SUSITNA HYDROELECTRIC PROJECT

FEDERAL ENERGY REGULATORY COMMISSION PROJECT No. 7114

ANALYSIS OF FACTORS AFFECTING DEMAND, SUPPLY AND PRICES OF RAILBELT COAL

PREPARED BY

DAMES & MOORE

UNDER CONTRACT TO

HARZA-EBASCO
SUSITNA JOINT VENTURE

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1.0 INTRODUCTION: ALASKA RAILBELT COAL

1.1 PURPOSE OF THIS REPORT

The Railbelt area encompasses seven major coal fields, as illustrated on Figure 1-1. Two of these fields, Beluga and Nenana, have the greatest economic potential. Coal from these fields could provide supplies for electrical generation in both the Railbelt and the Pacific Rim nations. Surface minable coal resources in both these fields are sufficient to maintain a very large annual production.

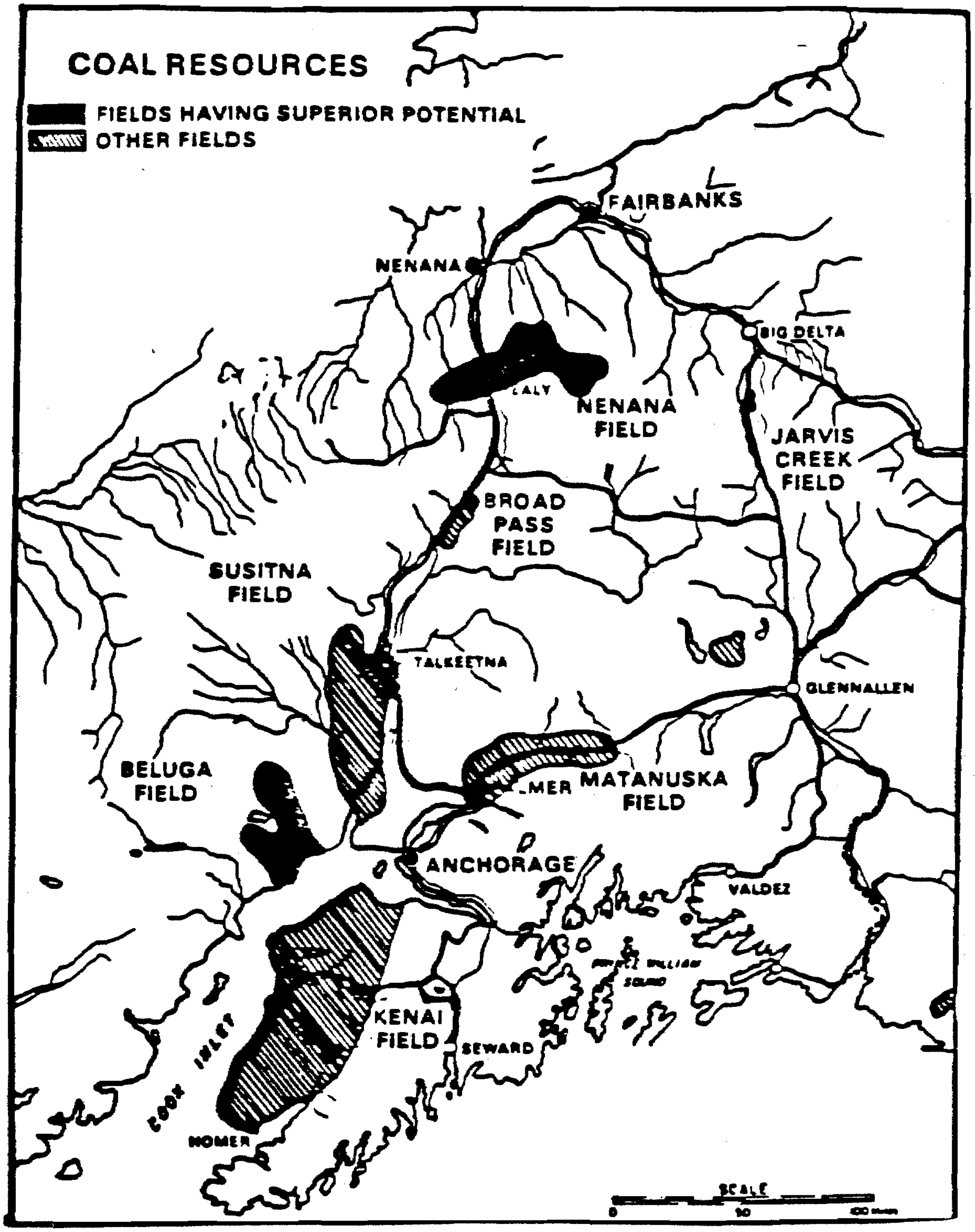
Because of the abundance of Railbelt coal resources and because of their apparent commercial viability, coal is the major component of the thermal alternative scenarios in the economic analysis of the Susitna hydroelectric project proposed by the Alaska Power Authority.

1.2 ORGANIZATION OF THIS REPORT

The price of Railbelt coal supplies to electric utilities over the economic life of the proposed Susitna project (1993-2050) can be estimated in a number of ways. The cost of production and transportation is an irreducible lower bound on price. No one will supply coal on a long-term basis for less than the full cost of production. Section 2.0 of this report documents Dames & Moore's projections of future production costs. These projections begin with 1985 production cost estimates for hypothetical railbelt area mines developed by the Paul Weir Company. Based on historical price trends and future projections of the cost of factors of production, Dames & Moore developed real price escalation factors. Dames & Moore applied those escalation factors to Paul Weir Company's present production cost estimates in order to forecast future production costs. Railroad transportation costs for transporting Nenana coal to a suitable generating site are also projected. The analysis does not include the production cost increases over time which would result from resource depletion.

The Pacific Rim supply/demand balance and resulting price structure are also relevant for Railbelt coal. Section 3.0, which develops the analysis

FIGURE 1-1



RAILBELT STUDY AREA

of Railbelt coal in the context of future Pacific Rim demand, concludes that Beluga coal will be competitive in this market. Because Railbelt coal producers would have the option of selling coal on the world market at a higher netback price than their production costs there is good reason to believe that netback price rather than production cost will govern the domestic coal price faced by Railbelt utilities. Section 3.0, therefore, carefully documents supply, demand, and price conditions expected to prevail in the Pacific Rim for 1990-2040.

This report has several appendices. These appendices contain the documentation of analysis provided in Sections 2.0 and 3.0 as well as copies of the source documents from which much of the data contained in this report were obtained.

2.0 COAL PRODUCTION AND TRANSPORTATION COST ESCALATION

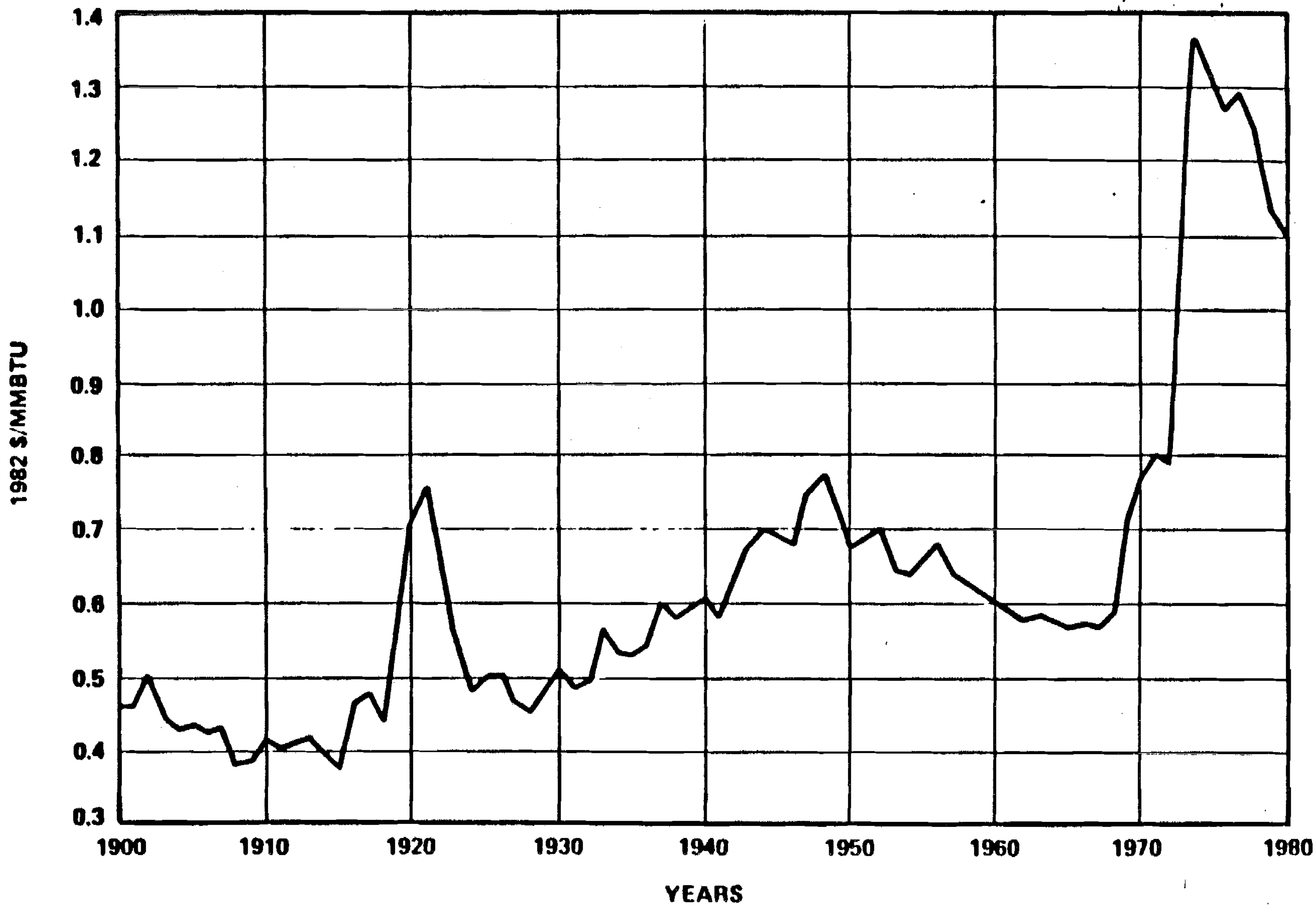
Production costs for hypothetical Beluga and Nenana coal mines were estimated by Paul Weir Company. The Weir estimates are only the starting point for projecting future production costs, inasmuch as they yield the levelized cost per ton stated in January "instant build" 1983 dollars. These figures must be escalated to take into account the projected real changes in the cost of operating a mine over the 1993 to 2050 period of analysis. "Real" price changes are increases over and above the general inflation rate.

Dames & Moore has performed an analysis of the factors of production and other operating costs in order to project their real escalation rates. Labor, fuel and lubricants, and electricity costs are all expected to rise faster than the general inflation rate. Royalties are a fixed percentage of selling price. As other production costs escalate, royalty payments then escalate as well, amplifying the effects of escalation of other factors. Production cost factors which are not projected to rise include capital costs, normal profits, income taxes, production taxes, and parts and supplies.

2.1 HISTORICAL COAL PRICE TRENDS IN THE TWENTIETH CENTURY

Historical data support the fact that real coal prices have trended upward throughout the Twentieth Century. Figure 2-1 illustrates this escalation. Data for real coal prices were obtained from a time series of bituminous coal prices compiled by the U.S. Department of Commerce.[1,2] This series, which extends back to the beginning of the century, expresses bituminous coal prices in nominal dollar terms. These nominal costs were corrected to eliminate the effects of changes in the value of the dollar using the Wholesale Price Index.[3,4] The data in Figure 2-1 reflect this

1. U.S. Department of Commerce, 1971, Historical Statistics of the U.S. Colonial Times to 1970, Part I (For 1910-1970) Series M96.
2. Ibid., 1983 Statistical Abstract of the U.S. 1982-83, p. 715, Table 1278 (for 1970-81).
3. Op. cit. Note 1, Series E23, p. 199 (For 1910-70).
4. Op. cit. Note 2, Table 751, p. 456 (For 1971-82).



Source: See Table 2-1

SUSITNA HYDROELECTRIC PROJECT

REAL COAL PRICES

FIGURE 2-1

correction. Table 2-1 documents the calculations used to derive Figure 2-1.

Overall, between 1900 and 1980 real coal prices have escalated at an average compound annual rate of 1.2 percent. Even prior to the dramatic price rise in 1973, coal prices from 1900-1973 escalated at a real annual rate of 0.8 percent.

Historically, the factors driving the real price escalation of coal include real labor cost escalation, price escalation of substitute energy sources and resource depletion effects. Countering the trend toward increasing coal prices are increases in productivity which occurred as large-scale mechanized surface mining techniques replaced labor-intensive underground mining. Despite these cost-saving productivity increases, real coal prices have risen steadily. There is good reason to expect this trend to continue into the next century because the forces causing the escalation will likely continue, while the productivity increases (which tend to lower prices) have probably peaked out.

2.1.1 A Note on Productivity

Labor costs represent a large part of production costs. Increases in wages can be offset by increases in labor productivity. Productivity increases can occur due to improved mining methods and equipment. Figure 2-2[5] represents productivity between 1948-1983 in the U.S. coal mining industry. Surface mining productivity increased at an average rate of 3.2 percent per annum through 1973. This increase was due to a shift to better mechanized production and larger and more powerful equipment in surface mines. However, such trends are not without limit and may even be reversed. Starting in 1966, United States surface mine productivity began to level off and then to decline; this was well before the imposition of stringent reclamation regulations. The effects of more stringent safety and environmental regulations, along with labor force changes and other

5. Energy Information Administration, Annual Report to Congress, Vol. II, 1982.

TABLE 2-1: HISTORICAL TRENDS OF COAL PRICES [illegible]

YEAR	WHOLESALE PRICE INDEX 1967=100 (a,b)	WHOLESALE PRICE INDEX 1982=100 (c)	BITUMIN. COAL PRICE $ PER TON FOB MINE (d,e)	REAL COAL PRICE 1985 $ PER TON FOB MINE (f)	COST PER MMBTU 1985 $ FOB MINE (g)
1900	28.9	9.0		0.00	0.00
1901	28.5	8.8	1.05	11.87	0.49
1902	30.4	9.4	1.12	11.87	0.49
1903	30.7	9.5	1.24	13.01	0.54
1904	30.8	9.6	1.10	11.51	0.48
1905	31.0	9.6	1.06	11.02	0.46
1906	32.0	9.9	1.11	11.18	0.47
1907	33.6	10.4	1.14	10.93	0.46
1908	32.4	10.1	1.12	11.14	0.46
1909	34.9	10.8	1.07	9.88	0.41
1910	36.4	11.3	1.12	9.91	0.41
1911	33.5	10.4	1.11	10.68	0.44
1912	35.6	11.0	1.15	10.41	0.43
1913	36.0	11.2	1.18	10.55	0.44
1914	35.2	10.9	1.17	10.71	0.45
1915	35.8	11.1	1.13	10.17	0.42
1916	44.1	13.7	1.32	9.64	0.40
1917	60.5	18.8	2.26	12.02	0.50
1918	67.6	21.0	2.58	12.30	0.51
1919	71.4	22.2	2.49	11.24	0.47
1920	79.6	24.7	3.75	15.18	0.63
1921	50.3	15.6	2.89	18.51	0.77
1922	49.9	15.5	3.02	19.50	0.81
1923	51.9	16.1	2.68	16.64	0.69
1924	50.5	15.7	2.20	14.04	0.56
1925	53.3	16.5	2.04	12.33	0.51
1926	51.6	16.0	2.06	12.86	0.54
1927	49.3	15.3	1.99	13.01	0.54
1928	50.0	15.5	1.86	11.99	0.50
1929	49.1	15.2	1.78	11.68	0.49
1930	44.6	13.8	1.70	12.28	0.51
1931	37.6	11.7	1.54	13.20	0.55
1932	33.6	10.4	1.31	12.56	0.52
1933	34.0	10.6	1.34	12.70	0.53
1934	38.6	12.0	1.75	14.61	0.61
1935	41.3	12.8	1.77	13.81	0.58
1936	41.7	12.9	1.75	13.60	0.57
1937	44.5	13.8	1.94	14.05	0.59
1938	40.5	12.6	1.95	15.51	0.65
1939	39.8	12.4	1.84	14.90	0.62
1940	40.5	12.6	1.94	15.43	0.64
1941	45.1	14.0	2.19	15.65	0.65
1942	50.9	15.8	2.36	14.94	0.62
1943	53.3	16.5	2.69	16.26	0.68
1944	53.6	16.6	2.92	17.55	0.73
1945	54.6	16.9	3.06	18.05	0.75
1946	62.3	19.3	3.44	17.79	0.74
1947	76.5	23.7	4.16	17.52	0.73
1948	82.8	25.7	4.99	19.42	0.81
1949	78.7	24.4	4.88	19.98	0.83
1950	81.8	25.4	4.84	19.06	0.79
1951	91.1	28.3	4.92	17.40	0.73
1952	88.6	27.5	4.90	17.82	0.74
1953	87.4	27.1	4.92	18.14	0.76
1954	87.6	27.2	4.52	16.62	0.69
1955	87.8	27.3	4.50	16.51	0.69
1956	90.7	28.2	4.82	17.12	0.71
1957	93.3	29.0	5.08	17.54	0.73
1958	94.6	29.4	4.86	16.55	0.69
1959	94.8	29.4	4.77	16.21	0.68
1960	94.9	29.5	4.69	15.92	0.66
1961	94.5	29.3	4.58	15.62	0.65
1962	94.8	29.4	4.48	15.23	0.63
1963	94.5	29.3	4.39	14.97	0.62
1964	94.7	29.4	4.45	15.14	0.63
1965	96.6	30.0	4.44	14.81	0.62
1966	99.8	31.0	4.54	14.66	0.61
1967	100.0	31.0	4.62	14.89	0.62
1968	102.5	31.8	4.67	14.68	0.61
1969	106.5	33.1	4.99	15.10	0.63
1970	110.4	34.3	6.26	18.27	0.76
1971	114.0	35.4	7.07	19.98	0.83
1972	119.1	37.0	7.66	20.72	0.86
1973	134.7	41.8	8.53	20.40	0.85
1974	160.1	49.7	15.75	31.70	1.32
1975	174.9	54.3	19.23	35.43	1.48
1976	183.0	56.8	19.43	34.21	1.43
1977	194.2	60.3	19.82	32.88	1.37
1978	209.3	65.0	21.78	33.53	1.40
1979	235.6	73.1	23.65	32.34	1.35
1980	268.8	83.4	24.57	29.45	1.23
1981	293.4	91.1	26.00	28.55	1.19
1982	299.4	92.9		0.00	0.00

Source: Dames & Moore calculations, July, 1985

Notes: See next page

NOTES TO TABLE 2-1:

a. U.S. D.O.C., 1975, Historical Statistics of the U.S., Series E, p. 99 (1900-1970).

b. Ibid., Statistical Abstracts of the U.S. 1982-3, Table 1281, p. 717.

c. Column (1) reindexed from 1967 base to 1982 base.

d. Op. cit. Note (a), Series M96, p. 589.

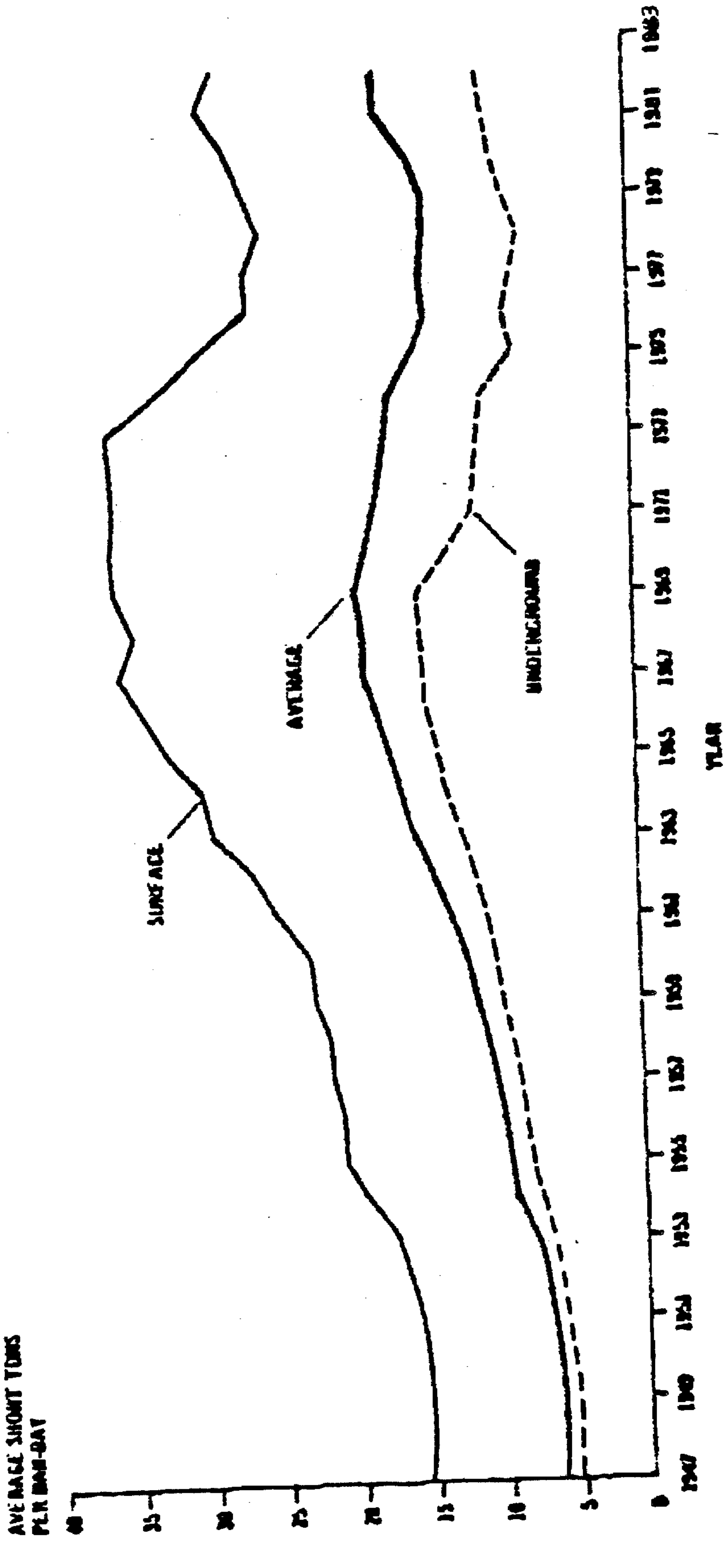
e. Op. cit. Note (b), Table 1278, p. 715.

f. Column (3) indexed to 1982 W.P.I.

g. Column (4) divided by 24 (average BTU content of bituminous coal equals 24 MMBTU per ton).

FIGURE 2-2

PRODUCTIVITY TRENDS BY METHOD OF MINING, 1948 - 1982



factors, led to a 1.8 percent per annum decline in U.S. surface mining productivity from 1973 to 1983. Though reclamation requirements are already fairly strong, increased regulation is possible and may tend to offset further productivity gains achieved through better technology. Figure 2-2 suggests, on balance, that productivity in surface mining was flat during the 1960's, declined in response to regulations and is flat now at a lower level of productivity.

To translate labor rate increases into coal mining unit cost increases net of productivity gains recognizes explicitly that other factors beyond labor utilization and wages act on mining costs. Increased regulation, taxation, and depletion are important considerations. These three factors act to raise unit costs, while only productivity gains act to lower cost. Clearly, as Figure 2-1 shows, real coal prices rose from 1900 to 1973 (at 0.8 percent annually) despite large technological improvements in mining. Thus, we estimate that the trend in unit labor costs will continue to raise the real cost of coal mining. Productivity increases, if any, are not expected to overcome the effects of increased regulation, taxation and depletion. At best overall labor productivity will remain flat, allowing any real wage escalation to affect unit production costs.

2.2 FACTOR COST ESCALATION RATE ESTIMATES

Coal contracts negotiated between coal producers and utilities attempt to strike a balance between price stability and recognition of potentially destabilizing economic forces.

Agreements between coal suppliers and electric utilities for the sale/purchase of coal are usually long-term contracts, which include a base price for the coal and a method of escalation to cover cost of mining increases in future years. The base price provides for recovery of the capital investment, profit, and operating and maintenance costs at the level in existence when the contract is executed. The intent of the escalation mechanism is to recover actual increases in labor and material costs from operation and maintenance of the mine. Typically the escalation mechanism consists of an index or combination of indices such as the producer price index, various commodity and labor indices, and consumer price index applied to operating and maintenance expenses, and/or regulation related indices. These characteristics are exhibited by the Usibelli contracts with FMUS and GVEA (FMUS, 1976; Hufman, 1981).

In addition to price escalators, long-term coal contracts typically include "price reopener" clauses. These clauses allow renegotiation of the base price if some agreed-upon measure of coal market prices falls above or below a predetermined level. These clauses protect both utilities and coal producers against major fluctuations in market prices resulting from forces beyond either party's control, such as major supply disruptions or unusually severe swings in the business cycle. As illustrated in the discussion in How to Negotiate and Administer a Coal Supply Agreement (McGraw-Hill, 1981, pp 350) price reopeners are becoming more common because coal prices have been somewhat unstable over the last decade and because mining companies do not want to be "locked in" to current market prices that may not reflect longer run prices.

The following analysis attempts to forecast future coal prices, assuming that those prices will be based on the cost of production, as reflected in a long-term utility coal supply contract. From the above discussion it is clear that the coal supply contract would reflect changes in operating costs including labor costs and energy supply costs and royalties. Other factors which would not escalate in real terms include capital costs, parts and supplies, profit, and production taxes. Each of these categories is discussed below.

Resource depletion would, over time, cause additional escalation of coal prices. Depletion caused price escalation, although potentially significant, is not considered in this analysis. Omission of this consideration creates a conservative bias in the cost escalation factor estimates reported in this study.

2.2.1 Labor Rates

Long-range historical data indicate that for the past seventy years real U.S. wage rates have risen both in the bituminous coal industry and in all U.S. industries. There is good reason to believe that the trend will continue for the next seventy years. This is because the basis macroeconomic projections on which the energy balances and the other economic analyses of the Susitna project depend indicate a long-term continuing growth in the U.S. GNP and GNP per capita. Rising wages are a basic reflection of improving prosperity.

Figure 2-3 (documented by Table 2-2) shows the real wage rates for bituminous coal workers and all industries from 1910 through 1981. The nominal dollar wages for annual statistics (compiled by the U.S. Department of Commerce Bureau of Labor Statistics) were corrected for changing prices using the Consumer Price Index. The hourly wages shown on Figure 2-3 are thus real (constant dollar) 1985 equivalents. There is a very definite upward tend in both wage series although bituminous workers consistently receive higher wages than the all-industry average.[6]

A statistical procedure was used to establish rigorously the historic trend in wage rates. First a log transportation was performed on both wage series to yield the annual rates of change. These transformed series then were regressed against time using an ordinary least squares (OLS) linear regression. The coefficient of these regression lines indicates the best fitting linear (in logs) estimate of this annual rate of change.

Both the bituminous and all-industry series yielded a regression coefficient of 0.022 on the wage variable, i.e., a 2.2 percent average annual rate of change. Figures 2-4 and 2-5 illustrate how the fitted trendline corresponds to the observed real annual wage rates. An R square test was

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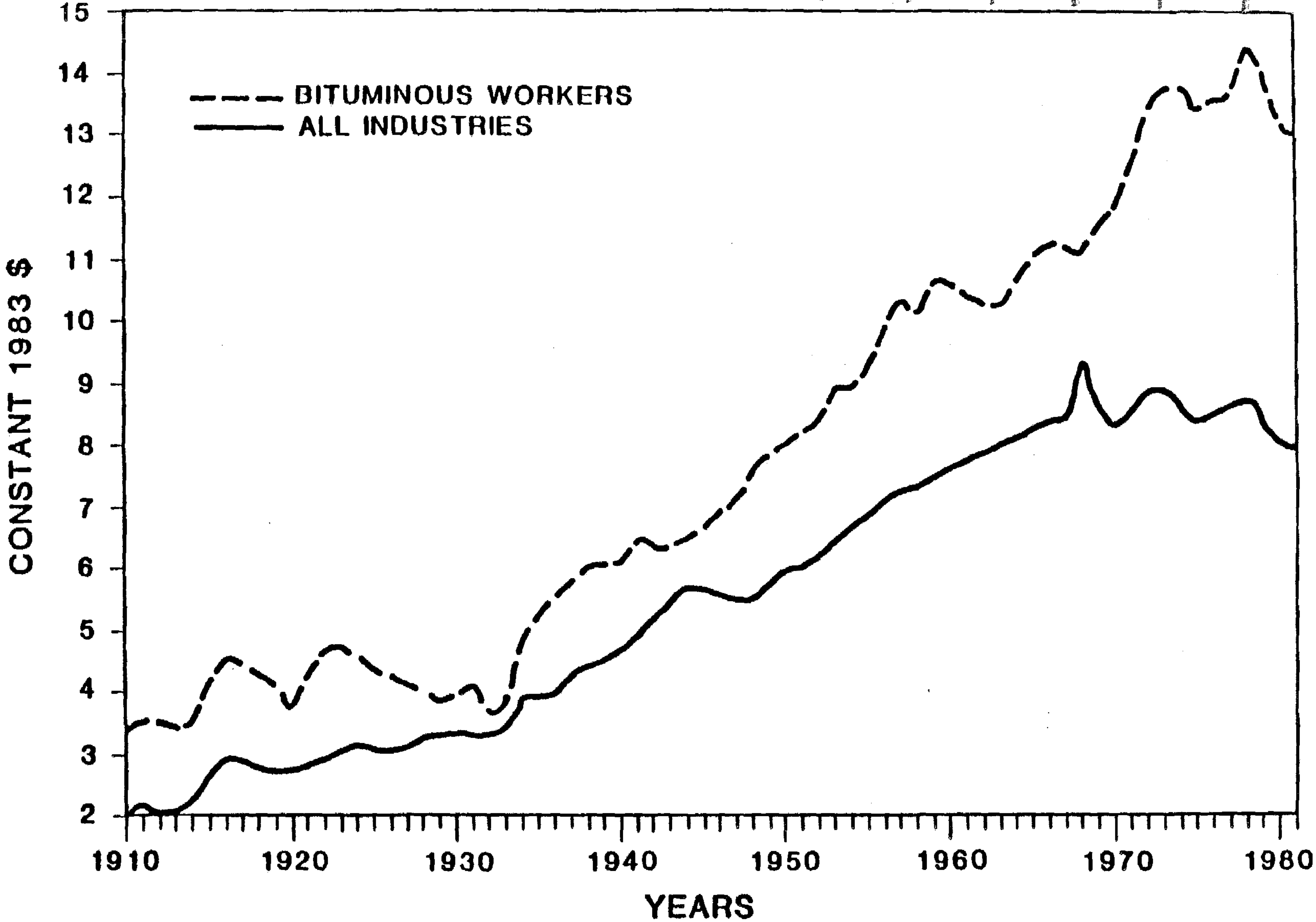
6. The U.S. wage data for the bitumious coal industry and all manufacturing are used as proxy for Alaska coal (which is subbitumious) because of the lack of Alaska coal industry wage data. Information on coal wages in Alaska is not publicly available according to the Alaska Division of Labor. The only available series for Alaska is called Other Mining, which includes all non-petroleum mining activities. Even this series is only available after 1971. Long term publicly available data on subbituminous coal or lignite mining wages for the U.S. as whole are also lacking, since such coal has not been mined in significant quantities in the U.S. Therefore wage series for the U.S. bituminous coal industry and for all industries are used as proxies for Alaska coal industry wages throughout this analysis.



