other explanatory variables. By evaluating earlier work by Zimmerman (to be fully discussed below), the hypothesis that rents are uncorrelated with other explanatory variables can be accepted at the 95 percent confidence level. Nevertheless, the possibility of this bias should be made clear. Furthermore, independent of the bias, the coefficient of the variables constructed to explain the difference between railroad and shipper owned equipment rates are not purely cost-related. They only explain the difference in rates, and may well pick up a rent variation as well as a cost variation.[18]

Table 8 presents the estimated equation for the combined South/Midwest 1979 sample. All the coefficients have signs as expected, with only the coefficient on loading and unloading times being

Table 8

Regression Results: Midwestern and Southern/Eastern Sample
(January 1, 1979)

TA78 = -.07 + .0105 * M + .00237 * u + .369 * IMAT + 1.21 * DUMR + .0016 * DM + 1.005 * DUMEQ

Standard Error:	.438	.0011	.0062	.2234	.3357	.0012	.515
T Statistic:	-.16	9.12	.38	1.65	3.61	1.31	1.95

Standard Error of the Regression: .797
Number of Observations: 58
F Statistic: 106.321
R^2: .926

TA78 = tariff per ton
M = one-way mileage
u = loading plus unloading time
MAT = minimum annual tonnage (in million tons)
IMAT = 1/MAT
DUMR = 0 if destination is the midwest, 1 if south or east
DUMEQ = 0 if shipper-owned equipment, 1 if railroad-owned
DM = DUMEQ * M

Source: author's calculations

statistically insignificant at the 95 percent confidence interval.[19] The eastern and southern rates are significantly higher than the midwestern rates. This is not surprising given the competition from barges in the Midwest.

Almost all of the southern rates and the majority of the midwestern rates are escalated according to ICC general rate level increases. In recent years various exemptions have led to variable increases in rates. Nonetheless, a comparison between the three samples of rates for which direct comparisons were possible showed consistent increases in all rates. From 1970 to 1975, rates increased by an average of 70 percent, and no significant regional variations were observed. From 1975 to 1978, midwestern and eastern rates increased at the same annual rate. The period increase was approximately 33 percent. However, southern rates, in this case referring exclusively to destinations in Georgia, South Carolina, North Carolina, Florida, and Alabama, have increased at an annual rate of 16 percent, or 58 percent between 1975 and 1978. Primarily responsible for this has been the exceptionally high increase recently allowed on Louisville and Nashville shipments, though all shipments have increased at rates higher than elsewhere.[20] It should be noted that the ICC is currently considering an additional increase for midwestern shipments; applicable to shipments which are escalated by ex parte increases, not those which are escalated by agreements. Therefore, the rate of increase in the Midwest may well approximate that in the South in the next few years.

Calculating such increases on an annual basis yields approximately

11.6 percent annual increases for the Midwest and East between 1970 and 1978. In the South, rates increased at this rate between 1970 and 1975, but have since increased at an average of 16 percent per year. Note that the increases themselves are irregular, so these percentages reflect average increases over the periods considered.

Finally, it should be noted that approximately 90 percent of the rates in the East, South, and Midwest have been posted before 1973. The small number of new rates, primarily to Michigan, Florida, Alabama, and Georgia, are not statistically significantly different from the old rates. This is not surprising given the ICC reluctance in the past to allow rates that are signficicantly different from an existing, comparable rate structure. To the extent that these rates increase in the future, it will be according to general rate level increases allowed by the ICC. Even given the recent rapid increases allowed by the ICC, the existence of a well-defined rate structure in these regions is important for two reasons. First, it has acted in the past as an effective constraint on monopoly pricing. Second, it facilitates statistical estimation of railroad costs in these regions. Both these points will be discussed below.

Western Rates

Rates originating in the West have followed a more complex pattern over the years. The first western rates were posted in the late 1960's, involving coal shipments from Wyoming and Montana to Minnesota. These rates were set at very low levels as an inducement to western steam coal market development. After the first Minnesota rates, rates from the

Powder River Basin to Illinois, Indiana, Wisconsin, Iowa, Kansas, and Nebraska were posted between 1972 and 1975. These rates were 20 to 30 percent higher than the Minnesota rates, with the rates to Indiana and Illinois set at the highest levels.[21] Finally, since 1975, a series of new and still higher rates has been posted, especially to destinations in Texas, Arkansas, and Mississippi.

Table 9 summarizes the current western rates. Note that in 1979 "new" rates are higher than the "old" rates posted prior to 1975: 10 versus 8 mills on shipper-owned equipment, 12.4 versus 11 mills on railroad-owned equipment.[22] Note also that distances are on average longer, loading and unloading times shorter with less variation, and annual tonnage requirements higher. Furthermore, virtually all the new unit-train rates involve shipper-owned equipment. This last fact is attributable to a number of factors. First, the railroads have a basic dislike of inflexibility, and the unit-train service car utilization is by definition inflexible. Second, shipper-owned cars have allowed for more efficient car utilization. Third, utilities have had greater success in financing car equipment costs, so that current cost savings are realized.[23]

Table 10 presents regression results for western rates. A dummy variable is used to pick up the higher post-1975 rate levels. Regression analysis of western rates indicates the lack of a well-defined rate structure in contrast with the Midwest, South and East regions. For example, the negative coefficient suggests a truncated sample at a high mileage level. All coefficients have the expected signs, and are significant at a 95 percent confidence level.

Table 9

Western Unit-Train Rates (January, 1979)

	Mean	Standard Deviation	Minimum	Maximum
Tariff per ton-mile (in cents)				
New, Shipper	.0101	.0014	.0078	.0125
New, Rail	.0124	.0009	.0115	.0132
Old, Shipper	.0082	.0006	.0071	.0089
Old, Rail	.0110	.0017	.0078	.0130
One-Way Mileage				
New, Shipper	1259	483	498	2013
New, Rail	792	23	773	818
Old, Shipper	953	235	652	1248
Old, Rail	1052	240	640	1290
Loading Plus Unloading Time				
New, Shipper	8	2	4	9
New, Rail	18	5	8	28
Old, Shipper	9	2	8	14
Old, Rail	21	8	8	28
Minimum Annual Tonnage (1/million short tons)				
New, Shipper	.58	.17	.25	.77
New, Rail	.63	.12	.36	.91
Old, Shipper	.99	.85	.29	3.03
Old, Rail	.91	.56	.22	2.00

Table 9 (continued)

NOTES: Rates are through ex parte 357, 12/15/78.

Number of Observations: New Shipper = 12; New Rail = 4; Old Shipper = 9; Old Rail = 13.

SOURCE: "Unit Train and Annual Volume Coal Rates," Mobil Oil Corporation, Traffic Department, Jan. 15, 1979.

Table 10

Regression Results: Western Sample
(January 1, 1979)

TA78 = -5.75 + .0127 * M + .0596 * u + .929 * IMAT + .668 * DUMEQ + .00124 * DM + 2.134 * DUMT

Standard Error:	.876	.0007	.0284	.321	1.21	.0011	.467
T Statistic:	-6.56	19.38	2.09	2.89	.55	1.10	4.56

Standard Error of the Regression:	1.121
Number of Observations:	.959
F Statistic:	117.38
R^2:	37

TA78 = tariff per ton, January 1, 1979
M = one-way mileage
u = loading plus unloading times
MAT = minimum annual tonnage (in million tons)
IMAT = I/MAT
DUMEQ = 0 if shipper-owned equipment, 1 if railroad-owned
DM = DUMEQ * M
DUMT = 0 if rate posted price to 1975, 1 otherwise

Source: author's calculations

Most Western rates increase according to escalation agreements, generally based on the Association of American Railroads (AAR) cost scales. Burlington-Northern (BN), for example, raises its rates on July 1 of a given year by 80 percent of the cost increases for the western district from the preceding year.[24] The relative increases in effective rates have been relatively consistent in the West. Since 1975, rates have increased an average of 31 percent; both for new and old rates. The AAR index over this period, multipled by 80 percent, equals 1.30. Note again, however, that although new rate increases have been consistent with the AAR index, the new rates are significantly higher at the time of posting than the escalated old rates. This is indicated in the regression results above. The AAR cost indexes from 1967 to 1979 are presented in Table 11.

A few observations on the western rate structure versus the southern and midwestern rate structures should be made. First, they are different. Analysis of covariance on the pooled samples showed that both the intercepts and slopes are significantly different. Pooling the samples showed that the western and midwestern rates are approximately the same for equivalent operating parameters, while the southern rates are significantly higher. Direct observation of equivalent mileages further supports this conclusion. Of course, this does not indicate that rents are lower in the West than in the South. Conceivably, costs are higher in the East and South than in the West. We will investigate this question further below.

Another important observation is that the western rate structure is

TABLE 11

Association of American Railroads
Economics and Finance Department
Washington, D.C. 20036

Series QMPW - 106

January 30, 1980

INDEXES OF
RAILROAD MATERIAL PRICES AND WAGE RATES
Railroads of Class 1

1. Annual Indexes of Charge-out Prices and Wage Rates
(Average 1967 = 100)

District and Group	1967	1968	1969	1970*	1971*	1972	1973	1974	1975*	1976	1977	1978*	1979p
UNITED STATES:													
Fuel	100.0	103.5	106.7	110.5	114.6	117.1	136.5	272.0	321.9	350.1	389.6	406.9	606.4
Other material & supplies	100.0	102.6	105.5	109.4	113.5	118.7	122.9	142.1	190.2	203.2	217.2	230.6	252.5
All material incl. fuel	100.0	102.7	105.8	109.7	113.7	118.1	126.7	178.9	227.2	244.5	265.3	279.9	347.8
Wage rates	100.0	105.1	112.2	122.7	136.8	149.5	164.4	173.4	190.8	210.7	227.3	250.0	275.1
Material prices and wage rates combined	100.0	104.7	110.9	120.2	131.2	141.8	155.2	174.7	202.2	221.3	239.2	259.4	297.9
Wage rates and supplements a	100.0	106.3	113.6	125.6	139.4	153.4	173.9	189.1	207.1	232.0	251.6	276.5	302.8
Material prices, wage rates & supplements combined (excl. fuel) a	100.0	105.7	112.3	122.9	134.9	147.4	165.1	181.0	203.8	226.4	244.9	267.5	293.0
Material prices, wage rates & supplements combined (incl. fuel) a	100.0	105.7	112.3	123.0	133.7	145.6	163.5	186.8	212.6	235.4	255.4	277.4	315.2
EASTERN DISTRICT:													
Fuel	100.0	103.3	106.0	109.2	115.3	117.7	137.3	271.4	323.8	350.8	396.7	414.7	593.3
Other material & supplies	100.0	102.7	105.5	109.4	113.2	118.5	122.2	140.1	188.0	198.0	210.6	222.1	245.2
All material incl. fuel	100.0	102.8	105.6	109.4	113.8	118.3	126.4	176.6	225.7	240.3	261.5	275.0	338.3
Wage rates	100.0	105.9	113.2	122.9	136.6	150.0	165.5	175.2	191.3	212.1	230.9	255.5	280.9
Material prices and wage rates combined	100.0	105.4	111.9	120.7	131.8	143.3	157.2	175.5	200.5	219.6	239.1	260.7	296.2
Wage rates and supplements a	100.0	107.0	114.6	126.0	139.2	154.3	175.1	191.4	207.5	233.2	255.6	283.8	310.1
Material prices, wage rates & supplements combined (excl. fuel) a	100.0	106.4	113.3	123.6	135.3	149.0	167.2	183.8	204.3	227.5	248.3	273.8	299.6
Material prices, wage rates & supplements combined (incl. fuel) a	100.0	106.4	113.3	123.6	134.3	147.4	165.7	188.6	211.7	234.9	257.0	281.7	316.7
SOUTHERN DISTRICT:													
Fuel	100.0	104.4	104.6	106.4	110.0	112.9	129.7	251.1	298.1	322.7	362.5	375.8	524.6
Other material & supplies	100.0	102.5	105.0	109.0	112.7	118.1	122.1	140.2	188.6	199.8	213.4	226.5	247.3
All material incl. fuel	100.0	102.9	104.9	108.3	111.9	116.6	124.1	169.9	217.8	232.7	253.3	266.5	321.7
Wage rates	100.0	104.6	111.4	122.4	135.3	149.1	163.7	173.1	189.9	210.4	226.0	248.8	274.0
Material prices and wage rates combined	100.0	104.2	110.0	119.3	127.6	138.5	150.8	172.1	199.4	218.0	235.3	254.8	290.3
Wage rates and supplements a	100.0	106.4	113.4	125.5	138.2	153.0	172.6	188.5	206.7	232.4	251.1	275.9	302.4
Material prices, wage rates & supplements combined (excl. fuel) a	100.0	105.6	111.7	122.2	131.9	144.4	160.1	176.6	202.8	225.4	243.0	265.2	290.5
Material prices, wage rates & supplements combined (incl. fuel) a	100.0	105.6	111.7	122.1	130.3	142.1	158.1	182.9	210.0	232.5	251.8	273.1	308.2
WESTERN DISTRICT:													
Fuel	100.0	103.2	108.1	113.4	116.2	118.7	138.6	281.1	328.9	359.1	395.4	414.0	643.0
Other material & supplies	100.0	102.5	105.9	109.4	114.1	118.1	123.5	145.0	192.8	207.4	222.5	236.7	258.6
All material incl. fuel	100.0	102.7	106.6	110.6	114.7	118.2	128.0	185.8	233.4	252.5	273.3	289.2	364.7
Wage rates	100.0	104.6	111.5	122.7	137.6	149.3	163.7	172.3	190.8	210.0	225.3	246.8	271.7
Material prices and wage rates combined	100.0	104.3	110.6	120.4	132.1	141.7	155.0	175.6	205.2	224.3	241.5	261.1	303.0
Wage rates and supplements a	100.0	105.7	112.7	125.4	140.1	153.2	173.6	187.9	207.2	231.1	249.0	272.3	298.5
Material prices, wage rates & supplements combined (excl. fuel) a	100.0	105.1	111.5	122.6	135.7	147.2	165.1	180.6	204.1	226.0	243.3	264.7	290.0
Material prices, wage rates & supplements combined (incl. fuel) a	100.0	105.1	111.6	122.8	134.4	145.5	163.6	187.4	215.0	237.5	256.2	277.3	318.2

a - Includes payroll taxes, health and welfare benefits and other allowances.

* - Wage indices for 1970, 1971, 1975 and 1978 include retroactive wage increases paid in 1971, 1972, 1976 and 1979 respectively.

p - Wage rates and wages and supplements indexes, and combinations including them, are preliminary. Indexes for fuel and materials and supplies are final.

far more unstable than that in other regions. Though increases in the South and Midwest have been large recently, they have been applied to the entire rate structure and the overall consistency has been maintained. In the West, however, a well-defined structure never existed, and so the constraint of comparability has not been effective. Note furthermore that the rates currently being requested by the railroads in coal rate cases are higher in some cases than even these 1979 levels. The importance of this instability will be appraised in detail below.

In summary, the following ranges seem reasonable for long-distance shipments of steam coal in unit trains. In the West, in railroad-owned equipment, 8.5 mills to 13.5 mills, in the East 15 mills to 18 mills (1979 dollars). Note that on a 1000-mile western shipment this difference would amount to $5.00 per ton, certainly a margin worth investigating in detail.

METALLURGICAL AND EXPORT RATES

Metallurgical and export shipments reflect different competitive environments, and the rates would be expected to differ. Nonetheless, it is important to review them briefly since they might bear on the development of steam coal exports.

First, domestic metallurgical rates are based on a variety of services: unit train, trainload, and single-car shipments. They are generally higher than steam coal domestic shipments if they originate in the East and Midwest. For example, an analysis of 20 domestic coal train rates, destined for Illinois, Indiana, Pennsylvania, and Ohio, showed

that they ranged from 20 to 50 percent higher.[25] In the West, metallurgical unit-train shipments were not statistically different from steam coal rates.

Export rates are higher still. A rate is set for a given group of origins to a port or group of ports. Historically, export rates have been set at levels higher than comparable domestic rates to maximize transport profits on metallurgical exports.[26] Shipments are charged according to single-car rates, independent of the actual method of transportation. In recent years, as domestic rates have steadily increased, and competitive pressures on metallurgical coal exports have also increased, the margin between domestic and export rates is not as great as it has been. Nonetheless, the rates are 30 to 70 percent higher than domestic steam coal rates. The highest margins exist at the origins closest to ports since rates for a given origin group are set according to costs incurred from the furthest originating point. Table 12 summarizes rates to New Orleans, Hampton Roads, and Baltimore, through ex parte 375.

Although no steam coal currently moves under these single-car rates, it has in the past and could in the future. Conversations with railroad officials revealed a general lack of interest in setting different rates, say unit-train rates, for potential steam coal exports.[27] In regions where an export-rate structure does not exist for coal, for example, West Coast ports and Gulf Coast ports, it is not clear what rate structure would obtain. This problem will be considered further below.[28]

Table 12

EXPORT COAL RATES: THROUGH EX PARTE 357,[1] December 1978

Origin	Destination	Tariff per ton	Average One-Way Mileage	Unit-Train[2] Equivalent
Pocahontas-Tug River	Lamberts Point, Virginia	10.54	388	8.05
Virginia-Upper Buchanan		10.54	388	8.05
Clinch Valley no. 1		10.54	388	8.05
Clinch Valley no. 2		10.75	426	8.51
Thacher-Kenova-Tiller		10.75	440	8.68
New River	Newport News, Virginia	10.53	430	8.56
Kanaba		10.75	556	10.09
Big Sandy		10.99	646	11.17
Westmoreland	Baltimore	10.48	336	7.42
Gauley		10.48	406	8.27
Somerset		9.84	220	6.02
Elk River		10.48	331	7.36
Clearfield		10.62	317	7.20
West Kentucky and Southern Illinois	New Orleans	11.51	624	9.70
Springfield		13.48	759	11.33
Clinton, Ind.		12.60	685	10.91
St. Louis		13.40	685	10.44
Birmingham		10.99	299	5.77
Western Kentucky and Southern Illinois	Mobile	9.85	570	9.05
Springfield		10.17	641	9.91
Clinton, Ind.		11.97	706	10.69
St. Louis	Mobile	11.17	671	10.26
Birmingham		6.99	213	4.72

Table 12 (continued)

NOTES:
1. All rates are single-car shipments, and apply both to metallurgical and steam coal shipments.
2. Unit-train equivalent is based on Table 8. Midwestern rates to New Orleans, Mobile; Eastern to Baltimore, and Hampton Roads ports. U is assumed at 48, MAT at 1.20 million tons.

SOURCE: Personal correspondence with Norfolk and Western, Chessie, ICG, Southern, Louisville and Nashville, and Coal Week.

SUMMARY

In summary, domestic steam coal unit train rates have followed different patterns regionally, but in all regions they are increasing at a rapid rate. In the South, East, and Midwest, rate structures are well-defined, but recent allowances for general rate level increases indicate that either greater rents are being realized, or that costs are increasing faster than the AAR index estimate. In the West, no firm rate structure exists. Therefore, newly posted rates have been posted at high levels, and the railroads have attempted to pull up the old rates to the corresponding high levels. The role of the ICC in this evolving structure will be analyzed in Chapters II and III. Export and metallurgical rates are significantly higher than domestic steam coal rates. These high rate levels are potentially important factors in the development of steam coal exports.

In the following sections, we will evaluate these rates in depth. Our purpose will be to estimate the amount of rents that exists in these rates, the future course of these rates, and the potential impact of existing rate patterns on future steam coal exports. Recall that a great deal of the following sections is as important to the understanding of domestic coal markets as to export coal markets. The detailed analysis of ICC costing procedures and recent ICC proceedings is important to both coal markets. However, certain readers may choose to bypass detailed segments of the material.

FOOTNOTES--CHAPTER I

[1]U.S. Department of Energy, "Bituminous Coal and Lignite Distribution, Calendar Year 1978," Energy Data Reports, April 1979, p. 9.

[2]Slurry pipelines carried only 1.2 MT in 1978, but will be considered below as a future option. The residual 14 percent was carried to mine-mouth power stations (11 percent), or used for power and heat at the mine, made into beehive coke at the mine, or used for other purposes at the mine. National Coal Association, "Coal Traffic Annual," 1978, Washington, D.C., p. I-2.

[3]This is on a tonnage basis. If calculated on a ton-mile basis, the relative modal importance would be skewed to rail since average distance was 397 miles for rail, 280 miles for barge, and 20 miles for truck in 1976. Ibid., p. II-4.

[4]U.S. Department of the Interior, Bureau of Mines, International Coal Trade, Vol. 48, no. 2, Washington D.C., February 1979, p. 14.

[5]From 1965 to 1974 a different pattern obtained. Barge transport increased, railroad decreased, and trucks were stable. See Sargent, D., "Western Coal Transportation Unit Trains or Slurry Pipelines," U.S. Department of Transportation, 1976, p. 6 for pre-1975 summary.

[6]Keystone Coal Industry Manual, McGraw-Hill, N.Y., 1979, p. 242.

[7]Note that the ICC regions are not necessarily related to economic markets. In Chapter III, we will analyze the extent of market power held by the railroads.

[8]Keystone Coal Industry Manual, 1979, op. cit., pp. 256-260.

[9]U.S. Department of the Interior, Bureau of Mines, "Long-Distance Coal Transportation; Unit Train or Slurry Pipeline," Information Circular 8690, GPO, 1975, p. 11.

[10]Schmidt, R., Coal in America, McGraw-Hill, New York, 1979, p. 298.

[11]Other types of rates exist, but because they are not pertinent to steam coal export evolution, they will not be considered. For full description of coal rate structures see ICC, "Investigation of Railroad Freight Rate Structure--Coal," ex parte no. 270 (sub-No. 4).

[12]For an interesting analysis of the evolution of unit trains, see: McAvoy, P. and Sloss, J., Regulation of Transportation Innovation, Random House, New York, 1967.

[13]Schmidt, op. cit., p. 298.

[14]a. Mobil Oil Corporation, Traffic Department, "Unit Train and Annual Volume Coal Rates," January 15, 1979.
b. Peabody Coal Company, Traffic Department, "Tabulation of Unit Train Tariffs on Coal, All Rail," August 1970, August 1975.

[15]"East" and "South" include destinations in Florida, Georgia, Michigan, New Hampshire, New York, North Carolina, Ohio, Pennsylvania, and South Carolina. Midwest includes destinations in Indiana, Illinois, Kentucky, and Wisconsin. "South" henceforth refers to "East" and "South," unless otherwise noted.

[16]Zimmerman, M.B., "Long-Run Mineral Supply: The Case of Coal in the United States," Ch. III: "Transport Rates," unpublished Ph.D. dissertation, MIT, 1975.

[17]For a description of covariance analysis and chow tests, see: Johnson, J., Econometric Methods, McGraw-Hill, New York, 1972, pp. 192-207.

[18]To see this, consider the following simplified example:

Let $T_R = \alpha(1 - \beta)m + \beta PGD$

where: T_R = the tariff for railroad-owned equipment

m = mileage

PGD = the price of an alternative fuel, delivered, minus the delivered price of coal.

Let: $T_S = (\alpha_S - \beta\alpha_S)m + \beta PGD$

where T_S = shipper-owned equipment tariff

$T_C = \alpha(1 - \beta)m + \beta PGD + D(\alpha_S - \beta\alpha_S)m$

where T_C = tariff for combined sample

$= [\alpha(1 - \beta)]m + DM(\alpha_S - \beta\alpha_S) + \beta PGD + \varepsilon$

The cost parameters are not identified unless β is identified. In other words, without determining rents, we cannot say whether the cost coefficients are purely cost-related or not.

[19]The statistical insignificance of the unloading and loading times is not very surprising. The reason is that there is very little variability, and the variability is generally explained by unspecified variables, such as the time when the facilities were installed.

[20]The ICC, in justifying the recent increases allowed on Louisville and Nashville shipments, has cited higher regional cost increases and the deteriorating position of L+N railroad. The AAR index does not support the former reason. The 1975 to 1978 increase for the South was 29.7 percent, versus 31.1 percent in the East and 29.3 percent in the West. Whether the recent increases represent in effect the subsidization of a deteriorating railroad or the realization of greater rents is unclear. Association of American Railroads, "Indices of Railroad Material Prices and Wage Rates," January, 1980. For a complete discussion of the L+N rate requests, see ICC Decision no. 37063, August 28, 1979.

[21]Zimmerman, M.B., op. cit., pp. 62-64.
Zimmerman, "Rent and Regulation in Unit-Train Rate Determination: Regional Discrimination and Inter-fuel Competition," MIT Energy Laboratory, June 1978, pp. 22-26.

[22]Though the post-1975 rates are significantly higher than the pre-1975 rates, we cannot be certain that this is totally explained by increased rents. Part of the difference can be explained by the Burlington-Northern mechanism for escalating rates. Using their method, rates increased by 37 percent from 1975 to 1979. Based on a strict application of the AAR index, the increase would be 48 percent. Now, the 80 percent BN adjustment is economically logical for old rates, since capital costs are constant. However, the full index is representative of the actual cost differences between a shipment initiated in 1975 and one initiated in 1979.

[23]Phillips, Peter J., "Coal Preparation for Combustion and Conversion," prepared by Gibbs and Hill, Inc. for Electric Power Research Institute, May 1978, pp. 5-4, 5-18.

[24]See, for example, Interstate Commerce Commission, Decision I + S, No. 9199. Unit Train Rates on Coal--Burlington Northern, Inc. Appendix B, p. 2. Decided July 13, 1979.

[25]Rates were drawn from: Mobil Oil Corporation, op. cit.

[26]Adelman, M.A., "American Coal in Western Europe," in Journal of Industrial Economics, Vol. XIV, no. 3, July 1966, pp. 199-211.

[27]William Roe, Assistant vice-president, Rates, Norfolk and Western Railway Co. and M.D. Gibon, Director, Export Traffic, Chessie system.

[28]Another precedent worth noting is port equalization rates. Under this classification, rates from an origin or group of origins to a group of ports, are set on the basis of the distance to the midpoint port. This suggests lower rates than would otherwise obtain to distant ports (losses or: lower rent) and higher rates to close ports (losses in traffic). This structure is adopted to protect geographically disadvantaged ports and to eliminate competitive modes. It is widely practiced on grain shipments. For a complete discussion of port equalization rates, see ICC, Rail Services Planning Office, "Rail Rate Equalization To and From Ports," Final Report, January 1979.

CHAPTER II

AN ANALYSIS OF UNITED STATES RAILROAD COSTS

INTRODUCTION

In Chapter I we analyzed the existing rate structure for unit-train coal shipments. We concluded that rates have been increasing rapidly in the past few years, and that these increases will probably continue. The most complex and controversial dimension of the rate structure is whether the rates equal costs or whether they include substantial monopoly rents.

This chapter analyzes railroad costs. As we will see, the subject is a terribly complex one and conceivably even intractable. Our purposes are two-fold. First, and primarily, to establish a lower-bound for unit-train coal rates. If rates include a large rent component, the reduction in rates to costs may be an important factor in the U.S. role in steam coal export markets. Second, the analysis focuses primarily on the recent Interstate Commerce Commission (ICC) coal-rate investigations. The issues presented in these cases, and their resolution, are critical to U.S. domestic coal markets as well as export markets. The detailed review of the important conceptual and empirical issues in the coal-rate cases and related ICC investigations provides an interesting case study in regulation and transportation economics.

PROBLEMS IN RAILROAD COST ESTIMATION

We want to estimate long-run marginal costs (LRMC) of unit-train service. Pricing at this level is consistent with the conditions for economic efficiency. Two other cost estimates will also be important to

the analysis: average costs and short-run marginal costs. Average costs, both short-run and long-run, will be important evidence in justfying rates at LRMC versus some other level. Short-run marginal costs, where plant and facilities are taken as fixed, will be useful in analyzing capacity utilization in the short and long runs.

Before we analyze the approaches that have been applied to railroad cost estimation, a brief discussion of the problems inherent in all types of cost estimation is appropriate. The first problem is that railroads provide a wide variety of services; not only passenger and freight service, but many types of freight service. In large part the railroad plant and facilities are jointly used in producing this variety of services. The existence of these joint-production costs presents serious problems for the allocation of costs to particular services.

Two basic dimensions of this problem must be confronted, one related to fixed costs and the second to joint-variable costs. First, consider fixed costs, i.e., costs that are not variable with traffic levels. Basically, any allocation of these costs to different service units is arbitrary. These are costs that would exist independent of traffic levels, and so to assign them to traffic units is in a strict sense a meaningless cost concept. Furthermore, given fixed costs, and given a variety of diverse service units (say passenger and freight), selection of an appropriate output unit (i.e., revenues or ton-miles) will further complicate the allocation. This is the basic problem of joint-production costs cited in railroad costing literature, and it renders meaningless any estimation of average costs for a single product.[1] Note however

that this dimension of the joint-cost problem is of lesser importance for estimating marginal costs. Only if average costs exceed marginal costs by some significant margin need we be concerned with the allocation of fixed costs. Related to this is the problem is that given fixed costs there is no widely accepted method to divide rail costs between fixed and variable components. This is largely because the railroads have imperfect knowledge about cost/output relationships.

The second dimension of the joint-production cost problem relates to joint-variable costs, that is, costs that are variable with aggregate output levels, but that cannot be assigned to particular output units. This problem is especially important for our analysis. In this case, the allocation of costs is complicated more empirically than theoretically. We might in theory determine incremental costs for a shipment. However, because of the indivisibility of railroad plant investment, empirical separation over output units is very difficult if not impossible. Furthermore, to the extent that synergism exists in railroad investment (that is, beyond the indivisibilities problem, savings arise from combined services), even theoretical allocation of these joint-variable costs loses meaning.

A second problem complicating railroad cost estimation is network capacity. Many studies in the past have implicitly assumed excess capacity on coal lines. Given this, the incremental costs of rail service properly exclude investment costs. However, given full capacity utilization (or capacity utilization on the increasing segment of the

long-run average cost curve), or a long enough period to require replacement investment, investment costs should be incorporated into cost estimation. Failure to account for this can lead to unjustifiably low cost estimates. Furthermore, given full capacity, long-run marginal cost estimates are difficult since variations in costs as a function of capacity utilization are not well understood even by the railroads. In general, an understanding of, and proper accounting for, capacity utilization are important to reliable cost estimates.

Related to this is a third problem: the inherent indivisibility of railway plant and facilities, and the difficulties this creates for estimating marginal costs. Ideally, the railroads know with certainty all future traffic flows, and based on their forecasts they adjust plant and equipment over time to provide optimal utilization of capacity. In fact, future traffic flows cannot be forecast with certainty. In this case, the railroads would prefer to build capacity as demand develops, assuming adequate time for these investments. And, if investment was instantaneous and the railroad plant perfectly divisible, the incremental costs of a particular shipment would be simple to ascertain. In fact, however, the railway plant is to a large extent indivisible. Therefore, investment strategies at any given time will by necessity be affected by forecasts of future traffic volumes. An understanding of output/investment relationships is therefore especially important to guide us in determining the necessary investments for particular unit-train services. For example, given basic indivisibilities in plant, the railroads will invest at any point in time for traffic volumes greater

than those required for a given unit-train service. In determining the proportion of this investment economically attributable to a given unit-train service, the optimal output level given this investment level must be understood. As we will see below, this issue is especially important in the recent coal rate cases and in the interpretation of ICC costing procedures.[2]

APPROACHES TO RAILROAD COST ESTIMATION

These problems are common to the two basic costing procedures: statistical and engineering/accounting. The choice of methodology depends on the characteristics of the question to be answered and the extent to which a given approach compensates for these inherent complexities.

STATISTICAL COST ESTIMATION

Statistical estimation of railroad cost functions has been well developed. The traditional form is to fit the following relationship over a cross section of firms:

$$TC = \alpha + \beta x$$

where TC is a vector of cost observations, x is a vector of output observations, and α and β are intercept and slope terms respectively. The arguments of the cost function and the functional form vary widely over studies.[3]

The primary difficulty in this approach is, again, the division of

costs between fixed and variable components and the allocaton of joint-production costs over different service units. Though subject to the normal errors of statistical estimation, at least this approach lifts the allocation of joint costs and the separation of fixed versus variable costs out of some arbitrary framework. To the extent that fixed costs are high, and that direct observation of cost/output relationships is not feasible, statistical cost estimation may be recommended, especially where particular characteristics of the railroad cost function (such as economies of scale) are the major objective of the analysis.[4]

For our purposes (the estimation of costs for a particular type of service), however, this approach is suspect. Since there are relatively few roads carrying virtually all the coal on railroads, the relevant sample size would be far too small.[5] While the results of recent analyses of special characteristics of railroad cost functions will be used, no comprehensive study of this type has focused on coal explicitly, and no original estimation will be undertaken.

Statistical methods have also been used to estimate costs as a function of rates. In practice, most studies have not explicitly accounted for the existence of railroad monopoly. A few other studies, notably Zimmerman's, have explicitly modeled monopoly power.[6] Unfortunately, given today's competitive environment, the rate-making process is less easily specified. The concise specification of rents as related to the price of alternative fuels in Zimmerman's model is no longer realistic for the new rate structures in the West. However, to

the extent that the rate structure has been maintained in the East, South, and Midwest, this approach is useful, and it will be employed to a limited extent below.

ENGINEERING/ACCOUNTING COST ESTIMATION

The second basic approach to railroad cost estimation is engineering/accounting analysis. Simply stated, the output parameters of a particular service are observed, and the costs accountable to each unit summed. This too is complicated by basic problems of joint-cost allocation and separation of fixed from variable costs. However, for coal these problems are mitigated with this approach for two reasons. First, fixed costs on high-volume, long-distance unit-train shipments are relatively low. Second, given the nature of unit-train service, where equipment and even roadway are utilized in large part for coal traffic alone, joint-production costs can be allocated over output units in a less arbitrary fashion. On balance, for our purposes, where low fixed costs exist, and where direct observation of cost/output relationships is still difficult, but easier than usual, this approach is advisable conceptually.[7]

In practice, nonetheless, severe problems persist. Primarily, cost estimates are based on an incomplete understanding of cost/output relationships, in part due to the limited experience with unit trains, and in part due to incomplete cost records. Most analyses of this type depend on unit-cost data, and whether they are provided by the railroads or obtained from ICC records, they generally represent average costs over

different levels of output, not actual costs of particular services. With few exceptions, these are simply all the data that exist.

Given our purposes, and given low fixed costs and more easily observable output/cost relationships, an engineering/accounting analysis is possibly the better approach. However, the fact is that the cost data are imperfect or nonexistent. Though conceptually better, empirical problems constrain the usefulness of this approach.

RAIL FORM A COST ESTIMATION

This problem leads us to a specific method of cost accounting employed by the ICC for cost estimation: Rail Form A. Basically, total costs are recorded for all expense accounts by territory and equipment class (for example, yard expense, train expense, etc.) for all Class I railroads in the United States. Total costs are then divided into fixed and variable components. Variable costs are allocated over variable output units, and fixed costs are allocated over ton and ton-miles or allocated on a ratio basis. Then, for a particular service, unit costs are aggregated to derive variable cost and fully-allocated cost estimates.[8]

Criticism of rail form A procedures has been extensive. In some cases the criticisms are irrelevant to the coal movements; in others the problems are pervasive in all estimating procedures, and the ICC methodology is arguably no worse than others.[9] A more basic problem with ICC estimates is special to rail form A, and requires the following extensive consideration.

The problem is the ICC's division of expenses into fixed and variable components. Initially the ICC estimated the following regression over all Class I railroads:

$$y = \alpha + \beta x$$

where y = expense per mile of road

x = output per mile of road.

Percent variable is calculated as

$$\frac{\beta \bar{x}}{\alpha + \beta \bar{x}}$$, $\bar{x}$ equals the average level of output per mile of road.

The approach has been thoroughly criticized on several grounds.[10] Some of these criticisms are no longer valid given ICC revisions. For example, a single percent variable figure was initially used for all expense accounts. Currently the percent variable is estimated separately for each expense account, using a different output variable in each case. Also, a parabolic functional form ($y = a + bx + cx^2$) has been substituted for the initial form.[11]

The basic problem that persists is that given fixed costs, the percent variable is in fact <u>variable</u> as a function of output. At a higher output level, for a given sized plant, the percent variable will be higher than at a lower output level. Therefore, to the extent that output levels vary, calculating the percent variable at a given output level will bias the estimate of variable costs.

In practice, a major source of the problem is giving too much weight to the small Class I railroads that may have systematically different percent variables than the larger railroads. For example, roads with 500

miles or less of track comprise almost 50 percent of Class I railroads, but only 5 percent of total costs.[12] The ICC calculates the percent variable at the average level of output per mile of road. This approach yields a percent variable for an arbitrarily defined average ton. That is, it is not strictly the average ton moved. Rather it is representative of average cost per ton-mile over all Class I railroads.

Now, if all railroads have the same average outputs per mile of road, and the same average expenses per mile of road, this approach is not unreasonable. (Of course, it could still be biased in application to a particular shipment.) If, however, there is some well-defined variation over size of railroads, then this approach is questionable at best.

In fact, there are several reasons to believe that small railroads are different. First, and most important, we would expect less output per mile of road for small railroads. That is, given indivisibilities in railroad plant and facilities, a minimum-sized plant would in most cases be able to carry efficiently more traffic than it is built to carry. ICC data support this hypothesis of excess capacity. Output per mile of road is on average 30 percent less for roads with less than 1000 miles of roadbed.[13]

Second, we would expect higher fixed costs per mile of road. Fixed costs are: "those which are unaffected by increases or decreases in production."[14] Some of these costs are clearly independent of miles of road; set-up costs for example. As miles of road increase, then, we would expect lower fixed costs per mile of road. Unfortunately, data are not available to specify the magnitude of this difference but we can be

reasonably certain that it does exist.

Let cost equations 1 and 2 represent a small and large railroad respectively.

(1) $TC_S = \alpha_S + \beta_S x_S$

(2) $TC_L = \alpha_L + \beta_L x_L$

where:

TC = total cost per mile of road

α = fixed costs per mile of road

x = output per mile of road

β = variable costs per unit of output

As noted above, variable costs per unit of output are approximately constant:

(3) $\beta_S = \beta_L$

Also, we know from ICC data that total costs per mile of road do not vary significantly over size:

(4) $TC_L = TC_S$

And, that output levels are higher per mile of road for large railroads:

(5) $x_L > x_S$

Therefore, total variable costs will be higher for larger railroads

(6) $\beta_L x_L > \beta_S x_S$

and given that total costs are equal, it follows that fixed costs per mile of road are higher for small roads:

(7) $TC_S - \beta_S x_S > TC_L - \beta_L x_L$

$\alpha_S > \alpha_L$

For the same reasons that we expect a higher percent variable for larger railroads, we would expect lower unit costs for larger railroads. Fixed costs per mile of road will be less, and since output per mile of road is greater, fixed costs per unit of output will be less:

$$(8)\quad \frac{\alpha_L}{x_L} < \frac{\alpha_S}{x_S}$$

Furthermore, this relationship will be inversely symmetrical. That is, as the percent variable increases, unit costs will decrease so that our estimate of variable costs per unit of output will be the same as the ICC's:

$$(9)\quad \frac{\beta_L x_L}{\alpha_L + \beta_L x_L}\left(\beta_L + \frac{\alpha_L}{x_L}\right) = \frac{\beta_S x_S}{\alpha_S + \beta_S x_S}\left(\beta_S + \frac{\alpha_S}{x_S}\right)$$

And, from (9), fully-allocated costs per unit of output for large railroads will be less than for small railroads:

From (4) above, we know $\alpha_L + \beta_L x_L = \alpha_S + \beta_S x_S$, so from (9):

$$\beta_L x_L\left(\beta_L + \frac{\alpha_L}{x_L}\right) = \beta_X x_S\left(\beta_S + \frac{\alpha_S}{x_S}\right)$$

From (3) above, we know $\beta_S = \beta_L$, so:

$$x_L\left(\beta_L + \frac{\alpha_L}{x_L}\right) = x_S\left(\beta_L + \frac{\alpha_S}{x_S}\right), \text{ or}$$

$$x_L\beta_L + \alpha_L = x_S\beta_S + {}_S\alpha_S$$

From (5) above, we know that $x_L > x_S$, so:

$$\frac{x_L\beta_L + \alpha_L}{x_L} < \frac{x_S\beta_S + \alpha_S}{x_S}$$

Statistical evaluations of these points yield the same conclusions. The most comprehensive analysis, by Griliches, separates railroads into size groups, and estimates the percent variable as 90.0 to 99.1 percent for large railroads, calculated for the "average ton," versus 60 to 70 percent for the small roads.[15] Furthermore, variable costs per unit of output are not statistically different over size groups, while fixed costs per unit of output are significantly higher for small railroads. We estimate, then, that variable costs are between 90 and 100 percent of total costs, while unit costs are symmetrically less. Therefore, in reference to rail form A cost estimates, the variable cost estimates are accepted as reasonable, while the fully-allocated cost estimates are believed to be high.[16a]

In summary, ICC rail form A costs suffer from serious estimation problems. In some cases, the problems are not more or less serious than those confronted in any approach to railroad cost estimation. In others, especially determination of the percent variable, rail form A is more seriously flawed. This analysis suggests that we can reasonably accept the Rail Form A of variable costs, but that the 20 to 25 percent markup of this cost to fully-allocated costs is misleading. In fact, due to the biases of the Rail Form A allocation of fixed and variable costs, a 5 to 10 percent increase in fully-allocated costs is more reasonable, especially when we consider the fact that a large proportion of the fixed costs may be due to excess capacity accountable to other commodities, and not to coal. Though far from being a certain estimate of long-run marginal costs, this modification of Rail Form A is probably the best we

can do, given existing data limitations and given our specific focus on coal shipments.

Furthermore, the rail form A estimates have been improved in the coal rate cases by, wherever possible, adding direct cost data. These modifications mitigate some of the general problems in employing system-wide average cost data.

Finally, one point on the specifics of ICC rail form A estimates should be made. In the general case, "variable costs" as constructed by the ICC are short-run average variable costs. However, by employing actual cost data, and by using costs of incremental units, they approximate LRMC. If excess capacity exists, SRMC may be less than LRMC. In fact, however, the railroads have advocated including a fixed-plant investment figure in variable cost components. Therefore, the railroads' variable cost estimate seems to be a more reasonable approximation of LRMC.

AN ANALYSIS OF RAILROAD COST ESTIMATES BASED ON DATA SUBMITTED TO WESTERN COAL-RATE CASES

Given the deficiencies in the Rail Form A costing approach, and given the suggested adjustments, we now proceed in analyzing the newest and most comprehensive evidence on unit-train costs, that assembled for the various ICC coal-rate cases and proceedings.

Since 1975, a large number of railroad rates have been submitted for ICC investigation. Many of these have been rate incentive requests,

filed by the railroads in accordance with the Railroad Revitalization and Regulatory Reform Act (4-R Act) provisions.[16] Others have been initiated by shipper protests. The vast majority have focused on western originating rates, and Burlington-Northern, the largest western railraod, has in the majority of cases been a defendant. The statements submitted have therefore been conceptually similar, with differences primarily in operating parameters.

The set of cases from which the bulk of this analysis is drawn includes:

1) San Antonio, Texas versus Burlington Northern
2) Houston Light and Power versus Burlington Northern et al.
3) Nevada Power Co. versus Union Pacific
4) Iowa Power and Light versus Burlington Northern
5) Southern Electric Power versus Burlington Northern et al.[17]

Lesser attention is focused on the major eastern rate case involving Potomac Electric Power Co. (PEPCO) in Virginia.[18] This set, though by no means exhaustive, is representative of the issues and decisions in other cases as well. The analysis also draws from recent ICC proceedings focused either directly or indirectly on coal shipments.[19]

Tables 1 through 4 provide a summary of the cost estimates presented in four recently decided cases. The railroads have typically provided a range of estimates, based on various assumptions on the cost of capital, and various approaches for determining fully-allocated costs. Method 1 uses 11 percent cost of capital overall; method 2 uses embedded debt rates, except 8.7 percent on equipment; method 3 uses 11 percent, except

Table 1

Wyoming to Flint Creek, Arkansas Cost Estimates
Decided May 21, 1979
(current dollars)

	Railroad			Utility	ICC[1]
	(Method 1)	(Method 2)	(Method 3)		
Variable cost	$8.61	$7.29	$8.49	$5.67	$7.21
Fully-Allocated Cost:					
Ton, Ton-mile Basis	12.98	10.52	12.86		
Dollar-Ratio Basis	11.15	9.05	11.03		9.57

One-way mileage = 1036

Rate proposed by Railroad = $11.35 per ton July 1, 1978

Rate proposed by utility = $8.67 per ton.

Rate allowed by ICC = $10.24 per ton = $9.57 x 1.07

Method 1 = 11 percent after-tax current cost of capital is used for all capital expenditures.

2 = embedded debt rate is used on capital expenditures, except cabooses and locomotives, for which the equipment trust certificate rate of 8.70 percent after-tax is used.

3 = 11 percent after-tax current cost of capital is used for all capital expenditures except cabooses and locomotives, for which 8.70 percent is used.

Notes: 1. The ICC estimate reflects their "revenue-need level," not the strict-cost level. See text.

2. See text for the explanation of these two methods for increasing variable cost to fully-allocated cost.

Source: ICC, Decision no. 36970. Annual Volume Rates on Coal--Wyoming to Flint Creek, Arkansas.

Table 2

Hiawatha, Utah to Moapa, Nevada Cost Estimtes
Decided July 31, 1979
(current dollars)

	Railroad		Utility	ICC[1]
	(Method 1)	(Method 2)		
Variable costs	$7.48	$5.48	$4.50	$6.08
Fully-allocated costs:				
Dollar-Ratio Basis	8.69	7.07	5.63	7.57

One-way mileage = 465

Railroad rate = $9.21 per ton, October 1, 1978.

ICC allowed rate = $7.91 per ton, October 1, 1978.

Method 1 = 11.3 percent cost of capital, after tax

2 = embedded debt level

Notes: 1. Revenue-need level.

2. Railroad-owned equipment.

Source: ICC Decision no. 37038, Bituminous Coal, Hiawatha, Utah to Moapa, Nevada.

Table 3

Wyoming to San Antonio, Texas Cost Estimates
Decided May 23, 1979
(current dollars)

	Railroad		Utility	ICC[1]
	(Method 1)	(Method 2)		
Variable costs	$14.42	$12.05	$9.79	$11.84
Fully-allocated costs				
Ton, ton-mile basis	22.45	20.08		
Dollar-ratio basis	18.38	14.80		15.50

One-way mileage = 1640

Rate proposed by the railroad = $18.23 per ton, October 1977.

Rate allowed by ICC = $16.12 per ton, later increased to $17.23 per ton.

Cost levels, October 1977

Method 1 = 11 percent after-tax cost of capital

Method 2 = embedded debt rates, except 8.70 percent on locomotives, cabooses

Notes: 1. Revenue-need level

Source: ICC Decision no. 36180, San Antonio, Texas versus Burlington Northern et al.

Table 4

Wyoming to Council Bluff, Iowa Cost Estimates
Decided July 13, 1979
(current dollars)

	Railroad			Utility	ICC[1]
	(Method 1)	(Method 2)	(Method 3)		
Variable costs	$5.85	$4.91	$5.67	$3.90	$5.23
Fully-allocated costs:					
Ton, ton-mile	9.06	7.33	5.88		
Dollar-ratio	7.55	6.10	7.38		6.78

One-way mileage = 663

Rate proposed by utility = $5.62 per ton.

Rate proposed by railroad = $7.30 per ton.

Rate allowed by ICC = $7.25 per ton.

Method 1 = 11 percent after-tax cost of capital.

Method 2 = embedded debt rate, 8.70 percent on locomotive, caboose

Method 3 = 11 percent, 8.7 percent locomotive, caboose.

Notes: 1. Revenue-need level.

Source: ICC Decision, I and S no. 9199, Unit Train Rates on Coal--Burlington Northern, Inc. versus Iowa Power and Light Company.

8.7 percent on equipment costs. The ton, ton-mile basis regresses fixed costs over distance. The costs related to distance are allocated on a ton-mile basis, the residual on a ton basis. In the dollar-ratio basis, total expenses are divided by total variable expenses, and this ratio is multiplied by variable costs to calculate fully-allocated costs. The ton, ton-mile basis yields far higher estimates of fully-allocated costs, largely due to the high density of coal shipments relative to other shipments. The ICC has not uniformly recommended one method over another, but in several recent coal proceedings, the ratio basis has been judged more appropriate.[20]

Tables 1 through 4 show the considerable variation in cost estimates. In the Flint Creek, Arkansas case, for example, the railroad's estimate of variable costs ranges from 129 percent to 152 percent of the complainants' estimates. The next step is to analyze these differences in detail. Though differences exist in almost every cost category, the bulk of the variation is attributable in most rate cases to three issues: cost of capital, fixed plant investment, and equipment costs. Therefore, these three issues and their treatment in the rate cases will be examined in depth.

COST OF CAPITAL

First, and most important, we will consider the cost of capital, or the opportunity cost of funds provided to the firm. Until recently, both the complainants (utilities) and the ICC held fast to the incorrect concept that the cost of capital should be represented by the historical

embedded debt rate, as generated by rail form A, of approximately 5.7 percent.[21] Largely as a result of the insistent prodding of the railroads in the western coal-rate cases and the provisions of the 4-R act (see below), the ICC has gradually moved towards the correct concept that the cost of capital is the current weighted average cost of each type of capital used by the firm.[22] The utilities, on the other hand, have continued to advocate the use of historical embedded debt rates, arguing, without a theoretical foundation, that rates above this level do not represent costs, but are, in fact, "profits."[23]

The last debate between the ICC and the railroads, with respect to the current cost of capital, was largely one of semantics. The ICC in fact advocated the use of the current weighted average cost of capital, but defended the notion that capital costs above embedded debt rates were not "costs in the strictest sense" but "rather reflect revenue need levels."[24] With the decisions of the ICC investigations this too has been clarified, and the accepted definition of the cost of capital is correct.[25]

Though the conceptual differences have been mitigated in the past year, considerable differences persist on the proper estimation of the cost of capital. These differences are in part attributable to the fact that actual estimation of the cost of capital is as much an art as a science, and in part to fundamental misunderstandings of the determinants of cost of capital.

The major problem area has understandably been the most difficult: the cost of equity capital, or the change in the return to equity holders

with respect to the change in their investment. A variety of approaches have been utilized, and estimates range between 9 and 16 percent as the 1978 nominal after-tax return on equity capital. The most comprehensive set of estimates is provided in a recent ICC investigation, Adequacy of Railroad Revenues, where estimates from 11.5 to 15.5 percent are presented. The high estimate of 15.5 percent is based on a comparable earnings study. Dr. J. Rhodes Foster looks at "returns being earned on book equities of unregulated undertakings having generally similar financial risks."[26] The reliance on book values, the failure to recognize variations in capital structure, and the imprecise determination of risk classes are sufficient grounds to discredit this estimate.[27] The second highest estimate, 14.1 percent, also presented by Dr. J. Rhoades Foster, incorrectly includes a full one percent margin for flotation costs, and can similarly be discredited.

The 11.5 percent estimate, presented by Dr. Shuman is based on an equity risk premium analysis, where equity risk premiums are added to current yields on long-term debt. Again, the data selected do not fully take account of risk and capital structure, and this estimate can also be discredited.

This leaves a range of estimates for the current cost of equity capital between 12.5 percent and 13.6 percent. Estimates within this range are based on two approaches: discounted cash flow and the capital asset pricing model. The capital asset pricing model has been justified on theoretical and empirical grounds, though it has not generally been accepted in utility rate cases to date.[28] Essentially, it adds the

risk-free interest rate and the "systematic" risk premium required by investors in the company. Under this formulation:

$$R_j = R_f + \beta_L * (R_m - R_f) + \varepsilon$$

where R_j = return on the jth asset

R_f = return on the risk-free asset

R_m = return on the market

ε = random disturbance term with usual properties

$$\beta_L = \frac{Cov(R_j, R_m)}{Var\ R_m}$$

Unfortunately, in the application of this formulation, two parameters, , the risk factor, and R_m, the expected market return, are inherently uncertain, and are in good part judgmental. In the ICC proceeding, Dr. Zepp estimates β as .87, based on his analysis of nine Class I railroads. In estimating the market risk premium (Rm - Rf), he groups the companies into portfolios, determines the betas for these portfolios, and performs a regression on the returns and the betas of the portfolios over several 50-year intervals. He calculates that the past market risk premium falls between 7.4 and 7.8 percent.[29] Using 7.0 percent as the nominal current yield on Treasury bills, his estimate of the after-tax, nominal cost of equity capital is:

$$7.0 + (.87 \times 7.6) = 13.6 \text{ percent.}$$

Another widely applied approach is the discounted cash flow method. Under this formulation:

$$R_j = \frac{D_{jo}}{P_{jo}} + g$$

where

R_j = equity rate of return

D_{jo} = dividend on the jth security in the current period

P_{jo} = price of the jth security in the current period

g = estimated future growth of dividends.

Application of this technique yielded estimates of 13.0 and 13.14 percent.[30]

This author applied the capital-asset pricing model to published data to test further Dr. Zepp's estimates. First, we must identify firms of homogeneous business risk. A sample of nine coal-carrying railroads, five from the West and four from the East, was selected. All railroads in the sample are diversified companies with 50 percent or more of their revenues accountable to rail, and all railroads are major coal carriers. Betas were obtained for this group of railroads from Value Line Investment Survey.[31] The betas ranged from .80 to 1.15.

To account for variation in capital structure, the levered betas were unlevered as follows

$$\beta_{unlevered} = \frac{\beta_{levered}}{1 + (1 - T) * D/E}$$

where T = .46, federal corporate tax rate

D = long-term debt

E = equity.

Note that several assumptions underly this adjustment: 1) the bond beta is zero, 2) the current debt/equity ratio is close to the firm's target D/E return, and 3) the firm's business risk has not changed

dramatically over the recent past. Conversations with financial analysts and railroad personnel indicate that these assumptions are in fact reasonable approximations of reality.[32] Total debt and equity were drawn also from the Value Line Survey.

Unlevered betas were averaged, then levered given the average D/E ratio. The risk-free rate, including 6.0 percent inflation, of 6.4 percent was drawn from Ibbotson and Sinquefield's study of return over the period 1929-1976.[33] Average risk premiums, as noted, are to some extent judgmental. One possibility is to use the average risk premium over a long period of time in the past as an approximation of expectations. Ibbotson and Sinquefield's estimate from 1929-1960 is 9.2 percent. This, however, may be too high for expectations. As a low bound, 6.9 percent is employed, based on Ibbotson and Sinquefield's expected return between 1976 and 2000. Based on this range, the minimum required nominal equity return for railroads, financed with the usual proportion of debt, is bounded by

$$R_j = 6.4 + .95\ (9.2) = 15.14$$

$$R_j = 6.4 + .95\ (6.0) = 12.10$$

with an average of 13.62.

Note from Table 5, however, that the calculated cost of equity capital is higher for the western roads, bounded by 12.34 percent and 15.51 percent, as compared with 11.68 percent to 14.50 percent for the eastern and southern railroads. This is attributable to the higher betas for western railroads, indicating higher risks. Nonetheless, other

Table 5

Cost of Capital Data

(millions of dollars)

Railroad	Total Debt	Net Worth	Debt/Equity	β_L	β_U
West:					
Burlington-Northern	1135.3	1950.7	.58	1.15	.88
Denver Rio-Grande	111.5	236.1	.47	1.05	.84
Santa Fe	760.2	1891.2	.40	1.00	.82
Southern Pacific	1145.7	1967	.58	.80	.61
Union Pacific	932.4	2286	.41	.95	.78
East:					
Chessie	1137.8	1221	.93	.85	.57
Illinois Central	1287.9	1206	1.06	.95	.61
Norfolk and Western	647.8	1236.5	.52	.80	.63
Southern	842.3	1105	.76	.90	.64

Total Sample	East	West
Average β_u = .71	.61	.79
Average D/E = .634	.82	.49
Average β_L = .95	.88	.99

Source: Value Line Investment Survey, "Ratings and Reports," March 21, 1979 and author's calculations.

financial evidence indicates that the risks for western roads are in fact lower than these high beta levels indicate and that increased coal traffic will generally contribute to an equalization of beta across territories. Since other beta estimates suggest no regional variations in betas, this difference should not be given too much credence.

The ICC accepted 13.0 percent on the basis of these proceedings. Given the judgmental nature of the estimate, we cannot base an argument on the small difference, and 13.0 percent is not unreasonable as a system-wide average. Nonetheless, possible variations in this estimate are conceivable.

The remaining calculations are by and large straightforward. An extensive study of marginal corporate bond rates estimated an 8.5 percent return. The average capital structure assumed was 40 percent, 60 percent, very close to the estimates obtained here (39, 61 percent).[34] The current average cost of capital is then:

$$(13.6 \times .6) + (.54 \times 8.5 \times .4) =$$

$$8.16 + 1.84 = 10.00$$

The ICC calculates the cost of capital on new investments as:

$$(13.0 \times .6) + [(1 - .46) \times 8.50 \times .4] = 9.66 \text{ percent.}$$

The ICC also calculates the cost of capital for net investment, or "investments that carriers were required to make at various times in the past to perform the services represented by rail form A service units."[35]. It is easy to be misled by this calculation. An immediate reaction is that the ICC is charging the oncoming service for investments that are "sunk," i.e., not incremental investments, and

therefore not appropriately included in incremental costs. In fact, these net investments are implicitly used as a proxy for the required incremental investments for "ordinary" traffic. Furthermore, they are expected to represent the long-run marginal costs of the service. Therefore, the return on net investment is a real concern.

As a practical matter, however, approaching the problem this way is complex. The ICC estimates the required return on net investment as:

(13.0 x .6) + (7.0 x .4) = 10.6 percent

The 7.0 percent represents the estimated current embedded debt rate, in contrast to the current marginal debt rate of 8.5 percent. The ICC does not adjust for taxes, as they did in the new investment calculation above. They justify this on the accounting grounds that the tax benefit from the inclusion of interest expenses is currently reflected in the income figure. Thus, they argue, the tax benefit is included in the capital return on investment, and there is no additional basis for reducing the cost of capital on net investment.[36] This argument could be correct, but it is virtually impossible to verify empirically. From a purely practical viewpoint, however, it is of little concern. That is, using 7.0 percent without a tax adjustment, or 8.5 percent with a tax adjustment generates a difference of less than one percent in variable costs calculation.[37]

Another problem with this approach is that applying current cost of capital to book values in order to approximate incremental investment is clearly flawed. Depreciated book values are almost certain to understate the costs of incremental investment. This problem suggests that we might

use a higher cost of capital to offset this underestimation, or different cost data based on actual incremental investment costs. This will be considered further below in our discussion of investment additives and related problems in the investment rate base. For a detailed analysis of another facet of the rate base question, see Appendix A.[38]

To conclude, the ICC has only recently accepted the use of current average weighted cost of capital. Even given this acceptance, there are still problems in actually determining the required rate. Inherent in the process is a not inconsiderable judgmental factor. The ICC figure, as any other precise figure, can be argued. However, on balance it is not unreasonable, and it is representative of the range of reasonable estimates. For our purposes their estimates will be accepted, although the sensitivity of costs to variations from 12 to 15 percent in equity return (and 9.04 to 10.84 in weighted capital costs) will be analyzed below.

EQUIPMENT COSTS

The second major issue to consider is equipment costs. Two problems dominate this controversy; the imputed price of new equipment, usually just locomotives and cabooses given the recent predominance of shipper-owned cars, and the calculation of "cycle" or "round-trip" times.

Regarding the imputed price of new equipment, the essence of the controversy is the nature of locomotive and caboose utilization. Basically, locomotives purchased ostensibly for an incremental unit-train service are not necessarily used exclusively for this service, but rather

are added to the railroad's "locomotive pool," which is then allocated over all services in an allegedly optimal fashion. The railroads contend that the proper cost of locomotives to impute to the new service is the price of the new locomotives. The utilities argue that since these new locomotives benefit other services as well, the average pool price, including the new locomotives, should be used.

The railroads are correct in theory. Given that a certain number of locomotive units are essential to this incremental service, the new locomotive purchase price should be used. The fact that other services might benefit from the utilization of an improved locomotive pool is irrelevant to the calculation of incremental costs.

However, what we cited as "given" above must be carefully scrutinized. That is, the nature of the procedure provides an incentive for the railroads to overestimate incremental requirements. Furthermore, with the continuous retiring and adding of locomotives, real incremental requirements are very difficult to estimate.[39]

Evidence presented in the coal-rate cases manifests this problem. In the Flint Creek case, the ICC decided in favor of the utilities that the average pool price is appropriate. However, the railroad's estimate of locomotive requirements was overstated, primarily due to an excessive backup-unit requirement of 30 percent. After correcting for the railroad's mistakes in the Flint Creek case, the ICC recommended use of 14.6 locomotive units, not the railroad figure of 17.65.

The second critical factor in calculating equipment costs is the calculation of round-trip cycle time, or the total round-trip time.

Clearly, this is an important calculation: the faster the cycle time, the less equipment is required to deliver a given annual volume. In theory, the appropriate calculation is clear. If investments in plant and equipment are undertaken to reduce cycle times, and corresponding net cost savings are realized, rates should be adjusted downward. The railroads would ideally estimate planned investment to reduce cycle times, estimate the net cost savings, and account for these savings in future rates. However, given that contracts between the railroads and the shippers have not been allowed to date, and given the consequent uncertainty in future investment patterns, the ICC has been reluctant to allow for future investments. The railroads have therefore advocated the use of current cycle times based on investments to date. Given the ICC constraint, this is a reasonable approach.

The utilities have advocated the use of future cycle times, yet they exclude the future investments required to obtain these lower cycle times in their cost calculations.[40] Clearly this is biased on the low side. Given the possibility of faulty investment reporting, the extent of this bias is unclear. That is, while we are interested in the past investments undertaken to bring cycle times to current levels, the railroads may include investments in fact expected to yield the lower future cycle times. Unfortunately, untangling this issue is no simple task. As we will see below, existing data do not allow for consistency checks on actual investment requirements versus stated investment requirements.

Another problem evidenced in this case, yet permeating other issues,

is the indivisibility of railroad plant and facilities. Investment undertaken today to decrease cycle times in the future will no doubt benefit more traffic than just the given unit-train service. This problem will also be considered in detail below.

Finally, the cost-of-capital percentage applied to equipment acquisition is important. The railroads advocate the weighted average cost of capital, 11 percent by their calculations. The ICC has decided that the rate on equipment trust certificates, 8.7 percent, should be used. In many cases, applying a particular rate for a particular type of financing is difficult. Even though a particular investment can be related to a specific source of financing, lenders may actually examine a firm's overall earnings potential and financial structure before deciding to accept security based on specific collateral. However, in this particular case, an alternative to issuance of equipment trust certificates is equipment leasing. The railroads do in fact lease equipment in many cases. Given this option, and the close correspondence between equipment purchases and equiment trust financing, 8.7 percent is a more realistic approximation.[41]

FIXED-PLANT INVESTMENT

The last, and possibly most intractable problem is the fixed-plant investment additive. We will briefly summarize the controversy. The railroads allocate funds each year to plant investments--track, roadbed, sidings, etc. First, they contend that these investments can be clearly separated between coal-related and non-coal related shipments. They note

also that given the fundamental indivisibility of railroad plant, the coal investment benefits not only a given service, but other coal shipments that utilize the same track segment(s). Therefore, they allocate the incremental coal-related investments over different coal shipments according to volumes carried.[42]

The utilities argue that these are not strict variable costs, but rather fixed costs that are properly allocated according to the averages in rail form A. For variable costs, they calculated this fixed-investment additive as zero. The ICC takes an intermediate stance. They state that in fact these are not "strict variable costs," but are also not properly reflected in rail form A and therefore should be included.

The solution to this controversy is not easy. In addition to extensive practical problems, there are real conceptual problems as well. First, investments undertaken for a particular service are part of LRMC. If the railroad spends X million dollars to move an incremental shipment, then this is properly included in long-run marginal costs. In theory, then, we would want to calculate the incremental fixed-plant investment for a particular service and account for this in the cost calculation.

Unfortunately, this straightforward approach is not possible, and the basic problem is plant indivisibility. Building a roadway that handles, say, 1.5 million tons for this shipment, then another for the next shipment is inefficient. In fact, a minimum-sized facility can handle far more than 1.5 MT.[43] Therefore, any investment for this incremental service will in fact benefit other potential users.[44]

In one sense the problems are similar to those for equipment cost. In that situation we noted the fact that benefits that were realized by other services were not relevant in determining the costs of the incremental service. In a strict sense, this is true here also. But the nature of fixed-plant investments forces a different interpretation from a practical viewpoint.

The problem is, in essence, the problem of joint-production costs, and as in all cases, there is no generally accepted way to allocate costs unless all of the traffic is coal. In theory, these variables costs may be synergistic, and so any division of them is by definition arbitrary. In practice, even if synergism was not a problem, it is impossible empirically to break down the indivisible investment into realistic unit costs.

The problems of allocation aside, investment strategies can also be disrupted. The railroads would prefer to estimate future coal flows, estimate related investments, and then to allocate them as above. However, the ICC prohibits this practice by failing to recognize future investments and traffic flows beyond five years. Consequently, the railroads have estimated coal flows five years in the future (i.e., 1983 for 1979 rate cases), and allocated investments, allegedly to support this 1983 traffic level, according to 1983 shares. This clearly creates problems. Specifically, it can be expected to have one of three effects. First, the railroads actually invest now only for traffic levels that will occur in five years. Given expected increases in coal flows, this practice is unlikely, and probably inefficient. Second, the

railroads invest according to long-run expected coal flows, and hypothetically separate this investment between what is actually required for 1983 levels, and what is required for post-1983 traffic levels. Third, the railroads invest today for traffic volumes beyond 1983, yet allocate the entire investment over 1983 traffic levels.

Clearly, all three outcomes are undesirable. The first is likely to be inefficient, the second is exceedingly arbitrary, and the third could place disproportionate burdens on 1983 traffic. In any case, the ICC has created serious problems in making this calculation.

Furthermore, there is no conclusive way to monitor this accurately, even given the ICC constraints. Clearly there are inconsistencies in the railroads' reports. In one case, over a 14-month interval expected investments were increased by substantial amounts, and at the same time expected traffic flows were substantially reduced.[45] However, monitoring the system beyond this is complex. Not only must output projections and investment requirements be monitored, but also the relationship between the two, and even the railroads do not fully understand these relationships.

This inherent difficulty is evidenced repeatedly in recent ICC decisions. In the San Antonio case, fixed-plant investments as estimated by the railroad were at one point reduced by 30 percent by the ICC. Later the commission admitted that this reduction was arbitrary, and was forced hesitantly to accept the initial figure.[46] In another case, Houston Light and Power, the ICC accepted the San Antonio estimate for 1976 investments, but not the Houston estimate for 1977 investments. As

a general case, the monitoring of this investment has proved to be extremely difficult, if not impossible.

In summary, the railroads' costs should include a component for fixed-plant investment additive. However, given the indivisibility in railroad plant, calculating specific traffic shares is by definition somewhat arbitrary. Finally, given ICC restrictions, calculation of shares is either inefficient or inequitable.

Another problem with the fixed-plant investment additive is more technical.[47] The utilities argue that the fixed-plant investment additive reflects double counting of coal-related investments. The ICC has acknowledged this possibility. In order to mitigate this error, they have attempted to ensure that investments specifically for coal traffic are excluded from the rail form A cost accounts. However, the utilities argue that this correction still overestimates investment costs. As noted above, the fixed-plant investment additive should represent the difference between incremental coal-related costs and the incremental costs of "normal" traffic increases. The incremental costs of a normal traffic increase are based on rail form A system-wide averages. So, if the incremental costs of coal shipments exceed the incremental costs of other shipments, we should add only the difference between the two. The utilities argue that even if coal-related investments are deducted from rail form A, costs can still be overstated since the railroad coal-related incremental investments represent not the difference between them and the normal traffic incremental investments, but rather represent the total incremental investment. In other words, the railroads calculate

first the normal incremental investment, and then add not just the extra amount due to coal, but the entire incremental coal investment. It is impossible to detect if this is in fact true, but written evidence indicates that the possibility should not be deemphasized.

To conclude, calculation of fixed-plant investment costs is inherently difficult, and the ICC has at least compounded these difficulties. There is substantial evidence that the railroads have not presented the most realistic estimates of incremental coal-related investment costs. There is also evidence that the ICC arbitration is biased towards excessive remuneration in a strict cost sense. However, given the basic uncertainty in the calculation, and the possibility of rail form A underestimation, adjustments to the ICC estimates cannot be based on a sound economic foundation. Furthermore, it is possible that even the railroads are underestimating their costs.

Given the well-established fact that railroads are spending large sums of money on coal, and given that system-wide averages would understate these coal-related costs, we draw the following conclusions. First, rail form A proxies for incremental investment costs certainly understate actual incremental cost for coal unit-train shipments, and possibly even incremental costs for normal traffic. Second, the fixed-plant additive will compensate for this possible understatement. Third, it is conceivable that these estimates combined will overstate incremental costs. Nonetheless, we have no concise foundation for reducing the ICC adjusted estimates given the inherent uncertainties in the calculations, and they will be reluctantly accepted.

SUMMARY

To summarize, there are many differences between the complainants and the defendants' variable cost estimates in the coal rate cases. Three issues, however, account for most of the variation: cost of capital, equipment costs, and fixed plant investment additive. In this chapter we have analyzed these differences, and found that the ICC position on them is justified conceptually in most cases. The current weighted average cost of capital is economically justified rather than embedded debt rates. Rail form A underestimates incremental investment costs, and current cycle times are reasonable to use given ICC restrictions on investment reporting. Only one specific detail of equipment cost estimation (where the ICC recommends imputing average pool costs rather than new equipment costs) is conceptually wrong.

Empirically, the adjustments to reflect these conceptual issues are more difficult to judge. In large part, the empirical issues are simply impossible to verify given data limitations. Nonetheless, there is no solid basis for allowing the ICC calculations, with the exception of equipment costs.

These detailed adjustments are summarized in Table 6 for the Flint Creek, Arkansas case. The railroad estimate of variable cost at the July 1, 1978 level is $8.55 per short ton. The utilities' estimate is $5.67 per ton. The ICC estimate, adjusted for equipment cost differences, is $7.31 per ton. Approximately 45 percent of the difference between the ICC estimate and the utilities' estimates is explained by using the current cost of capital versus the embedded debt rate. Another 32

Table 6

Flint Creek--Detailed Adjustments[1]

(current dollars)

	Railroads	SwepCo.	ICC
Terminal costs	$20.70	$9.35	$9.50
Line-haul costs	626.02	534.24	613.35
Loss and damage	.72	.73	.72
Additional MW+S[2]	20.26	0	0
Fixed plant investment			
1974	1.55	0	1.22
1975	1.80		1.45
1976	10.14		8.17
1977	17.39		13.90
1978	31.34		24.87
Equipment capital cost			
locomotive	113.51	20.23	54.03
caboose	2.04	.27	.50
Variable cost:			
per carload	846.07	564.82	727.72
per ton	8.55	5.67	7.31
Fully-allocated cost			
per carload	1096.11	0	966.41
per ton	11.08	0	9.70

NOTES: 1. July 1, 1978 cost levels.
2. Maintenance of way and structures.

SOURCE: Interstate Commerce Commission, Decision no. 36970, 36980, Decided May 21, 1979. Appendix II.

percent is accountable to the fixed plant investment additive.

Note that $7.51 per ton equals approximately 7.1 mills per ton-mile. From Chapter I, the predicted rate for shipper-owned equipment with operating parameters set equal to those on this movement is $8.42 for "old" shipments, and $10.55 for "post-1975" shipments, or 8 mills per ton-mile and 10 mills per ton-mile respectively. The rate allowed by the ICC was $10.24 per ton.

In the recent coal-rate cases, the ICC-adjusted estimates of variable costs have also been substantially below the railroads' estimates (see Tables 1 through 4). In the Moapa, Nevada case the railroad's estimate for railroad-owned equipment variable costs, was $7.48 per ton, versus $6.08 per ton by the ICC. In the San Antonio case, the railroad estimated shipper-owned equipment costs as $14.42 (8.8 mills per ton-mile) per ton, versus $11.84 per ton (7.2 mills per ton-mile) by the ICC. In the Sergeant Bluffs, Iowa case, the respective estimates were $7.35 per ton (9.8 mills per ton-mile), and $5.91 per ton (7.8 mills per ton-mile) for a 753 mile shipper-owned equipment shipment. Note also from Tables 1 through 4 that the ICC variable costs estimates are from 70 percent to 75 percent of the rate levels ultimately allowed by the ICC.

Given all of the uncertainties in this chapter, we cannot conclude with certainty that the variable costs estimated by the ICC are representative of long-run marginal costs. However, it is certainly reasonable to state that these estimates represent a lower bound to long-run marginal costs, and that rents between $2.00 and $4.00 per ton exist on unit-train shipments. Variable costs range from 7 to 9 mills per ton-mile for shipper-owned equipment, depending on distances.

COMPARISON WITH OTHER COST ESTIMATES

The validity of other unit-train cost estimates is generally difficult to ascertain. Most studies are not specific as to the basis for their estimates: Are they average costs or marginal costs, long-run or short-run; how do they treat capacity, how do they allow for rents in unit-train shipments? A 1976 evaluation of western unit-train costs by this author, adjusting as best we could for these problems, yielded a range of 6 to 8 mills in 1975 dollars for long-haul, high-volume shipments.[48] Updating to January 1, 1979 rate levels yields a range of approximately 8 to 11 mills per ton-mile for railroad-owned equipment.[49] The estimates in the higher range typcially did not distinguish between rents and costs, so real costs are more likely to be in the 8 to 10 mill range. Adjusting for shipper-owned equipment, this would be approximately 6.5 to 8.5 mills, which is consistent with our estimate from the rate case analysis of 7 to 9 mills per ton-mile.[50]

These studies were completed by 1976. Since then, two extensive analyses have been published. The first, by Michael Rieber et al., involved an extensive engineering/accounting analysis of track conditions and necessary expenses to move increased volumes of coal.[51] It admittedly represented the most pessimistic outlook for the railroads in that all infrastructure improvements were allocated over a volume of coal that was far less than full-capacity volume, and probably less than optimal capacity volume. For long shipments in railroad-owned equipment, he estimated unit-train costs from 7 to 9 mills per ton-mile. Escalated

to December, 1978 dollars, this equals approximately 8.5 to 11 mills per ton-mile.[52]

The other recent study was prepared by the Office of Technology Assessment as evidence for the unit-train, slurry-pipeline Congressional hearings.[53] The cost estimates were prepared by the General Research Corporation. As in Rieber's study, the methodology was an engineering/accounting analysis. Volume projections were provided by Teknetron. Given these, investment requirements were calculated for specific routes. Incremental cost estimates for four routes are shown in Table 7 for railroad-owned equipment in 1977 dollars. The low figure (5.7 mills) reflects a coal shipment with very high volume and long distance. Unfortunately, it was not possible to adjust these costs for lower tonnages. The Barstow, California, and Florida cases reflected tonnages closer to actual practiced tonnages. The costs, however, are higher due to poor terrain and extensive track upgrading required in these areas. The significance of this for export movements to the West coast should not be overlooked. It suggests that costs over undeveloped routes with poor terrain may exceed costs in other cases. In these cases, rates at existing levels might be required to recover costs. For example, the OTA estimated rate to Barstow, California equals about 12 mills per ton-mile in 1978. This is approximately equal to the railroad owned equipment rate estimated in Chapter I.

To conclude, these other cost estimates cannot be given too much weight. However, having made adjustments where possible, they at least contribute to our conclusions on minimum cost levels.

Table 7

OTA Unit-Train Cost Estimates

(1977 dollars)

Origin	Destination	Annual Tonnage (million tons)	Cost per ton (dollars)	Cost per ton-mile (mills)
Gillette, Wyoming	Houston, Texas	17	9.08	5.7
Colstrip, Montana	Becker, Minn.	10	5.37	7.1
Price, Utah	Barstow, Cal.	6	7.55	11.0
Tracy City, Tenn.	Tampa, Fla.	8	8.99	11.6

SOURCE: Office of Technology Assessment, Task Report: Slurry Coal Pipelines, Volume II, Part I, 1979.

EASTERN, MIDWESTERN, AND SOUTHERN COSTS

The last problem that confronts us is the estimation of costs in the East, Midwest, and South. As noted, the only significant case that has not dealt with western coal shipments involved the Potomac Electric Power Company. The focus of that case was narrower, and many of the issues raised above were not confronted. Consequently, the evidence presented does not allow for firm cost conclusions.

Another possible approach is to work off the ICC carload cost scale data.[54] With this data we can approximate unit-train costs according to regions. However, preliminary calcultions with these absolute data resulted in estimates for the West far different from those presented in the coal rate cases. The reason for this must be that a significant number of actual marginal cost data were substituted for rail form A data in the Western rate cases. In any event, direct calculations of this type are not reasonable.

Instead we could look at the relative difference in costs over regions. Analyzing the ICC carload cost scales (adjusted for unit trains) showed that costs in the West are approximately the same as for the South and the Midwest. Eastern costs were some 13 percent higher.[55] However, given the generally shorter distances in these other regions, we cannot apply this information directly without a better understanding of distance, cost relationships.

Given these problems, the best alternative action is to apply results of a study undertaken by M.B. Zimmerman, with assistance from

this author.[56] Zimmerman estimated unit-train costs by regressing 1970 unit-train rates on the cost variables described in Chapter I, and a rent variable. The hypothesis underlying the specificaton of the rent variable was that alternative fuels, in this case natural gas, provided a backstop to the delivered coal prices. The rent variable represented the difference between the delivered price of the alternative fuel and the delivered coal price, including transportation cost. The coefficient of the rent variable represents the random proportion of this appropriable rent that is actually appropriated by the railroads. Using Zimmerman's notation:

$$(1) \quad t = \hat{t} + \beta(\text{PGAS} - \text{FOB coal} - \hat{t})$$

where

t = tariff per ton

$\hat{t}$ = the cost of the shipment

Since β depends on an indeterminate bargaining situation between the railroad and the utility, β itself is a random coefficient. Thus:

$$(2) \quad t = \hat{t} + (\bar{\beta} + \eta)(\text{PGAS} - \text{FOB coal} - \hat{t})$$

where $\bar{\beta}$ is the expected value of β and the term η reflects the indeterminacy of the bargaining process. Rewriting equation (2):

$$(3) \quad t = \hat{t}(1 - \bar{\beta}) + \bar{\beta}(\text{PGAS} - \text{FOB COAL}) + \eta(\text{PGAS} - \text{FOB COAL})$$

Adding the components of $\hat{t}$ to (3) yields

$$t = \alpha_0 + \alpha_1(1 - \bar{\beta})M + \alpha_2(1 - \bar{\beta})\,\text{IMAT} + \alpha_3(1 - \bar{\beta})L + \bar{\beta}(\text{PGDD})$$
$$+ [\eta(\text{PGDD} - \alpha_0 - \alpha_1 M - \alpha_2 \text{IMAT} - \alpha_3 L) + \varepsilon]$$

where t = tariff in dollars per ton

IMAT = 1/minimum annual tonnage in thousands

L = loading plus unloading time

PGDD = (price of gas - price of coal FOB mine), in dollars per ton of coal

PGAS = price of natural gas delivered to the utility

FOBCOAL = mine mouth price of coal.

Zimmerman's estimation revealed that in both the East and Midwest the railroads were able to appropriate a significant piece of the possible rent, 19 percent in the midwest, and 22 percent in the East. In the Midwest the rents were, on average, 32.8 percent of the tariff, versus only 1.3 percent in the East. This was due mainly to the higher gas prices in the Midwest.[57]

This model provided an explanation for rates as of 1970. However, after 1970 natural gas shortages began to develop in wholesale markets, and the price of natural gas no longer reflected an alternative to electric utilities. After 1973, oil prices jumped and nuclear power problems cumulated. For current purposes, the interfuel competition model as specified by Zimmerman is not realistic.

However, in the East and the Midwest there is reason to believe that the rate structure in 1970 holds today. Once the rate pattern is established, the ICC has made it difficult to introduce a newly patterned rate. In fact, Zimmerman's work has shown that very few new rates have been posted since 1970 in the East, South and Midwest, and those that have been posted since 1970 are not significantly different from the

existing rate structure. In other words, the current rates should be equal to the 1970 rates escalated according to cost increases, independent of the changes in the competitive structure. Consequently, escalating the cost components estimated for the 1970 sample to January 1, 1979 cost levels should be a reasonable approximation of the current costs for Eastern, Southern, and Midwestern shipments. Based on Zimmerman's calculations, assuming minimum annual tonnages equals 1 MT, and that loading plus unloading times equal 24 hours, the estimated costs at January 1, 1979 levels for 250, 500, and 1000 mile shipments are, respectively, $3.60 per ton, $6.22 per ton, and $11.50 per ton.[58] Note that for the 1000 mile shipment, the cost is in fact higher than our estimate of western costs with railroad-owned equipment of $10.00 per ton. We will use these cost levels for the integration below.