Source: See Table 2-2

BITUMINOUS VS ALL INDUSTRIES

REAL HOURLY WAGE RATES

FIGURE 2-3

TABLE 2-2: HISTORICAL TRND OF REAL HOURLY WAGES IN THE
BITUMINOUS COAL INDUSTRY AN IN ALL MFG INDUSTRIES

YEAR	HOURLY WAGES BITUM (a,b) NOM. $	HOURLY WAGES ALL IND (d,e) NOM. $	CPI 1967=100 (g,h)	CPI 1985=100 (k)	HOURLY WAGES BITUM (l) 1985 $	HOURLY WAGES ALL IND (m) 1985 $	WHOLESALE PRICE INDEX (n,o) 1967=100	WHOLESALE PRICE INDEX (q) 1985=100
1910i	0.32 i	0.19 i	28.0	8.8	3.63	2.15	36.4	11.3
1911i	0.33 i	0.19 i	28.0	8.8	3.74	2.15	33.5	10.4
1912i	0.34 i	0.20 i	29.0	9.1	3.72	2.19	35.6	11.0
1913i	0.34 i	0.21 i	29.7	9.4	3.63	2.24	36.0	11.2
1914	0.35	0.22	30.1	9.5	3.69	2.32	35.2	10.9
1915i	0.43 i	0.27 i	30.4	9.6	4.44	2.82	35.9	11.1
1916i	0.50 i	0.32 i	32.7	10.3	4.87	3.10	44.1	13.7
1917i	0.58 i	0.37 i	38.4	12.1	4.77	3.06	60.5	18.8
1918	0.65	0.42 i	45.1	14.2	4.60	2.95	67.6	21.0
1919	0.73	0.47	51.8	16.3	4.47	2.88	71.4	22.2
1920i	0.75 i	0.55	60.0	18.9	3.97	2.91	79.6	24.7
1921i	0.77 i	0.51	53.6	16.9	4.56	3.02	50.3	15.6
1922i	0.79 i	0.48	50.2	15.8	4.99	3.03	49.9	15.5
1923	0.82	0.52	51.1	16.1	5.09	3.23	51.9	16.1
1924	0.79	0.54	51.2	16.1	4.89	3.35	50.5	15.7
1925	0.77	0.54	52.5	16.6	4.65	3.26	53.3	16.5
1926	0.76	0.54	53.0	16.7	4.55	3.23	51.6	16.0
1927	0.73	0.54	52.0	16.4	4.45	3.29	49.3	15.3
1928	0.69	0.56	51.3	16.2	4.27	3.46	50.0	15.5
1929	0.66	0.56	51.3	16.2	4.08	3.46	49.1	15.2
1930	0.66	0.55	50.0	15.8	4.19	3.49	44.6	13.8
1931	0.63	0.51	45.6	14.4	4.38	3.55	37.6	11.7
1932	0.50	0.44	40.9	12.9	3.88	3.41	33.6	10.4
1933	0.49	0.44	38.8	12.2	4.01	3.60	34.0	10.6
1934	0.65	0.53	40.1	12.6	5.14	4.19	38.6	12.0
1935	0.72	0.54	41.1	13.0	5.56	4.17	41.3	12.8
1936	0.77	0.55	41.5	13.1	5.89	4.20	41.7	12.9
1937	0.83	0.62	43.0	13.6	6.12	4.57	44.5	13.8
1938	0.85	0.62	42.2	13.3	6.39	4.66	40.5	12.6
1939	0.86	0.63	41.6	13.1	6.56	4.80	39.8	12.4
1940	0.85	0.65	42.0	13.2	6.42	4.98	40.5	12.6
1941	0.96	0.73	44.1	13.9	6.91	5.25	45.1	14.0
1942	1.03	0.85	48.8	15.4	6.70	5.53	50.9	15.8
1943	1.10	0.96	51.8	16.3	6.74	5.88	53.3	16.5
1944	1.15	1.01	52.7	16.6	6.92	6.08	53.6	16.6
1945	1.20	1.02	53.9	17.0	7.06	6.00	54.6	16.9
1946	1.36	1.08	58.5	18.4	7.37	5.86	62.3	19.3
1947	1.58	1.22	66.9	21.1	7.49	5.78	76.5	23.7
1948	1.84	1.33	72.1	22.7	8.09	5.85	82.8	25.7
1949	1.88	1.38	71.4	22.5	8.35	6.13	78.7	24.4
1950	1.94	1.44	72.1	22.7	8.53	6.34	81.8	25.4
1951	2.14	1.56	77.8	24.5	8.73	6.36	91.1	28.3
1952	2.22	1.65	79.5	25.1	8.86	6.58	88.6	27.5
1953	2.40	1.74	80.1	25.3	9.50	6.89	87.4	27.1
1954	2.40	1.78	80.5	25.4	9.46	7.01	87.6	27.2
1955	2.47	1.86	80.2	25.3	9.77	7.36	87.8	27.3
1956	2.72	1.95	81.4	25.7	10.60	7.60	90.7	28.2
1957	2.92	2.05	84.3	26.6	10.99	7.71	93.3	29.0
1958	2.93	2.11	86.6	27.3	10.73	7.73	94.6	29.4
1959	3.11	2.19	87.3	27.5	11.30	7.96	94.8	29.4
1960	3.14	2.26	88.7	28.0	11.23	8.08	94.9	29.5
1961	3.12	2.32	89.6	28.2	11.05	8.21	94.5	29.3
1962	3.12	2.39	90.6	28.6	10.92	8.37	94.8	29.4
1963	3.15	2.46	91.7	28.9	10.90	8.51	94.5	29.3
1964	3.30	2.53	92.9	29.3	11.27	8.64	94.7	29.4
1965	3.49	2.61	94.5	29.8	11.71	8.76	96.6	30.0
1966	3.66	2.72	97.2	30.6	11.94	8.88	99.8	31.0
1967	3.75	2.83	100.0	31.5	11.90	8.98	100.0	31.0
1968	3.86	3.30	104.2	32.8	11.75	10.05	102.5	31.8
1969	4.24	3.19	109.8	34.6	12.25	9.22	106.5	33.1
1970	4.58	3.23	116.3	36.7	12.49	8.81	110.4	34.3
1971	5.11 i	3.46 i	121.3	38.2	13.36	9.05	114.0	35.4
1972	5.64 i	3.71 i	125.3	39.5	14.27	9.40	119.1	37.0
1973	6.16 i	3.98 i	133.1	42.0	14.67	9.48	134.7	41.8
1974	6.82 i	4.27 i	147.7	46.6	14.65	9.16	160.1	49.7
1975	7.22	4.53	161.2	50.8	14.21	8.91	174.9	54.3
1976	7.75	4.86	170.5	53.8	14.42	9.03	183.0	56.8
1977	8.24	5.26	181.5	57.2	14.40	9.20	194.2	60.3
1978	9.49	5.70	195.4	61.6	15.41	9.25	209.3	65.0
1979	10.26	6.16	217.4	68.5	14.97	8.99	235.6	73.1
1980	10.86	6.66	246.8	77.8	13.96	8.56	268.8	83.4
1981	11.89	7.25	272.4	85.9	13.85	8.44	293.4	91.1
1982		7.63 f	289.1	91.1			299.4	92.9
1983			298.4 j	94.1			303.1 p	94.1
1984			307.7	97.0			312.5	97.0
1985			317.2	100.0			322.2	100.0

Source: Dames & Moore calculations, July, 1985

Notes: See next page

NOTES TO TABLE 2-2:

a. U.S. D.O.C., 1975, Historical Statistics of the U.S. Colonial Times to 1970, Series D813 (For 1910-1970).

b. Ibid., 1983, Statistical Abstracts of the U.S. 1982-83, Table 1281, p. 717 (For 1970-1981).

c. Ibid., 1984, Statistical Abstracts of the U.S. 1984, Table 1272, p. 717.

d. Op. cit. Note (a), p. 170-71, Series D802 (For 1910-1969).

e. Op. cit. Note (b), p. 401.

f. Op. cit. Note (c), p. 401, Table 665.

g. Op. cit. Note (a), Series E135, p. 211 (For 1910-1970).

h. Op. cit. Note (b), Table 757, p. 461 (For 1970-82).

i. Interpolated or extrapolated data point.

j. U.S. Department of Commerce, 1981, Survey of Current Business, V. 64, No. 2, p. 55.

k. Column (3) reindexed to 1985 = 100.

l. Column (1) indexed to 1985 using CPI from Column (3).

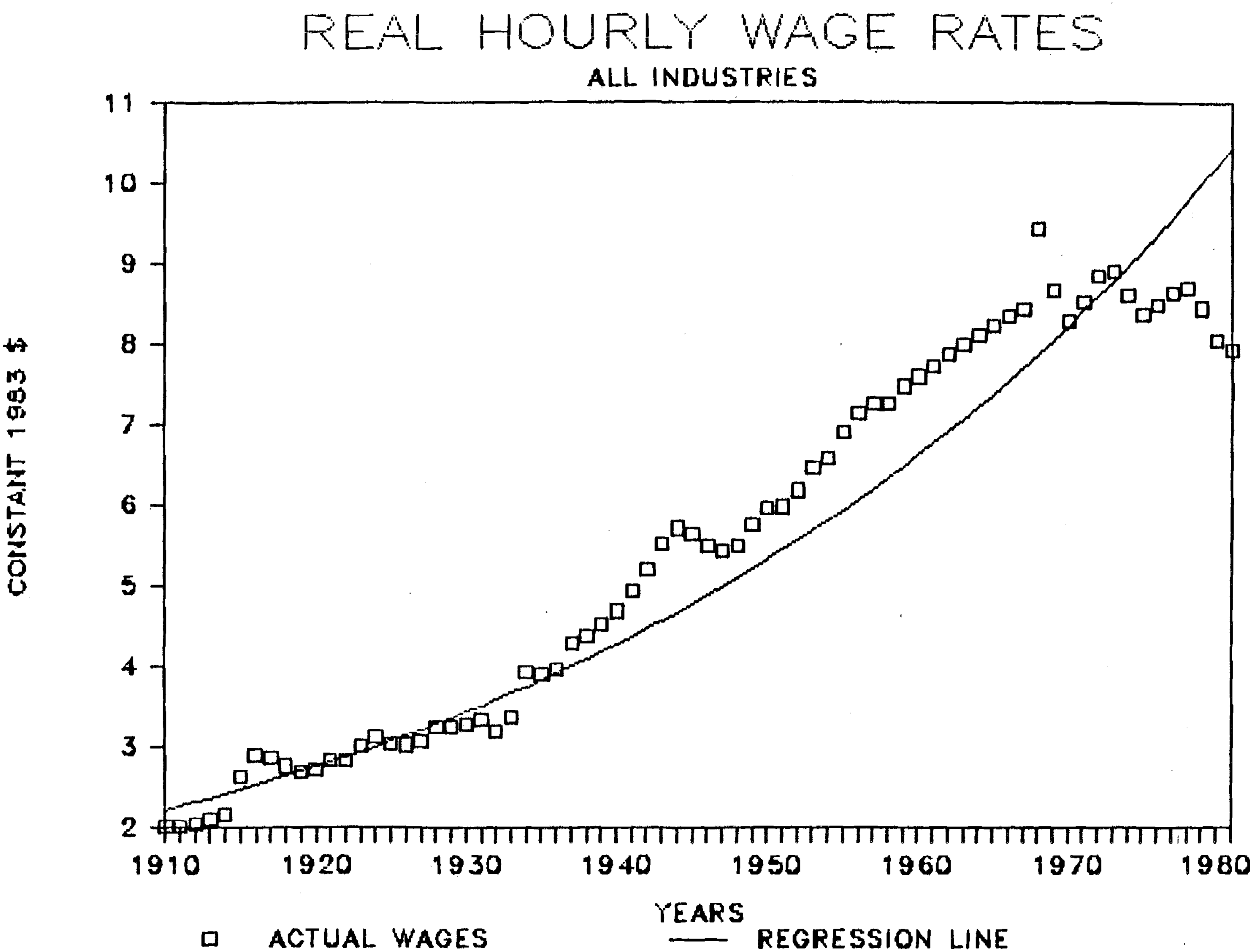
m. Column (2) indexed to 1985 using CPI from Column (3).

n. Op. cit. Note (a), Series E23, p. 199 (For 1910-1970).

o. Op. cit. Note (b), Table 751, p. 456 (For 1971-82).

p. Op. cit. Note (j), p. 55.

q. Column (7) reindexed to 1985 = 100.



REAL HOURLY WAGE RATES
ALL INDUSTRIES
CONSTANT 1983 $
11
10
9
8
7
6
5
4
3
2
1910
1920
1930
1940
1950
1960
1970
1980
YEARS
ACTUAL WAGES
REGRESSION LINE

FIGURE 2-4

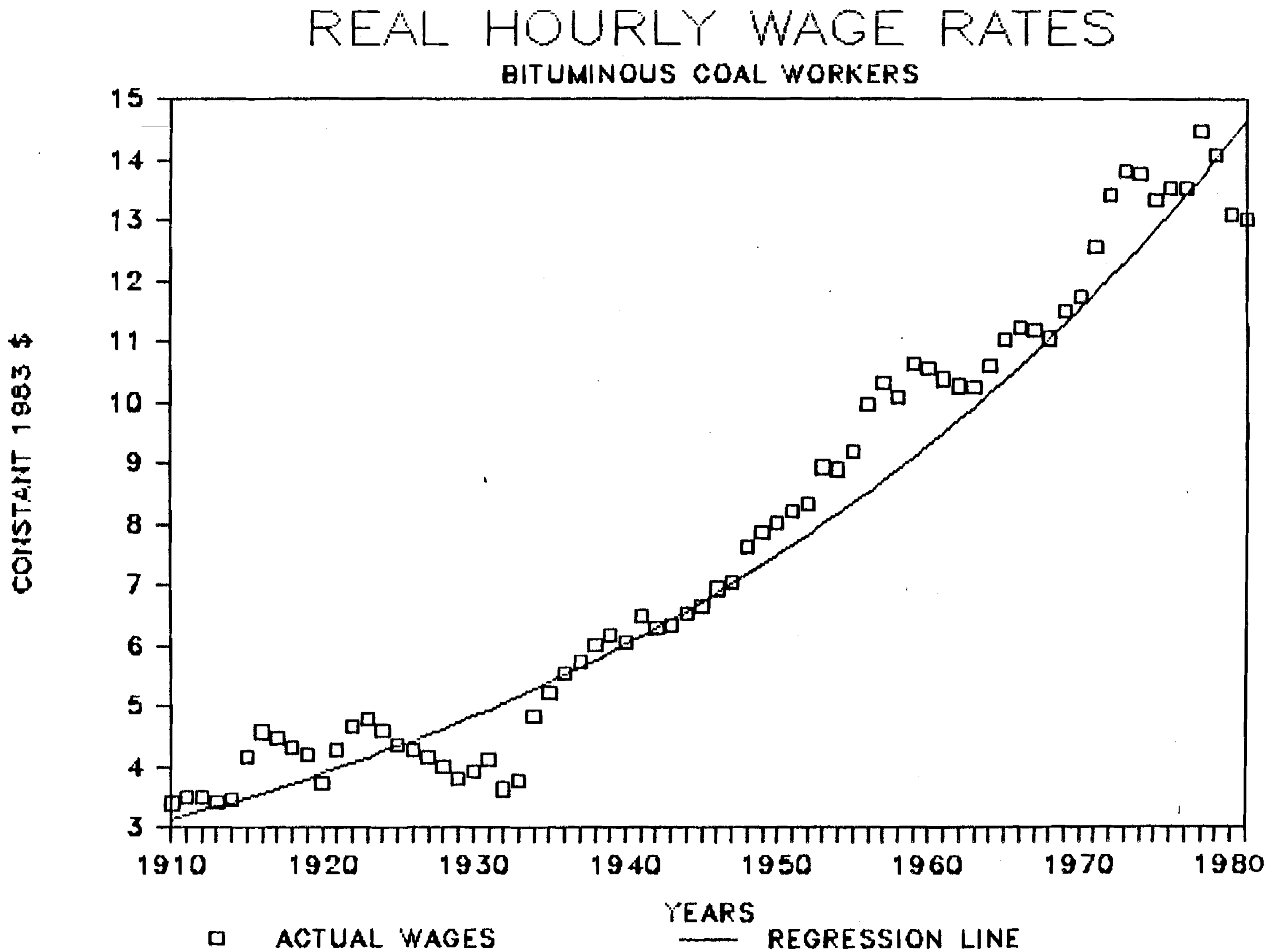

REAL HOURLY WAGE RATES
BITUMINOUS COAL WORKERS
CONSTANT 1983 $
15
14
13
12
11
10
9
8
7
6
5
4
3
1910
1920
1930
1940
1950
1960
1970
1980
YEARS
ACTUAL WAGES
REGRESSION LINE

FIGURE 2-5

used to determine how well the derived trend line fits the observed data. For both wage series a 95 percent correlation was obtained, indicating a very close fit (a perfect fit is 100 percent). Thus the historical real wage rate has increased 2.2 percent per year for the past 70 years, whether all industry or bituminous industry wages are considered. This rate of increase is projected to continue through 2050.

2.2.2 Energy Price Escalation

The price of energy inputs used in coal mining has a small but significant effect on production costs. Two energy sources predominate--diesel fuel and electricity. Both of these sources are projected to escalate in real terms from 1985 to 2050, thus inducing a real escalation of coal mining costs.

According to a H-E Composite Oil Price Projection the 1985 constant dollar price of diesel fuel delivered in the Railbelt area is projected to rise from $7.18 to $19.62 per MMBTU (million British thermal units) from 1985 to 2023, then level off due to competition from synfuels. This results in a real average annual price escalation of 2.23 per cent. Lubricant prices are assumed to follow this same price trend.

The future cost for electricity in the railbelt is dependent on the method of electrical generation. Because coal price affects the forecast price of electricity in non-Susitna electrical generation, a degree of circularity is implicit in forecasting the electrical price componente of coal mining costs. This circularity, though unavoidable, has a minuscule effect on the coal price escalation rate.

According to Harza-Basco Joint Venture projections,[8] real electricity prices in the Fairbanks area are expected to remain flat at about 0.096 per

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8. Harza-Basco Joint Venture, Bruno Trouille. Personal communication to Marvin Feldman, 7/19/84.

KWH (or about $28.06/MMBTU). The prices during this period will be stabilized by the intertie to the lower priced Anchorage area grid. From 2010 to 2050 electricity prices are expected to rise at 1.9 percent per year. The average annual real escalation from 1985 to 2050 is projected to be 1.3 percent.

The Anchorage area electricity price is 0.0479 per KWH ($14.03 per MMBTU) in 1985. This price is projected[9] to rise at a real average annual rate of 1.9 percent per year from 1985 through 2050. By 2050 the real (constant 1985 $) price of electricity is projected to be $0.163 per KWH ($47.66 per MMBTU).

The energy price projections for diesel oil and electricity are illustrated in Figure 2-6 and documented in Table 2-3.

2.2.3 Royalties

Royalty payments are presently set at 12.5 percent of the realization (selling price). As the labor and energy prices escalate in real terms, the royalty payments will also escalate in proportion.

2.2.4 Non-Escalating Production Costs

The remaining production costs include depreciation of capital investments, parts and supplies, explosives, normal profits, income and production taxes. All of these costs are assumed to remain constant (in real terms) over the 1985 to 2050 assessment period.

Capital depreciation, parts and supplies and explosives are assumed to escalate at the same rate as general inflation, thus exhibiting zero real escalation. This is a conservative assumption insofar as the costs for items are driven in part by energy and labor costs which can be expected to escalate.

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9. Ibid.

PROJECTIONS OF ENERGY PRICES

FOR ELECTRICITY AND DEISEL FUEL, 1984-2050

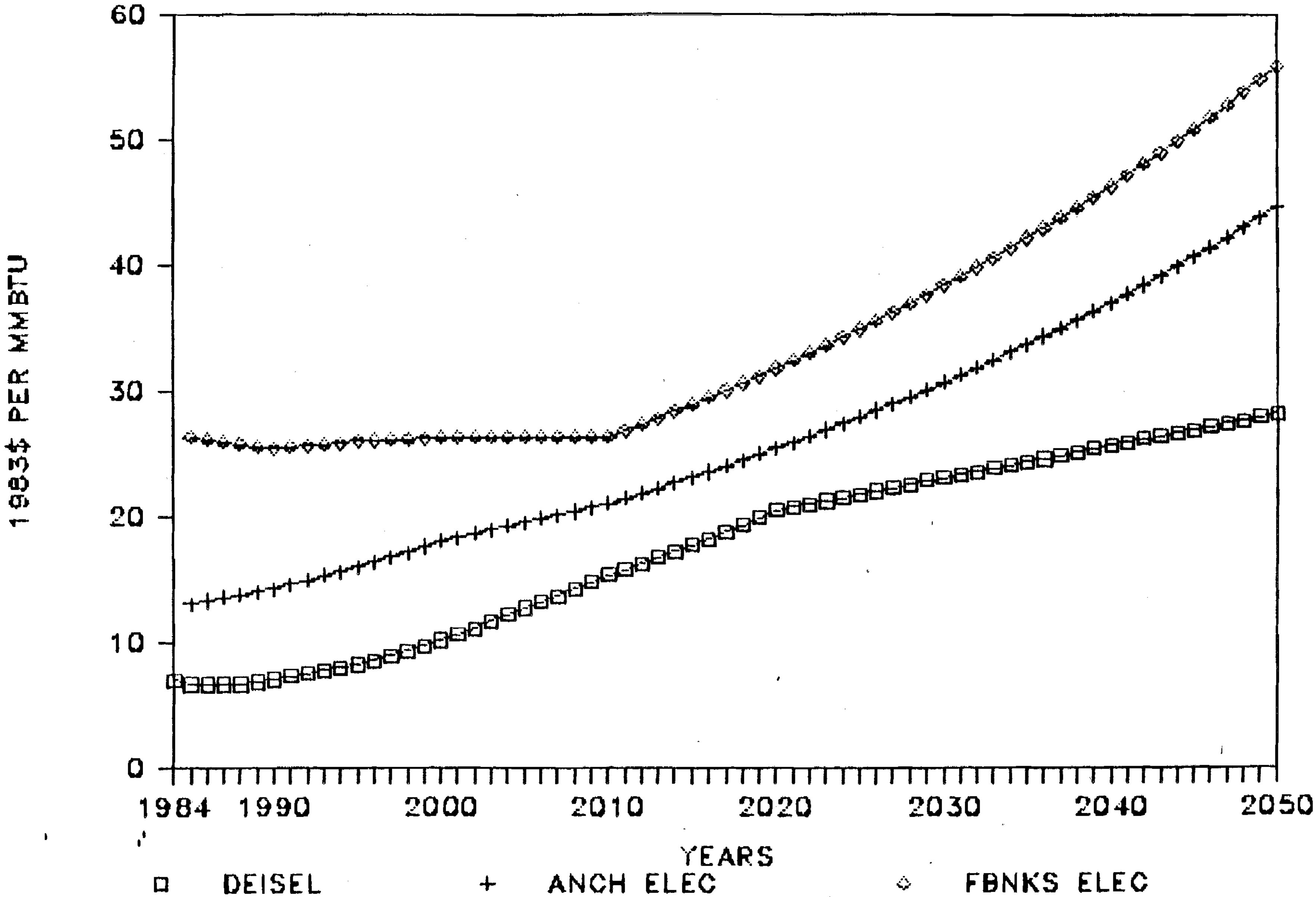

FIGURE 2-6

TABLE 2-3: FUEL AND ELECTRICITY PRICE PROJECTIONS

	(1)	(2)	(3)	(4)	(5)
YEAR	DEISEL FUEL 1985 $/MMBTU	ANCH AREA ELEC COST 1985 C/KWH	ANCH AREA ELEC COST 1985 $/MMBTU	FBNK AREA ELEC COST 1985 C/KWH	FBNK AREA ELEC COST 1985 $/MMBTU
1985	7.18	4.79	14.03	9.57	28.06
1986	7.18	4.87	14.27	9.51	27.87
1987	7.18	4.95	14.52	9.44	27.68
1988	7.18	5.04	14.77	9.38	27.49
1989	7.39	5.13	15.02	9.32	27.30
1990	7.62	5.21	15.28	9.26	27.13
1991	7.85	5.33	15.63	9.30	27.25
1992	8.08	5.46	16.00	9.34	27.38
1993	8.34	5.59	16.38	9.38	27.50
1994	8.61	5.72	16.76	9.43	27.63
1995	8.87	5.85	17.15	9.47	27.75
1996	9.26	5.99	17.56	9.49	27.81
1997	9.65	6.14	17.99	9.51	27.87
1998	10.05	6.29	18.42	9.53	27.93
1999	10.48	6.44	18.87	9.55	27.99
2000	10.93	6.60	19.33	9.57	28.06
2001	11.41	6.70	19.63	9.57	28.06
2002	11.95	6.80	19.94	9.57	28.06
2003	12.50	6.91	20.25	9.57	28.06
2004	13.05	7.02	20.57	9.57	28.06
2005	13.65	7.13	20.89	9.57	28.06
2006	14.17	7.23	21.19	9.57	28.06
2007	14.68	7.34	21.50	9.57	28.06
2008	15.22	7.44	21.81	9.57	28.06
2009	15.79	7.55	22.13	9.57	28.06
2010	16.38	7.66	22.45	9.57	28.06
2011	16.86	7.80	22.87	9.76	28.59
2012	17.35	7.95	23.31	9.94	29.14
2013	17.86	8.10	23.75	10.13	29.69
2014	18.38	8.26	24.20	10.32	30.25
2015	18.92	8.42	24.66	10.52	30.83
2016	19.47	8.58	25.13	10.72	31.42
2017	20.04	8.74	25.61	10.92	32.01
2018	20.62	8.90	26.10	11.13	32.62
2019	21.23	9.07	26.59	11.34	33.24
2020	21.85	9.25	27.10	11.56	33.87
2021	22.11	9.42	27.61	11.78	34.52
2022	22.37	9.60	28.14	12.00	35.17
2023	22.64	9.78	28.67	12.23	35.84
2024	22.91	9.97	29.22	12.46	36.52
2025	23.18	10.16	29.77	12.70	37.21
2026	23.46	10.35	30.34	12.94	37.92
2027	23.74	10.55	30.91	13.18	38.64
2028	24.02	10.75	31.50	13.44	39.38
2029	24.31	10.95	32.10	13.69	40.12
2030	24.58	11.16	32.71	13.95	40.89
2031	24.85	11.37	33.33	14.22	41.66
2032	25.11	11.59	33.96	14.49	42.45
2033	25.37	11.81	34.61	14.76	43.26
2034	25.64	12.03	35.27	15.04	44.08
2035	25.92	12.26	35.94	15.33	44.92
2036	26.19	12.49	36.62	15.62	45.77
2037	26.47	12.73	37.32	15.91	46.64
2038	26.75	12.97	38.02	16.22	47.53
2039	27.03	13.22	38.75	16.53	48.43
2040	27.32	13.47	39.48	16.84	49.35
2041	27.58	13.73	40.23	17.16	50.29
2042	27.85	13.99	41.00	17.49	51.25
2043	28.11	14.25	41.78	17.82	52.22
2044	28.38	14.52	42.57	18.16	53.21
2045	28.66	14.80	43.38	18.50	54.22
2046	28.93	15.08	44.20	18.85	55.25
2047	29.21	15.37	45.04	19.21	56.30
2048	29.49	15.66	45.90	19.58	57.37
2049	29.77	15.96	46.77	19.95	58.46
2050	30.05	16.26	47.66	20.33	59.57

Source: Dames & Moore calculations, July, 1985

NOTES TO TABLE 2-3:

Column (1) Delivered diesel fuel projections by Sherman H. Clark Associates in a letter dated 23 April 1984 from SHCA to Pillsbury, Madison & Sutro, counsel to APA. Values from 2011-2019, 2021-2029, 2031-2039 and 2041-2049 interpolated logarithmetrically.

Columns (2) and (4) Based on Harza-Basco Joint Venture, Bruno Trouille, personal communication to M. Feldman, July 1984.

Columns (3) and (5) Calculated by Dames & Moore based on 3412 BTU per KWH.

Income taxes and profits are assumed to remain constant in real terms because normal profits are based on a return on capital investments, which are assumed not to escalate. Because profits will not escalate, income taxes, which are based on profits, will not escalate.

Production taxes include the Alaska License Tax and the federal Black Lung Tax. Production taxes total $0.85 per ton in 1983. They are expected to increase at the general inflation rate over the period of analysis, hence a zero real escalation rate.

2.3 ESCALATED PRODUCTION COSTS FOR BELUGA AND NENANA MINES 1983-2050

The Paul Weir Company has developed mining cost data for several alternative hypothetical coal mines in the Beluga and Nenana coal fields. The cost data developed by Weir, although levelized over a 38-year mine life, are expressed in "instant-build" January 1983 dollars. That is to say that all years' mining activities are costed as if they took place at January 1983 prices.

As discussed in Section 2.1 and 2.2 certain cost factors are projected to escalate over time. Using the Weir Company's factor breakdown of levelized costs, Dames & Moore applied the cost escalation factors developed in Section 2.2. The relevant Weir Company data are reproduced in Appendix G.

In applying the escalation factors to the Weir Company production cost data, only selected operating cost factors were escalated. Labor costs plus general and administrative costs were escalated at the labor cost escalation factor of 2.2 percent per year. Fuel and lube, and electrical power were escalated at their appropriate rates. Royalties were escalated to reflect the escalation of the above mentioned factors. All other cost factors included in the realization (selling price) were held constant at the 1985 instant-build levels but expressed in 1985$.

Tables 2-4, 2-5 and Figure 2-7 illustrate the effects of factor escalation on the production cost of coal at a hypothetical 8 MMTPY (million ton per year) mine at Beluga. Tables 2-6 through 2-11 present the calculations used to estimate the escalated production costs from 1985 to 2050 for 1, 3, 8 and 12 MMTPY mines at Beluga and for an incremental 2 MMTPY mine and a new 3 MMTPY mine at Nenana.

2.4 RAIL TRANSPORTATION COST ESCALATION

Nenana field coal from Healy is likely to be transported by rail for Railbelt electrical generation. This coal would almost certainly be burned outside of the Healy area which is in a restrictive Class I airshed due to its proximity to Denali National Park. The thermal alternative scenario assumes that the two new Nenana coalfield-fired generating plants would be located in Nenana, which is the lowest-cost rail haul from the existing Usibelli mine at Healy.

2.4.1 Current Alaska Rail Tariffs

Table 2-12 shows the 1985 published Alaska Railroad (ARR) rail tariffs for carload shipments of coal from Healy to alternative destinations.

Usibelli Mining Company (UMC) owns and operates a loading facility at Healy. This facility has a capacity for up to about five million tons per year. The cost for loading is included in the price quotes for Usibelli Coal.

According to John Gray, Alaska Railroad, (personal communication to Marvin Feldman, Dames & Moore, 7/85), unit train operations could reduce rail costs by 15 to 25 percent. However, because the haul distance from Healy to a presumed powerplant site in Nenana is so short (about 60 miles), it would be difficult to have a sufficient rate of utilization to justify the high capital investment necessary for unit train equipment. Thus the $0.39 per MMBTU cost for rail transportation to Nenana might reasonably apply even to large volumes.