SUMMARY

To conclude, the issue of cost estimation is, above all else, confusing. However, it is important to understanding future developments in both domestic and export steam coal markets. In this section we have analyzed the materials in the recent coal rate cases to add conceptual and empirical understanding about unit-train costs. There are many complexities and uncertainties that we cannot resolve, but the conclusions that rents are substantial in all regions of the United States and that variable costs on long-run shipments with shipper-owned equipment in the West range from 7 to 9 mills per ton-mile at January 1979 cost levels are

reasonable. In the East, South, and Midwest, rate patterns are more easily defined and costs can be approximated from earlier analyses by Zimmerman. Though we cannot specify with certainty absolute rent levels, there is clearly the possibility of rates being lowered, and still covering long-run marginal costs. The significance of these possible reductions for export steam coal markets will be analyzed below.

As noted in this chapter, the rates allowed by the ICC have been far higher than variable costs, and even above fully-allocated costs. In fact, costs are only one factor used by the ICC in rate determination. The next chapter analyzes other important factors.

APPENDIX A

FURTHER NOTES ON COST-OF-CAPITAL ESTIMATION

A few further notes related to the cost of capital estimation are important. First, when a particular road is evaluated, the cost of capital may well vary according to variation in risk and capital structure. The railroads have noted this problem, and suggested plugging in the particular capital structure in the estimating equation. The ICC has rightly rejected this approach. The reason is that the cost-of-equity capital will also vary depending on capital structure. Therefore, using the system-wide cost of equity capital with specific capital structure inputs will yield unreliable results. Given the problems of estimating the cost-of-equity capital, the ICC has advocated using one estimate in all cases and has accordingly enforced input of system-wide capital structures.

Another pending controversy in determining the cost of capital on existing investments is whether to apply the current nominal cost of capital, or some higher rate to compensate for using original book values in the existing rate base.

The railroads' case, as presented by Foster, is that employing original costs does not adequately account for the effects of inflation.[1] He acknowledges the difficulty in applying a "fair value rate base," and instead advocates utilization of a higher cost of capital. His argument is essentially that the regulated firms' employment of original costs puts investors at a disadvantage over investors in

unregulated industries. He advocates, in particular, a rate of return on equity based on a study of comparable earnings in unregulated firms. He estimates the 1978 nominal return on equity capital at 15.1 percent, versus the 13 percent estimate based on other approaches.[2]

Dr. Foster's inclinations are correct. Using original values for property can create problems.[3] However, his treatment of the issue is flawed in several respects.

Foster considers a $1000 initial investment, an 8 percent real expected return, and a 6.5 percent annual inflation component. In the regulated case, using original book values, he notes that each year the investor will receive 14.5 percent of $1000, or $80 in real return, $65 as an inflation component. In the unregulated firm, he notes that the first-year return will also be $145, however, in the second year, the investor will receive 14.5 percent on $1065 (the inflated base) or 15.2 percent on $1000. He contends, based on this scenario, that the unregulated firms' investor is at a disadvantage and is not being compensated for inflation.

The ICC replied that if those who made:

> "the investment received a return on it over the years equal to the market value cost of capital, they would be compensated for the decline in the purchasing power of their book equity. That is, since the market value of capital rises with inflation, the earnings would have contained an inflation factor. Had the portion of their money been reinvested, the basic equity would have increased over the years."[4]

Foster acknowledges this fact in part. Given this reinvestment of the inflation premiums, he states that "the same situation as under competition" would obtain.[5] However, he argues that this

reinvestment represents an economic sacrifice on the part of the investors that should not be expected. "Why should the equity owners of the railroad be asked to make a sacrifice not made by investors in unregulated enterprise."[6] In fact, this reinvestment is not an economic sacrifice, but rather a rational use of funds. Foster's example of an investor using these funds instead for "personal gratification," is not a sound economic example. In fact, we could argue that just as much a sacrifice is made by the unregulated investors, where the inflation premium is held by the firm and not available for reinvestment.

A more basic problem with Foster's presentation is the calculations themselves. Foster assumes that the 14.5 percent return is based each year on the following:

$$1000(1.065)^{n-1}$$

Therefore, in year 2 the unregulated firm's investors receive (.145) x (1065). This is clearly speculative. The 1000 initial investment represents the discounted present value of the expected future returns. Inflation in year two of 6.5 percent does not necessarily mean that this discounted present value will increase to $1065. In fact, depending on market conditions, this $1000 could be $1500 or $500 or any number within a reasonable range. That is, the rate base in each succeeding year is not simply the inflated rate base, but the current market value of the initial investment.

Furthermore, to the extent that replacement costs might be a reasonable approximation of current market value, Foster's calculations

are again unfounded in theory. We are interested in the replacement costs of the asset as it stands in year n, not as it stood in year 1. That is, the base must be adjusted for depreciation. Therefore, even if current market values reflect closely replacement costs, Foster's simple approximation of replacement costs is unjustified.

Note that it is important to know the relationship between book value and current market value. Current market value will usually exceed book value, so higher returns would be justified. However, data constraints prohibit us from more than speculating.[7]

Now, one more problem should be considered. Foster assumes that inflation will be constant, and that this constant rate will be equal to expectations. In fact, this may not happen. For example, inflation may exceed expectations in one year, but return to normal the next year. This type of shock does in fact hurt the investors in the regulated firm, but it also hurts other unregulated investors, for example, bond holders. The question of whether this represents "fair treatment" is judgmental, and, as Meyers has noted, depends on the understanding of the investor-regulator pact.[8] If we presume that regulators should absorb all risks of inflation, then using book value in certain circumstances is unfair. If not, then it is fair. Since unregulated firms do not absorb all the risks of inflation, and furthermore, since if inflation is lower than expected in a given period the regulated firms investors can gain, it is difficult to argue that use of original book values is "unfair."

Finally, after arguing for a higher cost of capital, which could be but is not necessarily justified, Dr. Foster employs a comparable earnings study of unregulated industries to estimate this higher cost of capital. Given the inherent flaws in this approach, even had his other arguments been accepted, it would be difficult to base conclusions on evidence such as this.

Finally, it should not be inferred from this appraisal that using book values as opposed to current market values does not present problems. Actually, if current market values do not equal book values, then resources will be misallocated.[9] However, this is not the same as saying that investors are necessarily unfairly treated, or not compensated for inflation by using original book values in the rate base. In fact, they could conceivably be better off because of it. In addition, as noted below, this does not suggest that using current cost of capital with book values will not underestimate incremental investment costs. On the contrary, it most certainly will. However, as we will see below, incremental investment costs are accounted for in other ways as well, and the overall treatment of incremental investment is complicated in many other ways.

FOOTNOTES--CHAPTER II

[1]Several important studies that emphasize the difficulties in railroad cost estimation are:

a. Friedlaender, A., The Dilemma of Freight Transportation Regulation, The Brookings Institution, Washington, D.C., 1969.

b. Griliches, Z., "Cost Allocation in Railroad Regulation," in The Bell Journal of Economics and Management Science, Vol. 3, Spring 1972, pp. 26-41.

c. Kneafsey, J., "Costing in Rail Operations; a Proposed Methodology," MIT Studies in Railroad Operations and Economics, Vol. 13, 1975.

d. Meyer, J., Peck, M., Stenason, J., and Zwick, C., The Economics of Competition in the Transportation Industries, Harvard University Press, Cambridge, Mass., 1959.

e. Borts, G.H., "The Estimation of Rail Cost Functions," in Econometrica, Vol. 28, No. 1, January 1960, pp. 108-131.

f. Keeler, T., "Railroad Costs, Returns to Scale, and Excess Capacity," in Review of Economics and Statistics, 56, May 1974, pp. 201-208.

g. Spady, R.H., "Econometric Estimation of Cost Functions for the Regulated Transportation Industries," MIT PhD Thesis, Department of Economics, September 1978.

[2]Note that with respect to the direct estimation of long-run marginal costs, this is not so serious a problem. However, the problem of calculating the proportion of the long-run investment chargeable to short-run traffic flow is critical to evaluating the ICC coal rate cases, and consequently, critical to our investigation of costs.

[3]See Spady, Griliches, Borts, Kneafsey, and Keeler, op. cit.

[4]See Meyer et al., op. cit., pp. 18-32.

[5]See also a recent criticism of statistical estimation of railroad cost functions. Daughety, A. et al., "A New Approach to Railroad Cost Estimation," Transportation Research Forum, Vol. XX, no. 1, 1979, pp. 188-197. The major criticisms raised are the basic deficiencies of the ICC accounts that have been used in most previous analyses. In particular, the ICC data ignores network complications, quality of service, and allocates costs arbitrarily. In this study a new data set is compiled from actual firm data.

[6]See Zimmerman, M.B.., "Rent and Regulation in Unit-Train Rate Determination: Regional Discrimination and Inter-fuel Competition," MIT Energy Laboratory, June, 1978.

Charles River Associates, "The Economic Impact of Public Policy on the Appalachian Coal Industry and the Regional Economy," June 1972, pp. 3-20.

Friedlaender, A., Fergusen, W., and Sloss, J., "The Rate Structure of Unit Coal Trains in the 1970s," MIT Center for Transportation Studies, November 1978.

[7]See Meyer et al., op. cit., pp. 18-32.

Gordon, R., "Transportation and the Future of Coal," Pennsylvania State University, University Park, Pennsylvania, Unpublished paper, 1976.

[8]For a full explanation of ICC costing procedures, see:

"Explanation of Rail Cost Finding Procedures and Principles Relating to the Use of Costs," ICC Statement no. 7-63, November 1963.

For a description of recent modifications, see:

"Railroad Carload Cost Scales, 1975," Statement no. ICI-75, February 1978.

Also see:

Peat, Marwick, Mitchell and Co., "Rail Carloads Costing and Evaluation of Alternatives," undated.

[9]First, their method for dividing fixed costs between passenger service and freight service is based on revenues and is arbitrary. For our purposes this is unimportant, because, with the exception of Conrail, passenger operations now account for less than 1 percent of total operating expenses for major coal railroads. Second, joint variable costs present problems. In this case, they are grouped with all variable costs and allocated over different service units depending on the expense account. This is to a degree arbitrary and is not necessarily representative of incremental costs. That is, as noted above, savings through synergism may exist in part simply because investment is not disaggregated over individual service units. Therefore costs cannot be meaningfully split between service units. The costs necessary to move a particular output level may be significantly different from the costs allocated ex post over all service units. The very nature of these joint-production costs makes it difficult to say whether they would or would not exist for different output levels. Also, different capacity utilization in a given period could yield different unit costs than in another period. Finally, independent of theoretical constraints, meaningful determination of incremental costs is empirically intractable.

Nonetheless, the treatment of joint-variable costs as updated by the ICC is as consistent as any and is more an empirical issue than a theoretical one. Though the problem should not be ignored in any case and will be confronted in detail below, this is not one of the major criticisms with the ICC procedure per se.

Another problem is the allocation of fixed costs over output units. Again, this is by nature arbitrary. The ICC has traditionally allocated fixed costs over tons and ton-miles (See ICC statement no. 7-63, op. cit.). Recently, however, they have accepted what they call the "dollar" or "ratio basis." Total railroad costs are divided by variable costs, and this set percentage is used to mark up variable costs to fully-allocated costs for all commodities. The ton, ton-mile basis places a heavier burden on high-density shipments, such as coal, and consequently yields a far higher fully-allocated cost estimate. In the recent coal cases, both the ICC and the railroads have accepted the ratio basis as more reasonable.

[10]A careful analysis of the research underlying the original percent-variable determination (ICC Statement no. 7-63, Ch. 2) shows that the system-wide percent variable of 80 percent was based on several arbitrary decisions relating both to the sample selected and the averaging procedure. In fact, the 80 percent figure was the lowest estimate over a variety of approaches. In other words, even accepting the ICC methodology in a general sense, their ultimate choice of percent variable was curious at best and certainly not adequate for basing cost estimates on.

[11]See ICC Statement ICI-75, op. cit., pp. 154-155.

[12]The mechanism for doing this is deflation of the output and expense variables by miles of road for the estimation of the regression coefficients. In a statistical sense this approach is not unreasonable. If total costs are a function of size and not just tons of traffic, deflation can reduce a three-variable problem to a two-variable problem, and reduce the influence of sheer size on the estimation. However, it has been shown that even in a statistical sense deflation by size is not justified, and creates more problems than it solves (see Griliches, p. 31, op. cit., and Kuh, E. and Meyer, J.R., "Correlation and Regression Estimates when Data are Ratios," Econometrica, Vol. 23, No. 4, October, 1955, pp. 400-16). It could also be argued that errors increase with size, and this adjustment would mitigate the problem of heteroskedasticity. However, this again has been shown to be a minimal concern and, furthermore, deflating by miles (which implicitly weights miles by $1/m^2$) is not an efficient proxy for weighting (see Griliches, Borts, op. cit.). In summary, though deflation by miles can be appropriate in some cases, the approach used by the ICC has been shown to be biased and inefficient.

[13]Interstate Commerce Commission, Bureau of Accounts, "Financial and Operating Statistics--Class I Railroads," Statement no. 100, 1976.

[14]ICC Statement no. 7-63, op. cit., p. 3.

[15]Grilliches, op. cit.

[16a]There is still the possibility of variation in the percent variable for particular railroads, and therefore a danger in using any system average. Ideally, we would like to estimate the percent variable for a given road. Unfortunately, this was not possible given data constraints. Another possibility was to gauge the biases over particular railroads. Output variables were available for analysis. Some territorial variations did exist, but there was no overall evidence of territorial bias after excluding roads with less than 1000 miles of roadbed. There was significant variation over individual roads in most output groupings. However, the overall bias was impossible to specify given the lack of corresponding expense data. The ICC's detailed investigation of percent variable (ICC St. No. 7-63, op. cit.) showed little variation territorially over large railroads.

Another important observation about the ICC method of calculating fully-allocated costs is the nature of capacity utilization. As we will see below, it is likely that excess capacity exists in many areas of even large railroad operations and that this is not due to coal traffic problems. Accordingly, if these problems were mitigated, even given ICC costing procedures, the percent variable would be even larger and total costs would be smaller.

[16]Railroad Revitalization and Regulatory Reform Act of 1976, Public Law 94-210.

[17] 1) Interstate Commerce Commission, Decision no. 36180, San Antonio, Texas acting by and through its City Public Service Board versus Burlington Northern, Inc., et al. Decided May 23, 1979.
2) ICC, Decision no. 36579. Houston Lighting and Power Company versus Burlington Northern, Inc. et al.
3) ICC Decision no. 37038, Bituminous Coal, Hiawatha, Utah, to Moapa, Nevada, Nevada Power Company versus Union Pacific Railroad Company and Utah Railway Company, Decided July 31, 1979.
4) ICC, No. 36608, Incentive Rate on Coal--Cordero, Wyoming to Smithers Lake, Texas, Decided November 30, 1977.
5) ICC Decision, I and S no. 9199, Unit Train Rates on Coal, Burlington Northern Inc, Includes No. 37021, No. 36944 (Iowa Public Service Company vs. Burlington Northern, Inc., et al.). Decided July 13, 1979.
6) ICC, Decision no. 36970, Annual Volume Rates on Coal--Wyoming to Flint Creek, Arkansas; No. 36980, Southwestern Electric Power Company versus Burlington Northern, Inc., et al. Decided May 21, 1979.
7) ICC, no. 36792, Incentive Rate on Coal, Belle Ayr, Wyoming to Council Bluffs, Iowa. Decided June 15, 1978.

[18]ICC Decision, Docket no. 36114 (sub. no. 1), Potomac Electric Power Company vs. Consolidated Rail Corporation. Decided April 10, 1979.

[19]See Chapter III.

[20]ICC Decision no. 36970, 36980, op. cit., pp. 44-45.

[21]ICC Decision no. 36579, Rebuttal Statement of Fact and Argument of Complaintant, Houston Lighting and Power Company, pp. 289-302, August 8, 1977. Also see Rules to Govern Assembling and Presenting Cost Estimates, 377 ICC 298.

[22]ICC Decision, ex parte no. 353, op. cit., decided December 1, 1978.

[23]ICC Decision no. 36579, Rebuttal Statement, op. cit., pp. 289-302.

[24]ICC Decision no. 36970, 36980, op. cit., p. 12.

[25]ICC Decision, ex parte 353, 338, op. cit.

[26]ICC Decisions, ex parte 353, December 1, 1978, op. cit., pp. 22-32.

[27]Ibid., pp. 29-31. See also Meyers, S.C., "Finance Theory in Rate Cases," in The Bell Journal of Economics and Management Science, Vol. 3, No. 1, Spring 1972, pp. 58-97.

[28]See Meyers, op. cit., and Haley, C.W. and Schall, L.D., The Theory of Financial Decisions, Second Edition, McGraw-Hill, New York, 1979.

[29]ICC Decision, ex parte no. 353, December 1, 1978, op. cit., pp. 17-18.

[30]See Haley and Schall, op. cit.; Meyer, op. cit.; for justifications of this approach.

[31]Value Line Investment Survey, "Ratings and Reports," March 21, 1979.

[32]Layton Smith, Salomon Brothers, New York, N.Y.

[33]Ibbotson, R. and Sinquefield, R., "Stocks, Bonds, Bills, and Inflation: Simulations of the Future (1976-2000)," in Journal of Business, 1976.
Ibbotson, R. and Sinquefield, R., "Stocks, Bonds, Bills, and Inflation: The Past (1926-1976) and the future (1977-2000)," in Financial Analysts Research Foundation, 1977, p. 57.

[34]ICC Decision, ex parte no. 338, op. cit. Decided January 31, 1978.

[35]ICC Decision no. 36970, 36980, p. 32.

[36]ICC Decision, ex parte no. 353, p. 6.
ICC Decision no. 36970, 36980, p. 34.

[37]For example, in the Flint Creek case (ICC Decisions no. 36970, 36980), using 10.6 percent cost of capital, the return on net investment amounted to approximately 70 cents per ton, or approximately 10 percent of variable costs. Using 9.6 percent cost of capital, the return on net investment equalled 63 cents. The difference of 7 cents equals 0.8 percent of variable costs.

[38]For a detailed analysis of another facet of the rate base issue, see Appendix A.

[39]For example, see ICC Decision no. 36608, op. cit., p. 8.

[40]The difference is often substantial. Due to important infrastructure expansions, the future cycle time in the Flint Creek case was projected to be 112 hours, versus the current cycle time of 199 hours. This is, however, an extreme case. See ICC Decision no. 36970, 36980, pp. 19-20.

[41]See Bierman, H. and Smidt, S., The Capital Budgeting Decision, MacMillan Publishing Co., Third Edition, 1971, p. 144.

[42]This is not necessarily a contradictory statement. Certain investments are made on track segments used exclusively for coal. Also, it is often true that track strengthening is undertaken only for coal shipments, even though other commodities may use the same route segment. Neither of these instances contradicts the basic indivisibility of railroad investments.

[43]For example, a single track with 2-mile sidings at 40-mile intervals can handle between 5 and 8 trains in each direction each day. This would allow as much as 70 MT throughput per year. For analyses of railroad capacity, see:

a. DeSai, S. and Witten, J., "Rail Transportation Requirements for Coal Movements in 1985," U.S. Department of Transportation, December 1978.

b. Manalytics, Inc., "Coal Transportation Capability of the Existing Rail and Barge Network, 1985 and Beyond," Electric Power Research Institute, September 1976.

[44]Note again that this concern is not important to the direct estimation of LRMC. It is, however, critical to the evaluation of the ICC rate cases, and consequently is important to our indirect estimation of LRMC.

[45]See ICC Decision no. 36579, op. cit., pp. 320-323.

[46]ICC Decision no. 36180, pp. 15-16. Decided October 19, 1978. ICC Decision no. 36180, pp. 4-5. Decided May 23, 1979,

[47]Beyond this are additional technical problems. First, the utilities argue that these investments should be allocated over all services, not just coal services. However, if investments are undertaken strictly for coal, the utilities' position is wrong. The evidence suggests and the ICC accepts the conclusion that the railroads would not have made "these investments but for unit coal train service." (ICC Decision no. 36870, p. 18)--"these" investments meaning the difference between the large coal-related investments (track reinformcement, for example) and system average fixed plant investments. As the ICC notes, "other shippers do not require, nor have they asked for, this level of service. It would be unfair to present them with a share of the bill." (p. 18, ICC Decision no. 36970).

Second, the utilities and the ICC question the railroads' calculations of the betterment portion of improvements included in operating expenses. This betterment portion is treated as a capital item. "This means that when 90 lb. rail is replaced with 132 lb. rail, the 42 lb. difference (called the betterment portion) is treated as a capital investment. The remainder is charged to the operating expense accounts, and would have to be made without coal traffic. Furthermore, a portion of the operating expenses should be allocated to non-coal traffic." (pp. 37-39, Appendix C., ICC Decision no. 36970). The ICC makes a minor adjustment in this proportion in favor of the utilities. They also make an adjustment for the railroads' "improper" adjustment for the depreciation tax shield (pp. 39-41). Both these issues are straightforward and minor factors. They need not be discussed in detail.

Third, one special case, Sergeants Bluff, Iowa, presented a unique problem in the allocation of investments. In this case, the utility had an option to terminate the contract with their coal supplier after a five-year period. Given this, the railroads argued that the service should be charged for all these investments in the five guaranteed years. The ICC majority position was that 20 years was more appropriate in that the five-year annuity would create the possibility of double-charging at later dates. The minority position was that the five-year period was in fact reasonable. Though a unique situation, this too shows up the basic problems in monitoring the system.

[48]Sargent, op. cit., pp. 30-52.

[49]Based on the AAR index change from 1975 to 1978.

[50]For data on car ownership costs, see:
ICC Decision no. 36970, 36980, op. cit.
ICC Decision no. 36180, op. cit.
ICC Decision, I and S 9199, op. cit.

[51]Rieber, M., "Comparative Coal Transportation Costs: An Economic and Engineering Analysis of Truck, Belt, Rail, Barge and Coal Slurry and Pneumatic Pipelines," Illinois University at Urbana, Champaign, August 1977.

[52]It should be noted that Rieber has provided cost evidence for railroads in the slurry pipeline debates. His original estimates were far below any other estimates, which of course benefited the railroads' case. The work was flawed, and his updated estimates adjust for these flaws, so the initial estimate itself is meaningless. It does represent an interesting example of the railroads' having their cake and eating it too.

[53]Office of Technology Assessment, Task Report, "Slurry Coal Pipelines," Vol. II, Part I, January 1978.

[54]ICC, "Rail Carload Cost Scales," Statement no. ICI-75, 1975.

[55]Ibid.

[56]Zimmerman, 1978, op. cit.

[57]This difference is also due to the shorter shipment distances in the Midwest.

[58]The equation used in these results is one developed by Zimmerman and this author for the combined Eastern, Midwestern shipments. The results are not significantly different.

FOOTNOTES--CHAPTER II--APPENDIX A

[1]It should be noted that the following analysis focuses on the particular issue of whether the use of book values for net investments handicaps investors in the regulated firm in that it does not account for inflation. In particular, it appraises Dr. Foster's argument for a higher cost of capital to compensate for this problem. It does not confront the closely-related issue of net investment as a proxy for incremental costs. As we will see in a later section, we might advocate a higher imputed rate of return to adjust for this problem. Note finally that Foster's argument for return on old investments is not per se appropriate as an incremental cost. The railroads and the ICC seem to have lost sight of this fact. That is, to the extent that other proxies are used for incremental investment costs, calculation of return on net investment is incorrect, no matter what cost of capital estimate is selected.

Foster's arguments are presented in: ICC, ex parte no. 363, The Fair Return Component of Adequate Railroad Revenue Levels, 1979 Determination, Verified Statement of J. Rhoads Foster, June 1976.

[2]Ibid., pp. 88-108.

[3]See, for example, Meyers, op. cit., Morton, W., "Guides to a Fair Rate of Return," Public Utilities Fortnightly, Vol. 86, no. 2, May 1952, pp. 91-131.

[4]ICC Decision, ex parte no. 353, op. cit. Decided December 1, 1978, p. 34.

[5]ICC Decision, ex parte no. 363, op. cit., p. 76.

[6]Ibid., p. 97.

[7]One interesting specification of the problem is presented by Meyers. He shows how in competitive equilibrium the current market value (CMV) will be related to book value (BV) as LRMC is to LRAC. If, as the railroads generally contend, LRAC is greater than LRMC, then BV would in fact be greater than CMV. Meyers, op. cit., pp. 85-86.

[8]Ibid., pp. 79-82.

[9]Ibid., pp. 79-87.

CHAPTER III

THE INTERSTATE COMMERCE COMMISSION AND RAILROAD COAL-RATE DETERMINATION

INTRODUCTION

The previous chapter analyzed costs of unit-train shipments of coal. While some uncertainties exist, the evidence supports the conclusion that long-run marginal costs are substantially below railroad rates.

To reinforce this conclusion, and to provide additional insight into ICC regulatory policies and practices, this section will consider the same problem from a different perspective. Where before we asked: "Can rates be explained by costs alone?" we now ask: "Can we reject the hypothesis that rates are partly explained by rents?" Our answer is a resounding no. In fact, as we will see, the railroads advocate and the ICC explicitly allows rates to exceed even Rail Form A fully-allocated costs. In addition to demonstrating this practice, the possible justifications for this practice will be analyzed.

THE INTERSTATE COMMERCE COMMISSION: PAST PRACTICES

Interstate Commerce Commission policies have been thoroughly analyzed. Their inconsistencies and inefficiencies have been documented and there is no need here for an extensive reconstruction of the important arguments. Most authors conclude that restrictions on entry and abandonments, and minimum and maximum rate regulation have decreased competition and induced significant inefficiency in the provision of

transportation services.[1] Nonetheless, a few general points pertinent to our analysis should be made prior to the discussion of the ICC's actions in the recent coal-rate cases.

First, though the initial intentions of Congress are debatable and though the written intentions of the Interstate Commerce Act and related amendments are chronically ambiguous, it is generally accepted that in practice the ICC has been primarily committed to first establishing and then reinforcing the position of the railroads in freight transportation.[2] The most recent amendment to the Act, the Railroad Revitalization and Regulatory Reform Act of 1976 (4R Act), is the last of many amendments designed to protect, enhance, or restore the position of the railroads.[3] Its stated purpose is to:

> Provide the means to rehabilitate and maintain the physical facilities, improve the operations and structures, and restore the financial stability of the railway system of the United States.[3a]

In fact, as will be seen below, the rate-making and regulatory reforms (or the interpretation of these reforms) contained in the 4R Act have been the catalyst for the current controversies over coal rates.

CONTROL OF ENTRY

Second, the most powerful tool that the ICC has used to protect the railroads (though not always successfully) has been the control of entry. Starting with the Transportation Act of 1920, which gave the ICC the authority to limit the establishment of new railroads and to control the extension and abandonment of railway lines, and continuing through the 1940 National Transporation Policy Act, which added entry control of

water carriers to that of trucks and rail, the ICC has been committed to using this mechanism to "protect" the railroads and other modes from each other and from external competitive threats.[4]

In the ICC's words:

> It has consistently been held that existing carriers should be afforded the opportunity to transport all the traffic which they can handle adequately, economically, and efficiently in the territory they serve before a new service is authorized.[5]

On occasion the Supreme Court has criticized these policies. In a 1957 decision, for example, the Court overturned an ICC decision because:

> To reject a motor carrier application on the bare conclusion that existing rail service can move the available traffic, without regard to inherent disadvantages of the proposed service, would give one mode of transport unwarranted protection from others.[6]

Nonetheless, the interpretation of "inherent advantage" has never been clearly specified, and evidence suggests that restrictive policies persist.[7]

Not surprisingly, the situation that has obtained is one where the railroads frequently have exclusive access over a given origin-destination group. Of course this is partly explained by the nature of railroad operations--though railroads may not be natural monopolists in a strict sense, optimal plant size in some markets would justify service by only one railroad, independent of controls.[8] However, the ICC has reinforced the railroads' monopoly position.

A recent National Coal Association (NCA) study analyzed in detail the extent of railroad monopoly power for coal shipments.[9] It defines "captivity" as existing when both:

1) a single rail carrier represents either the only present transportation alternative for the entire shipment, or a substantial share of the routes for the shipment in question; and

2) the next best future transportation alternative (other rail carriers or other modes) is one that would cause injury to the shipper's competitive position if forced to adopt that alternative.[10]

The NCA determined that 93.81 percent of western unit-train shipments, 89.22 percent of shipments originating in the central United States, and 92.58 percent of Appalachia shipments are captive under this definition. Clearly, this is not a rigorous definition of monopoly power. Geographic and product competition are ignored. Nonetheless, it is a firm indication of the fact that a given route is almost exclusively served by only one railraod.

RATE REGULATION

The third major point to make is that the ICC has wide-reaching legislative control over rates, but has for the most part interpreted this control and implemented this control to further insulate transportation in general, and the railroads in particular, from competition, as is the case of entry control. More specifically, "all charges shall be just and reasonable, and every unjust and unreasonable charge--is prohibited and declared to be unlawful." The Act explicitly prohibits personal discrimination, undue preference between persons,

localities, and types of traffic, and the practice of charging more for a short-haul than a long-haul over a common line. Further, they have authority to determine maximum or minimum rates where these principles are violated.[12]

The obvious ambiguities in the Act as written have allowed room for interpretation. The ICC's interpretation has been liberal, to say the least. Historically, they have been primarily concerned with minimum rate legislation, rejecting rate reductions due to their detrimental impact on alternative modes. In other cases, the ICC's non-economic definition of discrimination has kept unnecessary rates in effect. The case of coal unit-train rates is particularly interesting. Due to ICC policies, lower rates could be charged on unit trains only if all service, independent of volumes, received the same rate. Eventually the ICC relaxed this restriction, but it was largely due to increased competition from alternative fuels and alternative unregulated transportation modes. In this case and others, the ICC has on balance maintained a higher rate floor than would otherwise have obtained.[14]

Conversely, examples of rate-specific maximum rate regulation have been rare.[15] Where maximum rates have been imposed on specific shipments, they have usually been imposed at the point when rates are first posted. In that most rates are initiated in competitive environments, monopoly rents at this stage are not typical, so the fact that few maximum rate cases have been heard is not surprising. Once a rate structure has been established, rate increases have been limited to the general rate level increases allowed by the ICC. In theory, new

rates posted once this structure is established are kept in line with the existing rate structure by the ICC. Therefore, if competition decreased, the railroads' ability to realize higher rents would be constrained by the ICC. In practice, however, given the historical competitive pressures on railroads, the ICC has rarely had reason to do this. In the current coal cases, however, the ICC's willingness to constrain rates is being tested. One critical factor is the time lag between the first posted rates and the point where large monopoly rents are appropriated. If this time is very short, as it has been for western coal rates, then the definition of the existing rate structure is more difficult, and the ability of the ICC to set maximum rate levels is complicated. Furthermore, we will see that even though maximum rate regulation is authorized in a general sense, the limits that can actually be prescribed by the ICC are nebulous at best.

In other instances the ICC has prohibited "discrimination" that is not discriminatory in an economic sense. For example, long-haul rates have been forced to be equal to short-haul rates, and these rates are generally keyed to the long-haul distances on short hauls. Here also, the ICC has exerted little pressure on the higher end of rate structure.[16]

In other instances that are discriminatory in the true economic sense, discrimination is rampant, yet has been sporadically prohibited. In particular, value-of-service ratemaking, where consumers with different elasticities of demand but otherwise identical situations have received significantly different rates, has been ubiquitous. Where discrimination in this sense has been protested, the ICC has further

complicated the interpretation of discrimination to "undue discrimination."[17]

Another example pertinent to our evaluation is export rates. The ICC has the authority to establish "proportional rates," or maximum and minimum proportional rates on export traffic, defining proportional rates only as "those which differ from the corresponding local rates."[18] In this case, discrimination is explicitly allowed and practiced, as export rates are historically higher than comparable domestic rates.*[19]

The rate-setting structure that has obtained is essentially one where the ICC has shown great concern with minimum rate levels, yet little concern with maximum rate levels. In the case of coal, rate structures have been developed with only occasional interference from the ICC to date.

SUMMARY

In summary, the railroads' position as monopolists has been reinforced, if not created by ICC policies. Historically, there has been little if any constraint by the ICC on maximum rate levels, yet a definite constraint on minimum rate levels. As noted above, this is in part attributable to the poor competitive position of railroads in the past. Therefore, the interpretation should not be that the ICC will not limit rates, but rather that they have not often done so in the past. The current coal cases represent a break in tradition as the railroads can and will attempt to appropriate monopoly rents. The likelihood of the ICC limiting monopoly profits on coal shipments will be analyzed next.

ICC REGULATION: CURRENT PRACTICE IN THE COAL-RATE CASES

We have shown that coal-carrying routes are controlled by only one railroad in most cases, and that the ICC policies to date have not focused on maximum rate regulation. In this section, we will take a close look at current coal-rate cases and the related testimony for two reasons. First, to reinforce the contention that rail rates are higher than costs, no matter how costs are estimated. Second, to consider possible justifications for rates exceeding long-run marginal costs.

First, we will set the stage. The railroads in most cases have at least some monopoly power, though the extent of this power is variable. Once a contract has been signed between a utility and a coal company, there is no doubt that the railroad has substantial monopoly power. This power may be constrained by ICC regulations, but, more likely, the utilities, in the role of a monopsonist, will battle the railroad for the difference between the cost of using coal and the cost of the next best alternative.[20] The proportion that each party in this bilateral monopoly appropriates depends on their relative strengths. In theory, if utilities get the rent the gain will be at best short-lived as electricity rates decrease proportionately. These gains are disaggregate over many people, suggesting the possibility that they have less aggregate motivation. Conversely, if the utilities lose the surplus, they can ultimately pass it on to consumers. The railroads, on the other hand, will reap the monopoly profits. Nonetheless, it is risky to

speculate as to the average outcome. It depends in each case on unobservable bargaining conditions. In certain cases where the utility controls several large plants, American Electric Power for example, the railroads' ability to obtain large rents may well be constrained.

Prior to this stage, however, the extent of railroad monopoly power is not so clear. Most importantly, competition from different coal producers could curtail the railroads' power. Intraregional competition might in some cases act as a constraint, but given the small number of competing roads within each region, interregional competition is a more likely limiting factor. However, there are two possible problems with this. First, it is not unreasonable to project collusion between midwestern and western railroads, say, on shipments to the Gulf Coast. Second, though competition may exist at the supply point, many power plants have only one carrier at the terminating point. With the existing barriers to entry, this also could reduce the threat of interregional competition.

Note that the amount of appropriable rent is by all estimates substantial. There is uncertainty about the actual magnitude but most studies estimate that the rates currently being sought by the railroads could be increased further and still yield increased revenues. That is, the existing rates are set at an inelastic point of the utilities' demand curve. One recent study estimates that for shipments to Texas, rates could increase from the current levels of $16.00 to $20.00 with no significant change in demand.[21] The next-best option in most cases is in fact coal from another region, i.e., Texas lignite or Southern Illinois

bituminous coals. If the railroads collude in rate-setting, as suggested above, it is conceivable that appropriable rents will be even higher.

We now proceed in analyzing recent coal-rate cases. Recall that in the previous sections we estimated the costs of railroad coal shipments. In most cases, the rates advocated by the railroad were approximately equal to their fully-allocated cost estimates. In some cases they were higher, in fewer still lower. This, however, is only part of the debate raging in the coal-rate cases. The railroads contend, and the ICC supports the contention, that cost of service is only one factor in determining the reasonableness of a rate. The fact that a rate is above costs by some margin is not sufficient grounds to reject it. In the course of the debate, numerous issues are presented and evaluated. In this section, only the major ones will be considered.[22]

MARKET DOMINANCE

One major issue is the determination of market dominance. Its importance, as is the case with many other issues, is raised in the 4R Act. Section 202 states:

> No rate shall be found to be unjust or unreasonable, or not shown to be just and reasonable, on the grounds that such rate exceeds a just or reasonable maximum for the service rendered or to be rendered, unless the Commission has first found that the proponent carrier has market dominance over such service.

In addition, "a finding that a carrier has market dominance over a service shall not create a presumption that the rate or rates for such service exceed a just and reasonable maximum."[23] Therefore, a finding of market dominance is a necessary, but not sufficient condition, for setting a maximum rate.

As is typically the case, the 4R Act is ambiguous in its definiton of market dominance. "Market dominance refers to the absence of effective competition from other commodities or modes of transportation for the traffic or movement to which a rate applies."[24]

Equally unsurprisingly, the ICC's interpretation of the clause is flawed. After extensive investigations, they ultimately described three situations, any one of which creates the "rebuttable presumption of market dominance."

1) when the proponent carrier has handled 70 percent or more of the involved traffic or movement during the preceding year: the market share of the proponent will be defined to include the share of any affiliates, and of any carrier participating in the rate or with whom the proponent carrier has discussed, considered, or approved the rate in issue, or,
2) where the rate at issue exceeds the variable costs of providing the service by 60 percent or more, or,
3) when affected shippers or consignees have made a substantial investment in rail-related equipment or facilities which prevents or makes impractical the use of another carrier or mode.

The definition of market dominance is in any case a difficult task. It is somewhat arbitrary and must be based on imprecise price and demand estimates. This definition, nonetheless, is worse than most. Recall that determination of market dominance is intended to be indicative of non-effective competition, or, going one step further, of monopoly

pricing powers. In the first criteria above, the fact that "70 percent or more of the involved traffic" is carried by the railroad is clearly an insufficient indication of non-effective competition.[25] The percentage is arbitrary, but more importantly it could just as likely obtain given effective competition.

In the second criteria, prices above variable costs are a reasonable foundation for determining non-effective competition, but the percentage is again arbitrary, and the costing procedures of the ICC are unreliable enough to question this approach.

In the third criteria, the investment requirement is conceivably an indication of short-run market dominance. However, again it is arbitrary, and the criterion could well apply where no market dominance exists.

The ICC definition seems to presume market dominance, and then speculate as to ex post conditions likely to obtain given market dominance. It is certainly not a valid ex ante determination of market power.

It should be noted that the ICC's position is that if the criteria are fulfilled, "there is not necessarily market dominance. The test is merely a threshold determination for directing the commission's attention to those situations in which competitive forces may not be sufficient to insure just and reasonable rate levels."[25] This is certainly a reasonable position. However, the criterion has in fact been employed and in virtually all the coal cases the ICC has found that the railroad in question has market dominance over the traffic in issue. Independent of the ICC's cautious interpretation of this test, they have effectively

removed the Congressional requirement for market dominance to set maximum rates.

The railroads, among others, have noted these flaws. They have rightly suggested that effective competition should consider geographic and product competition. In this case, the railroads argue that coal from other regions and other fuels are competitive factors. Independent of the actual extent to which this would alter the conclusions, the railroads' position is correct.

None of the parties have been quick to present different practicable methodologies. In fact, any definition based on imperfect information must be somewhat arbitrary. Ideally, we would want to consider substitution possibilities in production and consumption: coal from other regions, other fuels, and other possibilities than electricity in final demand sectors. In other words, we would want to reflect the choices that utilities and consumers have beyond coal from a given origin.

No precise definition will be presented here. Nonetheless, any reasonable definition that adjusted for these flaws would no doubt yield similar conclusions. Though the extent of market power no doubt varies with the particular characteristics of the demand and supply centers, as noted above, and though this market power may be largely the construction of the ICC, coal-carrying railroads in most cases have considerable monopoly power, and their pricing practices should be monitored. The ICC is again reappraising the definition of market dominance. Hopefully a new method will be formulated to alleviate the existing criticism, but the conclusion should be the same.

Another important short-run concern is the nature of the bargaining process between the utilities and the railroads and the possibility of abuses. The utility must in the planning stages consider options and select the least-cost option, based on negotiated but non-contracted rail rates. Assume they decide to purchase coal based on these negotiations. They then enter into a long-term contract with the coal supplier (usually 20 years or more), and conceivably build unloading facilities, and railroad cars, in addition to the construction of the generating plant. Now, when the coal begins to move, the railroads say that in fact they will charge a higher rate. As devious as this may seem, it is a recurrent problem in virtually all the recent coal-rate cases. The railroads argue that early rates presented were merely "planning rates" and should not be interpreted as actual rate estimates. Most evidence suggests, however, that the railroads clearly led utilities to base plans on these rates.

In one particularly suspect case, the railroads had offered a rate of $5.23 to Iowa Power and Light.[28] When the rate was to become effective, the railroad offered instead a rate of $6.32, with the threat that failure to accept this rate would invite the railroads to file a capital incentive rate of $7.38. In this case, the ICC firmly reprimanded the railroads for "bait and switch" tactics, and rejected the capital incentive rate request.[29] It should be noted, however, that the ICC reprimanded the railroads for this practice in 1978. In 1979, the ICC allowed a rate of $7.25 and made little mention of the "bait and switch" tactics. In other cases, the tactic has been prohibited, but, if

other evidence supported higher rates, it has not been the dominant consideration in rate-setting.

In future instances this element of monopoly power will be minimized. The 4R Act allows for effective contracts where investments in facilities are required.[30] However, in current cases it is an important factor in the railroads' ability to realize monopoly profits.

In summary, the ICC definiton of market dominance is clearly flawed. However, given a more efficient indication of non-effective competition, market dominance should in most cases of concern be established, particularly in the cases we examine where contracts have not been allowed. However, the future decisions of the courts and the ICC cannot be predicted, and the intended constraint on maximum rate setting may be reinforced, therefore allowing for long-lived monopoly profits.

COMPARABLE RATES

As noted above, determination of market dominance is not sufficient evidence to set a maximum rate. The ICC then has to decide what is "reasonable."

One basis for this determination in the past has been rate comparisons. The ICC has given weight to evidence that shows a given rate to be higher (or lower) than rates in the same geographic region involving the same costs and services. In fact, their acceptance of comparability has no doubt been one strong factor in keeping rate levels down. That is, when rates first become effective, they are often set at competitive levels. Once a rate structure evolves around this level, the

ICC has made it difficult for individual railroads to respond to less competitive conditions that might arise in the future.

However, this historical constraint has been ineffective in recent coal cases. First, in the East, South, and Midwest, where coal-rate structures have been long established and the ICC would not likely allow variations from this structure, they have been allowing larger than usual general rate level increases.[31] Furthermore, in the western rate cases, the ICC has adopted the position that "rate comparisons should be given little weight in determining the reasonableness of the rate."[32] In one case they note "the lack of a well-defined western coal rate structure." "Without such an established rate structure, rate comparisons are of little value".[33]

In a more recent case involving Council Bluffs and Sargeant Bluff, Iowa, the ICC states:

> Rate comparisons are useful as rough estimates of rate reasonableness, but cost evidence takes precedence. This is especially true where there is no well developed rate structure. Further, the commission has announced a policy of increased deference to carrier pricing. Thus the carriers will not be required to establish and maintain elaborate and precise rate relationships. In this setting, rate comparisons must be given decreased emphasis in litigated cases.[34]

The real problem has been that the parties have presented vastly different comparable rate evidence. As always, part of the difference relates to various interpretations of costs. But the major difference is the role of "value-of-service" in rate-setting. For example, in the Flint Creek case the railroads contend that only the post-oil embargo rates are reasonable in comparison, in that only these rates reflect the

current value of service. The shippers, Swepco in this case, contend that pre-1975 rates should be the basis for comparability. "The new rates are not probative of the going rate for this service in that virtually all of these new rates are currently the subject of pending or active litigation."[35] The ICC is currently investigating the western rate structure (ex parte 347) and they may ultimately give greater weight to comparable rate evidence. However, given the short-lived western rate structure, and the intentions of the 4R Act, this is unlikely. Regardless, value of service will no doubt be an important factor in comparability. In fact, the ICC's resolution of this issue will, in good part, determine the extent to which the ICC acts as a constraint on railroads' monopoly powers. The remainder of this chapter considers this issue in depth.

VALUE-OF-SERVICE RATEMAKING

The railroads' statement in the Houston Light and Power case presents the essence of value-of-service pricing. Note that the statement is equivalent to the basic rationale for monopolistic pricing, including price discrimination.

> Santa Fe's ability to provide the shipping public with competitive prices and efficient service is directly dependent on being able to set freight rates based on value of service. The railroads should be able to earn relatively greater profits for providing service which is particularly beneficial to the shipper.[36]

Considering wheat, Santa Fe's major commodity, they note:

> Wheat frequently moves at rates above the variable costs level, but below fully-allocated costs because of competition and the nature of the commodity. Under these circumstances there must be other

> commodities which move at rates well above average costs if we are to earn adequate overall revenues and be able to maintain our service capabilities for the benefit of all shippers. There is no unfavorable subsidization in this situation. Any traffic which moves at rates in excess of variable costs makes a contribution to fixed costs and therefore reduces the burden which must be borne by other traffic.[37]

The ICC has historically permitted value-of-service pricing. In the early 20th century, high-value manufactured commodities were carried under rates above fully-allocated costs, while low-value bulk commodities were carried at low rates. The term "value of service" is derived from this practice, i.e., value-of-service used as an approximation of elasticity of demand. Note that this concept used to be referred to as "charging what the traffic will bear." In recent proceedings the ICC has continued to accept value-of-service pricing.

> The setting of rates for individual service is complicated by the fact that a railroad incurs fixed or overhead costs from its general operations, in addition to the specific costs caused by the provision of particular service. Thus, its rates cannot be set simply to cover the costs incurred in providing the particular service, but must be set at a higher level where possible to make a contribution to the coverage of fixed costs.[38]

Furthermore,

> The railroads must be able to price some of their services above full cost if they are to compensate for the fact that competition forces them to price certain service above variable costs but below full costs.[39]

This explicit acceptance of value-of-service pricing is very important. It says, in effect, that aside from the uncertainties in cost estimation, and aside from the determination of the proper cost concept, rates <u>can</u> exceed costs. Is this the same as explicitly stating that rents exist on coal shipments. Basically, yes. However, given the

possibility that these rents are used to subsidize other traffic, and the notion expressed above that this is somehow not the same as pure monopolistic pricing, the arguments for value-of-service pricing should be analyzed in detail.

Justifications for Value-of-Service Ratemaking

The issue is a complex one, embracing both theoretical and practical dimensions.[40] Throughout the theoretical discussion, we will factor out problems with the ICC costing procedures.

Value-of-service pricing is clearly price discrimination. Consider first the case where long-run marginal costs (LRMC) are less than long-run average costs (LRAC). This is the classic natural monopoly where pricing at LRMC will generate insufficient revenues to cover total costs. A number of solutions to this problem have been advocated: average cost pricing, marginal cost pricing with subsidies, two-tier pricing where a lump-sum fee is assessed over all users, while incremental use is priced at marginal costs. Another option in theory is price discrimination.[41] In fact, if first or second degree price discrimination, where all the consumer surplus or approximately all of the consumer surplus is appropriated by the producer, is practiced, output levels that obtain will approximately equal the competitive output level, and inefficiencies will be minimal.[42] On efficiency grounds, the practice is preferable to average cost pricing. It does involve substantial income transfers between consumers and producers, transfers that are difficult to justify on grounds of economic expediency alone.

Nonetheless, it is a conceivable approach to a difficult problem.

On the other hand, railroad price discrimination is better classified as third-degree price discrimination.[43] Essentially, the railroads set separate prices for separate demand groups, with different elasticities of demand. Though less efficient than perfect price discrimination, in certain cases charging a higher price to the group with an inelastic demand curve than to the group with the elastic demand curves can lead to more efficient plant size, larger output, and a net gain in social welfare than were strict average cost pricing employed.[44]

In fact, there is little evidence to support the hypothesis that LRAC exceeds LRMC in the strict sense.[45] Consider, however, another problem: excess capacity in the short run, so that SRAC exceed LRMC, and pricing at LRMC levels yields losses.[46] Assume also that this excess capacity is attributable to problems with all traffic. Here third-degree price discrimination can be applied in the same way. However, in this case very different issues are involved. Consider two groups of traffic. The railroad builds a system for the first traffic group, and charges them prices equal to the system-average costs. Though this is inefficient, it is necessary for the railroads to survive, and the shippers can survive with these high average cost rates. Given inherent plant indivisibilities, the system may well be able to handle additional traffic. The second group of shippers can afford to pay only their variable costs. Even though the average costs, given both traffic groups, would be less, by charging the second group only their variable costs, and by charging the first traffic group the higher average cost

that they would have received anyway, capacity utilization increases and no one is worse off because of this discriminatory pricing. In special cases like this, price discrimination is not unreasonable.

These theoretical abstractions are very different from the actual situation, and most arguments in support of value-of-service pricing have ignored the important practical elements. In essence, the situation described in the example above is one where the burden on the existing traffic could be reduced by adding traffic with a more elastic demand curve, and charging them rates equal to or above their marginal costs, but below the expanded system's average costs. The inelastic demand group may now pay rates above the expanded systems average costs, but equal to or below their original average costs. The key is that the inelastic demand group is <u>not</u> worse off than they were previously.

In the case of coal, however, the situation is different. Basically, the bulk of the Western infrastructure was built for agricultural commodities, especially wheat and grain. In the early 1970's there was excess capacity. Given the highly competitive agricultural markets, and the high proportion of transportation costs to wheat or grain costs, the railroads faced an elastic demand curve for wheat and grain shippers, and were unable to set average cost rates. Coal shipments developed in the early 1970's, and the railroads realized that they faced an inelastic demand curve in this case. To support the elastic demand traffic, they argued for charging rates above the expected system's average costs. But, where in the example above no traffic group is worse off than they were before, coal shippers may well be worse off

with the existence of sub-profitable wheat and grain shipments. That is, if the railroad system had been built to serve only coal and other profitable shipments, the average costs of that system might well have been less than the average costs of the existing system that also serves wheat and grain shippers. Furthermore, by charging coal shippers rates above the expanded system's average costs, the railroads are almost certainly burdening coal shippers with problems accountable to agricultural shipments. In summary, the statement by the railroads that wheat and grain shipments ease the burden on coal shipments is incorrect. More likely, wheat and grain shipments increase the burden on coal shipments. There may be other justifications for this practice, but they are not the traditional economic ones for price discrimination.

Some other problems with value-of-service pricing should also be noted. First, value-of-service pricing as practiced has created a serious misallocation of resources. For example, truck rates are set equal to the high railroad rates, and given better service, trucks have diverted traffic from the railroads that the railroads could more efficiently carry.[47]

Second, in practice, some traffic is charged below even SRMC, while other traffic is not charged rates as high as the market allows.[48] In the first case, the railroads acknowledge this problem and contend that they are trying to eliminate these shipments. In the second case, the ICC often sets rates in consideration of consuming industry characteristics. Both these factors lead to excessive and exceedingly arbitrary burdens on shippers.

Third, the ICC Rail Form A cost estimates are flawed. As we discussed in Chapter II, fully allocated costs are set in an arbitrary and questionable way, and they may not correspond to LRAC. Consequently, setting prices above Rail Form A fully-allocated costs may in fact be even further above actual LRAC.

Fourth, the logical maximum for value-of-service pricing, i.e., the average costs of serving the profitable traffic alone, is almost certainly below the profit-maximizing price. So, in not being able to determine average costs this way, allowing value-of-service pricing allows for profit-maximizing price levels.

To conclude, allowance for value-of-service pricing as practiced by the railroads is not consistent with economic principles, and given the multitude of practical problems, it is difficult to justify on economic grounds. Very simply, the increment charged over costs is rent.

One last issue must be considered. Allowing value-of-service pricing does not necessarily mean that maximum rate regulations are nonexistent. The railroads argue that any rate should be allowed as long as overall revenue levels are not above adequate revenue levels.[49] The ICC has, however, been more restrictive, if inconsistent. Even given the general allowance for value-of-service pricing:

> The railroads should not be allowed to make up their entire shortfall by extracting monopoly profits from captive shippers. It is essential that some limit be placed on rates to prevent unfairness to individual shippers and distortions in the economy. The question is one of determining the extent to which some shippers should subsidize others in the interest of producing a financially viable rail system.[50]

This is a reasonable statement. Furthermore, in recent ICC cases and investigations, the ICC has shown concern with problems of mismanagement, traffic being charged rates below variable costs, and other problems that I have noted above.[51] In the Council Bluffs case, for example, the ICC states a policy "to encourage innovative and aggressive marketing and pricing policies on competitive traffic" and expresses concern that value-of-service pricing will not further these goals.[52]

However, no final decision has been made on the limit of rates above fully-allocated costs. The ICC has suggested that only rates that are 180 percent or more of variable costs should be limited.[53] However, recent practice has been hesitant, and inconsistent. In the Pepco case, rates as much as 200 percent above variable costs have been allowed.[54] In Houston Light and Power, anong others, rates as high as 20 percent above fully-allocated costs have been allowed.[54] In contrast, in the most recent coal cases, the ICC has allowed only 7 percent above fully allocated costs, which equals approximately 135 percent of variable costs.[55] The uncertainty over the future practice, however, is evidenced in the minority position in the Council Bluffs, Sergeant Bluff, Iowa case. The dissenting opinion states that:

> Although the majority gives lip service to these principles here (value-of-service pricing) the 7 percent ceiling imposed is, in my opinion, so low as to make a mockery of the entire concept of differential pricing.

and goes on to advocate rates as high as 30 percent above fully-allocated costs, or 160 percent of variable costs.[56]

It is possible, then, that though value-of-service pricing will be allowed, bounds will be placed on the railroads and the ability of railroads to capture monopoly rents will be limited. Furthermore, given the Congressional mandate to improve the railroads' condition, some reasonable limit above actual long-run marginal costs, say 7 percent, is difficult to argue against in practice. Nevertheless, it is a rent, it is not strictly justified in economic terms, and it allows for the possibility of rates still higher than existing levels.

Lastly, looking back at all of these issues, what is the appropriate price to charge for coal shipments Average cost pricing is clearly wrong. It is based on a necessarily arbitrary allocation of fixed costs, and it induces inefficient capacity utilization. It is possibly advised only where LRAC exceed LRMC. Even in this case, however, other solutions, such as marginal cost pricing in conjunction with subsidies, or two-tier pricing are probably preferable. Price discrimination is another alternative, but the form of price discrimination practiced by the railroads has created greater distortions than it has solved. If LRMC equals LRAC, but SRAC exceeds LRMC, excess capacity exists. But in addition to the problems cited above, average cost pricing which allocates these excess capacity costs over all traffic implicitly burdens coal shippers with problems that in large part do not exist because of coal shipments. Adding even 7 percent onto average costs in the name of value-of-service pricing only amplifies the burden.

SUMMARY

Let us summarize our analysis to this point. We have established the fact that large rents are appropriable in steam coal transportation, and that the railroads are often in a position to appropriate them. One possible constraint on this power is the ICC. Historically, the ICC has rarely acted in setting maximum rates. However, this is partly attributable to the fact that railroads have historically been in a weak competitive position. Furthermore, in instances where the railroads' competitive position improved over time, the ICC has not allowed a change in the overall rate structure so that initial rate-cost relationships have been maintained.

Coal, however, is a unique case. Historically the railroads have been in a weak competitive position--but given recent developments, this position is suddenly very strong and getting stronger. The actions of the ICC in this situation were uncertain based on past practices. However, observing current practice, the 4R act has been a catalyst to rapidly increasing rate levels and the ICC has not effectively limited rents. In the East, Midwest, and South the long- established rate structure has been upheld in that overall consistency between rates is enforced, but very high general rate level increases in the recent past have effectively mitigated the existing constraint on individual rates. In the West, the ICC has acknowledged the non-existence of a well-defined rate structure, and has been forced accordingly to arbitrate individual rate cases. Though the monopoly power of the railroads may have been

constrained to some limited extent, rates have been allowed far in excess of long-run marginal costs as estimated in Chapter II, and even in excess of fully-allocated costs as estimated with Rail Form A. The increments over fully-allocated costs are justified by the ICC and the railroads as reasonable and efficient business practice. However, as we have shown above, they are not justified economically as they place a disproportionate cost burden on coal shippers and they are fundamentally equivalent to monopoly rates. What has obtained are rapidly increasing coal rates nationwide. We can expect even greater increases in the future.

Our conclusion that rates far exceed costs is pertinent to the evaluation of steam coal exports. If rates are set close to costs on export movements, the competitive position of the railroads in export markets might be significantly improved. However, the nature of past regulatory policies and practices complicates the issue. Even if the railroads wanted to charge lower rates for exports, they have interdependent concerns. Both the current export rate structure and the current domestic rate structure could be jeopardized. It is unlikely that the revenues on steam coal export markets would justify possibly jeopardizing these existing rate structures. This will be further considered below. First, however, the economics of alternatives to railroad transportation for steam coal exports will be analyzed.

FOOTNOTES--CHAPTER III

[1]See for example:
Friedlaender, A., The Dilemma of Freight Transportation Regulation, The Brookings Institution, Washington, D.C., 1969.
Fulda, C., Competition in the Regulated Industries: Transportation, Little, Brown and Co., 1961.
Harbeson, R.L., "Recent Trends in the Regulation of Intermodel Rate Competition in Transportation," in Land Economics, Vol. 42, Aug. 1966, pp. 315-26.
Harbeson, R.L., "Towards Better Resource Allocation in Transportation," in Journal of Law and Economics, Vol. 12, 1962, p. 321.
Johnson, J.C. and Harper, D.L., "The Potential Consequences of Deregulation of Transportation," in Land Economics, Vol. 51, 1975, p. 58.
Moore, T.G., Deregulation of Surface Freight Transportation In Promoting Competition in Regulated Markets, Edited by Almarin Phillips, The Brookings Institution, Washington, D.C., 1975, pp. 55-98.
Moore, T.G., "Freight Transportation Regulation; Surface Freight and the ICC," American Enterprise Institute for Public Policy Research, 1972.
Nelson, J., The Effects of Entry Control on Surface Transportation, Transportation Economics, Columbia University Press, 1965, pp. 381-422.
Nupp, Byron, "Control of Entry as an Economic and Regulatory Problem," in I.C.C. Practitioners Journal, Vol. 35, 1968, p. 591.
Phillips, C.F., The Economics of Regulation: Theory and Practice in the Transportation and Public Utility Industries, Richard D. Irwin, 1969.
Wilson, G., "The Effect of Rate Regulation on Resource Allocation in Transportation," in The Crisis of the Regulatory Commission, Edited by Paul MacAvoy, W.W. Norton and Co., Inc., New York, New York, 1970.

[2]See Hilton, G., "The Consistency of the Interstate Commerce Act," Journal of Law and Economics, Vol. 9, 1966, p. 87.

[3]Railroad Revitalization and Regulatory Reform Act of 1976, Public Law 94-210, 90 Stat. 41.

[3a]U.S. Congress, Interstate Commerce Act, U.S. Code, Title 49, Chapter 1, Section 101A.

[4]Sargent, D.A., "Western Coal Transportation: Unit Trains or Slurry Pipelines," U.S. Department of Transportation, August 1976, pp. 62-66.

[5]Kahn, A. The Economics of Regulation, Vol. II, New York: John Wiley and Sons, Inc., 1970, p. 185.

[6]U.S. Reports. Schaffer Transportation Co. et al. vs. United States et al., 355. Cases adjudged in the Supreme Court at October term, 1957.

[7]Moore, T.G., Freight Transportation Regulation, Surface Freight and the ICC, American Enterprise Institute for Public Policy Research, Washington, D.C., 1972, pp. 41-48.

[8]Sargent, op. cit., pp. 70-73.

[9]National Coal Association, "Survey of Captive Coal Shipments by Rail for 1977," May 1979.

[10]Ibid., pg. 3.

[11]See below for discussion of monopoly power.

[12]See Sections 1 through 4 and Section 15-1, Interstate Commerce Act, U.S. Code, Title 49, Ch. 1.

[13]It should be noted that rates are only monitored by the ICC when protested by some party. Historically, fewer than 2 percent of railroad rate cases are heard in courts by the ICC, and in only 50 percent of these cases are rates altered. In other words, rate regulation as referred to below effectively focuses on high and low ranges at best. Most rates are never arbitrated by the ICC. See Moore, T.G., 1972, op. cit., p. 49.

[14]For details of the ICC role in retarding unit-train development, see MacAvoy and Sloss, op. cit.

[15]Nelson, Railroad Transportation and Public Policy, The Brookings Institution, Washington, D.C., 1959, Chapter IV.

[16]An interesting exception is the case of port equalization rates. Consider a particular origin and three port destinations. In order to protect geographically disadvantaged ports, rates to all three destinations have been based on the midpoint distance, that is, the port of the three different distances that is at the middle distance. This is another case of discrimination that has been allowed by the ICC and the courts.

[17]Another interesting instance of "discrimination" (in an economic sense) allowed by the ICC is "intermediate application rates" on origins and destinations. As a case of "destination intermediate application," consider a shipment from Wyoming to Texas, for which a tariff is posted. Now, consider a new shipment from the same origin to some intermediate destination. According to this rule, the new shipment can be charged the same rate as the next furthest coal destination. In many cases this "next furthest" destination is relatively close; however, in some cases, notably Flint Creek, Arkansas, the next furthest point is 300 miles away,

and the rate posted is some 30 percent higher per ton-mile than for the next point (Welsch, Texas). See BN Tariff 260, Belle Ayr, Wyoming to Welsch, Texas. Also see ICC Decision no. 36980, p. 4.

[18]Interstate Commerce Act, op. cit., Section 1, II-b.

[19]It appears that there is no explicit written restriction on export rates being less than equivalent domestic rates. Grain shipments currently fit this pattern. However, it should be noted that the ICC maintains full discretion over export rate levels. Grain rate levels are currently being evaluated in this sense. It is possible that the ICC will not allow steam coal export rates to be less than domestic coal rates. Note, however, that one clause in the Interstate Commerce Act (MM 476, Section 28) states that rates to or from ports cannot be lower than local rates, unless the shipments to or from the port are on U.S. vessels. The importance of this will be considered below.

[20]Other strong participants in the fight for coal rents are the supplying states. This is important to the extent that railroad rents could be limited. However, it is not important for our ultimate purpose since the delivered price to ports would be unaffected.

[21]Theodore P. Heuchling, verified statement submitted to ex parte 347, Appendix C. "Outlook for Coal-Based Electricity Prices." Arthur D. Little.

[22]For additional materials on the issues discussed in this section, see: a. Interstate Commerce Commission, ex parte no. 353, "Adequacy of Railroad Revenue," Decisions: December 1, 1978; March 21, 1979; December 6, 1979; May 30, 1980.

b. Interstate Commerce Commision, ex parte no. 338, "Standards and Procedures for the Establishment of Adequate Railroad Revenue Levels," Decisions: June 6, 1978; January 31, 1978.

c. ICC, Ex parte no. 327. "Rate Incentives for Capital Investment." Decisions: May 23, 1977.

d. ICC, Ex parte no. 320. "Rail Market Dominance and Retail Considerations;"

e. ICC, Ex parte no. 347. "Western Coal Investigation--Guidelines for Railroad Rate Structure."

[24]Railroad Revitalization and Regulatory Reform Act, op. cit., Section 202.

[25]The concept of "involved traffic" was unclear in the initial 4R formulation. The criteria have since been revised to "that the proponent railroad carries more than 70 percent of the traffic in the relevant market." The "relevant market" definition is under continuing debate. See 49 U.S.C. Section 10709.

[26]ICC, ex parte no. 320. Decided September 30, 1976. pp. 13-14.

[27]For recent developments in the definition of market dominance, see: a. Comments of the United States Department of Justice, Rail Market Dominance and Related Considerations, ICC Ex parte no. 320, sub-no. 1. April 2, 1980.
b. Comments of the United States Department of Transportation, Ibid., April 2, 1980.

[28]See ICC, Incentive Rate on Coal. Belle AYR, Wyoming to Council Bluffs, Iowa. Decided June 15, 1978. Docket no. 36792, pp. 202-206.

[29]Ibid., p. 209.

[30]Railroad Revitalization and Regulatory Reform Act of 1976, Section 206.

[31]Annual increases as high as 22 percent have been allowed for certain shipments.

[32]ICC Decision no. 36970, Flint Creek, op. cit. p. 10.

[33]Ibid., p. 12.

[34]ICC Decision I&S no. 9199, op. cit. p. 36.

[35]ICC Decision no. 36970, op. cit. p. 10.

[36]Verified statement of John Grygiel, ICC Decision no. 36579, op. cit., pp. 7-8.

[37]Ibid., p. 9.

[38]ICC, Standards and Procedures for the Establishment of Adequate Railroad Revenue Levels, ex parte no. 338, January 31, 1978, p. 17.

[39]ICC Decision no. 36970, op. cit., p. 23.

[40]For detailed theoretical and practical analyses of price discrimination, see:
Kahn, A., The Economics of Regulation, Vols. I, II.
Scherer, F.M., Industrial Market Structure and Economic Performance, Rand McNally, 1970.
Piqou, A.C., The Economics of Welfare, London: MacMillan, 1970, pp. 240-256.

[41]See Vickrey, W., "Economic Efficiency and Pricing," in Mushkin, S. (editor), Public Prices for Public Products, The Urban Institute, Washington, D.C., 1972, pp. 53-71.

[42]Scherer, op. cit., pp. 250-255.

[43]Ibid., pp. 253-255.

[44]Kahn, op. cit., Vol. II, pp. 138-139.

[45]Sargent, op. cit., pp. 70-73.

[46]Note that to the extent that excess capacity is not a short-run but a long-lived phenomenon, this situation is in theory no different than the long-run costs situation above. The justification depends in part on whether this long-lived excess capacity is a function of the ICC restrictions on abandonments, or mismanagement. The evidence suggests that it is in only small part due to ICC restrictions. See Friedlaender, op. cit., pp.

[47]Friedlaender, 1969, op. cit., pp.

[48]ICC, ex parte no. 338, Decided January 31, 1979, p. 36.

[49]Ibid., p. 15.

[50]ICC Decision no. 36970, op. cit., pp. 23-24.

[51]For example, ICC, ex parte no. 338, Decided January 31, 1979, pp. 33-38.

[52]ICC, Decision, I and S no. 9199, Decided July 13, 1979. p. 48.

[53]ICC, ex parte no. 338, decided June 6, 1978. pp. 274-275.

[54]ICC, Decision, Docket no. 36114 (sub-no. 1). Potomac Electric Power Company vs. Consolidate Rail Corporation, Decided April 10, 1979.

[55]In terms of variable costs, we need to know the actual fully-allocated/variable cost ratio that varies. An average is 80 percent variable, 20 percent fixed. Thus 7 percent above fully-allocated is equivalent to 134 percent of variables costs.

[56]ICC, Decision, I and S no. 9199, pp. 56-57.

CHAPTER IV

OTHER COAL TRANSPORTATION OPTIONS AND U.S. EXPORT ROUTE ANALYSIS

INTRODUCTION

In this chapter we complete the analysis of current patterns of U.S. inland coal transportation. In the first section the economics of barges, trucks, intermodal transfers, and loading and unloading systems will be analyzed. Barges are important to our analysis in that they might provide cheaper transportation than the railroads, and thus increase the competitiveness of U.S. coal in foreign markets. Trucks are important to export markets only as connecting carriers. Intermodel transfer costs, and loading and unloading costs are important to the integration of all these other cost components.
3This integration is the subject of the second section of this chapter. Potentially important steam coal export routes will be delineated, and the range of costs for shipments over these routes will be assembled from the preceding materials. Though the summary will point out the transportation cost minimizing routes, the ultimate importance of this section will not be realized until the transportation costs are integrated with the supply and ocean transportation variables analyzed in Part B and Chapter VII.

OTHER COAL TRANSPORTATION OPTIONS

Two current alternatives to railroad transportation, both for export and domestic coal shipments, are barges and trucks. The practicability of both, however, is limited: barges, due to the geographic limits of

the inland waterway system; and trucks, due to the fact that they are economical only for very short distances.

Barges, under favorable geographic conditions, might provide an efficient alternative to railroad transportation. A brief analysis of barge transportation economics is therefore appropriate. In addition, truck transportation, though of limited use as a single carrier, will be necessary as a link between coal fields and inland waterways loading points. Therefore, truck costs, along with other short-range transportation and transfer options, will also be briefly considered.

BARGE TRANSPORTATION

As in the case of railroad transportation, our purpose is to estimate the long-run marginal costs (LRMC) and the relationship between LRMC and rates for barge shipments of coal. Two major differences between railroad and barge economics simplify the analysis. First, dry-bulk shipping in general, and coal shipments in particular, are exempt from ICC regulation. There are exceptions to this. For example, no more than three commodities can be carried in the same vessel, and regulated commodities cannot be moved with unregulated commodities if the unregulated commodities are to maintain their status.[1] Furthermore, in some states, Illinois for example, intrastate movements of coal by barge are regulated. Nonetheless, for all practical purposes, barge movements of coal, either for domestic consumption or export are not regulated by the ICC.

The second major difference that alleviates many of the problems we confronted in the railroad case is that cost estimation is far less

complex in theory. Primarily, the problem of joint-production costs is significantly mitigated if not eradicated in the barge case. (There are, of course, general overhead costs, but these are very small.) The main reason for this is that the infrastructure is not owned or operated by barge carriers, but by the U.S. government, specifically the U.S. Army Corps of Engineers. This, then, is not to say that joint-production costs do not exist, but rather that they do not show up in barge rates.

Not only is our task less complex in theory, but also in practice since all the costs associated with the infrastructure, costs which were in good part intractable in the railroad case, need not be estimated for present purposes. It should be noted that user charges have recently been levied on barge operations to cover part of the infrastructure costs.[2] The problem of cost estimation therefore will become more complex both in theory and in practice. However, in that the government determines this charge, the estimation of ultimate costs as reflected by rates is still straightforward.

The market structure in this unregulated industry is far more competitive than the railroad industry. Comprehensive data on industry structure are not available, but there are literally thousands of for-hire service companies and private carriers.[3] A 1970 survey identified 73 unregulated dry bulk carriers on the Mississippi River system.[4] The Keystone Coal Manual identifies 34 coal carriers in 1979. In fact, approximately 25 percent of the coal shipments are handled by four companies: Ohio River Co., Counce Corp., American Commercial Barge Line, Valley Line Co.[5] However, the relative ease

of entry, the large number of small firms, and the option of private carriage, indicate a competitive pricing industry. Given this competitive structure, we expect long-run prices to equal long-run marginal costs, which are estimated below.

Barge Cost Estimation

Before we begin the actual estimation of barge costs, it should be stated that we expect barge costs to be less than rail costs for a number of reasons. First, as noted above, the infrastructure that allows for river movements is financed, operated, and maintained by the U.S. government, not by the barge carriers. As noted, user charges have been recently implemented, but at levels which will pay for only a small part of current and future system expenditures.[6]

Second, the operating costs of moving commodities on the waterways are cheaper for two reasons: 1) the tractive effort required to move a given floating weight is less than on wheels; 2) the economies of scale are more easily exploited on waterways than on land. There are, on the other hand, factors that to some extent offset these cost advantages. Mainly, barge transportation is circuitous and slow. Though significant, they are dominated by the factors above.

The service provided for coal is characterized by towboats pushing flotillas of integrated barges ahead of the towboat. The towboats range in size from 1000 horsepower (HP) to 10,000 HP units. Open hopper barges are used. Though many sizes are employed, three representative standards for coal barges are 175' by 26', 195' by 35', and 290' by 50'. They

carry, respectively, 1000 net tons, 1500 net tons, and 3000 net tons.[7]

The selection of the flotilla and barge size is affected by waterway and lock dimesions. In theory, the optimal decision is complicated by a variety of factors.[8] In practice, however, coal carriers generally use 195' by 35' barges, and the flotilla size is constrained by the width of the waterway, and the dimensions of the locks. As a general rule, the maximum flotilla size, as constrained by locks, is the size that allows for no more than one breaking of the flotilla to pass through a given lock. For example, for a 110' by 1200' lock, the maximum would be 30 195' by 35' barges, arranged in two 3 by 5 blocks. For a 110' by 600' lock, the maximum would be 15 barges. Technically, it is possible to handle larger flotillas by triple-locking, but in practice this is rarely realistic.[9] Other factors important to flotilla size are the width of the river, and the navigational characteristics. In some cases, as few as 6 barges per towboat are practicable, while in other cases up to 45 barges per towboat can be used.

Given the maximum allowable flotilla size, a towboat is selected to minimize costs. Again, this is in theory a complicated decision. Speed, costs of delays, river depth and width are all important.[10] In practice, the decision is less complicated. Based on current practice these cost calculations will assume 5600 HP for towing 15 barges, 8400 HP for 30, 1800 HP for towing 6 barges. It is impossible to determine if this is the optimal size, given limited data. Conversations with barge company personnel indicated that they may be above the optimum in some cases.[11] Nevertheless, they are representative system averages.

Other important variables are whether the flotilla is "fully-integrated," and whether the service is "dedicated." In the first case, fully integrated tows are constructed so as to approximate a monolithic hull. This allows for faster speeds and lower costs. In the second case, dedicated service is analogous to unit-train service. The towboat remains with the barges during loading, unloadng, and round-trip transport. This facilitates the use of integrated tows, faster turn-around times, and the corresponding lower costs. In certain instances these conditions may not hold. However, in that we are interested in LRMC, which by definition reflects the most efficient utilization of plant and equipment, the cost estimation will assume both dedicated service and fully-integrated tows.

Given these general observations, we can proceed in calculating the costs for particular services. Annual operating costs for towboats, according to horsepower, and barges, according to size and type, are taken from December 1976 U.S. Army Corps unpublished data.[12] The costs represent "average" new investment costs, and include return on investment, administration and supervision, wages, and fringe benefits, fuel, maintenance, and repairs, supplies, subsistence, insurance, and "other." They are not commodity-specific. It is therefore possible that coal costs might systematically vary from these figures. However, this author has not found any reason sufficient to adjust these costs in any direction. Maintenance and repairs would seem to be the only real variant, and this comprises less than 5 percent of annual costs.

More difficult than the unit costs is the calculation of the number

of units required to move a given volume over a given river segment. In this case, few data exist on most of the important variables, for example, loading, unloading times, lock delays, and line-haul transit times. A survey of the existing literature led to assumptions on all of these factors. These assumptions were later discussed with barge-company personnel.[13] In some cases the assumptions were modified as a result of these conversations, but only in the direction of cost savings. That is, where the literature suggested a high loading time, and the barge companies suggested this was significantly overstated, the time was reduced.

The assumptions made are: 1) 24 hours loading time, 24 hours, unloading time; 2) 40 minutes for a single-pass through a lock, 90 minutes for a double-pass (a single-pass indicates that the flotilla does not have to be split and then reconnected. In a double-pass it does); 3) an additional 3 hours for pass through locks 52, 53 and Gallapolis on Ohio River; 4) speeds drawn directly from Army Corps data.

Costs are escalated from December 1976 levels in the following way. The proportion of costs accountable to fuel was calculated from the Army Corps data. This proportion was escalated according to increases in diesel fuel No. 2 prices. The increment varied over HP size but was approximately 30 percent over the two-year interval.[14] The remainder of the costs was escalated according to the Wholesale Price Index for all industrial commodities. Conversations with Tennessee Valley Authority (TVA) rate personnel established that this index was in fact used in barge contracts.[15] Given this, and given direct checks on

purchase prices for new equipment and the lack of a useful overall index, this practice seems acceptable. The increment over this two-year period was approximately 20 percent.

Costs were estimated for five river shipments:

(1) St. Louis to New Orleans;

(2) Huntington, West Virginia to New Orleans;

(3) Wheeling, West Virginia to New Orleans;

(4) Shawneetown, Illinois to New Orleans, and

(5) Birmingham, Alabama to Mobile, Alabama.

It is possible that port facilities at Mobile will be required for export coal, so that shipments from the first four origins to Mobile should also be considered. However, given the rigid constraint of the Gulf intercoastal waterway (where as few as 4 barges per tow are practicable), this option is unrealistic. The expansion of the Tombigbee-Warrior River system will facilitate direct shipments to Mobile, but this will not be serviceable until after 1985.

From St. Louis, a 8400 HP tow with 30 barges was assumed. From Huntington and Wheeling, a 5600 HP towboat with 15 barges was assumed. From Shawneetown, which is only 130 miles up the Ohio River from the Mississippi River, it was assumed that an 8400 HP towboat would carry 15 barges to Cairo, Illinois, on the Mississippi, return to pick up another 15 barges, and then carry 30 barges over the lower Mississippi segment of the haul. This procedure was not economically efficient for the origins higher up on the Ohio River. From Birmingham, a 1800 HP towboat with 6 barges was assumed. All these assumptions reflect river and lock

constraints of the specific river segments. Cost calculations are presented in detail in Appendix A.

The cost estimates in 1979 dollars are:

(1) $3.84 per ton from St. Louis (3.6 mills per ton-mile);

(2) $4.19 (4.2 mills) from Shawneetown;

(3) $8.76 (5 mills) from Wheeling;

(4) $7.45 (4.8 mills) from Huntington; and

(5) $7.83 (7.2 mills) from Birmingham to Mobile.

To summarize and expand on uncertainties in these estimates, a few points should be made. First, it is possible that less powerful towboats, or larger flotilla sizes could be used on the lower Mississippi River segment, leading to lower costs. Second, if standby loading and unloading is not available, loading and unloading times may be so long that it becomes more efficient to have more than one set of barges for a given towboat. Related to this is the general problem of turn-around time. One study by the Illinois Central Railroad assumed 72 hours loading, 120 hours unloading time.[16] This assumption was not documented, and 24 hours was considered reasonable by barge company employees. However, it should be noted that longer times are conceivable.

Finally, the related issue of capacity utilization is important. Our estimates calculate a round-trip cycle time for each shipment. For each year, 340 days (8160 hours) of operating time is assumed. Therefore, if the cycle time is 400 hours, we implicitly assume approximately 20 trips per year. In practice, the evidence suggests that capacity utilization is not so efficient. Though barge company personnel consider

these assumptions reasonable, aggregate data indicate some greater inefficiencies. As a rough approximation, in 1975 104 million tons of coal were shipped on the inland waterway system. The average distance was 350 miles, and approximately 3730 barges were used in this service, with average capacity of 1160 tons.[17] If we assume 5 mph as a system average, 48 hours loading and unloading time, and 10 barges per average tow, each barge would make approximately 40 round trips per year. In fact, given these assumptions, 25 trips per year would yield 104 MT of coal, indicating that there is either excess capacity, or inefficient use of existing capacity. This is not a precise test of actual capacity utilization, nor does it alter our basic characterization of efficient services. However, this and other factors above could in pratice contribute to higher costs than calculated above.

Other Estimates of Barge Costs

In contrast to the extensive analyses of railroad costs and rates, barge cost estimates are few. Some studies have attempted to specify cost relationships by regressing rates on cost-determining variables. The Bureau of Mines estimated a regression as follows:[18]

$$y = 61.5 + .244x$$

where y = costs per ton in 1973 dollars

x = one-way mileage.

For a thousand-mile shipment, this is approximately $5.00 per ton in December 1978 dollars.

The Department of Transportation estimates a regression as:[19]

$$\text{Ln Rate} = 1.94 + .587 \text{ Ln miles}.$$

For a 1000-mile shipment, escalated to 1978 dollars the rate would be $4.92.

Both these estimates are close to our cost estimate for shipments on the Ohio River, higher than our cost estimate for the Mississippi River, and lower than our cost estimates for the Tombigbee-Black Warrior River system. The problem with this approach, however, is that the rate information is imperfect. Given the unregulated nature of barge shipments, very little rate information is available. What is available, for example, the Donley report from 1972, is used in many rate analyses.[20] Furthermore, most analyses of this type ignore variations in costs due to specific river segment characteristics. As we have seen, this is an important factor in practice.

Two other recent studies present engineering/accounting estimates of barge costs. Both approaches are similar to the one used in this study, and their results are equivalent to ours. Rieber estimates $2.79 per ton from St. Louis to New Orleans in 1976 dollars (approx. $3.43 in December, 1978 dollars). Manalytics estimates $2.52 per ton for the same shipment in 1975 dollars.[21]

Finally, this author cross-checked these estimates with two other sources. First, Coal Week provides barge rates for metallurgical coal shipments for selected origin-destination pairs.[22] In December 1978, for example, contract rates of $5.20 per ton were quoted from South Central Tennessee to New Orleans, via the Tennessee and Mississippi River. Second, a sample of barge operators and consumers was asked for representative barge rates. Due to the contractual nature of these

shipments, most parties were unwilling to provide actual observations. One direct observation was provided by a barge operator of $5.28 a ton for a new long-term contract from Grand River, Kentucky to New Orleans for metallurgical coal.[23] Adjusting for distance and time, this is close to our estimate. Finally, rate personnel at TVA suggested 5 mills on the lower Mississippi River, and 6 mills on Ohio River.[24] Escalating our December 1978 estimates to the present yields estimates slightly below this. Nonetheless, given the contingencies listed above, and recent fuel price increases, these other estimates do not contradict the estimates developed above.

One other issue should be discussed, As noted above, the user charge on barges will be implemented in 1980 at 4 cents a gallon, increasing by 2 cents a year until it reaches 10 cents a gallon.[25] It is not a simple task to determine the exact effect of the user charge on barge rates since we have an imperfect understanding of fuel consumption. If we assume current fuel prices of 40 cents per gallon, and we assume that fuel comprises 30 percent of total costs, then in 1980 a 4 cent per gallon charge would amount to approximately a 3 percent increase in costs. At the 10 cent level, the corresponding increase would be at most 7.5 percent.[26] Finally, there are no firm conclusions as to what the total burden of the user charge on shippers would be, other than the fact that the legislated charge accounts for only a small proportion of infrastructure costs. Most estimates indicate that the 4 cent level will account for 10 to 20 percent of total current and future costs.[27] Assuming 15 percent, this indicates the possibility of costs increasing

20 percent above the base level (excluding user charge) if user charges covered total costs. Though it is unlikely that the full burden will fall on barge operators, Congress will reevaluate the existing rules, and the possibility of future increases in user charges should not be ignored.[28]

To conclude, we estimate barge costs ranging from 3.6 mills to 7.2 mills over the river segments that concern us. Though incomplete and imperfect, most other evidence supports our conclusions. The one factor that may restrict this cost level is capacity utilization. Furthermore, user charges as legislated will increase rates by approximately 3 percent in 1980, rising to no more than 7.5 percent in 1983, and conceivably by as much as 20 percent in the future. The importance of all these factors to the competitive position of U.S. coal in export markets will be considered in Part B. Nonetheless, it is clear that barge transportation, where practicable, is far cheaper than rail on a ton-mile basis.

TRUCKS AND TRANSFERS

A final task is to review the economics of truck transportation, in the limited role as a connecting mode, the economics of intermodal transfers, and the costs of loading and unloading for the different transportation modes.

Trucks

First, consider trucks. As is the case for railroad transportation, trucks are in most cases regulated by the ICC. And, analyses of motor

carrier regulations have been just as extensive as in the railroad case.[29] If trucks represented a realistic alternative to long-haul transport by rail or barge, we would be forced to consider in detail the implications of regulation for rate-making purposes.

In fact, truck transportation is not a realistic alternative except for very short movements of coal. This is due to the fact that terminal costs for truck transportation are far less than for railroads, while line-haul costs are far greater and not affected by economies of size or distance. Consequently, on a very short railroad haul, the terminal costs dominate unit costs, and lead to costs in excess of short-haul truck costs. However, as distance and volume increase, the inherent advantages of rail transportation take over, and, somewhere between 30 and 100 miles, trucks become more costly.[30]

For our ultimate purposes, the evaluation of steam coal exports, the distances required for inland transportation are far longer than the point where trucks are competitive with rail. As a single carrier, then, they are unimportant. They are an important connecting mode, primarily for shipments from mines to waterway terminals. However, in this case regulation is largely unimportant.

Actually, the regulatory restrictions vary depending on whether the shipment is local, intrastate, or interstate. In most cases, the shipment could be subject to regulation. However, if these regulatory forces, be they state or ICC, biased rates to levels above costs, then the coal companies would logically pursue their legal option of purchasing their own trucks, which would then be unregulated. In any

case, there is little evidence in practice, and no strong explanation in theory for regulation having any impact on truck rates for these short connecting modes. Given this, we can reasonably expect truck rates to equal marginal costs.[31]

Estimation of truck costs is relatively straightforward. As in the case of barges, the basic infrastructure, in this case the highways, is constructed and maintained by the U.S. government. Trucks absorb some of this burden through fuel taxes that all motor vehicle operators pay, but far less than the incremental costs that these heavy vehicles incur in coal transportation.

The costs that are reflected in rates include terminal costs and line-haul costs. Costs are not highly sensitive to variations in distance or tonnages above, say, 3 miles or 20,000 lbs. They are sensitive to variations in roadways, for example, hilly roads, or roads that require slow speeds will lead to increased cost levels.

Despite this relative simplicity, very few studies have estimated truck costs. However, those that have estimated costs generate a narrow range. The most comprehensive recent analysis was by Rieber.[32] Using an engineering/accounting approach, he estimates costs for a variety of truck sizes, annual volumes, distances, and truck speeds. For annual tonnages in excess of 250,000 tons per year, 5 axle trucks, and distances greater than 10 miles, his estimates range from 3.4 to 5.8 cents per ton-mile in 1976 dollars.

The Bureau of Mines also estimates truck costs.[33] Their estimate, based on an analysis of truck rates, equals 5 cents per

ton-mile. Another study presented at a recent symposium on coal transportation authored by Robert Greene cites truck costs at approximately 6 cents per ton-mile in 1978 dollars.[34] Given recent fuel cost increases, the six cent estimate will be used throughout our analysis. Conversations with officials in coal companies have indicated that this is a conservative estimate, and in almost all cases a reasonable maximum.

Note furthermore that railroad rates over less than 100 miles range from 3 to 10 cents per ton-mile. Finally, shipments by conveyor belt cost between 5 and 30 cents a ton-mile. They are an efficient alternative to trucks only for very high volumes, and very short distances (less than 5 miles).

Transfers

It is also necessary to consider costs related to shipments that are not directly accounted for in transportation rates, specifically, intermodal transfers and loading and unloading costs. For this estimation we rely in large part on a comparative analysis of transfer costs by Manalytics.[35] They evaluate different loading and unloading options for barge and rail transport and calculate costs according to various annual throughputs. In 1978 dollars, they estimate rail loading costs (which will be reflected in coal prices) at 25 cents per ton, and rail unloading at 31 cents per ton. Barge loading costs are estimated at 60 cents per ton, and barge unloading costs at 38 cents per ton. The transfer cost from rail to barge would be 91 cents per ton, or

approximately $1.00 per ton at December 1978 price levels.

Finally, less evidence was available for estimates of truck unloading and loading times. One estimate is provided in Greene's study. He estimates 50 cents a ton for both truck loading and unloading.

To conclude, we will use 6 cents per ton-mile as a represetnative cost for truck connections and $1.00 per ton for intermodal transfers in the integration of transportation costs below.

UNITED STATES EXPORT ROUTE ANALYSIS

Our ultimate purpose is to estimate the United States role in future steam coal export trade. The previous sections have analyzed the important transportation features that might affect this role. In this section we will apply our conclusions on transportation costs and regulation to potential export movements and estimate the range of transportation costs for particular export links. In later sections these results will be integrated with supply and demand factors, and the sensitivity of the U.S. role in steam coal export trade to changes in transportation variables will be explained.

The analysis focuses on eight representative supply districts, and eight port destinations. There are, of course, a far greater number of possible supply districts and port destinations. However, this degree of disaggregation is sufficient for capturing the important variations in supply price, transportation costs, and ultimate consuming regions.

The eight supply points and the supply regions they represent are:

1) Billings, Montana for the Powder River Basin,

2) Rock Springs, Wyoming for the Hanna Basin;

3) Price, Utah for coal fields in Utah and Colorado;

4) Gallup, New Mexico for Arizona and New Mexico coal fields;

5) Harrisburg, Illinois for Southern Illinois and Western Kentucky;

6) Lynch, Kentucky for Central Appalachia;

7) Wheeling, West Virginia for Northern Appalachia;

8) Birmingham, Alabama for Southern Appalachia.

The eight port destinations are:

1) Portland, Oregon in the Northwest;

2) San Francisco, for central California;

3) Los Angeles, Long Beach for Southern California;

4) Houston for the western Gulf Coast;

5) New Orleans for the central Gulf Coast;

6) Mobile for the eastern Gulf Coast;

7) Baltimore; and

8) Newport News, Viriginia, for the mid-Atlantic seabord.

The ports have been selected to represent the range of geograhical alternatives for inland transportation. A secondary criterion is the existence of coal facilities, or plans for the expansion of coal facilities.[36]

The selection of transportation mode for these routes is currently constrained to barge and/or rail with trucks or rail serving as connecting modes. Coal slurry pipeline development has to date been

constrained by the railroads. The possibility of future development of coal slurry pipelines will be discussed in Chapter V.

From western supply points to the West Coast destinations, only rail is practicable, as is the case for shipments to Houston from western origins. From Harrisburg to New Orleans, barge or rail shipments are practicable. Shipments from Harrisburg to Houston could involve all-rail, or all-barge including a segment via the intercoastal waterway from New Orleans to Houston. Shipments from Harrisburg to Mobile could involve rail, or barge movements from New Orleans via the intercoastal waterways. Shipments from Birmingham to Mobile could be via barge or rail. Shipments from Harrisburg to Baltimore or Newport News could be all rail, or rail combined with barge. Shipments from Lynch and Wheeling to the Atlantic ports will be all rail, and to the Gulf ports could involve all rail or all-barge movements.

Another issue that must be considered is the length for connecting hauls. Clearly, the longer the distance between the mine and the river system, the less the advantage of barge transportation over rail transportation. It is therefore important to scrutinize carefully the lengths of connecting hauls.

First, there are very few uncontracted waterside mines, so some intermodal connection is inevitable.[37] Even though Wheeling is effectively at water's edge, it is likely that some connection will be required. Furthermore, to impute a lesser connecting cost for the designated origins closer to the river system than for those further away might bias the actual allocation of costs from various origins to various destinations.

Given this, the following strategy was pursued. Based on Bureau of Mines data and conversations with coal companies, the average haul to the river system from each origin point was estimated.[38] From Harrisburg this was 70 miles, from Wheeling 50 miles, from Lynch, 110 miles, and from Birmingham, 25 miles. Then rail rates and truck costs were analyzed to estimate connecting costs. As a practical matter, the difference between 50 and 110 miles was of little importance since at the low range truck and rail costs are approximately equal at 4 to 6 cents per ton-mile, while at the high range, rail costs are approximately 2 cents per ton-mile. On balance, connection costs were approximately $2.00 a ton for Harrisburg, Wheeling and Lynch origins, and $1.00 a ton for Birmingham. It should be made clear that this is only a system average. To the extent that mines closer or further away are available, the costs should be adjusted. Nonetheless, given the limited availability of water-accessible mines, this estimate seems reasonable.

The next task is to determine the least-cost mode over these conceivable routes. It should be clear from the previous sections that this is not a certain task. However, based on the understanding of the complexities discussed above, a reasonable range of estimates can be calculated.

First, barge rates, as noted above, can be assumed equal to long-run marginal costs. The low end of the range can be based on the cost estimates in this chapter. The high end, based on current conditions, would increase these costs to reflect full user costs.

Trucks will be used exclusively as a connecting mode for barge

shipments. Again, costs of truck transportation are relatively straightforward They are summarized in this chapter.

Rail rates are far more difficult to specify. The low end of the range should reflect long-run marginal costs. For western shipments these are based on evidence in the recent coal-rate cases, as adjusted In Chapters II and III. For midwestern and eastern shipments, the cost estimates developed by the application of Zimmerman's work will be used.

Note that U.S. exporters might have to charge the lower cost-based rates on export shipments to compete with other suppliers in international steam coal markets. However, in doing so they might jeopardize the existing domestic unit-train rate structure. That is, lower rates would either indicate that the railroads marginal costs are below the levels that they have presented in the ICC rate cases, or that export traffic is being subsidized by other more profitable traffic. The gains through the export market certainly will not offset the losses if the domestic rate structure is knocked down. Consequently, the probability of applying these lower rates on export shipments is uncertain. We will give further consideration to this issue in the analysis of railroad deregulation in the concluding chapter.

The high end of the railroad rate range is largely indeterminate at this point. There is clearly no restriction on export rates exceeding domestic equivalents, and so supply and demand variables must be analyzed to determine the profit-maximizing rates. This will be undertaken below. As we will see, it is not of great importance since rates higher than existing levels would almost certainly eliminate the United States from steam coal export markets.

More important will be intermediate rate levels and their effect on future export rates. In the West, if rates on exports are set according to the new domestic rate structure, we can expect rates as established in Chapters I and II This serves as a reasonable high end.

In the East and Midwest a realistic high end of the range is the existing export rate structure, based on single-car shipments. Another important reference point is the existing domestic rate structure. This is difficult to apply to the export rates with certainty in that no annual unit-train shipments move over the routes in question. All export shipments are posted as single-car rates. Consequently, a rate precedent is nebulous at best. This is particularly true with respect to Gulf Coast destinations. Applying Zimmerman's model yields zero rents for shipments to Mobile and New Orleans. If on the other hand, rates to these destinations are consistent with the existing regional rate structure, they would be far above Zimmerman's predictions. In Table 1, the higher rate levels are presented along with Zimmerman's cost estimates. For East Coast and Gulf Coast destinations, the existing rate level presented in Table 1 is based on this author's analysis of rates in Chapter I.

It should also be noted that rail rates on shipments to the river system for transfer beyond in barges are generally higher than they would otherwise be. For example, shipments from Wyoming to East St. Louis are carried at 15 mills per ton mile, versus 12.5 mills for shipments to the area but not for transfer via barge. This practice is not surprising. It reduces the benefit of rail/barge transport and biases allocation to

all rail shipments. The importance of this policy to our analysis is minimal, in that the optimal routes are not sensitive to this variation. Nonetheless, it should be noted.

All of these estimates and the calculation of transportation costs are presented in detail in Table 1. The estimates are adjusted to reflect January, 1979 price levels.

A few major points should be made. First, shipments from western origins to western ports will be moved exclusively by rail. Transportation cost savings of $3 a ton could be realized by a reduction in rates to long-run marginal cost levels. Transportation costs to Los Angeles are lowest from Gallup. Transportation costs to Portland are lowest from Billings, and to San Francisco they are lowest from Price, Utah.

Transportation costs to Gulf Coast ports are minimized on shipments from Harrisburg to New Orleans and Houston, and from Birmingham to Mobile. What is interesting in this case is that rail <u>costs</u> are competitive with barge transportation costs given the additional costs of intermodal transfers and shipments from the mines to waterway terminals. However, rail rates, as representative of domestic unit train rates, or, worse yet, export rates, are much higher than barge costs. If user charges reflected full system costs, barge costs would still be lower than rail rates, but above rail costs. For example, from Harrisburg to New Orleans the barge cost would be $8.02, versus the rail cost of $7.40. Also interesting is the fact that shipments from Lynch to Gulf Coast ports are less expensive via rail than barge, even at unit-train

Table 1

U.S. Railroad and Barge Coal Rates and Costs
January 1, 1979
(Dollars per short ton)

		1 Portland	2 S.F.	3 L.A.	4 Houston	5 N.O.	6 Mobile	7 Balt.	8 Hampton
Billings	1	12.20 9.61	18.56 14.18	19.05 14.52	23.27 17.55	25.63 19.24 20.46 16.00	26.10 19.58	27.87 20.85	29.69 22.15
Rock Springs	2	12.75 10.00	12.75 10.00	12.75 10.00	19.79 15.05	23.16 17.47 20.83 17.20	24.86 18.69	27.87 20.85	29.69 22.15
Price	3	13.08 10.24	12.08 9.52	9.82 7.90	18.74 14.36	22.62 17.08 23.68 18.00	24.57 18.48	29.05 21.70	30.81 22.95
Gallup	4	24.79 18.64	13.24 10.38	9.13 7.40	14.09 10.96	18.03 13.79	21.18 15.20	30.21 22.52	30.50 22.73
Harrisburg	5				10.94 9.98	8.71 7.40 7.18B 12.00E	7.98 6.63 8.28B 10.00E	12.51 7.71	13.30 8.47
Lynch	6					10.12 8.76 10.45B	8.90 7.55 11.75B	8.20 6.52 11.00E	8.10 6.68 11.00E
Wheeling	7					13.51 12.15 11.67B	12.46 11.18 12.80B	7.29 5.10 10.50E	8.89 6.76 10.50E
Birmingham	8						4.75 3.41 4.82B 6.99E		

TABLE 1 (continued)

NOTES: 1. For origins 1-4,
First number equals rail rate
Second number equals rail cost
Third number equals rail rate/barge cost
Fourth number equals rail cost/barge cost
For origins 5-8,
First number equals rail rate
Second number equals rail cost
B = barge rate
E = export rail rate

2. All rail rates are through ex parte 357, Jan. 1979.

3. Barge, rail transshipments cost $1.00

4. Transportation to riverway from:
Wheeling = $2.00
Lynch = $2.00
Harrisburg = $2.00
Birmingham = $1.00

5. Billings to St. Louis = 1100 rail miles
Rock Springs " = 1221
Price " = 1425
Gallup " = 1379

6. Western rail rate equation:
-5.75 + .0127*M + .0596*u + .668 DUMEQ + .929 IMAT + .00124 DM
+ 2.134 + DUMT
U=14
MAT=1,000,000
DUMEQ, DM=1 i.e., rail-owned equipment
DUMT = new rate level
See Chapter I

West costs = 10 mills per ton mile -- see Part A, Chapter I.

7. Eastern, mideastern rates as estimated in chapter I.
-.07 + .0105*M + .00237*U + .369*IMAT + 1.21*DUMR + .0016*DM
+ 1.005*DUMEQ
DUMR = 1 East, 0 Midwest
DUMEQ = 1 railroad, 0 shipper

8. Eastern, Midwestern costs:
   a. If i = 5 - 7, j = 5 - 6, TA = [.133136 + (8.691*IMAT) + .009543*L) + 54(MDUM) + (.004595*M) + (.0188*PGD) + (.0358*PDUM)]2.29
      Rent = (.0188*PGD) 2.29
   b. If i = 7, j = 7 - 8, same but BDUM = 1, PGD is positive
   c. If i = 8, j = 5 - 6, PGD = 0, use a
   d. If i = 8, j = 7 - 8, PCFOB = 8.09, PG = 40, BTU = 28, BDUM = 1, use a
   e. PG, PCFOB from MBZ computer printout (all as B.P. still x (1.09) See Chapter II.

9. a. For destinations 5 and 6, and origins 6-8, Zimmerman estimates rents at zero. Rate levels are based on this author's regressions. (See note 7.)
   b. For destinations 5 and 6, and origin 5, Zimmerman estimates rents at 12 cents per ton. Rate levels are based on this author's estimation.
   c. For destinations 7 and 8, and origin 5 Zimmerman's rate estimates are $13.17 and $13.92. Table one includes this author's rate estimates.
   d. For destinations 7 and 8, and origin 6, Zimmerman's rate estimates are $8.34 and $8.40 versus this author's estimates of $8.20 and $8.10.
   e. For destinations 7 and 8, and origin 7, Zimmerman's rate estimates are $6.45 and $7.98, versus $7.29 and $8.89 estimated by this author. Zimmerman's cost estimates are $4.53 and $6.06. Cost estimates in Table one are equal to this author's rate estimate adjusted by the proportionate difference between Zimmerman's rates and costs.

10. Barge rates -- see barge section -- Appendix A.

Source: Author's calculations.

Table 2

Distances Between Supply and Demand Points
(Statute Miles)

	1 Port.	2 S.F.	3 L.A.	4 Houston	5 N.O.	6 Mobile	7 Balt.	8 Hampton
1. Billings	961	1418	1452	1755	1924 2149B	1958	2085	2215
2. Rock Springs	1000	1000	1000	1505	1747 2270B	1869		2215
3. Price	1024	952	790	1430	1708 2474B	1848	2170	2295
4. Gallup	1864	1038	740	1096	1379 1378R 1049B 2427B	1520	2252	2273
5. Harrisburg					642 1001B	573	889	955
6. Lynch					776 1542B	660	594	584
7. Wheeling					1100 1760B	1000	392	545
8. Birmingham					335	266 396B	799	800

Notes: 1. For origins 1-4, B represent joint rail-barge distance. Rail to St. Louis, barge from St. Louis to New Orleans (1049 miles)

2. For origins 5-8, B represents barge distance plus short connecting haul (less than 100 miles in all cases).

Source: Railroad Atlas of the United States, Rand-McNally, N.Y., 1975. American Waterways Operators, Inc., Big Load Afloat, Washington, D.C., 1973.

rates. Barge costs for shipments from Wheeling to New Orleans are cheaper than rail rates.

Transportation costs to Atlantic ports are minimized with rail shipments from Wheeling or Lynch. However, if the existing export rate structures are applied to steam coal exports in the future, distortions will arise. For example, coal from Lynch, Kentucky will be more cheaply moved to New Orleans than to Baltimore or Newport News.

Lastly, it should be noted that the difference in rail costs between shipments from the West to the Gulf and shipments from the West to the Atlantic Coast are relatively small.

To conclude, this section has assembled inland transportation cost estimates over important potential steam coal export links. The range from long-run marginal costs to effective rates is substantial in all cases, and the pricing practices of the railroads could be an important factor in the development of steam coal trade. In Part B we will integrate these results with supply and demand prices so as to determine the ultimate importance of inland transportation variables. In the next chapter we will consider long run factors in United States coal transportation.

APPENDIX A. BARGE-COST CALCULATIONS

This appendix presents the details of the barge cost calculations.

1. Unit Costs: December, 1976 levels

	1800 HP	5600 HP	8400 HP
Towboats, annual operating costs:	$730,220	$1,594,600	$2,202,700
	195' x 35', 1500 tons capacity		
Open hopper barges, annual operating costs:	$24,000		

SOURCE: Army Corps. of Engineers, unpublished data.

2. Operating Parameters:

   a. Annual operating days = 340 (8160 hours)

   b. One spare barge required per fifteen barges

   c. Fuel component escalated according to diesel no. 2 price increases, 31 percent to December 1978.

   d. Residual cost component escalated according to wholesale price index, all industrial commodities, 20 percent to December, 1978

3. a. Fuel cost per hour, December, 1976

   8400 HP, 32 barges = $106.7 per hour

   5600 HP, 16 barges = $69 per hour

   1800 HP, 6 barges = $22 per hour

b. Fuel cost per ton for various origins.

St. Louis: $38,838 per trip fuel cost: 87 cents per ton = 29 percent of 1976 tariff

Shawneetown: $44,814 per trip fuel cost: 100 cents per ton = 29 percent of 1976 tariff

Wheeling: $45,126 per trip fuel cost: 200 cents per ton = 28.4 percent of 1976 tariff

Huntington: $38,788 per trip fuel cost: 172 cents per ton = 28.4 percent of 1976 tariff

Birmingham: $4,224 per trip fuel cost: 47 cents per ton = 20.4 percent of 1976 tariff

SOURCE: Army Corp of Engineers, unpublished data.

4. St. Louis to New Orleans:

Distance = 1049 statute miles

Barges = 30 + 2 spare = 32

Towboat = 8400 HP

Loading, unloading = 24 hours each

Speed = 5 MPH upstream, 10 MPH downsteam

Locks = 0

Hourly costs = $364

Hours per trip = 364.7

Total costs = $132,751

Tons = 30 x 1500 = 45,000

Cost per ton = $2.95 December, 1978

Annual fuel costs = $875,394

Trips per year = 22.36

Annual volume = 1,006,200

Fuel cost = 87 cents per ton

December, 1978 cost =
1.31 x .87 + 1.2 x 2.08
= 1.14 + 2.50
= $3.64 per ton

5. Shawneetown to Cairo:

Distance: 871 mile on the lower Mississippi, 130 miles on the Ohio

Barges: 32; 15 per flotilla on Ohio, double time necessary

Towboat: 8400 HP

Speed: 5.0 MPH upstream full, 6.5 MPH upstream loaded on the Ohio

6.0 MPH downstream full, 7.5 MPH downstream empty on the Ohio

Speed on the Mississippi, 5 MPH upstream, 10 MPH downstream

Locks: 6; 3 double (1.5 hour delay), 3 single (.67 hour delay)

3 hours extra for locks 52, 53 for waiting time

Hourly costs = $364

Hours per trip = 420.30

Total costs = $152,989.20

Costs per ton = $13.40, December 1976

$4.18, December 1978

6. Wheeling to New Orleans

Distance: 871 miles on lower Mississippi, 889 miles on the Ohio

Barges: 15, 1 spare = 16

Towboat: 5600 HP

Speed: same as 4

Locks: 25; 14 single, 11 double.

Add 3 hours for 52, 53, and Gallopolis.

Hourly costs = $242.46

Hours per trip = 654

Total costs = $158,568.84

Tons per trip = 22,500

Cost per ton = $7.05, December 1976

$8.67, December 1978

7. Huntington to New Orleans

Distance: 871 miles on lower Mississippi, 671 on Ohio River

Barges: 16

Towboat: 5600 HP

Speed: Same as 4

Locks: 17; 10 single, 7 double

Add 3 hours for 52, 53

Hourly costs: $242.46

Hours per trip: 562

Total costs: 136,262.5

Cost per ton: $6.06, December, 1976.

$7.45, December, 1978.

8. Birmingham to Mobile:

Distance: 396 miles

Barges: 6

Towboat: 1800 HP

Speed: 6 MPH

Locks: 6, all single

Hourly costs: $107.64

Hours: 192

Total costs: $20,666.8

Costs per ton: $2.30, December 1976

$2.82, December 1978

FOOTNOTES--CHAPTER IV

[1]Interstate Commerce Act, Part III, Section 303, The Transportation Act of 1940.

[2]Inland Waterways Revenue Act of 1978, Public Law 95-502 92 Stat. 1693.

[3]American Waterways Operators, Inc.. "Big Load Afloat," Washington, D.C., p. 3. For additional data on industry structure, see U.S. Congress, "A Legislative Background of the Waterway User Charges Legislation during the 95th Congress," October 1978, pp. 600-603.

[4]U.S. Department of the Interior, Bureau of Mines, "Coal Transportation Practices and Equipment Requirements to 1985," Information Circular 8706, 1976, p. 10.

[5]Keystone Coal Industry Manual, op. cit., 1979, pp. 256-260.

[6]For a detailed discussion of the effect of user charges, see:
U.S. Congressional Budget Office, "Financing Waterway Development: The User Charge Debate," Washington, D.C., GPO, 1977.
U.S. Department of Transportation, Transportation Systems Center, "Modal Traffic Impacts of Waterway User Charges," Vol. I, II, March 1977.

[7]"Big Load Afloat," op. cit., p. 27.

[8]See:
Howe, C.W., "Methods for Equipment Selection and Benefit Evaluation in Inland Waterways Transportation," Water Resources Research, Vol. 1, no. 1, 1965.
Hoffmeister, J.F., "The Economics of Inland Waterway Transportation," MIT Masters Thesis, 1972.
Oliver, Norm, "The Energy Requirements for the Movement of Coal by Barge," MIT Masters Thesis, 1976.

[9]For a detailed description of locking procedures see: Manalytics, "Cost Models for Coal Transportation by Common Carrier," prepared for the Electric Power Research Institute, March 1979, pp. 55-63,; Howe, op. cit.

[10]Howe, op. cit.

[11]Alan Shew of Valley Line Co. and Dale Chandler of the Ohio River Co. were of particular help in developing these materials.

[12]U.S. Army Corp. of Engineers, "Estimated Hourly Operating Cost of Towboats on the Mississippi River System," December 1976 (Revised).

[13]In particular:

a. Greene, Robert, "The Economics of Barge Transportation," Proceedings of Symposium, Critical Issues in Coal Transportation Systems, Maritime Transportation Research Board, Washington, D.C., 1979, pp. 189-197.

b. Rieber, M. et al., "Comparative Coal Transportation Costs: An Economic and Engineering Analysis of Truck, Belt, Rail, Barge and Coal Slurry and Pneumatic Pipelines," Volume 4, Barge Transport, Center for Advanced Computation, University of Illinois, Urbana-Champaign, August 1977.

c. Manalytics, Inc., "Cost Models for Coal Transportation by Common Carrier," prepared for the Electric Power Research Institute, March 1979.

d. "Big Load Afloat," op. cit.

e. Bureau of Mines, Information Circular 8700, op. cit.

f. Howe, op. cit.

g. Meyer, J. et al. The Economics of Competition in the Transportation Industries, Harvard University Press, Cambridge, Massachusetts, 1959.

h. Oliver, op. cit.

i. Hoffmeister, op. cit.

Alan Shew of Valley Line Co. was particulrly helpful in developing these assumptions.

[14]U.S. Department of Energy, in Monthly Energy Review, Part 9, July 1979.

[15]Lee Stone, Tennessee Valley Authority, Rate Section, Knoxville, Tennessee.

[16]Illinois Central Railroad, Market Research Department, "Inland Waterways Transportation," Vol. 2, 1972.

[17]Bureau of Mines, Informaton Circular 8706, op. cit., p. 48.

[18]Ibid., p. 30.

[19]U.S. Department of Transportation, Transportation Systems Center, "Regional Market, Industry and Transportation Impacts of Waterway User Charges," June 1976, pp. II-9, II-11.

[20]Donley, Charles and Associates, "Origin Destination Rate Analysis of Commodity Movements Passing Through Locks No. 26, Mississippi River, Alton, Illinois," Pittsburgh, 1975.

[21]Rieber, op. cit; Manalytics, op. cit.

[22]"Representative Rail and Barge Rates for U.S. Metallurgical Coal Movements," in Coal Week, December 4, 1978, p. 6.

[23]Carl Badgett, Badgett Terminal Corp., Grand River, Kentucky.

[24]Lee Stone, Rate Division, Tennessee Valley Authority.

[25]Inland Waterways Revenue Act of 1978, Public Law 95-502, 92 Stat. 1696. Section 4042(b). Note that charging users per gallon of gasoline is not necessarily an accurate reflection of facility usage. In particular, it does not account for regional variations in facility costs, nor does it necessarily account for tonnage carried. It is simply a rough approximation of aggregate use.

[26]If fuel prices increase rapidly, the proportional effect of the user charge increase will be less. For example, diesel fuel prices in 1976 were approximately 31 cents per gallon. Fuel costs were about 30 percent of total costs on long shipments. Assume fuel prices in 1983 are 70 cents per gallon, and that fuel costs are 35 percent of total costs. In this case, the 10 cent user charge will amount to only a 5 percent increase in costs.

[27]See U.S. Congressional Budget Office, op. cit., for a comparison of several estimates of the effects of the user charge.

[28]The user cost issue is fairly straightforward. To the extent that facilities are congested, the user charge is efficient practice. However, user charges for all operators, independent of whether they use a congested facility are inefficient. See Vickery, W., "Congestion Charges and Welfare," in Journal of Transport Economics and Policy 2, 1968, pp. 107-118.

[29]For example, see Friedlaender, The Dilemma of Freight Transportation, op. cit., Moore, T.G., Freight Transportation Regulation; Surface Freight and the ICC, Washington: American Enterprise Institute for Public Policy Research, 1972.

[30]For a detailed description of truck economics, see Friedlaender, op. cit., and Meyer, J. et al., The Economics of Competition in the Transportation Industries, op. cit., Chapter IV.

[31]Whatever regulatory constraints might have existed at the time of this writing have since been eliminated with the deregulation of trucking.

[32]Rieber, op. cit., Volume 6, "Truck Haulage."

[33]Bureau of Mines, Information Circular 8706, op. cit.

[34]Greene, Robert. "The Economics of Barge Transport of Coal," op. cit., pp. 193-197.

[35]Manalytics, op. cit., pp. 32-42.

[36]Note that there are other port options. For example, in the Gulf region, Baton Rouge is another conceivable option. Furthermore, to the extent that coal slurry pipelines are developed, the constraint of having a traditional port facility is alleviated since coal can be piped directly to an offshore terminal. This possibility will be considered further in Chapter VI.

[37]Bureau of Mines, Information Circular 8706, op. cit., pp. 31-33.

[38]Ibid., pp. 31-33.

CHAPTER V

LONG-RUN FACTORS IN UNITED STATES COAL TRANSPORTATION

INTRODUCTION

In the previous sections we have analyzed the economic and regulatory issues affecting coal transportation in the United States, based on past and present conditions. We observed the fact that railroads are the dominant mode for coal transportation, and the fact that railroads currently seem to earn substantial monopoly rents on coal shipments. There are, however, possible future economic and institutional developments that could significantly affect the situation in coal transportation. This section considers three major interdependent possibilities. First, coal-slurry pipelines. The commercialization of this alternative transportation mode could increase competition in coal transportation, and decrease railroad monopoly rents. Second, the full or partial deregulation of U.S. railroad transportation. This development could in fact enhance the railroad's ability to realize rents. Third, the long-run ability of the railroads to finance capacity expansion.

COAL-SLURRY PIPELINES

A slurry pipeline is basically any pipeline that carries a solid material suspended in a liquid carrier. While the idea of using a pipeline for the transport of solids in a slurry form is not new (it was conceived over 80 years ago), until recently such use has been limited to relatively short lines, primarily within the mining industry. Today,

commercial slurry pipelines are scattered throughout the world, operating in Tasmania, South Africa, Japan, and both North and South America, carrying a wide range of commodities, including limestone, iron, copper, zinc-concentrate, gilsonite, kaolin, and coal.

The first experience with coal-slurry pipelines in this country was the Consolidated Coal Company's line in Cadiz, Ohio. This line was first operated in 1957, transporting 1.3 MTPY of thermal coal through a 108-mile, 10-inch-diameter pipeline. Its construction was spurred by the high railroad tariffs prevailing in Ohio at that time. However, the threat of this competition was met by the railroads through the implementation of unit trains with lower rates, and after six years, and the hauling of approximately 7 MT of coal, the line was shut down.

The world's longest (273 miles) and largest (18 inches in diameter) coal-slurry pipeline is in the United States. It carries coal from the Black Mesa coal fields in Arizona to the Mohave Generating Station in southern Nevada. It began operating in 1970 and is still in operation, presently carrying 4.8 MTPY.

There have been numerous plans for coal slurry pipelines in recent years. The Oil and Gas Journal reported seven current proposals in September, 1979.[1] Six of the seven are planned to originate in western coal fields. Destination points are the West and Gulf Coasts. One other, the Florida pipeline, is planned to originate in Appalachia and carry coal to Florida power stations. The most prominent among these is the line being planned by the Energy Transportation Systems, Inc. (ETSI). This involves a 1036-mile, 38-inch-diameter line from mines in

Gillette, Wyoming, to a series of electric plants around White Bluff, Arkansas. The throughput for this line is estimated at 25 MTPY. Another major plan is a 38-inch line proposed by Brown and Root, Inc. It would carry between 25 and 38 MTPY from the Wyoming-Montana border to Houston, Texas, a distance of 1260 miles. Combined, the projected capacity of the seven lines already planned is approximately 125 MTPY.

While the technology of coal-slurry pipelines has been thoroughly discussed in the literature, and varies from situation to situation, a brief description of the system is useful. Since the Black Mesa line is the only one currently existing in this country, it will be used as a representative illustration.

The process involves three main components: preparation, pipelining, and separation. First, coal is delivered by conveyor belt to the preparation plants, where it is pulverized, mixed with an equal weight of water, and then delivered to storage tanks. Next, the slurry product is pumped through a pipeline by four pumping stations located over the 273-mile line. Upon arrival at the power plant, the slurry is stored in four 7.8 million-gallon storage tanks. Next, it is pumped into a battery of centrifuges, where 72 percent of the water is removed. The resulting coal "cake" is further dried down to 25-percent moisture by burning natural gas in the drying air stream and is finally delivered to the pulverizers to be reduced to a size suitable for firing in the power boiler system.

Although extensive plans exist for coal-slurry pipelines, and have existed for more than five years, actual construction has not yet begun.

To understand this fact we must consider both the costs of coal-slurry pipelines, and institutional barriers to pipeline development.

COST ESTIMATES

Although elaborate plans for coal slurry pipelines have been formulated, the limited operating experience with high-volume, long-distance shipments contributes to significant uncertainty in slurry pipeline cost estimates. In theory, costing of pipeline operations is relatively straightforward. In practice, however, a wide range of costs have been estimated. In part this reflects various technological uncertainties in the pipeline operation. Also, this reflects operational uncertainties such as water costs and availability, start-up times, and gathering and distribution costs. Before we confront these issues in detail, however, some generally accepted points about coal slurry pipeline costs should be noted.

First, for short hauls, say less than 500 miles, and/or low annual throughputs, less than 5 million ton per year (MTPY), railroads are a more efficient transportation option. Second, for very high annual throughputs, say 20 MTPY, and/or long hauls, 1000 miles and above, coal-slurry pipeline costs are at least as low as railroad costs. The reasons for this are technological economies of scale, and high fixed costs. Coal-slurry pipelines have long-run decreasing costs primarily due to the fact that the cost of the pipeline is a function of the surface area, and thus proportinate to its diameter. The capacity of the pipeline is proportionate to the square of the diameter. Therefore, as throughput

increases, unit costs increase far less rapidly. With respect to distance, fixed costs, independent of distance, such as preparation and dewatering costs, are large so that shorter distances yield higher unit costs. Though the break-even point between slurry pipelines and railroads has not been determined, the general conclusion that pipelines are economic only for long distances and large annual throughputs can be accepted.

Beyond this general observation, there is considerable dispute about slurry pipeline costs. A previous analysis by this author showed a range of 5 to 12 mills per ton mile (1975 dollars) for 1000 mile, 25 MTPY shipments.[2] After factoring out glaring deficiencies, a more reasonable range was from 6 to 11 mills per ton-mile. Two more recent extensive analyses, by Rieber et al and the Office of Technology Assessment, support the low level of this range.[3] Reiber estimates costs at approximately 8 mills per ton-mile in 1976 dollars; OTA estimates a range from a low of 5.7 mills per ton-mile to a high of 19 mills per ton-mile.

A number of important factors account for this variation. First, the cost of water is an important determinant in slurry pipeline costs. The first studies by Bechtel estimated intrinsic water costs at approximately $5 per acre foot (1975 dollars).[4] This contrasts with current estimates ranging from $20 to $80 per acre foot.[5] Given water shortages in the West, the pipeline planners have become aware that water does not come cheap. The difference between $20 and $80 in intrinsic water costs would amount to approximately 1 mill per ton-mile.

Possibly more important than the intrinsic costs of water is the simple availability of water. To date, water rights at originating points have been tenuous, at best, and non-existent, at worst. The alternative is to recycle water from a remote source, the Arkansas River in the ETSI case. Estimates of this extra cost vary depending on the pipeline route, but the extra cost has been estimated as 20 to 30 percent above previously planned practices.[6]

Another considerable problem in slurry pipeline systems is gathering and distributing coal. In many of the early studies this problem is given only cursory attention, or not dealt with at all, and a hypothetical single-origin, single-distination system is considered. In fact, this hypothetical case is unrealistic, especially when 25 MTPY shipments are considered. Recent analyses have shown that both extensive gathering and distribution systems are essential to the systems planned, and can amount to as much as 20 percent of total delivered prices.[7] Not only does this create extra investment and operating costs, but the necessity of organizing several consumers has created serious negotiating problems as well.

Another consideration is the start-up assumptions used by the pipeline companies. They generally assume full-capacity utilization by the third year of operation, and relatively minor drop-offs in later years. This has been shown to be overly optimistic. In fact, full capacity may never be achieved, and start-up and drop off periods could be far more important. The difference could conceivably increase tariffs by 10 percent.[8]

There is considerable uncertainty with the economics of coal-slurry pipelines vis-a-vis unit trains. Other factors, however, favor coal-slurry pipelines. First, it has been argued that the relative escalation rates of the various factor costs for each transportation mode would favor slurry pipelines. Specifically, labor costs will increase while capital costs are constant, and the proportion of labor costs to capital costs is higher for railroads than for pipelines. The calculations in support of this factor have been incorrect, and the actual advantage is far less than the pipeline companies have stated, but proportional savings do exist, and cost advantages to railroads of as much as 10 percent at start-up time could be offset in future operating years by this factor.[9]

Second, railroad routes are in practice more circuitous than pipelines need be. As a rule of thumb, railroad routes are generally 20 to 30 percent longer than pipelines.[10] This is sometimes due to geological barriers prohibiting railroad construction, and at other times to the necessary utilization of the already existing railroad infrastructure.

Third, there are some important service-quality dimensions that have frequently been ignored in modal comparisons. Where unit trains deliver large quantities in single blocks, pipelines deliver a constant flow over long time periods. In addition, questions of reliability may prove important. Consensus holds that slurry pipelines are a more reliable mode, less subject to intermittent failures, than railroad operations.[11] However, offsetting this is the fact that railroad

operations are generally more flexible. While a breakdown in a pipeline would eliminate service for a period of time, railroad traffic could normally be diverted over other routes when problems arose. Little empirical evidence is available on these considerations. Nonetheless, these brief remarks should serve as an indication of general uncertainties.

The effect of these various factors on the utilization of pipelines for coal export trade should be considered. First, the only links where pipelines might be practicable are the western coal fields to the West coast or the Gulf Coast ports, and Southern Illinois, Western Kentucky fields to the Gulf ports. The West-to-West Coast shipments are less likely to be cheaper via pipeline for two reasons. First, the terrain is extremely rough. Of course, this holds for railroad shipments also, but in their case roadbeds already exist, though considerable improvements may be required. One useful approximation of this problem is included in the recent OTA analysis where a shipment from Price, Utah to the Southern California Coast was estimated to be 30 percent more expensive than rail transport, even though rail transport costs on this link were significantly higher than over other routes.[12]

Compounding the problems for a pipeline to the West Coast is the fact that in the foreseeable future, high enough volumes to benefit from pipeline economies are not likely in that export trade levels will be far below 25 MTPY, and domestic West Coast coal consumption will be small. One current plan for pipeline transportation over this route has initially planned a 10 MTPY throughput.[13] Negotiations for this tonnage have

been difficult, and secondary plans have involved a five MTPY line, with the addition of a parallel 5 MTPY line in the future.[14] Although the uncertainties in pipeline cost estimation are significant, the relationship between costs at various output levels is reasonably well understood. Bechtel Corporation, for example, estimates that unit costs in 1975 dollars would increase from 5 mills at 25 MTPY, 1000 miles to 7.5 mills (approximately the level of 1975 unit train rates) at 10 MTPY, to 10.5 mills at 5 MTPY.[15] Furthermore, the relative disadvantage that pipelines have at low volumes could well mean that even if far larger volumes obtain in the long-run, railroads will have already contracted the service.

Shipments from the West to the Gulf, and Southern Illinois to the Gulf face a more favorable environment in both these respects. The terrain is less difficult, and domestic markets for steam coal in the Gulf region are rapidly developing. To the extent that slurry pipelines represent an efficient alternative to rail, these links are the most likely to be developed.

All these factors considered, the following conclusions are reasonable. First, long-distance, high volume coal slurry pipeline transportation costs are between 8 and 15 mills per ton mile at January 1979 cost levels. Under ideal circumstances, costs may be below railroad costs (as opposed to rates) by a significant but small margin. Under difficult circumstances, such as extensive gathering and distribution systems, water rerouting, and rough terrain, pipeline costs almost certainly exceed railroad costs by some margin. In general, it is safe

to say that there is limited applicability for coal-slurry pipelines, but in ideal situations, such as the Western coal fields to the Gulf coast or Pacific coast, they might represent a realistic transport alternative. The actual cost savings are uncertain, but their existence should not be ignored.

COAL-SLURRY PIPELINE REGULATION

Note, however, that railroad rates are currently far higher than the best estimate of rail long-run marginal costs, and that railroads have cited serious problems in capacity expansion. Under these conditions we would expect, at the very least, commercialization of pipelines in the ideal situations cited above. In fact, only one pipeline is currently operating: a 273-mile, 18-inch diameter pipeline carrying coal from the Black Mesa coalfields in Arizona to the Mohave generating station in Southern Nevada.

Several factors have constrained slurry pipeline development. Most important, the railroads have not allowed pipelines to cross under railroad lines, and Congress to date has not granted the right of eminent domain to pipeline companies. An alternative course of action is to receive eminent domain from individual states. The ETSI pipeline has in fact accomplished this, though the route length has become more circuitous than initially planned.[16] In other cases, the roadblock persists.

This controversy has been raging since 1975, and the Congress has come increasingly close to approving slurry pipeline bills in various forms.[17] Unfortunately, the proceedings have focused primarily on

the uncertain question of which mode is generally cheaper, while neglecting the more basic question of whether the economy is better off with or without competition, engendered by the question of pipelines right to eminent domain, and possible economic justifications for restrictions on pipeline development. This author has previously written on the possible justifications for restrictions on pipeline development.[18] The most frequent arguments are: 1) that railroads are natural monopolists, and efficient provision of transportation services mandates the existence of only one supplier; 2) that railroads will not be able to finance required capacity expansion if profits are not assured; 3) that the transportation system will be subject to destructive competition; and 4) that coal- slurry pipelines will only service the high-volume, more lucrative markets, leaving smaller, less profitable shipments to the railroads. In all cases the justifications for restricting pipeline development were weak.[18] If these issues alone are considered, the firm conclusion was that pipelines should be granted eminent domain. However, given the uncertainty in cost estimation, the acceptance of this position has lagged behind realities. The bill will come up again this year, and given the administration's coal program goals, and the fact that some key adversaries to the pipelines in Congress and the Senate have not been reelected, passage is again conceivable, though uncertain.

Even so, the bill as stated would not give unilateral approval to all slurry-pipeline development. Rather, a certificate of "public convenience and necessity" must be granted by the Department of The

Interior. If the proposed project "is in the national interest," and could serve as a common carrier, this certificate would be granted.[19] Given the ambiguity in these criteria, however, at the very best slurry pipelines would be limited to some extent.

Some lines will be built even without eminent domain. ETSI, as noted above, has cleared this hurdle and Federal eminent domain would only allow for a less circuitous route. Other proposals cite eminent domain as a surmountable hurdle in most cases.[20] A more pressing problem appears to be water availability. Again, ETSI has negotiated with the state of Wyoming, and received clearance for 20,000 acre feet per year, but this is an exception. In other cases, plans have been delayed or postponed due largely to this constraint. Alternatives to water have been considered, for example, liquid carbon dioxide and fuel-grade methanol, and even oil.[21] However, in the foreseeable future, this problem may be insurmountable.

To conclude, there are no doubt circumstances where coal-slurry pipelines represent a less costly transportation alternative. Furthermore, even where pipeline costs equal or exceed rail costs, pipeline costs would in many instances be less than the current high railroad rates, and even the threat of pipeline competition could bring down railroad rates. To date pipeline companies have not received the right to eminent domain, and this has effectively prohibited their development. If eminent domain is granted in the future, and other legal and regulating constraints and water problems can be circumvented, pipelines will at least offer an attractive alternative to rail rates, possibly forcing these rates down.

In reference to export movements, the most likely areas for application are the Western coal fields to the Gulf coast and Pacific coast. Given the uncertainties in costing, we cannot specify the savings with pipeline transport, but the possibility should not be neglected.

RAILROAD DEREGULATION

The future course of coal slurry pipeline development is important to our second long-run concern, railroad deregulation. The pros and cons of railroad deregulation have been extensively analyzed, and there is no need to rephrase these arguments. In essence, most authors conclude that restriction on entry and abandonments, and minimum and maximum rate regulation have decreased competition and induced significant inefficiency in the provision of transportation services, and that full deregulation, or partial deregulation including some form of maximum rate regulation, is the preferable alternative.[22] However, some observations on the importance of railroad deregulation to coal transportation in particular, and on recent proposals for railroad deregulation, in general, should be made.[23]

First, consider full deregulation of freight transportation. The literature, past and present, has extensively analyzed the anticipated gains and losses from rail deregulation. The gains to deregulation most frequently cited are increased efficiency in the provision of transportation services and elimination of enormous administrative costs borne both by the regulators and the transportation companies. The

arguments presented most frequently against deregulation are, broadly, that competition in transportation services would be destructive, and that railroads are natural monopolies. Related concerns are the problems of inadequate investments, technological innovation, excess capacity, and cream-skimming. As noted earlier, this author has previously written on these justifications for the particular case of coal transportation. Though each argument has some validity, the overwhelming conclusion in this case was that the justifications are weak. Other authors have similarly concluded that the justification for regulation on these grounds never existed, do not exist, and probably never will exist. In fact, problems of investment, pricing, excess capacity, and technological innovation have more likely been compounded by transportation regulation. Most analyses have concluded that deregulation is a preferable alternative.

The one factor that argues strongly against total transportaton deregulation is monopoly pricing by transportation modes, especially the railroads. For most commodities, the railroads lack significant pricing power, so the problem is non-existent. In our case, however, where considerable monopoly power exists, the issue is of primary importance, and is a critical factor in the advisability of full deregulation or some partial alternative.

The foundation of this concern is of course the fact that railroads do possess significant monopoly power over many coal hauls. The critical question however, is whether regulation as such constrains this monopoly power, and whether deregulation would, at least in the long run, mitigate

monopoly power. To the extent that we answer no and yes, respectively, to these queries, this factor loses some relevance in the arguments against deregulation. To the extent that we answer yes, and/or no, respectively, the concern is more pressing.

In response to the first query, "does regulation constrain monopoly power," the answer, based on the analysis in previous chapters of past and present ICC policies, is "only to a limited extent." Recent practices have been erratic, and though in some instances rate increases have been prohibited, the allowed rates have still exceeded long-run marginal costs. If profit-maximizing monopoly rates are in fact even higher than today's rates, and the railroads attempt to increase rates to these higher levels, the increased stress on the system might force the ICC to take a stronger stand in holding rates down. However, to say that the problem of monopoly pricing is mitigated through existing regulation is arguable at best. Furthermore, the administrative costs, and the related inefficiencies of rate regulations almost certainly offset the benefits of ICC rate regulation as practiced today.

Second, will total deregulation mitigate monopoly power in the long run? In this case the answer is uncertain. In the short run a consumer may be forced to employ one railroad's services. In the long run, however, with no entry barriers, a realistic constraint on monopoly pricing is entry by slurry pipelines or competing railroads. The entry of competing railroads is a less certain constraint. In some instances, as noted, only one railroad can efficiently serve a particular route. However, coal flows out of the West have reached such high levels that

competition is more likely to be constructive. The expansion of infrastructure by, say, the Union Pacific Railroad, to compete in Burlington Northern territory is not an unreasonable possibility. Of course, in this small numbers game the possibility of oligopoly pricing exists. However, given deregulation, this would be subject to the same anti-trust regulations that other oligopolies confront. Note also that anti-competitive practices in pricing by a railroad monopolist could similarly be constrained by anti-trust regulations.

In summary, the major justifiable concern with respect to railroad deregulation is monopoly pricing. On balance, however, the ICC does not do a very good job as it is (though, as noted above, until recently they have rarely been called upon to do so), and the railroads' long-run power to set monopoly prices might be reduced by the threat of competing modes and judicial actions.

With respect to export shipments, the importance of railroad deregulation is also uncertain. In metallurgical coal export markets, U.S. railroads have traditionally charged discriminatory tariffs on export shipments. However there are two reasons to suggest that this is less likely to be important in steam coal markets. First, the United States has historically held a strong monopoly position in metallurgical coal markets.[24] In recent years this position has been eroded. Rates are <u>still</u> well above domestic equivalents, but the gap has decreased. In contrast, the United States is currently in a weak competitive position in international steam coal markets, and therefore is less able to charge monopoly rates. Though they may continue to do

so, this would be more a reflection of bad business than economic sense. Second, metallurgical coal prices are generally double steam coal prices, so that the demand for metallurgical coal is less responsive to increases in transportation tariffs. Furthermore, the most likely steam coal export shipments will originate in western coal fields and cover distances much greater than most current metallurgical coal shipment distances. Given these two factors, the importance of deregulation to export steam coal markets is less important than to domestic coal markets.

The one positive force of deregulation is that the uncertain restrictions on future steam coal export rates vis-a-vis domestic rates and existing export rates would be reduced. That is, the threat of jeopardizing domestic rate structures with low export rates would disappear. In this sense, deregulation would represent, at worst, a net gain; at best, significant improvement for the U.S. coal export position.

In fact, total deregulation of railroad transportation is unlikely to obtain in the foreseeable future. Partial deregulation in some form is more likely. The most recent legislative proposal (S.796) by the Carter administration, currently being heard in Congress, is representative of partial deregulatory schemes.[25] Its principal components are less rigid requirements for railroad abandonments, alterations of merger and acquisition rules, greater restrictions on price discrimina- tion, termination of rate bureau evaluations of single line rates, termination of anti-trust immunity, and, most important to our analysis, increased flexibility in rate setting. In specific, the

railroads would have "the flexibility to charge rates within a zone of reasonableness of 7 percent per year in 1980 dollars." Rate changes within the zone would be deregulated, while changes outside the zone would continue to be regulated by the ICC. Rates above the zone would be subjected to a three-step procedure which involves competition and reasonableness. Rates below the zone would be subjected to a predatory pricing test. On rates above the zone, the shipper must prove that he/she is captive, i.e., he/she has no reasonable transport alternative (reasonable defined as 120 percent of existing transport cost if trucking is an alternative, 110 percent if barging is an alternative). If the shipper can prove the above condition, the carrier must prove that the rate is reasonable (justified on the basis of cost). If not, the ICC sets the rate.

Extensive arguments for and against this bill have been presented. The major arguments in favor cite, for example, increased efficiency, competition, and reduced regulatory interference. The major argument against the rate regulation principles is that the zone of reasonableness provides insufficient protection to the captive shipper; or, from the railroad perspective, that the zone of reasonableness is too restrictive.

The bill unfortunately ignores several important issues, all of which are critical to the effects of deregulation. For example, coal-slurry pipelines are not considered explicitly, nor are acquisitions and construction, and intermodal ownership. With these omissions, the extent to which partial deregulation would significantly affect current rate levels on coal shipments is uncertain. Rates would no doubt increase

from today's levels, but it is possible that they will increase even given the existing regulatory structure. Given the inherent uncertainties with total deregulation, an incremental step towards partial deregulation such as this is not unreasonable, but by enacting more rigid constraints on coal rates, or by allowing for freer entry of competing railroads and slurry pipelines, the efficiency of the coal transportation system could be increased.

FINANCING CAPACITY EXPANSION

As noted repeatedly above, a major impetus to deregulation and recent ICC decisions is the 4R act, and the major impetus to the act was the deteriorating financial position of certain railroads. The reasons for railroad deterioration are wide-reaching and complex and will not be considered here.[26] However, a particular facet of this broad concern, the ability of railroads to attract capital for expansion, has been repeatedly raised by public and private observers and should be considered briefly. Two factors are important. First, the profitability of coal traffic alone. Second, the profitability and financial stability of railroads as a whole.

In the first case, there is virtually no doubt that coal traffic is profitable at rates far below existing levels. Given proper calculation of the cost of capital, there is little doubt that the railroads will be able to attract capital in the long run, based on the coal operations alone. In essence, coal markets are financially sound, and in most

cases, the railroads have an inherent advantage over competing transport modes. There is, of course, debate about the precise profitability of coal shipments, but it is safe to say that if non-coal operations are financially sound, the railroads ability to attract capital for capacity expansion is as certain as can be expected given inherent uncertainties in financial markets.

The more pressing concern, then, and the one that permeates all recent controversies, is the overall financial position of the railroads. To the extent that non-coal operations are not profitable, and that company-wide profitability is accordingly low, the ability of the railroads to finance capacity expansion must be questioned. In some cases, such as equipment trust obligations, for example, the overall financial status of the railroads is not that important since these costs are tied to particular assets, not company-wide assets. Even in case of bankruptcy, these debts have been fully paid. The most pressing financial concern is the expansion of roadway and structures where the corresponding risk is greater.

In fact, the financial condition of the railroads is widely variable. In some cases, the railroads are considered very good investments. Union Pacific, Southern Pacific, Seaboard Coastlines, Southern Pacific, Norfolk and Western, and the Chessie systems fall in this category. Their ability to raise funds is unquestioned by financial analysts. At the other extreme, some railroads, primarily in the Northeast and Midwest, are in poor financial condition. Recent comprehensive analyses have shown dangerously low levels of working capital, insufficient cash flows,

inadequate earnings and rates of return on both net investment and equity, and low and decreasing fixed charge coverage.[27] These roads are in definite need of additional revenues. In between lie railroads in generally sound, but questionable financial condition. As a rule, with the exception of Louisville and Nashville, railroads in the South and West are in the stronger set financially. Recent financing operations have indicated that the large coal-carrying railroads will not have difficulty in long-run capacity expansion. Though exceptions may occur, it is unlikely that the railroads will not meet future capacity requirements.

Nonetheless, for roads in the middle range of financial stability, for example, the Burlington-Northern, a particular danger exists. In trying to recoup losses on other traffic due to poor management, ICC constraints, and adverse competitive conditions, the railroads may price coal traffic at exceedingly high levels in the short run, and in so doing will jeopardize the entire operation in the long run. In these cases, coal shipments, though profitable in their own right, might not be able to pull the railroad out of overall financial difficulties, and attempts to do so could result in extensive losses in the long run. Whether or not this is a real danger is uncertain, but the inefficiency of railroad management in the past suggests that it not be overlooked.

To conclude, there has been considerable concern with the railroads' financial condition and their ability to attract capital for capacity expansion. In the case of coal-hauling roads, the problem does not seem to be a long-run constraint. Coal shipments alone promise to improve the

railroads overall financial stability, and most coal carrying roads are relatively strong as is. Roads with poor financial conditions on overall operations will have greater problems, but even these should not be severe when coal operations are the subject of capital financing. One realistic concern, however, is that overall railroad operations are in such poor shape that revenues on coal traffic cannot salvage them. If the railroads attempt to salvage them with coal revenues, the overall operations may deteriorate even further.

FOOTNOTES--CHAPTER V

[1]"Outlook Improving for U.S. Coal Slurry Lines," in Oil and Gas Journal, Sept. 10, 1979, pp. 91-95.

[2]Sargent, D.A., "Western Coal Transportation: Unit Trains or Slurry Pipelines," U.S. Department of Transportation, August 1976.

[3]a. Rieber, M. and Soo, S.L., "Comparative Coal Transportation Costs: An Economic and Engineering Analysis of Truck, Belt, Rail, Barge, and Coal Slurry and Pneumatic Pipelines," Vol. 3, "Coal-Slurry Pipelines," prepared for the U.S. Department of the Interior, Bureau of Mines and the Federal Energy Administration, August 1977.

b. Office of Technology Assessment, Slurry Coal Pipelines--Task Reports, Volume II, Part 1, January 1978.

[4]Aude, T.C., Thompson, T.L., and Wasp, E.J., "Economics of Slurry Pipeline Systems," Presented at the Third International Conference on the Hydraulic Transport of Solids in Pipes, Colorado School of Mines, Golden, Colorado, May 15-17, 1974.

[5]OTA, op. cit., Volume II, Part 1, pg. A.68.
Rieber, op. cit., pp. 3-37, 3-48.

[6]Sargent, op. cit., pp. 39-40.
Rieber, op. cit., pp. 3-8 to 3-10.
OTA, op. cit., pg. 43.

[7]Sargent, op. cit., pp. 40-42.
OTA, op. cit., Appendix A.
Rieber, op. cit., pp. 3-11.

[8]U.S. House of Representatives, "Coal Slurry Pipeline Legislation," Hearings before the House Committee on Interior and Insular Affairs on H.R. 1863, H.R. 2220, H.R. 2553, H.R. 2986, Serial No. 99-g, 94th Congress, 1st Session, 1975, pp. 952-957.

[9]More specifically, slurry pipelines are capital intensive in that approximately 70 percent of the pipeline tariff is capital-related charges. Unit trains, on the other hand, are highly labor intensive: as much as 80 percent of the unit-train tariff is operating costs and 20 percent is capital-related charges. Since capital costs are constant, while operating costs escalate with the rate of inflation, the labor intensity of unit train operations versus the capital intensity of pipeline operations will lead to faster cost escalation for unit train

service. The mistake made in calculating this advantage is that the future savings have not been discounted as the costs of the modes diverge. Also, when the chosen mode is initially more expensive, interest charges on the initial monetary difference borne by the consumer are typically ignored. See Sargent, op. cit., pp. 48, 49.

[10]Of course, this conclusion assumes that only technological constraints exist for pipeline development. Given the problems of securing right-of-ways, the advantage is reduced, as will be seen below.

[11]Hudson Institute, "Research Analysis of Factors Affecting Transportation of Coal by Rail and Slurry Pipeline," New York, April 1976; Sargent, op. cit., pp. 49-50.

[12]OTA, op. cit., Appendix A.

[13]Boeing Engineering and Construction Company, Seattle, Washington.

[14]Private correspondence with Len Kopeiken, Boeing Engineering and Construction Company.

[15]Aude, et al., op. cit.

[16]The initial plan called for a pipeline 1030 miles long. The current phase 1 plan pipeline is 1365 miles. The existing railroad mileage is 1300 miles. Oil and Gas Journal, op. cit., pg. 93.

[17]For an extensive analysis of these issues and debates, see:

a. White, D.M., "An Analysis of Transportation Alternatives for Meeting Texas' Industrial Demand for Western Coal Through the Year 2000," Center for Energy Studies, The University of Texas, 1978.

b. The National Energy Law and Policy Institute, "The Legal and Regulatory Issues of Transporting Coal by Slurry Pipelines." Task Reports: Slurry Coal Pipelines, Office of Technology Assessment, Part 1, Vol. 2, 1978.

c. Reed, N.T., "An Analysis of Technical and Legal Issues Raised by the Development of Coal Slurry Pipelines," in Houston Law Review, No. 3, 1976.

[18]Sargent, op. cit., pp. 69-78.

[19]House Resolution 4370; Coal Pipeline Act of 1979.

[20]Oil and Gas Journal, op. cit., p. 91.

[21]Oil and Gas Journal, op. cit., p. 95.

[22]For extensive analyses of railroad regulation, see, among others:

a. Friedlaender, A., The Dilemma of Freight Transportation Regulation, The Brooking Institution, Washington, D.C., 1969.

b. Harbeson, R.L., "Recent Trends in the Regulation of Intermodel Rate Competition in Transportation," in Land Economics, Vol. 42, August 1966, pp. 315-26.

c. Johnson, J.C., and Harper, D.L., "The Potential Consequences of Deregulation of Transportation," in Land Economics, Vol. 51, 1975, p. 58.

d. P.W. MacAvoy and J.W. Snow (eds.), Railroad Revitalization and Regulatory Reform, American Enterprise Institute for Public Policy Research, Washington, D.C., 1979.

e. Moore, T.G., "Deregulation of Surface Freight Transportation," In, Promoting Competition in Regulated Markets, Almarin Phillips (ed.), The Brooking Institution, Washington, D.C., 1975, 55-98.

[23]The issues of deregulating barge and truck transportation have also been extensively analyzed. However, as noted above, regulation of these modes is of little direct importance to long distance export coal transportation.

[24]See Adelman, M.A. "American Coal in Western Europe," in Journal of Industrial Economics, Vol. XIV, No. 3, July 1966, pp. 199-211.

[25]See National Coal Association, "Railroad Deregulation: Implications and Alternatives for Coal Producers and Users," Washington, D.C., May 23, 1979.

[26]For example, see Interstate Commerce Commission, Evaluation of the U.S. Railway Association Preliminary System Plan, ex parte 293, sub. no. 5, April 1975.

[27]The reasons for this unsound condition are complex and are attributed to both external and internal forces. For example, trends in intermodal competition, shifts in traffic demand, unbalanced federal investment policies, and adverse regulatory policies have been cited as external reasons. Internal reasons typically cited are inflexibility to change, lack of technological and pricing innovation, poor management, and capital and operating difficulties.

a. See Barber, R.J., Verified Statement, Houston Lighting and Power versus Burlington Northern et al., Docket no. 36579, Interstate Commerce Commission, July 7, 1977.

b. Coyne, F.H., Verified Statement, Houston Lighting and Power Company versus Burlington Northern et al., Docket no. 36579, ICC, July 1977.

c. Interstate Commerce Commission, Decision ex Parte 338, Standards and Procedures for the Establishment of Adequate Railroad Revenue Levels. Decided January 31, 1978.

d. ICC Decision ex parte 353, Adequacy of Railroad Revenues. Decided December 1, 1978.

For an updated discussion of many of the pending coal rate issues discussed in these chapters, see: U.S. House of Representatives, Coal Rates and Federal Railroad Regulations, Hearings Before the House Committee on Interstate and Foreign Commerce, Subcommittee on Oversight and Investigations, 96th Congress, First Session, 1979.

CHAPTER VI

FOREIGN COAL TRANSPORTATION

INTRODUCTION

We have analyzed coal transportation patterns in the United States in the previous sections. Our purpose was threefold. First, the analysis of economic and regulatory factors underlying U.S. coal transportation was essential to projecting the U.S. role in international steam coal markets. Second, the analysis contributed to a better understanding of domestic steam coal transportation. Third, the analysis was an interesting case study in transportation economics and regulation.

We will analyze coal transportation patterns and prices in other potentially important steam coal importing and exporting countries in the following sections. Broadly, we are interested in the role of inland transportation in the development of international steam coal markets. Specifically, we are interested in the patterns of coal transportation in these countries, the tariffs charged for coal transportation, and the relationship between tariffs and long-run marginal costs. The analysis serves two main purposes: first, it provides the input necessary to estimate optimal trade routes and to establish country-by-country comparative advantages in international steam coal trade; second, it provides us with an interesting contrast to the U.S. coal transportation experience. It contributes to our understanding of rate-setting practices in non-U.S. countries, and shows that the experiences in these countries are not dissimilar from the U.S. case.

The analysis is far more limited than the U.S. case. Tariff information, where available, was often incomplete. More difficult was the

approximation of long-run marginal costs. As evidenced in the previous sections, this is an exceedingly complex issue, but an important one to understanding future coal transportation developments. Data constraints in other countries prohibited any rigorous estimation of long-run marginal costs. At best, rough inferences from regulatory patterns and general economic variables could be drawn to approximate cost levels. It should be noted that the data constraints were, in part, attributable to the basic difficulties of international communications, and, in part, attributable to the unwillingness of the various transportation organizations to publicize data. Nonetheless, a more pressing constraint was a chronic lack of data on transportation costs, especially railroad costs, in all the countries studied. Aggregate expense data are, of course, compiled, but incremental costs, or even average costs for particular commodities are with few exceptions (primarily South Africa) poorly compiled. In this respect, cost data for the United States, with all the problems noted above, seem to be far in advance of those for the other countries studied.

The sections are organized as follows. First, coal transportation in Australia and South Africa will be analyzed in detail. In both cases: 1) the existing patterns of coal transportation; 2) the institutional structure; 3) the existing tariff structure; 4) the relationship between tariffs and long-run marginal costs; and 5) the extent of future capacity constraints will be discussed. Second, the same issues will be analyzed for Canadian coal transportation. The analysis will be less detailed, largely due to the similarities to the U.S. experience. Third, the

importance of coal transportation in Western Europe and Japan will be briefly appraised.[1]

SOUTH AFRICA

The coal transportation system in the Republic of South Africa is less complex than in the other countries in our analysis. Several underlying factors jointly account for this: 1) Coal transportation is controlled by a government-owned monopoly; 2) export coal is carried almost exclusively over one major inland transportation route; 3) virtually all export coal is carried by rail; 4) rates and rate increases fit a well-defined and consistent pattern; and 5) existing network capacity, and capacity expansion are relatively well-understood.

EXISTING PATTERN OF COAL TRANSPORTATION

Coal shipments in South Africa are carried almost exclusively by rail. Inland barge transportation simply does not exist as an option, and trucks are used mostly as connecting carriers. Volumes carried from coal fields increased from approximately 6 million metric tons in 1910 to 29 million metric tons (MT) in 1965.[2] Between 1965 and 1975, Coal transportation was relatively stable at approximately 25 million metric tons per year. Only in 1976 did rapid increases develop. By 1978, approximately 40 MT of coal were carried. This amounted to approximately 27 percent of all freight carried.

Export steam coal originates almost exclusively in the Transvaal

coal fields, and is carried exclusively to Richards Bay Harbour on the Southeast coast of South Africa; a rail distance of between 450 and 600 kilometers.* Coal export levels have been controlled historically by the Government. Beginning in December 1970, the government granted approval to the Transvaal Coal Owners Association to export not more than 108 million tons of coal from Transvaal coal fields, at a rate of not more than 9 million tons per year to begin in 1976 with 2.7 MT contracted with Japanese consumers. With the "fuel crisis" in 1973, the Government subsequently gave approval for the export of additional quantities of coal.[3] Since then, the ceiling has steadily increased according to market forces, and the railroads have kept pace with capacity expansion. In 1979, approximately 24 MT of coal were exported, of which 7 MT are metallurgical, 1.5 MT anthracite, and the remaining 16.5 MT steam coal. This compares to total coal exports of 13.3 MT in 1978 (33 percent of total coal tons carried), and allowances for 40 MT in 1985, with all the increment attributable to steam coal flows.[4]

The transport of Transvaal coal to Richards Bay entails the running of 13 unit trains daily, each train comprised of 76 to 80 wagons, with trainloads of 4013 and 4224 tons respectively (approximately 50 ton carloads). This contrasts with the U.S. unit trains which generally consist of 105, 100 net ton cars. The South African practice is dictated

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*The one exception is coal from the Natal region. This coal is primarily anthracite and amounts to less than 5 percent of export volumes. It will not be an important factor in steam coal trade development and will be largely ignored in this analysis. See supply section for additional details.

by the fairly narrow standard track gauge (1063 millimeters), which, in turn, is dictated by engineering and economic considerations at the time of original construction. Most important is the mountainous terrain throughout the provinces. Rapid loading and unloading installations are in place at both mines and ports with current practice at 3 hours for each. The line-haul train speed on the Transvaal to Richards Bay route averages approximately 19 mph.[5]

INSTITUTIONAL STRUCTURE

The South African Railways (SAR) came into being with the establishment of the Union of South Africa in 1909.[6] At that time they assumed responsibility for the railroad infrastructure constructed by the British Government in the last half of the 19th century, primarily for diamond, gold, and coal movements. In their initial charter they were given control over the railways throughout the four provinces of South Africa. In later years they further assumed responsibility for harbors, pipelines, road transport, and airways.

The SAR functions in a strict sense as a government department, administered by the Ministry of Transport. In a practical sense, however, the administration of SAR, under the direction of the Railways and Harbour Board, is in large part independent. Nonetheless, given government ownership, the SAR is subject to control by the Parliament, and Parliament sanction is required for new rail lines and harbors, and for the annual SAR budget. In reference to this budget; operating expenses come from railroad revenues, capital for investment comes from

treasury loans in perpetuity, and, to a limited extent, foreign loans. In addition, all revenues go into the Railways and Harbours Fund, from which moneys necessary to meet SAR expenditures approved by Parliament are withdrawn.

Restrictions on the SAR within the boundaries of parliamentary control are nebulous. The central guideline in the SAR charter states that:

> The railways, ports and harbours of the Republic shall be administered on business principles, due regard being had to agricultural and industrial development within the Republic and to the promotion, by means of cheap transport, of the settlement of an agricultural and industrial population in the inland portions of all provinces."
> (Section 103(1). Republic of South Africa. Constitution Act.)

The only other substantive provisions advocate maintaining a balance between revenues and expenditures and prohibit excessive profits:

> Total earnings shall not be more than are sufficient to meet the necessary outlays for working, maintenance, betterment, depreciation, and payment of interest due on capital.
> (Section 103(3a). Republic of South Africa. Constitution Act.)

As is the case in the U.S. Interstate Commerce Act, the guidelines for administration are subject to various interpretations. In general, the only firm inference is that the initial intention was to run the railways on "business principles." However, the reference to national interests clouds even this observation. More specific evidence on interpretations will be provided below.

SOUTH AFRICAN TARIFFS

South African railroad tariffs for all shipments of coal, whether domestic or export, steam or meturallurgical coals, are based on an SAR tariff schedule.[7] The schedule sets tariffs per 100 kilograms (kg) for distances between 1 and 5000 kilometers (km). Statistical analysis of the 1979 tariff schedule (provided by SAR) showed that these tariffs fit a parabolic form:

$$TA = C + \alpha_1 M + \alpha_2 M^2$$

where:

TA = tariff-rands per metric ton

M = one-way distance, in kilometers

The regression results under this functional form are:

TA =	1.349 +	.0142 x M -	.340E-05 x M^2
Standard Error	.013	.778E-04	.875E-07
T-stat.	103.67	182.6	-38.8

R^2 = .9999

F st. = 15643

It is clear from these results that the rate schedule is in fact constructed to fit this relationship though the formula is not official. Though there has been considerable debate by railroad analysts over this functional form's accuracy in approximating costs, it does represent that form used extensively in railway cost estimation in the past.

Unit train rates in South Africa are systematically less than these levels. Table 1 presents representative unit-train rates from Transvaal coal fields to Richards Bay, as well as the normal tariff from the SAR

rate schedule. As a rule, unit-train tariffs are 40 percent less than the normal tariffs. The unit-train tariffs are conditioned on the conveyance of 18 MT per year, three-hour loading times at the mines, specified origins and destinations, and specified commitments of not less than 1 year. If these conditions are not met, intermediate rate levels, "block rates," are set 5 percent below the normal tariff levels.

RATE/COST RELATIONSHIPS

Unit-train tariffs, converted to U.S. dollars (according to the 1979 average exchange rate, 1.20 U.S. $ per rand) equal approximately 15.5 mills per short ton-mile. Based on the analysis in Chapter I, the U.S. midwestern and eastern rates for railroad-owned-car shipments of approximately 600 km are approximately 16.0 mills per short ton-mile and 19 mills respectively. Do these levels approximate long-run marginal costs, or do they reflect other factors, as is the case in the United States This is an important question. Unfortunately, the data simply do not exist to specify the relationship between costs and rates rigorously. The best we can do is draw some rough inferences from the data and information that do exist.

First, consider the regulatory framework. The charter of the South African Railways is even more nebulous regarding rate setting than the U.S. Interstate Commerce Act. As noted above, "the railways shall be administered on business principles, with due regard being had to agricultural and industrial development." Beyond this there is no explicit reference to rate-setting procedures. From a more pragmatic

Table 1

South African Unit-Train Tariffs -- April, 1979

Forwarding Station	Distance Conveyed (kilometers)	Unit-train tariffs/ton All-inclusive (rand)	Normal Tariff/ton (rand)
Saalwater	599	5.27	8.89
Blackhill	633	5.51	9.27
Ermelo	445	4.63	7.25
Vandyksdriff	583	5.09	8.77
Broodsnyersplaas	564	4.86	8.57

Source: "Information on Steam Coal Transportation," Internal Materials, South Africa Railways, 1979, unpublished.

viewpoint, the structural setup of the SAR, where all revenues are funneled into a fund to be used only for parliamentary approved SAR expenditures, suggests that excessive profit levels are not encouraged. However, though this limits aggregate profits, it does not explain anything about the railroads individual rate-setting procedures.

Beyond this, there has been criticism of SAR rate policies. Two commissions have established a variety of discriminatory rate-setting practices that resemble those in the United States.[8] The base for these policies is "charging what the traffic will bear," which, as a practical matter, has been manifest in discrimination between classes of goods. The SAR has 14 classes of goods, rated in order of value, and in the past, the tariff on class one goods has been as much as 10 times that on class 14 goods.[9]

Other observations raised in these proceedings have been the power of the farmers' lobby in obtaining low rates on agricultural goods, which, given the SAR mandate of balancing their budget, forces higher rates elsewhere. Also, nearest port rates and special rates to centers of distribution have been practiced. In general, rate-setting practices resemble closely those in the United States.

Unfortunately, though these general observations are ubiquitous in analyses of the SAR, observations on coal rates and the relationship between these rates and costs have not been obtained by this author. Accordingly, though this general evidence suggests the possibility of almost any relationship between rates and costs, they do not allow us to pinpoint any particular cost/rate relationship.

Another indirect approach to specifying cost-rate relationships is to evaluate aggregate railroad cost data. A recent study divided total system-wide freight revenues by total freight ton-miles for various countries including the United States.[10] Using an estimate of U.S. unit-train costs as a base, railroad rates in these countries were estimated by adjusting the U.S. cost estimate by the difference between the U.S. revenue per ton-mile estimate and the given countries' revenue per ton-mile estimate. For example, if the U.S. unit-train cost estimate is 10 mills per ton-mile, and South African system-wide revenues per ton-mile are twice as high as U.S. revenues per ton-mile, then the South African rates are estimated to be 20 mills per ton-mile. This approach, either for rate or cost estimation, is badly flawed. It ignores, among other things, the effect of subsidies on rates, the commodity distribution of traffic, the geographical distribution of traffic, the specific infra-structure characteristics of a country's railroad system, and accounting practice variations. Had this approach been used to estimate South African rates, the estimates would have been 25 to 27 mills per short ton-mile versus the actual 15.5 mills. With regard to costs, even greater error is probable.

Unfortunately, more detailed cost information is not available from the SAR. Another conceivable approach is to consider component costs. Labor, in particular, accounts for 50 to 60 percent of railroad expenses.[11] Adding locomotive and railroad car costs, and the cost of supplies (railroad ties specifically) might give us a fair approximation of intercountry cost variations. Again, however, this

approach provides little specificity. We do know that labor is far cheaper in South Africa; for example the per employee cost for the SAR is U.S. $3,600 versus U.S. $18,000 for U.S. Class 1 railroads (1975 dollars).[12] However, we do not have detailed data on the cost of labor for specific skills. In fact, the SAR uses 5 times as many employees per route mile (normalized for density), indicating either greater labor intensity in their production function or lower average skills, or, most probably, a combination of both.[13] In either event, conclusions on the effect of these lower costs on aggregate costs are uncertain at best.

Equipment costs are easier to estimate conceptually, but more difficult to obtain empirically. Direct price data are unavailable from either the SAR or equipment manufacturers. This is due to the fact that, especially with regard to locomotives, individual prices are controlled by a few large firms, and for competitive reasons, are confidential. However, given the distributional system of locomotive parts, where 40 to 60 percent of ultimate price is accountable to U.S. produced exports, and given representative freight rates for these component parts, locomotive prices in South Africa are probably no more than 15 percent in excess of U.S. prices.[14] Railroad cars are less reliant on complex technologies and are largely produced in foreign countries. Direct price data were again unavailable, but a 15 to 20 percent margin is realistic.

These imprecise estimates do not get us very far in final cost estimation. Furthermore, even with precise estimates, an equally or more important factor is the particular operating parameters in foreign

countries. For examole, in South Africa the terrain is mountainous, and a narrow track gauge (1063 milimeters) is used system wide. This forces use of smaller locomotives (2600 horsepower versus 3000 horsepower and above in the United States), and smaller trainloads (4000 tons versus 11,000 tons). The impact of these factors on final costs is impossible to determine without a complete cost analysis, the data for which simply do not exist.

To conclude, though present rate levels in South Africa are certain, the relationship between costs and rates cannot be estimated with any certainty given data constraints. It is possible that, given the historical practice of cost-based rates on mineral commodities, the rates do not exceed costs by substantial margins. However, transportation rate discrimination may well exist on coal shipments. Furthermore, unlike the U.S. unstable environment, it is unlikely that rates would be reduced. In fact coal companies in South Africa have commented on their "extremely attractive rail rates." Whether this indicates their feeling that rates equate costs, or simply indicates the strong competitive position of South African coal in foreign markets is unclear.

CAPACITY

A final concern is railroad capacity in South Africa. Given the export structure, where one railroad invests for a centralized group of coal producers and shipments are carried on one route, we would expect an efficient investment program, constrained only by serious capital shortages or physical constraints. Practice supports this expectation.

The government has steadily increased capacity to 25 MT, and has plans to increase capacity to 60 MT. Communications with the SAR indicate an extensive understanding of and planning for capacity utilization.[15] For example, intermediate increments in traffic will be handled by greater car size and more trains per day, and segment by segment improvements for increases beyond 30 MT are well-defined. Furthermore, SAR and coal company officials estimate that rates will not change in real terms as a function of capacity expansion up to 60 MT.[16] This has been the case for capacity increments from 5 to 25 MT, as capital costs have offset volume increases.

Beyond 60 MT, the constraints on capacity expansion are uncertain to this author. Presently, export levels are not allowed to increase beyond 40 MT in 1985. To the extent that demand might justify exports above this level, we will further consider this problem below.

AUSTRALIA

Coal transportation in Australia holds similarities with both the U.S. and South African experiences, but the combination of elements from each forms a very different overall transportation system. Most importantly, railroad transportation is govenment owned and controlled, as is the case in South Africa, but road transportation is a private industry, subject to regulation . The combination of these different structures, reinforced by problems in transportation faced by most other nations, has contributed to a complex transportation system riddled with political and economic problems, uncertainties, and anomalies.