TABLE 2-4: SUMMARY OF FACTOR PRICE ESCALATION EFFECTS ON BELUGA COAL PRICES

FACTOR	REAL ESCALATION RATE PCT	1985 COST 1 MMTPY 1985 $/TON	2050 COST 1 MMTPY 1985 $/TON	1985 COST 3 MMTPY 1985 $/TON	2050 COST 3 MMTPY 1985 $/TON	1985 COST 8 MMTPY 1985 $/TON	2050 COST 8 MMTPY 1985 $/TON	1985 COST 12 MMTPY 1985 $/TON	2050 COST 12 MMTPY 1985 $/TON
LABOR	2.20	11.59	47.68	10.17	41.83	7.28	29.95	7.47	30.73
FUEL & LUBE	1.58	1.49	4.13	1.34	3.71	0.90	2.49	1.00	2.77
ELECTRICITY	1.90	0.08	0.26	0.36	1.24	0.66	2.24	2.42	8.23
CAPITAL+TAX	0.00	20.13	20.13	13.62	13.62	8.51	8.51	8.89	8.89
ROYALTY	VAR.	4.75	10.31	3.64	8.63	2.48	6.17	2.83	7.23
TOTAL	VAR.	38.04	82.51	29.13	69.02	19.83	49.37	22.60	57.85

Source: Dames & Moore calculations, July, 1985

TABLE 2-5: SUMMARY OF FACTOR PRICE ESCALATION EFFECTS ON NENANA COAL PRICES

FACTOR	REAL ESCALATION RATE PCT	1985 COST 2 MMTPY 1985 $/TON	2050 COST 2 MMTPY 1985 $/TON	1985 COST 3 MMTPY 1985 $/TON	2050 COST 3 MMTPY 1985 $/TON
LABOR	2.20	8.69	35.75	9.27	38.13
FUEL & LUBE	1.58	1.05	2.91	1.04	2.88
ELECTRICITY	1.30	0.71	1.64	0.78	1.79
CAPITAL+TAX	0.00	11.18	11.18	15.37	15.37
ROYALTY	**	3.09	7.35	3.78	8.31
TOTAL		24.71	58.84	30.23	66.49

Source: Dames & Moore calculations, July, 1985

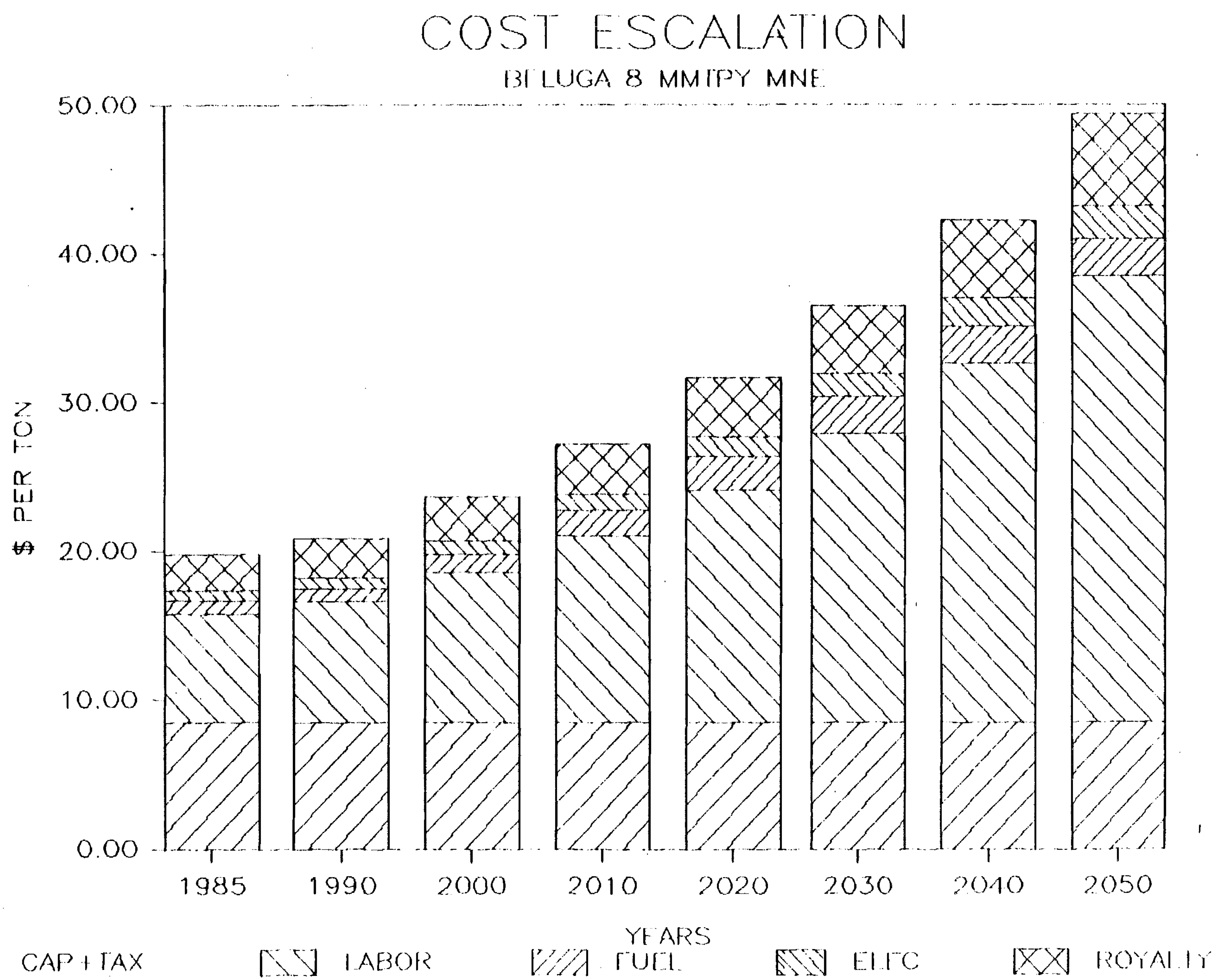
COST ESCALATION
BELUGA 8 MMTPY MNE
$ PER TON
50.00
40.00
30.00
20.00
10.00
0.00
1985
1990
2000
2010
2020
2030
2040
2050
YEARS
CAP+TAX
LABOR
FUEL
ELEC
ROYALTY

Figure 2-7

TABLE 2-6: PRODUCTION COST ESCALATION--BELUGA 1 MILLION TPY MINE

Year	CAPITAL+TAX PROFIT+PARTS 0% ESC. 1985 $ Per Ton	LABOR 2.2% ESC. 1985 $ Per Ton	FUEL+LUBE VAR. ESC. 1985 $ Per Ton	ELECTRICTY 1.9 % ESC. 1985 $ Per Ton	ROYALTY @12.5% OF REALIZATION 1985 $ Per Ton	TOTAL ESCALATED COST 1985 $ Per Ton	TOTAL ESCALATED COST 1985 $ Per MMBTU
1983	20.13	11.10	1.49	0.07	4.68	37.47	2.50
1984	20.13	11.34	1.49	0.08	4.72	37.75	2.52
1985	20.13	11.59	1.49	0.08	4.75	38.04	2.54
1986	20.13	11.84	1.48	0.08	4.79	38.32	2.55
1987	20.13	12.10	1.48	0.08	4.83	38.62	2.57
1988	20.13	12.37	1.47	0.08	4.86	38.91	2.59
1989	20.13	12.64	1.46	0.08	4.90	39.22	2.61
1990	20.13	12.92	1.46	0.08	4.94	39.53	2.64
1991	20.13	13.21	1.51	0.09	4.99	39.92	2.66
1992	20.13	13.50	1.57	0.09	5.04	40.32	2.69
1993	20.13	13.79	1.62	0.09	5.09	40.73	2.72
1994	20.13	14.10	1.68	0.09	5.14	41.14	2.74
1995	20.13	14.41	1.75	0.09	5.20	41.57	2.77
1996	20.13	14.72	1.81	0.10	5.25	42.01	2.80
1997	20.13	15.05	1.88	0.10	5.31	42.46	2.83
1998	20.13	15.38	1.95	0.10	5.36	42.92	2.86
1999	20.13	15.72	2.02	0.10	5.42	43.39	2.89
2000	20.13	16.06	2.09	0.10	5.48	43.87	2.92
2001	20.13	16.42	2.16	0.10	5.54	44.35	2.96
2002	20.13	16.78	2.22	0.11	5.60	44.84	2.99
2003	20.13	17.15	2.29	0.11	5.67	45.34	3.02
2004	20.13	17.52	2.36	0.11	5.73	45.85	3.06
2005	20.13	17.91	2.43	0.11	5.80	46.37	3.09
2006	20.13	18.30	2.50	0.11	5.86	46.91	3.13
2007	20.13	18.71	2.58	0.12	5.93	47.46	3.16
2008	20.13	19.12	2.65	0.12	6.00	48.02	3.20
2009	20.13	19.54	2.73	0.12	6.07	48.59	3.24
2010	20.13	19.97	2.81	0.12	6.15	49.18	3.28
2011	20.13	20.41	2.90	0.13	6.22	49.78	3.32
2012	20.13	20.86	2.99	0.13	6.30	50.40	3.36
2013	20.13	21.31	3.08	0.13	6.38	51.03	3.40
2014	20.13	21.78	3.17	0.13	6.46	51.67	3.44
2015	20.13	22.26	3.26	0.14	6.54	52.33	3.49
2016	20.13	22.75	3.36	0.14	6.63	53.00	3.53
2017	20.13	23.25	3.46	0.14	6.71	53.69	3.58
2018	20.13	23.76	3.56	0.14	6.80	54.40	3.63
2019	20.13	24.29	3.67	0.15	6.89	55.12	3.67
2020	20.13	24.82	3.78	0.15	6.98	55.86	3.72
2021	20.13	25.37	3.90	0.15	7.08	56.62	3.77
2022	20.13	25.93	4.01	0.16	7.17	57.39	3.83
2023	20.13	26.50	4.13	0.16	7.27	58.19	3.88
2024	20.13	27.08	4.13	0.16	7.36	58.86	3.92
2025	20.13	27.67	4.13	0.16	7.44	59.54	3.97
2026	20.13	28.28	4.13	0.17	7.53	60.24	4.02
2027	20.13	28.91	4.13	0.17	7.62	60.96	4.06
2028	20.13	29.54	4.13	0.17	7.71	61.69	4.11
2029	20.13	30.19	4.13	0.18	7.80	62.43	4.16
2030	20.13	30.86	4.13	0.18	7.90	63.20	4.21
2031	20.13	31.53	4.13	0.18	8.00	63.98	4.27
2032	20.13	32.23	4.13	0.19	8.10	64.77	4.32
2033	20.13	32.94	4.13	0.19	8.20	65.59	4.37
2034	20.13	33.66	4.13	0.19	8.30	66.42	4.43
2035	20.13	34.40	4.13	0.20	8.41	67.27	4.48
2036	20.13	35.16	4.13	0.20	8.52	68.14	4.54
2037	20.13	35.93	4.13	0.21	8.63	69.03	4.60
2038	20.13	36.72	4.13	0.21	8.74	69.93	4.66
2039	20.13	37.53	4.13	0.21	8.86	70.86	4.72
2040	20.13	38.36	4.13	0.22	8.98	71.81	4.79
2041	20.13	39.20	4.13	0.22	9.10	72.78	4.85
2042	20.13	40.06	4.13	0.23	9.22	73.77	4.92
2043	20.13	40.94	4.13	0.23	9.35	74.78	4.99
2044	20.13	41.85	4.13	0.23	9.48	75.82	5.05
2045	20.13	42.77	4.13	0.24	9.61	76.87	5.12
2046	20.13	43.71	4.13	0.24	9.74	77.95	5.20
2047	20.13	44.67	4.13	0.25	9.88	79.06	5.27
2048	20.13	45.65	4.13	0.25	10.02	80.19	5.35
2049	20.13	46.65	4.13	0.26	10.17	81.34	5.42
2050	20.13	47.68	4.13	0.26	10.31	82.52	5.50

Source: Dames & Moore calculations, July, 1985

TABLE 2-7: PRODUCTION COST ESCALATION--3 MILLION TPY BELUGA MINE

Year	CAPITAL+TAX PROFIT+PARTS 0% ESC. 1985 $ Per Ton	LABOR 2.2% ESC. 1985 $ Per Ton	FUEL+LUBE VAR. ESC. 1985 $ Per Ton	ELECTRICTY 1.9 % ESC. 1985 $ Per Ton	ROYALTY @12.5% OF REALIZATION 1985 $ Per Ton	TOTAL ESCALATED COST 1985 $ Per Ton	TOTAL ESCALATED COST 1985 $ Per MMBTU
1983	13.62	9.73	1.34	0.35	3.58	28.62	1.91
1984	13.62	9.95	1.34	0.36	3.61	28.87	1.92
1985	13.62	10.17	1.34	0.36	3.64	29.13	1.94
1986	13.62	10.39	1.33	0.37	3.67	29.39	1.96
1987	13.62	10.62	1.33	0.38	3.71	29.65	1.98
1988	13.62	10.85	1.32	0.39	3.74	29.92	1.99
1989	13.62	11.09	1.32	0.39	3.77	30.19	2.01
1990	13.62	11.34	1.31	0.40	3.81	30.47	2.03
1991	13.62	11.58	1.36	0.41	3.85	30.82	2.05
1992	13.62	11.84	1.41	0.42	3.90	31.18	2.08
1993	13.62	12.10	1.46	0.42	3.94	31.54	2.10
1994	13.62	12.37	1.52	0.43	3.99	31.92	2.13
1995	13.62	12.64	1.57	0.44	4.04	32.30	2.15
1996	13.62	12.92	1.63	0.45	4.09	32.70	2.18
1997	13.62	13.20	1.69	0.46	4.14	33.10	2.21
1998	13.62	13.49	1.75	0.47	4.19	33.51	2.23
1999	13.62	13.79	1.82	0.47	4.24	33.94	2.26
2000	13.62	14.09	1.88	0.48	4.30	34.37	2.29
2001	13.62	14.40	1.94	0.49	4.35	34.80	2.32
2002	13.62	14.72	2.00	0.50	4.40	35.24	2.35
2003	13.62	15.04	2.06	0.51	4.46	35.69	2.38
2004	13.62	15.37	2.12	0.52	4.52	36.15	2.41
2005	13.62	15.71	2.18	0.53	4.58	36.62	2.44
2006	13.62	16.06	2.25	0.54	4.64	37.10	2.47
2007	13.62	16.41	2.32	0.55	4.70	37.59	2.51
2008	13.62	16.77	2.39	0.56	4.76	38.10	2.54
2009	13.62	17.14	2.46	0.57	4.83	38.61	2.57
2010	13.62	17.52	2.53	0.58	4.89	39.14	2.61
2011	13.62	17.90	2.61	0.59	4.96	39.68	2.65
2012	13.62	18.30	2.69	0.61	5.03	40.23	2.68
2013	13.62	18.70	2.77	0.62	5.10	40.80	2.72
2014	13.62	19.11	2.85	0.63	5.17	41.38	2.76
2015	13.62	19.53	2.93	0.64	5.25	41.97	2.80
2016	13.62	19.96	3.02	0.65	5.32	42.57	2.84
2017	13.62	20.40	3.11	0.67	5.40	43.19	2.88
2018	13.62	20.85	3.21	0.68	5.48	43.83	2.92
2019	13.62	21.31	3.30	0.69	5.56	44.48	2.97
2020	13.62	21.78	3.40	0.70	5.64	45.14	3.01
2021	13.62	22.25	3.50	0.72	5.73	45.82	3.05
2022	13.62	22.74	3.61	0.73	5.81	46.51	3.10
2023	13.62	23.24	3.72	0.75	5.90	47.23	3.15
2024	13.62	23.76	3.72	0.76	5.98	47.83	3.19
2025	13.62	24.28	3.72	0.77	6.06	48.44	3.23
2026	13.62	24.81	3.72	0.79	6.13	49.07	3.27
2027	13.62	25.36	3.72	0.80	6.21	49.71	3.31
2028	13.62	25.92	3.72	0.82	6.30	50.36	3.36
2029	13.62	26.49	3.72	0.83	6.38	51.03	3.40
2030	13.62	27.07	3.72	0.85	6.46	51.72	3.45
2031	13.62	27.66	3.72	0.87	6.55	52.42	3.49
2032	13.62	28.27	3.72	0.88	6.64	53.13	3.54
2033	13.62	28.90	3.72	0.90	6.73	53.86	3.59
2034	13.62	29.53	3.72	0.92	6.83	54.61	3.64
2035	13.62	30.18	3.72	0.93	6.92	55.37	3.69
2036	13.62	30.84	3.72	0.95	7.02	56.15	3.74
2037	13.62	31.52	3.72	0.97	7.12	56.94	3.80
2038	13.62	32.22	3.72	0.99	7.22	57.76	3.85
2039	13.62	32.93	3.72	1.01	7.32	58.59	3.91
2040	13.62	33.65	3.72	1.03	7.43	59.44	3.96
2041	13.62	34.39	3.72	1.05	7.54	60.31	4.02
2042	13.62	35.15	3.72	1.07	7.65	61.20	4.08
2043	13.62	35.92	3.72	1.09	7.76	62.10	4.14
2044	13.62	36.71	3.72	1.11	7.88	63.03	4.20
2045	13.62	37.52	3.72	1.13	8.00	63.98	4.27
2046	13.62	38.34	3.72	1.15	8.12	64.94	4.33
2047	13.62	39.19	3.72	1.17	8.24	65.93	4.40
2048	13.62	40.05	3.72	1.19	8.37	66.94	4.46
2049	13.62	40.93	3.72	1.22	8.50	67.98	4.53
2050	13.62	41.83	3.72	1.24	8.63	69.03	4.60

Source: Dames & Moore calculations, July, 1985

TABLE 2-8: PRODUCTION COST ESCALATION--8 MILLION TPY MINE

Year	CAPITAL+TAX PROFIT+PARTS 0% ESC. 1985 $ Per Ton	LABOR 2.2% ESC. 1985 $ Per Ton	FUEL+LUBE VAR. ESC. 1985 $ Per Ton	ELECTRICTY 1.9 % ESC. 1985 $ Per Ton	ROYALTY @12.5% OF REALIZATION 1985 $ Per Ton	TOTAL ESCALATED COST 1985 $ Per Ton	TOTAL ESCALATED COST 1985 $ Per MMBTU
1983	8.51	6.97	0.90	0.64	2.43	19.45	1.30
1984	8.51	7.12	0.90	0.65	2.45	19.64	1.31
1985	8.51	7.28	0.90	0.66	2.48	19.83	1.32
1986	8.51	7.44	0.90	0.68	2.50	20.02	1.33
1987	8.51	7.60	0.89	0.69	2.53	20.22	1.35
1988	8.51	7.77	0.89	0.70	2.55	20.42	1.36
1989	8.51	7.94	0.88	0.71	2.58	20.63	1.38
1990	8.51	8.11	0.88	0.73	2.60	20.84	1.39
1991	8.51	8.29	0.91	0.74	2.64	21.10	1.41
1992	8.51	8.48	0.95	0.76	2.67	21.36	1.42
1993	8.51	8.66	0.98	0.77	2.70	21.63	1.44
1994	8.51	8.85	1.02	0.79	2.74	21.90	1.46
1995	8.51	9.05	1.06	0.80	2.77	22.19	1.48
1996	8.51	9.25	1.09	0.82	2.81	22.48	1.50
1997	8.51	9.45	1.13	0.83	2.85	22.77	1.52
1998	8.51	9.66	1.18	0.85	2.88	23.08	1.54
1999	8.51	9.87	1.22	0.86	2.92	23.39	1.56
2000	8.51	10.09	1.25	0.88	2.96	23.70	1.58
2001	8.51	10.31	1.30	0.90	3.00	24.02	1.60
2002	8.51	10.54	1.34	0.91	3.04	24.34	1.62
2003	8.51	10.77	1.38	0.93	3.08	24.67	1.64
2004	8.51	11.00	1.42	0.95	3.13	25.01	1.67
2005	8.51	11.25	1.47	0.97	3.17	25.36	1.69
2006	8.51	11.49	1.51	0.98	3.21	25.71	1.71
2007	8.51	11.75	1.56	1.00	3.26	26.08	1.74
2008	8.51	12.01	1.60	1.02	3.31	26.45	1.76
2009	8.51	12.27	1.65	1.04	3.35	26.82	1.79
2010	8.51	12.54	1.70	1.06	3.40	27.21	1.81
2011	8.51	12.82	1.75	1.08	3.45	27.61	1.84
2012	8.51	13.10	1.80	1.10	3.50	28.01	1.87
2013	8.51	13.39	1.86	1.12	3.55	28.43	1.90
2014	8.51	13.68	1.91	1.14	3.61	28.85	1.92
2015	8.51	13.98	1.97	1.17	3.66	29.29	1.95
2016	8.51	14.29	2.03	1.19	3.72	29.73	1.98
2017	8.51	14.60	2.09	1.21	3.77	30.19	2.01
2018	8.51	14.92	2.15	1.23	3.83	30.65	2.04
2019	8.51	15.25	2.22	1.26	3.89	31.13	2.08
2020	8.51	15.59	2.28	1.28	3.95	31.62	2.11
2021	8.51	15.93	2.35	1.31	4.01	32.11	2.14
2022	8.51	16.28	2.42	1.33	4.08	32.62	2.17
2023	8.51	16.64	2.50	1.36	4.14	33.14	2.21
2024	8.51	17.01	2.50	1.38	4.20	33.59	2.24
2025	8.51	17.38	2.50	1.41	4.26	34.05	2.27
2026	8.51	17.76	2.50	1.43	4.31	34.52	2.30
2027	8.51	18.15	2.50	1.46	4.37	34.99	2.33
2028	8.51	18.55	2.50	1.49	4.44	35.48	2.37
2029	8.51	18.96	2.50	1.52	4.50	35.98	2.40
2030	8.51	19.38	2.50	1.55	4.56	36.49	2.43
2031	8.51	19.80	2.50	1.58	4.63	37.01	2.47
2032	8.51	20.24	2.50	1.61	4.69	37.54	2.50
2033	8.51	20.68	2.50	1.64	4.76	38.09	2.54
2034	8.51	21.14	2.50	1.67	4.83	38.64	2.58
2035	8.51	21.60	2.50	1.70	4.90	39.21	2.61
2036	8.51	22.08	2.50	1.73	4.97	39.79	2.65
2037	8.51	22.57	2.50	1.76	5.05	40.38	2.69
2038	8.51	23.06	2.50	1.80	5.12	40.99	2.73
2039	8.51	23.57	2.50	1.83	5.20	41.61	2.77
2040	8.51	24.09	2.50	1.87	5.28	42.24	2.82
2041	8.51	24.62	2.50	1.90	5.36	42.89	2.86
2042	8.51	25.16	2.50	1.94	5.44	43.55	2.90
2043	8.51	25.71	2.50	1.97	5.53	44.22	2.95
2044	8.51	26.28	2.50	2.01	5.61	44.91	2.99
2045	8.51	26.86	2.50	2.05	5.70	45.62	3.04
2046	8.51	27.45	2.50	2.09	5.79	46.34	3.09
2047	8.51	28.05	2.50	2.13	5.88	47.07	3.14
2048	8.51	28.67	2.50	2.17	5.98	47.82	3.19
2049	8.51	29.30	2.50	2.21	6.07	48.59	3.24
2050	8.51	29.94	2.50	2.25	6.17	49.38	3.29

Source: Dames & Moore calculations, July, 1985

TABLE 2-9: PRODUCTION COST ESCALATION--12 MILLION TPY BELUGA MINE

Year	CAPITAL+TAX PROFIT+PARTS 0% ESC. 1985 $ Per Ton	LABOR 2.2% ESC. 1985 $ Per Ton	FUEL+LUBE VAR. ESC. 1985 $ Per Ton	ELECTRICTY 1.9 % ESC. 1985 $ Per Ton	ROYALTY @12.5% OF REALIZATION 1985 $ Per Ton	TOTAL ESCALATED COST 1985 $ Per Ton	TOTAL ESCALATED COST 1985 $ Per MMBTU
1983	8.89	7.15	1.00	2.33	2.77	22.14	1.48
1984	8.89	7.31	1.00	2.37	2.80	22.37	1.49
1985	8.89	7.47	1.00	2.42	2.83	22.60	1.51
1986	8.89	7.63	1.00	2.47	2.86	22.84	1.52
1987	8.89	7.80	0.99	2.51	2.89	23.08	1.54
1988	8.89	7.97	0.99	2.56	2.92	23.33	1.56
1989	8.89	8.15	0.98	2.61	2.95	23.58	1.57
1990	8.89	8.33	0.98	2.66	2.98	23.83	1.59
1991	8.89	8.51	1.01	2.71	3.02	24.14	1.61
1992	8.89	8.70	1.05	2.76	3.06	24.46	1.63
1993	8.89	8.89	1.09	2.81	3.10	24.78	1.65
1994	8.89	9.08	1.13	2.87	3.14	25.11	1.67
1995	8.89	9.28	1.17	2.92	3.18	25.45	1.70
1996	8.89	9.49	1.22	2.98	3.22	25.80	1.72
1997	8.89	9.69	1.26	3.03	3.27	26.15	1.74
1998	8.89	9.91	1.31	3.09	3.31	26.51	1.77
1999	8.89	10.13	1.36	3.15	3.36	26.88	1.79
2000	8.89	10.35	1.41	3.21	3.41	27.26	1.82
2001	8.89	10.58	1.45	3.27	3.46	27.64	1.84
2002	8.89	10.81	1.49	3.33	3.50	28.03	1.87
2003	8.89	11.05	1.54	3.39	3.55	28.42	1.89
2004	8.89	11.29	1.58	3.46	3.60	28.83	1.92
2005	8.89	11.54	1.63	3.52	3.66	29.24	1.95
2006	8.89	11.79	1.68	3.59	3.71	29.66	1.98
2007	8.89	12.05	1.73	3.66	3.76	30.10	2.01
2008	8.89	12.32	1.78	3.73	3.82	30.54	2.04
2009	8.89	12.59	1.83	3.80	3.87	30.99	2.07
2010	8.89	12.86	1.89	3.87	3.93	31.45	2.10
2011	8.89	13.15	1.95	3.95	3.99	31.92	2.13
2012	8.89	13.44	2.00	4.02	4.05	32.41	2.16
2013	8.89	13.73	2.06	4.10	4.11	32.90	2.19
2014	8.89	14.03	2.13	4.18	4.18	33.41	2.23
2015	8.89	14.34	2.19	4.25	4.24	33.92	2.26
2016	8.89	14.66	2.26	4.34	4.31	34.45	2.30
2017	8.89	14.98	2.32	4.42	4.37	34.99	2.33
2018	8.89	15.31	2.39	4.50	4.44	35.54	2.37
2019	8.89	15.65	2.46	4.59	4.51	36.11	2.41
2020	8.89	15.99	2.54	4.67	4.59	36.68	2.45
2021	8.89	16.34	2.61	4.76	4.66	37.27	2.48
2022	8.89	16.70	2.69	4.85	4.73	37.88	2.53
2023	8.89	17.07	2.77	4.95	4.81	38.50	2.57
2024	8.89	17.45	2.77	5.04	4.88	39.03	2.60
2025	8.89	17.83	2.77	5.14	4.95	39.58	2.64
2026	8.89	18.22	2.77	5.23	5.02	40.14	2.68
2027	8.89	18.62	2.77	5.33	5.09	40.71	2.71
2028	8.89	19.03	2.77	5.43	5.16	41.30	2.75
2029	8.89	19.45	2.77	5.54	5.24	41.89	2.79
2030	8.89	19.88	2.77	5.64	5.31	42.50	2.83
2031	8.89	20.32	2.77	5.75	5.39	43.13	2.88
2032	8.89	20.76	2.77	5.86	5.47	43.76	2.92
2033	8.89	21.22	2.77	5.97	5.55	44.41	2.96
2034	8.89	21.69	2.77	6.08	5.63	45.07	3.00
2035	8.89	22.17	2.77	6.20	5.72	45.75	3.05
2036	8.89	22.65	2.77	6.32	5.81	46.44	3.10
2037	8.89	23.15	2.77	6.44	5.89	47.15	3.14
2038	8.89	23.66	2.77	6.56	5.98	47.87	3.19
2039	8.89	24.18	2.77	6.68	6.08	48.61	3.24
2040	8.89	24.71	2.77	6.81	6.17	49.36	3.29
2041	8.89	25.26	2.77	6.94	6.27	50.13	3.34
2042	8.89	25.81	2.77	7.07	6.36	50.92	3.39
2043	8.89	26.38	2.77	7.21	6.46	51.72	3.45
2044	8.89	26.96	2.77	7.34	6.57	52.54	3.50
2045	8.89	27.55	2.77	7.48	6.67	53.38	3.56
2046	8.89	28.16	2.77	7.63	6.78	54.23	3.62
2047	8.89	28.78	2.77	7.77	6.89	55.11	3.67
2048	8.89	29.41	2.77	7.92	7.00	56.00	3.73
2049	8.89	30.06	2.77	8.07	7.11	56.91	3.79
2050	8.89	30.72	2.77	8.22	7.23	57.84	3.86

Source: Dames & Moore calculations, July, 1985

TABLE 2-10: PRODUCTION COST ESCALATION--INCREMENTAL 2MMTPY NENANA MINE

Year	CAPITAL+TAX PROFIT+PARTS 0% ESC. 1985 $ Per Ton	LABOR 2.2% ESC. 1985 $ Per Ton	FUEL+LUBE VAR. ESC. 1985 $ Per Ton	ELECTRICTY 1.3 % ESC. 1985 $ Per Ton	ROYALTY @12.5% OF REALIZATION 1985 $ Per Ton	TOTAL ESCALATED COST 1985 $ Per Ton	TOTAL ESCALATED COST 1985 $ Per MMBTU	RAIL TRANS HEALY TO NENANA 1.8 % ESC. $ Per Ton	TOTAL ESCALATED COST FOB NENANA $ Per Ton	TOTAL ESCALATED COST FOB NENANA $ Per MMBTU
1983	11.18	8.32	1.05	0.69	3.03	24.27	1.60	5.64	29.91	1.97
1984	11.18	8.50	1.05	0.70	3.06	24.49	1.61	5.64	30.13	1.98
1985	11.18	8.69	1.05	0.71	3.09	24.72	1.63	5.92	30.64	2.02
1986	11.18	8.88	1.05	0.72	3.12	24.94	1.64	6.03	30.97	2.04
1987	11.18	9.08	1.04	0.73	3.15	25.17	1.66	6.14	31.30	2.06
1988	11.18	9.28	1.04	0.74	3.18	25.40	1.67	6.25	31.65	2.08
1989	11.18	9.48	1.03	0.75	3.21	25.64	1.69	6.36	32.00	2.11
1990	11.18	9.69	1.03	0.76	3.24	25.89	1.70	6.47	32.36	2.13
1991	11.18	9.90	1.07	0.77	3.27	26.18	1.72	6.59	32.77	2.16
1992	11.18	10.12	1.10	0.78	3.31	26.49	1.74	6.71	33.20	2.18
1993	11.18	10.34	1.15	0.79	3.35	26.80	1.76	6.83	33.63	2.21
1994	11.18	10.57	1.19	0.80	3.39	27.12	1.78	6.95	34.07	2.24
1995	11.18	10.80	1.23	0.81	3.43	27.45	1.81	7.08	34.53	2.27
1996	11.18	11.04	1.28	0.82	3.47	27.79	1.83	7.20	34.99	2.30
1997	11.18	11.28	1.32	0.83	3.52	28.13	1.85	7.33	35.46	2.33
1998	11.18	11.53	1.37	0.84	3.56	28.48	1.87	7.47	35.95	2.36
1999	11.18	11.78	1.42	0.85	3.61	28.84	1.90	7.60	36.44	2.40
2000	11.18	12.04	1.48	0.86	3.65	29.21	1.92	7.74	36.95	2.43
2001	11.18	12.31	1.52	0.87	3.70	29.58	1.95	7.88	37.45	2.46
2002	11.18	12.58	1.57	0.88	3.74	29.95	1.97	8.02	37.97	2.50
2003	11.18	12.86	1.61	0.89	3.79	30.33	2.00	8.16	38.50	2.53
2004	11.18	13.14	1.66	0.90	3.84	30.73	2.02	8.31	39.03	2.57
2005	11.18	13.43	1.71	0.92	3.89	31.13	2.05	8.46	39.58	2.60
2006	11.18	13.72	1.76	0.93	3.94	31.54	2.07	8.61	40.15	2.64
2007	11.18	14.02	1.81	0.94	3.99	31.96	2.10	8.77	40.72	2.68
2008	11.18	14.33	1.87	0.95	4.05	32.38	2.13	8.92	41.31	2.72
2009	11.18	14.65	1.93	0.97	4.10	32.82	2.16	9.08	41.91	2.76
2010	11.18	14.97	1.98	0.98	4.16	33.27	2.19	9.25	42.52	2.80
2011	11.18	15.30	2.04	0.99	4.22	33.73	2.22	9.41	43.14	2.84
2012	11.18	15.64	2.10	1.00	4.27	34.20	2.25	9.58	43.78	2.88
2013	11.18	15.98	2.17	1.02	4.33	34.68	2.28	9.76	44.44	2.92
2014	11.18	16.33	2.23	1.03	4.40	35.17	2.31	9.93	45.10	2.97
2015	11.18	16.69	2.30	1.04	4.46	35.67	2.35	10.11	45.78	3.01
2016	11.18	17.06	2.37	1.06	4.52	36.19	2.38	10.29	46.48	3.06
2017	11.18	17.43	2.44	1.07	4.59	36.71	2.42	10.48	47.19	3.10
2018	11.18	17.82	2.51	1.08	4.66	37.25	2.45	10.67	47.92	3.15
2019	11.18	18.21	2.59	1.10	4.73	37.80	2.49	10.86	48.66	3.20
2020	11.18	18.61	2.67	1.11	4.80	38.36	2.52	11.05	49.42	3.25
2021	11.18	19.02	2.75	1.13	4.87	38.94	2.56	11.25	50.19	3.30
2022	11.18	19.44	2.83	1.14	4.94	39.53	2.60	11.45	50.98	3.35
2023	11.18	19.87	2.91	1.16	5.02	40.13	2.64	11.65	51.79	3.41
2024	11.18	20.30	2.91	1.17	5.08	40.65	2.67	11.87	52.52	3.46
2025	11.18	20.75	2.91	1.19	5.15	41.18	2.71	12.08	53.26	3.50
2026	11.18	21.21	2.91	1.20	5.21	41.72	2.74	12.30	54.02	3.55
2027	11.18	21.67	2.91	1.22	5.28	42.27	2.78	12.52	54.79	3.60
2028	11.18	22.15	2.91	1.23	5.35	42.83	2.82	12.75	55.58	3.66
2029	11.18	22.64	2.91	1.25	5.43	43.40	2.86	12.98	56.38	3.71
2030	11.18	23.13	2.91	1.27	5.50	43.99	2.89	13.21	57.20	3.76
2031	11.18	23.64	2.91	1.28	5.57	44.59	2.93	13.45	58.04	3.82
2032	11.18	24.16	2.91	1.30	5.65	45.21	2.97	13.69	58.90	3.87
2033	11.18	24.70	2.91	1.32	5.73	45.83	3.02	13.94	59.77	3.93
2034	11.18	25.24	2.91	1.33	5.81	46.47	3.06	14.19	60.66	3.99
2035	11.18	25.79	2.91	1.35	5.89	47.13	3.10	14.44	61.57	4.05
2036	11.18	26.36	2.91	1.37	5.97	47.80	3.14	14.70	62.50	4.11
2037	11.18	26.94	2.91	1.39	6.06	48.48	3.19	14.97	63.45	4.17
2038	11.18	27.53	2.91	1.40	6.15	49.18	3.24	15.24	64.42	4.24
2039	11.18	28.14	2.91	1.42	6.24	49.89	3.28	15.51	65.40	4.30
2040	11.18	28.76	2.91	1.44	6.33	50.62	3.33	15.79	66.41	4.37
2041	11.18	29.39	2.91	1.46	6.42	51.36	3.38	16.08	67.44	4.44
2042	11.18	30.04	2.91	1.48	6.52	52.12	3.43	16.37	68.49	4.51
2043	11.18	30.70	2.91	1.50	6.61	52.90	3.48	16.66	69.56	4.58
2044	11.18	31.37	2.91	1.52	6.71	53.70	3.53	16.96	70.66	4.65
2045	11.18	32.06	2.91	1.54	6.81	54.51	3.59	17.27	71.77	4.72
2046	11.18	32.77	2.91	1.56	6.92	55.34	3.64	17.58	72.91	4.80
2047	11.18	33.49	2.91	1.58	7.02	56.18	3.70	17.89	74.08	4.87
2048	11.18	34.23	2.91	1.60	7.13	57.05	3.75	18.22	75.26	4.95
2049	11.18	34.98	2.91	1.62	7.24	57.93	3.81	18.54	76.48	5.03
2050	11.18	35.75	2.91	1.64	7.35	58.84	3.87	18.88	77.71	5.11