EXISTING PATTERN OF COAL TRANSPORTATION

The two states in Australia from which virtually all coal production originates are New South Wales and Queensland. These two states are contiguous, comprise approximately one-third of the area of Australia, and lie on the eastern part of the continent, bordered to the East by the Pacific Ocean. For export coal issues, only these two states directly concern us.

In New South Wales approximately 40 million metric tons (MT) of coal were transported from mines to consumers in 1978. Coal transportation was allocated between rail (31.7 percent), road to off-site rail-sidings (14.5 percent), all-road (27.7 percent), and conveyor belt (26.1 percent).[17]

The rail share, 16.5 MT, is carried exclusively by the Public Transport Commission of New South Wales. Coal freight accounted for approximately 50 percent of total railroad freight tonnage and 35 percent of total freight revenues.[18]

Coal exports in 1978 were 17.5 MT. Rail moved 12.1 MT of this amount, and truck transport accounted for the remaining tonnage. Of this 12 MT, 2 MT were steam coal, and 10 MT metallurgical coal. Of the 17.5 MT exports, 12 MT were destined for consumers in Japan, the remainder allocated over other countries in the Far East and Western Europe.[19]

Transportation of coal in Queensland amounted to 25 MT in 1978. Of this total, 22 MT were carried by the Queensland Government Railways.[20] Exports to overseas consumers were approximately 20 MT. The largest single consumer was again Japan (14.3 MT). As compared to New South Wales, the vast majority of coal was transported by rail. The 3 MT not carried by rail were carried by truck.

INSTITUTIONAL STRUCTURE

Regulation of freight transportation is imperfect in all countries, but the experience in Australia seems to have magnified these generic difficulties. A brief discussion of the regulatory environment is helpful to our understanding of rates and their relationship to costs.[21]

The regulatory system is complex, and varies from state to state. The fundamental reason for this variation is the fact that interstate transportation is unregulated, with the exception of health and safety regulations. The issue of interstate transportation regulation has been the subject of repeated court debates. These debates rotate around the various interpretations of Section 92 of the Australian Constitution. Though ambiguous, the interpretation of this section, given in numerous decisions of the High Court of Australia, has been that Section 92 guarantees the absolute freedom of interstate trade.[22] It is doubtful that this interpretation will change in the foreseeable future. Independent of this, however, interstate regulation will affect export movements only indirectly since all existing inland routes to ports are intrastate.

Given the non-existence of interstate transportation regulation, the responsibility for the transportation system lies with the individual states. Regulation in each of the five Australian states has certain similarities, but important differences. For our purposes we need only consider New South Wales and Queensland.

With regard to the railroads, both Queensland and New South Wales

rail systems are wholly owned and controlled by the State Government. The administrative system is similar to South Africa's, with a railway board acting as a largely independent unit, subject to budgetary approval by Parliament. In both cases, government transportation acts are unclear on guidelines for pricing and investment policies. The general conflict between economic and social objectives, that is prevalent also in South Africa, is not given the explicit attention it is in the South African Constitution. The New South Wales Government Railways Act defines conduct towards the customers in terms equivalent to the U.S. Interstate Commerce Act, citing, for example, reasonable tolls and charges, the government's authority to set maximum charges, and the illegality of discrimination. However, the railroads are not given explicit directions to operate their enterprise profitably or otherwise.[23] The Queensland Railway Act is similar in focus, setting general guidelines for rate-setting, but offering no criteria for railway management in an aggregate sense.[24] As a general rule, the railways have enormous lattitude, with no well-defined guidelines. In both cases the practical interpretation of transportation acts has been to maximize railway traffic, subject to no binding constraint.

Road regulation has historically been used to protect the railroads traffic share. Over time, a variety of taxation and licensing schemes has been practiced in Queensland and New South Wales, primarily to reduce truck competition. The effects of these regulations have generally been disastrous. In some cases truck competition was not eliminated, and railroads have either lost traffic or, in competing with trucks, held

unprofitable traffic and incurred heavy financial losses.[25]

Currently, truck regulation in Queensland takes the form of entry-control and road-maintenance taxes.[26] With respect to coal, intrastate movements of 25 km or less are not controlled. For shipments longer than 25 km, licenses are required, and are generally not provided. In New South Wales, truck transportaion was deregulated in 1973/1974. Prior to that, taxation and entry control had been practiced. One might suspect that deregulation would lead to increased utilization of truck transport. However, the isolated effects of regulation are not possible to determine given additional recent changes. (See below). In many instances truck regulation in New South Wales was circumvented by "border-hopping," that is, a shipment would make an intermediate stop at a station just over the border. As an interstate movement, it therefore became exempt from intrastate regulation.

The transportation system that has obtained from this system of combined government ownership and regulation is, bluntly, a mess. First, as in most countries, rail rates are set according to value, with large variation between the varous goods classifications. However, even with truck regulation, the railroads are not perfect monopolists, and competition from trucks has to a significant extent undermined value-of-service pricing. In some cases, particularly high-value commodities, the railroads have almost jealously sought to hold this traffic, even when trucks may have an inherent advantage, and for that matter, even when rail movements are unprofitable. In other cases, the railroads have lost traffic to the trucking industry. What has obtained is a gross

misallocation of traffic, and heavy financial losses by the railroads.[27] In New South Wales, for example, on revenues of 437 million A $, a deficit of 398 million A$ was incurred. Of this loss, 248 million A $ was accountable to passenger traffic, but even freight operations lost 149 million A $ on revenues of 282 million A $.[28]

With no competition from trucks, revenues from high-valued commodities would, no doubt, exceed costs. However, with this competition, trucks have either diverted traffic to themselves, or successfully eroded profits in these cases. The result has been that mining and agricultural commodities, (the commodities for which rail has a strong inherent advantage), and coal in particular, have been used to finance part of this deficit. Although no exact figures for coal alone exist, it is widely believed that revenues exceed expenses by considerable margins.[29]

This basic problem has contributed to other ills. Given pricing practices largely independent of costs, misallocations have arisen, and investment planning has been inefficient. It has not generally been keyed to prices, but rather to maximize railroad traffic levels. Finally, uneven service, poor maintenance, and inadequate financing have further contributed to a poor railroad system.

AUSTRALIAN TARIFFS

Coal rates in Australia reflect these problems. Data on coal transportation rates are imperfect, but some firm conclusions can be drawn.

First, unit trains are the predominant method of movement.

Generally 3600 HP locomotives move 5000 net ton volumes in trainloads of 70 to 80 wagons. New South Wales railroad rates were provided by the Public Transport Commission. A schedule headed "Contract Shipment Coal in Commission's Wagons from 1.4.79" listed rates per tonne from 1 to 644 km over various short intervals.[30] The schedule fits a parabolic form, as for South Africa. The extimated regression results are:

TA = Tariff per metric ton, A $

M = one-way kilometers

	TA =	1.35150	+	.0395 x M	-	.331E-04 x M^2
Standard Error =		.08		.0071		.115E-05
T-stat.		16.87		55.76		-28.8

R^2 = .9939

F-stat. = 5977

Rates for owners' wagons are 10 percent less than these, independent of distance.[31]

The most important point to make is that these rate are very high relative to U.S. unit-train rates. Converting to U.S. dollars based on the 1979 average exchange rate (1.13 U.S. $ per Australian $) for 50 km the tariff amounts to 10 cents per short ton-mile in U.S. $, for 100 km, 8 cents, and for 200 km 6.6 cents per short ton-mile. The longest distance represented in the schedule is 644 km, or 400 miles. The tariff is 3.4 cents per short ton-mile. In all cases these levels are orders of magnitude above comparable rates in South Africa and the United States.

For example, the U.S. East and Midwest tariffs for 400 mile shipments are approximately 19 and 16 mills per short ton-mile respectively. For a 200 km shipment, the U.S. East and Midwest equivalents are 4.3 and 3.3 cents per short ton-mile respectively.

What is not certain is the extent to which actual contract rates equal these scheduled rates. Even communications will the railroads and coal companies did not totally eliminate this uncertainty. Nonetheless, the following conclusions seem to be accurate. First, the schedule rates are maximum rates for coal movements. Second, rates below these levels are provided in some cases. In general, concessions are allowed on the scheduled rates for the provision by the mines of fast loading/unloading facilities meeting certain requirements, and also for the longer hauls to the seaboard from western and north-western coal fields. A list of concessions as of January 1978 was provided by the coal companies.[32] Though the concessions were varied in certain instances, 80 percent of them ranged between 60 and 80 Australian cents, and the amount was independent of mileage. If we assume that the concession stayed the same proportionately between 1978 and 1979, the tariff levels reflecting these would range from 8.1 cents per short ton-mile at 40 km, to 6.7 cents at 111 km and 5.9 cents ar 207 km. These are still far in excess of U.S. rates noted above. Note however that no data have been provided for 1979 concessions, which may well differ from previous concessions. Also note that the percentage increase in tariffs, as represented by the schedules for 1977, 1978, and 1979, is different for different mileages. From 1977 to 1979 tariffs for 25 km shipments increased by 21 percent, tariffs for

100 km shipments increased by 14 percent, and tariffs for 200 km shipments increased by 13 percent. Finally, note that concessions do not apply on all shipments, so that this reduction in tariffs on all routes would underestimate transport costs overall. For example, a sample of 12 tariffs from the coal companies as of August 1979 showed that only Western Main and Lithgow to Balmain received a concession from the rate schedule.

Less information was available on truck rates in New South Wales.[33] As a general rule, truck rates for distances below 25 km are marginally less than rail rates. For example, the 13 km distance from South Bulli to Port Kembla costs A $1.67 via rail and A $1.30 via road. For longer distances, up to say 200 km, truck transportation rates per ton mile are generally competitive with rail. In some cases, however, where rail access is not close to the mines, truck transportation is far cheaper. For example, Wollondilly coal to Port Kembla must be diverted by approximately 30 km to a rail siding at Glenlee for transfer. In addition, truck routes are often more direct than the circuitous rail lines. The Woolondilly Washery, for example, is 78 km from Port Kembla (via Picton). This compares to 30 road km to Glenlee, and 142 km via rail from Glenlee to Port Kembla.

An interesting comparison of coal transportation patterns, provided by Clutha Development Pty., shows the optimal transportation modal selection for eight different shipments.[34] Road rates range from 8 cents to 10 cents per ton mile. On five of the eight movements, all-road movements represent the cheapest alternative. One other movement is best served by a road, rail combination. Table 2 compares the tariffs for the

same routes given that railroad service is used wherever possible, and given existing infrastructure. It is interesting that shipments from Glennlee to Port Kembla will cost A $6.55 via rail versus A $4.61 via truck, while Wollondilly coal to Port Kembla will cost A $8.95 via rail versus A $5.95 or A $5.11 via truck (depending on routing). It is clear that if the government continues to push railroad transportation, and to curtail truck transportation, significant economic losses will obtain.

We have less information on Queensland coal rates. In general, longer hauls to ports are involved in Queensland (170 to 380 km), and rail carries virtually all of these export movements. Six tariffs as of August 1979 have been provided by the coal companies.[35] These range from approximately 3.8 U.S. cents per short ton-mile to 3.1 U.S. cents per short ton-mile over distances from 177 km to 343 km. In comparison, the U.S. East and Midwest rates for 177 km shipments are approximately 3.1 to 4.3 cents per short ton-mile respectively. For 343 km shipments, the corresponding rates are 2.2 and 2.6 cents per short ton-mile. This compares with scheduled rates of 7.0 cents at 177 km and 5.1 cents at 343 km in New South Wales, or approximately 4.5 to 6.4 cents given possible concessions (all in U.S. dollars). This comparison can be deceptive, however, for a number of reasons. First, the New South Wales rates are keyed to shorter-distance shipments, mostly below 150 km and often as short as 20 km. In Queensland, the longer distances suggest more efficient system-wide use of rolling stock. Furthermore, coal companies have noted that New South Wales shipments are primarily along relatively

Table 2.

New South Wales Coal Transportation Alternatives

(A $/metric ton)

	Present mode			Rail haulage maximized		
Wollondilly Coal	(Road)	(+Rail)	(Total)	(Road)	(+Rail)	(Total)
Glenlee to Balmain		3.65	3.65		3.65	3.65
Glenlee to Port Kembla	4.61		4.61		6.55	6.55
Wollondilly to Port Kembla via Picton	5.11		5.11	2.40	6.55	8.95
Wollindilly to Port Kembla via Narella	5.95		5.95	2.40	6.55	8.95
Tahmoor Coal						
Tahmoor to Balmain	2.20	3.65	5.85			
Tahmoor to Port Kembla						
Other Coal						
South Bulli to Port Kembla	1.30		1.30			
Coalcliff to Port Kembla		1.93	1.93			
Coalcliff to Port Kembla	2.45		2.45			

Source: Private correspondence with British Petroleum, London, U.K. and Clutha Development, Pty, Ltd.

congested old track. Most Queensland traffic moves to Hay Point on relatively newly constructed and uncongested lines. Finally, this line was completely funded by the Central Queensland Coal Associates on a security deposit basis. According to coal companies, the freight rate includes three components: 1) operating costs; 2) profit or tax component; 3) amount to repay the Central Queensland Coal Associates security deposit.[36] Nonetheless, this financing system may, in part, account for lower rates.

In addition, recent rail rates for new developments have been planned at far higher levels than currently exist. In 1977, the government planned a freight rate of A $6.90 from Norwich Park to Hay Point.[37] Assuming an increase at 10 percent to current dollars, this amounts to A $7.59 or approximately 4.7 U.S. cents per short ton-mile. What rate will actually develop is uncertain.

RATE/COST RELATIONSHIPS

As in the case of the United States and South Africa, the next question is, are these transportation rates equal to costs First, consider trucks. The trucking industry is competitive in Australia, and rates should reflect costs including a normal profit. The Long Distance Road Association of Australia estimates road costs as a function of truck size and annual miles.[38] They range from 6 to 9 Australian cents per ton-mile. Given the relative density in New South Wales, and a 10 percent markup of rates for normal profits, we can say with reasonable certainty that rates approximate long-run marginal costs. Note of course

that, as in the United States, road infrastructure costs are not included in this estimate. Note also that the difference in Australian costs versus U.S. costs is attributable to high equipment costs (for example, 5-axle truck: U.S. $80,500 versus U.S. $55,000; 3-axle truck: U.S. $38,000 versus U.S. $22,000), and higher fuel and labor costs.[39]

In regard to rail costs, estimation of rail/cost relationships is not possible. It is doubtful whether even the state railways know their costs.[40] Nonetheless, some general observations are possible.

First, rail costs in both Queensland and New South Wales no doubt exceed costs in the United States. Equipment costs are approximately 20 percent higher, labor unions are very strong, and fuel costs high. However, as is the case with South Africa, evaluating these factors independent of other factors in the production functions is hazardous at best. (See South Africa Section).

Second, there is little doubt that the higher cost levels in Australia do not justify the extremely high rail rates. With reasonable certainty we can say that the rates include substantial rents. Coal traffic is used to subsidize other traffic, and this practice is explicitly acknowledged by the states.[41]

Unfortunately, the extent of this margin is uncertain. However, the possibility that rates can be lowered so that they are closer to costs to attract traffic cannot be ignored, and this must be considered as an important factor in Australian involvement in international steam coal trade.

CAPACITY

The last subject to discuss in the case of Australia is the future ability of the transportation infrastructure to carry increased volumes of coal. This has been a large concern of observers and participants in the Australian coal market, and a considerable amount of planning has been undertaken. A number of points should be made.

First, increments in coal transport will be mostly carried by rail as trucks are prohibited to greater and greater extents.[42] There are two explanations for this prediction. First, the traditional interest of the railroads is to maximize rail traffic. Second, and largely as an impetus to the railroads' goals, there are increasing health and environmental concerns with truck movements in New South Wales. The public has become increasingly outraged with large coal trucks moving on mountainous terrain in rural areas, largely as a result of serious truck accidents, often involving cars and property, along the routes.[43] As a general rule it is unlikely that trucks will carry incremental export movements.

Given this, the ability of the railroads to handle increased volumes of coal has been questioned. In response to this concern, the Public Transport Commission has evaluated in detail the capacity of the existing rail network and the investments required to have additional tons of coal moved to export destinations The system presently carries approximately 12 million metric tons per year, and the Commission estimates a theoretical capacity of 30 MT.[44] However, to carry the 1985 forecast export tonnage of 48 million metric tons per year economically, an

investment of A $78 million in track and A $73 million in associated signalling would be necessary; together with A $273 million in equipment. The Public Commission predicts that the increased volume levels should service these capital expenditures at current real rate levels.[46]

More interesting than these aggregate figures is the plan itself, which has been subject to considerable controversy. In essence, the government has decided which port facilities to improve or construct, and it has planned related railroad improvements accordingly. However, the goal in doing this has been primarily to maximize rail traffic, and system-wide operating efficiency has in some instances been neglected.

In the Northern District (Hunter Valley), new port infrastructure developments at Port Waratah and Newcastle have been planned. However, all road traffic must be phased out over a ten-year period. A penalty of 40 Australian cents per metric ton in $1979 is intended to obtain this goal.[47] In that the Hunter Valley is accessible to rail facilities, this particular facet of the government's plan has not been controversial.

More controversial are the coalfields in the West, South, and Southwest of New South Wales. These producers have been well-positioned traditionally for export shipments. However, for increased volumes, expanded port facilities and transportation infrastructure are required. The realistic options involved building a new coal loader at either Port Kembla or at Port Botany. Since Port Kembla would put Burragorang Valley Coal at a serious geographical disadvantage, and Port Botany afforded greater freight economies due to larger size ships, the producers agreed to locate the new coal loader at Port Botany. This provided the least cost alternative.

However, with the change of State Government, the decision of the previous government to approve, in principle, the Port Botany plan was overturned. In June 1977, Port Kembla was nominated instead. Furthermore, truck traffic received at Port Kembla will be limited to 2 MTPY from nominated collieries. The producers argue that in seeking to maximize rail traffic, the object of efficiency has been removed. The government, in contrast, cites the existing rail facilities to Port Kembla and environmental concerns in their decision.[48]

To conclude, two factors in long run development in New South Wales should be considered. First, large investments will be required to carry additional coal volumes. Second, the government plans for infrastructure development will impose greater costs on large producers in the western coal districts, both due to questionable selection of port facilities and reduction of truck transport. On balance, even though we have concluded that rates are far above costs, it is unlikely that rates will be reduced given these developments.

Finally, brief notes on Queensland should be made. First, the rail system in Queensland is in a general sense in better shape than that in New South Wales. Expansion to carry increased exports will no doubt be less expensive, although no estimates exist similar to those for New South Wales. More important is the indication that the Queensland government is trying to appropriate coal company profits. Since the A $6 per ton coal levy has been repealed, freight rates are the easiest mechanism by which to reap profits earned by large multinational companies.[49] As much as anything, the issue reflects the political

embarassment of large profits being earned by non-Australian firms. A variety of factors enter into the issue: employment at coal fields, foreign investments, and the economic picture as a whole. The focal point of the political debate is Utah Development Companies Norwich Park project, where very high rail rates have been negotiated by the Government. Though any forecast is speculative, the prospect for rail rates in Queensland is increasing instability and possibly increased rate levels.

CANADA, WESTERN EUROPE, JAPAN

We consider inland coal transportation prices and patterns in Canada, Western Europe, and Japan in this section. Our primary purpose is to assemble the information required for the analysis of delivered coal prices and coal demand. Other issues that have been analyzed in the United States, Australian, and South African cases will be given little or no attention for the following reasons. First, in the case of Canada, their coal transportation system closely parallels coal transportation in the Western United States. In addition, Canada's situation has been extensively analyzed by others in recent years.[50] Second, in Japan, power stations have been and will continue to be located at coastal sites, and this locational choice is virtually independent of fuel choice. Although nuclear power would conceivably free the Japanese of this constraint, nuclear power plants have also been located at coastal sites. Third, in Western Europe, most coal-fired power plants will also

be located at coastal sites. Where they are not, transportation distances will normally be short relative to the inland movements in exporting countries. Fourth, in many cases very little transportation rate or cost data are available.

CANADA

Our main concern in Canada is with western coal reserves and the shipment of coal to West Coast ports. Although coal reserves in eastern provinces (Nova Scotia in particular) could be developed for export, the amounts are small, the costs high, and their importance is minimal (See Part B, Chapter I). Of Canadian coal reserves, 99 percent are in the western Provinces of British Columbia, Alberta, and Saskatchewan. British Columbia and Alberta have bituminous coal; Saskatchewan has only lignite. These coal fields are from 600 to 1000 miles east of the West coast port facilities: Roberts Bay, Port Moody, and North Vancouver.

The only existing transportation mode over this route for coal is rail. Also, coal shipments over this route are almost entirely metallurgical coal, mainly destined for consumers in Japan. In 1978, approximately 14 million metric tons (MT) of export coal were carried by the railroads.[51] Furthermore, export coal movements were the largest single commodity in tons and revenues for the entire Canadian rail freight system.

The railroad system in Canada is unique. All long-haul coal shipments, in fact virtually all rail freight shipments, are handled by one of two railroads-the Canadian National Railway (CN), which is

government owned and controlled, and the Canadian Pacific Railways (CP), which is privately owned and controlled. The regulation of railroad transportation resembled closely rail regulation in the United States until the Canadian National Transporation Act of 1967. Similar to current U.S. deregulation proposals, this act removed most of the rate restrictions that had previously existed. Specifically, the new act only prohibits non-compensatory rates, defined as below variable cost levels (as calculated by the commission), and unreasonably high rates under monopoly conditions, defined as more than 250 percent above variable costs.[52] In this system the railroads have considerable control over rate levels, and most destinations are serviced by only one railroad.

Rail transportation of coal is predominantly in unit trains. The distance of existing export movements ranges from 560 to 730 miles. The operations resemble the most efficient services in the Western United States, with 3000 HP locomotives and 100 net ton cars. Unit-train rates from mid-1977 ranged from 1.40 to 1.68 cents per short ton-mile (Canadian dollars).[53] Escalating this to mid-1979 levels (AAR index), and converting to U.S. dollars (.85 U.S. $ per Canadian dollar), yields an average of 1.6 cents per ton-mile in U.S. dollars. This compares to the Western U.S. rate of approximately 1.2 cents per ton-mile for a shipment of 700 miles.

As before, we are interested in the relationship between rates and costs. Again, however, there is no solid evidence on this relationship. Given the significant monopoly power of the railroads, the possibility of rents certainly exists, but data are not available to

specify rent levels accurately. One empirical estimate of rents on Canadian coal shipments was made by James Sloss.[54] Using company expense and revenue data, and estimating the allocation of expenses and revenues over unit train export movements in 1969 and 1975, Sloss generated "an extremely approximate estimate of the gain or loss experienced by the participating railroads in hauling unit coal trains in the year 1975." He concluded that for CN marginal revenues were 147 percent of marginal costs, and for the CP, 338 percent of marginal costs.[55] However, given the data deficiencies that Sloss himself notes, this conclusion is not sufficient for adjusting actual rate levels. Current CP rates are not systematically higher than CN rates, and it is difficult to imagine long-run cost differences between the railroads of this magnitude.

To conclude, the unit-train rates of 1.6 cents per ton-mile may well include a significant rent component. The main factor affecting rent levels is the railroads' monopoly position. Factors suggesting lower rents are the extremely mountainous terrain on export routes and the competitive metallurgical coal market. We do not have the data to specify costs exactly. As a lower-end Western U.S. cost estimates are a reasonable approximation.

UNITED KINGDOM

The British public utility, The Central Electricity Generating Board (CEGB), consumed 75.5 million metric tons (MT) of coal in 1978. Coal-fired power stations are distributed throughout the country, but the

greatest concentrations are in the Southeast (London), the Midlands (Nottingham, Birmingham), the Northeast (Harrogate, Leeds), and the Northwest (Manchester).[56]

The location of these plants has gone through several stages. As a general rule, it is more economical to locate base-load stations near the fuel source and then to transmit electricity to markets than to put power stations at the markets and carry coal to them. In practice, however, this has not always happened, largely because generating capacity becomes obsolete so quickly. A given plant in the past did not contribute to base-load generation for more than a few years, after which it was used to meet middle and peak demand. Since it was not economic to transmit middle or peak power over any distance, plants were often built close to markets for long-run cost savings.[57]

Since nationalization, however, the power industry has moved to minimization of transport costs, and large new stations are built near fuel sources. This explains the large number of coal-fired stations in East Midlands and Yorkshire. Finally, the most recent trend has seen a move to oil-fired and nuclear power stations at coastal sites. In addition, all of the coal-fired power stations commissioned in 1978-1979 are located at or close to the coast.[58]

Several transportation modes are used to distribute coal to power stations. In 1977, the CEGB received 68.75 MT: 54.9 MT by rail; 7 MT by truck; 4 MT by coastal shipping; 2 MT by conveyor belt; and .75 MT by canal. For the most part, hauls are over short distances, less than 50 km. 90 percent are over distances less than 100 km.[59]

Railroad transportation of coal is moved exclusively by the government owned British Railways. The British Railway's largest single customer is the CEGB, and their contractual arrangement is an important factor underlying British coal transportation patterns. The agreement with the British Railways is to transport coal by rail to any rail connected power stations unless "it is inconvenient to do so." In return, the British Railways give the CEGB a "generous review of freight rates in return."[60]

Road transport is chiefly to old stations low on the merit order and lacking rail connections. In some cases, road transport is in fact cheaper than rail, but under normal circumstances its use is not possible under the contractual arrangement between the British Railways and the CEGB.

Rail movements in Britain are primarily in unit trains, or "Merry-go-round" (MGR) trains, in the British vernacular. In 1978, 75 percent of coal movements on the CEGB were MGR service, and virtually all the new rail connections are of this type. Typical service involves 2500 HP locomotives, cars with 30 ton capacity, and trainloads of approximately 1000 tons.[61]

Rail rate informaton is unavailable given the contractual arrangement. In fact, given this system, individual rail rates may have little meaning. One imperfect estimate of average freight rates is as follows. In 1977, the total CEGB rail bill amounted to 55 to 65 million pounds. The average distance, weighted by tons, was 50 km, and tons-carried amounted to 54.8 million metric tons.[62] This indicates

a tariff of 6.5 to 7.5 U.S. cents per short ton-mile for a 50 km haul (assuming the average 1979 conversion rate of 2.24 dollars per pound). United States shipments of less than 50 km range from 5 to 9 cents per ton-mile. Given the tight concentration of distances on this average, this estimate can be used as a reasonable approximation of rail rates.

To conclude, coal power plants in the United Kingdom using imported coal will most likely be located at coastal sites. To the extent that inland stations use imported coal, short-hauls will be the norm, and a tariff of 7 cents per short ton-mile is an imperfect, but reasonable approximation. Note finally that this is considerably lower than short-haul rates in Australia, and approximately equal to short-haul rates in South Africa, and the United States.

WEST GERMANY

Limited data have also been obtained for West Germany. Two facets of West German Coal transportation are important to our analysis: the costs of Ruhr Valley coal in German consuming centers, and the costs of transporting coal from ports to German consuming centers.

First, consider Ruhr coal. This coal is carried by rail, barge, and truck. Truck movements are only economical on short-hauls of 60 km or less. Intrastate barge movements are regulated at levels above marginal costs. They are very high relative to the United States. For example, a shipment from Furst Leopold to Stuttgart (601 km) in 1979 costs DM 30.30 per metric ton, or approximately U.S. 4.0 cents per short ton-mile.[63]

As a general rule, intrastate rail rates are competitive with

intrastate barge shipments only if unit-train rates are prescribed and the receivers cannot be reached directly by barges so that an additional connecting mode is required. The railways set higher rates when barge competition is weak; for example, from the Ruhr Valley to Munich. Unit train concessions depend on volumes carried and frequency of shipments. As an example of this adjustment, a unit-train rate from Hervest-Dorsten to Hannover is DM 22.62 per metric ton, compared with the base rate of DM30.40. Even with this adjustment the rates are extremely high. The unit train concession rate to Hannover amounts to approximately 7.5 U.S. cents per short ton-mile.[64]

Second, consider import movements. In this case data are available for barge shipments from Rotterdam to various German destinations.[65] These intercountry rates are unregulated and far lower than intracountry rates. For example, the intracountry barge rate from Furst-Leopold to Stuttgart is DM 30.30 (610 km). The intercountry barge rate from Rotterdam to Stuttgart is DM 22.00 (860 km). In U.S. dollars the intracountry rate is approximately 4.0 cents per short ton-mile, versus 2.1 cents per short ton-mile for the intercountry shipment (.55 U.S. $ equals 1 DM). Note that even the intercountry barge rates are as much as four times higher than U.S. equivalents.

OTHER COUNTRIES

Finally, a few words about the remaining countries. First, in Japan, all non-hydro existing and planned power stations are located at coastal sites. Inland transportation is therefore not important to

consider in our study. Of course, some method of distribution from ports will be required, but this will almost certainly be performed by small seagoing vessels since the dockside facilities at coastal power plants are limited to receiving smaller ships.

In European countries other than Great Britain and Germany, the importance of inland transportation is less certain. The location of power plants involves a set of non-transportation factors, including environmental constraints, existing coal facilities, and patterns of electricity demand. In most cases coal power plants will be located on the coast, but this simple assumption could be misleading. Even so, in most other cases, due to simple geography, inland coal hauls will be relatively short relative to U.S. hauls, and only a small factor in the development of steam coal trade. Given this, and serious data limitations, the general assumption will be coastal power stations, unless otherwise noted.

In Italy, Denmark, and the Netherlands, this appears to be a sound assumption. (See Demand Section for details on power plant location). In France, coal power stations wil either be coastal, or possibly in the Paris region. In the later case, barges from the Le Havre will be employed. Barge rates in France are not available. We will assume that they are equal to West German intercountry rate levels.

SUMMARY--FOREIGN COAL TRANSPORTATION

Several salient points from this brief analysis should be reemphasized. First, the predominant mode of coal transportation in all

the countries studied, in the past, the present, and most likely the future, is the railroads. Second, railroad coal rates in foreign countries are at least as high as in the United States, and in some cases, notably New South Wales and West Germany, far higher. Third, although there are wide international variations in the structure of railroad ownership and regulation, a common denominator across all the countries studied is significant monopoly power held by the railroads, and value-of-service pricing. Fourth, with the possible exception of South Africa, our limited evidence suggests then coal rates exceed incremental costs by significant margins in all the countries studied. Fifth, the profits on coal shipments are used to finance the deficit incurred by other railroad traffic, freight and passenger. Sixth, even with this subsidization of other traffic, all the foreign railroads operate at large system-wide deficits. Finally, as coal is in many cases one of only a few profitable commodities, it is unlikely that reductions to cost levels will be obtained in the future.

FOOTNOTES--CHAPTER VI

[1]Throughout the discussion below, many interesting issues, especially regulatory issues, will be given little or no attention if analysis does not contribute directly to a better understanding of the given country's role in export coal markets. For detailed analyses of transportation regulation in these countries, see in particular: Moore, T.G., Trucking Regulation, Lessons from Europe, American Enterprise Institute for Public Policy Research, Washington, D.C., 1976; Kolsen, H.M., The Economic Control of Road-Rail Competition, Sydney University Press, Sydney, Australia, 1968; Stenason, W.S. and Romoff, H.M., "Transportation Pricing and Regulated Competition: The Canadian Experience," in Criteria for Transport Pricing, Nelson, J.R. (ed.), Cornell Maritime Press, June 1973, pp. 204-216.

[2]"Annual Report," South African Railways and Harbours, 1977-1978.

[3]Information on Steam Coal Transportation, Internal materials, South African Railways.

[4]"Annual Report," South African Railways and Harbours, 1978-1979.

[5]Information on Steam and Coal Transportation, op. cit.

[6]Background on the South African Railways is drawn from the following sources:

a. "The South African Railways: History, Scope, and Organization," South American Railways, 1947.

b. D. Herbert Houghton, The South African Economy, Oxford University Press, Oxford, England, 1964.

c. Hurwitz, Nathan et al., The Economic Framework of South Africa, Shuter and Shooter, 1963.

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[8]"Report of the Commission of Inquiry into Railways Rating Policy in South Africa," U.G. 32/1950; Schuman and Nepal, "Report of the Committee on Railway Rating Policy and Industrial location in South Africa," 1967.

[9]Houghton, op. cit., p. 192.

[10]Technical Analysis of Steam Coal Prices in Six OECD Countries, Prepared by ICF Inc. for the U.S. Department of Energy, October 1978.

[11]A Survey of Railroads of Selected Industrial Countries, Union Pacific Railroad Company, New York, September 1977, p. 112.

[12]Ibid., pp. 21 and 112.

[13]Ibid., pp. 21 and 112.

[14]Based on conversations with G.E. International, Mr. Bojarski.

[15]"Information on Steam Coal Transportation," South African Railways and personal correspondence.

[16]Personal correspondence with South African Railways and R.L. Cohen, Anglo-American Coal Corporation, Ltd., April 1979.

[17]Black Coal in Australia, 1977-1978, Joint Coal Board, New South Wales, p. 166.

[18]"Annual Report," Public Transport Commission of New South Wales, 1978, pp. 36-37.

[19]Black Coal in Australia, 1977-1978, op. cit.

[20]The Queensland Coal Board, 28th Annual Report, June 30, 1979; "Report of the Commissioner for Railways," Queensland Railways, June 30, 1978.

[21]The discussion of Australian Transport Regulations is based primarily on: Australian Transport Economics, G.R. Webb and J.C. McMaster (eds.), Australian and New Zealand Book Company, Sydney, Australia, 1975.

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[22]Commission of Enquiry into the N.S.W. Rail Freight Industry. Working paper no. 2. "Two notes on the development of the interpretation of S.92 in relation to interstate transport," February 1979.

[23]Hunter, op. cit., pp. 94-103.

[24]Ibid., pp. 94-103.

[25]Kolsen, op. cit., pp. 132-147.

[26]Private correspondence with H.M. Kolsen, July 1979, University of Queensland.

[27]Kolsen, op. cit., pp. 132-149. Wheeler and Gilmour, op. cit., p. 262.

[28]Public Transport Commission of New South Wales, "Annual Report," 1978, pp. 60-62.

[29]Based on communications with H.M. Kolsen, G.R. Webb, G.S. Aislabie, The Public Transport Commission of N.S.W., Utah Development Co., Clutha Development Company, Conzinc Rio-Tinto Co.

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[47]Based on personal communications with R.E. Barnes, Clutha Development Pty. Ltd., August 1979.

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[54]Sloss, J. and Ferguson, W.L., "Coal Markets and Rail Utilization in Canada since the National Transportation Act," M.I.T., Center for Transportation Studies, December, 1977.

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[61]Ibid., p. 80.

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CHAPTER VII

OCEAN TRANSPORTATION

INTRODUCTION

This chapter analyzes the role of ocean transportation in international steam coal trade development. The purpose is to estimate the long-run marginal cost of ocean transportation of coal. A cost model is estimated for coal movements over potentially important steam coal trade routes. The model incorporates ship size-distance trade-offs, backhaul opportunities, and alternative vessel technologies. The cost calculations will be integrated with the other cost variables in Part B.

Two related topics are analyzed in lesser detail. First, the market structure and price formation in bulk carrier markets. The interaction of prices and costs, and various supply alternatives in ocean transportation are explained. Second, the role of port facilities in steam coal trade development is evaluated in Appendix B.

OCEAN-SHIPPING MARKETS

Two related markets are important to ocean-going coal shipments: bulk commodity markets and oil markets. Table 1 shows major bulk commodity and oil seaborne trade from 1967 to 1978.

Coal trade in 1978 equaled 122 million metric tons (MT), approximately 75 percent of which was metallurgical coal.[1] Only grain and iron ore shipments exceeded coal shipments in volume (149 MT and 265 MT respectively). Other major bulk commodities are bauxite and phosphate, with shipments in 1977 of 46 MT and 44 MT respectively.[2]

The tanker market includes crude oil and oil products. Seaborne shipments from 1967 to 1978 are also shown in Table 1. In 1978, crude oil shipments equaled 1440 million tons, almost three times the volume of iron ore, coal, and grain shipments combined. Oil product shipments amounted to 270 MT in 1978, approximately equal to iron ore shipments in that year.

Table 2 depicts the world shipping fleet from 1967 to 1979. Oil tankers serve the oil and oil products market, bulk carriers serve the bulk commodity markets, and combined carriers serve both markets. Combined carriers are classified as either ore-oil carriers (O/O), or ore-bulk-oil carriers (OBO). Note in particular the increasing importance of combined carriers between 1967 and 1979. In 1967 they amounted to 3 percent of total deadweight tonnage (DWT), versus 10 percent in 1979.

The market in both cases closely approximates the perfectly competitive paradigm.[3] In the bulk carrier market certain suppliers (for example U.S. Steel) control a large proportion of the available tonnage. However, the ownership of the residual tonnage by brokers, shipping companies, and financial institutions undermines any effective collusion. Easy and cheap entry, the lack of significant economies of scale in vessel ownership, the lack of regulation (with the exception of safety regulations), and the mobility of vessels between markets makes market control next to impossible in theory.[4] In practice, there is no evidence to contradict this hypothesis.[5]

SUPPLY ARRANGEMENTS

In both bulk carrier and tanker markets, a chain of supply arrangements is provided by the market. In bulk carrier markets the

Table 1

World Seaborne Trade 1967-1978

(million metric tons)

	Crude Oil	Oil Products	Iron Ore	Coal	Grain	Other Cargo Estimate	Total Trade Estimate
1967	672	193	164	67	83	685	1864
1968	768	207	188	73	78	727	2041
1969	871	209	214	83	71	789	2237
1970	995	245	247	101	89	804	2481
1971	1068	247	250	94	91	825	2575
1972	1184	261	247	96	108	866	2762
1973	1365	274	298	104	139	940	3120
1974	1360	264	329	119	130	1045	3247
1975	1259	233	292	127	137	995	3043
1976	1418	260	294	127	146	1075	3320
1977	1467	273	276	126	147	1120	3409
1978	1440	270	265	122	149	1185	3431

Source: Fernley and Egers Chartering Co. Ltd. Review 1978, Norway, 1979, Table 1, p. 14.

Table 2

World Fleet 1967-1979

(Numbers of ships[1] and million dead weight tons)

	Oil Tankers	Combined Carriers	Bulk Carriers
1967	2860- 95.6	109- 4.4	1271- 30.9
1968	2911-104.1	153- 7.8	1498- 39.3
1969	2984-116.1	175-10.4	1761- 48.2
1970	3008-131.5	195-12.4	1964- 55.1
1971	3094-151.0	221-15.6	2131- 61.7
1972	3206-171.1	251-21.1	2345- 70.4
1973	3193-188.9	301-29.0	2580- 79.9
1974	3293-215.6	355-37.4	2781- 89.4
1975	3406-254.6	386-42.1	2992- 97.8
1976	3439-290.9	398-44.2	3197-105.7
1977	3384-320.5	414-46.8	3464-116.6
1978	3301-331.9	419-48.3	3826-129.0
1979	3130-327.4	416-48.7	3671-135.3

Notes: 1. Includes vessels over 10,000 DWT.

Source: Fearnley and Egers Chartering Co. Ltd. Review 1978, Table 3, page 15.

options are dimensioned mainly according to time and risk, ranging from vessel ownership by the coal company to various forms of chartering. Chartering is done indirectly through brokers, or directly by vessel owners. At one end of the chartering spectrum is spot, or single-voyage, charters. In this case the charterer specifies the cargo (commodity and tonnage), loading and discharge ports, when the vessel is to be available for loading, and payment per cargo ton. Since all vessel costs are covered by the owner, the terms normally specify loading and discharging times, and demurrage fees. The elapsed time between the agreement to charter and the shipment itself is rarely more than a month and often only a day or less.

At the other end of the spectrum are bareboat charters, where a ship is chartered for five years or longer and the charterer pays all costs except capital charges and sometimes repairs. In many cases a bareboat charter will extend for most of a vessel's useful life. In between these two extremes are 1) trip charters, usually for one voyage, where the charterer specifies the vessel size and speed, date of availability, and payment on a daily basis; 2) time charters, where the vessel, employing the owner's crew, is taken for a period which may range from a few months to several years, and where payment is per vessel deadweight ton (DTW); and 3) contracts-of-affreightment, where large quantities of a commodity are transported on a particular route for a specified period of time. In the latter case usually more than one ship is involved and a rate per ton delivered is agreed upon. Financing for newbuilding is often hard to obtain without this type of arrangement.

The distribution of tonnage over these various supply alternatives varies between markets. Coal and iron ore markets have traditionally relied on vertical integration and contracts-of-affreightment. Though exact figures are not available, it is estimated that less than 10 percent of coal movements are contracted on the spot market, and that 80 percent or more are carried by contracts of affreightment, supplier-owned vessels, and time charters.[6] In the iron ore business, large steel companies own the majority of their tonnage, or they have binding relationships with a shipping company which effectively ties the vessels into the steel companies' service for the useful life of the vessel (for example, D.K. Ludwig in West Germany with U.S. Steel). In Japan a similar practice is frequently used. Japanese flag carriers are almost exclusively tied in for life to Japanese producers and rarely show up on the charter market. In coal, Kaiser Resource and Utah International are two examples of large vertically integrated coal exporters.[7]

PRICE FORMATION

To understand this pattern of supply arrangements requires some comprehension of the complex relationships between the various chartering forms within and between different markets. The various types of chartering arrangements approximate a complete set of substitutes, bound together by the market's perception of the net advantage of one over another at any point in time. The "advantage," however, is a function of many variables, both endogenous and exogenous to, in our case, the coal trade. In the former case, the advantages of long-term arrangements to

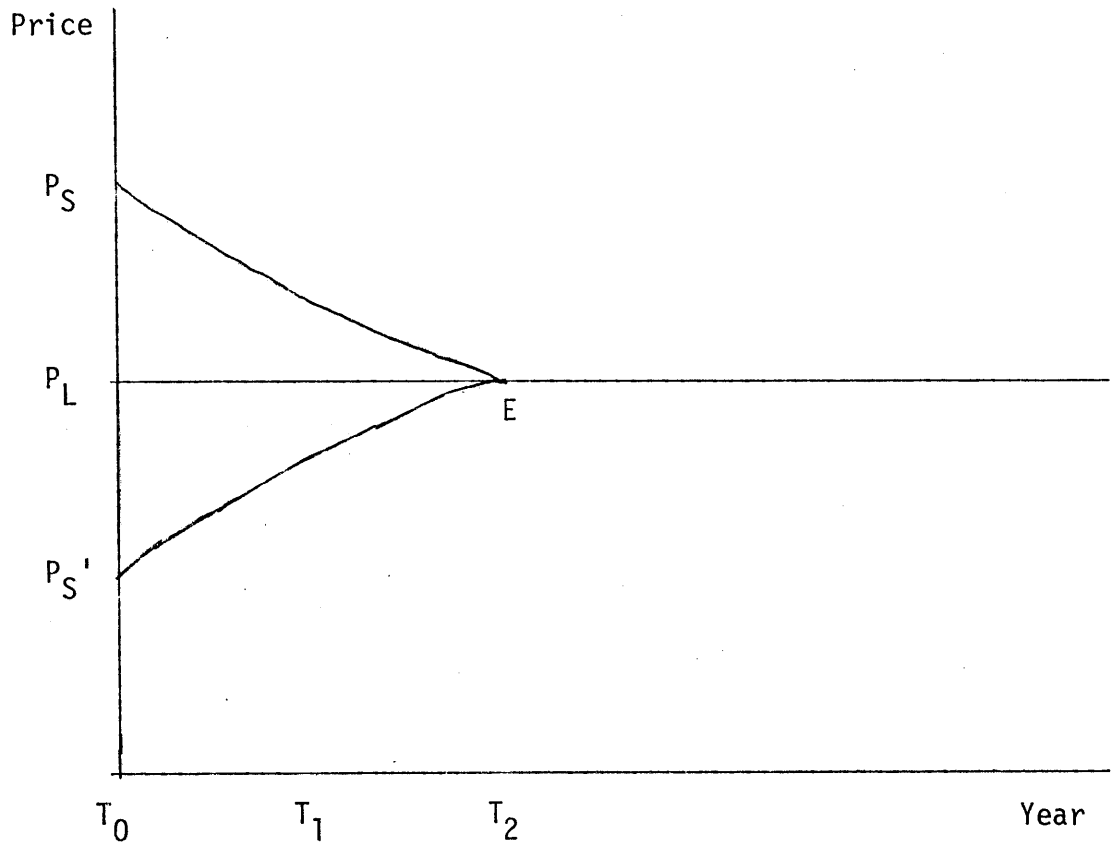
the shipper are lower procurement costs, better coordination, and increased efficiency as optimal ships can be employed. In the latter case, exogenous factors, the advantage or disadvantage is tied to shifts in supply and demand, and equally important, expectations of future shifts in supply and demand in any of several interrelated markets.

These shifts play a critical role in price formation and price relationships across alternative contractual arrangements. A brief explanation of them is important. In essence, as demand increases in the short run in a market, spot rates increase dramatically, the actual increase being dependent on the elasticity of demand for vessels, which in turn is dependent on the proportionate share of spot contracts in the given market and related markets. Where spot contracts comprise a smaller percentage of vessel tonnage, a shift in demand for coal will be translated into a larger shift in spot rates. Furthermore, to the extent the ore carriers, say, are substitutable for coal carriers, an increase in demand for coal tonnage might draw spot market ore tonnage to the coal market.

These price/quantity shifts will in turn affect the levels of trip charters and time charters, a somewhat surprising result. There are cases where current spot rates should affect time charters. For example, if spot rates are above long-term equilibrium rates due to a permanent upward shift in demand, a ship-owner must be paid the present discounted value of the revenue stream P_sE, depicted in Figure 1, in order to enter into a long-term contract in year t_0. However, in the case of the shorter-run disruptions that are generally observed in shipping markets,

Figure 1

Rate Relationships



the effect of current spot rates should be less significant, and time charters should more heavily depend on the owners' and charterers' expectations about long-run equilibrium rates. The fact that current spot rates are so important in determining charters may simply be a reflection of the speculative nature of ship owners. When spot rates are higher than long-run costs, owners are reluctant to charter their vessels for lower rates, preferring instead to play out the game, and risk vessel lay-offs as the market drops. When spot rates are low, the owners might take a time charter at some higher rate, probably below long-run costs, to avoid costly layups. Shippers in this case are reluctant to pay the long-run price, also preferring to play out the game. In sum, when spot rates are low, time-charters will be low, but above spot rates. When spot rates are high, time charters will be high, but below the spot equivalent.

The strange, but not implausible, market mechanism is in turn reflected in newbuilding activity and newbuilding prices. As time charters increase, newbuilding activity increases, or the pressures on newbuilding activities increase, and newbuilding prices rise.[8] Certainly newbuilding activity should be affected by signals that long-term rates are increasing. However, they should not be heavily affected by short-run disturbances in spot rates. Consequently, if time charters are heavily affected by spot rates, as suggested above, the relationship between newbuilding activities and time charters should not be as strong. Norman presents one conceivable explanation. He suggests that a prospective ship owner might charter the new ship for anything up to 20

years at the time he signs a contract with the shipbuilding yards. "Rather than doing his own independent analysis based on his own expectations regarding future demand/supply conditions," he could base his decision on profitability on the time charter rate existing at the time of contracting, on the assumption that time charters reflect charterers' assessments of future market conditions.[9] This is possible, and consistent with the basic speculative nature of the shipping business.

Compounding the complexity of rate relationships are vessel substitution possibilities across markets, for example, between grain and coal, or oil and coal. In some cases substitution possibilities might dampen spot rate volatility in a given market. OBOs probably serve this purpose in the oil trade. However, where the complement market is more volatile than the central market, then the substitution possibilities could increase volatility. Grain, for example, might act this way with coal. As the highly volatile grain markets shift, vessels allocated to the coal trade will be drawn into (or out of) the grain trade, increasing (or decreasing) spot rates for grain. On balance, shifts spurred by volatility in other markets might compound the volatility that would exist in coal markets if no substitutions were possible.

Given these brief explanations, let us return to the initial question--the advantages of long-term charters. First, the actual observed advantage or disadvantage of one contractual form versus another is always shifting, as market prices are in constant adjustment to reflect changing circumstances. As Adelman notes, "The (spot) rate curve whips up and down, above and below the long-term rate which serves as its

(movable) anchor point."[10] Though we cannot quantify the advantage in static terms, we can specify the constant perception of the advantages to shippers and vessel owners in long-term contracts--reduced risk--and the reduction extends at least through contracts of affreightment. Furthermore, in coal markets, where volumes are large and relatively certain, and where a large premium on vessel size and specifications and vessel coordination exists, and where the cost of service delays are high, this trend towards long-term charters observed in practice, is logical in theory.[10a] It says in essence that the expected losses in efficiency from spot charters are greater than the expected long-run gains from speculative purchasing.[10b]

These explanations are essential to evaluating coal trade. They tell us several things. First, spot prices are a very poor approximation of long-run costs. Second, time charters, though a better approximation, are also a biased indicator of long-run costs. They are significantly tied to spot rates, and also tied to second-hand vessel prices which in themselves are highly volatile.[10c] Based on these observations, an estimate of long-run marginal costs cannot rely on spot or time charter data. Contracts-of-affreightment or bareboat charter data might be a better approximation. However, these data are unavailable. Consequently, we must resort to an engineering-accounting estimation of long-run costs. Nonetheless, the above explanations also tell us that care should be taken with this approach.

THE LONG-RUN COSTS OF OCEAN-BORNE COAL TRANSPORTATION

In this section we estimate the long-run costs of ocean-borne coal transportation. First, the cost calculations will be summarized. Second, the sensitivity of these cost estimates to changes in cost variables will be considered. Third, comparisons will be drawn between the cost estimates and comparable ocean-freight rate data. Fourth, the importance of return cargoes to ocean freight costs will be appraised. Finally, alternative shipping technologies and their effect on future ocean transportation costs will be discussed.

COST CALCULATIONS

Long-run marginal costs include four elements: capital costs, quasi-fixed operating costs, fuel costs, and port and canal charges. For a specific route and ship specification, annual costs are divided by annual cargo transported to obtain the required freight rate (RFR) per ton to cover all the expenses of the incremental ship. Appendix A explains the cost calcualtions and the underlying assumptions.

Based on these assumptions and procedures, the cost calculations are presented below at January, 1979 cost levels. Table 3 summarizes costs for each route for 60,000 DWT vessels, the smallest sized ship likely to be employed for long-distance ocean coal movements. It highlights, where important, the trade-offs between distance and the canal charges and delays. Where the shorter route requires canal passage, the lowest required freight rate corresponds to the canal passage with the exception

Table 3

Cost Calculations - 60,000 DWT

(Required Freight Rate, dollars per metric ton, January 1979)

	Yokohama	Taranto	Rotterdam
Gladstone	8.32	19.58(S)	23.60(S), 24.15(H)
Port Kembla	8.75	19.19(S)	22.57(H)
Richards Bay	13.47	13.94(H), 12.88(S)	13.28(H)
Baltimore	19.19(P)	9.36	7.73
Hampton Roads	18.96(P)	9.16	7.52
Mobile	18.34(P)	11.08	9.47
Los Angeles	9.55	17.35(P)	16.04(P)
Vancouver	8.61	19.22(P)	17.96(P)

Notes: S = Suez Canal

P = Panama Canal

H = Cape of Good Hope

Where one Required Freight Rate is given, the route specified in this table is cheaper than the alternative listed in the mileage table.

Source: Author's Calculations.

of Australian shipments to Rotterdam, where a slight economic advantage is realized by the Cape of Good Hope routes. From Australia to Taranto, the Suez Canal routing provides the lowest rate.

Based on these calculations, Japan is served most cheaply by Vancouver and Australia. Los Angeles is a reasonably close competitor with a RFR of $9.55 to Yokohama, versus $8.32 from Australia to Yokohama at January, 1979 price levels. Freight rates from South Africa to Japan are $5.00 higher per ton than rates from Australia. Freight rates from the U.S. Gulf Coast to Japan are $10.00 higher per ton than rates from Australia.

The U.S. East Coast is the optimal supplier for Taranto. Shipments originating on the U.S. Gulf Coast are approximately $2.00 more expensive per ton. South African shipments to Taranto are $4.00 more expensive, and shipments from other supplying points cost from $8.00 to $10.00 more than shipments originating at Hampton Roads.

With respect to Rotterdam the same relationships hold approximately. One exception is Australian rates. They are as much as $17.00 per ton higher than are rates from Hampton Roads to Rotterdam.

In fact, port constraints are not equal worldwide, but vary considerably even among the major ports analyzed here (see Appendix B for details on draft constraints). And, as port constraints are alleviated, freight rates are reduced.

The proportional savings in greater vessel size increase with distance, and decrease with size, while the absolute savings are approximately constant. Table 4 presents the cost calculations for each

Table 4

Economies of Vessel Size

(Required freight rates, dollars per metric ton, January 1979)

DWT (000s)	Hampton Roads to Rotterdam (3591 miles)		Richards Bay to Rotterdam (7118 miles)		Port Kembla to Rotterdam (12617 miles)	
60	7.52(2.09)		13.29(1.87)		22.57(1.79)	
80	6.46(1.80)		11.27(1.58)		18.83(1.49)	
100	6.07(1.65)		10.41(1.46)		17.31(1.37)	
120	5.81(1.62)		10.27(1.44)		16.26(1.29)	
150	5.62(1.57)	5.92(1.65)	9.40(1.32)	10.03(1.41)	15.39(1.22)	16.44(1.30)
180		5.80(1.61)		9.76(1.37)		16.07(1.27)
200		5.68(1.58)		9.50(1.34)		15.60(1.24)
250		5.52(1.54)		9.24(1.30)		14.80(1.17)

Notes: Numbers in parentheses equal mills per ton-mile. The column shift at 150,000 DWT represents the shift from diesel to steam turbines.

Source: Author's calculations.

size vessel over three different routes; Hampton Roads to Rotterdam, Richards Bay to Rotterdam, and Port Kembla to Rotterdam. Between 60,000 and 120,000 DWT, the percentage reductions in the required freight rates range from 23 percent to 28 percent depending on distance. Above 120,000 DWT, the difference is dampened due to decreasing economies of size, and the switch to steam turbines with higher fuel consumption rates. A reference point is provided at 150,000 DWT to show cost changes given constant fuel consumption rates. For practical purposes, to obtain significant savings beyond 120,000 DWT, a vessel of at least 180,000 DWT must be contracted to offset the greater fuel consumption rates. The savings in moving from a 120,000 DWT vessel to a 250,000 DWT vessel range from 5 to 9 percent, again depending on distance. With the exception of very long routes, this saving is not likely to justify significant port facilities expansion beyond the capacity to handle 120,000 DWT vessels. (See Appendix B for more details.)

Based on the existing port constraints, the effects of size differential on ocean freight rates are summarized in Table 5. Shipments from Baltimore, Los Angeles, and Port Kembla are constrained to 60,000 DWT. Shipments from Hampton Roads and Mobile (McDuff terminal) can be carried on 80,000 DWT vessels. Shipments from Gladstone can be carried on 120,000 DWT vessels. Shipments from both Richards Bay and Vancouver can be carried on 250,000 DWT vessels. However, only Rotterdam can receive these ships. Taranto and Yokohama are constrained to 120,000 DWT vessels. The Panama Canal is constrained to 60,000 DWT vessels, and the Suez Canal to 120,000 DWT vessels.

Table 5

Cost Calculations--Existing Size Constraints

(Required Freight Rate, dollars per metric ton, January 1979)

	Yokohama	Taranto	Rotterdam
Gladstone	6.37 (120)[1]	15.05 (120) (S)	17.39 (120) (H)
Port Kembla	8.75 (60)	19.19 (60) (S)	22.57 (60) (H)
Richards Bay	10.00 (120)	10.47 (120) (H)	9.85 (120) (H),
		10.18 (120) (S)	9.50 (200) (H)
Baltimore	19.19 (60) (P)	9.36 (60)	7.63 (60)
Hampton Roads	18.96 (60) (P)	7.83 (80)	6.48 (80)
Mobile	18.34 (60) (P)	9.40 (80)	8.08 (80)
Los Angeles	9.55 (60)	17.35 (60) (P)	16.04 (60) (P)
Vancouver	6.56 (120)	19.22 (60) (P)	17.96 (200) (P)
			17.58 (200) (C)
			16.72 (250) (C)

Notes: S = Suez Canal
P = Panama Canal
H = Cape of Good hope
C = Cape Horn

Numbers in parentheses indicate the existing ship size constraints in thousand DWT.

Source: Authors Calculations.

Given these revisions, Los Angeles freight rates to Japan are more expensive relative to rates from Vancouver and Australia, the difference now amounting to $3.00 a ton. For shipments to Rotterdam, the gap between Richards Bay shipments and Hampton Roads shipments decreases from $6.00 to $3.00 per ton. Australia and Vancouver ship rates are still considerably more expensive than Hampton Roads rates ($10). To Taranto, a similar shift is observed. Note in all cases, however, that the least-cost supplier is not charged for any of the consuming regions. Note also that the use of the Suez Canal is no longer economical in shipping from Gladstone to Port Kembla, while from Richards Bay to Taranto the advantage is only 30 cents a ton. The only route that still depends on the Suez Canal is from Australia to Taranto, where the losses in Cape Horn transit amount to $4 per ton from Port Kembla, and $5 per ton from Gladstone. Given the current instability in the Suez region, this is an important variable to consider.

Finally, with reference to the Panama Canal, the only case where it is uneconomical to use it is from Vancouver to Rotterdam, where ships above 200,000 DWT can be used more economically around Cape Horn.

The significance of these differences and the advisability of port expansion in various areas will be discussed in Part B. For a more detailed discussion of existing port capacities, and problems of port expansion see Appendix B.

COST SENSITIVITY ANALYSIS

As noted earlier, some of the assumptions used in the cost calculations are uncertain. Consequently, the sensitivity of costs to

shifts in variables should be considered.

First, consider the sensitivity of required freight rates to fuel price. The elasticity depends on distance and size but is constant as a function of fuel increases for a given distance and size. For a 20 percent increase in fuel prices, required freight rates increase from 4.5 to 6.0 percent. The elasticity of the required freight rates (RFR) with respect to fuel prices therefore equals .22 to .24. Note that as fuel prices increase, the proportional increase in required freight rates does not vary substantially with distance. However, the absolute increase will be very large on the longer shipments. For example, a 50 percent increase in fuel prices would increase ocean freight rates from Gladstone to Rotterdam by $2.30 per metric ton. The same fuel price increase would increase rates from Hampton Roads to Rotterdam by only 70 cents per metric ton. Given the rapid recent increases in fuel prices, the significance of this factor to the competitive structure in international steam coal markets will be assessed in Part B.

The sensitivity of rates to port changes depends primarily on distance. For shorter routes the effect is larger. For example, from Richards Bay to Rotterdam, the elasticity of the RFR with respect to port charges equals .08. The sensitivity to changes in port delays is approximately equal to the sensitivity to changes in port charges.

For capital costs, an increase of about 20 percent in the capital recovery factor yields a 6.8 percent to 7.7 percent increase in the RFR, depending on distance. For operating costs, the elasticity is equal to .25. The various elasticities are summarized in Table 6.

Table 6

Sensitivity Analysis

	Elasticity of Required Freight Rates with Respect to:[1]	
	Hampton Roads to Rotterdam	Richards Bay to Rotterdam
Fuel price	.22	.24
Port charges	.10	.08
Days in port	.14	.10
Capital costs	.39	.44
Operating costs	.25	.25

Notes: 1. Elasticity = $\frac{\text{percent change in RFR}}{\text{percent change in fuel price}}$

Source: Author's calculations.

RATE/COST COMPARISON

It is interesting to compare these costs to rates. A perfect comparison is not possible due to time lags and route and ship specification variations. However, observing recent rates does further our comprehension of rate-cost relationships.

Tables 7 and 8 presents spot rates from various supply areas to demand points in 1979.[11] Over this period rates were increasing steadily. Only recently have they dropped in response to the termination of U.S.-Russian grain sales. These rates are almost always lower than the long-run cost estimates, although the actual difference varies over geographical areas. For example, rates from South Africa are very low relative to estimated long-run costs while rates from Mobile are very close to estimated long-run costs. The lower spot rates are not surprising given the depressed state of shipping markets until late in 1979. This was reflected in low spot rates, time-charter rates, second-hand vessel prices, and newbuilding prices.[12]

Table 9 summarizes time charter rates in 1979. It shows the range of rates per DWT per month in 1979. These can be compared to the capital and operating costs estimated above, and shown in Column 2.

With the exception of the 60,000 DWT and 150,000 DWT categories, time-charter rates were considerably below long-run costs early in 1979 and have recently exceeded long-run costs (at January 1979 levels). The primary reason for this is the very low second-hand vessel prices in early 1979 which have escalated rapidly in the past 12 months.

Table 7

Spot Rates: Canada, South Africa, Australia

Origin	Destination	Ship Size (DWT)	Date	Rate per Metric Ton (US $)
Canada				
Roberts Bank	Japan	55,000	2/79	6.90
Roberts Bank	Dunkirk	50,000	7/79	20.00
Roberts Bank	Japan	95,000	8/79	8.30
South Africa				
Richards Bay	Japan	100,000	1/79	5.25
Richards Bay	Holland	115,000	7/79	13.00
Richards Bay	Continent[1]	120,000	9/79	4.35
Australia				
Hay Point	Continent	60,000	11/78	13.50
Gladstone	Japan	50,000	3/79	7.50
Port Kembla	Le Havre	55,000	5/79	18.00
Port Kembla	Continent	50,000	7/79	23.00
Hay Point	Continent	140,000	9/79	14.25
Hay Point	Rotterdam	140,000	11/79	17.00

Notes: 1. Continent refers to ports from Rotterdam to Hamburg, W. Germany.

Source: a. Skaarup Shipping Corporation, unpublished data. Compiled by David Elsy.
b. Rodriguez Sons Company, Inc., "Coal Trade Freight Report," various issues.

Table 8

Spot Rate: United States

Origin	Destination	Ship Size (DWT)	Date	Rate per Metric Ton (US $)
Mobile	Taranto	50,000	7/79	11.65
Mobile	Japan	55,000	7/79	18.60
Mobile	Japan	55,000	11/79	18.65
Mobile	Taranto	55,000	11/79	15.50
Mobile	Japan	55,000	12/79	19.00
Hampton Roads	Japan	55,000	2/79	10.25
	Japan	55,000	3/79	14.00
	Japan	50,000	6/79	18.00
	Japan	55,000	7/79	18.45
	Japan	55,000	8/79	16.30
	Japan	55,000	9/79	18.45
	Japan	50,000	9/79	21.00
	Japan	55,000	11/79	19.30
Hampton Roads	Dunkirk	50,000	12/78	7.00
	Italy	60,000	2/79	6.80
	Piombino	50,000	6/79	18.00
	Ensted	60,000	6/79	11.65
	Dunkirk	75,000	7/79	11.25
	Piombino	50,000	7/79	11.47
	Port Talbot	67,000	8/79	8.00
	Hamburg	50,000	8/79	11.00

Notes: 1. Continent refers to ports from Rotterdam to Hamburg, W. Germany.

Source: a. Skaarup Shipping Corporation, unpublished data. Compiled by David Elsy.
b. Rodriguez Sons Company, Inc., "Coal Trade Freight Report," various issues.

Table 9

Time Charter Rate and Cost Comparison

(1979)

Ship Size (000's of DWT)	Time-Charter Rate (Dollars per DWT per month)	Long-Run Cost (Capital plus operating cost per DWT per month)
60	3.20 to 5.25	5.76
80	3.00 to 6.15	4.77
100	2.75 to 5.00	4.35
120	2.20 to 4.50	4.08
150	1.80 to 3.75	3.93

Source: Time-charter rates, Skaarup Shipping Corp. Long-run costs, author's calculations.

RETURN CARGOES

In the cost calculations above it was assumed that the return leg on each trip was entirely in ballast. Clearly, if a return cargo can be secured at the coal delivery point destined for the coal originating point, the cost per ton transported will be reduced by approximately 50 percent.

In practice, direct backhauls are rare. In our case, Europe and Japan offer no suitable backhaul commodities for shipments to coal exporting regions. The only conceivable direct backhaul might be steam coal from South Africa to the United States, and then metallurgical coal to South Africa.[13]

Nevertheless, some reduction in required frieght rates can be achieved with multi-leg shipments. This section reviews the economics of multi-leg shipments applicable to possible steam coal trade routes.

First, consider bulk commodities. Several bulk commodities are traded internationally; iron ore, bauxite, phosphate rock, alumina, and grains are the major ones. Grain is not a realistic backhaul possibility given that grain supply regions correspond closely to coal supply regions, and given the difficulties in cleaning ship holds for coal to grain transfer. All of the other commodities are possible for backhauls. However, with the exception of iron ore, they are usually moved in 20,000 to 40,000 DWT vessels, and in most cases they offer limited freight rate reductions at best. Iron ore on the other hand moves in large bulk carriers and offers significant backhaul possibilities.

The major origin points for iron ore are West Africa, South America,

Australia, Asia, North America, and Scandinavia. The current exports from these areas are listed in Table 10. West African and South American exports are best situated for backhauls in coal trade routes. The likely destination points for iron ore within coal trade patterns are the U.S. Gulf Coast, the U.S. East Coast, and Japan. Current imports in these areas are also depicted in Table 10. The actual multi-leg journeys that could benefit from iron ore shipments are listed in Table 11.

Where backhauls in bulk commodities are not available, another possibility is backhauls in petroleum or petroleum products. For these journeys OBO's are used.[14] The important supply points for petroleum are North Africa, Persian Gulf, Indonesia, and Alaska. The multi-leg journeys involving petroleum shipments are also included in Table 10.

Costs are calculated for these multi-key journeys under the following revised assumptions.[15]

1. Cleaning time between oil and coal: 72 hours per round trip.
2. Cleaning time between ore and coal: 48 hours per round trip.
3. Oil port time: 75 percent of coal port time.
4. Ore port time: 100 percent of coal port time.
5. OBO ship acquisition costs: 10 percent greater than traditional bulk carrier acquisition costs for a 60,000 DWT vessel, and 12 percent greater for a 120,000 DWT vessel.

We must also decide how to allocate the total costs of the journey for each commodity. This is a classic joint-production cost problem, and as in all cases there is no meaningful way to allocate the joint-costs, in this case the cost of the ballast portion of the journey. From a practical viewpoint, we might assume the existing ore journey, and calculate the increment costs of the coal journey. On this basis, the coal journey incremental costs will approach zero as the ballast distance

Table 10

Iron Ore Seaborne Trade, 1977

('000's metric tons)

From: \ To:	UK/Cont.	Mediterranean	Other Europe	USA	Japan	Others	Total
Scandinavia	16517	-	4534	155	-	43	21249
Other Europe	2759	1601	212	87	968	1	5628
North Africa	230	68	400	27	81	100	906
West Africa	15725	4224	857	1820	1490	100	24216
S/E Africa	4639	620	200	254	6944	-	12657
North America	10131	2060	799	7500	3639	453	24582
S. America, Atlantic	22132	6036	5637	8555	23912	1406	67678
S. America, Pacific	678	-	64	1610	9694	-	12046
Asia	557	-	1150	-	20210	200	22117
Australia	10078	1523	591	310	65649	4336	82487
Other	1204	752	-	-	-	-	1956
Total	84650	16884	14444	20318	132587	6639	

Source: Fearnley and Egers Chartering Co. Ltd. World Bulk Trades, 1977. Table 10, p. 19.

Table 11: Return Cargo Possibilities

United States Gulf to Japan--60,000 OBO	
New Orleans to Yokohama	9126, coal
Yokohama to Bahrain	6541, ballast
Bahrain to New Orleans	9104, oil
Vancouver to Europe	
Vancouver to Toronto (P)[1]	9651, coal
Toronto to Oran	1037, ballast
Oran to Hampton	3538, oil
Hampton to Vancouver (P)	5854
Los Angeles to Japan[2]	
Los Angeles to Yokohama	4839, coal
Yokohama to Valdez	3440, ballast
Valdez to Los Angeles	2220, oil
Richards Bay to Japan	
Richards Bay to Yokohama	7230, coal
Yokohama to Bahrain	6541 ballast
Bahrain to Durlan	4900, oil
Durlan to Richards Bay	110, ballast
Gladstone to Rotterdam	13526, coal (H)
Rotterdam to Liberia	3391, ballast
Liberia to Yokohama	11500, ore
Yokohama to Aust.	4090, ballast
Hampton Roads to Rotterdam	3591, coal
Rotterdam to Liberia	3391, ballast
Liberia to Hampton	3900, ore
Hampton Roads to Rotterdam	3591, coal
Rotterdam to Liberia	5300, ballast
Brazil to Hampton	4723, ore
Mobile to Rotterdam	4795, coal
Rotterdam to Liberia	3391, ballast
Liberia to Mobile	4621, ore

Table 11 (Continued)

Richards Bay to Rotterdam	7118, coal
Rotterdam to Liberia	3391, ballast
Liberia to Yokohama	11,000 ore
Yokohama to Richards Bay	7230, ballast

Notes: 1. P = Panama Canal.
2. Vancouver shipments to Japan offer a similar backhaul opportunity, yet no savings are realized on balance.

Source: Author's calculations.

approaches zero. However, this may not be a realistic long-run picture. In the market, the price of the coal shipment will end up somewhere between zero and the price of shipping coal alone--the actual point is indeterminate. From the vessel owners viewpoint, and for purposes of illustration, we will allocate the total costs of the round trip according to the ratio of the coal loaded distance to the oil or ore loaded distance.

Finally, for ore and oil supply points, we use: Monrovia, Liberia for West Africa; Bahrain for the Persian Gulf, San Nicholas for Peru, Sepetiba for Brazil, Oran for Algeria, the Sundra Strait for Indonesia, and Valdez for Alaska.

The cost calculations for major coal trade routes are presented in Table 12. The reductions in required freight rates range from 6 to 30 percent. Do these reductions affect the optimal coal trade patterns? The only major routes where no advantages are realized are Australia to Japan, and Vancouver to Japan and Europe. To Japan, Australia is still the cheapest supplier. However, Mobile and Los Angeles freight rates given backhauls are closely competitive with rates from Australia. To Europe no significant shifts are observed, but shipments originating in Australia become more competitive given backhaul possibilities.

Should we impute these reduced rates to coal movements? This depends on two issues. First, are the shipments likely to be available on a regular basis? This depends on the relative volumes of on ore and coal, or oil and coal. In the cases listed, the return cargoes will cover probable coal export volumes.[16] However, there will be other

Table 12

Return Cargo Rates

Origin	Destination	Ship Size (DWT)	Return Cargo (Cargo, Supply Point)	RFR With Return Cargo	RFR Without Return Cargo
R. Bay	Yokohama	120,000	oil, Bahrain	9.45	10.00
L.A.	Yokohama	60,000	oil, Valdez	8.57	9.55
Vanc.	Yokohama	120,000	oil, Valdez	6.71	6.56
Gladstone	Rotterdam	120,000	ore, Liberia	12.49	17.39
Mobile	Japan	60,000	oil, Bahrain	12.92	18.34
R. Bay	Rotterdam	120,000	ore, Liberia	8.19	10.00
Hampton	Rotterdam	80,000	ore, Liberia	4.95	6.48
Mobile	Rotterdam	80,000	ore, Liberia	6.52	8.08
Hampton	Toronto	80,000	ore, Liberia	5.98	7.83

Source: Author's calculations.

commodities competing for the coal leg on these journeys, and there is no quarantee that the reduced rates will obtain. Second, will this advantage favor coal more than oil in electricity generation? Probably not since oil will benefit to the same extent. Consequently, we will use fully built-up costs, but also evaluate the importance of reductions through backhauls on international steam coal trade.

ALTERNATIVE SHIPPING TECHNOLOGIES

Three alternative ocean shipping technologies should be considered briefly: self-unloaders, slurry carriers, and restricted draft vessels.[17]

First, self-unloaders are currently used for short voyages where there is a high loading and unloading frequency, or where terminal facilities are limited. Trade in the Great Lakes is one situation where they have been employed. The primary advantage is the high discharge rate (as high as 20,000 tons per hour). The disadvantage is higher acquisition cost and limited flexibility since most self-unloaders can handle only one commodity. Acquisition costs are estimated as 20 percent higher than traditional bulk carriers for 60,000 DWT vessels, and 10 percent higher for 120,000 DWT vessels.[18] Hydronautics calculations show that for long-haul, high volume shipments, required freight rates exceed those for traditional carriers by 5 percent to 8 percent.

Second, restricted draft vessels are also used. As noted earlier, these vessels have different ship dimensions so as to maximize DWT for a given draft constraint. The new design concepts include the development

of wide beam hull forms to obtain greater displacement at a given draft, while retaining the seakeeping and handling characteristics of conventional ships. Increases in DWT for a given draft can range as high as 30 percent by departing from conventional designs.

Hydronautics calculations show reductions in RFR from 12 percent to 16 percent.[19] However, the penalty for this savings is greater costs at deeper drafts. That is, a restricted draft design will reduce the RFR for a given draft, but given the DWT, deeper draft vessels are cheaper to run. Furthermore, a problem with the new designs is compatibility with the dimensions of existing loading and unloading facilities. It is probable that there will be an increase in restricted draft vessels in the longrun and a consequent downward pressure on costs. However, the degree of this shift cannot be specified.

Third, coal-slurry carriers are a possible shipping technology. In this system, coal slurry is pumped from shore storage tanks to special storage tanks via submarine pipelines. The cargo is then dewatered to the maximum degree consistent with port time. The advantages are reduced cargo handling time, less pollution, the ability to operate from offshore terminals, and compatibility with inland slurry pipelines. The disadvantages are higher acquisition costs per DWT, due both to expensive handling machinery and the water content of the coal. In the latter case, a 75 percent coal, 25 percent water mixture is probable. This means that a 250,000 DWT slurry carrier will carry less than 200,000 DWT of coal.

The RFR for slurry carriers is estimated to be as much as 36 percent higher than traditional bulk carriers.[20] The higher capital costs

per DWT, due both to handling machinery and the water content of the slurry mixture, dominates the economies of ship size. Nonetheless, in certain special circumstances, where port facilities are limited, the savings in ship size and loading and unloading costs might yield some advantage to slurry carriers.[21]

The results of this analysis will be integrated with the analysis of coal supply prices in Part B.

FOOTNOTES--CHAPTER VII

[1]"The Platou Report," Oslo, Norway, 1979, p. 24.

[2]Fearnley and Egers Chartering Co. Ltd., "World Bulk Trades," 1977, Table 1, p. 5. Some minor bulk commodities and their 1977 seaborne trade in millions of metric tons include: Manganese ore (7.2); non-ferrous ores (8.2); petroleum coke (6.7); gypsum (7.4); limestone (1.2); salt (6.4); cement (12.5); raw sugar (11.1); scrap (5.1); sulphur (6.7). Fearnley and Egers, "World Bulk Trades," 1977, p. 40.

[3]For a detailed analysis of tankship markets, see Adelman, M.A., The World Petroleum Market, Johns Hopkins University Press, Baltimore, Maryland, 1972; and Zannetos, Z., The Theory of Tankship Rates, M.I.T. Press, Cambridge, Massachusetts, 1966.

[4]With regard to vessel ownership, one possible economy of scale is in acquisition costs. That is, as more vessels are contracted, a cheaper unit price from the shipyard is probable. Nonetheless, this is not especially important in the aggregate. Hydronautics estimates that unit costs for a run of ten vessels are 80 percent of unit costs for a run of one vessel. (Roseman, D., "Relative Costs of Alternative Modes of Ocean Transportation of Coal," Appendix II, Hydronautics, Inc., October 1979.)

[5]Possible exceptions are cases where special ship types, unique cargo handling gear, or integrated transportation systems are necessary. Some monopoly power has been observed in these special instances. See Norman, V.D., "The Economics of Bulk Shipping," in "Reading Materials," Department of Ocean Engineering, Course 13.69, Professor Ernst Frankel, M.I.T., p. 13.

[6]Hettena, Ran, "Economics of Oceanborne Coal Transportation," presented at the Symposium on Critical Issues in Coal Transportation Systems, Maritime Transportation Research Board, Washington, D.C., June 14, 1978, p. 14.

[7]H.P. Drewry, Inc., "Organization and Structure of the Dry Bulk Shipping Industry," No. 63, June 1978.

[8]In fact, the increase in time-charter rates is initially reflected in increases in second-hand vessel prices. These increases are in turn reflected in newbuilding activity increases.

[9]Norman, op. cit., p. 18.

[10]Adelman, op. cit., p. 115.

[10a]It contrasts the situation in grain, where up to 25 percent of tonnage is carried on the spot market. H.P. Drewry, op. cit., p. 36.
It is interesting to note that as bulk shippers have moved to long-term contracts or vertical integration to avoid risk in the voltaile spot markets, the volatility of spot markets has by definition increased.

[10b]One final issue worth noting is the possibility of extended profits by shippers from operating on-the-spot or time-charter markets. It is conceivable that the vessel markets are in long-lasting or everlasting disequilibrium. If so, the advisability of vertical integration might be questioned. There are certainly extended periods of excess capacity in vessel markets, lasting up to 5 years. Hettena, in fact, offers the possibility of this being a permanent bias. If the elasticity of supply exceeds the elasticity of demand, a trend toward permanent excess capacity could develop (analogous to the Cobweb Theorem). Hettena cites poor coordination and an unstable balance between bulk shippers and shipbuilders as an explanation for this hypothesis. The possibility should not be ignored, and it certainly warrants additional research. However, the risks could still exceed the potential gains, and it is unlikely that market relationships would be altered. Furthermore, in a true long-run sense, if it were proven that this long-run disequilibrium holds, instititutional and market adjustments would likely eliminate the market imperfection over time. Hettena, op. cit., pp. 21-24.

[10c]Time charters will approximate equilibrium in some cases. For example, when new building activity is increasing, we can expect that time charters are approximating long-run costs.

[11]All rate information is drawn from: Maritime Research, Inc., "Weekly Newsletter;" Rodriguez Sons Company, Inc., "Coal Trade Freight Report;" and a sample compiled by David Elsy, Skaarup Shipping Corp.

[12]See The Platou Monthly, December 1979, for an evaluation of 1979 shipping markets. Also see Fearnley and Egers Chartering Co. Ltd., "Review 1979," for summary and second-hand vessel prices.

[13]There have been recent statements by Gulf Coast utilities about the advantages of South African coals versus Powder River Basin coals. However, no actual contracts have been signed to date to the author's knowledge. Based on the cost calculations in this thesis, the price of South African coal delivered to Houston is $1.68 per million Btu while the price of Western coal is $1.50 per million Btu.

[14]In practice OBOs are often assigned to one commodity trade for extended time periods, and not to multi-commodity trade. The reason is that it is costly to clean the holds between cargoes. The incentive to purchase an OBO is nonetheless strong since it allows the vessel owner greater flexibility in chartering and the additional capital acquisition costs are low.

[15]Based on assumptions used in Roseman, op. cit., App. II, and discussion with various shipping industry analysts.

[16]For a comprehensive analysis of future commodity movements, see Marad, op. cit., Appendix A.

[17]For a detailed discussion of alternative vessel technologies see Roseman, D.P., et al., "Characteristics of Bulk Products Carriers for Restricted Draft Service," in Transactions of the Society of Naval Architects and Marine Engineers, 1 974; Jones, R.M., et al., "A Study of Large Self-Unloading Vessels," in Transactions of the Society of Naval Architects and Marine Engineers, 1972; Roseman, D.P. and Tomassoni, C.L., "A Preliminary Feasibility Study of Steam Coal Slurry Marine Transport Systems," Hydronautics Technical Report No. 7692-1, April 1977.

[18]Roseman, 1979, op. cit., pp. 4-6.

[19]Roseman, D.P., "Alternative Modes of Ocean Transportation of Coalm" Hydronautics, 1978, pp. 9-11.

[20]Roseman, 1979, op. cit., pp. 7-9.

[21]See, for example, a joint Marad/Boeing study which evaluates pipeline systems for U.S. coal exports to Japan. The economic analysis in this study suggests that the slurry carrier system will be cheaper than alternatives. However, the data are vague, and recent developments indicate that the estimates may have been optimistic. Phase 0 and Phase 1 Report, Mared/Boeing Study, Dept. of Commerce, Contract No. DO-A01-78-00-3038, July 1978.