Source: Dames & Moore calculations, July, 1985

TABLE 2-11: PRODUCTION COST ESCALATION--NEW 3 MILLION TON PER YEAR MINE

Year	CAPITAL+TAX PROFIT+PARTS 0% ESC. 1985 $ Per Ton	LABOR 2.2% ESC. 1985 $ Per Ton	FUEL+LUBE VAR. ESC. 1985 $ Per Ton	ELECTRICTY 1.3 % ESC. 1985 $ Per Ton	ROYALTY @12.5% OF REALIZATION 1985 $ Per Ton	TOTAL ESCALATED COST 1985 $ Per Ton	TOTAL ESCALATED COST 1985 $ Per MMBTU
1983	15.37	8.87	1.04	0.76	3.72	29.76	1.96
1984	15.37	9.07	1.04	0.77	3.75	29.99	1.97
1985	15.37	9.27	1.04	0.78	3.78	30.23	1.99
1986	15.37	9.47	1.04	0.79	3.81	30.47	2.00
1987	15.37	9.68	1.03	0.80	3.84	30.72	2.02
1988	15.37	9.89	1.03	0.81	3.87	30.97	2.04
1989	15.37	10.11	1.02	0.82	3.90	31.22	2.05
1990	15.37	10.33	1.02	0.83	3.94	31.48	2.07
1991	15.37	10.56	1.05	0.84	3.97	31.80	2.09
1992	15.37	10.79	1.09	0.85	4.02	32.12	2.11
1993	15.37	11.03	1.13	0.86	4.06	32.45	2.13
1994	15.37	11.27	1.18	0.87	4.10	32.79	2.16
1995	15.37	11.52	1.22	0.88	4.14	33.13	2.18
1996	15.37	11.77	1.26	0.89	4.19	33.49	2.20
1997	15.37	12.03	1.31	0.91	4.23	33.85	2.23
1998	15.37	12.30	1.36	0.92	4.28	34.22	2.25
1999	15.37	12.57	1.41	0.93	4.33	34.60	2.28
2000	15.37	12.84	1.46	0.94	4.37	34.99	2.30
2001	15.37	13.13	1.51	0.95	4.42	35.38	2.33
2002	15.37	13.42	1.55	0.97	4.47	35.77	2.35
2003	15.37	13.71	1.60	0.98	4.52	36.18	2.38
2004	15.37	14.01	1.65	0.99	4.57	36.59	2.41
2005	15.37	14.32	1.69	1.00	4.63	37.02	2.44
2006	15.37	14.64	1.75	1.02	4.68	37.45	2.46
2007	15.37	14.96	1.80	1.03	4.74	37.89	2.49
2008	15.37	15.29	1.85	1.04	4.79	38.35	2.52
2009	15.37	15.62	1.91	1.06	4.85	38.81	2.55
2010	15.37	15.97	1.96	1.07	4.91	39.28	2.58
2011	15.37	16.32	2.02	1.08	4.97	39.77	2.62
2012	15.37	16.68	2.08	1.10	5.03	40.26	2.65
2013	15.37	17.04	2.15	1.11	5.10	40.77	2.68
2014	15.37	17.42	2.21	1.13	5.16	41.29	2.72
2015	15.37	17.80	2.28	1.14	5.23	41.82	2.75
2016	15.37	18.19	2.35	1.16	5.30	42.36	2.79
2017	15.37	18.59	2.42	1.17	5.36	42.92	2.82
2018	15.37	19.00	2.49	1.19	5.44	43.49	2.86
2019	15.37	19.42	2.56	1.20	5.51	44.07	2.90
2020	15.37	19.85	2.64	1.22	5.58	44.66	2.94
2021	15.37	20.28	2.72	1.23	5.66	45.27	2.98
2022	15.37	20.73	2.80	1.25	5.74	45.89	3.02
2023	15.37	21.19	2.88	1.27	5.82	46.52	3.06
2024	15.37	21.65	2.88	1.28	5.88	47.08	3.10
2025	15.37	22.13	2.88	1.30	5.95	47.64	3.13
2026	15.37	22.62	2.88	1.32	6.03	48.22	3.17
2027	15.37	23.11	2.88	1.33	6.10	48.80	3.21
2028	15.37	23.62	2.88	1.35	6.18	49.40	3.25
2029	15.37	24.14	2.88	1.37	6.25	50.02	3.29
2030	15.37	24.67	2.88	1.39	6.33	50.65	3.33
2031	15.37	25.22	2.88	1.40	6.41	51.29	3.37
2032	15.37	25.77	2.88	1.42	6.49	51.94	3.42
2033	15.37	26.34	2.88	1.44	6.58	52.61	3.46
2034	15.37	26.92	2.88	1.46	6.66	53.29	3.51
2035	15.37	27.51	2.88	1.48	6.75	53.99	3.55
2036	15.37	28.11	2.88	1.50	6.84	54.71	3.60
2037	15.37	28.73	2.88	1.52	6.93	55.44	3.65
2038	15.37	29.36	2.88	1.54	7.02	56.18	3.70
2039	15.37	30.01	2.88	1.56	7.12	56.94	3.75
2040	15.37	30.67	2.88	1.58	7.21	57.72	3.80
2041	15.37	31.35	2.88	1.60	7.31	58.51	3.85
2042	15.37	32.04	2.88	1.62	7.42	59.33	3.90
2043	15.37	32.74	2.88	1.64	7.52	60.16	3.96
2044	15.37	33.46	2.88	1.66	7.63	61.00	4.01
2045	15.37	34.20	2.88	1.68	7.73	61.87	4.07
2046	15.37	34.95	2.88	1.70	7.84	62.75	4.13
2047	15.37	35.72	2.88	1.73	7.96	63.66	4.19
2048	15.37	36.50	2.88	1.75	8.07	64.58	4.25
2049	15.37	37.31	2.98	1.77	8.19	65.53	4.31
2050	15.37	38.13	2.88	1.79	8.31	66.49	4.37

Source: Dames & Moore calculations, July, 1985

TABLE 2-12

ALASKA RAILROAD TARIFFS FOR COAL SHIPMENTS ($1985)

Healy (Suntrana) to:	Mileage	$/Ton (a)	$/MMBTU (b)
Nenana	58	5.92	0.39
Willow	177	9.54	0.63
Matanuska	212	10.84	0.71
Anchorage	248	12.15	0.80
Seward	363	12.83	0.84

Notes: a. Source: personal communication with Dennis Smith, Alaska Railroad, 7/85.

b. Cost per million BTU assuming 7600 BTU per pound coal.

2.4.2 Rail Cost Escalation

ARR personnel refused to reveal factor cost data which would have supported an analysis similar to that developed for mining production cost escalation. Instead, rail cost escalation was estimated using two approaches: factor cost escalation based on U.S. average rail costs and U.S. historic rate trends.

U.S. Average Rail Cost Escalation

U.S. rail cost data disaggregated by individual cost factors were obtained from an American Association of Railroads publication. Using a factor escalation approach and correcting for inflation, an average annual rail cost escalation of 2.0 percent was obtained, as shown in Table 2-13.

U.S. Historic Rail Cost Trends

To buttress the reliability of the American Association of Railroads' data, a second estimation approach was based on the producer price index for coal transport. The real compound escalation of rail rates computed by this method for the period 1970 to 1981 is 1.8% as shown on Table 2-14. This lower value has been adapted for this analysis.

The statistical basis for the coal transportation PPI shown in Table 2-13 is a Bureau of Labor Statistics "Price Index for Railroad Freight of STCC11-Coal." This index was initiated in 1969. According to the Association of American Railroads,[10] this index is ". . . the only independent, comprehensive index of railroad rates available," although it overstates costs somewhat since it does not take into account the negotiated contract rates (as opposed to published rates) made possible by the 1980 Staggers Rail Act.

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10. Association of American Railroads, 1984, Railroad Coal Rates Since the Staggers Act: The Statistical Record, Washington, August 1984.

TABLE 2-13

U.S. AVERAGE RAILROAD COST AND ESCALATION RATES

Factor	Proportion of Total Costs (Percent)[a]	Average Annual Escalation Rate (Percent)[b]	Factor Weighted Escalation (Percent)
Labor	47.2	11.1	5.2
Fuel	12.2	10.5	1.3
Materials & Supplies	12.2	4.7	0.6
Equipment Rents	6.7	13.2	0.9
Purchased Services	6.2	10.0	0.6
Depreciation	4.3	4.2	0.2
Interest	3.8	4.8	0.2
Taxes (other than income and payroll)	1.4	0.6	0.055
All other operating expenses	5.9	6.5	0.455
Total Annual Escalation			9.4
Implicit Price Deflator[c]			7.3
Real Rail Cost Escalation Rate (%)[d]			2.0

Notes:

a. Personal communication, Carol Lutz, AAR, 5/84.

b. AAR Railroad Cost Recovery Index, 3/84 (1979-1983 U.S. average).

c. DRI Review of U.S. Economy, 9/83 (1979-1983 U.S. GNP deflator).

d. Real escalation is calculated as follows:

$$\frac{1.094}{1.073} = (1.0196-1) \times 100 = 1.96\%$$

There being no basis for believing that the ARR has characteristics different from the average U.S. railroad, these data support a positive rail escalation rate.

TABLE 2-14

RAIL PRICE ESCALATION

	1970	1981	Average Annual Pct. Change
Producer Price Index (PPI):			
Rail Freight, Coal Transport[a]	108.6	305.7	11.25
Producer Price Index:			
All Commodities[b]	110.4	293.4	9.29
Real Escalation Rate:			
Based on PPI = 1.8%			

Source: U.S. Statistical Abstracts, 1982-1983.

Notes:

a. Page 628, Table 1093.

b. Page 456, Table 751.

2.4.3 Conclusions Regarding the Railroad Transportation Cost Escalation

There are three reasons why rail rates for coal transportation have increased in real terms, as measured by the statistics reported above. First, certain components of the railroads' cost of operation, notably diesel fuel and railroad labor costs, have increased faster than inflation. Second, the railroads specifically have been allowed, in certain cases, to raise rail rates in order to earn a return on invested capital to allow the railroad to be financially self-sustaining. Third, in many cases the railroads have had sufficient market power due to lack of competition for shipment of coal over specific routes, to allow them to raise rates and earn a better profit.

The same factors are relevant in the case of the Alaska Railroad. According to the H-E Composite Oil Price projections, diesel fuel prices will increase in real terms over the study period at a rate of 1.6 percent per year. Furthermore the Alaska Railroad has been consistently unprofitable and, therefore, presumably must raise rates above their current level to be financially sound. The only competition that the railroad would face for coal movements is trucking, at costs significantly higher than the current rates. There is, therefore, every reason to expect ARR to follow the same course as has been taken by other U.S. railroads. Given this close analogy to the situation of other U.S. railroads, it is reasonable to assume that ARR rates will escalate at the historical rate established above for other U.S. railroads -- 1.8 percent.

3.0 EXPORTS OF ALASKA COAL TO THE PACIFIC RIM MARKET AND PROJECTED NETBACK PRICES

Dames & Moore has completed research for the Alaska Power Authority to examine: (1) whether coal from the Beluga coalfield (and possibly the Nenana coalfield) in Alaska could move into the Pacific Rim energy market during the period of the economic life of the Susitna hydroelectric project; and (2) what would be the likely price at which Alaska coal could sell in the market (the "netback price"). This section reports on export coal market conditions for Alaska coal during the project economic life, which extends from the mid 1990's to 2040.

3.1 INTRODUCTION TO PACIFIC RIM MARKETS FOR ALASKA COAL

Analysis shows that there will be a large coal export market for shipment to consumers in the Pacific, including Japan, Korea, Taiwan, Hong Kong, Singapore, and other countries. Compared to competing producers, Alaska coal should be highly cost competitve in this market, even considering its low calorific value. Due to the increasing quantities of coal demanded, particularly after the year 2000, there will be an upward movement of coal prices in the Pacific market. These demand increases will bring into development coal sources with increasingly difficult mining conditions and higher transportation costs. Steam coal will be exported from Australia and Canada and eventually high cost coal will be brought into production from Colorado and Wyoming.

Section 3.1 introduces the Pacific Rim Market for Alaska Coal. Section 3.2 consists of a country-by-country estimate of coal production for each of the major Pacific Rim coal producers. The comparative production costs for each coal exporting nation in the Pacific Rim is discussed in Section 3.3. Section 3.4 consists of a compilation of the supply curve for each of the coal exporting nations in order to produce an aggregate supply curve for the region. Finally, Section 3.5 analyzes the supply/demand balance for Pacific Rim through year 2040 and estimates the netback price to Alaska.

3.1.1 Alaska Coal Will Move Into Electric Power Sector

The presence of a large Pacific Rim Market will ensure the use of Alaska coal by Pacific nations. Export markets for Alaska coal will depend on the coal requirements of energy consumers and their ability to obtain coal locally. Some countries that are or will be major coal consumers, such as Indonesia, will be self-sufficient in coal. This market analysis has therefore estimated coal consumption and domestic production for each country and then examined competing suppliers to determine how Alaska coal fits into the net import requirements.

Alaska coal has a low calorific value compared to that supplied by competitors such as Australia. Because of its low quality, Alaska coal is totally unsuitable for use in steel making. Alaska coal will be used only in the "steam" coal market, which includes coal used for cement kilns and minor industrial non-boiler applications. Primarily, Alaska coal will be used by the electric power sector, in which boiler modifications necessary to use this lower quality coal are more economical than in the industrial sector. Therefore, it is important to identify what portion of each market will use coal for electric power generation and in what part of this market Alaska coal will be competitive.

3.1.2 Market Study Focus on Net Imports

The coal consumption estimates used in this study were prepared by the HE Joint Venture based on a composite of price forecasts from Wharton, DRI, DOE, CER and SHCA*. Dames & Moore prepared the estimates of domestic production in each coal consuming nation in the Pacific basin to determine the net import requirements. In some cases, such as the Philippines and Thailand, domestic production will be sufficient to cover requirements for some time, but eventually imports will be required.

Australia is included as a consumer in this study even though it will be a major net exporter. Because the supply-demand analysis must include the demand of all consumers in the market, domestic consumption of Australian coal must be considered. Only the demand estimated for New

* Hereafter referred to as "the APA composite forecast".

South Wales and Queensland is included; these two states produce all of Australia's coal exports and also supply their own internal requirements (Australian Dept. of Trade, 1983b). Other Australian states are self-sufficient in coal but not exporters.

Estimates of steam coal consumption for all consuming sectors and estimates of domestic production for all Pacific region net coal importers are shown in Table 3-1. This table shows the demand, domestic production and net import estimates in Metric Tonne of Coal Equivalent (MTCE),[10] a unit of energy content that provides a common basis for comparing coals of varying quality. This unit is really a more familiar shorthand for the fundamental energy unit of calorific value, usually expressed in British Thermal Units (Btu's). The MTCE is based on 12,600 Btu per pound coal and is a more interpretable measure than estimates expressed in billions or trillions of Btu.

Table 3-1 shows that imports of coal consumers in the Pacific market will rise rapidly, particulary after the year 2000. Beginning at 63 million MTCE in 1990, imports (plus Australian demand) rise over fourfold to 278 million MTCE in 2010, and in 2040 reach a level of 569 million MTCE annually. This tremendous growth in net imports will be mainly the result of increasing consumption, though depletion of domestic producton in Korea, Japan, the Philippines, and Thailand will contribute to increased imports in the later years. Japan and Korea are currently the largest importers and will continue as such, taking 77 percent of all imports in 2010. Even in 2040, despite increases in newly industrialized countries such as Malaysia, Japan and Korea will still require 71 percent of imports in the Pacific.

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10. The MTCE is the energy content of a metric ton (tonne) of coal that contains 12,600 Btu per pound. There are 27.8 million Btu per MTCE calculated as 12,600 Btu per pound multiplied by 2204 pounds per tonne or 27,700,440 rounded to 27.8. The consumption in each country was expressed in actual tonnes. The average Btu contents for coal used in each country were converted into MTCE. The conversion requires multiplying the actual tonnes by the ratio of the actual calorific value, say 24 million Btu per tonne, to the calorific value of the MTCE, i.e., 27.8 million Btu. A similar conversion was carried out for the estimated domestic production in each country considered. (Wilson, 1980a)

TABLE 3-1: PACIFIC RIM COAL DEMAND 1985 TO 2050
MILLION METRIC TON COAL EQUIVALENT

	NOTE	1985	1990	2000	2010	2020	2030	2040	2050
AUSTRALIA									
GNP GROWTH ANN %		2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
ELECTRIC TOTAL:	a	45.8	48.1	50.6	53.1	55.8	58.7	61.7	64.8
NEW COAL	a,b	36.4	37.6	38.8	40.1	41.5	42.9	44.4	46.0
REPLACE W COAL	a,k		0.0	0.0	0.0	0.0	0.0	0.0	0.0
CEMENT	a,m	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
SYNFUEL	a,c				2.7	5.4	8.1	8.1	8.1
INDUST. STEAM	a,l	4.7	4.9	5.4	6.0	6.6	7.3	8.1	8.9
COAL DEMAND		42.1	43.5	45.3	49.8	54.5	59.3	61.6	64.0
EXPORT DEMAND	r	21.1	21.8	22.6	24.9	27.2	29.6	30.8	32.0
JAPAN									
GNP GROWTH ANN %		4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0
ELECTRIC TOTAL:	d	218.1	240.8	265.9	293.6	324.1	357.9	395.1	436.2
NEW COAL	b,d	18.1	29.5	42.0	55.8	71.1	88.0	106.6	127.2
REPLACE W COAL	f,d			35.2	70.3	105.5	105.5	105.5	105.5
CEMENT	d,m	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5
SYNFUEL	c,d				25.0	50.0	75.0	75.0	75.0
INDUST. STEAM	d,l	3.1	3.3	3.6	4.0	4.4	4.9	5.4	6.0
COAL DEMAND		28.7	40.2	88.2	162.6	238.4	280.8	299.9	321.0
KOREA									
GNP GROWTH ANN %		7.0	7.0	7.0	4.0	4.0	2.0	2.0	2.0
ELECTRIC TOTAL:	s,g	21.2	29.7	58.5	86.6	128.2	156.2	190.4	232.1
NEW COAL	b,s	6.6	10.8	25.2	39.3	60.1	74.1	91.2	112.0
REPLACE W COAL	f,s			2.1	4.1	6.2	6.2	6.2	6.2
CEMENT	e,h	3.4	4.8	9.4	9.4	9.4	9.4	9.4	9.4
SYNFUEL	c,j				3.4	6.7	10.1	10.1	10.1
INDUST. STEAM	e,i	2.1	2.5	3.5	4.3	5.2	5.8	6.4	7.0
COAL DEMAND		12.1	18.1	40.2	60.4	87.6	105.5	123.2	144.7
TAIWAN									
GNP GROWTH ANN %		5.0	5.0	5.0	4.0	4.0	4.0	4.0	4.0
ELECTRIC TOTAL:	t,j,g	18.1	23.1	37.6	55.6	82.4	121.9	180.5	267.1
NEW COAL	b,t	3.0	5.5	12.8	21.8	35.2	54.9	84.2	127.6
REPLACE W COAL	f,t			3.9	7.7	11.6	11.6	11.6	11.6
CEMENT	e,h	2.1	2.7	4.4	4.4	4.4	4.4	4.4	4.4
INDUST. STEAM	e,i	2.1	2.4	2.7	3.0	3.4	3.7	4.1	4.5
COAL DEMAND		7.2	10.6	23.7	36.9	54.5	74.6	104.3	148.0
SING.& MALAY.									
GNP GROWTH ANN %		7.0	7.0	7.0	5.0	5.0	4.0	4.0	4.0
COAL DEMAND	n,o,p	4.0	5.5	7.8	9.5	11.6	12.8	14.2	15.6
TOTAL DEMAND		73.0	96.2	182.5	294.4	419.3	503.3	572.3	661.4
TOTAL PRODUCTION EXCLUDING AUSTRALIA		33.0	33.0	32.0	16.0	16.0	16.0	3.0	3.0
NET IMPORTS		40.0	63.2	150.5	278.4	403.3	487.3	569.3	658.4
CUMULATIVE IMPORTS	q	0.0	516.1	1584.7	3729.2	7137.6	11590.9	16874.1	23012.6

SOURCE: DAMES & MOORE CALCULATIONS

NOTES:
a--OECD, 1985. ENERGY BALANCES 1983/1983. P.29. Electrical growth at half the GNP growth rate.
b--Assumes that 50% of the electric demand growth is supplied by coal-fired plants.
c--Assumes that coal to synfuel projects provide up to 10 % of the current oil and gas consumption.
d--OECD, 1985. ENERGY BALANCES 1983/1983. P.77. Electrical growth at half the GNP growth rate.
e--WESTPO, 1981.Western Coal Exports, Final ,Report. P.22. Electrical growth at GNP growth rate.
f--Assumes that all 1985 oil and gas fired generation is replaced by coal during the period 2000-2020.
g--Electrical demand is assumed to grow at the GNP growth rate.
h--Coal demand for cement production grows at the GNP rate through 2000 then is flat.
i--Assumes industrial steam coal demand grows at the GNP growth rate; half of the growth is fueled by coal.
j--WESTPO, 1981, Western Steam Coal Exports to the Pacific Basin. Demand Task Group.P.14.
k--Assumes no replacement of oil and gas fired capacity with coal in Australia.
l--Coal demand assumed to grow at 25 % of the GNP growth rate.
m--Assumes flat demand for coal in cement production.
n--Malaysian coal demand in 1985-90 based on Mann et al,1983. ASEAN COAL. Table 1.1, P.2.
o--Singapore Coal demand in 1985-90 based on WOCOL forecasts in ICF,1980,Table S-3, P.4-115.
p--Demand from 1990 to 2050 is assumed to grow at half the GNP growth rate.
q--Calculated as the arithmetic average of each column and the previous column times ten, plus the previous co
r--Assumes that half the Australian coal demand is in potentially exportable locations.
s--Based on 1984 data provided by H. Cheung, KEPCO B.C. to M.Feldman, D&M.8/85.
t--Taiwan Power, September 1984, Unpublished generation plan.

The last line of Table 3-1 shows the cumulative imports for each year. This figure is the sum of annual imports from 1990 to that date (estimated by 10 times the arithmetic average of the starting and ending year annual imports). This figure is important because each year's coal production leaves a little less to be mined, and the effect is cumulative.

As noted above, coal from Alaska will be used primarily for electric power generation. Net imports for use in this demand sector are estimated in Table 3-2. The estimates for net imports for use in the electric power sector are also keyed to the consumption estimates.

The estimates of imports for use in electric power generation shown in Table 3-2 provide a more direct indication of the potential market for Alaska coal. From 60 to 65 percent of the total imports will be for electric power use, depending on the year. The size of this potential market for Alaska coal exports is truly impressive. For example, in 2000, an estimated 117 million MTCE of coal will be imported for power generation. Considering the difference in calorific value, this is equivalent to 218 million tons of coal of the quality found in the Beluga coal field. In later years (for example 2020), the total rises to 257 million MTCE of coal imports per year. The largest importers are Japan, Korea, and Taiwan.

3.2 PACIFIC RIM DOMESTIC COAL PRODUCTION

This section describes the basis for the estimates of domestic production. Two major coal consuming countries, China and India, are not mentioned as importers, though there is some chance that they might be. Each has tremendous geologic reserves; but they are large countries with poor transportation networks, and consequently may import a small portion of

TABLE 3-2

Coal Consumption (1) Domestic Production (2)
and Net Imports For Use in the
Electric Power Sector for Pacific Market Importers
1990-2040
(million MTCE)

	1990	2000	2010	2020	2030	2040
MALAYSIA & SINGAPORE						
Demand	6	8	10	12	13	14
Domestic Prod.	0	1	1	1	1	0
Net Imports	6	7	9	11	12	14
JAPAN						
Demand	29	77	126	177	193	212
Domestic Prod.	10	8	5	5	5	
Net Imports	19	69	121	134	188	212
KOREA						
Demand	11	27	43	66	80	97
Domestic Prod.	2	2				
Net Imports	9	25	43	66	80	97
TAIWAN						
Demand	6	17	30	47	67	96
Domestic Prod.	1	1	1	1	1	1
Net Imports	5	16	29	46	66	95
TOTAL IMPORTS	39	117	202	257	346	418

(1) Dames & Moore estimates.
(2) Dames & Moore estimates. See Section 3.2.
(3) No domestic production.

their requirements if this proves more economical than transportation from inland sources.[11]

In order to give the most conservative treatment to the import levels projected in this study, we have assumed the maximum feasible exploitation of known coal resources for each country examined. We also have assumed these resources are developed speedily so that they are exhausted before imports begin. Since very little coal mining now takes place in the Philippines, Malaysia, and Thailand, there is little to be said about current production costs and trends or the difficulties likely to be encountered by bringing coal reserves into production in isolated areas such as Sarawak in East Malaysia. Therefore, while the estimates presented below may seem simple-minded in development, they are purposefully so--to yield an outside estimate of the potential domestic production.

3.2.1 Philippines

The Philippine Bureau of Energy Development estimates coal resources to be 1.7 billion tons, with proven reserves of 283 million tons of coal (Mann, et a., 1983). Coal reserves, as opposed to resources, are deposits that have been sufficiently explored to be accurately measured, and are identified as being generally of minable characteristics. For example, very thin seams are usually excluded for estimated reserves (for example, see USDOI, 1974b). The coal resource, on the other hand, is the total coal thought to be in the ground, including estimates for seams that may be only sketchily known.

Only a fraction of the resource base is likely to be economically recoverable since some coal cannot be mined at all due to adverse geology. Even where reserves are mined, not all the coal in place can be recovered. In underground mining, pillars of coal are left to support the mine roof. In room-and-pillar mining, which dominates underground production in the

11. "Technically and economically recoverable reserves" are estimated at 33.7 billion MTCE (World Bank, 1979). Production in 1977 was 33.8 million MTCE, or one thousandth of reserves (World Bank, 1979). Dames & Moore estimates consumption in the year 2010 at 292 million tons, or 210 million MTCE. This implies a compound rate of increase in production of 4.7 percent per annum over this 33-year period. It will be difficult, in the author's opinion, for India's coal industry to sustain this growth rate and also produce an exportable surplus.

United States and Australia today, as much as 65 percent of the coal in place is left for roof support. In longwall mining, which is becoming increasingly important, recovery can be as high as 80 percent, because most of the mine roof is allowed to collapse. High recovery with longwall mining is possible today only where geologic conditions are very favorable, including consistent seams with thicknesses from 40 to 12 feet (1 to 4 meters). In surface mining a small fraction of reserves is left in the pit floor to avoid picking up the underlying rock; a portion is spilled or accidentally covered with rock. (U.S. Department of the Interior, Bureau of Mines, 1974). Therefore, assuming a fairly high recovery of the resource base probably results in an estimate on the high side.

Our objective was to determine the maximum likely production; thus, production of a goodly fraction of the resource base was adopted as a suitable estimating basis. In the case of the Philippines, we assumed 50 percent recovery of estimated coal resources. Recovery during mining underground is usually about 50 percent; it is from 70 to 90 percent in surface mines. (For mining recovery in the United States, see U.S. Department of Energy, Interagency Coal Task Force, 1981.) Naturally some deposits cannot be mined at all because of land use conflicts, adverse geology (e.g., excessive water inflow), or other factors. Hence, if we assume a balance between surface and underground mining (i.e., half of each, with a resulting average recovery of 65 percent, and assume 25 percent of those resources are unminable) then the total recoverable coal will be 936 million tons. Using an average calorific value of 8,200 Btu/lb (Dames & Moore estimate based on data in Mann, 1983), Philippine coal resources equal 552 million MTCE.

Demand estimates show that cumulative consumption[12] will equal 632 million tons in 2020, exhausting the resources. Hence, all requirements after 2020 will be met by imported coal. We therefore assume no imports from 1990 to 2030.[13] Starting with our 2030 estimate all coal will be imported. However for a conservative estimate these imports are ignored in Table 3-1.

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12. That is, the sum of consumption over time.

13. While some imports will actually occur, where there is any doubt our assumption will tend to <u>understate</u> the size of the market available to Alaska producers.

3.2.2 Thailand

Coal resources in Thailand consist of low quality lignite coals in several locations, with the bulk of the resources located in northern Thailand near Chiang Mai. These reserves are already being mined for the Mae Moh mine mouth powerplant which will be expanded over the next decade.

Thailand's "probable reserves" of lignite are 1.3 billion tons with average calorific value estimated at 5,000 Btu/lb (Mann, et al., 1983). Potential production is estimated to be approximately 70 percent of the probable reserves, or 330 million MTCE. These reserves will probably be developed to support mine mouth power generation over a 50-year period (1985-2035), implying a 6.6 MTCE per year production rate. Estimates of consumption exceed this production level starting around 2010. Therefore, domestic production is estimated 6.6 million MTCE per year until exhaustion in 2035. As a result, no imports are necessary until after 2010. To be conservative, these imports are not included on Table 3-1.

3.2.3 Malaysia

Coal reserves located in Sarawak and Sabah total approximately 385 million tons (Mann, et al., 1983), with an average calorific value of about 6,000 Btu/lb. Potential production is estimated by Dames & Moore at 50 percent of this total, or 115 MTCE, assuming (as discussed above for the Philippines,) a mix of surface and underground mining and typical limitations on recovery.

The consumption estimates show that only a modest 3 million MTCE per year is required until 2010, when consumption rises to 9 million MTCE per year. Given that there is now no production, it is reasonable that production will phase in slowly, beginning some time in the 1990's and rising and a level of about 4 million MTCE per year. This production could be sustained until 2030, after which the reserves will be gone.

3.2.4 Japan

Minable reserves (The Tex Report, Ltd. 1984) are 1,100 million tons (including metallurgical coal). The 1982 production was about 15.2 million tons of steam coal plus 4.9 million tons of metallurgical coal (20.1 total), down from 27.6 million tons total in 1970 (The Tex Report, Ltd., 1984). Current plans are to sustain the present rate until at least 1995 (The Tex Report, Ltd., 1984), albeit at uneconomical levels of production cost. Since reserves will sustain the current level of steam and metallurgical coal production until exhaustion in 2035 (i.e., 1,000 tons reserves divided by 20.1 million tons per year equals 55 years from 1982 or 2037), we assume this current production level will continue until then. Because of the high calorific value of Japanese production, this equates to 18.2 million MTCE per year.

3.2.5 Korea

Korean minable reserves are approximately 310 million tons. The 10th World Engineering Conference estimate (World Bank, 1979) of 1977 reserves was 425 million tons, less depletion of about 20 million tons per year (mmtpy), over 1977-1983 (World Bank, 1979; Gordon, 1984). This will support current production of 20 mmtpy (of anthracite) only until 2000 (i.e., 310 million tons divided by 20 million tons per year equals 15 years from 1983, or 1997). Korea already imports anthracite, an indication of the cost and difficulty of increasing production from current levels. Korea will become a strong market for import coal.

3.2.6 Taiwan

While data are sparse, current domestic production is 2.7 million tons per year (Gordon, 1984), equivalent to about 3 million MTCE per year. We assume production at this level can continue indefinitely. This projection is probably optimistic given the recent mine disasters in Taiwan, which will focus attention on the poor conditions in existing mines. The reserves are very deep (over 7,000 feet in some cases) and the seams dip steeply (Gordon, 1984).

3.3 COMPETING SUPPLIERS FOR THE PACIFIC RIM IMPORT MARKET

3.3.1 Estimating Costs of Coal Supply

Having established what coal imports of Pacific market consumers will be, the next step in this analysis is to determine which supplies are available, excluding coal from Alaska, to satisfy this coal demand. To do so, we must make a number of theoretical and practical assumptions and simplifications.

The ideal approach to determining supplies would be to develop a supply curve. Due to data limitations we had to utilize a solution curve instead. The solution curve is a good approximation to the supply curve if input quantities can be accurately specified. The following paragraphs expand on this theoretical distinction.

To develop formally what economists call a supply curve, we must be able to specify the optimum combination of coal reserves and mining depletion rate, capital investment, labor, and materials to maximize the producers' profits. The range of possible combinations is referred to as a production function. If we then specify a normal rate of return on invested capital, a relationship can be developed between the required selling price and the characteristics of a particular seam. Since some deposits cost more to mine than others, a curve can be plotted that relates the price to quantity of reserves that can be mined (Henderson and Quandt, 1980). Two assumptions necessary in such an analysis are perfect competition between suppliers and the absence of externalities.

Developing a true supply curve for years to come is too difficult because we cannot readily quantify possible tradeoffs of inputs (capital, labor, materials) for mining a given seam. To do so, we would have to evaluate numerous technical alternatives for mining each seam. Instead, it is only possible to determine, within limits, the efficient method of mining a particular deposit given current mining technology and relative input costs. Technology will change, but it is impossible to say how.[14]

Because the relative costs of labor and other inputs change, as well as production constraints and technology, supply curves would have to be estimated for each year. This would impose a burden both in calculation and in the necessity to make numerous assumptions.

A production function on which to build a supply curve would specify an optimal depletion rate of reserves. This rate is a function of market prices which in turn are a function of marginal cost and the interest rate (Peterson and Fisher, 1977; Herfindahl, Mason Gaffney, ed.). For this analysis, we assume that production capacity and reserves are unbounded. An optimum depletion rate is therefore nebulous, and we instead assume a mine lifetime and production rate based on a technical judgment. For this study a mine life of 20 years is assumed. (For similar analysis see USDI, Bureau of Mines, 1974; USDOE, Energy Information Administration, 1978.)

Due to these limitations, the analysis presented below must be considered a technical analysis and the result must be classified as a <u>solution curve</u> rather than a <u>supply curve</u>. A solution curve shows the price-quantity relationships given the quantity of coal produced with quantity an exogenous variable. In contrast, a supply curve shows the price-quantity relationship where quantity produced is endogenous to the calculation of price. For example, given a production function that relates quantity produced as a function of the level of inputs and a cost function that relates costs as a function of input prices, we would calculate price and quantity as functions of varying levels of inputs and input prices. In a true supply curve optimum levels of inputs are determined from profit (or quantity) maximization, whereas in a solution curve the optimum

14. Due to the great uncertainties inherent in technology, we make the simplifying assumption that present mining technologies will similarily be the optimum technology of the future. Any attempts to define a "futuristic" technology would simply be a guess. Therefore, technology is assumed to be essentially fixed.

combination of inputs is an assumption. A solution curve may slightly overstate the required prices compared with a true supply curve.