APPENDIX A

COST MODEL FORMULATION AND ASSUMPTIONS

Long-run marginal costs include four elements: capital costs, quasi-fixed operating costs, fuel costs, and port and canal charges. For a specific route and ship specifications, annual costs are divided by annual cargo transported to obtain the rate required per ton to cover all the expenses of the incremental ship. This appendix explains the cost calculations and underlying assumptions.

First, consider ship sizes. In the past decade, the distribution of ship sizes, according to deadweight tonnage (DWT), has steadily shifted toward larger ships. In 1968, only 35 percent of coal tonnage was moved in ships larger than 40,000 DWT. In 1977, this figure increased to 67 percent.[1] The largest coal-carrying vessels in use today are approximately 150,000 DWT. Table A1 shows the distribution of bulk carrier and combined carrier ship sizes in 1969 and 1979. Also important to our analysis are combination carriers, specifically ore-bulk oil carriers (OBOs). The distribution of OBO's according to size is also depicted in Table A1.

The most important range for our purposes are vessels from 50,000 DWT to 120,000 DWT. Ships much below 50,000 (Panamax size) are very costly to run, whereas ships above 120,000 DWT are constrained in use to only a few bulk carrier facilities worldwide. However, smaller vessels may be used for regional distribution, and larger vessels may have broader applicability in the future as port facilities expand.

Table A1

Bulk Fleet 1969-1979 -- Development of Size Distribution

	1969	Percent	1979	Percent
Combined Carriers--Total	175	100	418	100
10- 60000	88	50	48	11
60- 80000	48	27	72	17
80-100000	31	18	53	13
100-150000	8	5	133	32
150-200000	-		79	19
200-300000	-		33	8
Bulk Carriers--Total	1761	100	3960	100
10- 18000	557	32	765	19
18- 40000	918	52	2280	58
40- 60000	223	13	487	12
60- 80000	55	3	266	7
80-100000	6	-	29	1
100-150000	2	-	122	3
150000-	-	-	11	-

Source: Fearnley and Egers Chartering Co. Ltd., World Bulk Fleet, January 1979. Table 3, p. 5.

Consequently, costs will be estimated for the following ship sizes: 30, 60, 80, 100 120, 150, 180, 200, 250 (000s DWT).

Costs are estimated as of January 1, 1979 levels. They are calculated as follows:

$$RFR = \frac{(CRF \times SAQC) + OC + Fuel + Port}{VPY}$$

where:

RFR = required freight rate (RFR), in U.S. $ per metric ton

CRF = capital recovery factor

OC = operating costs

SAQC = ship acquisition costs

Fuel = fuel costs

Port = port and canal charges

VPY = volume shipped per year in metric tons.

The related calculations and assumptions are discussed in detail below.

1. The Capital Recovery Factor is based on United States Maritime Administration calculations.[2] It is calculated as follows:

$$CRF = E \times \frac{i(1+i)^n}{(1+i)^n - 1} - \frac{t}{n} + D \times \frac{m(1-t) \times [1 + m(1-t)]^n}{[1 + m(1-t)]^{n-1}} \times \frac{1}{1-t}$$

where:

CRF = capital recovery factor before taxes

E = percentage of equity, = 25 percent

P = percentage of debt, = 75 percent

i = return on investment after taxes = 10 percent

m = interest rate on loan = 8 percent

t = tax rate = 48 percent

n = economic life, loan life, and depreciation period = 20 years.

Based on these assumptions, the capital recovery factor is 11.8 percent.

2. Ship Acquisition Costs are derived from an acquisition cost computer model developed by Hydronautics, Inc.[3] The costs are based on the weights of the ship structure and outfit, main propulsion requirements, and electric power requirements. The costs are for double-skinned side-shell configurations. There are some operating advantages to this design, but the acquistion costs are greater.[4] Hydronautics uses the double-skin configuration to permit direct comparison with similar sized combination carriers. For single-shell configurations, the normal design of traditional bulk carriers, acquisition costs are reduced by 10 percent.[5]

The ship acquisition cost data developed in the Hydronautics study are based on American Shipyard construction costs, adjusted for the maximum United States construction differential subsidy (CDS) of 50 percent. The CDS has been the subject of extensive controversy. Newbuilding prices may vary significantly from this ratio at any point in time, so that the CDS of 50 percent may be insufficient to attract buyers to U.S. shipyards.[6] Currently analysts contend that prices in the United States are at least twice those in Europe and Japan. In 1979 Japanese prices were even less given the declining value of the yen.

However, with respect to construction costs, the U.S. Maritime Administration concluded that U.S. costs have historically been twice that of an equivalent foreign-built ships.[7] Given an interest in long-run marginal costs, the 50 percent adjustment is therefore employed.[8]

3. Annual Fixed Operating Costs are the expenses that are incurred in the day-to-day running of bulk vessels, excluding interest, depreciation, fuel costs, and port charges. They include labor and subsistence, stores and supplies, maintenance and repair costs, and insurance. They are not strictly fixed costs, but rather they are approximately constant for a vessel in full service. They can be reduced or eliminated only if the vessel withdraws from the market. They vary considerably according to vessel registry, ownership, and age and type of vessel.

The operating cost calculations present several problems. In specific, the difference between U.S. flag and foreign flag operating costs for bulk carriers is not certain, and it has yet to be proved that the operating differential subsidies close the gap, especially "given the stringent terms and conditions laid down in the current legislation. The fact that not one conventional bulk carrier has been constructed to date under the subsidy program for operation in foreign trade indicates the extent of the problem."[9]

Consequently, Hydronautics data, based on U.S. operating costs, are not directly used. Instead, other published data were analyzed for 60,000 DWT carriers, and a slightly lower estimate was developed.

However, for other size ships, similar data were not available. Hydronautics estimates for U.S. operating costs had to be used indirectly in this case. Based on an earlier Hydronautics study with 1976 data, the relative shifts in operating costs as a function of ship size were calculated according to the following formulas:[10]

1. Labor and subsistence are constant.

2. Stores and supplies = $3\ [\frac{SHP}{3} + 14500 + .21(DWT + 9500)]$

   SHP = shaft horsespower

   DWT = total deadweight tonnage.

3. Maintenance and repairs = $3[(90400 + CN - 1500).69)]$

   $CN = \frac{LBP \times B \times D}{100}$ = cubic number

   LBP = length between perpendiculars in ft.

   B = breadth, molded, in ft.

   D = depth, molded, in ft.

4. Insurance, hull and machinery = $SAQC\ [.01 + \frac{.00006\ DWT}{1000}\ ]$

   Insurance, Protection and Indemnity = $3(750N + .61\ CN)$

   N = ship's complement = 27.

Since the ratio of one cost component to another varies between foreign and U.S. flags, operating differential subsidies have to be applied to these equations in order to approximate actual relationships. They are as follows:

labor and subsistence, 70 percent

maintenance and repairs, 30 percent

insurance, 30 percent

Given these relationships, operating costs were calculated for each ship size, and proportional relationships were determined. The 60,000 DWT base point, calculated from current data, was adjusted accordingly. It is possible that the cost components have shifted disproportionately in magnitude over the past few years so that current proportions would be slightly different, but no way of adjusting for this possible bias was determined.[11]

4. Two variables used in the operating cost calculations have not been discussed: horsepower and ship dimensions. Both variables are determined by a complex set of economic and engineering relationships, subject to certain engineering constraints.

The ship and power plant are designed to minimize the required freight rate. Hydronautics calculations show the following.[12] For bulk carriers, the lowest freight rate, subject to two engineering constraints ($LBP/B > 5$ and $LBP/D \leq 15$), corresponds to the following rules:

1. Given draft, choose the biggest DWT design,
2. Given DWT, pick the deepest draft design, which corresponds to the minimum length design.

The first principle is not representative of current practice. To date, most owners have specified a "normal" deadweight vessel for a given draft constraint. Recently, however, vessels have been designed that

increase the DWT for a given draft. The advantage is lower costs for a given draft, while the disadvantage is higher costs for a deeper draft. For flexibility, owners have preferred traditional designs. The future developments in this area will be considered below.

Given the second objective, subject to the constraints, a "normal" vessel is used for the base calculations. The assumed relationships are:[13]

$d/D = .70$

$L/D = 11.0$

$L/B = 6.0$

$CB = .82$

where d = draft

D = depth

L = length

B = breadth

CB = block coefficient $= \frac{V}{L \times B \times D}$

V = displacement in cubic meters.

The dimensions of each ship size are calculated from these relationships.

Horsepower requirements are also a complex multi-variable decision. Horsepower is a function of displacement, speed, and fuel consumption. This relationship shifts with shifting fuel prices and other prices. The Hydronautics study revealed that lower service speeds correspond to the lowest required freight rate.[14]. Throughout the study, we assume a service speed of 15 knots. Horsepower ratings for each size ship are calculated from an Odense Steel Shipyard Ltd. report.[15]

5. Fuel consumption is a function of horsepower and the resistance of the ship hull to water. The relationship is linear, but varies across types of propulsion machinery. For bulk carriers, ships use either low-speed diesel engines or steam turbine engines. The latter are used for very large ships, say, 150,000 DWT and above.[16] We assume .32 lb/HP/hour fuel consumption at sea, plus auxiliaries ranging from 2 to 4 tons per day, depending on ship size. For steam turbines we assume .48 lb/HP/hour.[17]

Fuel consumption in port is more difficult to specify. Based on Marad data approximately 15 percent of the fuel consumption per day at sea is assumed for port fuel consumption. Adjusting for fuel price variations, fuel consumption rates are listed in Table A3.[18]

6. Days in port are a function of loading and unloading times, waiting times, and navigation times, and are widely variable from port to port. In theory, there is an optimal port time for each size ship on each route. It would equate the marginal cost of vessel time with the marginal cost of the loading or unloading operations. However, the calculation requires data that are not available. For example, the costs of loading and unloading operations, separated into fixed and variable components, and the changes in these component costs as a function of loading, unloading rates, and stevedoring costs. Furthermore, in practice the optimum is not likely to obtain. Vessel owners lose money as they wait, but the gains in waiting time to the loading facility (as berth occupancy increases) are, on the one hand, not likely to be perfectly responsive to waiting time, and on the other hand, not likely

to be transferred to ship owners since loading and unloading costs are usually paid by the vessel owner. In practice, what is more likely is a maximum acceptable waiting time, in proportion to berth time. Nonetheless, within this inefficient system, some reasonable principles can be developed to help construct the port time curve.

1. Nominal loading rates vary from 2000 tons per hour (Tph) to 8000 TPH. Discharge rates vary from 1000 to 4000 Tph. Actual loading rates, depending on the type of system, vary from 60 to 70 percent of nominal rates. As a rule, larger facilities have higher loading and unloading rates.[19]
2. The marginal cost of a ship's time in port is approximately constant as a function of time (based on my calculations).
3. The marginal cost of a ship's time in port increases, but less than proportionally, as a function of ship size. In other words, the decrease needed in loading or unloading costs for larger ships is less per ton, but more per ship.
4. The longer the route, the less the proportional cost increases of increased time in port. That is, the longer the route, the smaller the proportion of port time to round trip time. Thus, a one-day increase in port time increases the round trip time by a smaller proportion for larger routes.
5. As waiting time increases relative to berth time, berth occupancy increases. In addition, as the number of berths increases, the berth occupancy ratio (occupied time divided by operating time) increases for a given ratio of waiting time to berth time.[20]

6. The optimal waiting time as a percentage of loading or unloading time will decrease for bigger ships. That is, a one-day increase will yield a lower percentage increase in the berth occupancy ratio (BOR), so there are less savings to the facility. So, if the cost per unit time to the ship is constant over time, and cost savings to the facility decrease as days increase, the optimum will obtain at a lower ratio. (Note, however, that if there is a tendency towards more berths at larger facilities, then for equivalent waiting time, the BOR will be higher for larger ships.

7. The optimal waiting time in absolute terms is probably higher for bigger ships, but data are insufficient to verify this hypothesis.

Given these hypotheses, a curve is estimated for port delays. It has been cross-checked with several other sources. It is roughly equivalent to assuming a single berth at all facilities, constant loading and unloading times, and a .33 BOR for 200,000 DWT ships, a .44 BOR for 120,000 DWT ships, and .60 BOR for 60,000 DWT ships.

6. Port charges are widely variable across ports, not only in component prices, but in components charged. An example of a port charge for a 120,000 DWT vessel, loaded with 90,000 tons, in October 1978 at Dunkirk is:[21]

Pilotage - 30,500

Boatage - 5,000

Towage - 81,900

Dues - 207,500

Clearance - 2,300

Federal Tax - 2,400

Agency Fees - 1,500

Other - 14,000

TOTAL - 345,000

At the December 1978 exchange rate, this equals approximately U.S. $70,000. At the same time, a Panamax size vessel at Dunkirk was charged 175,000 francs.

A survey of port charges showed variation from as little as 15 cents to $1.00 per ton. In the United States and South Africa, port charges are at the low end, while in Northern Europe, they are typically at the higher end of this range. In the Mediterranean (Taranto) charges are in between. In Australia port charges are as high as U.S. $1.00 per ton. Some examples are set out in Table A2. For the base calculation, we assume 75 cents per ton per round trip.

For canal charges, we assume U.S. $1.50 for a Panama Canal round trip, and U.S. $2.00 for a Suez Canal round trip. The sensitivity of total costs to changes in these variables will be determined below.

8. Other Assumptions

a. Working days are assumed at 345 per year.

Table A2

Port Charges

Port	Ship Size	Date	Charges
Richards Bay	110,000	Oct., 78	$15,000
Dunkirk	120,000	Oct., 78	345,000 francs
	50,000	Oct., 78	175,000 francs
Rotterdam	120,000	Nov., 78	$65,000
Taranto	120,000	Oct., 78	8,068,900 Lire
Redcar	120,000	Oct., 78	32,000 pounds
Gladstone	-	Aug., 79	A 80 cents per ton

Source: David Elsy, Skaarup Chartering Corp., Greenwich, Conn., unpublished data.

b. Hours per day - 24 hours. (Note: generally true from survey, though an overtime wage scale is effective after 16 hours in many cases).

c. Stores per day = 20 tons at sea.

d. Deadweight cargo tonnage (DWCT) = (Fuel per day x days per one-way trip) - (stores per day x days per one-way trip). We would expect some variation in this due to required bunker price variations, but on average this is a reasonable approximation.

e. Fuel costs are extremely volatile. For example, high quality diesel oil (180 CST) was priced on the spot market in Rotterdam in January 1980 at $188 per metric ton. By February, the price was $160.00 per metric ton. The price as of January 19, 1979 was $87 per metric ton. The price used in this analysis is $100.00 per metric ton.[22]

f. Canal delays: we allow round-trip delays beyond normal transit time of one day in the Panama Canal, and two days in the Suez Canal.[23]

9. Finally, connecting points for coal movements must be specified. For the cost analysis, a subset of ports, representative of the important supply and demand regions, are selected. These are:

South Africa - Richards Bay

Australia - Gladstone, Hay Point

Canada - Vancouver

U.S. East Coast - Hampton Roads

U.S. Gulf - Mobile

U.S. West - L.A., Long Beach

Northern Europe - Rotterdam

Mediterranean - Taranto

Japan - Yokohama

Connecting distances, in nautical miles, are calculated from U.S. Navy tables.[24] Several key geographical trade-offs should be highlighted.

First, from the West Coast of the United States or Canada to Europe, the route options are the Panama Canal or Cape Horn. The additional distance via Cape Horn is 4945 miles to the Mediterranean (Straits of Gibraltar), and 5575 miles to Northern Europe (Bishops Rock or Ushant).

Second, from the U.S. East Coast or Gulf Coast to Japan, the route options are the Panama Canal or the Cape of Good Hope (versus Cape Horn). From Mobile to Yokohama, the additional distance is 6500 miles. From Hampton Roads, the additional distance is 5766 miles.

Third, from South Africa to Europe, the route choice is between the Suez Canal and the Cape of Good Hope. To Northern Europe, the Cape of Good Hope route is shorter. To the Mediterranean, the Suez Canal route is shorter. For example, to Taranto from Richards Bay the mileage via the Cape is 7224. From Richards Bay to Taranto via the Suez Canal, the mileage is 5411.

Fourth, from Australia to Europe, several route options must be considered. If the originating port is in New South Wales, the route through the Wilson Strait is shorter to both the Cape of Good Hope and

the Suez Canal. If the originating port is in Queensland, the route through the Torres Strait is shorter to the Suez Canal, while the route through the Wilson Strait is shorter to Cape of Good Hope. For shipments from Australia to Europe, it is always shorter to use the Suez Canal than to go around the Cape of Good Hope. For example, from New South Wales to the Strait of Gibraltar, it is 1263 miles shorter, and from Queensland to the Strait of Gibraltar, it is 1927 miles shorter.

Fifth, the choice between Kiel Canal and Skaggens Odde for shipments to Denmark will be ignored in the calculations. The additional distance is less than 200 miles. Given the draft constraint in the canal (30,000 DWT), the diseconomies in ship size will clearly offset the shorter distance.

10. One final assumption that is only indirectly important here, but will be required for the integration of costs is loading and unloading cost. In most cases, these costs are separate from port charges. Australia is an exception to this, and in Baltimore the dumping charge is included in the rail rate. A survey of port facilities showed a range from U.S. $1.00 to U.S. $4.00 for services at either end of the trip including unloading the ocean vessel, storage, and loading the inland carrier. Most facilities charged between $2.50 and $3.50 per ton. For the maritime component (only unloading or loading the vessel), the charge ranged from $1.50 to $2.00 within the $2.50 to $3.50 range.[25] None of these costs is reflected directly in ocean rates. They will, however, be applied in the integration below.

The important cost variables and connecting mileages are summarized in Tables A3 and A4.

Table A3

Cost Calculation Assumptions

Deadweight tons (000s)	Ship Requisition costs (millions)	Operating Costs (000s)	Fuel Consumption at Sea (tons per day)	Fuel Consumption in Port (tons per day)	Days in Port
30	15.5	1092	38	5.70	4.0
60	22.4	1680	50	7.50	5.0
80	24.8	1848	56	8.40	5.6
100	28.4	2100	64	9.60	6.3
120	32.8	2260	71	10.65	7.0
150	40.2	2650	78 (110)	11.70	7.7
180	45.0	2970	86 (126)	12.90	8.2
200	48.0	3200	93 (136)	13.95	8.6
250	57.7	3910	105 (152)	15.75	9.5

Notes:
1. Numbers in parentheses represent steam turbine fuel consumption rates. Others represent diesel rates.
2. Fuel consumption is adjusted for auxiliary price differentials.
3. All costs at January, 1979 levels.

Source: See text.

Table A4

Distances Between Ports

	Yokohama	Taranto	Rotterdam
Gladstone	4090	9442(S), 13626(H)	11800(S), 13526(H)
Port Kembla	4350	9203(S), 12723(H)	11615(S), 12617(H)
Richards Bay	7230	5411(S), 7224(H)	7118(H)
Baltimore	9626(P)	4726	3714
Hampton Roads	9504(P), 15270(H)	4604	3591
New Orleans	9126(P), 15709(H)	5830	4850
Mobile		5777	4795
Los Angeles	4839	8532(P)	7755(P), 13330(C)
Vancouver	4262	9651(P)	8874(P), 14449(C)

Notes: P = Panama Canal routing
H = Cape of Good Hope routing
C = Cape Horn routing
S = Suez Canal routing

Source: Distance between ports, U.S. Naval Oceanographic Office, Washington, D.C., 1965.

FOOTNOTES--CHAPTER VII--APPENDIX A

[1]Fearnley and Egers, World Bulk Trades, 1977, p. 28.

[2]U.S. Dept. of Commerce, Maritime Administration, Office of Commercial Development, "Development of a Standardized U.S. Flag Dry Bulk Carrier," Appendix E, p. 16-17.

[3]Roseman, D., "Relative Costs of Alternative Modes of Ocean Transportation of Coal," Hydronautics, Inc., Oct. 1979.

[4]Ibid., p. 2.

[5]Ibid., Appendix II.

[6]As an example of variations in newbuilding prices, Japanese newbuilding prices for a 60,000 DWT bulk carrier were $21.6 million in 1976, $19.9 million in 1977, $17.6 million in 1978, and $25.0 million at the end of 1979. U.S. Department of Commerce, Appendix C, p. 258; op. cit., , The Platou Monthly, Dec. 1978, p. 3.

[7]Marad, op. cit., App. C., p. 257.

[8]The Marad estimates for foreign flag construction costs are 3 percent to 6 percent lower than the Hydronautics estimates. However, they also use a higher capital recovery factor for foreign flags due to different tax and depreciation conditions. On balance, the annual capital costs are very close. Marad, op. cit., App. E. For a detailed analysis of operating and construction differential subsidies in U.S. shipbuilding, see Marcus, H. and Frankel, E., Federal Port Policy in the United States, MIT Press, Cambridge, Mass., 1976.

[9]Marad, op. cit., App. C, p. 257.

[10]Roseman, D. and Tomassoni, C., "A Review of Coal Slurry Carrier Transportation Costs," Hydronautics, Appendixes 1, 2, November 1977.

[11]After this exercise was completed, additional operating cost data were obtained from Marad. There was insufficient time to reperform the calculations. Preliminary checks, however, closely corresponded to the above results.

[12]Roseman, 1979, op. cit., p. 3.

[13]There is no precise definition of a normal vessel. These parameters are based on a review of actual traditional bulk carrier designs, Hydronautics assumptions, and Marad design parameters. Marad, op. cit., App. E., Design Selection.

[14]Roseman, op. cit., 1979, p. 3.

[15]World Coal Study, Maritime Transport, Odense Steel Shipyard Ltd., Odense, Denmark, June 1979.

[16]This point is an approximation based on an analysis of actual ship specifications, and discussions with ship brokers. Note that some very large ships may instead use two diesel engines.

[17]Roseman, op. cit., 1979, App. 2, Odense Steel Shipyard Ltd., op. cit., p. 8.

[18]The price relationships between fuels change over time. Based on an analysis of worldwide fuel prices reported by Bunkerfuels Corp., bunker C fuel for steam turbines was assumed to cost 90 percent of the price of 180CST diesel, which in turn was assumed to cost 55 percent of higher quality maritime diesel oil.

[19]H.W. Drewry, "Ports and Terminals for Large Bulk Carriers," No. 46, 1976, London.

[20]For a detailed discussion of these issues, see E.G. Frankel, "Port Capacity, Productivity and Effectiveness Measures," U.S. Department of Commerce, Maritime Administration, undated.

[21]Port charge data provided by David Elsy, Skaarup Chartering Corp., Greenwich, Connecticut.

[22]Bunkerfuels Corp., "Monthly Report," January, 1979.

[23]International Energy Agency, Economic Assessment Service, "The Long-run Economics of the Ocean Transport of Coal," December, 1978, p. 20.

[24]"Distances between Ports," U.S. Naval Oceanographic Office, Washington, D.C., 1965.

[25]No adequate documentation on loading and unloading costs existed. These estimates are drawn from personal communications with port and shipping authorities in the U.S., Canada, South Africa, Australia, and Europe.

APPENDIX B

PORTS

The following section reviews the role of ports in steam coal trade development. First, the location and water depth of existing facilities are presented. Second, the issues of current port capacity and future port capacity are discussed.

PORT FACILITIES

The existing port facilities capable of handling large coal carriers are summarized in Tables B1 and B2. A brief discussion of each port region follows.

Exporting areas

In the United States, there are three important export regions: the Gulf coast, East coast, and the West coast. On the East coast, Hampton Roads, Baltimore, and Philadelphia are all capable of handling coal. Hampton Roads is the most accessible, as Baltimore and Philadelphia require longer trips up the Chesapeake Bay (150 miles to Baltimore). Hampton Roads also can receive larger ships, up to 80,000 DWT vessels (conventional design), while Baltimore can receive 60,000 DWT vessels, and Philadelphia can receive 40,000 DWT vessels. However, the Hampton Roads facilities are old and heavily congested.

In the Gulf coast, three areas are important. Mobile and Myrtle Grove, a new facility designed primarily for intercoastal movements to

Table B1

Exporting Ports

Port	Draft (meters)	Maximum Size (000's DWT)
U.S. East Coast		
Baltimore	12.2	60
Philadelphia	11.3	40
Hampton Roads	13.7	80
U.S. Gulf Coast		
Devant	11.6	45
New Orleans	10.7	35
Mobile	13.4	75
Myrtle Grove	11.8	50
U.S. West Coast		
Galveston	13.4	75
Houston		
Los Angeles	12.0	60
Long Beach	12.0	60
San Francisco	12.0	60
Portland	12.0	60
Seattle	12.0	60
Canada		
Vancouver	19.8	250
Sydney	11.0	38
South Africa		
Richards Bay	18.0	200
Durban	11.0	38
Australia		
Gladstone	17.0	120
Hay Point	17.0	120
Port Kembla	12.2	60
Sydney	12.2	55
Newcastle	12.2	55

Source: Same as Table B2.

Florida power plants, can receive 75,000 DWT and 55,000 DWT respectively. In the New Orleans area, Devant lies below New Orleans on the Mississippi river. It is capable of receiving 55,000 DWT ships. New Orleans itself can receive 40,000 DWT ships. Further to the west, Galveston and Houston have the draft to receive larger ships, but both has virtually no current capacity.

On the West coast, Los Angeles and Long Beach can both receive 60,000 DWT ships, but both have limited loading facilities. No other West coast port can currently handle large bulk carriers. Possible areas for future development are in the San Fransisco/Oakland area and in the Portland/Seattle area.

In Canada, Western coal is moved to facilities in the Vancouver area. The Roberts Bank terminal can receive ships up to 250,000 DWT. The Neptune and Pacific coast terminals can receive 95,000 DWT and 55,000 DWT ships respectively. In eastern Canada, Sydney, Nova Scotia can handle 40,000 DWT ships.

For shipments from both the United States and Canada, Great lakes ports are possible, but due to the size limitations for access to the Atlantic Ocean (30,000 DWT) they are far too expensive for long ocean movements.

In South Africa, Richards Bay is expected to handle virtually all future South African coal exports. Ships up to 200,000 DWT can be received. Approximately 200 km to the Southwest, the port of Durban is possible for overflows, but Durban can receive only 40,000 DWT ships.

In Queensland, Gladstone and Hay Point will handle most of the

projected coal exports. Each can receive 120,000 DWT vessels. Bowen and McKay are possible locations for future developments. In New South Wales, Port Kembla, Newcastle, and Sydney will handle coal exports. Each can receive vessels up to 60,000 DWT.

Finally, briefly consider other potential exporting countries, which will not be dealt with in detail in this study. China's main coal port is Lu-Tu, capable of handling 30,000 DWT ships. Colombia can handle 30,000 DWT ships in Cartagena. India's exports will probably move through Haddia (60,000 DWT capacity) or Paradap (50,000 DWP capacity). The Soviet Unions exports could move through Vostochyny, on the Pacific Coast (100,000 DWT) or Ilichevsk on the Black Sea (40,000 DWT). In Poland, Godensk can handle 100,000 DWT ships.

Importing areas

In Europe, three regions should be analyzed: the Mediterranean, Northern Europe, and Scandanavia. In the Mediterranean, the largest facilities are Taranto (150,000 DWT capacity) and Marseilles (180,000 DWT capacity). Scattered throughout the region are several smaller facilities. East of Taranto is Trieste (80,000 DWT capacity). Between Taranto and Marseilles are Piombino, La Spezia, Genoa, and Savona, where vessels from 40,000 to 60,000 DWT can be received.

In Northern Europe, the major port is Rotterdam, where 250,000 DWT vessels can be received. There are, however, many other smaller facilities throughout the region: Gijon (80,000 DWT) and Bilbao (75,000 DWT) in Spain; Le Havre (70,000 DWT), Dunkirk (75,000 DWT) and Rouen (35,000 DWT) in France.

Table B2

Importing Ports

SPAIN	Draft (meters)	Maximum Size (000's DWT)
Gijon	13.4	75
Bilbao	14.0	80
FRANCE		
Marseilles (fos)	19.5	180
Dunkirk	13.4	75
Le Havre	12.8	70
Rouen	10.0	35
ITALY		
Trieste	13.7	80
Taranto	15.2	100
Piombino	11.9	50
La Spezia	11.0	38
Savona	11.6	45
Genoa	12.2	55
BELGIUM		
Antwerpen	13.1	70
Ghent	12.2	55
NETHERLANDS		
Rotterdam	19.8	250
Amsterdam	13.7	80
Ismuiden	13.7	80

Table B2 (Continued)

	Draft (meters)	Maximum Size (000's DWT)
Delfzijh	12.8	65
Ternuezen	12.2	55
UNITED KINGDOM		
Port Talbot	15.2	100
Redcar	16.0	120
Hunterston	17.1	150
Immingham	11.0	35
WEST GERMANY		
Emden	11.3	40
Hamburg	14.5	90
Nordenhaven	12.8	65
Bremershaven	10.0	30
Brunsbuttle	11.3	40
Wilhelmshaven	14.0	80
DENMARK		
Ensted	16.0	120
Stignaes	16.0	120
Esberg	9.5	30
Kalunberg	11.0	38
Studstrup	11.9	50
Aalberg	10.0	30
SWEDEN		
Goteborg	19.8	250

Table B2 (Continued)

	Draft (meters)	Maximum Size (000's of DWT)
JAPAN		
Muroran	15.8	110
Kashima	15.8	110
Chiba	17.1	145
Kimitsu	15.8	110
5. Mizushima	18.0	185
6. Fukiyama	17.1	145
7. Kure	18.9	185
8. Kobe	11.9	50
9. Kakogawa	16.5	125
10. Wakayama	13.7	60
11. Sakai	14.0	80
12. Hirohata	12.5	60
13. Kamaishi	13.1	70
14. Yawata	16.0	120
15. Kohure	16.0	120
16. Oita	24.8	250

Sources: H.P. Drewry, Inc. "Ports and Terminals for Large Bulk Carriers," Report no. 46, London, 1976.

Ports of the World, Thirty-third Edition, Benn Publications, Ltd., London, 1980.

International Energy Agency, Economic Assessment Service, "The Long-Run Economics of Ocean Transport of Coal," Report no. D1/78, London, England, December 1978.

In the United Kingdom, Port Talbot, near Swansea in the English Channel, can receive 100,000 DWT ships. Redcar, near Middlesborough on the North Sea, and Hunterston, also on the North Sea, can handle 120,000 DWT and 150,000 DWT vessels respectively.

In Belgium, Antwerpen (100,000 DWT) and Ghent (55,000 DWT) are possibilities. In the Netherlands, Amsterdam (80,000 DWT), Delfzijl (65,000 DWT), Ijmuiden (84,000 DWT), and Ternuezen (55,000 DWT) are alternatives to Rotterdam. In West Germany, Wilhemshaven (80,000 DWT) and Hamburg (90,000 DWT) are the major facilities. Smaller ports are Emden (48,000 DWT), Bremerhaven, (35,000 DWT), Nordenham (65,000 DWT) and Brunsbuttle (40,000 DWT).

In Denmark, Ensted and Stignaes can both handle ships up to 120,000 DWT. Other receiving points are Kalundburg (45,000), Studstrup (60,000), Esbjerg (50,000), Copenhaven (30,000), and Aalburg (40,000). In Sweden the major port is Goteburg, which can handle 250,000 DWT vessels.

Finally, in Japan, several areas are important. In the Northern Province of Hokkaido, Muroran is the main facility, capable of receiving 110,000 DWT vessels. In the Southern Province of Kyushu, Yawata, Kohura, Oita, and Nagasaki can receive coal ships. Oita is the largest of this group, capable of receiving 250,000 DWT ships. In the Honshu province, several facilities are located near Tokyo: Koshima, Chiba, Kimitsu, and Yokohama are the major ones. Ships from 100,000 to 150,000 DWT can be received. Near Osaka there are several major facilities: Kobe, Kakogawa, Wakayama, Sakai, and Hirohota handling facilities range in size from 50,000 to 80,000 DWT vessels. Nagoya, between Osaka and Tokyo can receive

70,000 DWT vessels. Kamaishi, north of Tokyo, and Mizushima, Fukiyama, and Kure, Southwest of Osaka, are other possible coal receiving ports.

The maximum permissable draft and ship sizes (traditional design) are presented in Tables B1 and B2.

PORT CAPACITY

Two concerns remain: existing port capacities and the expansion of port capacities. In both cases, the answer is complex and subject to significant uncertainties. Nonetheless, some brief remarks are essential to our overall appraisal of steam coal trade.

First, consider existing port capacity. Some recent studies have made reference to existing capacities of port facilities. However, only vague reference is made to how these figures are calculated and what they really mean. In fact, capacity estimation is a very complicated calculation, dependent on several uncertain variables. We will discuss several of these uncertainties.

First, the capacity of the loading and unloading facilities alone, that is, isolated from the rest of the ports' operating characteristics, must be determined. Capacity, or annual throughput, can be defined as:

$$WH \times OD \times (U/L) \times BOR \times NB$$

where:

WH = working hours per day

OD = operating days per year

U/L = actual loading or unloading rates in tons per hour

BOR = berth occupancy rate

NB = number of berths

The values selected for these variables depend on our objectives. If, for example, we want to maximize capacity, the berth occupancy ratio would be set close to 100 percent. This, however, would require a waiting-time-to- berth-time ratio of close to 20 (given 2 berths). Clearly, maximizing capacity is not a useful concept.[2]

What is more important is optimal capacity, subject to some objective function, say cost minimization or profit maximization. In this case, each variable would be chosen to maximize the profits of the operation. For example, the berth occupancy ratio would be set where the marginal costs of waiting to ship owners equals the marginal benefits of greater berth occupancy. Working hours would be set based on the labor supply curve, which reflects wage increases as the operating portion of the day increases. If the data were available, the optimal capacity could be simply computed.

Unfortunately, the data are not available. (Furthermore, facilities do not operate in this way, as was noted earlier.) A more likely practice is maximum acceptable waiting times, and additional constraints on labor availability, and working days. Instead of the optimal capacity, we could make a reasonable approximation of actual capacity.

From a survey of the ports, operating days are set at 345. Working hours are set at 24 hours per day. However, stevedoring costs increase by up to 50 percent for night shifts and weekend shifts.[3]

Nominal loading and unloading rates can also be obtained.[4] These must be adjusted for lost time in berthing, deberthing, and hatch shifting (4 hours per ship) and losses in loading efficiency, depending

on the type of loading equipment. Continuous belt loader have approximately a 75 percent efficiency.[5] The number of berths can also be obtained by survey.[6] Lastly, the BOR depends on the size of ship, distance of haul, and costs of loading and unloading. It is impossible, given data limitations noted earlier, to determine the optimal BOR, but reasonable approximations are possible. A reasonable assumption would be that the maximum acceptable waiting time is 50 percent of berth time, decreasing with ship size. Thus, if only one berth exists, the BOR is set at 35 percent. If two berths exist, the BOR is set at 58 percent, and if three berths exist, the BOR is set at 68 percent. What is most important is consistency. Some studies, for example, set very high berth occupany ratios, and yet calculate very low ocean freight rates. In fact, a high BOR means long waiting times relative to berth times, and a higher freight rate.

Even given an estimate of actual capacity in this way, two other factors must be considered: storage capacity and the capacity of the port as a whole, both for inland transport access and vessel access. As storage capacity is reduced, the BOR will decrease. This is a common constraint on the West coast of the United States. Port congestion is also a common problem, especially in Hampton Roads.

Furthermore, even if we have a reasonable estimate of the capacity of a facility, this in itself says nothing about excess capacity. To the extent that a facility is contracted to metallurgical coals, assessment of this capacity is meaningless and alone serves a limited purpose. Nonetheless, some guidelines on relative capacity magnitudes are

helpful. Based on direct calculations as described above and a survey of the literature, a brief assessment of existing capacity follows.[7]

First, consider the United States. In 1979, Hampton Roads handled 31 million metric tons (MT), and in 1978 15 MT. Baltimore handled 7.6 MT in 1978, while Philadelphia handled virtually nothing. The maximum tonnage moved in the past 5 years was 36.7 MT through Hampton Roads, 8.2 MT through Baltimore, and 1.3 MT through Philadelphia. This suggests that at least some excess capacity exists. Our estimate of capacity, based on the assumptions above, is 23.5 MT in Newport and, 41.7 MT in Norfolk, or a total of 65.3 MT for Hampton Roads. For Baltimore we estimate 15.4 MT of capacity, and for Philadelphia 3.6 MT of capacity. From these imperfect calculations, there appears to be a great deal of unused capacity on the U.S. East Coast.

In the U.S. Gulf, there is virtually no existing capacity at Galveston. Houston's general cargo terminal could handle approximately 2 MT according to Houston Port officials. Devant can handle approximately 4.1 MT, Mobile 4.5 MT, and Myrtle Grove, 3.5 to 4.5 MT. Current exports and imports suggest that approximately 90 percent of this capacity is being utilized.

On the West Coast, only Los Angeles and Long Beach can currently handle coal. Their combined capacity is between 4 and 5 MT. Most of this is available for incremental coal shipments according to port officials.

As a rough estimate then, there is approximately 36 MT excess capacity on the East coast, 4.5 MT on the Gulf Coast, and 3.6 MT on the West coast.

South African capacity is unclear. Current exports are 20 MT. Given the integrated plan, which calls for exports of up to 40 MT in 1985, we can assume that port capacity will build up to this level. In Vancouver, there is 15 MT capacity, 9 of which is in Roberts Bay. Of this amount very little is unutilized.

In Australia, the Joint Coal Board estimates the following capacities and current utilization: Newcastle 21 MT, (9.0 actual); Sydney 3.0 (2.31 actual), Port Kembla, 7.5 (6.32 actual), Hay Point 20, (14.15 actual), Gladstone 13, (6.37 actual). Based on these estimates, total excess capacity is approximately 26 million tons.

In consuming areas, fewer data are available. In Japan, very little excess capacity exists. This is evidenced by the plans for a offshore coal receiving and distribution center. In France, Dunkirk has approximately 12 MT of capacity (5 MT actual), and Le Havre 6 MT of capacity (5.2 actual in 1978). In the Netherlands, capacity has been estimated at 30.6 MT, 14 MT of which was utilized in 1978. Most of this capacity is divided between Rotterdam and Amsterdam. In Germany, there is approximately 6 MT capacity, virtually all of which is currently used. In Denmark, capacity is estimated at 15.5 MT, 10.5 of which was used in 1978. In Italy, no firm data are available.

To conclude, even this rough approximation of existing capacity indicates that for large increases in coal trade, port facilities must be expanded, with a possible exception being the U.S. East Coast.

FUTURE CAPACITY

A more important question than the level of existing capacity is the future availability of port facilities. This section briefly discusses this issue.

The first, and best indication of the problem is existing plans for capacity expansion. In Australia, extensive expansions are already in progress, and extensive long-run developments have been formulated. In Newcastle, the harbor is being dredged from 11.0 to 15.2 meters and ultimately to 17.2 meters to receive 110,000 DWT vessels. Completion is expected by 1982. This will increase the capacity of the facility from 20 to 30 MT. Possible additional expansions have been considered, for example, at Koorangang Island (25 MT). In Port Kembla, new loading facilities are being constructed that will increase capacity from 7.5 MT to 14.0 MT and allow for 110,000 DWT vessels by 1982. There is a possibility of expansion to 17.2 meters and an ultimate capacity of 24 MT. At Gladstone, a major new loader is scheduled for completion in 1981, and plans for expansion to 45 MT and 170,000 DWT vessels have been formulated.[8]

In Vancouver, there are plans for expanding the Roberts Bank terminal, and constructing a new port north of Vancouver. The total ultimate capacity is estimated at 60 MT.[9] In Rotterdam, a new Maasvlakt facility is being constructed capable of handling 25 MT per year. In Denmark, there are plans for the expansion of Kalundborg to 120,000 DWT vessel capacity, and possible new ports in the Jutland or the Fenen area. In Japan, there are plans for an offshore coal center. In

South Africa, current plans call for expansion to 40 million tons. In France, there are plans to dredge Le Havre and Dunkirk to 23 meters, and Fos to 20 meters, and plans for new loaders at Le Havre (12 MT) and Dunkirk (10 to 12 MT). In the United States, Galveston and Houston have plans for large export, import terminals and Los Angeles is considering an expansion to 65 feet, 180,000 DWT, 15 MT. Finally, there have been various discussions for new facilities in the Northwest.[10]

In Australia and South Africa there seems to be little doubt of significant port expansion. In Northern Europe, Rotterdam will grow, and France and Denmark do not seem to have major constraints. However in all cases the costs of expansion and the possible long-run constraints on expansion should be considered.

Consider physical constraints. In all major cases except in the United States, dredging to receive 120,000 DWT vessels is possible. In the United States, however, physical constraints are more binding. In Baltimore, it is possible to dredge the channel to 50 feet (Sorcs), but this involves dredging 36.6 miles of channel. In Philadelphia the channel length is even greater. In Hampton Roads, they can dredge to 58 feet without interfering with the Chesapeake Bay Bridge Tunnel and the Hampton Roads Bridge Tunnel. In New Orleans, dredging to 50 feet is possible, but very high siltation rates make it costly. In Mobile, there are 26 miles of channel.[11] The most likely area for future expansion in the gulf region is Galveston, where 150,000 DWT ships could be handled.[12]

Another major physical constraint is land for storage and loading facilities. San Francisco and Seattle are cases in point. In San

Francisco, the rights to land that could be used for facility are being battled in court.

In all cases, another important constraint is environmental. Los Angeles is a good example.[13] They plan to dredge the current facility to 65 feet. However, to carry this out they need a permit from the Army Corp of Engineers, who in turn require approval by the Department of Interior's Fish and Wildlife Bureau. The potential effect in biological production in the area is a serious constraint. Also, air pollution from trains and ships and from the loading area are a problem. In Los Angeles case, the state of California has jurisdiction over this, and is likely to be a rigid constrant.

Other areas are similarly plagued with environmental restrictions. Vancouver has not approved the expansion of Roberts Bank, nor gained approval for a new port facility. In Australia, the Port Botany expansion was rejected on environmental grounds. A plan under study by the U.S. Army Corps of Engineers to deepen the main channels at Hampton Roads has also encounted stiff environmental resistance. No one can predict the long-term implications, but environmental constraint on expansion, especially in the United States and Canada, should not be ignored.

Finally, the last important issue is what will future expansion cost. First, consider harbor expansions. There are limited data, and the details of expansion plans vary from port to port. However, some examples provide us with a rough indication of costs. In Newcastle, the expansion from 11.2 to 15.2 meters is estimated to cost $70 million.

Expansion from 15.2 to 17.2 meters is estimated to cost A $45 million. A Port Kembla expansion from 15.2 meters to 17.2 meters is estimated to cost A $43 million. The IEA estimates 50 cents to $1.00 per ton[14] for expansion in general. However, these are little more than guesses. Furthermore, even if we know the costs exactly, there is no consistent relationship between costs and port charges. In some cases, the costs of expansion will be reflected in charges. Australia, for example, has charged fees consistent with port expansion costs. In others, however, they are not. It depends on the institutional structure, which varies enormously across countries, and on particular demand, supply conditions in the given countries. The chances are that port charges will increase, but we can not predict by how much.[15]

With respect to new loading facilities, prices do correspond closely to costs, at least where the facilities are private. There is, however, no reason to expect loading and unloading costs to increase significantly in real terms.

To conclude, port expansion will be necessary to handle large increments in the coal trade. Unfortunately, the costs and constraints on expansion cannot be specified with any certainty. In most cases, costs will probably not change significantly in real terms. The one area that could be seriously constrained is the United States. We will evaluate the importance of this constraint below.

FOOTNOTES--CHAPTER VII--APPENDIX B

[1]Port data are obtained from the following sources: H.P. Drewry, "Ports and Terminals for Large Bulk Carriers," No. 46, 1976.
"Guide to Port Entry," Vol. 1, in Port Information, produced by Colin Pielow, 1979/80.
Ports of the World, Thirty-third edition, Benn Publications, Ltd., London, 1980.
Personal Communications with David Elsy, Skaarup Shipping Corp., Greenwich, Conn.
International Energy Agency, Economic Assessment Service, "The Long-Run Economics of the Ocean Transport of Coal," Report No. D1/78, London, England, December 1978.

[2]For a detailed evaluation of port capacity estimation see Frankel, op. cit. Note that the berth occupancy ratio equals the percentage of operating time that the berth is occupied. It ranges from 0 to 1. It is a function of waiting time, service time, and the number of berths available. The relationships cited in the text are drawn from a table relating waiting time/service time ratios to berth occupancy for a given number of berths. The calculations are based on a queueing theory formula with poisson arrivals and exponential service times with first-come, first-served queue discipline.

[3]Ports of the World, op. cit.

[4]Drewry, op. cit., No. 46.

[5]Based on discussions with Ernst Frankel, Professor of Ocean Engineering, MIT..

[6]Ports of the World, op. cit.

[7]Drewry, op. cit.; IEA, op. cit.; Black Coals in Australia, 1978-79, op. cit.; World Coal Study, op. cit., 1980; "The Ports of Greater Hampton Roads," Annual, 1980; Conversations with Port Authorities.

[8]Black Coal in Australia, op. cit., 1977-1978 and 1979-1980 editions. The Queensland Coal Board, 28th Annual Report, June 30, 1979; "Coal Exports Strategy Study," Commissioned by the New South Wales State Government, June, 1979.

[9]Private correspondence with Kaiser Resources, Vancouver, British Columbia.

[10]Port plan specifications based on discussions with port authorities, and Kaiser Resources in Canada; International Coal Trade for Rotterdam; Nordel, 1980 For Denmark; personal correspondence with Japanese officials, WOCO for France, SOROS Associates and ORBA for U.S. Gulf.

[11]Based on estimates by Soros Associates Inc. "Offshore Terminal System Concepts," A Report Submitted to the U.S. Department of Commerce, Maritime Administration, N.Y., 1977, Part 1.

[12]For details of Galveston plan, see "The Galveston Regional Coal Distribution Center Plan," ORBA Corporation, Fairfield New Jersey.

[13]Based on correspondence with Los Angeles port authorities.

[14]Australian estimates from Coal Exports Study, op. cit., IEA, Steam Coal: Prospects to 2000, op. cit.

[15]See Walters, A. and Bemathon, E., Port Pricing and Investment Policy for Developing Countries, A World Bank Research Publication, Oxford University Press, Oxford, England, 1979.

PART B

INTERNATIONAL STEAM COAL MARKETS:
AN ANALYSIS OF DELIVERED PRICES AND DEMAND

INTRODUCTION

In Part A we analyzed the economics of coal transportation. The ultimate purpose was to determine the importance of coal transportation to the development of international steam coal markets. In this part we will relate the transportation analysis to an analysis of steam coal supply and demand, and explain the importance of transportation, and supply and demand variables to the development of international coal trade.

Part B is organized as follows. Chapter I analyzes coal supply in Australia, Canada, the United States and Australia. The emphasis is on current coal prices, and prospective changes in these prices as coal output cumulates, and market and governmental factors shift. Chapter II integrates the supply price information with the transportation cost information developed in Part A to determine cost-minimizing trade patterns on the basis of existing economics and policy. The relative economic importance of inland versus seaborne transportation, transportation versus coal supply prices FOB mine, and the competitive position of each country will be assessed. In addition, the effect of non-incremental structural shifts in transportation and supply variables on future trade patterns will be appraised.

Chapters III through V focus on the demand for steam coal. Chapter III explains the existing structure of steam coal demand in Western Europe and Japan. Chapter IV reviews several recent estimates of steam coal demand in these regions. We will see that these estimates are

deficient in several respects. Consequently, in Chapter V we will analyze further the economics and policy of steam coal demand in two especially important countries, Japan and France.

Finally, we will summarize the results of Part B, and discuss further critical transportation, supply, and demand factors underlying the development of international steam coal trade.

CHAPTER I

INTERNATIONAL STEAM COAL SUPPLY

INTRODUCTION

In Part A we have estimated inland and ocean freight coal transportation costs. In order to calculate delivered coal prices to coastal coal-fired power stations in Western Europe and Japan, this chapter analyzes the current and future prices of steam coal at the mine.

Four countries will be analyzed: Canada, Australia, South Africa, and the United States. There are several reasons for choosing this set. Most importantly, these countries will probably account for most steam coal exports into the 21st century. The World Energy Conference estimates that they account for approximately 40 percent of hard coal reserves that are technically and economically recoverable, and 50 percent of brown coal reserves.[1] Their production of bituminous coals and anthracite amounts to 30 percent of the world total, and their exports comprise 55 percent of the world total. Excluding the U.S.S.R. and Poland, their exports comprise 89 percent of world coal exports.[2]

Consider other important potential steam coal exporters. Reasons for not focusing on them are varied. First, in Russia and other Eastern European countries (primarily Poland and Czechoslovakia), information beyond general industry appraisals was unavailable. Also, the likelihood of increased exports from them to non-Communist nations is small. In fact, it is more likely that exports from these countries will decrease in the future. Poland, traditionally a major supplier of coal to Western Europe, has manifested this by withdrawing coal supplies from the European market in favor of expanded sales to the Eastern Bloc nations.

Second, in coal-producing countries, such as the United Kingdom, West Germany, Japan and Korea, increments to production will be small, and prices are far too high to encourage their significant participation in steam-coal export markets. Third, in countries where coal industries are developing, primarily India, China, and Columbia, the coal industry production and transportation infrastructures are severely limited, and their contribution to steam coal markets more uncertain and more distant in the future.[3] To conclude, though this is clearly an imcomplete view of the future markets, the four countries analyzed will as a group dominate steam coal exports in the next 20 years.[4]

The chapter is organized as follows. First, the existing pattern of coal production will be described. Second, the reserve base of each country will be described. Third, the structure of developing steam coal markets will be considered. A more detailed evaluation of all of these subjects is provided in Appendix A. Fourth, current coal prices will be analyzed. Fifth, long run changes in coal prices will be evaluated. In the next chapter, coal prices and transportation costs will be integrated to calculate and explain cost minimizing delivered prices to Western Europe and Japan.

RESERVES-PRODUCTION AND MARKET STRUCTURE

COAL CHARACTERISTICS

Before we can actually discuss reserves of coal, the various types of coal should be explained.

Coal is not a homogeneous substance. Rather, there is a wide range

in the composition and in the chemical and physical properties of different kinds of coal. Since variations over this range are important to end-uses, an explanation of the various coal classifications is essential prior to the analysis of coal reserves, prices, and production.

Fundamentally, variations in organic composition yield variations in coal type (e.g., humic or sapropelic); different temperatures to which coals were subjected determine the rank (e.g., peat, lignite, subbituminous, bituminous, anthracite); the composition and rank determine the various properties of coal (heating value, ash content, sulfur content, ash fusion temperature, moisture content, volatility, grindability, density), including those that are used to assess its grade. For example, density (weight per unit volume) is low for bituminous coals; heating value increases from peat to bituminous; higher ranks correspond to lower volatile matter.[5]

The relative importance of these different coal properties depends on the end-use. Coking coal is used for metallurgical purposes, and steam coal primarily for power generation. Coking coal:

> ... should be of high grade and calorific value with a low ash content; it must swell to some extent, and be moderately plastic, and it should have a volatile content on a dry, ash-free basis of 21-30 percent (medium volatile, bituminous rank). A combination of these characteristics gives a strong, high quality coke. Low sulfur content is also important as a higher sulfur content causes brittleness in steel, as well as metal corrosion and air pollution.[6]

For steam generation, the most important characteristics are heating value and sulfur content. Also important are volatile matter, moisture

content, ash content, ash-fusion temperature, and grindability. For steam generation, setting these variables is more largely a function of economics at the design stage, while for metallurgical purposes certain qualities are technologically essential for coking (i.e., plasticity).

There is no precise boundary point between steaming and coking coal. That is, some "steaming coal" may be used for "coking coal" and vice-versa. With the recent increase in the premium on low-sulfur coal in the United States and Japan, this distinction is especially vague. Though coal is classified as coking or steaming coal, and though the end-uses for coal from particular mining properties are generally power generation or metallurgical purposes, this substitutability should not be overlooked.

COAL PRODUCTION

World bituminous and anthracite coal production in 1978 was 2630 million metric tons (MT). Lignite production amounted to 940 million metric tons.[7] Bituminous and anthracite production by region and principal-producing countries are presented in Table 1.

Three countries, China, the U.S.S.R., and the United States, account for 66 percent (1735 million metric tons) of the total bituminous and anthracite coal production. The top 12 producing countries account for 95 percent of the total production. They are shown in Table 1. Canada, Australia, South Africa, and the United States account for approximately 30 percent of world bituminous and anthracite production. However, excluding China, U.S.S.R. Poland and Czechoslavakia, the four accounted

Table 1

World Production of Bituminous and Anthracite Coal--1978[1]

	Million Metric Tons	
North America:	594	
United States		565
Canada		25
South America:	10	
Europe:	483	
Germany (F.R.)		90
United Kingdom		122
Poland		193
U.S.S.R.:	556	
Asia:	819	
China		618
India		101
Korea[2]		63
Africa:	95	
South Africa		90
Oceania:	74	
Australia		72
World Total:	2630	

Notes: 1. Data for some countries were estimated where no statistics were available.
2. Includes North Korea (45 MT) and South Korea (18 MT).

Source: Coal International, Zinder-Neris, Inc. Washington, D.C., Vol. 1, No. 1, May 1979.

for 61 percent of the world's coal production.[8]

More important for our purposes is the role of these countries in the coal export market. Worldwide they accounted for 55 percent of total exports in 1977, and 89 percent of exports excluding the U.S.S.R. and Poland. Coal exports are shown in Table 2.

Appendix A presents a more detailed description of coal production patterns in Australia, Canada, South Africa, and the United States. For the reader not interested in that level of detail, some major points are included here.

Two Australian states, Queensland and New South Wales, account for approximately 92 percent of Australian black coal reserves, and 95 percent of Australian black coal production. New South Wales raw coal production was 50.5 million metric tons (MT) in the 1978-1979 fiscal year. Saleable coal production was 42.4 MT, 56 percent of which was consumed domestically, and 44 percent exported. 76 percent of the exports were used for metallurgical purposes, and 22 percent for electricity generation. Virtually all of the coal was low-sulfur bituminous coal, and 76 percent of the raw coal production was from underground mines. The New South Wales coal mines are relatively close to ports, ranging in distance from 25 kilometers (km) to 100 km.[9]

Queensland raw coal production in 1978-1979 was 37.3 MT. Saleable output was 26.9 MT. In contrast to New South Wales, 88 percent of the raw coal production was from open-cut mines, and only 12 percent from underground mines. Exports in 1978-79 equaled 18.8 MT, 99 percent of which were used for metallurgical purposes. The low-sulfur, bituminous

Table 2

World Coal Exports--1978

	Million Metric Tons
United States	37
Canada	14
Germany (F.R.)	19
United Kingdom	2
U.S.S.R.	26[1]
Poland	40
Australia	39
South Africa	15
Total	192
World Total	199[2]

Notes: 1. Estimated.
2. Includes France, Belgium, Netherlands, Czechoslovakia, other.

Source: Coal International, Zinder-Neris Inc., Washington, D.C. Vol. no. 3, 1979.

coal mines are further from port facilities than are New South Wales mines, ranging in distance from 177 to 490 km.[10]

South African coal production was 90.4 MT in 1978, 15.4 MT of which were exported. 1979 exports increased to 22.5 MT. Approximately 90 percent of these exports were for electricity generation. The largest producing region in South Africa is the Transvaal State, which accounted for 71 percent of the 1978 output. Coal in this region is high-ash, low to medium sulfur (.5 percent to 1.2 percent), bituminous steaming coal. The average distance to port is 540 km.[1]

Total Canadian coal production was 30.4 MT in 1978. Exports equaled 13.6 MT, more than 90 percent of which were used for metallurgical purposes. The most important producing districts for export are British Columbia and Alberta. British Columbian production in 1978 was 9 MT, virtually all of which was exported for metallurgical uses. Almost all of the production was surface-mined, low-sulfur, bituminous coal. Alberta coal production of bituminous and sub-bituminous, low-sulfur coal equaled 13.5 MT in 1978. Approximately 50 percent of the Alberta production was subbituminous coal used in domestic power stations. The remaining bituminous production was exported for metallurgical purposes. Distances to West coast ports range from 700 to 800 miles.[12]

United States bituminous and lignite coal production equaled 603 MT in 1978, approximately 38 MT of which was lignite. Exports were 37 MT, virtually all of which were used for metallurgical purposes. There are three major coal producing regions: the West, the Midwest, and Appalachia. Western coal production is low-sulphur bituminous and

subbituminous coal. 1978 output equaled approximately 159 million metric tons, more than 90 percent of which was from surface mines. Midwestern production was approximately 112 MT in 1978. Roughly 68 percent of this total was produced from surface mines. The coal is typically medium to high sulphur bituminous coal. Appalachia production in 1978 was approximately 333 MT, most of which was medium to high sulphur bituminous coal produced from underground mines. Finally, Western mines are on average 1000 miles from West coast ports, Midwestern mines are approximately 600 miles from Gulf Coast ports, and Appalachian mines range from 300 to 600 miles from Atlantic Coast ports.[13]

COAL RESERVES

Current coal production statistics tell us about existing coal markets, and possible short-term developments, but very little about future supplies and markets. Coal reserve data should guide us in predicting availability and production costs in the long-run.

Unfortunately, reserve classification systems do not fully provide the amount of economic and geologic information that we need. We know that there is lots of coal in the ground, and that much of it is economically and technically recoverable, but we are unable to predict with confidence the change in production costs as output cumulates. Therefore, it is necessary to discuss the classification systems and the problems with them so as to add meaning to country coal-reserve data.

United States Coal Reserves

The reserve classification systems in the United States have been thoroughly criticized elsewhere.[14] The basic categorization was developed by the United States Geological Survey (U.S.G.S.). Total resources are separated into identified and undiscovered resources, the latter category including hypothetical resources (surmised to exist in known mining areas), and speculative resources (possible resources in areas where coal has been previously discovered). The volume of identified resources is so large that speculative and hypothetical reserves need not concern us for at least the remainder of the century.[15]

The U.S.G.S. classifies identified resources according to the certainty with which deposits are known and the physical characteristics of deposits. The physical dimensions include depth of the seam from the surface (less than 1000 ft, 1000-2000 ft, 2000-3000 ft), and the thickness of coal seams (14" to 28", 28" to 42", and 42" and greater). The certainty dimension is subdivided into measured, indicated, and inferred categories.

They are defined as:[16]

- Measured: Measured resources are resources for which tonnage is computed from dimensions revealed in outcrops, trenches, mine workings, and drill holes. The points of observation and measurement are so closely spaced, and the thickness and extent of the coal are so well defined, that the computed tonnage is judged to be accurate within 20 percent of the true tonnage. Although the spacing of the points of observation necessary to demonstrate continuity of coal differs from region to region according to the character of the coal beds, the points of observation are, in general, about half a mile apart.

- Indicated: Indicated resources are resources for which tonnage is computed from specific measurements and partly from projection of visible data for a reasonable distance on the basis of geological evidence. In general, the points of observation are about one mile apart from beds of known continuity. In several states, particularly Alabama, Colorado, Iowa, Montana, and Washington (where the amount of measured resources is very small) the measured and indicated categories have been combined.

- Inferred: Inferred resources are resources for which quantitative estimates are based largely on broad knowledge of the geologic character of the bed or region and for which few measurements of bed thickness are available. The estimates are based primarily on an assumed continuity in areas remote from outcrops of beds, which in areas near outcrops were used to calculate tonnage classes as measured or indicated. In the intrest of conservatism, the areas in which the coal is classed as inferred are restricted as described under the heading, "Areal Extent of Beds." In general, inferred coal lies farther than two miles from the outcrop in areas for which mining or drilling information is available.

The United States Bureau of Mines (U.S.B.M.) has refined this classification with the purpose of restricting the definition of reserves to "economically available reserves".[17] Their demonstrated reserve base includes measured and indicated reserves in bituminous seams greater than 28" and less than 1000 ft below the surface. Subbituminous and lignite reserves are included if they are in seams greater than 5 ft. The demonstrated reserve base is defined as a whole as:

> ... that portion of the identified coal resource that can be economically mined at the time of determination. The reserve is derived by applying a recovery factor (approximately 30 percent) to that component of the identified coal reserve designated as the reserve base.[18]

In Zimmerman's words, the U.S.B.M. claims that:

> ... the reserve base, once adjusted for a recovery factor, represents coal that is economically available according to the joint definitions of the U.S.G.S. and the U.S.B.M.[19]

Finally, the demonstrated reserve base is divided into underground and strippable reserves. In general, the portion of the reserve base that lies less than 120 ft below the surface is categorized as strippable.

This classification scheme has marked deficiencies as a guide to the behavior of costs as output cumulates. Zimmerman has shown that in several ways the classification simply does not measure what it claims to measure--that is, economic availability.[20] A brief diversion into mineral economic theory is essential to understanding this deficiency.

Three principles are important. First, mineral economic theory tells us that the cheapest resources will be exploited first. Second, economic theory predicts that in long-run competitive equilibrium the cost of the marginal output (including user cost) will equal minimum average production cost. In the case of coal (and other minerals), however, mines with more favorable mining conditions will produce simultaneously with less favored mines and earn higher rates of return. Third, the "incremental mine" is the last or least favored mine opened to meet demand, and its minimum average cost is the long-run marginal cost of the industry.[21] As a consequence of these three principles, changes in output levels are not sufficient to predict changes in production costs. Equally important are variations in geologic conditions. To predict production cost changes we must evaluate the geologic conditions of the incremental mine at various output levels. If the incremental mine is extracting reserves that lie on the boundaries of the USBM reserve definition, then the definition is a reasonable guide to today's economically recoverable coal reserves.

In fact, Zimmerman has argued that the United States reserves include a lot of coal that cannot be ecomomically extracted with current technology at today's prices.[22] Furthermore, the broad categorization of seam thicknesses and the omission of other important mining condition data (roof, floor, water, etc.) do not allow for accurate predictions of production costs as output cumulates. In essence, the data ignore important cost-determining conditions and this has led to incorrect interpretations of reserve data. Hear Zimmerman:

> ... Reserve and resource data tell us that there is a great deal of coal in the ground. Even the narrowest reserve classification is broader than what it was intended to be. Needed information is lacking. There have been attempts to deal with this missing information and to fill the gaps, and there have been some tentative conclusions, but more information is necessary if we are to make more confident predictions. We lack information on unobserved characteristics and on the distribution of seam thickness. There have been attempts to fill that lack but, at this point, we can only characterize the results as tentative.[23]

South African Coal Reserves

The deficiencies in the reserve classification systems of other countries are equally troublesome. In South Africa, the 1975 Report of the Commission of Inquiry into the coal reserves of the Republic of South Africa (A.K.A. Petrick Report) assessed South Africa's coal reserves. The commission estimated resources in terms of:[24]

> a. total mineable in situ resources; that portion of the coal in situ which can be mined by existing technologies, and
>
> b. total extractable resources; that portion of the mineable coal in situ which is extractable in prevailing or slightly less rigorous economic conditions.

Mineable coal is subdivided into proven, indicated, and inferred categories, and then further subdivided into types (steam, metallurgical, anthracite) and grade (according to heating value). Extractable coal is subdivided into underground and surface mining resources. The estimates are based on an ash content of less than 35 percent, a seam thickness of at least 1.2 meters (for bituminous coal) and a mining depth of less than 300 meters (for bituminous coal). For metallurgical coal and anthracite, the corresponding figures are .7 meters, and 500 meters.[25] Though the comparison is imperfect, the South African mineable and extractable categories correspond roughly to the U.S. demonstrated reserve base and recoverable reserves, respectively. Note, however, that extractable resources are approximately 58 percent of mineable resources in South Africa, while recoverable reserves are approximately 30 percent of the demonstrated reserve base in the United States. Given the lack of details on the determination of recovery factors, the reason for this difference cannot be specified with any certainty.

Ellis, among others, has analyzed the Petrick report classification system.[26] Though the specific objections vary, the conclusions parallel Zimmerman's for the U.S. system: the classification fails to adequately describe economically extractable coal in South Africa. Not surprisingly, other studies have estimated economically available reserves as both much higher and lower than the Petrick report figures.[27]

Australian Coal Reserves

Australia's coal classification system closely parallels the U.S. system. The National Energy Advisory Committee completed an assessment of Australia's energy resources in December, 1977, which adapted the U.S.G.S.-U.S.B.M. methodology.[28] However, the adaptation falls short in several respects. First, physical properties are categorized more broadly. Overburden is listed for reserves under 600 meters, and under 300 meters only. Seam thickness is only constrained at the minimum point of 1.5 meters (1 meter in special circumstances). Second, demonstrated economic resources includes reserves in deposits with less than 600 meters of overburden, whereas the demonstrated reserve base in the United States sets a maximum of approximately 300 meters.[29] Note also that the recoverable coal is approximately 55 percent of the demonstrated reserve base. This is again much higher than the U.S. estimate, and approximately equal to the South African recovery factor estimate.

A more thorough analysis of coal reserves was completed in 1979 by the New South Wales Joint Coal Board (JCB).[30] Within the same basic classification system, seam thicknesses and depth ranges are estimated for each seam within mining areas. The reserves are further subdivided into twelve categories formulated by the board as being representative of the coal products marketed by New South Wales. Volatile matter, ash content, and coking or non-coking uses are specified characteristics. The exact estimation procedure is unclear. The JCB notes that "where necessary, quality was estimated from borehole data and by comparison with adjacent areas".[31] Furthermore:

> There is a considerable range in the reliability of the resource estimates presented. Those within allocated areas generally fall within the measured or indicated reserve classes; while those within the unallocated areas are generally indicated or inferred reserves.[22]

Finally, one further category estimated by the JCB (and South Africa) is marketable (or saleable) coal. This is a subset of recoverable coal, calculated on the basis of market expectations with regard in particular to coking and non-coking markets.[33] The actual mechanics of this calculation were unavailable, so its usefullness cannot be criticized. Conceptually, however, it is a useful measure of market potential.

In Queensland, the 28th annual report (1979) follows more closely the 1977 national report. Reserves are categorized as measured, indicated, and inferred. They are subdivided on a geological basis (Permian or Mesozoic eras) and in strippable (less than 60 meters) and underground categories.[34]

Canadian Coal Reserves

Canada's system also closely parallels the U.S.G.S.-U.S.B.M. system. Identified resources are classified by the Geological Survey of Canada as measured, indicated, and inferred.[35] However, physical properties are deficient. This author was only able to find average regional physical properties. In various Canadian reports estimates of recovery factors have also varied significantly, and no official figure is provided. Further work is being undertaken in Canada to obtain a more accurate assessment of coal reserves and to arrive at a figure of

economically recoverable reserves in terms of current operating conditions and markets.

Reserve estimates for these four countries are presented in Tables 3 through 6. It should be obvious that comparisons have limited value given the substantial variation in restrictions and definitions in the various systems, and that economic interpretations are likely to be fallacious given the imperfect correspondence between economic recoverability and the various reserve categories. Nonetheless, the estimates provide at least a reasonable ordinal picture of coal reserves in these four countries. Specifically, the United States demonstrated reserve base is approximately twice the reserve base of Canada, Australia, and South Africa combined. The U.S. recoverable reserves also far exceed the other countries' recoverable reserves combined. Of the remaining countries, Canada and Australia demonstrated reserves combined are approximately equal to the South African demonstrated reserves.

World Energy Conference Coal Reserves Estimates

The World Energy Conference (WEC) has attempted to integrate these and other national classification systems into two categories:

> 1. Geological resources: these are understood to mean resources that at some time in the future may acquire an economic value for mankind; and
>
> 2. Technically and economically recoverable resources: used to cover only those reserves that, under technical and economic conditions, are applicable to the present day, and are considered to be exploitable.

Table 3

DEMONSTRATED RESERVE BASE[a] OF COALS IN THE UNITED STATES
ON JANUARY 1, 1976, ACCORDING TO RANK[b]
(million short tons)

State	Anthracite	Bituminous	Subbituminous	Lignite	Total
Alabama	--	2,008.7	--	1,083.0	3,091.7
Alaska	--	697.5	5,446.6	14.0	6,158.2
Arizona	--	325.5	--	--	325.5
Arkansas	96.4	270.1	--	25.7	392.2
Colorado	25.5	9,144.0	4,121.3	2,965.7	16,256.4
Georgia	--	0.9	--	--	0.9
Idaho	--	4.4	--	--	4.4
Illinois	--	67,969.3	--	--	67,969.3
Indiana	--	10,714.4	--	--	10,714.4
Iowa	--	2,202.2	--	--	2,202.2
Kansas	--	998.2	--	--	998.2
Kentucky, E.	--	13,540.1	--	--	13,540.1
Kentucky, W.	--	12,460.8	--	--	12,460.8
Louisiana	--	--	--	c	c
Maryland	--	1,048.3	--	--	1,048.3
Michigan	--	126.8	--	--	126.8
Missouri	--	5,014.0	--	--	5,014.0
Montana	--	1,385.4	103,416.7	15,766.8	120,568.9
New Mexico	2.3	1,859.9	2,735.8	--	4,598.0
N. Carolina	--	31.7	--	--	31.7
N. Dakota	--	--	--	10,145.3	10,145.3
Ohio	--	19,230.2			19,230.2
Oklahoma	--	1.618.0	--	--	1,618.0
Oregon	--	c	17.	--	17.5
Penn.	7109.4	23,727.7	--	--	30,837.1
S. Dakota	--	--	--	426.1	426.1
Tennessee	--	965.1	--	--	965.1
Texas	--	--	--	3,181.9	3,181.9
Utah	--	6,551.7	1.1	--	6,552.8
Virginia	137.5	4,165.5	--	--	4,302.9
Washington	--	255.3	1,316.7	8.1	1,580.1
West Virginia	--	38,606.5	--	--	38,606.5
Wyoming	--	4,002.0	51,369.4	--	55,371.9
TOTAL	7,371.1	228,924.6	168,425.0	33,616.6	438,337.3

Source: U.S. Bureau of Mines, as reprinted in Keystone Coal Industry Manual, 1978, p. 694.

Table 3 (continued)

Notes:
[a]Includes measured and indicated resource categories as defined by the U.S.G.S. and represents 100 percent of the coal in place.,

[b]Data may not add to totals shown due to rounding.

[c]Quantity undetermined (basic resource data do not provide the detail required for delineation of reserve base).

[d]Recoverable reserves equal 68,340 million tons of bituminous coal, 56,227 million tons of subbituminous coal, and 2,234 million tons of anthracite.

Table 4

SOUTH AFRICA'S COAL RESERVES AND RESOURCES

Mineable in situ Resources	Million Metric Tons
Raw Bituminous Coal	81,274
Metallurgical Coal (washed)[1]	3,451
Anthracite (washed)	744
TOTAL	85,469
Extractable Resources (underground mining)	
Raw bituminous coal	24,915
Metallurgical coal (washed)	705
Anthracite (washed)	375
TOTAL	25,995
Extractable Resources (Surface mining)[2]	
Raw bituminous coal	23,680
Metallurgical coal	124
Anthracite	32
TOTAL	23,836

Notes: 1. I.e., on a washed-coal basis.

2. Assuming a strippable ratio, i.e., ratio of overburden volume to tons of coal, of 10:1.

Source: South African Department of Mines, Minerals Bureau, Internal Report no. 48, Coal in South Africa, 1979, p. 16.

Table 5

AUSTRALIA-DEMONSTRATED ECONOMIC RESOURCES OF BLACK COAL[1]
(10^6 metric tonnes)

	Total in Situ	Bituminous in Situ (percent)	Depth of Cover Less than 300 meters	Recoverable New Coal	Total Saleable Coal	Saleable coking Coal
New South Wales	16,150	98	13,080	9,030	7,556	4,890
Queensland	17,360	98	16,270	10,130	8,112	4,020
Tasmania	120	100	120	60	50	-
Western Australia	1,950	0	1,550	390	390	-
South Australia	720	0	720	650	650	-
TOTAL	36,300	91	31,740	20,260	16,758	8,910

Notes: Australia's Black Coal category is almost exclusively bituminous coal. Negligible amounts of anthracite and subbituminous coal are also included. Lignite is classified as "brown coal" in Australia. More specifically, coal with a gross specific energy value of less than 20.00 MJ/kg (approximately 19 million Btu per metric ton) is classified as brown coal. Coal with a gross specific energy value of 27.00 MJ/kg (approximately 25.7 million Btu per metric ton) is classified as Black bituminous coal. Coal between these limits is black subbituminous coal.

Source: National Energy Advisory Committee, Australia's Energy Resources: An Assessment, December, 1977, p. 51, 59.

Table 6

COAL RESOURCES OF WESTERN CANADA BY PROVINCE

(Millions of short tons)

Province	Measured	Indicated	Inferred	Total
B.C.	7,329	11,175	40,953	59,547
Alberta	2,204	32,096	12,940	47,240
Sask.	292	7,024	4,698	12,014
TOTAL	9,824	50,296	58,592	118,711

Source: Latour, B.A. and Chrismas, L.P. Preliminary Estimate of Measured Coal Resources Including Reassessment of Indicated and Inferred Resources in Western Canada; Geological Survey of Canada, paper 70-58, 1970.

In making the distinction between these two categories, depth limits for "geological resources" were "advised" at 2000 meters for hard coal, and 1500 meters for brown coal. For "technically and economically recoverable reserves," the corresponding restrictions are 1500 meters for hard coal, and 600 meters for brown coal. The minimum seam thickness for technically and economically recoverable reserves "is generally in the range of around 0.6 meters in the case of hard coal, and 2.0 meters for brown coal."[36]

The last sentence should evidence the problems pervasive in this study, or, for that matter, in any effort to integrate various national reserve estimates. In essence, reserves are not estimated in accordance with international agreements of standard guidelines. Rather, reserve numbers estimated by each country according to their classification system are made to fit into the two WEC categories. In many cases this calls for a two-inch dowel to be forced into a one-inch bore-hole. The WEC acknowledges these problems to some extent:

> The difference in the international criteria of assessment, together with the very considerable worldwide difference in the degree of geological exploratory work carried out on the coal deposits in the various countries restrict to a large extent the possibility of affecting a comprehensive and generally valid appraisal of raw material deposits, particularly those of coal.[37]

In fact, the matching of WEC categories to various national categories is very difficult, and comparisons based on the WEC categorization scheme are likely to be misleading, especially in the geological resource category. This author was unable to consistently match even the technically and economically category to what seemed to be reasonably

equivalent national categories. In particular, the WEC U.S. estimate of technically and economically recoverable reserves is substantially higher than the actual U.S. recoverable reserve estimates, while the WEC South African and Australian estimates are reasonably consistent with those countries' estimates of recoverable reserves. Possibly the WEC imputed a higher recovery factor in the U.S. case. In any event, the WEC estimates of technically and economically recoverable reserves are presented in Table 7. Though inconsistent, they also present a reasonable ordinal picture of coal reserves.

To conclude, we know there is a great deal of coal, and that these four countries own a large share of it. However, the reserve estimates must be used with caution both in international evaluations of production costs and in international comparisons of output potential. We will briefly return to the former case in the discussion of depletion costs below. For a more detailed description of coal reserves and production, see Appendix A.

MARKET STRUCTURE

Another important determinant of prices in steam coal export markets is market structure. However, in a largely undeveloped market such as this, where entry is taking place as new firms are buying up coal reserves, and where the extent of interregional competition is still unclear, relatively little can be said about future competition and the ability of producers to realize rents in international steam coal markets. Nonetheless, a brief review of the existing market structure in

Table 7

WORLD ENERGY CONFERENCE
TECHNICALLY AND ECONOMICALLY RECOVERABLE RESOURCES
(Million Tons of Coal Equivalent)

	Hard Coal	Brown Coal
Africa:	34,033:	90:
South Africa	29,903	-
North America:	126,839:	71,081:
U.S.	113,236	64,358
Canada	8,708	673
Asia:	219,226:	29,626:
China	98,883	N.A.
USSR	82,900	27,000
India	33,345	355
Australia:	18,128	9,225
Europe:	94,210:	33,762:
U.K.	45,000	-
Germany	23,919	10,500
Poland	20,000	1,000
TOTAL	492,472	
143,892		
Canada, US, Australia, South Africa	38 percent	49 percent

Notes: N.A. indicates "not available."

Hard Coal = bituminous and anthracite
Brown Coal = Subbituminous and lignite.
Ton of Coal Equivalent = 7×10^6 Kcal
Source: World Energy Conference, Coal Resources, 1978.

each country will improve our understanding of existing prices and future price changes.

Additional details on the existing market structure are included in Appendix A. To summarize them, in Canada most current export production is for metallurgical purposes. The Alberta mountains region and the British Columbian producers are competitors with one another. The Herfindahl Index for the six producers in these regions equals 0.264.[37a] The reciprocal, 3.78, indicates that the industry performs like about four equal suppliers.

Current steam coal production is primarily in the Alberta plains. Very little of it is exported. The Manalta mines produced 6.97 MT of the 8.30 MT total. However, some of their mines are actually owned by public utilities. Two other companies in the Alberta plains produced less than 1 MT per year. Another British Columbian company, Byron Creek, produced 0.52 MT of steaming coal for export.[38]

In South Africa, three companies controlled 75 percent of total production. The largest six companies controlled approximately 88 percent of total production. The Herfindahl index is 0.247, indicating that the industry performs as four equal firms. Equally important to competition in South African export markets, however, is the marketing structure in South Africa. Major producers' associations are assigned export quantities by the government, and they in turn allocate these quantities to their member companies. Although recently some large mines have been able to circumvent this system, this marketing arrangement sets the foundation for a non-competitive pricing industry.[39]

In Australia, Queensland and New South Wales producers compete with one another. Like Canada, the relative dominance of metallurgical coal producers clouds the future competitive structure for steam coal exports. The three major steam coal districts, Kianga-Moura, Blackwater, and Blair Athol, are controlled by seven companies, though various sets of these companies have formed conglomerates in different areas. This joint-ownership might mitigate the competition that would otherwise obtain from this many firms. In New South Wales, steam coal production is greater than in Queensland, but the data does not allow for separation between steam coal and metallurgical coal output. Nonetheless, there are ten companies in New South Wales that produce over 1 MT of coal. Given competition between Queensland and New South Wales, the Australian industry seems to be a very competitive one.[40]

Lastly, consider the United States. Zimmerman has evaluated coal industry market structure in the United States, and the following conclusions can be drawn.[41] In the East, competition is strong. Taking the reciprocal of the Herfindahl Index for the top 15 producers suggests that the industry behaves as 13.2 equal firms. In the Midwest, markets are far more concentrated. In Districts 9, 10, and 11, the reciprocal of the Herfindahl Index is 5.73. In the West, there are a few very large firms. Five companies control almost 50 percent of the Western production. However, these five companies are almost equal competitors, and the large number of smaller companies should check any anti-competitive collusion.[42]

To conclude, steam coal markets are not yet sufficiently developed to offer any firm conclusions on the extent of competition. More needs to be known about the long run development of each country's steam coal export industry. In addition, these countries will not be sealed from each other, so that in certain cases the relative market will include all four of them, and the fact that one nation's industry, say South Africa, is not competitive is only important if South Africa has a comparative advantage over other nations in certain markets. The extent of international competition will be discussed in Chapter II. Based on the existing structure, it seems likely that future markets will be competitive. If, however, South Africa is positioned to realize large locational rents in international markets, the existing structure suggests that they could well do so. We will return to this below.

Note finally that existing markets do seem to be competitive. Though this is uncertain, it suggests then the prices we analyze in the next section are competitive prices, and do not include significant monopoly rents.

PRICES

We would like to estimate long-run equilibrium prices and quantities in international steam coal markets, but this is beyond the limits of this research. However, by analyzing current prices we can construct a foundation for the steam coal market, from which we can begin to develop a better understanding of steam coal markets in the future. Questions of

particular interest are: What is the importance of location to patterns of market development? Which subset of countries are likely to be competitors for a given demand region? Which supply region's exports are likely to increase by the greatest amount?

After analyzing current prices, we will then consider changes in real prices as output cumulates, and, in the next chapter, the amount demanded at these price levels. Recall that these are not equilibrium prices. Nonetheless, they are important indicators of future prices, especially if markets are competitive and if supply is highly elastic.

First, by way of background, consider the types and dimensions of coal prices.

Coal is sold for varying contract periods. Spot contracts typically have a duration of less than one year. In a spot contract, both the coal company and the consumer (say, utility) are exposed to high risk. A miners' strike, or inclement weather, or other short-term disruptions in normal practice can leave the utility at a disadvantage. The coal company will lose when demand is lower than expected. Also significant for the utility is the problem of securing the coal quality for which his boiler was designed.