The estimated coal solution curve consists of an arrangement of the potentially available coal supplies in increasing order of delivered cost to the consumer. Because the demand projection indicates a fairly steady growth in consumption, coal producers will almost constantly be building new mines (except perhaps during recessionary periods). Therefore, the market price must be at least at a level sufficient to attract capital for opening new mines. Because this analytic convention postulates a perfectly competitive industry, producers opening new mines are assumed to earn only the market rate of return on investment. This provides a base price trend projection keyed to the marginal cost of the last increment of production, the incremental mine. Of course, market fluctuation can cause prices to oscillate around this price level. For this study we used the cost of capital to United States coal producers (as determined by the Harza-Ebasco Joint Venture) of 11 percent (real dollars, after taxes). The cost of production used to develop the solution curves includes market return on capital as well as operating costs, taxes, and royalties. Taxes and royalties are assumed to remain constant at existing levels. Doubtless, these could increase as producing countries move to capture more of the rent of the resource. We anticipate this to happen, but we haven't estimated the magnitude or timing.

Mine production and transportation costs (including inland freight, port charges, and ocean freight) affect the costs of each supplier. The position of each increment of supply is a function of the sum of these costs. The solution curves for each producing region discussed below assume current mining methods and productivity. A continuation of current taxation and rail pricing is also assumed. Fortunately, coal reserves are fairly well known and characterized and it is possible to estimate with reasonable accuracy the amounts and costs of coal that can be mined in each area. Coal reserves are relatively easy to discover because minable coals are found at shallow depths (from 0 to 2,000 feet), because the seams often outcrop and such seams or coal bearing formations tend to be continuous over large areas, up to hundreds of square miles in some cases. Coal reserves are explored in detail only when they may soon become economical to develop. In areas where transportation, coal quality, and mining conditions are favorable for exploitation today or in the near future, reserves are usually fairly well known. Given the ease of exploration, it is unlikely that significant low-mining-cost reserves remain to be discovered and measured. The unknown reserves are those clearly unknown from lack of markets and/or because they are so difficult to develop that they cannot be produced competitively.

Therefore, it is unlikely that discoveries of reserves can result in unanticipated low-cost supplies. Even though the coal supply potential discussed in this chapter is based on current reserve estimates, it does not understate the amount of economical reserves.

The solution curves discussed below represent the total reserves available for mining plotted against cost of production. No annual production capacity constraints are assumed because the analysis focuses on the period beginning in the mid-1990's. Since mine planning and construction times are usually less than 10 years even for the most complex projects, production capacity should always be sufficient. This is of course subject to the assumption that producers are able to forsee demand.

3.3.2 <u>Production Cost Estimates of Competing Suppliers</u>

Alaska coal must compete in the Pacific market against coal from Australia, Canada, China, Colorado, Wyoming, and South Africa. The major supplier of steam coal to the Pacific market is now Australia. In order to compete in the market, production and transportation costs for Alaska coal must match the delivered price of coal from these competing sources. In fact, as will be discussed in more detail later, Alaska coal can be delivered to Pacific consumers more inexpensively than most competing coals. The maximum price at which Alaska coal can sell, which is one of the key findings of this study, is the price delivered to the consumer (and adjusted for any differences in costs of utilizing the coal) that equates with the price of coal from the marginal competitors.

Therefore in this section we will discuss the production costs and potential production for each of the major competing suppliers; only two possible suppliers are not included. South Africa now supplies a few million tons per year to Japan. Europe will become the best market for South African coal, considering transportation costs (i.e., 11,700 kilometers from Richards Bay Terminal (east coast of South Africa) to Rotterdam versus 13,300 kilometers from Richards Bay to Yokohama). The world market analysis shows that coal requirements in Europe wil be very large, and could absorb everything the South Africans could produce. We therefore believe that little South African coal will find its way into the Pacific. By eliminating consideration of these "crossflows" between the Pacific and Atlantic markets, the net effect is to understate demand for Pacific market supplies. Hence, we can exclude South Africa, making the parallel of exclusion of Australia for the European market.

A small amount of coal from Siberia mostly of metallurgical quality, is also shipped to Japan. There are no plans to increase steam coal supplies from this source and the development of the metallurgical coal mines, financed by the Japanese, has been very difficult.

The basis for the estimates presented below is that the Pacific market for coal will contine to be competitive and that prices will be set by the production cost, including a market return on invested capital, of the marginal coal supplier. No increases in the government "take" (in the form of taxes, infrastructure funding requirements, or padding in rates of government owned railroads) are included.

3.3.2.1 Australia

Profile of Industry. The industry consists of private firms dominated by a few large companies: Broken Hill Proprietary (BHP), CSR, Ltd., British Petroleum Australia, Ltd. (BP), CRA (subsidiary of Rio Tinto), Utah

Development, and Royal Dutch Shell. Japanese companies are minority participants in many projects, especially the metallurgical mines (e.g., Mitsui, Mitsubishi, Sumitomo). Current law requires a minimum of 51 percent Australian ownership. Exports account for half of bituminous production.

The coal industry has grown rapidly, primarily for metallurgical coal export to Japan. The potential for highly profitable operations has attracted major mining and oil companies from around the world to invest in Australia. Production is a mix of surface and underground mining. At 32 billion tons (about 26 billion MTCE demonstrated economic recoverable resources) reserves are extensive and not a limiting factor, though surface reserves are not large enough to displace underground mining in the long run (Australian Department of Trade, 1983a). Most near-term, new steam coal projects are surface mines with some expansion of existing deep mines. Reserves are mostly within 250 rail miles of the coast. Leasing of reserves is controlled by the State governments.

The political situation is reasonably stable, though government is heavily involved in the coal industry--for example, the limitation on foreign ownership, an export levy, coal royalties, requirements for private contributions to town site infrastructure, and an argumentative relationship with mining companies over taxation. Regulation is fairly stringent. The labor situation is somewhat unfavorable with militant unions organized along craft lines (a number of unions at each mine). As mines are opened in more remote areas (western areas of New South Wales coal fields and in Queensland generally), substantial rail and town site infrastructure must be built, largely paid for by the coal producers.

Coal Quality. Australia exports both steam and metallurgical coals. Most metallurgical exports are of high volatile coals. Generally, Australian metallurgical coals are higher in ash (averaging about 9.5 percent) than U.S. (6 to 7 percent) and Canadian (7 to 8 percent) metallurgical exports. The boundary line between the better steam coals and the metallurgical coals is unclear and a number of projects that do or will produce metallurgical coal will also sell a "middling" steam product. The range of steam coal quality (clean basis) is as follows: caloric value 11,500 to 12,200 Btu/lb; ash 12 to 18 percent; sulfur 0.2 to 1.5 percent. A typical product would be 11,800 Btu/lb, 15 percent ash, 0.6 percent sulfur. Ash fusion temperature is generally over 2700°F. Hardgrove grindability of 50 is usual (Australian Department of Trade, 1983a).

Port Facility. Current port capacity[15] is 77 million tons per year (Tex Report, 1984), with planned expansion to 176 million tons per year in 1985. Current and future capacity and water depth are summarized in Table 3-3.

There are no significant obstacles to long-run development of deepwater ports and railroads to serve them. Railroads are financed by coal producers and built and run by the government. Producers are repaid with credit for tonnes shipped. Port costs have been financed by the government and funds are tight. As a result, producers will have to finance more, as is now being done in Queensland and for the Kooragong Island loader recently built at Newcastle in New South Wales.

Reserves & Production Costs. The potential supply of steam coal from Australia includes production from existing mines, expanded mines, and new mines. The problem of estimating production and transportation costs is obviously easier in the case of existing mines than for new mines, particularly for possible new mines beyond the proposed mining projects on which significant engineering and planning work have been done. The approach taken by BXG, Inc.,* to the development of the cost estimates presented in this section was to draw on the extensive published sources of statistical and descriptive information on existing mines and proposed projects. These include government sources such as annual reports of the Joint Coal Board (NSW) and the Queensland Coal Board; company sources such as annual reports; environmental impact statements (often containing details on proposed mining plans); and reports in the trade and daily

15. Theoretical capacity; practical capacity is 65 to 70 percent of stated figures.

* BXG is a mining engineering and coal exploration firm located in Boulder, Colorado. Their analysis of the Australian coal industry is the basis for the production and transportation presented in this section.

TABLE 3-3

Current and Future Australian Port Capacity (*)

Port Name	Current Capacity (Million tons)	Current Depth (feet)	Planned Capacity (million tons)	Planned Depth (Feet)
New South Wales				
Newcastle	30	50	55**	50
Balmain	3.6	36	5	36
Balls Head	.5	36	1.0	
Port Kembla	8	38	26	54
Queensland				
Gladstone	25	37	36	
Hay Point #1	22	55	27	55
Hay Point #2	-	-	11	55
Abbot Point	-	-	11	55
Bowen	.5	30	1	
Brisbane	.3	33	1	
TOTAL	70.9		160.0	

* Source: Tex Report, 1984, and Appendix C.
** Probably not complete until 1987-88.

press. The sources are used to assemble the necessary mine specific data on production, productivity, mining method, equipment used, and sometimes provide information on geologic conditions. These mine specific data are then combined with certain industry-wide relationships and factors such as the wage rates, required labor overheads (social costs), per-mile transportation costs, and tax and royalty rates. This information is then synthesized into a cost estimate for each existing or proposed mine, and in some cases was extended to estimate costs of developing adjacent deposits for which no specific mine plan exists, but where geologic information is available. The details of this approach are documented fully in Appendix C.

The mines that comprise the resulting supply curve include both underground and surface mines and production from both New South Wales and Queensland. The mix of labor, capital, and rail freight charges among these various supply source varies significantly. For example, rail freight from mines in New South Wales varies from \$3 per ton for some South Coast mines to \$17 per ton for mines at the western end of the Hunter Valley. (See Table 3-4.) The direct operating cost shown in Table 3-4 includes labor costs as well as materials and supplies. The labor cost is highest for underground mines in Queensland. For example, costs are about \$20 per ton in the West Moreton district, compared to only \$3.00 per ton in the most efficient Bowen Basin open cut (surface) mines. These variations account for the wide range in the total FOBT cost of coal from Australian mines. As summarized in the cumulative solution curve shown in Figure 3-1, the FOBT costs range from \$15 per metric tonne up to \$80 per tonne (in Australian dollars, currently equivalent to US\$0.90).* The bulk of the potential production has FOBT costs between \$50 and \$73 per MTCE (converting from Australian to U.S. dollars, and adjusting for the calorific value of Australian coal, assuming an average calorific value of 11,400 Btu per pound).

The total cumulative reserves covered by this solution curve are 7.3 billion MTCE (8.9 billion tons). This amounts to 30 percent of the

* Metric tonnes are used here since the material is reproduced 'as is' from the original source.

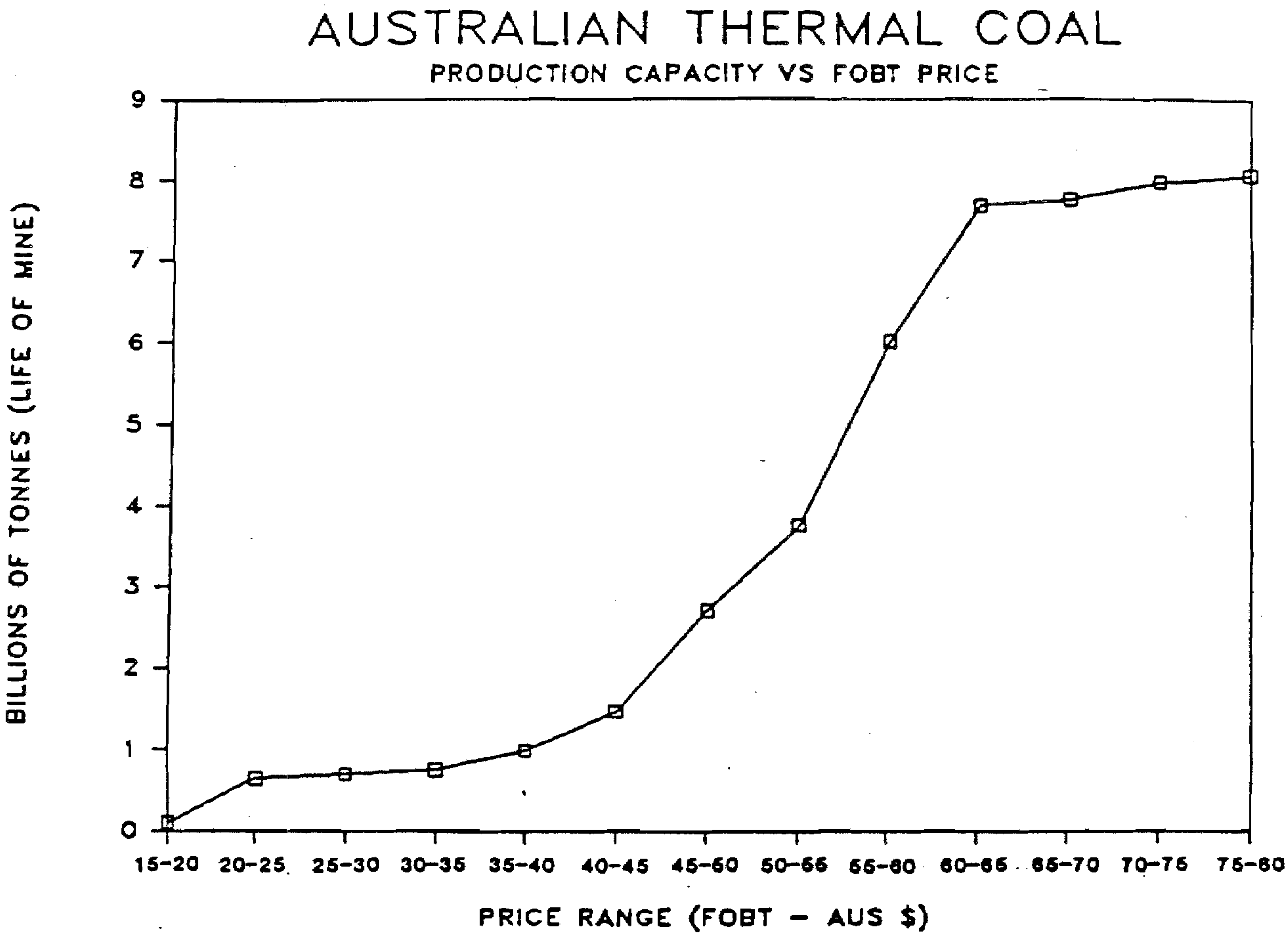
TABLE 3-4

Representative Costs and FOR/FOBT Prices *
(1983 Australian dollars per ton)

Representative Mines	Labor as % of DOC	DOC	Capital	Gov´t Charges	FOR Price	Freight	Port	FOBT Price
New South Wales								
Singleton, NW Dist.	53-63%	$18-23	$5-14	$2	$24-$38	$9-11	$5	$38-54
New Castle, NW Dist.	55-56%	$16-23	$5-14	$2		$3-5	$5	
South Coast, NW Dist.	60-70%	$25-29	$4-5	$2		$3-7	$5	
West, NW Dist.	55-60%	$11-16	$7-11	$2		$13-15	$4-5	
Burragorang Valley	65%	$23-27	$3-5	$2		$15	$5	
Queensland								
Underground Mines								
West Moreton	58-68%	$25-29	$3-5	$2		$5-6	$6	
Bowen Basin	50-70%	$25-29	$5-9	$2-5		$6-10	$3-4	
Open Cut Mines								
West Moreton	35-40%	$24-31	$3-5	$2		$5-7	$6	
Bowen Basin	32-42%	$7-18	$9-23	$2-5		$6-10	$3-4	

* Source: BXG, Inc. (See Appendix C)

FIGURE 3-1



FOBT PRICE RANGE (IN 1983 AUS $)	CUMULATIVE TOTAL PRODUCTIVE CAPACITY (OVER LIFE OF MINE) BILLIONS OF TONNES
15-20	0.107
20-25	0.645
25-30	0.695
30-35	0.76
35-40	0.988
40-45	1.4646
45-50	2.7006
50-55	3.7501
55-60	6.0193
60-65	7.7073
65-70	7.7873
70-75	7.9973
75-80	8.0873

Sou Source: BXG, Inc. See Appendix C.

reserves (economically recoverable reserves) and 17 percent of the coal resources (in situ demonstrated economic resources) estimated for New South Wales and Queensland combined (reserves as given in Australian Department of Trade, 1983a). Therefore it does not cover all the coal that might eventually be produced. However, the results of the supply-demand analysis presented below show that not all the coal included in this solution curve can be competitively produced for the Pacific market, even through 2040. Therefore the coverage of the supply curve is more than adequate.

3.3.2.2 China[16]

Profile of Industry. The coal industry in China is completely controlled by the government. The Coal Ministry, one of 40 ministries in the central government, is responsible for 60 percent of China's coal production; local and communal governments control the rest. Industry organization (under the Coal Ministry) is as follows:

Coal Ministry
Provincial Coal Mining Associations
Coal Mining Bureaus
Individual Mines

Total production in 1978 was 681 million tons, 95 percent of which came from underground mines. Seams mined are currently in excess of 4.5 feet and 50 percent are thicker than 11 feet. Slopes are commonly less than 25 degrees but mining has also been accomplished in seams with dips up to 90 degrees. In mines controlled by the ministry, 70 percent of production comes from nonmechanized (i.e., hand loading) faces, 25 percent from conventionally mechanized faces, and 5 percent from fully mechanized faces. Surface mining technology includes standard rotary drills, 30-ton trucks, 4 cubic yard shovels, and relatively small earthmoving equipment. The trend, however, is toward large-scale draglines and bucket wheel excavators (China Consultants International (Hong Kong) Ltd., 1981).

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16. This section is based primarily on PN Consultants, 1982.

The coal industry's modernization plan anticipates production of over 1 billion tons by 1987, requiring annual increases of 30 to 40 million tonnes. To expand the coal industry, Chinese authorities have begun the following:

- o Expanding and renovating existing mines;
- o Constructing eight new coal bases each with 45-55 million tons of production capacity;
- o Developing small mines with capacities ranging from 10,000 to several hundred thousand tonnes each;
- o Increasing the use of sapropetic coal, coal pebble, lignite, and peat to conserve higher grades;
- o Turning to the West for machinery and technology to accelerate development.

Coal Quality. Chinese coal ranges from lignite to anthracite. About 220 billion tons of reserves are thought to be coking quality containing 14 to 35 percent volatile matter. Most of China's coking coals are located in the Provinces of Shanzi and Hupei.

Chinese steam coal shows considerable quality variation but much of the reserve base has sulfur contents of 1 percent or below; high ash may be a problem.

Infrastructure. China currently has the potential to produce an exportable surplus of coal. However, necessary export infrastructure is lacking (Ref. Wilson, C.L., 1980b). Rail lines are old, rolling stock outdated (e.g., 50-ton wooden cars), and the rail system is designed to support internal distribution. Until now development has been aimed at building new lines in remote areas. Emphasis is, however, shifting to commercial interests, and freight and passenger demand will receive greater priority in the future.

China's ports are also inadequate to support increases in coal exports. China currently has two major coal ports, neither of which can handle Panamax vessels:

- o Qinhuangdao -- 25,000 DWT[17] maximum
- o Lianyungang — 18,000 DWT maximum

As with the railroads, however, expansion plans have already been announced.

Production Costs. Production costs are impossible to estimate, but labor cost per hour is extremely low.

Pricing Position and Strategy. Pricing of exports will be tied to negotiation of "soft" financing of projects and is likely to be at levels below competing coals (Wilson, 1980).

Potential Steam Coal Exports. China's production capability could expand to serve a large export market. This market is, however, constrained in the near- to mid-term by inadequate infrastructure. Table 3-5 summarizes existing estimates of potential Chinese exports of steam coal.

TABLE 3-5

Projections of Potential Chinese Steam Coal Exports

(million tons)

	1985	1990	2000
WOCOL (1) (includes metallurgical coal)	N.A.	N.A.	35
IEA (2)	3	5	7
ICE Task Force (3)	3-5	8-12	25-35

(1) Wilson, C.L. 1980.
(2) International Energy Agency, 1978.
(3) USDOE, Jan. 1981.

China is already becoming a significant exporter, and has the advantages of low production costs and favorable location. However, the

17. Dead weight ton (DWT) is a measure of ship capacity; it is the total weight of maximum cargo plus fuel and stores. A 65,000 DWT vessel draws around 40 feet of water, fully laden, although there is some variation with ship design.

transportation network for coal exports is very poor (as is the transportation network generally) and the internal requirements for coal are likely to be enormous. The Chinese have a strong incentive to export--to earn hard currency--and they are making efforts to improve their rail and port facilities. Under the current Chinese economic system pricing is centrally directed and coal exports can be priced as low or high as the government feels the market can sustain. If they choose coal explorts as a source of foreign exchange, they can provide resources and pricing to encourage exports. Given the cross-cutting nature of these factors and the very sparse data available on coal in China, we have allocated a 15 percent share of the total export market to China, as a best guess.

3.3.2.3 Canada

Profile of Industry. Western Canadian (British Columbia and Alberta) coal mines have been a major source of metallurgical coal for export to Japan and Korea. Beginning in the early 1970's a series of mines (mostly surface) have been developed which yield high quality, low volatile coal. Even with the sharpened interest in steam coal exports, the most serious attention has been on development of new metallurgical coal mines in northeastern British Columbia.

Coal reserves are government-owned and provincial governments have a very heavy hand in decisions about financing of necessary infrastructure improvements (rail lines and townsite development), taxation of mining and exports, environmental issues, and even coal pricing. The overall economic benefit of infrastructure improvements to increase exports has been hotly debated (British Columbia, Ministry of Industry and Small Business Development, 1982).

Political climates for coal development in the two provinces mentioned have swung markedly over the last decade. A major national debate is now taking place about the implications of "Canadization" policies for the economy (Robinson Dames & Moore, 1980). Therefore the security of foreign investments must be considered less than optimum.

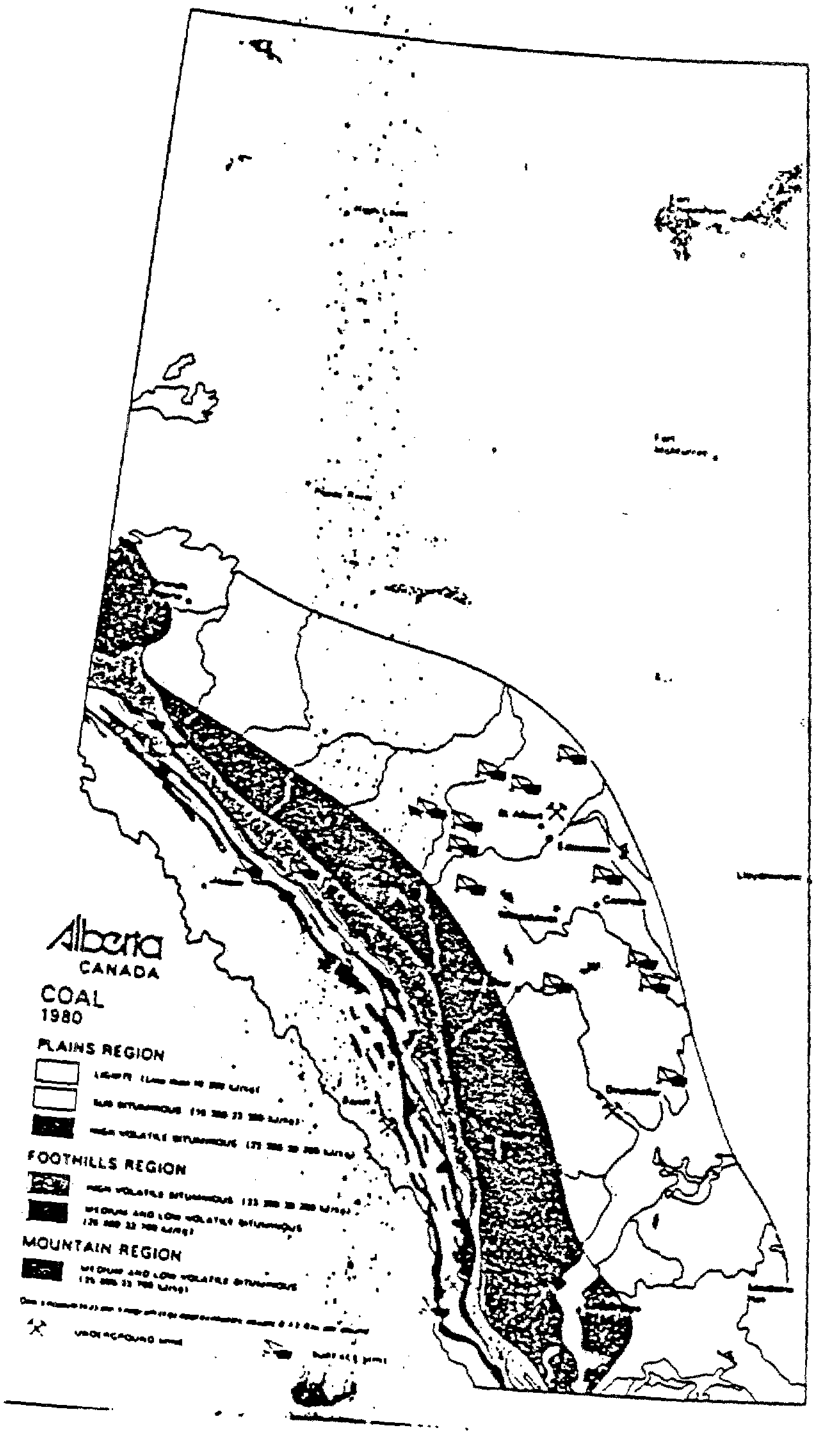
Reserves are very large, but at relatively long distances from the coast, and rail transportation costs are substantial.

The industry can draw on strong engineering and operational skill pools, and labor problems are not particularly great. However, new mines are often in very remote locations, necessitating extensive town site development. (For example, see British Columbia, Ministry of Industry and Small Business Development, 1982.)

Coal Quality. Western Canadian steam coals are generally very low in sulfur and have variable calorific value and ash content. Some steam coal will be produced from the exposed outcrop portions of metallurgical coal mines (primarily in British Columbia). Coal near the surface that is exposed to weathering suffers a sharp loss of desirable coking properties and hence must be considered steam coal, though the calorific value may be in excess of 12,500 Btu/lb, with ash of less than 10 percent. Steam coal produced in Alberta is similar in quality to bituminous coal from Utah and Colorado, ranging from 11,000 to 12,000 Btu/lb (Alberta Economic Development, Energy, and Natural Resources, 1981).

Port Facilities. Canada has excellent deepwater port facilities near Vancouver, including the Pacific Coast Bulk Terminals (65,000 DWT berth capacity), Neptune Terminals (125,000 DWT berth capacity), and the Roberts Bank Terminal (125,000 DWT berth capacity) operated by Westar Resources (formerly Kaiser)(Sato, 1983). A new facility just completed at Ridley Island near Prince Rupert is handling coal from northeast British Columbia.

Reserves and Production Costs. The primary reserves of high volatile bituminous steam coal that could be exported from Canada are in the Foothill region of Alberta (Figure 3-2), with scattered deposits of higher rank (medium to low volatile) in the Mountain region in Alberta and British Columbia. Recoverable reserves are estimated to be about 3.05 billion MTCE assuming an average 11,000 Btu per pound (Dames & Moore, 1978; Mann, 1983). Of this total, surface minable reserves amount to 365 million MTCE as shown in Table 3-6. In addition, 163 million tonnes of surface minable bituminous reserves exist in the East Kootenay Field in British Columbia. Hence,



COAL REGIONS OF ALBERTA, CANADA

FIGURE 3-2

Source: Alberta, 1981.

TABLE 3-6

Steam Coal Reserves of Western Canada
(millions MTCE) (1)

Producing Region	Surface	Underground	Total
Alberta Foothills	365 (2)	2,680 (3)	3,046
British Columbia (Kootenay)	163 (4)		163
Other	220 (5)		220
			3,428

(1) Assuming average calorific value of 11,000 Btu/lb.
(Jeremic, 1981,page 44), indicates 24.2 to 24.4 megaJoule(mJ)/kg = 10,410 Btu for Foothills high volatile bituminous and 24.8 to 31 mJ/kg = 10,664 to 13,330 for Southeastern British Columbia medium volatile bituminous. In order not to understate reserves we use 11,000 Btu/lb as an estimated average value.
(2) Recoverable surface reserves (Dames & Moore, 1978).
(3) Total recoverable less surface (Dames & Moore, 1978, Page 66).
(4) Robinson Dames & Moore, 1980
(5) Production potential of existing mines and projects times 20 years, possibly a low estimate since some mines may have. more than 20 years reserves (Dames & Moore, 1983).

the bulk of the reserves are underground minable in mostly flat-lying seams from 6 to 20 feet thick.

Production costs for Alberta Foothills production and the East Kootenay deposit can be estimated for coal from the proposed Obed-Marsh mines, which are representative of the stripping ratios (i.e., the ratio of overburden to coal thickness) associated with the surface minable reserves. These stripping ratios are estimated to be around 15:1 maximum. Total required FOBT prices as estimated in a recent report to the World Bank (Dames & Moore, 1983-1984) (in 1985 US$ per MTCE) are $55 for Obed-Marsh & $56.38 for Mercoal at full production levels of 5 and 3.5 million tonnes per year, respectively. (Appendix A presents detailed cost estimates for these two mines and a summary of data sources.)

Costs for future underground steam coal mining in the Foothills coal province of Alberta are difficult to estimate because there are not operating underground steam coal mines today. We must estimate costs based on experience in other regions. Mining conditions are similar to those in the Rocky Mountain coal province of the United States (comparing the seam thickness, depths, and geology (British Columbia Ministry of Industry and Small Business Development, 1982; Canmet, 1983) for Alberta to the geology of Colorado coals as described Keystone, 1984), where total mine prices are in the range of $24 to $29 per ton (Dames & Moore, 1983). FOBT costs will therefore be in the range of $53 to $60 per MTCE (1985 $).

In addition to these sources, coal from a few other existing and planned mines in British Columbia can be produced at FOBT prices in the range of $42.55 to $53.19/MTCE (1985 $), including the Harmer, McCleod, Line Creek, and Quinsam mines (Dames & Moore, 1978). Total reserves producible in this cost range are about 220 million MTCE. The potentially available coal from Canada therefore includes the following increments of supply:

1. First, and least expensive, the steam coal from existing mines in British Columbia, with reserves of 220 million MTCE and costs of less than $53 per MTCE (1985 $), FOBT Pacific coast ports.

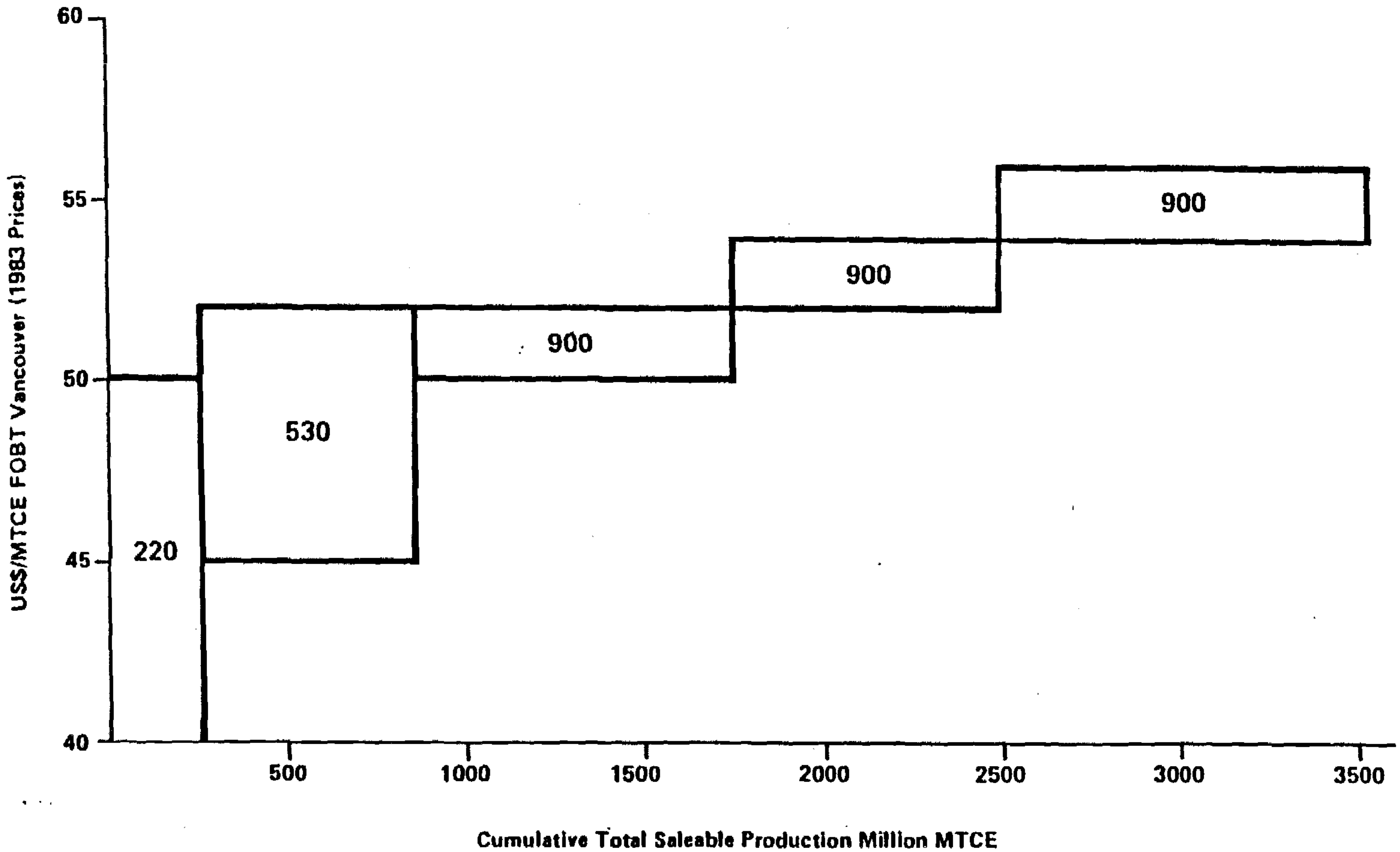
2. Surface minable coal, primarily in the Foothills region of Alberta, with reserves of 528 million MTCE (including Kootenay) and costs of $56 per MTCE.
3. 2,680 million MTCE of underground minable reserves in Alberta, with FOBT costs ranging from $53 to $60 per MTCE (1985 $).