As in other markets (i.e., shipping), long-term contracts are signed to reduce buying and selling costs and to smooth out short-term market fluctuations. The longest contracts (say 20 to 30 years) should therefore accurately reflect producers' and consumers' expectations of long-run price and cost developments (given that they call for the initial delivery of coal in some period after the contract is negotiated, so as

to allow for full market adjustment). Unfortunately, data on long-term contracts are rarely available, and any thorough analysis of them is impossible.

Instead, we are left with spot price data and contract price estimates which weight spot and long-term expected prices. We know that spot prices will vary around long-term equilibrium prices according to the direction and expected duration of a market fluctuation in demand or supply conditions.[43] Consequently, we must be careful in interpreting price observations.

There are several important dimensions to coal prices. First, consider heating value. Clearly, coal with a higher British Thermal Unit (Btu) content will be more valuable per ton than coal with a lower Btu content. To adjust for this, it is useful to set prices per million Btu. Still, a higher heating content per ton means lower transporation and handling costs per Btu. Transportation costs must be applied per ton. Handling cost variations are a negligible component of delivered prices.[44]

Second, consider ash content. Lower ash content is significant for several reasons. It reduces handling and transportation costs per million Btu; it reduces ash disposal costs; it reduces operating and maintenance costs of pulverizers, and it reduces precipitator capital costs. However, within the range of ash contents reported in price data (that is after beneficiation), the variation in costs is also negligible.[45] Note, however, that the cost of beneficiation must be considered when calculating coal production costs from FOB pier prices.

Third, consider moisture content. Again, moiture increases the costs of handling and transportation. It is picked up by calculating transportation costs per ton, and then converting to costs per million Btu.

Fourth, ash fusion temperature is a critical variable in boiler design. Given an existing boiler, changes in ash fusion temperature may be very important to boiler operating and maintenance costs. However, given constant coal quality, this variation should not be that important in the planning stages.

Fifth, consider sulfur content. Sulfur content of coal has become increasingly important as air pollution regulations have stiffened. In some cases, coals with a certain sulphur content can simply not be burnt. In other cases, high sulfur content requires greater capital expenditures on cleaning equipment. In general, there is a premium on low-sulfur coal.

In the U.S. markets this premium is critical. The ability of western coal to compete in eastern or mideastern markets depends on the relative economic advantages of low-sulfur versus high-sulfur coal.[46] In this analysis, however, the importance is less. In Japan and the Far East, sulfur limitations are stringent, and all of the likely suppliers (Australia, Canada, and western United States) have low-sulfur coal. In Western Europe, an option exists between low-sulfur South African coal and high-sulfur U.S. eastern or mideastern coal. However, existing regulations in Western Europe are very slack relative to the United States or Japan, and the premium is small. We will assess the

importance of this factor below. In general, however, given the locational parameters of international coal markets, the lowest-sulfur coal will be selected.

CURRENT PRICES

As noted, price information is limited by the confidentiality of coal contracts. We are forced to rely on imperfect information, but useful guidelines can nonetheless be constructed.

For the United States, two biweekly price series are published in Coal Week: "current contract and spot marker steam coal prices," and "current international spot steam coal prices."[47]

In the first price series, spot and term prices (FOB mines per short ton) are presented for Bureau of Mines Districts according to Btu/lb, sulfur content, and ash content. The

> "prices quoted do not represent actual transactions. They are a synthesis of market conditions for each producing district based on the characteristics of Coal Week's market prices. Prices reflect the state-of-the-trade as perceived and discussed in confidence by buyers, sellers, traders, and brokers for unwashed coal of the market's specifications. Prices are updated bi-weekly as noted. Quality specifications are derived by computer analysis of utility coal purchase statements submitted to the Federal Energy Regulatory Commission (see Table 8-a)."

Also important is the fact that "contract markets coal prices are based on a 20,000 to 30,000 ton per month contract over five to ten years. Sellers, traders, and brokers are the source for the 'ask' prices; buyers for the bid prices."[48] Clearly, this is not an ideal reflection of long-run market conditions. However, it does contribute to our

estimation of current contract prices.

Our eight supply points correspond to the U.S.B.M. districts as follows: Wheeling, 1-4; Lynch, 7-8; Birmingham, 13; Harrisburg, 9-11; Price, 16,17,20; Gallup, 18; Rock Springs, 19 south; Billings, 19 north, 22. Prices for various periods in 1978, 1979, and 1980 are presented in Table 8.

Note that price increases on contracts have been very small. In fact, between March 1979 and January 1980 reported contract prices were constant; and between September 1978 and March 1979 some reported prices actually declined by small amounts.

In March 1979 Coal Week began to present contract terms for low-sulfur eastern coal. This subdivision is useful for our purposes. At this time, prices per million Btu ranged from 92 cents to $1.16 in Districts 1-4 (Wheeling). Ohio coal was significantly more expensive. Ignoring Ohio coal, and subtracting the 1.0 percent sulfur coal in central Pennsylvania and the high Btu coal in West Virginia, the range was $.92 to $1.05 per million Btu. Low-sulfur coal (1.0 percent) in central Pennsylvania was priced at $1.10 per million Btu, or 20 cents per million Btu more than the 2.0 percent sulfur coal from the same district.

In the Lynch area, districts 7 and 8, low-sulfur coal (0.7 percent) was priced at $1.27 to $1.28 per million Btu, again 20 cents per million Btu less than coal in the 1.5 percent to 1.6 percent sulfur category.

In the Midwest (districts 9,10, 11), high-sulfur coal (3.5 percent) was priced at $1.00 per million Btu. 0.9 percent sulfur coal in West

Table 8-a

CURRENT CONTRACT AND SPOT MARKER STEAM COAL PRICES

Producing Districts*	Btu/lb.		Sulfur%		Ash%		FOB Mines $/t Ask	FOB Mines $/t Bid	Adjustment Ask	Adjustment Bid	FOB Mines $/t Adj.†	
	Term	Spot	Term	Spot	Term	Spot	Term		Term		Spot	Spot
(1) Central PA	12,000	12,100	2.0	2.0	15.7	13.8	$19.50	$18.75	—	—	$24.00	↑3.25
(2) Western PA	11,600	12,000	2.5	2.3	16.5	13.6	18.00	17.75	—	—	23.25	↑3.50
(3) Northern WV	12,600	12,200	2.4	2.1	12.0	13.6	21.00	20.00	—	—	25.00	↑3.00
(4) OH	11,100	10,900	3.6	3.2	16.0	16.0	20.50	20.00	—	—	22.00	↑2.25
(7) Southeastern WV & parts of VA	11,300	12,000	1.1	1.0	17.5	12.5	25.00	22.00	—	—	28.50	↑2.00
(8) Southern WV, eastern KY, northern TN & parts of VA	11,800	11,700	1.5	1.3	13.5	13.1	25.50	22.50	—	—	27.75	—
(9) Western KY	11,000	11,200	3.6	3.5	14.2	13.3	22.50	20.50	—	—	25.00	↑2.00
(10) IL	10,800	10,800	3.0	2.9	11.4	11.6	19.25	18.50	—	—	20.00	—
(11) IN	10,800	10,900	2.8	2.7	11.0	11.6	18.75	17.25	—	—	18.75	—
(12) IA	9,200	9,400	3.5	4.8	15.4	17.3	15.00	14.00	—	—	12.00	—
(13) AL & southern TN	11,700	11,900	1.5	1.5	14.7	13.4	25.00	23.00	—	—	27.00	↑0.25
(15) KS, MO & parts of OK**	10,200	11,900	4.4	3.8	19.8	13.6	15.00	14.00	↑1.00	↑0.25	18.00	↑1.00
(16) & (17) CO & northeastern NM	10,900	11,200	0.5	0.6	9.3	10.6	17.50	17.00	—	—	17.00	↑0.75
(18) Parts of NM & AZ	10,000	10,600	0.5	0.4	14.7	8.2	14.00	13.75	—	—	15.00	—
(19) Southern WY	10,500	10,500	0.6	0.6	8.5	8.5	15.50	14.50	—	—	15.00	—
(19) Northeastern WY	8,100	8,100	0.5	0.5	6.0	6.0	6.75	6.25	—	—	7.75	—
(20) UT	10,900	11,400	0.5	0.5	10.3	10.8	17.50	17.00	—	—	18.00	—
(22) MT	9,000	8,600	0.6	0.9	7.5	8.8	8.75	8.50	—	—	8.00	—

*as defined by Bituminous Coal Act of 1937
**excluding TX lignite

†prices adjusted bi-weekly as warranted

PRICES quoted don't represent actual transactions. They are a synthesis of market conditions for each producing district based on the characteristics of *Coal Week*'s "marker" coals. Prices reflect the state-of-the-trade as perceived and discussed in confidence by buyers, sellers, traders and brokers for unwashed coal of the marker's specifications. Prices are updated bi-weekly, as warranted.

QUALITY SPECIFICATIONS for each marker coal are derived by computer analysis of utility coal purchase statements submitted to the Federal Energy Regulatory Commission. They are updated quarterly. The current specs reflect reports in the third quarter, 1977. *Coal Week* adjusts specs off the computer, where warranted, to account for differences between historical interest and current interest in a higher quality product.

PRODUCING DISTRICT 19 (Wyoming) is subdivided to reflect the quality differences between northeastern and southern Wyoming coals.

CONTRACT marker coal prices are based on a 20,000 to 30,000 ton per month contract over five to 10 years. Sellers, traders and brokers are the source for "ask" prices; buyers, the "bid" prices.

Source: Coal Week, March 6, 1978.

Table 8-b

CURRENT CONTRACT AND SPOT MARKER STEAM COAL PRICES

Producing Districts*	Btu/lb.		Sulfur%		Ash%		FOB Mines $/t Ask	FOB Mines $/t Bid	Adjustment Ask	Adjustment Bid	FOB Mines $/t	Adj.†
	Term	Spot	Term	Spot	Term	Spot	Term		Term		Spot	Spot
(1) Central PA	12,000	12,000	1.9	2.1	15.7	13.8	$23.00	$22.00	—	—	$21.75	—
(2) Western PA	11,800	11,800	2.4	2.3	15.6	14.4	22.50	21.00	—	—	21.25	—
(3) Northern WV	12,500	12,200	2.5	2.0	12.1	13.3	23.75	23.25	—	—	21.50	—
(4) OH	11,200	10,800	3.5	3.2	15.6	16.6	24.25	23.75	—	—	23.00	—
(7) Southeastern WV & parts of VA	11,200	12,000	1.0	1.1	17.2	12.8	24.50	21.75	—	—	24.75	†0.25
(8) Southern WV, eastern KY, northern TN & parts of VA	11,700	11,800	1.2	1.3	13.4	12.9	25.00	22.00	—	—	22.50	—
(9) Western KY	11,000	11,100	3.5	3.4	14.1	12.7	23.00	20.00	—	—	20.75	—
(10) IL	10,700	10,800	2.9	3.0	11.5	11.7	22.50	20.50	—	—	18.00	—
(11) IN	10,800	10,900	2.8	2.6	10.8	10.9	21.50	19.25	—	—	17.00	—
(12) IA	9,500	9,100	3.8	3.7	15.4	17.8	16.00	15.00	—	—	12.00	—
(13) AL & southern TN	11,700	11,900	1.5	1.5	14.2	13.0	24.00	22.00	—	—	22.75	—
(15) KS, MO & parts of OK**	10,100	11,700	4.4	3.5	19.4	13.5	17.50	16.00	—	—	18.25	—
(16) & (17) CO & northeastern NM	10,900	11,000	0.5	0.5	9.5	9.2	17.75	17.25	—	—	18.00	—
(18) Parts of NM & AZ	10,000	10,700	0.6	0.4	15.2	8.6	17.25	16.75	—	—	17.50	—
(19) Southern WY	10,500	10,500	0.6	0.6	8.5	8.5	16.75	15.75	—	—	16.00	—
(19) Northeastern WY	8,100	8,100	0.5	0.5	6.0	6.0	7.00	6.50	—	—	8.00	—
(20) UT	10,800	11,500	0.6	0.6	11.0	10.4	18.00	17.75	—	—	19.00	—
(22) MT	9,000	8,400	0.7	0.7	7.3	10.9	9.50	9.00	—	—	8.75	—

* as defined by Bituminous Coal Act of 1937
** excluding TX lignite

†prices adjusted bi-weekly as warranted

Source: Coal Week, September 4, 1978.

Table 8-c

CURRENT CONTRACT AND SPOT MARKER STEAM COAL PRICES

Producing Districts*	Btu/lb.	Sulfur%	Ash%	FOB Mines $/t Term	Adj.†	Spot	Adj.†
(1) Central PA	12,300	2.0	13.0	$23.50	.96	$22.50	
	12,500	1.0	10.0	29.00	1.16	28.00	
(2) Western PA	12,500	3.0	15.0	23.00	.92	22.00	
	12,800	2.5	9.0	27.00	1.05	26.00	
(3) Northern WV	12,300	3.0	13.0	23.00	.93	22.00	
	13,000	2.5	9.0	28.50	1.10	27.50	
(4) OH	11,200	3.4	15.0	22.50	1.12	21.50	
	11,800	3.0	11.0	25.50	1.06	24.00	
(7) Southeastern WV & parts of VA	12,500	1.5	12.0	26.75	1.07	24.00	
	12,000	0.7	10.0	30.50	1.20	26.75	
(8) Southern WV, eastern KY, northern TN & parts of VA	12,200	1.6	13.0	26.25	1.05	23.00	
	13,000	0.7	9.0	33.25	1.28	29.50	
(9) Western KY	11,000	3.6	14.2	22.00	1	19.25	
	12,000	0.9	11.0	28.25	1.18	26.75	
(10) IL	10,500	3.5	13.0	21.00	1	18.50	
	11,700	2.5	8.5	27.50	1.18	25.00	
(11) IN	10,500	3.0	12.0	20.00	.95	17.75	
	11,300	2.5	9.0	26.50	1.17	24.00	
(12) IA	9,500	4.0	15.0	17.00	.89	15.75	
(13) AL & southern TN	12,000	1.6	13.1	26.00	1.05	21.75	
	12,500	0.75	10.0	29.50	1.18	27.00	
(15) KS, MO & parts of OK**	11,500	3.5	11.0	17.00	.79	16.00	
	12,000	2.5	10.0	24.00	1	23.00	
(16) Northern CO	10,700	0.5	9.1	17.50	.82	16.75	
(16) & (17) CO & northeastern NM	11,600	0.5	9.0	19.00	.82	18.00	
(18) Parts of NM & AZ	10,000	0.5	10.5	16.00	.80	15.00	
(19) WY	10,500	0.6	8.5	16.50	.79	15.50	
	8,100	0.5	6.0	6.75	.92	6.25	
(20) UT	11,500	0.6	9.0	19.75	.86	19.00	
(22) MT	8,600	0.7	8.0	8.50	.99	8.00	
	9,300	0.4	6.0	9.75	.57	8.75	

*as defined by Bituminous Coal Act of 1937
**excluding Texas lignite

†prices adjusted bi-weekly as warranted

Key to price table

Coal Week's current marker coal prices are derived from confidential discussions with buyers, sellers, traders and brokers for coal of the marker's specifications. "Marker" prices reflect state-of-trade and don't necessarily represent actual transactions. Prices are updated bi-weekly, as warranted.

Quality specifications are constant, so that price trends may be plotted. Specifications are derived from market sources and represent coals of current interest. In some cases, a producing region is sending both a low- and a high-quality coal into the market. *Coal Week's* prices reflect that situation.

Spot prices relate to theoretical deliveries that span one year or less time.

Users of this data are reminded that coal prices vary with quality differences. Deviations from the marker coal's specs for heat value, sulfur and ash content should be considered when comparisons are made with coals of personal interest.

Source: Coal Week, March 26, 1979.

Table 8-d

CURRENT CONTRACT AND SPOT MARKER STEAM COAL PRICES

Producing Districts*	Btu/lb.	Sulfur%	Ash%	FOB Mines $/t Term	Adj.†	Spot	Adj.†
(1) Central PA	12,300	2.0	13.0	$23.50	—	$22.00	—
	12,500	1.0	10.0	29.00	—	27.25	—
(2) Western PA	12,500	3.0	15.0	23.00	—	21.50	—
	12,800	2.5	9.0	27.00	—	26.00	—
(3) Northern WV	12,300	3.0	13.0	23.00	—	21.25	—
	13,000	2.5	9.0	28.50	—	27.50	—
(4) OH	11,200	3.4	15.0	22.50	—	21.00	—
	11,800	3.0	11.0	25.50	—	24.00	—
(7) Southeastern WV & parts of VA	12,500	1.5	12.0	26.75	—	22.50	—
	12,000	0.7	10.0	31.50	—	27.00	—
(8) Southern WV, eastern KY, northern TN & parts of VA	12,200	1.6	13.0	25.00	—	21.75	—
	13,000	0.7	9.0	35.25	—	31.00	—
(9) Western KY	11,000	3.6	14.2	22.00	—	19.25	—
	12,000	0.9	11.0	28.25	—	26.75	—
(10) IL	10,500	3.5	13.0	21.00	—	18.50	—
	11,700	2.5	8.5	27.50	—	25.00	—
(11) IN	10,500	3.0	12.0	20.00	—	17.75	—
	11,300	2.5	9.0	26.50	—	24.00	—
(12) IA	9,500	4.0	15.0	17.00	—	15.75	—
(13) AL & southern TN	12,000	1.6	13.1	26.00	—	21.75	—
	12,500	0.75	10.0	31.00	—	28.00	—
(15) KS, MO & parts of OK**	11,500	3.5	11.0	17.00	—	16.00	—
	12,000	2.5	10.0	24.00	—	23.00	—
(16) Northern CO	10,700	0.5	9.1	17.50	—	16.75	—
(16) & (17) CO & northeastern NM	11,600	0.5	9.0	19.00	—	18.00	—
(18) Parts of NM & AZ	10,000	0.5	10.5	16.00	—	15.00	—
(19) WY	10,500	0.6	8.5	16.50	—	15.50	—
	8,100	0.5	6.0	6.75	—	6.25	—
(20) UT	11,500	0.6	9.0	19.75	—	19.00	—
(22) MT	8,600	0.7	8.0	8.50	—	8.00	—
	9,300	0.4	6.0	9.75	—	8.75	—

*as defined by Bituminous Coal Act of 1937
**excluding Texas lignite

†prices adjusted bi-weekly as warranted

Key to price table

Coal Week's current marker coal prices are derived from confidential discussions with buyers, sellers, traders and brokers for coal of the marker's specifications. "Marker" prices reflect state-of-trade and don't necessarily represent actual transactions. Prices are updated bi-weekly, as warranted.

Quality specifications are constant, so that price trends may be plotted. Specifications are derived from market sources and represent coals of current interest. In some cases, a producing region is sending both a low- and a high-quality coal into the market. *Coal Week's* prices reflect that situation.

Spot prices relate to theoretical deliveries that span one year or less time.

Users of this data are reminded that coal prices vary with quality differences. Deviations from the marker coal's specs for heat value, sulfur and ash content should be considered when comparisons are made with coals of personal interest.

Source: Coal Week, September 10, 1979.

Table 8-e

CURRENT CONTRACT AND SPOT MARKER STEAM COAL PRICES

Producing Districts*	Btu/lb.	Sulfur%	Ash%	FOB Mines $/t Term	Adj.†	Spot	Adj.†
(1) Central PA	12,300	2.0	13.0	$23.50	–	$21.00	–
	12,500	1.0	10.0	29.00	–	27.25	–
(2) Western PA	12,500	3.0	15.0	23.00	–	20.00	–
	12,800	2.5	9.0	27.00	–	25.00	–
(3) Northern WV	12,300	3.0	13.0	23.00	–	20.00	–
	13,000	2.5	9.0	28.50	–	27.00	–
(4) OH	11,200	3.4	15.0	22.50	–	21.00	–
	11,800	3.0	11.0	25.50	–	24.00	–
(7) Southeastern WV & parts of VA	12,500	1.5	12.0	26.75	–	22.50	–
	12,000	0.7	10.0	31.50	–	27.00	–
(8) Southern WV eastern KY, northern TN & parts of VA	12,200	1.6	13.0	25.00	–	21.75	–
	13,000	0.7	9.0	35.25	–	31.00	–
(9) Western KY	11,000	3.6	14.2	22.00	–	19.25	–
	12,000	0.9	11.0	28.25	–	26.75	–
(10) IL	10,500	3.5	13.0	21.00	–	18.50	–
	11,700	2.5	8.5	27.50	–	25.00	–
(11) IN	10.500	3.0	12.0	20.00	–	17.75	–
	11,300	2.5	9.0	26.50	–	24.00	–
(12) IA	9,500	4.0	15.0	17.00	–	15.75	–
(13) AL & southern TN	12,000	1.6	13.1	26.00	–	21.75	–
	12,500	0.75	10.0	31.00	–	28.00	–
(15) KS, MO & parts of OK**	11,500	3.5	11.0	17.00	–	16.00	–
	12,000	2.5	10.0	24.00	–	23.00	–
(16) Northern CO	10,700	0.5	9.1	17.50	–	16.00	–
(16) & (17) CO & northeastern NM	11,600	0.5	9.0	19.00	–	17.00	–
(18) Parts of NM & AZ	10,000	0.5	10.5	16.00	–	15.00	–
(19) WY	10,500	0.6	8.5	16.50	–	15.50	–
	8,100	0.5	6.0	6.75	–	6.25	–
(20) UT	11,500	0.6	9.0	19.75	–	18.00	–
(22) MT	8,600	0.7	8.0	8.50	–	8.00	–
	9,300	0.4	6.0	9.75	–	8.75	–

*as defined by Bituminous Coal Act of 1937
**excluding Texas lignite
†prices adjusted bi-weekly as warranted

Key to price table

Coal Week's current marker coal prices are derived from confidential discussions with buyers, sellers, traders and brokers for coal of the marker's specifications. "Marker" prices reflect state-of-trade and don't necessarily represent actual transactions. prices are updated bi-weekly, as warranted.

Quality specifications are constant, so that price trends may be plotted. Specifications are derived from market sources and represent coals of current interest. In some cases, a producing region is sending both a low- and a high-quality coal into the market. *Coal Week's* prices reflect that situation.

Spot prices relate to theoretical deliveries that span one year or less time.

Users of this data are reminded that coal prices vary with quality differences. Deviations from the marker coal's specs for heat value, sulfur and ash content should be considered when comparisons are made with coals of personal interest.

Source: Coal Week, January 21, 1980.

Virginia cost $1.18 per million Btu. The price of low-sulfur coal (0.75 percent) in Alabama was also $1.18 per Btu.

In the West, Price coal (districts 20, 10, 17) ranged in price from 82 cents to 86 cents per million Btu for sulfur levels of 0.5 percent to 0.6 percent. Gallup (District 18) coal was close in quality and price at 80 cents and 0.5 percent sulfur. Rocksprings bituminous coal was in the same range at 79 cents and 0.6 percent sulfur.

The subbituminous coal in the Powder River basin ranged in price from 42 cents to 52 cents per million Btu. Coal Week reports showed Wyoming coal at the low end of the range relative to the more expensive Montana coal.

These prices reflect domestic market conditions, which may not be in line with international market conditions. A comparison with the Coal Week "current international spot steam prices" will clarify the relationship between current spot export prices and domestic long-term prices.

Table 9 presents spot coal prices FOB piers (per metric ton) in Mobile, Baltimore and Hampton Roads. Since late 1978, Hampton Roads prices have been close to $38 per metric ton, FOB pier; for coal that has 12,500 Btu per lb, approximately 1 percent sulfur, and 13 percent ash content. This equals approximately $1.38 per million Btu. Compare this to the Central Pennsylvania FOB mine price in March 1979, for 12,500 Btu/lb, 1 percent sulfur, 10 percent ash coal. The FOB mine price was reported as $1.16 per million Btu. Transportation from Central Pennsylvania at that time was approximately $11.00 per short ton, or 44 cents per million

Btu. The total delivered price would be $1.60 per million Btu. Adding a small dumping fee and possible preparation costs might yield an expected cost of $1.64 per million Btus. This suggests that spot export prices are significantly lower than domestic prices. Given the current minimal role of U.S. exports, and the slack eastern coal markets, this is not a surprising result.

For Baltimore, the calculation yields the same conclusions. For Mobile, the price was approximately $34 FOB pier per metric ton ($1.29 per million Btu). Coal quality at the pier was reported as 11,200 Btu/lb., less than 1.0 percent sulfur, and 11.0 percent ash. From Western Kentucky, the FOB mine price was approximately $1.18 per million Btu, and transportation costs were approximately .45 cents per million Btu. The total delivered price would be $1.63 per million Btu. From Alabama, coal would be priced at $1.24 FOB mine, and transportation at $.28 per million Btu. The total, $1.52 per million Btu, is still well above the spot export rate of $1.29 per million Btu.

South African coal prices can be specified with greater accuracy, since the exporters associations set a price FOB pier for all steam coal exports. In 1979, the price set was Rand 21.08 per metric ton. The typical coal quality FOB pier is reported as 11,300 Btu/lb., 1.0 percent sulfur and 15.0 percent ash. Based on the 1979 average exchange rate, this equals approximately US $25.30 per metric ton.[49].

We can add some meaning to this price by looking at transportation costs, and the government controlled pithead prices for domestic consumption. In 1979, railroad rates average about 5 Rand per metric ton

Table 9
INTERNATIONAL SPOT STEAM COAL PRICES
(U.S. dollars per metric ton FOB export pier)

	United States			South Africa	Australia
Date	Hampton Roads	Baltimore	Mobile	Richards Bay	Port Kembla/ Newcastle
3/9/77	12,000 Btu per lb. 12% ash, <1% sulfur $31.50/ton	11,500 Btu per lb. 20% ash, 2.0% sulfur $21.00/ton	12,200 Btu per lb. 14.0% ash, 1.25% sulfur $29.00/ton	11,300 Btu per lb. 15% ash, <1% sulfur $19.00/ton	10,800 Btu per lb. 17.0% ash, <1% sulfur $25.00/ton
6/6/77	31.50	25.00	29.00	19.00	25.00
7/20/77	35.00	25.00	29.00	19.00	25.00
8/1/77	35.00	30.00	29.00	22.00	25.00
9/26/77	35.50	30.50	30.00	19.25	25.00
1/9/78	37.50	12,000 Btu/ lb., 14.5% ash, 1.5% sulfur, 29.00	30.00	19.25	25.00
2/6/78	37.50	29.00	30.00	20.50	12,000 Btu /lb., 15.0% ash, <1.0% sulfur, 26.75
3/20/78	42.50	39.25	38.00	20.50	20.75
4/17/78	43.00	39.75	38.50	20.50	20.75
5/29/78	43.00	39.75	38.50	20.50	30.50
6/22/78	40.75	34.00	35.00	20.50	30.50
11/13/78	12,500 Btu/ lb., 11.0% ash, 1.5% sulfur, 39.00	33.50	34.75	20.50	30.50
2/12/79	12,000 Btu/ lb., 13% ash <1% sulfur 33.00	33.00	34.50	20.50	30.50

Table 9 (Continued)
INTERNATIONAL SPOT STEAM COAL PRICES (per metric ton)

	United States			South Africa	Australia
Date	Hampton Roads	Baltimore	Mobile	Richards Bay	Port Kembla/ Newcastle
2/26/79	33.00	33.00	11,200 Btu /lb., 11.0% ash, <1% sulfur 32.00	20.50	30.50
6/18/79	12,500 Btu/ lb., 11.0% ash, 1.25% sulfur 38.50	12,500 Btu/ lb., 12.0% ash, 1% sulfur 38.50	32.00	20.50	30.50
7/16/79	12,000 Btu/ lb., 13.0% ash, <1% sulfur 37.00	38.50	32.00	20.50	30.50
10/8/79	37.00	38.50	32.00	24.50	32.75
1/7/80	38.00	12,500 Btu/ lb., 12.0% ash, 1% sulfur 39.50	33.00	a. 11,300 Btu/ lb., 15% ash, 1.0% sulfur 24.50 b. 11,000 Btu/ lb., 15.5% ash, 1% sulfur 28.00	a. 12,000 Btu/ lb., 13.0% ash, <1.0% sulfur 32.75 b. 11,400 Btu/ lb., 15.5% ash, 1.0% sulfur 26.50
2/4/80 a.	12,000 Btu/ lb., 13.0% ash, 1.2% sulfur 40.50	39.50	33.00	a. 26.50	a. 32.75
b.	11,000 Btu/ lb., 13% ash, 1.5% sulfur 35.25			b. 28.00	b. 27.00

Source: Coal Week, "Current International Spot Steam Coal Prices," various issues.

or U.S. $6.00 per metric ton. Loading charges are in the vicinity of $1.50 per metric ton. This suggests a price FOB mine of approximately $17.80 per metric ton.

The FOB local price for Grade A coal in 1979 was $9.02. Clearly, even allowing for substantial benefication costs, prices to the coal companies on exports far exceed domestic prices. Either exporters are realizing significant rents, or domestic prices are set below the incremental mine's production costs.[50]

For Australia and Canada, available price data are even less satisfactory than for the United States. In both cases only sparse observations can be made.

First, consider Australia. Coal Week reports spot prices to Port/Kembla or Newcastle since 1977. (See Table 8.) For coal with 12,000 Btu/lb., less than 1.0 percent sulfur, and 13 percent to 15 percent ash, spot prices have increased from $25 per metric ton ($.95 per million Btu) in late 1977 and early 1978, to $30 in mid 1978 ($1.14 per million Btu) to $32.75 ($1.24 per million Btu) in early 1980.

Does this make sense? Unfortunately, we have little data to cross-check this with. Depending on the origin and mode of transportation, transport charges could range from $2 to $10 per ton. We will tentatively assume an origin in the Singleton-Northwest district, approximately 100 km from port (see Appendix A). The transportation charge would be approximately $5.65 per metric ton. Adding a $1 state royalty, and say, $1.50 per ton loading charge, we expect the FOB mine price, for a FOB pier price of $25, to be $16.85. At FOB pier $32.75,

the FOB mine price would therefore be approximately $24.60.[51] Again however, we do not know whether the producing mine is open-cut or underground, so only very tentative conclusions can be formed.

A literature survey and contacts with Japanese utilities added clarity to this picture. In mid-1979, contracts were being signed with Australian producers for approximately $30 per ton CIF Japan. As an example, a Japanese utility contracted 200,000 tons per year of low-sulfur coal (.65 percent), with a heating value of 24.2 million Btu per metric ton. The contract is scheduled to begin in 1981 and continue through 1983 at $30/ton, CIF Japan, subject to escalation. The producing mine is Lithgow Valley, which is 158 km from Sydney and 237 km from Port Kembla. The 1979 rail freight to Sydney is $6.58 (Aust $), or U.S. $7.41.[52] The open-cut production in this area is negligible, so we assume an underground mine.

Ocean freight charges are approximately $7 per metric ton. The state royalty is $1 per ton. Subtracting these costs alone yields an estimate (FOB mine) of $14.58 per ton or 60 cents per million Btu. This is certainly more consistent with the $25.00 FOB pier price than with the $30.00 FOB pier price.

These observations lead us to question the currently high spot prices. The industry consensus is that the spot market in Australia is very tight in recent months since most production, even through 1985, has been contracted out. Whether $30 CIF Japan is a reasonable long run approximation, or whether $30 FOB Australia is an accurate approximation is very difficult to say in the early market stages.

In the case of Canada, information is even more limited. This is not surprising, given the fact that negligible quantities of steam coal are currently exported. Coal Week's series does not even include Canadian price data. Industry sources estimate FOB pier prices at $25 to $30 per short ton.[53] Rail rates are approximately $13 per short ton. Adjusting for dumping charges, the FOB mine estimate would be fairly close to Montana coal. In fact, given mining conditions and coal quality similarities between the two areas, it is reasonable to assume that production costs in Southern British Columbia and Southwestern Alberta will be equal to production costs in Utah, and that Alberta plains production costs will be equal to Powder River Basin production costs.

LONG-RUN CHANGES IN COAL SUPPLY

There are a number of factors that may significantly affect coal prices in the future. In this section we will briefly discuss some of the more important ones: 1) the effect of depletion on production costs as output cumulates; 2) changes in labor and capital costs; 3) changes in the competitive structure of international coal markets; 4) changes in governmental policy.

Depletion

First, consider depletion. As noted earlier, as coal output cumulates producers are forced to move to less favorable mines to satisfy the incremental coal demand. The extent to which the geological

conditions at the incremental mine change as output cumulates determines the change in production costs, and therefore the change in coal prices in competitive markets.

Martin Zimmerman has modelled this supply phenomenon for the United States.[54] Basically, he estimates a cost function based on an engineering model of coal production that explicitly accounts for the impact of geology on the cost of production. He then estimates the distribution of coal in the ground according to geologic conditions (seam thickness, overburden ratio, and other factors). The cost function is combined with the reserve distribution to yield cost as a function of cumulative output.

Table 10 summarizes Zimmerman's results. For each producing district, and for three different sulphur categories the table shows the effect of depletion as output increases from 1975 levels by 5 times and 20 times.

For low-sulfur coal, the effect of depletion of reserves west of the Mississippi is very small. Powder River Basin coal production costs per short ton increase by only 27 cents (1977 $) if production stays at 42.37 million short tons for twenty years. In percentage terms, other Western regions are equally unaffected by depletion.

In the Appalachian districts depletion is far more significant for low sulfur coal. In southern Appalachia, which is subdivided into Birmingham and Lynch in this study, coal supply prices will increase by 33 percent, from $36.44 per short ton to $48.45 per short ton, if cumulative production is increased by a factor of twenty. In northern

Table 10
THE EFFECTS OF DEPLETION ON U.S. COAL PRICES
APRIL 27, 1978 SIMULATION: BASE CASE[1]
(million short tons)

		1975. Prod. Vol.	1975 Prod. Vol. *5	1975 Prod. Vol. *20	Prices per short ton in: ($ 1977) 1 Year	5 Years	20 Years
Low Sulfur (0 - .84%)							
N. App.	1	7.678	38.39	153.56	35.93	36.97	39.96
S. App.	2	117.452	587.26	2349.04	36.44	38.03	48.45
Midwest	3	na	na	na			
Powder River Basin	4	42.373	211.865	847.46	7.72	7.78	7.79
Utah, Col.	5	16.195	80.975	3239	18.43	18.69	19.45
Ariz, N.M.	6	14.755	73.775	245.1	12.38	12.54	13.24
Medium Sulfur (.85 - 1.84%)							
	1	45.892	229.46	917.84	28.78	30.07	34.46
	2	87.381	436.905	1747.62	29.65	30.85	37.46
	3	10.717	53.585	214 34	24.10	25.25	27.89
	4	3.485	17.425	69.7	7.71	7.71	7.72
High Sulfur (1.85 - 9.00%)							
	1	124.998	624.99	2499.96	22.67	23.21	27.39
	2	13.074	65.37	261.48	23.33	24.19	30.04
	3	130.019	650.095	2600.38	24.20	24.94	25.91

Notes: 1. Includes state tax revisions.
2. na = not applicable.

Source: Zimmerman, M.B. Coal Supply Model, unpublished documentation.

Appalachia, prices should increase from $35.93 to $39.96 per short ton. The estimated percent increases in cost over 50 years at current rates of output is 98 percent in southern Appalachia, yielding a real price of $72.15.

Relative to the effects of depletion in other regions of the country, Zimmerman postulates that low-sulfur Appalachian coal, particularly southern Appalachian coal, will soon be priced out of other than domestic and export metallurgical markets.

For medium-sulfur coal (.85 percent to 1.84 percent), the West is again largely unaffected by depletion. The Midwest region is less elastic; prices would increase by 16 percent with 20 years of current output. Again, both Appalachian regions are most heavily affected. In southern Appalachia prices would increase by 26 percent, versus 20 percent in northern Appalachia.

For high-sulfur coal, the supply curve in the Midwest is highly elastic. A price rise of 7 percent would suffice to bring forth 20 years of production at current output rates. The effect of depletion in the Appalachian regions for high-sulfur coal is approximately equal to the medium-sulfur case.

To conclude, depletion is a relatively unimportant economic variable in the United States for the West, and for Midwest high-sulfur and medium-sulfur coal. For the Appalachian regions, however, depletion may have a significant effect on coal prices, especially low-sulphur coal prices. The ultimate importance of these possible changes in price will be analyzed below.

Phil Ellis has attempted to apply Zimmerman's methodology to South African coal.[55] The method was modified to accommodate data available for South Africa, but the general approach is similar. As in the western United States, depletion is of minor importance. Based on an annual production scenario, which starts at 32.76 MT in 1975 and increases to 85.80 MT in 2000, depletion costs for high-grade coal in $1975 per metric ton increase from 30 cents in 1980 to 69 cents in 1985 (57.40 MT) to $1.15 in 1990 (60.90 MT) to $1.69 in 1995 (72.30 MT) to $2.38 per metric ton in 2000 (85.80 MT). In Zimmerman's terms this means that production could continue at current rates for at least 50 years and costs in $1975 would only increase by $2.38 per ton or 10 cents per million Btu.

Time and data constraints did not allow for a similar analysis of the effects of depletion in Canada and Australia. Most importantly, seam thickness and overburden ratio data are not adequate to duplicate these calculations. From the large reserve estimates, we can tentatively conclude that depletion is equally unimportant in these countries, but further research is certainly warranted.

Capital and Labor Price Increases

The second factor that may significantly affect coal prices in the future is factor price increases. It is not the purpose of this study to project real increases in capital and labor costs over time. However, some general comments, and one particularly important shift, should be noted.

Specifically, capital and labor costs have been increasing rapidly in coal production. The most important factor in the United States has been increasing wages and decreasing productivity as a function of changes in the United Mine Workers contracts. The 1978 contract calls for wage increases of 23.5 percent in 1978, 4.8 percent in 1979 and 4.6 percent in 1980. Assuming inflation at 5.5 percent per year, this implies an average annual real increase of 5.6 percent.[56]

Real capital costs have also been increasing. Zimmerman shows that from 1971 to 1978, the annual rate of increase in the mining machinery index is 11.9 percent, versus 6.8 percent for the GNP deflator.[57]

In absolute terms, however, these increases are not likely to affect critically coal markets. What is more important are relative shifts in capital and labor costs, and the corresponding shifts in market patterns. Both Australia and Canada have suffered through labor and capital cost increases similar to those in the United States, so for this set of suppliers, the shifts are not likely to be critical in the long run. South Africa, on the other hand, is far more unstable in this respect. Given their position on apartheid and the world response to it, significant changes beyond those experienced in the other supplying countries may well take place.

Ellis has thoroughly analyzed these potential changes. While he concludes that the costs associated with depletion will not seriously threaten the competitive advantage of South African coal in this century, labor and capital costs changes may well threaten this advantage.

The main basis for this conclusion is black wages. In 1977, the

white South African miner earned $12,305 on average, versus $1,490 for his black counterpart. As dramatic as this difference appears, black wages have increased since 1970 by much higher rates than white wages. In 1974 whites earned $8,273 (nominal) and blacks earned $596.00. The rates have been higher, but the difference is still enormous. Since 90 percent of coal miners are black, aggregate wage levels have increased by approximately 12 percent real per year.[58] The implications of this shift for the competitiveness of South African coal in the future are considerable.

South African producers will attempt to mitigate the effect of increased labor costs by using more capital intensive mining methods, particularly in the form of increased surface-mining. However, this will not fully offset the effect of increased labor costs. Ellis has shown that increased capital-intensity is in fact not keeping pace with increased labor costs. Also, he notes that a shift to strip-mining will magnify the effect of depletion costs in South Africa. Capital costs are also likely to increase rapidly. International hostility towards South African policies has been reflected in a decline in the availability of foreign capital. Consequently, shifts to capital-intensity may be limited.

Ellis calculates the effect of these possible factor price changes on South African coal prices. In his "most likely scenario," where capital costs are assumed to increase 5 percent per year (real), and labor costs 15 percent per year, the advantage of South African coal over U.S. East Coast coal deteriorates by 1990. The South African FOB pier price would

increase from $22.00 per ton in 1978 to $63.32 in 1990 (in 1978$). Assuming constant real shipping costs, this means that U.S. coal could increase by 4.9 percent per year to $67.00 FOB pier (from $38.00) and be competitive. Based on DRI's real cost increase forecasts, the 1990 U.S. price would be aproximately $68.36, or very closely competitive with South African coal.[59]

Competitive Structure

The third issue to consider is the possibility of changes in the competitive structure of international steam coal markets. Very little can be said given the fact that markets are currently underdeveloped. Nonetheless, some general comments can be made.

First, based on the existing market structures in the four countries, the extent of competition is unclear. In the United States, domestic markets are reasonably competitive, and there is no reason to believe that exporters will not be similarly competitive. The existing market structures in Canada and Australia similarly suggest a reasonably competitive environment.

In South Africa, the extent of competition is less clear. Certainly the structure for realizing rents exists in the export associations. Whether rents themselves are available, and if they are, whether they will continue to be available will be discussed in Chapter II.

Independent of the competitive structure within each country, inter-country competition among these four nations for Western European and Japanese markets should curtail economic rents. The actual extent of

international competition relative to certain markets will be discussed below. However, one possibility that is frequently mentioned is collusion between exporting nations in the form of a coal cartel similar to OPEC. It is unlikely that the coal companies themselves would collude to control output and prices. There are simply too many companies, and in the United States antitrust policies would hinder this practice. However, as in the case of OPEC, there is a possibility that the various national governments would collude. The Australian and South African governments already have significant control over prices and export quantities. They could easily appropriate monopoly rents. The United States government could implement a tariff policy to curtail output and increase prices. It is unlikely that they would do so given their commitment to Western Europe and Japan, but the possibility of an international coal cartel should not be overlooked.

Government Policies

The fourth factor that may significantly affect coal prices in the future is government policy. There are several government policies that may affect the supply side of international steam coal markets. All of these issues have been given treatment elsewhere.[60] Nonetheless, a few brief qualitative comments should be made. A more detailed quantitative analysis of these issues would be a useful future subject for research.

First, a variety of environmental policies affect the recovery factor for coal mines in all the countries considered. Strip-mining

regulations, surface subsistence regulations, acid mine drainage regulations, federal leasing limitations, and waste disposal requirements are major examples of such policies. All of the countries cited are regulated in these areas. The costs of compliance and the specifics of the written regulations vary both across countries and within countries. With some exceptions, such as strip-mining of hilly slopes in Appalachia, costs of compliance are a small factor in total production costs.[61] It is possible, however, that regulations could tighten worldwide as production levels expand and that the economic implications of this tightening would be far greater.

Other policies may affect the supply side economics in different ways. In Australia, the western United States, Alberta, and British Columbia, state governments have in the past implemented state taxes on production. This situation is most dramatic in the western United States where, in an effort to obtain rents, Montana and Wyoming have enacted taxes of 35 percent and 18 percent per short ton FOB mine, respectively. Whether or not this practice would carry over to export shipments is unclear.[62] In Australia, state royalties on exports have in the past existed, but are currently applicable only to metallurgical coal. In Canada, most properties are owned by the states, and a complicated system of land rental fees, leasing charges, and royalty rates exist. The ability of state governments to realize rents in future international coal markets through these schemes must not be overlooked.

Other possible government actions of this type are price controls or monitoring, or export quotas. In Alberta, the state government enacted a

coal policy in 1975 that is alleged by industry officials to seriously hamper the competitive position of Canadian coal.[63] This is not surprising in that Albertas's oil and gas industries, from which far greater royalties are realized, are effectively sealed from coal competition. A combination of limits on exploration and development, hesitancy to approve new projects, and the authority to redetermine export prices every two years is perceived as a real constraint on Alberta's exports. A shift to British Columbia, where policies are more responsive to coal mining interests, is foreseen.

In Australia, the Federal government also has the authority to set prices, but has to date not done so. The only significant step that the Australian government has taken to date is to enforce 50 percent domestic ownership in all energy projects. Exceptions have, however, been granted.

Only South Africa currently controls export quantities. The export quota is planned to increase to 44 MT by 1985.[64] Beyond that time it is difficult to project South Africa's actions. Currently there is a heated internal debate about the optimal use of South Africa's reserves. Specifically, there is a real concern about ensuring domestic needs as the socio-economic pressures from external energy suppliers increase. The Petrick Commission report magnified this concern by placing a limit, albeit high, on South African coal reserves. It is not inconceivable that South Africa will eventually abandon exports, and use coal to support its isolation. This is possible since a large share of their lignite fuel requirements could in fact be met by the "Sasol" coal conversion process.

It is unlikely that other countries will similarly constrain exports. Nonetheless, a more real concern is that in a period of short-term energy supply disruptions, exports to foreign countries would be curtailed. With respect to short-run OPEC oil-supply disruptions, it is unlikely that the United States would curtail coal exports since short-run substitution possibilities of coal for oil are limited. With respect to coal supply disruptions, it is conceivable that domestic supply shortages could be met by curtailing planned export tonnages. This is a concern that has been raised by potential importers. The role of the government in mitigating this concern will be considered below.

To conclude, there are several conceivable ways in which government policy could affect the supply-side development of international steam coal markets. Most important, stricter environmental policies would increase production costs, and the states and/or national governments could restrict competition by enacting taxes or export quotas. Little can be said about these possibilities, however, other than that they are possible. The advisability of government manipulation of coal markets in either direction will be further considered below.

FOOTNOTES--CHAPTER I

[1]Peters, W. and H.D. Schilling, "An Appraisal of World Coal Resources and their Future Availability," in World Energy Resources 1985-2000: Coal Resources, The Full Report of the Conservation Commission of the World Energy Conference, World Energy Conference, IPC Science and Technology Press, England, 1978, pp. 23, 25, 29, 32, 34.

[2]World Coal, "Annual Review and Buyer's Guide," 1979, November 1979, p. 33.

[3]Columbia may be an exception. An Exxon subsidiary, International Columbia Resources, is engaged in a joint venture with the state-owned coal company (Carbocol) at the Columbian Cerrejon deposit. A contract with the Danish utility Elsam for deliveries of approximately 2 MT per year beginning in 1986 has already been negotiated, and a massive infrastructure development plan is underway. Coal Week, June 16, 1980, p. 4.

[4]Other studies that have analyzed coal supply worldwide are:
a. World Bank, Coal Development Potential and Prospects in Developing Countries, Industrial Projects Development, August 1979.
b. World Coal Study, Coal: Bridge to the Future, Ballinger Publishing Co., Cambridge, Massachusetts, 1980.
c. ICF Inc., Technical Analysis of Steam Coal Prices in Six OECD Countries, April 1978.
d. ICF, Inc., Coal Reserves and Production in Eight Major Non-U.S. Coal Producing Countries, December 1978.

[5]For a complete discussion of these subjects see Schmidt, R.A., Coal in America, An Encyclopedia of Reserves, Production and Use, McGraw-Hill, New York, New York, 1979.

[6]South African Department of Mines, Minerals Bureau, Internal Report No. 48, "Coal in South Africa," Braamfontein, 1980, 1979, p. 3.

[7]World Coal, op. cit., p. 33.

[8]Ibid.

[9]New South Wales Coal Statistics are drawn from:
Joint Coal Board, Black Coal in Australia, 1978-79, Sydney, March 1980.
Mileage data are drawn from unpublished information provided by the Public Transport Commission of New South Wales. In New South Wales,

saleable coal production has been defined as the tonnage of coal dispatched to market plus or minus the change in coal stocks over the period, actual stocks being adjusted to a saleable basis. Raw coal production is the amount extracted from coal seams, the measurement being made prior to treatment in a coal washery. Joint Coal Board, Black Coal in Australia, Sydney, 1978-79, p. 3.

[10]Queensland Coal Board, 28th Annual Report, Brisbane, June 30, 1979.

[11]South African Department of Mines, op. cit.

[12]Canadian Department of Energy, Mines and Resources, "Canadian Coal, 1979," Ottawa, May 1979.

[13]U.S. Department of Energy, Energy Data Reports, "Production of Coal, Bituminous and Lignite, 1980," Weekly Coal Report No. 126, February 29, 1980.
U.S. Department of the Interior, Bureau of Mines, "International Coal Trade," Vol. 48, no. 2, February 1979.

[14]See in particular:
a. Zimmerman, M.B., "An Economic Interpretation of Coal Reserve Estimates," in Adelman, M.A. et al., Estimation of Reserves and Resources, by Ballinger Publishing Co., Cambridge, Massachusetts, 1980.
b. Schanz, J.J., Resource Terminology: An Examination of Concepts and Terminology and Recommendations for Improvement, Electric Power Research Institute, Palo Alto, California, 1975.

[15]U.S. Geological Survey, "Principles of the Mineral Resources Classification System of the U.S. Bureau of Mines and the U.S. Geological Survey," Bulletin 1540-A, GPO, Washington D.C., 1976.

[16]Ibid.

[17]U.S. Bureau of Mines, "The Resource Base of U.S. Coals by Sulphur Content," Information Circulars 8680 and 8693, U.S. Government Printing Office, Washington, D.C., 1975.

[18]U.S. Geological Survey, "Coal Resource Classification System of the U.S. Bureau of Mines and the U.S. Geological Survey," U.S. GPO, Washington, D.C., U.S.G.S. Bulletin 1450-B, 1976.

[19]Adelman, et. al., op. cit., pp. 2-3.

[20]Ibid.

[21]Ibid.

[22]Ibid.

[23]Ibid., pp. 9-1.

[24]"Commission of Inquiry into the Coal Resources of the Republic of South Africa," Report to the State President of the Republic of South Africa, Pretoria, April 3, 1975.

[25]South African Department of Mines, op. cit., pp. 16, 17.

[26]Ellis, P., "An Economic Analysis of the South African Coal Industry with a Focus on Exports," Sloan School of Management, M.I.T. Masters Thesis, 1979.

[27]See also Burnton, D.E., "Big Increases in S.A.'s Coal Reserves," Chamber of Mines, Mining Survey, Vol. 90, no. 3/78, 1978.

[28]National Energy Advisory Committee, "Australia's Energy Resources: An Assessment," Report no. 2, published by the Department of National Development, December 1977.

[29]Ibid., pp. 55.

[30]Joint Coal Board, 1979, op. cit.

[31]Ibid.

[32]Ibid.

[33]Joint Coal Board, Thirty-Second Annual Report, 1978-79, Sydney, p. 21.

[34]Queensland Coal Board, op. cit., pp. 54-57.

[35]Canada Department of Energy, Mines, and Resources.,"1976 Assessment of Canada's Coal Resources and Reserves," Report EP 77-5, 1977.

[36]World Energy Conference, op. cit. Note that there is no consistency worldwide in the use of the terms brown coal, hard coal, black coal, and soft coal. In the WEC report, "hard coal" includes bituminous and anthracite coal. "Brown coal" includes subbituminous and

lignite coal. The dividing point is heating content. Coal is categorized as "brown" if the heating content is less than 5700 kcal per metric ton, or 22.6 million Btu per metric ton. In a strict sense, "hard coal" should refer to anthracite, and "soft coal" to bituminous and lignite. "Black coal" should refer to anthracite and bituminous, and "brown coal" to lignite.

[37] Ibid., pp. 14.

[37a] The Herfindahl Index is a measure of market concentration. It equals:

$$H = \sum_{i=1}^{N} S_i^2$$

where S_i is the market share of the ith firm. When an industry is occupied by one firm, it takes the maximum value of one. The index declines with increases in the number of firms, and increases with rising inequality among a given number of firms (see Scherer, F.M., Industrial Market Structure and Economic Performance, Rand McNally, Chicago, 1970 pp. 51-52.

[38] Canadian Department of Energy, Mines, and Resources, "Canadian Mineral Survey, 1978," p. 76.

[39] South African Department of Mines, Minerals Bureau, "Coal Mines in the Republic of South Africa," Directory No. 2/79, Braamfontein, May 1979.

[40] Joint Coal Board, Black Coal in Australia, 1977-78 Sydney, New South Wales, Queensland Coal Board.

[41] Zimmerman, M.B., "Long-Run Mineral Supply: The Case of Coal in the United States," Ch. II, M.I.T., unpublished PhD thesis, Department of Economics, 1975.

[42] Keystone Coal Industry Manual, 1979, pp. 863-1240.

[43] See Zimmerman, op. cit., 1975, Ch. 4, and Adelman, M.A., The World Petroleum Market, John Hopkins Press, Baltimore, 1972, pp. 115-117, for more detailed analyses of spot price, contract price relationships.

[44] Zimmerman, op. cit., 1975, Appendix IV-A.

[45] Ibid. See also Phillips, P.J., "Coal Preparation for Combustion and Conversion," Electric Power Research Institute, Palo Alto, California, May 1978.

[46]For a complete analysis of the importance of sulphur content to U.S. coal markets see Zimmerman, M.B., "The U.S. Coal Industry: The Economics of Policy Choice, M.I.T. Press, Cambridge, Massachusetts, forthcoming.

[47]"Current Contract and Spot Marker Steam Coal Prices," and "Current International Spot Steam Coal Prices," in Coal Week, biweekly.

[48]Ibid. One of the problems with the coal-quality data is the nebulous nature of this approach. It is not clear exactly how these quality data are developed. They are intended to represent the average coal sold in the district.

[49]World Coal, November 1979, p. 53.

[50]For a detailed analysis of South African production costs, see Ellis, op. cit.

[51]Based on unpublished data provided by the New South Wales Public Transport Commission and various coal companies. See Part A, Chapters V and VI.

[52]Unpublished contract data provided by Chuba Electric Company, Japan.

[53]Coal Week, October 22, 1979.

[54]See Zimmerman, M.B., op. cit., 1980.

[55]Ellis, op. cit., p. 75, Table 13.

[56]Zimmerman, M.B., The U.S. Coal Industry: The Economics of Policy Choice, op. cit., 1980.

[57]Ibid.

[58]Ellis, op. cit.

[59]Ibid.

[60]See for example World Coal Study, op. cit., Chapter 4. For the U.S. coal industry, see Zimmerman, op. cit., 1980 and Gordon, R.L., Economic Analysis of Coal Supply, An Assessment of Existing Studies, Electric Power Research Institute, Palo Alto, California, 1975.

[61]Ibid.

[62]Zimmerman, M.B. and Alt, C., "Rents in the Case of Western Coal," unpublished paper, M.I.T. Energy Laboratory, Cambridge, Massachusetts, 1979.

[63]see Canadian Coal 1979, Canadian Department of Energy, Mines, and Resources, Ottawa, 1980 and ICF, Inc., op. cit., December 1978.

[64]South African Department of Mines, "Coal in South Africa," op. cit.

APPENDIX A

RESERVES; PRODUCTION: COUNTRY SPECIFIC ANALYSIS

This appendix presents a more detailed evaluation of coal production and reserves in each country. Also included are descriptions of coal characteristics, mine locations, proximity to ports, and market structure. Our purposes are both to check and contribute to the integration and price analysis, and to provide the reader with a more detailed understanding of the respective national coal industries.

AUSTRALIA

Australia is divided into six states (Queensland, New South Wales, Victoria, Tasmania, South Australia, and Western Australia), and one territory (Northern Territory). Each of the six states has coal reserves, but approximately 92 percent of the black coal reserves are located in Queensland and New South Wales.[1]

New South Wales

New South Wales raw coal production was 50.5 million metric tons (MT) in the 1978-79 fiscal year, up 24.5 percent from the 1975-76 fiscal year. In 1977-78, total production amounted to 49.25 MT, 37.88 of which was underground production, and 11.38 of which was open-cut (strip mined).

Saleable black coal in 1977-78 equaled 41.67 MT, approximately 56 percent of which was consumed domestically, and 44 percent exported.[3]. The domestic consumption was comprised primarily of iron and steel (60 percent), and electric power generation (34 percent). Of

the exports, 76 percent were used for metallurgical purposes, and 22 percent for electricity generation.

Total exports increased from 17.74 MT in 1977-78 to 19.44 MT in 1978-79.

The New South Wales state is divided into six mining districts: South Maitland, Singleton-Northwest, Newcastle, West, Burragorang Valley, and South Coast. Their recent production and reserves are summarized in Tables A-1 and A-2. Also included are underground and open-cut mining subdivisions.[4]

Our concern is with the areas in New South Wales that currently play or will play in the future an important role in steam coal export markets. Coal characteristics, mining conditions, and proximity to port facilities for each district should therefore be briefly considered.

Coal quality data are not complete. One source describes the typical raw coal as having a heating value of 21 to 24 million Btu per short ton, 12 percent to 20 percent ash content, 25 percent to 28 percent volatile matter, and .4 percent to .7 percent sulfur content.[5] However, there are considerable variations in coal characteristics across New South Wales, and these variations are not adequately specified in the literature. Descriptions according to seam provide more detailed, though still incomplete, information.

The largest steam coal producing district is Singleton-Northwest. Its two major seams are Liddell and Bayswater. In Liddell, coal is classified as highy volatile (more than 33 percent), low in ash (less than 16 percent), and low in sulfur (less than .5 percent) coking coal. In Bayswater (and Ravensworth) the coal is highly volatile, medium to

Table A-1
NEW SOUTH WALES' RAW COAL PRODUCTION
(000's metric tonnes)

District:	1975-76	1977-78	1978-79	Change since 1975-76
South Maitland	1189	1676	1502	126.4
Singleton-N.W.	10713	14023	15406	143.8
Newcastle	11358	13324	12914	113.7
West	3523	4128	4322	122.7
Burragorany Valley	5202	5004	5039	-3.1
South Coast	8605	11099	11334	131.7
TOTAL	40590	49254	50517	124.5
Underground	32214	37875	38205	118.6
Open-cut	8376	11379	12312	147.0

Source: Joint Coal Board, 32nd Annual Report, 1978-79, p. 4.

Table A-2
BLACK COAL RESERVES AND RESOURCES OF NEW SOUTH WALES, 1979
(MILLION METRIC TONNES)

Region:	Measured Plus Indicated Reserves			Inferred Resources	
	In Situ	Recoverable	Marketable	In Site	Recoverable
Singleton-Northwest	13137	6876	4439	389996	184705
South Maitland	345	238	192	429	172
New Castle	4120	1740	1318	7728	3146
TOTAL	17602	8854	5949	398153	188023
Western	1390	941	727	35811	21247
South-Southwestern	3251	1877	1423	6822	3882
Oaklands	500	450	450	10000	2000
Sydney	-	-	-	39250	15700
TOTAL	22743	12122	8549	490036	230852

Source: Joint Coal Board, 32nd Annual Report, 1978-79, p. 21.

high ash (more than 20 percent) steaming coal. In 1977-78, production from Liddell equaled 3.68 MT versus 5.14 MT from Bayswater. The district total was 12.33 MT. Saleable coal output was 11.31 MT; 5.74 MT were consumed in domestic markets, and 5.57 MT were exported. Of the domestic consumption, 5.6 MT were used in power generation.[6]

Second in importance as a steam coal producing district is Newcastle. This district covers several coking and steaming coal seams. The Great Northern and Wallarah seams hold highly volatile, medium to high ash, and very low-sulfur steaming coal. Production from the Great Northern seam was 5.2 MT in 1977-78, versus 1.44 MT from the Wallarah seam. Total district production was 12.06 MT in 1977-78, 11.58 of which was saleable output. Of this amount, 8.74 MT were consumed domestically, and 2.0 MT were exported. The domestic production included 6.25 MT for power generation.

The Western district's major seam is Lithgow. Coal in the seam is classified as highy volatile, medium to high ash, and medium sulfur steam coal. Production in 1977-78 from this seam was 3.33 MT of the district total (4.13 MT). Saleable prouction was 3.69 MT, 2.0 MT of which was exported, and 1.66 of which was consumed domestically. Of the domestic consumption, 1.07 MT were for power generation.

The three other mining districts in New South Wales currently play a minor role in both domestic and export steam coal markets.

South Maitland lies on the Greta seam, which holds very highly volatile, low ash coal used in coking blends and in producing town gas in Japan. Production in 1977-78 was 1.68 MT. Burragoramg Valley lies on the

Bulli Seam, which primarily yields low volatile, medium ash, very low sulfur coking coal. Production in 1977-78 was 5.0 MT. Saleable production was 3.53 MT, 3.41 MT of which were exported. The distribution between end-uses is not available. However, some coal in this district, for example Wollondilly coal, though best suited to coking, may be used for steam coal exports as coking coal export demand stabilizes or declines.

The South Coast district's main seams are the Bulli Seam and the Wangawilli Seam. Both have primarily yielded coking coal to date. In 1977-78, the district produced 8.82 MT of saleable coal; 5.7 MT for domestic uses, and 3.1 MT for export. Of the 5.7 MT of domestic consumption, only .39 MT were used for electric power generation.

Mining conditions also vary within and between mining districts. Singleton-Northwest is the only major open-cut producer (10.2 MT open-cut, 3.8 MT underground). Newcastle open-cut mining production was 1.1 MT (13.32 MT total) in 1977-78. Open-cut mining in the other districts combined was only 60,000 tons.

Another important variable in Australia is the captivity of production, that is, which mines are tied exclusively to particular consumers, usually the iron and steel industry or public utilities.[7] In Singleton-Northwest, 5.6 MT of the 17.0 MT were captive to public utilities. In Newcastle, 2.16 MT were captive to the steel industry, 4.83 MT to public utilities, and 6.34 MT were non-captive. In the Western district .55 MT were captive to public utilities, .37 MT to the iron and steel industry, and 3.21 MT were non-captive.

Finally, we are concerned with the ports that serve the different mining districts, and the corresponding distances.[8] Singleton-Northwest uses the port of Newcastle almost exclusively (5.55 of 5.57 MT). Mileages to port vary depending on the originating mine, but average approximately 100 kilometers (km). As examples of the larger mines, Buchanan-Lemington is approximately 15 road km from MT. Thorley, which is 85 rail km from Newcastle. Ravensworth is approximately 108 rail km from port. Most coal, except that consumed on site, utilizes rail service for at least part of the trip to port.

The Newcastle district also relies primarily on the port of Newcastle (2.28 of 2.63 MT). Distances to port are very short, typically less than 25 km. For example, the Bloomfield mine is approximately 10 km from a rail siding, and 22 km from Newcastle. Wallsend is approximately 25 km from port. An outlier is Wayee, which is about 60 km from Newcastle. Rail and road haulage currently share this market equally.

The Western district exports coal through both Port Kembla (1.13 MT), and Sydney (.9 MT). The distance from a representative point, Lithgow Valley, is 158 km to Sydney, and 237 km to Port Kembla. Both rail and road transport are used. The South coast district uses Port Kembla (2.94 MT of 3.1 MT). To the north, Coalcliffe is 61 km from Sydney, and 28 km from Port Kembla. All other coal fields are within 70 km of Port Kembla. Here also both train and rail are utilized.

Burragorang Valley also uses Port Kembla (2.03 MT) and Sydney (1.3 MT). Distances to port vary according to transport modes. Wollondilly to Port Kembla is 101 km by road. Glenlee, a central washery and rail

station in the area, is 63 km from Sydney, and 142 km from Port Kembla. Currently rail and truck are equally utilized.

Lastly, let us consider future developments in New South Wales. Table A-2 presents reserves in each district. Clearly, the most important district in this respect is Singleton-Northwest. Newcastle also have very large reserves, while the other districts have far lower quantities. This is reflected in recent plans for mine development in New South Wales. Major new underground mines are planned for the Singleton-Northwest, Newcastle, and Western districts, while major new strip-mines are being developed in Singleton-Northwest.[9]

Queensland

Queensland's raw coal production was 37.25 MT in 1978-79, up 15 percent since the 1975-76 Fiscal year. In contrast to New South Wales, 88 percent (32.83 MT) of the 1978-79 raw coal production was from open-cut mines, and 12 percent (4.43 MT) from underground mines.[10]

Saleable black coal was 26.94 MT in 1978-79 and 24.95 MT in 1977-78. Of the 1978-79 total, 18.84 MT were exported to overseas countries. Of the exports, 99 percent were coking coal. The 6.1 MT consumed in the state were allocated mainly to electricity generation (4.5 MT) and an alumina refinery (1.1 MT). Total exports in 1978-79 decreased by 1.28 MT from the previous fiscal year as coking coal markets in Japan slackened.

Queensland is divided into 9 mining districts: West Moreton, Darling Downs, Maryborough, Kianga-Moura, Callide, Blackwater, Blair

Athol, Mackay, and Bowen. Recent production is summarized in Table A-3. Also included are underground and open-cut mining subdivisions.

Again, we are interested in the districts that may play an important role in steam coal export markets. Coal characteristics, mining conditions, and proximity to port facilities should be described for each district.

Coal quality data are more complete for Queensland than for New South Wales, if still not perfect. A district by district evaluation of developed mines is possible.[11]

In Northern Queensland, the Bowen district includes four mines at Collinsville, 86 rail km southwest of the port of Bowen. The two underground mines produced .4 MT of raw coal; the two open-cut mines produced .4 MT also. Two seams, Bowen and Blake, are included in the area. The Blake seam coal is high ash (19.4 percent), low sulfur (.45 percent) steaming coal with a heating value of 23.2 million Btu per short ton. The Bowen seam coal is a medium volatile coking coal with sulfur content from 1 percent to 3 percent in underground mines, and from .5 to 1.0 percent in open-cut mines. Exports in 1978-79 were only 10,202 tons, all of which were used for power generation.

In Central Queensland, the Blair Athol district includes on large open-cut mine. The mine is approximately 490 rail km from the port of Gladstone. The seam averages 26 meters, with an overburden ratio of 1.3:1. Production in 1978-79 was 113,331 metric ton. The coal is a medium-volatile steam coal with sulfur content of .3 percent, ash content of 8.2 percent, and heating value of approximately 23 million Btu per

Table A-3

QUEENSLAND SALEABLE COAL PRODUCTION[1]
(Metric Tons)

District	Underground Mines	Open-cut Mines	Total 1978-1979	Total 1977-1978
West Moreton	1442692	779044	221736	2641514
Darling Downs	7494	--	7494	7659
Maryborough	42870	--	42870	40944
Kianga-Moura	403877	2081767	2485644	2269793
Callide	--	1906620	1906620	1530097
Blackwater	580739	5400858	5981597	4744123
Blair Athol	--	113331	113331	147148
Mackay	201766	13147942	13349708	12657973
Bowen	414575	415739	830314	913643
TOTAL	3094013	23845301	26939314	24952894

Notes: 1. Saleable coal production has been defined as the tonnage of coal dispatched to market plus or minus the change in coal stocks over the period, actual stocks being adjusted to a saleable basis. Raw coal production is the amount extracted from coal seams, the measurement being made prior to treatment in a coal washery. Queensland total raw coal producton in 1978-79 was 37.7 MT.

Source: Queensland Coal Board, 28th Annual Report, June 30, 1979. pg. 12.

short ton. Steam coal exports in 1978-79 were only 5,736 tons.

Also in central Queensland is the Kianga-Moura District, which includes three underground and two open-cut mines. Production in 1978-79 equaled .53 MT from the underground mines, and 3.1 MT from the open-cut mines. Moura is approximately 177 km southwest of Gladstone. Kianga is 16 km south of Moura. Kianga coal is high volatile, weak to medium coking coal with low ash and sulfur content. A higher ash non-coking coal is also produced. Specific heating values are not available. The Bowen Basin range is 23 to 27 million Btu per short ton. Exports in 1978-79 were 2.25 MT, including 100,000 metric tons of steaming coal.

The Callide District is also in Central Queensland, approximately 163 km by rail from Gladstone. All the production (1.9 MT) was from open-cut mines, and exports were negligible. The coal is a subbituminous steaming coal with 15 percent ash, .2 percent sulfur, and 19.4 million Btu per short ton. Local consumers are power stations and an alumina refinery.

The Blackwater district includes five mines; two open-cut and three underground. Underground production was 68 MT versus 6.45 MT of open-cut production. Exports were 4.5 MT in 1978-79, 32,000 metric tons of which were used for power generation. The largest mine is the Blackwater open-cut mine, which is 330 rail km from Gladstone. Most coal is medium volatile, bituminous coking coal. A typical washed analysis is 8.3 percent ash, 0.5 percent sulfur, and 27.6 million Btu per short ton.

Also in the district are the South Blackwater mines, one open-cut and one underground. The rail distance to Gladstone is 343 km. Both

non-coking and coking coal is produced. Non-coking coal has 23.7 percent volatile matter, 10.9 percent ash, 0.8 percent sulfur, and 25.8 million Btu per short ton. Lastly, Leichardt and Cook Collieries, also in the district, are relatively small producers of coking coal.

The largest producing district in Queensland is Mackay, which includes one underground mine (263,634 metric tons production) and three large open-cut coal mines: Goonyella, Peak Downs, and Saraji. Total production in 1978-79 was 20 MT, 12 MT of which were exported. The mines are between 192 and 216 km from Hay Point port facilities. Production is primarily coking coal with volatile matter of 19.5 percent to 26.0 percent, ash content of 7.5 percent to 9.5 percent, sulfur content of 0.5 percent, and 27 million Btu per short ton.

The Darling Downs district includes one small mine in the Clarence-Moreton Basin (8000 metric tons production). West Moreton includes 12 open-cut, and 12 underground mines, all with production less than 0.6 MT. Total raw coal production in West Moreton was 1.77 MT in 1978-79. Only 16,000 tons were exported, all through Brisbane. Coal is typically steaming coal (20-23 million Btu per short ton, 17 percent to 28 percent ash, 0.4 to 0.7 percent sulfur).

The future production pattern in Queensland is not as clear as in New South Wales, given the small level of steam coal exports. It is possible that districts currently producing coal for metallurgical purposes could move to steam coal markets. However, the most likely areas for steam coal exports are Blackwater, Blair Athol, and the Kianga-Moura districts. Southern fields around Brisbane are possible,

Table A-4

QUEENSLAND RESERVES OF BLACK COAL 1979

(Figures are progress totals in millions of tonnes for raw coal **in situ**; losses will occur in mining and washing.)

AREA AUTHORITY TO PROSPECT OR MINING	MESOZOIC BASINS — NON-COKING COAL							
	MEASURED			INDICATED FIRST CLASS			TOTAL M + 1	IN-FERRED
	O-C	U-G	TOTAL	O-C	U-G	TOTAL		
IPSWICH BASIN								
IPSWICH								
Mining leases	—	390	390	—	100	100	*490	—
TARONG BASIN								
TARONG								
AP 197C[18]	175	25	200	25	35	60	*260	Large
CALLIDE BASIN								
CALLIDE								
AP 188C[17], mining leases	105	20	125	10	95	105	230	Large
MULGILDIE BASIN								
MULGILDIE	—	—	—	—	15	15	†15	—
SURAT/MORETON BASIN								
TAROOM-WANDOAN								
AP 189C[5]	105	3	108	25	10	35	143	—
AP 152C[19]	—	—	—	10	—	10	10	Very small
AP 157C[3]	175	—	175	140	—	140	315	Large
AP 182C[19]	85	—	85	20	—	20	105	Small
AP 138C[19]	—	—	—	25	—	25	25	Small
WANDOAN-DALBY								
AP 156C[20]	—	—	—	—	60	60	60	Small
AP 102C[19]	30	—	30	45	—	45	*75	Large
AP 150C[19]	25	—	25	5	—	5	*30	Small
AP 77C[21]	120	—	120	—	—	—	*120	Large
DALBY-MILLMERRAN								
AP 205C[20]	—	—	—	270	80	350	*350	Large
AP 129C[22]	145	—	145	50	—	50	*195	Large
Acland mining leases	—	10	10	—	—	—	10	—
Rosewood mining leases	—	5	5	—	—	—	5	—
AP 203C[23]	175	—	175	400	—	400	*575	Large
TOTAL — SURAT/MORETON BASIN	**860**	**18**	**878**	**990**	**150**	**1 140**	**2 018**	**Large**
STYX BASIN								
STYX	—	4	4	—	—	—	4	—
TOTAL-MESOZOIC BASINS	**1 140**	**457**	**1 597**	**1 025**	**395**	**1 420**	**3 017**	**Large**

* Washing may be required to produce a marketable coal. † Less than 60 m in depth.

RECOVERABLE RESERVES — MESOZOIC BASINS

On the assumption that 90 per cent of open-cut coal and 50 per cent of underground coal are extracted by mining and using existing experimental data or otherwise an arbitrary figure of 65 per cent, where washing is required to produce a marketable coal, recoverable reserves are NON-COKING COAL — 1 770 million tonnes.

Table A-4 (continued)

PERMIAN BASINS

AREA AUTHORITY TO PROSPECT OR MINING LEASE	COKING COAL								NON-COKING COAL							
	MEASURED			INDICATED First Class			TOTAL M + 1	INFERRED	MEASURED			INDICATED First Class			TOTAL M + 1	IN...
	O-C	U-G	TOTAL	O-C	U-G	TOTAL			O-C	U-G	TOTAL	O-C	U-G	TOTAL		
BOWEN BASIN																
Theodore																
AP 202C[1]	—	—	—	—	—	—	—	—	125	500	625	20	590	610	1 235	Large U-G
Moura/Kianga																
(a) Moura Franchise Area[2]	110	750	860	—	—	—	860	Large U-G	20	10	30	—	—	—	30	Large
(b) AP 53C[3]	—	—	—	—	365	365	365	—	—	—	—	—	—	—	—	—
Baralaba																
Mining leases[4]	—	—	—	—	—	—	—	—	—	15	15	—	—	—	15	—
Bluff																
(a) Mining leases[5]	—	—	—	—	—	—	—	—	—	—	—	—	10	10	10	—
(b) AP 190[6]	—	—	—	—	—	—	—	—	—	—	—	7	2	9	9	Very Small
Yarrabee																
(a) ML 196[6]	—	—	—	—	—	—	—	—	25	—	25	—	—	—	25	Very Small
(b) AP 123C[3]	—	—	—	—	—	—	—	—	15	—	15	—	15	15	30	Small
Hall Ck/Lake Elphinstone																
AP 62C, ML 312[24]	160	—	160	15	635	650	810	—	—	—	—	—	—	—	—	—
Collinsville																
Mining leases[7]	30	140	170	5	—	5	175	—	4	40	44	7	—	7	51	—
Newlands																
ML 365[8]	—	—	—	—	—	—	—	—	70	85	155	—	10	10	165	Small
Eastern Creek																
AP 73C[9]	—	—	—	—	—	—	—	—	12	15	27	—	—	—	27	—
Nebo Project[2]																
(a) Bee Creek, ML 368	—	—	—	—	—	—	—	—	20	25	45	—	35	35	80	Large U-G
(b) South Walker Ck.									85	—	85	—	190	190	275	
(c) Walker Ck. ML 367	—	—	—	—	—	—	—	—	40	40	80	—	40	40	120	
(d) Kemmis Ck									15	—	15	—	—	—	15	
(e) Lancewood, ML 370	—	—	—	—	75	75	75	—	—	4	4	—	—	—	4	—
(f) Wards Well, ML 260	—	340	340	—	—	—	340	—	—	85	85	—	—	—	85	—
(g) Riverside, ML 152	95	—	95	—	—	—	95	—	—	—	—	—	—	—	—	—
(h) Poitrel, ML 366	80	35	115	—	—	—	115	—	—	—	—	—	—	—	—	—
(i) Winchester, ML 261	4	—	4	—	—	—	4	—	—	—	—	—	—	—	—	—
(j) AP 213C	1	—	1	—	—	—	1	—	5	—	5	—	—	—	5	
Moranbah	—	—	—	—	2 050	2 050	†2 050	Large U-G	—	—	—	—	—	—	—	—
C.Q.C.A. Areas[10]																
(a) Goonyella, ML 127	135	30	165	65	1 110	1 175	1 340	Large U-G	—	—	—	—	—	—	—	—
(b) Peak Downs, ML 210	165	15	180	370	1 230	1 600	1 780	Large U-G	—	—	—	—	—	—	—	—
(c) Daunia, ML 244	55	50	105	20	35	55	160	Large U-G	—	—	—	—	—	—	—	Small
(d) Norwich Park, ML 245	125	30	155	150	460	610	765	—	—	—	—	—	—	—	—	—

Table A-4 (continued)

Burton Downs	—	—	—	45	70	115	115	—	—	—	—	—	—	—	—	—
Winchester South	—	—	—	—	—	—	—	—	—	—	—	80	75	155	155	—
Blair Athol																
ML 315[11]	—	—	—	—	—	—	—	—	275	—	275	—	—	—	275	—
German Creek																
AP 206C, 219C[12]	†† 90	220	310	†† 3	280	283	593	Large U-G	—	—	—	25	—	25	25	—
Roper Creek	—	—	—	—	—	—	—	—	—	—	—	/ 40	585	625	625	—
Oaky Creek																
AP 208C, 218C[13]	** 90	270	360	—	195	= 195	555	Large U-G	—	—	—	—	—	—	—	—
Gregory																
AP 89C, ML 259[14]	45	15	60	10	55	65	125	—	—	—	—	—	—	—	—	—
Emerald																
(a) AP 209C[14]	—	—	—	—	170	170	170	} Large U-G	—	—	—	—	—	—	—	—
(b) Departmental area	—	—	—	—	555	555	555		—	—	—	—	730	730	730	Large U-G
Capella																
AP 52C[11]	30	—	30	9	—	9	39	Large	30	—	30	40	—	40	70	Large
Blackwater																
(a) Departmental areas																
(i) Jellinbah/Caledonia	—	—	—	—	—	—	—	—	—	—	—	—	90	90	# 90	—
(ii) Minyango	—	—	—	—	265	265	265	—	—	—	—	—	15	15	15	—
(iii) Togara	—	—	—	—	—	—	—	—	—	—	—	—	1 270	1 270	1 270	Large U-G
(b) Company areas																
(i) AP 217C[25]	90	—	90	30	100	130	220	—	120	25	145	50	1 240	1 290	1 435	—
(ii) ML 110[15]	70	—	70	—	525	525	595	—	35	—	35	—	205	205	240	—
(iii) ML 121[15]	35	—	35	—	380	380	415	Large U-G	2	—	2	—	65	65	67	—
(iv) MLs 194,195,242,296[14]	—	105	105	—	635	635	740	Large U-G	—	—	—	—	—	—	—	—
(v) AP 25C, ML 197[16]	—	130	130	—	360	360	490	Large U-G	—	—	—	—	—	—	—	—
(vi) AP 10C, MLs 193,198[17] 199,284,662	35	300	335	5	—	5	340	Large U-G	4	—	4	—	—	—	4	—
Rolleston																
AP 57C[3]	—	—	—	—	—	—	—	—	185	90	275	—	120	120	395	Small
TOTAL — BOWEN BASIN	**1 445**	**2 430**	**3 875**	**727**	**9 550**	**10 277**	**14 152**	**Very Large**	**1 087**	**934**	**2 021**	**269**	**5 287**	**5 556**	**7 577**	**Very Large**
GALILEE BASIN	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	**Very Large**

* Crucible swelling no. 3.
† Includes 555 million tonnes which yields washed product of ash 11-14%.
# May be coking in part.
/ To 50 m in depth.
†† Includes 30 million tonnes in seams ◄1.5 m thick.
** Includes 45 million tonnes in seams ◄1.5 m thick.
= Departmental estimate.

Source: Queensland Coal Board, 28th Annual Report, June 30, 1979.

RECOVERABLE RESERVES — PERMIAN BASINS

On the assumption that 90 per cent of open-cut coal and 50 per cent of underground coal are extracted by mining, and using existing experimental data, or otherwise an arbitrary figure of 65 per cent, for the recovery of coking coal after washing, recoverable reserves are COKING COAL — 5 510 million tonnes, NON-COKING COAL — 4 250 million tonnes.

but less likely, steam coal exporters in the future.

This conclusion is reinforced by the non-coking coal reserve estimates in Table A-4. Blackwater is the major coal region. Major planned steam coal mine developments are Theodore, near Moura, Blair Athol, Baralaba (near Moura), and the Nebo project mines (South Walker, Newland) in the north near Hay Point.