These supply components are arranged into a solution curve in order of FOBT cost, shown as Figure 3-3, and contain a total reserve of 3,428 million MTCE; production and transportation costs range from $43 to $60 per MTCE (1985 $).

3.3.2.4 Colorado[18]

Reserves. Demonstrated reserves of coal potentially minable by under-ground mines in Colorado (USDOE, Energy Information Administration, 1983 Table A4) are 8,408 million tons. Based on estimates prepared for the World Bank (World Bank, 1983-1984), these reserves can be produced at prices (in 1985 dollars) from $23 to $30 per ton, FOB mine ($29 to $37 MTCE 1985 $). This range in costs reflects differences among mines in geologic conditions and mining methods, as well as management. We believe that a uniform distribution of cost versus reserve tonnage over this range is a reasonable estimate. Of the 7,644 million tonnes of demonstrated reserves, recoverable reserves will be no more than 45 percent, assuming that one-third of the reserves are unminable for environmental and geologic reasons (a similar assumption is made by the U.S. Department of Energy, see USDOE, Energy Information Administration, 1983) and that recovery of the remainder by a combination of longwall and room-and-pillar methods would average 70 percent. In 1982 the United States' average recovery percentage for underground mines was 63.48 percent (USDOE, Energy Information Administration, 1983). Total recoverable reserves are therefore estimated to be about 3,750 million tons. The average quality of these reserves is about 11,200 Btu/lb (Western Coal Export Task Force, 1981, Vol. 3). Hence, the reserve base expressed in MTCE is 2,750 million MTCE.

18. While significant coal reserves in Utah might be developed for export, it is likely that over the long run these limited reserves will be devoted to domestic power generation. This assumption may slightly understate the available western United States export coal.



SUPPLY CURVE FOR WESTERN CANADIAN COAL

FIGURE 3-3

(See Section 3.3.2.3)

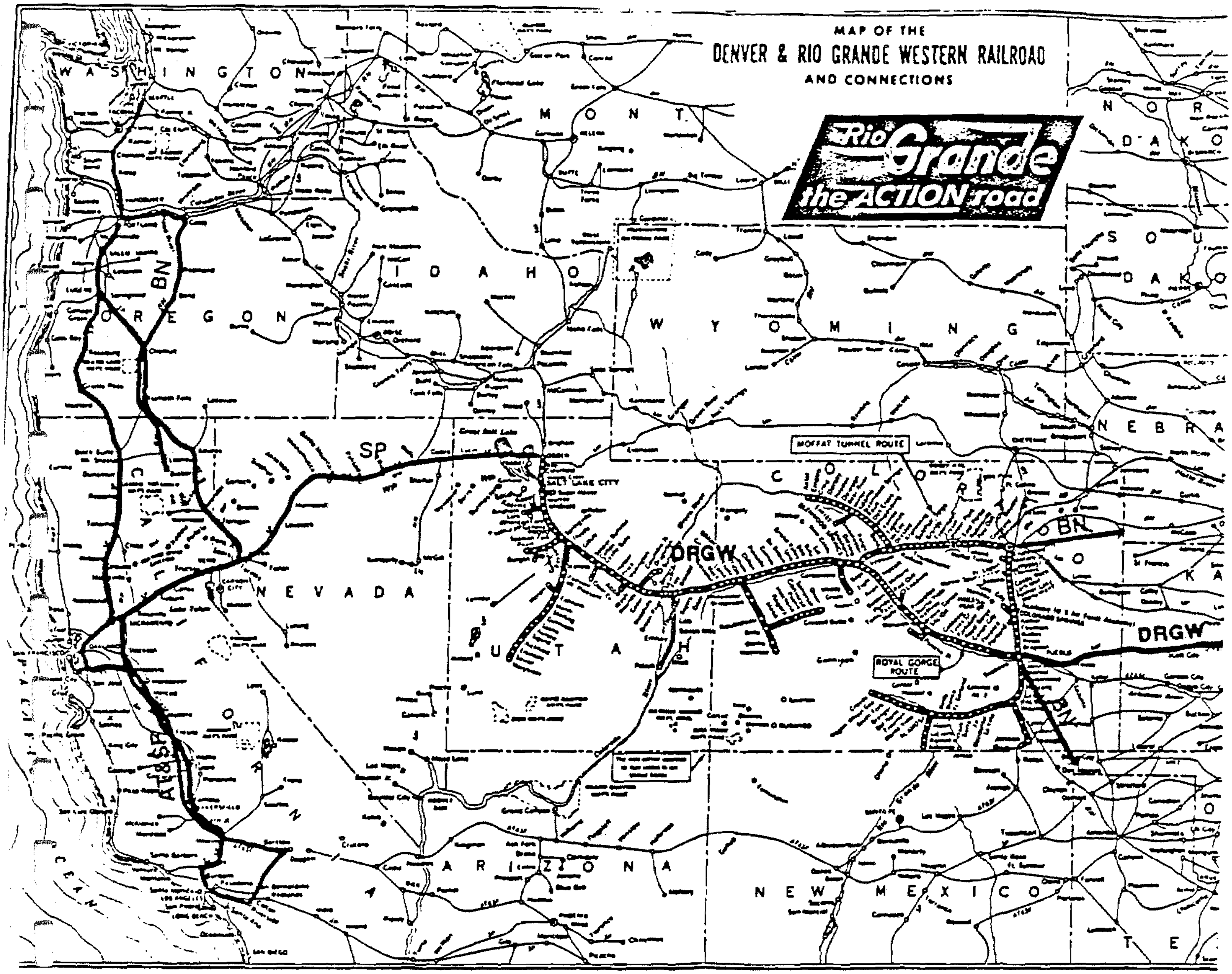
Dames & Moore

Transportation Costs. Current rail rates for export of Colorado coal are $27 per tonne (plus or minus $1.50) or $34 per MTCE (1985 $) (Denver & Rio Grande Western Railroad Company, 1982). The Denver & Rio Grande Western (DRGW) railroad (Fig. 3-4) has exclusive control of Colorado coal origins, though alternative routes (Union Pacific or Southern Pacific) exist for movements from Ogden, Utah, to the Pacific Coast (assuming a new port facility in San Francisco). Current port charges of $4.00 per ton ($5 per MTCE) are high enough to support long term capacity expansion.

The supply curve shown in Figure 3-5 shows 2,750 million MTCE of reserves ranging in FOBT cost from $68 per MTCE to $77 per MTCE (1985 $). The lower range is the sum of the low range of mine production costs, $29 per MTCE plus $34.04/MTCE per MTCE rail freight and port charges of $5 per MTCE. The reserves are distributed uniformly up to the highest mine cost of $37 per MTCE (1985 $).

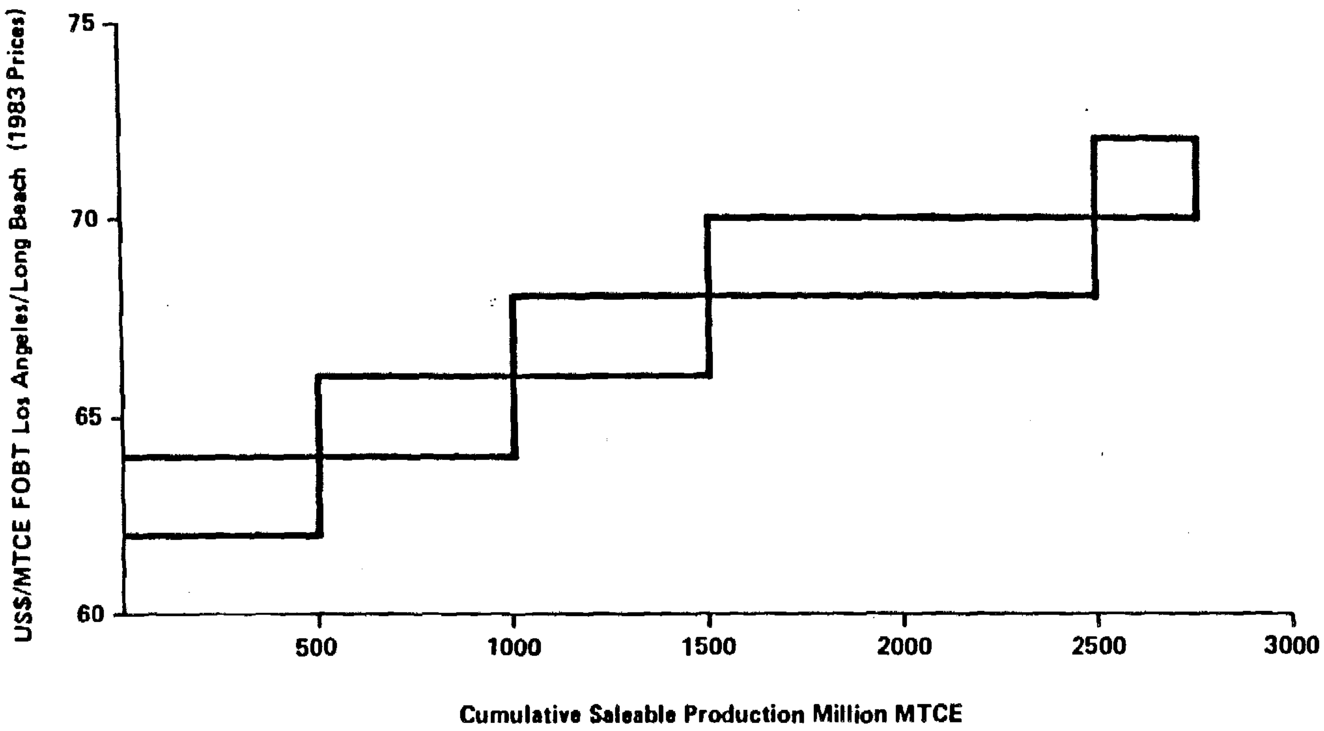
3.3.2.5 Coal Supply: Powder River Basin

Coal Reserves. In 1983 105 million tons of coal were produced from the Powder River Basin in Wyoming and Montana (Ref. USDOE, Energy Information Administration, 1983). The average production per mine was about 4.4 million tons and the average productivity was about 90 tons per man-shift. This tremendous production and productivity resulted from exploitation of coal seams that are sometimes over 100 feet thick and required the removal of only 0.5 to 2 cubic yards of overburden per ton of coal (Western Coal Export Task Force, 1981). Current (end of 1983) selling prices are $6.35 per ton for long term contracts (Murdoch, 1983). The EPRI Technical Assessment Guide (Electric Power Research Institute, 1982) estimated long run selling prices at $9.60 per ton in December 1980. Coal producers estimate that replacement cost for existing mines and capital recovery to earn 10 percent real after tax DCF would be around $9 to $10/ton. (For example, see USDOI, Bureau of Mines, 1974.) While there is currently considerable excess production capacity it will eventually be absorbed. For example, ICF, Inc., (EPRI, May 1983) estimates 1983 production capacity in the Powder River Basin (which ICF refers to as Western Northern Great Plains)



Map of the Denver & Rio Grande Western Railroad
and Connections
FIGURE 3-4

Source: Denver & Rio Grande Western Railroad



SUPPLY CURVE OF COLORADO COAL
FIGURE 3-5

(See Section 3.3.2.4)

Dames & Moore

at 198 to 220 million tons per day while they estimate year 2000 production in this region to be 330 million tons. Therefore, we estimate the long term price to be about $9.57 ton ($17.02/MTCE (1985 $), adjusted for moisture as per Beluga; see Appendix A). As demonstrated reserves of sub-mituminous coal in Wyoming exceed 65 billion tonnes (USDOE, Energy Information Administration, 1983), they can be considered as infinite for this analysis. The reserves included in the solution curve are 20 billion MTCE.

Transportation Costs. Rail transportation alternatives for Powder River Basin coal are Burlington Northern (BN) to Portland, Oregon, or Seattle, Washington, and the Union Pacific (UP) in San Francisco. Existing port facilities are in Los Angeles and Long Beach. A half finished facility also exists at Portland. We assume that new facilities could be built, probably at Seattle to take advantage of the availability of deep draft sites.

Rail distances in miles from Gillette, Wyoming (Rand McNally, 1973) are:

- To Portland, Oregon, via BN = 1,226
- To Seattle, Washington, via BN = 1,156
- To San Francisco, California, via UP = 1,500

There remains the question of competition versus cooperation. There is a long history of rate-making collaboration between railroads prior to the passage of the 1980 Staggers' Rail Act (rail deregulation). Also, in a similar situation in the eastern United States since the passage of the Staggers' Act, two potentially competitive export railroads (CSX and Norfolk-Southern) have avoided competition. Based on this evidence, competition in these circumstances is unlikely. Without it, rates will rise at least within the broad limits of the Staggers' Act guidelines, the market permitting.

If rates were established on a competitive basis,[19] the rate would be set by the longer UP movement, because the BN would set a rate that just undercuts the minimum rate the UP could charge and still cover costs. We estimate the variable cost (i.e., the directly attributable and variable costs such as car ownership and train crews) for a long distance unit train movement to be 1.3 cents per ton mile. (Dames & Moore estimate based on White & Haynes, 1979; also, similar estimate by J. Heller, 1984.) In addition to the costs directly attributable to movement of coal over a single route, the railroad must also pay other certain costs that are at least partly variable with overall traffic levels. For example, the railroad operates an extensive switching, signalling, communication, and central control system to schedule movement of trains through the rail system. The railroad must pay for some overhead expenses, such as marketing, that are partly variable with traffic.

The ICC has developed various formulas that attempt to represent, based on extensive econometric analysis of railroad cost data, the extent to which these indirect costs are variable with traffic. Recently, James Heller of Fieldston Company estimated variable costs, including the non-train cost elements for a representative western coal export movement (Mann, 1984). This analysis indicates that the ratio of total variable costs to "pure" variable costs is around 135 percent. This is a realistic measure of the true long run cost to the railroad of a coal unit train shipment. Therefore, we estimate that rates would initially be set at 135 percent of the $0.013 per ton-mile variable cost mentioned above. A

19. Several different economic mechanisms could determine the rail rates for export of Wyoming coal, two major factors being the degree of competition between the rail carriers (BN and UP) and the elasticity of demand. Four combinations are possible. First, if demand is inelastic and competition occurs, then the rate is set, as described in this section, by the cost of the longer of the two carrier routes. Second, if demand were elastic, the BN, the shorter route, might charge a rate as low as its variable cost (including the 35 percent "margin") to gain volume. Third, if the railroads cooperate in oligopolistic pricing (easy enough with only two competing firms) and the demand is inelastic, then they will raise rates to the point where Wyoming coal just keeps its market compared to the next most expensive source. Fourth, if the two railroads cooperate and demand is elastic, both will be forced to charge rates that are close to costs. We will show later that the demand is inelastic.

minimum rate equal to 135 percent of variable cost would be $25.85 per ton ($46.81 per MTCE) in 1985 dollars.

After Powder River Basin coal begins to enter the market in significant quantities and forces less severe competition from other suppliers, the railroads will be able to raise their "markup" from the very minimal 35 percent above variable costs projected for the initial rate. We assume rates will increase to 150 percent of variable cost in 2030 and 180 percent in 2040. The current legislative "trigger" for possible ICC jurisdiction over rail rates now starts at 160 percent of variable cost and will rise to 180 percent over the next few years (Heller, 1983). Therfore, the rail rates, without escalation, would be $49 per MTCE in 2030 and $59 per MTCE in 2040. Depending on market conditions, higher rates are possible. The validity of these rail pricing assumptions is examined later in this section after the competitive position of Wyoming coal is determined.

Port costs would be about $3.00 per ton (Western coal Export Task Force, 1981, Vol. 5) or $4.79 per MTCE (1985 dollars). Most likely, a new deep water port would be built, either in San Francisco or Seattle. Should this prove to be impossible due to environmental constraints, the Port of Portland, Oregon, is another option. Unfortunately, Portland can accommodate ships of only up to 50,000 tonnes DWT, which would raise ocean freight costs by $4 to $5 per ton or about $7 per MTCE. Total FOBT cost would be $68.62 per MTCE (1985 dollars), for the entire 20 billion MTCE available supply. The FOBT cost, before escalation would be $73.93 in 2030 and $84.57 in 2040 (1985 dollars).

3.3.3 Factor Cost Increases For Supply Cost.

The principal components of the cost of mining coal are labor (including payroll overhead), costs of owning machinery, supplies such as equipment parts, explosives, tires, fuel, and power. To the extent that the constant dollar costs (i.e., after adjustment for inflation) of any of these items increases, the cost of coal production must rise. As is discussed in detail below, wages in many countries have risen over recent decades at a rate faster than price. Indeed, this is the basic measure of economic betterment. Therefore we must give consideration to increases in coal miners' wages, oil, and oil products (such as lubricants, tires (consisting of rubber derived primarily from oil), and ammonium nitrate fuel oil,[20] an explosive made from natural gas). The APA composite oil and gas price projections show that oil and gas prices will be rising through year 2020, at which time they level off. Hence, the effect of rising energy prices is included in the supply cost estimates. Prices of machinery and parts exhibit no long term trend of increase and should therefore be held constant.

In the remainder of this section we discuss the factors affecting labor costs and the significance of energy prices in the cost of mining in each of the areas competing in the Pacific Rim coal market. In addition, the effects of increases in diesel fuel costs on the rail haulage of coal for export is discussed, since rail costs are a substantial part of the total cost of coal exported from these countries.

3.3.3.1 Australia and Canada

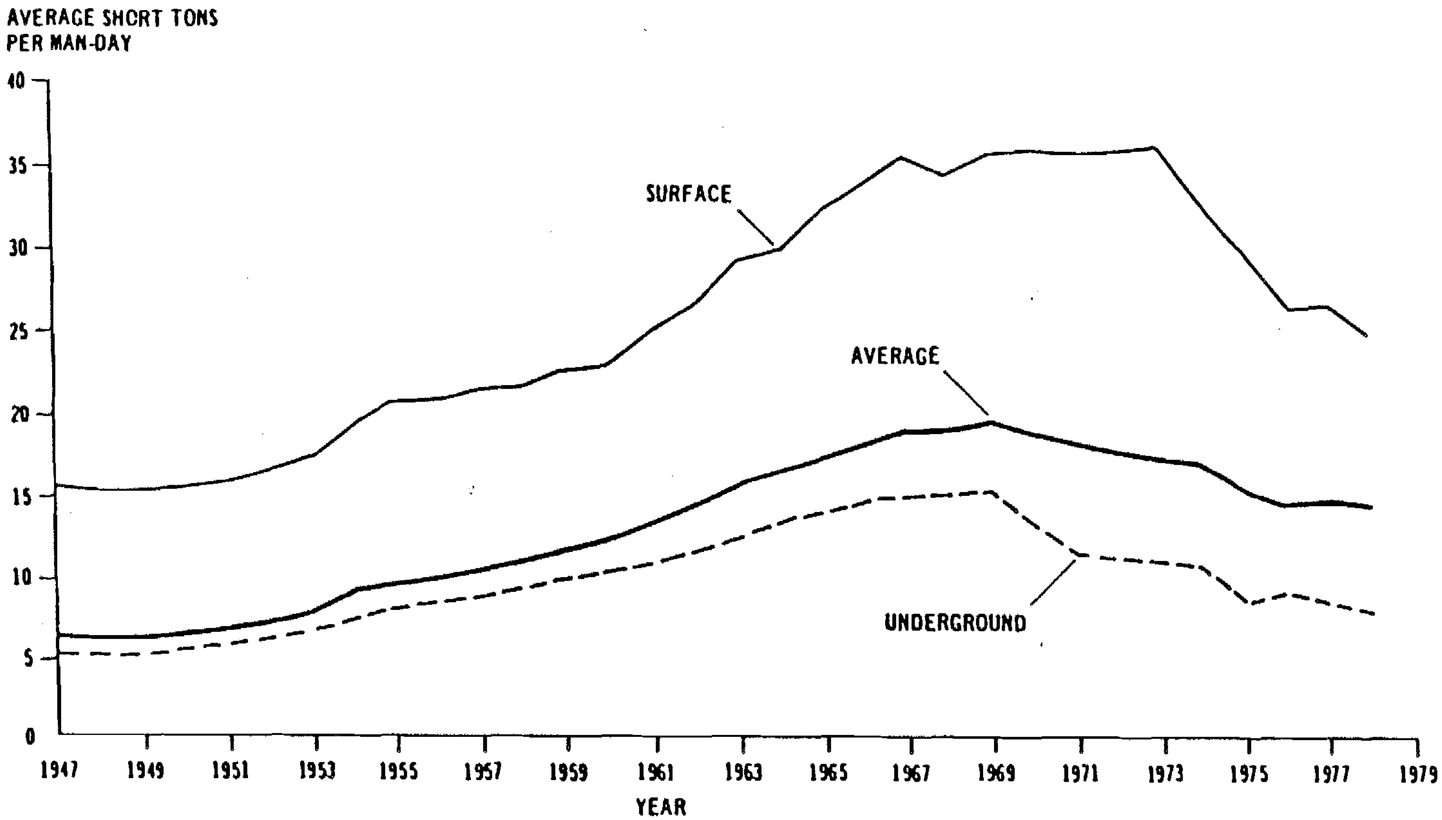
The long term trend in Australia and Canada, as in the United States, has been for increasing (constant dollar) wages. Wages and diesel fuel costs are two readily identifiable factor costs that can be expected to increase in price. Increases in wages can be offset by increases in labor productivity. Productivity increase can occur due to improved mining methods and equipment. Figure 3-6, for example, represents productivity between 1948 and 1978 in the U.S. coal mining industry when it increased at an average rate of 2.8 percent per annum (Robinson-Dames & Moore, 1980). This increase was due to a shift from hand loading in underground mines to mechanized production and use of larger and more powerful equipment in surface mines. However, such trends are not without limit and may even be reversed. The effects of more stringent safety and environmental regulations, along with labor force changes and other factors, led to a 4.1 percent per annum decline in U.S. coal mining productivity from 1969 to 1979.

Starting in 1966, United States surface mine productivity began to level off and then to decline; this was well before the imposition of stringent reclamation regulations. Aggregate measures such as the average

20. A mixture of 95 to 96 percent ammonium nitrate and 4 to 5 percent Number 2 fuel oil.

PRODUCTIVITY TRENDS BY METHOD OF MINING, 1948-1978 *

FIGURE 3-6



1948-1978	Annual increase rate of	(+) 2.8%
1960-1978	Annual increase rate of	(+) 0.9%
Since 1969	Productivity decreasing at annual rate of	(-) 4.1%

Source: Energy Information Administration, Annual Report to Congress, Vol. II, 1978. President's Commission on Coal (1980).

mining productivity figures just cited, as well as examination of particular method and equipment changes, suggest that only minor technical improvements in surface mine productivity are possible. Underground mining probably still offers considerable latitude for improved methods.

The primary sources of production of steam coal for export from Australia and Canada are surface mines. Regulation of these mines could certainly be more vigorous than it is, though reclamation requirements are already fairly strong. Increased regulation will tend to offset productivity gains achieved through technology.

In all countries, governments are zealous in their search for "economic rents" earned by mining companies and are eager to tax them away. In doing so, they may increase the production costs of all mines, including the marginal mine (which earns no economic rent). Some examples include the 30 percent severance tax imposed by the State of Montana on out-of-state coal shipments and the export rail rates in Queensland and New South Wales, Australia, which are 2.5 to 5 times variable costs (Mann, 1984). Similarly, severance taxes on oil and "windfall profits" taxes have been raised to capture prospective rents.

One positive factor--technology--acts on productivity; three negative ones are also significant: depletion, regulation, and taxation. Depletion of less costly reserves is explicitly quantified in the supply curve development. Without any ready method for quantifying these other effects, we regard them as cancelling out. That is, increased regulation and taxes will counteract the effect of improved technology. Therefore, the trend of unit labor costs (dollars per ton) will equal the constant dollar wage trend, with adjustments upward for depletion effects.

Data were assembled on the average nominal increase in wages in Australia (Paxton, J. ed., 1980, pp. 109, 351) and Canada (Paxton, J. ed., 1980, pp. 249, 275) for the period 1920 to 1980, and on the price index for the same period. In Canada the net of nominal wage escalation and inflation (as measured by the consumer price index equivalent) was 2.3 percent per annum compound growth (Bank of Canada, Ottawa, Personal Comm. to I.

Storace, 5/25/84); in Australia it was 3.0 percent (Australian Embassy, Ottawa, personal communication to I. Storace, 5/25/84). These increases in labor cost will affect the approximately 35 percent of the total mining cost that is direct labor, and is thus susceptible to labor cost escalation.

Rail costs account for 30 percent of the total FOB cost of coal from the two exporters. Diesel fuel accounts for 10 percent[21] of the total rail tariff for Australian exports and 30 percent for Canadian. The difference is due to the longer hauls in Canada and to the Australian rail rates which include large overhead and profit margins, that reduce the proportional importance of fuel costs. The forecast of oil prices shows a 2 percent average escalation over the period. In addition, oil related costs (diesel fuel, tires, ammonium nitrate, and lubricants) are 6 percent of the total cost. These will escalate with the same trend as this forecast, i.e., at 2 percent per annum.

As shown in Tables 3-7 and 3-8, combining the projected weighted escalation of mining and rail transportation costs yields an overall escalation rate of .85 percent per annum for Australia and .743 percent for Canada.[22]

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21. Calculated on the basis of 250 ton-miles per gallon for coal unit trains and $1 per gallon as-burned cost of fuel (Heller, 1984). The mileage for each movement (from Rand McNally, 1983 and other sources) is divided by 250 and multiplied by $1 per gallon to determine the fuel cost. This is divided by the rail rate to determine fuel cost as a percentage of the total rate.

22. This method of calculation understates the true escalation because the escalated share of total cost is held constant. In fact, each year the portion subject to escalation becomes a larger part of the total since it increases in relation to the nonescalating costs. For example, suppose that the initial total cost is $10 per tonne, of which $5 escalates at 1 percent per annum. Using the weighting method presented above, escalation is calculated at $5 divided by $10 times 1 percent, or .5 percent per annum. After 20 years this equals $11.05. Alternatively, if $5 per tonne is escalated at 1 percent per annum for 20 years and added back with the nonescalated $5, the total is $11.10 because the basis for escalation grows each year.

TABLE 3-7

Calculation of Composite Escalation
Rate for FOBT Cost of Coal--Australian

Cost Component	% of FOBT Prices (1)	Escalation Rate (%) (2)	Weighted Escalation Rate (%) (3)
Railroad Fuel	3.0	1.6	0.0548
Mine Labor	24.5	3.0	0.735
Mine Fuel & Related	4.2	1.6	0.67
			.85

* * * * * *

TABLE 3-8

Calculation of Composite Escalation
Rate for FOBT Cost of Coal--Canada

Cost Component	% of FOBT Prices (1)	Escalation Rate (%) (2)	Weighted Escalation Rate (%) (3)
Railroad Fuel	9.0	1.6	.144
Mine Labor	24.5	2.3	.564
Mine Fuel & Related	4.2	1.6	.0672
			.743

(1) Contribution of each cost component to 1983 dollar FOBT price.

(2) Annual rate of increase in real (constant dollar) cost. For fuel prices reference APA Composite Oil Price Forecast. For Labor costs see Section 2.2

(3) Percent weight in FOBT price times escalation rate, expressed as a percentage of FOBT price (e.g., .03 * .016 = .00048 = .048 percent).

3.3.3.2 Colorado And Wyoming

The U.S. long-term trend of increases in real wages (average for all industries 1910-1981) is 2.2 percent per annum (see Section 2-2). As discussed earlier, technical changes may cause productivity increases that offset wage increases, but increased regulation may reduce productivity. As before, we will treat these effects as balancing each other, and increase the labor portion of mining costs by the wage increase rate. This affects both labor operating costs and the labor portion of capital costs, which are about 25 percent of the total mine cost for mines in Colorado and Wyoming.

Rail costs are a high percentage of the FOB price of coal from both Colorado (50 percent) and Wyoming (75 percent). Fuel costs are 10.5 percent of the rail costs for Colorado export coal and 23.3 percent for Wyoming coal.

Hence, diesel fuel price increases averaging 1.6% per annum will cause .12 percent per annum and .34 percent per annum increases in the FOB price of Colorado and Wyoming coal, respectively.

Combining the effects of the mine labor and rail fuel increases, as shown in Tables 3-9 and 3-10, the weighted annual escalation rate for Colorado coal is .443 percent per annum and that for Wyoming coal is .51 percent.

3.3.4 Ocean Freight Costs

The price of Alaska coal sold into the Pacific market will depend on the transportation costs of Alaska coal to the prime market areas. Most of the demand comes from consumers in Japan, Korea, and Taiwan. Since these buyers are located at similar distances from the sources of supply and comprise most of the market, it is likely that prices will be closely related to the delivered costs to Japan. Small premiums or discounts could exist among the competing suppliers to account for transportation differentials into the southeast Asia markets. For example, given the differences in transportation costs, Canadian coal would need to sell at a lower cost

TABLE 3-9

Calculation of Composite Escalation
Rate for FOBT Cost of Coal--Colorado

Cost Component	% of FOBT Price (1)	Escalation Rate (%)(2)	Weighted Escalation Rate (%)(3)
Railroal Fuel	7.5	1.6	.12
Mine Labor	12.5	2.2	.275
Mine Fuel and Related	3.0	1.6	.048
			.443

* * * * * *

TABLE 3-10

Calculation of Composite Escalation
Rate for FOBT Cost of Coal--Wyoming

Cost Component	% of FOBT Price (1)	Escalation Rate (%)(2)	Weighted Escalation Rate (5)(3)
Railroad Fuel	21.0	1.6	.336
Mine Labor	6.3	2.2	.139
Mine Fuel and Related	2.3	1.6	.0367
			.51

(1) Contribution of each cost component to 1983 dollar FOBT price.

(2) Annual rate of increase in real (constant dollar) cost. For fuel prices reference APA Composite Oil Price Forecast. For labor costs see Section 2.2.

(3) Percent weight in FOBT price times escalation rate, expressed as a percentage of FOBT price (e.g., .75 * .016 = .0012 = .12 percent).

aboard ship than Australian coal for sales to the Philippines, while prices would be equal for sales to Japan.

Estimates of ocean freight rates have been developed based on costs of ownership (including 10 percent return on capital) for new vessels and using current costs for bunkers (i.e., ship's fuel). Since the import projections indicate a rapidly rising coal trade additional shipping capacity will be required continuously. Ocean freight rates, at least over the long term, should therefore be related to costs for owning and operating new vessels.

Sources of data for these estimates are confidential estimates provided by the shipping departments of two major oil companies and new building costs reported in the Lloyds Shipping Economist (1982). Assumed for all the movements are 120,000 dwt vessels since this vessel size can already be loaded at the Australian and Canadian coal ports and is within the water depth limits for a Puget Sound coal port when one will be needed in the 2020 period (Western Coal Export Task Force, 1981). This is also the planning standard for the new coal port proposed by the Port of Los Angeles. Some smaller receiving ports may continue to be limited to smaller vessels, and some ports make take larger vessels, but shipments in vessels of this dominant size will be the key to price setting (Western Coal Export Task Force, Vol. 5).

The estimated ocean freight rates in dollars per tonne and dollars per MTCE are summarized in Table 3-11. The shipping costs, at $10.64 to $11.70 per MTCE (1985 dollars), are nearly equal for each of the sources except Wyoming. The shortest movement is from Alaska to Japan, but the distance advantage is counteracted by the low calorific value of Alaska coal. Development of even larger colliers will therefore decrease the absolute cost of shipping but not the relative position of Alaska compared to the competing producers.

Fuel oil is a major component of the cost of ocean shipping, amounting about 40 percent of ocean freight cost (Westpo, 1981). APA oil price projections show that fuel oil costs will be rising over the 2000 to 2050 period at about 1.6 percent per year. Therefore, the overall cost of ocean

TABLE 3-11

PACIFIC RIM SHIPPING DISTANCES
Coal Loading Ports to Yokohama
(nautical miles)[1] and
Estimated 1985 Freight Rates
Based on New Buildings Charter
120,000 dwt Vessels

	Miles	$/TON	1983 $ /MTCE	1985 $ /MTCE(2)
Beluga (Anchorage)	3,200	7.00	11.00	11.70
Colorado (Los Angeles)	4,839	9.00	11.00	11.70
Wyoming (Seattle)	4,245	8.00	15.00	15.96
Australia (Newcastle)	4,270	8.00	10.00	10.64
Alberta/British Columbia (Vancouver)	4,262	8.00	10.00	10.64

(1) Paxton, J., Ed. The Statesman's Year-Book. 1980-81. MacMillan St. Martin's Press (London) P. 109, 351.

(2) Inflated to 1985 dollars by a 1.0638 factor.

freight will escalate at 0.64 percent per year.

3.4 COMPILATION OF AGGREGATE SOLUTION CURVE BY YEAR

The solution curves for each of the competing producers are brought together in this section with the cost escalation rates estimated for each region to produce an aggregate solution curve for each of the forecast years.

First, the aggregate solution curve combines the supplies available from each region into a single graph. This is accomplished by adding up the supplies available at each price level from Australia, Canada, Colorado, and Wyoming. As noted previously, supplies from China are not included in the solution curve, but will be accounted for by assigning 15 percent of the consumption to China. This reduces the demand that other suppliers must satisfy.

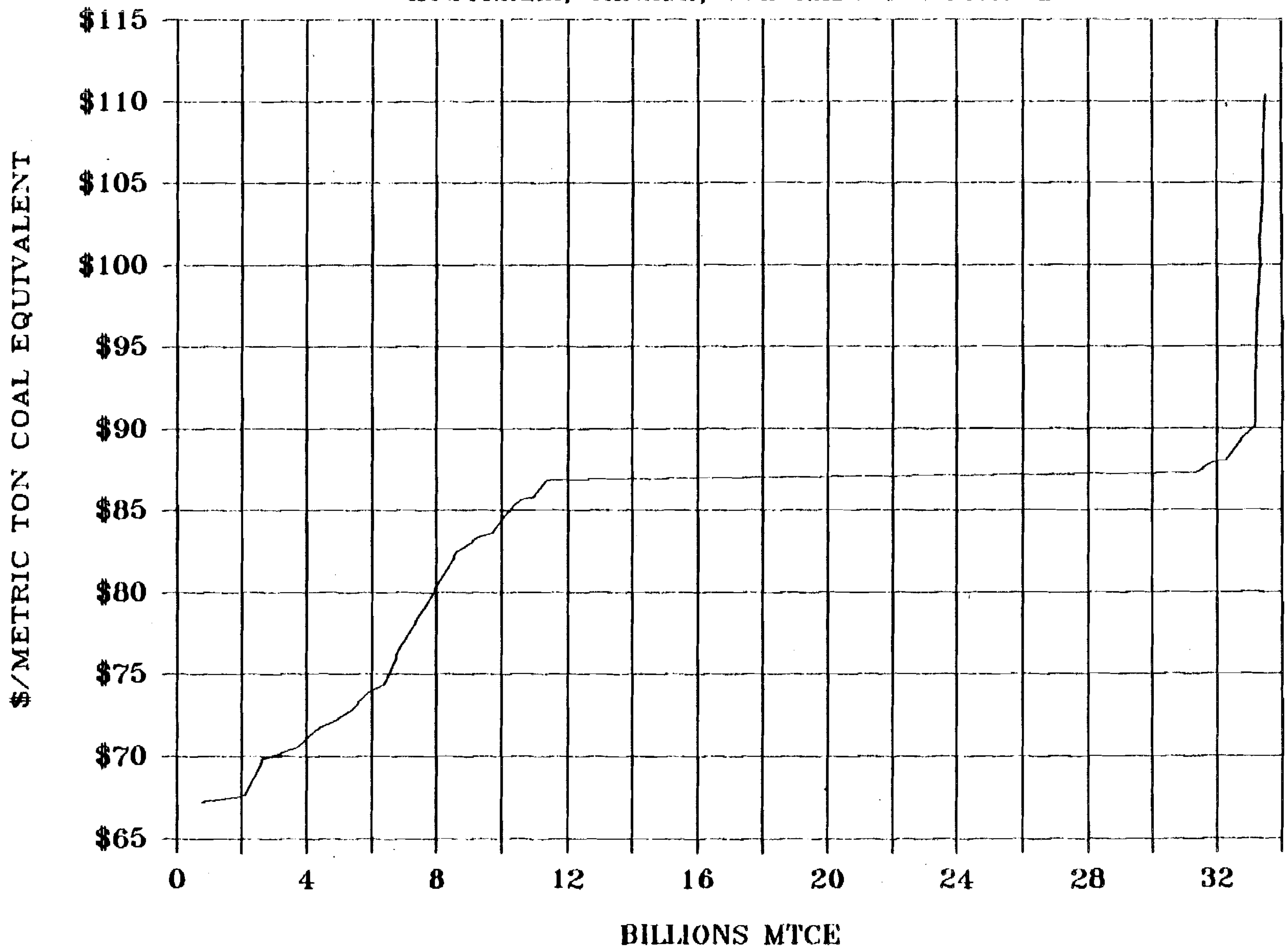
The costs of production for each supplying country, which escalate at differing rates, must be calculated for each forecast year from 1990 to 2040. The difference in escalation rates changes the relative position of the various supply areas over time. For example, Colorado coal prices escalate more slowly than others, and as a result, in later years Colorado coal will become more cost competitive compared to Australian coal.

The solution curves are represented graphically in Figures 3-7 through 3-12. For each year the curve shows the total reserves that could be produced versus the required price, delivered to Japan. The escalation rates have the effect of shifting the curve upward with time. Note that the same reserve level (on the horizontal axis) corresponds to a higher price in each year. Since Wyoming coal is the largest single component of supply, the "flat" portion of the curve rises from one figure to the next at about the Wyoming escalation rate of 0.56 percent per year.

The least expensive supplies are some Australian reserves and production from Canada. Next highest in cost are the Colorado coal reserves.

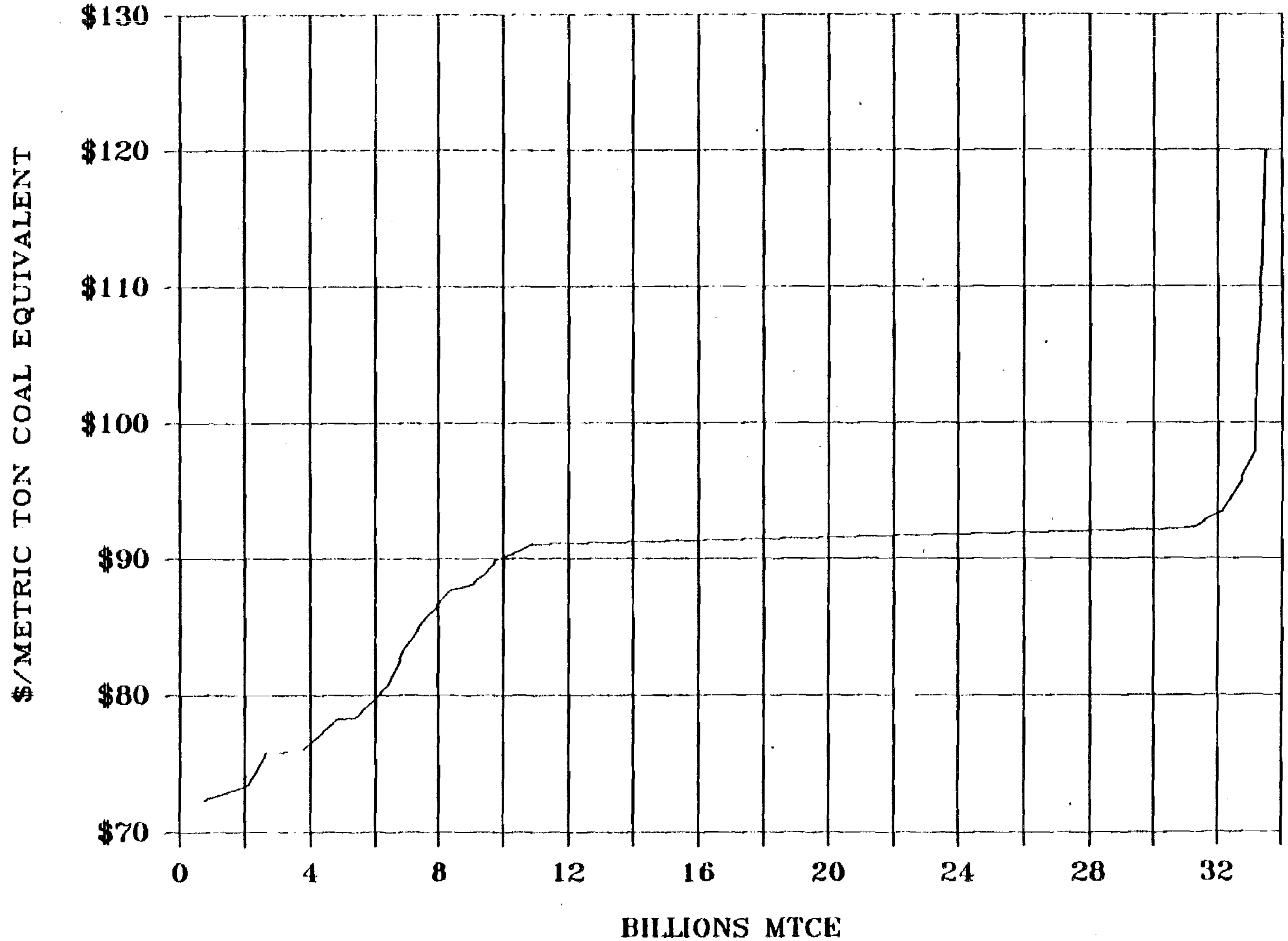
STEAM COAL PRODUCTION - 1990

AUSTRALIA, CANADA, COLORADO & WYOMING



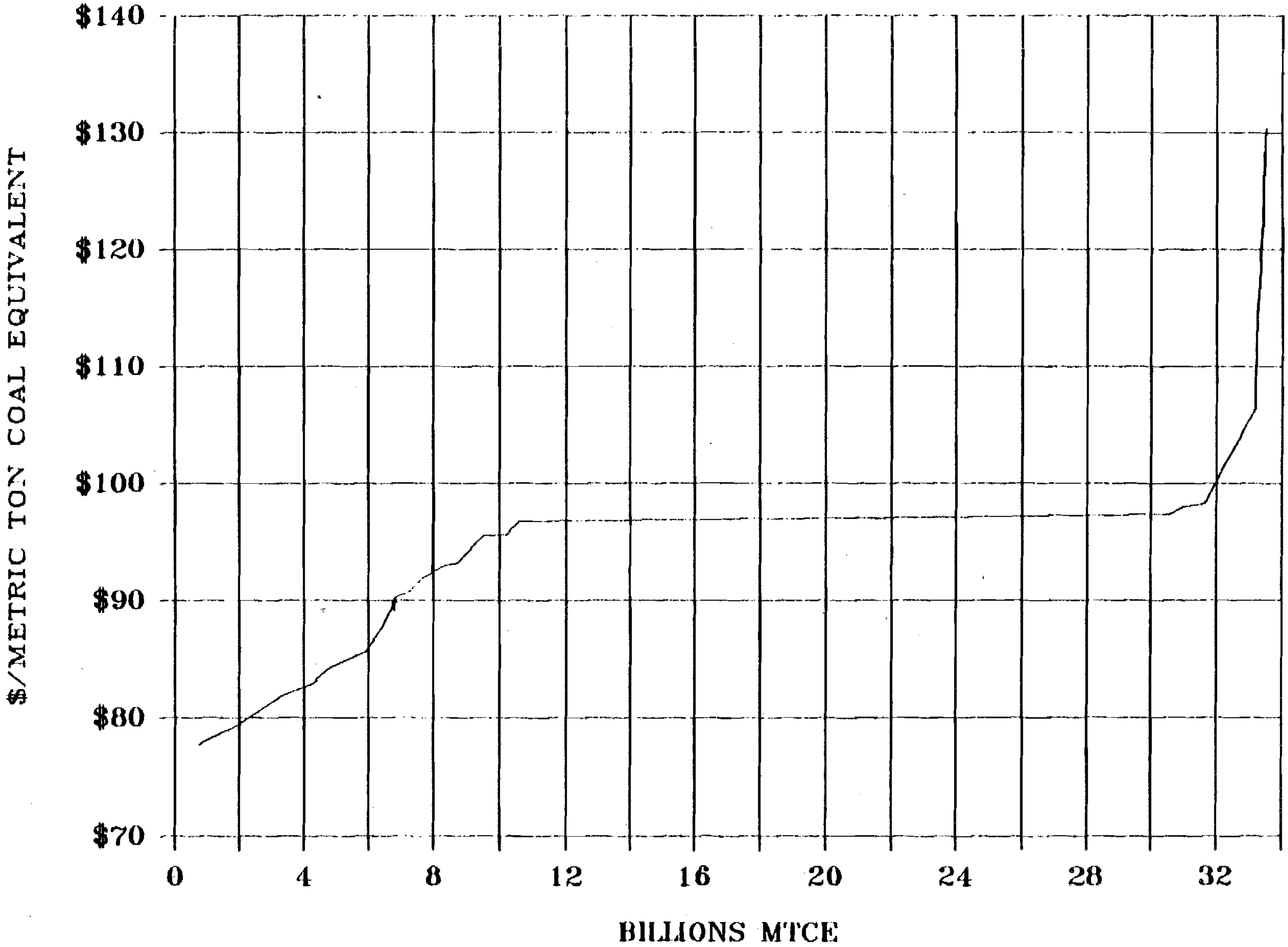
STEAM COAL PRODUCTION – 2000

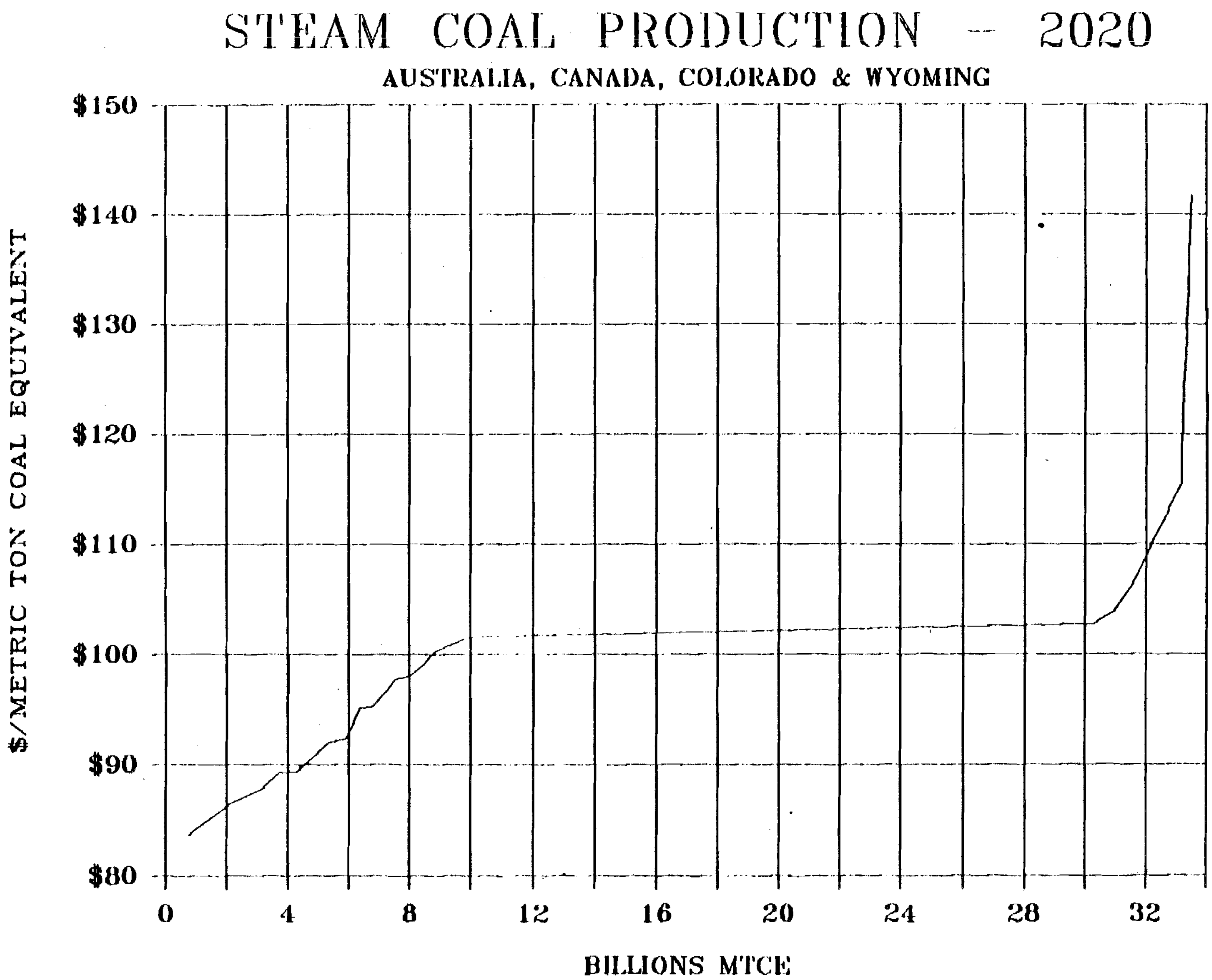
AUSTRALIA, CANADA, COLORADO & WYOMING



STEAM COAL PRODUCTION - 2010

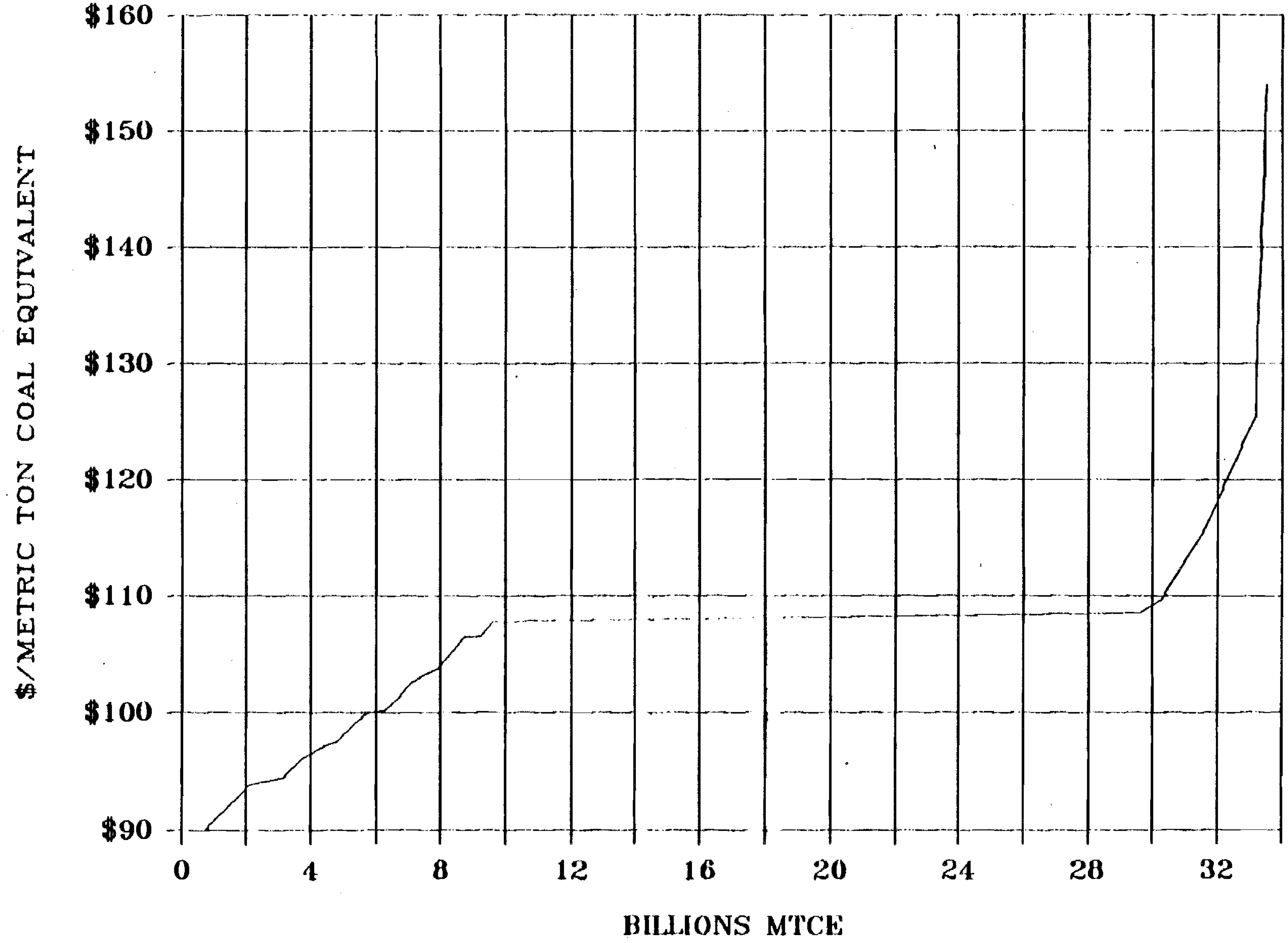
AUSTRALIA, CANADA, COLORADO & WYOMING

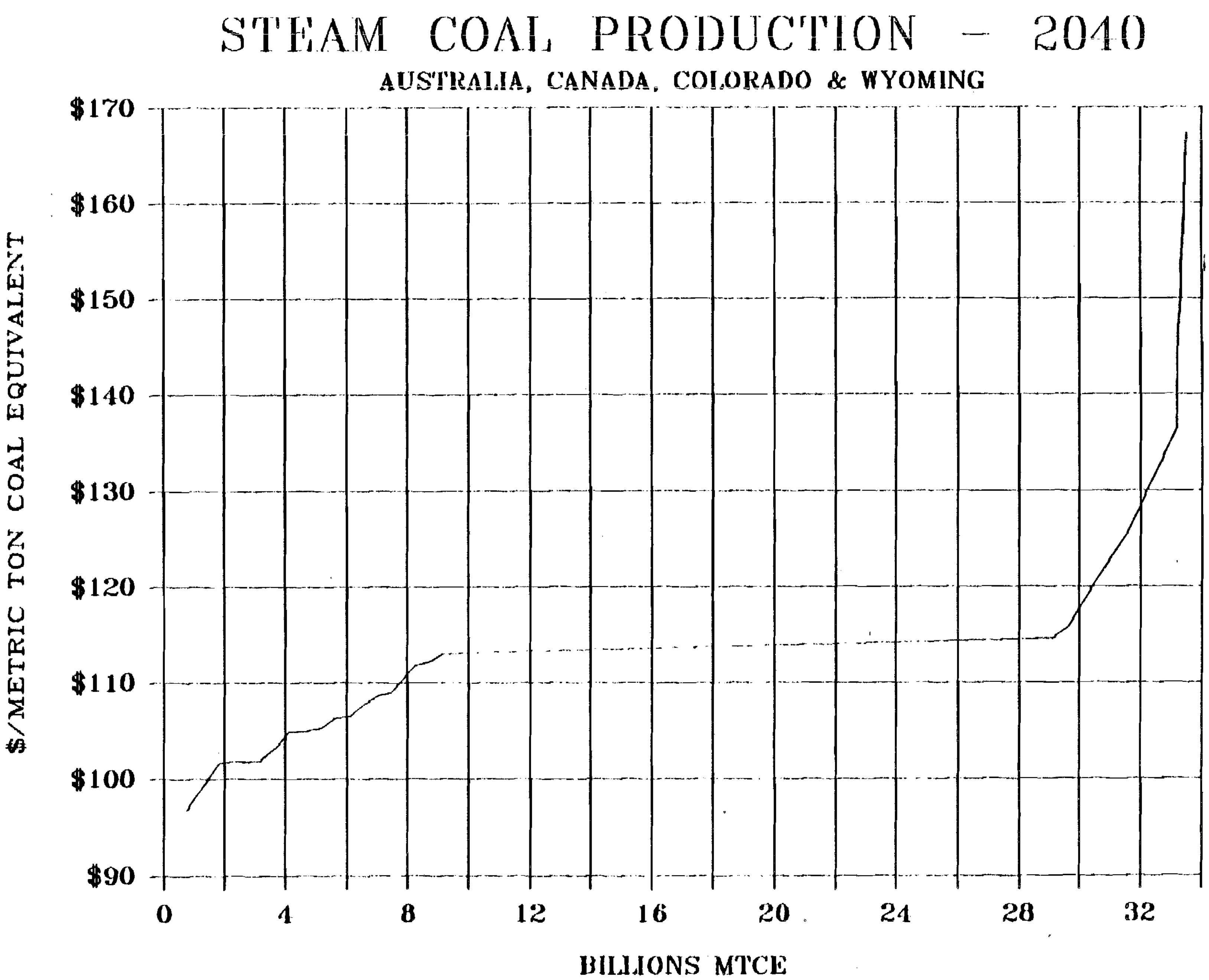



STEAM COAL PRODUCTION - 2020
AUSTRALIA, CANADA, COLORADO & WYOMING
$/METRIC TON COAL EQUIVALENT
$150
$140
$130
$120
$110
$100
$90
$80
0
4
8
12
16
20
24
28
32
BILLIONS MTCE

STEAM COAL PRODUCTION – 2030

AUSTRALIA, CANADA, COLORADO & WYOMING




STEAM COAL PRODUCTION – 2040
AUSTRALIA, CANADA, COLORADO & WYOMING
$170
$160
$150
$140
$130
$120
$110
$100
$90
$/METRIC TON COAL EQUIVALENT
0
4
8
12
16
20
24
28
32
BILLIONS MTCE

The Wyoming coal is most expensive. Thus the curve flattens once it reaches the level of Wyoming delivered prices.

The conspicuous flattening of each of these curves results from the very large amount of coal available from Wyoming, at a constant but high price. The "flat" curve indicates a large increment of supply with a small change in price. The available supply from Wyoming is at least 20 billion MTCE (see Section 3.3.2.5), which is sufficient, combined with lower cost coal from some other sources, to provide all the coal necessary to meet the expected demand, as discussed in the next section.

3.5 SUPPLY/DEMAND ANALYSIS AND PRICE FORECAST

The trend of the long term price of coal at any time is determined by the cost of production of the marginal (i.e., highest cost) mine required to open to satisfy the demand. This basic economic concept follows from the fact that mines are logically developed in the order of cost of production, starting with the lowest cost mines. In a market with rising demand, the consumer must pay the producer enough to get him to open a mine.[23] Each additional increment of demand must be matched with a steadily more expensive increment of supply. Prices therefore can be determined by finding the cost of supplying a given level of demand (consumption).

The solution curves relate coal price to coal reserves "used." The reserves used include those mined between today and the forecast year, plus reserves dedicated to future production at that time. This is true because mines are not opened for a single year's production of coal (see Section 3.3.1), but rather for a productive life of 10 to 30 years (even longer occasionally). Therefore, dedicated or committed reserves are the sum of depletion plus reserves dedicated to future production. Reserves dedicated to future production are estimated in this study to be 20 times current production levels. As we have already established a solution curve that

23. This is somewhat of a simplification for purposes of exposition. What actually happens is that mines already in existence expand to meet rising demand, but as they do so their variable costs start to rise. This forces prices up; when they reach a sufficiently attractive level producers invest in new mine capacity. In this sense, the long term supply curve is the sum of the short term curves for each mine.

relates production levels and costs, the next step is to compare these solution curves with demand.

3.5.1 Market Demand

The figure that we must use for coal demand is not simply the current consumption level in a given year. It must also reflect depletion and reserve commitments. Depletion is the reduction in available reserves to account for past production. Therefore, as discussed in Section 3.3.1, the cumulative past demand by year was estimated.

To determine future reserve commitments, coal production (which equals consumption) is multiplied by 20. For example, consumption in the year 2000 (from Table 3-1) is projected to be 183 million MTCE. Reserve commitments are therefore 3660 million MTCE, for future depletion, plus cumulative production of 1585 million MTCE.

The balance of supply and demand, determined by the cost of opening the last new mine to satisfy the increasing demand level, is related to the solution curves developed here by comparing the demand, represented by the reserve commitments, with the supply, which represents the cumulative reserves developed.

Before making this supply/demand comparison, an allowance must be made for the participation of China in the market. As was described in Section 3.3.2.2, in this analysis we are allocating a 15 percent share of the market to China "off the top" before comparing the projected supply and demand. Each step of this calculation is shown in Table 3-12.

First, Table 3-12 shows the total imports by year for the Pacific coal importers (from Table 3-1). These rise from 150 million MTCE in 2000 to 569 million MTCE in 2040. On the second line of the table, the cumulative imports are shown, the sum total production over time (also from Table 3-1). These rise from 1585 million MTCE in 2000 (the cumulative total from 1990 to 2000) to 16,874 in 2040.

TABLE 3-12

Reserve Commitments for Pacific Rim Export
Steam Coal for 1990-2040
(Billion MTCE)

	2000	2010	2020	2030	2040
Total Imports per Year (1)	0.15	0.28	0.40	0.48	0.57
Cumulative Imports (2)	1.6	3.7	7.1	11.1	16.9
Less Chinese Share (3)	1.3	3.2	6.1	9.9	14.3
Reserve Commitments (4)	3.9	7.9	12.9	18.1	24.0

(1) Source: Table 3-1.
(2) Total by year of 10 times the arithmetic average of column and previous column.
(3) Exports from China are assumed to account for 15 percent of cumulative imports.
(4) Sum of cumulative imports less Chinese share plus 20 times the imports in that year, also less 15 percent for Chinese share of exports. Reserve commitments are the measure of necessary deductions of the coal reserve base.

Next, the Chinese 15 percent market share is counted for by reducing the cumulative production by 15 percent (calculated by multiplying the cumulative imports by .85). For example the cumulative imports in 2000 are reduced from 1,585 million MTCE to 1,347 million. Reserve commitments are shown on the next line of the table. This line is the sum of the cumulative imports, less the Chinese share, plus 20 times the production in that year, also less 15 percent for the Chinese share. For example, in 2000 the reserve commitment of 3,900 million MTCE is the sum of the cumulative imports less the Chinese share of 1,347 million MTCE, plus 20 times 150 million MTCE of imports in 2000, times .85.

3.5.2 Supply/Demand Comparison and Prices Without Alaska Exports

If we now compare the reserve commitments shown in Table 3-12 to the solution curves for each year (Figures 3-7 through 3-12) we can determine what price is needed to produce enough coal to satisfy the demand, assuming that all coal from the non-Alaska sources is incorporated in the supply curves. The price determination is made simply be reducing across the horizontal axis of the solution curves to the appropriate tonnage of reserves and reading the price for that point on the supply curve. Implicitly, we assume that the demand is completely inelastic, that is, that coal prices do not influence the consumption of coal. Figures 3-13 through 3-17 show the supply/demand comparison for the non-Alaska suppliers for 2000-2040. In each figure the demand, with and without export of Alaska coal, is shown as a vertical line. The price is shown where a horizontal line connects the intersection of the demand estimate and the solution curve.