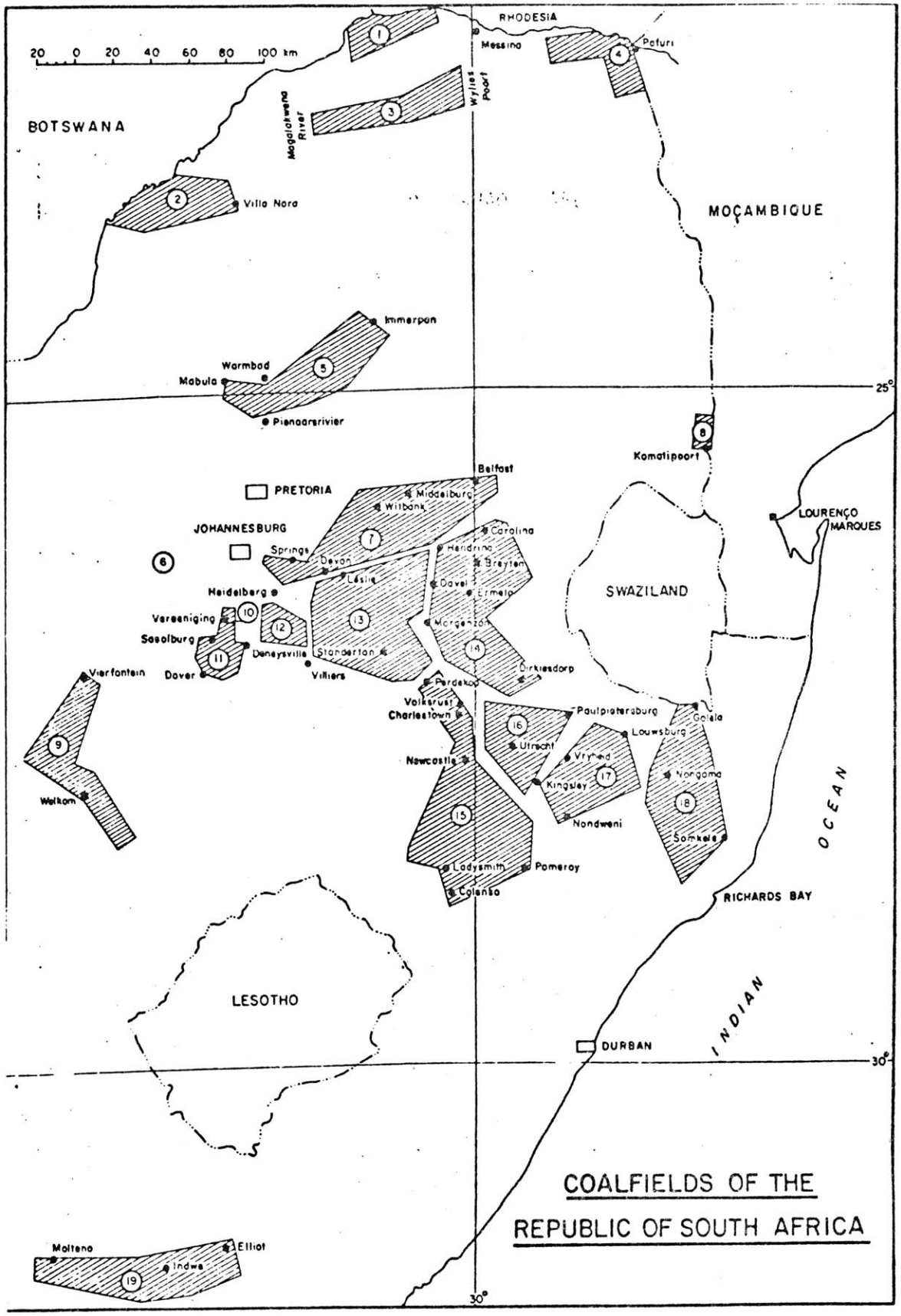
SOUTH AFRICA

Saleable coal production in South Africa equaled 90.36 MT in 1978, 15.4 MT of which were exported. In 1979 estimated coal exports were 22.5 MT. Unlike the other countries analyzed in the study, most of the exports were steam coal. Current figures are not available, but in 1976 87 percent of the total South African saleable coal output was consumed by power stations.[12]

There are five states in South Africa: Natal, Transvaal, Orange Free State (O.F.S.), Cape of Good Hope, and Transkei. The first four all have coal reserves, though the Cape of Good Hope has no developed coal mines. Transvaal is by far the largest producer, accounting for 71 percent of the 1978 coal sales (62.1 MT). Orange Free State's 1978 coal sales were 13.5 MT, and Natal's, 11.6 MT.

South African fields are pictured in Figure A-1. Fields 1 through 5 represent isolated basins and troughs in the northern and central Transvaal. Field 19 lies in the central part of the main Karoo Basin on the Cape of Good Hope. Orange Free State fields include O.F.S. Vierfontein (9), Old Springfield (10), Vereeniging-Sasolburg (1), and

Figure A-1



Source: Petrick Report.

South Rand (12). Natal coalfields are numbered 15-18, and Southeastern Transvaal coalfields are numbered 7, 13, 14. Natal and southeastern Transvaal fields lie in the main part of the Karoo Basin.

With the exception of some Transvaal fields, almost all of South African mining is underground. In 1976, Transvaal underground production was 46.3 MT versus 10.7 MT of open-cut production. In Natal and Orange Free State the corresponding figures are: Natal 1.3 MT open-cut, 11.4 underground; O.F.S., 0.0 MT open cut, 13.8 MT underground.

Currently Transvaal is the largest steam coal exporter. Orange Free State coal is used exclusively by domestic power stations and Sasol plants. There are no exports from this state. Natal coal is both anthracite and bituminous, and there are negligible steam coal exports. Typical coal characteristics in O.F.S. are: sulfur, 0.2 percent to 1.1 percent; ash, .25 percent to 36 percent; and heating value, 14.4 to 17 million Btu per short ton. In Natal, Bituminous steam coal ranges from 11 percent to 24 percent ash, 0.4 percent to 2.2 percent sulfur, and 22 to 26 million Btu per short ton.[13]

Transvaal coal is also variable in quality. In the Ermelo area, the ash content is 12 percent to 16 percent, the sulfur content is 0.8 percent to 1.2 percent, and the heating value is 22 to 24 million Btu per short ton. In the Witbank area, exported steam coal was 13 percent to 18 percent ash, 0.5 percent to 0.9 percent sulfur, and 23 to 27 million Btu per short ton.

Distances from Southeastern Transvaal coal fields to Richards Bay Port facilities average 540 km. They range from Ermelo (445 km) to

Blackhill (633 km). Distances from Natal coal fields to Richards Bay average 280 km. All movements to Richards Bay are by rail.[14]

The reserve estimates in Table A-5 suggest the continued importance of Transvaal coal. Proved and indicated reserves of bituminous coal equal 58 billion tons. Recent mining developments have occurred in both the Witbank and Ermelo areas. It is unlikely that export production in the next twenty years will originate elsewhere.

CANADA

Canadian coal production in 1978 equaled 30.4 MT. Exports amounted to 13.6 MT, more than 90 percent of which were for metallurgical purposes.[15]

Coal reserves exist in the eastern provinces of Nova Scotia and New Brunswick, and in the western provinces of British Columbia, Alberta, and Saskatchewan. Of the measured and indicated reserves, 97 percent are in the Western provinces. Production by province is listed in Table A-6.

For export purposes, Alberta and British Columbia are of primary concern. Nova Scotia is a potential exporter, but Nova Scotia's coal is very expensive and high in sulfur content (>3 percent). Saskatchewan's coal is exclusively lignite, and further removed from West Coast facilities.

British Columbia coal production in 1978 was 9 MT. The major mines are located in the southeast, approximately 700 to 750 miles from Vancouver. All production is from surface mines. With the exception of a negligible amount of steam coal, all exports are used for metallurgical

Table A-5

SOUTH AFRICAN COAL RESERVES

Proven plus indicated

(million short tons)

	Bituminous		Anthracite	Total
Province	(Metallurgical)	(Steam)		
Transvaal	916	58152	203	59271
Natal	301	1324	356	1981
Orange Free State	-	4547	-	4547
Cape of Good Hope	-	-	-	-
TOTAL	1217	64023	559	65799

Source: Commission of Inquiry into the Coal Resources of the Republic of South Africa, "Report to the State President of the Republic of South Africa," Pretoria, April 3, 1977, Tables 3-2 to 3-18.

Table A-6

CANADIAN COAL PRODUCTION

(million metric tons)

	1969	1977	1978
Province:			
Nova Scotia	2.3	2.0	2.0
New Brunswick	.6	.4	.3
Saskatchewan (lignite)	1.8	5.5	5.0
Alberta (Bit. and subbit.)	4.0	12.0	13.5
British Columbia	.8	8.5	9.0
Bituminous		15.1	17.1
Subbituminous		7.8	8.3
Lignite		5.5	5.0
TOTAL:	9.5	28.4	30.4

Source: Canadian Department of Energy, Mines, and Resources, Canadian Coal 1979, Ottawa, 1980, p. 9.

purposes. Undeveloped coal reserves also exist in the northeastern region of British Columbia.

Alberta has both subbituminous and bituminous coal, all of which is surface-mined. The bituminous mines are located in the southwest and the subbituminous mines in the northern plains. Virtually all of the southern production is exported for metallurgical uses, while the plains production is used primarily for Canadian power generation. Southern mines are from 700 to 750 miles from port, and northern mines 700 to 800 miles from port.

Coal quality data by mines is not available. In the southeastern sections of British Columbia and in Alberta's Southwestern section (the lower-inner-foot belt district), typical coal is 0.6 percent sulfur, 26 million Btu per short ton, and 10 percent ash coking coal. Byron Creek is the only steam coal mine in the area. Coal there is approximately 12 percent ash and 0.5 percent sulfur. In the Alberta plains (i.e. Luscar, Forrestburg), subbituminous coal has 10 percent ash, 0.5 percent sulfur, and 18 million Btu per short ton. In northeastern British Columbia, coal is 5 percent ash, 0.5 percent sulfur, and 29 million Btu per short ton coking coal.[16]

Reserves by area are presented in Chapter I, Table 6. Major steam coal mine developments are planned by Kaiser Resources, Fording and Byron Creek in southeastern British Columbia, Luscar and Manalta in upper Alberta, and Crowsnest and Elco in the southeast.[17]

UNITED STATES

United States production of bituminous and lignite coal was 665 million short tons in 1978. Exports were 40 million short tons, virtually all of which were for metallurgical purposes.[18]

We have discussed producing areas in the transportation analysis above (Chapter IV, Part A). Eight originating points were selected, each associated with a subset of the U.S. Bureau of mines districts. Let us reconsider each briefly.[19]

First, Rock Springs represents Wyoming's Hanna Basin and parts of northern Colorado. All production is strip-mined. Typical saleable coal characteristics are 21 to 23 million Btu per short ton, 0.5 percent to 0.6 percent sulfur, and 8.5 percent to 9.0 percent ash. The U.S.B.M. districts included are the southern part of 19, and 16.

Billings, Montana is used to represent the Powder River Basin in Montana and Northern Wyoming. The enormous coal reserves are all strippable. The subbituminous coal has 16.2 to 18.6 million Btu per short ton, 0.4 percent to 0.5 percent sulfur, and 6 percent to 8 percent ash. U.S.B.M. districts 19 (Northern Part) and 22 correspond to this area.

Price, Utah, which represents Utah and northern New Mexico mines, includes U.S.B.M. districts 20 and 17. All of the Utah mining is underground. Typical saleable quality is 23 million Btu per short ton, 0.5 percent to 0.6 percent sulfur, and 10 percent to 13 percent ash.

Gallup, New Mexico represents coal fields in Arizona and southern New Mexico. All production is strip-mined. Typical coal has 18 to 20 million Btu per short ton, 0.4 percent to 0.7 percent sulfur, and

10.50 percent to 15.0 percent ash. District 18 corresponds to this area.

Harrisburg, Illinois represents coal fields in Indiana, Illinois, and West Kentucky (Districts 9, 10, 11). Production is almost equally divided between strip-mines and underground mines. In Illinois, saleable coal is typically 21 to 23 million Btu per short ton, 2.5 percent to 3.5 percent sulfur, and 8.5 percent to 13.0 percent ash. In Western Kentucky coal varies from 22 to 26 million Btu per short ton, 0.9 percent to 3.0 percent sulfur and 11 percent to 17 percent ash.

Lynch, Kentucky represents central Appalachian coal fields in West Virginia, Virginia, and Eastern Kentucky (districts 7 and 8). The majority of the production is underground, but strip-mine production is substantial. Typical coal has 22 to 26 million Btu per short ton, 1.0 percent to 3.4 percent sulfur, and 9 percent to 15 percent ash.

Wheeling, West Virginia represents coal fields in northern Appalachia in Ohio, Pennsylvania, and North, West Virginia (Districts 1-4). Production is from both underground and strip-mines. Typical coal has 22 to 26 million Btu per short ton, 1.0 percent to 3.4 percent sulfur, and 9 percent to 15 percent ash.

Lastly, Birmingham, Alabama represents coal fields in southern Appalachia. Typical saleable coal has 24 to 25 million Btu per short ton, 0.75 percent to 1.6 percent sulfur, and 10 to 13 percent ash. Approximately 60 percent of the production in this area (District 13) is strip-mined.

Production by state is summarized in Table A-7.

Table A-7

U.S. Production of Bituminous Coal and Lignite in 1978

State	Production (Thousand short tons) (Underground)	(Surface)	(Total) 1/
Alabama	6,169	14,383	20,533
Alaska	-	731	731
Arizona	-	9,054	9,054
Arkansas	3	516	519
Colorado	4,511	9,303	13,814
Georgia	-	113	113
Illinois	24,841	23,760	48,600
Indiana	522	23,630	24,182
Iowa	108	342	450
Kansas	-	1,226	1,226
Kentucky			
East	41,624	65,608	96,233
West	17,860	21,596	39,456
Total	59,484	76,204	135,689
Maryland	382	2,616	2,998
Missouri	-	5,665	5,665
Montana	-	26,600	26,600
New Mexico	576	12,056	12,632
North Dakota	-	14,028	14,028
Ohio	11,897	29,340	41,237
Oklahoma	2	6,068	6,070
Pennsylvania	32,925	48,551	81,477
Tennessee	4,150	5,882	10,032
Texas	-	20,020	20,020
Utah	9,141	-	9,141
Virginia	21,511	10,435	31,946
Washington	-	4,708	4,708
W. Virginia	65,216	20,099	85,314
Wyoming	708	57,620	58,328
TOTAL 1/	242,177	422,950	665,127

Notes: 1. Data may not add to totals shown due to independent rounding.

Source: U.S. Department of Energy, Energy Data Reports, "Production of Coal, Bituminous and Lignite, 1980." Weekly Coal Report No. 126.

MARKET STRUCTURE

In this section the details on which the discussion of market structure was based are presented.

CANADA

In Alberta there are four metallurgical coal producers for the export market: Coleman Collieries, Canmore Mines, Cardinal River Mines, and McIntyre Mines. Production in 1978 was respectively, 0.95 MT, 0.1 MT, 1.9 MT, and 1.6 MT.[21]

Subbituminous production in the plains region is all consumed domestically. The Manalta mines produced 6.97 MT of the 8.3 MT total. However, some of their properties are owned by Calgary Power. Forestburg and Luscar produced 0.9 MT and 0.58 MT respectively. Part of their production was also tied to the electric utilities.

In British Columbia, three companies exist: Kaiser, Fording and Byron Creek. Total production equaled 9 MT (5.0 Kaiser, 2.8 Fording, and 0.52 Byron Creek). Kaiser and Fording production was almost entirely for coking coal exports. Byron Creek produces steam coal both for export and Ontario Hydro.

Several companies are planning steam coal expansions. Existing companies planning new mines are Kaiser, Luscar, Bryon Creek, Fording, and Manalta. New companies with mines in the planning stage are Union Oil, Denison, Pacific Petroleum, Crows Nest, and Elco Mining.[22]

SOUTH AFRICA

In South Africa, 39 of the 56 mines are controlled by six companies. Anglo-American Corp's company "Amcoal" produced 34 percent (28.75 MT) of the total production.[23] General mining and finance's company Trans Natal Coal produced 25.86 MT, or 30 percent. Rand mines (Barlow Rand's Wilbank and Welgedecht Colliery Ltd. and T.C. Lands) produced 9.1 MT or 11 percent of the total output. Smaller producers are J.C.I. (4.3 MT), Lonhro S.A. Ltd. (2.6 MT) and Gold fields of South Africa (2.35 MT).

Other important producers are Shell Oil in the Rietspruit Colliery with Rand, British Petroleum with General Mining and Total Oil at Ermelo, the South African Iron and Steel Corp. (1.4 MT) and the South African Oil, Coal, and Gas Company (5.77 MT). Six other companies produced 4.6 MT in the 15 remaining mines.

Equally important to competition in South Africa is the marketing structure. Major producer associations are assigned export quantities by the government, and in turn allocate these quantities amongst their producers. Recently, some large mines have made arrangements to sell their own coal directly on the export markets.[24] Government allocations for 1979 to 1985 are listed in Table A-8.

QUEENSLAND

Given the small amount of steam coal exports, Queensland's market structure is especially hard to interpret. A district-by-district analysis is, however, helpful.[25]

Table A-8

SOUTH AFRICAN EXPORT ALLOCATIONS

(million metric tons)

	1979-85	1985
Transvaal Coal Owners Association	9.6	10.0
Natal Associated Collieries	1.2	2.0
Ermelo Mines*	3.0	-
Amcoal	2.0	6.0
Anthracite Producers Association	1.2	4.0
General Mining	-	6.0
British Peroleum	-	5.5
Shell Oil	3.0	5.5
Total Oil	-	2.5
T.C. Lands (Barlow Rand)	-	2.5
TOTAL	20.0	44.0

*Ermelo Mines includes General Mining, British Petroleum and Total Oil. For 1985 these allocations are shifted to the individual companies.

Source: Coal in South Africa, 1979, South African Dept. of Mines, Minerals Bureau, Internal Report, No. 48, pg. 41.

In West Moreton, eight companies produced 4 MT in 1978-79. The largest company, Rhonda Colliers, produced 1 MT. In Darling Downs, one small company produces 8000 tons.

In Kianga-Moura, a conglomerate, Theiss-Dampier-Mitsui produced 3.64 MT in five mines. Theiss Holdings controls 22 percent, Dampler Mining 58 percent, and Mitsui and Co. 20 percent of the conglomerate.

In Callide, Theiss Brothers, a subsidiary of Theiss Holdings, produced 1.9 MT. In Blair Athol, Conzinc Rio Tinto (62 percent) and ARCO Coal (38 percent), jointly control the properties.

In Blackwater, Utah development produced 5.5 MT. Theiss Brothers produced 1.15 MT (South Blackwater). Queensland Coal Mining, a subsidiary of Broken Hill Proprietory Company, produced 0.45 MT, and Dampier Mining Company is developing properties.

In Bowen, one company, a subsidiary of MIM Holdings Ltd., produced 0.83 MT. In Mackay, a consortium, the Central Queenland Coal Associates, produced 19.46 MT. The joint venture is managed by Utah Development. They own 76.25 percent of the company. Other participants are Mitsubishi Developments Pty. Ltd. (12.0 percent), Utah Mining Australia Ltd. (4.0 percent), and Australia Mutual Provident Society (7.75 percent). Companies developing mines include Dampier, Theiss Holdings, Central Queenland Coal Associates, Houston Oil and Minerals, AAR Ltd., ESSO Exploration and Production Australia, U.K. National Coal Board, Ruhrkohle and Shell.

NEW SOUTH WALES

New South Wales coal production by company is presented in Table A-9. In most cases it is impossible to separate steam coal from coking coal output.

Major producers are the steel industry and the state. In the steel industry, two producers, Broken Hill Proprietory, and Australian Iron and Steel Pty. Ltd. (a Broken Hill subsidiary) control production. For the State, electricity commission subsidiaries' production tied to electricity plants equals approximately 12 MT.

Of the remaining producers, Clutha Development Pty. Ltd. is the leading producer, with 7.87 MT of the remaining 29.78 MT. Coal and Allied Industries production was 4.25 MT. Seven other companies produce between 1 and 3 MT annually. The major producers in Singleton-Northwest are R.W. Miller and Coal and Allied Industries.

UNITED STATES

Martin Zimmerman, among others, has evaluated the coal market structure in the United States and the following conclusions can be drawn.[26] In the East, competition is strong. Taking the reciprocal of the Herfindahl index for the top 15 producers suggests that the industry behaves as 13.2 equal firms. In the Midwest, markets are far more concentrated. In Districts 9, 10, and 11, the reciprocal of the Herfindahl Index is 5.73. In the West, there is less competition also. At the time of Zimmerman's analysis, western coal markets were undeveloped and the market structure could not be meaningfully

Table A-9
NEW SOUTH WALES COAL PRODUCERS
1977-78 Production
(Million metric tonnes)

		Operating Districts
Steel Industry:		
Broken Hill Proprietory Co.	2.16	S.C.
Australia Iron and Steel Pty. Ltd. (subsidiary of Broken Hill)	4.23	S.C.
State Ownership:		
Subsidiaries of the Electricity Commission (Elcon, NewCom, Huntley Collieries)	7.48	N,W,S.C
Contractors to the Electricity Commision (Swamp Creek and Ravensworth No. 2)	5.59	SN
Other:		
Clutha Development Pty. Ltd.	7.87	SN,W,BW
Coal and Allied Industries	4.26	SM,SN,N
Kembla Coal and Coke Ltd.	2.92	SC
Buchanan Borehole Collieries	2.32	SN, N
Austen and Butta Ltd.	2.29	W,SC
R.W. Miller	1.77	SN,N
The Bellambi Coal Co.	1.52	SC
Peko-Wallsend Co.	1.49	SM,N
Coaltex Pty.	1.49	W
Bloomfield Collieries	.94	N
Bayswater Colliers	.68	SN
Wambo Mining Corp.	.52	SN
Others:	1.71	-
TOTAL:	49.25	

Note: SC = South Coast, SN=Singleton Northwest, BU=Buragorang Valley, SM=South Maitland, N = Newcastle.
Source: Joint Coal Board, Black Coal in Australia, 1977-78.

evaluated. Since then, a clearer picture has developed.

In most western regions, the market is heavily concentrated relative to eastern coal markets.[27] In Montana, six companies produced 26 million short tons in 1978. The two largest producers, Decker Coal Co., and Western Energy Co., accounted for more than 20 million short tons alone. In Wyoming 1978 production was 49 million short tons. Of this, 18 million short tons were produced by Amax Coal Company. Six other companies produced between 2.0 and 8.4 million short tons.

In Arizona all of the 11.7 million short tons output was produced by Peabody Coal. In New Mexico, Utah International produced 8 million short tons of the 13.0 million short tons. total. Two other companies accounted for the remaining 7 million short tons.

Colorado and Utah are the only western states where production is not highly concentrated. The largest producer in Colorado was Energy Fuels Co., with 2.9 million short tons of the 13.35 million short tons total. In Utah, total production was 10.2 million short tons. American Coal Company produced 2.5 million short tons, and 13 other companies produced the remaining tonnage.

FOOTNOTES--CHAPTER I--APPENDIX A

[1]There are also approximately 40 billion tons of demonstrated economic brown coal resources, 98 percent of which are in Victoria. The Victorian coal is all lignite. Given the low heating content, Victorian coal is not expected to be exported. Furthermore, Victoria consumes very little Queensland and New South Wales coal, so an expansion of Victorian production will not be indirectly important to the export market either. See Australia's Energy Resources, op. cit., Chapter 7.

[2]Joint Coal Board, Thirty-second Annual Report, 1978-79, p. 4.

[3]Joint Coal Board, Black Coal in Australia, 1978-79, p. 7, Table 8, p. 67.

[4]Ibid., p. 10.

[5]See ICF, Inc., Coal Reserves and Production in Eight Major Non-U.S. Coal Producing Countries, 1978.

[6]See Joint Coal Board, 1978-79, op. cit., "District Reviews--New South Wales."

[7]Ibid., p. 12.

[8]Ibid., p. 185.

[9]Joint Coal Board, 1977-78, op. cit., pp. 174-175.

[10]All Queensland data is from Queensland Coal Board, op. cit.

[11]Ibid., p. 58-73.

[12]South African data are from "Coal in South Africa, 1979," op. cit.

[13]Petrick Commision Report, op. cit.

[14]Unpublished data provided by the South African Board of Railways and Harbours. See Chapter VI, Part A.

[15]Canadian Department of Energy, Mines, and Resources, Canadian Coal, 1979, Ottawa, 1980.

[16]Canada Department of Energy, Mines, and Resources, "1976 Assessment of Canada's Coal Resources and Reserves," Report CP-77-5, 1977, p. 14.

[17]Canadian Department of Energy, Mines and Resources, op. cit., 1980.

[18]U.S. Department of Energy, Energy Data Reports, "Bituminous Coal and Lignite Distribution, Calendar Year 1978," April 1979.

[19]Statistics based on "Current Contract and Spot Market Steam Coal Prices," in Coal Week, various issues, and Keystone Industry Coal Market, 1979, "Description of Seams."

[21]Canadian Department of Energy, Mines, and Resources, op. cit., 1978, p. 76.

[22]Canadian Department of Energy, Mines, and Resources, op. cit., 1980, pp. 16-19.

[23]South African Department of Mines, Minerals Bureau, "Coal Mines in the Republic of South Africa," op. cit.

[24]"Coal Exports, Export Quotas," in Financial Mail, Vol. 71, no. 2, June 12, 1979, p. 28.

[25]Queensland Coal board, op. cit.

[26]Zimmerman, M.B., "Long-run Mineral Supply: The Case of Coal in the United States," Ch. II, op. cit.

[27]Keystone Industry Coal Manual, 1979, op. cit.

CHAPTER II

AN ANALYSIS OF CURRENT DELIVERED STEAM COAL PRICES, AND POSSIBLE FUTURE SHIFTS IN THE COMPETITIVE STRUCTURE OF INTERNATIONAL STEAM COAL MARKETS

INTRODUCTION

In this chapter we integrate the transportation and supply analyses to calculate the delivered prices of steam coal to coastal-fired power stations in Western Europe and Japan. We will analyze the existing competitive structure, and consider the importance of possible future shifts in supply and transportation variables to the development of steam coal trade.

CURRENT DELIVERED PRICES

Tables 1 through 4, and Table 5 in the ocean section (Part A, Chapter VII) provide all the pertinent information used to calculate cost minimizing delivered prices to Europe and Japan based on existing conditions and constraints. To summarize briefly, United States coal prices, FOB mine, are taken from Coal Week's "current steam coal spot and term marker prices." The lowest sulphur level for which prices are reported is used for eastern and midwestern coal. Transportation rates and costs are taken from Part A, Chapters IV and VI. In the base calculation of cost minimizing transportation choices, railroad rates are set according to the existing U.S. domestic unit-train rate structure. Connecting costs, transhipments from rail or truck to barges, and port dumping charges are calculated as discussed in Chapter IV, Part A.

For Australia, two FOB pier prices are accounted for: the first is consistent with contracts signed in 1978-79; the second consistent with

spot prices in 1978-79. As discussed earlier, the evidence suggests that the higher spot prices reflect short-term supply constraints, not long-run conditions. However, the evidence is inconclusive. Australian transportation tariffs are drawn from actual tariff samples.

For Canada, two main supply regions are considered: the Alberta plains; and the mountainous terrain in southern British Columbia and Alberta. Prices per million Btu (MBtu), FOB mine, are equated to those in Montana for the plains in Alberta, and those in Utah for the southern region of British Columbia and Alberta. Transportation tariffs are drawn from actual tariff samples.

For South Africa, the FOB pier price is, as discussed earlier, set by the government. Transportation tariffs are again taken from the South African railways tariff sheets. Exchange rates for conversion to U.S. dollars are based on 1979 average exchange rates reported by the International Monetary Fund.

Ocean transportation costs are based on the results presented in Part A, Chapter VII. The base calculations assume conventional bulk vessels, existing port size constraints and no return cargoes. All delivered prices represent the cost to the overseas docksides; they do not include the costs of unloading the ocean vessels. Finally, prices are adjusted to January 1979 price levels.

Table 4 presents the cost-minimizing delivered prices to three destinations: Yokohama, Japan; Taranto, Italy; and Rotterdam, the Netherlands. Also included are estimates of the ocean and inland transportation charges that are included in the delivered prices. Let us

consider the results for each destination.

First, consider Japan. The cheapest supplier to Yokohama (and all other Japanese ports) is Australia. Queensland coal exports through Gladstone can be delivered for $1.19/MBtu on the low end, or $28.56 for a normalized 24 million Btu ton. New South Wales coal delivered to Japan costs $1.28/MBtu or $30.72/24 MBtu. The next closest competitor is South Africa. In spite of the larger inland and ocean distances, the cheaper rail costs per ton-mile and lower priced coal (FOB mine) yields a delivered price of $1.40/MBtu, or $33.60/24 MBtu. Approximately equal to this price level is Canadian coal at $1.43/MBtu. The cost minimizing Canadian supply region is southeastern British Columbia and Alberta. The higher coal price per ton, and per million Btu, is offset by cheaper transportation costs per million Btu due to the very high Btu content of British Columbian bituminous coal.

United States producers are currently in a weak competitive position for the Japanese market. Delivered prices from Los Angeles to Yokohama are $1.71/MBtu or $41.00/24 MBtu. This is approximately $3 greater than even the highest Australian price range of $1.47/MBtu. Note that the cost-minimizing-coal-supply region to Los Angeles is Price, Utah. Lastly, medium-sulfur coal shipped to the East Coast or Gulf Coast is priced still higher. Northern Appalachian coal via Hampton Roads to Japan cost $2.21/MBtu. Southern Appalachian coal via Mobile to Japan cost $2.08/MBtu. Based on high-sulfur prices, $5.00 to $6.00 less per ton, the delivered price from these origins would still exceed the price of Los Angeles exports delivered to Japan by at least $3.00/24 MBtu.

A different picture emerges for European markets. Consider Rotterdam as a reference point for Northern European markets. Despite a long ocean shipment relative to the U.S. origins, South African coal is cheapest at $1.38/MBtu. The closest competitor, Australia, can deliver coal for $1.61/MBtu or $5.52/24MBtu more. However, besides South Africa, all other originating points are relatively competitive with one another. Shipments from Gladstone cost $1.61/MBtu. Coal from Hampton Roads and Mobile or New Orleans can be delivered to Europe for $1.70 to $1.76/MBtu. It is interesting to note that Australia's ocean freight cost is 42 cents/MBtu, or approximately $10.00/24 MBtu higher than the ocean freight cost on shipments from Hampton Roads to Rotterdam. However, based on January 1979 cost levels, the lower price of coal FOB mine dominates this disadvantage.

If we ignore South Africa, the other originating points are also reasonably competitive in Northern Europe. Coal from Gallup could be delivered via Houston for $1.93/MBtu or 46.32/24 million Btu. Lastly, due to the significant economies of scale in ship sizes, coal from Vancouver is priced at $1.82/MBtu in Rotterdam. The delivered price from Los Angeles is $1.96/MBtu.

In Taranto, Italy, which represents Southern Europe and the Mediterranean, the competitive structure is similar. Again, South Africa is by far the cheapest supplier. The only significant difference is that Australia's competitive advantage relative to the U.S. East Coast is slightly increased due to the locational shift.

It is also interesting to note the relative importance of

transportation and supply variables to the competitive pattern that obtains in Japanese and European markets. In the case of Japan, there are four closely competitive originating points: Vancouver, Richards Bay, Gladstone, and Port Kembla. The proportion of transportation costs to delivered cost ranges from 43 percent to 46 percent. On the basis of ocean transportation costs, Vancouver and Gladstone are the cheapest supply points. On the basis of inland transportation costs, Port Kembla and Richards Bay are the cheapest. Coal prices FOB mine range from 67 cents to 78 cents per million Btu (assuming the low cost Australian scenario). Australia has both low ocean freight and inland transportation costs, and so is the cheapest supplier by a significant margin. Vancouver and Richards Bay have high inland costs and ocean costs respectively. Los Angeles, the next closest competitor, has both high ocean and inland costs which effectively prices West Coast coal out of the Japanese market.

While transportation is the critical variable for coal shipments to Japan, it is less important on shipments to European markets. In fact, coal supply prices FOB mine are the dominant factor. U.S. East and Gulf Coast origins are the cheapest to Europe based on transportation costs. However, the high coal prices in these areas dominate this advantage, and allow both Australian and South African suppliers to compete. From the United States, transportation costs are 28 percent to 32 percent of delivered prices, versus 45 percent to 59 percent from Richards Bay and Gladstone, respectively. The United States is doubly cursed in this sense. On shipments to Japan, they are handicapped with high

Table 1
U.S. Railroad and Barge Coal Rates and Costs
January 1, 1979
(dollars per short tons)

	1 Portland	2 S.F.	3 L.A.	4 Houston	5 N.O.	6 Mobile	7 Balt.	8.. Hampton
1 Billings	12.20 9.61	18.56 14.18	19.05 14.52	23.27 17.55	25.63 19.24 20.46 16.00	26.10 19.58	27.87 20.85	29.69 22.15
2 Rock-Springs	12.75 10.00	12.75 10.00	12.75 10.00	19.79 15.05	23.16 17.47 20.83 17.20	24.86 18.69	27.87 20.85	29.69 22.15
3 Price	13.08 10.24	12.08 9.52	9.82 7.90	18.74 14.36	22.62 17.08 23.68 18.00	24.57 18.48	29.05 21.70	30.81 22.95
4 Gallup	24.79 18.64	13.24 10.38	9.13 7.40	14.09 10.96	18.03 13.79	21.18 15.20	30.21 22.52	30.50 22.73
5 Harrisburg				10.94 9.88	8.71 7.40 7.18B 12.00E	7.98 6.63 8.28B 10.00E	12.51 7.71	13.50 8.47
6 Lynch					10.12 8.76 10.45B	8.90 7.55 11.75B	8.20 6.52 11.00E	8.10 6.68 11.00E
7 Wheeling					13.51 12.15 11.67	12.46 11.18 12.80B	7.29 5.10$_E$ 10.50^E	8.89 6.76$_E$ 10.50^E
8 Birmingham						4.75 3.41 4.82B 6.99E		

(continued)

TABLE 1 (continued)

NOTES: 1. For origins 1-4,
First number equals rail rate
Second number equals rail cost
Third number equals rail rate/barge cost
Fourth number equals rail cost/barge cost
For origins 5-8,
First number equals rail rate
Second number equals rail cost
B = barge rate
E = export rail rate

2. All rail rates are through ex parte 357, January, 1979

3. Barge, rail transshipments cost = $1.00

4. Transportation to riverway from:
Wheeling = $2.00
Lynch = $2.00
Harrisburg = $2.00
Birmingham = $1.00

5. Billings to St. Louis = 1100 rail miles
Rock Springs " = 1221
Price " = 1425
Gallup " = 1379

6. Western rail rate equation:
-5.75 + .0127*M + .0596*u + .668 DUMEQ + .929 IMAT
+ .00124 DM +2.134 + DUMT
U=14
MAT=1,000,000
DUMEQ, DM=1 i.e., rail-owned equipment
DUMT= new rate level

West costs = 10 mills per ton mile - see Chapters II, IV, Part A.

7. Eastern, Mideastern rates as estimated in Chapter I, Part A:
-.07 + .0105*M + .00237*U + .369* IMAT + 1.21*DUMR + .0016*DM
+ 1.005*DUMEQ
DUMR = 1 East, 0 Midwest
DUMEQ = 1 railroad, 0 shipper

8. Eastern, Midwestern costs:
a. If i = 5 - 7, j = 5 - 6, TA = [.133136 + (8.691*IMAT)
+ (.009543*L) + 54(MDUM) + (.004595*M) + (.0188*PGO)
+ (.0358*PDUM)]2.29
rent = (.0188 * PGD) 2.29
b. If i = 7, j = 7 - 8, same but BDUM = 1, PGD is positive
c. IF i = 8, j= 5-6, PGD = 0, use a

d. If i = 8, j = 7 - 8, PCFOB = 8.09, PG = 40, Btu = 26, BDUM = 1, use a
e. PG, PCFOB from MBZ computer printout (all as B.P. x (1.09) See Chapter II, Part A.

9. a. For destinations 5 and 6, and origins 6-8, Zimmerman estimates rents at zero. Rate levels are based on this author's regressions. (See note 7.)
b. For destinations 5 and 6, and origin 5, Zimmerman estimates rents at 12 cents per ton. Rate levels are based on this author's estimation.
c. For destinations 7 and 8, and origin 5 Zimmerman's rate estimates are $13.17 and $13.92. Table on includes this author's rate estimates.
d. For destinations 7 and 8, and origin 6, Zimmerman's rate estimates ae $8.34 and $8.40 versus this author's estmates of $8.20 and $8.10.
e. For destinations 7 and 8, and origin 7, Zimmerman's rate estimates are $6.45 and $7.98, versus $7.29 and $8.89 estimated by this author. Zimmerman's cost estimates are $4.53 and $6.06. Cost estimates in Table one are equal to this author's rate estimate adjusted by the proportionate difference between Zimmerman's rates and costs.

10. Barge rates -- See Part A, Chapter IV, Appendix A.

Source: Author's calculations.

Table 1a

Distances Between U.S. Coal Fields and Ports (Statute Miles)

	1 Port.	2 S.F.	3 L.A.	4 Houston	5 N.O.	6 Mobile	7 Balt.	8 Hampton
1. Billings	961	1418	1452	1755	1924 2149B	1958	2085	2215
2. Rock Springs	1000	1000	1000	1505	1747 2270B	1869		2215
3. Price	1024	952	790	1430	1708 2474B	1848	2170	2295
4. Gallup	1864	1038	740	1096	1379 2427B	1520	2252	2273
5. Harrisburg					642 1001B	573	889	955
6. Lynch					776 1542B	660	594	584
7. Wheeling					1100 1760B	1000	392	545
8. Birmingham					335	266 396B	799	800

Notes: 1. For origins 1-4, B represents joint rail-barge distance. Rail to St. Louis, barge from St. Louis to New Orleans (1049 miles)

2. For origins 5-8, B represents barge distance plus short connecting haul (less than 100 miles in all cases).

Source: 1. Railroad mileages, United States Railroad Atlas, Rand-McNally
2. Water mileages, American Waterways Operators, Big Load Afloat.

Table 2

U.S. FOB Mine Prices -- January, 1979
(short tons)

Billings	.4% sulfur, Montana 52 cents/MBtu $9.75/ton	.7% sulfur, Montana 49 cents/MBtu $8.50/ton	.5% sulfur, Wyoming 42 cents/MBtu $6.75/ton
Rock Springs	.6% sulfur 79 cents/MBtu $16.50/ton		
Price	.6% sulfur 86 cents/MBtu $19.75/ton		
Gallup	.5% sulfur 80 cents/MBtu $19.75/ton		
Harrisburg	3.55% sulfur 100 cents/MBtu $21.50/ton	.9% sulfur 118/MBtu $28.25/ton	
Lynch	.7% sulfur 127 to 128 cents/MBtu $30.50 to $33.25/ton	1.5 to 1.6% sulfur 107 to 108 cents/MBtu $26.25 to 26.75/ton	
Wheeling	1% sulfur 116 cents/MBtu $29.00/ton	2.5 to 3.5% sulfur 92 to 105 cents/MBtu $23.00 to $27.00/ton	
Birmingham	.75% sulfur 118 cents/MBtu $29.50/ton	1.6% sulfur 108 cents/MBtu $26.00/ton	

Source: Coal Week, "Current Contract and Spot Marker Steam Coal Prices," March 26, 1979.

Table 3

U.S. FOB Pier Prices -- January, 1979
($ per million Btu)

MMBTU/ton		1 Port.	2 S.F.	3 L.A.	4 Houston	5 N.O.	6 Mobile	7 Balt.	8 Hampton
1	Bill.	1.22	1.59	1.62	1.87	1.70	2.04	2.14	2.25
2	R.S.	1.39	1.39	1.39	1.73	1.60	1.97	2.11	2.20
3	Price	1.43	1.38	1.29	1.67	1.64	1.93	2.12	2.20
4	Gallup	2.04	1.46	1.26	1.50	1.70	1.86	2.31	2.33
5	Harr.				1.63	1.48	1.51	1.52	
6	Lynch						1.70	1.60	1.68
7	Wh.						1.66		1.48
8	Birm.						1.37		

Note: 1. All prices assume unit-train rate levels.

2. None of the prices include loading from rail to ship. $1 per ton estimate in the United States.

3. For East and Midwest origins (5-8), delivered prices are based on the lowest sulfur levels reported by Coal Week in the respective regions.

4. Estimated heating values per short ton for supply points 1 through 8 are: 1, 17 MBtu/ton; 2, 21 MBtu/ton; 3, 3, 23 MBtu/ton; 4, 24 MBtu/ton; 5, 24 MBtu/ton; 6, 24 MBtu/ton; 7, 25 MBtu/ton/ 8, 25 MBtu/ton.

Source: Author's calculations.

Table 4
Delivered Steam Coal Prices in Western Europe and Japan
($/MBtu)

	Yokohama	Taranto	Rotterdam
New Orleans		2.03 Billings, .5% sulfur	2.18 Billings, .5% sulfur
Hampton	2.21 Wheeling, 1% sulfur .69 ocean .32 inland	1.81 Wheeling, 1% sulfur .29 ocean .32 inland	1.76 Wheeling, 1% sulfur .24 ocean .32 inland
Mobile	2.08 Birm., .75% sulfur .67 ocean .14 inland	1.75 Birm. .75% sulfur .34 ocean .14 inland	1.70 Birm. .75% sulfur .29 ocean .14 inland
Los Angeles	1.71 Price .38 ocean .43 inland	2.02 Price .69 ocean .43 inland	1.96 Price .63 ocean .43 inland
Vancouver	1.43 B.C. .23 ocean .42 inland	1.90 B.C. .67 ocean .42 inland	1.82 B.C. .59 ocean .42 inland
Richards Bay	1.40 .40 ocean .24 inland	1.40 .40 ocean .24 inland	1.38 .38 ocean .24 inland
Gladstone	1.19-1.38 .24 ocean .28 inland	1.52-1.71 .57 ocean .28 inland	1.61-1.80 .66 ocean .28 inland
Port Kembla	1.28-1.47 .33 ocean .21 inland	1.68-1.87 .73 ocean .21 inland	1.81-2.00 .86 ocean .21 inland

Notes:
1. Total price delivered to dockside, originating point, sulfur level, ocean transportation cost, and inland transportation cost.
2. January, 1979 price levels.
3. U.S., Canada include $1.00 per ton dumping fee.
4. Australia:
   a. 24 million Btu/short ton.
   b. $.95 to $1.14 per million Btu, FOB pier.
   c. Inland Transportation based on 108 km from N.S.W. = $5.00 A, $5.65 U.S. From Queensland , inland transportation cost based on South Blackwater = $6.58 A, $7.43 U.S. per metric ton.
   d. Average 1979 exchange rate, 1 Australian dollar equals 1.13 U.S. dollars.

TABLE 4 (continued)

5. South Africa.
    a. 23 million Btu/short ton
    b. $1.00/MBtu FOB pier price, or 21.08 Rand per metric ton
    c. $6.00 per metric ton, inland transportation costs.
    d. 1979 exchange rate, 1 Rand = 1.2 U.S. dollars.

6. Canada:
    a. Based on British Columbia origins
    b. 26 MBtu/short ton
    c. FOB mine price assumed at $20.00 U.S. per short ton.
    d. Inland transportation costs estimated at $11.00 U.S. per short ton.

Source: Author's calculations.

transportation costs, and on shipments to Europe they are handicapped with high coal prices. In the next section we will consider possible future shifts in this competitive structure.

POSSIBLE FUTURE SHIFTS IN THE COMPETITIVE STRUCTURE OF INTERNATIONAL STEAM COAL MARKETS

Having analyzed the existing economic structure of international steam coal markets, we can begin to consider the importance of possible future shifts in supply and transportation variables to the development of steam coal markets.

We will focus on potential shifts relative to their effects on U.S. participation in steam coal export markets. In essence, we ask: What changes are likely to shift the economic structure of international steam coal markets in the United States' favor?

First, consider inland transportation tariffs. In the United States, shifts in both directions are possible. In the calculations above, the railroad tariff used for shipments to the East Coast ports is based on existing domestic unit-train rate levels. In fact, the existing export rate structure is significantly higher than this level. From Northern Appalachia to Hampton Roads, the January 1979 rate ranged from $10.00 to $11.00 per short ton. This will add 10 cents per million Btu to prices from this area, or $2.40/24 MBtu. From Birmingham to Mobile, the rail rate would increase from $14.80 per ton to $16.80 per short ton, or 9 cents/MBtu. Given no existing export rate structure based on

western U.S. origins, the higher export rate levels are less likely for western originating shipments.

Another possible shift in U.S. railroad rates is a change in unit-train rate levels in either direction. As discussed in the inland transportation chapters, railroad rates are significantly higher than long-run marginal costs. Based on the estimates of costs in Table 1, significant price reductions could obtain. For example, the estimated cost to Los Angeles from Price, Utah is $7.90 per short ton, versus the existing tariff of $9.82 per short ton. The savings in delivered prices to Japan would amount to 8 cents per MBtu. To East Coast and Gulf Coast ports, savings realized by rate reduction to marginal cost levels are approximately the same.

Note, however, that with the current deregulatory bills in the U.S. Congress, it is equally likely that domestic unit train rates will continue to increase rapidly. Though drastic increases on export shipments would seemingly eliminate the United States as a competitor abroad, the risk of jeopardizing the lucrative domestic market with export rate reductions to normally profitable levels must be a concern. On the other hand, it is possible that the ICC will ignore the differences between export and domestic rate structures, as they have in the past, and allow rate discrimination to exist. Note also that other exporting countries could similarly cut railroad rates to counteract this strategy.

Another possible development is port expansion and/or new port development. A number of options exist. First, assume that Los Angeles

is expanded to handle 120,000 DWT vessels. The ocean freight would be approximately $6.78 per short ton versus $8.69 per short ton, a savings of 8 cents per million Btu.

A second possibility is to develop coal handling facilities and expand ports elsewhere on the West Coast. Portland is 4323 miles from Yokohama, or approximtely 516 less than Los Angeles. For a 60,000 ton vessel, the saving would be 79 cents per short ton, or 3 cents per 24 MBtu. The cost minimizing origin via Portland to Japan is Billings, Montana. The delivered price is 1.62/MBtu, versus $1.71 for Los Angeles with a facility that can handle 60,000 DWT vessels. Rock Springs, Wyoming and Price, Utah coal could be delivered to Japan through Portland for $1.72 MBtu.

A similar facility in San Francisco would receive coal from Price, Utah and deliver it to Japan for $1.67/MBtu.

With respect to the Japanese market, the minimum delivered price in Japan would involve Billings coal via Portland. With railroad rates at marginal cost levels, and a 120,000 DWT port facility in Portland, the price would be $1.47/MBtu. Even with this optimistic scenario, Australian, Canadian, and South African coals are cheaper in Japan, but western United States coal would be closely competitive. (Note also that this assumes no increase in port charges with port expansion. In fact, there is virtually no correspondence between port charges and port-expansion costs. However, in real economic terms, these additional costs would have to be justified (see Part A, Chapter VII.)

With respect to the European market, port expansion should also be

considered. First, consider shipments from Hampton Roads. Expansion to allow for 120,000 DWT vessels would reduce ocean freight costs by only 3 cents/MBtu to Rotterdam. This expansion plus a reduction in rail rates would not make much difference in the existing competitive structure. South African coal would still be far cheaper, and U.S. coal is currently competitive with other potential suppliers.

Another possibility is expanding the Gulf port(s). If New Orleans was expanded to allow for 120,00 DWT vessels, the delivered price of Billings coal in Rotterdam would be $2.06/MBtu. Low-sulfur coal to Houston from Gallup would be priced at $1.88/MBtu in Rotterdam. Medium-sulfur coal from Western Kentucky would be priced at $1.79/MBtu if a 120,000 DWT facility was developed in the New Orleans region. Also, if rail rates dropped to the level of marginal costs, delivered prices in Rotterdam would drop further to $1.65/MBtu.

To summarize, expanded facilities on the Gulf or East coasts would not significantly affect the existing competitive structure of U.S. coal in Europe.

Two other inland transportation shifts should be briefly recalled. First, coal-slurry pipelines. As discussed earlier, the economics of coal-slurry pipelines are uncertain. It is, however, possible that costs could be equal to or below rail marginal costs, and well below existing railroad rates. A savings of up to 10 cents/MBtu could be realized by this development.

Secondly, waterway user charges may be increased for barge movements on the inland waterway system. This would affect shipments to the Gulf

coast, but would have a negligible effect on delivered prices in Japan or Europe.

Finally, recall again that all of these potential changes could be counteracted by the supplying countries.

Next, let us briefly consider changes in the ocean transportation base case assumptions. One development that might affect the United States relative to other exporters is the availability of return cargoes. As described in Part A, Chapter VII, South Africa and the western United States both have return cargo possibilities on shipments to Japan. Shipments via Los Angeles can save 4 cents/MBtu by returning oil from Alaska. South Africa can reduce delivered prices to Japan by 2 cents/MBtu by returning oil from Bahrain. In and of itself, this does not mitigate Australia's competitive advantage in Japan. However, in the ideal case cited above, the savings would further narrow the competitive advantage of Australia's coals (1.43 Portland versus 1.28 Port Kembla).

Another important shift is in fuel prices. As noted in Part A, the proportional effect of fuel price increases on ocean rates does not vary substantially over distance. The absolute effect, however, will be far greater on longer shipments. The major implications of large fuel price increases will be that Australia's competitive position in Europe will be damaged, as will South Africa's competitive position in Japan. Specifically, a 60 percent increase in fuel prices will increase the price of Australian coal delivered to Rotterdam by approximately 10 cents per million Btu. The corresponding increase in U.S. coal prices delivered to Rotterdam is 3.25 cents per million Btu. If the long run

coal prices in Australia are at the low end of estimated range, then Australian coal would still be competitive with U.S. coal in Europe. However, if prices are in the higher end of th range, U.S. coal will be significantly cheaper in Europe. Overall, the increase in fuel prices will icrease the importance of transportation, and limit the number of competitors in each demand region.

Now, consider the possibility that high-sulfur coal could be used. This would significantly affect only the U.S. East coast and Gulf coast exports. To New Orleans, the delivered price of 3.5 percent sulfur coal in Rotterdam would be $1.64/MBtu. This is still well above South African price levels, but further below other countries' delivered prices. To Hampton Roads, high-sulfur coal could be delivered to Rotterdam for $1.52/MBtu, a price that is very competitive with South African prices ($1.40/MBtu). The premium on low-sulfur coal in Western Europe will be evaluated below to see if this is a reasonable projection.

Finally, let us consider potentially important supply-side shifts. The most important, given the existing economic structure of steam coal markets, is the likelihood of South African coal prices increasing at a faster rate than prices in other exporting countries.

As discussed above, Ellis' most likely case assumes that South African prices, delivered to Europe, will equate U.S. prices by 1990. Adjusting his calculations to reflect the existing vessel economies of scale realized in Richards Bay, the delivered price of South African coal in 1990 would be $3.13/MBtu. Given the existing delivered price of coal through Hampton Roads, $1.76/MBtu, this means that the price of coal

delivered to Europe could increase by 5 percent real per year and be equal to South African prices.[1]

Zimmerman has estimated that medium-sulfur and low-sulfur coal prices in the eastern United States will also escalate rapidly.[2] For the FOB mine price of northern Appalachian medium-sulfur coal (.84 percent to 1.85 percent), he estimates an increase of 33 percent (real) from 1978 to 1990, yielding $1.54/MBtu. The rail rate is currently 32 cents/MBtu, and the ocean freight 24 cents/MBtu. Allowing for a 7 percent real increase per year in railroad rates, the delivered price in 1990 would be $2.50/MBtu, well below South African prices. Note however that prices in Australia may increase at slower rates over this period, so that the competitiveness of eastern coal is not certain.

It is also useful to consider the competitiveness of low-sulfur western U.S. coal in Europe given these rapid increases in South African prices. For example, consider coal from Gallup, New Mexico, delivered to Europe via a port facility in Houston. The current price of coal FOB mine is 80 cents/MBtu. Zimmerman projects an increase to 92 cents/MBtu in 1990.[3] The current inland transportation cost is 70 cents/MBtu. Ocean freight in an 80,000 DWT vessel to Rotterdam is 43 cents/MBtu. The current delivered price in Europe is $1.93/MBtu. The 1990 rate, increasing railroad rates by 7 percent per year, is $2.93/MBtu, again below the South African price.

To conclude, South African labor and capital cost increases in the next decade may well eliminate the competitive advantage that they now have in European markets. If so, U.S. East Coast medium-sulfur and

western low-sulfur coal may compete in Europe with South African coal. However, the ability of U.S. coal to compete in Europe with Australian coal is not clear. Large fuel price increases will favor the United States in European markets. The effects of depletion on low-sulfur and medium-sulfur United States coal in the East and Midwest will favor Australia. Significantly divergent real rates of cost increases in other mining and transportation variables may also affect the existing competitive balance. Further research is necessary to specify the future competitive structure with greater certainty.

In the next chapters we will analyze the demand for steam coal at these delivered prices.

FOOTNOTES-CHAPTER II

[1]See Ellis, P., "An Economic Analysis of the South African coal Industry with a Focus on Exports," Sloan School of Management, Master's Thesis, MIT, 1979.

[2]Zimmerman, M.B., Coal Supply Manual, unpublished documentation; and Zimmerman, M.B., The U.S. Coal Industry: The Economics of Policy Choice. M.I.T., Cambridge, Massachusetts, 1980.

[3]Ibid.

CHAPTER III

THE EXISTING STRUCTURE OF STEAM COAL DEMAND IN WESTERN EUROPE AND JAPAN

INTRODUCTION

In the previous chapters on supply and transportation we have estimated the delivered price of steam coal to markets in Western Europe and Japan and have analyzed some of the important economic and institutional variables affecting international steam coal markets. The next three chapters analyze steam coal demand in Western Europe and Japan. Our purpose is twofold. First, to explain the structure of steam coal demand, primarily for electricity generation, in Western Europe and Japan. By this we mean to analyze the economic and policy variables that will affect steam coal demand, and to explain the interaction between these variables and demand. Second, to estimate future steam coal demand, and to analyze the effect of changes in supply, transportation, and demand variables on steam coal imports.

Chapters III through V are organized as follows. Chapter III will describe the existing structure of coal demand in Western Europe and Japan. Chapter IV will present and criticize estimates of steam coal demand to the year 2000. Given the deficiencies and/or uncertainties in the forecasts, Chapter V will present a more detailed analysis of steam coal demand for electricity generation based on the economics of power generation, the current structure of electricity generation, and various assumptions on power plant fuel choice, and electricity demand growth rates from the present to the year 2000.

THE EXISTING STRUCTURE OF COAL DEMAND IN WESTERN EUROPE AND JAPAN

Table 1 summarizes total primary energy demand in Organization for Economic Co-operation and Development (OECD) countries. The solid fuels column includes coal, coke oven gas, blast furnace gas, peat, wood, and black liquor. Coal, however, accounts for virtually all of the category. The salient point to make is that coal is a large input to energy demand, yet it is dwarfed by oil, gas, and hydro resources. In OECD Europe, and the United States, approximately 20 percent of primary energy demand is met by solid fuels. In Japan solid fuels account for 14 percent of primary energy demand versus 42 percent in Australia.

Note also the relative magnitudes of primary energy demand. The United States is by far the largest OECD consumer. They required 1857 million tons of oil equivalent (MTOE) in 1978. OECD Europe as a whole consumed 1227 MTOE. The largest European consumers, France, Italy, West Germany, and the United Kingdom, accounted for 66 percent of Europe's energy requirements. Japan's primary energy demand was 357 MTOE in 1978, the second highest country total in the OECD.

Tables 2 and 3 present a more detailed analysis of coal consumption, production, imports, exports, and applications. Again, the largest producer and consumer is the United States. They produced 58 percent of the hard coal (anthracite and bituminas) output in the OECD, and 13 percent of the total brown coal (lignite) output. Adjusting for the

Table 1
OECD Total Energy Requirements-1978
(million tons of oil equivalent)

	Solid Fuels	Crude Oil + NGL	Petroleum Products	Gas	Nuclear Power	Hydro and Geothermal	Electricity	Total
N. America	380	927	51	508	79	131	-0.21	2077
U.S.	362(19)[1]	836	53	465	71	70	2	1857
Canada	18 (8)	91	-1	43	8	61	-2	219
OECD Europe[2]	251(20)	671	5	171	39	90	-	1227
Austria	4(16)	10	2	4	-	6	0	25
Belgium	10(22)	34	-10	9	3	-	-	45
Denmark	4(20)	8	8	-	-	-	-	20
Finland	8(33)	11	1	1	1	2	-	24
France	33(17)	119	-5	20	7	16	-	190
Germany	73(27)	108	38	41	8	4	-	273
Italy	10 (7)	113	-21	23	1	11	-	137
Netherlands	3 (5)	58	-31	33	1	-	-	64
Norway	1 (5)	9	-	1	-	12	-	22
Spain	11(15)	50	-2	1	2	10	-	72
Sweden	5(10)	15	10	-	6	14	-	49
Switz.	1 (4)	4	10	1	2	8	-	24
Turkey	13(42)	13	3	-	-	2	-	31
U.K.	70(33)	98	-4	38	9	1	-	212
Japan	51(14)	239	18	16	15	18	-	357
Australia	29(42)	32	-2	6	-	4	-	69

Notes: [1]Numbers in parentheses represent solid fuel percentage shares.

[2]OECD Europe also includes Greece, Iceland, Ireland, Luxembourg, Portugal. Total fuels include coal, coke oven gas, blast furnace gas, peat, wood, blacke lignite.

Source: International Energy Agency, Energy Balances of OECD Countries, 1974/1978, Paris, 1980

differences in heating contents between hard and brown coals, the United States consumed 558 million metric tons in 1978, versus 398 million metric tons in OECD Europe.[1] Japan consumed approximately 71 million tons of hard coal in 1978.

The primary uses of coal are in the energy transformation sector, specifically coke ovens and thermal power stations. In OECD countries 23 percent of total hard coal consumption was in coke ovens for metallurgical purposes, and 63 percent in thermal power stations. Eighty-seven percent of brown coal consumption was in thermal power stations. Excluding the United States, however, the relative importance of transformation applications shifts significantly. In Europe 53 percent of hard coal is used in thermal power plants. In Japan, only 11 percent of all coal consumed is used for power generation, while 77 percent is used for metallurgical purposes.

Final consumption of coal is small in all these countries. Only 11 percent of the hard coal is used in final consumption and 6 percent of the brown coal. In Europe, final coal consumption is evenly split between the residential and industrial sectors. In North America and Japan, virtually all of the final consumption is in the industrial sector.

Tables 2 and 3 also include coal imports in 1978. Europe imported approximately 77 million metric tons in 1978. The largest European importer was France with 23.4 MT. Belgium, Denmark, Finland, West Germany, Italy, the Netherlands, Spain, Sweden and the United Kingdom imports ranged from 1.5 to 7.0 million metric tons of coal.

Table 2
OECD Coal Consumption-1978
(Thousand metric tons)

Country	Coal Type	Total Domestic Consumption	Production	Imports/ Exports	Consumption uses: Electric Power	Coke Ovens	Final Consumption	Other
OECD Total	Hard	977720	930796	146970/110784	611556	227959	115170	14484
	Brown	247667	246368	1765/38	216535	-	15593	1592
U.S.	Hard	541842	566374	2679/36914	408048	64495	60487	-
	Brown	32591	32591	-	28500	-	4091	-
Canada	Hard	18593	17141	14119/13988	10350	6909	1525	-
	Brown	13157	13336	/12	12625	-	389	-
Japan	Hard	70710	19820	52860/	7730	54270	3220	4860
Aust.	Hard	32447	70981	13/37911	20482	8609	3379	89
	Brown	30485	30485	-	26322	-	1314	2848
OECD Europe	Hard	312149	255007	77298/21959	164355	93626	45309	8864
	Brown	171267	169768	1765/26	1499088	-	9295	1924

Notes: 1. "Other" includes energy sector transformations, patent fuel plants, gas works, blast furnace gas, producer gas, petroleum refineries.

2. Conversion factors: Ton of oil equivalent = 10^7 Kcal; ton of coal equivalent = 7×10^6 Kcal; ton of lignite equivalent = 2×10^6 Kcal. Typical conversion factors:

U.K. hard coal = 5.4×10^6 kcal to 6.6×10^6 kcal
U.S. hard coal = 6.4×10^6 kcal
U.S. brown coal = 3.1×10^6 kcal
Canada Bituminous = 6.7×10^6 kcal
Subbit = 4.5×10^6 kcal
lignite = 3.1×10^6 kcal
Australian hard = 6.2×10^6 kcal
brown = 2.2×10^6 kcal
Europe hard coal imports 6.0 to 7.0×10^6 kcal.

Source: International Energy Agency, Energy Statistics, 1974/1978. Paris, 1980

Table 3
1978 Coal Consumption - OECD Europe
(Thousand metric tons)

Country	Coal Type	Total Domestic Consumption	Production	Imports/ Exports	Consumption Uses: Electric Power	Coke Ovens	Final Consumption	Other
OECD	Hard	312149	255007	772982/1959	164355	93626	45309	8864
Europe	Brown	171267	169768	1765/26	149088	-	9295	1924
Austria		2277	-	2277/	1	1938	338	-
		3130	3076	245/5	2179	-	880	71
Belgium		13800	6590	7007/226	3698	7220	2794	128
Denmark		5655	-	6111/	4923	-	718	92
Finland		5401	-	4789/	3832	-	1506	-
France		44590	19690	23441/443	22160	12980	6019	3440
			2730	10/10	2340	-	270	10
Germany		80022	90104	6931/18788	35118	32183	9874	2840
		125231	123587	1460/11	111575	-	1600	12000
Italy		12456	-	12456/	1971	10006	454	25
		1215	1188	27/	1155	-	60	-
Netherlands		4689	-	4797/73	1225	3275	272	14
Norway		831	378	447/77	15	443	374	-
Spain		13193	11387	3443/10	6818	5161	1099	115
		8161	8261	6/	8086	-	67	8
Sweden		1628	16	1543/31	9	1227	393	-
Switz.		149	-	141/	8		141	-
Turkey		4440	4440	-	1162	1875	1323	80
		9190	9190	-	3960	-	5211	19
U.K.		120863	121695	2352/2253	83208	16763	18450	2056

Source: International Energy Agency, Energy Statistics, 1979/1978, Paris,1980.

The split between steam coal and metallurgical coal imports is not available for 1978. However, the electric power consumption figures combined with production and imports give a reasonable indication of the relative volumes. In Denmark and Finland, all imports were for thermal power generation. In the Netherlands, approximately 26 percent of the imports were used for thermal power generation. In Sweden, 1 percent of the imports were used for thermal power generation. In Italy, less than 16 percent of imports were for thermal power generation. For Belgium, France, and Spain, the data in Table 2 are insufficient to split imports between thermal uses and other uses. For 1976, the IEA estimated the splits as follows: Spain, 4 percent thermal; France, 49 percent thermal; Belgium, 34 percent thermal.[2] Germany's imports in 1977 are estimated at 90 percent thermal, and the United Kingdom's are estimated to be 50 percent thermal.[3] Based on these estimates, steam coal imports in these major countries amounted to approximately 36 MT in 1978 (see Table 4). Japan imported approximately 8 MT of thermal coal in 1978. Metallurgical and other hard coal imports equaled 41 MT in these European countries, and approximately 45 MT in Japan.

Also note in Table 5 the current distribution patterns of hard coal for Japanese and major European consumers. Japan's major suppliers are Australia, Canada, and the United States. For Europe, Poland, Australia, West Germany, South Africa, and the United States are the major suppliers. Note in particular the large European imports from Poland.

Table 4

Steam Coal Imports in Europe and Japan - 1978

(Million metric tons)

France	11.5
Japan	8.0
West Germany	6.3
Denmark	6.1
Finland	4.8
Belgium	2.4
Italy	1.9
The Netherlands	1.25
United Kingdom	1.2
TOTAL	43.45

Source: see text, pp. 6-7.

Table 5

Hard Coal Distribution Patterns--Europe and Japan,-1978

(Percent)

	Suppliers										
	Aust.	Can.	W. Germ.	Belg.	Pol.	Fr.	S. Afr.	Russia	U.S.	U.K.	Other
Demanders											
Jap.	48	21	1		1		5	5	17		2[1]
Fr.	7		29		20		30	4	6	4	
Germ.	12	5		1	32	4	17	2	10	10	7[2]
Den.	1				75		1	15	1	1	6
Belg.			47						30		
Ital.	11		19		25		7	9	26		3
U.K.	44		11		18			4	18		5
TOTAL											

Notes: 1. 1.5 percent China

2. Including Netherlands, Czechoslovakia

3. Example: Australia supplies 44 percent of Japan's imports.

Source: a. France, Spain, Italy from World Coal, "Annual Review," November, 1979.

b. Germany, United Kingdom from U.S. Department of the Interior, Bureau of Mines, International Coal Trade, February 1979.

c. Belgium, Denmark from Eurostat, Coal Statistics, Luxembourg, 1977.

With respect to thermal coal imports in 1976, the IEA estimated that approximately 50 percent of EEC Europe's third-party steam coal imports (24 MT total) are supplied by Poland, 13 percent by the United States, 3 percent by Canada, 7 percent by Australia, 14 percent by S.A., and 12 percent by the U.S.S.R.[4]

Table 6 presents a more detailed look at electricity consumption. The major consumers of electricity are the industrial, residential, and commercial sectors. In the OECD, 39 percent of electricity was consumed in industry in 1978, 26 percent in the residential sector, and 16 percent in the commercial sector. In Europe, 42 percent was consumed by industry, 25 percent by residences, and 13 percent by the commercial sector. Although a minor component of total consumption, the European transportation sector, principally the railroads, consumed 35444 million kilowatt hours (kWh) in 1978, or 2 percent of the total consumption. In Japan, 3 percent of total electricity consumption was by the railroads. In the United States, in contrast, electrification in the transportation sector is negligible. Other minor consumers of electricity are the agricultural and public service sectors.

As shown above, electricity generation is a major consumer of coal in the OECD. However, coal does not dominate all other inputs to electricity generation (see Table 7). In the OECD as a whole, 35 percent of electricity was generated by coal, 32 percent by oil and gas, 20 percent by hydro, 11 percent by nuclear, and a negligible amount by geothermal plants. The relative importance of coal varies geographically. In the United States, 45 percent of the electricity was

Table 6

Electricity Consumption in Europe and Japan by Sector

(Millions of kWh)

	Total Cons.	Energy Sector	Transp. Sector	Industry Sector	Residential Sector	Commercial Sector	Other
Jap.	563990	68301	14961	313767	112841	49122	4998
U.S.	2418708	372818	3497	814294	664412	458240	105417
Can.	324720	43496	-	119190	77410	78230	5420
Aust.	85982	17513	700	40581	27188	-	-
OECD Eur.	1638796	244688	35444	685893	415911	211228	45367
Aust.	35307	4815	2012	13246	8154	4065	3015
Belg.	48061	6715	907	23500	10462	5659	818
Den.	24462	3653	125	5330	7430	5660	2264
Fin.	37088	4638	155	19400	7760	4785	350
France	230980	32923	6681	91833	53891	41255	4397
Germ.	356515	51446	9500	143999	110420	32000	9150
Italy	177167	28241	5294	91269	334404	13384	4575
Neth.	62013	5999	720	29050	14150	10826	1068
Norway	78252	8883	600	38789	23000	3480	3500
Spain	98003	17908	1613	50645	15984	8792	3061
Sweden	91845	10796	2112	39559	21618	14260	3500
Switz.	37810	5464	2034	11004	8552	9712	769
Turkey	22215	4372	206	11315	2748	3107	467
U.K.	287613	50942	2971	93370	85802	48264	6264

Source: International Energy Agency, Energy Statistics, 1974/1978, Paris, 1980.

Table 7

Electricity Production by Fuel Type-1978

(Gigawatt Hours)

	Production	Coal	Oil	Gas	Nuclear	Hydro and Geothermal
Aust.	85982	62976	2692	5248	-	14537
Japan	563990	36175	330042	63413	59314	75046
Canada	345100	50624	13000	12870	31500	236370
U.S.	2400208	1077790	401579	336993	292987	289968
OECD Eur.	1636646	519418	316912	141621	167874	417780
Austria	38069	2475	4666	5411	-	24891
Belgium	50838	13544	17410	6622	12513	503
Denmark	20782	11167	9595	-	-	20
Finland	35810	11745	6399	1870	3320	9840
France	226692	63072	56413	6638	30485	69580
Germany	353429	196542	33846	66603	35942	18496
Italy	175041	9477	98732	10986	4428	49907
Netherlands	61597	7059	10586	38870	4060	
	81642		-142-*			81500
Spain	99853		-50388-**		7649	41497
Sweden	92853		-11355-***		23858	57640
Switz.	43204		1974		8395	32835
Turkey	21594	5540	6532			9358
U.K.	286506	188178	52874	4191	37224	4039

Notes: *142 = oil and gas
**50388 = coal, oil, and gas
***11355 = coal, oil, and gas

Source: International Energy Agency Energy Balances of OECD Countries, 1974/1978, Paris, 1980.

generated by coal versus 32 percent in Europe, and 6 percent in Japan. The role of nuclear power is close to constant across regions, contributing 10 percent in Europe, 12 percent in the United States, and 11 percent in Japan in 1978. Hydro generation amounted to 13 percent in Japan, 12 percent in the United States, and 26 percent in Europe. Oil contributed 59 percent in Japan, 19 percent in Europe, and 17 percent in the United States. Gas power contributed 11 percent in Japan, 14 percent in the United States, and 9 percent in Europe. Most striking is Japan's dependence on oil relative to Europe and the United States.

To summarize, several salient points in reference to Europe and Japan should be restated. First, coal is a large contributor to primary energy demand, but is a minor contributor relative to oil and gas in Europe and Japan. Second, major uses for coal are in thermal power plants and coking ovens. In Europe, more than half of coal consumption is in thermal power plants. In Japan, only 11 percent of coal consumption was in thermal power plants in 1978, while 77 percent of coal consumption was for metallurgical purposes. Third, though an important source of electric power, coal is dominated by other fuel inputs in Japan, particularly oil, and contributes only 32 percent of the power requirements in Europe. Fourth, thermal coal imports to Japan and Europe are currently exceeded by metallurgical coal imports: 36 million metric tons versus 41 million metric tons in Europe, and 8 MT versus 45 MT in Japan. Fifth, the largest OECD steam coal importer is France (11.5 MT in 1978). Following France are: Japan (8 MT); Germany (6.3 MT); Denmark (6.1 MT); Finland (4.8 MT); Belgium (2.4 MT); Italy (1.9 MT); U.K. (1.2 MT), and

the Netherlands (1.25 MT). No other European country imported more than 500,000 tons in 1978.

In the next chapter we will review some recent forecasts of how this structure of coal demand might evolve through the remainder of the twentieth century.

FOOTNOTES--CHAPTER III

[1]For this comparison, brown coal heating content was assumed at 50 percent of hard coal heating content. In fact, actual relationships vary from as low as 30 percent in Germany to as high as 60 percent. OECD conversions are presented in International Energy Agency, Energy Balances of OECD Countries: 1974/1978, Paris, 1980, pp. viii-xiii. Note that we use the "brown coal", "hard coal" classification only because the OECD does. "Hard coal" refers to Anthracite and Bitumous coal, and "Brown coal" refers to Lignite. The treatment of subbituminous coal is inconsistent. In Canada, it is included in the brown coal category. In the United States, it is considered "hard coal." With this exception, hard coal is "coal, generally of gross califoric value of more than 5700 kcal/kg", or approximately 22.6 Btu per metric ton.

[2]International Energy Agency, Steam Coal Prospects to 2000, Organization for Economic Cooperation and Development, Paris, 1978, pp. 139, 140.

[3]World Coal Study, Coal: Bridge to the Future, Ballinger Publishing Co., Cambridge, Massachusetts, 1980, pp. 232, 247. 1980.

[4]International Energy Agency, op. cit., p. 155.

CHAPTER IV

A REVIEW OF STEAM COAL DEMAND FORECASTS FOR WESTERN EUROPE AND JAPAN

INTRODUCTION

This chapter reviews several forecasts of international coal demand. It will show that with few exceptions existing estimates of coal demand are not very useful. Three fundamental reasons underly this conclusion. First, most of the international energy demand models do not approach the level of analytical sophistication seen in current U.S. energy demand models. Judgmental scenario building normally takes the place of developing consistent economic relationships. Second, energy demand models for individual countries outside the United States are equally unsophisticated. Though there are exceptions, the documentation for these exceptions is generally poor. Third, the energy demand models that are more reliable generally do not focus on steam coal markets, but rather on oil markets and aggregate primary energy deamnd.

Nonetheless, a brief review of several forecasts with steam coal demand outputs is important. Some of these forecasts are widely-publicized and a critique of their results is useful. Also, given the scope of international modeling efforts for coal, we must expect a lower level of sophistication than with domestic modelling efforts. Only by reviewing these forecasts can we determine the value of further demand research. Finally, if further research is justified, the existing studies provide a useful contrast to other results.

ENERGY DEMAND MODELING

Prior to this review, a brief discussion of energy demand modeling is useful as a foundation for the criticisms that follow.

Many methodologies have been used in recent years to estimate energy demand. Given our primary concern with steam coal demand for electricity generation, electricity models, or overall energy demand models which focus on interfuel substitution and incorporate electricity demand, are most useful.[1] Electricity demand models vary in several respects: the level of geographical and sectoral disaggregation, the behavioral model and assumptions, statistical and econometric techniques and data, and the incorporation of technological and policy variables. The more sophisticated theoretical models, though often less refined empirically, deal with the competition from other fuels and from new technologies. The essence of these demand models is to capture the consumption decision. Typically the models separate the consumption decision into two or more discrete steps. For example, the residential or commercial consumer first decides how much income to spend on energy, and then which fuels to use, subject to some objective function, normally cost minimization. The determinants of this choice process might include income, population, prices, and climate. The models are constructed so that the effects of shifts in these variables on electricity demand can be determined.

These models estimate the demand for electricity. The other problem is to estimate the supply of electricity. In this case very different

techniques have been applied. Most supply models incorporate four major elements: 1) investment in generating capacity; 2) investment in transmission and distribution networks; 3) production; and 4) pricing. The investment-in-capacity decision is typically represented by a capacity expansion model. Briefly, the utility estimates demand in a future period, and based on existing capacity, decommissioning and derating, and the anticipated shape of the load curve, determines the capacity needs for future generations, subject to some objective function (normally cost minimization). The transmission, distribution investment models develop the geographical distribution of generating capacity by trading off transmision and distribution costs with plant size and fuel acquisition cost factors. The production models determine how to generate electricity at the variable cost-minimizing level, given the existing plant mix and transmission-distribution system. The pricing models are developed to calculate the regulated price of electricity at given production levels.

These supply and demand models can then be integrated so that the effects of changes in prices, incomes, and policies can be factored into changes in fuel demand.

None of the current electricity models are ideal. Various compromises are made depending on the application of the model and data and financial constraints. None presents a complete general equilibrium system where a change in any variable is coordinated over time with changes in all interrelated variables. It is an impossible task to model every important factor simultaneously, dynamically, and endogneously. This can result in some inconsitencies between exogenous and endogenous

variables. Nonetheless, electricity demand models are a useful tool for developing a consitent and well-defined framework within which economic and policy changes can be analyzed. Let us proceed in reviewing some recent efforts at estimating steam coal demand worldwide. We will see that in most cases these studies are far inferior to the conceptual paradigm outlined above.

A REVIEW OF STEAM COAL DEMAND FORECASTS FOR WESTERN EUROPE AND JAPAN

The four major studies are: 1) World Energy Demand, by the World Energy Conference (WEC); 2) Coal-Bridge to the Future, Report of the World Coal Study (WOCO); 3) Demand for World Coal Through 1995, by the United States Department of Energy (DOE); and 4) Steam Coal-Prospects to 2000, by the International Energy Agency (IEA).

WORLD ENERGY CONFERENCE

The 1978 report, World Energy Demand, represents the coordinated efforts of university, government, and industry representatives worldwide. FOr the years 1985, 2000, and 2020, energy demand by sector and fuel are estimated for seven groups of countries: 1) North America; 2) Wetern Europe; 3) Japan, Australia, and New Zealand; 4) the U.S.S.R.. and Eastern Europe; 5) China and Centrally Planned Asia; 6) OPEC developing nations; and 7) non-OPEC developing nations.

The approach is essentially scenario building. Assumptions are made about energy demand and supply growth rates, and, based on one of several scenarios, future demand is extrapolated from current demand. For each scenarios, the demand forecast includes three stages.

First, total primary energy demand is estimated with a constant elasticity demand function linking energy demand to income and energy prices. Income eleasticities are set at 0.95 in the OECD, and at 1.1 elsewhere. Price elasticities are set equal to -0.3, and the assumed world income growth rate ranges from 3.0 percent to 4.2 percent annually.[2]

Second, if this estimate of primary energy demand exceeds exogenously determined supply levels (based on WEC reports), adjustments are made on the growth of oil demand in developing an "oil-constrained" forecast.

Third, given further inconsistencies, additional adjustments to fossil fuel demand are made in obtaining fossil fuel constrained forecasts. "Inconsistencies" refer in general to results inconsistent with accepted ad hoc projections.

Within this simple model, three energy price scenarios are constructed: 1) energy prices are constant in real terms; 2) real oil prices rise fourfold and average energy prices rise 80 percent between 1977 and 2020; 3) oil prices rise eightfold, while average enrgy prices increase by 120 percent. In both the second and third cases, estimated demand exceeds projected supply levels so that the second stage oil constrained forecast is used. In the oil-constrained forecast, demand projections are disagregated by sector and fuel, using constant

elasticity sectoral demand functions and assuming constant fuel shares within the sectors. Oil demand is then reduced according to various ad hoc assumptions. In the transport sector, car demand saturation and increased fuel efficiency are assumed. Feedstock demand is adjusted according to revised income elasticity assumptions. Fuel oil demand in the remaining sectors is lastly adjusted to meet supply constraints.

This stage equates supply and demand of fuel, but creates an inconsistency in other fuel shares as they have moved upward. In particular, as coal was substituted for fuel oil, coal demand levels exceeded WEC coal supply forecasts.

To adjust for this the fuel substitution model is used. The model specifies a preference for use of indigenous supplies and a preference order for fuels based on cost and convenience. It also restricts the rate at which one fuel may be substituted for another, as a reflection of inertia in market peneration. This third-stage adjustment yields consistent estimates of demand by fuel and sector.

WORLD COAL STUDY

The World Coal Study (WOCO) and its predecessor, the Workshop on Alternative Energy Strategies (WAES) forecasts are similar in many ways to the WEC forecast. They are the product of collaborative efforts between national groups, coordinated by Professor Carroll Wilson and staff. In brief, demand and supply are predicted for each country, given a number of assumptions.[3] The results are checked for consistency, and "gaps" are closed by a judgmental fuel adjustment model similar to

that used by the WEC. What makes the WOCO estimates more troublesome are the demand and supply forecasts themselves. Each is provided by a national team, and a wide range of methodologies are used, from econometric forecasts to energy balance projections. Although a specific set of assumptions is given to each country for the independent modeling efforts, the consistency among these diverse results must be questioned, but cannot be evaluated in detail due to inadequate documentation.

Given these national reports, demand and supply projections are integrated in various stages. The unconstrained integration simply compares supply and demand in each country and calculates the required exports and imports for each fuel. THese are then aggregated to check that required exports equal required imports. Imbalances are adjusted for the constrained integration with a fuel substitution model. In WAES, a linear programming model allocates fuel to various demand categories to minimize total fuel costs. In that fuel preferences are ignored, a big switch from oil to coal and nuclear obtains.

Comments on WOCO and WEC

The WOCO/WAES and WEC forecasts are not without merit. They offer a forum for analysts and policy makers in governments and energy industries to discuss the prospects for energy markets. In addition, they have provided some useful information for policy makers. In specific, they show that if prices do not rise dramatically, world fossil-fuel supplies might not meet future demand based on current prices.

Given their intentions, it might also be argued that criticisms on the basis of methodological sophistication are unwarranted. Nor does

criticism of specific details serve much purpose. If the studies are interpreted correctly as simply judgmental scenario building based on disequilibrium prices and quantities, their value should not be questioned.

In fact, however, these studies have been interpreted as forecasts of equilibrium prices and quantities. Accordingly, the basic deficiency in the fundamental economic logic underlying these studies must be noted. In essence, though the studies occasionally point out the infeasibility of certain scenarios, they typically repress the actual market mechanisms that would coordinate intertemporal shifts in prices and quantities. In the WEC study, for example, supply levels are not allowed to respond to increased prices so that an illusory "gap" develops, which is then narrowed by a series of ad hoc adjustments. Actually, this gap would not develop. Price responses would coordinate demand and supply levels over time. Though the authors of these studies seem basically to grasp this concept, the adjustments made to equate supply and demand may not reflect actual market responses.

Drawing simple inferences from disequilibrium prices about future equilibrium prices and quantities can be misleading if the reasons for the initial disequilibrium are not analyzed in detail. Policy makers should be particularly aware of this deficiency. The inference of "gapology" is that prices will rise sharply in response to gaps, when in fact markets could adapt over time and dampen price rises. Plans for developing alternative technologies, for example, formulated on the basis of sharp price increases, would clearly be endangered given different price paths.

To conclude, though these studies may provide some reasonable judgemental best-guesses about future energy needs, interpreting them as economic analyses that integrate supply and demand in a consistent and logical manner promises to be misleading.

INTERNATIONAL ENERGY AGENCY

The OECD and their affiliate, the IEA, have published several energy demand forecasts.[4] Though their analyses differ in assumptions and perspective, all their analyses are based on "energy balance calculations."[5] This methodology includes several steps. First, total energy and electricity demands are drawn from government forecasts and modified according to OECD/IEA assumptions, or calculated from simple projections of GNP and energy consumption based on constant energy/GNP elasticities. Second, estimates of indigeneous supply and net imports of solid fuels and gas are constructed, based on judgments and independent estimates. With the exception of oil, production plus imports is set equal to total energy supply. Third, subtracting non-fossil fuel electricity generation from total electricity demand yields the amount of electricity to be generated from fossil fuels. Typically, coal and gas estimates are based on government forecasts, and oil is ocnsidered a residual fuel. This yields the total energy supply for electricity. By subtracting total energy supply of all fuels other than oil from total energy demand, oil requirements are calculated. Finally, by subtracting oil production from total energy demand for oil, net imports are calculated.

In the IEA steam coal analysis, a different perspective was taken from other OECD reports.[6] In this case, oil is not used as a residual to close the gap. Rather, it is assumed that oil exporting countries will not make available the supplies of crude oil required to satisfy demand. Based on this non-price assumption, a "potential net world excess demand" is calculated. Coal, nuclear, and conservation efforts are considered as the most likely ways to close this gap. Two scenarios, "the reference case," assuming constant market and policy trends, and "the enlarged coal case," assuming policy actions in favor of coal, are projected.

The deficiences in this approach should also be clear. Though it provides a consistent and well-defined framework for analyzing energy supply and demand, the components of this framework are generally based on judgments, and the equilibrium is not price-responsive. As with WEC and WOCO, the exercise is more helpful to tell us what cannot happen. For example, the IEA scenario has demand growing on the basis of historical growth rates and supply expanding on the basis of constant prices. Clearly a "gap" will develop under this scenario. The IEA then considers how to fill this gap. Though the IEA at least notes that markets do not work this way, the concept of "gapology" is implicitly accepted in their analysis.

UNITED STATES DEPARTMENT OF ENERGY

A more sophisticated analysis of world coal markets was recently released by the DOE, Energy Information Administration. For the years

1985, 1990, and 1995, metallurgical and steam coal demands are calculated for OECD country groups: United States, Canada, OECD Europe, Japan, Australia and New Zealand.

The DOE analysis of coal markets draws from several models covering different aspects of international energy markets.[7] Though the exact interaction of these different models is unclear, the coal report notes that "the most significant contribution is from the International Energy Evaluation System." This is not one model, but a set of sub-models dealing with different facets of demand. As a group, the system forecasts energy prices and quantities for 33 international regions. The methodology is similar to the mid-range energy forecasting system developed in 1974 for the United States.[8]

More specifically, a demand curve is derived for each region and fuel with econometric fuel demand equations. Supply curves are based on a loosely defined process that relies primarily on technical analyses, judgements, and government estimates. Also included are a transportation and conversion submodel, a refinery model, and an electric utility supply model. Oil prices are determined exogenously in the oil market simulation model. These components are integrated in a linear program that minimizes the cost of supply. An equilibrium solution obtains through the price mechanism, which equalizes consumption to the sum of domestic production plus imports.

This analysis is clearly better formulated than any of the previous efforts. Though not as refined as some current U.S. demand models, it at least approaches the ideal model formulation described earlier. There

are particular problems, for example, GNP is exogenous and may be inconsistent with prices. But, in general, the forecast should be more reliable. However, the documentation of the component models and the integration of these models is either poor or nonexistent. Accordingly, it is impossible to evaluate them fully. It should also be noted that though the overall framework is consistent, some of the studies used as inputs to the model, in particular on transportation and supply, are seriously flawed.

ASSUMPTIONS AND RESULTS

All of the studies forecast demand under a variety of scenarios, each constructed under a wide-range of different assumptions. In some cases, the assumptions are poorly defined, for example, conservation and policy assumptions are typically specified only in general terms. In other cases, for example, income and price elasticities, assumptions are not documented. Consequently, care should be taken in interpreting the results summarized below. In all cases, the range of forecasts represents the extreme scenarios for a given study.

Some assumptions that are clearly defined and that are critical to demand forecasts are summarized in Tables 1 and 2. Average GNP, energy, and electricity demand growth rates are provided for the 1977 to 2000 interval. In all cases the growth rates decrease over time, so that the projected rate for 1977 to 1985 will be much higher than from 1990 to 2000. For example, IEA projects GNP growth rates at 3.9% from 1976 to 1985, 3.5% from 1985 to 1990, and 3.0% from 1990 to 2000. Some important

contrasts are the low oil prices assumed in the IEA analysis and the higher electricity growth rates calculated by the IEA relative to WOCO.[9] Note however that the WOCO estimates are based on energy inputs, while IEA's are based on electricity production. Consequently, if thermal efficiency rises, the difference would be reduced by a small amount.

The WOCO "high coal case" represents high growth rates, high oil prices, and lower rates of nuclear penetration. The IEA reference case considers normal market trends with one variation. "Low nuclear" corresponds to currently planned rates of nuclear power development, while "high nuclear" corresponds to faster rates. The IEA also develops an "enlarged coal case," which assumes greater policy incentives to coal development. The DOE high case assumes high growth rates, high energy supplies, and minimum conservation. The WEC high case assumes high growth rates and high oil prices. It should again be stressed that comparisons between the studies should be made carefully. The set of assumptions in one study's high (low) case may differ significantly from another study's high (low) case. It would be useful to compare forecasts with some consistency in this respect, but this proved to be impossible given the limited documentation.

Given these qualifications, the results of these studies are shown in Tables 3 through 10. The first four tables show coal's role in electricity generation for each of the four studies. Table 7 puts the different estimates on a comparable basis.

Table 1

Economic, Energy, Electricity Growth Rates (Annual Percent)

	GNP Growth			Energy Growth	Electricity Growth	
	WOCO	IEA	DOE	WOCO	WOCO	IEA
Japan	4.1-4.6	4.9	5.2-6.1	3.5-2.9	4.0-4.5	4.2
Japan, Aust., New Z.,		4.2				
Aust./ New Z			3.6-2.7			
Denmark	2.8-3.4	3.3		1.6-2.4	5.0-4.4	2.4
Finland	3.0-3.0	2.9		2.0-2.0	3.3-3.3	4.3
France	3.0-4.0	4.1		3.1-2.3	3.9-4.8	5.9
Germany	3.0-3.3	3.4		1.8-2.1	3.7-3.5	4.1
Italy	2.8-3.3	3.6		2.3-2.5	3.2-3.6	4.9
Nether-lands	2.2-3.0	2.9		2.0-2.7	2.0-2.9	3.5
Sweden	2.6-2.6	2.7		1.5-1.6	2.7-1.7	3.0
U.K.	2.0-3.0	2.3		0.7-1.7	1.6-2.5	2.1
OECD Europe	2.7-3.2	3.6	3.0-3.9			

Notes:

1. DOE based on 1976-1995 annual growth rates.
2. IEA based on 1976-2000
3. WOCO based on 1977-2000
4. "Electricity growth" represents the growth of energy inputs to electricity production for WOCO, and represents the growth of electricity production for the IEA.
5. "Energy growth" represents primary energy demand growth.

Table 1, Cont.

Sources:

a) World Coal Study, Coal: Bridge to the Future, Ballinger Publishing Co., Cambridge, MA, 1980.

b) International Energy Agency, Steam Coal: Prospects to 2000, Paris, 1978.

c) U.S. Department of Energy, Energy Information Administration, Demand for World Coal Through 1995, Washington, D.C., May, 1979.

Table 2

Oil Price Assumptions

	DOE[1]	WOCO[2]	IEA[3]
1985	$15.00-$17.00		$12.70
1990	$16.00-$21.00		
1995	19.50-$25.50		
2000	$25.00-$35.00	$25.00-$35.00	$18.40

Notes:

1. $1973, delivered price to U.S. East Coast.
2. Average oil price-all OECD countries. Delivered price to the United States.
3. 1977 dollars--Arabia, API 34° crude oil. 2 1/2 percent per year increase, 1985 to 2000.

Sources:

DOE, WOCO, IEA (See Table 1)

For Japan, each study forecasts large increases in coal use for electricity generation, both in absolute and relative terms. The WOCO "high coal case" estimates demand at 72 million tons of coal equivalent (MTCE) in 2000, versus 57 MTCE in the "low coal case." The IEA estimated range is approximately equal at 45 MTCE for the low nuclear reference case, and 75 MTCE for the high nuclear reference case.

In both studies the relative contribution of coal to power generation increases substantially from 1985 to 2000. For the IEA study, the increase is from 5 percent in 1985 to from 12 percent to 17 percent in 2000. For the WOCO study, the increase is from 6 percent in 1985 to from 15 percent to 17 percent in 2000. The DOE's estimates are slightly lower than WOCO's or the IEA's. In 1990, the DOE estimates 25 to 33 MTCE, in contrast to the IEA and WOCO estimates of 32 MTCE and 30 to 37 MTCE respectively. The main reason for this difference is the lower rate of coal penetration in the electric sector forecast by DOE. For 1990, WOCO forecasts coal penetration in the electric sector from 11 percent to 13 percent, versus 8.6 percent to 11 percent for DOE. It should be noted that the DOE estimates are in tons of coal. THe IEA and WOCO estimates are in tons of coal equivalent. Conversions are necessary for comparisons. For Japan, OECD adjustment figures are used.[10] For Europe, the adjustment is more complex, as we will see below.

The WEC only presents an estimate for total coal use for Japan, Australia, and New Zealand as a group. For the year 2000, they estimate coal use at 157 to 257 MTCE. The IEA estimate on this basis is 289 MTCE.

Forecasts for Europe differ to a greater extent. First, the WOCO and

IEA estimates are again approximately equal. For the eight countries that WOCO analyzed, they estimated consumption in 2000 at 222 to 327 MTCE, versus 237 to 322 MTCE by the IEA. Note, however, that the estimates for particular countries differ substantially, especially in Scandanavian countries. WOCO's estimate for Finland ranges from 4.2 MTCE to 8.9 MTCE in 2000, versus the IEA's estimated range of 2.4 to 3.4 MTCE. In Sweden, WOCO estimated a range of 7 to 15 MTCE, versus 0 to 1.6 by the IEA. In Denmark, WOCO's range is 8.6 to 18.9 versus 3.9 to 11.4 by the IEA. Table 8 provides a breakdown of fuel inputs into electricity generation as estimated by these two studies. Generally, the explanation for these differences is a higher rate of nuclear penetration assumed by the IEA for Scandanavian countries.

The DOE estimate for EEC Europe is especially difficult to convert from tons of coal to tons of coal equivalent. In partiuclar, the split between lignite and hard coal is not specified, and so the average conversion factors cannot be determined with certainty. In Table 5 one reasonable adjustment is made which assumes that lignite consumption in the EEC does not increase between 1976 and 1995. Virtually all lignite consumption is of coal produced in the EEC, and in fact it may well decrease in the future. On this basis, DOE estimates for EEC Europe are far below WOCO and IEA, as shown in Table 7.[11]

A safer comparison is the relative role of coal in power generation. From 1985, DOE estimates a large relative loss of coal generation in Europe. In 1985, 37.7 percent to 40 percent of the primary energy inputs into electricity generation are estimated to be coal, versus 25.2 percent

to 30.7 percent in 1995. In the IEA study, in contrast, coal maintains a 30 percent to 35 percent share to the year 2000. Note finally that the DOE shift is attributable to a greater role for nuclear power. Coal actually contributes a greater percentage of fossil fuel inputs in 1995 (55.3 percent to 60 percent) than in 1976 (49.7 percent).

With respect to imports, several points should be noted. First, in Japan's case, the differences in steam coal imports exactly parallel differences in steam coal use, since production approaches zero and exports are zero. In Europe, however, some differences should be noted. For France, WOCO estimates steam coal imports of 26 to 100 MTCE, versus 56 MTCE in the IEA low nuclear case. Table 9 provides some clarification of this. For electricity generation, the WOCO estimates are similar to the IEA's. However, WOCO projects a much greater demand for steam coal in industry (10 to 40 MTCE). The IEA's estimated demand for all uses other than electrical and metallurgical is only 10 to 25 MTCE, versus WOCO's estimate of 21 to 60 MTCE.

In Germany, the IEA projects 72 MTCE of steam coal imports, versus an estimated range of 20 to 40 MTCE by WOCO. In this case (see Table 9), higher coal use in electricity generation and in the metallurgical sector is assumed by the IEA. This is partially offset by WOCO's projections of greater industrial, residential, and synthetic fuels demand for coal.

In Italy, WOCO projects steam coal inputs in 2000 at 17 to 45 MTCE, versus 22 MTCE for the IEA low nuclear case. The difference is attributable to a high projected use of coal in the electric sector in WOCO's high coal case. As seen in Table 8, WOCO projects 32 percent coal

penetration in the year 2000, versus a high of 13 percent in IEA low nuclear case.

SUMMARY

For Japan, all of the studies project a large increase in coal use for power generation, but the DOE analysis estimates a significantly lower absolute level of consumption, and relative share for coal in power generation. The IEA and WOCO foresee coal use in 2000 at levels six to ten times higher than in 1977.

For Europe, WOCO and IEA estimate smaller increases in coal use for power generation, ranging from a 37 percent to a 100 percent increase by 2000, and no relative increase in coal inputs. Again, the DOE estimate is more conservative. They estimate a small increase in coal consumption, in absolute terms, from 1985 to 1990 and a decrease in relative terms; mainly due to the projected nuclear power increases in the EEC. However, they forecast an increase in EEC steam coal imports from 23 million tons in 1976 to 65-92.4 MT in 1995.

Note also steam coal export estimates in Table 8. Several points are important. First, Poland's role in steam coal export markets is not expected to grow substantially by WOCO and is actually expected to decrease by the DOE. Second, there is considerable uncertainty about the role of the United States in steam coal export markets. WOCO projects U.S. steam coal exports of 85 to 130 MTCE by 2000. The IEA low nuclear case estimates only 60 MTCE, and DOE estimates 24 to 50 MT in 1995. Third, there is also considerable uncertainty about Australia's role.

The IEA projects Australian exports in the year 2000 at 120 MTCE, versus 75 MTCE estimated by WOCO. The DOE, in contrast, estimates only 19 MTCE by 1995.[12] Fourth, the DOE study is more optimistic about Canadian exports than WOCO, and both studies project a large rate for South African exports.

Metallurgical coal markets are expected to expand less rapidly. For Japan and Western Europe as a whole, the projected increase in metallurgical use is approximately 23 percent between 1976 and 2000. Only WOCO analyzes other uses in detail. They estimate substantial increases in coal demand for synfuels (from a negligible amount to 20 to 110 MTCE in 2000) and industry (23 MTCE to 68-124 MTCE in 2000).

In general, factors favorable to coal consumption are high growth, high oil prices, low conservation, and slow nuclear power development. Note again, however, that different subsets of assumptions are used in each study. Consequently, comparisons between studies are risky, and given poor documentation, there is no precise way to specify the differences. Given the general flaws in the analyses, the rough specification of assumptions and methodologies, and the significant variations both within and between studies, the results of the WEC, WOCO, and IEA analyses give use little more than a reasonable speculation about coal demand in the future. The DOE analysis is certainly better formulated but also poorly documented. Any accurate assessment of the DOE results is impossible. Although the range of demand may be capture by these studies, certainly there is room for additional research to

obtain both better forecasts of demand, and, more important, a better understanding of the structure of demand in elecricity generation in Western Eurpoe and Japan. Chapter V will analyze further steam coal demand in two important countries, Japan and France.

Table 3

International Energy Agency Forecasts

		Coal Used in Electricity (MTCE)	Primary Energy Input (percent)	Steam Coal Imports (MTCE)
Japan	1985	13.9	5	13.7
	1990	32.1		33.1
	2000	45.3-75.7	12-17	76.5
Denmark	1985	6.0	70	7.6
	1990	4.3-9.1		10.8
	2000	3.7-11.4	31-97	13.4
Finland	1985	2.7	20	3.2
	1990	2.7		3.7
	2000	2.4-3.4	9-12	5.6
France	1985	15.9	14	17.9
	1990	17.3		24.9
	2000	23.7-42.6	9-17	55.8
Germany	1985	76.0	60-68	7.0
	1990	91.5		22.3
	2000	94.2-138.7	32-47	72.1
Italy	1985	8.3	1	8.3
	1990	12.9		12.7
	2000	16.4-21.4	10-13	21.6

Table 3, continued

		Coal Used in Electricity (MTCE)	Primary Energy Input (percent)	Steam Coal Imports (MTCE)
Nether-lands	1985	4.7	20	4.8
	1990	12.5		14.2
	2000	23.4-30.8	50-66	33.7
Sweden	1985	.0	0	2.4
	1990	.0		2.6
	2000	0-1.6	0-3	4.4
U.K.	1985	71.4	65	1.4
	1990	72.4		.0
	2000	74.7	50	.0
OECD	1985	227.7	23	63.0
Europe	1990	274.8		111.0
	2000	313.0-424.7	23-31	254.0

Notes:

1. Column 1- Reference case low nuclear, high nuclear. Where one number is given, the estimate is the same for both cases.

2. Column 3- Numbers for imports correspond to low nuclear case, i.e. high coal case.

3. OECD Europe includes EEC countries plus Greece, Iceland, Austria, Finland, Norway, Portugal, Spain, Sweden, Switzerland, and Turkey.

Source: International Energy Agency, Steam Coal: Prospects to 2000, OECD, Paris, 1978. Table 1-1, pp. 139.140. Table 1-2, pp. 141-143.

Table 4
World Coal Study Forecasts

		Coal Used in Electricity (MTCE)	Primary Energy Input (percent)	Steam Coal Imports (MTCE)
Japan	1985	13-14	6	6-7
	1990	30-37	11-13	24-33
	2000	57-72	15-17	53-73
Denmark	1985	10	85	11
	1990	13	90	14
	2000	9-19	31-92	9-21
Finland	1985	2	10	3
	1990	4	24	7
	2000	4-9	20-43	8-12
France	1985	12-25	11-21	11-34
	1990	10-30	8-20	14-51
	2000	10-45	6-21	26-100
Germany	1985	76-79	47-50	9-11
	1990	84-89	45-49	18-26
	2000	99-106	38-44	20-40
Italy	1985	10	13	10-13
	1990	9-19	11-20	11-20
	2000	17-38	16-32	17-46

Table 4, continued

		Coal Used in Electricity (MTCE)	Primary Energy Input (percent)	Steam Coal Imports (MTCE)
Nether-lands	1985	4	18	7
	1990	6-9	26-33	10-13
	2000	14-26	51-78	20-34
Sweden	1985	0-1	1-2	3
	1990	1-6	2-20	5-12
	2000	7-15	14-39	14-23
U.K.	1985	68-72	61-62	0
	1990	69-73	57-58	0
	2000	70-77	45-51	0-15

Notes: 1. Ranges reflect difference between the "high coal" and "low coal" cases.

2. Numbers rounded to million tons of coal equivalent.

Source: Report of the World Coal Study, Coal-Bridge to the Future Carroll Wilson, Director, May, 1980. Appendix 1, pp. 222-245.

Table 5

United States Department of Energy Forecast--Coal Demand[1]
(million metric tons)

		Coal Used in Electricity (MTC)	Fossil Fuel (percent)	Total Inputs (percent)	Net Imports(+), Exports (-) (MTC)
U.S.	1985	640.5-692.3	69.3-69.4	48.4-48.5	-20.1,-34.5
	1990	860.3-1017.3	82.7-83.2	53.9-56.0	-22.0,-41.7
	1995	1114.3-1340.7	88.2-96.9	54.7-62.6	-24.2,-48.6
Canada	1985	6.8-17.6	81.7-89.2	3.3-8.9	-10.6,-13.6
	1990	7.2-7.2	73.8-74.0	3.0-8.6	-9.0,-21.9
Japan	1985	14.6-19.5	7.7-8.7	5.1-6.6	20.5, 25.5
	1990	27.3-37.5	13.9-17.1	8.6-11.0	29.5, 42.7
	1995	40.9-56.9	17.5-20.6	10.2-12.7	44.7, 63.9
Aust/NZ	1985	45.0-48.3	89.4-89.6	59.9-62.2	-10.7,-11.9
	1990	39.9-42.0	88.2-85.5	58.0-58.3	-14.6,-14.6
	1995	36.1-39.0	81.5-77.4	49.1-52.8	-19.2,-19.2
EEC[2]	1985	272.3-301.6	61.4-63.1	37.7-40.0	49.7, 64.9
	1990	223.0-279.1	56.9-61.0	30.0-34.7	53.0, 72.5
	1995	216.0-292.0	55.0-60.0	25.0-31.0	65.0, 92.0
Other	1985	47.0-59.1	75.4-74.7	8.1-11.3	12.9, 19.2
OECD	1990	26.0-51.3	64.4-63.6	4.5-10.7	12.9, 19.2
	1995	22.2-37.3	70.6-54.0	3.3-7.5	6.0, 20.9

Notes:

1. Includes Lignite and hard coal.
2. Belgium, Luxembourg, Denmark, France, Germany, Ireland, Italy Netherlands, and the United Kingdom comprise the EEC.
3. High numbers refer to high growth, high non-OPEC energy resources, minimum conservation.

   Low numbers refer to low growth, low non-OPEC energy resources, high conservation.

Source: U.S. Department of Energy, Energy Information Administration, Demand for World Coal Through 1995, Washington D.C., May 1979.

Table 6

World Energy Conference Coal Demand

	Electricity (TWH)	Total Coal Demand (MTCE)
North American		
1985	2683-2926	643- 787
2000	4390-5854	1044-1459
OECD Europe		
1985	1707-1829	286- 329
2000	2805-3659	644- 844
Japan, Australia, New Zealand		
1985	610- 732	100- 100
2000	1341-1829	157- 257

Notes:

1. Low numbers represent scenario L4--Low growth, moderate conservation, high price response, oil constraint.
2. High numbers represent H4--High growth, moderate conservation, high supply prices, oil constraint.

Source:

World Energy Conference, World Energy Demand, IPC Science and Technology Press, N.Y., 1978, Appendix A.

Table 7

Coal Used in Electricity Generation

(MTCE)

		DOE	WOCO	IEA
Japan	1985	12-17	13-14	14
	1990	24-33	30-37	32
	1995	36-50		
	2000		57-72	45-76
Europe 8	1985		181-201	183
	2000		222-327	237-322
EEC	1985	174-200		190
	1990	131-180		208-224
	1995	124-191		
	2000			247-342

Notes: 1. The conversion to tons of coal equivalent from tons of coal for DOE extimates is as follows:

a. Japan: MTC x .88 = MTCE.

b. EEC: Lignite consumption is held equal to 1976 levels for each future period, at 127 million tons. Hard coal consumption is calculated by subtracting this from totals in Table 3. For Hard coal, MTC x .88 = MTCE; for lignite, MTC x .36 = MTCE. See IEA, Energy Balances of OECD Countries, 1974/1978, Paris, 1980. pp. vii-xii for conversion data. Hard coal and lignite consumption data are from IEA, Energy Statistics, 1974/1978, Paris, 1980.

Source: WOCO, IEA, DOE, (See Tables 1-3).

Table 8
Fuel Choice in Electricity Generation
IEA, WOCO

Country	Source	Coal (percent)		Nuclear (percent)		Oil and Gas (percent)		Hydro and Other (percent)	
		1976	2000	1976	2000	1976	2000	1976	2000
Japan	WOCO	4	15-17	7	47-49	73	26-28	16	18-21
	IEA	4	12-17	8	32-41	68	37-39	20	12
Denmark	WOCO	50	31-92	0	0-65	50	3	0	0
	IEA	50	22-63	0	0-56	50	7-8	0	0
Finland	WOCO	22	20-43	9	24-46	18	6	51	27
	IEA	22	9-12	0	50-64	28	3-5	34	16
France	WOCO	29	6-21	8	65-76	28	3-5	34	16
	IEA	33	9-17	7	65-66	35	4	24	14
Germany	WOCO	56	38-44	11	44-49	23	4-5	10	-
	IEA	60	32-47	8	35-57	25	5-12	8	6
Italy	WOCO	4	16-32	2	21-34	60	29-31	34	18-19
	IEA	6	10-13	2	36-51	60	26-39	32	12
Nether-lands	WOCO	8	51-78	8	4-30	84	13-15	0	-
	IEA	8	50-66	7	3-32	85	17-30	0	0
Sweden	WOCO	0	14-39	23	0-38	15	2-3	61	46-58
	IEA	0	0-3	20	41-52	13	4-11	67	45
U.K.	WOCO	66	45-51	14	39-47	19	8-10	0	0
	IEA	65	50	13	33-40	20	10-16	2	1

Notes: IEA low numbers refer to "high nuclear" case, high numbers to "low nuclear" case. WOCO's range corresponds to high coal, low coal cases.

Sources: WOCO, IEA. (See Table 1)

Table 9

Coal Use In Japan and Western Europe - 1976 to 2000

(Million Tons of Coal Equivalent)

Country	Source	Total Use		Electricity		Mat.		Synfuels	Industrial		res./comm.		IEA other
		(76)	(2000)	(76)	(2000)	(76)	(2000)	(2000)	(76)	(2000)	(76)	(2000)	(2000)
Japan	WOCO	79	150-224	6	57-72	69	89-92	0-48	4	7-12	0	0	
	IEA	83	200	7	76	69	114						7-10
Denmark	WOCO	5	9-21	4	9-19	0	0	0	1	1-2	0	0-1	
	IEA	4	13	4	11	0	0						1-2
Finland	WOCO	4	9-13	2	3-8	1	1	0	1	1	1	3-4	
	IEA	4	7	3	3	1	1						1-2
France	WOCO	45	48-125	22	10-45	14	17-20	3-10	3	14-40	6	4-10	
	IEA	45	82	19	43	16	15						10-25
Germany	WOCO	102	150-175	61	99-106	23	22-25	10-25	5	8-12	13	8-10	
	IEA	112	190	67	139	35	38						10-13
Italy	WOCO	14	32-61	2	17-38	11	12	0-8	0	3	1	0	
	IEA	14	38	2	20	10	14						2-5
Neth.	WOCO	5	23-38	1	14-26	3	3-4	1-3	0	3-4	0	1	
	IEA	4	38	1	30	3	5						1-4
Sweden	WOCO	2	17-26	0	7-15	2	3	1	0	3	0	3-4	
	IEA	2	7	0	2	3	3						1-3
U.K.	WOCO	109	133-179	65	70-77	18	16-21	4-13	9	28-47	17	15-21	
	IEA	102	120	63	74	20	24						118-23

Notes: 1. IEA estimates represent the low nuclear reference case.
2. "IEA other" column includes all non-electric, non-metallurgical uses.
3. IEA current estimates are from 1976.
4. WOCO current estimates are from 1977.

Source: WOCO, IEA

Table 10

Coal Exports
(MTCE)

		1976-1977			1995-2000		
		(Met)	(Steam)	(Total)	(Met)	(Steam)	(Total)
U.S.	WOCO	37	11	48	60-70	65-130	125-200
	IEA	43	10	53	70	60	130
	DOE	43	10	53	53-73	24-49	81-122
Aust.	WOCO	34	3	37	85	75	160
	IEA	28	3	31	75	120	195
	DOE	32	3	35	94-131	19	113-150
Canada	WOCO	10	1	11	23	4-24	27-47
	DOE	11	1	12	27-36	14-41	41-77
South Africa	WOCO			12			55-75
	DOE	1	7	8	25-27	46	71-73
Poland	WOCO			39			50
	DOE	11	28	39	5	23	28
USSR	WOCO			25			50
China	WOCO			3			30
West Germany	WOCO	17	5	22	15-20	0	15-20
India/ Indonesia	WOCO			1			5
Other	WOCO			7			25-50

Notes: IEA and DOE initial estimates are for 1976.
WOCO initial estimates are for 1977.
DOE final estimates are for 1995; others are for 2000.
DOE South African estimate includes India exports.

Sources: WOCO, DOE, IEA

APPENDIX A

OTHER STEAM COAL DEMAND ESTIMATES

There are a number of other forecast of coal demand for countries outside the United States. However, in most cases documentation is even less extensive than for the studies listed above. Consequently, a review of the results is not particularly useful.

Two studies do provide some useful comparisons, however. First, the Institute of Energy Economics (IEE) in Japan has developed an energy system model, with energy supply and demand and macroeconomic components.[1] Communications with IEE analysts provided only narrow insight into the actual methodology. For example, the demand model is based on econometric demand equations, and the fuel share mode is based on a linear programming model. The exact specification is unclear.

The IEE's most recent estimates appeared in March 1979, based on December 1978 data. Oil prices are assumed constant in real terms at 1978 levels. GNP is assumed to grow at 5.5 percent per year from 1978 to 1985, and 5.0 percent per year from 1985 to 1990. Energy growth is projected at 4.0 percent per year from 1978 to 1985, and 3.4 percent from 1985 to 1990. Electricity consumption grows by 4.6 percent from 1976 to 1985, and 4.9 percent from 1985 to 1990. Forecasts of electricity generation, fuel demand, and steam coal imports for 1985 and 1990 are presented in Tables A-1 and A-2.

Steam coal demand projections for 1990 are 20.23 MTCE, versus 30 to 37 MTCE for WOCO, and 24 to 33 for DOE. Note that the difference is

largely explained by the role of coal penetration for 1990. Nuclear power is assumed to take on a large role in the IEE study than in other studies, and coal is expected to take a smaller portion of fossil fuel inputs (11 percent as estimated by IEE, 14 percent to 17 percent as estimated by DOE).

Another set of demand estimates has been provided by the United Nations European Commission for Europe.[2] All the estimates are based on government reports submitted by each country to the United Nations. The results are summarized in Table A-3. In most cases, the results are close to previous studies. Two notable exceptions are the low coal forecast for France (5.4 MTCE in 1990, versus 10 to 30 MTCE for WOCO), and the increase in consumption predicted for the United Kingdom. In these estimates, nuclear and hydro power are estimated to account for 92 percent of France's power needs in 1990, versus 47 percent in 1975. These results suggest that special attention be paid to Japan and France in additional research.

Lastly, a Scandanavian utility group, Nordel, provides some insight into the differences between the IEA and WOCO coal penetration rates for these countries.[3] For Denmark, in 1990 Nordel projects that 88 percent of electricity wil be coal-fired, for Sweden, 4 percent, and for Finland, 12 percent. For both Sweden and Finland, the IEA estimates are equivalent to Nordels, while WOCO assumes considerably greater rate for steam coal. As we will see later, WOCO's may be closer in line with more recent nuclear power projections in Scandanavian countries.

Table A-1

Japanese Electricity Generation--Public Utilities
(Million KWh)

	1975	percent	1985	percent	1990	percent
Hydro	78.5	19.0	72.9	10.8	76.9	8.9
Thermal	309.6	74.9	462.0	68.2	558.9	65.0
Nuclear	25.1	6.1	140.3	20.7	220.8	25.7
Geothermal	--	--	1.8	0.3	3.4	0.4
Total	413.2	100.0	667.1	100.0	859.9	100.0
Total (including private sources)	475.2	115.0	760.8	112	966.1	112.0

Table A-2

Japan--Fuel Demand in Thermal Power Plants--Public Utilities
(MTCE)

	1975	percent	1985	percent	1990	percent
Coal	6.0	5.8	12.9	8.6	20.2	11.2
LNG	6.3	6.1	37.1	24.7	51.3	28.3
Oil	87.0	83.6	94.1	62.8	102.3	56.5
Other	4.7	4.5	5.8	3.9	7.2	4.0
Total	104.0	100.0	149.8	100.0	181.1	100.0

Steam coal imports are projected to be 7 MTCE in 1985, 14 MTCE in 1990.

Source: "Middle, Long-Term Energy Supply-Demand Projection-Forecast for 1985-1990," Energy In Japan, The Institute of Energy Economics, March, 1979. p. 49.

Table A-2

United Nations--Government Estimates

		Electricity (tWh)	Coal Use in Electricity (MTCE)	Capacity from Coal (percent)	Thermal Capacity (megawatts)	Steam Coal Inports (MTCE)
U. K.	1975	254	60	64	71472	4
	1980	279	68	69	76300	1
	1985	322	71	63	82400	0
	1990	373	83	63	95600	0
Belgium	1975	39	2	16	7682	1
	1980	48-52	3-4	19-21	8685	0
	1985	59-71	4-5	21-22	8900 to 9500	0
France	1975	179	12	18	26123	4
	1980	255	20	21	29000	13
	1985	340	10	8	30000	
	1990	420	5	4	26300	
Finland	1975	25	2	20	5013	5
	1980	39	3	16	8690	5
	1985	46	3	13	9460	6
	1990	56	4	14	11760	7
Germany	1975	302	55	53	65344	6
	1980	399	64	47	82900	
	1985	524	69	39	96900	
Neth.	1975	54	0	1	14562	4
	1980	66	3	17	18400	6
	1985	82	4	13	17900	7
	1990	90	8	27		11

Source: United Nations, Economic and Social Council, Economic Commission for Europe, Coal Committee, "The Use of Steam Coal in Power Stations," Eighteenth Session, Geneva, June 1978.

FOOTNOTES--CHAPTER IV

[1]See, in particular:

a. Wood, D.O. and Hoffman, U., "Energy System Modeling and Forecasting," in Annual Review of Energy, Vol. 1, 1976, pp. 423-453.
b. Hartman, R. "A Critical Review of Single Fuel and Interfuel Substitution in Residential Energy Demand Models," M.I.T. Energy Laboratory, Cambridge, Massachusetts, 1978.
c. M.I.T. Model Assessment Group, "Independent Assessment of Energy Policy Models: Two Case Studies," M.I.T. Energy Laboratory, Cambridge, Massachusetts, 1978.
d. Ulph, A.M., "World Energy Models--A Survey and Critique," in Energy Economics, Vol. 2, no. 1, January 1980, pp. 46-59.
e. Energy Modelling Forum, Coal in Transition, 1980-2000, Vols. 1 and 2, Stanford University Press, Stanford, California, 1978.
f. Turvey, R., Optimal Pricing and Investment in Electricity Supply, M.I.T. Press, Cambridge, Massachusetts, 1968.
g. Baughman, M. and Joskow, P., Electric Power in the United States: Models and Policy Analysis, M.I.T. Press, Cambridge, Massachusetts, 1979.
h. Pindyck, R., "The Structure of World Energy Demand," M.I.T. Energy Laboratory, Cambridge, Massachusetts, September, 1978.
i. Nordhaus, W., International Studies of the Demand for Energy, North-Holland Press, Amsterdam, 1977.
j. Griffin, J.M., Energy Conservation in the OECD, 1980 to 2000, Ballinger Publishing Company, Cambridge, Massachusetts, 1979.

[2]World Energy Conference, World Energy Demand, IPC Science and Technology Press, N.Y., 1978, pp. 31-43. Also used in this review are details provided by Ulph, op. cit.

[3]The WOCO Report (World Coal Study, Coal-Bridge to the Future, Ballinger Publishing Co., Cambridge, Massachusetts, 1980) does not describe in detail the methodologies or assumptions used. The comments below are based on more detailed materials produced during the course of the study, and direct communications with Michael Gallagher, Technical Director of the Report.

[4]See for example, OECD, World Energy Outlook, Paris, 1977.

[5]For a more detailed evaluation of energy balance calculations see:

Wood and Hoffman, op. cit., pp. 423-453. For a description of the OECD procedure, see OECD, World Energy Outlook, Annex B, 1977, pp. 102-106.

[6]See International Energy Agency, 1977, Steam Coal--Prospects to 2000, pp. 15-19 for details, Paris, 1980.

[7]The DOE report provides a very limited explanation of the methodology. Additional observations were drawn from Desouza, G.L., "International Energy Models in the Public Sector: A Critical Guide," The Journal of Energy and Development, Autumn, 1979, pp. 95-106 and direct conversations with Henry Weigel, the project director. U.S. Department of Energy, Energy International Administration, Demand for steam coal through 1995, Washington, D.C., May 1979.

[8]This model was formerly entitled "The Project Independence Evaluation System (PIES)." As noted, the studies used as inputs to the model are not specified in the report. It is known that the coal supply components were developed by ICF, Inc. Two of their reports are:

1. ICF, Inc. Coal Reserves and Production in Eight Major, Non-U.S. Coal Producing Countries, Dec. 1978.
2. ICF, Inc. Technical Analyses of Steam Coal Prices in Six OECD Countries, April 1979.

Both studies are admittedly rough. The transportation cost estimates, referred to earlier, are an indication of the type of approximations used.

[9]Note also the fact that expected oil prices were far below current oil prices after the Iranian disruption. As we will see below, coal-fired power was probably cheaper than oil-fired power even before this shift, so the importance is minimal. However, in these studies the estimates of coal use may have increased given the higher oil price assumption.

[10]The adjustment used is TC x 0.88 = TCE. This is consistent with the Btu content of coals used in Japan as of 1980. See OECD, Energy Balances of OECD Countries, 1974/1978, pp. viii-xiii, Paris, 1980.

[11]Conversations with the project director, Henry Weigel, indicated that the lower estimates are partly attributable to greater nuclear penetration assumed by the DOE study and partly to lower electricity demand growth rates assumed. The actual assumptions were not available.

[12]Note, however, that the DOE estimate for metallurgic! exports from Australia is considerably higher than the others. It is conceivable that coal traditionally classified as metallurgical, but used for steam generation in the future, is included in the metallurgical case. However, conversations with Henry Weigel, Project Director, indicated that this is not the case.

FOOTNOTES--CHAPTER IV--APPENDIX A

[1]The Institute of Energy Economics, "Middle, Long-Term Energy Supply-Demand Projection Forecast for 1985, 1990," in Energy in Japan, March 1979, pp. 34-35.

[2]United Nations, Economic and Social Council, Economic Commission for Europe, Coal Committee, "The Use of Steam Coal in Power Stations," 1978.

[3]Nordel, Annual Report, Elsam, Denmark, 1978, pp. 38-42.

CHAPTER V

A STEP TOWARDS A BETTER UNDERSTANDING OF FUTURE STEAM COAL DEMAND IN WESTERN EUROPE AND JAPAN

INTRODUCTION

Ideally we would like to estimate an integrated electricity supply/demand model for Western Europe and Japan, similar to the description above. However, this is beyond the reaches of this thesis. Data limitations and uncertainties encountered by this author prohibited a rigorous electricity demand model. Instead, this chapter attempts to further our understanding of future steam coal demand in Western Europe and Japan, and to serve as a cross-check on other estimates by analyzing the economics of power generation, and the possible patterns of electricity generation capacity expansion in two major countries, Japan and France. We make no effort to model steam coal demand rigorously. However, with the available data we can isolate and thereby clarify major uncertainties in the development of steam coal trade.

There are several fundamental uncertainties underlying thermal coal demand. First, at what rate will electricity demand grow. Second, given the levels of electricity demand, what will the demand for steam coal be in the future. Clearly these are interdependent issues, and consistency between the two must be considered. However, in this rough analysis we will basically segment the two issues by taking electricity demand as exogenous, and then analyzing in detail electricity supply choices for given demand levels.

There are several reasons for this approach. First, data and financial constraints do not allow for the estimation of an integrated electricity model. Second, electricity demand in Western Europe and

Japan has been estimated by others. In contrast, electricity supply has not been analyzed at the level of detail that we can now provide.

The key is to recognize possible inconsistencies between the exogenously determined electricity demand levels and the endogenously determined electricity supply decisions. Electricity demand growth depends to some extent on electricity prices so that to use very high price levels with a given very high demand level would be misleading. However, this is more a problem of interpretation than of inherent inconsistency. Our goal is not to generate a point estimate of coal demand. Rather, it is to analyze electricity supply choices at various electricity demand levels. In essence, we acknowledge the range of possible electricity demand growth rates and leave the explanation for this range as a function of electricity prices, economic growth, etc., unresolved, while concerning ourselves instead with the specifics of electricity supply choices.

The simplified approach, modified for data constraints and uncertainties, is as follows. First, the economics of power generation will be analyzed for France and Japan. Second, based on the range of projected electricity demand growth rates, peak load demand will be calculated for the year 2000. Third, peak load demand will be translated into installed capacity requirements based on historical peak-load reserve margins. Fourth, existing capacity will be subtracted from required capacity in 2000. Fifth, derating and decommissioning of existing capacity will be estimated and added to required capacity for 2000. This will yield capacity expansion needs for 2000. Sixth, based on an assessment of the

power generation cost estimates, the annual load duration curves, the existing plant mix, and the plants on order, the characteristics of new capacity will be approximated according to various assumptions.

Recognize fully the deficiencies of this approach. Even the most refined capacity expansion models are flawed in some respects.[1] This simplified approach suffers from more severe data limitations. The estimated costs of power generation are very imprecise. Consequently, an electricity supply model that allocates capacity to various fuels on the basis of exact power generation economics is likely to be misleading, and we are forced to use a less rigorous methodology. Certain factors, such as load curve shape and thermal efficiency, are assumed to be constant over time. Other variables, such as decommissioning and derating of power plants, and hydro plant capacity factors can only be roughly approximated. In addition, by ignoring production decisions, the estimates of coal consumption could be misleading. The demand for coal generation could shift enormously with changes in production and operating conditions. Nevertheless, the exercise provides a foundation for analyzing certain critical variables and at least a better understanding of steam coal demand.

COSTS OF POWER GENERATION

This subsection provides a rough-cut estimation of power generation costs. In general, the data are inadequate for precise calculations, and significant uncertainties exist. Nevertheless, some reasonable

conclusions can be formed from the available materials.

First, consider power generation costs in the United States. Three main conclusions dominate the literature: 1) oil- and gas-fired thermal power is more expensive than coal-fired power, even at 1977-78 oil price levels. Recent oil price increases have only amplified the difference in power generation costs; 2) nuclear power has had a narrow cost advantage over coal-fired power at current coal prices for baseload plants. However, the cost differential is small, and has eroded as constraints on nuclear power plants development have increased; 3) gas turbines are still the cost-minimizing choice for peaking plants (utilization rates are generally less than 10 percent).

Joskow, among others, has substantiated these conclusions.[2] Table 1 presents his estimates of capital, operating and maintenance, and fuel costs for each plant type in future years. The most significant variables are fuel cost and capital costs.

Nuclear capital costs are 26 percent greater than coal capital costs in 1980, and 46 percent greater than oil capital costs. However, given utilization rates above 60 percent, the lower nuclear fuel costs offset this disadvantage. Note the low capital costs for gas turbines. Given very low utilization rates this difference dominates any conceivable disadvantage of higher fuel and maintenance costs for gas turbines. Note also that coal capital costs include scrubbing costs of approximately $120/kW in 1985 dollars, and that nuclear capital costs are based on normal engineering and financial lead times as opposed to allowing for political and legal constraints.

Table 2 calculates the costs per kWh based on these estimates. First, coal and nuclear economics are compared in 1985, based on 17 percent annual capital charges, and 70 percent utilization rates.[3] In regions where coal is expensive, for example, the Middle Atlantic region, nuclear power has a significant advantage. However, in other regions where coal is cheaper, this advantage is reduced. In the cheapest coal region, the mountain states, coal generation is actually cheaper than nuclear power. Another factor mitigating the nuclear cost advantage is the fact that nuclear utilization rates rarely exceed 60 percent. As the realized utilization rate decreases, the economic advantage of nuclear plants will similarly decrease.

Also in the table is a comparison of oil and coal plants in 1985 (1985 $). A utilization rate of 30 percent is assumed. The oil price assumed is $26 per barrel in 1985, far below the likely price level given recent develdopments in the Middle East. In this comparison we assume the high Middle Atlantic delivered coal price. Nonetheless, even given these assumptions, coal-fired power plants are considerably cheaper than oil-fired plants.

Other estimates of power generation costs differ in some variables. In specific, the capital costs of power generation, both for coal and nuclear, are generally higher. Nonetheless, the conclusions are similar. Coal and nuclear are closely competitive, even with scrubbers on coal-fired plants, and both are considerably cheaper than oil-fired plants.[4]

Data on foreign power generation costs are sparse, but similar

Table 1

U.S. Costs of Power Generation

a. Power Plant Capital Costs--New England

($ per kW, nominal dollars)

	Coal	Oil	Natural Gas	Nuclear	Gas Turbines
1980	591	511	395	746	179
1985	772	714	516	997	251

Source: Baughman, M., et al., Electric Power in the United States: Models and Policy Analysis, MIT Pres, Cambridge, Mass., 1980, p. 242.

b. Operating and Maintenance Costs

(Mills/kWh, nominal dollars)

	Coal	Oil	Natural Gas	Nuclear(LWR)	Gas Turbines
1980	3.40	3.01	2.61	1.72	3.92
1985	4.44	3.93	3.42	2.22	5.12

Notes: Inflation is assumed at 5.5 percent annually.

Source: Baughman, et al., op. cit., p. 244.

Table 1 (continued)

c. Fuel Costs-Mid-Atlantic
(nominal dollars)

	Nuclear Fuel Cycle Costs (Mills/kWh)	Oil ($/barrel)	Coal ($/short ton)	Gas (cents/mcf)
1975	3.2	9.92 (1.65)	25.57 (1.07)	176.5 (1.72)
1985	9.58	26.18 (4.36)	47.64 (1.99)	361.0 (3.52)

Notes: 1. Numbers in parentheses equal $/MBtu. The conversions are based on the following heating values:

2. a. 6 MBtu/Barrel of oil

3. b. 24 MBtu/short ton coal

4. c. 1025 Btu/cubic foot gas

Source: Baughman et al., op. cit., p. 240 and pp. 248-250.

d. Current Delivered Fuel Costs-1977
($/MBtu)

	Oil	Gas	Coal
New Jersey	2.30	1.80	1.40
Ohio	2.60	1.40-1.70	1.00
Pennsylvania	2.90		1.00
California	2.40		1.70-2.30

Source: Edison Electric Institute, Steam Electric Plant Factors, 1978 Edition.

Table 2

A Comparison of U.S. Power Generation Costs in 1985

a. Coal versus Nuclear--Baseload Plant, Mid Atlantic

($1985, Cents/kWh)

	Coal	Nuclear
O + M	.44	.22
Fuel	1.40-1.99	.96
Capital	2.26	2.93
Total	4.10-4.69 cents/kWh	4.11 cents/kWh

Assumptions: 70 percent utilization

17 percent annual capital costs

Heat rates: coal-10,000; oil, 10,000; nuclear 10,500; gas turbine 11,000

b. Oil versus Coal-Cycling Plants
($1985, Cents/kWh)

	Oil	Coal
O + M	.39	.44
Fuel	3.90	1.99
Capital	4.60	5.00
Total	8.89 cents/kWh	7.43 cents/kWh

Assumptions: 30 percent utilization

Source: Authors calculations are based on data provided in Baughman et al., op. cit., 1980.

conclusions are typical. In Great Britain, the British Department of Energy studied the economics of power generation in 1977.[5] Capital costs of power plants in the 1977 pound were estimated as:

Coal: 290 pounds/kW

Steam-generating heavy water reactor: 525 pounds/kW

Advanced gas-cooled reactor: 470 pounds/lW

Pressurized water reactor: 407 pounds/kW

Coal capital costs thus range from 56 to 71 percent of nuclear costs. The difference between these costs in Great Britain and the United States is probably attributable to the exclusion of scrubbing capital costs. At the existing coal prices (.33 pence/kWh in 1977), coal-fired power generation had a cost advantage on all types of nuclear power generation. This price per kWh is approximately equal to 82 cents/MBtu coal. As the coal price increased to .52 pence/kWh (1.30/MBtu), nuclear power is cheaper for base-load power generation.

In West Germany, a 1978 study by the Energy Economic Research Institute of Cologne University also compared the economics of coal with nuclear power generation.[6] Where load factors exceed 46 percent, nuclear power is cheaper than coal fired power in 1985 by significant margins. However, the assumed coal price was 155 DM/ton, or approximately $88/ton, which is the domestic coal price. At imported coal prices, coal would be very competitive with nuclear power at higher load factors. Note however that this study does not specify the treatment of scrubbing equipment. If scrubbing costs are included, then nuclear power would maintain an advantage even at imported coal prices.

In Japan, similar conclusions obtain but certain estimates differ in significant ways. Specifically, the relative capital costs are different. In the United States, as noted, coal capital costs (with scrubbers) are 80 to 87 percent of nuclear capital costs. In Japan, the estimated percentage (also with scrubbers) is 64 to 70 percent. An IEE study notes this difference, but offers no explanation.[7] It is possible that the limited experience in Japan with coal-fired plant construction accounts for this uncertainty, and in fact the difference between coal and nuclear capital costs will be similar to the difference in the United States.

In Table 3 we compare the cost of nuclear power with coal-fired power in 1979. The nuclear power data were provided by Chuba Electric and are based on 1979 costs. The coal plant capital costs are based on the high end of the ratio of coal plant to nuclear plant capital costs estimated by the IEE, 70 percent. The price for coal is equivalent to approximately $40 per metric ton. A utilization rate of 60 percent is assumed. Based on these assumptions, coal-fired power is closely competitive with nuclear power. If, however, the ratio of coal-fired plant capital costs to nuclear plant capital costs is higher, nuclear power would gain an advantage.

Another difference in the Japanese estimates is the ratio of oil capital costs to coal capital costs. Coal capital costs are estimated to be 1.4 to 1.5 times oil plant costs. This narrows the advantage of coal versus oil that was demonstrated in the U.S. case. In Table 3 calculations on oil versus coal are shown. For new plants, in $1978, at

a 50 percent utilization, oil is slightly less expensive than coal. However, this is based on the low oil prices in 1978. Also in the table are calculations for oil priced at $25/barrel. In this case, even at 30 percent utilization, coal is considerably cheaper than coal.

Finally, let us consider the economics of power generation in the light of delivered coal prices calculated in Chapter III. In Japan, all coal except that from the U.S. East and Gulf Coasts would be cheaper than oil. Coal from Australia, South Africa, and Canada would be closely competitive with nuclear power if coal plant capital costs are really as inexpensive relative to nuclear plant capital costs as the Japanese data indicate. The calculation in Table 3 imputes a coal price equivalent to the coal prices from these countries, including $3.00 per ton for local handling. If, on the other hand, coal capital costs are as much as 80 percent of nuclear capital costs, not even the cheapest Australian coal would compete with nuclear power. Additional data is necessary to clarify this uncertainty.

In Western Europe, the range of coal prices C.I.F. piers is $1.38 to $1.90/MBtu. The power generation cost data are inadequate for drawing firm conclusions. However, a reasonable inference is as follows. First, any coal-fired power will be cheaper than oil-fired power. Second, the cheapest coal will be competitive with nuclear power at coastal power stations, even with scrubbers. Third, as coal prices increase over the range noted above, nuclear power will be cheaper than coal-fired power even at coastal sites. Given the high price of European inland transportation (see Chapter VI, Part A), the likelihood of even the

Table 3

A Comparison of Japanese Power Generation Costs

a. Coal versus Nuclear, 1978 New Plants
(cents/kWh)

	Coal	Nuclear
Fuel	1.50	.36
Capital	2.3-2.8	3.3-4.0
Total	3.8-4.30	3.66-4.36

Assumptions: 60 percent utilization, 19 percent annual capital costs.

b. Oil Versus Coal--1978 New Plants
(cents/kWh)

	Oil	Coal
Fuel	2.20	1.35
Capital	2.26	3.16
Total	4.46	4.54

Assumptions: 50 percent utilization, $14 per barrel oil price

Source: Author's calculations.

c. Oil Versus Coal--1978 New Plants
(cents/kWh)

	Oil	Coal
Fuel	3.75	1.35
Capital	3.76	5.26
Total	7.51	6.61

Assumptions: 30 percent utilization, $25 per barrel oil price

Source: Author's calculations.

cheapest imported coals competing with nuclear power at inland sites is small.

Given these general conclusions, the next section will consider capacity expansion in France and Japan.

CAPACITY EXPANSION IN JAPAN AND FRANCE

As noted above, the uncertainties in power generation costs suggest that rigorous demand models that allocate capacity on the basis of exact power generation cost economics are likely to be misleading. However, with the available data on the existing structure of electricity demand, we can isolate and thereby clarify major uncertainties in the development of steam coal demand. As discussed above, two issues will be highlighted in the analysis: 1) the rate of electricity demand growth; and 2) the allocation of capacity expansions over different plant types. More specifically, three dimensions are taken as variable: 1) growth rates in electricity demand; 2) nuclear penetration in the electric sector; and 3) the allocation of non-nuclear plants between coal and oil or gas.

JAPAN

For Japan, electricity demand growth rates of 4 percent and 6 percent are taken as extremes for the 1977-2000 period. The high rate is based on actual growth rates from 1970 to 1976 (see Tables 4 and 5). Note that this compares to a growth rate in electricity production of 12 percent between 1960 and 1970. However, most analysts predict that even

Table 4

Electricity Production Growth Rates

(Actual Percent)

	1960-1970	1970-1976
U.S.A.	6.90	3.50
Japan	12.00	6.00
West Germany	7.40	5.44
U.K.	6.16	1.80
France	6.95	5.46
Italy	7.65	5.79

Source: Overseas Electric Industry Survey Institute, Inc., "Electric Power Industry in Japan," 1978, p. 7, Table 1.

Table 5

Japan-Electricity Growth Rates

(Percent)

	1960-1970	1970-1976	1977-1978
Peak load	11.23	8.30	6.20
Peak capability	11.60	10.30	6.16
Production	12.00	6.00	5.60

Notes: 1977-78 growth rates projected based on decided plants, as of January 1, 1979.

Source: a. Japan Electric Power Survey Committee, "54th Semi-Annual Power Survey," Tokyo, Japan, April, 1979.

b. Overseas Electric Industry Survey Institute, Inc., "Electric Power Industry in Japan," Tokyo, Japan, 1978, p. 7.

the 1970's rate of 6 percent will not be matched in the last part of the 20th century. The 4 percent rate allows for a gradual decline in the growth rate of electricity demand from 1977 to 2000, reaching as low as 3.0 percent in the last 5 years of the century.

Three nuclear penetration assumptions are made. The first assumes 20 percent of the capacity in 2000 will be nuclear. This is equivalent to the percentage of capacity that is planned for nuclear plants in 1988.[8] The middle assumption is 30 percent by 2000. The high assumption is 40 percent. Which level actually obtains is more a function of politics than economics. As noted above, the costs of nuclear power are very close to the costs of coal-fired poer. Given this, and given the public resistance to nuclear power in Japan, it is unlikely that more than 30 percent of the total capacity in 2000 wil be nuclear power. However, if nuclear power continues to penetrate the electric sector in the 1990's at the rate planned for the 1980's, a contribution of as high as 40 percent is possible. Note that based on the 1976 load duration curves, approximately 50 percent of the installed capacity is used more than 57 percent of the year.[9] Consequently, 40 percent penetration means that the vast majority of baseload power will be generated by nuclear plants.

Peaking plants, used less than 1000 hours per year, are assumed not to be coal or nuclear. The existing percentage of total capacity which is used for peak service is 16 percent.[10] Hydro capacity currently accounts for 22 percent of existing capacity. Projections for 1988 show a decrease to 20.8 percent. We assume 20 percent hydro capacity in

2000. Unfortunately, it is difficult to determine the percentage of hydro capacity used to serve peak demand. Based on a detailed listing of non-hydro plant load factors, non-hydro plants contributed 31 percent of peaking (<1000 hours) capacity, indicating 67 percent of peaking capacity was provided by hydro plants.[11] Thus, approximately 50 percent of the hydro capacity is assumed to be peaking plants. (In other words, 11 percent of total capacity is hydro-peaking capacity.) The residual non-peaking conventional thermal capacity additions are assumed to be met by all coal, or 50 percent coal and 50 percent oil and gas.

Derating and decommissioning of power plants is more difficult to specify. Projections to 1988 suggest that virtually none of the existing cpacity will be decommissioned by this time.[12] A reasonable figure for the entire period is a loss of one percent per year.[13]

Table 6 presents these rough calculations. The broadest conceivable range of steam coal demand increases for electricity generation is 18 MTCE to 219 MTCE. The most likely scenario would be 30 percent nuclear penetration, 5 percent electricity demand growth rates, and 50 percent of new conventional thermal plants being coal fired. Based on these assumptions, coal consumption increases to the year 2000 would amount to 59 MTCE. Total consumption would be approximately 65 MTCE. Note that this is consistent with the WOCO range of 57 to 72 MTCE in 2000.[14]

FRANCE

This section presents similar calculations for France. In this case, an electricity demand growth rate range of 4.0 tO 5.5 percent is assumed.

Table 6

Increments to Steam Coal Demand in Japan--1977 to 2000

	High Growth Rate				Low Growth Rate			
	100% Coal		50% Coal		100% Coal		50% Coal	
	(MW)	(MTCE)	(MW)	(MTCE)	(MW)	(MTCE)	(MW)	(MTCE)
Low Nuclear	138552	(219)	69276	(110)	69537	(109)	34769	(55)
Medium Nuclear	102524	(162)	51262	(81)	46289	(73)	23145	(37)
High Nuclear	66496	(104)	33248	(52)	23041	(38)	11520	(18)

Note:
1. High growth rate = 6.0 percent annual.
   Low growth rate = 4.0 percent annual.
2. Low nuclear = 20 percent total capacity in 2000
   Medium nuclear = 30 percent
   High nuclear = 40 percent
3. 100 percent (50 percent) coal case means that 100 percent (50 percent) of non-peaking conventional thermal plant additions will be coal-fired.
4. 50 percent utilization is assumed.
5. Current coal demand is 8 MTCE.
6. Hydro capacity is 20 percent of total capacity in 2000. We assume that 50 percent of the hydro capacity is used to serve the peak load.
7. Heat rating = 10,000.
8. Peaking capacity (<1000 hrs. utilization) is assumed to equal 16 percent of total capacity.
9. Example: If electricity demand grows at 6 percent per year in 2000, and if coal plants amount to 50 percent of non-peaking conventional thermal plant additions, then coal demand in 2000 will be 81 MTCE per year.

Source: Author's calculations. See text.

Table 7

Existing Coal Plants in Japan, 1979

Company	Plant (units)	Fuel	Date	Capacity (10^3kW)	Net Generation (10^9kWh)	Utilization (percent)
Hokkaido	Takigawa (3)	c/o	1960-62	225	1.39	70.3
	Sunagawa (3)	c/o	55,58,77	195	.96	56.1
	Ebetsu (3)	c/o	63,65	375	2.49	75.8
	Naie (2)	c/o	68,70	350	2.58	84.1
Tohoku	Hachinoe (4)	c/o	58	650	3.22	56.5
	Sendai (3)	c/o	59,61	525	1.60	35.1
Chogoku	Sanban (4)	c/o	36,39	76	4.00	0.6
	Shimonoseki (2)	c/o	67,77	575	4.10	81.3
Kyushu	Karita (5)	c/o	56,59 67,72	982	2.02	23.5
	Minato (2)	c/o	60,60	312	1.06	38.8
EPDC	Isogo (2)	c	67,69	530	3.54	76.2
	Takasago (2)	c	68,69	500	3.37	77.0
	Takehara (2)	c/o	67,64	600	3.72	70.7
	Wakamatsu(2)	c	63	150	.12	9.1
				6045	34.18	

Source: Unpublished data provided by Tokyo Electric Power Company, 1979.

The high figure is based on actual growth rates from 1970 to 1977. The low figure allows for a gradual decline in electricity growth rates in the 1990s.

Again, three nuclear penetration assumptions are made. The first assumes that 12 percent of total capacity in the year 2000 will be nuclear power plants. This is equal to the 1978 percentage. The second and third cases assume 25 and 50 percent nuclear capacity. The latter figure is closest to planned nuclear penetration by EDF.[15] Whether or not it obtains is uncertain. Public resistance to nuclear power is strong in France, but EDF has not recently cut back their nuclear projections for the future.

Peaking plants used less than 100 hours per year are assumed not be to coal or nuclear. Thirteen percent of total capacity is currently used for peaking plants (less than 1000 hours). Hydro capacity currently accounts for 34 percent of total capacity. We assume a decrease to 20 percent by 2000. As for Japan, it is difficult to determine the percentage of hydro capacity used for serving the peak. Based on capacity factors for different types of peaking plants, it is assumed that 50 percent of the peak load is served by hydro plants.[16] Nonpeaking conventional thermal plant additions are allocated both evenly between coal and oil or gas, and exclusively to coal. Derating and decommissioning could not be specified with any accuracy. As for Japan, a 1 percent per year loss was assumed.

The estimates for steam coal demand in France in 2000 are summarized in Table 8. For the 50 percent nuclear assumption, the range is 6.5 to

Table 8

Increments to Steam Coal Demand in France--1977 to 2000

	Low Growth Rate				High Growth Rate			
	100% coal		50% coal		100% coal		50% coal	
	(MW)	(MTCE)	(MW)	(MTCE)	(MW)	(MTCE)	(MW)	(MTCE)
Low Nuclear	57170	(90)	28585	(45)	88640	(140)	44230	(70)
Medium Nuclear	40530	(64)	20265	(32)	65348	(103)	32674	(52)
High Nuclear	8530	(13)	4265	(6.5)	20555	(33)	10277	(17)

Notes:

1. High annual growth rate in electricity demand = 5.5 percent
   Low annual growth rate = 4.0 percent
2. Low nuclear = 12 percent of total capacity in 2000
   Medium nuclear = 25 percent
   High nuclear = 50 percent
3. 100 percent (50 percent) case means that 100 percent (50 percent) of non-peaking conventional thermal plant additions will be coal-fired.
4. 50 percent utilization is assumed.
5. Heat rating = 10,000.
6. Peaking capacity (< 1000 hrs. utilization) is assumed to equal 13 percent.
7. Hydro capacity equals 20 percent of total capacity in 2000. 50 percent of the peak load is served by hydro capacity.

Source: Author's calculations.

33 MTCE. There is not sufficient data to estimate the consumption of existing coal-fired plants in the year 2000. A rough approximation is 8 MTCE. The total coal demand range would thus be 14.5 to 41.0 MTCE. WOCO's range for France in 2000 is 10 to 45 MTCE.

To conclude, this rough analysis does not significantly contradict the range of steam coal demand estimates in Chapter IV. The analysis does, however, serve to clarify this range by relating capacity expansion to different assumptions on electricity demand growth rates, nuclear penetration, and the allocation of non-nuclear plants between coal and oil or gas. In further research, this methodology could be refined. In conjunction with a better understanding of power plant economics, and a clearer picture of the political-economic environment surrounding nuclear power development, a more rigorous projection of steam coal demand could be developed.

APPENDIX A

SULFUR EMISSION REGULATIONS

Sulfur dioxide regulations should be considered for two reasons. First, the additional costs of sulfur control might handicap coal versus nuclear or oil power generation economics. Second, sulfur controls, or the lack of controls, may be important in determining coal supply patterns. In particular, if sulfur regulations exist, the competitive position of Eastern and Midwestern high and medium sulfur coal is damaged.

On the demand end, sulfur regulations could be an important factor in power generation economics. There is a considerable range of cost estimates for controls. At the high end, the International Energy Agency calculated the total cost of 90 percent scrubbing with Fluidized Gas Desulphurization at 4-5 mills per kWh, or approximately 44 cents/MBtu heat input. This difference is important to the competitive position of coal versus nuclear power. The calculations in Chapter V generally include costs at this level, and coal is closely competitive with nuclear power. If regulations did not exist, the advantage might swing to coal fired power in more cases.

At the supply end, sulfur regulations are also significant. In certain countries restrictions are rigid, and medium- to high-sulfur coal would not be an economic choice. In other countries, sulfur controls are presently nonexistent. In these cases Eastern and Midwestern coals would be preferred.

Data on sulfur regulations are inconsistent. Table 1 reports some fuel standards for European countries (EIS), based on 7000 kcal/kg. With

the exception of the United Kingdom, all countries prohibit the use of high-sulfur (| 3.0) coal, but generally allow sulfur content in the 1-2 percent range. However, in some cases emissions standards are more restrictive. In West Germany, emissions standards are 1.80 lbs SO_2/million Btu heat input. This corresponds to a 1 percent weight sulfur restriction on coal input. In Japan, sulfur emissions standards can be met with 1.0 percent sulfur coal in non-urban areas, but .2 percent sulfur in cities, meaning that scrubbers are required.

In Italian urban areas, the restriction is 1.20 lbs SO_2/MBtu heat input, which could be met by .76 percent sulfur coal. In Denmark, the Netherlands, and the United Kingdom, no emission standards exist. In all the cases where regulations do exist, emission standards can almost certainly be met more cheaply with low-sulfur coal without scrubbers than with high-sulfur East or Midwest coal.

Note finally that sulfur regulations will no doubt tighten in countries where they are currently loose. For future economic assessments it is safer to assume that low-sulfur coal will be supplied, and scrubbers will be required, as is currently the case in the United States and Japan.

Sulfur Restrictions

(Percent Based on 7000 kcal/kg)

Denmark	1.68	.66 (Copenhagen)
West Germany	1.88	1.22 (in polluted areas)
France	2.75	1.38 (in Paris)
Italy	2.75	2.01 (in major cities)
Netherlands	1.68	
Sweden	1.68	.68 (in major cities)
U.K.	None	

Source: "Steam Coal and Energy Needs in Europe to 1985," Economic Intelligence Unit, London, 1979

FOOTNOTES--CHAPTER V

[1]See:
a. Energy Modeling Forum, "Electric Load Forecasting, Probing the Issues with Models," EMF Report 3, Vol. 1, Stanford University, 1979.
b. "Independent Assessment of Energy Policy Models: Two Case Studies by the MIT Model Assessment Group," MIT Energy Laboratory Report No. MIT-EL 78-011, May 1978.
c. Turvey, R., Optimal Pricing and Investment in Electricity Supply, MIT Press, Cambridge, Massachusetts, 1968.
Some particular problems with the traditional capacity expansion model are: 1) the detailed time relevance of the loading pattern is lost with the annual load curve. In practice, the model will bias the results towards baseload plants; 2) it simplifies complicated tradeoffs between economic costs, environmental problems, risks, and siting difficulties, etc.; 3) by aggregating regions, the outcome predicted may differ from the outcome predicted by a number of small systems, each reaching for its own optimum.

[2]Baughman, M., Joskow, P., and Kamat, D., Electric Power in the United States: Models and Policy Analysis, MIT Press, Cambridge, Mass., 1980.

[3]Ibid., p. 126.

[4]a. Toth, G. et al., "The Economics of Electricity Generation in Principal OECD Countries," Prepared for U.S. Department of Energy by N.U.S. Corp., March, 1978.
b. Institute of Energy Economics, "Power Generation Costs of Nuclear and Thermal Stations, Supplement to Energy in Japan," No. 42, September 1978.
c. Electric Power Research Institute, "Coal and Nuclear Generating Costs," Palo Alto, California, April 1977.

[5]U.K. Department of Energy, "Comparative Study of Generation Costs between Coal and Nuclear Generation," April 1978.

[6]Energy Research Institute of Cologne University, "A Parametric Study of Power Generation Cost from Coal and Nuclear Power," 1978.

[7]Institute of Energy Economics, op. cit.

[8]Japan Electric Power Survey Committee, "54th Semi-Annual Electric Power Survey," April 1979.

[9]Load curve data provided by A. Yajima, Central Research Institute of Electric Power Industry, Tokyo, Japan, October 1979.

[10]Ibid.

[11]Unpublished data provided by Y. Tamaki, Tokyo Electric Power Company.

[12]Japan Electric Power Survey Committee, op. cit.

[13]Unpublished data provided by Tokyo Electric Power Company.

[14]World Coal Study, Coal: Bridge to the Future, Ballinger Publishers Inc., Cambridge, Massachusetts, 1980, p. 237.

[15]Electricite de France, "Production Thermique," Rapport d'Activite, 1978.

[16]Electricite de France, "Resultats Techiques d'Exploration," 1978, pp. 10-11.

[17]World Coal Study, op. cit., p. 231.

CONCLUSIONS

In the past few years, as oil prices have rapidly increased and as nuclear power development has been stalled by public concern with health and safety, the probability of a major transition to coal for power generation has increased substantially. In certain cases, for example the United States, the transition is far along. New power plants are almost exclusively coal-fired, and conversions of existing oil-fired plants to coal are ubiquitous. In other cases, for example Western Europe and Japan, the transition is in the early stages, and the extent of the transition is less certain. Nevertheless, a large increase in coal consumption, and consequently in international coal trade, is generally foreseen in these cases also. The 1980 Venice economic summit meetng declared an active commitment to doubling world coal production and use in the next decade.

We have analyzed the economics of coal transportation, supply, and demand in order to expand our comprehension of the developing international steam coal markets and, in turn, to contribute to more effective government planning for the development of steam coal markets. In these concluding remarks we will summarize the current economic structure of international steam coal markets and the potentially important future economic and policy changes in these markets. In addition, we will briefly discuss possible government participation in the development of international steam coal trade.

We focused on four major coal suppliers (Australia, South Africa, Canada, and the United States) and two demand regions (Western Europe nd Japan). There are and will be other producing and consuming countries, but the majority of international steam coal trade should be accountable to this subset. Within this subset, South Africa is the cost-minimizing supplier of coal to Western Europe. The delivered price of low-sulfur bituminous steam coal to Rotterdam as of January 1, 1979 was approximately $1.38 per million Btu, or $33.12 per 24 million Btu. South Africa's closest competitors in Europe, Australia and the United States are closely competitive with each other, but coal from these countries costs at least $5.50 per 24 million Btu more than South African coal delivered to Rotterdam. South Africa's very low coal prices (FOB mine) are more than enough to offset the longer transportation distance required for South African shipments.

Australia is the cost-minimizing supplier to Japan. Low-sulfur steam coal can be delivered to Yokohama for $1.19 per million Btu, or $28.56 per 24 million Btu. However, this assumes that the current high spot prices in Australia are due to short-run supply constraints, and that the prices in late 1978 and early 1979 are a more accurate indication of long-run costs. If this is not correct, then Canada, South Africa, and Australia are very closely competitive in Japanese markets. Prices would then equal approximately $35 per 24 million Btu. On all these shipments to Japan, transportation costs account for approximately 45 percent of delivered prices.

The most striking result of these calculations is the relatively

poor competitive position of United States coal. United States coal cannot be delivered to Japan for less than $41 per ton, or at least $5 per ton more than Australian, Canadian, and South African coal. The disadvantage is largely due to both high ocean transportation and inland transportation costs, while for the other originating points at least one cost component is relatively low. For example, South Africa has very high ocean transportation costs, but low inland transportation costs, while Canada has low ocean transportation costs, but high inland costs. United States coal is currently no better off in European markets. The delivered price to Rotterdam is at least $6.48 per 24 million Btu higher than that for South African coal. In this case the disadvantage is not directly due to transportation. In fact, coal transportation to Europe is approximately $4.00 per 24 million Btu less from the United States than from South Africa. Rather, it is due to the very high coal prices FOB mine in Appalachia and midwestern U.S. coal fields.

As we have shown, this competitive structure could change in the future as supply and transportation variables change. Focusing on the United States, a reduction in rail tariffs to equal long-run marginal cost levels, and the expansion of West Coast port facilities to handle larger vessels would make U.S. coal more competitive with other suppliers in Japanese markets. In the ideal case, if a new port facility were constructed in Portland that could handle 120,000 DWT vessels, and if railroad rates decreased to estimated marginal costs, coal could be delivered to Japan for $1.47 per million Btu. This delivered price would still be significantly higher than the delivered price of Australian coal

under the most optimistic Australian price scenario. However, the lowest U.S. price is very close to South African and Canadian delivered coal prices in Japan, and if Australian prices stay at the high 1979 levels, U.S. coal would be very competitive with Australian coal.

With respect to European markets, expansion of port facilities to handle larger ships and a reduction in rail rates would make less of a difference to U.S. exports. South African coal would still be substantially less expensive, and the U.S. coal is already competitive with other potential suppliers. A more important transportation factor is the increase in ocean-freight fuel prices. As noted earlier, a 60 percent increase in fuel prices will increase the ocean-freight rate from Australia to Rotterdam by approximately 10 cents per million Btu. A 60 percent increase in fuel prices will increase the ocean-freight rate from Hampton Roads to Rotterdam by only 3.25 cents per million Btu. Consequently, if Australian long-run coal supply prices are consistent with contract data observed in late 1978 and early 1979, Australian coal delivered to Europe will cost about the same amount as U.S. coal delivered to Europe. If, however, Australlian long-run coal supply prices are consistent with the recent spot price levels, then U.S. coal will be cheaper in Europe than Australian coal. Nonetheless, both Australian and U.S. coal will be more expensive in Europe than South African coal. Note also that increased fuel prices would narrow the set of effective competitors in Japan, as South African coal shipments to Japan are far longer than other shipments. The increased cost would seriously handicap South Africa's competitive position in Japan.

Certain developments could instead further handicap U.S. coal exports. For example, the railroad rates imputed for the base calculation were based on the existing domestic unit-train rate structure. If the existing single-carload export rate structure instead were maintained, delivered prices would increase by as much as $3.00 per ton. Railroad deregulation could endanger U.S. domestic coal markets as rates become even higher, but it should not significantly affect export markets.

There are other potentially important changes in transportation variables. Commercialization of coal-slurry pipelines might lead to less expensive transportation in certain cases, and might push down railroad rates. Second, waterway user charges would increase costs, but waterway shipments are of secondary importance to U.S. exports, and the cost increase would be insignificant in proportion to delivered prices. Third, the availability of return cargoes would also increase the competitiveness of U.S. coal in the Japanese market.

To conclude, there are possible transportation developments that would increase the competitiveness of U.S. coal in foreign markets. Most important would be a reduction in railroad rates to equal marginal cost levels and an expansion of port facilities. Note, finally, however, that other suppliers might counteract these moves and regain at least some of the their competitive advantage.

There are also potentially important supply-side changes. In the base-case calculations, we assumed that low-sulfur coal is used. In Japan and most of Western Europe this will probably be true. However, in

some instances, Denmark for example, there is no market premium on low-sulfur coal. High-sulfur eastern coal could be delivered to Rotterdam for $1.52/MBtu, or only 7 cents/MBtu more than South African coal.

The future change in South African prices is potentially more important. If, as anticipated, labor and capital costs increase faster in South Africa due to political-economic pressures, the economic advantage of South African coal could be eliminated over the next ten years. However, we can expect a simultaneous, though slower, increase in the cost of U.S. eastern and midwestern low-sulfur and medium-sulfur coal. Although the United States may become competitive with South Africa, Australian coal might be less expensive than both, depending mainly on future bunker price increases.

The competitiveness of steam coal markets is also important to future patterns of steam coal trade. As discussed earlier, current markets appear to be competitive, but it is too early to formulate any conclusions. Particular concerns are the possibility of South Africa realizing monopoly rents in Europe and the possibility of an international coal cartel similar to OPEC. In the first case, South African has a marketing structure conducive to monopoly pricing. It is certainly possible that it will appropriate monopoly rents in the next decade. As to the possibility of a cartel, it would require the participation of the U.S. coal companies, participation that is per se illegal under antitrust laws. This does not mean that it is impossible, as evidenced by international uranium markets, but it is unlikely.

Another possibility is that the United States government supports a worldwide cartel with tariff policies, or similar mechanisms to reduce output and elevate prices. This is, however, less likely given the United States ties to Japan and Western Europe.

Note also that our assessment of the competitive structure in international steam coal markets does not mean that only the least-cost supplier will actually supply coal. There are additional important economic and political factors on both the demand and supply sides. First, importing countries will probably seek to diversify coal suppliers in order to minimize risks. Recent purchases by European and Far Eastern consumers of U.S. coal manifest this. Second, South African exports have been limited by the South African government to 44 million metric tons in 1985. Export quotas after 1985 may be below free-market levels. Consequently, after this quota is sold, the United States and Australia will be competitive in Europe. Third, there is considerable public opposition to any involvement with South Africa and this opposition might dominate the pure economic advantage of South African coal in Western European markets. Fourth, in most cases supply curves seem to be very elastic, so prices will not shift substantially as output cumulates. However, prices will increase to some extent, and as they do, incremental suppliers will become involved. At competitive equilibrium, FOB prices will actually be equal after adjusting for transportation differentials.

The demand for steam coal in Western Europe and Japan is less certain. Coal-fired power is clearly cheaper than oil- or gas-fired power for baseload or cycling plants, and it is reasonably competitive

with nuclear-fired power at coastal power stations. Just as important as the economics, however, are the policies of the importing nations. If nuclear power is constrained due to health and safety concerns, the increase in coal-fired power will obviously be much greater. Both Japan and Western Europe governments have generally expressed a commitment to nuclear power. In France and Great Britain, especially, nuclear power has been planned for most future baseload generation. In all cases, however, the government projections of nuclear power, formulated in the late 1970s, have been significantly cut back due to public opposition. The Three-Mile Island accident has brought resistance to a peak. Governments still project a substantial role for nuclear power, but in many cases their hands are currently tied by public opposition.

Possibly as important to the increase in coal-fired power is the development of environmental regulations, both on the supply and demand sides. We have shown that even with rigid sulfur-emissions standards, coal-fired power is still cheaper than oil or gas, and competitive with nuclear power. However, large increases in coal-fired power may bring about more stringent standards on sulfur and particulate emissions. On the supply side, more stringent surface mining controls are the most critical factor inhibiting development of coal markets.

As we have shown repeatedly, the role of government in the development of international steam coal markets is especially important. A few final normative remarks on this are in order. First, where market inefficiencies can be identified and where efficient solutions to these problems can be formulated and successfully implemented, the governments

should of course pursue them. For example, a way to reduce the inefficiencies in railroad rates should be pursued in the United States. Second, where friction exists in coal markets and where this friction is attributable to cumbersome government restrictions, the governments should seek to eliminate them. In particular, environmental regulations are essential to the socially-efficient development of coal markets, but the regulations have often been poorly formulated and exceedingly complex. In many cases they could be streamlined without decreasing their ultimate effectiveness.

Related to this is the question of governments serving as coordinating mechanisms that would expedite the development of coal markets. The multinational oil companies act as economic coordinators for world oil markets, and possibly some private institution can be developed for coordinating the various components of international steam coal markets. However, in many cases the uncertainties in developing steam coal markets are directly related to government policy, so some government organization to expedite market transactions is also warranted. For example, importers are generally concerned about the future security of U.S. coal supplies. Past monitoring of metallurgical coal exports and the current embargo on grain shipments to the U.S.S.R. have created these fears. Given this uncertainty, foreigners have been unwilling to sign long-term contracts with U.S. coal producers. Furthermore, without long-term contracts, U.S. companies have been largely unwilling to invest in the infrastructure expansions necessary for expanding exports. Only the government can assure the importers that

arbitrary constraints on exports will not be imposed in the future. One possibility for the United States is to assign this responsibility to the newly formed Energy Mobilization Board.

Beyond this, however, government involvement must be carefully planned. There have been recent suggestions by governmental and intergovernmental agencies that they should take an active financial role in the development of steam coal markets. In particular, direct financial incentives for developing coal export and import facilities have been proposed. In advocating these measures it is important to separate the social benefits or costs from the private benefits or costs. For importing countries, the social benefits may be substantial. Increased utilization of coal is an integral component of energy policies designed to reduce dependence on OPEC oil. However, government incentives create the possibility of government funds being substituted for what would have been private funds. That is, it is possible that conversion from coal to oil will be just as rapid without government incentives.

On the supply side, subsidization of coal exports is more difficult to justify. Certainly, an increase in coal exports benefits the U.S. balance of trade. There are gains in terms of good will in contributing to the energy objectives of Japan and Europe. Also, there are possible economic justifications for developing port facilities that are not directly related to the benefits of expanding coal trade. However, great care should be taken to avoid government involvement purely for the sake of government involvement when private market responses may be equally or more efficient.

Suggestions for Additional Research

This dissertation only begins to develop understanding of international steam coal markets. There are many instances where additional research is warranted. Most important are: 1) the expansion and formalization of a coal demand model for Western Europe and Japan; 2) an analysis of energy policies in Western Europe and Japan; 3) an analysis of coal prospects in other potential coal-supplying countries; 4) an anlysis of industrial markets for coal in Western Europe and Japan; 5) an analysis of coal gasification and liquefaction markets and prospects in Western Europe and Japan; and 6) the development of an integrated supply/demand, transportation world coal model. It is clear that coal markets will gain importance in the future, and research on these issues will contribute to intelligent planning practices.

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