The effect of exports of Alaska coal is, of course, to increase the supply available to Pacific market consumers. Hence, to calculate the effect on prices, the solution curve should be shifted to the right, increasing the available supply at a given price. For ease of mechanics of presentation, the demand is shown as shifted to the left by the amount of Alaska exports. This allows both states of the market (with and without Alaska exports) to be shown on a single graph. The result of this comparison are summarized in Table 3-13 and show estimated Pacific market prices (in 1985 $) by year without Alaska exports. The price estimated for 2000 is $76

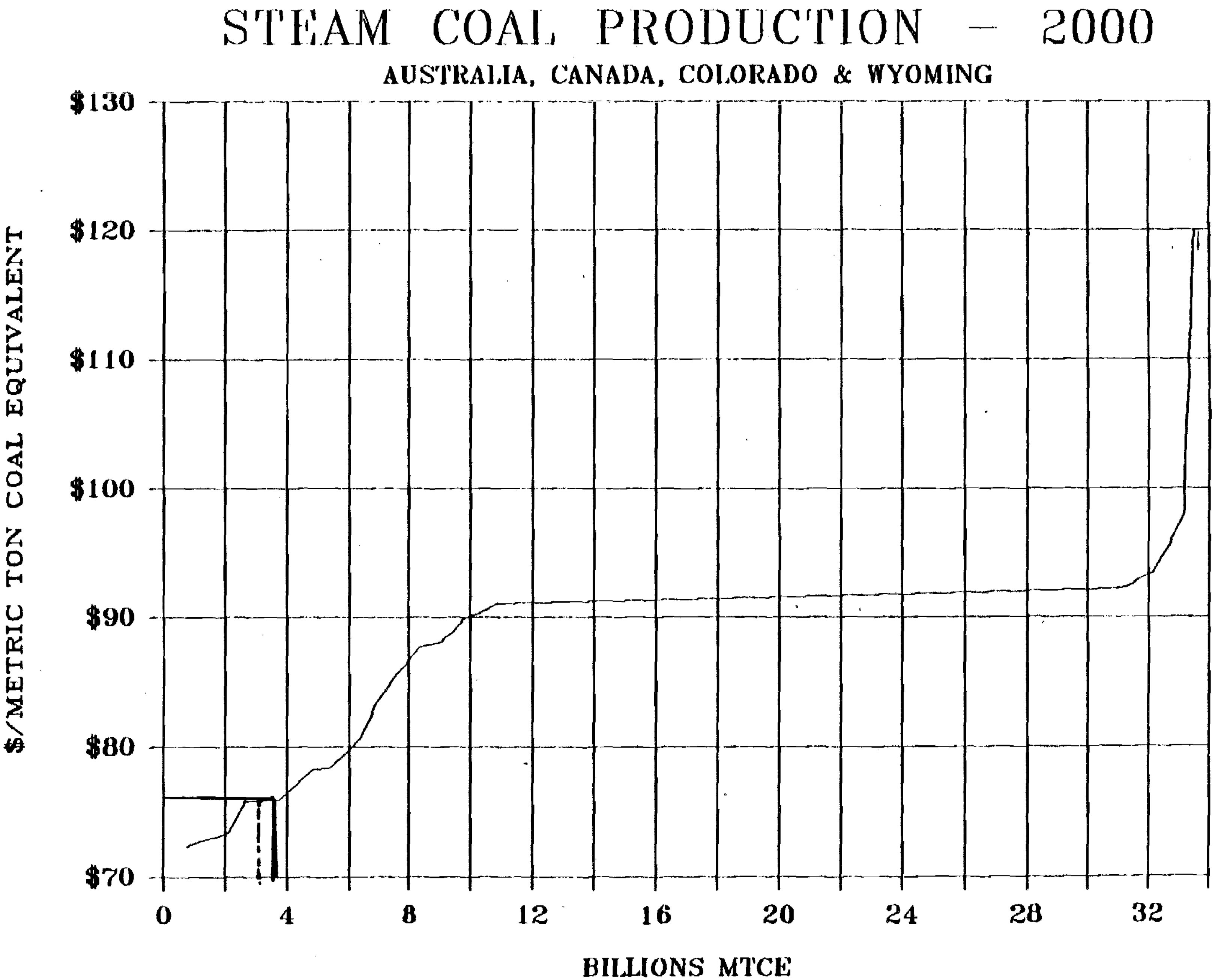

STEAM COAL PRODUCTION – 2000
AUSTRALIA, CANADA, COLORADO & WYOMING
$/METRIC TON COAL EQUIVALENT
$130
$120
$110
$100
$90
$80
$70
0
4
8
12
16
20
24
28
32
BILLIONS MTCE

Figure 3-13

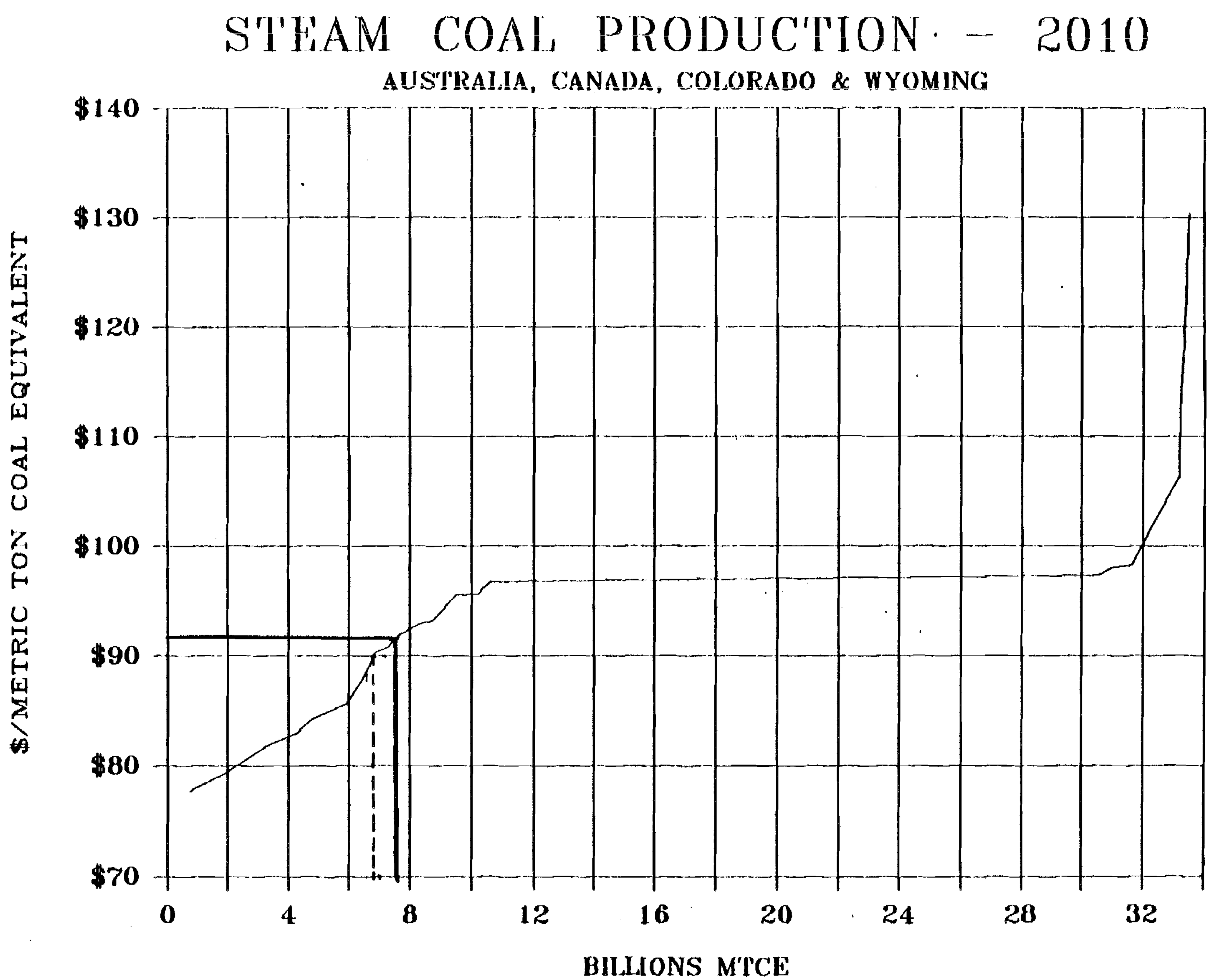

STEAM COAL PRODUCTION – 2010
AUSTRALIA, CANADA, COLORADO & WYOMING
$140
$130
$120
$110
$100
$90
$80
$70
$/METRIC TON COAL EQUIVALENT
0
4
8
12
16
20
24
28
32
BILLIONS MTCE

Figure 3-14

STEAM COAL PRODUCTION — 2020

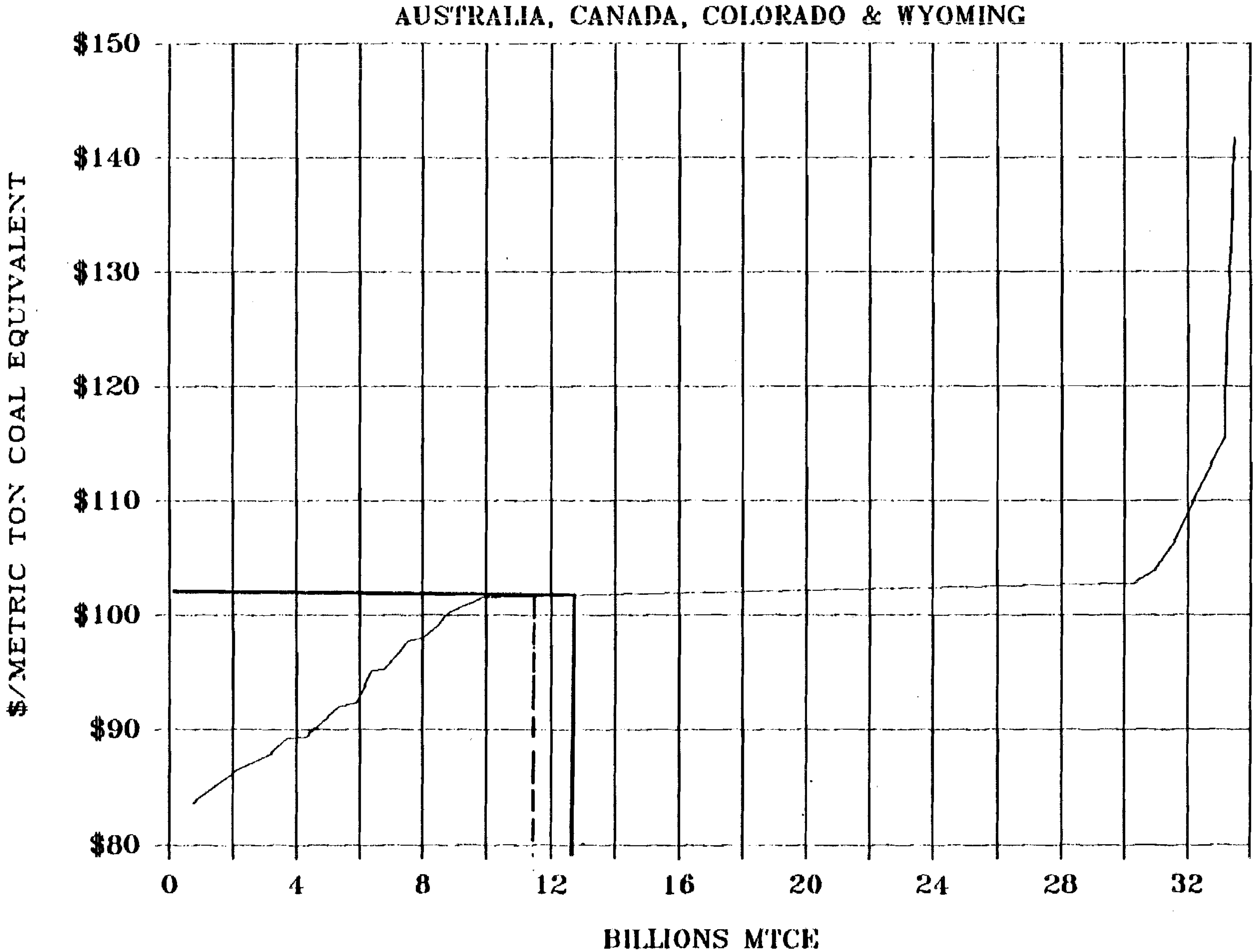


Figure 3-15

STEAM COAL PRODUCTION - 2030

AUSTRALIA, CANADA, COLORADO & WYOMING

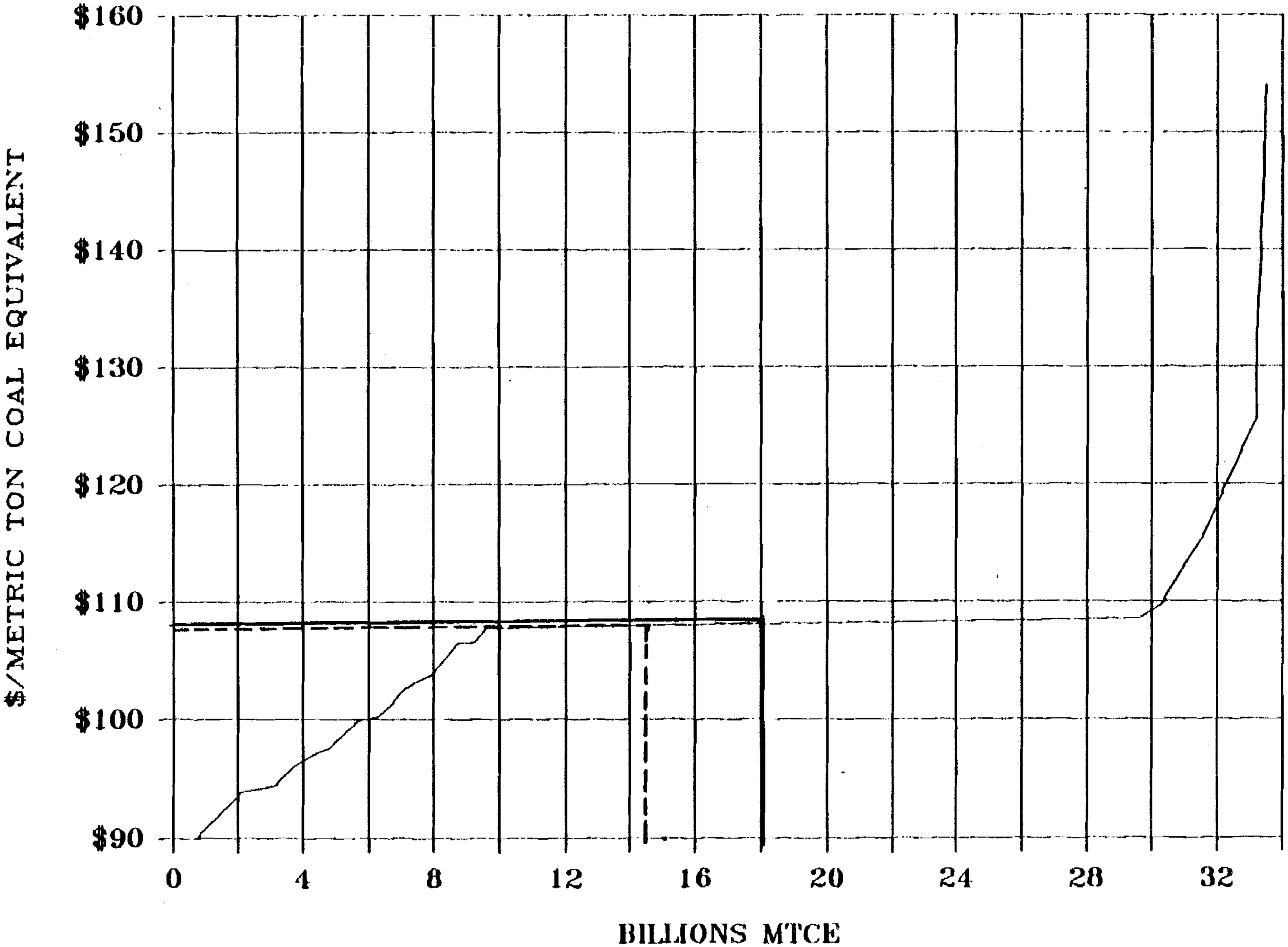


Figure 3-16

STEAM COAL PRODUCTION – 2040

AUSTRALIA, CANADA, COLORADO & WYOMING

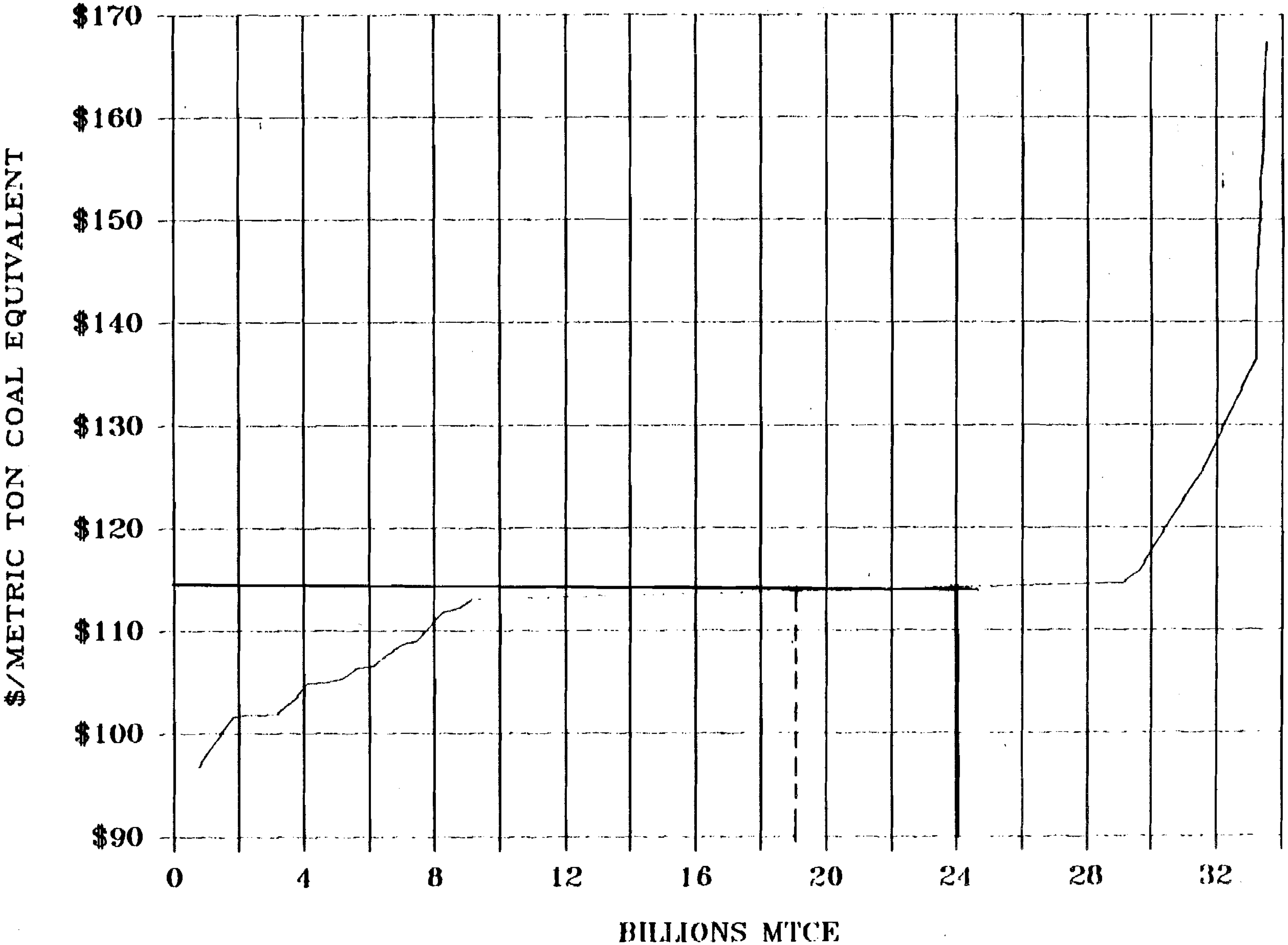


Figure 3-17

TABLE 3-13

Estimated Pacific Market Prices by Year
Without Alaska Exports (1)
(1985 $ price CIF Japan)

	2000	2010	2020	2030	2040
No Wyoming Constraint (2)					
$/MTCE	76	93	102	109	115
$/MMBtu	2.73	3.35	3.67	3.92	4.13
With Wyoming Constraint (3)					
$/MTCE	76	93	102	119	125
$/MMBtu	2.73	3.35	3.67	4.28	4.50

(1) Derived from Dames & Moore supply/demand analysis. See text.
(2) Prices as derived from comparison of demand with solution curves as indicated in Figures 3-13 to 3-17.
(3) Price including added cost for Wyoming coal in 2030 and 2040 of additional ocean freight from Portland, Oregon or other shallow port, as discussed in Section 3.5.2.

per MTCE, or \$2.73 per million Btu (calculated by dividing the per MTCE price by the 27.8 million Btu in an MTCE). The prices rises to \$93 per MTCE in 2010 and \$115 per MTCE in 2040.

It is possible to infer from the source composition of the solution curve the relative annual production levels from each source. This is done by referring to tables of the supply and cost of each source and determining what fraction of the total reserve commitments are supplied by each source, based on reserves available from that source at the market price. Reserve commitments by source by year are summarized in Table 3-14. The result is not exact because those sources that come into production first (some Australian coals and Canadian coals) are substantially depleted in later years. Nonetheless, a good approximation of annual production by source can be made. The results are checked as shown in the table, by recalculating the reserve commitments from these producers' estimates. Table 3-15 agrees with the required reserve commitment (Table 3-12) of 24.0 billion MTCE.

If this is done for the years 2030 and 2040 it is apparent that exports of Wyoming coal would be very large. The estimated supply source mix for those years is given in Table 3-15. It shows Wyoming coal exports of 187 million MTCE in 2030 and 238 billion MTCE in 2040. From a purely theoretical, logistical point of view there is little reason to doubt that such export levels could be mined, railed, and loaded aboard ships. However, the two port locations where large (120,000 dwt) vessels could be loaded are Puget Sound (Seattle or vicinity) and San Francisco Bay. Both have been the scenes of great concern and controversy over the environmental effects of large scale industrial and coal port development. (For example, see Western Coal Export Task Force, 1981). As a result, it is likely that a limit would be placed on how much coal could be moved through these areas. For example, if one major port facility were allowed a volume of around 30 million (20 million MTCE) per year, this could be attained. Such a limitation could be overcome in a number of ways.

TABLE 3-14

Reserve Commitments (1) by Year and Source (2)
(Billion MTCE)

	2000	2010	2020	2030	2040
AUSTRALIA	1.19	3.4	4.1	4.8	6.5
CANADA	2.0	3.5	3.5	3.5	3.5
COLORADO	0.00	1.0	2.7	2.7	2.7
WYOMING	0.00	0.00	2.6	7.1	11.3
TOTAL	3.9	7.9	12.9	18.1	24.0

(1) From detailed supply tables, see Appendix D.
(2) Supply not including Alaska coal, but including Chinese coal.

TABLE 3-15

Projected Exports of Major Pacific Rim Steam
Coal Exporters 2000-2040 Without Alaska Coal (1)
(Million MTCE)

	1990 (2)	2000	2010	2020	2030	2040	Reserve Commitment in 2040 (3) (Billion MTCE)
Australia	53	85	93	112	113	120	6.5
Canada	10	43	55	55	60	60	3.5
Colorado			19	56	66	66	2.7
Wyoming			68	120	174	233	11.3
Subtotal:							24.0
China (5)		23	43	60	74	90	
TOTAL	63	151	278	403	487	569	

(1) Dames & Moore estimates based on composited coal supply curve. See Table 3-14 and Appendix D (supply curves).
(2) Actual 1990 supply will probably not resemble this mix because it reflects: 1) longer terms supply economics and 2) eliminates minor suppliers (i.e., U.S.S.R.).
(3) Calculated by arithmetic average of each ten year interval of exports plus production from 2040 to 2060.
(4) Includes domestic production in New South Wales and Queensland, Australia.
(5) Chinese exports estimated at 15 percent of total imports., except 1990.

Coal could be shipped via Portland, Oregon; as mentioned earlier this would incur a higher ocean freight cost of $7.45 per MTCE (in 1985 dollars) (or $9.46 in 2030 and $9.96 in 2040 with escalation) due to the draft limitation in the Willamette River. Realistically there is probably a limit on how much coal could move through Portland. There is a major highway bridge that must be lifted each time a large ship moves up to the present terminal sites.

Wyoming coal could be exported via a new port in an isolated location. This would necessitate expensive upgrading of rail lines and probably extensive breakwater construction since few sheltered sites are available. Alternatively, more costly coal from Australia could fill the gap.

The least costly of these alternatives is the $10 per MTCE (1985 dollars in 2030) additional ocean freight. In 2030 a supply mix including even 75 million MTCE of Wyoming coal would require an additional 6 billion MTCE of reserve commitments of Australian coal, raising the price from $109 per MTCE to over $119 per MTCE as shown in Table 3-13.[24]

Therefore it is mostly likely that the supply cost of Wyoming coal will be about $10 per MTCE above the price indicated by the "unconstrained" solution curve.

This constraint on Wyoming coal exports also confirms the rail rate discussion in Section 3.3.2.5, since the railroads will in effect, be facing a totally inelastic demand for Wyoming coal, which will encourage them to raise the rates as indicated.

Exports of Alaska coal and their effect on market prices are discussed in the next section.

---

24. Total reserve commitment of 13.5 billion MTCE. The supply mix (expressed in terms of reserve commitments) summarized in Table 3-14 shows 11.0 billion MTCE of non-Wyoming supply and 7.1 billion MTCE from Wyoming. The total amount of supply of non-Wyoming coal included in the supply curve for 2030 (Figure 3-11) is only 13.5 billion MTCE.

3.5.3 Market Penetration of Alaska Coal

Alaska coal can be produced at a cost that is very competitive with the prices projected in Table 3-13, which does not reflect exports from Alaska. To determine just how economically competitive exports for Alaska might be, the Pacific market price netted back to a mine in Alaska must be compared with production costs in Alaska. In Section 2.3 the projected production costs of coal from the Beluga coalfield were discussed. They are shown on the last line of Table 3-16.

The transportation costs from the mine to Japan include trucking costs to a port on Cook Inlet, costs for port ownership, and operation and ocean freight costs from Alaska to Japan. These costs are shown on the second and third lines of Table 3-16. A detailed discussion of the derivation of the port and inland transportation costs is presented in Appendix E. The port and inland transportation costs rise over time due to the increase in diesel fuel costs for truck hauling from the mine to the port. As discussed earlier, ocean freight costs also rise (at 0.7 percent per year) due to increasing fuel costs. In 2000 the ocean freight plus inland transportation and port costs are $23 per MTCE (1985 $); they rise to $30 per MTCE in 2040.

The price of coal from competing sources delivered to Japan less the transportation costs from the mine in Alaska to Japan equal the maximum price at which the Alaska coal producer is competitive. This price is shown on the line in Table 3-16 labeled, "FOB Mine." The term netback is used to expess the idea that this is the net price for the producer, worked backwards from the delivered market price. The netback price in 2000 is $53 per MTCE, or $1.78 per million Btu.

In order to make a fair comparison between this netback price and the production cost of Alaska coal, it is necessary to account for the difference in quality between Alaska coal and the coal from the competing producers. Coals from Australia, Canada, and Colorado are of considerably higher calorific value than Alaska coal. To compensate for this and other quality differences (see Appendix A for a complete discussion) we deduct 5 percent from the apparent calorific value of Beluga coal. The represen-

TABLE 3-16

Pacific Rim Market Prices
Alaska Net Back Prices and
Alaska Production Costs
(1985 $)

	2000	2010	2020	2030	2040
Pacific Delivered Price ($/MTCE) (1)	76	93	103	119	125
Ocean Freight Alaska-Japan ($/MTCE) (2)	13	14	15	16	17
Port & Inland Transport in Alaska ($/MTCE) (3)	10	11	12	12	13
Net FOB Mine ($/MTCE)	53	68	76	91	95
Net FOB Mine ($/ton) (4)	29	37	41	49	51
Net Adjusted for Quality ($/MMBtu) (5)	1.78	2.30	2.57	3.08	3.22
Production Cost Beluga Field ($/MMBtu) (6)	1.58	1.81	2.11	2.43	2.82

(1) Table 3-13
(2) Table 3-11
(3) Appendix E
(4) Net FOB price per short ton for 7,500 Btu/lb Beluga coal
(5) Net FOB mine price/MTCE divided by 27.8 million Btu/MTCE times 0.95; discounting for moisture.
(6) See Section 2.3

tative Btu content of coal from the Beluga field used in this study is 7,500 Btu per pound. This must be reduced to 7,125 Btu per pound to adjust for the quality disadvantage of Beluga coal compared to competing suppliers. In addition to this 5 percent "discount" a further reduction in the FOB mine price of $.43 per tonne must be made to further account for the quality differential (see Appendix A). Therefore the value to the consumer of Alaska coal, and hence the netback price, must be reduced by 5 percent and $.74 per MTCE ($.032 per million Btu).

The netback price adjusted for quality differences and expressed in dollars per million Btu is shown on the next line of Table 3-16. This netback price begins at $1.78 per million Btu in 2000 and rises to $3.22 per million Btu in 2040. Finally, the netback price can be compared with the production cost of Alaska coal, shown on the last line of the table. In 2000 the netback price is $1.78 per million Btu, compared to the production cost of $1.58 per million Btu. This indicates that, at least as early as 2000 that Alaska coal will be competitive in the market. By 2010 the cost advantage of Alaska coal increases significantly. The netback price in 2010 is $2.30 per million Btu, versus the production cost of $1.81 per million Btu.

Having established that Alaska coal will be very cost-competitive in the Pacific market, we can now estimate the probable exports of Alaska coal and re-estimate the market price, taking account of the reduction in needs for coal from competing sources.

Because the Beluga coal is much lower in quality then coal from the principal competing supplies (until 2030, when Wyoming coal begins to move into the market), boilers and other plant equipment must be specially adapted to burn this coal. Shifting between Alaska coal and coal from other sources will be difficult for the user. Therefore only the large coal fired boilers used in the electric power sector are a good market for Alaska coal. We therefore believe that the market penetration of Beluga coal will be confined to the electric power sector. Consumers also seek to maintain a diversity of coal sources, both to preserve security of supply and to maximize bargaining leverage.

Based on an examination of other cases of constrained (e.g., by security or quality considerations) market penetration, such as that of South Africa into the European steam coal market and Australian into the Pacific metallurgical coal market, we estimate that Alaska coal producers can capture no more than 25 percent of the Pacific electric power coal import market. This market penetration estimate, combined with our assurance of the low production cost of Alaska producers, is the basis for the projected Alaska coal exports shown in Table 3-17.

The exports for Alaska in 2000 are 16 million MTCE (30 million tons) rising to 40 million MTCE in 2010, 67 million MTCE (131 million tons) in 2020, and 116 million MTCE (211 million tons) in 2040. The market share of Alaska producers in relationship to the total imports from all sources is 10 percent in 2000, rises to 17 percent in 2020, and reaches 20 percent in 2040. Considering the cost advantage of Alaska coal producers this market penetration is modest. It is sufficient, however, to affect the market price of coal in the Pacific.

Table 3-18 shows the downward revision of reserve commitments, compared to those in Table 3-12 to account for the exports of Alaska coal. These revised reserve commitment figures are then used, by comparison with the supply curves as before, to determine a new set of Pacific market prices and Alaska netback prices. The revised reserve commitment estimates are calculated simply by multiplying the original reserve commitment figure by one minus the Alaska share of the total market. Therefore, they are from 10 to 18 percent lower than the original reserve commitment figures.

The revised reserve commitment figures are shown in Figures 3-13 through 3-17 as dotted lines. They are, of course, lower and result in slightly lower prices than the demand excluding Alaska coal. Since the solution curve is fairly flat, this reduction in demand does not result in a significant change in the prices. The revised netback prices are identical except for 2010, when the demand falls on a rising section of the solution curve. In that year the revised netback price is $2.19 for MMBTU compared with the $2.30 computed without consideration of Alaska supply impact on Pacific Rim Price.

TABLE 3-17

Projected Exports of Major Pacific Rim Steam Coal Exporters 2000-2040 (1)
(million MTCE)

	2000	2010	2020	2030	2040
AUSTRALIA	80	88	100	100	85
CANADA	32	97	120	40	10
COLORADO	-	10	56	66	48
WYOMING			0	115	253
ALASKA (2)	16	40	67	92	114
CHINA (3)	23	43	60	74	90
TOTAL	151	278	403	487	569
IMPORTS FOR ELECTRIC POWER (4)	117	202	257	346	418
ALASKA SHARE OF TOTAL EXPORTS (%) (5)	11	14	17	19	20
ALASKA EXPORTS (million tons) (6)	31	78	131	179	222

(1) Dames & Moore estimates based on composited coal solution curve. See Table 3-14 and Appendix D (solution curves).
(2) Alaska exports estimated at 15 to 25 percent of electric power market imports.
(3) Chinese exports estimated at 15 percent of total imports.
(4) See Table 3-2.
(5) Alaska exports divided by total imports.
(6) Converted from MTCE based on 7,500 Btu/lb for Beluga coal less 5 percent of Btu content to account for the higher moisture content of competing coals.

TABLE 3-18

Revised Reserve Commitments
of Competing Suppliers
Accounting for Alaska Coal Exports

	2000	2010	2020	2030	2040
Original Reserve Commitment (billion MTCE) (1)	3.9	7.9	12.9	18.1	24.0
Revised Reserve Commitments (2)	3.4	6.8	11.8	14.5	18.8
Revised Pacific Market Price ($/MTCE) (3)	76	90	103	119	125
Revised Alaska Netback Price ($/MMBtu quality adjusted) (4)	1.78	2.19	2.57	3.08	3.22

(1) Table 3-12
(2) Reduced by reserve commitment of Alaska coal, calculated from Alaska exports in Table 3-17.
(3) Derived from supply/demand analysis, see Figure 3-12 to 3-17.
(4) Derived as shown in Table 3-16. (NOTE: ROUNDED TO THE NEAREST 5¢.)

As was done for the market balance without Alaska exports, the composition of the solution curve can also be used to derive an overall supply/demand balance for the Pacific market, in which Alaska coal exports may be seen in perspective. As shown in Table 3-17, the Chinese share is 15 percent. The Alaska share (based on 35 percent of imports for electric power generation) increases from 11 percent to 19 percent from 2000 to 2030. Exports of the other supplier, based on the proportion of reserves they contribute to the overall solution curve, are led by Australia with 48 percent in 2000, dropping to 13 percent of the market in 2040. Wyoming coal enters the market in 2030. Canadian producers reach maximum capacity in 2020, and Colorado producers reach maximum output in 2030.

Overall, this supply-demand analysis shows that there is plenty of "room" in the market for Alaska coal. It also shows that, due to the overlap of supply costs of various producers, the conclusion as to prices are likely to be insensitive to any small errors in the supply cost of any source. One might ask whether the large levels of exports projected for Alaska coal could be attained. The known resources in the Beluga field are large even in relationship to these export levels. The reserve commitment of Alaska coal to sustain the projected export levels are summarized in Table 3-19. The calculation of reserve commitments of Alaska coal is similar to that described earlier, that is, the sum of depletion (past production) plus 20 times the export level in each year. The reserve commitments rise from 0.75 billion tons (converted from MTCE, using the ratio of calorific values) to 10 billion tons in 2040. Estimated reserves under lease in the Beluga field are 2,930 million tons (D&M estimate based on sources listed in Appendix H and contact with leaseholders), but resources are in excess of 10 billion tons (Barnes, 1966).

TABLE 3-19

Exports (1) And Reserve Commitments (2) of
Alaska Coal
2000-2040

	2000	2010	2020	2030	2040
Alaska Exports Million MTCE	16	40	67	92	114
Alaska Exports Million Tons (3)	31	78	131	179	222
Cumulative Exports Million MTCE	64	344	879	1674	2704
Reserve Commitments Billion MTCE	0.4	1.1	2.1	3.6	5.2
Reserve Commitments Billion Tons	0.75	2.2	4.3	7.2	10.0

(1) See Table 3-17
(2) Reserve commitments are the sum of cumulative production plus 20 times the production in that year.
(3) Converted from MTCE based on 7,500 Btu/lb for Beluga coal, less 5 percent of Btu content to account for the higher moisture compared to competing coals.

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